OILFIELD TECHNOLOGY

EXPLORATION | DRILLING | PRODUCTION NOVEMBER 2017

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November 2017
Volume 10 Issue 11

Front cover

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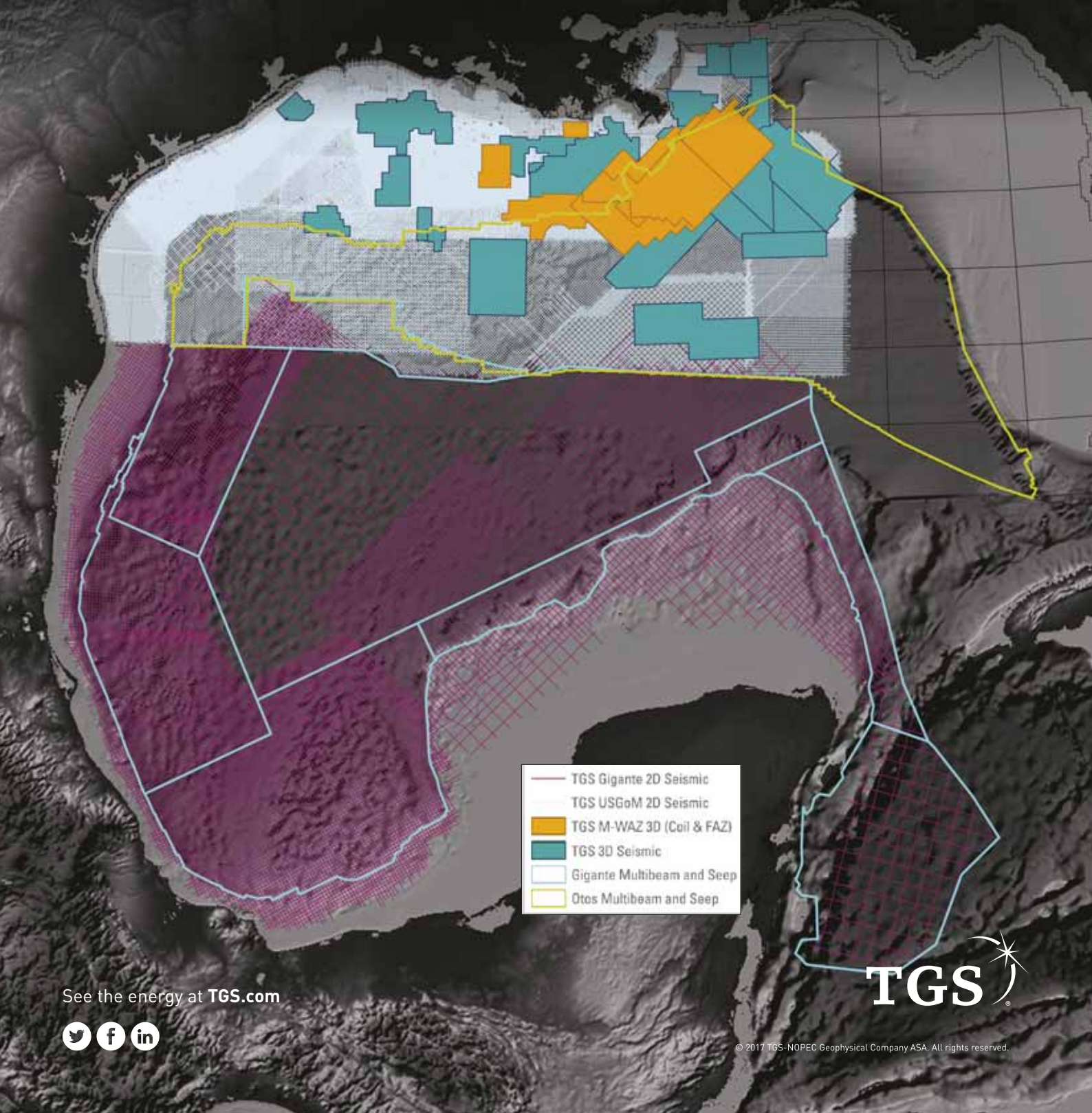

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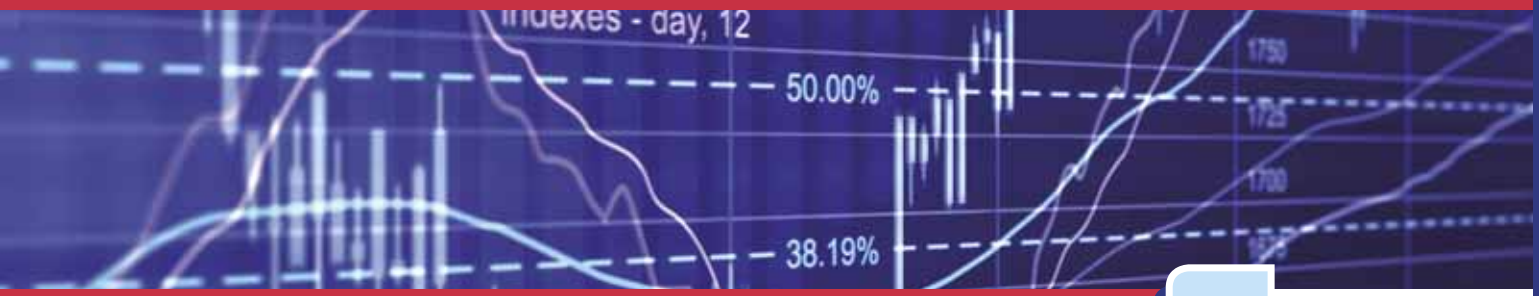

Comment

November 2017

David Bizley, Editor
david.bizley@oilfieldtechnology.com

According to headlines, traders believe they have encountered another important sign that the oil market is rebalancing. The six-month spread of WTI futures has moved from a state of 'contango' to one of 'backwardation'.

These two terms, which sound vaguely like medical conditions, refer to the fact that the market has moved from a state where the price of oil futures is higher than the current spot delivery price (contango), to one where the current spot delivery price is higher than the price of oil futures (backwardation). In less convoluted terms, backwardation is often taken as a sign of increased immediate demand. WTI's transition into backwardation echoes a similar change seen in the Brent market earlier this year.

