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Last month, Scotland narrowly voted in favour of retaining its 307-year union with the rest of the United Kingdom. The 55% ‘no to independence’ vote came out on top, despite many polls in the days leading up the historic referendum suggesting the opposite. The world watched as debates about oil and gas reserves, currency options, and apportioning national debt took over in Westminster and Holyrood. The dust has now settled in the polling stations, however, political uncertainties remain, and the oil and gas industry continues to be a focal point.

Oil and gas reserves were a hot button topic during the debate, with the ‘yes’ side impressing on the public a rich future of up to 24 billion barrels left to be exploited, and the other emphasising long-term decline and lower reserves. Former Wood Group CEO and author of the Wood Report (DECC-sanctioned review on maximising recovery from the UKCS) published earlier this year, Sir Ian Wood himself favours a more modest estimate of 15 - 16.5 billion barrels. We still don’t have conclusive evidence of proven reserves, and the estimates are wide ranging with the cautious DECC covering all bases, estimating reserves from 4 billion up to 34 billion barrels.

In the weeks leading up the referendum, the three main Westminster parties offered ambiguous assurances of further devolution of powers to a Scottish government, providing it stayed in the Union. Prime Minister David Cameron has since reiterated this, promising a draft Scotland Bill by January 2015. This essentially means that until then Scotland’s status in the Union remains unclear. Considering that the oil and gas industry makes up the country’s largest industrial sector, industry body Oil & Gas UK is pushing for issues such as taxation to be at the forefront of negotiations. This ‘no’ result is not a vote for the status quo.

In its recently published annual economic report, Oil & Gas UK has highlighted the need for fiscal reform, immediate and full implementation of the Wood Review recommendations, and a call for action to tackle costs, efficiency and productivity challenges.1

Key analysis in the report paints a grim picture. Exploration activity has dropped with only 15 wells drilled last year; production is in steady decline from the 1999 peak and reserves are more difficult and expensive to find and produce. Despite an 8% fall in production in 2013, operating expenditure rose by 15.5%.

Some 43 billion barrels have been extracted from the North Sea so far, at a total cost of £525 billion. UK Oil & Gas states that £1 trillion is needed to recover an estimated remaining 20 billion barrels, a reflection on how high these production costs have become.

Service providers and operators alike have been forced to trim expenses where they can. Aberdeen has suffered from these cost cutting measures, with Shell UK and Chevron both announcing job losses over the summer.

Decommissioning challenges have remained in the shadows, but with ageing assets running beyond their intended lifecycles, it is an issue that will only grow in importance. It is predicted that decommissioning costs could reach £40.6 million by 2040, a significant burden when facing lower revenues.

Without assuming how Scotland would have fared on its own, it seems likely that the referendum and doubt over the country’s future have delayed investment decisions this year. If the Wood Review recommendations can be agreed upon, the right economic stimulus injected, and operations made more efficient, then the North Sea could continue to serve the UK’s energy needs for many years to come.

I’m looking forward to seeing how the industry and government collaborates and makes better. The North Sea is an impressive hub of technological innovation that has global application; but it would be nice to see local support and growth as well. With the looming January 2015 deadline, the status quo will remain no more.

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Joint ExxonMobil/Rosneft Arctic project to be halted by sanctions just as discovery is made

A joint oil exploration project conducted by Rosneft and ExxonMobil in Russia’s Kara Sea is due to be wound down as US sanctions prohibiting American companies from conducting operations in Russia’s offshore Arctic territory come into effect.

Referring to the reports that the last well drilled by the ExxonMobil/Rosneft partnership had struck oil, Richard Keil, a Houston-based spokesperson for ExxonMobil said, “We have encountered hydrocarbons but it is premature to speculate on any potential outcome [...] Our current focus is on completing the well and safely winding down operations consistent with our license with the US government.” In contrast, Igor Sechin, CEO of Rosneft, close advisor to President Putin and himself a target of US sanctions claimed that the find exceeded expectations and said that find was of “exceptional significance in showing the presence of hydrocarbons in the Arctic.”

According to Sechin, the Kara Sea field in which the discovery was made is to be named “Victory” and will be ready for production in five to seven years. The well in question had targeted the Universitetskaya formation and was drilled to a total depth of more than 6500 ft.

Sechin also estimated that the find could hold for 100 million t of oil and 338 billion m³ of gas. ExxonMobil was not the only foreign company to have been involved in operation, with Nord Atlantic Drilling, Schlumberger, Halliburton, Weatherford, Baker Hughes, Trendsetter and FMC Technologies mentioned as contributing to the discovery.

Shell evacuates North Sea Brent Alpha platform

Royal Dutch Shell was forced to evacuate non-essential personnel from the Brent Alpha platform, located in the North Sea, after a container unit fell from the platform.

The company blamed the incident on a mechanical failure that affected the crane. The crane operator was able to move the container away from the platform and its support vessel.

Shell released a statement saying that “Personnel on the platform were called to a muster, all of whom are safe and well. As a precaution the Brent Alpha and Bravo, which were already shut down as part of ongoing maintenance works, were depressurised.”

The container had been attached to the platform by rope, but was later lowered to the seabed. The company stated that “An effort to recover the container and transfer it to a vessel is currently being planned. A support vessel is currently travelling to the Brent field.”

Nam Cheong to make US$ 41 million from sales

Nam Cheong Limited has announced that it has sold three vessels worth approximately US$ 41 million. These latest three contract wins come after five earlier vessel sales to PT Pelayaran Nasional Bina Buana Raya tbk (BBR), which netted Nam Cheong approximately US$ 126 million.

Leong Seng Keat, CEO of Nam Cheong said, “The regional and global OSV industry continues to see good demand for shallow water OSVs, despite some softening of oil prices. As evidenced by the securing of these orders which has helped buoy our order book to a healthy level of approximately RM 1.9 billion, we continue to be a beneficiary of the robust growth in the shallow water segment.

“These three orders, [...] represent the results of our sustained pursuit of being at the forefront of the OSV industry as a global player, beyond the shores of Malaysia.”

All eight vessels are scheduled for delivery across 2014 and 2015.

UK

The Nexen-operated Buzzard field, located in the UK North Sea has come back online after being shut down for maintenance. The field will continue to ramp up production to normal levels over the following days.

A spokesperson for Nexen said, “Following a minor system fault on Friday 26 September we can confirm that exports from Buzzard are now back online.” The Buzzard field normally produces 200 000 bpd.

Russia

Independent Russia oil company Sistema has had its stake in Bashneft seized by the Russian government continues to press charges against its owner, Vladimir Yevtushenkov.

The seizure has raised investor fears that the Kremlin is looking to reclaim former state assets and reign in the power of certain oligarchs. Parallels have been drawn between the case against Yevtushenkov and the Kremlin-driven downfall of Mikhail Khodorkovsky, former CEO of Yukos. Khodorkovsky’s arrest preceded the break up of Yukos and the acquisition of its assets.

Kazakhstan

Kazakhstan’s Deputy Oil and Gas Minister, Magzum Mirzagaliyev announced that production from Kashagan would not resume until the second half of 2016. He said, “We hope that after the replacement of pipes, we will start production in 2016.”

Production was postponed after a gas leak occurred just weeks after the facility became operational in September 2013. The Kashagan field is believed to hold some 13 billion bbls of recoverable oil and more than 1 trillion m³ of natural gas.
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**Murphy Oil to sell Malaysian assets**

Murphy Oil Corporation has revealed that its wholly owned subsidiaries, Murphy Sabah Oil Co., Ltd. and Murphy Sarawak Oil Co., Ltd., have entered into an agreement with PT Pertamina Malaysia Eksplorasi Produksi to sell 30% of Murphy’s Malaysian oil and gas assets for an aggregate sales price of US$ 2 billion in an all cash transaction, subject to customary closing costs and adjustments.

Roger W. Jenkins, Murphy Oil’s CEO commented, “This transaction marks the value of the high-margin, long-term assets in our Malaysian business. We are excited to strengthen our partnership with Pertamina and look forward to working with them and our other partners in Malaysia […] This transaction allows us to re-deploy the proceeds through an individual or combination of strategic and financial initiatives such as increased drilling capital in the Eagle Ford Shale, acquisition opportunities, debt reduction and share repurchases.”

**Cairn Energy to farm out 10% stake in Catcher**

Cairn Energy has announced that it has entered into a farm out agreement for the sale of a 10% interest in the Catcher development and adjacent acreage in the UK North Sea. With effect from January 2014, Dyas UK Limited (Dyas) will acquire 10% in each of the following UK Continental Shelf licences P1430, P2040, P2070, P2077 and P2086 by funding Cairn’s exploration and development costs in respect of the licences up to a cap of US$ 182 million.

As a result of this transaction Cairn will reduce its Capex to the end of 2017 in the Catcher area by approximately US$ 380 million to US$ 200 million.

CEO, Simon Thomson, said the company “remains focused on delivering value for shareholders from disciplined capital allocation and portfolio management across a balanced asset base. This value enhancing transaction provides us with significant additional operational flexibility to deliver the Group’s strategy.”

**Encana to boost oil production by buying independent Athlon Energy for US$ 5.93 billion**

Encana Corporation and Athlon Energy Inc. have announced that they have entered into a definitive merger agreement for Encana to acquire all of the issued and outstanding shares of common stock of Texas-based Athlon by means of an all-cash tender offer for US$ 5.93 billion (US$ 58.50 per share), as well as Encana assuming Athlon’s US$ 1.15 billion of senior notes, for a total transaction value of approximately US$ 7.1 billion. The Athlon board of directors has unanimously recommended to its shareholders that they tender to the offer.

Encana’s President and CEO, Doug Suttles was quoted as saying, “This transformative acquisition further accelerates our strategy and provides us with a prime position in what is widely acknowledged as one of North America’s top oil plays […] The Athlon team has built an exceptional asset with massive running room that includes greater than 10 years of drilling inventory with up to 11 potential productive horizons of high-margin liquids.”

The transaction is expected to add an additional 30 000 boepd to current production based on Athlon’s current estimated production including recent acquisitions. There is also the potential for approximately 5000 horizontal well locations with potential recoverable resources of approximately 3 billion boe.

Encana has revealed that it intends to invest at least US$ 1 billion of capital in the play and ramp up from three to at least seven horizontal rigs by the end of 2015. The Permian will play an important part within Encana’s growth portfolio, contributing significantly to company-wide projected total liquids production of around 250 000 bpd by 2017.
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Egypt to pay back US$ 1.5 billion

The Egyptian government has made a payment totalling US$ 1.5 billion to foreign energy companies after it had to postpone payments due to instability in the country following President Hosni Mubarak removal from power in 2011.

The country still owes approximately US$ 4.9 billion to foreign energy companies; this most recent payment was made using a loan from Egyptian banks.

A significant factor behind the repayments is to reassure oil companies and potential investors, and to encourage them to explore for oil and gas in country. Egypt's Oil Minister, Sherif Ismail, was quoted as saying, "The government aims to reduce the debt owed to partners in the oil sector to an appropriate level to motivate them to intensify research and exploration."

Russian oil production near record levels

Despite the threat of US and EU sanctions, Russian oil production has, according to the Russian Energy Ministry, continued to grow and, at the time of writing, is close to the country’s post-Soviet record.

In September this year, the country’s oil output rose by 0.9% to 10.61 million bpd, just shy of the post-Soviet record of 10.63 million bpd. According to Energy Ministry data, much of the production increase has actually come from foreign led projects. Output from Production Sharing Agreements rose by 24%, contributing close to an additional 300,000 bpd.

The precise breakdown of the output from PSAs is unknown, but major many foreign companies are involved including ExxonMobil, ONGC, Sodeco, Shell, Mitsui, Mitsubishi, Total and Statoil.

Natural gas production for August also rose, showing a significant increase from the previous figure of 1.38 billion m³ to 1.52 billion m³.

Noble provides update on Falklands Drilling

Noble Energy, Inc. has confirmed plans to resume exploration drilling in the Falkland Islands in 2015 following the acquisition and evaluation of an extensive 3D seismic programme over portions of the its 10 million acre position.

The company's initial operated prospect has been named Humpback and is located in the Fitzroy sub-basin of the Southern Area License.

Mike Putnam, Vice President of Exploration, said, "We are excited about our upcoming exploration programme in the Falkland Islands where we will be testing a basin with multibillion barrel potential. Our recent 3D seismic acquisition has confirmed our initial thoughts that the basin contains prospects of material size with ample follow on opportunities. The Falklands provides an opportunity to create another core area for Noble."

Dana Gas wins Egypt exploration rights

Dana Gas, the private sector natural gas company, has announced that its wholly owned subsidiary, Dana Gas Egypt, has been awarded the North El Salhiya (Block 1) and El Matariya (Block 3) onshore concessions in the Nile Delta as part of the 2014 EGAS bidding round held recently in Egypt.

The awards are subject to the execution of Concession Agreements, which is expected to take place in the coming weeks.

The company will operate the Block 1 concession area on a 100% basis. It is expected that exploration success and future production from conventional gas reservoirs in the Block, utilising Dana Gas Egypt’s existing infrastructure, has the potential to extend the company’s successful gas production business onshore the Nile Delta.

Dana Gas Egypt will participate in the Block 3 Concession Area on a 50% basis with BP as partner and operator.

Pakistan to sell OGDC shares for US$ 815 million

The government of Pakistan is hoping to raise some US$ 815 million from the sale of 323,460,900 shares in the national oil company, Oil & Gas Development Co. (OGDC).

According to officials, the sale is part of an ongoing programme to raise US$ 5 billion from the privatisation of 68 companies, including 10 banks. The government has already raised US$ 367 million and US$ 146 million respectively from two previous divestments.

Muhammad Rafi, Managing Director and CEO of OGDC commented on the asset sale: “OGDC is the largest upstream player in Pakistan and we believe the company is well placed to take advantage of the new opportunities in the market, which will further cement our leadership position.”

Norway Energy Minister concerned over prices

Tord Lien, Norway’s Energy Minister, has been quoted by Reuters as saying that there was reason to be concerned about declining oil prices as it was causing projects to be put on hold.

Lein stated that “We like to see oil prices above US$ 100 and we like to see them stable, but we also see a technical floor under oil prices [...] at around or above US$ 80.” Although Lien added that he did not expect prices to fall to as low as US$ 80, he noted that “there’s never been a technical floor in the oil market before. Earlier the floor depended on political decisions in large oil-producing countries.”

Another concern for the Norwegian government is that continuous low oil prices may drive operators to move from the region permanently, harming the its ability to recover should prices later rise again. Lien summarised the situation: “In the 1990s, when oil prices started to rise, the supplier industry didn’t have the capacity to meet demand.”

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Bringing R&D to RSS: interview with Weatherford

Last month, Oilfield Technology took in a tour of Weatherford’s new Rotary Steerable Systems (RSS) facility in Tewkesbury, Gloucestershire, UK. Editor Cecilia Rehn discussed all matters technology, health and safety, and Gloucester’s rich engineering history with Weatherford’s RD & E Director RSS, Daryl Stroud.

How is the Revolution RSS meeting the demands of the oil and gas industry?

Revolution RSS has proved very effective in many diverse and challenging applications around the world. It is a point-the-bit RSS with proportional control and therefore drills an excellent quality borehole with low tortuosity, this provides many advantages including maximising drilling efficiency, hole cleaning and ease of completions. It is particularly well suited to the emerging unconventional markets since it has the ability to drill an entire well in a single run, i.e., drill the vertical, curve and lateral without POOH to change the BHA. In addition, Revolution has amongst the highest temperature, pressure and steering deviation ratings in the industry.

How is Weatherford investing in R&D and testing?

In 2013, Weatherford invested in a new building for the main technology centre in Tewkesbury. This investment has facilitated an increase in R&D activity at the site; plus the opening of a nearby environmental test laboratory, which is used to evaluate new RSS designs for under deck access. The company recently completed the Aqua Milling of a 6 in. gas import riser for North Sea operator Talisman Sinopec. The team mobilised to the Claymore platform to clean the riser for inspection, which could not be cleaned by conventional methods due to the tight bend configuration near the access point. Mobilising offshore within a controlled worksite, Pipetech used the fully contained, remotely operated jetting system at 140 m depths and at a 950 barg working pressure. The system negotiated six bends – two at 45˚ angles – using the specialist nozzle deployed on the company’s flexible hose system. Accessing the riser through only one access point, reduces setup requirements and downtime.

Meeting cleaning and inspection challenges

Complex pipe layouts and ageing infrastructure present a number of cleaning and inspection challenges. These can be compounded by access difficulties, which in turn can lead to the need for greater reliance on platform core resources such as the provision of scaffold for under deck access.

UK-based Pipetech has a suite of high-pressure water technologies to remove scale and debris from pipelines safely and without the need for environmentally harmful chemicals. The technologies, Aqua Sonic® and Aqua Milling® are operated remotely, enhancing the element of safety. This, coupled with the Aqua Milling capability to reach 500 m from a single entry point, reduces setup requirements and downtime.

The company recently completed the Aqua Milling of a 6 in. gas import riser for North Sea operator Talisman Sinopec. The team mobilised to the Claymore platform to clean the riser for inspection, which could not be cleaned by conventional methods due to the tight bend configuration near the access point. Mobilising offshore within a controlled worksite, Pipetech used the fully contained, remotely operated jetting system at 140 m depths and at a 950 barg working pressure. The system negotiated six bends – two at 45˚ angles – using the specialist nozzle deployed on the company’s flexible hose system. Accessing the riser through only one access point, reduces setup requirements and downtime.

Recycling drill cuttings and drilling muds

Drilling mud – also called drilling fluid – is an essential component of the drilling process. Drilling mud aids in the process of drilling a borehole into the earth. Such holes are drilled for oil and gas extraction, core sampling and a variety of other purposes. The fluid is used to lubricate the drill bit and transport the drill cuttings to the surface. Drill cuttings are broken bits of solid material that are produced as the drill bit breaks the rock. As it circulates up from the drill bit, the drilling mud carries drill cuttings up to the surface, where the mud and the cuttings are separated.

Fortunately, waste streams that are high in hydrocarbons, such as OBM, are excellent candidates for thermal treatment technologies, such as thermal desorption. Thermal treatment uses high temperatures to reclaim or destroy hydrocarbon-contaminated materials. This process is an efficient treatment for destroying organics and reduces the volume and mobility of inorganics, such as metals and salts.

In the thermal desorption process, heat is applied either directly or indirectly to drilling wastes to vaporise the volatile and semi-volatile components without incinerating or damaging the soil. One of the best ways to thermally treat drilling wastes is with an indirect heated rotary kiln. A rotary kiln uses hot exhaust gases from fuel combustion to heat the wastes and remove the hydrocarbons, allowing the drilling muds and drill cuttings to be put to beneficial reuse.

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BOOM, NOT Bust
North America’s oil and gas industry is booming. According to PIRA Energy Group, a consultancy, the US is expected to average 12.1 million bpd production of oil, natural gas liquids (NGLs) and condensates this year, making it the world’s largest producer of combined crude liquids. According to the US Energy Information Administration (EIA) total wet gas production in the Lower 48 US, which stood at 48 billion ft³/d in 2007, surpassed 74 billion ft³/d in July 2013.

In addition, according to the National Energy Board (NEB), Canada is currently producing 3.8 million bpd crude and 13.2 billion ft³/d of marketable gas. The NEB expects Canada’s marketable natural gas production to rise to 17.4 billion ft³/d by 2035, and crude production to increase to 5.8 million bpd in that same time period.

The boom in the US is largely due to two major technological advances; horizontal drilling, which greatly increases the wellbore’s exposure to a reservoir, and hydraulic fracturing, which shatters the

Oilfield Technology Correspondent Gordon Cope shows how North America’s oil and gas industry is growing from strength to strength.
reservoir in order to allow large volumes of hydrocarbons to escape. Although shale gas production first began in the Barnett formation in Texas, it has since spread to several other basins, with astonishing success. Production from the Marcellus Shale formation, which lies below West Virginia, Pennsylvania and Ohio, is nearing 15 billion ft$^3$/d, approximately 20% of all lower 48 production.

In Canada, shale formations in northeast British Columbia (BC) and northwest Alberta hold several hundred trillion ft$^3$ in place. The NEB recently announced that the Montney formation alone has 449 trillion ft$^3$ of marketable natural gas, 14 billion bbls of marketable natural gas liquids and 1.1 billion bbls of marketable oil.

Explorers are also releasing crude from liquids-rich shale. North Dakota’s production of light, sweet oil from the Bakken formation has risen from 100 000 bpd in 2005 to over 1 million bpd in late-2013. The Eagle Ford formation in South Texas also produces gas condensate and oil, and the play is expected to grow to 1 million bpd by 2014.

The oilsands, located in northern Alberta, contain almost 2 trillion bbls of bitumen (over 168 billion bbls recoverable), trapped in sand and carbonate rock. The NEB expects oilsands production to increase from current levels of 1.9 million bpd to 5 million bpd by 2035. Recent announcements of new projects include Shell’s Jackpine mine expansion (an additional 100 000 bpd, to a total of 300 000 bpd), Suncor Energy’s Fort Hills mine (73 000 bpd by 2017), and Shell’s Carmon Creek in-situ project (80 000 bpd).

Although the western provinces dominate the Canadian oil patch, the East Coast has had a thriving hydrocarbon community for several decades. In 2013, Newfoundland and Labrador produced an average of 230 000 bpd of crude, primarily from offshore fields situated southeast of Newfoundland in the Grand Banks. And the future looks bright; ExxonMobil is building a gravity-based production structure for its C$ 14 billion Hebron heavy-oil project off the east coast of Newfoundland. Located near Hibernia, the 1 billion bbl field is expected to add 150 000 bpd of production over a 30 year period. Start-up is planned for 2017. Husky expects its South White Rose field to come on-stream later this year, and the West White Rose field in 2017.

Further offshore, Statoil and Husky have made three significant discoveries in the deepwater Flemish Pass Basin; Mizzen, Bay du Nord and Harpoon. Husky estimates that the Mizzen and Bay du Nord prospects hold 530 million bbls of recoverable oil. No estimates have been released regarding the Harpoon find, but company executives are confident that the discoveries can be commercially developed. Plans are underway to secure a deepwater rig to test further prospects in 2015. The region has the potential to produce at least 150 000 bpd by 2020 - 2021.

Many exciting plays are just beginning to emerge. The Duvernay formation, which underlies much of the Western Canadian Sedimentary basin, is one of the richest shale plays in existence. The Alberta Energy Regulator (AER, the successor to the ERCB) recently reckoned that the Duvernay (as well as the Montney and Muskwa formations), held 3300 trillion ft$^3$ of gas and 420 billion bbls of oil. Major oil companies have already spent over C$ 6 billion building land positions, and are now beginning to explore its potential. Chevron recently completed an initial 12-well exploration drilling programme in the liquids-rich portion of the Duvernay.

The US-based company reported that liquids yield for the wells ranged from 30 - 70%, with initial flow rates up to 7.5 million ft$^3$ of natural gas per day and 1300 bbls of condensate per day.

**Trials and tribulations**

The renaissance of North America’s oil and gas industry has not been without its detractors, however. Spurred by the burning of coal, crude and natural gas, the concentration of greenhouse gases (GHGs) in the atmosphere has been rising at a steady clip, eclipsing 400 ppm for the first time in civilised history. Climate scientists have associated the increase with the gradual warming of the atmosphere and oceans. If left unchecked, there is concern that glaciers will melt, causing sea levels to rise and inundate coastal regions. Many species will also suffer stress and potential extinction. Weather patterns will be altered, and humans increasingly subjected to extreme weather events.

Canada’s petroleum industry comes under special scrutiny over oilsands production, which requires the use of additional energy to coax the heavy bitumen out of the ground and upgrade it to higher quality crude. This extra processing causes it to be considered ‘dirty oil’, and various jurisdictions, including California and the EU, have tried to have it banned.

Environmentalists have strongly objected to moving oilsands output from Alberta to heavy-crude hungry refineries in the US Gulf Coast. In 2008, TransCanada proposed the 2720 km Keystone XL pipeline that would deliver more than 800 000 bpd of bitumen and heavy crude directly to Texas from Alberta. Since then, presidential approval for the US$ 5.3 billion line has been thwarted by White House protests and other acts of opposition. The decision for the project has now been postponed until after the mid-term 2014 elections, and many pundits speculate that it may not take place until a new administration takes office after 2016.

Concerns over hydraulic fracturing, have arisen. During the process, millions of litres of water and viscosity-reducing additives are injected under high pressure into reservoirs, crushing the rock and increasing permeability. Environmentalists are concerned that escaping fluids might pollute aquifers. Residents in arid regions worry that the practice is diverting scarce freshwater resources.

**Solutions**

Much work is being done to address fossil fuel-related issues. The governments of Alberta and Canada recently contributed C$ 865 million to Shell’s Quest project. Starting in 2015, Quest will capture more than 1 million tpy of CO$_2$ from Shell’s Scotford upgrader near Edmonton. It will then be transported 65 km and injected underground into an oil reservoir as part of an EOR project. Efforts are underway to reduce the amount of energy needed to coax bitumen out of the ground by experimenting with fire-fronts, solvents and electromagnetic waves. Innovative catalysts are being tested to partially upgrade the bitumen while it is still in the reservoir, reducing its viscosity.

Issues surrounding hydraulic fracturing are also being addressed. The Environmental Protection Agency (EPA) will examine the full cycle of frack water, from acquisition to mixing and post frack stage (where produced water must be managed and properly disposed). Fracking companies are devising new chemicals made from benign household products and food ingredients, and reducing the amount of water used. Service companies are building portable modules to recycle frack water that returns to surface.
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Industry has been promoting understanding of the practice through education efforts and public announcements. In 2013, the Petroleum Services Alliance of Canada (PSAC) issued the Hydraulic Fracturing Code of Conduct for its members (which include all Canadian frac services companies). Members of PSAC agree to follow five key standard practices and goals: water and the environment, fracturing fluid disclosure, technology development, health, safety and training and community engagement.

Operators are looking to export natural gas in the form of liquefied natural gas to energy-poor countries like Japan that are willing to pay a premium. Shell and Southern Liquefaction received approval to build the Elba Island LNG terminal near Savannah, GA. The facility will have a total liquefaction capacity of approximately 2.5 million tpy. ExxonMobil, BP, ConocoPhillips and TransCanada have announced preliminary details to ship up to 18 million tpy of LNG from Alaska to Asian markets from their proposed facility on the Kenai Peninsula.

In Canada, the NEB has approved nine LNG facilities on the west coast of British Columbia to ship gas to Asia. Among the projects, Encana, Apache Canada and EOG Resources received approval to build the C$ 5.6 billion Kitimat LNG project, capable of liquefying 1.4 billion ft³/d. Royal Dutch Shell, Korea Gas, Mitsubishi and China National Petroleum Corp. are also contemplating the LNG Canada project, a Kitimat facility that would convert 1.8 billion ft³/d. BG Canada has proposed the Ridley Island LNG project that would handle 4.2 billion ft³/d in Port Rupert, BC.

Faced with stiff opposition to Keystone XL, pipeline companies are seeking alternative routes. Enbridge has plans to expand deliveries to Quebec; it has been given approval by the NEB to reverse Line 9B, which delivers crude from Quebec to Sarnia, Ontario. The reversal will allow the company to deliver up to 300 000 bpd of heavy oil and lighter Bakken crude to refineries in the Montreal region. TransCanada is looking to repurpose its Mainline gas transmission system running from Alberta to Ontario, then to extend it with new-build. The 4500 km Energy East pipeline would deliver up to 1.1 million bpd from Alberta to the deepwater port of St. John, New Brunswick.

Canadian and American operators in the oilsands and the Bakken are increasingly relying on rail to get to market. Currently, approximately 180 000 bpd travels by rail, but the Canadian National Railway (CN), Canadian Pacific Railway (CPR), and other US firms are building tanker loading facilities and devising crude-only trains that exceed 100 tankers in order to lower transportation costs. Analysts now expect crude-by-rail capacity to exceed 1.1 million bpd in 2014.

In addition to Canada’s stymied efforts to find new routes to market for increased bitumen production, American producers face their own dilemma. Since the early 1970s, they have been confronted by a virtual ban on crude exports. The instigation of the ban was a result of events surrounding the Yom Kippur war in October 1973. When Syria and Egypt launched a co-ordinated attack to regain land lost in the 1967 Six Day War, the US came to Israel’s aid with arms supplies. Some members of OPEC decided to retaliate with an oil embargo against Canada, Japan, the Netherlands, the UK and the United States.

By 1974, the Nixon Administration had negotiated troop withdrawals and a cessation of hostilities, and the embargo was withdrawn. The action itself, however, had much farther reaching effects. OECD consumers faced massive fuel line-ups and price rises. The US, which was challenged by both rising consumption and falling production, was especially hard-hit. In 1975, Congress passed the Energy Policy and Conservation Act (EPCA) that sought to decrease dependency on foreign oil through conservation and energy diversification to coal, nuclear and natural gas.

