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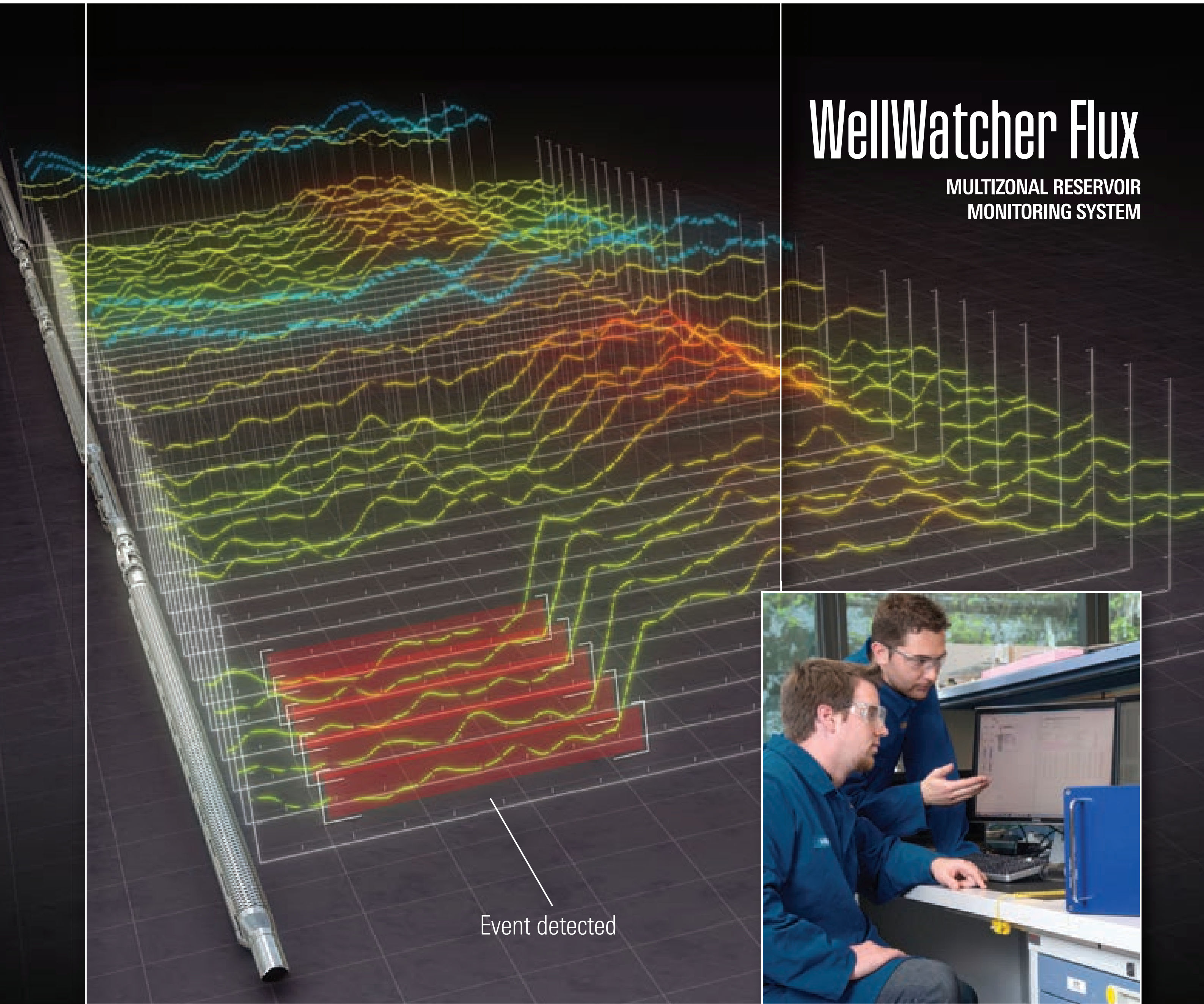
JPT
<Oilfield Analytics Arrive/>
FIELD DEVELOPMENT PROJECTS
NEW-FRONTIER RESERVOIRS II
PETROLEUM DATA ANALYTICS
SAND MANAGEMENT AND SAND CONTROL
FEATURES
Permian Basin Attracts Drillers
NASA and the Oil Industry
Oil Prices Stuck in a Rut



A single wellhead penetration along with inductive couplers enable multidropping of PT gauges into the lower completion, and arrays of digital temperature sensors provide the highest-resolution measurements in the industry.

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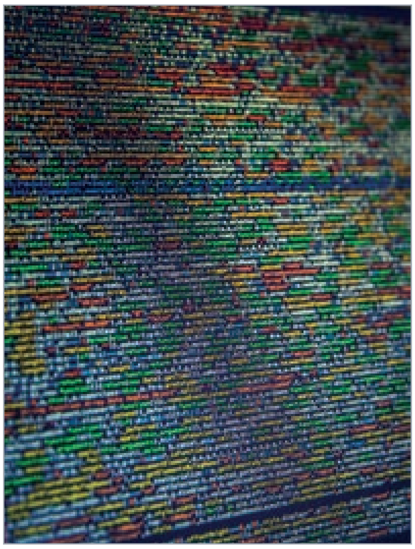

The source code of a software application displayed on a monitor. Such intricate coding work is delivering a new breed of advanced algorithms that oil and gas companies are using to predict the future and analyze the past. *Source: Getty Images.*

DEPARTMENTS

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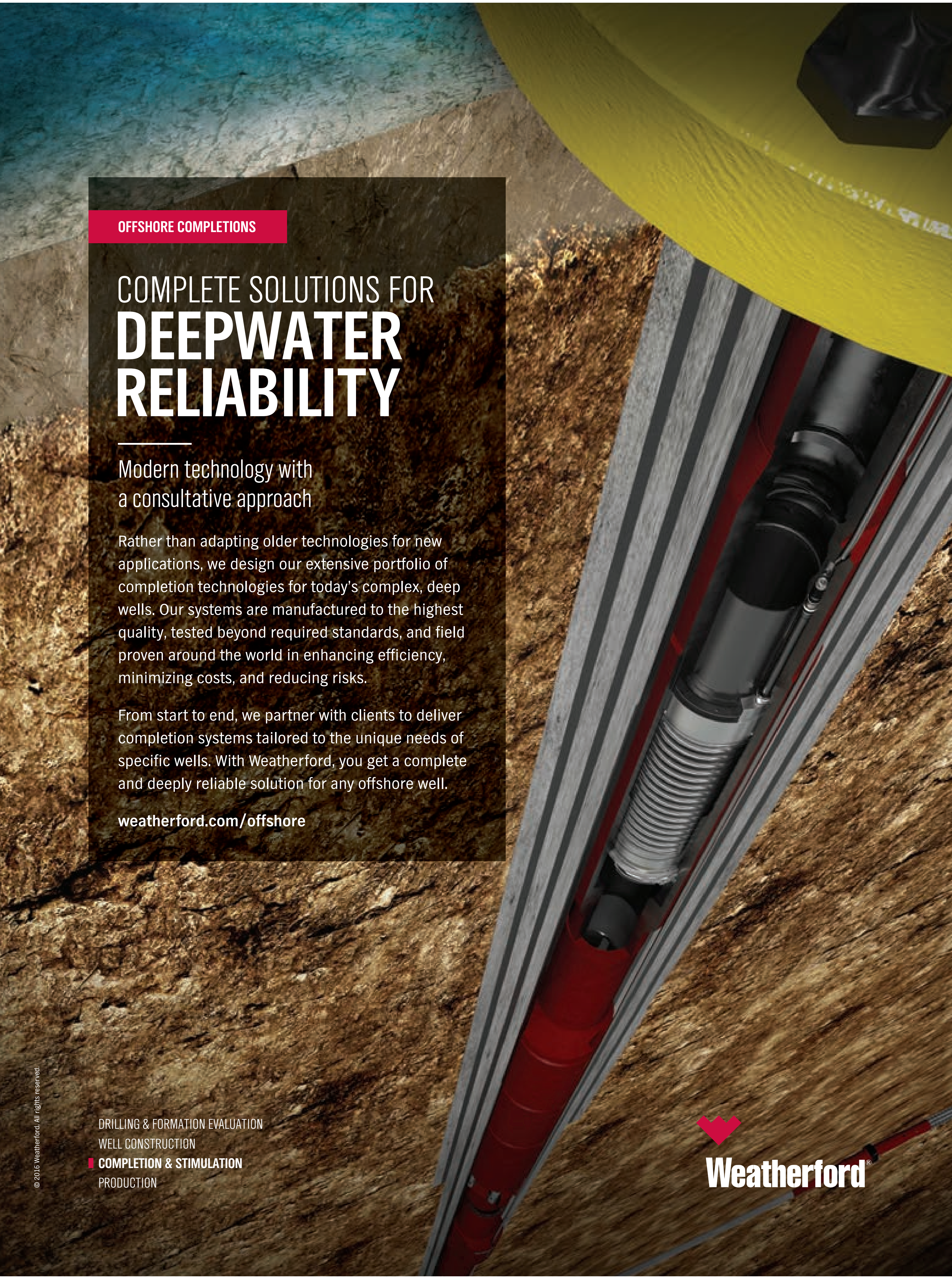
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PERFORMANCE INDICES

WORLD CRUDE OIL PRODUCTION+‡

THOUSAND BOPD

OPEC	FEB	MAR	APR	MAY
Algeria	1320	1320	1320	1320
Angola	1840	1845	1840	1865
Ecuador	540	552	555	556
Indonesia	837	847	844	841
Iran	3550	3700	4000	4100
Iraq	4225	4225	4475	4325
Kuwait[1]	2550	2550	2320	2550
Libya	360	320	330	285
Nigeria	2200	2120	2100	1850
Qatar	1517	1537	1537	1537
Saudi Arabia[1]	9990	10040	10240	10340
UAE	2745	2595	2595	2670
Venezuela	2400	2400	2400	2300
TOTAL	**34074**	**34051**	**34556**	**34539**

THOUSAND BOPD

NON-OPEC	FEB	MAR	APR	MAY
Canada	3797	3767	3429	2811
China	4133	4091	4036	3973
Egypt	*491*	491	494	493
Mexico	2247	2249	2210	2180
Norway	1675	1632	1666	1607
Russia	10485	10522	10450	10440
UK	1014	986	985	979
USA	*9157*	9168	8947	8894
Other[2]	12803	12640	12453	12751
TOTAL	***45802***	**45546**	**44670**	**44128**
Total World	***79876***	**79597**	**79226**	**78667**

INDICES KEY

+ Figures do not include natural gas plant liquids.

[1] Includes approximately one-half of Neutral Zone production.

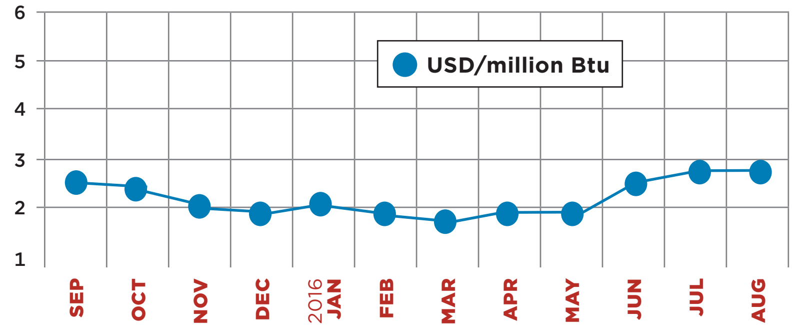
[2] From this issue of *JPT*, the "Other" line item also includes Argentina, Australia, Azerbaijan, Brazil, Colombia, Denmark, Equatorial Guinea, Gabon, India, Kazakhstan, Malaysia, Oman, Sudan, Syria, Vietnam, and Yemen. Monthly production from these countries was listed individually in previous *JPT* issues. Ongoing work on the US Energy Information Administration (EIA) website is disrupting the regular updating of these countries' production numbers. Additional annual and monthly international crude oil production statistics are available at: http://www.eia.gov/beta/international/.

[3] Supply includes crude oil, lease condensates, natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

† *Source:* Baker Hughes.

‡ *Source:* EIA's *Monthly Energy Review.* Numbers revised by EIA are given in italics.

HENRY HUB GULF COAST NATURAL GAS SPOT PRICE‡



WORLD CRUDE OIL PRICES (USD/bbl)‡

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG
Brent	30.70	32.18	38.21	41.58	46.74	48.25	44.95	45.84
WTI	31.68	30.32	37.55	40.75	46.71	48.76	44.65	44.72

WORLD ROTARY RIG COUNT†

REGION	FEB	MAR	APR	MAY	JUN	JUL	AUG
US	532	478	437	408	417	449	481
Canada	211	88	41	42	63	94	129
Latin America	237	218	203	188	178	186	187
Europe	107	96	90	95	91	94	96
Middle East	404	397	384	391	389	390	379
Africa	88	91	90	91	87	82	81
Asia Pacific	182	183	179	190	182	186	194
TOTAL	**1761**	**1551**	**1424**	**1405**	**1407**	**1481**	**1547**

WORLD OIL SUPPLY AND DEMAND[3]‡

MILLION BOPD			2016	
Quarter	3rd	4th	1st	2nd
SUPPLY	96.38	96.47	95.59	95.79
DEMAND	95.06	94.15	94.14	95.04

Monoline flanged-connection fracturing fluid delivery technology reduces installation time by more than 60%, Eagle Ford Shale.*

AFRICA

Tullow Oil announced in mid-August that first oil has flowed from the Tweneboa, Enyenra, and Ntomme (TEN) fields offshore Ghana, which was on time and on budget for the project's development plan approved by the government in May 2013. The company expects oil output to ramp up gradually through the rest of the year toward a production facility capacity of 80,000 B/D. Tullow is the operator of the TEN fields with a 47.18% stake. Its joint-venture partners are **Anadarko** (17%), **Kosmos Energy** (17%), **Ghana National Petroleum Corporation** (15%), and **PetroSA** (3.82%).

ASIA

Rosneft has made a discovery at the PLDD well in the Wild Orchid gas condensate field in Block 06.1 of the Nam Con Son Basin offshore Vietnam. The discovery is being evaluated for the volume of reserves and commercial attractiveness, and there is a potential synergy with the nearby Rosneft-operated Lan Tay production platform, the company said. Rosneft is the operator and holds a 35% interest in Block 06.1, with the remaining interests held by **Petrovietnam** (20%) and **ONGC** (45%).

Oil & Gas Development Company (OGDC) has successfully tested and completed the X-6 and X-7 development wells in the Nashpa field in the Karak and Kohat district of Pakistan's KPK Province. The Nashpa X-7 well, drilled to a 15,079-ft depth, produced 2,700 B/D of oil and 7.4 MMscf/D of gas through a 36/64-in. choke at wellhead flowing pressure of 1,886 psig. The Nashpa X-6 well, drilled to a 16,486-ft depth, produced 2,550 B/D of oil and 16.3 MMscf/D of gas through a 36/64-in. choke at wellhead flowing pressure of 2,667 psig. OGDC is the operator with a 56.45% interest in the field. **Pakistan Petroleum** (28.55%) and **Government Holdings** (15%) have the remaining interests.

Jura Energy reported a gas discovery at the Khamiso-1 exploration well in Pakistan's Guddu Block. The well was drilled to a total depth of 2,470 ft in an Eocene limestone of the Pirkoh formation. During a short-duration prestimulation test conducted on a 32/64-in. choke, the well encountered an average gas flow of 2.95 MMcf/D. Jura holds a 13.5% interest in the block, which is operated by **OGDC.**

AUSTRALIA/OCEANIA

Beach Energy completed logging at the Callawonga-12 oil development well in Petroleum Production License 220 on the western flank of South Australia's Cooper Basin. The well was being cased and suspended after reaching a total depth of 4,754 ft in the Westbourne formation. The presence of a gross oil column of 13 ft, or a net column of 6.6 ft, was interpreted in the primary target, the McKinlay member and the Namur sandstone. The company operates and holds a 75% interest in the license, with the remaining stake held by **Cooper Energy.**

EUROPE

Premier Oil has discovered oil at the Bagpuss 13/25-1 well on the Halibut Horst in the Outer Moray Firth of the United Kingdom North Sea. The well encountered 41 ft of hydrocarbon-bearing sands within a 68-ft hydrocarbon column, which was in line with predrill estimates, and reached a total depth of 1,532 ft. Hydrocarbon and reservoir analysis are under way to determine whether the discovery is commercial. The joint-venture partners in the Bagpuss prospect are operator Premier, with a 37.5% interest, **Maersk** (25%), **EnCounter Oil** (15%), **North Sea Energy** (15%), and **Groliffe** (7.5%).

Statoil has started oil and gas production from the Fram C East well offshore Norway. The well was drilled from the Fram subsea template, and production is being tied back to the Troll C hub in the North Sea. The company said that project capital cost had been reduced to USD 73 million from an originally estimated USD 97 million as a result of "a simple, smart well concept and significantly increased drilling efficiency." Statoil, the operator, holds a 45% interest in the well, with **ExxonMobil** (25%), **Engie** (15%), and **Idemitsu** (15%) holding the remaining interests.

MIDDLE EAST

Tethys Oil is maintaining its increased level of oil production in Oman, where it produces from onshore blocks 3 and 4. A second-quarter net output of 1.096 million bbl followed a nearly identical net total of 1.101 million bbl produced during the first quarter. Production in both periods exceeded a net output of 997,904 bbl during the fourth quarter of last year. Tethys is one of the largest onshore oil concession holders in the Sultanate of Oman with a current net production of about 12,000 B/D.

Gas Plus Khalakan (GPK) reported that the No. 1 sidetrack well in the Shewashan field of the Kurdistan Region of Iraq was successfully drilled and recompleted recently as a horizontal producer in the Qamchuga formation. The well is producing from 500 B/D to 700 B/D of oil, although it may require further stimulation to meet predrill production estimates that were based upon the original Shewashan-1 vertical well. The company expects total production at the Shewashan development to hit 10,000 B/D early next year. GPK is the operator with an 80% interest in the development.

NORTH AMERICA

Anadarko has drilled a successful appraisal well at the Shenandoah field in Walker Ridge Block 51 of the US Gulf of Mexico. Drilled in 5,900 ft of water to a total depth of 31,100 ft, the Shenandoah No. 5 well encountered more than 1,000 net ft of high-quality oil pay in the Lower Tertiary Wilcox sands. The well's results indicate an extension of the field reservoir boundaries to the east. Anadarko, the operator, holds a 33% interest in the field, with other interests held by **ConocoPhillips** (30%), **Cobalt International Energy** (20%), and **Venari Resources** (17%).

SOUTH AMERICA

Andes Energia announced discoveries in the Chachahuen Block in Mendoza Province, Argentina. About 20 ft of net oil pay was discovered by exploration well Cerro Redondo x-1 in the Rayoso formation sandstone, and gas was found by exploration well La Orilla x-1 in the deeper horizon of the Lotena formation. Gas was also found by exploration well Remanso del Colorado x-1 in the deeper horizon of the Cuyo Group. The discoveries reaffirm "the large-scale potential of Chachahuen," said company Chairman Nicolas Mallo Huergo. Andes Energia is developing the block in a joint venture with **YPF** and **Energia Mendocina. JPT**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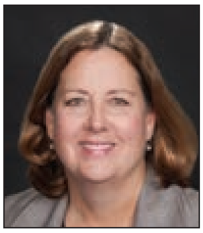
Mitigating Risks To Improve Project Results

Janeen Judah, 2016 SPE President



I am honored to serve the Society of Petroleum Engineers as president this year. Each president chooses a theme, and for me, my theme was obvious: risk and reward.

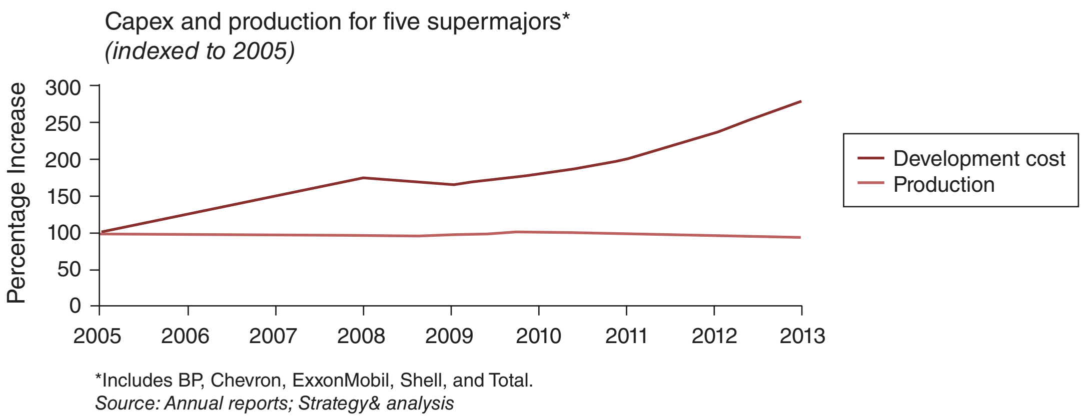
Ours is a risky business, and that is what makes it fun and challenging. Risk also drives the big rewards when what we do pays off. Mitigating risk is the very core of what we do on a daily basis: drilling risk, subsurface risk, cost/schedule risk, performance risk, safety risk, geopolitical risk, and price risk. Projects are a constant juggle to find the sweet spot where we produce oil and gas safely, responsibly, and profitably. But as an industry, we make decisions to eliminate risk through analysis rather than manage the risk that will always be there. The petroleum industry is fundamentally a commodity business. Commodity prices change, but combine that with a capital-intensive business with big upfront investments and long payouts, and commodity price swings hit us hard.

Engineers are paid to predict the future, especially production, reserves, cost, and schedule. We cannot control price risk, but we can improve performance. I have always been interested in the intersection of engineering and risk evaluation with oil and gas economics. I wrote my master's thesis on what we would now call "decision analysis." I was intrigued by deterministic project and economic evaluation and how data are interpreted within the bands of possibility to get a project over economic hurdles. Even with today's sophisticated probabilistic economic analysis, results still fall short of expectations and promises to stakeholders.

Too Many Projects Fail

The stakes are incredibly high. Independent analysis of large capital projects has shown that as an industry, we are not very good at delivering on our promises. In its spotlight article on oil and gas megaprojects, Ernst & Young estimates that 64% of major capital projects overrun on cost, and 74% face schedule delays. Cost and schedules are overrun in every region of the world. Independent Project Analysis (IPA) comes to very similar conclusions in its subscription benchmarking service, estimating that 60% of projects overrun costs by more than 20% while only 18% of projects meet both cost and schedule targets. IPA also estimates that projects deliver 35% less of their planned overall net present value from financial investment decision to lookback. Some estimate that more than 75% of projects deliver more than 25% less value than promised.

On the production and reserves side, the story is not any better. Ernst & Young's 2015 US Oil and Gas Reserves study shows that integrated companies failed to replace US production for 2010–2014, despite more than USD 2 billion in capital investment. Independents fared much better at production and reserve replacement during this time period due to high activity in the US shale plays, but shale production will decline rapidly with diminished development programs.



Oil and gas production has not kept up with development costs. *Source: PricewaterhouseCoopers*

To contact the SPE President, email president@spe.org.

Those new barrels came dearly. During the period 2005–2013, PricewaterhouseCoopers' (PwC) analysis showed that global production for the five super majors (BP, Chevron, ExxonMobil, Shell, and Total) has remained flat, while development cost almost tripled (Tideman et al. 2014).

We Overestimate and Under-Deliver

All published studies agree that, as an industry, we consistently overestimate production attainment and underestimate cost and schedule. IPA's analysis of production attainment shows the too-narrow range of expectations and failure of the results to fall within the P10/P90 range. The average production attainment is only 78%, so production facilities are also oversized. How could we be so wrong?

Fundamentally, our industry usually manages the business to short-term metrics. For publicly held companies, that usually means analysts' and shareholders' expectations, annual performance promises, and executive performance goals. For national companies, the stakeholders are different, but the pressure to meet annual metrics, such as cash delivered to the finance ministry, are very similar.

The oil business is a long-term game. We invest billions in projects destined to produce for 30 years or more. Future undiscovered technology advancements will produce marginal barrels over those 30+ years, but we do not know the final estimated ultimate recovery until the last barrel is produced. Short-term metrics in a long-term business is not a formula for sustainable success.

So, What Can We Do Differently?

Ours is a risky business and not for the fainthearted. But we can mitigate some of the unnecessary risks. Many of our gaps are in:

1. **Engineering oversight.** Most people would agree that engineering oversight has declined in the last 20 years as operators have outsourced almost all design to service and engineering, procurement, and construction contractors. In the last 10 years or so, these contractors have been stretched thin to meet the very high demand for their services. Operators were also people-constrained as their activities ramped up, along with the first wave of retirements from the big crew change. Many misses on cost and schedule have been due to poor interpretation and design mistakes that could have been avoided with more technical review.
2. **Executive overconfidence.** The PwC article summarized the problem very well: Management sets optimistic goals for a first oil date, and then creates a very tight project to meet that deadline. Once projects are underway, it becomes apparent that the deadline cannot be met within the given budget. Project teams try to speed the schedule by adding resources, and then often blow both cost and schedule.

The real question is: Would we make the same investments if we were honest with ourselves around investment metrics, especially cost and schedule? Analysis of project results consistently reveals the same issues across all projects: outcome ranges that are too narrow, confirmation bias, anchoring, and general overconfidence. With all those negative results, can engineers challenge ourselves to reduce risk and improve reward? Possible solutions include:

1. **Technology.** Our past performance has shown that advances in technology can help reduce risk. We can increase the predictability of outcomes through better analysis. We can reduce failures and increase safety and operational performance by better monitoring of our operations. And we can create new technologies to increase our opportunities. History has shown that our industry tends to make technology leaps in hard times because we are forced by economics to innovate. I will discuss this issue more in future columns.
2. **Better engineering.** We need a rebirth of technical oversight for our initial project designs. I believe that at least part of this will come through better institutional memory contained in design systems. We also need to reduce complexity and standardize more designs. Too many projects are completely custom-designed, creating openings for design errors and reducing opportunities for cost savings through standardization.
3. **Better business analysis.** Are we doing the right development, in the right place, at the right time? Large capital projects have skewed project risks, not normal distributions, with a lot of 'tail risk' (low probability but often high consequence). Do we assess those risks well? Do we include learnings from prior projects to improve our economic analysis? Do we monitor changes in risk profiles as projects move forward and act on those changes?
4. **Make tough decisions.** Finally, management should "just say no" to some projects. Reward systems should reinforce right decisions, not encourage making promises that we cannot keep. We need to find new ways to monitor and reward long-term actual results of projects, not short-term metrics such as final investment decision and first oil promises.

Finally, I think we need a new level of cooperation between operators and the service sector. Service companies are essential to implement projects, yet when times get tough, operators stop the music too quickly. In addition, innovations will be more of a cooperative venture between the asset owner and the service sector. We need a healthy service sector to effectively develop projects, and we need to find a better way to work together.

Risk and reward drive all of our decisions. We balance many, often unmeasurable, risks to develop resources to provide energy for the world. We can do a better job for ourselves, our companies and our stakeholders. **JPT**

For Further Reading

Tideman, D., Tuinstra, H.T., and Campbell, B.J. 2014. Large Capital Projects in the Oil and Gas Sector: Keys to Successful Project Delivery, http://www.strategyand.pwc.com/media/file/Large-capital-projects-in-the-oil-and-gas-sector.pdf (accessed 7 September 2016).

Resilient Production

John Donnelly, *JPT* Editor

This issue of *JPT* offers two suggestions as to why crude oil prices may not rise significantly in the near future. The role of unconventional production becoming the industry's "swing producer" in reaction to oil prices is laid out in the Management column beginning on page 42 (see also Comments, March 2015 *JPT*). And the continued strength of Permian Basin output is described in an article beginning on page 24.

Although global crude oil production has declined in some regions since the collapse in oil prices began, and there have been massive cuts in company spending, world output has remained stubbornly resilient. Global petroleum production rose in 2015 and 2016, and is projected to rise slightly in 2017, according to the US Department of Energy's Energy Information Administration (EIA) *Short-Term Energy Outlook,* published in September.

US crude oil production averaged 9.4 million BOPD in 2015 and is forecast to average 8.8 million BOPD this year and 8.5 million BOPD in 2017. The US production forecast is 0.2 million BOPD higher than one the EIA made in August as it cited an uptick in drilling activity, rig efficiency, and well productivity.

The steep decline in North American rig activity over the past year came primarily from the onshore light tight oil sector, which has short development cycles that allow producers to react quickly to price signals. Production from the US Gulf of Mexico is expected to reach record highs next year due to previous big deepwater discoveries.

Changes to Performance Indices Page

Beginning with this issue, the World Crude Oil Production table in the Performance Indices page will include fewer countries. The table lists the monthly crude oil production numbers from the EIA. Ongoing work on the EIA's website is disrupting the regular updating of some countries' production numbers. This has been going on for several months, which is causing considerable delays in our reporting of this information. EIA recently launched the redesign of its International Energy Portal at http://www.eia.gov/beta/international and is currently beta testing it.

Over the years, our readers have indicated that they use the Performance Indices to gather data for their research and analyses. Therefore, we decided not to source production data from another provider in order to preserve the continuity of data for our readers. Other reporting services use different methodologies to collect production information.

In this issue of *JPT* and going forward, crude oil production data (crude oil including lease condensate) will be sourced from the EIA's *Monthly Energy Review*. The Review includes statistics on total energy production, consumption, and trade; energy prices; overviews of petroleum, natural gas, coal, electricity, nuclear energy, renewable energy, and international petroleum; carbon dioxide emissions; and data unit conversion values. It is available at http://www.eia.gov/totalenergy/data/monthly/, including historical data back to October 1974. **JPT**

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Risk Management at NASA and Its Applicability to the Oil and Gas Industry

David Kaplan, Safety and Mission Assurance, NASA Johnson Space Center

On initial consideration, one might reasonably ask: What can the National Aeronautics and Space Administration (NASA) contribute to the oil and gas industry?

About 3 years ago, a senior principal at Deloitte Advisory's Energy & Resources Operational Risk Group reached out to NASA to better understand the safety culture at NASA with the intent of understanding how that culture might translate to oil and gas operations. Very quickly, the conversation expanded to the realm of risk management.

Working with Deloitte, NASA came to appreciate the remarkable similarities between an offshore deepwater facility and the International Space Station. Both exist in extremely hostile environments. Both function in remote locations where movement of crew and supplies must be carefully choreographed. Both are extremely complex engineering structures where human reliability plays a critical role in mission success, and both have a deep commitment to personal and process safety.

It also should be noted that both have dedicated teams—the onboard crew and the onshore support experts—that live by the mentality that "failure is not an option" because of the consequences to life and the environment should a catastrophic mishap occur.

At NASA, we use qualitative techniques—such as fault trees, failure modes and effects analyses, hazard assessments, etc.—to understand risk based on statistics, experience, or possibilities that our engineers can anticipate. Similarly, upstream oil and gas exploration and production uses qualitative techniques—such as process safety methods, barrier analyses, bowtie charts, hazard identification, hazard and operability studies, etc.—to assess risk. At NASA, these qualitative approaches are augmented by a quantitative risk-assessment technique called probabilistic risk assessment (PRA) to uncover and mitigate low-probability sequences of events that can lead to high-consequence outcomes.

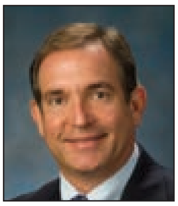
Why PRA?

The technique of PRA was developed by the nuclear power industry and initially published in mid-1975, though not widely publicized. However, the investigation of the Three Mile Island incident in 1979 revealed that the PRA had documented the sequence of low-probability events (both of hardware failures and human errors) that led to the high-consequence near-meltdown of the nuclear core. As a result, the US Nuclear Regulatory Commission has required a facility-specific PRA for every nuclear power plant in the United States.

In February 2003, Space Shuttle *Columbia* was lost on re-entry when a piece of insulation foam broke off from the external tank and struck the wing leading edge of the space shuttle. Recognizing that the cause of this accident was a low-probability, high-consequence event, NASA committed to strengthen its safety and mission assurance capabilities. PRA was adopted and embraced by the Space Shuttle and International Space Station programs.

A PRA creates a rigorous logic flow for a complex system. Every safety-related hardware component is captured as a node and quantitative reliability performance numbers are assigned to each possible outcome. For example, a pump can function as commanded, remain off when commanded on, remain on when commanded off, or operate at only a partial level of capability. Human actions also are captured as logic nodes that can have quantitative reliability information assigned to them. For example, a person can push the correct button within the assigned timeframe, push the wrong button, push the correct button outside the assigned timeframe, or do nothing.

A rigorous PRA also can account for common cause failures in both hardware and software. For example, if a pump fails in one system, then all similar pumps from the same lot/vendor that may exist in entirely separate systems are now suspect.



David Kaplan is a leader at the National Aeronautics and Space Administration (NASA) Johnson Space Center with more than 30 years of experience in aerospace engineering and management. He has been a project manager for Mars hardware, a space shuttle flight controller, and managed the crew health-care equipment on the International Space Station. Most recently, Kaplan served as chief of the Quality Division at the space center. In that position, he managed the NASA Failure Analysis Laboratory, which is instrumental in detecting counterfeit parts and assisting projects to reduce their risks associated with fabrication and operations. Currently, he is involved in assessing the applicability of NASA's quantitative risk-management techniques to the oil and gas industry. He may be contacted at david.i.kaplan@nasa.gov.