One of the key factors behind this change in the market is, of course, OPEC's decision to implement production cuts from the beginning of this year. When taking into account the support of non-OPEC members, such as Russia, the group has managed to remove approximately 1.8 million bpd from the market – roughly 2% of global supply. Furthermore, whilst previous attempts at production cuts have been marred by cheating, a survey conducted by Reuters shows that this latest round of cuts is currently being met with 92% compliance.[1] Recent months have seen additional cuts to output, including a 120 000 bpd drop in production in October when Iraqi forces took control of oilfields formerly controlled by Kurdish fighters.[2] 2017 has also seen upwards pressure on oil prices from the demand side, with the year seeing some of the strongest global economic growth since the 2008 financial crisis.

These factors have led to the highest oil prices since mid-2015, with Brent reaching US$61/bbl at the end of October. Bjarne Schieldrop, chief commodities analyst at SEB was quoted in the *Financial Times* as saying: "Oil has always been a cyclical market and at the moment traders are realising they're still living off just two things to meet rising demand: US shale and the legacy investments in fields made prior to the price crash in 2014".[3] He went on to add that "from 2019 the pipeline of supply could dry up pretty quickly and the industry – including US shale producers – are signalling they need these higher prices."[4]

For those concerned that OPEC might decide to call off the production cuts and flood the market with oil, Saudi Arabia's Crown Prince Mohammed bin Salman expressed his country's support for extending the cuts into 2018, "The Kingdom affirms its readiness to extend the production cut agreement, which proved its feasibility by rebalancing supply and demand."[5]

So, whilst the upstream industry has broadly accepted that the 'lower for longer' environment is here to stay, it appears that positive trends are emerging both in the markets and out in the field. Whether the developments of recent months actually translate into a full-blown recovery is far from certain, but the industry has more reason to be optimistic than it's had for a while.

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World news

November 2017

INEOS completes acquisition of North Sea Forties pipeline system and Kinneil terminal from BP

INEOS has completed its acquisition of the Forties Pipeline System (FPS) and associated pipelines and facilities from BP. The 235 mile pipeline system links 85 North Sea oil and gas assets to the UK mainland and the INEOS site in Grangemouth, Scotland, delivering almost 40% of the UK's North Sea oil and gas production.

Ownership and operation of FPS, the Kinneil gas processing plant and oil terminal, the Dalmeny storage and export facility, sites at Aberdeen, the Forties Unity Platform and associated infrastructure has now transferred to INEOS FPS, together with approximately 300 personnel.

Andrew Gardner, CEO INEOS FPS said, "Our acquisition of the Forties Pipeline System and associated assets together with its highly skilled workforce is significant and strategic. It demonstrates INEOS' commitment to securing a competitive long-term future for this critical piece of oil and gas infrastructure and provides the platform to potential future offshore INEOS investments. We will bring our focus and proven track record on safety, reliability and excellence in operations and apply them throughout the FPS business."

The deal consolidates INEOS' position as a top ten company in the North Sea. It further expands the INEOS oil and gas business interests following the acquisitions of the Breagh and Clipper South gas fields in the Southern North Sea from Letter1 in 2015 and the Dong Oil and Gas business from DONG Energy at the end of September this year. 20% of the oil that passes down the Forties pipeline feeds the refinery that in turn provides more than 80% of Scotland's transport fuels.

Vintage Energy to farm into Galilee sandstone

Comet Ridge Limited (COI) has announced that an agreement to farm-out the Sandstone reservoir sequence of its Galilee Basin permits ATP743, ATP744, and ATP1015 has been executed with Vintage Energy Pty Limited (Vintage). Funding by Vintage of approximately US$8.5 million will entitle it to 30% interest in the Sandstone targets.

The farm-out relates only to the 'Deeps Area' within each of the Petroleum blocks, which is defined as including all strata commencing underneath the Permian coals (Betts Creek Beds or Aramac coals) with the main target being the Galilee Sandstone sequence, which has previously flowed gas to surface during formation testing at the Lake Galilee 1 (1964) and Carmichael 1 (1995) wells.

Comet Ridge Managing Director, Tor McCaul, said this transaction is a key step in unlocking significant value potential from the Galilee Basin.

Anadarko announces Q3 2017 results

Anadarko Petroleum Corporation has announced its third-quarter 2017 results, reporting a net loss attributable to common stockholders of US$699 million, or US$1.27 per share (diluted). These results include certain items typically excluded by the investment community in published estimates. In total, these items increased the net loss by US$272 million, or US$0.50 per share (diluted), on an after-tax basis. Net cash provided by operating activities in the third quarter of 2017 was US$639 million.

"I am very proud of the efforts exhibited by our people and the results achieved in the face of an unusually active hurricane season in the Gulf of Mexico and a continuing volatile commodity environment," said Al Walker, Anadarko Chairman, President and CEO. "We have made significant progress in shifting our production mix toward higher-value oil, which has improved our margins per barrel by about 34% year over year."

In brief

Gabon

Royal Dutch Shell plc (Shell), through its affiliates, has completed the sale of its entire Gabon onshore oil and gas interests to Assala Energy Holdings Ltd. (Assala Energy) a portfolio company of The Carlyle Group, for a total of US$628 million including an amount equivalent to interest. This sale was announced on March 24, 2017 with an economic date of December 31, 2015.

With this transaction, Assala Energy will assume debt of US$285 million. The transaction will result in a total post-tax impairment for Shell of US$151 million. Of this impairment, US$53 million was taken in Q1 2017, US$98 million will be taken in Q3 2017 with a final reconciliation to be reflected in Q4 2017.

Australia

INPEX has announced that INPEX Browse E&P Pty Ltd a subsidiary, was individually awarded an exploration permit for Release Area WA-532-P in Australia's 2016 Offshore Petroleum Exploration Acreage Release. INPEX Browse will hold a 100% participating interest in the Block where it will henceforth pursue exploration activities as operator.

Block WA-532-P located off the coast of Western Australia covers an area of 26 300 km^2 where the water is approximately 60 - 250 m deep.