In addition, the EPCA restricted the export of US crude unless a licence was granted for that purpose. Those seeking to export had to approach the Department of Commerce’s Bureau of Industry and Security (BIS) and apply under the Short Supply Controls guidelines. The result was a virtual cessation of exports of US crude.

Although the US will still have to import oil for many years to come, its current supply growth in the Eagle Ford and other unconventional plays is largely comprised of light, sweet crude. Gulf Coast refineries have limited ability to process the crude, and there is a growing chorus to lift the export ban. Recently, IHS released a report (commissioned by energy companies including Exxon Mobil Corporation, Chevron Corporation and ConocoPhillips) that concluded that lifting the ban would result in US$ 1 trillion to government revenues through 2030, trim fuel prices, and add an average of more than 300 000 jobs a year.

“Additional exports could prompt higher production, generate savings for consumers, and bring more jobs to America,” said Kyle Isakower, the API’s vice president for regulatory and economic policy, in a prepared statement. “The economic benefits are well-established, and policymakers are right to re-examine 1970s-era trade restrictions that no longer make sense. Of course, some will continue to argue that limits on trade are in the interests of consumers. But these arguments ignore the simple fact that consumers buy fuel – not crude oil – and the prices of refined products are set by a global market. Gasoline is already eligible for trade after oil is refined. Restricting the flow of America’s growing crude supplies only puts downward pressure on US energy production – not prices at the pump.”

In spite of all the tribulations, North America’s oil and gas industry continues to move from one promising unconventional play to the next.

Recently, attention has focused on the Cline formation, which lies in the Permian basin in west-central Texas. Initial tests have indicated that the shale, which ranges from 200 – 550 ft in thickness, holds an average of 3.6 million bbls of light, sweet recoverable oil per square mile. All in all, the Cline shale may hold an estimated 30 billion recoverable bbls, 50% more than the Eagle Ford and Bakken plays. Recently, Apache spent US$ 7.6 million drilling a 6800 ft lateral with 15 hydraulic stages. The estimated ultimate return is 423 000 boe, of which 87% is liquids.

No one doubts that North America’s oil and gas industry has tremendous potential, but it also faces significant challenges that need to be addressed. It will have to spend billions of dollars re-aligning existing energy transportation networks to take into account the growth of new sources, while at the same time communicating to the public that it is doing so in a safe manner. It must continue to reduce its environmental footprint and meet ever-stricter regulatory rules. It is obligated to seek out new international markets for its products while ensuring consumers at home that they will not face undue financial hardships. Doing it all correctly will not only impact the continent’s energy future, but will have an unprecedented effect on the world as well.
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Dave Lipomi, Tensar International, USA, explains how geogrid systems can provide the infrastructure support that oil and gas operations need, whilst saving money on aggregate costs.

Infrastructure has rapidly improved to sustain increased traffic levels noticed in the last few years in the USA. Due in large part to the boom brought about by horizontal drilling and hydraulic fracturing, the oil and gas industry is one of the many industries contributing to increases in traffic and transportation changes such as heavier trucking loads.

This tremendous growth has made adapting to support the heavy loads transported on these roads an ever-evolving challenge. Specifically, within the upstream sector, service companies use roads to transport equipment to and from remote well sites. While the midstream sector of the industry relies heavily on either transporting crude, refined petroleum or natural gas products, or building pipeline infrastructure to move the products from place to place.

Additionally, construction costs for these roads have increased dramatically in recent years. This is a direct result of the presence of soft soils as well as unforeseen environmental impacts, including unpredictable harsh winters, in these rural areas.

As the oil and gas industry continues to boom, the constant use of these roadways leads to faster deterioration and unstable grounds. Over time, this becomes a hazard that puts the entire industry’s safety, production rates and costs on the line.

Improving road infrastructure
The slightest surface deformation can cause the loss of expensive equipment or, even worse, it can cause injury to those out in the field. Most access roads are not designed to withstand a haul trucks’ heavy weight and the amount of traffic to and from an active well site. Additionally,
highly variable subgrade made of weak soils may quickly deteriorate to create potholes or washouts.

Recently, Tensar International’s TriAx® Geogrid application has seen use by operators due to its solution-based capabilities, preventing rigs from leaning and stabilising roads pummeled by heavy trucks. By using geogrid applications, operators can reduce aggregate requirements up to 50% while also reducing labour and equipment needs. The improved surface quality creates longer lasting roads with lower maintenance requirements, yielding fewer accidents and costs.

**Challenged to find a new approach**

Typically, the daily expenses involved in operating a rig can run to as much as US$ 1 million, and operators cannot risk the financial loss incurred due to a stalled or overturned truck due on an unstable road. This scenario illustrates the reasons why operators and contractors are looking for ways to improve roads and infrastructure.

Tensar’s Geogrid applications have been used at drilling sites throughout the US and Canada, including the Marcellus and Utica Shale regions, giving operators and producers a way to increase the performance of access roads and well pads, while maintaining safe operations and costs down.

One gas producer saved US$ 1.4 million over 10 miles of road. This means this producer paid for the geogrid and put US$ 1.4 million back in their pocket.

TriAx Geogrid is a polymeric geosynthetic material that is manufactured into triangular-shaped apertures, from a punched and drawn polypropylene sheet. The triangular structure traps aggregate and prevents it from moving by providing in-plane stiffness, which reinforces weak subgrades under the well pad, roads and parking lots.

This application leverages multi-directional strength properties to provide an improved level of stability for both permanent paved surfaces and temporary working surfaces alike.

Together, the reinforcement mechanisms of lateral confinement and bearing capacity improvement allow for the system to deliver enhanced performance.

**A scientific approach**

Access roads, otherwise known as haul roads, are often made-up of soft soils from the surrounding areas. These are then used to transport tools, rig-crews and other materials to the well sites, exposing them to severe damage. The safety hazard and financial burden these roads create has led operators to invest in improving the infrastructure around well sites.

The geogrid structure utilises lateral confinement by confining granular aggregates, increasing the modulus of the confined aggregate. Lateral confinement is considered to be the primary reinforcement mechanism, and is defined by the US Army Corps of Engineers as “confinement of the aggregate material during loading, which restricts lateral flow of the material beneath the load.”

Bearing capacity, the load limit of a soil layer, is increased significantly with the use of geogrid. Rutting is almost always a result of subgrade soil movement while the roadway structure or construction platform is in service. As such, bearing capacity improvement, also known as the ‘snowshoe effect’, becomes an important mechanism when the subgrade support effectively controls the life space of the structure built on softer soils.

Utilising the combination of lateral confinement and bearing capacity allows for longer service life where geogrid is installed and thus less expenditure on maintenance for the contractor and operator.

**Stabilising well pad foundation**

When used under a well pad, savings on aggregate costs have been as much as US$ 1.5 million on a single project – removing just 2 in. from the
Introducing RapidStart™ Initiator CT sleeves – the only sleeves that do not require over-pressurizing. Traditional completion sleeves require activation pressures so high that they can invalidate the results of a casing integrity test. Halliburton’s new RapidStart Initiator CT sleeves are different. They activate after a customizable time at a lower pressure, so they do not over-pressurize the casing. They also create a “second chance” window so operators can delay the activation and still retest the casing if an issue arises.

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Creating a stable foundation

In Clearfield County, Pa., an oil and natural gas company was building a number of well pads and associated access roads in the State Game lands. This area has roads that are governed and maintained by the Department of Conservation of Natural Resources (DCNR) and the Bureau of Forestry.

The company used the public roads to transport vehicles and equipment for construction, drilling and hydraulic fracturing. As part of the agreement with the Forestry Service, the company had to regularly maintain the nine-and-a-half mile stretch of road, and incur any costs associated with maintenance.

The cold climate and foundation soils at the site in Clearfield County added to the overall costs and challenges. Additionally, due to its proximity to Lake Erie, the region experiences a great deal of lake effect snow. The snow then accumulates on roads where trucks start transporting before plowing occurs, making the roads unsuitable for traffic.

As trucks drive on snow covered roads, 15.2 cm (6 in.) of snow can change to 5.1 cm (2 in.) of ice, in what is locally referred to as an ‘ice lens.’

This effect caused heavy deterioration during the annual spring thaw cycle. As more aggregate is brought in to maintain the roads, additional snowfall starts the cycle over again. The layers become a striation of ice and stone.

The Forestry Service was concerned about the spring thaw and moisture retention in the clay subgrade creating an unstable roadway. These two conditions would make roads impassable in the spring months.

The project owner considered restoration strategies such as soil cement, a new 33 in. thick aggregate top layer, or an alternative geogrid system in combination with an aggregate top layer. These solutions were rejected due to concerns over environmental impact, cost, and performance respectively.

The incorporation of a layer of TriAx TX7 geogrid was suggested and identified as the preferred solution for stabilising the roadway for public and commercial use. The system allowed the contractor to bridge saturated and crumbling soils by placing the geogrid directly on the existing grade.

On a local haul road in Highlands, Texas, the contractor used TriAx TX160 Geogrid to improve the road area. A haul road was needed to bring in 18-wheelers with a turn-around and offload area. The site had stiff crust, but once opened, the highly plastic clay subgrade could not carry any load. Tensar Engineers suggested 8 in. of aggregate base on top of the geogrid. The contractor was able to finish the 8 in. of material, then placed one layer of TriAx TX5 Geogrid and an additional 8 in. of limestone. The contractor was able to finish the project ahead of schedule at a reduced cost. By using the geogrid, the client noticed added strength to handle the continued truck traffic by protecting the subgrade. In the long-term, this stability will lower maintenance costs and reduce long-term rutting issues.

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Success in the field

Oil and gas producers have saved hundreds of thousands of dollars in stone cost alone for a single well site when using this Geogrid application. Several projects in Texas illustrate the efficient, cost effective results that this Geogrid yields.

- An operator in Cuero, Texas, required the widening and reconstruction of a road due to ageing pavement and increased truck traffic from the oil and gas industry. The client, a design-build firm, reclaimed the existing county road and re-compact ed approximately 8 in. of material, then placed one layer of TriAx TX5 Geogrid and an additional 8 in. of limestone. The contractor was able to finish the project ahead of schedule at a reduced cost. By using the geogrid, the client noticed added strength to handle the continued truck traffic by protecting the subgrade. In the long-term, this stability will lower maintenance costs and reduce long-term rutting issues.

- In Los Angeles, Texas, an operator recently installed geogrid application at a treatment facility access road project. The original design called for 18 in. of aggregate and geotextile fabric to stabilise the pad sites and access roads for this job. By using TriAx TX160 Geogrid, the contractor was able to save 12 in. of aggregate and eliminate the geotextile fabric.

Conclusion

Unfortunately, most roads are not designed to withstand a trucks’ heavy weight and the amount of traffic to and from an active site. Roads using a geogrid system can endure more weight, allowing for larger quantities of loads and fewer trips. The improved surface quality can create longer-lasting roads with lower maintenance requirements, meaning lower costs. Reduced labour and equipment needs are a direct result of road improvement as well.
Optimising hydraulic fracturing design and well spacing is essential to make the production of unconventional resources profitable. Indeed, drilling, completion and stimulation costs are the highest expenditures in such plays, in which thousands of long, expensive horizontal wells with dozens of hydraulic fracturing stages are drilled every year.

To rationalise those operations, oil and gas companies are looking to find out the drainage volume of each well and even of each fracturing stage, the so-called stimulated reservoir volume (SRV). It is also essential for the industry to have a predictive solution so that operational parameters, such as the number of stages or type and amount of injected fluids, can be adjusted.

Martin Weber and Thierry Lemaux, Beicip-Franlab, France, discuss a new approach to predicting hydraulic fracturing impact on the formation and optimising well performance.
to the formation’s petrophysical properties, in order to find the best economic development scheme. Having a predictive approach makes a great difference as the process of operational trial and error, implying the drilling of many costly wells, can be avoided or reduced.

A new modelling approach
The techniques for modelling SRV are not quite mature today and a lot of progress has to be made to make them more reliable. Traditional characterisation techniques relying only on static data are incomplete, as they need to be enriched to take into account what happens during stimulation. Several empirical approaches that have recently emerged are increasingly used: different attributes – from seismic, microseismic and production – are analysed to establish relationships between them. A popular method is, for example, to map microseismic amplitude in 3D and empirically look for a mathematical relationship with stimulated permeability. Results can be good but these techniques are generally not predictive and are not able to explicate the physical mechanisms behind the relationships between those parameters. Therefore, the physics of hydraulic fracturing must be properly understood and included into classical characterisation techniques to obtain an accurate and predictive method.

Beicip-Franlab, an independent oil and gas consultant, proposes new methods to overcome those challenges and such a new practical approach is currently being developed. It aims at capturing the physics of hydraulic fracturing to deliver an accurate model of the stimulated formation. This new solution predicts how the formation is impacted by hydraulic fracturing at a very fine resolution, thus allowing prediction of the future production associated with different developments plans.

Modelling the physics of hydraulic fracturing
As the pressure increases during injection, the creation of hydraulically induced fractures is modelled, as well as the reactivation of natural fractures, which often exist in this type of play. An example can be seen in Figure 1. One of the main ideas behind this new technique is that the natural fractures are essential in the propagation of the treatment through the formation and that they control the resulting SRV shape, extension and properties. Indeed, natural fractures act as pre-existing planes of weakness where the rock is more likely to break than in any other place. Therefore their orientation, in relation to the main horizontal stress azimuth, will control the direction in which fracturing will occur. Their size and density are also essential parameters that will influence the final shape and properties of the SRV.

Benefiting from decades of expertise in natural fracture modelling and with its dedicated software package, Beicip-Franlab is in the position to investigate and develop such a new approach. Indeed, a reliable model of the natural fracture network is a prerequisite and can be obtained through the company’s classical fracture characterisation methodology. In a first step, static and dynamic data, such as borehole imagery or well test and flowmeter results, are analysed and compared with structural information to understand the fracture network geometry and organisation. In a second step, a fracture model...
that populates the reservoir grid with fracture properties is created. After that, one can compute the hydraulic properties of the fractures through calibration of well test data and finally compute fracture equivalent properties through upscaling.

Through a dynamic simulation of the injection process, it is then possible to use hydraulic and mechanical laws to predict how each fracture plane is affected and modified by changing pressure and stress at each time step. Both elastic and plastic deformation are modelled, the latter leading to the generation of simulated microseismic events. In this approach, the stress tensor is used along with mechanical properties of the formation. Deformation of each fracture therefore not only depends on the pressure inside the fracture, but also on the orientation of the fracture with regard to the stress tensor.

The simulator uses a very fine unstructured mesh at the scale of the natural fracture network – a discrete fracture network (DFN) – and several tens of thousands of fractures can be used, making the approach compatible with realistic fracture networks. Such a mesh is shown in Figure 2. A flow simulation is then performed in this mesh and coupled with the mechanical laws mentioned above. At the end of this process a deformed discrete fracture network (DDFN) is obtained, in which each fracture will have a computed final aperture and conductivity resulting from the stimulation process.

It has to be noted that this solution is not a full geomechanical coupling: indeed in the reality, pressure change in one fracture can modify the stress field and opening of every other fracture of the system. Taking into account that such complex interactions would be extremely CPU-time intensive and would not be compatible with realistic fracture networks that typically contain several thousands or even tens of thousands of fractures. To handle such large fracture networks, it has been decided in a first approach to simplify the problem and neglect those interactions. However, Beicip-Franlab is currently looking at ways to improve the model and go beyond this first assumption. So far, comparisons of the approach with an explicit geomechanical resolution on synthetic cases have been performed and few differences observed.

**Concrete applications of the methodology**

This DDFN therefore gives a measurement of the SRV size, shape and its modified petrophysical properties, and can then be used in a conventional fluid-flow simulator to establish a production forecast. Alternatively, the company is developing a solution to use the fine unstructured mesh for the production forecast: this technique would allow for the capture of the true complexity and heterogeneity of the DDFN instead of relying on conventional fracture upscaling, which tends to homogenise the fracture properties. An example of DDFN is displayed in Figure 3.

The whole workflow can be repeated several times so that different fracturing designs or well spacings can be compared, and lead to the choice of the most optimal ones. It is, for example, possible to compare the efficiency of a cross-linked gel treatment with a slickwater treatment or assess the influence of different injection durations and rates. It is also possible to determine the optimal number of stages needed to stimulate the whole well without stimulating twice the same zones or leaving unstimulated areas behind.

To increase its predictability, the Beicip-Franlab workflow can be applied first in a calibration phase, in which observed fracturing job results, such as measured well bottom hole pressure (BHP), and recorded microseismic events will be
matched. In fact, both information are computed during the hydraulic fracturing simulation and can be compared with the observed values. This calibration phase will narrow down the uncertainties on the model’s parameters and in turn increase the accuracy of future predictions. This methodology has already been applied in several plays of North America and the company’s conclusion is that having those two different calibration targets considerably increases the confidence of the adjusted model: the well BHP is matched quantitatively and allows adjusting of fracture hydraulic and mechanical properties, while microseismic is matched qualitatively and allows for the adjustment of the geometry of the fracture network. Indeed for the latter, the company is looking to match the shape and extent of the whole of the recorded events, as shown in Figure 4. Experience has shown that it is possible to obtain a very good match in pressure but with simulated microseismic events in the wrong direction and locations: therefore both calibrations are complementary and only does their combination give a truly reliable model.

Depending on the context, this new approach will be used slightly differently. In a new zone with little experience and data, the model will be less constrained and the approach will be used for risk mitigation or to help with the design of a first well. However, it is in an existing and ‘mature’ zone where the main concern is optimising the development scheme, that this approach will deliver its highest added-value. By having access to calibration data such as treatment BHP and microseismic on some wells it will be possible to increase the reliability and predictability of the model. For such plays in which hundreds of wells can be drilled every year, planning every one of them individually may prove too tedious a job, so the approach will be to rather focus on optimising the general fracture design and well spacing, or adapt it to new zones with slightly different reservoir properties, such as brittleness, natural fracture density or formation thickness.

**Going a step further**

As mentioned above, geomechanical interactions between fractures are currently not taken into account but this is definitely a topic will be looked into in the near future. Another essential physical phenomenon to model is proppant distribution during the hydraulic fracturing treatment: its effect is currently modelled empirically, but an explicit distribution mechanism would improve the model. In fact, one of the crucial questions when dealing with hydraulic fracturing is not only to open up as much new fracture volume as possible, but also keeping it open with proppant while avoiding a screen-out.

Those two examples show that there is room for improvement of the methodology, and this is the reason why the company has decided to launch a consortium, in order to find partners to share know-how and experience and discuss future new developments.
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n the midst of the shale energy revolution and surging levels of oil and natural gas production in America, oil and gas operators are faced with the considerable pressure of keeping the momentum going.

The very nature of shale gas and oil production makes sustainable commercial operations difficult. Independent economist Deepak Gopinath explained these difficulties: “Oil and gas trapped in relatively impermeable and less porous shale rock formations do not flow unaided to the well … As a result, production at shale wells tends to fall off steeply after an initial few months of high output.”

This is where new and evolving well-stimulation technologies come into the picture. By enhancing the oil and gas extraction process, well stimulation plays a critical role in keeping shale energy production commercially viable.

One of the currently available well stimulation technologies, the zipper frac technique – which involves fracking two wells at once – has been growing in popularity among shale energy producers. In 2012, engineers rolled out a ‘modified’ zipper frac technique that improves upon the original technology – meaning that now, operators have access to two efficient, effective fracking tools.

Improving a ‘primitive’ technique
Extracting oil and natural gas from shale – or other rock formations – begins with drilling a well. An operator might drill down into the earth as much as a mile and then drill horizontally one or two miles to reach the shale formation.
Hydraulic fracturing comes next. During this step, a mixture of water, sand and additives is injected at very high pressures into the rock at the base of the well. The high pressure cracks open – or fractures – the shale and allows operators to access trapped natural gas or oil.

While traditional fracturing techniques are still widely used, they have been faulted for being less efficient than they could be. Last year, consulting firm Bernstein Research published a study that concluded fracking is an inefficient process, and that half of all fracturing stages contribute no additional production from a given well.

The general consensus among industry leaders is that, when it comes to fracking, while the process is proven, there is room for improvement. In a recent Reuters interview, Nansen Saleri, President and CEO of consulting firm Quantum Reservoir Impact, said, “In a few years the techniques used today for fracking will be viewed as primitive.”

A team of Texas Tech University researchers has been leading the way toward a less ‘primitive’ fracking process. The team developed the ‘zipper’ technique for fracking in hopes of helping oil and gas operators increase their efficiency, cut costs and boost their output.

The zipper technique calls for fracking two adjacent wells at the same time, or in an alternating sequence. The idea here was that fractures created at the tips of these two wells would spread toward each other, and the resulting stresses would force the fractures being made into the rock to go even further – and as a result, increase output. The technique can be utilised in two lateral wells anywhere from 250 ft to more than 1,000 ft apart.

Saving valuable time and money

The zipper frac technique has achieved its developers’ goals, to some extent, but its impact has been more about economics than increased output.

Zipper fracs help operators save time and money because one crew can frack two or more wells simultaneously.

These benefits certainly have held true for Canary LLC and the companies it serves. Zipper fracking saves a lot of time and a lot of manual labour. It means fewer man-hours, and it lessens the time of the frac. Other companies have made similar observations. For example, Kodiak Oil & Gas reported in Q4, 2013 that it had used zipper fracs to reduce its average fracking time from 7.5 days to 5.4 days per well.

The technique seems to save money as well: Penn Virginia’s average drilling and completion cost per frac stage fell to US$380,000 in the fourth quarter, down almost 3% sequentially.

Zipper fracs are beginning to gain popularity outside America: The technology recently made news in China, where the country successfully attempted the process with four wells at the Changning H2 national demonstrative shale gas mining block in Sichuan, held in March. The technique was praised for doubling working efficiency.

Back in the United States, at the Eagle Ford Shale, Pioneer Natural Resources Co. recently utilised zipper frac stimulation on three-well and four-well pads, resulting in a 20% increase in estimated ultimate recoveries for those wells.

Natural gas producer EQT Corp., which is headquartered in Pittsburgh, PA, has been analysing the efficiencies of zipper fracking for approximately five years. The company initially started the process as it was believed that it would help to reduce traffic stress and enhance production flow. Today, it views zipper fracking solely as a method of improving efficiency. Zipper fracking allows for much better planning logistics for sand and water deliveries, as well as for scheduling onsite crews. The process essentially doubles available manpower as it allows the company to do two things at the same time, perforate the pipe and hydraulically stimulate or fracture – and this can be done on multiple stages of multiple wells at the same time.

New and improved

Essentially, EQT’s discovery is a succinct summary of the zipper frac’s primary limitation: the technique does make a difference in terms of speed and efficiency, but it does not improve on fracking effectiveness, said Mohamed Soliman, George Livermore Chair Professor and Department Chairman of Petroleum Engineering at Texas Tech University.

“I had one of my students, a PhD student, working further on the subject, looking at zipper fracturing, and we discovered that the zipper frac may be good, but it does not result in the complexity that one would want in fracturing shale,” said Soliman, a former technical professional and manager for Halliburton Energy.

In this case, ‘complexity’ refers to creating and opening the fractures necessary within a shale reservoir to trigger optimal natural gas and oil flow from the fractures to the wellbore.

Soliman is confident that the 2.0 version of the zipper frac that he and his research team developed – the modified zipper frac – is capable of creating that complexity.

The modified technique is initiated in a staggered and overlapping pattern to induce stresses in the rock formation, not only at the well tips, but also in the middle area between fractures. “You’re opening natural fractures and the planes of weaknesses within the formation,” Soliman said. “The regular zipper frac does not do any of that.”

Soliman and his team have filed patents for the modified process, and Halliburton already has expressed interest in utilising it, Soliman said.

One of the reasons he believes traditional zipper fracking failed to reach its full potential is the technique does not fully account for the
mechanical properties of the shale formation beneath the ground’s surface.

Generally, cracks form naturally within shale, but during the fracking process, those cracks are compressed and squeezed shut by contrasting downhole stresses.

The key to resolving these contrasts is to get the stresses close to each other.

“So you are changing ‘Mother Nature’ to make those stresses close to one another, then as the hydraulic fracture intersects those natural fractures, all of a sudden, you have a hydraulic fracture that has a lot of branches to it,” said Soliman. “So, it would be as if, rather than one highway, you have a lot of narrow highways crossing it, and those narrow highways are pulling fluid from deep inside the formation into the larger highway, which is the hydraulic fracture.”

The question is: how does one achieve this objective?

According to Soliman, the answer to that question is not simple. “It requires some interference between fractures. One has to know the conditions, how to build up those hydraulic fractures at the right distance from each other, what fluid you use and so forth. Doing the calculations, however, is very, very complex. I had a student doing his PhD working on that subject,” he said.

In addition to creating the modified zipper frac technique, Soliman and his team have developed an optimisation technique that calls for variable spacing between hydraulic fractures. The fractures are not spread equally: measurements are taken after the first fracture to determine the placement of the next fractures.

From there, the operator determines the optimal distance between fractures based on stress interference, the complexity needed and the projected spread of the fractures. This optimisation technique, ideally, would be used in concert with the modified zipper frac.

No one said it would be easy

Both traditional zipper fracs and modified zipper fracs come with their own sets of pros and cons. “With the zipper frac, the challenges are operational,” Soliman said. “You have to drill the wells; you have to fracture simultaneously in two different wells. There is the co-ordination of determining the distance for the perforations, and how much to inject in each. Before you even do that, one has to determine the stress orientation within the rock formation, which requires a lot of testing, a lot of work. Then there’s a lot of monitoring of special data during the job.”

The modified zipper frac has some disadvantages, too. “It requires more engineering work on the front side, and the multiple wells probably need to be closer to each other,” Soliman said. “Those disadvantages should be offset when you get the large increase in production quickly. When you consider the time value and money, it would be very beneficial.”

Soliman pointed out that he is not shooting down zipper fracking. The way he sees it, zipper fracking and modified zipper fracking are both good options, depending on the operator’s goals.

“If your goal is to create many fractures and make sure you are covering the reservoir very well, in a very quick fashion, the zipper frac works very well. If you are trying to increase the complexity of fracking, then no, it is not the right tool.”

“It is like anything in life. If you want to drive from one place to another in a certain number of hours, you can use multiple cars. But if you want to drive in a very short time, then you need to drive a Ferrari.”

In other words, he said, operators have technology options to help them optimise shale energy production. It is just a matter of selecting the most suitable technology for their specific needs.

Reference
Matthew Doyle and Jessica McDaniel, CSI Technologies, USA, examine the steps to take in order to avert sustained casing pressure in US shale plays.
The Irish poet and playwright Oscar Wilde once stated that success is a science. If you have the conditions, Wilde wrote, you get the result.

Science, though, can be inexact at times. Such is the case with sustained casing pressure (SCP) in US shale plays. SCP is a result of incomplete zonal isolation and gas migration through the damaged cement in the annulus between casing and the formation in oil and gas wells. Incomplete zonal isolation can create a path for gas migration, and this can happen anytime during the life of the well. However, there are two time frames to focus on for optimising cement design and operations: short-term and long-term gas migration. Short-term gas migration occurs when the cement slurry is in transition from the liquid to solid state. Long-term gas migration, occurs after the cement has hardened and is developing compressive strength. With the current emphasis on US shale drilling,
improvements in production efficiency, safety and environmental impact are very valuable. These improvements can be made by successful zonal isolation through improved cement performance.

Activity in the Marcellus shale play has grown rapidly since 2008, and average natural gas production in the Marcellus increased by 61% between 2012 and 2013. This increase in production over the past year accounted for 75% of all production growth in the six major unconventional basins. Currently, the Marcellus shale play is estimated to hold 141 trillion ft$^3$ of gas. Continuing efficient production and safe operations on any well is dependent on adequate zonal isolation. Drilling and completing shale gas wells can be a technically complex and challenging operation, especially in the Marcellus. However, by addressing deficiencies with the cement slurry and operations before a cement job helps ensure proper techniques and systems are in place. This reduces overall costs as well as improves safety during rig operations and decreases the possibility of environmental concerns.

As stated earlier, SCP prevention has to address both short-term and long-term gas migration mechanisms. Laboratory testing of cement field blends showed two cement systems that had been designed to prevent short-term gas migration using short static gel strength transition times and optimised fluid loss control. However, field results indicated one system had a nearly 90% success rate for prevention of sustained casing pressure, while the second system was only around 40% successful. Results from testing showed the cement system had low potential for short-term gas migration; this indicated the possibility that long-term gas migration may be the reason for sustained casing pressure in these situations. Previous studies have indicated that cement mechanical properties and durability are important in determining if a cement sheath can provide zonal isolation for the well’s lifetime. Cement design and operation optimisation can help to prevent long-term gas leakage by preventing damage and leakage during post-cement operations.

When cementing a well, preventing gas flow for life of the well is vital for safe operations, environmental impact and optimal production from the well. However, it is difficult to determine if and when a well will leak. A RPSEA research project offers some insight on why some wells leak and some do not. Cement design is a significant factor. There is no one specific property in cement design that can predict gas flow, often a combination of properties are needed to make this prediction.