Given a high-consequence undesirable event (such as loss of hydrocarbon containment), every single path through the logic model that could lead to that event can be assessed. Should a low-probability action occur (perhaps a highly trained individual is distracted and fails to observe a change in the mud flow rate in vs. the mud flow rate out), then every other subsequent low-probability action(s) can be identified to mitigate the undesirable event.

Why BSEE?

In April 2015, I attended a conference that explored crossover technologies that might have applications to the space and energy sectors. Brian Salerno, director of the Bureau of Safety and Environmental Enforcement (BSEE), gave a presentation that included an acknowledgement that BSEE would need better tools to assess risk as operators moved to deeper drilling; higher temperatures and pressures; less well understood environments; and introduced new, emerging technologies. He suggested the need for a quantitative approach to risk management.

The outcome of several meetings was a US Government Interagency Agreement between BSEE and NASA signed in January 2016, formalizing a partnership between the two organizations for 5 years. Under this agreement, NASA will work with BSEE to develop a process for preparing PRAs for offshore deepwater drilling and production operations. Together with the oil and gas industry, we will evaluate whether the additional insights of a PRA provide meaningful information for the operators and contractors as well as for the regulator, BSEE.

NASA has a document to guide in the preparation and execution of a PRA referred to as the "Probabilistic Risk Assessment Procedures Guide for NASA Managers and Practitioners" (NASA document number SP-2011-3421). The first task that BSEE has given NASA is to rewrite the PRA Guide to be relevant to the oil and gas industry. NASA is scheduled to deliver the initial version of the document to BSEE by the end of the 2016 calendar year.

Projects With Anadarko

In addition to working with other government agencies, NASA has a special mechanism for working with commercial organizations. In situations where NASA has unique facilities, technologies, techniques, or experiences, it may enter into a reimbursable agreement (referred to as a Space Act Agreement) to perform work for the mutual benefit of the Space Act partner and NASA.

Anadarko Petroleum is working with suppliers to develop various subsea equipment with working pressures of more than 15,000 psi for their Shenandoah field in the Gulf of Mexico. The director of Engineering and Technology Global for Anadarko, Jim Raney, wanted to have a set of eyes from outside the industry look over the approach to risk management being used by his team for this activity. Anadarko entered into a Space Act Agreement with NASA in November 2014, enabling NASA to engage and participate in the project.

Anadarko introduced NASA to the unique layout of bowtie charts (an integration of fault trees and event trees), to the barrier analysis approach, etc. Our eventual assessment back to Anadarko was that all their risk-management techniques were qualitative and, while excellently executed, might not capture low-probability, high-consequence events. NASA explained its use of quantitative PRA modeling to capture these types of events.

Anadarko was open-minded to the possibility that PRA might provide insights not otherwise available through their more traditional qualitative risk-management techniques. Since the project would require a blowout preventer (BOP) with a rated working pressure up to 20,000 psi, Anadarko asked NASA to prepare a PRA for a generic 20,000-psi BOP. The work began in October 2015.

The development of the BOP PRA was a true partnership; Anadarko provided world-class expertise on the design and operations of BOPs, and NASA provided world-class modelers and data analysts. The results of the BOP PRA model were presented to Anadarko management on 28 July 2016. A final report was delivered at the end of August.

While it is not my place to discuss any facet of the work that NASA did in partnership with Anadarko, I am able to state that Anadarko followed up the BOP work by asking NASA to perform a PRA of the dynamic positioning system being considered for the Shenandoah development. The PRA for that began in June and is ongoing.

NASA is just beginning to work with BSEE and the oil and gas industry. Our hope is that the benefits of a quantitative assessment of risk will both complement the industry's current approach to risk management as well as help with risk-informed decision making. It has worked for NASA in the exploration of space. Could it also work for offshore deepwater drilling and production operations? **JPT**

Chris Carpenter, *JPT* Technology Editor

Shear-History Simulator

The rheology of fracturing fluids used by the oil and gas industry is affected by a range of factors and conditions, and shear-history simulators have proven useful for determining how well these fluids perform in transporting proppants. The Chandler Engineering Model 5600-Auto shear-history simulator simplifies the process of preparing and loading water-based fracturing fluids into rotational viscometers (**Fig. 1**). The process begins with a gel-based fluid that is placed into a pressurized supply reservoir that delivers the fluid to an injection pump. The fluid is pumped through a combination of tubes at various rates and durations to simulate pumping conditions experienced during fracture treatments. Pressure is applied to the reservoir through an air regulator mounted onto the face panel. The gel pump is constructed of high-pressure, corrosion-resistant stainless steel and is driven by a servo motor that can deliver 0 to 140 mL/min. An additional stainless-steel pump is able to deliver 20 mL/min of crosslinker. The simulator features a maximum operating pressure of 2,000 psi at ambient temperatures; features also include multiple tubing configurations, four shear-history-tube assemblies, and a panel-mounted computer with touch-screen interface and automatic loop-flushing features.

▸ For additional information, visit www.chandlereng.com.

Fluids-Separation Technologies

High-quality oil and water separation is critical to the success of most upstream oil production facilities but often results in increased operational challenges and costs associated with the process. Baker Hughes' TRETOLITE SNAP fluids-separation technologies help operators overcome these challenges by achieving dry oil and clean water (**Fig. 2**). This generation of water clarifiers and demulsifiers exceeds current performance standards, including oil-in-water requirements and basic sediment and water key performance indicators, and enables a more-controlled water/oil interface. This allows steam-assisted-gravity-drainage operators to reduce equipment fouling and upsets as well as decrease slop oil generation and disposal, which results in less recycling and more production throughput. For conventional producers, the products can provide oil and water separation to meet water-discharge-regulation requirements.

▸ For additional information, visit www.bakerhughes.com/SNAP.

Hydraulic-Fracturing System

The ability to use multiple fuel types, including field gas, offers the potential for fracturing-cost-reduction. Evolution Well Services' hydraulic-fracturing system uses 100% electrically powered process equipment (**Fig. 3**). The electric power is generated by burning natural gas through a customized-for-purpose turbine system. For primary equipment,

Fig. 1—The Chandler Engineering Model 5600-Auto shear-history simulator.

Fig. 2—Baker Hughes' TRETOLITE SNAP fluids-separation technologies achieve dry oil and clean water.

the system uses a blender with ambidextrous suction/discharge capability with rate capacity of up to 240 bpm. The chemical additive system features low- and high-rate pumps and flowmeters. The fracturing pumps are mounted with dual pumps on each trailer. The data van is designed for safety, control, and comfort, using real-time data-acquisition software. Remote-control cameras monitor equipment and allow the removal of all personnel from high-pressure areas and exposure to chemical hazards and silica dust.

▸ For additional information, visit www.evolutionws.com.

Fig. 3—An Evolution Well Services hydraulic-fracturing facility, featuring electrically powered equipment.

Fig. 4—The Compact formation sampler from Weatherford provides efficient PVT sampling in diverse boreholes.

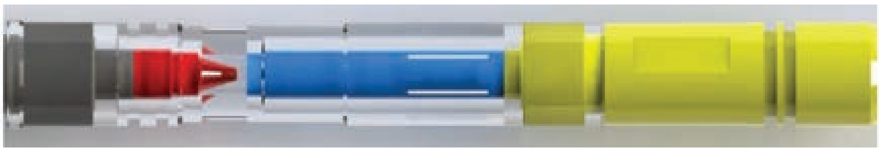


Fig. 5—Schematic of Tech-Flo's Surface Jet pressure-reducing system.

Slim-Profile Formation Sampler

The Compact formation sampler is a slim, lightweight tool that provides efficient pressure/volume/temperature (PVT) sampling in diverse boreholes (**Fig. 4**). The sampler can capture up to three true 700-cc PVT samples in a range of wellbore sizes from less than 3 in. to 14 in. The self-centering design reduces formation-sticking risks, enables a more-efficient and faster connection with the target zones, and makes it possible to deploy the tool on traditional wireline or through drillpipe. The sampler can be deployed on monocable or heptacable, which is particularly advantageous in offshore environments. Real-time and recorded pressure data acquired by the sampler can be used to calculate formation-pressure gradients, ascertain fluid-contact levels, determine fluid mobility, and define formation permeability. The combined capabilities of the sampler enable operators to obtain reliable, representative formation fluid samples by wireline, resulting in operations that are safer and simpler than those using traditional formation-testing tools.

▸ For additional information, visit www.weatherford.com.

Pressure-Reducing System

Tech-Flo's Surface Jet is a Venturi-based pressure-reducing system. This system operates by channeling a high-pressure source (high-pressure wells, high-pressure gas from a process system, or a high-pressure water or oil line) through the surface jet to create a pressure drop, allowing a lower-pressure system to enter the higher-pressure system (**Fig. 5**). Typical applications include reducing line-operating pressure, reducing vessel pressure, high-pressure well boosting of low-pressure wells, and artificial-lift support. The system functions by using the Venturi effect, a special case of Bernoulli's principle stating that as fluid flows through a pipe with a constriction in it (nozzle), the fluid must speed up in the restriction, reducing its pressure and producing a vacuum through the Bernoulli effect. This vacuum is what allows a low-pressure system to enter a higher-pressure system. **JPT**

▸ For additional information, visit www.tech-flo.net.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A Holistic Approach To Controlling Torsional Dynamics in the Drillstring

Liam Lines, SPE, Weatherford

Understanding drilling dynamics, the downhole shock and vibration that occur while drilling, is a crucial step to improving drilling efficiency and reducing nonproductive time (NPT).

Industry statistics suggest that 20% to 30% of all downhole failures are related to adverse drilling dynamics (SPE 127413 and SPE 98150), and that drilling tool providers spend roughly USD 750 million per year on repair and maintenance. This amount pales compared with the untold costs borne by exploration and production companies as the result of drilling and completion inefficiencies, NPT, and tools lost in the hole.

Preventing adverse dynamics requires a strong understanding of the fundamentals, particularly in addressing torsional dynamics: time-based variations in downhole rotational speed and torque.

A common misconception is that torsional dynamics is limited to stick/slip. However, stick/slip is only one of three distinct modes of torsional dynamics, each with its own unique indicators, potential for damage, effect on drilling efficiency and—importantly—most effective means of mitigation.

Differing Dynamics

In addition to full stick/slip (FSS), the modes include low-frequency torsional oscillation (LFTO) and high-frequency torsional oscillation (HFTO) **(Fig. 1).** LFTO and FSS both typically occur at less than 2 Hz; HFTO occurs at between 50 and 250 Hz.

LFTO, probably the most common of all three modes, is the excitation of a fundamental torsional natural frequency of the drillstring. The excitation causes the drillstring to act as a long torsional spring, which results in sinusoidal oscillations in bit speed and torque. The oscillation frequency is a function of the drillstring length and stiffness, and is typically less than 0.5 Hz for all drillstrings (SPE 21945). LFTO is characterized by a maximum revolutions per minute (RPM) of up to twice the average drillstring RPM and a bit that may stop, but only instantaneously.

FSS is characterized by distinct periods of zero or low drill-bit RPM (the "stick") followed by an abrupt release (the "slip") where the string unwinds at an extremely high rate that in some cases has exceeded the average drillstring rotation rate by more than a factor of six. The high torque (sticking) required to create FSS can be generated by multiple points in the drillstring, not just the drill bit.

HFTO, the most damaging form of torsional dynamics, is the excitation of a local torsional resonance in the bottomhole assembly (BHA) and is prevalent when drilling through hard carbonate formations (SPE 167968). Because of the high frequency, the resultant torque and RPM fluctuations are attenuated as they travel up the drillstring and are not measureable at the surface. Without downhole sensors providing a real-time indicator, HFTO can quickly cause extensive and premature failure of downhole drilling tools and polycrystalline diamond compact (PDC) drill bits (SPE 49204).

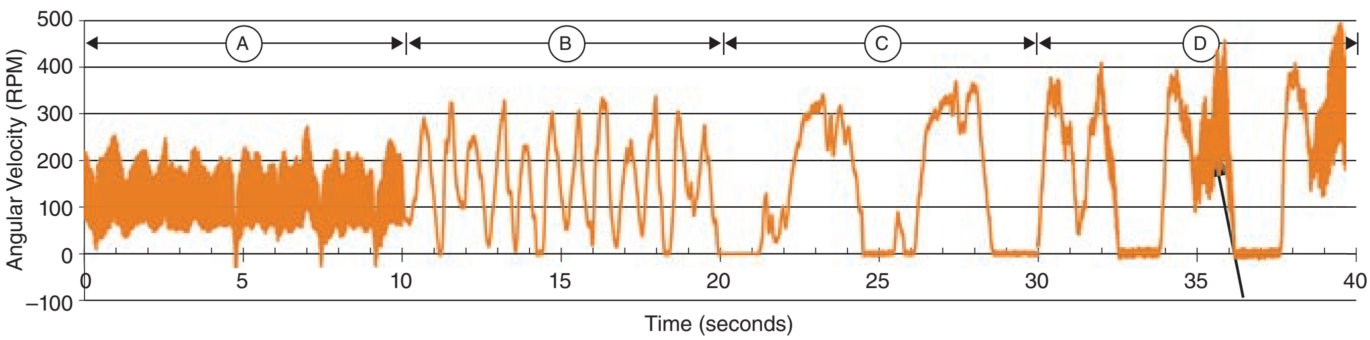

Fig. 1—There are three distinct modes of torsional dynamics (A) HFTO is marked by rapid downhole speed changes. (B) LFTO is indicated by sinusoidal variations in RPM (C) FSS has distinct periods of low or zero RPM during a stick, followed by a ramp-up in RPM during a slip. (D) The modes may also occur simultaneously; the example shows FSS with periods of HFTO during the slip phase (arrowed). *Source: Weatherford.*

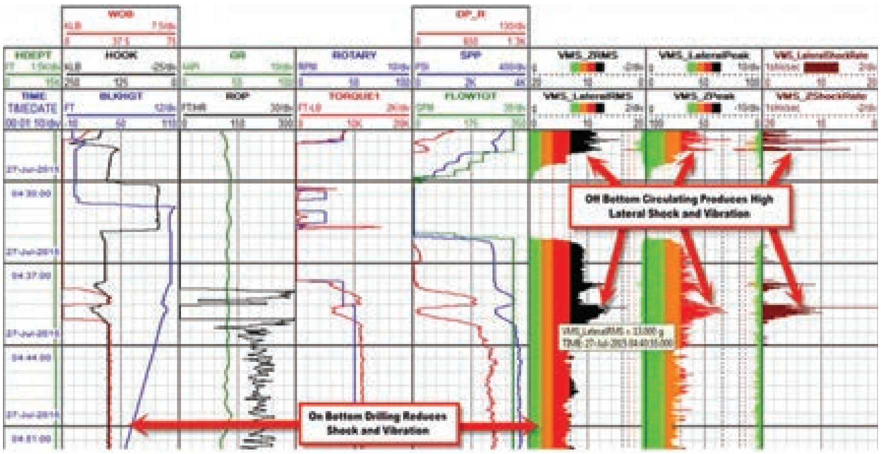

Fig. 2—MWD data showed that the highest shock and vibration levels in a PDM BHA occurred while circulating off-bottom with no rotation. *Source: Weatherford.*

A Multistage Solution

Understanding the exact nature of torsional dynamics is essential for determining when and how to mitigate it. The most effective strategies involve four aspects: measurement, modeling, mitigation, and monitoring.

Measurement. The availability of quality downhole dynamic measurements has increased rapidly over the past decade (SPE 170586). Some sensors are integrated with rotary-steerable systems (RSSs) and logging-while-drilling (LWD) tools. Others are available as standalone devices that can be installed throughout the drillstring, even in the bit itself, and connected by fiber-optic cables to surface (SPE 170770).

Transparency and standardization of measurement is very important, especially with the drive to feed these data directly into drilling automation systems (SPE 174874). One invaluable real-time metric for distinguishing FSS from LFTO is the stick/slip index (SSI) (SPE163428): SSI <1 indicates LFTO and SSI >1 indicates FSS. HFTO detection requires measurements from tangential and radial accelerometers. When the ratio of tangential to radial acceleration is greater than 1, HFTO exists.

Post-run damage assessment is also important for understanding and identifying torsional dynamics. Overtorqued connections, connections that unscrew downhole, and bit wear to the face and gauge are indications of FSS. Rapid fatigue failure of alignment pins, such as those in RSSs, axial cracks in tubulars, dislodgement of large components from printed circuit boards, and spalling of PDC cutters signal HFTO. LFTO rarely causes significant damage.

Modeling. LFTO and HFTO result from the excitation of structural resonances in the drillstring and BHA, respectively. Industry-standard critical speed analysis—the method of calculating the RPM at which these resonances occur—requires the user to tune the models. This method has significant limitations and relies on the availability of a significant amount of offset data. Without these data, predictions are almost worthless.

To remedy this problem, there has been a recent focus on time-domain simulations. These simulate the complex interaction between the wellbore, stabilizers, under-reamers, drillstring members and—especially important for the prediction of FSS and HFTO—the drill bit and formation (SPE 178866 and SPE 178874).

Mitigation. FSS can respond well to surface-based parameter optimization, namely a reduction in weight on bit and an increase in RPM. LFTO and HFTO do not. In these cases, changes to the BHA or the addition of novel technologies offer significant benefits. In some cases, a simple increase in the drillpipe outside diameter can significantly reduce FSS and LFTO (SPE 151133).

The addition of a positive displacement motor (PDM) into the BHA can significantly reduce the severity of both LFTO and HFTO. Because the amplitude of LFTO is based on string speed, slowing the rotation and providing a second RPM source near the drill bit reduces the amplitude of drill-bit RPM oscillation. PDMs also act as a low-pass filter, which prevents HFTO generated at the drill bit from travelling across into the measurement-while-drilling (MWD)/LWD sensors above.

It should be noted that PDMs may cause a dramatic increase in lateral and axial shock and vibration. During full-scale flow-loop testing, Weatherford found that some PDMs generated more than 50 times the peak axial and 20 times the peak lateral accelerations, compared with the baseline. Field trials also showed, surprisingly, that the highest levels of shock and vibration occurred while circulating off-bottom, waiting for a wellbore survey, when the drillstring was not rotating (**Fig. 2**).

Novel torque-limiting downhole tools can be very effective at combating the severity of bit-induced FSS and HFTO. Weatherford's latest torque-limiting tool is a purely mechanical device that is placed above the BHA, which extends and contracts in response to drill-bit torque. The extension and contraction moderates bit engagement with the rock face, contracting as the drill bit begins to torque up and preventing a full stick, then extending during the slip (or high-RPM) phase to allow the bit to remain engaged as the rate of rock removal increases. These tools, like PDMs, also act as low-pass filters, and can be used to isolate sensitive BHA components from HFTO.

A technology that has seen a big resurgence is intelligent topdrive systems (TDSs). TDSs provide torque to rotate the drillstring. Intelligent TDSs use sophisticated control algorithms to reduce torsional fluctuations and are extremely effective at combating LFTO, if tuned correctly (SPE170925). New bit technologies also help to reduce torsional dynamics. Drill-bit design plays a significant role in FSS and HFTO, especially the bit aggressiveness. One recent innovation is PDC bits that self-adjust bit aggressiveness while drilling (SPE 178815).

Monitoring. To reduce the demands on drillers, there is a movement toward automation techniques that monitor parameters and provide warnings and instruction to the drilling team (SPE 178773). The ultimate goal is to close the feedback loop using rig systems that automatically optimize drilling parameters through the control of the drawworks and topdrive.

Conclusions

Drilling dynamics and optimization have received a growing share of attention in the past few years, particularly with the advances in drilling automation technology and the move into deeper, more complex formations. The ability to detect, categorize, and mitigate torsional dynamics downhole is critical if the driller is to reach target depth quickly, safely, and cost-effectively. **JPT**

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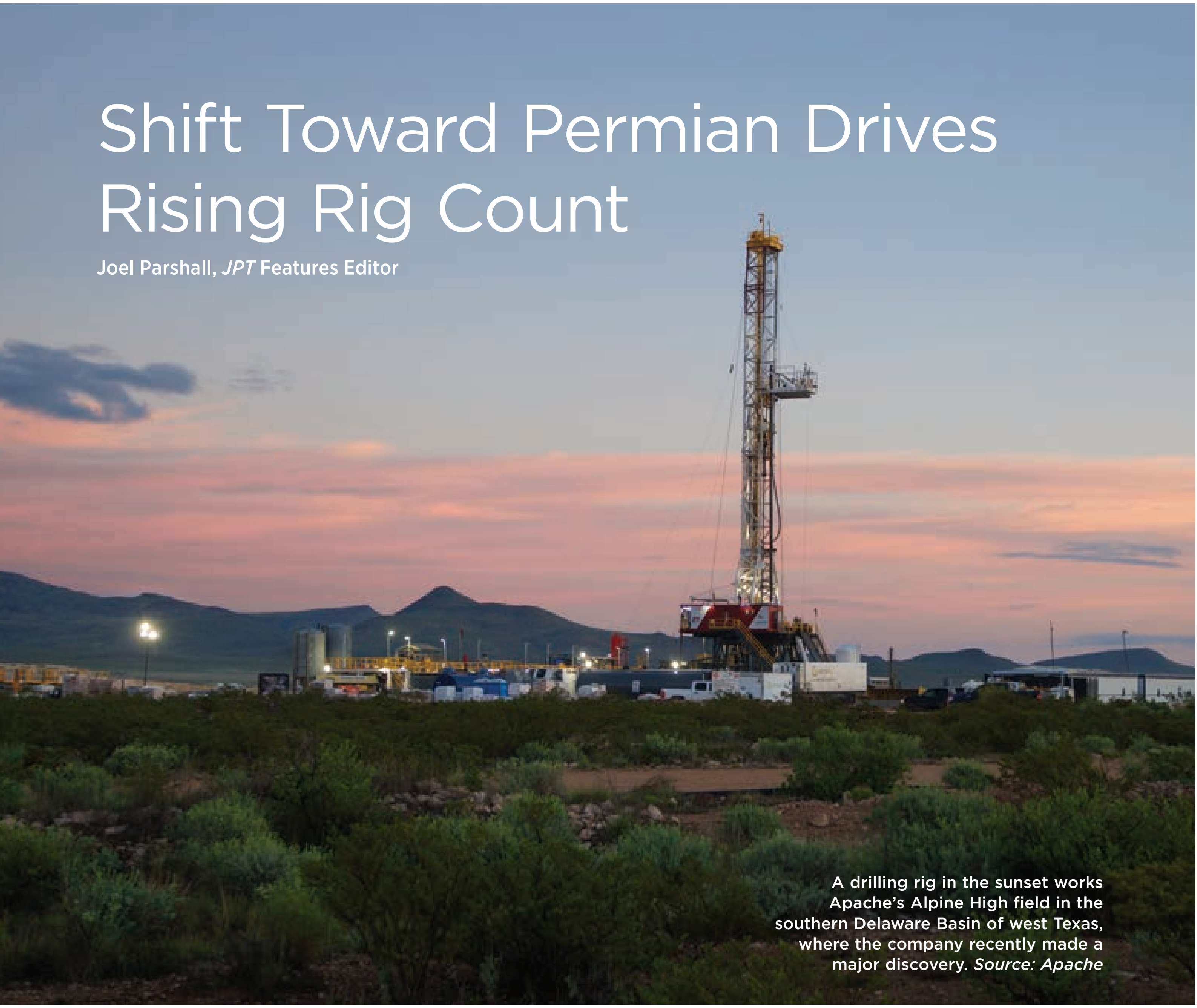
Shift Toward Permian Drives Rising Rig Count

Joel Parshall, *JPT* Features Editor



A drilling rig in the sunset works Apache's Alpine High field in the southern Delaware Basin of west Texas, where the company recently made a major discovery. *Source: Apache*

Don't look now, but the United States rig count has inched up in recent months, and the driver has been the old reliable of onshore oil production, the Permian Basin of west Texas and New Mexico.

While some observers might see the scenario as a simple case of drillers responding to the recovery of oil prices over the spring and summer, the fact that rig growth occurred chiefly in the Permian indicates there is more to the story. And along with a similar, smaller shift of gas rig activity toward the Marcellus and Utica basins in Pennsylvania and Ohio, the statistics suggest what the geographic footprint of an eventual, long-term recovery may look like in the US.

The number of active oil rigs nationwide rose to 407 for the week ending on 2 September, according to Baker Hughes, up from 316 for the week of 27 May. Of the additional 91 rigs, 65 were activated in the Permian Basin. Beginning from a low point of 132 rigs operating in the week of 29 April, the basin has added 70 rigs, and it currently has more than 50% of the horizontal oil rigs operating in the US, up from 15% in 2011.

A smaller growth trend has emerged in Oklahoma, where 10 rigs were added between 13 May and 2 September to bring the statewide total to 66. The increase has centered on the SCOOP (South Central Oklahoma Oil Province) and STACK (Sooner Trend, Anadarko [Basin], Canadian [County], and Kingfisher [County]) plays.

On the US natural gas side, the 88 rigs operating at the beginning of September reflected little change since spring. However, a shift in deployment had added six rigs to the Marcellus since 5 August and four rigs to the Utica since 20 May. The total number of rigs operating in the two basins were 27 and 14, respectively.

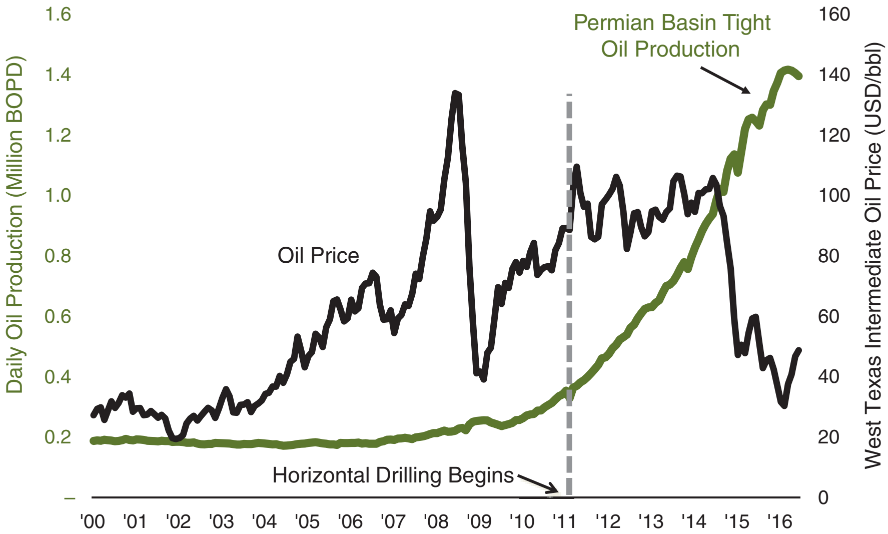
High-Grading Portfolios

"Companies are high-grading within their portfolios, which leads to an overall high-grading within the domestic system in the Lower 48," said Reed

Olmstead, director of commercial plays and basins at IHS Markit. "So that's why we see operators dropping rigs out of the worst parts of their acreage, and that leads to a natural contraction of where activity is happening. Operators are looking to focus their money on areas that can generate economic returns at depressed oil prices, and the Permian keeps rising to the top when you look at cost and performance."

The attractions of the Permian Basin are high-quality rock with significant stacked play opportunities, well-developed infrastructure in many areas, and the fact that the industry has a wealth of experience in the basin.

The most active driller is Pioneer Natural Resources, which is adding a 17th rig to its Permian operations. Others with high activity levels include Concho Resources, ExxonMobil's XTO unit, and Parsley Energy, while Anadarko, Chevron, Cimarex Energy, Apache, EOG, and Occidental are among the companies with substantial current activity and/or high production.



Countering the trend of falling crude oil prices, Permian Basin tight oil production has continued to rise strongly. *Source: Pioneer Natural Resources (US Energy Information Administration data).*

Permian Resurgence

For a basin that has produced oil since 1920, the Permian has seen a remarkable resurgence. In its core Central Basin platform (CBP), the location of most of its conventional fields, production in 2007 stood at a nearly 6-decade low of less than 800,000 B/D. Since then, production has grown to 2 million B/D, a level not seen since the early 1970s, with a shift toward horizontal drilling since 2011 driving most of the increase.

In the Midland Basin, adjacent to the CBP, the Spraberry and Wolfcamp plays have generated an increase of approximately 850,000 BOE/D since 2009, according to data from IHS. Initial growth primarily reflected vertical well activity, but horizontal drilling has taken over in the last 4 years.

The surging production has made the Permian the only major US oil shale play to experience growth since crude prices began to fall, with US Energy Information Administration data showing an almost 20% rise in basin output since the start of last year.

Long-Term Production Growth

Scott Sheffield, chairman and chief executive officer (CEO) of Pioneer, told a plenary session audience at the SPE-cosponsored Unconventional Resources Technology Conference in August that the Permian will drive long-term US oil production growth. He forecast that the basin's production will increase by an average of 300,000 B/D annually over the next 10 years and reach 5 million B/D by 2025.

The Permian Basin is now in direct competition with Saudi Arabia, Sheffield said, noting the basin has produced 35 billion BOE over its commercial life and has an additional 150 billion BOE of recoverable reserves that can be produced as the Midland and Delaware basin plays expand to their potential.

Sheffield said that Pioneer expects to achieve a 30% annual production growth in the Permian and that the company's Midland Basin horizontal drilling prospects can break even at an average price of USD 25/bbl—which he noted was the price needed to earn a 10% return on the present value of investment.

The opportunities present in the Permian have spurred a rash of acquisitions and land deals, including EOG's September announcement that it would purchase privately held Yates Petroleum for USD 2.5 billion. The additional Permian acreage would complement EOG's current acreage there as the company shifts emphasis away from the more expensive Eagle Ford Shale. With the acquisition, EOG Chairman and CEO Bill Thomas said, "We'll be able to grow oil [production] with less capital and more efficiently than we do now."

The news followed Concho's mid-August announcement that it would buy 40,000 core Midland Basin acres from Reliance Energy for USD 1.6 billion.

Land Deals

Recent land deals have transacted at per-acre prices of USD 58,000 in the Midland Basin and USD 27,000 in the more remote Delaware Basin, although one independent reportedly paid USD 150,000 per acre to acquire some Delaware Basin holdings.

Acreage swaps have also become commonplace, as land is a currency available regardless of commodity prices.

Bruce Palfreyman, general manager of the Permian asset at Shell, discussed swaps in the Delaware Basin at a recent presentation on the company's unconventional resources business. "There is going to be continued consolidation across the basin in terms of people putting acreage together," he said. "Everybody knows the value enhancement of long laterals, so you're going to see lots more trading and swaps as we go forward from smaller to larger units, where they can lay out their development programs with as long a lateral as they can execute."

Shell holds a net 300,000 acres in the Delaware Basin through a 50/50 joint venture to develop an area of mutual interest with Anadarko. Assets include 400 Shell-operated wells and more than 5,000 possible well locations. "In the current environment, we're ready to move a few things into development, and that's going to be our focus going forward," Palfreyman said.

Overall, Delaware Basin operators have been shifting from delineation to optimization, which is reflected in longer laterals and higher proppant loading.

According to Jeanie Oudin, a senior research manager at Wood Mackenzie, "The Midland and Delaware basins hold the largest number of undrilled, low-cost tight oil locations in the Lower 48. No other region comes close."

Apache's Big Discovery

One company that has been patiently drilling the Delaware is Apache, which announced a major discovery on 7 September.

The Alpine High discovery, primarily in Reeves County, Texas, in the southern part of the basin, holds an estimated resource in place of 75 Tcf of gas and 3 billion bbl of oil in the Barnett and Woodford formations. Apache has also confirmed oil-bearing potential in the Pennsylvanian, Wolfcamp, and Bone Springs formations, company CEO and President John J. Christmann IV said. He called Alpine High "a world-class resource play."

The discovery followed a meticulous 18-month process of assembling a position of 307,000 net contiguous acres among 352,000 gross acres and drilling 19 wells, nine of which were on production when the discovery was announced. To accelerate delineation and development at Alpine High, Apache boosted current capital spending by USD 200 million. The new play represents more than 25% of the company's 2016 capital budget.

SCOOP and STACK Plays

Interest has also been building in Oklahoma. Continental Resources, a leading operator and the largest acreage holder in the Bakken Shale of North Dakota and Montana, has shifted significant attention to the SCOOP play, which represented 29% of company production at the end of last year.

"When you look at their presentations and have conversations with them, they're much more focused on Oklahoma than they had been, say, 2 or 3 years ago," said IHS' Olmstead. "When you look at where their growth story is and where they feel their best returns are, it's the SCOOP."

Continental had significantly delineated various SCOOP discoveries before oil prices fell and thus has been able to move quickly into development drilling. Marathon Oil and Newfield Exploration are also major operators in the SCOOP. Some smaller companies active in the play hope to be able to prove up acreage to sell to the larger companies, Olmstead said.

In the STACK play, Devon Energy has a strong legacy position that it enhanced early this year with the USD 1.9-billion acquisition of privately held Felix Energy, which held key prospects in the Anadarko Basin.

Similarly, Marathon is bolstering its presence in the Anadarko with the USD 888-million purchase of privately held PayRock Energy Holdings, which was due to close by the end of the third quarter. Newfield, Husky Ventures, Cimarex, and Chaparral Energy are other major STACK play operators.

At least some operators have turned toward the SCOOP and STACK plays, Olmstead said, because "they're at a point in their portfolio where they need another asset—whether it's because they are running out of inventory in other assets (or) they don't like the economics and think that despite the risks the economics here are worth it."