The block lies in the vicinity of the Ichthys gas-condensate field where INPEX is developing the Ichthys LNG Project as operator. In the vicinity of the block, promising gas fields have been discovered and are being developed at multiple blocks in which INPEX holds equity interests. It is expected that the block is also located in a promising exploration area with a high potential for gas, condensate and oil accumulations.

World news

November 2017

Diary dates

13 - 16 November, 2017

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E: mercedesderiada@dmgevents.com
www.adipec.com

07 - 09 February, 2018

Subsea Expo
Aberdeen, UK
E: events@subseauk.co.uk
www.subseaexpo.com

13 - 18 February, 2018

North America Natural Gas & NGL Forum
Houston, USA
E: tanvir@adi-analytics.com
www.adi-analytics.com

20 - 22 February, 2018

IP Week
London, UK
E: joanne.mcbratney@hg3.co.uk
www.ipweek.co.uk

06 - 08 March, 2018

IADC/SPE Drilling Conference
Fort Worth, USA
E: registration@spe.org
www.spe.org/events

Web news highlights

- HydraWell goes for rig-less P&A
- Clariant expands support for local NORAM Oil Services customers
- AISUS launches new tool for enhanced offshore inspection
- Gardner Denver drilling programme poised for expansion

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CGG final PSDM products for Cairenn survey

CGG has announced the completion of the Pre-Stack Depth Migration (PSDM) of its Cairenn multi-client survey in the Porcupine Basin, west of Ireland. Cairenn is the first of a series of multi-client surveys that CGG has recently been acquiring in the area. PSDM products for its Galway survey will be delivered before the end of the year.

The data sets from both surveys have been processed through an advanced velocity modelling and depth imaging sequence, including multi-layer tomography and full-waveform inversion, to deliver results with high clarity and deep imaging quality, from the Triassic/Jurassic fault blocks, through the Cretaceous section and up to the Cenozoic reservoirs. Fast-track results from additional surveys in the area acquired in 2017 have already been delivered, with final PSDM products due in the second quarter of 2018.

SA Equip in distribution agreement with DFT

SA Equip has increased its presence in the Gulf Cooperation Council (GCC) with the appointment of hazardous area specialist, Daly Fluid Technologies (DFT) as official distributor for the GCC Region.

This strategic move to expand into the UAE comes after the firm's continued success achieved through global distribution channels and an increased demand for safe and reliable EX equipment in this region. This new relationship will widen SA Equip's presence in this region and enable DFT to provide specialist technical advice and know-how on behalf of the company to their growing customer base.

DFT has experience in the Middle East region that will support SA Equip to expand successfully into the GCC region. Branching into the UAE Market is a key step for SA as the requirements for EX Equipment for Oil and Gas projects is continually growing.

Ocean Installer awarded agreement for Cambo Field

Ocean Installer has been awarded an agreement with Siccar Point Energy and Baker Hughes, a GE Company to support the appraisal and early production phases of the Cambo Project, with the ability to extend into the future developments.

"An alliance like this enables us to improve execution efficiency and risk mitigation through the creation of shared project objectives, and minimise tendering costs, with the ultimate objective of creating more efficient subsea solutions," said Steinar Riise, CEO of Ocean Installer.

This is Ocean Installer's first contract with Siccar Point, which has established itself as a key operator after acquiring OMV UK earlier this year. The field is located north-west of the Shetland Islands in the UK at a water depth of 1100 m, one of the deepest fields in Northern Europe yet to be developed. Over 100 million bbls of recoverable resources have already been discovered.

"We are delighted that Siccar Point has chosen to work with us. With several other upcoming projects in the pipeline, we hope this will be the first of many jobs we win with Siccar Point. We also look forward to working together on this project as part of a long-term collaboration with BHGE," said Riise.

Phase 1 of the Cambo Field Development will be an early production system (EPS), followed by a Phase 2 full-field development. The project is scheduled to commence in 2018 and will be managed from the Ocean Installer Aberdeen office. The construction support vessels *Normand Vision* and *Normand Reach* will be utilised for the offshore execution.

World news

November 2017

Weir Oil & Gas announces maintenance contract with Eni Iraq B.V.

Weir Oil & Gas Dubai announced it has been awarded a contract with Eni Iraq BV (Eni) to provide global maintenance services for gas compressor units and associated equipment located in the three Initial Production Facilities (IPF) plants in the Zubair fields in southern Iraq.

The gas compressor units are comprised of gas engines, gas compressors, and relevant associated equipment. There are 30 compressors in total, with 18 at Hammar, six at Zubair and six at Rafidya. Weir engineers are now responsible for maintenance servicing of all compressors at each of the sites.

"Weir was selected for this contract due to our experience in Iraq, local footprint and know-how of the specific rotating machines and Field Maintenance methodologies," said Ronan Le Gloahec, EMEA Regional Managing Director of Weir Oil & Gas. "In addition to our state-of-the-art manufacturing facilities in Dubai and service centre in Abu Dhabi, we have a dedicated service centre in Basra, the first facility in Iraq has both API and ISO licenses."

Weir Oil & Gas Services provides equipment and services throughout the Middle East. Weir provides operation and maintenance of plants, such as central processing facilities, initial Production facilities, power plants, compressor station, pipelines, water injection station, and others and equipment and engineering workshop services to primarily upstream oil and gas customers.

The business also manufactures conventional and unconventional wellheads, repairs API pressure control equipment and accessories in the Middle East, and has various premium threading licenses across the region.

Emerson signs collaboration agreement with Statoil

Emerson has signed a collaboration agreement with Statoil to further develop its Roxar RMS™ reservoir characterisation and modelling software. This is series of partnerships between Emerson and Statoil that has spanned many years and includes high-value contracts on a number of Statoil's North Sea fields as well as R&D collaborations.

Under the terms of the three-year agreement, Statoil will share with Emerson some of its Intellectual Property from its internal FMU™ workflow that operates within Roxar RMS, with the goal being to make both workflows even more efficient. The collaboration will include knowledge- and experience-transfer from a number of existing and future Statoil internal FMU projects within Roxar RMS. Areas that will be covered will include improving efficiencies, quality control (QC) of subsurface reservoir models, the handling and analysis of big data, and information management.