Historically, service companies and operators have taken an off-the-shelf, assembly line style approach to operate in unconventional fields. The assembly line approach does work well; however, it requires the utmost attention to detail encompassing the entire cementing process. Each well and every string of pipe can present its own unique challenges that require some level of engineering job design. Standardisation of slurry performance requirements for all strings of pipe is appropriate, and requires engineering design up front and continual effort and monitoring to ensure the end product is meeting the requirements set for each application. A high level of interaction between drilling engineers, operations personnel, and the service companies is essential for an effective cementing programme in shale well environment.

What has been done?

To follow up an initial study by McDaniel et al (2014), a secondary study was conducted to investigate trends and, by using dimensionless variables, predict the durability needed from a set cement system to resist gas migration for the life of the well. Two variables were introduced, energy resistance and energy applied. These two variables were calculated and plotted against each other using laboratory data to find a correlation to predict failure. Ultimately, these variables can be calculated using field data and reliable field energy estimations to determine cement properties needed to prevent failure.

In order to determine energy resistance, the study utilised a combination of cement properties in a ratio. To determine each property, cement samples were cured 24 hours at well conditions prior to testing. Cement systems selected for this expanded study were based on results from the initial investigation, to evaluate how different additive concentrations in the cement systems affect set cement properties. The properties used are described below:

- Young’s Modulus: A Young’s Modulus is associated with increased stiffness and brittleness. The cement, though, may not be strong enough if the value is too low. This property must be optimised in a cement system.
- Poisson’s Ratio: An increase in Poisson’s Ratio is associated with an increase in the cement system’s durability during a cyclic stress event.
- Anelastic strain potential: This is a measure of how much cement deforms plastically over time when exposed to a cyclic load. The more the cement deforms, the higher the anelastic strain potential is. Ideally, a low number would mean a more durable cement.
- Ultimate compressive strength: This property must also be optimised. Very high compressive strengths may correspond to more brittle materials.
- Impact strength: Cement systems with more impact strength will perform better when exposed to a cyclic stressing event. This property is positively correlated with energy resistance.
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Tensile strength: Cement tends to have very low tensile strength. High tensile strength would improve a cement’s durability.

In the laboratory, the Energy Applied ratio was determined using the borehole geometry and the energy calculated from the annular seal durability test. This resulted in the second dimensionless variable to be plotted against the Energy Resistance variable discussed above. While Energy Resistance must be determined in the laboratory, Energy Applied can be calculated using field energy.

Utilising laboratory testing, the Energy Applied variable was plotted against the Energy Resistance variable. The result is a correlation showing average failure potential for a cement system with given properties. With a predicted Energy Applied on the specimen, if the point falls below the average reading, potential of failure is much higher, and it is recommended to increase the Energy Resistance of the cement system by adjusting specific properties. If the point falls above the average reading, the particular specimen should survive the Energy Applied. With the variables being dimensionless, this relationship is scalable to field applications.

What has the outcome been?
The validity of this relationship model was put to the test using the field data gathered earlier in the project. The field cement samples were tested for durability and Energy Resistance. They showed a noticeable difference in performance.

Energy Resistance was determined for the field samples using the testing methods indicated earlier. Next, Energy Applied was determined using actual field data regarding the geometry of the wells and estimated field energy. Through this investigation, it was found that the system with the higher success rate in the field also fell just on the ‘average failure line’ pictured in Figure 2. The second system, with a much lower success rate, around 40%, fell lower than the average failure line. This indicates that with further refinement, this correlation may be used to predict cement failure in the field based on laboratory-determined set cement properties and predicted Energy Applied to the cement over the life of the well. This prediction may allow for better designed cement systems to be applied in the Marcellus play, ultimately reducing the occurrence of SCP in the area.

Going forward, additional research and development is needed to achieve more definitive results because energy analysis on a cement sheath is complicated. The correlations revealed between Energy Applied and Energy Resistance need to be refined with more field data, more lab data and more cement systems. However, these correlations show a general pattern in Energy Resistance of cements and how it can be predicted on a lab scale and then applied to field data. With additional refinement, the model utilised may be used to predict the properties needed from a cement to withstand predicted stress for the life of the well.

Future efforts will focus on further developing this model. To achieve this, a reliable and accurate prediction of the stress imparted on a cement sheath over the life of the well is needed. Additional data points to strengthen the current model will be included and other cement properties such as flexural strength will be considered in future calculations.

If the additional development does provide successful conditions, then as Wilde wrote, the results will be evident.

References

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Sudhendu Kashikar, Carl Neuhaus and Jon McKenna, MicroSeismic Inc., show how deterministic fracture diagnostics enhances the value of hydraulic fracture monitoring in unconventional resources.

**DETERMINISTIC** diagnostics

**Microseismic monitoring** is the best technology for providing measurement of fracture propagation away from a borehole undergoing stimulation. The process of hydraulic fracturing generates stress in rocks, which is released in the form of fracturing, failure, and movement often along pre-existing natural fracture networks. This stress release generates microseismic waves that propagate outward from the source. These microseismic waves are detected by an array of surface, near-surface, or downhole geophones. The recorded signals are processed to determine the subsurface location of the fracture. As such, microseismic is principally a geophysical measurement. A lot of focus, research and engineering are being applied to improve the geophysical understanding and accuracy of the measurement.

One of the reasons for microseismic monitoring is to gain a better understanding of the efficiency and effectiveness of the hydraulic fracture geometry. To fully optimise the completion and hydraulic fracture treatment it is important to evaluate various aspects of the treatment’s impact on the surrounding rock, such as differentiating propped and un-propped fractures, fracture growth and geometry, fracture overlap between stages and wells, stress shadowing effects and treatment efficiency. Today most of the fracture diagnostics are performed using various modelling techniques such as: geomechanical modelling, stochastic fracture modelling, reservoir simulation and history matching. These tools use microseismic pointsets to qualitatively calibrate the model – trying to gain an understanding of the underlying fracture properties. New methods are applied that combine contextual information such as geology, well logs, treatment data, etc. with deterministic analysis of the microseismic measurements to gain a deeper level of understanding.

This article will demonstrate new developments that enable valuable information to be extracted via the combination of contextual information with deterministic analysis of the microseismic pointsets. The methods discussed have been successfully implemented in multiple countries globally; however, this article will use examples from US basins. This distinct process of completions evaluation consists of a workflow and tools to perform diagnostic analysis of microseismic pointsets, enabling accurate evaluation of the fracture treatment. It is designed to deterministically characterise fracture network growth and complexity, while providing a methodology to evaluate the wellbore spacing, stage lengths, cluster spacing and treatment parameters.

**Marcellus case study**

A dataset collected from the acquisition array in Figure 1 was recorded in the near-surface with a permanently-installed array of 101 stations covering...
an area of over 18 square miles that included five treatment wellpads. The Marcellus shale stretches over several states in the northeastern United States including New York, Pennsylvania, West Virginia and Ohio. As with all shale reservoirs, due to low matrix permeability, hydrocarbon production is dominated by the natural fracture networks present in the rock. In the Marcellus, the well-studied, pre-existing natural fracture sets are known as the J1 and J2.

After acquisition and data processing to determine the microseismic pointsets, a magnitude calibrated discrete fracture network (M-DFN) is modelled onto the microseismic events in two steps. The basic assumption is that every event is representative of a fracture, which can then be modelled and is centred on the event. Through source mechanism analysis, the strike and dip of the failure plane is identified for each individual event in step one. The characteristics of each individual failure plane are then determined through the microseismic magnitude of an event incorporating rock and fluid properties resulting in the M-DFN shown in Figure 2 in the second image. The microseismic event pattern and the orientations of the stimulated fractures show reactivation of the two sets of natural fractures – J1 and J2. The growth away from the wellbore follows the J1 fractures, in a northeast to southwest orientation, and the J2 joints connect the longer, linear trends generated by the joints stimulated along the J1 direction. This information is invaluable as it tells the operator that both fracture sets are being activated.

A subset M-DFN is generated from the full M-DFN to evaluate proppant placement and estimate the productive part of the total stimulated rock volume. Estimating the propped half-length is performed by filling the subset M-DFN with proppant from the wellbore outward on a stage by stage basis. The packing density of the proppant is variable and can be adjusted based on the specific gravity of the proppant and fluid type. The northernmost well in Figure 2 has a propped half-length of 500 ft.

Evaluating proppant placement in the calibrated M-DFN allows operators to discern between the part of the stimulated rock volume (SRV) that contributes to production in the long-term from the part of the reservoir that was affected by the treatment, but may not be hydraulically connected over a longer period of time and only contributes to initial production. Figure 3 shows the total Productive-SRV™ for all three wells and captures the variation in the Productive-SRV volume realised for each well. The undrained reservoir between the centre and southernmost well suggests that wellbore spacing may be slightly reduced in order to provide a well-connected propped fracture network without any un-drained parts between wellbores.

**Eagle Ford case study**

In the Eagle Ford example the array used to acquire the data for the study wells can be seen in Figure 4. It consisted of 10 surface deployed arms and 1200 stations of seismic recording with six geophones per station. The total area under the array footprint is approximately 10 square miles. The high fold, wide azimuth and large aperture geometry of the monitoring array provides a consistent imaging resolution under the entire array and provides a high-confidence estimate of event magnitude. Another advantage compared to single well downhole monitoring is the capability to determine source mechanisms; a crucial input for the analysis presented in this case study.

The microseismic pointset acquired and processed during the 18 stage treatment of both wells can be seen in Figure 5 and shows that two types of source mechanisms occurred. While induced fracture related failure was recorded in a dip-slip mechanism indicating that the maximum principal stress is vertical, a pre-stressed, pre-existing feature was observed in the south southeast to north northwest direction failing in strike-slip mode. During the course of the treatment a large geohazard was activated and mapped from the toe of the wellbores extending approximately 4000 ft to the south southeast with a 160˚ strike. As seen in Figure 5, the events related to the geohazard reactivation were mostly strike-slip indicating a stress regime deviating from the in-situ stress conditions observed elsewhere in the area. The geohazard was continuously activated during the zipper-frac treatment from Stage 2 of well A through Stage 6 of well B, spanning around 2000 ft of lateral length. Most of the geohazard related events occurred during stages within a 500 ft radius of it. For maximum treatment efficiency on adjacent wellpads, the stimulation may be monitored over this 500 ft interval in real time in order to cease pumping when the feature is being activated.

An M-DFN workflow was applied to the microseismic pointset. Source mechanism analysis provided the strike and dip of the failure plane for individual events while the magnitude of the event along with rock rigidity and injected fluid volumes permitted estimating the length, height and aperture of the individual fractures. A proppant filling algorithm was then applied to the modelled fractures providing the propped filled fracture network or Propped M-DFN as shown in Figure 6.

From the propped M-DFN in Figure 6 a conservative average propped half-length estimate of around 270 ft is observed for both wells suggesting an ideal wellbore spacing of close to 540 ft. That means that the propped...
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fractures from each well butt up against each other leaving very few unpropped fractures in between.

To properly understand the impact of the treatment schedule on fracture growth, one needs to look at the fracture growth as a function of time and injected slurry volumes. This is accomplished by analysing the fracture growth during the high viscosity proppant-laden gel phase of the treatment. The lateral distance of the microseismic events can be mapped with the injected fluid volume as seen in Figure 7. The blue curve is generated by running a moving average window through the microseismic data for all stages as a function of normalised average fluid volume. This identifies the average lateral distance of the fracture network front towards adjacent wells throughout the treatment. The graph shows how the low viscosity slickwater pad established the initial geometry of the fracture network while microseismicity concentrates closer to the wellbore after the introduction of high viscosity gel, indicating an increase in fracture width and near-wellbore complexity. Since the gel carries most if not all of the proppant, the microseismicity associated with the gel should give a good estimate of the proppant half-length. As seen in the plot, the average distance of the near-wellbore microseismicity is about 270 ft, which matches the half-length obtained from the proppant filled M-DFN.

**Summary**

Evaluating proppant placement in the calibrated DFN allows operators to separately identify the part of the SRV that contributes to production in the long-term, and the part of the reservoir that was affected by the treatment but may not be hydraulically connected over a longer period of time and only contributes to initial production. As seen in the two examples presented, microseismic monitoring was used as a reservoir characterisation tool in order to further the understanding of hydraulic stimulation and evaluate the efficiency of a hydraulic fracturing treatment. With the use of source mechanisms, an M-DFN was modelled onto the microseismic events recorded during the treatment. With proppant placement analysis propped and unpropped parts of the M-DFN were identified implying productive and non-productive parts of the total SRV for long-term production. Deterministic analysis of the microseismic data presented here provides a unique methodology to quantify the realised fracture geometry and understand and optimise the treatment parameters on future wells.

**References**

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Many analysts consider the shale oil reserves in the United States to be key to the nation’s strategic future. Because of shale oil, US crude production is at its highest level in decades. However, extracting oil from the shale is no simple task. According to Peake and Whatley (2014), 73% of operators say they do not know enough about the subsurface. In fact, according to the summaries presented at the Permian Basin Conference in May 2014 in Fort Worth, 95% of oil from shale plays is left in the ground and two-thirds of fracks produce no oil.

This article presents a new technology to guide shale oil development by identifying where to frack vertical wells and where to drill horizontal wells. Technology developed by Amros Corporation uses standard open-hole log data to calculate a production profile that shows where the recoverable oil is located. It specifies to operators where to frack vertical wells and where to drill horizontal wells in order to optimise field development. It eliminates unnecessary fracks, reducing costs and environmental impact. The technology could lead to significant improvements in recovery efficiency with impacts equivalent to the discovery of huge new oilfields.

Vladimir G. Ingerman, Amros, USA, shows how a new method of interpreting log data can lead to optimised field development for shale plays.
The current status of rock characterisation for shale oil deposits

Traditional methods and techniques for log data interpretation, successfully used for conventional reservoirs, are not applicable to shale plays. A lot of research was done (without practical success) to implement seismic parameters and special core and cuttings analyses to identify total organic carbon (TOC), or organic richness, maturity and brittleness. One of the main challenges is the geological nature of shale oil that is trapped in source rock with very low permeability. Because of a lack of subsurface information, many operators have resorted to ‘statistical drilling’ and ‘geometric completions’, which amounts to guesswork that follows predefined trajectories, spacing and parameters.

Figure 1 illustrates the results of this approach for a vertical well in the Permian Basin.

Columns 1 - 3 present log data. Column 4 presents fracking zones (magenta) where the horizontal length of the zones corresponds to breakdown pressure from the fracking report. Column 5 is the total gas reading from the mud log.

Columns 6 - 9 present the results of cuttings analysis in the laboratory, which was available four months after the well completion. Column 6: TOC, column 7: Production Index (PI = S1 / (S1 + S2)), column 8: Production Ability (PA = TOC * PI) and column 9: Brittleness; where:

- S1 = Free oil content or free oil and gas that could have been generated in-situ.
- S2 = Remaining hydrocarbon potential or the hydrocarbon content of the residual kerogen.
- PA = Production Ability or the movable part of TOC (green) that represents the production potential of the rock.

According to the PA configuration, the bottom six frack zones did not produce. These are the most expensive zones with maximum breakdown pressure. At the same time the operator missed the best intervals above 9000 ft.

Permeability and calibration log data

One of the main goals of rock characterisation is the permeability calculation, because permeability is a key parameter for effective development of oil and gas fields.

Basic sources of information about permeability are normally provided by core data and well testing and accordingly are very limited. The existing methods for permeability calculation from log data do not provide reliable results in most cases.

However, log data can be used to make permeability prediction. Many factors have similar influences on log readings and permeability. The factors that have little or no influence on log data, such as the pressure gradient, viscosity and so forth, usually do not change significantly in the field and accordingly do not create large errors. Predicting permeability from log data is an interpretation challenge; there is no theoretical solution to this task because of the complexity and diversity of the rock. In this case, as for many geological and petrophysical problems, a statistical approach is used.
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This approach is made up of three basic steps: calibrating log data, finding the type of equation that connects log data and permeability and finding the parameters of the equation for the specific deposits.

Using core data analysis\(^2\) is a common way of calibrating log data. This approach provides generally good results, but not for permeability, because of the dynamic, anisotropic nature of permeability \(K\). The degree of inhomogeneity for permeability is usually much higher than for porosity. For this reason, the same core data may work for porosity but prove to be incorrect for the permeability calibration.

The inhomogeneous nature of permeability raises the problem of different scale averaging for core and log data. The average scale of core data is about 20 - 200 cc. For log data with vertical resolution of 1 - 2 ft and radius of investigation of 1 - 4 ft, the average scale is 0.1 - 3000 m\(^3\). Comparison of these results from inside and outside of the well for inhomogeneous layers is groundless in many cases. In addition, the permeability dynamic value depends on overall pressure and the direction of differential pressure. It is obvious that the pressure conditions in situ are different from the ambient conditions of core lab measurements.

The permeability derived from hydrodynamic well tests or pressure build-up well testing refers to the drainage area with a volume of 1 - 100 000 m\(^3\). That volume is much closer and pressure build-up well testing refers to the drainage area with in situ are different from the ambient conditions of core lab differential pressure. It is obvious that the pressure conditions in situ are different from the ambient conditions of core lab measurements.

Studies of many oilfields in Russia, including the huge Samotlor and Zhetibai fields in Kazakhstan and exploration areas offshore Mexico shows that in many cases core permeability has no correlation with log data even for relatively homogeneous parts of rock with good core data representation. At the same time, for these deposits the permeability derived from the hydrodynamic well tests shows good correlation with log data.\(^4\) Therefore, the permeability derived from the hydrodynamic well tests is more desirable for log data calibration than core permeability.

### A new technology

The key element of Amros’ technology is equation (1) for the calculation of permeability, which was developed as result of the analysis of dozens of oilfields in Western Siberia, with more than 400 permeability values derived from hydrodynamic well tests or pressure build-up well testing. It is an Archie-type equation with empirical coefficients that should be identified for different deposits. The equation has been successfully applied to conventional reservoirs in Russia, Kazakhstan, Mexico and Canada.

\[
K = c + d \cdot \psi (X1, X2, X3)
\]

(1)

Where:
- \(K\) = permeability.
- \(X1, X2, X3\) = different log data.
- \(c, d\) = constants.

The structure of unconventional reservoirs is more complicated than conventional reservoir structure; in addition, the amount of movable hydrocarbons is highly variable, both laterally and vertically. Accordingly equation (1) can be used only after proper petrophysical and geographical zonations. Log data calibration should be performed to identify different constants \((c, d)\) for different zones. This approach was successfully tested in the Permian Basin in Texas and in the Marcellus Shale in Pennsylvania.

Equation (1) can be applied to each depth and as a result the Production Profile that is created shows where the recoverable oil is located. Applying the technology for the Permian Basin shows that instead of 10 - 12 fracking stages per vertical well it is sufficient to frack only 5 - 6 stages without diminishing production. Because of precise targeting of the best intervals, in most wells production will be increased.

The technology has been verified in 100 vertical wells in the Permian Basin. For an area with 41 wells, the correlation between calculated production and actual production is given by \(R = 0.93\). Figure 2 shows an application of the technology to a vertical well in the Permian Basin.

Columns 1 - 3 present log data with fracking zones (lower left circle) in column 2. Column 4 is the total gas reading from the mud log. Column 5 presents a production profile (upper right circle) in bpd for 100 ft, calculated by the Amros technology.

The actual thickness of hydraulic fracturing of the well is 2652 ft. These zones provided a maximum output of 36 bpd for 30 consecutive days. Analysis of the production profile shows that it would be more effective to frack only 484 ft in the top (upper right circle); the calculated production for that interval is 50 bpd.

With a fracking cost of US$ 30 000 per 100 ft, the cost of the differential perforation (2168 ft) is US$ 650 000. Assuming a crude price of US$ 90 per bbl and 25% royalty, the income from additional oil (14 bpd) is about US$ 1 380 000. The total additional profit for the lifetime of one vertical well is US$ 2 030 000.

Production profiles for a group of vertical wells can be used for mapping production for different formations and selecting the best location for horizontal wells. Analysis of a random area in the Permian basin shows that a 6000 ft horizontal well will be producing 340 bpd, 490 bpd or 560 bpd depending on the formation selected. An operator can unlock hydrocarbons in all three levels or just pick up the best vertical location that has 65% increase in production compared with the lowest. 3D optimisation will result in much greater benefits.

### Conclusion

This new technology has been developed to guide shale oil development and lead significant increases in the return on investment. The technology uses standard well log data to predict where the movable oil is located. The method has been verified in 100 Permian Basin wells. It increased well production by at least 20% and reduced fracking costs by as much as 50%. The technology also reduces the amount of water injection in formations, which should have great positive environmental impact.

The technology provides data for building a 3D model of recoverable hydrocarbons for optimising field development that can make dramatic improvements in recovery efficiency and total production; which could be equal to the discovery of new oilfields.

### References

Today, oilfield operators are facing a difficult challenge: advanced drilling techniques and dwindling access to easy oil have led to a surge in the development of new petroleum reserves, but these reserves are increasingly corrosive and abrasive. Existing materials are not sufficient to withstand these more extreme operating environments. As a result, operators are experiencing accelerated oilfield component degradation in the form of corrosion and wear.

Christina Lomasney, Modumetal, USA, reveals how new materials and advanced alloys are key to driving improved performance from oilfield assets.
These challenges increase operations and maintenance (O&M) costs as well as operational downtime, and to combat the issue, oil producers are quickly turning to new materials. By developing and deploying new materials that can better withstand aggressive environments, producers can improve oilfield component longevity and return on assets.

A new class of materials, called ‘nanolaminated materials’, has been proposed as a potential solution to this challenge. The concept of laminated metals is by no means new – the technique can be found in the Tower of Gizeh, constructed in 2750 BC – but recent advances in materials science are enabling the construction of alloys with nano-scale layers, between 10 and 100 nanometres in thickness, with highly controlled properties. These alloys can be produced using commonly available raw materials to achieve new levels of performance in corrosion resistance, strength, hardness, wear resistance and fracture toughness.

Nanolaminated materials represent an entirely new way to produce metals for oilfield components, delivering unparalleled performance. Modumetal has developed a proprietary process to manufacture these coatings at a cost that is competitive with conventional metal alloys and coatings.

The benefits of nanolaminated alloy coatings

When assessing existing materials solutions, oilfield operators are generally left with two options. The first is to select a low-budget material with the understanding it cannot withstand aggressive environments and will require frequent replacement. A common choice in this category is hot dip galvanised metals, which offer a compelling price point, but at the expense of performance. Alternatively, operators may secure a higher-performance material and sacrifice the considerable CAPEX that comes along with it. Common options in this category include tungsten carbide and emerging diamond-like carbon materials.

Conversely, nanolaminated alloy coatings offer the best of both worlds – high performance, delivered at the cost of today’s less expensive materials. But how exactly are these benefits achieved?

The performance characteristics of nanolaminated alloy coatings are derived from a unique manufacturing process. Today, most metals and alloys used to produce oilfield components are manufactured as homogeneous materials that possess specific properties. Modumetal’s technology enables modulation, essentially layering nano-scale layers of homogenous alloys on top of one another, providing those materials with an interface. This layering delivers properties that can be tailored to make the materials stronger, harder and generally more resistant to structural or mechanical failures.

Today, when developing alloys, materials engineers can typically only control two main factors...
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to maximise the performance of their products: alloy chemistry and alloy microstructure.

Alloy chemistry refers to the material composition of the metal. For example, bronze is an alloy that derives benefits from the unique properties of its primary components: copper, zinc and possibly tin. Steel, on the other hand, will derive benefits from the properties of elements such as iron, carbon and other alloying elements.

Alloy microstructure refers to the way that the alloy is organised, speaking simply. This microstructure is usually engineered through heat treatment of a metal or through some form of mechanical working, such as tempering, to affect the crystallinity or grain size, which can also be on a nanometre-scale, of the metal.

Modulation represents a third, new factor that can be controlled. By layering different metals, the end result is a new class of alloys that exhibit enormous interface density, and the finished products’ properties are strongly influenced by this layered configuration. In other words, this technology uses the same raw material stock as conventional alloys, but it produces metals with dramatically improved properties and performance.

The manufacture of this new class of alloys is enabled by a revolutionary approach to metals engineering. Existing production techniques utilise heat as the input form of energy. However, using heat does not allow manufacturers to control metal formation on a small enough scale to effectively produce nano-layered structures. To achieve the desired result, the new method employs an electricity-based process. This electrometallurgical process is inexpensive – the process runs near room temperatures – and is easily scaled, as it is very similar in principle to electroplating used by metals manufacturers today.

**Delivering improved corrosion resistance in the field**

So, how does this new class of alloys improve corrosion resistance and metal asset performance?

In sum, by layering metals, the new coatings can impart performance that is not possible with traditional, homogenous alloys. Corrosion in alloys can occur when two metals or alloys are in contact with one another. This is called a galvanic couple. When such a couple is created, the alloys interact to exchange electrons, an interaction that usually results in one metal being protected at the expense of the corrosion of the other.

This new approach layers metals in a controlled way, meaning that the process can actually prevent the corrosion from starting and/or delay the progress of the corrosion during this interaction. The technology utilises the same raw materials found in conventional alloys, but produces a structure that corrodes as much as 8 times more slowly.

The performance of these nanolaminated materials has been validated in the field across a number of applications. In one case, Modumetal was engaged by a US Department of Defense (DoD) customer to solve a particularly challenging corrosion problem. This customer operates routinely in an aggressive marine environment, and its team found that even using state-of-the-art corrosion-resistant coatings, they were experiencing significant corrosion of critical fastener components in a short timeframe.

Modumetal worked with this customer to deploy the nanolaminated alloy coating solution, which was delivered at a cost that was competitive to existing coating systems. Since it was first implemented almost two years ago, performance has surpassed expectations with no evidence of corrosion to date. For the customer, the nanolaminated alloy coating has resulted in significant cost savings – estimated at more than three times the value of the current component systems. For this very targeted application, that is a cost saving of thousands of dollars. This solution has also resulted in unseen benefits, such as the avoided potential cost of asset failure, estimated to be worth millions of dollars.

**Fatigue and wear challenges**

Modumetal’s nanolaminated alloy coatings can deliver significant value to oil and gas industry. Corrosion is clearly a major challenge facing oil producers today, and as the US DoD case study above illustrates, the company’s new alloys have been proven to improve corrosion resistance. Nanolaminated materials have also demonstrated performance advantages in addressing two other challenges facing oil producers: fatigue and wear.

In the case of fatigue, oil and gas assets often start to exhibit cracking after heavy use. However, the nanolaminates possess crack-arresting characteristics at the interfaces of the layers, and the interface itself can serve to deflect, blunt or even arrest crack propagation. This results in significant improvement in anti-fatigue properties, and testing has demonstrated 10 to 100 times improved performance as compared to traditional alloys.

Modumetal has deployed this coating in a number of topside field trials on oil rigs around the world, in partnership with leading oil and gas companies. For one major oilfield customer, the performance of the corrosion- and wear-resistant coatings for metal assets in a single oilfield was examined. The customer estimated that the longevity and performance improvements imparted by the nanolaminated alloys can save the company more than US$ 250 million over the life of the field. The improved performance will also lead to reduced operational downtime – which usually happens as a result of needing to replace critical assets – and thus, higher oil production rates over the lifetime of the field.

These coatings are now being trialled in well control, artificial lift and tubular applications. Further, a technology partnership has been established with Hess Corp. to measure the effective capability of the nanolaminated alloys to enhance certain properties of steel.

**Ushering in a new era of materials**

A new class of nanolaminated alloys are coming to the oil and gas sector at the industrial scale, and at competitive costs. There exists a fundamental limitation with today’s metals, and it is clear that the industry needs to explore and deploy new technologies to address the growing problems of corrosion, fatigue and wear.

Metals science is being reinvented, providing oil producers with a unique approach to nanolamination to help curb rising costs associated with harsh production environments. Most importantly, these solutions are being developed alongside industry leaders.
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Shale oil production continues to be at the forefront of news reports and analyst discussions. Some experts estimate global shale oil production may account for nearly 12% of the world’s total oil supply by 2035. At the same time, shale regions lose their initial glow fast. In eight to ten years, many shale gas wells will dry up if they are not refracked. E&P companies and investors are increasingly focusing on new methods to further extract resources from existing wells rather than drill new wells. It is less expensive to improve existing wells and it also minimises the environmental impact.

In addition to refracking, there are a variety of well stimulation approaches that can be the key to significantly improved production. With many solutions available, it is helpful to understand their capabilities and know how to develop a strategy that gives the best opportunity for success.

Production decline culprits
Scale, migrating fines, paraffin, drilling mud and asphaltenes increase wellbore blockage or restriction. They reduce production, increase injection rates in disposal wells and frequently result in downtime as operators try to minimise their impact. It is estimated that poor...
Debris management contributes up to 30% of an operation’s non-productive time (NPT). Needless to say, significant amounts of money are spent on potential solutions, as the upside of a successful treatment can be tremendous. Correctly cleaning out the wellbore by removing near wellbore skin damage increases the conductivity of the formation, resulting in an immediate production increase that can last in the subsequent months that follow. The bottom line is that financial expectations of improving the rate of return are greatly improved when the well is producing at its maximum production rate.