Marcellus and Utica

In natural gas activity, the Marcellus and Utica plays have lately attracted additional rigs. "We're very bullish on those plays," Olmstead said.

Similar to Continental's refocus from the Bakken to the SCOOP play, Southwestern Energy curtailed gas drilling in the Fayetteville Shale to concentrate "on the better part of their portfolio, the Marcellus acreage," Olmstead said. The best near-term opportunities, he believes, lie in the northeastern Pennsylvania dry gas window.

"We've seen some very strong wells out of the Utica," Olmstead continued. "EQT and a couple of other companies have had some amazing results. The question is really just the repeatability."

The Shape of Things To Come

Current trends suggest that the geographic footprint of the US shale oil industry will be more centered on the Permian Basin when drilling activity recovers than it was before oil prices collapsed. The case is plausible, but there are some caveats when projecting to a full recovery environment.

Analyst Richard Zeits, who covers oil, gas, and commodities on the website *Seeking Alpha,* believes that Pioneer's projection for 2025 industry production in the Permian is achievable and possibly conservative. Nonetheless, he notes some hurdles to be scaled as a recovery builds.

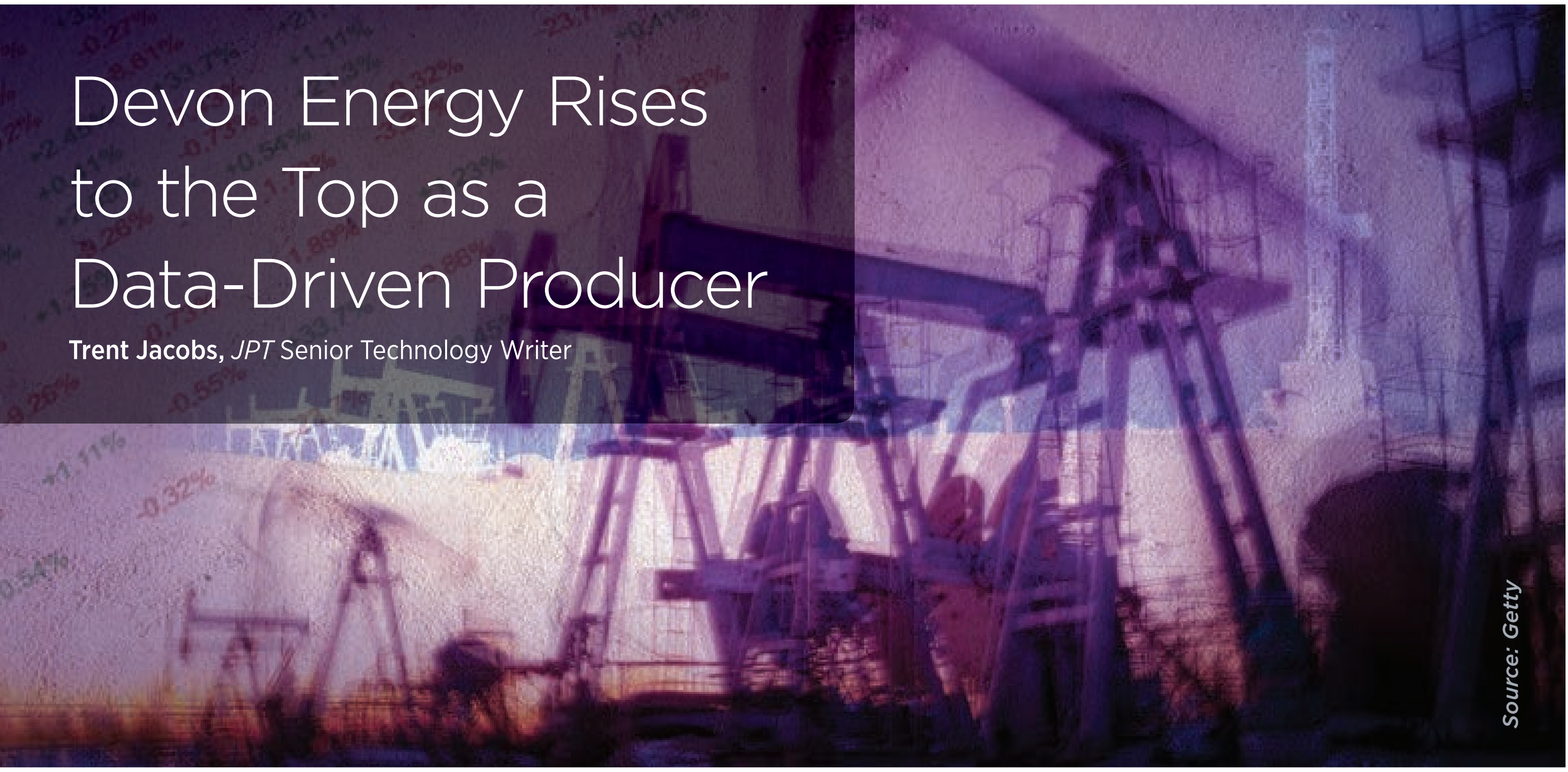
- Additions to processing, storage, and takeaway capacity and particularly the time and expense to develop processing capability for liquid-rich natural gas.
- The need to spread drilling to less-productive acreage.
- Eventual cost inflation in the supply chain.

Zeits emphasizes shale oil's broadly distributed US production base that he believes can again come to the fore in a full recovery. "The industry will likely continue to rely on several prolific basins, most of which will contribute significantly to production growth in an upcycle," he said.

However, it appears safe to say that while the Permian Basin did not lead the shale oil revolution, it will lead the US shale oil industry *into* the next recovery when it happens. And the same can be said of the Marcellus for shale gas. **JPT**

Devon Energy Rises to the Top as a Data-Driven Producer

Trent Jacobs, *JPT* Senior Technology Writer



After becoming one of the first shale producers to adopt advanced data analytics, Devon Energy is now one of its most ardent champions. The results speak to why that is.

Since 2012, when Devon began investing in big data technology, its 90-day production rates from horizontal wells have increased by 250%—an improvement that according to IHS Markit data has lifted the Oklahoma City-based company's early-time production from new wells to the highest level in the US onshore market. Additionally, Devon's costs to drill, complete, and operate its well have fallen by as much as 40%, the company said.

It is fair to attribute some of these significant gains to the quality of the company's positions inside North America's most prolific shale plays, and also the pressure that oilfield contractors are under to make price concessions in a down market.

However, that does not complete the story.

From exploration and drilling to completions and production, Devon has put to work a small arsenal of sophisticated algorithms designed to find the otherwise hidden insights and engineering tweaks that are driving more value out of the shale fields it operates.

This realm of computer science has also made routine tasks that once took engineers hours to complete possible to do in a few minutes, or less. And that some of these programs can literally think for themselves, although in a limited mathematical sense, is not hyperbole.

Today's offerings in artificial intelligence and machine learning technology can be trained to look for defined outcomes, or they can be set free to decide on their own what to look for and will rewrite their underlying algorithms in order to do so.

Humans Still in the Loop

As intriguing as this emerging world of intelligent software is, when discussing how it has changed her company, Kathy Ball, manager of advanced analytics and data science at Devon, begins by stressing the importance of the human element.

"It is about culture and collaboration," she insisted, adding that those two ingredients constitute the "secret sauce that makes this all work."

In other words, implementing a sophisticated data-driven approach to field development—one that relies on real-time streaming from remote field sensors, cloud-based analytics services to crunch the data in seconds, and effective procedures on how to take action on that information—depends largely on solid teamwork and sound business decisions.

Part of this requires getting analytics experts, information technology staff, and engineering leaders from different departments to climb out of their respective silos so they can share data and develop new solutions together.

On the economic justification, one simple way to assess the value of advanced analytics was put to Ball by a completions engineer, who she quoted as saying, "If it doesn't help us extract oil and gas from the ground, then so what?"

Ball has come to call this the "so what" test. She applies it to herself, the engineers who come to her team wanting a shiny new algorithm, and to the software vendors touting their product as the latest and greatest breakthrough in artificial intelligence.

This approach filters out the ideas not worth pursuing, while allowing engineers and data experts to focus resources on ones with the most potential to generate revenue. So far, more than a dozen analytics programs have made the grade and are now integrated into the company's day-to-day operations.

They address several key aspects of shale development: pilot testing, well spacing, expected drilling time, geosteering, geohazard prediction, bottomhole assembly selection, real-time hydraulic fracturing risk analysis, and artificial lift optimization.

Finding the Bit

Geosteering is one area where Devon believes analytics is clearly making a difference. This drilling technology has become a favorite among shale producers because it gives them a degree of precision when tapping into relatively thin pay zones.

The downside is that geosteering tools sit some distance behind the bit and surveys are only taken every 90 ft, leaving more than 100 ft of unknown wellbore trajectory each time drilling moves forward. To overcome this data gap, Devon developed a real-time drill bit tracker that leans on artificial intelligence and machine learning to work the math and figure out a well's true path.

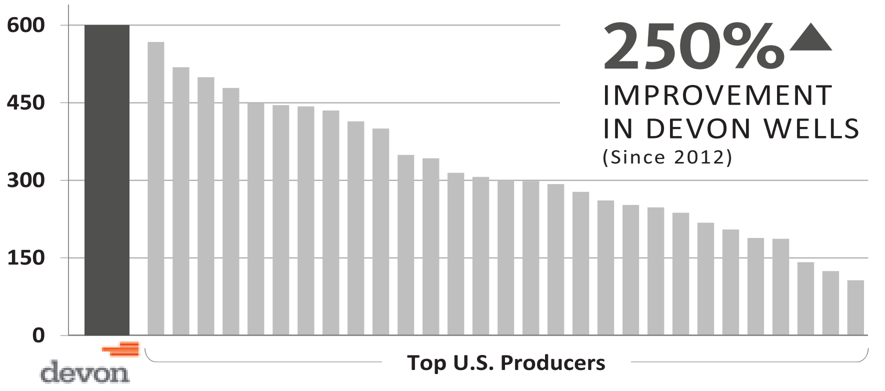
Engineers at the company's drilling center keep a watchful eye on this drilling data as it is streamed in and visualized, enabling them to call for adjustments if the bit is veering off the planned course.

"That is just priceless," Ball said of the bit tracker. "It keeps us in a producing zone, and helps us assess the landing curve," the critical juncture where the vertical well section gives way to the horizontal section. On its website, the company credits this program with reducing the number of unplanned sidetracks it has had to drill to get wells back on their intended trajectory.

Similar analytic programs are used to model which bottomhole assembly kits will perform best in a particular well and will chart their actual performance as they rotate down the hole. Another one predicts which sections of a well are most likely to give drillers trouble (i.e., nonproductive time) and which parameters are contributing most to the rate of penetration (e.g., weight-on-bit). Taken as a whole, these drilling-focused analytics programs are preventing costly errors and helping rig crews deliver better wells in less time.

Screening Out Screenouts

Devon is also using real-time analysis to avoid screenouts—a common problem in hydraulic fracturing that happens when sand or proppant stops flowing into open fractures and begins to plug up the wellbore instead. Screenouts can be expensive to remediate and have thus encouraged the development of algorithms to detect their telltale signs.



Based on its own data and that of IHS Markit, Devon Energy reports to have achieved the best initial production rates in the US onshore. *Source: Devon Energy*

The analysis behind Devon's old warning system was capable of assigning risk levels between 1–4 to indicate the probability that a screenout was near. That system has since evolved into a much more deterministic model that factors in the type of fracturing fluid being used, formation characteristics, and field history.

Characterizing the role of artificial intelligence in making models like this more accurate, Ball said, "It has gone from an engineer saying, 'Here is the pattern that you need to look for,' to 'All right, we have built that pattern, now let the machine make it even smarter.'"

In this case, the smarter model does away with the risk levels and instead sends engineers a 15-second warning only when a screenout is imminent. The next step is to develop a 30-second warning: plenty of time to tone down the pumping while also ensuring that maximum pressures inside the wellbore are maintained for as long as possible. Ideally, that would lead to a better stimulation treatment.

Production and Reservoir Management

One example of how analytics is giving valuable time back to engineers is an interactive map that Devon uses to calculate how much oil or gas is left in any given shale field in the US. Ball explained that an engineer tasked with doing this for 50 wells might have needed a week to do so.

"We are now able to do that through a big data solution and come up with a calculation for the Lower 48 in probably 10 minutes," she said.

The mapping program includes data from more than 100,000 horizontal wells drilled by Devon and its competitors in the past decade. Tools such as this are allowing producers to peer over the lease line and compare their completion designs to offset operators.

For Devon, the mapping program has identified refracturing candidates and is accelerating pilot programs that seek to prove new techniques. This form of predictive analytics is also used to assess the company's entire fleet of artificial lift units. The program determines the mean time to failure and flags lift units if the potentiality for a rod or pump failure is detected.

As a result, Devon's field maintenance strategy has transformed from one based on a cyclical schedule to one that is largely prescriptive. Instead of field technicians inspecting a set list of wells in sequential order, the analytics program now sends them two reports a day that target only those units truly in need of attention.

"It is really important to go beyond just preventative," Ball explained. "That will tell you that I need to replace something because it might fail—the analytics is going to tell you when it is going to fail." She added that this program has turned out so well that it now represents one of the company's largest areas of cost savings.

In terms of uplift, the company has noted that this combination of analytics and automation has netted single-digit percentage increases in production across its portfolio.

Four Answers to the Question: *What Can I Learn From Analytics?*

Stephen Rassenfoss, *JPT* Emerging Technology Senior Editor

The future of data-driven analysis in exploration and production (E&P) will depend on whether it can add value in the field.

Four examples of what is possible were presented recently at the 2016 Unconventional Resources Technology Conference (URTEC) in San Antonio with the authors of papers posing questions such as:

- Does it matter if a lateral is drilled toe-up or toe-down?
- What are the changes in a fracturing design that will offer the biggest production payoff?
- Why has the drilling slowdown not depressed production from unconventional gas plays?
- What is the half-life of my field, and why should I care?

The stories below bring together advanced statistical analysis methods with multiple names: analytics, big data, machine learning, and even a "physio statistical engine for automatic stochastic production forecasting."

All this new E&P math is aimed at identifying patterns and relationships that otherwise would be missed. But automatic and self-learning does not mean all-knowing.

For example, one of the programs used to analyze fracturing used facial recognition to classify pressure changes during each stage to sort them into different classes.

Production data revealed that one of the classes of fractures, characterized by a pressure bump near the end of the stage that could mean trouble, were often more productive than those that went exactly according to plan. But it was up to the completion team to figure out how to apply that observation.

The process is "brutally empirical," said Roger Anderson, president of AKW Analytics, who led the study for Range Resources. He said the method is good at identifying what is happening, but it is unable to determine why or how it happened.

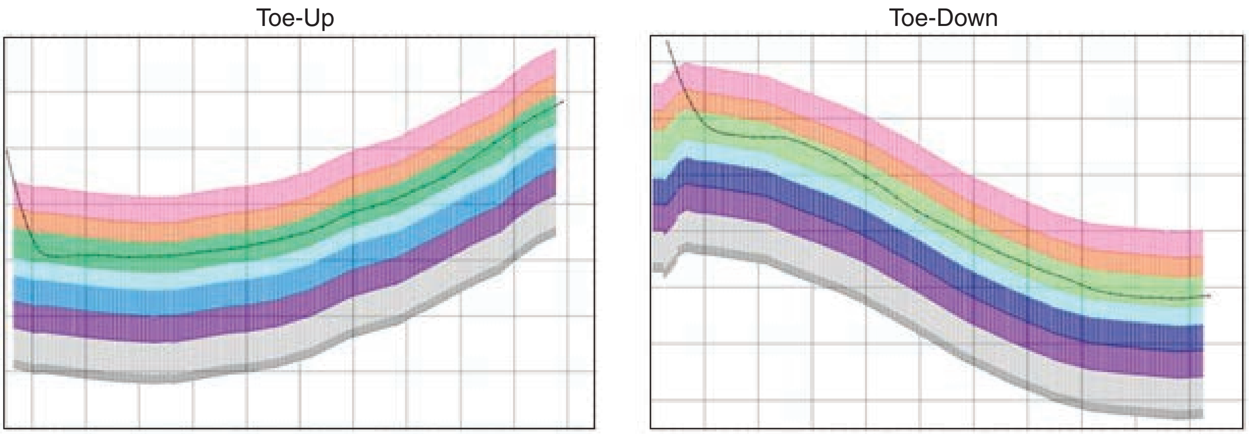
Toe-Up or Toe-Down: Does It Really Matter?

For years, an unresolved question for those drilling horizontal wells has been: Does it matter if it is toe-up or toe-down?

Horizontal wells generally follow an up or down slope following the most productive rock, which can mean large changes in elevation from the heel—the curve from vertical to horizontal—to the toe.

Results from modeling have not settled the matter. Recently, Devon Energy offered its response based on the performance of more than 300 similar wells drilled in the Cana-Woodford Shale in Oklahoma.

The comparison was possible because the company had mass-produced simi-



Example of the difference between a toe-up and a toe-down well. ***Source: URTEC 2461175***

lar wells, giving it a large sample of wells with 4,800-ft laterals where it fractured 10 stages with 40 perforation clusters using 3.5 million lb of proppant located in a compact area with similar geology in the three depths studied.

The analysis was done in a way that ensured, as much as is statistically possible, that "only toe-up or toe-down could be affecting the production performance of the wells analyzed," said Sam Browning, a reservoir engineering for Devon who delivered the paper at URTEC.

It concluded that toe-up wells produce more. And the greater the elevation change between the heel and the toe, the greater the impact.

"The more toe-up they are, they [wells] appear to be better, and the more toe-down is worse," Browning said, adding "All the best wells were toe-up."

Devon found that toe-down wells produced 25% less based on a year's worth of production, he said. The difference was narrow in the early days of production and widened over time.

The results were compared based on the depth of the wellbore—shallow, middle, and deep—because of differences in the zones. For example, the condensate-rich production in the shallower zone is more likely to be affected by liquid holdup than the gas-prone deep zone.

The widest variation between toe-up and toe-down wells was seen in the middle zone where the elevation changes were greatest. In those toe-down wells, the elevation changes were nearly all in the 100–200 ft range, while the dips at other depths were less than 100 ft.

The paper predicted that an extreme toe-down well in the lowest-pressure area would produce 30% less over its life.

The paper suggested toe-up wells may perform better by offering a gravity boost for the liquids-rich flow, and toe-down can allow liquid to build up in the production zone, hindering the flow.

Browning is planning to come back to these wells to see how they are doing in the future, which will address questions about whether changes that come with age, such as increased water production requiring pumping, will alter the conclusion.

Devon is using this study when planning new wells in other areas with similar conditions, such as projects to drill infill wells in spots with relatively low pressure to overcome liquid buildup. The location of the well, though, may require drilling a well toe-down to stay within the most productive rock.

And the sample size in this case is too small to generalize about all horizontal wells. But based on the Devon study, the potential reward for knowing if toe-up is better or worse can be big enough to justify the cost of a study to answer the question.

URTEC 2461175 Effects of Toe-Up versus Toe-Down Wellbore Trajectories on Production Performance in the Cana Woodford *by S. Browning and R. Jayakumar, Devon Energy.*

Is the Struggle Really Worth It?

When it comes to pumping a proppant into a fracture, a job that goes according to plan may not be the best option.

A statistical analysis of fracturing using machine learning found that the smoothest fracturing stages often underperformed those where the operators struggled to get all the sand into the formation.

The study presented by AKW Analytics at URTEC used a system comprising multiple software programs to seek out telling patterns in several streams of data from 1,800 fracture stages in 156 wells completed by Range Resources in the Marcellus Shale.

The study focused on two groups of classes of fractures: ones where the pressure rose before it completed pumping the planned amount of proppant, raising concerns that an excessive amount of sand might block the fracture by causing a screenout, and another class where the pressure hardly changed because "everything went as scheduled," according to the paper.

But the production from the fractures that went smoothly was often not as good as those that required a struggle. "Perfect means you will not do as well if you do not struggle to get in that last sand," said Roger Anderson, president of AKW Analytics, who delivered the paper on a 4-year study for Range. "Perfect may mean the sand (volume) was short."

The difference among fracture classes, which was only noticed in 69 of the wells, was one of many variables studied to see which factors have the biggest impact on production.

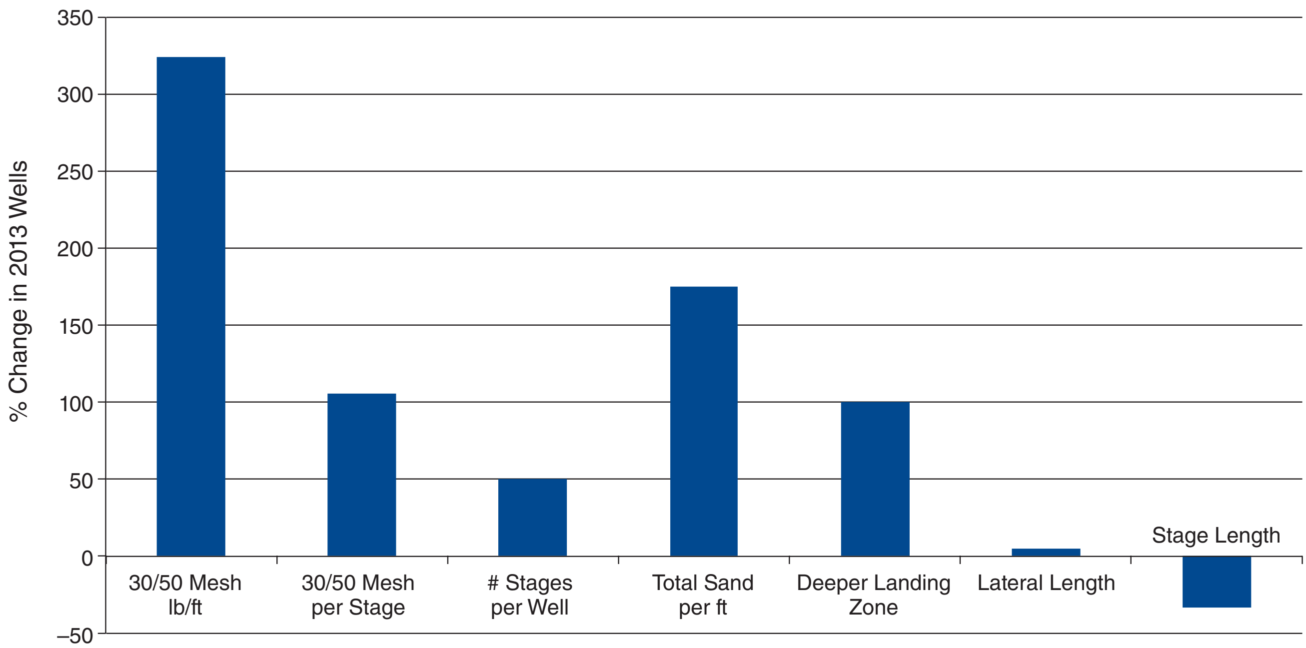
The goal was to learn how to predict future performance when completion teams are considering which variables will have the most effect during the design stage.

The multivariable analysis showed an oil field is no place for a statistician looking for clean, consistent data sets over time. Prior to the last year of the study, Range Resources revamped its completion method. The pounds of sand placed per foot nearly tripled, with coarse sand used and more stages in longer laterals drilled deeper in the formation.

The paper points out that "determining which (change) led to the greatest improvement is difficult because" there were so many big ones. The bottom line, though, was positive, with the new approach yielding a "remarkable increase in condensate and gas production per well in 2013," the paper said. And Anderson pointed out the changes were generally in line with the study's conclusions about which factors matter most.

The most influential ones were not surprising—the percentage of the wellbore in the targeted reservoir rock, the total volume of proppant placed, and the number of stages were among them—but it also quantified the potential impact and predicted how different combinations of attributes will perform.

By using 34 attributes, for example, Anderson said the model was 78% accurate, with a wide error range. With more



This quantifies changes in the completion methods used by Range Resources, including a reduction in the space between stages, to produce significantly more gas in the Marcellus. ***Source: URTEC 2430481***

data to consider and time to learn, the system could improve its accuracy. "It is not something you would want to report to the SEC; it is not good enough yet," he said, adding, "but it is better than guessing."

URTEC 2430481 Using Machine Learning to Identify the Highest Wet Gas Producing Mix of Hydraulic Fracturing Classes and Technology Improvements in the Marcellus Shale *by R. Anderson, B. Xie, L. Wu, AKW Analytics et al.*

URTEC 2426612 Petroleum Analytics Learning Machine To Forecast Production in the West Gas Marcellus Shale *by R. Anderson, B. Xie, L. Wu, AKW Analytics et al.*

Why Does Drilling Drop, Not Kill, Gas Production?

Shale wells are known for their rapid production declines. So when drilling activity dropped in 2008 and again in 2014, steep declines were widely predicted.

But that is not how it has played out in the three biggest US shale gas plays—the Barnett, Haynesville, and Marcellus—where production has held up even though only a few rigs have been running.

The reason why the expectation and the realization have been different is due to the industry's increasing productivity and the fact that thousands of unconventional wells perform differently than a single well, according to Philippe Charlez, a senior technical advisor to Total, who delivered a paper on his research on resilience at URTEC.

Total's Unconventional Factory Development Simulator was used to study the decline rate of a large shale play with 3,000 wells producing 1 Bcf/D of gas. The results showed that the impact of the rapid early decline rate of new wells can be muted by the slow, steady production from thousands of older wells drilled over many years.

While the paper said it takes a fleet of drilling rigs to reach that peak—16 rigs working for years—once at that peak level, only four are required to maintain that level for many years. In practice, operators are likely to add rigs when gas prices are high enough to make it an attractive investment. "When the price is relatively high, I drill a lot to feed my well portfolio. When prices are low, I live on existing wells," Charlez said.

There is a significant reward for productivity gains increasing the estimated ultimate recovery (EUR). "If it is higher, I need less rigs to maintain the plateau rate," he said. And if an operator increases the EUR by about 20% over a 3-year period, a simulation concluded the increased productivity would be possible to maintain the production plateau for 10 years with only two rigs.

The simulator was also used to predict what would happen in the three biggest US gas shale plays if drilling stopped. It found that the Barnett was the most resilient based on the expected rate of decline, the Haynesville the least, and the Marcellus in between.

"The Barnett is very resilient. There is a large well portfolio," drilled over many years, Charlez said.

If drilling stopped for 10 years, the Barnett production would be down 50% while the Haynesville would have dropped to zero by 2025, according to the study that said Marcellus would drop nearly 75% if there was no drilling during that period.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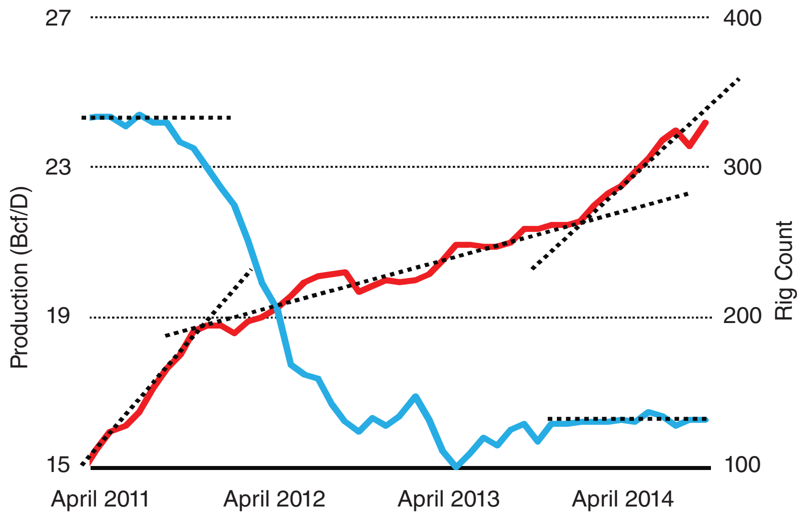


While the number of rigs drilling in the Barnett, Haynesville, and Marcellus formations dropped sharply (blue line), production has risen in the three largest US gas-producing shale formations (red line). ***Source: URTEC 2439429***

As the oldest shale play, the Barnett has the edge because about 15,000 wells have been drilled there vs. 3,700 in the Haynesville, and the Barnett has more, older wells whose steady output reduces the impact of the sharp declines seen in new wells.

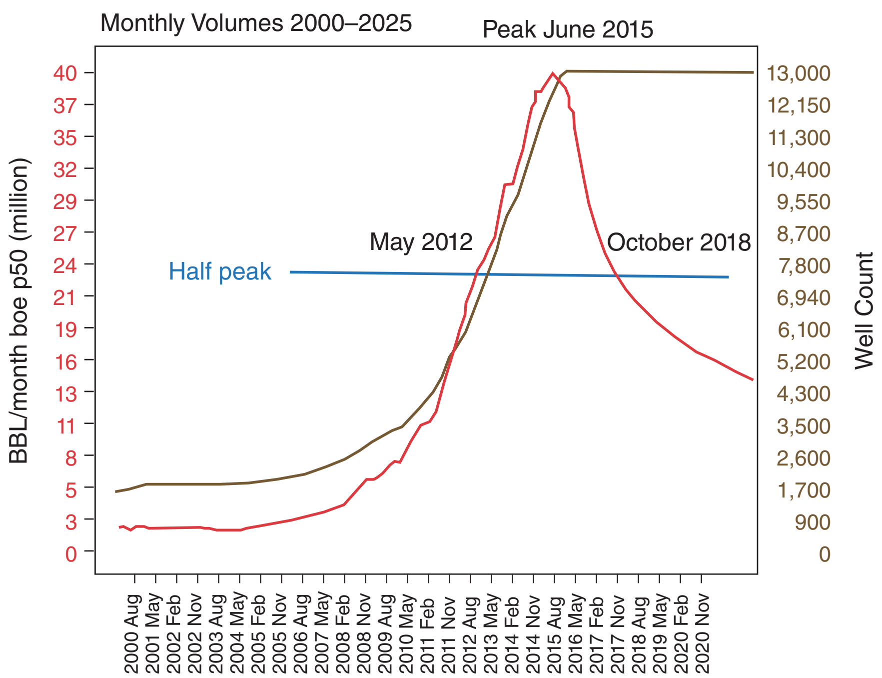
The net effect of a mix of prolific fast-declining young wells and low-producing steady old wells is roughly analogous to a diversified investment portfolio with volatile high-performing stocks balanced by the modest, steady cash flow from bonds.

URTEC 2439429 Resilience of the US Shale Production to the Collapse of Oil & Gas Prices *by P. Charlez, Total, and P. Delfiner, PetroDecisions.*

What is the Half-Life of That Shale Play?

Half-life is a commonly used way to measure the life of radioactive materials, but not oil fields.

The founder of a data-driven forecasting company, though, argues that it is a useful benchmark for companies with substantial production from unconventional oil fields, because it can be used to estimate when a company will need to spend money to sustain production at a level that satisfies investor expectations.



If all drilling stopped when oil production peaked in the Bakken, it would drop to half that level in 3 years and 4 months, according to a study based on a statistical analysis of the production reports from 14,000 wells. ***Source: URTEC 2461672***

To make her case, Heidi Kuzma, founder and chief technical officer of BetaZi, applied its statistical analysis method to forecast production from more than 13,000 wells in North Dakota and concluded it would take 3 years and 4 months for the output of all those wells to decline 50%.

"Somehow, if production is to be brought up to its peak 2015 levels, half of that production must be replaced by the end of 2018. Worst case scenario, that means another 6,000 or 7,000 wells," need to be drilled and completed, said Kuzma, a geophysicist by training. "That is a huge amount of capital."

The actual statewide decline rate will not be that fast, because while the calculation assumed no drilling, there were 27 drilling rigs working in North Dakota in late August, according to the Baker Hughes rig count. Those wells are for companies focused on speeding the construction of significantly more productive wells.

For individual operators, however, the half-life of their assets is shorter. The pressure is greatest for those who drilled most of their wells at the tail end of the boom, which ended during the second half of 2014.

"There are already a significant number of operators whose Bakken production is very close to half of what it was at its peak in 2015," she said. Many of those cannot afford to drill and complete wells. "In this case, depletion might be a function not of the asset, but of the capital needed to exploit it," Kuzma said.

BetaZi's statistical approach estimated the decline rate by inputting monthly oil, gas, and water production figures reported to the state of North Dakota for each well, and also the number of days the well was flowing. The company's predictions were created using its proprietary "physio statistical engine for automatic stochastic production forecasting."

Estimates of reserves and ultimate recoveries do not figure into the calculation. In shale, it appears the amount of oil produced is a small percentage of what is in the ground. Actual recoveries will depend on the future price of oil, and whether improved techniques are developed and applied.

"Reserves and EUR [estimated ultimate recovery] are estimated numbers that are difficult to test. They constantly change," Kuzma said.

Production decline rates have always been tracked, but are not featured in financial reporting. Predicting long-term decline rates from unconventional wells is a challenge. The proper method for predicting the long-term decline rate for unconventional wells is not settled among petroleum engineers. And the skills and methods of those drilling and completing wells varies widely among operators, which also have varying approaches, and budgets, for maintaining production.

Based on the conclusions of Kuzma's paper, and one presented by Phillippe Charlez, a senior technical advisor for Total, long-term production predictions are tricky.

Both estimated production on a well by well basis and combined it using their company's proprietary software engine. He drew his information from decline curve analysis, while she statistically predicted future monthly production rates. And both said their predictions were in line with actual production results.