Cyberhawk achieves ABS and USCG recognition

Cyberhawk Innovations, a provider of inspection and survey using unmanned aerial vehicles (UAV), has been certified as an External Specialist by the American Bureau of Shipping (ABS) in providing inspections for internal tanks using UAVs. Achieving ABS recognition means that the data captured by Cyberhawk's UAVs can now be used by ABS surveyors to make decisions affecting classification surveys of cargo oil tanks (COT) and other bulk storage tanks on vessels.

As part of the External Specialist certification procedure, Cyberhawk completed two internal tank inspections on an Aframax class oil tanker in the USA in collaboration with an ABS Surveyor. The inspection took place in Portland, Oregon, where the surveyor examined all safety and inspection processes required to accept Cyberhawk's high quality inspection technique. The two inspections were part of a larger project, involving a survey of all 14 COTs using a drone on a sister vessel. The project was completed in just six days by the Cyberhawk team.

IOG commits to drill Harvey appraisal well

Independent Oil and Gas plc has announced its commitment to drill an appraisal well on Harvey and the results of a Competent Person's Report (CPR) on the Harvey licence by ERC Equipoise Limited (ERCE).

Harvey lies directly between IOG's Blythe and Vulcan Satellites hubs. Upon successful appraisal, Harvey gas could be exported via the nearby Thames Pipeline, in line with IOG's hub strategy. The CPR states that the Harvey structure lies up-dip of a well drilled in 1984 on the west flank of the structure that may have encountered a gas column of 30 ft in the Leman sandstone.

An appraisal well is required to clarify the up-dip potential of the Harvey structure. Accordingly, IOG has committed to drilling an appraisal well on the Harvey structure by 20 December 2019. This is subject to acceptance and a licence extension by the OGA. A Harvey development would be likely to have significant economic synergies with IOG's two nearby gas hubs.

KBR awarded engineering support services contract

KBR, Inc. has been awarded a contract to provide Engineering Support Services for Operations for Abu Dhabi Gas Development Company (Al Hosn Gas), a 60/40 joint venture of ADNOC and Occidental.

Under the terms of the contract, KBR will provide personnel, equipment and resources to carry out engineering tasks and technical support on Al Hosn's Shah facilities in Abu Dhabi, United Arab Emirates.

"KBR is pleased to have the opportunity to provide our value added support services to Al Hosn Gas, and highlights Al Hosn Gas' confidence in KBR's capabilities to deliver in multiple engineering discipline areas across a variety of projects," said Jay Ibrahim, KBR's President for Europe, Middle East and Africa.

The UAE remains a key market for KBR's global energy and hydrocarbons business and this award demonstrates KBR's ability to offer cost-effective solutions to customers by combining global expertise and local presence.

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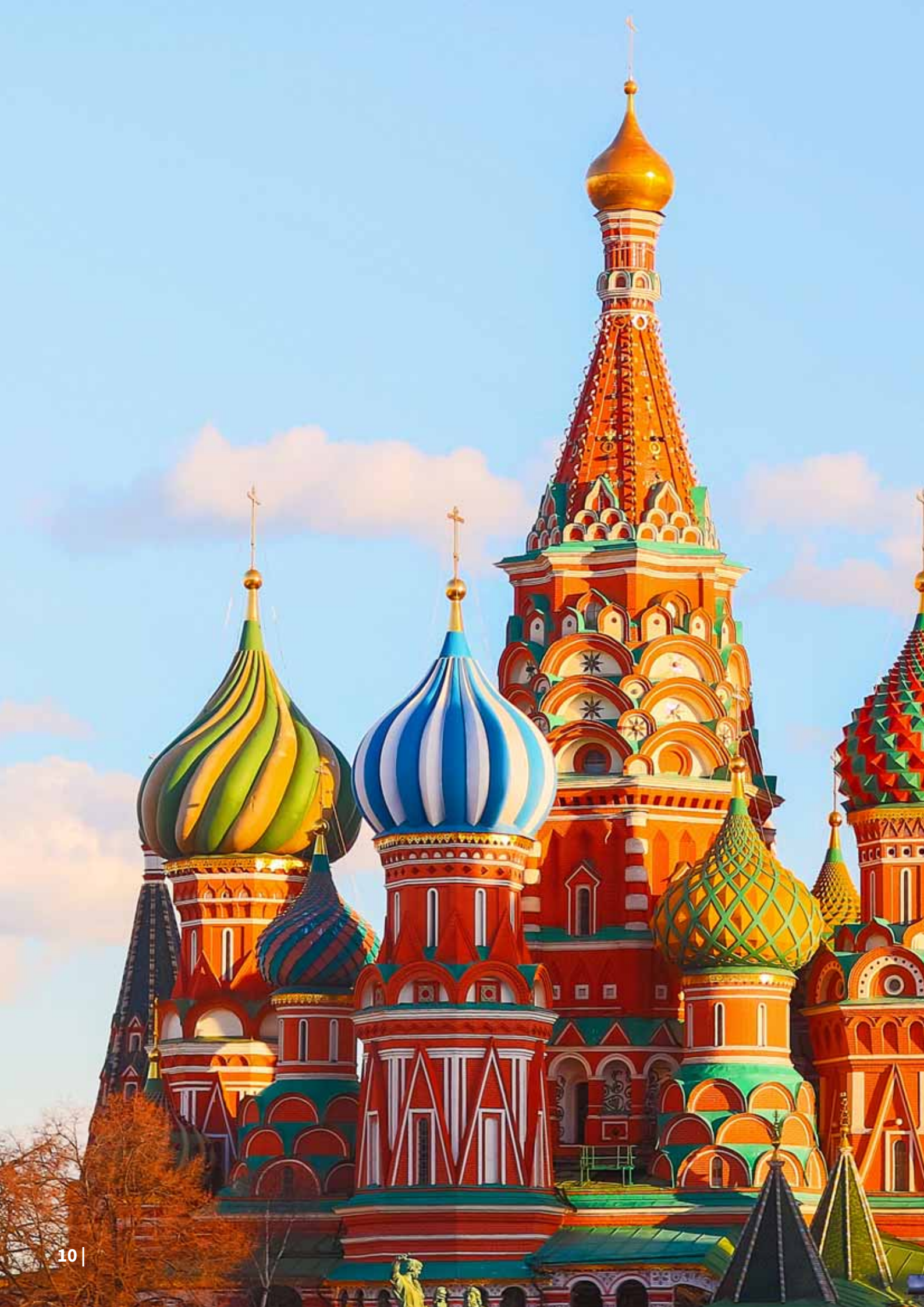

Sustainable self-sufficiency

Igor Yusufov, Corporation Energy, Russia, provides a detailed overview of the Russian upstream sector and shows how, despite challenges, it remains a self-sufficient hub of sustainable growth.