**A buffet of options**

There are many options to consider around what direction to take to clean or stimulate a well. Table 1 compares the primary capabilities and limitations of the most common approaches.

Operators often try to clean wells first using hot oil treatments and acid jobs. As improvements from the treatments start to decline, they look for other options. While pin-point injection packers and fracturing may produce better results than simple treatments like hot oil alone, they risk damaging the wellbore and come with a higher price tag. Today, operators have another choice. They can use a stimulation and intervention service that leverages an oscillation tool. Operators turn to this service when they need a chemical delivery mechanism more effective than jet nozzles and they want to remove deposit blockages from all perforations. Such services are commanding significant attention from the market place. Even operators that have relied exclusively on fracturing for re-stimulation are taking a second look at their approach.

**Like a needle in a haystack**

It is the go-to approach for many operators. Once the damage mechanism is identified, a workover operation commences. Most workover operations involve cleaning the immediate wellbore of scale, organic material and/or replacing downhole hardware. During this operation, cleaning the near-wellbore and perforation tunnels are often overlooked or neglected.

In the cases where they are not overlooked, operators often choose to refracture the wellbore as a last resort to regain lost production. This option, while effective, can be a very expensive resolution and dramatically decrease a well’s ROI and payback timeline. There are other economical options that should be considered to remove near-wellbore damage before commencing an expensive refracture operation.

When a well demands the cleaning of the immediate wellbore and the replacement of downhole hardware, it is now possible to clean the near-wellbore...
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and perforation simultaneously on the same run by modifying the bottomhole assembly (BHA). By deploying a stimulation and intervention service that includes a downhole oscillation tool in the BHA, an energised pressure pulse wave is created with circulation. This energised pressure pulse wave, which oscillates at a rate of 200 times per second in a 360˚ direction, cleans the immediate wellbore while penetrating the near-wellbore and perforation tunnels.

Once in the near-wellbore, the wave places its energy into the debris, thus mechanically altering it while delivering debris removal chemistry deeper into the formation. As the wave mechanically disrupts the debris, the chemistry penetrates the boundary layer between the debris and the formation pore throat and solubilises it into the fluid.

After it is dissolved, the fluid can flow back. The flow back is enhanced as the pressure pulse wave bounces back to the immediate wellbore. By combining a mechanical and chemical solution, the immediate and near-wellbore can be cleaned simultaneously during a workover operation and eliminates the requirement to refracture a wellbore due to debris plugging. Expenses from extended downtime, and service costs associated with refracturing, are avoided.

Another key advantage of a well stimulation and intervention service is that the technology can be deployed on a wide variety of applications. The most common include:

- OHGP (open hole gravel pack).
- CHGP (case hole gravel pack).
- CH frac pack.
- OH-barefoot.
- Hydraulic fractured.
- Salt water disposal.
- Gas storage.

**Custom chemicals are a well’s life insurance policy**

While successful well stimulation and intervention services boost production, they cannot be used alone to improve production longevity. To successfully treat a well long-term, what is making it sick needs to be understood. Is it heavy scale, paraffin build up or solid debris? Operators need to share fluid samples with their solution provider so that their wells can be diagnosed. Fluid properties considered include scaling tendencies, pour point depression, fluid viscosity, asphaltene/paraffin concentration, melting point and fluid-fluid compatibility.

After a well’s specific problem is diagnosed, a comprehensive lifecycle chemical programme should be designed that addresses methods for treating and curing the problems as well as how to prevent them from recurring in the future. Chemical usage does not stop at the well stimulation and cleanout step. Just as a patient will re-lapse if he does not take medicine for a recurring disease, build up in a well will re-emerge if not kept at bay.

In addition to deploying a chemical programme at the right intervals of a well’s lifecycle, it is equally important to make sure that the right chemicals are implemented in the right quantity. For example, a commercial operator of salt water disposal wells deployed a chemical programme to address solids build-up. However, pressures continued to increase and injection levels continued to drop months after the programme was implemented.

Greenwell partnered with the operator to identify the problems. The operator’s chemical programme was assessed and its fluid samples were analysed. It found the operator was deploying chemicals to fight off elements the well did not have and not deploying chemicals to fight off elements the well did have. For instance, iron removal chemicals were used when the well contained no iron in its fluid.

By identifying what was specifically wrong with the well and pairing it with custom-blended chemicals unique to the damage mechanism, the operator was able to reduce the quantity and variety of chemicals that it used. The custom approach saved the operator considerable maintenance costs.

**Decide what success looks like**

There is no question that well stimulation services require time and investment. But how does one know if a solution is paying back? Before implementing a plan, the well’s history needs to be assessed. What was its initial production? When did it decline? What other stimulation treatments have been tried? What is the most the well ever produced?

Once these data points have been attained, realistic goals should be set for the stimulation service and they should align with the solution provider’s. Each stakeholder needs to know what success looks like to design the best solution. Common KPI’s that are measured before treatment, directly after treatment and one month, six+ months and beyond include:

- Pressure, psi.
- Production flow rate, bpd and/or scfm.
- Water production, bwpd.
- Chemical quantities.
- Production bpd versus chemical programme cost per bpd.
**Case studies: Integrated well stimulation and intervention services achieve better results than tools or treatments alone**

**Independent operator**

**Situation:** Prior to treatment, the well produced 5 bpd.
- Well fracked in 1990s.
- Five hot oil treatments performed.
- Production only increased in short-term.

**Treatment in 2013:** Greenwell’s G-Terminator™ Service deployed (oscillation tool combined with proprietary chemical solution).
- Well samples analysed and found to contain paraffin, scale, migrating fines and other well debris.
- Chemicals selected based on damage mechanisms.
- Proprietary solution included a blend of non-emulsifiers and acid-dissolving scale inhibitors that remove wellbore debris.

**Results:** Production stabilised at 20 bpd - an increase of 400%.
- Over two decades since the well had produced over 5 bpd.
- Payback period for G-Terminator < 30 days.

**North American operator**

**Situation:** Prior to treatment well shut-in.
- When initially drilled in 2005, the well produced 18 - 20 bpd.
- By May 2012, it was down to 0 bpd.
- Hot oil and chemical treatments applied but with minimal effects.

**Treatment in 2012:** Greenwell’s G-Terminator service deployed.
- Well samples analysed and contained heavy paraffin and iron sulfide scale.
- Chemicals selected based on damage mechanism.
  - Phase 1 removed paraffin by solubilising the paraffinic debris and preventing it from re-crystallising while leaving the formation water wet.
  - Phase 2 removed other debris with a nano-fluid technology.

**Results:** Production increased to 22 bpd - an increase of 2000%.
- After production stabilised, nearly every 10 days production increased by a barrel.
- Payback for G-Terminator < 30 days.

**Doing the homework**

When comparing different stimulation and intervention services, operators should evaluate them based on attributes that lead to greater long-term success. At a minimum, solutions need to fulfil the following requirements:
- Delivery mechanism enables correct placement of treating chemicals.
- Tool design is an all-inclusive, one-component mechanism, indifferent to extreme temperatures or powerful chemicals.
- Service can be executed within hours without changing or switching out pipe.
- Solutions are effective in small or large diameter casing.
- Removal of debris versus breakdown of debris is achievable.
- Case studies that illustrate production increases extending months out from treatment dates.
- Technology that has been deployed by major oil and gas operators.

With the right service, operators can have a cost-effective approach to treat near-wellbore and perforation damage. The increase in production puts wells back into the green and maximises operators’ profits over the long-term. After selecting the right service, only one question remains – How much revenue will operators lose from not implementing an optimal well stimulation and intervention service sooner?

**Reference**

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Hydraulic fracturing in the United States offers inexpensive, clean natural gas to power the future and reduce dependency on foreign oil, but it comes at a cost to water supplies. Environment America found in a recent study that 280 billion gallons of wastewater was generated from fracking in 2012, and a recent Ceres report found that nearly half of oil and gas wells recently hydraulically fractured in the US are in regions with high or extremely high water stress. With drought conditions plaguing western states and water management becoming a more critical national issue, the oil and gas industry must own up to its water addiction and devise a path forward.

Bill Charneski, OriginOil, USA, looks at how to quench the thirst of the shale industry without putting undue strain on water supplies.
Two types of wastewater are produced from oil and gas wells – produced and frac flowback water. In the first few days and weeks following a hydraulic fracturing operation, as much as 30% of the water used in the fracturing operation flows back to the surface. That returning water is called frac flowback water. Over time, the chemistry of the flowback water changes to resemble that of the formation water, or the water naturally found within the shale, at which point it is referred to as produced water. The chemistry of the produced water is determined by the chemistry of the shale: if there are toxic elements in the shale, there will likely be toxic elements in the produced water as well. The US DOE reports that an average of eight barrels of water are ‘produced’ or brought to the surface for every barrel of oil.

Both produced and frac flowback water have traditionally been disposed of in evaporation ponds or disposal wells, which is an expensive process. Energy companies are now paying US$ 3 to US$ 12 per barrel to dispose of produced water, representing a total cost worldwide of US$ 300 billion to US$ 1 trillion per year. Treating and reusing produced water and frac flowback water, rather than trucking it away for disposal, offers well operators the opportunity to incur significant savings and reduce the growing strain on water resources.

What if there was a different way?

Both sourcing new water for hydraulic fracturing and disposing of wastewater has become a challenge for well operators. Water, once considered an abundant resource, is quickly becoming a valuable and limited asset to their operations. There is a strong and growing trend that these waters must be treated and reused instead of using ‘new’ fresh water. With recycling, operators benefit twofold: first from reducing the cost of fresh water and second from eliminating the logistical costs of water management, such as storage, trucking and disposal. Additionally, by reusing water, hydraulic fracturing’s burden on local fresh water resources is reduced, which is crucial in areas experiencing drought conditions.

Recycling technologies are quickly being introduced to the market in order to help oilfield operators maximise the value of their water resources and lessen their impact on the environment. OriginOil has one such technology called Electro Water Separation (EWS) – a continuous,
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high speed, chemical-free process that efficiently extracts oils, suspended solids, insoluble organics and bacteria from frac flowback and produced water.

Emulsified produced water is fed to the EWS system following free oil or heavy solids upfront pretreatment, such as a three-phase separator, skim tank or hydro-cyclone. Within the system three distinct mechanisms are used to treat the influent stream; electro-coagulation, electro-flocculation and electro-oxidation. Electro-coagulation functions to: de-stabilise the emulsion, neutralise the electro-static charge of non-soluble hydrocarbons as well as suspended solids allowing the dispersed oil and suspended solids to agglomerate and flocculate into large non-soluble particles. Electro-oxidation deactivates biological activity and mineralises dissolved organic materials and soluble hydrocarbons. Following coagulation the influent stream passes through the electro-flocculation chamber where the less dense agglomerated particles are lifted from the feed stream and solids are allowed to settle, resulting in an effluent quality ready for re-use as downhole stimulation or additional polishing as required by site specifications.

In contrast to conventional electro-coagulation systems, the EWS technology was designed to incorporate electro-coagulation in-line with downstream electro-oxidation depending on the influent and effluent specifications required for a site. Incorporating downstream electro-oxidation enables a reduction in cost-of-water treated over comparable competitive technologies by providing biological deactivation and dissolved hydrocarbon removal in a single modular system rather than requiring additional stand alone equipment.

Additionally, within the electro-flocculation section of the EWS process, a control programme enables the systematic production of a high concentration density of microscopic flotation bubbles. The production of this high concentration density bubble flotation improves the final effluent water quality enabling advanced downstream treatment without additional intermediate treatment steps.

All of these processes are controlled by a supervisory control and data acquisition system (SCADA). The SCADA system can monitor specific water parameters and make real time adjustments to control the electromagnetic pulse characteristics for maximum efficiency and minimum energy usage. It also allows for remote monitoring and control. Integrating these multiple process steps in a single system enables the displacement of up to three pieces of equipment with conventional competitive technologies.

**Third party testing**

When EWS and a downstream technology are integrated, it falls within the product line under the name CLEAN-FRAC. At ISI Technology in Delta, Colorado the CLEAN-FRAC 1000, embedded with the EWS technology and TriSep’s iSep™ ultrafiltration (UF) membranes, was tested on produced and frac flowback water from the western slope. During tests, the system was shown to remove 99% of hydrocarbons and other organics in a single pass.

Lizard Analytical Laboratories, a third party testing organisation, verified the results of the system in the field. The lab concluded CLEAN-FRAC does have a very low energy usage of 0.22 kwh/bbl of water, which amounts to approximately US$ 0.03/bbl. Energy usage could be lowered further in other field applications if the water salinity is higher, which would be typical for most oil and gas plays (ISI has low salinity).

Additionally, Lizard Analytical Laboratories concluded that this system, incorporating Sep ultrafiltration (UF) membranes reduces contaminants in the following amounts:

- 99.6% of turbidity.
- 90.3% of total suspended solids.
- 90.5% of oil in water.

Original equipment manufacturers (OEMs) can integrate EWS and downstream polishing solutions, like iSep, into CLEAN-FRAC to provide an end-to-end solution. To date, the company has signed licensing agreements with four companies, including ISI, Pearl H2O, E3 and Burgan One.

Pearl H2O, an oil and gas water treatment spinoff of PACE (Pacific Advanced Civil Engineering), completed the first commercial-scale water treatment system integrating OriginOil’s EWS technology. The 1200 bpd system named ‘Pearl Blue’ processes frac flowback and produced water from California’s Monterey Shale formation at a treatment site in the Bakersfield area of California. In addition to OriginOil’s EWS, the system utilises EconoPure, a continuously cleaned LFNano™ nanofiltration system.

Pearl Blue achieves the optimal level of treatment for reuse by removing the majority of scaling salts (Ca²⁺, Mg²⁺, Ba²⁺, Sr²⁺, SO₄²⁻, CO₃²⁻), resulting in an odourless, colourless, oil-free water. Many other treatment systems over-treat water, which is more expensive than hauling or disposing and removes beneficial monovalent salts, or they under-treat wastewater, requiring excessive maintenance in the long-term due to the damage inflicted on well equipment. The system has been tested and proven to remove:

- 100% of petroleum-based material.
- 100% of suspended solids.
- 75% of salts and scalants.
- 90% of chemicals.
- 100% of all sulfides and biological materials.
- And reduce chemical oxygen demand (COD) by approximately 80%.

Beyond strength of treatment technology, economics are also a key consideration for oilfield operators when determining if recycling makes sense for their operation. For a typical hydraulic fracturing operation, fresh water costs between US$ 0.25 and US$ 1.75 per barrel. Trucking logistics ranges from US$ 0.50 to US$ 14 per barrel, and disposal costs between US$ 0.50 to US$ 3 per barrel. Water technologies that eliminate these line items can reap savings almost immediately. Technology such as that produced by OriginOil, for example, can help generate savings within the first 18 months.

**Conclusion**

The USA’s shale oil resources may be vast, but they are not easy to access. Water is an essential part of the drilling process, placing a great strain on water resources. The costs of sourcing fresh water for oil and gas operations, as well as treating it for disposal, are volatile. If operators can recycle their water supply, both their bottom line and the environment can benefit.

Technologies are available today to recycle large amounts of frac flowback and produced water quickly, efficiently and economically, without the use of chemicals. Integrating these processes into existing hydraulic fracturing infrastructure can help propel the industry forward.

**Reference**

It is no secret that oil and gas drilling operations over the past decade have taken on new challenges which required innovative solutions capable of combining high HSE standards, enhanced performance and competitive costs in all conditions.

The design and the technology behind land drilling rigs has remained very conservative and traditional for too long. In contrast, downhole tools and well drilling technologies have undergone significant changes.

Angelo Calderoni and Marco Cercato, Drillmec, Italy, examine a new generation of fully automated drilling rigs designed to provide enhanced HSE and improved drilling efficiency levels.

Figure 1. AHEAD 350 drilling rig.
involving innovative approaches towards the design and engineering of many drilling rigs components.

The vision of new fully automated drilling rigs driven by well data gathered in real time has only recently started spreading in the drilling rig market.

Automated drilling has rapidly become one of the oil industry’s most important innovation targets, mostly because of the difficulties and increasing costs of operating on the new oil and gas frontiers.

**A new generation**

Drillmec has been able to achieve impressive results thanks to many years of international experience and its innovation-driven business model. The latest generation of its drilling rigs is named AHEAD (Advanced Hydraulic Electrical Automated Driller).

In the middle of the 1990s, Drillmec had launched a new semi-automated hydraulic rig design, the HH Series, with design characteristics that allowed for a reduced crew, fast movement, easy rig up/down, high safety and small footprint. It was not long before the new design proved to be efficient and competitive against conventional rigs of comparable power. Starting from the first 100 t prototype and the first 150 t rig, the G125, manufactured and launched in July 1996, the series introduced larger models up a 300 t static hook load capacity: HH102, HH150, HH200, HH220 and HH300.

The HH Series rigs, are recognised for their safety and drilling performance benchmark; their success is based on a number of key technical solutions.

The most apparent feature is the self-erecting hydraulic telescopic mast characterised by a pull down capacity of up to 30 t. This solution, along with a vertical pipe racking that surrounds the rig floor, an automated pipe handler, hydraulic power tong and an unique hydraulic top drive with horizontal displacement capability, allows most of the routine drilling operations to be performed from the driller’s cabin with an almost unmanned rig floor.

Moreover, the trailer-mounted configuration, with self-erecting rig modules permanently mounted on semi-trailers, assures very low rig moving time and safe and fast rig up/down.

Using experience gained from the development of the HH Series and from the field results achieved, Drillmec has recently developed the AHEAD series, a new concept of fully automated drilling rigs where enhanced HSE standards and drilling efficiency are provided through automation and a complete drilling package able to ensure a continuous dialogue with the bottom hole.

With the introduction of this series, a new standard has been set for Drillmec’s hydraulic rigs. The HH rigs range from 75 t to 300 t of static hook load capacity; with the new series, this range will increase to 350 and 500 t, making these hydraulic rigs competitive with conventional 1500 - 2000 hp rigs and also viable as a solution in the offshore market, particularly for platforms with limited space available.

**New developments**

The main development introduced by the Drillmec R&D team is the new hydraulic telescopic mast equipped with a double hydraulic piston in tandem, a technical innovation that gives AHEAD the capability of handling 90 ft stands comprised of two API Range 3 (or three API Range 2), drill pipes, maintaining the fast moving characteristics. The mast configuration has been designed to divide the mast into two independent sections transportable on two standard semi-trailers. The connection and disconnection of the two pistons is easy and fast; these always take place at ground level, with the aid of a crane, in safe conditions.

A fully automated offline system allows making up and breaking stands directly in the mouse hole, drastically reducing the downtime related to the operations performed on the rotary table.

The drill pipes, placed horizontally on transportable racks, are taken by an automatic sliding clamp and positioned on the first pipe handler which carries out the vertical overturning in the mouse hole. The drill pipe make-up and break-out is performed by a power tong installed at the mouse hole and characterised by a vertical sliding system capable of ensuring the proper alignment of the drill pipes before the connection.

Once the stand is composed, it can be directly taken by the top drive at the mouse hole and brought to the well centre, or it can be positioned in the vertical pipe rack, using a second pipe handler installed on a vertical rotating tower.

The system works automatically in a programmed logic controlled (PLC) sequence but the driller maintains the ability to manage directly the whole system directly from his cyber chair.

The vertical pipe rack is located on the right side of the rig. It is comprised of mobile bins that contain stands 90 ft long. Characterised by a modular structure, it is sized for a pipe storage capacity of 5000 m (90 ft stands composed by 5 ½ in. Range 3 drill pipes); it can be easily assembled and disassembled.

The offline system is able to handle casing joints in the same way as the drill pipes, placed on special racks, which are positioned on the ground. The drill collars are handled by an auxiliary crane, able to handle up to two 9 ¾ in. drill collars at a time. A dedicated rack, placed next to the vertical pipe rack, assures the storage of the drill collars.

To ensure high drilling performance in deep wells as well as in horizontal wells, the rigs are equipped with the new Drillmec ETD (Electric Top Drive) Series, able to provide high torque level in a wide rpm range. The ETD configuration for the rigs includes the horizontal displacement system, which allows it to move the pipes from the centre hole to the mouse hole and vice versa.

The hydraulic sling shot substructure ensures high structural stiffness and, at the same time, the easy access to install and operate on the BOP system. All rig up/down operations take place at the ground level, minimising crane operations at considerable height.

Once the rig is completely assembled, the mast is raised to vertical position by two hydraulic pistons integrated in the lower section. After that, the rig is raised to the required substructure level. This procedure reduces the number of drilling personnel required, which results in increased safety and faster operations. Only one
Proven performance for any application

Whether drilling with a PDC or roller cone bit and regardless of the formation, Dyna-Drill power sections deliver the power you need to optimize ROP.

Dyna-Drill manufactures high-performance mud motor power sections from conventional to ultra torque. Stator rubber formulations developed by Dyna-Drill have produced innovations in elastomer durability resulting in products that serve specific applications which can be compounded to withstand the most punishing drilling fluids and downhole temperatures.

For over 50 years, Dyna-Drill has offered operators the most technologically advanced and efficient downhole motor equipment in the oil and gas industry.
individual is required in the driller’s cabin to supervise operations, in addition to a mechanic and a mud engineer.

**New design**

The new rigs have been designed from the ground up to increase drilling efficiency and safety while reducing NPT, moving time and costs: only 21 loads are necessary to move the rig package from one site location to the next and no oversize vehicles or special permission are required. Furthermore, the rigs, complete with their vertical drill pipe rack, can be equipped with a walking system, thus further helping reduce NPT and additional costs for the drilling contractor.

Although these rigs are able to handle 90 ft stands, the compact design characterising the new hydraulic telescopic mast does not compromise the environmentally friendly design of Drillmec hydraulic rigs. The rig footprint, including all equipment needed for drilling operations, takes up a space 40% smaller than an equivalent conventional rig. Moreover, the hydraulic technology results in a reduced visual impact, lower noise levels and minimised waste production.

In order to ensure improved safety and reliability, the rigs are equipped with a remote monitoring satellite system, the Drillmec Monitoring System (DMS). This system ensures the display of data in real time anywhere in the world through a simple Internet connection showing daily trends of rig and drilling parameters.

The development introduced during this last year does not concern the rig only. The company’s vision of the new fully automated drilling rigs is to be able to offer a complete drilling package.

For this reason, the R&D team has developed, in parallel to the AHEAD rigs, an innovative drilling package, named HoD – Heart of Drilling. The HoD was created to guarantee a continuous dialogue with the bottom hole, assuring, at the same time, the optimal working conditions for each sensitive rig component, such as the BOP and top drive.

The HoD combines continuous circulation, flow rate monitoring system and an anti-friction device for the first time, in order to obtain enhanced HSE standards and improved drilling performance.

The AHEAD Series will be the first drilling rigs able to communicate with the bottom hole thanks to the direct integration of the HoD package with the rig. However, each HoD component is also designed to be installed as a stand-alone element, easily integrated in any rig.

The continuous circulation, intrinsic to the HoD package, represents a technology ready to become an important step change in oil and gas drilling activity in the near future.

Managing downhole pressure and drilling through very narrow pore/fracture pressure windows is possible only without interruption of the mud circulation. Indeed, interrupting mud circulation to make-up or break-out drill pipes connections is one of the main causes of typical drilling problems, which can vary in severity depending on well conditions.

The continuous circulation of mud keeps an uninterrupted dialogue with the bottom hole and the presence of a double barrier in the well (circulating mud and BOP) is constantly active.

At the same time, the continuous cuttings transport and the optimisation of mud properties helps provide a significant improvement in ROP and NPT, with very short connection time.

A special sub, made up on the top of the drill pipe stand or integrated directly into the drill pipe tool joint, allows to switch the mudflow from the top drive to the HoD valve and back again, with the assistance of a special automatic clamp and a dedicated manifold directly integrated in the rig pump manifold or positioned on the rig floor.

High safety levels, both on the drilling floor and in the well are guaranteed by a double safety barrier between the mud pressure and outside, each one complying with a working pressure of 7500 psi.

The opening and closing of the external safety barrier is provided by the automatic clamp, which is remotely controlled via a dedicated touch screen located directly in the driller’s control cabin or away from the rig floor. The clamp is fully automatic and driven from the driller’s cyber chair.

In addition to continuous circulation, the HoD provides also a flow rate monitoring system and an antifriction device.

The high-resolution flow rate monitoring system is able to detect and signal kicks and circulation losses to the driller in real time. The system, combined with continuous circulation, represents an open-loop managed pressure drilling device that, unlike most of the MPD systems currently on the market, requires a very short installation time.

The anti-friction device integrated in the sub or directly on the drill pipe tool joint, assures the optimal working condition for the top drive, reducing stress and drill pipe wear.

The use of the HoD system allows targets to be reached in all challenging operating conditions, especially in HP/HT wells, extended reach wells and in deepwater, with high HSE standard and a significant reduction of time and project costs.

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**Figure 3. HH-300 side view.**
Ray Nagatini, Encapso, USA, shows how innovations in applied biotechnology are enabling operators to implement smarter, leaner mud programmes that activate lubrication on-demand and only where needed.

According to the US Department of Energy, increased industrial and commercial energy demand will consistently ratchet up US primary energy use between now and 2040. Meeting that demand will require a number of upstream technological innovations along the way.

Drilling mud then and now
Drilling fluids have evolved in recent decades from basic Spindletop-era water-and-clay to incredibly nuanced systems designed to address dozens of downhole variables relating to the wellbore, drillstring, formation chemistry, rock dynamics and more. In the early 1900s, nobody gave much thought to drilling mud – mixing water with whatever local soil was around. But as wells grew more and more complex across the 20th century and beyond, the industry has demanded more
and more from its mud. In the 1930s advances such as barite, bentonite, starches and iron oxide were employed as additives to water-based fluids. And by the time WWII rolled around, there was intense pressure on the industry to improve efficiencies and keep American oil flowing. One such innovation rising to the challenge was the use of oil-based drilling fluids.

Operators found that oil-based fluids provided superior lubrication, thermal management and possessed other chemical advantages. And, in addition, they prevented the instability that shales develop when reacting to water exposure.

If the 1940s made oil-based fluids possible, the ’50s, ’60s and ’70s made them profitable – enabling numerous variants and advancements that allowed operators to tackle a variety of downhole challenges. These muds were basically a mixture of diesel fuel and asphalt. Effective as they were, the 1970s also began an era of new and more restrictive environmental regulation of drilling fluids. Concerns regarding the toxicity of downhole fluids and oilfield waste in general meant the pressure was on to replicate oil-based mud performance – particularly in terms of lubrication – with the environmental performance of water-based fluids.

**Drilling lubricants and the balance sheet**

The cost of drilling mud comprises only 5 to 15% of total drilling costs. So at first glance, it is easy to focus optimisation efforts on bigger ticket items such as rig day rates, casing or formation stimulation. But selecting and engineering a drilling mud is not really about what gain be gained, but rather about what can be avoided in the form of huge potential delays, asset risk and opportunity costs. This is especially true in the case of drilling lubricants. Friction-related drilling problems, and the non-productive time that goes with them, cost the industry hundreds of millions of dollars each year (some estimates say as much as between US$ 500 and US$ 600 million). The most common of these issues includes stuck pipe, borehole instability, formation damage, deviation and lost circulation. When the hundreds of millions of dollars spent on these problems is paired with the opportunity cost of slower-than-necessary rates of penetration (ROP), improvements in the performance of drilling lubricants can make a huge impact on a balance sheet. This is especially true when considering the economic impact after applying field-wide scalability. A high-performance drilling lubricant can be considered ‘drilling insurance’, employing the most responsible drilling issue resolution strategy ever devised: to avoid the problem in the first place.

**Conventional lubricant shortfalls**

The difficulty of engineering a truly elegant drilling lubricant is the interconnectivity of the fluid’s impact and its many complex relationships with the downhole environment. In a mud mix, it is difficult to address potential or existing problems in a vacuum; everything that is added has the potential to impact numerous other aspects of the fluid, well and reservoir. Conventional drilling lubricants are added to the mud mix and continually circulated throughout the fluid system. This is a plus when the lubricant is actually engaged because of consistent friction, especially in horizontal wells.

The problem is that conventional liquid lubricants are always present, whether or not the lubricant is needed. And the presence of the lubricant changes the composition of the drilling fluid wholesale. It burdens the entire fluids system even when there is no mechanical contact between the drillstring and open hole – and hence
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no lubrication required. It can seep into the surrounding rock. It can dissipate to low concentrations as it circulates through the fluid system and is pulled out after coating drill cuttings. And high total concentrations of lubricant can have a negative effect on the fluid system’s overall rheology (how matter flows through the system). As a result, there is a fair amount of system-wide waste involved in deploying conventional liquid lubricants. In addition, these conventional lubricants do little to close the performance gap between water and oil-based fluids with respect to the reduction of torque and drag.