Charlez concluded that if "no new development activity occurred, it would take 10 years for Bakken production to drop 50%," which is three times longer than Kuzma's prediction. His estimate was mentioned at the end of a study focused on major gas plays, where he said the longer histories allow more dependable statistical analysis.

Given the many variables, Kuzma said it is hard to prove who is right. "For the moment, any purely data-driven forecast that claims to be accurate beyond 6 or 7 years for unconventional production is a bit suspect, since we just don't have that much experience," she said, adding, "let's get back together in 10 years."

URTEC 2461672 Blinking Out: North Dakota Without Capital for Replacing Production
by H. Kuzma, C. Eklund, T. Rapp et al., BetaZi.

Analytics Firms Explore Oil and Gas Market

Trent Jacobs, *JPT* Senior Technology Writer

The oil and gas industry is facing an invasion of data analytics startups who saw a wide-open gap in the market a few years ago when talk of big data first began.

Many of these young companies vying for attention from producers are focused on alleviating the headaches associated with artificial lift systems. There are also a number of software products designed to handle difficult computations such as production forecasting and reserve estimation.

Some are selling analytics as a way to combat the growing threat of cyber attacks. Other programs interpret human semantics to extract valuable information out of the entirety of a company's document library.

Below is a closer look at what several of these analytics startups are offering to the industry—only there will be no deep dive into the layer cake of terminology that dominates this emerging software arena, e.g., artificial intelligence, machine learning, edge computing, etc.

Power of Integration

A sign of the industry's accelerating uptake of analytics came in May when a number of the world's largest producers made a USD-26 million investment in an industrial-focused analytics startup from Silicon Valley called Maana. The list of financiers includes the venture arms of Saudi Aramco, Chevron, Shell, and GE.

This may be a leading indicator of things to come because rather than focusing on any particular niche solution, Maana is a big-picture analytics platform. Able to reach between different silos within an organization, the program analyzes seemingly disparate sets of operational data and ties them all together.

Donald Thompson, cofounder and president of Maana, said such data integration is able to generate "new knowledge" that oil and gas producers can leverage to drive performance in the field.

"Most projects involve going and tackling a single isolated problem, but everything in a business tends to be highly interrelated," he explained. "So the failure of an individual pump is very interesting to understand, but its impact on production schedules is also interesting ... if one pump fails, how should you adjust all the other pumps in order to still meet your production requirements?"

Thompson, who pioneered knowledge- and semantic-based search engine tools during his 15 years at Microsoft, gave another example of an oil and gas project involving malfunctioning field sensors.

The sensors, managed by a remote monitoring team, were sending faulty telemetry alerts to the operator's support center. Unbeknownst to the latter group, the sensors had received a software update which was responsible for the glitch. By being in between the monitoring and support team, Maana connected the dots and determined the root cause.

"Individual analytics projects within each one of those groups," Thomp-

A worker installs a small sensor on a pump jack which turns the machine into an internet-of-things device that can be tracked, monitored, and controlled remotely or set to optimize itself autonomously. *Source: Ambyint* son said, "would never have detected a correlation between the two groups and those are the type of things we're enabling now."

Pumping Up the Data

One of the biggest targets for analytics vendors is artificial lift because rods, pumps, and motors are relatively easy for the latest generation of smart software to interpret and predict.

Calgary-based Ambyint is one of those firms. The company feels it has an advantage over its peers because it is leveraging a decade of Canadian oilfield pump data gathered by its holding company and predecessor, PumpWell.

Ambyint was formed to market an improved predictive maintenance program that analyzes the symptoms that precede a pump failure. Such programs alert producers to the precursors of a pump failure days before a total failure occurs. This allows field maintenance programs to be scheduled with precision and efficiency.

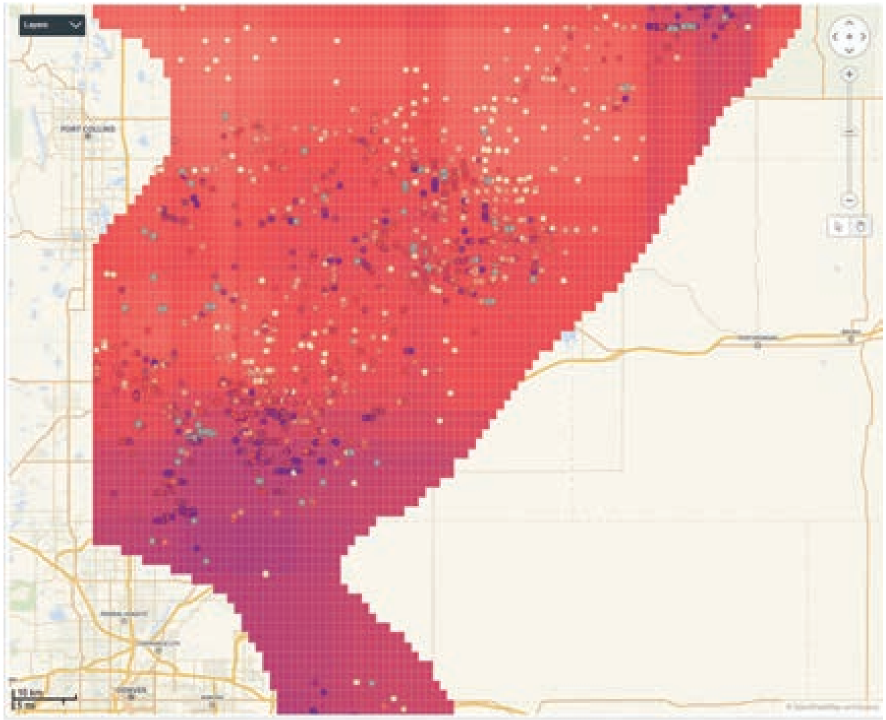
The firm's software can also automate pumping operations based on production targets or to stretch out the mean time to failure. Though clearly logical, this pairing of analytics and automation is in its infancy.

Nav Dhunay, president and chief executive officer of Ambyint, said producers who buy into predictive analytics must first become confident of its core features before taking that next leap.

"This industry is a bit conservative when it comes to technology adoption, so the last thing somebody wants to do is trust that a computer can make a better decision than they can—even though if you look at the majority of accidents that happen worldwide, they happen because of the human element," he said.

Ultimately, he added, software will win the day as it becomes better than humans at managing oil and gas wells running on pumps This transition will begin through a semiautomated system Ambyint calls a "recommendation engine," which requests that prescriptive actions be taken.

As production engineers accept more and more of those recommendations, "what we're going to do is turn this thing into an autopilot where it will start making decisions for you," Dhunay said.



A random forest modeling program allows users to quickly run queries over large swaths of producing areas to find new trends or well completion strategies. *Source: Ruth.ai*

Reading Between the Lines

Anyone with a smartphone has by now probably tried speaking to it to get directions, send a text, or run an internet search. Led by former oil and gas professionals who specialized in computer science, i2k Connect is trying to bring this natural language recognition technology to oil and gas companies.

But instead of spoken semantics, this company is teaching its software to understand written semantics. Moreover, it is trying to teach it oil and gas jargon using 15 different industry taxonomies.

"Companies run on data, and much of that data is in the text documents they create and store every day," said Reid Smith, one of i2k's founders. "Unfortunately, those documents are hard to find."

To solve the problem, this startup's intelligent software will pore over a company's unstructured text files and add structure by autotagging each PDF file, email, slideshow, or Word document with a keyword. The end result is an internal search engine that mimics many of the features used by Google or Amazon.

The company is currently fine-tuning its language recognition platform in a partnership with the SPE, the gatekeeper to hundreds of thousands of technical papers that date back to the 1800s. Smith said: "It's the best available content that could be imagined to train our system."

The goal is to create an enhanced search capability across all SPE online content including the technical paper database, OnePetro. Content and papers will be categorized based on the i2k program's understanding of their true context as opposed to only relying on keywords. Smith described it as "enriching the documents with subject matter expertise."

That means, for example, technical papers from related topics will be tagged more accurately. A paper relating to production logging but that does not use that exact term within the document will still be tagged "production logging," making it more visible in OnePetro searches on this topic.

Real-Time Processing

In August, real-time analytics firm SQLstream received a major endorsement of its platform when Amazon adopted it to become the engine behind a new web-based service for businesses. The San Francisco-based company is hoping to make a similar impression on oil and gas companies.

Named after the world's most common computer language, SQLstream says its platform is able to process more than a gigabyte of data per second with a delay of only 5 milliseconds.

Such processing capability is at the upper limit of what today's systems can handle and more than an hour faster than processing giant Hadoop, said Damian Black, the company's chief executive officer. He described the platform as a "universal mechanism for transforming any form of input, in any format, arriving at any time, into any output format."

This streaming data technology can be applied to just about anything using SCADA—supervisory control and data acquisition—systems. In modern oil fields it is hard to find anything not running on SCADA.

The SQLstream platform's flexibility includes a user-friendly interface that Black said requires no specialized training to master. Guided by the program's recommendations, users can build custom apps in minutes and establish rules that could be used to control automated field equipment.

With the back-end programming doing the heavy-lifting, users can change their minds and modify how data are analyzed or visualized on the fly. All modifications take effect immediately and without so much as a simple reboot.

Black stressed that up until just a few years ago, such app development for real-time data was the domain of very expensive software consultants that needed weeks to deliver.

"I like to draw the analogy with spreadsheets," he said. "Spreadsheets changed the way that people analyzed data, utterly. They are so easy to use and you can do complex formulations and build financial models. We're doing the same thing now for big, fast data, except I think this is even easier to use than a spreadsheet."

Disruptive Pricing

Troy Ruths founded his namesake startup Ruths.ai in 2013 after earning his PhD in computational biology from Rice University in Houston. While working as a self-described "data monkey" for Chevron before graduating, he realized the potential of analytics to become a central component of the oil and gas business going forward.

But something was missing—a marketplace where producers could buy these applications without going through the cumbersome process of vendor selection.

So Ruths.ai created an exchange where it sells analytics apps it developed along with those created by other software developers. Today the exchange hosts more than 80 programs designed for geoscience, play-wide analysis, production operations, and other areas.

Many of these apps can be downloaded for a few hundred dollars and only a handful cost more than USD 1,000. Ruths said his intent is to disrupt the current pricing model for these products to make his exchange stand out amid an increasingly crowded field.

"These prices are an order of magnitude less than the competing counterparts out there, and what we are trying to do is lower the bar so more people can have access to these types of solutions," he explained.

One of the apps enables operators to quickly analyze workover candidates and generate economic models for each potential job. This is an example of a task that might take hours of research for a single engineer to complete for an entire field.

When using this program, as the cursor is dragged across a field map, the calculations are completed almost instantaneously. "You just give it the three pieces of data that it needs—workover history, production, and well location—and then it will go through and calculate the uplift factor-ratios for each job," Ruths said.

He added that tools like this also allow operators to find answers to important questions. Why are some wells doing worse than others? Is it a completion problem, or a problem with the reservoir? Are there any clear trends that show why one part of the field is producing better than another?

Cyber Analytics

SparkCognition is another company specializing in predictive maintenance and has deployed its system with an airline manufacturer and the two largest operators of wind turbines in North America. It recently inked an agreement with Flowserve, the world's largest maker of oilfield valves, which is marketing the system as a way to avoid complete failures.

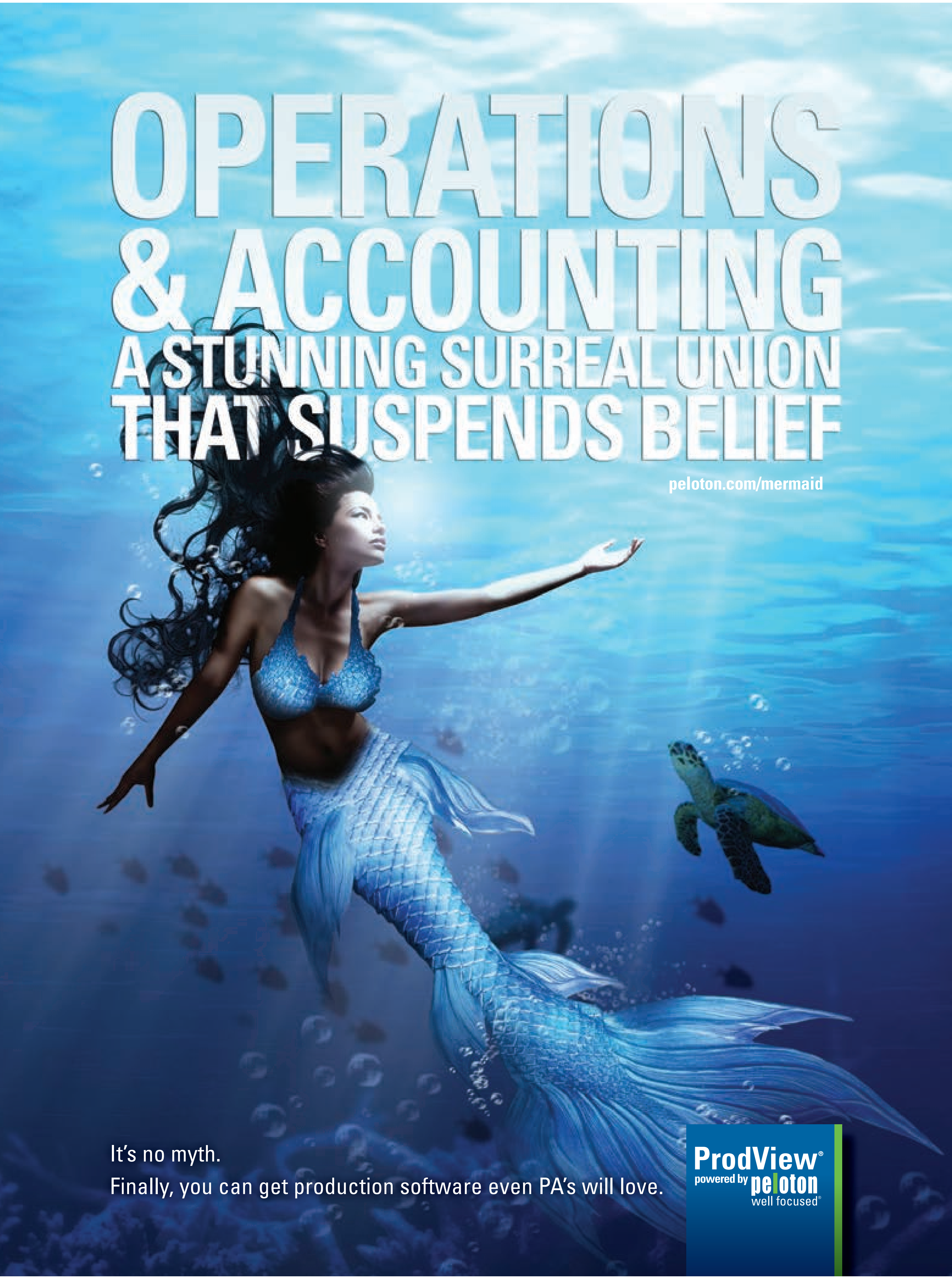
The Austin, Texas-based firm has also developed a cyber security analytics application that is being used by cyber antiterrorism authorities and as a fraud detection system for banks. This may be an interesting area to watch since the oil and gas industry is one of the most frequent victims of cyber attacks and espionage.

Philippe Herve, vice president of solutions at SparkCognition, said the cyber security product can be used as a standalone service, or it can be married with the firm's predictive maintenance software to add an extra level of assurance.

"When an asset is starting to misbehave, is it because we have a failure on it or is it because someone has attacked it," he asked. "If something goes wrong, you need to know why."

Herve added that unlike conventional antivirus software, which base their defenses around past attack methods, analytics-based security platforms actively monitor a company's networks for anomalies that may indicate when something or someone has invaded a secure system.

The SparkCognition software also runs constant internet queries to find new threats. When it discovers one, or detects an ongoing attack, the program automatically sends alerts and written reports to security experts to brief them on the situation.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Accelerating the Uptake Cycle Through Collaboration, Outsourcing

Trent Jacobs, *JPT* Senior Technology Writer

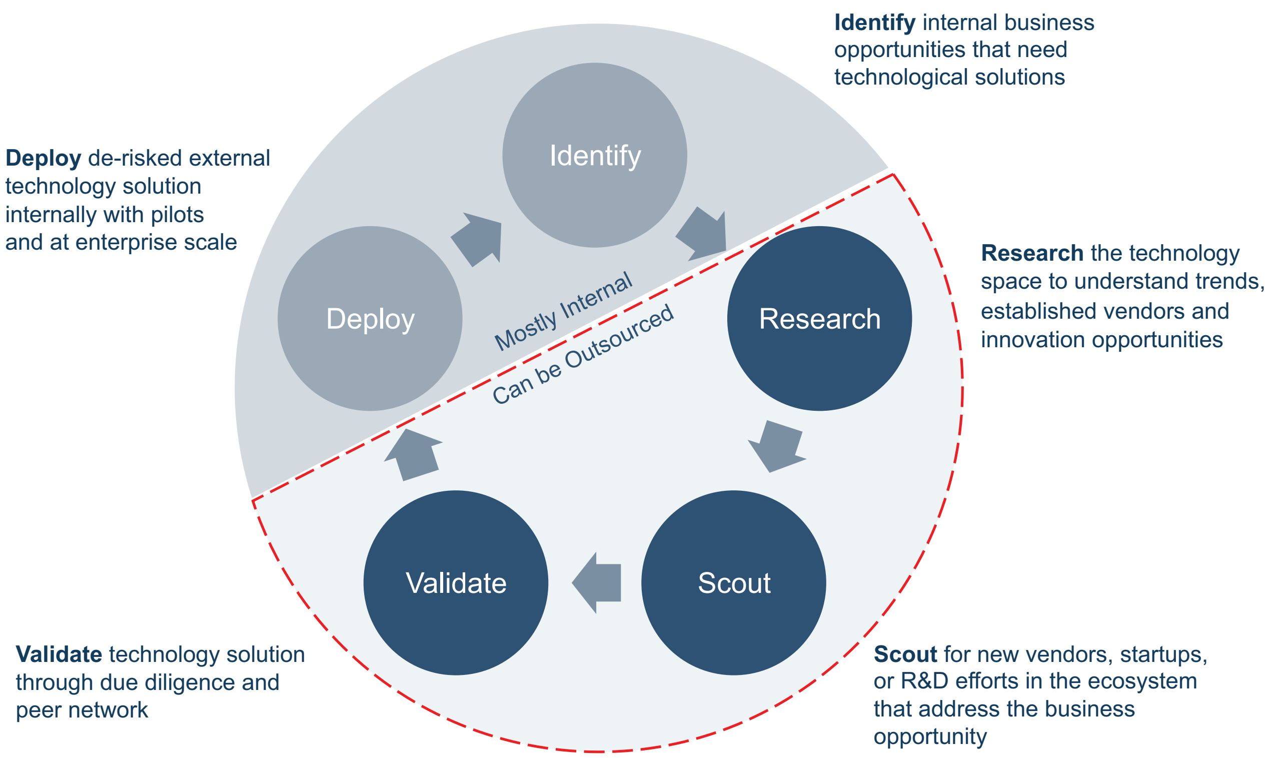
As a newcomer in the arena of oilfield market research, Houston-based Darcy Partners has set an ambitiously high bar for itself: to speed up the oil and gas industry's widely acknowledged and painfully slow rate of technology adoption.

Founded in 2015, Darcy is trying to accomplish this by melding its in-depth research studies with a collaborative approach to consulting. The latter part of this strategy involves placing a group of promising young companies and their potential suitors into the same room where the free flow of ideas is encouraged.

The firm's ultimate goal is to prove to oil and gas companies that technology validation becomes a much faster process when done collectively and openly compared with when it is all done internally.

"We are saying let's do innovation more efficiently," said Hossein Rokhsari, a partner at Darcy, adding, "which means outsourcing elements of the work that is required for technology development to a group like us, where we do the research, scouting, screening, and evaluation."

The culmination of all that groundwork is quarterly technology forums that Darcy hosts and moderates. The company has held two of these day-long events this year: one on advanced data analytics and another on new water management technologies for unconventional developments. Its upcoming forums will focus on unmanned aerial vehicles, completion optimization, cyber security, and another on advanced data analytics.



A new look at the innovation cycle proposes operators identify a challenge and then hand off many of the subsequent vetting duties to an outside firm before deploying the technology in a test environment. ***Source: Darcy***

In attendance are key decision makers from oil and gas companies whose biggest pain points are used to steer the direction of the forum. Presenting are the entrepreneurs that Darcy has high-graded based on their ability to cure those issues.

For the up-and-coming technology vendors, the forums are a chance to get invaluable face time with their target audience. Darcy takes a hands-on role with those entrepreneurs by providing them with corporate coaching to make their message as effective as possible. Once the pitch is made, operators have the opportunity to put questions to the entrepreneurs about the feasibility of their innovations.

Another of the firm's partners, Jeremy Sweek, emphasized that this sort of transparency is rare in the oil field but necessary to address the fact that the industry has a tendency to run too many pilot tests in isolation. He explained that when operators test-drive startups, the results are typically not shared publicly but end up percolating through word-of-mouth between professional colleagues and field workers.

This practice of informal information sharing is less than desirable from a startup's point of view because it makes it hard for the company to appear on another operator's radar screen and grow its business. According to Sweek, it also means disinformation about those startups often goes unchecked and leaves operators in a position where they are unable to fully leverage the sum of their aggregate experience.

"Most of the operators we have talked to have tried a pilot with one, two, or three of these companies but it is a different combination for each of them," he said. "So why as an industry do we need 100 pilot projects to determine that there is a clear winner, or two or three winners?"

Another problem Darcy is trying to address with its approach is vendor deluge. Using data analytics as an example, in this space alone there are hundreds of companies trying to break into the oil and gas business. Darcy has narrowed the list for its clients by distinguishing the startups selling what Sweek referred to as "fluff" vs. those selling actual breakthroughs that can lower operating costs or enhance reserves.

"When you say big data, we ask what do you really mean, and when you say analytics, what do you really mean," he said. "You have to pull it back to see whether or not it's really just a business intelligence tool that has a different user interface."

Rokhsari, who worked at an energy-focused venture capital firm before starting Darcy, insists that the point of all this is not only to encourage operators to become investors in the startups—it is to also encourage them to consider becoming paying customers.

The initial results of Darcy's research efforts and technology forums appear to be positive. The company reports that every operator has discovered at least two or three startups that they plan to work with, and in turn, each startup has walked away from the forums with three to five operators as potential clients. **JPT**

The Reason to Expect Prolonged USD 30–60/bbl Oil

Rodney Schulz, President, Schulz Financial

Since 1982, the year oil prices were deregulated in the US, the import oil price to the US has averaged USD 52/bbl in 2015 dollars. It is volatile, having a monthly standard deviation of 9%, although volatility ebbs and flows. The global oil price, like the price of any commodity or security in a free and open market, incorporates all available information almost instantaneously and follows a random walk pattern.

With the above factors in mind, what can today's oil and gas professional expect for the near- to mid-term oil price? Although the answer may not be welcome, a fairly stable set of conditions coalesce to make a strong reason to expect the oil price to generally range between USD 30/bbl and USD 60/bbl for the foreseeable future.

The Global Macro Situation

To understand the situation, it is helpful to first look at two global macro factors. First, the world consumes approximately 90 million bbl of oil every day. And second, three countries, Saudi Arabia, Russia, and the US, are the largest suppliers, with each producing between 9 and 11 million BOPD (**Table 1**). Beyond these three countries, production drops precipitously.

The Organization of Petroleum Exporting Countries (OPEC) produces approximately 30 million BOPD. Although OPEC may attempt to collude and control oil prices, world history has repeatedly proved that global cartels generally cannot control markets for any sustained period of time.

This article is not about geopolitical forces, but one can quickly see that OPEC members have distinct cultures, governments, customers, and priorities, as well as different production and reserve replacement costs. Hence, it is unlikely, and perhaps even unrealistic, for OPEC members to uniformly agree on production quotas and then expect each member country to behave accordingly. Therefore, it is probably a good assumption that global oil prices will submit to global market forces; i.e., oil prices will likely continue to depend on the supply and demand equation of competing producers and consumers.

The Reasons for a USD 30–60/bbl Range

Why can one expect prices to fall in the range of USD 30–60/bbl as previously suggested? The biggest reason is the supply trade-off between conventional and shale oil production, combined with fundamental investment economics. To first understand this one needs to look at the domestic oil production of the US vs. time (**Fig. 1**).

TABLE 1—WORLD'S TOP TEN OIL PRODUCERS BY COUNTRY

Country	Production, January–March 2016 (million BOPD)
Russia	10.5
Saudi Arabia	10.0
United States	9.2
Iraq	4.3
China	4.1
Canada	3.8
Iran	3.5
UAE	2.7
Kuwait	2.5
Venezuela	2.4
Total	53.0

Although oil prices spiked from the late 1970s into the early 1980s (**Fig. 2**), domestic production for the US moved minimally. However, during the strong oil price period from 2006 to 2014, US oil production increased from 5 million BOPD to 10 million BOPD due to shale oil. Moreover, it is now widely known that the US has 78 billion bbl of technically recoverable shale oil.

The investment economics of US shale production is easy to describe in terms of option pricing. Simply put, when the break-even, or option "strike" price, moves above where it is economically viable, the acreage owner can exercise its option to make a profit by drilling. This situation begs a few simple questions that can be easily answered.

First, what strike price is necessary to add shale oil production in the US? From a wide variety of sources and dependent on acreage location as well as other factors, the strike price of US shale oil

Rodney Schulz, SPE, is president of Schulz Financial, a retail advisory firm, and is the founder and exclusive instructor for Oil & Gas Economics and Uncertainty, a 2-day seminar taught both privately and through SPE. His oil and gas experience includes a wide range of engineering, finance, and operational responsibilities throughout North America for both major and independent producers as well as gas processing companies. Schulz's expert witness experience includes work for a major oil company, the Federal Bankruptcy Court in Corpus Christi, and an international law firm. He has also served as the financial director/chief financial officer for an organization with 150 employees in six states. He earned a BS degree in petroleum engineering from the University of Kansas and an MBA from Duke University.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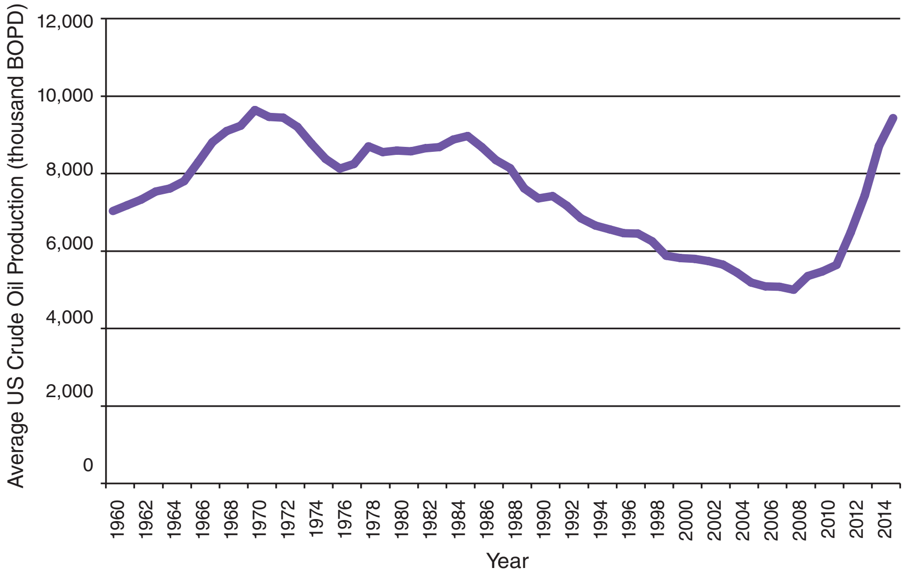


Fig. 1—US crude oil production by year. *Source: US Energy Information Administration.*

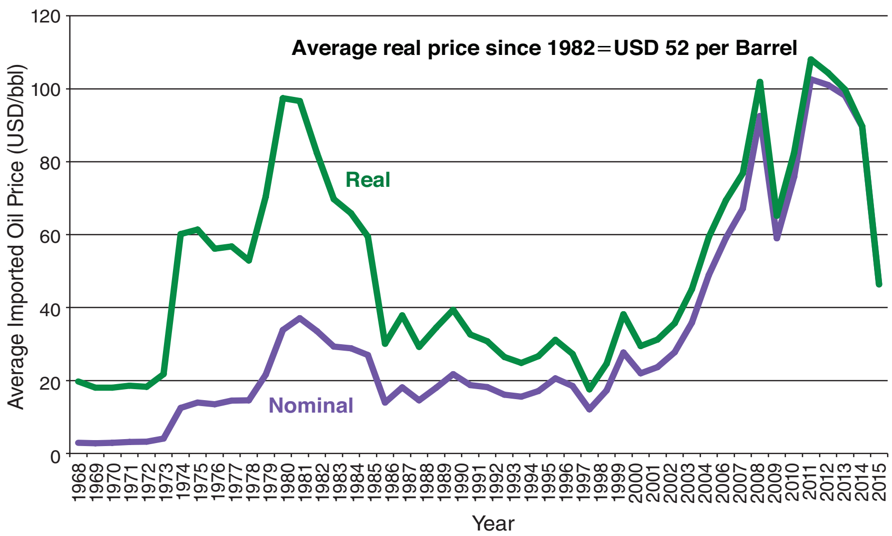


Fig. 2—US imported oil price vs. time. *Source: US Energy Information Administration.*

ranges from USD 30/bbl to USD 50/bbl. Therefore, when the oil price moves above the particular producer's break-even point/strike price, that producer can be expected to drill.

Second, how much production can US producers add as the oil price increases? Although all 78 billion bbl of technically recoverable shale oil may not be financially viable at USD 30–50/bbl, it takes only 0.365 billion bbl, or 0.5% of the 78 billion bbl, to add 1 million BOPD of production in a year.

Third, are an adequate number of drilling rigs and fracturing crews available to exploit the shale oil in the US? The answer is a simple "yes." Specifically, the US has a total inventory of 1,600 drilling rigs, a sizeable percentage of which can drill shale wells, and the current number of active domestic rigs is approximately 400. Therefore, the US has ample rig capacity to seize drilling opportunities as conditions warrant.

This raises the question: "How many drilling rigs does it take to add, for example, production of 1 million BOPD?" The answer to this is straightforward and simple.

For example, if the oil price is USD 40/bbl, the required payout time 18 months, the royalty 3/16, the cost to drill and complete a shale well USD 7 million, and the production cost USD 8/bbl after drilling and completing a well, it takes:

$$(1-3/16)\times(\text{USD }40-\text{USD }8)\times(\text{average BOPD for an 18 month payout})\times365\times1.5=\text{USD 7 million}$$

Thus, with the above cost and price structure, the average daily production rate for 18 months required for one well to satisfy the above economic equation is 491 BOPD. To simplify the equation, assume one drilling rig can add 500 BOPD per well, with the initial production rate being higher and the 18-month end rate being lower.

If one next assumes it takes 6 weeks to drill and complete a shale oil well, and if fracturing resources are available upon demand, one rig can drill approximately 8 wells per year. Hence, one rig is capable of adding 8×500=4,000 BOPD in a year. Therefore, it takes approximately 250 drilling rigs to add 1 million bbl of oil per day to the production capacity of the US.

With 1,600 domestic rigs available and approximately 400 rigs currently running, it is easy to see that the US has hundreds of rigs that could be put to work, as conditions warrant, and quickly add substantial production, thus putting the resulting downward pressure on oil prices.

As prices move higher, more producers will pick up drilling rigs to add production, make a profit, and supply markets with oil. And as prices move lower, producers will release rigs, allowing production to fall with natural decline, until global production falls to a point where demand again drives prices higher.

One may ask: "Why is the expected range USD 30–60/bbl when the common strike price for shale oil is USD 30–50/bbl?" In short, the USD 50–60/bbl zone is a reasonable buffer range. Should one also add a lower buffer range of USD 20–30/bbl? Probably not, because global reserve replacement becomes exceedingly difficult below USD 35/bbl. Again, one should look at the USD-30/bbl and USD-60/bbl price marks not as absolute borders, but as the range that contains most of the bell curve for sustainable oil prices.

In summary, production capacity, natural decline, prices, and drilling will move together to supply market demand. The world, in totality, generally operates on a capitalistic market supply and demand equation that has significantly influenced all aspects of global life and economics for centuries, if not millennia. Of course, low-cost producers will always have an advantage.

Other Considerations

One may argue that oil is different because a small number of producers "control" prices. However, if one compares the oil and gas industry with other industries, it is not unusual for two suppliers, in this case Saudi Arabia and Russia, to have a 25% market share.

Another argument is that the production economics in the Middle East are far more favorable than elsewhere in the world. This is true, but it is nothing unusual for a small number of suppliers to have an economic equation that is better than their competitors. For example, a farmer can raise wheat in West Texas, but the farmer with land in western Kansas will have a significantly better economic equation for wheat production than the farmer in West Texas.

One may also wish to bring political stability into the discussion. But again, political stability, or lack thereof, has always been a factor in economic equations. From the government side, the possibility of economic gain will always be an incentive to promote political stability. And from the investment side, companies will pursue business in politically unstable regions if the reward is worth the risk.

Technological advances have made shale oil production viable, given an adequate oil price. And it is safe to assume that technology will continue to advance. However, a 1,500-millidarcy, 7,000-ft deep, 40-°API oil reservoir will always have a competitive advantage over a 1-microdarcy, 7,000-ft deep, 40-°API oil reservoir. Why? It simply takes more horsepower and resources to extract oil from the 1-microdarcy reservoir than from the 1,500-millidarcy reservoir. But this is not the whole equation, as it is evident the world does not have enough 1,500-millidarcy oil production to fully supply demand.