Energy is the cornerstone of the Russian economy – this immutable fact seems to crop up in every tale about Russia, both artistic and economic, leading to descriptions of the country's immense territory and its richness in almost every natural resource. The Russian energy sector is an indispensable part of the world economy. The strength of this sector is complimented by the country's growing economic strength which hedges against geopolitical risks.

Overview

The modern world, burdened by new challenges ranging from terrorist threats to sanctions regimes, faces an increased level of instability. This instability is an unfavourable environment for the development of energy projects. Despite this, Russia is expected to produce some 549 million t (11 million bpd) of oil in 2017 (compared to 547.5 million in 2016) with Corporation Energy forecasting an output of 553 million t for next year. In the first half of 2017, Russian production of oil and gas condensate production reached a record level of 272.3 million t, a modest 1% more than in the same period of 2016.

Russia actually had the capability to reach the 550 million t level in 2017, but OPEC+ agreements limited crude production in order to provide improved stability for global markets.

As for gas, in 2017 Russia is expected to produce 640 - 650 billion m^3, retaining its 17 - 18% share and the second place in global production. Russia will be ready to cover all its needs and to increase exports to countries where this commodity is needed to sustain economic growth – to be specific: China and other Asian countries where growth is expected to reach 10%/yr in the coming years. Europe will be among the destinations of enhanced Russian energy exports if forecasts of considerable economic growth are confirmed. Furthermore, despite geopolitical instability and the diversification of gas deliveries, Gazprom delivered record volumes to Turkey (+22%), Hungary (+26.6%), Bulgaria (+12.6%), and Greece (+10%) in the first half of 2017, with total growth to European destinations of 12.3% in comparison with the first half of 2016. The forecast for mid-term development is positive too: American LNG which has thus far been imported in limited quantities is unable to offer a competitive price in Europe despite Polish readiness to globalise the Świnoujście LNG terminal.

By the end of 2016, Russian mining production amounted to 373.4 million t (an increase of 4.0% compared to 2015). The demand for coal products on the domestic market in view of imports in 2016 increased to 197.5 million t (and increase 1.3% on 2015). Russia's main energy source is gas, which meets 43% of domestic demand; coal accounts for 23%, hydroelectric power stations meet 18%, and nuclear power makes up 16%.

More important is the fact that the volume of both exploration and production drilling in the country is steadily growing: production drilling last year reached 24.7 million m (12% more than in 2015 and 80% more than in 2005). This is not merely a technical indicator: such growth shows that oil producers are optimistic about the Russian energy outlook.

Much has been said about the impact of the ruble devaluation. In energy the devaluation had a rather positive effect on the economics of oil projects, especially for companies with a large portfolio of export-oriented assets. According to the S&P Global rating, the return

to growth in the Russian energy complex and the economy as a whole is expected for the rest for 2017 with the Russian national currency, which is strongly supported by oil and gas revenues, being rated as BB+ with positive forecast.

Every strategic initiative in the Russian energy sector is rooted in the energy strategy adopted by the Russian Government in 2003. Analysts at Corporation Energy have confirmed the 2003 forecast that the share of the energy industry in the Russian GNP will decrease to approximately 26% by 2017, due to development of other industries. The share of hydrocarbons in national exports is decreasing too and is expected to reach the 55% level.

One of the main features of the National energy strategy outlined 15 years ago was the introduction of additional taxation privileges on production of hard-to-extract natural resources. As a result of this move, 2015 - 2016 saw an increase in production (by 7.5 and 13.3 million t respectively) on fields that have been subject to this benefit. Among them are deposits in Siberia, which are estimated to produce some 3.5 million t of oil annually. Exploration drilling in these projects was conducted in partnership with Halliburton. This cooperation provided additional assurance that investment into such projects would be fruitful and ensure positive results for further exploration and production plans.

Sanctions

The prospects of the Russian energy industry remain positive due to the favourable economic conditions in which Russian energy companies operate. This is despite external constraints caused by sanctions regimes or agreements with OPEC. These constraints are unlikely to hamper further increases in drilling – and they cannot prevent the maintenance of production at existing fields. In addition, until 2020, a significant role will be played by greenfields – including at least 19 new large deposits with the Verkhnechonskoye, Novoportovskoye, Russkoe and Messoyakhskoye fields among them capable of providing a total of 2.66 million bpd. Due to the development of these fields, production in the Russian Federation has the capability to reach a record 555 million tpy (11.65 million bpd).

Russia has surprised markets by showing impressive short-term production growth despite what appear to be extremely unfavourable external conditions. It remains uncertain as to whether it is possible to maintain these peaks over a longer period. According to Corporation Energy surveys, the most interesting developments will begin after 2020 when the inertia of past investments and the devaluation of the national currency will be exhausted. One of the answers to this challenge is the development of Russian oil and gas technologies – particularly those that have been barred from import by sanctions. On this note, Russian scientific institutions are actively developing roughly 70 significant import substitution projects for oil and gas production and transportation.

Naturally, Russia would prefer to operate in a free energy market. The benefits of this are clear: European and American firms could take part in the huge projects still available in Russia with up-to-date technologies, excellent management skills and corresponding financing. This is exactly the ideology that was specified with American counterparts after the proclamation of the bilateral energy dialogue by Presidents Putin and Bush 16 years ago. The details of this historical and mutually beneficial cooperation have been the subject of two Russian-American commercial energy summits (2002 in Houston, and 2003 in Saint-Petersburg) with broad participation from both government bodies and private business.