Changing categories

A new category of downhole lubricant has been developed that releases lubrication only when needed to overcome the limitations and risks inherent in traditional downhole drilling lubricants. Encapso™ is a dry, powdered product of micro-sized algal cells that is ten times smaller than a human hair when in solution (small enough to pass through any fluid system’s filtration process). These cells contain a pocket of high-performance lubricant inside.

These cells circulate freely and inertly through a well’s fluid system until they encounter sufficient friction and shear, such as the drill string engaging with the sides of an open hole. Upon encountering high friction areas, the cells break to release the lubricant where needed but remain safely ensconced in the cell elsewhere in the system. As a result of this innovative encapsulated delivery system, the lubricant is released only at the point of friction – avoiding potentially negative impacts to the drilling fluid’s rheology. The product’s encapsulation protects the lubricant’s potency when not needed, but delivers sufficient lubrication to the entire area when engaged. Unused oil cells not engaged at a point of contact merely circulate back to the surface for later use, eliminating product waste.

This lubricant delivery method not only assuages many of the limitations found in conventional products, but also radically improves drilling performance – helping companies to drill faster and with fewer problems. Specifically, operators in the field and scientists in the laboratory have proven Encapso lubricant to:

- Reduce friction by over 70%.
- Decrease torque by up to 42%.
- Decrease drag by up to 50%.

Critically, the product has been shown to increase ROP in the double digits when compared to conventional liquid drilling lubricants (generally around a 20% improvement). This represents a significant improvement in potential drilling efficiencies. An overall fluids performance enhancement of this magnitude means bringing wells online more quickly for faster time-to-market, improved ability to sustain intense production levels in the nation’s hottest plays and greater capital efficiency through lower-overhead drilling programmes. And though it is a newcomer to the market, numerous operators have already proven that this first-of-a-kind lubrication delivery system can help redefine expectations when it comes to drilling economics.

Tackling tough geometries in the DJ Basin

In one recent well in the northern Denver-Julesburg Basin, a regional operator planned to drill an S-curve off of an existing vertical well to maximise the length of the production lateral.

Figure 4. Case study data: Williston Basin - increasing ROP - average ROP (ft/hr).

Figure 5. Case study data: Williston Basin - increasing ROP - sliding ROP (ft/hr).

Figure 6. Case study data: Williston Basin - maximising uptime - non-productive time (hours).

Figure 7. Case study data: Williston Basin - maximising uptime - measured distance (ft) versus days.
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But the formation was a sticky one. It contained dolomite – a metastable carbonate that can be difficult and unpredictable, as well as reactive – inter-bedded and geo-pressured plastic flowing clays and salts. The team moved forward with its drilling plan, but had to cycle through a number of different tools and approaches. The tools just were not responding downhole. They had to make several turns at the surface until finally achieving a quarter-turn at the tool face. After significant effort, the team realised that using their mud system the rotary steerable system just could not make an S-curve happen in that environment. So Encapso was added to the mud mix. There was an immediate improvement in tool response. A quarter-turn up top meant a quarter-turn down below. Not only did the lubricant make the drill plan achievable but in all the team saw a 216% improvement in ROP after adding it to the mix.

Fighting friction in the Williston

The Williston Basin is notorious for issues with salinity. High salt content in the formation brine tends to render conventional liquid lubricants ineffective, causing it to ‘grease out’ and potentially damage the formation. So when one regional operator was tackling a well with an 80˚ azimuth needed to navigate a property line, the lubricant was added to help keep everything on path. It was a good fit. The encapsulated nature of the lubricant meant that it was protected from potential reactions from the drilling environment’s high salt content. The product readily disperses in water and is compatible with brines containing sodium, magnesium and calcium. The product helped the operator successfully execute the drill plan and improve several key performance indicators when compared to other similar wells in the region. This included a 20% increase in overall ROP, a 54% increase in slide ROP, a 17% reduction in torque and a 23% reduction in slide time. The team saved two days drilling the lateral, which translated into thousands of dollars in savings, as well as a more aggressive time-to-production.

Improving performance in the Permian

In another highly profitable application, an operator in West Texas was drilling a number of lateral wells in Pecos. The company had a two-year legacy of drilling similar wells, and specified Encapso lubricant for one of the last wells in the field development plan for the area. When compared to a very similar well just two miles away, the new lubricant well helped reduce comparative downtime by 62%. The project exhibited a 20% drop in pick-up weight (the total of string weight and frictional drag as measured at the surface). And not only was the well drilled a day-and-a-half more quickly but more than 650 ft farther. In several field tests, the lubricant has enabled drillers to drill longer distances than when using conventional liquid lubricants. Its superior lubrication and resulting thermal control does a better job at preserving the integrity of critical components such as the bit, casing and drillstring. This is especially advantageous when running horizontal wells with long laterals.

Safety and environmental impact

The lubricant is made from natural algae, which is non-toxic, biodegradable and safe for field personnel to handle with normal personal protective equipment. As the regulatory environment for service companies and operators continues to become more restrictive, products such as this serve not only as a means of financial optimisation, but they also provide an alternative to help ensure that the downhole drilling lubricants in play will help an operation to stay in compliance, safeguard environmental performance and protect the communities around the operation.

Conclusion

Now more than ever, operators and service companies are not only under pressure to meet growing energy demand, but also under pressure to deliver continuing improvements in financial and environmental performance.

Game-changing innovation comes in many forms. Most people think of radical, high profile disruptions highly visible outside of the industry. But many times the most profitable industry innovations are the focused, behind-the-scenes refinements that simply help everyone to do a better job. And this one is already on its way to helping North American operators live up to their production potential.
Nils Reimers, Tomax AS, Norway, examines the use of anti stall technology by operators running aggressive PDC cutter configurations.

Polycrystalline diamond compact (PDC) cutters revolutionised oilfield drilling operations through increased rates of penetration (ROP) and longer bit – and expandable reamer runs. A limitation to the potential of the PDC cutter is the subsurface uncertainty associated with the large number of variables that complicate simulations and design refinements. The result is the continuous risk of unpredictable dynamic effects that limits the cutter performance as well as the functional integrity of other bottom hole assembly (BHA) components. To mitigate this risk, various solutions are applied, most of them having a negative effect on drilling efficiency. A solution is now coming into use that both mitigates risk and provides the opportunity to maximise the energy input from the PDC cutters to drill rock.

PDC potential
A modern PDC cutter can easily cut hardened steel and is about twenty times stronger than the hardest volcanic rocks. This makes a PDC element around forty times stronger than granite and compared to most sedimentary rocks, the PDC has a strength ratio in excess of 500:1. These figures should produce fast drilling and low wear with PDC cutters in practically all rock types.

However, there are some trade-offs involved in the making of the relatively large PDC element:
- The binding between the sintered diamond fragments is subject to fatigue and also weakens with temperature.
The different thermal expansion of the materials involved in the making of a cutter produces high internal stresses. As a result of the increasing internal stress, the resistance to impact loads decreases with temperature. At the same time repeated impact loads cause fatigue. In practical terms the PDC weakens at an exponential rate from about 350 °C and will disintegrate between 700 and 800 °C. Due to the fundamental origin of these limits, the industry specialists see no significant improvement on the horizon. What has improved however, is the awareness of downhole impacts and vibration. This is as a result of the increasing use of electronics in the process of moving all formation logging into the drillstring. The new focus resulted in a new bit design trend where vibration management became important. In practical terms this trend involved methods that restricted rock engagement or the depth of cut (DOC). For example wear pads, back-rake and a more gentle chamfer angle on the PDC cutting edge are elements that give a manageable response through formation changes. The downside is that most measures taken to reduce the torsional response of the cutters have a negative effect on the mechanical specific energy meaning more energy goes into heating the cutter as well as other, more complex dynamics (increased compression loads increase the friction from interaction with the borehole wall).

**Return to fast bits and economical drilling**

The main reason for moving away from bits with aggressive cutting structures was the continuous risk from severe torsional shocks and vibrations. One foot of borehole can represent 20 000 years of depositions and a section length of 3000 - 6000 ft. can consequently hold many surprises. A drill bit less affected by the subsurface transitions will produce less shock and save unnecessary trips to replace the bit and damaged BHA components. The oil and gas industry, however, saw the risk of the new trend becoming counterproductive over time.

As an alternative approach for vibration mitigation, two major Norwegian operators funded the qualification of a dynamic, depth-of-cut control device initially named the Anti Stall Tool (AST). The new solution was first described in a publication by Selnes, K. et al. from Statoil in 2008. The AST is positioned on top of the BHA and balances the load or weight on bit (WOB) against the reactive torque from the bit. Any abrupt change in torque, such as a torque spike from the cutters hanging on a hard stringer, will cause a telescopic contraction of the unit along an internal helix (Figure 1). This contraction instantaneously reduces the weight on the cutters and consequently the depth-of-cut. The contraction continues until the depth-of-cut is reduced sufficiently for rotation to continue. An internal spring will gradually re-apply the initial weight and the tool will repeat the process as needed.

**Proving the concept**

The potential of the AST principle comes from bringing back the use of effective, aggressive PDC cutters into drilling operations. The first demonstration of the AST was performed within a phylitte formation widely known for its ability to destroy PDC bits. Phyllite is a type of foliated metamorphic rock created from slate that is further metamorphosed so that very fine grained white mica achieves a preferred orientation.

Two identical bits, with the most aggressive cutters available, were selected for a direct comparison. The demonstration was executed by the International Research Institute of Stavanger (IRIS) with the funding operators present for quality control and verification. The result was a clear improvement in PDC durability and efficiency with the use of the AST (Figure 2).

**Optimising the response**

The prevention of severe stick-slip fluctuations and PDC damage in difficult formations requires the AST tool to provide...
Elegantly Simple, Simply Effective.

When the problem is complex, the solution is often simple. Volant Casing Running Tools simplify well construction, reducing both manpower requirements and problems leading to hole instability and non-productive time. Volant HydroFORM™ Centralizers greatly improve casing runability with an enviable 100% failure-free track record. Volant MLT Rings™ provide high torsional capacity, critical for liner drilling operations.
The results highlighted that the use of modern drilling technology combined with an aggressive bit and the AST tool could deliver a 100% improvement in drilling performance with low vibrations, compared to offset wells having the vibration mitigation built in to the bit design.

**Under-reamer operations**

Inclusion of an under-reamer (UR) in a drilling operation adds a significant challenge in terms of predicting BHA stability. The reason is the arrangement of PDC cutters at different levels and the limited number of blades on the under-reamer that increases the likelihood of vibrations as the two different levels of cutters might be working in two different layers of rock simultaneously. The tendency of increasing vibration with under-reamer systems generally increases the risk of downhole tool failures and costly round-trips. In addition, the coupling of instabilities between the sets of cutters can produce an overall reduction in drilling efficiency of the system that adds additional cost through reduced progress with the under-reamer. For this reason AST was also tested at Ullrigg for this application. The result was the same as for the drill bits and the technology has since been taken in to widespread use for under-reaming. A particular interest has been from the deepwater exploration operations where the AST technology has made drilling faster and improved the productive time. The main contributor to the improvement is the prevention of downhole failures resulting from the under-reamer encountering underground surprises in combination with rig motions. A top hole section drilled at an increasing phase compared to offset wells is common from both semi-submersible rigs and drillships. With this saving comes also reduced exposure of the formation before the running of casing.

**Long laterals and ERD**

After the first tests with aggressive drill bits on Ullrigg, an early recipient of the AST was a project where long multilateral HTHP wells were was the limited weight available to make the bit bite. To overcome this challenge the sharpest bit available was run and the AST was then added to prevent cutter damage. The result was a 40 - 100% improvement in drilling speed and a significant boost in drilled distance. On this basis the AST became a standard item on several ERD and multilateral developments.

**Conclusion**

An effective method for limiting impact loads on PDC cutters is presented. By reducing the need for considering vibration mitigation in drillbit design, the path is open for a step improvement in ROP and PDC durability in many applications.

**References**

Børre Fossli, Enhanced Drilling, Norway, examines a new system designed to regulate drilling fluid levels in risers in order to manage wellbore and formation pressure.

When drilling in deepwater, in deep reservoirs and in HPHT environments, narrow drilling windows between formation pore pressure and formation strengths are often encountered. Non-productive time in drilling is often driven by pressure related issues. Furthermore, many subsea fields are now entering maturity. As reservoir pressure declines, this inherently introduces significant well construction and delivery challenges. Wells are the biggest driver for increased recovery. Depletion and increased formation pressure heterogeneity in mature fields are driving costs and slowing well delivery. For fields developed with fixed platforms, conventional pressurised managed pressure drilling (MPD) techniques developed on land have been used for some time to combat these challenges. For floaters with subsea blow out preventers (BOPs) and low pressure marine drilling risers in harsh environments, other technologies are needed. EC-Drill is a new technology developed by Enhanced Drilling specifically for floaters, which regulates the drilling fluid level in the marine riser in order to manage the wellbore and formation pressures. A subsea mud pump is connected to the marine drilling riser and is used to manage the fluid level.
within the riser. The drilling fluid is pumped back to surface from a lower level on the riser so that the hydrostatic pressure in the wellbore can be managed more effectively. The technique also allows for precise control of wellbore pressures and enables drilling with close to constant bottom hole pressure. The technology will help ensure improved hydraulics, which can result in improved hole cleaning, higher rates of penetration, improved casing/liner cementing, less downtime/NPT due to formation pressures heterogeneity and longer horizontal sections may now be drilled in deep or depleted reservoirs, etc.

**Background**

Globally there are more than 740 subsea fields producing with approximately 47 billion bbls of resources remaining.

The recovery factors expected in field developments vary greatly, depending on many factors such as; field size, form of reservoir sedimentation (carbonate versus clastic formations), reservoir fluids (gas or oil), reservoir complexity, pressure regime, water depth, etc. In mature subsea basins, such as the NCS, where fields have undergone subsea development, recovery is lagging far behind that of fields developed by fixed platforms. In certain deepwater areas such as the GOM the recovery from some procuring subsea fields is in single digits, i.e. less than 10%.

The main contributors or drivers for higher recovery factors are wells and well placement. Primary recovery strategy (depletion/injection) may cause pressure heterogeneity, reduction in the drilling window and is the main driver behind the time and cost of wells. Depending on the reservoir’s characteristics and development strategy, the drilling window could close entirely and depleted fields may very soon become un-drillable with conventional technology and procedures, creating huge losses in recoverable reserves for the operator and owners.

Conventional drilling principles are not effective when encountering heterogeneous pressure regimes with depth and narrow drilling windows, such as in deepwater and thick sedimentary basins. In order to manage difficult pressure regimes when drilling wells from land and structures fixed to the seabed, MPD is often considered the preferred solution. MPD was developed from land drilling and incorporates a pressurised closed loop drilling system. The annular space in the well between the drill pipe and casing/open hole is subjected to a varying degree of pressure trapped below a sealing element such as a rotating control device (RCD) or equivalent. A surface MPD drilling choke is then adjusted (manually or automatically) in order to manage the wellbore pressure accordingly. With respect to floaters (semi-submersible rigs or drill ships) this type of pressurised MPD technology is challenging, for several reasons. This is generally related to well safety and well integrity reasons, as well as rules and regulations and the operational environment. In order to manage pressure more effectively in floating drilling operations, other methods will be needed to cater for the special operating conditions from floating rigs and deeper waters.

The EC-Drill is a controlled mud level (CML) technology, which has undergone development over the last 13 years. The technology was
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As a true drilling-focused organization we direct all our resources, expertise and technologies to deliver the ultimate PDC bit solution to lower your drilling costs. Period.

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developed in order to provide improved functional and economic benefits during all subsea well operations including drilling, completion and subsequent well interventions and workovers. Thus, it can be used for all operations after the riser is run, for all types of well construction operations.

One important distinction with this technology is that it was designed and developed with the particular harsh metocean and environmental factors experienced on the NCS in mind. It was also a prerequisite to improve and increase the already high standards and principles of barrier philosophy, well integrity and well control.

The EC-Drill is an open-to-atmosphere system as opposed to a pressurised MPD system. A subsea mud pump system is installed mid water, taking the returns of drilling fluids from an outlet in the marine drilling riser above the BOP at some depth below sea level. The principle is based on controlling the amount of drilling fluid (i.e. the fluid level) in the marine drilling riser in order to manage the fluid gradient (level) and hence the pressure within the wellbore.

The main intention behind this technology is to improve the way the industry manages wellbore and underground formation pressures more effectively, without sacrificing barriers and compromising well integrity.

Furthermore, this technology was designed to keep the same barrier and well control principles as in conventional drilling, but with greater flexibility and the ability to manage pressure uncertainties in the well. For this reason, and in order to allow all types of tubular and equipment to be run into the well, it needs to be an open system, just like in conventional drilling. The primary barrier is still the drilling fluid (mud) and the secondary barrier is the subsea BOP, hence the well barrier diagram is the same as for conventional drilling. More specifically there are no changes to how a well control event may be handled; the EC-Drill system is isolated from the circulation path once the subsea BOP is closed. If needed, the riser isolation valves can be closed at any time during the operation, the riser filled up and conventional drilling can be resumed. The main advantages with EC-Drill are the versatility and simplicity of the system. Since there are no restrictions in the riser it can be used during drilling (casing/liner drilling), casing running operations as well as when running completions. Running the lower completion can often be a challenge in mature and depletes subsea fields. There are no stops necessary for installation or the retrieval and testing of RCDs, and the system may also be used for open or cased hole gravel packing, wireline logging, DP conveyed logging, coil tubing operations or other workover operations.

A brief description of the main components in the system is shown in Figure 3. These represent the EC-Drill technology as installed on the rig COSL Innovator for operation with Statoil on the Troll field on the NCS in first quarter 2014. A riser joint was taken from the rig inventory and modified in order for drilling fluid to be extracted from the riser. This riser joint is instrumented with pressure sensors and equipped with valves to isolate the main riser bore from the pump and the external environment. A subsea pump module (SPM) with a series of three pumps was docked to this outlet. A separate 6 in. mud return line (MRL) was installed and integrated into the riser in order to form a conduit for the drilling fluid back up to the surface. The SPM will be able to pump up to 6000 lpm and lift the drilling fluid in the riser from the outlet to the surface. The level of drilling fluid within the drilling riser will thus be managed, which in turn changes the bottom hole pressure (BHP). A control system manages the pump speed required, and thus the fluid level and the pressure acting in the well.

Other topside components are outlined in Figure 3. These main components are; a topfill pump in order to continuously fill the riser from above, a control container housing the variable speed drive (VSD) and...
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Compensating for frictional pressure transients (ECD)

Nowhere does the impact of the frictional pressure effects become more visible than in depleted reservoirs or in formations with a narrow mud window. In many ways this could be termed ‘the mother of all evil’ in drilling operations and particularly in low fracture environments and in HPHT wells. This added frictional pressure is referred to as the equivalent circulating density (ECD) effect. The ECD is defined as the increase in density due to friction and it is normally expressed in specific gravity (SG) or pounds per gallon (PPG).

Being able to compensate for this effect will have significant implications. In EC-Drill operations this is achieved by continuously calculating (in real time) the ECD while adjusting the drilling fluid level in the riser correspondingly to compensate for this effect. The measured pressures from the pressure while drilling (PWD) tool close to bit will then be compared to the results of the real time calculations in order to act as a ‘check and balance’. The intention is to compensate for or cancel out this ECD effect either completely or in part, as is required. The result will be that the bottom hole pressure or pressure at any point in the well will remain close to constant, regardless of whether the driller is pumping or not.

In order to be able to compensate for the ECD effect a minimum water depth is required. The ECD component will depend on factors such as the well length, well architecture, fluid type, density, circulation rates, etc. Typically, the EC-Drill technology needs to be in water at least 200 - 300 m deep in order to fully compensate for the ECD effects. In shallower water (less than 200 m) the effect is less pronounced but the technology may be used for other purposes such as shallow hazards, improved cement jobs and loss prevention in weak shallow formations.

Early detection of gains or losses

When operating in mature fields the operators and the drillers must often work to a narrow pressure regime, balancing between losses in one part of the formation and influxes or hole collapse in another. Early detection and improved volume control are among the main benefits of the EC-Drill system. An accurate flow meter is installed to measure the return flow rate from the mud return line. Additionally the pump controller will respond quickly to variations in flow. This is seen as variations in pump rpm and amperage (power). These measurements enable enhanced early detection of influx or losses. An influx or loss will be registered much earlier and more accurately on this measurement than in a conventional setup using a flow paddle in the flowline and the level measurements in the large volume active tanks.

With EC-Drill the mud return line will always be full of mud, resulting in a (continuous) flow measurement with improved accuracy. If losses are detected (often the main contributor to NPT) adjustments can be made to the pressure profile in the well by adjusting the level in the riser. To make such changes in wellbore pressures is not possible in conventional drilling.

Control system

The fluid level in the riser is controlled by a computer based control system capable of keeping the wellbore pressure within the operational window (drilling window). The operator work station is located at the drill floor together with the driller. The control system has three different modes:

- Manual: In manual mode the operator controls the pump speed manually based on riser pressure transmitter readings.
- Constant riser pressure: In this mode the pump will automatically adjust to hold a riser pressure set-point given by the operator.
- Automatic mode: In automatic mode the pump is also adjusted automatically, but now the riser pressure set-point is adjusted to maintain a constant bottom hole pressure by adjusting the riser pressure to compensate for ECD variations.

The control system will maintain a bottom hole pressure within a predefined envelope during planned operations such as drilling, cementing and completion of wellbore and reservoir sections. Redundant pressure measurements in the riser are provided, and the sensors are located at different heights, such that the density of the drilling fluids above the pump inlet can be calculated. The control system is also being used to remotely operate redundant valves mounted on the riser outlet. Topside there is an accurate flow meter with an accuracy of +/-0.5% in the relevant range. The subsea pump has an automatic trip function implemented to protect the equipment. Alarms are provided to warn the operator before the pump trips. The control system logic covers handling of emergency shutdown and other signals from the rig.

Training

In co-operation with operators, a dynamic training simulator has been developed to prepare for the operations. It consists of two fully operational driller’s chairs with three separate screens simulating drilling activity. The rig personnel can see the rig floor, the drilling parameters, and also a visual reproduction of the system itself and what happens if various parameters (i.e., pump speed, opening and closing valves) are changed. The drilling plan for the operation has been implemented in the simulator for the simulator training. Well parameters including formation data can been used to simulate realistic cases for the drilling crew.

EC-Drill applications in mature fields

There are many benefits that could result from using EC-Drill. Some of these applications and benefits will be briefly explained although it is not meant as a complete list of benefits with this technology.

Reduction in equivalent static density (ESD)

In many reservoirs that initially were normally pressured, the formation pressures will decrease by production to levels far below that of a conventional liquid density mud, requiring foamed or nitrified mud systems, which add cost and complexity to the operation. With EC-Drill technology and conventional mud systems the observed ESD or equivalent mud weight observed by the reservoir will be reduced. This effect might seem subtle at first glance but may offer significant benefits.

Drilling longer (horizontal) wells and extended reach drilling

The ability to reduce the ESD and or compensate for the ECD effects will enable longer wells to be drilled and increase the reservoir drainage per well. This effect will make it possible to reach new targets, which are not attainable with conventional drilling technology.

Improved hydraulics, ability to drill faster and compensate for cutting loading

Since the technology can compensate for whole or part of the ECD effects, this effect can be utilised to drill with higher circulation...
rates than what is possible conventionally, thereby improving hole cleaning and avoid pack-offs or build-up of cutting beds in deviated or horizontal wells. It may also increase rate of penetration (ROP) since the system can compensate for cutting loading, etc. This is particularly effective when drilling the first intermediate sections of a well.

Cementing of casing and liners
One of the main benefits with this technology will be realised in casing/liner running and casing/liner cementing operations. Loss of circulation during casing or liner running and cementing operations is not just an issue of cost for the drilling fluid lost, reservoir formation damage and increased NPT. Losses and restriction on pumping rates may also be contributors to not being able to construct effective cement barriers between the casing and open hole. Besides the well integrity issues, ineffective zonal isolation may give opening for cross flow between formations with different pressures, contributing to loss of reserves. Being able to perform cement jobs with full circulation may improve well integrity and improve on zonal isolation. Ultimately this could significantly affect the recovery from fields.

Running lower completion and performing other completion work
The technology may also be used for running of the lower completion and for other completion work such as gravel packing for sand control.

For completion options in low fracture reservoirs where sand control procedures are required, the following options exist:

- Pre completion.
  - Prevent excessive fluid loss during drilling and cleanup.
  - Faster drilling and shorter reservoir exposure time.
  - Potential to improve hole geometry.
  - Higher clean-up circulation and displacement rates to remove ‘fluff’.

- Running lower completion.
  - Prevent losses to formation.
  - Faster running (compensate for whole or part of the surge effect).

- During gravel pack operations.
  - Use system to re-think carrying fluid design.
  - Density and fluid properties will not have to be exact, level management will fine-tune what the reservoir will see of pressure.
  - Can use water-based brines where otherwise alternative fluid would be required.
  - Greater flexibility to select gravel properties and slurry densities.
  - Opportunities to use the larger operating margins towards frac/pore and ECD management to improve hydraulics.

Summary
In deeper waters, deep reservoirs and in mature subsea fields, pressure depletion and heterogeneous pressure regimes have pushed conventional drilling practices to their limit. Efficiency in well construction is not improving and pressure related NPT is on the rise, driving well costs to ever higher levels. Well delivery is running below expectation and behind plans.

New and more cost-effective technology to tackle the subsea environment is needed. EC-Drill is a technology where the mud level in the marine riser is adjusted real time in order to manage the wellbore formation pressures more effectively. The technology can be used in order to reduce nonproductive time during well construction, improve drilling speed and well length and drive down cost of wells. Ultimately the technology will be needed in order to increase the recovery factors from subsea field developments, with improved barrier quality and well integrity as a bonus.

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Providing global coverage of the exploration, drilling and production sectors.
Efficient cuttings transport is an important issue when drilling highly deviated and horizontal wells. In directional wells, drilled cuttings tend to accumulate on the lower side of the annulus and form a thick bed where they are naturally deposited when the flow velocity becomes insufficient. This is particularly prevalent in large holes drilled at high inclinations and in horizontal ERD wells where thick cutting beds can give rise to numerous difficulties such as high

Luc Van Puymbroeck, Vallourec, USA, explains how advanced hole-cleaning solutions for drill strings can improve drilling performance at every turn.
equivalent circulating density (ECD), lost circulation, differential sticking and high torque and drag. Experience reveals that less-than-optimal hole cleaning can lead to performance inefficiencies impacting non-productive time, borehole quality or even to the loss of the drill string and well. The paradox with maintaining cuttings in the hole to acceptable levels is that build ups will go unnoticed until symptoms from the well signal a growing problem. Thus, hole-cleaning becomes an important factor.

Flow rate is considered to be one of the main factors commonly understood for hole cleaning as it provides the continuous medium for cuttings to reach the surface. Achieving the proper flow rate can be made difficult because of several other factors affecting the drilling process and needing to be kept in balance. Hole inclination, pipe rotation, ratio of hole-to-pipe diameter, hole-to-pipe eccentricity, ROP, mud properties, cutting characteristics and behaviour have an impact and a role to play.

Limitations to increasing flow rates for reasons such as narrow ECD window, stand pipe pressure or availability of hydraulic horsepower usually need to be compromised with. Rotational speed (RPM) is the second most well-known, and well understood component impacting hole-cleaning component. Although increasing pipe rotation improves cuttings agitation and viscous coupling between the pipe and the drilling fluid, rotational speed has a limited effect maintaining cutting in suspension and cannot, by itself, achieve a completely clean hole. Increasing rotational speed also increases the risk of dynamic vibration and drill string fatigue. It also increases the risk of wellbore damage and casing wear.

Mud rheology plays a significant role in hole-cleaning as it impacts cuttings suspension in the flow to surface. Mud rheology and mud properties are mainly adapted to the formation and well profile.

Effective drilling-fluid selection and management requires significant engineering, laboratory work and field experience. Given their performance, invert oil-based muds and synthetic muds are usually preferred from a drilling standpoint. Given their performance, invert oil-based muds and synthetic muds are usually preferred from a drilling standpoint. Most operation data indicates that large holes with 30 - 75° inclination are most difficult to clean due to high hole-to-pipe diameter ratios creating difficult hole cleaning conditions.

In many respects, the first approach to hole cleaning can look simple when considering cutting transportation by rotation of the drill string and cutting displacement with flow rates and fluid velocities. Keeping the well clean does not mean removing 100% of the cuttings from the well, but is generally understood as removing sufficient cuttings to allow for trouble-free operations. It also implies dictating the amount of rig time spent on hole cleaning and thus, time not drilling. The execution at the well site usually requires the drilling team to manage pre-established rig practices through well bore monitoring and wellsite procedures to achieve real time performance. For example pick up weight (PUW), is one of tripping indicators measured while running pipe in and out of the hole. This practice is designed to mitigate drilling risks of tight hole, anticipate drilling dysfunctions and determine if the hole is safe enough to continue drilling. An engineered system approach customised to the challenges and risks of well is required to effectively manage the entire process. Such a system is designed to maximise drilling performance while mitigating the risks and would include pre-planning, measurements at the wellsite and an end-of-the well review with lessons learned. Results are expected to be measured and quantified with key performance indicators (KPIs).