Conclusion

Summarizing, it is likely that oil prices will range from USD 30–60/bbl for the foreseeable future. Short-term excursions outside of this range should not be surprising, but will probably not last for a sustained period of time. The reason for the likely USD 30–60/bbl range is the global interaction of producers and consumers, with a large potential shale oil supply that can be rapidly tapped as conditions warrant. A diminutive 0.5% of technically viable US shale oil can add 1 million BOPD of production for a year. The global oil supplier makeup is similar to that of other industries. Technology and political stability will factor into the equation, but this is nothing new. As with other industries, different suppliers have different economic equations, but this is common with the constantly shifting global economic order. **JPT**

Four Honored as Legends of Artificial Lift

Shauna Noonan, Occidental Petroleum, and **Jeanne Perdue,** Occidental Petroleum

The 2016 SPE Artificial Lift Conference and Exhibition for North America, to be held 25–27 October 2016 in The Woodlands, Texas, will feature a special Legends of Artificial Lift Luncheon honoring four people who have made outstanding contributions to the field of artificial lift technology. The 2016 SPE Legends of Artificial Lift Award recipients are John Bearden, Mark Mahoney, James McCoy, and Sid Smith Sr.

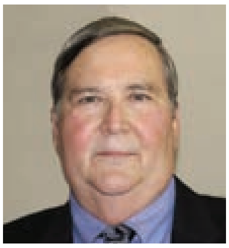
John Bearden has published 19 papers and holds 16 patents on the topic of electric submersible pumps (ESPs). He has worked on the SPE task groups that developed Recommended Practices on ESPs, authored the ESP chapter in the new edition of the *Petroleum Engineering Handbook,* and served on the committee that developed the ISO Standard for ESPs.

After earning BS and MS degrees in mechanical engineering from Texas A&M University, Bearden joined the Borg-Warner Ingersoll Research Center, which was Centrilift's corporate research facility. While there, he worked on various projects studying the effects of gas on downhole pumps, which resulted in the development of Centrilift's Rotary Gas Separator prototype. He transferred to Centrilift's Byron-Jackson Pump Department in 1976 as a project engineer and, after Baker Hughes acquired Centrilift, he worked his way up to the position of director of R&D systems engineering for Baker Hughes' artificial lift product line. He was presented the Baker Hughes Lifetime Technology Achievement Award in 2007, and retired in 2015.

His master's thesis was on the subject of turbomachinery and fluid dynamics, and his whole career involved the design, development, and application of ESP components and systems. "A career in artificial lift was good to me," he said. "I learned new technologies and new application solutions on a consistent basis. That learning came from others in the company, customer technologists, and even competitors."

Bearden credits his mentors for giving him the advice and support he needed to be successful.

"Find a mentor or mentors as you start pursuing your professional career," he recommends. "They can help guide you, but it is up to you to determine your course. I was fortunate to have several mentors during my career, and the one that helped guide me the most was John Tuzson, my manager at the Borg-Warner Research Center," who wrote the book *Centrifugal Pump Design*.



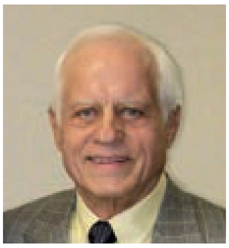
Mark Mahoney has received industry recognition for his work in developing improvements to rod pumping equipment to address problems such as sand production and high gas/oil ratios. Mahoney was involved in the pioneer work of placing rod pumps in the deviated section of horizontal wells, and he helped develop new designs and strategies for rod pumping in deviated wellbores.

Author/coauthor of numerous SPE papers and coauthor of three patents, Mahoney served on the API Committee for Standards and Recommended Practices for Sucker Rod Pumps for 10 years. He serves on the steering committees for the biannual Middle East Artificial Lift Forum, an annual international beam-pumping workshop held in Texas, and the biannual SPE Enhanced Oil Recovery/Improved Oil Recovery Conference in Oman. He is a peer review editor for the *SPE Production & Operations* journal and the *SPE Canadian Journal of Petroleum Technology,* and is a master class instructor for SPE.

Mahoney worked at Harbison-Fischer for more than 26 years in research and development of new products, reverse engineering and redesign of sucker rod pumps (SRP), SRP system designs, failure analysis, and training on SRP systems. He is an ISO/API Q1 trained internal auditor, and he developed new quality processes, work instructions, and procedures for both internal and external customers.

Mahoney also worked as the senior artificial lift consultant for the Production Optimization Group at Lufkin Industries, and held the positions of senior artificial lift projects manager and Middle East operations manager for Lufkin in Oman. Mahoney recently retired from Occidental Petroleum, where he worked as the artificial lift advisor for 3 years.

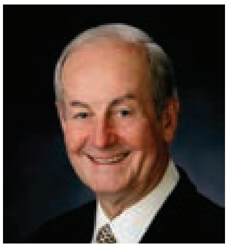
"My advice is to go and get as much field experience as you can, especially visiting the teardown of pumps/equipment and witnessing installation and pulls of pumps, gas lift, and plunger lift equipment," he said. "Visit manufacturers as well. Learn about how the equipment is made and the materials that are used so you better understand failures. Last but not least, find someone that is good at failure analysis and make good friends with him or her."



James McCoy graduated from the University of Oklahoma with a BS degree in petroleum engineering and from Penn State University with an MS degree in petroleum and natural gas engineering. He worked for a consulting firm and a major oil company, purchasing and operating oil and gas properties. In 1962 he acquired Echometer Company and expanded the acoustic liquid level instrument's capabilities into a full-fledged well analyzer system that is used worldwide to measure and improve the efficiency of producing oil wells. He has received industry recognition for his dedication and passion for teaching others how to use downhole pressure data and inflow performance to maximize well production.

McCoy is active in SPE, having authored or coauthored more than 30 SPE papers, the first being SPE 337 titled "Analyzing Well Performance." He holds numerous artificial lift patents and was instrumental in establishing the McCoy School of Engineering at Midwestern State University in Wichita Falls, Texas.

"The artificial lift industry has been a great way to support myself and my family," he said. "The job has been both in the office and in the field, which I like. The industry has a lot of challenges, and I have really enjoyed working on those challenges—the varied challenges have been fun. I recommend the artificial lift industry to young people looking for a profession that is interesting and exciting. I have been privileged to work with such a great group of people."



Sid Smith Sr. earned a BS degree in petroleum engineering from the University of Louisiana in Lafayette in 1958 and went to work for Camco, where he coauthored Camco's Gas Lift Manual with H.W. Winkler. In 1968, he joined Conoco as a gas lift expert and held positions in production engineering, operations, and management in Houston, Dubai, and Indonesia.

After taking early retirement from Conoco in 1993, Smith chaired the SPE Gulf Coast Section's Community Services Committee while consulting part-time for Camco and Shell. With Shell, he taught gas lift schools in The Hague, Gabon, Nigeria, Brunei, and Oman while assisting with the deployment and use of WinGLUE, Shell's patented gas lift surveillance software. He is currently working as a part-time consultant for Appsmiths, assisting with gas lift software development and services in Houston. For the past 10 years, he has been executive director of Urban Outreach Inc., a faith-based nonprofit serving inner-city families in Houston.

Smith said engineers can remain in production engineering on the technical ladder throughout their career, rather than climb the management ladder. "The key thing about being connected in artificial lift is, artificial lift can be and usually is utilized throughout the reservoir life cycle. So the opportunity for gainful employment is there even in times of low oil and gas prices. I am still as busy as I was before oil prices dropped below USD 100 a barrel." **JPT**

Field Development Projects

Maria A. Capello, SPE, Executive Adviser, Kuwait Oil Company

The low price of oil has had an immediate effect in the planning departments of oil companies. They were forced to shift the focus and carefully rank and select only those developments that would ensure profitability in the production of oil and gas. Hence, the field-development projects need to include and consider not only a static or dynamic subsurface characterization but also the production-systems and facilities options, to trigger profitability and establish clear break-even thresholds. More than ever, the consideration of deep water, tight reservoirs, shale oil, remote locations, or environmentally critical plays is placed under the microscope. Increasingly difficult project economics has delayed or stopped investments that were estimated to be safe and profitable before the price drop.

In this extended-low-oil-price framework, a positive economic return is actively sought by ever-incremental integration of subsurface and surface engineering, to select strategies that lower the production cost. I would like to mention that some of the key elements that enabled better economics in the most successful projects were new project designs that ensure flexibility; synergies with contractors, especially for supply-chain improvements; alliances; and inclusiveness of breakthrough technology. Additionally, a new trend in field development that has proved to be beneficial and that assesses profitability of production strategies is the incorporation of pilot or early- or initial-production units to establish real project economics and boost opportunities for understanding the cost-reduction opportunities. This is a strategy incrementally applied globally by international and national oil companies. The complexities of the development plans have propelled an integration among professionals of subsurface studies, production systems, construction engineering, transportation, and even marketing teams, to an increased collaboration not seen before.

The three papers selected for this feature typify this necessary integrated approach in field developments. In these papers, as well as in those suggested for additional reading, the main factor is the integration of all elements involved in ensuring economic profitability, including subsurface studies, drilling and completion, construction engineering, production systems, technology, environmental considerations, global supply and construction integration, compliance with government regulations, synergy with contractors and shareholders, consideration of other projects' supply chains in nearby fields, contract strategies, and even weather. Remarkably, the academic, theoretical, modeling, and research studies have also shifted toward assessing the optimal or economic development of shale oil and gas, offshore fields, and environmentally protected areas, marking an alignment within the industry to solve the current concerns and incorporating in the studies a very practical engineering or economic approach not frequently present before.

That all the optimizations, synergies, and successes presented in the papers you will read are flourishing now is not coincidental but clearly is a result imposed by the hard times derived from the low price of oil and the accelerated pace with which we want to produce our resources. An extended-low-price era seems to have settled in, and, even if in the future 3 to 4 years the price of oil rises, the new field-development-optimization strategies we are testing and applying now will serve our industry well, optimizing and lowering the break-even thresholds for the huge resources we still need to produce worldwide. **JPT**

Maria A. Capello, SPE, is an executive adviser with the Kuwait Oil Company (KOC) for the North Kuwait Asset, advancing strategic initiatives in reservoir-management best practices for all assets of KOC and diversity for all companies upstream and downstream of the Kuwait Petroleum Corporation holding. She is an experienced consultant for the oil and gas industry and an expert in field-development and -monitoring strategies. Capello has worked in Latin America, the United States, and the Middle East. She holds a licentiate degree in physics from Simon Bolivar University and an MS degree in geophysics from the Colorado School of Mines. Capello holds an honorary lifetime membership from the Society of Exploration Geophysicists and has received its Distinguished Member and Regional Service awards. She serves on the *JPT* Editorial Committee and can be reached at mcapello@kockw.com.

Recommended additional reading at OnePetro: www.onepetro.org.

SPE 178191 Cluster Wells Applied in Wetland Environment in North Azadegan *by Bingshan Liu, CNPC Drilling Research Institute, et al.*

SPE 177204 Defining the Optimum Exploitation Strategy Combining Water Injection, Field Development, and Artificial-Lift Analysis to a Mature Field Through Surface and Subsurface Coupled Models *by O. Espinola, Schlumberger, et al.*

SPE 175531 Effect of Well Spacing on Productivity of Liquid-Rich Shale Reservoirs With Multiphase Flow: A Simulation Study *by A. Khanal, University of Houston, et al.*

Sapinhoá Field, Santos Basin Presalt: From Design to Execution and Results

This paper presents the development of Sapinhoá field, covering the fast-track transition and decision-making process, from appraisal to conceptual and basic engineering of the Sapinhoá pilot project and on to its subsequent execution, highlighting the challenges, lessons learned, and results. Even though, at the time, several uncertainties about developing presalt areas were present, a fast-track strategy was chosen. A pilot project was seen as a means to provide valuable information for the remaining development of Sapinhoá and other fields in the presalt cluster.

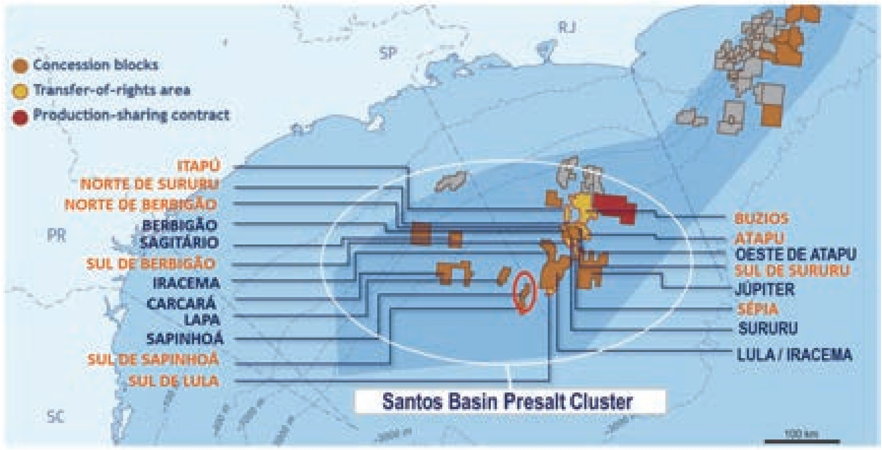


Fig. 1—Sapinhoá Field and Santos Basin presalt cluster.

Introduction

The Sapinhoá field is in Block BM-S-9 at the central portion of the Santos Basin (**Fig. 1**). The water depth is approximately 2140 m, and reservoir depth lies between 5000 and 6000 m, with salt-layer thickness up to 2 m.

The main objectives of the Sapinhoá pilot were to evaluate the production and injection behaviors in a carbonate reservoir of microbial origin and obtain information and provide technology development so that those could be used for the remaining development of the presalt cluster. This information would be useful to

- Define the best recovery method to be applied in future projects
- Define the best exploitation strategy
- Optimize location, geometry, and number of wells
- Evaluate reservoir hydraulic communication
- Estimate vertical and horizontal permeability

Project Engineering: Concept Overview

Production-development plans consisted of the installation of a chartered floating production, storage, and offloading (FPSO) vessel in the field's south area; a well-construction campaign; a subsea gathering system; and gas-export-pipeline installation.

Well System. Well design for the Sapinhoá pilot had to take into consideration requirements from other disciplines, which affected final configuration, including the following:

- Scaling precipitation risk, which was mitigated through inclusion of a downhole chemical-injection mandrel
- Number of permanent downhole gauges (PDGs) per zone, to manage the reservoir better
- Remote selectivity of the producing/injection zone, achieved through the selection of hydraulically operated control valves
- Lithology uncertainties, mitigated by the use of large-bore wellheads, allowing an extra casing string without affecting production-casing diameter

The project final scope consisted of 11 wells—six producers, one gas injector, one water-alternating-gas (WAG) injector, and three water injectors that later could be converted to WAG injectors if necessary.

As for completion design, intelligent completion was the primary choice, followed by single-zone completion, depending on the number of intervals found. All wells had a 6⅝- and 5½-in. combined production string, in order to cope with the expected high flow rates. Acid stimulation was considered for all wells, not only to achieve the maximum flow rate but also to guarantee that the production or injection profile would be close to the simulated distribution. Smart wells included PDGs, chemical-injection

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mandrels, and hydraulic valves below the feedthrough packer.

Subsea Production System. The development of a subsea production system for the Sapinhoá pilot was challenging. The carbon dioxide and possible hydrogen sulfide presence affected material selection for equipment and pipes in multiple ways because special alloys have longer lead times to delivery and required qualification of material and welding process. The 2000-m water depth, combined with metocean data that indicated a harsher environment in Santos Basin than in Campos Basin, posed a problem to riser design and installation. Finally, reservoir pressures and the requirement to inject gas demanded a highly resistant gas-injection line.

A buoy-supporting-riser (BSR) concept was considered the alternative with the best economics after technical-viability verification. The decoupled BSR gathering system was a new riser concept featuring a tethered buoy, measuring 52×40×10 m, which is submerged approximately 250 m and has 22 to 28 risers connected to it, including steel catenary risers (SCRs) for production and injection purposes, flexible lines for gas lift, and electric/hydraulic umbilicals.

The remaining architecture of the subsea system included satellite production wells connected individually from each pipeline end termination to its respective tree through flexible flowlines and a vertical connection module.

Flow-Assurance System. The main concern regarding flow assurance for the Sapinhoá pilot was the possibility of scaling precipitation in the production string. To mitigate this risk, it was recommended that all wells be stimulated to full capacity because smaller drawdowns reduced precipitation. Downhole scaling-inhibitor injection also was necessary because the precipitation normally occurs at the largest-differential-pressure point, which is the transition between the reservoir and the well.

FPSO Vessel. The FPSO vessel *Cidade de São Paulo* was converted from a double-sided single-bottom vessel in China, with the process modules being constructed at different sites worldwide and integrated at Brasfels shipyard in Brazil. The process plant has overall capacities of 120,000 B/D of oil, 150,000 B/D of liquid, 150,000 B/D of water injection, 5 000 000 m^3/d of gas production, and 3 250 000 m^3/d of gas export.

Project Strategies: Dealing With a Fast-Track Execution

Because of the fast-track guidelines adopted for this project, the project scope began being defined at an early stage. Strategies were needed that could guarantee some flexibility for the project, allowing for changes in the future.

Well-Construction Campaign. The strategy adopted for well construction was to charter three rigs to be dedicated to all projects of the block, including the Sapinhoá pilot. With dedicated rigs for the project, it was possible to specialize each of them in certain activities and, consequently, optimize the wells campaign, reducing time for each activity.

Subsea Equipment. Because of the scope uncertainties and the long-lead-time supply for subsea equipment, the presalt tree standard was defined as a unique model that could be used for producers, water injectors, gas injectors, and WAG wells. That way, the order could be made even if the scope or sequence of well construction had not been fully defined.

FPSO-Vessel Construction. The *Cidade de São Paulo* process plant was designed so that it would be able to receive different kinds of fluids and to deal with different recovery methods in the future.

Project Execution: Results and Lessons Learned

Reservoir Results. The drilling results confirmed the expectations for the Sapinhoá field, presenting excellent productivity and injection. The initial-production potential flow rates are ranging between 29,000 and 36,000 B/D, surpassing conceptual-design estimates of 25,000–30,000 B/D.

Wells Campaign. The Sapinhoá pilot well-engineering program had to deal with uncertainties and challenges from a technical point of view and from the imposed fast-track approach.

Despite this environment, the Sapinhoá pilot well-construction-campaign costs and schedule performance were reduced significantly during its execution because of an accelerated experience curve. At the basic-engineering phase, the campaign duration was estimated to last 2,368 days. It is now projected to take 1,997 days, a 15% reduction.

Subsea System. Because of the fast-track implementation and the innovative aspects related to the presalt subsea equipment, the first deliveries suffered delays, mainly with regard to the trees. To deal with that, the project team had to review its well-campaign schedule continuously, postponing some well completions and anticipating the drilling of new wells.

At the end, those delays had no direct effect on the project ramp up because the wells campaign was executed faster than planned.

Conclusion

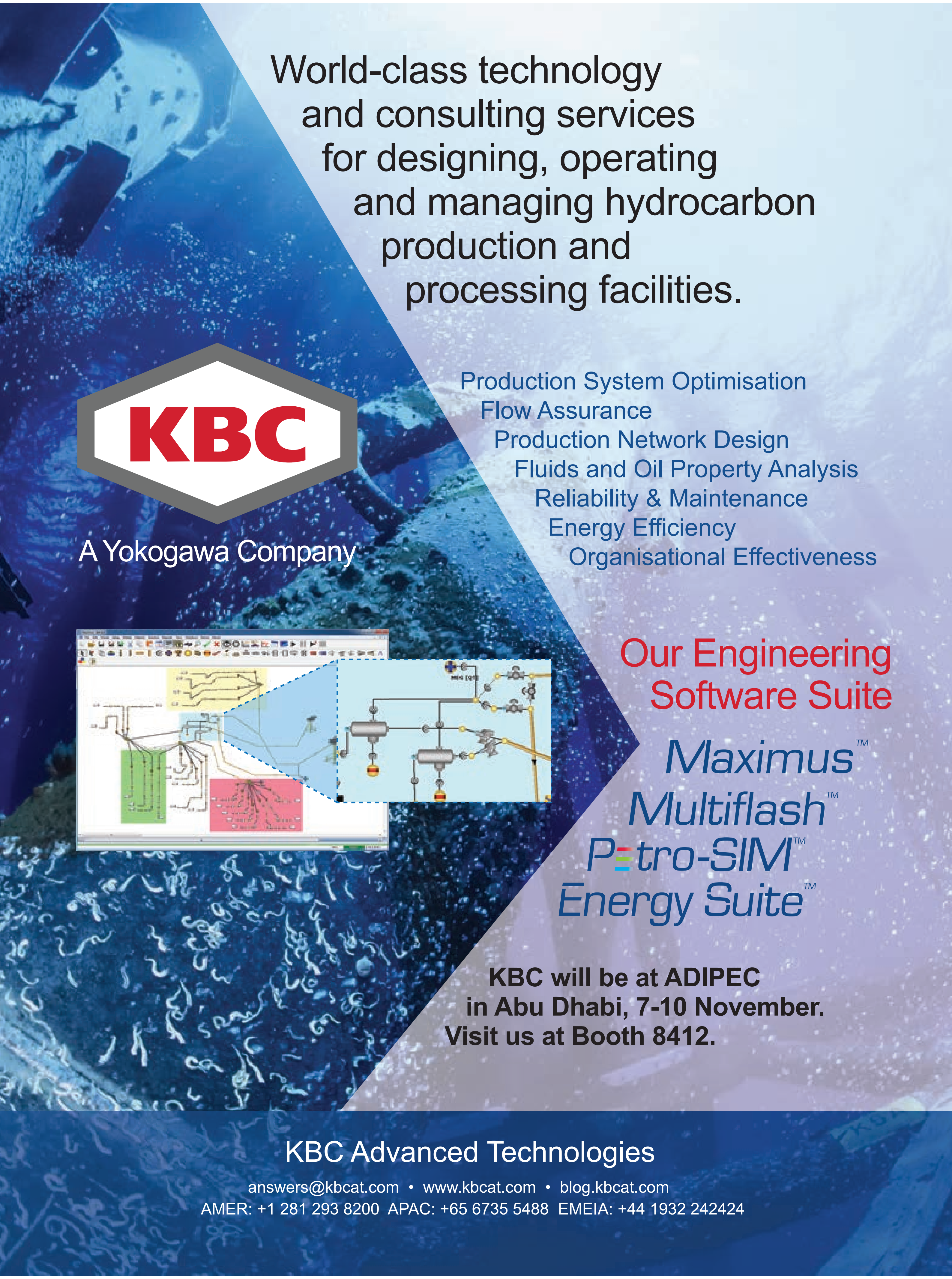
In spite of all the challenges and risks envisioned at the conceptual phase, the Sapinhoá pilot managed to become a successful project, both technically and economically. Approximately 1 year after the field's declaration of commerciality, the production unit was already operational, and, 2½ years after startup, oil production is at peak.

In order to deal with the complexity and uncertainties of the reservoir, combined with the fast-track implementation, the project conception and development strategies needed to be based on two pillars: flexibility and robustness.

Flexibility. This was applied, for example, in different possible recovery methods, number of wells, well-construction configurations, contingency plans for subsea activity, and different FPSO operation methods.

Robustness. This was applied, for example, with tree specifications, metallurgy selection, and wellhead and casing design.

The continuous search for and implementation of flexible and robust solutions were key success factors of the project, enabling the management team to deal with design and execution changes as they appeared, keeping the project optimized. **JPT**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Improving Megaproject Economics Through the Use of Early Production

A key aspect of the project discussed in this paper is the use of minimal initial-production facilities to achieve significant early production from each of four preconstructed artificial islands. The initial-production facilities leverage the use of spare processing capacity on existing adjacent satellite platforms to allow for production from each of the islands during the 4-year period between completion of the first wells and completion and startup of the permanent production facilities.

Introduction

The project is approximately 80 km offshore in the Persian Gulf and consists of four artificial islands. The objective of the initial production phase is to provide early and sustained production from wells drilled on the islands as soon as they are available, thereby achieving advanced revenue generation and improved project economics while the permanent production facilities are under construction.

Initial startup was achieved from the first island in November 2014, followed by initial startup of the second island in April 2015. This is the first phase of the plan to increase production from the field by approximately 40%. The project is segmented into an initial-production phase and permanent production buildup phases. The initial-production phase will continue until completion of the first permanent production buildup phase in 2018.

The project achieved startup of initial production within 4 years of conceptual design in 2010 and a minimum of 4 years before completion of the permanent production facilities, thereby achieving the goal of capturing the benefits of the initial-production strategy.

Benefits and Challenges

The initial production strategy evolved and was optimized from conceptual design through front-end engineering and detailed design, resulting in the fit-for-purpose initial-production facilities for the first three islands. Given the short operating duration of the initial-production facilities, cost efficiency was the key driver in decision making. To ensure implementation of only the most cost-effective fit-for-purpose facilities, the early operating experience from the first island was used to simplify further the design of the initial-production facilities on the fourth island.

Achieving the execution schedule for the initial-production facilities to allow startup to be achieved as early as possible in the drilling program, to maximize the duration of the initial-production phase, was a key driver and challenge. Without effectively managing the execution schedule to achieve startup on each island as planned, the economics of the initial-production phase becomes considerably challenged.

The project management team took a structured approach and implemented several key initiatives to allow efficient execution of the work while maintaining excellent safety performance. This structured approach was instrumental in managing the key project interfaces associated with the ongoing drilling program, space limitations inherent to an island, multiple contractor interfaces, logistics challenges, and simultaneous operations.

The initial-production facilities on each island were designed to avoid interference with the drilling program and construction phase of the permanent production facilities. Piping headers, as well as basic lighting, instrumentation, and controls to allow sustainably safe operation, were all designed to fit within a small space in such a way that the drilling rig could maneuver over the facilities to reposition to new drilling locations free of clashes with the initial-production facilities. This also will allow for easy dismantling of the facilities without production interruption following startup of the permanent production facilities. It was a significant design challenge to arrange all components of the facilities within the defined envelope, but achieving this allowed for increased production and, ultimately, approval of a more economically feasible project.

Coordination with the drilling group was integral during the design of the facility, to ensure that emphasis on safety in design was applied while also helping to ensure minimum downtime of the facilities. As part of the simultaneous operations on the islands, the initial-production-facilities scope is designed, installed, and commissioned in such a way that the drilling sequence of the wells requires no shutdown for the hookup of a new well to commence production. Continuous coordination meetings were held with the drilling group along with a structured approach to design freezes to the initial-production-facilities engineering to allow the drilling group the maximum flexibility in planning and initial drilling on each island while ensuring that fabrication and construction of the initial-production facilities could commence without affecting the schedule.

The initial-production facilities follow a low-cost, keep-it-simple philosophy. Given that the facilities are intended only for short-term operation, they require mainly attended operation, using manual valves, with the exception of the shutdown valves. On the first three islands, the facilities also share test headers and mul-

*This article, written by Special Publications Editor Adam Wilson, contains highlights of paper SPE 177729, "Improving Megaproject Economics Through the Use of Early Production," by **James A. Volker** and **Adam J. Bond,** Zakum Development Company, prepared for the 2015 Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, 9–12 November. The paper has not been peer reviewed.*

tiphase flowmeters. The fourth island was added after the initial three islands were designed, and experience learned from the previous islands was used to achieve greater efficiencies in the design and operations by removing the test header and temporary-equipment room altogether.

In addition to generating revenue with minimized investment, the initial-production facilities also provided a valuable mitigation for any schedule delays that might have been incurred regarding the completion of the permanent production facilities because all drilled wells are still able to produce through the initial-production facilities up until the planned startup of the permanent production facilities.

Startup of production from the first and second islands occurred soon after the first two wells were completed on each island, allowing for the minimum design flow requirements for the initial-production facilities. Subsequent wells are progressively hooked up to the initial-production facilities immediately following completion of drilling. Project teams have minimized the duration from completion of drilling to production flow by preinstalling all major components, except for the closing spool to the wellhead. All commissioning activities are completed before final hookup. Well-operations and project-construction teams complete their activities in parallel, to the extent possible, to reduce hookup duration following completion of drilling. This approach has been successful at quickly producing wells as they become available. Wells continue to be hooked up in an expeditious manner, and the third island will start up immediately following the completion of the first well.

One of the key challenges during the initial-production phase is the high degree of simultaneous operations during construction, and even more so after startup, on each island. Before initial startup on each island, the detailed coordination of work activities requires construction activities to progress efficiently in conjunction with drilling operations while minimizing the risk to personnel. Following startup, construction and commissioning activities associated with future well tie-ins occur in conjunction with ongoing drilling operations adjacent to producing facilities and alongside ongoing well operations and construction of permanent production facilities. This proved to be a substantial challenge considering the close, 6-m well spacing on the islands and numerous drilling locations per island. This challenge is managed and controlled by implementing detailed simultaneous-operations guidelines and procedures containing rigorous work-management and permitting requirements. Finally, strict and ever-changing area ownership and work-management principles have been applied, allowing for project, drilling, or operations ownership, depending on the phase of the project in any given area. Hard barriers are erected before startup, and areas adjacent to the live production facilities are under controlled access by the operations group as the area authority. Work performed outside this controlled-access area remains under the stewardship and permitting control of either the drilling group or the project group. This allows the party best suited to the environment to control the work and safe-working procedures.

Conclusion

The strategy to include an initial-production phase in the overall project-development scheme has been implemented successfully in a cost-effective manner by leveraging the spare processing capacity on the existing satellite platforms in conjunction with installation of minimal new initial-production facilities on each of four preconstructed artificial islands along with short interconnecting pipelines. Tightly controlled, cost-driven design and operating criteria ensured that the completed initial-production facilities were fit for purpose for the short 4-year operating life. The structured approach to managing the simultaneous operations and key interfaces helped deliver the execution certainty required to achieve completion of the initial-production facilities on the first three islands safely within the same time frame as completion of the initial wells required for startup, thereby maximizing the duration of the initial-production phase and maintaining the attractive project economics. Successful implementation of the initial-production phase also provides a valuable mitigation for any schedule delays that may be incurred with regard to completion of the permanent production facilities. **JPT**

Completion and Well-Spacing Optimization for Horizontal Wells in Pad Development

In organic shales, hydraulic fracturing is important for optimizing the production of horizontal wells. For a standalone lateral, the propped surface should be maximized to increase production. In the case of a pad, well spacing is an additional factor. Competition for production between laterals of a given pad should be minimized and is the result of both well spacing and hydraulic-fracture design. A numerical model coupling an explicit description of the hydraulic-fracture geometry and reservoir simulation is proposed to evaluate production interference.

Introduction

Well Spacing. One of the more critical questions that any asset team must consider concerns well spacing when designing the development plan for a new field. Well spacing defines the total number of wells, the drilling and completion schedule, and the field-production curve. The ultimate decision relies on economic analysis, balancing the expected ultimate recovery against capital and operational expenditures.

This work focuses on methods to evaluate different well spacing and on how to reduce the range of uncertainty in the development of the Vaca Muerta play.

Well-Spacing Evaluation. Well spacing depends on geomechanics, petrophysics, stimulation design, hydraulic-fracture geometry, and reservoir fluids. These factors are combined by use of numerical simulation to study their effects on the well spacing. The following are some of the methods that are applied to define possible well spacing.

Analogs. Using analog methods requires an older field already in development with similar rock and fluid quality, structural complexity, well architecture, and hydraulic-fracture stimulation. The analog approach leads to large uncertainties if any of these parameters are not within the same range or if the older analog field does not have sufficient statistical representation.

Simple Reservoir Description Without Explicit Hydraulic-Fracture Description. The first step in simulation is to start with a simple reservoir description in which each property is uniform (porosity, permeability, and fluid saturations). The reservoir model is then coupled with an analytical or numerical production simulator. This kind of approach is appropriate for a field with minimal information. The hydraulic fractures are represented as parallel planes that intersect the wellbore. Hydraulic-fracture properties are kept constant over their whole surface and along the lateral.

Simple Reservoir Description Including Explicit Hydraulic-Fracture Description. The next level of complexity with a simple reservoir-description model is to include variation in propped-fracture geometry. Some commercial software can handle this type of model, where each fracture can be defined individually in terms of length, height, and the angle with respect to the wellbore.

Complex Reservoir Description Without Explicit Hydraulic-Fracture Description. In the previous two methods, the simple reservoir description allows for an analytical model to be run in seconds or a numerical model in minutes. However, describing each reservoir property by a single value does not allow consideration of spatial variation of the reservoir. Once a larger set of static data becomes available, a more comprehensive model can be set up to assess the presence of, for example, petrophysical variations within the reservoir and their effect on the well spacing. This approach requires a complex numerical reservoir simulator. The fracture geometry is kept simple, building each fracture as a surface of constant properties in a single-porosity model or as creating a zone of enhanced porosity.

Complex Reservoir Description Including Explicit Hydraulic-Fracture Description. The last type of model features the explicit description of the hydraulic-fracture geometry by use of a fracture simulator along with a detailed description of the reservoir. Both hydraulic-fracture geometry and reservoir description are then merged into a simulation grid.