It should be noted that whilst these two energy superpowers have never seen fully eye-to-eye on a political level, 16 years ago this was not an obstacle for the development of common energy projects of mutual benefit. Times have now changed and there is a new round of sanctions against the Russian energy sector; considering the self-sufficiency of this sector, these sanctions appear to be more of a restriction of American participation in promising projects than a penalty for the Russian energy industry.

Russia would, of course, be glad to see ExxonMobil back in its Kara Sea projects again – but instead it will have to look for new partners and internal reserves. Incidentally, in terms of investment, 2016 was a record year for the Russian energy sector. Beijing Gas invested US$1.2 billion into the Rosneft project Verkhnechonskneftegas; US$5 billion was invested by India's ONGC Videsh Limited into East-Siberian Rosneft projects. Finally, the privatisation of 19.5% of Rosneft with participation of the Glencore and the Qatar Investment Authority brought US$10.2 billion to the Russian budget. No American companies were among participants of these deals – a marked departure from the successful energy dialogue of 16 years ago.

It is to be hoped that the coming years will once again see the doors opened to a new stage of Russian-American energy cooperation based on the synergy between the huge projects Russia has to offer and American investment, management practices, and technologies.

As it is, many Russian energy projects, e.g. in offshore areas, will benefit from participation of companies as BP, Statoil, Total and Eni. So, whilst it is true that sanctions have represented a serious stress test for the Russian energy branch, they have not acted as a fatal blow.

Another aspect of sanctions in their latest incorporation is their extension to US allies: the law signed in August by

Figure 1. *Location of projects across Russia.*

President Donald Trump prohibits US companies from investing in certain new oil and gas joint ventures when a sanctioned Russian company holds a 33% or larger stake in the project. This has raised concerns amongst European companies taking part in such projects that they too could be impacted by the new sanctions.

One project facing these complications is the construction of the Nord Stream-2, a 1244 km twin gas pipeline leading over the Baltic Sea directly to Germany.

Its supporters have expressed concerns that the expanded sanctions would affect EU infrastructure projects, particularly as Russia seeks to increase gas exports to Europe. Russia's Gazprom is spearheading the project in partnership with European investors – Engie, OMV, Shell, Uniper and Wintershall. As President Putin said during the G20 summit in Hamburg, despite the challenges Russia remains ready to follow the principles of open energy market competition.

Renewables and the environment

Reiterating another of President Putin's energy initiatives, 2017 was declared the Year of Ecology in Russia. Renewables are just at the early stages of implementation in Russia. Ever since the first energy strategy prepared in the Energy Ministry in 2002, renewables have been seen as a useful and promising addition to oil, gas and coal technologies with a possible 10% share in the national energy balance in 2030s.

In December 2015, Russia was among 195 countries to adopt the Paris climate change agreement set to reach net zero carbon emissions in the second half of this century. Russia sees this document as a cornerstone of the future environmentally conscious world – at the same it is clear that at this stage the Russian economy would not survive without the hydrocarbons its companies explore and produce.

OPEC+

16 years ago at the 177th OPEC Conference in 2001, the first ever oil production cut mechanism with Russian participation was agreed upon. This is worth mentioning because the same mechanism, now known as OPEC+, has in 2017 shown not only its effectiveness, but also its ability to develop and adapt itself to changing conditions. The production cut with the participation of both OPEC and non-OPEC countries adopted in late 2016 resulted in a mid-term stabilisation of oil markets around prices conceptualised in 2001 as fair for both producers and consumers – US$20/bbl in 2001 and US$50/bbl in 2017.

The unprecedented compliance rate of 98% in the OPEC+ deal reflected a belief in its positive influence on crude markets. As the result, the average price of Urals in January-July 2017 was US$49.94/bbl, which is almost 1.3 times higher than in the same period of 2016.

The achievements of the OPEC+ mechanism can be attributed to the efforts of countries, such as Libya and Nigeria, made at the Saint-Petersburg round of OPEC+ Ministerial monitoring committee session. A further milestone in this process would be the inclusion of the US, now a major energy commodities exporter with significant technological potential. The subject of this dialogue, first begun in early 2000s, would be a reasonable limitation of oil and gas supplies to traditional markets, thus preventing a price collapse.

Conclusion

In the modern world, no economic challenge or unilateral political initiative can result in the complete isolation of a part of the global energy sector as significant as its Russia's. Energy diplomacy has to find answers to new questions originating from the present situation – and help to find ways to promote harmonised energy development worldwide.

KEEPING AN EYE ON CLINKER

Sang Y. Lee, PhD, and Donald J. Broton, CTL Group, demonstrate how clinker microscopy, combined with other laboratory testing, such as X-ray diffraction (XRD), can be used as a quality control tool for oilwell cement production.

Class G cement, in accordance with standard 10A API (American Petroleum Institute), is one of the basic oilwell cements used in oilwell cementing. Oilwell cements require material characteristics and performance specifications quite different from the ordinary Portland cements that are used in conventional concrete construction.

Because of their specialised application and extreme exposure conditions, such as high temperature and pressure, oilwell cements require strict performance requirements for various aspects, such as thickening (setting) time, strength, high sulfate resistance, and consistency. In this article, a Glass G oilwell cement clinker is analysed microscopically to document the clinker mineralogy/microstructure, burning conditions, and their implications on the performance requirements. The purpose of this article is to demonstrate that clinker microscopy, combined with other laboratory testing, such as x-ray diffraction (XRD), can be used as a quality control tool for oilwell cement production.