A solution to hole-cleaning challenges

**Design**

Hydroclean® is a hydro-mechanical hole cleaning tool designed to erode stagnating cutting beds while drilling, thereby increasing hole-cleaning efficiency and drilling performances. Two design configurations including drill pipe (HDP) and heavy weight drill pipe (HHW) exist. Both are manufactured in joint lengths of R2 and R3, feature a dual OD tool joint and bladed scallops machined onto the pipe body upsets. The combination of rotational speed, flow rate and the specially profiled angled-blades produce a number of hydro-mechanical effects combining scooping of cutting beds, maintaining continuous flow of cuttings above the drill string in the high velocity annular space, and sustaining the conveyor belt effect for transport to the surface. A minimum rpm of 70 is sufficient to create these hydro-mechanical effects to initiate hole-cleaning. The bladed upsets are is composed of two distinct elements:

- The hydro-cleaning zone: provides an optimum scooping effect using a variable helix angle to accelerate the lifted particles and re-circulates them in the upper zone of the hole where fluid velocity is at a maximum.
- The hydro-bearing zone: protects the wellbore from the blades and provides optimised sliding properties.

**Table 1. Russian case study field results**

<table>
<thead>
<tr>
<th>Well</th>
<th>Planned well construction time</th>
<th>Achieved reduction of the construction time</th>
<th>Potential reduction of the construction time</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Days</td>
<td>Days</td>
<td>%</td>
</tr>
<tr>
<td>2580 G</td>
<td>52.5</td>
<td>3.2</td>
<td>6.1</td>
</tr>
<tr>
<td>2672 G</td>
<td>21.0</td>
<td>1.9</td>
<td>9.0</td>
</tr>
<tr>
<td>2491 G</td>
<td>25.7</td>
<td>1.9</td>
<td>7.4</td>
</tr>
</tbody>
</table>

- Time spent on hole cleaning.
- Reduction of torque and drag.
- Tripping.
- Sweeps.
- Tight hole and stuck pipe.
- Wellbore stability.
- Hydraulic fracturing and loss of circulation.
- Chemicals and fines.
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Particle transportation to surface is ensured at a minimum RPM of 70 by creating a ‘cuttings conveyor belt effect.’

Testing and qualification
A testing programme in a full size flow loop environment, to vary the inclination for 0 to 90˚ and drilling parameters with flow rates ranging from 300 - 600 gpm and rpm 60 - 120, was performed to compare cutting bed removal efficiencies and residual cutting bed heights of a 4 ½ in drill pipe string and the same string configured with Hydroclean. The objective of the flow loop test was to develop an analytical model for placement in the drill string and to estimate the residual cutting bed height using different drilling parameters.

Test results and conclusions
- The Hydroclean configurations show better cleaning efficiencies compared to the same drill string without at well inclinations above 35˚.
- Residual cutting bed heights were maximum at horizontal in both cases:
  - In the low range of rpm (60 - 100) the hydro-mechanical effects of the Hydroclean enables degradation of cutting beds, whereas higher rpm above 100 with the drill pipe are needed to enable ‘viscous coupling’ between the pipe and the fluids to start removing cutting beds.
  - For a given efficiency for same cutting bed height, the Hydroclean requires less flow rate than standard drill pipe. This represents a potential to reduce annular pressure and ECD without losing cleaning efficiency. As for erosion tests, equilibrium bed height depends on operating parameters and allows for potentially reducing flow rates (Q) by 15 - 20% from those used with standard drill pipe. A 40% annular pressure loss reduction could be achieved using the following pressure loss formula:

\[ \Delta P = k_p \times Q^{1.45} \]

Placement
Placement of Hydroclean in the drill string follows simple and straight-forward rules based on diversified field experiences. The guiding principle is to configure sufficient Hydroclean joints evenly spaced out in the drill string from the top of the BHA up to the 30/40˚ inclination zone of the well profile assuming that the drill bit will reach TD. Such assemblies will produce a cuttings transportation ‘conveyor belt’ effect from top of BHA up to the non-sedimentation zones of the well. The conveyor belt effect is the same whether in an open hole or cased hole. Other benefits of include easy tripping, torque and drag reduction, improved sliding behaviour of the drill string, better weight on bit transfer, less reaming and back-reaming, reduced tight hole, stuck pipe prevention, smoother casing and less equipment wear. Field experience has shown that the most common spacing will be two or three standard drill pipe stands between two Hydroclean joints. When reamers are used in conjunction with drill bit to enlarge holes, the spacing can be reduced to one Hydroclean joint between two stands of pipe including the heavy weight in the BHA.

Case study: Russia
Hydroclean drill pipe and Hydroclean heavy weight were used by TNK-Uvat in Russia to address drilling difficulties encountered in the Ust-Tegusskoye field.

Field results
While drilling the intermediate hole sections an increase of cutting removal of up to 1.5 - 2 times in volume was measured at surface by comparison with offset wells. Drilling run rates were also increased leading to higher averaged ROP. No slurry was observed in the section of the BHA and virtually no cuttings were encountered during tripping. The number of wiper trips was also reduced from three to one. The need for clean packs sweeps was also eliminated. Additional costs saving on chemicals were incurred due to the larger cutting sizes recovered at surface. Wash outs and caving were dramatically reduced leading to smoother casing runs and better cement jobs.

Rig time saving per well ranged from 6 to 11% or two to three days, with the potential for additional time savings (see Table 1).

Lessons learned
The three well trial with TMK Uvat in Russia was successful; time and costs savings were achieved. The operator believes this technology has potential to further increase those savings and lower costs. In summary, the technology has shown that the drilling challenges for these wells were address and the objectives met by keeping control of hole cleaning issues while drilling. As a result, overall drilling performances compared to drilling with the same drill pipe increased.

A new generation
A new drill pipe design integrating hydro-mechanical cleaning features in the tool joint has been developed to increase hole cleaning efficiencies and address annular pressure and ECD issues caused by stagnating cutting beds in horizontal and ERD wells. The Hydroclean Max™ drill pipe incorporates specially designed scallops in each tool joint of the drill pipe without compromising the performance of the drill string.

Conclusions
The Hydroclean and the new Hydroclean Max are designed to address hole cleaning issues resulting from stagnating cutting beds unavoidable in deviated and horizontal drilling environments. The overall benefit is to drill faster and safer. The Hydroclean is a field proven product and is used worldwide in a range of applications to increase drilling performance. The new Hydroclean Max integrates the same hole cleaning concepts and capability in each tool joint of the drill pipe without compromising the performance of the drill string. It is readily being deployed for an upcoming field trial to drill a horizontal well onshore. Short of a full analysis with KPI’s, increased drilling performances are expected with less time spent on cleanouts.
Reducing the total number of drilling days is one of the main objectives in any drilling programme. Every day saved by improving drilling performance and keeping the drillstring in the hole results in a well that produces one day earlier. Over the length of any given drilling programme, saved time adds up to significant financial gains. Circulating subs can play a significant role on the overall drilling performance. Although these tools are passive in the overall drilling process – and sometimes never activated – when they are needed, they can significantly alter drilling operations.

The circulation tools currently available in the marketplace require multiple ball drops to manually activate and cycle circulating subs to handle issues including fluid loss situations, LCM pills, hole cleaning operations, spotting...
acid and more. Such manual procedures are intrusive to the normal drilling process and are also inefficient.

To combat these problems, NOV developed the multiple opening circulating sub (MOCS), an advanced circulating sub that improves drilling efficiency and helps reduce drilling costs while enhancing the safety and wellbeing of drilling crews worldwide.

NOV collected field intelligence from many global circulating sub technology end users regarding the capabilities, limitations and expectations of a circulating sub. With that feedback, engineering teams developed simple, reliable field running procedures for the MOCS tool.

**Single-ball cycle helps increase efficiency**

The MOCS tool is activated and infinitely cycled with a single ball that changes the drilling fluid flow path from the ID of the string (non-bypass) to the annulus (bypass). The tool, which can be preloaded at the surface, cycles between bypass and non-bypass modes an unlimited number of times by simply changing flow regimes.

Tools that require dropping multiple balls for tool activation and cycling require an accurate count of ball drops, and their operation is limited to the maximum capacity of the ball catcher. These ball catchers or flasks can only be emptied by a dedicated trip, which severely affects the overall drilling efficiency of the operation. The MOCS tool does not require any dedicated trips to empty an internal ball catcher. In certain applications, the MOCS tool has been cycled more than 30 times in the same run, effectively allowing the drilling teams to deal with multiple mud/fluid-loss situations encountered in the same section without requiring any extra trips.

**Improving drilling crew safety**

Unnecessary trips to empty the ball catcher and flasks increase the overall risk associated with such operations. Equipment handling on the rig floor poses one of the biggest safety risks to drilling crews during the drilling process. Because the MOCS tool cycles indefinitely with only one ball, there is no need to trip, and the safety of the drilling crew is dramatically improved.

Having to limit the use of a circulating sub to the maximum capacity of the ball catcher reduces the situations in which the tool can be used. The MOCS tool gives the operator the flexibility to change the flow path as often as desired. This is particularly beneficial in hole cleaning situations and boosting annular fluid velocities as many times as a given section requires.

Avoiding dedicated trips reduces NPT and makes the drilling operation more efficient. The MOCS tool allows the drilling crew to keep the drillstring in the hole longer for continuous drilling.
Fishing crews find success

Recently, operators have used the MOCS tool to cure lost circulation across multiple strata, cycling repeatedly to pump down LCM pills. In a 12 ¼ in. hole section in India with a 24.9° inclination and 4.17' /30 m DLS, the tool was first activated at 108 m when complete losses were observed. The operator pumped a 60 lb/bbl LCM pill in the initial phase, and increased concentration to 90 lb/bbl for additional pills until reaching section total depth at 285 m. In total, the MOCS tool cycled 20 times (40 valve shifts) and cured all losses in a single run.

Elsewhere in India, the MOCS tool was run as part of an 8 ½ in. directional hole section with viscous water as the drilling fluid. The tool was first activated at 110 m when it came out from the conductor casing and reached the lost circulation zone. While drilling through the fault zone, the operator circulated 90 lb/bbl LCM pills. The losses were controlled, but the MOCS remained in the BHA with the dropped ball inside to tackle any further losses. Overall, the MOCS was cycled to bypass mode 18 times (36 valve shifts) until reaching total depth.

In a fishing application in Latin America, a crew preactivated a 6 ½ in. MOCS tool on surface and ran the tool in tandem with an Agitator™ oscillation tool, delivering excellent results during a 9 ⅝ in. packer retrieval operation. The objective for running the MOCS was to bypass flow to the annulus while preventing washing out the fishing BHA components with the high flow rates required for the Agitator tool to stimulate the fish. Additionally, while the MOCS tool was in bypass mode, the stand pipe pressure (SPP) was reduced considerably (2700 psi versus 1700 psi), preventing any premature damage to the pumps or surface equipment. The MOCS tool also allowed jar activation while the Agitator tool stimulated the fish, simultaneously delivering both high- and low-frequency impacts to the fish. The tool cycled a total of 23 times with the drop of a single ball, achieving higher stimulation flows that would not have been possible without the MOCS tool.

In Russia, a fishing crew used the MOCS tool in two runs. The crew intended to clean the borehole with a high viscosity (hi-vis) pill after drilling at the planned interval and to use the tool like a dump sub while tripping. The tool had an activation depth of 1228 m, and it was located 29 m above the bit. Using the MOCS tool allowed the crew to pump the hi-vis pill with a higher than usual flow rate and to replace the dump sub in the BHA. In one run, the crew drilled from 924 m to 1257 m with an operational flow rate of 32 lps and SPP of 118 atm, and circulated 10 m³ of hi-vis pill through the MOCS tool with a flow rate of 36 lps and SPP of 120 atm.

In the tool’s second run, the crew drilled from 1257 m to 1429 m with an operational flow rate of 32 lps and SPP of 120 atm. The tool had an activation depth of 1400 m, and remained 29 m above the bit. The crew circulated 10 m³ of hi-vis pill through the MOCS tool with a flow rate of 36 lps and SPP of 124 atm. After a combined total of 76 circulating hours, both runs ended with a dry pipe trip and 100% tool operational success. The crew controlled the tool’s cycling mechanism with flow rate alone, and circulation through tool ports were on a higher flow rate, successfully pumping 20 m³ of hi-vis pill.

Conclusion

The MOCS tool is a non-intrusive technology specifically designed not to interfere with normal drilling operations and to enhance the drilling process in all applications where a circulating sub is needed. It is user friendly and requires little to no training of drillers and drilling crews. Once the tool is added to the drillstring, it requires no direct interaction with the drilling teams beyond managing flow rates and pressure changes to determine whether the tool is in bypass or non-bypass mode. It enables superior product operational flexibility and productivity in applications where circulating subs are needed.

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Until recently, surface-acquired seismic data has been used almost exclusively to determine the overall structure of the subsurface, enabling local geological information from wells to be interpolated or extrapolated across a wider geographic area. Recent developments in seismic acquisition technology have improved both vertical resolution (i.e., temporal frequency bandwidth) and spatial resolution, which is especially important for the characterisation of unconventional resources such as tight oil, tight gas and shale gas reservoirs. The new acquisition methods, combined with advanced data processing, analysis and visualisation technologies, are enabling more knowledge to be extracted from recorded seismic wavefields.

Thomas Heesom, WesternGeco, UAE, describes how new point-receiver seismic data, combined with advanced data processing, analysis and visualisation technologies, helped characterise tight sand and carbonate reservoirs in China.
Highly integrated software systems and workflows, from acquisition through processing, interpretation, geobody extraction and lithology classification, enable the maximum value of seismic data to be realised efficiently and effectively. Details of spatial variations in geological, geophysical and rock physical parameters such as the distribution of sweet spots and fractures, as well as local anisotropy-related in-situ stress, provide valuable information to support well completions engineering and efforts to increase production such as optimising horizontal well placement and hydraulic fracturing design. This article presents a case study that utilised several state-of-the-art technologies in an integrated workflow to more accurately, compared to previous attempts, characterise tight sand and carbonate reservoirs in the central Sichuan Basin, China.

**Background**

The Gongshanmiao structure in the central Sichuan Basin has a long history of hydrocarbon exploitation. The main oilfield in the Sichuan Province has been producing for more than 30 years. For this project, PetroChina Southwest Oil and Gasfield Company (SWOGC) had the primary objective of characterising a tight oil sand reservoir consisting of multiple thin deposits, with secondary carbonate layer targets. These Jurassic horizons have a maximum depth of around 3500 m. The populous prospect area was covered with hills and dense vegetation, with forest in the mountainous areas and working rice fields in the lower regions.

No new seismic data had been acquired in the area for ten years, although there were two legacy 3D seismic datasets, acquired in 1999 and 2003. Imaging quality potential from these datasets was limited by their sparse spatial sampling, short offsets, low fold and narrow-azimuth geometries. Azimuth refers to the direction between seismic sources and receivers, and hence the direction of illumination of the subsurface. To understand any 3D object it is necessary to look at it from all directions, and in the same way, optimal imaging of the subsurface requires illumination from all azimuths. The benefits for imaging quality provided by full-azimuth high-density symmetrically sampled seismic data acquisition and processing are well documented; however, execution of such designs on a production scale has only recently been made economical and practical through the advent of new technologies including efficient high channel-count recording systems and lower cost computing power.

SWOGC concluded that the legacy seismic data was inadequate for locating wells in its future field development plans. To gain more insight into the characteristics of the reservoir formations, the company initiated a new long-offset, full-azimuth broadband seismic survey covering an area of approximately 180 km² located to the west of the main Gongshanhmiao structure. A dense point-source point-receiver survey design was selected, as fine point measurements increase spatial and temporal resolution.
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UniQ projects have been completed in 10 countries, totalling arctic environments. Since its introduction in 2010, more than including 2D, 3D, desert vibroseis, dynamite mode, jungle and has been proven to be flexible and robust in many applications, Vista* desktop seismic data processing software. The system based on the Omega* geophysics data processing platform or and repair equipment, and an infield quality control system planning software, mobile positioning and testing systems, test and repair equipment, and an infield quality control system based on the Omega* geophysics data processing platform or Vista* desktop seismic data processing software. The system has been proven to be flexible and robust in many applications, including 2D, 3D, desert vibroseis, dynamite mode, jungle and arctic environments. Since its introduction in 2010, more than 40 UniQ projects have been completed in 10 countries, totalling over 25 000 km² of 3D coverage. In Kuwait, where point-receiver onshore surveys have delivered successful results imaging complex potential hydrocarbon traps since 2004, WesternGeco has deployed a system with a record 210 000 live channels.

A single recorder can continuously acquire unlimited active channels while quality control of the data takes place in real time. The highly fault-tolerant system architecture includes built-in redundancies, such as multiple fibre-optic alternate data pathways, automated data rerouting and double-ended sensor strings that continue to stream data and provide power-paths even after a cable cut. Flexibility in design means that the system configuration can be strengthened in areas identified as being at high risk from accidental or deliberate damage. Automatic alarms immediately alert the operator to the damaged section, enabling prompt repair while acquisition continues. UniQ technology enables logistical advantages that are of particular benefit for operations in challenging cultural or physical environments. Several features of the system help to minimise its logistical footprint and visibility to local communities. The system’s low power consumption reduces the number of batteries and telemetry boxes required.

The system’s high-fidelity broadband geophone accelerometers (GACs) can be deployed at up to 30 m receiver intervals as standard. When combined with broadband source techniques and properly designed acquisition geometries, these GACs deliver the highest resolution data for reliable structural imaging. High-fidelity, low noise and stable wavelets deliver optimal data for accurate inversion to derive rock properties and estimate local stress regimes, thus helping to optimise well placement and completion strategies.

**The 3D survey**

Sichuan Geophysical Company (SCGC) utilised a 45 000 channel UniQ system to acquire the 3D seismic survey. A thorough pre-survey planning process concluded that a symmetrically sampled (equal source and receiver point and line interval) point-source point-receiver design would provide optimal spatial and temporal resolution. The geometry was also designed to illuminate the target with a full range of azimuths, so as to capture anisotropic information that would enable geomechanical characterisation of the reservoir in support of future well location planning. The survey provided a very high trace density of 12 960 000 traces per km², representing a new record for seismic acquisition in China. Average daily survey production was 2015 dynamite shotpoints, and peak production was 3372 shots in one day. This represented a new productivity record for explosive seismic acquisition in China and most likely globally. Despite operating in a difficult area with considerable interference, particularly in farmer’s fields, the system enabled this high productivity through its redundant line spread, continuous quality control of line noise and resultant low technical downtime.

**Data processing**

Quality control and initial processing work that started in the field was continued in a Schlumberger computing centre in Beijing using the Omega geophysics data processing platform. Key issues addressed included adequate de-noising of the high-density point-receiver data, and ensuring azimuthal information was properly retained in order to take full advantage of the subsurface information available from this rich broadband dataset to benefit field development plans. Correction for static effects was an important step to apply before noise attenuation, especially considering the localised variations in elevation and near-surface effects in the prospect area. Point-receiver recording enables static corrections to be applied on a sensor-by-sensor basis. Because there is no in-field summation of data from multiple sensors, high frequency information is not lost as would be the case with a geophone array.
As an independent manufacturer of turn-key packages for the oil and gas industry, Airpack Netherlands provides the highest quality innovative solutions for our customers. Our packages are reliable, fit for purpose, and adhere to the requirements of our customers and international standards. Airpack offers aftersales services worldwide and provides support for our packages over their entire lifetime.

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planted over a varying terrain. The fine spatial sampling of the point receivers further enhances data resolution and noise attenuation.

In addition to conventional methods such as the editing of large amplitudes in multiple domains, a novel technique called non-uniform environmental noise suppression (NU ENS) was successfully applied to the data to address ambient noise. NU ENS uses a diversity principle and frequency separation of signal and noise to model ‘random’ environmental noise, which can then be adaptively subtracted without affecting the underlying signal. The main coherent noise types encountered in the survey were direct and scattered surface wave noise. Non-uniform coherent noise suppression (NU CNS) uses local coherent noise modelling via an FX least-squared minimisation technique, and this was applied effectively.

To better suppress remaining scattered surface waves, an interferometry-based method was applied after NU CNS. The estimation of the scattered groundroll noise used a routine called model-driven interferometry (MDI), an extension of conventional interferometry that is based on the cross-correlation and summation of wavefields observed at a pair of receiver locations. The result of this process is an estimate of the wavefield (i.e. noise model) at one receiver as if a source had been placed at the other. If a source is also placed at the other receiver location then the noise estimate can be subtracted from the measured data.

**Imaging**

To take full advantage of the long-offset full-azimuth attributes of the dataset for complex structural imaging and azimuthal anisotropy description, offset vector tile (OVT) domain sorting and regularisation was employed prior to migration. Due to the existence of layers in the overburden and the data having sufficiently long offsets, clear evidence of vertical transverse isotropy (VTI) anisotropy was observed on the image gathers. Building the best possible velocity model so as to obtain optimum imaging precision are all greatly improved in the point-receiver dataset. The new image provides a more accurate description of the plane of the major fault in the centre of the section. The data is positioned more accurately and the contact relationship is clearer. Additionally, the new image shows the spatial distribution of multiple fracture systems and helps recognise development characteristics of the sand channels, allowing better prediction of their thickness and spatial extent.

**Reservoir characterisation**

Developments in extracting and visualising attributes are helping to reveal ever more detailed information from seismic datasets. For this dataset, advanced analysis, inversion, lithology classification and visualisation were performed using the Petrel E&P software platform. Figure 2 shows coherence sections of the vintage PSTM data and the new point-receiver VTI PSTM section, demonstrating dramatic improvement in fracture corridor imaging in the carbonate target, the results of which have been validated by a horizontal well.

Around 30 wells existed within a 100 km² zone around the study area, from which log data were available for 12 wells. A complete petrophysical log analysis was performed that extended beyond the seismic survey and included two wells whose seismic well ties on the full PSTM section had the highest cross-correlation among the seismic calibrations available of the seven wells within the block. Petrophysical log analysis included generation of volume fractions of clay, sand and carbonate; and total porosity based on normalised gamma ray, neutron and density data.

Shear velocity information was required for amplitude versus offset (AVO) inversion of the seismic data, but no downhole shear velocity measurements existed from within the study area; however, shear measurements were available from four wells in the surrounding area. Comprehensive and careful editing of measured compressional velocity, shear velocity and density log
data from these four wells provided a solid foundation for prediction of pseudo shear for part of the geological section. For the deeper section, multivariate regression by a neural network approach was used to predict shear velocity. Input log-derived data included gamma ray, resistivity, neutron, density, calcite volume fraction and compressional velocity calculated from acoustic logs. Predicted shear velocities agreed closely with shear measurements from the available log data, providing confidence in the modelling approach.

Acoustic impedance (AI), Vp/Vs and density were derived from simultaneous AVO, and overall were found to match with available log data. These rock physics properties were then transformed to lithology classes to predict reservoir properties. Probability density functions (PDFs) were chosen after log rock physics analysis with different combination scenarios between rock physics attributes of AI, Vp/Vs and density. Ant-tracking was employed to enhance and track small discontinuities in the seismic data and hence characterise small faults and fracture corridors.

Integrated analysis
The lithology classification based on the seismic data was in close agreement with geologic knowledge provided from wells, illustrating the potential of the technique for revealing stratigraphic details and supporting more accurate reservoir characterisation. Figure 3 shows a visualisation of the lithology classification over one of the reservoir units presented upwardly in 20 ms intervals. Moving up through the sequence reveals a series of isolated channel sands and multi-level fluvial braided channels around the central part of the block.

Three wells, one vertical, the second deviated and the third horizontal, were drilled before the study and penetrated the fluvial braided channel sand seen in Figure 3(c). These were used for blind validation purposes, because none of the information, including logs and interpretation, had been introduced into previous inversion. Figure 4 is an example lithology classification that incorporates the three well trajectories, and is a powerful demonstration that when sand is positioned where there is higher porosity within better overlying microfacies with rich macro- and micro-fracture development, then this a good prospect to drill. Clearly, such prospects also need good well design and completions such as perforation and sand fracture to achieve high production.

Another example of blind validation was through comparison with interpreted FMI fullbore formation microimager data that was available from logging-while-drilling through the horizontal section of a well. The downhole measurements supported fracture orientations indicated by the seismic-derived multi-scale fracture characterisation based on the ratio of fast to slow shear fracture characterisation and ant-tracking.

This case history is just one example of how new seismic acquisition methods, combined with advanced data processing, analysis and visualisation technologies, are providing knowledge beyond subsurface structures, such as the distribution of sweet spots, fractures and in-situ stress. Integrated workflows, from data acquisition through to lithology classification and beyond to reservoir modelling and simulation, mean that the value provided by modern seismic data can be realised efficiently and effectively.

**Note**
*Mark of Schlumberger.
Needles in the haystack
Flow profiling with tracer technology is a cost-effective way to obtain additional information about a reservoir. Extra information validates and authenticates choices made regarding the operation of, and interventions to, the well, saving the operator investment in time and capital in both the long- and short-term.

Flow profiling technology entails deploying a tracer (or tracers) downhole, subsequently analysing the produced fluids for that tracer or tracers, and delivering flow information to the operator based on that data. The flow could be water ingress, oil inflow, or gas flow. It could be during the early stages of the well clean up, or subsequently during the production lifetime of the well.

Tracerco smart tracer systems (unlike alternative methods of gathering flow data) do not interrupt or interfere with completions, do not require periods of...
shut-in, are wireless and non-radioactive, are compatible with reservoir treatment agents and have a proven track record over many years of delivering high-value information.

The application of world-class scientific and engineering development to tracers, analysis, and release technology is the driver for, and the goal of, the company’s research in this field.

**Rapid results from sensitive analysis**

Operators of oil wells require a number of criteria from any information-gathering technique.

Imperative is the economic benefit of the process, the fundamental reason for the technology is its ability to save the customer money by providing information which enables the operator to intervene or act differently in the future using the data as historical learning. To achieve this quality and quantity of information, which has genuine value, requires numerous tracers which can be used to trace oil, gas and water. Data on water ingress in multiple lateral wells permits the intervention topside which can allow water to regress and high levels of oil production to resume. Produced water processing is expensive, in addition to the obvious fact that every barrel of production which is not oil is lost revenue.

The application of tracers to sections of pipework is always a challenge. Operators frequently leave little space for tracer application, and sometimes require application to be made after the shroud has been applied to the pipe or ICD. Any tracing solution must be flexible and adaptable, with multiple application options to facilitate any type of screen or joint.

Rapid results from initial reservoir tracing are vital. Often treatment teams will only leave site when the tracer results confirm flow from all zones. Similarly, longevity of tracer systems for long-term operations such as late-life water ingress is important to operators, enabling production-critical decisions to be made in an informed manner late on in the operation.

Modern multi-lateral horizontal wells require 4 - 6 tracers to be installed in each lateral. For larger wells this can require in excess of 40 tracers for oil and water, over 80 in total. Due to the comingling of laterals prior to sampling on an FPSO or rig, all 80 tracers must be analysable in the presence of each other in the sampled fluid. Tracers are typically installed into the drainage layer of two or three screens or ICDs, so application space is at a premium, and there is a minimum quantity of tracer which can be applied. The obvious result of this, coupled with the vast quantities of fluid produced from these wells, is that the concentration of the tracer in the produced fluid is low, usually around the ppb (part per billion) or ppt (parts per trillion) level. Consequently, the analysis of the fluid must be highly sensitive, capable of reliably analysing for tracers at these low levels.

This is not an easy task – crude oil has a reputation as one of the most challenging non-aqueous matrices to quantify analytes in, even for single tracers. It regularly requires dilution for a number of techniques to be applied, and that dilution further lowers the analytical limit of detection.

**Smart tracer technology**

Tracerco seeks to address these needs through its science and technology experience, expertise and smart tracer technology.

It is straightforward to include a single tracer chemical in a basic holding material. Bituminous waxes will adhere tracers onto pipes and release them by wax dissolution. Cellulose polymers will rapidly release water tracers into aqueous fluids. Both of these systems are obsolete – they release the tracers very rapidly (over a matter of a few hours), are difficult to apply to pipe sections and present no possibility of longer-term release or controlled release.

Tracerco’s tracer release systems are engineered to deliver a high level of control over tracer release and selectivity of phase, vastly improving the accuracy of the data and the longevity of the tracer.
In our extensive experience with thousands of unconventional wells, the best time to save money is long before the on-site work begins. When we partner up early in the stimulation design, we can better understand the scope of the challenges, and we can build cost savings right into every stage of the program.