Production-Interference Characterization. Interference between wells in unconventional developments is more common than expected and can occur at different stages of well life. The interference could be

- Between a well being drilled and an adjacent well being stimulated
- Between two wells being stimulated
- Between a well in production and an adjacent well being stimulated
- Between two wells in production

In this work, focus is placed on the latter two types of interference, given their possible reduction of estimated ultimate recovery.

*This article, written by Special Publications Editor Adam Wilson, contains highlights of paper SPE 180956, "Completion and Well-Spacing Optimization for Horizontal Wells in Pad Development in the Vaca Muerta Shale," by **M. Suarez**, SPE, YPF, and **S. Pichon**, SPE, Schlumberger, prepared for the 2016 SPE Argentina Exploration and Production of Unconventional Resources Symposium, Buenos Aires, 1–3 June. The paper has not been peer reviewed.*

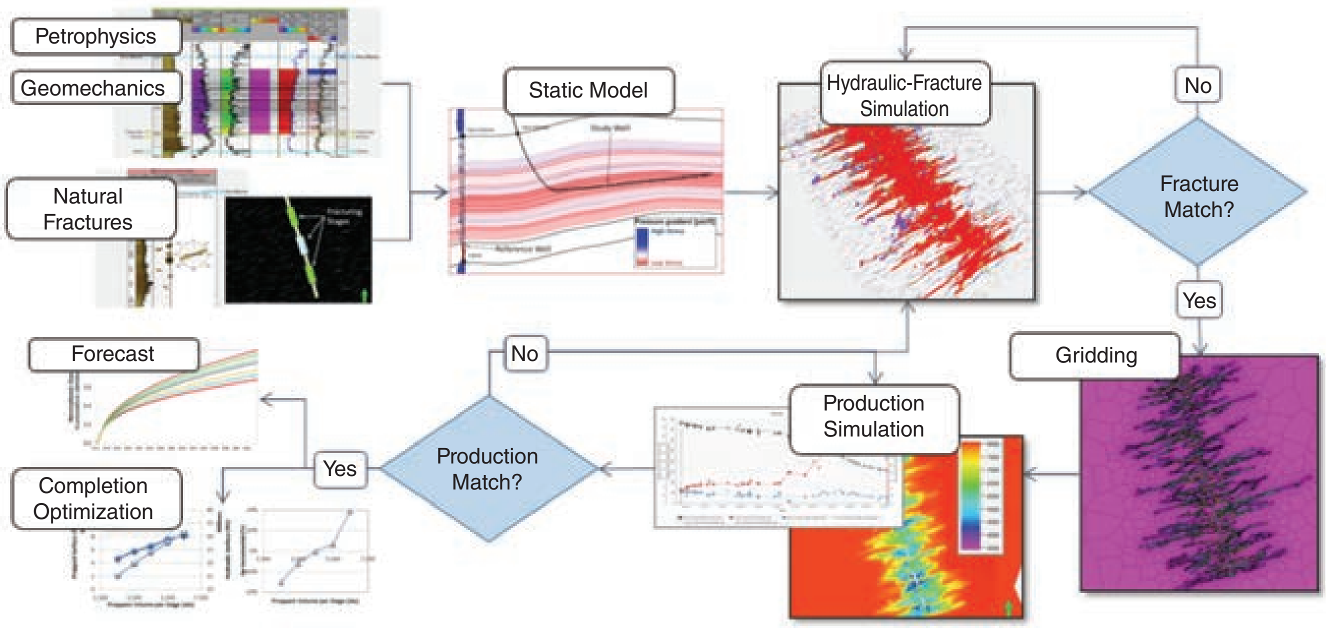

Fig. 1—Reservoir-centric fracturing-to-production work flow.

Methodology

Reservoir-Centric Fracturing-to-Production Work Flow. To model horizontal wells in organic-rich shale optimally, emphasis is made on maximizing the integration of reservoir description with the resulting propped hydraulic fracture that can be designed. This is achieved by coupling a hydraulic-fracture simulator with a reservoir simulator.

The reservoir-centric fracturing-to-production work flow (**Fig. 1**) allows for a high level of integration along with the possibility of separately varying each input to evaluate its effect on overall production. The basic steps of the fracturing-to-production work flow are the following:

- Integrate petrophysics, geomechanics, and natural-fracture characterization along with reservoir structure in a static model.
- Hydraulic-fracture simulation is performed using observed pressure data from fracturing operations as calibration points. It must be noted that the hydraulic-fracturing model solves explicitly for the interactions between geomechanics and natural fractures to define the resulting hydraulic-fracture geometry.
- For flow/production simulation, hydraulic-fracture geometry is explicitly gridded in an unstructured manner, populating properties from the formation from the petrophysical inputs and the properties of the hydraulic fractures as per the hydraulic-fracture simulation.
- A production history match is performed, adjusting dynamic properties of the reservoir to the production data.

From Single Well to Multiple-Well Pad. Well spacing being the final objective of the study, and knowing that production interference is because of the overlap of hydraulic fractures from different wells, the reservoir-centric fracturing-to-production work flow is the best-suited methodology.

To mimic the behavior of laterals in field development, a three-well-pad approach is proposed. Then, to evaluate production interference, two cases are proposed.

Single-Well Simulation. This considers a central standalone lateral. The single-well case is used as a baseline in which no production interference impairs well final recovery.

Pad Simulation. After emulating the hydraulic fracture in each of the wells, the pad is produced in a multiwell reservoir-simulation mode. This allows the pad case to consider explicitly the potential reduction in the rate of the central well caused by overlap of the drainage areas of the three wells.

Discussion

Hydraulic-Fracturing-Treatment Size. When designing a stimulation treatment for a well, a strong correlation has been seen between the propped area and final hydrocarbon recovery. The simplest option is to increase the treatment size and proppant mass. The higher production rate then can justify the increased cost. However, when considering competing production between neighboring wells within a pad, a new constraint to stimulation-treatment size is introduced.

To evaluate the case, a sensitivity analysis is performed by varying the size of the fracturing treatments while maintaining constant the number of stages and fluid and proppant-type fractions and comparing scenarios of a standalone lateral and a lateral surrounded by hydraulically fractured and producing neighboring wells. When comparing standalone-well and well-in-pad scenarios, the relative cumulative hydrocarbon gain when increasing the total amount of proppant per well is reduced by half when the well is competing for production with neighbors. Simply increasing the hydraulic-fracture size, even if effective for a single well, might not be the optimal solution for a pad development.

Stage Number and Cluster Spacing. The number of hydraulic fractures per lateral length is another design parameter. A sensitivity analysis is performed keeping the number of clusters per stage constant but increasing the number of hydraulic-fracturing stages from 15 to 20 within the lateral. Increasing the number of fracturing stages increases the total number of perforation clusters and reduces the spacing between perforation clusters.

When comparing simulated production in the pad configuration, the 15-stage scenario is shown to outperform the 20-stage scenario for long-term hydrocarbon recovery, regardless of the size of the hydraulic-fracture treatment. This result is counterintuitive but must be considered in the scope of hydraulic-fracture geometry and the resulting propped surface. In a horizontal well, competition for growth from the stress shadow within and between stages is an important factor to consider. By reducing the spacing between perforation clusters, each independent hydraulic fracture suffers a stronger stress shadow. This stronger stress shadow results in a higher fracture-propagation pressure developing within each hydraulic fracture. This higher fracture-propagation pressure strengthens the disequilibrium of fluid distribution among perforation clusters that limited entry might not be able to overcome. An uneven fluid distribution finally leads to a smaller created propped surface and then affects hydrocarbon recovery.

Well Spacing. The first option to reduce the competition between neighboring wells is to increase well spacing. Two cases are simulated by keeping the well completion constant but considering two different well spacings. Increasing well spacing leads to higher production and reduces the relative difference between a well in a pad and a standalone well.

However, by increasing well spacing, even if the performance of an individual well is improved, the total number of wells to develop a given area would be reduced, which might reduce total field production.

The method presented allows for the evaluation of the relative effect of each scenario and its economic outcome over the global field development. **JPT**

New-Frontier Reservoirs II

Leonard Kalfayan, SPE, Global Production Engineering Adviser, Hess Corporation

With crude-oil prices continuing to languish, margins in tight-reservoir-asset developments have continued to tighten and new drilling and completion activity, of course, is substantially reduced. Looking back 2 years, the focus in onshore-asset development has essentially shifted entirely from fast-paced growth of tight hydrocarbon reservoirs to production enhancement from existing (but still profitable) wells, as well as to maximizing productivity from the smaller number of new well completions.

However, enhancing production from multizone, propped-fracture completions in tight reservoirs, for example, is not straightforward. There are questions to address, especially with respect to the understanding of the contribution of natural fractures and induced unpropped (IU) fractures. How can natural and IU fractures be accessed or enhanced in new wells or in existing wells that are candidates for refracturing? Is there an opportunity with the use of smaller proppants? What are the implications of fracture and well spacing? Can the pumping and rate steps of fracture stages be redesigned for improved containment and fracture conductivity, even formation permeability enhancement? Are there learnings from long-term injection operations in tight reservoirs that can be applied to well-stimulation operations?

[E]nhancing production from multizone, propped-fracture completions in tight reservoirs, for example, is not straightforward. There are questions to address, especially with respect to the understanding of the contribution of natural fractures and induced unpropped fractures.

Also, for existing well completions, can reactive fluid (e.g., acid or other chemicals) be used effectively, and, if so, how? Can well production be enhanced by injection of fresh water to remove salt potentially residing in existing natural-fracture systems?

The papers featured this month provide assessments and discussions concerning these and other related questions. Each paper is unique, but they all share the intent of advancing efforts in enhancing production from existing and new well completions in tight reservoirs. **JPT**

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Recommended additional reading at OnePetro: www.onepetro.org.

SPE 180274 **Study of the Rock/Fluid Interactions of Sodium and Calcium Brines With Ultratight Rock Surfaces and Their Effect on Improving Oil Recovery by Spontaneous Imbibition** *by M.K. Valluri, Texas A&M University, et al.*

SPE 169843 **Estimating Long-Term Well Performance in the Montney Shale Gas Reservoir** *by Vu P. Dinh, Murphy Oil, et al.*

IPTC 17739 **A Comparison of North American and International Risks in Unconventional Resource Plays** *by D. Nathan Meehan, Baker Hughes*

The Role of Induced Unpropped Fractures in Unconventional Oil and Gas Wells

The term induced unpropped (IU) fractures refers to fractures created around the main propped fracture that are too small to accommodate any proppant. These could include natural fractures and microfractures induced along bedding planes or along other planes of weakness. On the basis of production data, diagnostic methods, and field observations, it is becoming increasingly clear that IU fractures created during the hydraulic-fracturing operation play a critical role in determining the success of fracture treatments.

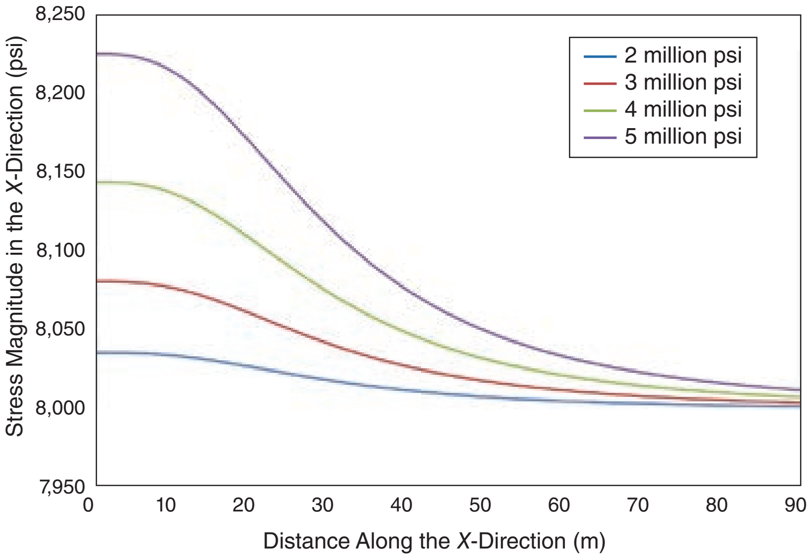

Fig. 1—Effect of Young's modulus on the stresses in the direction perpendicular to a penny-shaped fracture. The in-situ minimum horizontal stress used here is 8,000 psi, Poisson's ratio is 0.2, the desired maximum width of the fracture is 1 cm, and fracture height is 100 m.

Introduction

There has been a debate about whether certain shales are naturally fractured. The classic example of this is the Barnett Shale. Many authors have suggested that the Barnett Shale is highly naturally fractured, whereas others have argued that field observations in the Barnett can be explained on the basis of geologic lithofacies and heterogeneity. Observations made on cores clearly indicate the presence of fractures. Mineralization on the faces of these fractures indicates that they are not drilling-induced fractures but are instead native to the Barnett. Similar questions and discussions have arisen about the role of natural and induced fractures in other shale plays.

One reason that it is often difficult to resolve questions about natural fractures in shales is the extreme level of heterogeneity commonly observed in many types of shale. Differences in lithology and the highly laminated nature of many types of shale are apparent when viewing cores from source rocks such as the Eagle Ford Shale. In some instances, the boundary between the lithologically distinct layers is sharp and well-defined, but, in other instances, it is diffuse and displays its own characteristic lithologic gradation. Boundaries between lithologically distinct layers can often act as planes of weakness along which fractures can develop under stress.

What Are IU Fractures?

Microfractures can also be created in the rock by the mechanical stresses and strains imposed on the rock fabric during the process of creating the main hydraulic fracture. **Fig. 1** shows the magnitude of the stress induced by the creation of the main fracture as a function of distance from the fracture for several different values of Young's modulus. These stresses can result in the tensile or shear failure of planes of weakness that may be present in the rock. These stress-induced cracks can be referred to as IU fractures.

For the purposes of this paper, IU fractures are broadly defined as fractures that have widths that are so small that they are unable to accommodate any proppant, and as such will close over time as the fluid pressure within them is decreased. The presence of these induced microfractures is difficult to detect and prove because it cannot be observed in cores or on logs. Instead, one must infer the existence of these fractures indirectly by observations made through microseismic monitoring, production history matching, and interference between wells. The following subsections present five forms of evidence for the presence of these fractures.

The Fate of Injected Fracturing Water. Thousands of gallons of water are pumped into each fracture stage during a fracturing treatment. The fluid injected goes from the wellbore to the propped fracture and

This article, written by JPT *Technology Editor Chris Carpenter, contains highlights of paper SPE 174946, "The Role of Induced Unpropped Fractures in Unconventional Oil and Gas Wells," by* ***M.M. Sharma*** *and* ***R. Manchanda,*** *The University of Texas at Austin, prepared for the 2015 SPE Annual Technical Conference and Exhibition, Houston, 28–30 September. The paper has not been peer reviewed.*

leaks off into the reservoir. It is illustrative to perform a simple volume balance on the injected fluid to estimate the amount of fluid that is expected to go into each of the hydraulically connected regions.

On the basis of the simple material balance of the fracture fluid presented in the complete paper, the created area of these IU fractures is expected to be at least an order of magnitude larger than that of the main propped hydraulic fracture.

Another observation that supports this hypothesis of a large area associated with the network of IU fractures is the consistent observation from field data that, during flowback, most of the water that is injected is trapped in the formation and is not produced back immediately.

Production Response of Fractured Wells. When reservoir simulations are conducted to match the production response of horizontal wells completed in ultralow-permeability rocks such as shales, the production predicted from simulations is significantly lower than that of the field-measured production when using the matrix permeability. This is not the case with higher-permeability rocks. Several authors have discussed the concept of having a stimulated reservoir volume (SRV) in the vicinity of the hydraulic fractures and have analyzed the effect of SRV on the observed production.

This region of high permeability is a volume-averaged representation of a region where the presence of induced microfractures has increased the effective permeability of the rock. The precise density of microcracks and their orientation will depend on the rock fabric and the distribution of planes of weakness in the rock. A description of the rock at this level of detail is usually not available when describing the region around the main fracture.

Clearly, the process of history matching production data is not unique and there may be other sets of parameters that may provide a comparable history match. The characteristic of high initial production and a large initial decline rate is fairly typical of most shale production and can be matched best by postulating a region of high permeability around the fracture.

Microseismic Data. There is a large body of microseismic data that clearly shows the creation of shear-failure events during the process of fracturing. Not all of these shear-failure events result in the creation of fractures or even microfractures. However, slippage along planes of weakness does result in rupture of the existing rock fabric and the possibility of shear-induced dilation. Several authors have calculated the stresses in the vicinity of hydraulic fractures. These measurements can help to identify regions that are more probable to have shear failure and, thus, estimate the regions in which microseismic events may occur.

The density of microseismic events has sometimes been used as a surrogate for the density of microfractures that are being created. Whether these microfractures enhance permeability depends entirely on rock properties such as mineralogy and the in-situ stress state. In reservoirs with a high stress contrast, more-planar fractures are observed, while, in rocks under low stress contrast, the microseismic pattern indicates more-complex fracture patterns.

In most horizontal wells, microseismic events from one perforation cluster or stage overlap with those from an adjacent stage. This implies that shear-induced microfractures from one stage may hydraulically interact with another stage or another well. This is the case in many instances where pressure communication between stages and between wells is commonly observed. This would not be possible without high-permeability channels between wells that allow the pressure pulses to propagate such large distances.

Tracer Data. Tracer data also strongly suggest that pathways for fluid migration (IU fractures) exist. The results of previous studies that support this conclusion are presented in detail in the complete paper.

Pressure Communication Between Wells. Several authors have presented data showing the pressure response in a well when an adjacent well is being fractured. In some instances, pressure communication is observed not only in adjacent wells, but also in a well that is one well removed from the well being fractured and is more than 1,200 ft away. Clearly, the fracturing process is creating

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Injection in Shale: Experience on the Norwegian Continental Shelf

Waste injection in shale, with matrix permeability in the nanodarcy range and without the presence of any permeable layers, has been performed on the Norwegian Continental Shelf (NCS) for more than 15 years. To avoid leakages to the seafloor using this method, techniques have been developed that allow wells to dispose of several million barrels into individual shale domains, with vertical propagation of the disposal domain less than 1,000 ft above the injection point. Recently, use of frequent 4D interpretations of seismic surveys shot over a permanent sensor array allowed detailed domain mapping and independent dynamic monitoring.

Historical Perspective

Changes of North Sea regulations in the mid- to late 1990s made the seabed disposal of oily cuttings and other waste from drilling and production impossible without the use of significant topside cleaning systems. Meanwhile, the development of fields required increasingly complex wells, resulting in the almost systematic use of oil-based mud for efficient drilling. This led to a dual challenge for the industry, with an increased amount of waste generated and the difficulty of discharging it. Options were then reviewed between shipping onshore and treatment or reinjection into the subsurface with cuttings-reinjection (CRI) wells (a typical design of a CRI well in the Ekofisk Field region is outlined in the complete paper). Most operators concluded that the CRI option was much safer and more economically favorable than shipping to shore and onshore treating and disposal.

A survey of all CRI wells on the NCS noted that 110 had been or were operating, with approximately 30 of them still active at the time of the survey. This confirms the attractiveness of CRI wells as a means of waste disposal, at least as far as the NCS is concerned. Unfortunately, the same survey also revealed that 14 of these 110 wells had suffered from a leakage to the seabed, thus illustrating the risks associated with CRI operations.

An outcome of the investigation was the discovery that a vast majority of the leakage-to-seafloor cases occurred in wells where shallow sand bodies were lacking or where their quality was very poor. This justifies the general strategy traditionally adopted by Norwegian operators (i.e., avoiding the upward migration of hydraulic fractures with high-permeability sand bodies); this emphasizes the risks associated with the lack of good-quality "blanket" sands above the injection point.

Challenges and Opportunities for Waste Injection in the Ekofisk Field Region

The Ekofisk field is situated in the southern region of the Norwegian North Sea, close to the British and Danish sectors in an area where the Utsira sand is not present. The main challenges are the amount of waste generated every year at a regular rate (i.e., approximately 850,000 bbl/yr to be injected) and the absence of any significant permeable layer in the overburden of the field that can act as a barrier for the vertical propagation of the hydraulic fractures created during injection. One certainty is that the injection of such high volumes cannot be performed through a single discrete fracture, because it would necessarily extend all the way to the seafloor.

The main opportunities, though, involve the quantity and quality of monitoring systems used in the Ekofisk field, which are almost unique in the world. The systems include frequent seafloor bathymetry, regular logging of all wells, permanent downhole gauges, use of fiber optics along the tubings, and permanent seismic arrays on the seafloor, allowing both passive seismic monitoring and active seismic shooting every 6 months. A side benefit of this exceptional array of techniques is the possibility of detecting any anomaly caused by waste reinjection and the possible migration of fractures toward the seafloor.

The decision by the operator to inject the waste into the Ekofisk overburden resulted from a balanced approach using the opportunities offered by the monitoring systems to detect any abnormal vertical propagation of the waste-disposal domain and possible leakage that could have been triggered by the lack of a good-quality sand layer in the Ekofisk overburden formation. The environmental and economic benefit of this balanced approach has been demonstrated clearly by the more-than-15-year history of cuttings injection into the overburden in six wells in the greater Ekofisk area with no abnormal upward migration of the waste-injection domain, with no leakage to the seafloor, and with the capacity of some wells to accommodate up to 5 million bbl of waste fluids.

Round-the-Clock Monitoring and Real-Time Analysis

The analysis of past leakage cases shows that data acquisition alone is insufficient to ensure injection confinement and the avoidance of surface leakages. Conse-

This article, written by JPT *Technology Editor Chris Carpenter, contains highlights of paper SPE 170851, "Injection in Shale: Review of 15 Years of Experience on the Norwegian Continental Shelf and Implications for the Stimulation of Unconventional Reservoirs," by* ***F.J. Santarelli*** *and* ***F. Sanfilippo,*** *Geomec, and* ***R.W. James, H.H. Nielsen, M. Fidan,*** *and* ***G. Aamodt,*** *ConocoPhillips, prepared for the 2014 SPE Annual Technical Conference and Exhibition, Amsterdam, 27–29 October. The paper has not been peer reviewed.*

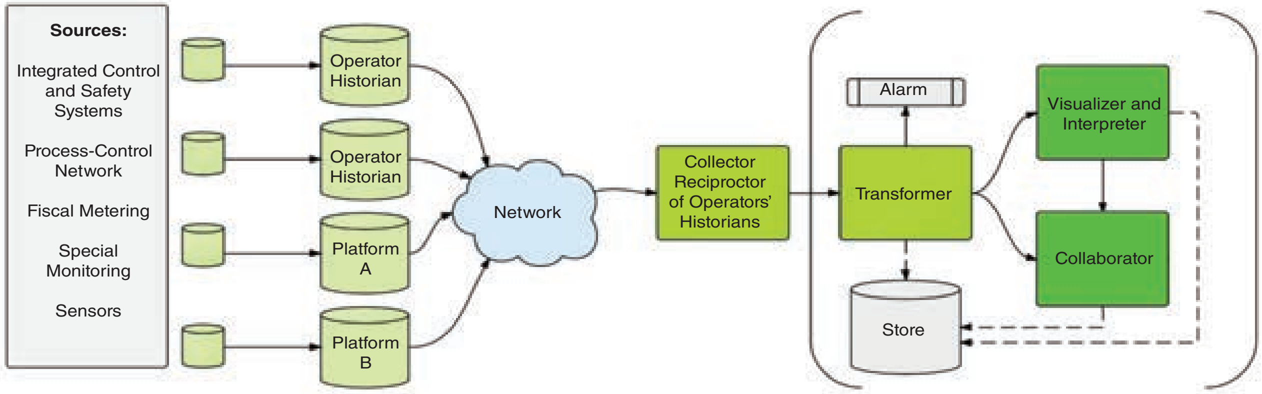

Fig. 1—Architecture of the system developed during the JIP on injection safety to ensure round-the-clock monitoring and real-time analysis of injection data.

quently, a joint-industry project (JIP) on injection safety was undertaken to develop a software system capable of performing automatic round-the-clock monitoring and real-time analysis of injection data for any given well. The architecture of this system is shown in **Fig. 1.**

The system has two key functions. One is to send an alarm or "flag" in case of anomalies in the injection process, and the other is to extract as much information as possible from the injection records. Both functions are performed simultaneously and benefit greatly from each other (e.g., the real-time extraction of the reservoir pressure in the injection domain allows round-the-clock calculation of the injectivity index and the detection of abnormal increases, which could be indicative of upward migration and eventual leakage).

The round-the-clock monitoring-and-automatic-alarm system fulfills three main roles, corresponding to three levels of alarms.

The first level simply ensures that all sensors are active when the injection process occurs and that adequate measurements are recovered effectively. The second level ensures that the procedures carefully established by the operator are followed effectively by the personnel performing the job. The third level detects and reports anomalies in the performance of the CRI well, which could correspond to a loss of injection efficiency or could mean an upward migration of the disposal domain, leading to leakage.

Mechanisms

It has been possible to dispose of millions of barrels of waste fluids in a limited volume of shale through a 10-ft-long perforation interval without any undue vertical extension of the disposal domain. The systematic extraction of information from all injection cycles has allowed quantification of three important features.

1. Injection of volumes of significant magnitude has been achieved by creating a multitude of fractures in the disposal domain instead of having a discrete number of fractures accommodating the injected fluid.

2. The secondary permeability in the disposal domain was repeatedly measured to be in the 0.1-darcy range, while the matrix permeability of the shale under realistic downhole conditions was measured to be between 10^{-9} and 10^{-8} darcies.

3. Another important observation is that the pressure inside the fracture network connected to the well is far in excess of the overburden stress and that the fracture network does not show any sign of extension after the well has been shut in, despite this very large net pressure.

From a physical perspective, two mechanisms acting simultaneously can be identified: One impairs the propagation of the

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Model for a Shale-Gas Formation With Salt-Sealed Natural Fractures

Most multiple-transverse-fracture horizontal wells in shale-gas formations remain in transient bilinear or linear flow for very long periods. However, there are often reported cases of shale wells that exhibit boundary-dominated flow in a very short period, which implies a stimulated rock volume (SRV) much smaller than would be expected. This paper offers an alternative explanation for the early boundary-dominated flow related to dissolution of salt-sealed natural fractures in the shale.

Introduction

Operators producing gas from the Haynesville, Marcellus, and Horn River shale formations have observed that produced water is more saline than the injected fracturing fluid. Additionally, the fraction of injected water that flows back when the well is put on production—termed load recovery—is low.

This study investigates the possibility that salts removed by flowing back injected low-salinity water-based fracturing fluid may be a mechanism for increasing the effective permeability in shale-gas wells within a limited volume surrounding the created hydraulic fractures. The study offers strong evidence that salt may be a key factor in productivity and ultimate gas recovery from shale-gas wells.

Interactions Between Fluids, Salt, and Shale

Several fracturing-fluid/formation interactive phenomena relate strongly to the material-balance model that the authors have developed. These phenomena include the imbibition and entrapment of injected fracturing fluid, the increase in salinity of the fluid in contact with the shale, and the deterioration of shale samples.

Several researchers have studied the relationship between the low load recovery of hydraulic-fracturing fluid and the elevated salinity of the fluid that does return. Many authors have proposed relationships between the surface area of the formation exposed to fracturing fluid, the characteristics of the fluid, the wettability of the rock, and the distribution or characteristics of the natural-fracture system. These findings are examined in detail in the complete paper.

Material-Balance Model for Injection, Flowback, and Production

The authors base a material-balance model on assumptions chosen so that the model applies to any formation that has a dissolvable mineral volume, measurable salt concentration in the flowback, inferred distribution of mineral in the formation, and inferred geometry of hydraulic fracture or SRV. Several of these assumptions are listed as follows:

- During a single-stage hydraulic-fracture treatment, the main fracture encounters a mineralized secondary fracture system. The secondary fracture system is represented as fracture porosity.
- Before the hydraulic-fracture treatment, the mineral in the secondary fracture system acts as a seal and as a barrier to flow.
- Where sodium chloride is the mineral in the secondary fracture system, hereafter it will be referred to as salt, with a fixed molar density of 1,049 mol/ft^3.
- As the main fracture opens under tensile failure, secondary fracture systems activate.
- Apart from imbibition, any leakoff during injection is only into the natural-fracture system.
- Injected water in the water-based fracturing fluid dissolves the salt encountered through leakoff into sheared mineralized fractures (equations for determination of compact dissolution are provided in the complete paper).
- Water in shear cracks of sufficient volume to dissolve the salt creates a productive secondary fracture system approximated as a dual-porosity continuum, described as fractures surrounding matrix cubes.
- The authors model the heterogeneous shale volume as homogeneous, with averaged inputs.
- Water in shear cracks of insufficient volume to dissolve the salt fails to mobilize gas.
- Water salinity increases in the main hydraulic fracture through diffusion from the secondary fracture system.
- Leakoff volume is equal to the volume remaining in the productive secondary fracture system plus the volume remaining in mineralized cracks plus the volume imbibed into the shale matrix.
- Initial flowback water is produced from the primary and secondary fracture systems by diffusion and displacement in response

*This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 175061, "Model for a Shale-Gas Formation With Salt-Sealed Natural Fractures," by **Hoagie Merry** and **C.A. Ehlig-Economides**, University of Houston, and **Pang Wei**, Sinopec Research Institute of Petroleum Engineering, prepared for the 2015 SPE Annual Technical Conference and Exhibition, Houston, 28–30 September. The paper has not been peer reviewed.*

to a pressure gradient and gas production, respectively.

- Imbibed water and residual water saturation in the propped fracture and in productive secondary fractures produce slowly in solution with gas.
- Newly productive secondary fractures are distributed evenly along the fracture plane.
- Dissolution of salt in shear cracks is slow compared with the time taken to flow into the cracks, and fast compared with the shut-in time before the onset of production to the well.
- The time required for water to imbibe into shale is fast compared with the time before the onset of production to the well.
- The bulk volume of rock containing newly productive secondary fractures has an effective permeability much larger than the shale-matrix permeability.

These assumptions allow adjustable user-defined inputs in order to match field data.

Shear-Fracture-Network Dissolution. Complete dissolution of salt in a sheared fracture enables the fracturing fluid to imbibe into the shale matrix and releases gas trapped in the shale matrix to flow into the newly developed effective permeability. However, complete salt dissolution requires an excess of leakoff fluid that will flow into sheared fractures but will not provide connection to gas in the shale matrix. A microseismic survey could give an impression of an apparent SRV larger than the bulk shale volume, with enhanced effective permeability caused by salt dissolution. The authors apply the term dissolved stimulated rock volume (DSRV) to the latter volume.

Subsections of the complete paper provide expressions for the determination of DSRV, fracture porosity, and imbibition volume.

Flowback and Production. The free-gas flow into hydraulic fractures before production can be described as countercurrent imbibition. By this mechanism, the volume of water imbibed from the main hydraulic fracture displaces an equivalent gas volume from the matrix into which it imbibes. This gas can contribute to elevated gas rate in early time, in part because of gravity segregation and the very high mobility ratio of gas to water.

Because the gas is replaced in the matrix by water that imbibes, this volume contributes to the displacement of water that is in the DSRV.

When the fracture has closed before the onset of well production, if no imbibition occurs, the volume that was occupied by salt and is exposed to surfaces open to imbibition has a maximum of 0.2 times the leakoff volume from the main fracture. The saturated volume leaked off into shear fractures outside the DSRV does not contribute to dissolution of salt and cannot imbibe because it is not in contact with an imbibing surface. The production mechanism for the water outside the DSRV is only pressure diffusion and isothermal expansion. Saturated water flowback from outside the DSRV can contribute no more than approximately 4% of the leakoff volume.

Gas will displace leakoff fluid from the main fracture and secondary fractures down to the residual water saturations in the main hydraulic fracture and in the secondary fracture system inside the DSRV.

Remaining residual water will then be vaporized with water/gas-ratio plot decline as the reciprocal of the cumulative produced gas. If imbibition occurs, the ultimate load recovery will be higher because less of the leakoff fluid will flow past the DSRV.

Regardless of whether imbibition occurs, the initial load recovery is a displacement process, and the ultimate load recovery through water vaporization is slow and will be produced in solution with the gas at much lower rates. As the residual water is produced from the main fracture and secondary fracture system, inferences can be made as to the change in permeability that may take place.

Conversely, as water is produced in solution with the gas, the dissolved salt that was suspended in the pore water is left behind; this salt may act to reduce the porosity and, hence, the absolute permeability.

The results of an example field case to demonstrate the applicability and the versatility of the model are provided in the complete paper.

Discussion

The hypothetical considerations in this work are consistent with many diverse investigations related to salt. An important implication is that fracturing with a fluid that would not dissolve the mineralized salt would not enable connection between previously mineralized fractures and the matrix and would not enhance the effective permeability of the shale. Despite its potential scarcity, in this scenario, essentially fresh water is the best fracturing fluid. This work also suggests that refracturing even without proppant may serve to restore lost permeability and extend the DSRV.

Conclusions

The objective of this research was to investigate the possibility that freshwater-based fracturing fluid injected into a shale formation could increase the permeability in a limited volume by dissolving salt in an existing natural-fracture system.

The authors developed a material-balance model that estimates the DSRV defined by the volume of shale gas rendered productive by injected water dissolving salt found in mineralized fractures sheared during hydraulic fracturing. The model presumes that produced gas will initially displace brine from propped and secondary fractures but that continued gas production will vaporize water from the remaining salt-saturated residual brine, depositing salt that could explain observed loss of shale effective permeability previously modeled as pressure-dependent permeability. The authors expect that, eventually, flowback-water salinity will drop to near zero.