Characteristics of oilwell cement clinker

The composition of oilwell cement clinker varies depending on the specific types, requirements of the appropriated specifications, and targets established by the manufacturer. However, the following clinker characteristics are generally considered desirable for oilwell cements, in comparison with conventional Portland cements:[1,2]

- Oilwell cements need to be less reactive than conventional Portland cements to control early thickening of cement slurry and to allow adequate placement time.
- Larger alite crystal size is desirable since it is less reactive and thus promotes longer thickening time.
- Higher ferrite and lower aluminates are needed for moderate-to-high sulfate resistance.
- Reducing condition should be strictly controlled, since such a condition promotes higher aluminates and highly reactive alkali-modified aluminates. High amounts of aluminates

Figure 1. *Representative grains of Class G oilwell cement clinker sample examined microscopically in this article. The scale represents inches.*

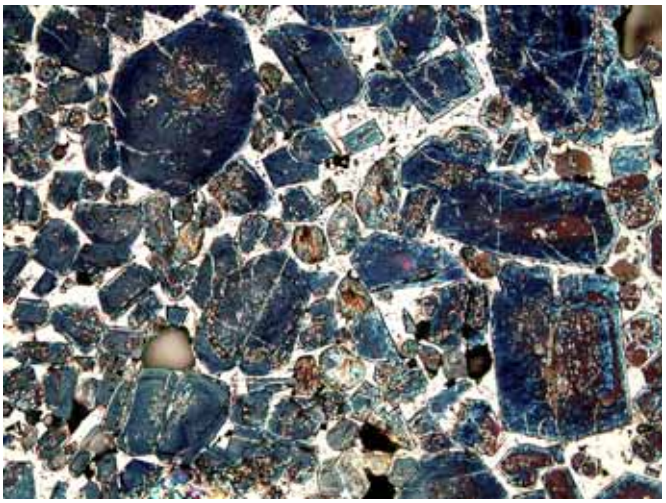

Figure 2. *Reflected light photomicrograph of Nital-etched polished section of Class G oilwell clinker sample showing large alite (blue) crystals. Alite is very coarsely crystalline with the estimated average size of 62 µm.*

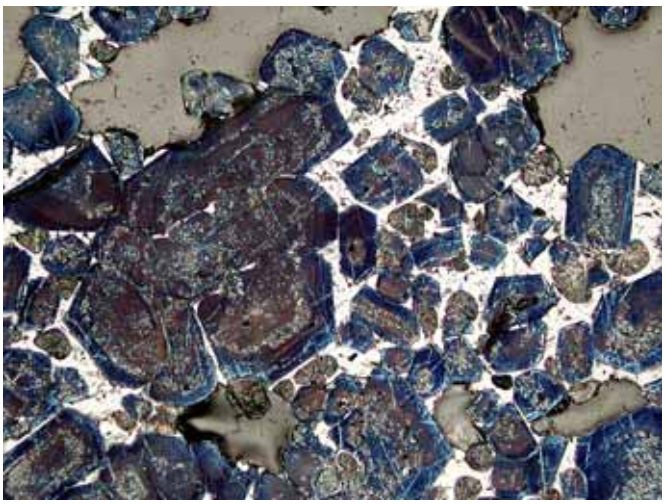

Figure 3. *Reflected light photomicrograph of Nital-etched polished section of Class G oilwell clinker sample showing cannibalistic (fused) alite crystals.*

decrease the thickening time due to their high reactivity and exothermic reaction.

- Amounts of free lime, periclase, and alkali sulfates should be strictly limited since these phases can affect the thickening characteristics of cement slurry and the soundness of hardened cement paste.
- Faster clinker cooling is desired since slower cooling produces a coarser matrix (coarser interstitial phases), which promotes faster thickening.
- Higher alite content is desirable to promote good strength development. Since they can cause poor strength development, large belite clusters should be avoided.
- Weathered clinker can affect the thickening time and the free water in oilwell cement and should thus be avoided.

Methods

Figure 1 shows the Class G cement clinker sample examined in this study. A representative portion of the Class G oilwell cement clinker (whole and crushed) was placed in a plastic cup, and was impregnated with epoxy resin.

Following the hardening of the resin, the specimen was sectioned with a low-speed, diamond-rimmed saw to obtain a flat cross-section through the clinker nodules. The exposed surface of the specimen was then ground to a rough polish using diamond impregnated discs with glycol as a lubricant, then to a finer polish on cloths lubricated with alumina powders (6 and then 3 µm). For the final polish, a glycol slurry using 0.3 µm Al2O3 was used to achieve a highly reflective surface. This surface was etched using water and then Nital (alcoholic nitric acid) before examination.

Examination was performed in reflected light on a petrographic microscope at magnifications of up to 400X. For Ono analysis, a sub-sample of the clinker sample was ground, sieved, and the fraction passing no. 200 mesh and retained on no. 325 mesh was retained for the analysis. A powder mount of the sample was prepared by placing a small amount of the ground and sieved clinker sample on a glass microscope slide, covering it with a thin glass coverslip, and infiltrating the refractive index liquid (1.70) under the coverslip. The powder was dispersed by gently shearing the coverslip. The prepared powder mount was examined in transmitted light on a polarised-light microscope at magnifications of up to 400X.

X-ray diffraction (XRD-Rietveld) analysis was performed using a ground powder sample of the Class G clinker using a PANalytical XPert Pro MPD diffractometer with the assistance of High Score Plus software for identification of the peaks.

Microscopical observations

Most clinker grains in the sample exhibit a black to dark gray colour, with moderately low to moderate porosity. Microscopical examination using the polished section and Ono's method revealed the following observations:

Polished section examination

Alite

Alite occurs mostly as subhedral to euhedral crystals, frequently linked, stacked, and zoned (Figure 2). Alite crystal size ranges somewhat widely within and among clinkers, with an estimated average size of approximately 62 µm (mode = 75 µm). Large cannibalistic masses are common (Figure 3), and crystals larger than 200 µm are locally observed. Alite crystals show virtually no surface deterioration to belite.

Table 1. Findings of Ono analysis.