**SAVING MONEY ON UNCONVENTIONAL RESERVOIRS CALLS FOR UNCONVENTIONAL THINKING.**

Think first, save always. That’s just one more example of how we deliver solutions to tough problems, saving you time and money. So if you’re as tenacious as we are about thinking, we need to talk. *Expect the Unconventional.*
of the systems. In one case study, continuous release was measured for 145 days, with tracer still releasing and forecast to continue to release when sampling was ceased following that. Other projects have required oil and water tracers designed to release over several years.

By using an understanding of polymer science, and the company’s capability to engineer bespoke polymers, Tracerco provides a wide range of application options for tracers. From ultra-flexible strips, through hard-wearing solid bars, to onsite injection application, any design of pipework can be accommodated.

The technology is wireless and requires no interventions to the production. Tracers, which are selective for both oil and water, are provided from a library of over 200 unique tracer species. From this extensive body of tracer data, which has been developed and researched over many years, it is possible to answer the demand for large numbers of tracers. Tracerco recently supplied over 60 tracers to a customer carrying out a complex multi-lateral well, with all tracers being analysable in the presence of one another, as well as passing other stringent requirements.

**Tracer release**

The release of tracer from the polymer matrix into the flowing reservoir fluid is the key variable, which must be controlled to assure high quality tracing data. As the fluid of interest flows across the release matrix, the tracer is released into the fluid. If the rate of this release is unknown, it is impossible to carry out flow quantification based on single readings of tracer concentration in the produced fluid. Ideally the release will result in a tracer concentration in the fluid which is marginally greater than the limit of quantification of the tracer. The concentration is not simply, however, a function of release with time, but also of the total fluid flow of the well – any released tracer will be diluted into the flow from all zones prior to sampling, therefore release at zone of 50 ppb in a 10 zone well will result in a concentration of 5 ppb top-side (assuming identical zonal contributions). The release must, therefore, ideally be large enough to cope with dilution effects, both at start up and in the event of increased flow from any zone. This release should be constant or near constant for the lifetime of the well for the greatest longevity. Tracerco has developed its engineered polymer technology to control release, giving confidence in the release profiles from the smart tracer systems.

The above description of tracer release (which results in fluids containing tracer at concentrations just above the limit of quantification) has a clear implication on analysis of the tracers in the matrix – specifically that the lower the limit of detection of the tracer, the more long-lived the tracer release system will be. Using state-of-the-art analytical techniques, it is possible to achieve detection limits at parts per trillion and below for some tracers. Tracerco’s ISO 9001-accredited UK laboratory with a tracer technology centre processes thousands of samples reliably at ultra-low levels of sensitivity. The global laboratories display a similar commitment to quality and reliability.

This experience and expertise is made more powerful by the associated logistical power that can be deployed. With seven analytical facilities across the globe, and more being built and commissioned each year, the company is well suited to handle the rapid turnarounds required for tracer analysis of large numbers of samples. However, even within logistical and analytical framework, the ‘sampling-to-result’ period is extensive, often in excess of two weeks just for transport time to the laboratory, before turnaround times are considered. If a tracer supplier has only one or two laboratories, or sub-contracts out the analysis, the time is extended even further. A month is a long, long time in the world of oil production.

In addition to the global presence, this customer-driven need is addressed in another way. Where appropriate, there is the capability to set laboratories up ‘onsite’, giving analytical results of the production fluids within minutes or hours of sampling taking place. This rapid analysis allows teams on the rig or at the drilling pad awaiting results, such as confirmed flow from all zones, to be released from site weeks or months before they would otherwise be.

**Conclusion**

It is never simple. Mother Nature ensures that each reservoir presents its own challenges, and each tracer job presents new ways to deploy skills, knowledge, and products to increase the productivity of a well. In cases where there are problems of an even more complex nature, the company makes use of the opportunity to step beyond the current boundaries and limitations of chemical tracing. It looks to solve problems in reservoirs in general, from developing suites of tracers that can withstand extremes of pressure and temperature (even by subterranean reservoir standards), through developing analytical methods that allow direct tracing of well treatment fluids such as corrosion inhibitors, to carrying out partitioning studies for EOR.

It is clear to customers that each situation is different. The company works to select tracer systems tailored to their needs, allowing for a service that goes beyond a simple tracer concentration figure. The company’s R&D team works at the forefront of tracing science. With experts in high-value brand assurance, fuel adulteration protection and subsea instrumentation, working alongside its reservoir research and development team, the company aims to deliver the next generation of reservoir tracing science, whether that is DNA-tagged nanoparticles or intelligent oil.
The petroleum industry is constantly looking for new ways to maximise oil and gas production through stimulation. In a recent study, BasoMSA (methanesulfonic acid), a new industrial scale chemistry, was found to generate wormholes when injected through limestone cores at 250˚F and 320˚F. BasoMSA demonstrates superior performance at high temperatures, good corrosion behaviour and a superb environmental profile and therefore is well suited for stimulating high temperature wells.

Hydrochloric acid (HCl) is often selected for carbonate acidising because it reacts readily with carbonate minerals producing soluble reaction products. Additionally, it is available in large quantities at a relatively low cost. The main disadvantage of HCl is its high corrosivity on wellbore tubular goods, especially at temperatures above 250˚F (Williams et al. 1979). Another limitation of HCl is its negative environmental impact. HCl lowers pH levels, is toxic to aquatic life and is not expected to biodegrade when it is released into the soil.

There are numerous problems associated with the high corrosion rate of HCl at high temperatures. First, well tubulars are often made of low-carbon steel, but in certain applications, the well completion may include aluminium- or chromium-plated components (i.e., 13% chromium tubulars suitable for applications involving CO2-rich environments) that become easily damaged upon contact with HCl solutions. In addition, HCl will dissolve any rust present in the tubulars and produce great quantities of iron (Fe+3), which will precipitate as Fe(OH)3 or, if H2S is present, as iron sulfide, potentially causing formation damage. Various additives, such as corrosion inhibitors and inhibitor aids, are used to reduce corrosion by HCl at high temperatures. The cost of these additives, however, may result in a reduced overall cost benefit.
in the treatment becoming uneconomical. Also, the use of corrosion inhibitors in high concentrations may result in undesired wettability changes of the formation as the inhibitor may adsorb on the rock surface. These drawbacks make organic acids attractive for stimulating high-temperature wells. However, an advantage of an alternative acid solution is reduced corrosivity compared to conventional acids thus reducing the additives or even eliminating the additives needed for stimulation (Figure 1).

Organic acids are typically used as an alternative to HCl in high-temperature formations. These acids are less corrosive and spend more slowly in carbonate rock than HCl, thus providing deeper penetration and improved stimulation. Therefore, they are preferred when the treating temperature prevents efficient protection against corrosion and/or when the treatments are limited to low injection rates to avoid fracturing the formation. In contrast to these advantages, there are some limitations associated with the use of weak organic acids: they cannot be used at high acid concentration, they have a low dissociation constant, their degree of hydrogen ion generation decreases with an increase in temperature and their cost is significantly higher than that of HCl for an equivalent mass of rock dissolved.

Some methods, including the use of sulfonic acids, have been tried in an effort to overcome the drawbacks for both mineral and conventional organic acid systems used in carbonate stimulation. Sulfonic acids, which have the formula RSO₃H, are described as a group of organic acids that contain one or more sulfonic, -SO₃H, groups. (Figure 2) Although the R-group may be derived from many different sources, typical R-groups are alkane, alkene, alkyne and arene. Sulfonic acids are such strong acids (as strong as sulfuric acid) that they dissociate completely in water. The obtained pKa value for methanesulfonic acid (BasoMSA) is -1.92. Because of their unique chemical and physical properties, sulfonic acids have found wide application in the chemical and pharmaceutical industries and most recently in oilfield applications. A coreflood study was conducted to determine the effectiveness of BasoMSA in creating wormholes during the stimulation or carbonate reservoirs. It was found to generate wormholes when it was injected through limestone cores at 250˚F and 320˚F.

Experimental Information
Laboratory coreflood experiments were conducted with Indiana limestone core samples and 10 wt% BasoMSA. The experiments were performed at a temperature of 250˚F and 320˚F. An overburden pressure of 1800 psi was applied to the core cell by means of a manual hydraulic pump connected to the coreflood setup. A new core was used for each experiment. The acid was injected into the core at a constant flow rate until breakthrough was observed. A minimum pressure of 1100 psi was maintained in the core by a backpressure regulator downstream of the core. This pressure was required to prevent a separate CO₂-rich phase from forming. During acid injection, samples of the effluent were collected and analysed for pH, calcium concentration and post-treatment acid concentration. An Orion PrepHeT Ross Electrode was used to measure the pH value of the samples. The calcium concentration and final acid concentration in the core effluent samples were determined by using the inductively coupled plasma (ICP) and the Titrando 907 equipment, respectively. Finally, after the acid injection, computed tomography (CT) scans of the core samples were performed to characterise the generated wormholes.

Results: optimum injection rate
The optimum injection rate is the rate at which the volume of acid required to achieve breakthrough is at a minimum. The volume of acid to breakthrough as a function of interstitial velocity is shown in Figure 3. In this plot graph, both 250˚F and 320˚F temperatures are highlighted. For the example of 250˚F, as the injection rate increases, the volume of acid to breakthrough decreases and reaches a minimum at a rate between 5 and 7.5 cm/min (2.6 to 3.9 cm/min). At injection rates higher than the optimal 250˚F and 320˚F, the volume of acid to

![Figure 1](image1.png)

**Figure 1. (Above) 13Cr coupons in the presence of inhibited BasoMSA at 320˚F. (Below) 22Cr coupons in the presence of uninhibited BasoMSA at 320˚F.**

![Figure 2](image2.png)

**Figure 2. (Left) Structural formula of MSA. (Right) Representation of MSA.**

![Figure 3](image3.png)

**Figure 3. Optimum injection rate curve for the reaction of BasoMSA with limestone at 250˚F and 320˚F.**
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achieve breakthrough increases again. However, the curve is steeper on the left side of the optimum injection rate and relatively flat for rates higher than the optimum. This fact indicates that the effect of the injection rate is more pronounced at low injection rates, corresponding to a mass-transfer-limited regime. On the other hand, a surface-reaction-limited regime is reached for high injection rates, with the pore volumes to breakthrough being less affected by changes in injection rate.

A plot similar to Figure 3 can be constructed by plotting, as a function of interstitial velocity, the photographs of the inlet side of the core samples after acid injection, shown in Figure 4. This is done to observe the dissolution patterns obtained at each flow rate, which will govern the shape of the optimum injection rate curve. As mentioned before, the optimum injection rate is determined by the dissolution patterns created by the acid reaction. As seen in Figure 4, at 250 °F and at low injection rates (1 cm³/min), some degree of face dissolution, as well as conical wormholes, is present in the core sample, making the acidising process (wormhole penetration) very inefficient. As the injection rate is increased for intermediate flow rates (from 5 to 10 cm³/min), almost no face dissolution appears on the core sample, and the tendency is to create a few dominant wormholes. The lowest volume of acid to breakthrough is obtained when acid is injected at 7.5 cm³/min, therefore, this is considered the optimum injection rate when 10 wt% BasoMSA is injected through limestone cores at a temperature of 250 °F. Finally, for high injection rates (above 10 cm³/min), several dominant wormholes were created with increased wormhole branching as flow rate increased.

Results from CT scan images
The dissolution structures that were created at the different flow rates considered in the coreflood study can be characterised by analysing the 2D scan images of the cores treated with 10 wt% BasoMSA at 250 °F. Figure 5 shows the CT scan images for a low-injection case (Core 2, 2 cm³/min), showing the wormholing ability of BasoMSA at this injection rate. Dissolution of the inlet face of the core can be observed in the initial images (dark spots in the images as a result of a low CT number). A conical wormhole is also visible, which caused the core stimulation to be inefficient (sub-optimal). It also shows the 2D scan images for a case close to the optimum rate (Core 3, 7.5 cm³/min), on which no face dissolution of the core was observed; additionally, a single dominant wormhole was created, penetrating the total length of the core. The size of the generated wormhole decreased as the acid penetrated deeply into the core until acid breakthrough was achieved. Additionally, at an intermediate injection rate (7.5 cm³/min) unconsumed, BasoMSA reaches the tip of the growing flow channels. Successive consumption at the tip extends the dissolution channels and leads to the development of a dominant wormhole of reduced size. This dominant wormhole requires a minimum pore volume of acid to break through the rock matrix. From the study of the 2D scan images, it is confirmed that BasoMSA can be used as an effective stimulation fluid at intermediate flow rates, being able to create deep, dominant wormholes without face dissolution. For acid-injection rates (i.e., 20 cm³/min) higher than the optimum acid-injection rate, the rate of permeability increment decreases with the increase in the injection rate.

Conclusions
BasoMSA is a suitable alternative stimulation fluid for carbonate acidising at high temperatures (250 °F and 320 °F). A 10 wt% aqueous acid solution was used to stimulate limestone cores using a coreflood setup. Based on the results obtained, the following conclusions can be drawn:

- It was found to be effective in creating wormholes in limestone cores at different injection rates and at temperatures of 250 °F and 320 °F.
- For the 250 °F example, low injection rates (lower than 1.5 cm³/min), face dissolution and conical channels were observed in the cores. At intermediate injection rates (5 to 10 cm³/min), almost no face dissolution appears on the core samples, and the tendency is to create a few dominant wormholes. At high injection rates (above 10 cm³/min), several dominant wormhole structures were found with increased branching for increased flow rates.
- For the acid injection rates covered in the current study, an optimum injection rate between 5.0 and 7.5 cm³/min was determined when BasoMSA (10 wt%) was used to stimulate limestone cores at 250 °F. ■

Note
This paper was published in its original form with the appropriate references at the AADE annual Conference. Alexis Ortega and Hisham A. Nasr-El-Din, Texas A&M University; Shawn Rimassa, BASF Corporation, Houston Texas, US, Acidizing High Temperature Carbonate Reservoirs Using Methanesulfonic Acid: A Coreflood Study, AADE-14-FTCE-3, 2014 AADE Fluids Technical Conference and Exhibition, Houston, Texas.
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Wherever there are oil and gas production facilities there is one specific piece of equipment that is almost always present, the separator. Depending on the nature of the reservoir, oil, gas and water are present in varying proportions.

The first stage of any hydrocarbon production process once the product has started to flow from the well is to separate the gas from the liquids and the hydrocarbon liquids from the produced water.

Chris Warnett, Rotork Controls Inc., USA, looks at the use of electrical control valve actuators on oil and gas production separators.
This is also true of unconventional oil and gas production, such as coal seam gas, shale oil or shale gas production. For shale facilities the hydrocarbon product needs to be separated initially from the flow back water and later from the produced water. Flow back water is the return of the hydraulic fracturing fluids used in ‘fracking’. Produced water is the water that is naturally present in the geological formations. This is often quite salty.

The proportion between the volumes of hydrocarbon product and the produced water will determine the capacity and nature of the separator. Fundamentally the process is the same for all sites regardless of whether the producing well is onshore or offshore. The three phase (oil, gas, water) separator is a fundamental requirement.

Separator operation

Oil, gas and water, mixed together, enters the separator from the wellhead via the wellhead pipework and the flow is usually controlled by the wellhead choke. Inside the separator, gravity works on the water so it settles at the separator base.

Oil floats on top of the water and, above the oil, gas is collected. A mist extractor will remove any further liquid from the gas, which is drawn off from the top of the separator vessel. There is usually a weir over which the oil can flow into a separate compartment to be piped away. This leaves the water, which is drained from the base of the vessel.

From a control point of view there are a few key parameters. The first is the volumetric flow into the separator vessel. This is controlled by the inlet valve position, often the wellhead choke valve. The outflows from the vessel are controlled by three control valves.

The pressure inside the vessel is controlled by the gas outlet control valve. This is operated from a pressure controller using a pressure sensor to measure the internal pressure of the vessel.

Control of the level of the interface between the water and oil is of primary importance to ensure that there is no carryover of liquids through the gas pipework due to high liquid level, nor any blow-by of gas into the liquid pipework due to an excessively low liquid level. A level sensor determines the position of the water-oil interface. This feeds to the water outlet control valve, via a controller, to make sure that the outflow of water maintains the oil-water interface within the tolerance bands. The outflow of oil is similarly controlled by a level controller taking a reading from an oil level transmitter and controlling the oil outlet valve.

The control of the separator is a continuous process maintaining the two levels and the internal pressure of the vessel within the required tolerance bands for various flow rates from the well.

The control valves associated with the separator vary in sophistication; sometimes level control is simply an on/off function. When a level reaches a certain point, the outlet valve is opened until the level drops to the lower tolerance band, at which point the valve is shut. However, much smoother continuous control can be achieved by proportionally positioning the control valves to accommodate a more steady flow of water and oil from the separator. This allows the downstream production equipment to operate with a minimum of fluctuation and disruption.

Downstream equipment could include, for example, scrubbers and gas conditioning on the gas side, water treatment on the water side and desulphurisation on the oil side.

There are both horizontal and vertical types of separators. Generally speaking horizontal types are used where there are...
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larger volumes of gas. The vertical types have good solid handling capability but are harder to service. They also have a smaller footprint.

Separator problems

Typical problems for a separator would be:
- Liquid carryover into the gas line.
- Gas blow-by into the liquids line.
- Emulsification of the interface between the oil and the water.
- Foaming.

There are various methods of minimising the emulsification and foaming problems using baffles and vortices. However, the avoidance of blow-by and carryover issues are functions of the manipulation of the inlet and outlet control valves.

In addition to the process control valves there are emergency shutdown (ESD) valves to isolate the separator. The separator must also have the capacity to accommodate slugs and surges in the well flow.

Many well sites are in remote locations and present their own sets of problems:
- There may be extremes of temperature and precipitation at the site. Wellhead equipment therefore needs to be robust, durable and reliable, to minimise the maintenance requirements.
- The remoteness of the wellhead may preclude the possibility of a power supply from a conventional electric grid.
- Sometimes the produced gas pressure can be used as a power source, but producers are reluctant to vent produced gas to the atmosphere, particularly on unconventional production facilities where there may already be a high degree of environmental constraint.

For these reasons, many remote well sites are solar powered, resulting in the control and supervisory equipment being restricted to the minimum of power consumption to operate the drill site.

Once the main hydraulic fracturing or dewatering pumps with their associated generators leave the site and the well is in its normal production mode, a simple solar powered control system is often employed.

The system may include a remote terminal unit and telemetry, coupled with high-efficiency actuators that require minimal current draw to provide the optimum solution for wellhead and separator control.

The conventional spring diaphragm pneumatic control valve for pressure and level control requires either the produced gas or an instrument air supply to run the actuators. Alternatively, low power electric control valve actuators can operate from a DC solar power unit.

The electrical solution

Electric control valve actuators for this type of application require certification for hazardous environments as well as a robust enclosure. They must also have the ability to constantly adjust valve position to accommodate a changing flow rate from the well.

Simple compact devices that have good environmental protection are essential so that a minimum of maintenance is required over the operating life of the well.

Because some unconventional production wells have a shorter life than conventional wells, the equipment needs to provide all of the functionality but at a cost that allows pay back over the shorter well life. Electric actuators that can provide the required functionality and reliability at a competitive price point are therefore attractive for automating well site separators.

Until recently, the modulating performance of electric actuators could not match the performance of pneumatic control valves. Rotork CVA actuators have introduced continuous, repeatable modulating electrical control with a programmable fail to position option. Operating on an industry standard 4 - 20 mA control signal or digital network, the resolution, repeatability and hysteresis performance is quoted at <0.1% of full scale, offering suitability for the most demanding applications.

Mechanical features include Rotork’s well-proven ‘double-sealed’ enclosure, which permanently protects internal electrical components from the effects of the operating atmosphere. The IP68 dust tight, watertight and temporarily submersible enclosure is universal to all models in the CVA range, including those with hazardous area approvals. On loss of mains power, built-in super-capacitors allow the actuator to move the valve to a desired position, programmable as open, closed, any intermediate position or stay-put.

CVA actuators utilise the company’s ‘non-intrusive’ communication technology for actuator programming and adjustment. Actuator set-up and configuration is performed using a Bluetooth enabled PDA or PC running Rotork Enlight software. Every CVA incorporates an onboard data logger, enabling operational data such as valve torque profiles, dwell times, actuator events and statistics to be downloaded for detailed investigation and diagnosis. After analysis, any required configuration changes can be uploaded into the actuator.

Digital control network options include HART, Modbus and Profibus protocols, facilitating enhanced installed economy as well as giving the CVA the increased ability to dovetail into existing asset management systems. The all-electric design, which can be specified for single-phase AC or DC supplies, also simplifies the process of retrofitting actuators onto existing valves.
With oil and gas demand outstripping supply and new discoveries often lagging behind current production rates, operators are facing increased challenges in maximising production and accelerating recovery rates from their existing fields. This is particularly the case when the average recovery rates vary significantly between 20% and 40%.

Furthermore, while there are plentiful supplies of unconventional hydrocarbons such as viscous oils, oil shales, shale gas and gas hydrates, the energy intensive nature of their extraction has meant that many operators are continuing to focus their resources on increasing recovery from existing fields.

The focus on increasing recovery is coming with ambitious targets as well. In the Norwegian North Sea, Statoil is looking to achieve average recovery rates of up to 60% and in the Middle East, Saudi Aramco, has set recovery rate targets of up to 70% on certain fields.

It is no accident therefore that the last few years have seen a renewed focus on extending the life of and increasing recovery from oil and gas reservoirs.
In gas lift, gases, such as CO₂, natural gas or nitrogen, are injected into the production tubing to reduce the impact of the hydrostatic pressure. This results in a reduction in bottomhole pressure allowing reservoir liquids to enter the wellbore at higher flow rates. Today, the side pocket mandrel (SPM) technique in gas lift that makes use of injection pressure operated (IPO) lift valves is one of the industry’s most widely recognised solutions.

There are a number of benefits to gas lift as compared to other techniques, such as ESP and rod pumps.

These include the fact that gas lift can be applied in a wide variety of well conditions; can handle high temperatures, gassy, sandy and corrosive fluids and deviated wellbores; provide full through bore access to the reservoir for investigation, treatment and repair; and is applicable to a wide range of production rates, being more suited to such environments than ESP and rod pumps. Furthermore, the SPM and gas lift injection valves allows for a deeper gas injection in the tubing.

Furthermore, the fact that in ESP installations the fluid flow to the surface is through the ESP device means that they are particularly vulnerable to sand and other contaminants – an issue that is not as great a concern with gas lift.

**Intervention challenges**

For all the benefits of gas lift, however, Camcon believes that the technology has failed to keep up with many of today’s expensive and complex wells, particularly in regard to well intervention requirements.

As previously mentioned, the primary gas injection method for gas lift today, and one that has been prevalent for almost 50 years, is side pocket mandrel configured completions where the valves are installed in a pocket inside the mandrel.

SPM tools, however, have no instrumentation on board with operators being able to access little information on pressure and temperature at the point of gas injection. The result is that with such limited information, monitoring gas lifted wells is confined to a basic ‘tick-box’ approach, focusing on wellhead pressure and the occasional fluid level or downhole pressure reading rather than consistent real time data.

Furthermore, the fact that the SPMs tend to host either temperature sensitive ‘injection pressure operated’ devices or a simple orifice with fixed port size makes them vulnerable to unstable operation when annulus and/or tubing pressures change.

It is when it comes to well intervention, however, that SPM-related gas lift is most limited with operators having little control and flexibility over altering injection rates in real time.

While it may be the case that sometimes only slight changes in the pocket-flow porting are required for annular-flow gas lift of gas/fluid flow through and below a packer, more often than not significant subsea intervention is required to change depth, port size and injection rates.

Much of these issues are addressed through wireline interventions with the inevitable risks that come with it. These include the dangers of tangled or broken cable in the well during the wireline operation and wireline or slickline tools being lost. There is also the potential loss of the well (if the wire snaps and junk plugs the tubing, for example) and the halting of production accompanying HS&E requirements.

Whether it be onshore or offshore such intervention can bring significant challenges to the operator. Offshore and the costs of intervention – especially in deepwater developments – is a significant barrier with a single intervention costing potentially hundreds of thousands of dollars and requiring specialist ROV equipment. Onshore and in certain countries, such as Nigeria and Algeria, there are security implications of having a significant number of personnel at the wellhead.
One recent example of the problems of well intervention offshore comes from a North Sea field. In this case, 13 valves were pulled from four wells all less than three years old and all of which had been gas lifted. One well was lost completely due to wireline plug problems, only half the valves passed flow check tests and some valves ended up being bent. This was in addition to the million dollar costs of rig-based well intervention.

In short, it is believed that too many of today’s gas lift solutions today, are characterised by weak equipment and operational designs resulting in frequent intervention problems that can have a negative effect on time, cost, risk and production.

The fact remains that well inflow performances change over time leading to a need to alter the depth of injection rates and optimise gas allocation changes. Today’s gas lift designs simply do not come with the necessary flexibility to achieve this.

**Going digital**

So how can the intervention requirements in traditional gas lift be reduced? Similar to many other areas of the oil and gas lifecycle today, there is a need to introduce greater digital intelligence into gas lift operations and address some of the weak equipment and operational designs around SPM-related gas lift.

Key to this greater intelligence is the ability for operators to vary injection rates and depths in real time without production interruption as well as negating the risks of well intervention already outlined. In this way, operators will be able to access pressure and temperature information throughout the gas injection process.

It is this focus on an era of intervention-free gas lift which has driven Camcon in developing its intelligent gas lift solution which at its core consists of a low energy pulse control which signals to switch an actuator between two stable positions to digitally operate a valve. The electrically actuated valves – opened individually or in specific combinations – allow for the real-time setting of injection rates and eliminate the need for SPMs and wireline intervention.

Another advantage of the new solution is that the orifice size is not fixed so that it can be varied on demand, thereby providing greater flexibility and meaning that operators do not have to size the conventional gas lift orifice for a limited gas injection range. There is also no production tubing obstruction at all at the point of gas injection – again simplifying the whole process and negating substantial intervention requirements. In this way, operators can manage the digital gas lift process offsite and in an environment of their choosing.

So, will intervention-free gas lift become a reality? There’s no doubt that more and more operators are seeing the benefits of digital gas lift and the limitations of SPM-related gas lift. Engineers are also beginning to appreciate the limitations imposed by the specification of a particular port size as compared to the range extension possible with a multi-ported valve unit as is the case with Camcon’s solution.

The company is currently deploying a digital gas lift solution on an onshore well in Oman where Camcon’s intelligent gas lift is being used to improve the production performance of the well and pre-empt well intervention requirements.

Here, all production control changes for this method of intelligent gas lift are managed and implemented from the safe environment of a production control room away from the inherent dangers present at the wellhead.

**An era of intervention-free gas lift**

Whether it be single subsea wells, deviated wells, multi-well onshore fields, dual gas lift completions or deepwater wells, operators today are looking for alternatives to their current gas lift operations as well as a relieving of the pressures on intervention. The era of intervention-free gas lift might be closer than many people think. 

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Within the context of ‘data’, the oil and gas industry has been on a rapid journey. Less than 10 years ago, the idea of historical operating data from a remote asset being available to an operator or engineer on a desktop computer in the office was revolutionary. In stark contrast, today, the expectation is that the same data, in a more digestible form, should be available on phones or tablets at any location in the world. Quite a shift!

This data accessibility has had a hugely positive impact on the industry, but taking a step back and considering semantics, when data is mentioned different people in different roles have widely differing perspectives on what the term ‘data’ actually means. The evolution of integrated operations means that more and more data sources are available, and industry standards (such as SCORM, PRODML, WITSML, OPC etc.) have opened up previously ‘closed’ databases. Clearly beneficial this has, however, created its own problems. Where data was previously scarce, there is now abundance, perhaps to the point of excess. The key question should be: how is this data used to extract salient and timely information to improve the overall safety, longevity and profitability of an organisation? The simple answer is often that the data enables review. However, without additional processing to provide insight, knowledge and ultimately, corrective action and improvements, many companies are missing the opportunity to drive unparalleled safety, productivity and efficiencies across the working environment for their staff.

Collecting and analysing
Back in 1986, Motorola first developed the ‘Six Sigma’ process which is a logical management philosophy that emphasises collecting data, and analysing results to a fine degree as a way to...
MANAGING THE DATA JUNGLE
reduce defects in products and services. Although initially applied to the discrete manufacturing process, this concept is equally pertinent to reviews on all aspects of a company’s operation – the steps of define, measure, analyse, improve and control. These steps can be applied to day-to-day activities to review what activities add value, what the root cause of underperformance is and how activities can be focussed to improve key metrics such as overall operational effectiveness (OOE), health, safety and environmental (HSE) performance and even lifting costs. This cycle is shown in Figure 1.