A field application performed on the basis of data from Haynesville Shale wells shows that the developed material-balance model estimated a bulk DSRV that could be consistent with observed gas-production behavior exhibiting boundary-dominated flow after a short period on production and that the modeled water-trapping mechanisms are consistent with observed low load recovery. **JPT**

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a network of fractures that extends through the failure of planes of weakness and can propagate a long distance. The proppant cannot take this tortuous pathway and is only placed in the main fracture, leading to the creation of rather long and complex patterns of IU fractures that temporarily provide hydraulic conductivity over long distances.

An equally important observation that is made in this and other studies is that this pressure communication does not appear to last much beyond the time when the fracture is being pumped. For example, the production response of these wells does not indicate any production interference for the first few years of production. This suggests that the microfractures that were created close over a period of time because they did not have any proppant to keep them open permanently. IU fractures are the only reasonable explanation for the pressure communication between wells that then disappears over time.

Implications of the Presence of IU Fractures. ***Use of Smaller-Diameter Proppant.*** As mentioned previously, the surface area of IU fractures can be at least an order of magnitude greater than that of the main propped fracture. This implies that, if it is possible to keep these fractures open by some means, one may be able to achieve a significant increase in well productivity. One way to achieve this is to use smaller-sized proppant so that it may have a better opportunity to enter the microfractures that would otherwise close during flowback.

Use of Acid or Other Chemicals To Etch the Surface of the IU Fractures. Another possible strategy would be to use dilute mineral acid to etch the surface of the IU fractures to provide some degree of surface roughness to the IU fractures.

Choosing Fracture Spacing and Well Spacing. Both well spacing and production have an important effect on the fractures that can be created in the infill well between two wells. Fracture spacing, well spacing, and production time of the outer wells could be optimized with the help of geomechanical simulations to create favorable conditions for creating networks of IU fractures. **JPT**

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primary fracture, and the other favors the opening of secondary fractures.

In the case of very-low-permeability shale such as that above the Ekofisk chalk hydrocarbon reservoir, the important issue is what is happening inside the fracture ahead of the fluid front. The matrix permeability value makes it obvious that no fluid from the rock matrix can be displaced to fill the volume created by the newly formed fracture ahead of the injected fluid. Consequently, this fracture volume ahead of the fluid becomes filled with vapor. This phenomenon is known as cavitation. It corresponds to the partial dehydration of the shale and leads to mechanical swelling when the dehydrated shale is contacted by water.

Here, it must be emphasized that mechanical-swelling stresses can often depend on the level of dehydration of the shale and are mainly independent of shale mineralogy. In turn, this swelling stress applies not only at the tip of the fracture but also over its entire length from previous sudden propagation events and can be viewed as a stress barrier added to the minimum in-situ stress. This added swelling stress explains why the pressure required to propagate a hydraulic fracture in shale can be much higher than the minimum in-situ stress and why no fracture propagation was ever observed during the shut-in periods of the CRI wells. The swelling stresses developed during the fracture-propagation process contribute to the mechanical equilibrium of the system, and the absence of propagation after well shut-in is further proof that the system is at a mechanical equilibrium during shut-in periods, despite the presence of a high net pressure in the fracture network.

Another mechanism governing the creation of the multiple-fracture network observed around the CRI wells in the Ekofisk field is the thermal effect. The fluid injected during the CRI operations in Ekofisk is colder than the formations where the injection takes place. Under typical conditions, the fluid is injected at 70 to 85°F for a virgin formation temperature of 175°F, corresponding to a cooling of approximately 100°F. This means that the formations in contact with the injected fluid will be cooled. **JPT**

Petroleum Data Analytics

Luigi Saputelli, SPE, Senior Reservoir Engineering Adviser, ADNOC, and Frontender Corporation

One of the many challenges we face today in the petroleum industry is the management of data and information. In some instances, we are overwhelmed by the amount and diversity of formats, and, in other cases, we are blinded from the right information to understand a process (What has happened?), to predict the immediate future (What could happen?), or to make proper decisions (What should we do?). The answer to these questions is data analytics supporting appropriate engineering and management judgment and the modeling of actual energy scenarios. Data analytics for strategic decision making is being constantly developed to mitigate low-oil-price scenarios.

For many decades, our technical and business processes have benefited from the wide use of data statistics for decision making. In many instances, predicting and prescribing have relied more on data evidences and trends than on first-principle simulation models. The advancement of computational power, sensor availability, and engineering models has promoted the exponential growth of data types and volumes. Data-driven techniques also have diversified and improved to address such incremental complexities. We are now referring to the professionals who manage and find value from data as "data scientists," and we are calling the management of large and complex data volumes "big data."

Data analytics, either big or small, is the collection of tools that leverages data collection, aggregation, processing, and analysis for describing insights into the past, predicting future performance, and prescribing actions from the optimization of possible outcomes. Current trends of data analytics differ from traditional statistics in the sense that the new data-driven predictive and prescriptive models go beyond data averaging, outlier detection, correlations, and multiple-parameter regression fitting.

Data-analytics tools may include one or more of the following groups: statistics (regression, time series, and factor analysis); pattern recognition (Markov models, principal components, ensemble averaging, classification, and regression); business intelligence (key-performance-indicator dashboards, multidimensional visualization); artificial intelligence for planning, creativity, perception, and social intelligence (knowledge representation, neural networks, support vector machines, Bayesian inference, decision tree, natural-language programming); machine learning (inductive logic programming, rule learning, and clustering); and management of large data sets, distributed and parallel computing, cloud computing services, and data cleansing and profiling.

A graduate degree may be required to master some of the techniques around data analytics, and decades may be required to adopt them across the industry, but it is also true that many of these techniques are evolving at such a fast pace that they become obsolete by the time we plan to roll out a trial pilot. We need to learn how to experiment with, implement, and capture results from data analytics faster than ever. We either evolve quickly or disappear. **JPT**

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SPE 179958 Detecting and Removing Outliers in Production Data To Enhance Production Forecasting *by Nitinkumar L. Chaudhary, University of Houston, et al.*

Functional Approach to Data Mining, Forecasting, and Uncertainty Quantification

The difficulty in applying traditional reservoir-simulation and -modeling techniques for unconventional-reservoir forecasting makes the use of statistical and modern machine-learning techniques a relevant proposition. However, the most current applications of these techniques often ignore the systematic time variations in production-decline rates. This paper proposes a nonparametric statistical approach, using a modern technique termed functional data analysis (FDA). In FDA, production data are modeled as a time series composed of a sum of weighted smooth analytical basis functions.

Introduction

Many companies have adopted a so-called "data-centric process" for understanding and forecasting in unconventional reservoirs. This data-centric process comes as a consequence of the shortcomings of conventional reservoir-data-analysis and -modeling approaches, which mostly belong to the preshale era. Either the huge quantity of data collected in shales cannot be used fully with conventional modeling techniques or the rapid nature of shale development simply does not allow for lengthy reservoir-modeling and -simulation studies.

Decision variables in shales are rates or volumes of produced hydrocarbons. Therefore, understanding shales and identifying value-creating practices by use of data-driven techniques require proper handling of production-time series. This is often challenging because production time series come as noisy, discrete observations of production rates over time. Conventional approaches to this problem rely on parameterizing the system with decline curves and work in the parameter space of the assumed decline model, or, even simpler, work with the raw data. This paper takes an alternative nonparametric approach wherein the data are used to find the most-appropriate smooth and continuous representation of declining production time series. The approach for this nonparametric form relies on the statistical discipline termed FDA.

FDA allows for the exploration of stochastic variation in functional data and construction of low-dimensional representations of time series. In the context of shale production, these low-dimensional representations will enable a better understanding of relationships between the wells and, in conjunction with a distance-based generalized sensitivity analysis (DGSA), identification of the most-influential completion and reservoir parameters. Additionally, FDA enables formulation of a forecasting framework with high-dimensional Kriging-based regression, to produce best-guess estimates of the entire production profiles for new well locations.

FDA

FDA is a statistical discipline that focuses on data that can be considered to be infinitely dimensional, such as oil and gas production curves over time, daily temperature measurements over time, or concentration of oxygen or plankton as a function of ocean depth. FDA starts from discrete measurements, regularly or irregularly sampled over the time domain by assuming they came from some smooth process corrupted by noise.

The first objective of FDA is to transform discrete measurements into a continuous approximation of the true underlying function. This is routinely accomplished with a basis expansion. In this basis expansion, raw measurements of functional data are approximated with a scaled sum of smooth analytical basis functions that span the same time domain as the original data.

Once the basis system is selected, it is necessary to find appropriate values for the scaling coefficients. This is accomplished with an objective to minimize the mean squared error of the fit.

In general, estimation of underlying functions has two competing objectives: to match observations as accurately as possible and to avoid overfitting, which results in fits that are too wiggly. In order to avoid overfitting and secure smooth variation of the fitted function across neighboring observations, an additional roughness penalty is often introduced into the fitting criteria. The simplest measure of a function's roughness is given by its integrated squared second derivative.

Functional-Principal-Component Analysis (FPCA)

After basis-expansion fitting, FDA allows for exploration of variations in production profiles and construction of low-dimensional spaces for data visualization. The main tool for this type of analysis is FPCA. FPCA is a technique for data transformation and dimensionality reduction that is similar to the well-known multivariate principal-component analysis (PCA). The main difference between functional and

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multivariate PCA lies in the way principal components are represented. In FPCA, principal components are functions, which span the same time domain as the original functional data. The authors observed that more than 95% of variance, within a given functional-data set, is fully described by the first two principal components. This also means that, in all subsequent analyses, the first two principal components can be worked with alone without much loss of information.

Functional Sensitivity Analysis

Because similar production profiles plot close to one another in a low-dimensional score plot, a visualization of what parameters (geological or completion) affect production is now possible. This is accomplished by coloring points in the score plot by parameter values and observing whether that coloring varies systematically within the plot. The authors argue that such systematic variation, or presence of a trend, indicates whether production is sensitive to the analyzed parameter. DGSA was used to calculate the numerical values (magnitudes) of relative parameter importance.

The main idea behind DGSA is that influential input parameters to some transfer function would separate resulting responses into discrete categories or clusters. In the original development, DGSA was focused on computing parameter sensitivities in Earth modeling with flow simulations where flow responses were transformed with multidimensional scaling, producing low-dimensional plots. In such low-dimensional space, clustering was performed and cumulative distribution functions (CDFs) of parameters associated with models in each cluster were constructed. If a parameter were important, its cluster-based CDFs would be well-separated (meaning deviated from the overall CDF), and, if it were not important, then the converse would occur.

In order to rank parameters from the most to the least sensitive, the L1 norm is computed between class-specific CDFs and the preceding CDF. The result is averaged and standardized with the P95 bootstrapped L1 norm from the same distribution. The averaging and standardization enable construction of tornado charts with parameter sensitivities and parameter ranking to aid better interpretation of the data.

Reconstructing Production Profiles With FPCA

FPCA also allows for production-profile reconstruction and dimensionality reduction. To reconstruct one production profile, one has to sum products of principal components and associated scores and add that sum to the mean function computed on the entire ensemble.

Forecasting Framework

Assuming that the mean function and functional principal components are reasonably estimated from existing wells (training set), all that is needed to forecast production at some new well location are the functional principal-component scores. In essence, this means that, by performing basis expansion and functional principal-component analysis on the training data, the production-forecasting problem is transformed from a difficult rate-vs.-time forecasting to a simple problem of forecasting functional principal-component scores, which are scalars.

Kriging

An alternative approach that is capable of exactly reproducing training data (up to measurement error) and is less sensitive to outliers is Kriging, a technique extensively used in geostatistics. Kriging falls into a bin of interpolation methods that is local in nature, given that it weights training data on the basis of their distances from an estimated point in the input space. Even though it was originally developed for low-dimensional problems, modern adaptations in metamodeling for computer experiments efficiently generalize Kriging to high-dimensional spaces. The idea here is to perform linear Kriging in the space constructed from the input parameters (geological and completion parameters) and to interpolate/Krige production decline for any new set of geological and completion parameters—for example, for new well locations, where geological parameters are estimated or measured and completion parameters are optimized.

Conclusions

This paper introduces a functional approach for analysis and forecasting of unconventional-reservoir data. It shows how functional basis expansion can be used to represent production decline in nonparametric fashion and without assumptions about the underlying physical mechanisms or relying on previously formulated decline models. It also demonstrates how to transform smoothed production profiles into a low-dimensional functional principal-component score plot to aid data mining and identification of the most-influential parameters.

This work deals with single variate reservoir-flow responses (oil rates), whereas wells in the used data set produced oil, water, and gas. Real business and engineering applications require joint analysis and forecasting of these functional quantities, and such complex multivariate data-mining and forecasting problems will be the focus of future work. **JPT**

Mitigating Drilling Dysfunction With a Drilling Advisory System

The ExxonMobil Drilling Advisory System (DAS) is a rig-based drilling-surveillance and -optimization platform that encourages regular drilloff tests, carefully monitors drilling performance, and provides recommendations for controllable drilling parameters to help improve the overall drilling process. Key technical components of the DAS include high-quality adaptive filtering algorithms for computing various drilling-system-performance measures, data-encapsulation/dimensionality-reduction techniques, and reduced-order-modeling techniques that are ultimately used to generate recommendations for improved performance.

Introduction

Approximately a decade ago, the company initiated an internal program to pursue real-time rigsite mechanical-specific-energy (MSE) surveillance. MSE, a quantity initially developed and applied in the mining industry and subsequently applied to oilwell drilling, provides a measure of the energy required for a drilling assembly to drill through an interval of subterranean formation; and underefficient drilling conditions correlate with the compressive strength of the rock being drilled. It was quickly demonstrated that frequent drilloff tests using MSE trends to maximize drilling performance were an effective means of optimizing the drilling process. The basic idea was to use MSE trends to identify and respond to drilling-system-performance limiters such as bottomhole-assembly (BHA) whirl, bit balling, and stick/slip, with the ultimate goal of producing consistently better and longer bit runs. The initial program was deemed highly successful and since has become a key component of the rate-of-penetration (ROP) -optimization process.

Although MSE-surveillance activities hold great potential for identifying and avoiding drilling-performance limiters, the following challenges often arise in the implementation of a rig-based MSE-surveillance work flow:

- Frequent drilloff tests are needed to maximize the benefit of the method. MSE surveillance requires almost constant interrogation of the weight-on-bit (WOB) and revolutions/minute (RPM) parameter space to collect the MSE data required for trending analysis. For statistically meaningful trending analysis, it is important to conduct drilloff tests over sufficiently long depth intervals for a given WOB/RPM set point.
- MSE data must be interpreted correctly to identify trends. Often, MSE data are noisy and their presentation on a doghouse computer can be limited to strip charts displayed over a fixed interval of time.
- Correctly identifying formation changes is key to a successful interpretation of MSE trends.
- Human resources on the rig need to be prioritized, and other activities often take precedence, resulting in the need for an automated drilling-performance-monitoring system.

These challenges can become compounded when a real-time MSE-surveillance program is combined with additional drilling-surveillance work flows that leverage downhole or surface drilling data to further assess the dynamical behavior of the drilling assembly. An example of such a work flow that has been used by the operator is real-time bit stick/slip surveillance monitoring, which enables virtual real-time observation of stick/slip severity on the basis of surface torque and RPM and a drilling-mechanics model of the drilling assembly. Reacting to several interdependent (and sometimes conflicting) performance metrics (MSE, ROP, stick/slip severity) in real time is a significant challenge.

To address many of the challenges and to ensure a more-consistent application of MSE-surveillance (and other surveillance) work flows, the operator has developed a real-time DAS. DAS is a real-time rig-centric software platform that is designed to interact with existing infrastructure available at a typical rigsite, such as the wellsite information transfer specification (WITS). The DAS system collects real-time drilling data, performs various levels of data processing, computes measures of drilling performance, and provides operational recommendations designed to assess the

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper IPTC 18333, "Mitigating Drilling Dysfunction With a Drilling Advisory System: Results From Recent Field Applications," by ***Gregory S. Payette,*** *SPE,* ***Darren Pais,*** *SPE,* ***Benjamin Spivey,*** *SPE, and* ***Lei Wang,*** *SPE, ExxonMobil Upstream Research Company;* ***Jeffrey R. Bailey,*** *SPE, and* ***Paul Pastusek,*** *SPE, ExxonMobil Development Company; and* ***Michael Owens,*** *XTO Energy, prepared for the 2015 International Petroleum Technology Conference, Doha, Qatar, 7–9 December. The paper has not been peer reviewed.*

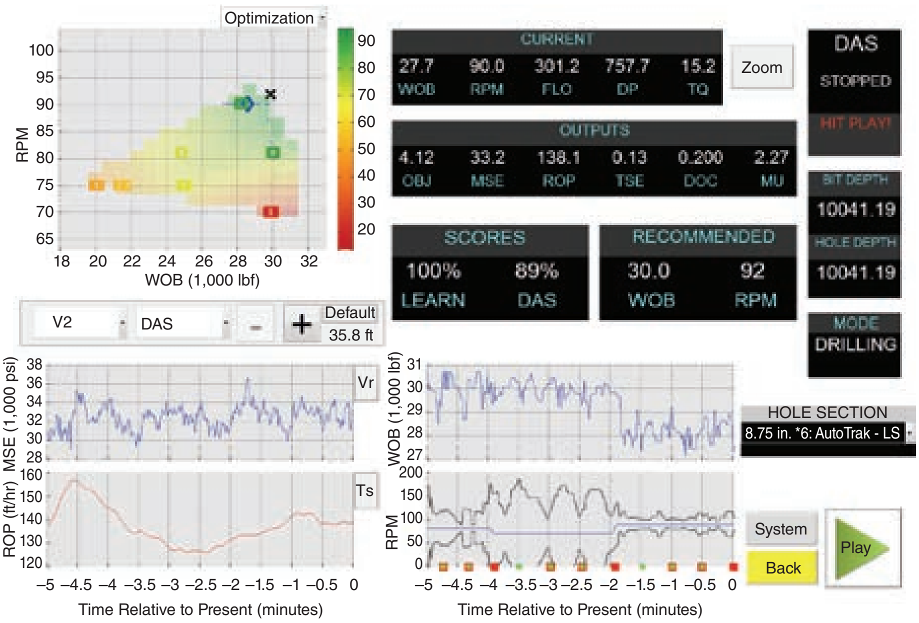


Fig. 1—A screenshot of one of the views of the DAS user interface.

drilling-performance landscape continually and ultimately maximize real-time drilling performance.

Technical Overview of DAS

The DAS system runs on a rig-based computer with limited computing power. Several versions have been developed as research has progressed, but, generally speaking, the DAS computer has a standard serial-cable WITS data feed from the mud logger and a serial output to provide the DAS recommendations back to the rig data-processing equipment. The DAS computer screen is configured to display state-of-health metrics as well as optimization charts that show the drilling parameters and DAS calculation results (**Fig. 1**).

A generic drilling-data architecture has been established to enable on-site DAS at a rig and remote monitoring by use of a Web-based application. The DAS computer may be at any number of locations at the rig, including the doghouse, provided that a WITS feed can be established between the mud-logging system and the DAS computer. Communication is established between the DAS and vendor computers through WITS records sent by means of serial connections. The minimal data-rate requirement for WITS Record 1 inputs to DAS is 1 second. Slower data rates (e.g., 5 seconds or more) limit the system's ability to perform stick/slip surveillance and generally reduce the effectiveness of DAS. DAS operational recommendations for WOB and RPM, along with other computed performance metrics, are sent to the vendor computer using a customized WITS record. These DAS outputs then can be distributed among vendor computers at the rig and shown as part of standard strip charts in front of the driller and rig supervisor. Finally, the DAS custom WITS records may be communicated to a WITS computer and streamed in real-time to an information-management-center server. This setup allows engineers at office sites to view real-time drilling data and DAS recommendations by means of a Web-based application. Furthermore, it enables information-center staff to log onto the DAS computer remotely for configuration and troubleshooting.

At a high level, the main steps in the DAS data-processing/optimization algorithms are

- Receiving raw WITS Record 1 surface data characterizing the state of the drilling assembly as measured at the surface.
- Performing preprocessing and cleanup of the raw WITS Record 1 data.
- Computing drilling-performance metrics such as MSE, ROP, stick/slip severity, and depth of cut.
- Aggregating input and drilling-performance-metric data over substantial periods of time and depth into response points for the purpose of obtaining characteristic response over average formation intervals.
- Upscaling the overall system response using collections of response points, fitted response surfaces, and optimization algorithms such as the simplex, steepest-descent, and Newton methods, ultimately to generate the DAS recommendations for operating parameters such as WOB and RPM.

A key constraint in developing data-processing algorithms for real-time systems is guaranteeing efficient and reliable computational performance over long continuous run times (possibly several days per hole section and weeks or months per well). As a result, particular care must be taken to ensure that run-time algorithms are simple and efficient. This issue is particularly relevant when run-time hardware has a relatively small footprint, as is the case for DAS (i.e., running on a conventional desktop or laptop in real time vs. off-site calculations on a server farm).

Conclusions

The DAS platform was developed to serve as a real-time MSE and stick/slip surveillance-based digital assistant, with the ultimate goal of helping the driller achieve consistently better and longer bit runs. The system encourages regular (guided) drilloff tests and carefully monitors drilling performance to provide recommendations for improved performance. The system has now demonstrated value in both offshore and onshore environments.

Future development efforts for DAS will focus on software engineering and the user's experience in particular. A fit-for-driller implementation will transform DAS from research software into an interactive, easy-to-use platform that continuously assists in the drilling-optimization process in a manner that removes the most tedious components of surveillance and trending analysis from the driller's work flow. **JPT**

Big-Data Analytics for Predictive Maintenance Modeling: Challenges and Opportunities

Big-data analytics can allow a better understanding of a production system's abnormal behavior. This knowledge is essential for the adoption of a proactive maintenance approach, leading to a shift toward condition-based maintenance (CBM). CBM focuses on performing interventions on the basis of actual and future states of a system determined by monitoring underlying deterioration processes. One of the building blocks of CBM design and implementation is the prognostic approach, which aims to detect, classify, and predict critical failures. This paper presents approaches for constructing a prognostic system.

Introduction

Optimization of maintenance costs is among operators' main concerns in the search for operational efficiency, safety, and asset availability. The ability to predict critical failures emerges as a key factor, especially when reducing logistics costs is mandatory.

Experience has shown that significant benefits can be achieved when major maintenance interventions (overhauls, usually performed periodically) can be postponed on the basis of conclusions from the use of degradation models. Such an approach can be complex, but its results may reduce maintenance and logistics costs while keeping availability within required levels.

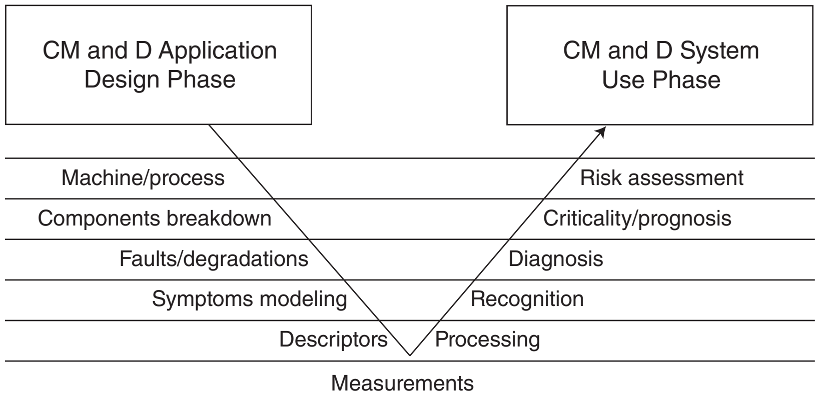


Fig. 1—Condition monitoring (CM) and diagnostics (D) cycle.

Traditional approaches to reliability estimations are based on the distribution of event records of a population of identical units. Many parametric failure modes, such as Poisson, exponential, Weibull, and log-normal distributions, have been used to model machine reliability. This project attempts to create an integrated solution using big data and analytics techniques to implement a CBM standard procedure for the target problem.

The V-Shaped Method

The International Organization for Standardization's standards for condition monitoring and diagnostics of machines offer good guidance to establish a CBM standard procedure, especially for the target problem of turbogenerator failures in a floating production, storage, and offloading (FPSO) vessel.

Diagnostics can be described as a procedure of reasoning to interpret the health condition of machinery by use of data acquired during its operation. It has a vital role in decision making for both operation and maintenance. In addition, diagnostic procedures should be adjusted according to potential failures (on the basis of their likelihood and severity) that could occur in a machine. The principle is shown in **Fig. 1.** The V-shaped array represents the high-level and low-level concerns.

Condition monitoring for offshore installations is certainly a challenge, especially when it comes to data quality and analysis. Having identified the critical functions, it would be possible to identify the critical components, failure modes, and degradation mechanisms.

Machine/Process. The system under study belongs to the main power-generation system of an FPSO unit operating in the Campos Basin. It has four turbogenerators, each consisting of an aero-derivative gas turbine driving an electric generator. The main emphasis of the complete paper is the gas-turbine engines.

This article, written by Special Publications Editor Adam Wilson, contains highlights of paper OTC 26275, "Big Data Analytics for Predictive Maintenance Modeling: Challenges and Opportunities," by ***I.H.F. Santos, M.M. Machado, E.E. Russo, D.M. Manguinho, V.T. Almeida, R.C. Wo, M. Bahia,*** *and* ***D.J.S. Constantino,*** *Petrobras;* ***D. Salomone, M.L. Pesce, C. Souza,*** *and* ***A.C. Oliveira,*** *EMC—Brazil Research Center; and* ***A. Lima, J. Gois, L.G. Tavares, T. Prego, S. Netto,*** *and* ***E. Silva,*** *PEE-COPPE/UFRJ, prepared for the 2015 Offshore Technology Conference Brasil, Rio de Janeiro, 27–29 October. The paper has not been peer reviewed.*

Components. From a maintenance perspective, it is of interest for the operator to have a functional tree representing the machine. This tree should be composed mostly of the maintainable parts, and, from the component breakdown, one should list all possible failure modes and their respective causes and degradation mechanisms.

Then, the criticality of each of the failure modes should be assessed through expert judgment or from historical data on the basis of significance and probability of occurrence.

Symptoms Modeling, Descriptors, and Measurements. In the modeling of symptoms, the operator must rely on the expertise within the organization with respect to a particular asset.

Descriptors can be obtained from condition-monitoring systems, either directly or after processing of the measurements. Descriptors have one big advantage over measurements: Their selectivity helps to increase the accuracy of the diagnostics significantly.

Data from sensors were stored, processed, and analyzed in order to identify correlations between parameters that explain the events best (e.g., principal-component analysis); patterns of behavior related to major occurrences; if there were variables that should be included in the monitoring set; and what more can be considered in the correlation of variables with their failure modes or critical components and subsystems.

In general, all collected data can be subdivided into two groups: (1) events, data that include information on what actually happened, what caused the event, and what was done, and (2) condition monitoring (CM), measurements related to the health state of the machine.

Typically, the event data collection requires manual data entry while CM data, nowadays, is collected automatically with the help of sensors.

Processing and Recognition. Data processing should be started with data filtration and cleaning because the collected data (especially those entered manually) may contain errors. The most common types of errors include those caused by the human factor and those caused by faulty or malfunctioning sensors.

The following step is data analysis. Several models, algorithms, and methods are available for data analysis, depending on the type of data collected.

Diagnosis and Prognosis. The final step in all CBM approaches is making decisions. The diagnostics of machine failures is basically a procedure of mapping the information obtained in the measurement space or features in the feature space to machine failures in the failure-mode space.

Prognostics is a complex task. In general, it is divided into two main types. The first includes a prediction of time until machine or component failure and is called "remaining useful life." The second is used to predict the time that a machine could operate without failure.

Research Hypothesis: The Challenge

One can observe that most failures are related to machine startups. This kind of event is a hidden failure and is difficult to predict. For the main failure event considered in the complete paper, one critical component is a valve from which precise behavior is demanded during the startup.

Considering that the action (countermeasure) for those events is the replacement of the valve, a question was raised for the research team: "If the abnormal valve's behavior could be detected during the run, could a predictive model be developed to assign a probability of failure at the next startup?"

Working with this notion, the team extracted sensor data from the industrial repository in order to train offline classifiers.

Classification Processes

Database Preprocessing. This step includes the removal of all major outliers and adjustment of the sampling frequency to a unique value (1 sample/min).

Event Annotation. In this stage, the time stamps of all normal stops (NSs) and machine failures (MFs) are determined. Removal of repeated NS and MF occurrences (in less than a given time interval) is also performed. For all validated NS or MF situations, a 24-hour interval is identified during which the machine operated without interruption before the stop that originated the associated event.

Feature Extraction. For all NS and MF events, the machine operation within the 24-hour interval identified in the preceding step is characterized by meaningful features that should act as the classifier input.

Classifier Training. Using the features extracted in the preceding stage, the chosen classifier is trained, following the event labels defined in the second step.

The result of this four-step procedure is a smart algorithm capable of identifying a faulty operation the next time the machine is started, on the basis of the features extracted during the 24 hours before the machine stop.

Final Considerations and Future Work

Starting from a challenging research proposition, such as to model and predict hidden failures, this study discusses the modeling of machine failures by the use of a big-data analytics approach with different classifiers.

In the search for a smart algorithm capable of identifying a faulty operation the next time the machine is started, on the basis of features extracted before the most recent machine stop, some classifiers were tested in a series of experiments. The results of those experiments are presented in the complete paper.

Among the problems encountered in this research were data-collection difficulties in terms of database standardization.

From the use of predictive models, once useful models are constructed in the near future, another problem that arises relates to the decision making, in which the process must include the model's predictions. In that sense, future work will consider more than one model, resulting in a voting system that would be able to provide reasoning for decisions. **JPT**

Sand Management and Sand Control

R.J. Wetzel, SPE, Drilling and Completions Senior Adviser and Team Lead, Chevron Energy Technology Company

I suppose that many of us are taking a deep breath just now. Many of us could be revisiting how we have been completing wells and what we might be able to improve. These improvement areas often involve some sort of trade-off between well deliverability and well/completion costs (in terms of equipment and rig time to deploy these various alternatives). I suspect that we all have been involved with completions where these two areas are debated.

In my experience, it seems that much of our discussion revolves around what the various participants "feel" is the best approach. Much of the decision eventually hinges on what we will do in the short term (deployment) rather than in the long term (deliverability). The reason is, in my opinion, that we are fairly sure about the near-term items (related to cost) but often very uncertain about the longer-term items (deliverability as a result of how well we deployed the lower completion). Why is it that many of our completion quality decisions are focused on cost and not deliverability?

[C]ould the development of consistent practices be a critical first step on our journey toward achieving improvements in completion quality?

I can think of two primary reasons: (a) We lack the metrics to support our decisions and (b) we do not have consistent practices (e.g., laboratory and design work, deployment processes) across our wells to allow us to compare our results. I suspect that you can think of others. Both of these areas offer improvement opportunities.

For those of us who have a robust set of metrics to evaluate our overall sand-control planning and deployment process, if the preparation work (e.g., core testing, compatibility testing, equipment selection) is not carried out in a consistent fashion, the variation in results as depicted in our metrics would not lead us to a specific course for improvement because the variation from well to well might simply be explained away by the differences in planning and execution.

Given the preceding idea, could the development of consistent practices be a critical first step on our journey toward achieving improvements in completion quality? The list of those practices that we should carry out in a consistent manner is quite long. For sand-control applications, we could start with those activities that occur early in the design process.

After reviewing the many high-quality technical papers written over the past year, I have found a few that I think offer a good place for you to start your journey toward consistency. The three summarized papers are all related to the selection of proppant and screens in your sand-control completions. I am not promoting any one of these papers over the others. However, I am suggesting that whatever your organization does in this area, your organization should do it consistently. You may find your organization's new, preferred approach to proppant and screen selection in one or more of the presented articles. **JPT**

R.J. Wetzel, SPE, is a drilling and completions senior adviser and the team lead for the SandFace Completions Team at Chevron Energy Technology Company. He has 36 years of experience, in all geographic areas, in various aspects of drilling, completions, and workover. Wetzel has performed technical, operations, and management roles. In addition to supplying technical support for Chevron's business units through the SandFace Completions Team, he also participates in numerous design reviews of Chevron's major capital projects, with specific focus on drilling and completions design selection and deployment plans. Wetzel also manages the SandFace Completions technology-development program focused on improving Chevron's lower-completion reliability and performance. He holds a BS degree in mechanical engineering from the University of Louisiana at Lafayette and serves on the *JPT* Editorial Committee. Wetzel can be reached at rjwetzel@hotmail.com.

Recommended additional reading at OnePetro: www.onepetro.org.

SPE 178966 Sand-Retention Testing: Reservoir Sand or Simulated Sand—Does It Matter? *by Tracey Ballard, Weatherford, et al.*

SPE 179036 Sand-Screen Design and Optimization for Horizontal Wells Using Reservoir Grain-Size-Distribution Mapping *by Mahdi Mahmoudi, University of Alberta, et al.*

Re-Evaluation of Gravel-Pack-Sizing Criteria

In this paper, gravel-pack pore size is evaluated further by use of the permeability of the gravel pack and other methods. A new sizing method is proposed that is based on the effective formation size and the gravel-pack pore size. In this manner, the gravel pack is effectively treated like a screen and the selection of gravel-pack size becomes similar to the selection of screen size.

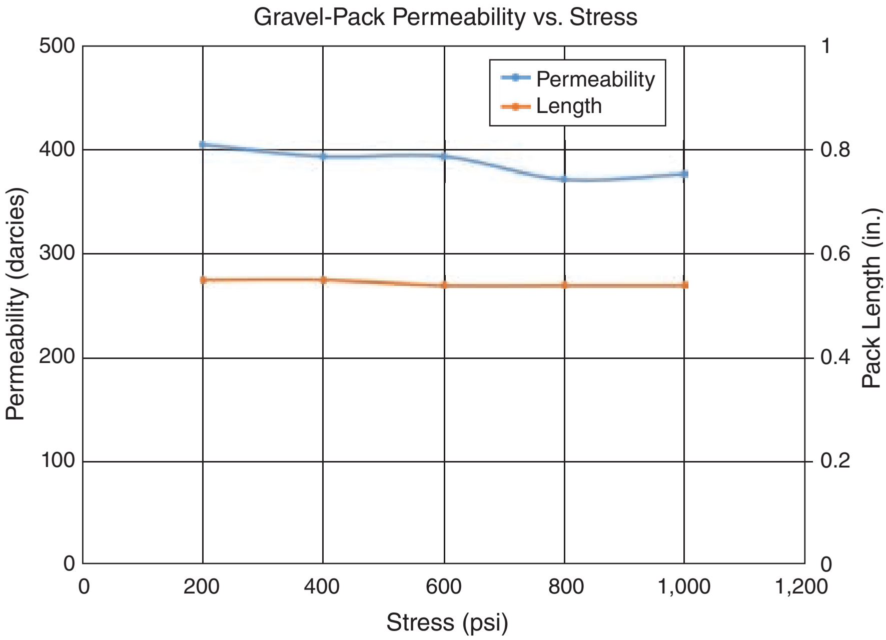


Fig. 1—Gravel-pack permeability for 20/40 gravel with increasing uniaxial stress.

Introduction

Use of a coarser-grained material to stop the production of a finer-sized formation sand in oil wells has been practiced for decades. The selection of the coarser-grained sand has usually been performed on the basis of a multiple of one or more of the smaller particle sizes in the formation material, with the goal being that the formation material will bridge on the larger gravel-pack particles without reducing flow capacity or allowing excessive solids production.

This paper presents an alternative approach to testing and selecting gravel sizes in which the size of the formation material is addressed by using an effective size of the formation grains defined as the median grain size (d50) divided by the uniformity coefficient (d40/d90) and the gravel pack is described by the apparent pore size of the gravel. This approach allows laboratory performance testing for solids production, size of solids, and retained permeability to be compared directly for gravel-pack completions and for screen-only completion. These data are especially useful in the selection of the completion method for horizontal wellbores. Testing methods have been modified so that gravel-pack tests can be performed by both constant-drawdown and constant-rate methods.

A summary of previous important studies investigating gravel-size-selection methods is provided in the complete paper.

Gravel-Pack Pore Size From Permeability Data. The packing arrangements of gravel, along with the size distribution and shape, ultimately determine the pore size between gravel particles. Several methods exist for estimating the pore size in porous media. These methods tend to be based on permeability, sizing ratios based on particle-size measurements, or pore size based on packing theory.

Permeability depends on the sizes and shapes of interconnections between adjacent pores, which, in turn, are influenced by the entire grain-size distribution. Particle shape has an important effect on permeability because it influences the size and shape of interconnections between particles. The more angular the grains are, the smaller the voids and the more tortuous the flow paths.

A discussion of methods of pore-size calculation and estimation is included in the complete paper.

Pore Size From Packing Arrangements. Pore size can also be obtained by assuming single-size particles in different packing arrangements. The pore size changes from a maximum for a cubic pack of 0.414 times the gravel size to a minimum of 0.1547 times the gravel size for hexagonal packing. While gravel

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper SPE 179023, "Gravel-Pack-Sizing Criteria: It's Time To Re-Evaluate," by ***Christine Fischer, Vernon Constien,*** *and* ***Carla Vining,*** *Constien and Associates, prepared for the 2016 SPE International Conference and Exhibition on Formation Damage Control, Lafayette, Louisiana, USA, 24–26 February. The paper has not been peer reviewed.*

packs certainly have a range of sizes and roundness, these very simple assumptions offer advantages for comparing data from large laboratory-test sets. Changes in packing order most frequently occur from differences in sedimentation or stress.

Comparison of Methods for Estimating Gravel-Pack Pore Size. Gravel packs are never single-sized particles, so there are variable pore sizes inside the pack. For laboratory-testing purposes, the gravel pore size can be adjusted on the basis of gravel distribution, shape, and stress. However, for comparative purposes across large data sets, it is helpful to maintain a single method for estimating gravel pore size.

For the tests in this work, the gravel-pack thickness was approximately 0.5 in. and the maximum net uniaxial confining stress was 1,000 psi. **Fig. 1** illustrates the change in gravel-pack permeability for a 20/40 gravel across the uniaxial-net-stress range of 200 to 1,000 psi in the oil-flow-test equipment. Very little change in permeability occurred, which indicates that the packing arrangement has probably not shifted to a smaller pore size.

To maintain a constant method for estimating gravel-pack pore size in evaluating performance master curves, the median gravel size multiplied by 0.414 was selected. This expression has been found to compare well with results from screen-only tests on the same formations.

Formation- and Gravel-Particle-Size Analysis. Regardless of the method used to select the gravel-pack sand, the first step is to obtain representative samples of the formation and determine the particle-size distributions. As wellbore construction has shifted to horizontal wellbores, the number of formation-particle-size distributions in the lateral can be quite large. Particle-size analysis should be performed for each interval sample. Because only one size of gravel pack is normally placed into a wellbore, methods for analyzing the large amount of formation-particle-size data and reducing it to a small number for testing must be implemented. Frequency plots of all the distributions present in a wellbore are helpful in reducing the data to critical distributions.

The most-common methods for analyzing formation-particle sizes include dry sieving, occasionally wet sieving, and laser particle-size analysis. In some cases, dry-sieve analysis may yield larger-than-actual particle-size values if fine particulates are present in large quantities. The electromagnetic forces between grains tend to promote aggregation, which shifts the percentage of fines present in the formation sand.

For this work, all formation-particle-size data were determined by laser analysis and all gravel data were determined by sieve analysis. Before beginning particle-size analysis, the disaggregated samples must be cleaned of reservoir fluids. It may also be necessary to re-establish wettability after drying the material if the particles are dispersed in water for laser analysis.

The parameters calculated from particle-size analyses—besides the cumulative plots by weight or particle volume—include the median, which is the 50th percentile on the cumulative curve; the mean, which is considered the average grain size; sorting, which measures the grain-size variation of a sample by encompassing the largest parts of the size distribution as measured from a cumulative curve; skewness, which measures the degree to which a cumulative curve approaches symmetry; and the uniformity coefficient, which is the ratio of the sizes at d40 to the size at d90 on the cumulative curve. For this work, the critical formation sizes are the d50 and the uniformity (d40/d90).

Gravel-Pack- and Screen-Test Methods. Several laboratory-evaluation methods for testing sand-control screens have been documented in the literature, but test methods that include gravel packs are rarer. The two methods that have been used to develop data presented in the complete paper are known as the constant-drawdown oil-flow (CDOF) test and the constant-flow-rate brine (CFRB) test. The CDOF method has been used in many screen-only and gravel-pack-plus-screen tests. The CFRB test has been developed for evaluating screens or gravel packs by a method that more closely simulates deposition on a screen or gravel pack from erosion of a sandface environment. The two methods are summarized in Table 4 of the complete paper.

Conclusions

Approaches to determine a representative gravel-pack pore size have been evaluated, and a simple relationship based on cubic packing has been selected to keep data sets constant. For special projects, other relationships such as permeability could also be used. Two testing methods that can use constant drawdown or constant flow rate have been used in screen-only and gravel-pack testing, and the data can be compared directly for performance of produced solids, retained permeability, and size of produced solids. Selection criteria can be established by choosing ranges on the performance master curves that meet expectations for gravel-pack performance. The ability to directly compare screen-only- and gravel-pack-test data should aid in completion designs in soft-formation reservoirs. **JPT**

Evaluating Sand-Screen Performance With Sand-Retention Tests and Numerical Modeling

This paper presents a combined experimental and numerical-modeling study on sand-screen performance. The objective is to develop an improved methodology for optimal sand-screen-aperture selection by addressing some of the limitations present in existing sand-retention tests. A new sand-retention-test facility has been developed that incorporates a number of improvements into the design and experimental procedure.

Existing Approach to Sand-Screen-Performance Evaluation

Empirical criteria have traditionally been applied for selecting screen size on the basis of one or two parameters derived from the particle-size distribution (PSD). Because of the problems associated with the empirical criteria, the industry standard practice is to conduct laboratory sand-retention tests on screen coupons. This is particularly relevant for premium sand screens, the filter media of which are fundamentally different from those of a slotted liner or wire-wrap screen. The same mechanisms for forming stable, multiparticle bridges may or may not be applicable. In most cases, the cross-sectional path through these filter media is tortuous and 3D. Laboratory sand-retention testing is typically required to determine the effective screen opening size. There are no universal industry standards on how sand-retention testing should be performed or results interpreted. Sand-screen performance is often evaluated on the basis of two criteria: screen plugging and sand retention.

Limitations of the Existing Approach. While the acceptance criteria for sand production and produced-particle size are well-defined and these factors are relatively straightforward to measure, screen plugging is defined differently by different investigators. There is currently a lack of measurements that can be used to accurately quantify screen plugging and screen permeability.

A recent review on sand-slurry experimental procedures and consequent interpretation methodologies identified a number of limitations of existing sand-slurry testing, one of which was fluid-flow velocity, which is adopted in some of the laboratories as being one to two orders of magnitude higher than the flow velocity typically expected in the field. A much higher fluid-flow velocity could exaggerate the difference in screen performances in the laboratory that might not exist under field-fluid-flow conditions. Others have recognized that simulating reservoir-sand-production situations in a sand-retention test may be problematic, because the reservoir sand-production situation would be highly variable and a much slower fluid-flow velocity could cause other ambiguities.

This article, written by JPT Technology Editor Chris Carpenter, contains highlights of paper OTC 26434, "Evaluating Sand-Screen Performance With Improved Sand-Retention Test and Numerical Modeling," by ***B. Wu, S.K. Choi, Y. Feng, R. Denke, T. Barton, C.Y. Wong, J. Boulanger, W. Yang,*** *and* ***S. Lim,*** *CSIRO, and* ***M. Zamberi, S. Shaffee, M.B. Jadid, Z. Johar,*** *and* ***B.B. Madon,*** *Petronas, prepared for the 2016 Offshore Technology Conference Asia, Kuala Lumpur, 22–25 March. The paper has not been peer reviewed.*

Development of a Sand-Retention-Test Apparatus and Test Procedure

A new sand-retention-test apparatus has been developed aiming to overcome or reduce some of the problems and limitations identified with the existing sand-slurry-retention tests. The apparatus comprises a clean-fluid (water) -injection system, a sand-slurry-injection system, a sand-retention-test cell, and a fluid- and solid-collection-and-separation system and is described in detail in the complete paper.

Experimental Procedure. Once the sand-retention cell was set up with the test screen coupon of the required slot size, all the pressure transducers for screen, cell, slurry, and clean-fluid pressure measurements were installed. The procedure for conducting a sand-screen-retention test was as follows:

- Fill the sand-retention cell and all the hydraulic tubes to pressure transducers with clean fluid (water).
- Pump clean fluid at a flow rate of approximately 400 mL/min using the triplex pump.
- Inject dense sand slurry at a rate of 5 mL/min while the mixer cell oscillates at 2 Hz.
- Collect the fluid and any sand passing through the screen coupon in a plastic container emptied approximately once per liter.
- Inject the clean fluid and dense sand slurry continually at the same time until the height of the sandpack is 10 to 20 mm or the maximum pressure capacity of the sand-retention cell is reached.
- Inject clean fluid at a constant rate to evaluate sand-screen and sand-pack permeability.

The photographs in **Fig. 1** were taken during a typical sand-retention test and show the process of sand

The complete paper is available for purchase at OnePetro: www.onepetro.org.

Fig. 1—Screen, sandpack formation, final sandpack height, and screen-pressure-measurement port (left to right).

retention on the screen, the sandpack height measurement, and the screen-pressure measurement.

Experimental Results and Analyses

The apparatus developed has been used to conduct sand-slurry-retention tests, which are described in detail in the complete paper. The experimental program included eight types of sand and wire-wrapped-sand-screen coupons with five different apertures ranging from 0.152 to 0.254 mm.

Numerical Modeling of Sand-Retention Tests With a Fully Coupled Discrete-Element-Method (DEM) and Computational-Fluid-Dynamics (CFD) Model

A fully coupled numerical model, by incorporating CFD in an in-house DEM code, has been developed and used to simulate sand-slurry flow and the sand-retention process in the sand-retention tests described in the complete paper. The objective of the numerical simulation was to carry out parametric studies to understand the effect of some key parameters on sand-screen performance.

In the numerical simulation of the sand-retention process, the DEM was used to model the solid phase and CFD modeled the liquid phase. The movements of discrete sand particles with different PSDs, the retention process of sand particles by the screen, and the degree of plugging/blockage of the screen aperture can be illustrated clearly. The interactions between individual particles, particles and screen, and fluid and particles, and their effects on retention behavior, can be studied at the sand-particle scale. Most importantly, different PSDs of the sand particles can be introduced readily in the simulation, and the underlying mechanisms can be demonstrated.

Simulation Conditions. To generate the particle population required for the simulation, the PSD curve was divided into equally sized bins, within which the particle size was assumed to be the same and equal to the bin's average particle size.

The computation domain was to be kept small to reduce computation time while remaining representative of the fluid- and particle-flow conditions in a sand-retention test. Thus, the sand screen was represented by a slice containing three slots. Two geometries were used for the simulation. Geometry 1 had a width, thickness, and height of 7.5, 2.5, and 30 mm, respectively, while Geometry 2 had a height of 15 mm and its width and thickness remained the same as those of Geometry 1. Five slot sizes were considered in the simulation study. The sand particles were assigned with properties of glass beads; liquid properties were those of water.

Sand-Retention-Test Simulation. In this simulation, for Rocla90 sand when the slot width was 0.2286 mm, solid volume fraction was 1%, and the liquid-flow velocity was 0.003 m/s, the solids and liquid continually flew into the simulation domain at the specified rate from the top inlet. The solids were treated as spherical particles, with their sizes generated randomly according to the PSD of the test sand. Once the particles hit the screen, some of the particles with a diameter less than the slot width passed through the screen. After the particles settled down to the screen, particle numbers passing through the slots were quickly reduced, with few particles passing through the slots at times along with the steady and continuous flow of the liquid phase. With more and more particles retained above the screen, the particles with diameters larger than the slot width accumulated above the slot. These particles blocked the slot. A steady state was quickly reached, with no clear particle-passing phenomenon, while the height of accumulated particles increased continually.

Parametric Studies. Parametric studies were carried out for three key parameters (i.e., liquid velocity, screen slot size, and particle concentration for two sands). The effect of liquid velocities was investigated with Geometry 1, and the effect of slot width and solid concentration was investigated with Geometry 2. A total of 19 cases were studied.

Effect of Liquid Velocity on Amount of Sand Produced. Sand production was enhanced by increasing the liquid-flow velocity.

Effect of Slot Size on Amount of Sand Produced. The volume of particles produced from the slot increased as the slot size increased. Also, the time to reach a stable retention increased as the slot size increased.

Effect of Particle Concentration on Amount of Sand Produced. The amount of particles produced reduced as the solid concentration increased. Also, the time to reach a stable sand retention reduced as the solid concentration increased.

Conclusions

- The amount of sand produced from a sand screen is correlated mainly with the ratio of screen aperture to particle size.
- Uniformity coefficient plays a dominant role in sand-screen permeability.
- The correlations for sand amount produced and the retained sand-screen permeability can be improved by incorporating sand-particle geometry into the correlations.
- A parametric study using the DEM-CFD model has demonstrated the major effect of liquid-phase velocity, solid volume ratio, and slot size on the amount of sand produced. **JPT**

Factors Governing the Performance of Multilayered Metal-Mesh Screens

Multilayered metal-mesh screens (MMSs) are widely used as standalone screens for sand control in unconsolidated formations. The nominal rating of such screens is usually based on the specifications of the filter layer. It is often found that screens with the same filter-layer nominal rating perform differently. It is shown in this study that the primary reason for this is that the sand-retention performance of multilayered MMSs is a strong function of not only the filter layer but also the protection layer and the support layer.

Introduction

The sand-retention ability of a multilayered MMS is evaluated by examining the pore-size distribution (PSD) of the screen as well as its slurry-test sand production [the sand-production evaluation is for plain-square-mesh (PSM) screens only]. Three major steps are involved in the evaluation process:

1. Generate a multilayered virtual mesh assembly (an example is provided in **Fig. 1**) based on the mesh specification and different layer-overlap, layer-alignment, and relative pore-size-ratio conditions.
2. Evaluate the PSD of the virtual screen with a specialized filtration model.
3. Enter the PSD information into the analytical slurry-test model to quantify the sand-retention performance of the target screen. The model incorporated in this study uses the entire PSD of a PSM screen to predict sand production.

Results

Three types of multilayered MMSs—175-µm PSM, 250-µm PSM, and 115-µm plain Dutch weave (PDW)—are studied. The name of each type corresponds to the nominal rating and the design of the filter layer. All of the MMSs have the same three-layered structure, with one protection layer above and one support layer below the filter layer. The protection and support layers are PSMs with nominal ratings of 542 and 864 µm, respectively.

Effect of Layer Overlap. In this study, the compression/sintering-induced thickness change of a multilayered MMS is characterized by the average overlap. It is a combined factor that accounts for the reduction in screen thickness caused by the inter- and intralayer wire deformation during screen manufacturing.

The thickness of a screen could be obtained either from a direct measurement of a sample or from computed-tomography-scan images. Once the thickness is known, the overlap can be calculated accordingly.

175-µm PSM. In investigating the effect of overlap on the 175-µm PSM screen, it is found that, for a multilayered screen, having larger overlap or, equivalently, smaller screen thickness decreases the percentage of large pores. This is because the lateral movement of sand particles between mesh layers is more limited with increased percentage of overlap. The size of the smaller pores becomes even smaller as the overlap increases. The change in screen PSD with different overlap is not merely induced by the deformation of the filter layer but is induced by the screen assembly as a whole.

With regard to the effect of overlap on model-predicted sand production of a 175-µm PSM, a universal decrease in sand production with an increase in overlap was observed for all tested PSDs.

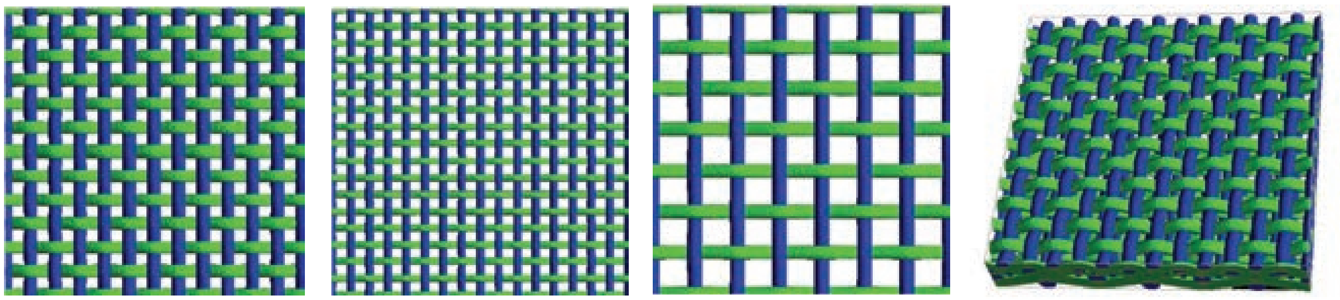
250-µm PSM. In the current case, increasing the overlap not only decreases the percentage of large pores but also decreases the size of the large pores. This phenomenon was not seen in the 175-µm PSM where the peak of all size distributions was at 180 µm. The reason that this different phenomenon is observed is that the variation of PSD of a PSM screen with respect to layer overlap is also influenced by the alignment of mesh layers and the relative pore size of adjacent layers.

115-µm PDW. When the overlap was changed on PSD of a 115-µm PDW, the results show that, as the overlap increases, the PSD shifts toward smaller pore sizes. The dominant pore size could be as small as 90 µm when there is 40% overlap for the screen. Moreover, a comparison between the PSD of a multilayered screen and the PSD of a single-layered PDW filter reveals that the PSDs at different overlaps are mainly controlled by the filter layer.

The layer overlap changes the PSD of a PDW screen and a PSM screen in different ways. When varying the overlap, the PSD of a multilayered PDW screen is primarily governed by the change in the filter layer. In contrast, for a multilayered PSM screen, the effect of varying layer overlap on PSD is obvious only when the protection and support layers coexist with the filter layer.

Effect of Layer Alignment. The effect of layer alignment is studied by shifting the position of the filter layer with respect to the protection and support layers. This is performed during the process of stacking individual mesh layers

This article, written by JPT *Technology Editor Chris Carpenter, contains highlights of paper SPE 178955, "Factors Governing the Performance of Multilayered Metal-Mesh Screens," by* ***Chu-Hsiang Wu****, SPE, and* ***Mukul M. Sharma****, SPE, The University of Texas at Austin, and* ***Rajesh Chanpura****, SPE,* ***Mehmet Parlar****, SPE, and* ***Joseph Ayoub****, SPE, Schlumberger, prepared for the 2016 SPE International Conference and Exhibition on Formation Damage Control, Lafayette, Louisiana, USA, 24–26 February. The paper has not been peer reviewed.*



(a) Layer 1
(Top Protection Layer)

(b) Layer 2
(Filter Layer)

(c) Layer 3
(Bottom Support Layer)

(d) Layers 1–3
(Stacked)

Fig. 1—(a through c) Individual layers are first generated according to mesh specifications. (d) All layers are then stacked together to simulate a multilayered virtual mesh screen.

together when building a multilayered screen. Note that all simulations in this section use the same mesh designs.

250-µm PSM. In this case, the results show that the PSD is a strong function of mesh alignment. It is shown that the filter-layer pores, which have a nominal rating of 250 µm, may not be fully open to the incoming sands in a small sample because of the pore blockage by wires of adjacent layers. Also, there is no obvious trend regarding how PSD changes with the filter-layer-alignment shift. This often-uninspected alignment variation between mesh layers plants some degree of uncertainty into the results of laboratory slurry tests conducted with coupon samples.

115-µm PDW. Here, almost no difference is found between the different alignment cases. This can be attributed to the fact that the PSD of a multilayered PDW screen is mostly dominated by the PDW filter; the filter-layer pore size is mainly governed by the mesh count, wire diameter, and the layer overlap.

The study also determined that a general decrease in sand production with an increase in overlap is observed for both alignment scenarios. The amount of sand being produced from a PSM screen is affected by its mesh alignment; this can cause the variations in results commonly seen in slurry tests performed with screen coupons.

Effect of Relative-Pore-Size Ratio. Certain degrees of interplay between the filter layer and its adjacent layers, especially for PSM screens, significantly affect the PSD and the sand-retention performance of a screen. It is important to review the design of a multilayered screen to determine whether these layer interplays could be diminished or even eliminated. Here, the issue is addressed by studying the relative-pore-size ratio, defined as the ratio of the pore size of a protection/support layer to that of the filter layer.

250-µm PSM. The filter layer of a standard 250-µm PSM screen in this study is sandwiched between a protection layer and a support layer. To isolate the influence of each layer, the simulation starts with modifying only the protection layer. The results show that, as the pore size of the protection layer increases, the percentage of small pores decreases. This allows a larger area of the filter layer to have unhindered exposure to the incoming sand.

When both the protection layer and the support layer are modified, it is shown that the interplays between the filter layer and its adjacent layers diminish as the pore-size ratio of the protection layer and that of the support layer both get larger. At high pore-size-ratio values for both the protection layer and the support layer, the PSD of a multilayered PSM screen will be very similar to that of a single-layered filter.

One can significantly overestimate sand production when the nominal rating is used to model the multilayered-PSM-screen performance. The difference between predictions made by the nominal rating and by the true PSD of a screen can be remarkable and is highly unpredictable because of variations in mesh alignment and layer overlap. The situation is improved as the pore-size ratios of the protection and support layers become larger.

115-µm PDW. Increasing the pore-size ratios of the protection and support layers of a multilayered PDW screen causes a negligible change in its PSD. The screens were all built with 30% layer overlap and 0% filter-layer-alignment shift. The result agrees well with the previous observation that the PSD of a PDW-screen assembly is mainly governed by the filter layer and is less affected by adjacent layers.

Summarizing all of the study's observations leads to the following conclusions:

- Having a protection layer can affect the PSD of a multilayered screen. The PSD of a PDW screen is less sensitive to the existence of a protection layer when the protection-layer pore size is larger than the filter-layer pore size. The PSD of a PSM screen is very sensitive to the addition of protection and support layers.
- Layer overlap changes the PSD of a PSM mainly by imposing constraints on the lateral movement of particles between mesh layers. Interplays between mesh layers should thus be considered when designing a screen.

Conclusions

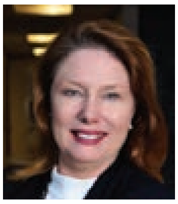
For a PSM screen, the PSD and the corresponding sand production are strong functions of layer overlap, layer alignment, and the relative-pore-size ratio. These factors govern the PSM-screen performance mainly by affecting the interplay between individual mesh layers. The presence of protection and support layers can downsize the pore throats in a multilayered screen, which results in a lower sand production than that produced from a single filter layer with the same nominal rating. Designing protection/support layers with large pore-size ratios helps to eliminate this complexity. **JPT**

ZUHAIR A. AL-HUSSAIN, SPE, retired from Saudi Aramco as vice president of southern area oil operations. He joined Saudi Aramco as a petroleum engineer in 1978 and held positions of increasing responsibilities over his 38 years of service with the company, including vice president of drilling and workover. Under Al-Hussain, the drilling program expanded from 25 rigs in 1996 to more than 200. The company's drilling and workover division has the highest percentage of Saudis manning service companies' and drilling contractors' rigs. He pioneered the use of local sand and seawater for gas well fracturing operations.

Hollek

Leyendecker

DARRELL HOLLEK, SPE, was appointed executive vice president, operations, at Anadarko, with responsibilities for US onshore exploration, production, and midstream activities, along with Gulf of Mexico and international operations. He was previously executive vice president, US onshore exploration and production. He will also remain a director of Western Gas Holdings, a subsidiary of Anadarko, and Western Gas Equity Holdings, the general partner of Western Gas Equity Partners. **ERNIE LEYENDECKER,** SPE, was appointed executive vice president, international and deepwater exploration. He was previously senior vice president, international exploration, and the other positions he held at the company include general manager for worldwide exploration engineering, planning, and international negotiations; vice president of corporate planning; and senior vice president, Gulf of Mexico exploration.

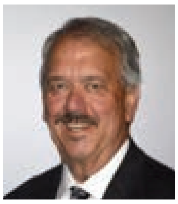


Howes

C. SUSAN HOWES, SPE, was appointed vice president of engineering at Subsurface Consultants and Associates. She will be responsible for maintaining the technical quality standards for the company's recruitment, consultancy, and training services. Howes began her career at Anadarko and held a variety of engineering positions in reservoir engineering, operations, mergers and acquisitions, technology and planning, and human resources, including senior staff engineer, engineering training and recruiting manager, employment manager, and learning and organizational development manager. In 2007, she joined Chevron as Horizons Program manager and later moved into its reservoir management function. Howes has coauthored papers and articles on uncertainty management, risk management, and talent management for SPE conferences and publications. She chairs the SPE Soft Skills Committee and previously served as the director of the SPE Gulf Coast North America region. She is a Distinguished Member of SPE and is a recipient of the SPE DeGolyer Distinguished Service Medal. Howes holds a BS degree in petroleum engineering from the University of Texas and is a certified Professional Engineer and Professional in Human Resources.

Matula

Rajagopalan



Lehman

CHUCK MATULA, SPE, **SHASHI RAJAGOPALAN,** SPE, and **LYLE LEHMAN,** SPE, founded Shale 2.0, a data analytics company focused on the improvement of completion strategies for oil and gas operators. Matula was previously an officer at ThruBit, cofounder and owner of Quantico Energy Solutions, and held executive positions at Weatherford and Halliburton. He is a graduate of Texas A&M University and holds a BA in engineering and an MBA in finance. Rajagopalan is experienced in the commercialization of business and technology startups in energy and worked at Halliburton, WellDynamics, Quanta Services, Genel Energy and other energy-related companies. He holds a bachelor of engineering in mechanical engineering from Queen Mary and Westfield College, University of London, and an MBA from the Fuqua School of Business, Duke University. Lehman was previously managing principal consultant at StrataGen and Pinnacle Technologies. He has 40 years of experience in stimulation and has written more than 24 technical papers and 10 business white papers, and holds 7 working patents. He is a member of the SPE Distinguished Lecturers Committee. Lehman holds a BS degree in chemistry from the University of Oklahoma.

TERRY EARL SWIFT, SPE, is retiring from Swift Energy as chief executive officer (CEO). Swift served as chairman of the board of directors from June 2006 to April 2016 and will remain a member of the board until he exits the CEO role. He joined the company in 1981 as manager of engineering and served in a variety of roles over the years, including executive vice president and chief operating officer, and president. Swift holds a BS degree in chemical engineering from the University of Houston and an MBA under the president/key executive program of Pepperdine University.

In Memoriam

The In Memoriam section lists with regret SPE members who recently passed away. If you would like to report the passing of a family member who was an SPE member, please write to service@spe.org.

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10–13 October ◗ Kuala Lumpur—SPE Reservoir Surveillance & Production Enhancement Through Cost-Effective Technology Integration and Operation Efficiency

11–12 October ◗ Houston—SPE /IMarEST Loop Current Eddy: Observations, Impacts, and Forecasts

11–12 October ◗ Doha—SPE Reservoir Characterisation

17–18 October ◗ Houston—SPE Deepwater Asset Integrity and Field Life Extension

17–20 October ◗ Kuala Lumpur—SPE Asset Abandonment—Emerging Reality

18–19 October ◗ Calgary—SPE Montney Play

19–20 October ◗ Bergen—SPE Workshops in conjunction with Offshore Technology Days (OTC)

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26–27 October ◗ Houston—SPE Diagnostic Fracture Injection Test (DFIT)—Processes and Applications

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21–23 November ◗ Kuala Lumpur—SPE Flow Assurance—Survival During Industry Downturn

28–29 November ◗ Kuala Lumpur—SPE GIWS: Maximising Asset Value in a Low Oil Price Environment Through Cost-Optimised Well Integrity Activities

5–6 December ◗ Kuala Lumpur—SPE Challenges of CO_2—Creating Value Through Innovative Technologies for Development, Separation and Utilisation

CONFERENCES

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24–26 October ◗ St. John's, Newfoundland and Labrador—Arctic Technology Conference

24–26 October ◗ Moscow—SPE Russian Petroleum Technology Conference and Exhibition

25–27 October ◗ The Woodlands—SPE Artificial Lift Conference and Exhibition-North America

25–27 October ◗ Perth—SPE Asia Pacific Oil and Gas Conference and Exhibition

1–3 November ◗ Astana—SPE Annual Caspian Technical Conference and Exhibition

7–10 November ◗ Abu Dhabi—Abu Dhabi International Petroleum Exhibition and Conference (ADIPEC)

14–16 November ◗ Bangkok—International Petroleum Technology Conference

30 November–1 December ◗ Manama—SPE Middle East Artificial Lift Conference and Exhibition

5–7 December ◗ Nairobi City—SPE/AAPG Africa Energy and Technology Conference

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SYMPOSIUMS

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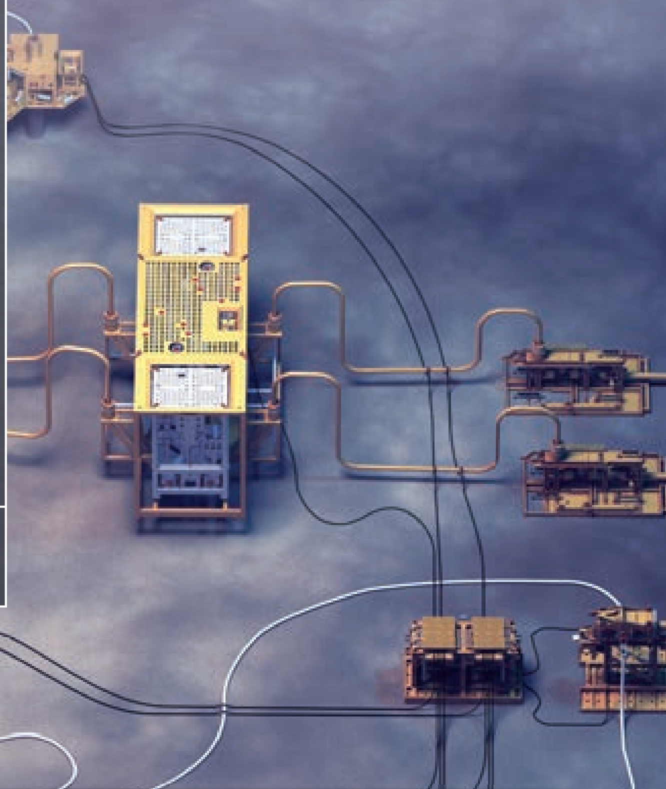

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