The Abnormal Situation Management (ASM®) consortium has conducted extensive research into the root cause of accidents and incidents and one of the foundation studies that was undertaken was an analysis of incidents in the US hydrocarbon industry over one year. It determined that 50% of avoidable incidents were attributable to people and the decisions they made, with 30% being attributed to equipment failure and 20% being due to the process unexpectedly causing problems. These incidents were only the externally reportable incidents (not internal, minor incidents) and yet they had a total estimated value of over US$ 20 billion. This can be related back to the performance of operating assets and their OOE, where many assets operate in the high 80% region, whilst their aim is to be in the mid 90%. What is the cost of this deferred production to the industry and how can it be helped through the use of data?

### Isolated data, unified environment

As referenced before, data arrives from many sources and is typically viewed in isolation, depending upon the organisational silos which exist. A non-exhaustive list of departments that typically exist includes:

- Human resources.
- Accounting.
- Geology and geophysics (exploration).
- Reservoir optimisation (simulation and planning).
- Production and operations.
- Maintenance.
- Procurement.
- Planning and scheduling.
- Logistics.
- Environmental, health and safety.

All of these departments are reviewing and making decisions related to different aspects of the same specific assets, using data from different sources, and yet this data is fundamentally correlated. For example, the cost of a maintenance activity will be affected by the cost and skills of the people performing the activity, the availability of spares and the maintenance procedures that staff will follow. The activity will impact planning, procurement, operations and environmental, health and safety. In itself that is nothing new, but what is surprising in light of data accessibility is that these adjacent areas are rarely viewed together in structured DMAIC process, to provide insight into incidents or process improvement and to learn from true root cause analysis.

Industry is being driven towards more rigorous proof and scrutiny of performance. HSE metrics that are required for governmental reporting, directives such as the EU Offshore Safety Directive (2013/30/EU) related to the reduction of accidents, and even the Sarbanes-Oxley Act of 2002 mean that reporting needs to be accurate, with the provenance of supporting data being proven. These requirements mean that data has to be reviewed, verified and signed off by accountable, qualified people and the ‘touch points’ recorded for future review. Importantly in this process, the original data must remain intact and federated, with calculations, verifications and adaptations being registered and logged externally to the original data. In this manner, there is only ever one version of the truth which can be referred back to.

Reviewing the data from different sources in a unified environment enables the time spent, activities performed, skills required, costs incurred and the OOE impact to be reviewed together. This approach, using standard Six Sigma-type tools, then enables a complete picture to be ascertained, but more importantly, learnings to be captured and implemented. Take for example a simple pump maintenance activity. Performing a multi-faceted review of this activity with all of the contextual, relevant data would enable:

- Root cause analysis of why maintenance activity was needed, compared to other similar pumps from different manufacturers, enabling improved equipment selection.
- Process conditions leading to the maintenance requirement to be reviewed for precursors, enabling better diagnostics and exception-based surveillance in the future.
- Procedures and the timings of activities to be reviewed against best practices to identify changes in procedures, procurement and activities to drive cost reductions.
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Templated structures can be used to accelerate and standardise delivery. This allows the roll up of production figures, costs and KPIs and means that more meaningful information can be federated since that information is now contextualised.

Once the hierarchy has been created, data from different sources should be linked in a semantic data brokering layer, which will then handle the connectivity between different data sources and the federation environment. This process is the means of aggregating the various data sources and contextualising the data in relation to assets – where assets can be people, equipment, reservoirs etc. The data is then available for calculations, exception-based surveillance or graphics and mimics without concern over how it will be abstracted from the various repositories, since the data broker handles this behind the scenes.

Data architecting is arduous and requires a lot of effort to create template structures, but a sound investment in this space is typically repaid many times over. Building a template structure for the data associated with one oil production well may take time for example, but once correct, all remaining oil wells can be produced in very little time. By taking this approach, schematics (such as the one in Figure 4) can be created to utilise the templated data structure meaning that visualisation is based on templates rather than bespoke displays and that implementation time and support requirements are reduced.

Having now developed asset hierarchies and data structures, the next activity is to determine what person needs to see what information, in what context, in order to drive what decision or action. The ability to federate data and information from a single environment means that the attention to information rendering and how workflow engines will be engaged are the next steps. Making sure, for example, that a production engineer gets an overview display of all the wells he is responsible for, which highlights – at a glance – which wells are abnormal or unstable. A good example, shown in Figure 5, is of a maintenance engineer who should have access to displays that demonstrate the dynamic performance of a compressor. This is all possible, but requires careful design to ensure that there is not an overload of unnecessary data that reduces someone’s effectiveness.

**Conclusion**

An organisation’s data can therefore be managed, turned into information, then federated to the correct people, at the correct time and in their necessary format to help them drive decisions. What remains is the last step, which is collaboration, co-operation and collective review between functional groups. As mentioned before, different groups in a company can all make decisions from, and find common touch points in, the same data but the collaborative review and progressive learning across an organisation is something that only data can effectively facilitate. Knowledge management systems such as wikis and sharepoints can also help record the results and learnings when they are extracted from the salient information.

The hardest part of the whole holistic review and learning process that has been described in the early part of this article is not technology – it is the virtualised silos which exist in a lot of organisations. The data and information can be federated across the virtual firewalls between departments, but the next step is not technology – it is change management. With behavioural change, and the support of the technology that exists today, true learning and collaboration can be achieved. Then, the true value of all of the different data sources can be used to change a company’s performance, results and development drastically. A veritable smorgasbord of information is available in the data repositories in most companies today – the change required to truly benefit from this feast is the behavioural change to work and learn together.

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Figure 4. Templated contextual high-performance displays.

Figure 5. Not just a graph – insightful information.

- Competence profiles, skills and training of people involved in the activity to be reviewed to determine what competence levels are required, what training needs can be improved and which skills are no longer required.

The data across an organisation resides in many different databases or repositories and in many different structural forms, with correspondingly disparate servers. The challenge then is how to access the different data sources, fetch the data for the appropriate time period, contextualise it and then render it in an intuitive form enabling the data to add value. Of course, the next challenge is to enable the information to be available to all who need it and not just this, for the data (or the feast) to be displayed in a contextual form meaningful to an individual’s role, through a standard web browsing tool.

**Taking control of the data**

They key starting point on this journey of managing data is to plan where the intermediate and final points will be on the data transformation journey, clearly defining the ‘to be’ state at the outset. Various repositories of data will reside in different organisational domains, and the engagement of a multi-disciplinary team from an early point is vital to ensure that the governance of a project is not driven by teams who will not be the end users – the risk is ending up with a tool that only certain people can and will use, the ‘only an engineer could love this’ syndrome.

One of hardest tasks to accomplish is determining the hierarchy and structure that the organisation and operation will be represented by, within the data federation space. Although many decry the tree structure within a file explorer on a computer, in terms of assets this is still the most prudent method of representation. Building an organisation hierarchy in terms of assets, from small to large, whilst using standard asset types, means that the operations can be viewed according to need whilst templated structures can be used to accelerate and standardise delivery.

For example, see the structure below where an organisation has been broken down from an operating area down into the individual assets, wells and then completions. This allows the roll up of production figures, costs and KPIs and means that more meaningful information can be federated since that information is now contextualised.
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The ability for exploration and production companies to optimise their oil and gas assets relies heavily on fast access to the most accurate versions of data and scientific analysis. Time-sensitive predictive decision making requires geologists and engineers to have confidence that operational and exploratory decisions are based on the most accurate and trusted information known to the corporation.

Engineers, scientists and management all want better visibility and access to the collective information that scientifically describes assets (wells, reservoirs, fields, etc.). This information typically resides in disparate scientific software systems, each with exclusive data silos that are designed for the unique requirements of that scientific discipline (geology, geophysics, reservoir engineering, land management, etc.). As a result, exploration and production companies are often challenged with providing their staff with quick access to vital information that resides within their various internal scientific applications and databases. Time-sensitive predictive decisions can be delayed as the scientific community brokers each other’s request for data and analysis from these various data silos. In some cases, analysis may be performed in spreadsheets and issues concerning version control can cause delays due to data validation.

The challenge is to make it easier for E&P companies to access the extremely valuable data that already exists in their informational assets. The optimal solution is not another repository, but rather a tool that provides easy access to the data and documents as they exist in the current data silos. The optimal solution also involves leveraging structured data and applying it to unstructured data like documents to make them easier to find and access.
The vision

One long-term customer engagement, with Jetta Operating Company, Inc., grew into a collaborative development project that has yielded a game changer for the oil and gas industry. The solution developed, based on Jetta’s vision, resulted in an improved approach for providing unified access to both structured and unstructured data, and introduced intelligent, intuitive data aggregation and company-wide data visibility.

The company’s growth depends on detailed reservoir analysis and the ability to accurately and efficiently extract insights out of company-wide, distributed information.

As the company continued to grow, operational complexities naturally increased. Jetta has always embraced and applied industry best practices for data management. The ability to access accurate information has been, and will continue to be, a major success factor for the ability to grow.

Like most oil and gas companies, Jetta is organised by operational departments such as geology, land, reservoir engineering, operations and accounting. Each of these groups typically utilises different software solutions for storing information associated with these disciplines.

The increasing complexity of the company’s numerous information silos posed several challenges. Collecting data from multiple silos required numerous export and import steps; engineers and management wanted a more streamlined solution for aggregating data from different sources. In some cases, file versions had to be compared and validated to find the precise and current information assets.

Jetta’s management team envisioned profound efficiency gains from a system that could rapidly retrieve and consolidate information. Additionally, they wanted to eliminate time-consuming verifications of revision levels. Engineers and management needed to know that they were analysing and applying the most recent and complete version of each information component.

Rethinking data architecture

Jetta initiated a formal evaluation project for a Master Data Management system in late 2010. The project team included collaborators from the company’s technical staff, IT and financial management. Since off-the-shelf systems did not allow the company to realise their vision, they reached out for a customised solution that would address their specific needs and requirements.

The company’s vision spanned three primary components: structured data, unstructured content and a single unified platform for accessing both sets of information. The ability to connect all of the data sources was essential to empower employees to quickly and easily access the precise information residing in their various business systems. Structured content included the data in SQL databases and other application-specific data files. Relating to production, land and operations, this data needed be efficiently accessed and searched using a GIS-based interface that displayed information related to wells in a visual map.

Unstructured files, such as drawings and digital documents, were more challenging. Creating a solution that connected the two, structured data and unstructured content, in a single, intuitive and unified platform was the ultimate challenge. The solution had to maximise productivity and optimise decision making with accuracy. And of course, visibility and access could not compromise the security of confidential information assets.

The company wanted to develop a centralised repository for data and create a graphical interface that revealed the information in an easy-to-use platform. It was known that the complex land aspects needed to be included in the scheme. The criteria were simple. Could one take a database like the PPDM, blend information from subscription services such as IHS, extract information from various departmental databases and create a user-friendly system that had a robust graphical user interface?

Step 1: Implementing a new foundation for managing unstructured information

The solution started to take shape when the right enterprise content management (ECM) platform was discovered. M-Files provided the key piece of the puzzle for the project at Jetta. Specifically, the ECM solution allowed the four primary criteria for harnessing distributed data assets to be addressed:

- Internal contents of structured data (residing within any database application) can be searched rapidly.
- Unstructured content, such as documents and spreadsheets, can be tagged with metadata, from the structured data, thus making it easy to locate documents.
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Regardless of the application in which it resides, WellMetrics and M-Files simply unlock this data and deliver fast access to the most accurate versions of documents and data sets to support and enhance decision-making.

Figure 3. WellMetrics and M-Files provide oil and gas companies with a single unified solution for accessing all structured and unstructured information related to their wells, ensuring authorised staff can locate the content they need, regardless of the application in which it resides.

- Automated version control, so that everyone knows exactly which copy of a document is the most current version.
- Programmatically, M-Files can be initiated on the fly, to deliver all documents relating to a specified topic, with results displayed in the format specified by the customer.

M-Files were deployed at Jetta first, which gave the engineers and management team the immediate benefits of fast access to unstructured data while the development of the integrated well-centric data tool was completed. This first step helped the company improve the organisation and management of E&P information including analysis, projections, daily reports, contracts and joint operating agreements.

The efficiencies from the new enterprise content management system accelerated adoption, and the decision was made to completely replace the network file folder system as the de facto approach for managing their documents and other unstructured information. In addition to well-specific documents, the company also began using M-Files to manage corporate information. Since this includes articles of organisation, employee identification, income tax data and compliance statements, M-Files document control features are used to enforce privacy policies as well as lock-down valuable data assets. M-Files enabled Jetta to ensure that only authorised individuals could access confidential information.

**Step 2: Introducing a new system**

With the new ECM solution in place, the next step involved rolling out a new system: WellMetrics. With an integrated GIS interface based on ESRI, the system allowed Jetta to:

- Leverage a GIS aerial map to access well data.
- Quickly find all structured and unstructured data for each well, or group of wells.
- View data from scientific data silos in a way that is easily understood by multiple disciplines.
- Locate documents based on attributes extracted from application databases.
- Query the system to extract specific insights (e.g., identify all wells that have produced more than 50 bpd over a period of interest).

The system features web services and a seamless integration with M-Files that gives fast access to huge data repositories that were previously disconnected and not easily accessible. This includes data residing in numerous industry applications such as Aires, Excalibur, LandWorks Rio as well as other custom applications. Nothing changes for these applications; they continue to store data in native formats. WellMetrics and M-Files simply unlock this data and deliver fast access to the majority of time to be spent analysing and strategising the data. Many teams at Jetta agree that this change has created superior decision opportunities with accurate data.

**Next steps**

The phase one deployment of M-Files and phase two deployment of WellMetrics were implemented based on employee-requested feature enhancements, and Jetta’s staff continues to help shape the WellMetrics solution. The next release will provide additional improvements such as data roll-over features, new query capabilities and expanded exportable-data features.

Jetta is now quickly approaching a time when all of its documents are managed through M-Files so that each person can review the history and versioning of the information they are using.

The ongoing transformation of information management and the optimisation of insight extraction at Jetta must be credited to the executive-level commitment and the engagement of multiple disciplines during both the planning and deployment phases. Incorporating the many aspects of the oil and gas business into a useable foundational system is not for the faint of heart.

Everyone on the project team was motivated by the need to deliver a solution that could ensure absolute reliability of the systems of record. The company required a 100% commitment to testing and retesting of M-Files and WellMetrics prior to company-wide roll outs. The champions of the new vision clearly articulated the reasons behind the changes, shared those reasons with the employees, and incorporated the business benefits into employee training.

The flexibility of the new data management architecture helps simplify connecting to existing databases and systems, and introduces a highly integrated environment for data sharing. Boosting production within the oil and gas industry has always come down to harnessing geological and operational knowledge, and instant access to precise information truly represents an important opportunity to cost-effectively keep up with worldwide demands for energy.
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RBL: DRIVING SPENDING WITH LENDING
Reserve based lending (RBL) is a flexible method of financing that is attractive for both lenders and borrowers, in which availability of funds is based on the value of oil and gas assets of the borrower as revised from time to time. Lenders may limit their risk by linking facility amounts to the net present value of one or several of such assets (whether or not currently producing), which corresponds to the difference between the present value of the amount of oil and gas that could be recovered and the project costs. The attractiveness for the lenders is linked to the fact that the risk associated with the volatility in commodity prices/market values for such assets is mitigated by the flexibility of a reserve based loan and lenders may continually adjust loan parameters either upwards or downwards to maintain adequate loan-to-value and cash flow coverage ratios to take into account a borrower’s activity (e.g., increase/decrease in oil and gas production).

For oil and gas companies who are either in a development phase in which production is imminent or already producing oil and gas and need to fund expansion, RBL provides an attractive and elastic financing tool in which amounts available are determined by expected production. Repayment of the debt stems from the revenue derived from the sale of the oil and gas, rather than from immediate balance sheet strength.

Eran Chvika, Norton Rose Fulbright LLP, Paris, explains the importance of reserve based lending for funding oil and gas projects.
The RBL loan market has its origins in the US in large project financings by majors and large independent oil and gas companies in the 1970s. In recent decades banks have become increasingly prepared to lend to smaller to medium-sized sponsors in emerging markets who lack the same access to corporate loans as the majors.

The RBL market has expanded over subsequent decades across the globe and there is currently an increase in the demand for the use of such financing techniques. However, market standards continue to vary considerably between jurisdictions such as the North American and UK markets, in which the practice is highly developed, and other jurisdictions such as countries in Sub-Saharan Africa, in terms of acceptable asset categories, lending structures and security packages.

RBL financing is fundamentally different from other financing tools primarily due to the producing nature of the reserves and the variation of the facility amount, which is calculated on the basis of the expected net present value of future production from the fields, or the ‘borrowing base.’ Regardless of the geographic location of the relevant market, there are a number of key issues that must be examined both by sponsors and prospective lenders. These issues are considered in this article.

**Fluctuating facility amount**

The facility amount is based on the borrower’s working interest in one or more upstream assets and is generally equal to a discounted amount of the net present value of the borrower’s future income from oil and gas developments in such assets.

The size of the facility is periodically determined by valuation of the reserves made by technical consultants based on economic/financial criteria and in particular on well-established production performance derived from volumetric, comparison with similar reservoirs, a computer simulation of new producing zones given lesser weight, geologic conditions as sand continuity, reservoir value and revised commodity pricing assumptions. As the borrowing base is therefore keyed to such valuations, forecast and redetermination provisions are highly negotiated in RBL financings. The borrower and lenders are permitted to review and object to any forecast under the RBL documentation in a revised forecast, which is resubmitted for review.

The amount of the facility will be increased or decreased by the addition or removal of qualifying assets at the borrower’s request or to meet mandatory prepayments due to a fall in the value of such assets.

In the event that the amount of the facility exceeds the value of the assets, there is a cancellation of the commitment in excess of the relevant value and a mandatory prepayment of outstandings in excess of value will be required, with any failure to make such prepayment potentially triggering an event of default.

By contrast, if the value of assets exceeds amount of the facility, the lenders should increase the available facility amount by such excess.

**RBL specific covenants**

Although RBL has some similarities to traditional lending facilities there are some key differences, including the discretion given to lenders to revise commodity pricing assumptions in order to value the reserves and to set the credit limit in the course of the life of the RBL loan, which is generally shorter than the expected production life of the reserves.

For instance, several banks made available a short-term, two year crude oil pre-export facility to a significant Nigerian independent oil producer, when it accessed the international market for the first time. The purpose of this facility was to invest in existing production and assist with payments due in respect of new licences awarded to this company. The amount of the facility was based on the banks’ assessment of the reserves in the field operated by the company and the production and price curves over the life of this term facility.

RBL documentation typically includes several covenants to address specific lender concerns similar to those found in other financings, such as financial covenants, restrictions, specific cash waterfall provisions, prohibitions on additional indebtedness and distributions. It also includes borrowing base deficiency provisions. The borrowing base deficiency can be cured by the borrower adding additional oil and gas properties to the collateral base; alternatively, the lenders can agree to graduated reductions in available lending commitments.

The RBL documentation typically allows debt levels/amortisation to be either increased or decreased to levels that maintain loan-to-value and cash flow coverage ratios that take into consideration changes in cash flow caused by acquisition, increase/decrease in production, operative costs or drilling activity since the last redetermination, any of which could impact the expected ultimate recoveries of reserves.

Bank legal counsel will also review/evaluate the borrower’s title to its oil and gas properties to verify that it matches the net revenue interest reflected in the technical consultants’ reports and forecasts.

Lenders require that the oil and gas entities further provide a number of financial documents and specialist reservoir engineers’ analysis on a regular basis, or to be notified of the occurrence of certain events (e.g. any force majeure event affecting the borrowing base asset) in order to enable them to monitor the increase/decrease of production and the financial situation of the oil and gas entity generally and the ability of the such entity to comply with the obligations under the RBL loan.

The lenders will further require the oil and gas entities to provide a number of specific covenants in the RBL loan agreement regarding the manner in which they carry out their business in order for the lenders to have a degree of control over such activity and management, such as key-men provisions.

A breach of any of such covenants may lead to an event of default and give to the lenders the right to accelerate the RBL loan.

**Security package**

Lenders normally require at least 80% of the initial collateral value to be covered by a perfected security interest and to have clear title under the security package.

A key legal consideration for any lender seeking to take security will be the licensing regime under which the borrowing base assets are operated. In many jurisdictions, it is not possible to take security in favour of the lenders over the underlying physical reserves themselves while they remain ‘in the ground’ since these are often owned by the host country rather than by the operator, who therefore cannot grant security over such reserves as it lacks the necessary title over such reserves to do so. In such a context, obtaining acceptable security over the reserves themselves would require the host government to grant advance approval to the assignment or transfer of such title in certain circumstances, a daunting prospect which may be difficult and time demanding to obtain.
For such reason, lenders generally look to other forms of security, such as assignments or pledges of contractual rights arising, for example, under an oil and gas licence, a production sharing agreement or a joint operating agreement and negotiate a suitable security package in line with the local legal framework and market practice.

Generally, a pledge over the shares of the borrower oil and gas entity holding an interest in the licence is considered as the security option of choice since it enables the lenders to take over such company upon the occurrence of an event of default and the enforcement of such pledge.

The assignment of key contracts is also often part of any security package and includes an assignment of the borrower’s rights, including any receivables due.

A pledge over the borrower entity bank accounts, in addition to a detailed bank accounts agreement, provides further comfort to the lenders in order to have adequate control over cash flows arising from the relevant borrowing base.

Many oil producing jurisdictions in sub-Saharan Africa are member states of OHADA, an organisation created by treaty for the harmonisation of business and commercial law in Africa. OHADA has promulgated a number of uniform laws, which, upon approval by the Council of Ministers, are automatically applicable in each of such member states. Recent modifications to the OHADA Uniform Act on Security Interests and the OHADA Uniform Act on Commercial Companies have resulted in a modern and sophisticated legal regime for the taking of security interests in a RBL context, including the ability to grant all security to a single security agent, an effective means of creating a security assignment of commercial receivables despite any contractual provision to the contrary, specific provisions permitting both outright cash collateral by way of transfer of title to the cash and pledges over outstanding balances from time to time of charged bank accounts, streamlined procedures for creating security over tangible fungible assets, company shares and receivables and, most critically, the ability to enforce most forms of security by outright transfer of the pledged assets to the beneficiary of the security (pacte commissoire), subject only to subsequent expert evaluation and the return of any surplus value of such assets over the secured debt to the security provider.

Nevertheless, it should be borne in mind that the legal framework of oil and gas exploration and operation of each OHADA member state remains a matter for its own legislation, and that the ability of borrowers in such jurisdictions to open and maintain bank accounts outside the relevant jurisdiction and their obligations to repatriate in-country the proceeds of sale of offtake into foreign jurisdictions will be subject to exchange control rules, either on a national level or those promulgated by west or central African central banks pursuant to regulations promulgated by regional monetary and finance unions.

It should also be noted that, although RBL is generally a technique of leveraged financing that involves lending on a non-recourse basis, in certain transactions lenders require a parent company guarantee securing the obligations of the asset holding company under the RBL loan.

Furthermore, where borrowing bases consist of assets owned by several entities within the same group, lenders may, subject to local guarantee restrictions, require each asset-owning entity to cross-guarantee the debts of each other entity and the liabilities to be secured by each of their assets.

There are therefore a number of differences between standard financing methods and RBL financings. Precedents do not set out the boundaries and lenders, borrowers and their advisers need to work together to create tailored made solutions to address those differences in the negotiation and documentation stages of a RBL setup.
Baker Hughes has announced the commercial release of two new motors designed for drilling unconventional reservoirs. The 7 in. Navi-Drill™ Ultra XL45™ motor offers high power and torque to reliably drill long sections through hard formations, and the 5 in. Navi-Drill X-treme™ eXtend motor provides higher power output and increased reliability drilling slimhole horizontal sections.

The 7 in. Ultra XL45 motor features one of the longest power sections in the industry, enabling it to drill long vertical sections with little need to correct for deviations, and its high torque capability also helps minimise stick/slip to increase performance and bit life. The motor uses a high-performance elastomer that provides additional power output to help achieve higher rates of penetration and reduce drilling costs.

The 5 in. X-treme eXtend motor easily drills slimhole sections that often present a challenge for conventional motor technologies. The unique design of the X-treme eXtend motor’s power section provides up to 100% greater torque than typical conventional motor offerings. The additional power enables operators to drill using more demanding, high-endurance PDC bits through long, hard and abrasive horizontal sections such as those in the Williston Basin.

Earlier this year, Baker Hughes announced the launch of its 6 ¾ in. Navi-Drill Ultra Curve™ motor, which drills high build-rate curves with precise directional control such as those found in the Barnett, Williston, Marcellus and Woodford/Anadarko shale plays. The Ultra Curve motor also has the ability to drill vertical, curve, and horizontal sections in one run.

Bentek Systems announces new satellite based remote asset monitoring system

The SAT110 is a portable RTU/Alarm Dialer Unit featuring built-in battery, vibration sensor, I/O, magnetic mount and C1D2 hazardous location certification that can be deployed for monitoring Run/No Run condition of compressors and generators. Integral GPS allows location tracking of remote assets such as generators, compressors, tanks, skids and buildings. The three integral I/O allows connection of alarm contacts and switches. The SAT110 can be easily interfaced to existing SCADA host or via smartphones and web browsers through the SatSCADA Server.

Paradigm releases new version of Sysdrill engineering software

Paradigm has announced the release of Sysdrill® 10, the latest version of its integrated suite of well planning and drilling engineering applications. This major upgrade is integrated with Peloton’s WellView®/Masterview® corporate database for drilling and well operations, and includes a new jar placement module based on technology acquired from Cougar Drilling Solutions.

The release, developed in collaboration with Sysdrill customers, offers significant engineering enhancements to the product’s existing well planning, torque and drag, hydraulics, casing design, cementing and well control modules. The new jar placement module allows calculation of optimal jar locations based upon the jar operating parameters, drilling parameters, and the well trajectory.

The integration with Peloton offers a complete solution for well planning, drilling engineering, daily reporting and data management throughout the well lifecycle. Drilling engineers can send a fully engineered Sysdrill well design to WellView, and during drilling operations, data captured in MasterView can be used in Sysdrill to perform engineering analysis to monitor drilling and prevent NPT events.

Sysdrill 10 allows drilling engineers to perform advanced engineering analysis with minimum effort, in a single, integrated application, thus saving valuable time.
Well Ops announces the arrival of the Skandi Constructor to GoM in Q1, 2015

Well Ops, Inc., a subsidiary of Helix Energy Solutions Group, Inc., has announced that its well intervention vessel, Skandi Constructor, will be available for operation in the Gulf of Mexico for the first quarter of 2015.

The Skandi Constructor is a dedicated light intervention mono hull equipped with the Helix 7 ⅜ in. 10 000 psi subsea intervention lubricator (SIL) package. The planned campaign in the Gulf of Mexico follows three successful campaigns in West Africa, UK North Sea and East Coast Canada.

The vessel is purpose built and permanently equipped and crewed for light well intervention (LWI).

AXON Energy Products: revisiting CT injector technology

As the industry increasingly seeks to build bigger, more powerful coiled tubing (CT) equipment, AXON Energy Products employs Alternative Thinking™ in its customer-centric approach, ‘Design For Serviceability’ (DFS), while maintaining existing operational outputs.

AXON analysed CT injector fundamentals and revisited its operating parameters. Several key features are included this new development to achieve maximum DFS, including optimised cylinders, chains/grippers, bearing slides, frame, drive motor and gearbox.

Cylinders
The operating cylinders (to provide clamp force via the grippers/chain) and tensioning cylinders (to ensure the chains are properly preloaded) are designed with identical specifications. With this feature, inventory options are more viable because a singular cylinder could serve as a communal spare. Moreover, all major serviceable components, including the cylinders, are located externally for easy removal during maintenance.

Chains/grippers
A combined chain and gripper assembly to aid maintenance and size changeover. Rather than dealing with maintenance issues such as individual inserts and damaged screws, a simple removal of the chain master link allows the whole assembly to be removed and replaced in a matter of minutes.

Bearing slides
As part of the gripping function, a bearing plate is employed to ensure the chain and gripper operate in a rectilinear manner. The bearing plate also engages with additional grippers to reduce bearing load per gripper, extending the life of the chain, gripper, and associated bearings.

Frame construction
A fully bolted frame construction was utilised, rather than a fabricated assembly, for easy access to components during maintenance. The frame consists of high-grade, high-strength steel in conjunction with aircraft-grade aluminum to achieve optimal strength and weight.

Drive motor and gearbox
The drive mechanism utilised for the chains and grippers are constructed identically to further minimise the CT spare parts requirement. Additionally, the drives are mounted opposing to one other, allowing for the counter-rotating movement of the chain and grippers.

A new CT injector head will be configured in a manner to allow operators ease of operation and maintenance. This DFS methodology, combined with the CT injector’s field-proven technologies, aids in reducing downtime. From externally located components to combined assemblies, AXON’s focus on aftermarket at the onset of the design process results in added benefits to the operator.
Coming up next month

- West Africa regional report
- Drill bits
- Downhole tools
- Artificial lift
- Completions
- Workovers/interventions
- Decommissioning
- Workforce challenges

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