Microscopical Parameters	Microscopical Results	Hydraulic Activity Rating	Interpretation of Kiln Condition
Alite size	62 µm	Poor (1)	Slow heating rate
Alite birefringence	0.009	Excellent (4)	High maximum temperature
Belite size	29 µm	Excellent (4)	Long burning time
Belite colour	Yellow	Average (2)	Moderately slow cooling rate

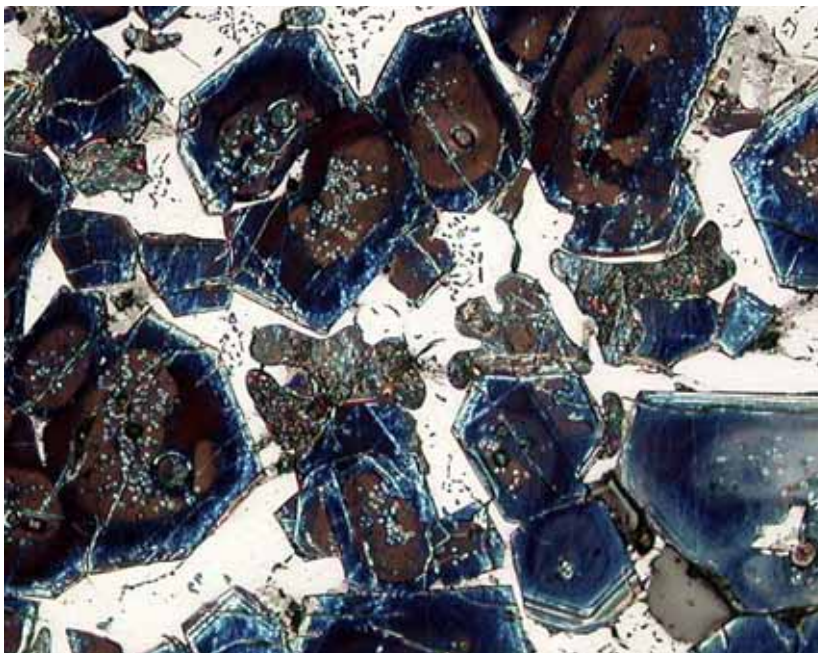

Figure 4. *Reflected light photomicrograph of Nital-etched polished section of Class G oilwell clinker sample showing irregularly-shaped or amoeboidal belite crystals (arrows) around alite.*

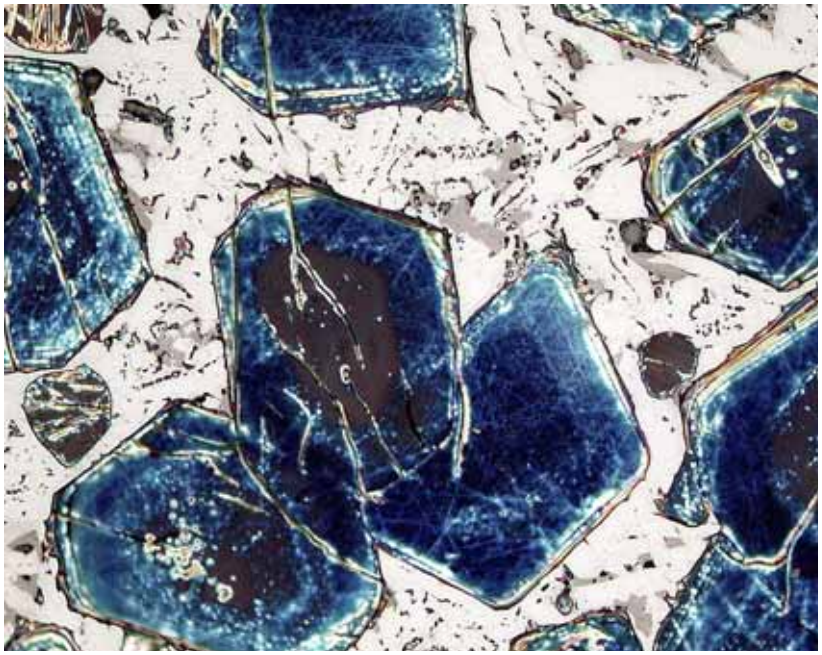

Figure 5. *Reflected light photomicrograph of Nital-etched polished section of Class G oilwell clinker sample showing the matrix (interstitial phases). The matrix consists almost entirely of brightly-reflecting ferrite (light gray) with a small amount of aluminate (dark gray). Alite crystals (blue) show virtually no surficial deterioration to belite.*

Belite

Belite occurs individually as crystals, and locally as small, loosely-packed nests (less than 10%). Belite distribution is uniform. Irregularly-shaped amoeboidal belite crystals are commonly observed and tend to wrap around alite (Figure 4). Belite crystals exhibit rounded to slightly ragged edges, with ordinary, multidirectional, thin lamellae. The average size of a belite crystal is approximately 29 µm.

Interstitial phases

The matrix consists almost entirely of ferrite with a small amount of aluminate (Figure 5). Ferrite exhibits generally bright reflectivity, and occurs as tabular to locally massive form. Aluminate occurs mainly as micro-fine crystals in the spaces between ferrite crystals. Prismatic alkali aluminate is not observed. Distribution of ferrite and aluminate is uniform within and between clinkers.

Free lime, periclase, alkali sulfates

No visible free lime, periclase, or alkali sulfates are observed in the clinker sample.

Ono analysis

The results of Ono analysis and the interpretations of the kiln conditions are given in Table 1. The maximum temperature is high, the burning time is long, the heating rate is slow, and the cooling rate is moderately slow. The predicted 28 day mortar-cube strength is 39.6 Mpa (5747 psi).

Clinker phase abundances

Quantitative determination of clinker phase abundances is performed both by microscopical point-count and XRD-Rietveld (Figure 6). The results are provided in Table 2.

Discussion

- The clinker is characterised by relatively high alite (low belite) content. No evidence of free lime, periclase, or alkali sulfate was observed. The alite in the clinker is very coarsely crystalline, with the estimated average size of 62 µm. The matrix consists predominantly of ferrite, with a small amount (less than 1%) of aluminate. These observed features are considered characteristic of a Class G oilwell cement clinker with a high-sulfate resistance (HSR).
- Alite exhibits a wide range of crystal size and cannibalistic crystals are common. Apparent alite birefringence is high (0.009). Amoeboidal belite crystals locally wrap around alite. These observations suggest a high burning temperature. A relatively long burning time at high temperature is indicated by the most common belite size of 29 µm. These findings are consistent with some of burning conditions (hot burning zone and long retention time[2]) typically required for production of oilwell cement clinker. Despite the presence of some cannibalistic crystals, alite crystals are generally well formed, with virtually no surficial deterioration to belite.
- Belite occurs as individual crystals and, locally, as small, loosely-packed nests (the belite is

readily available for hydration in the cement). The clinker exhibits a uniform composition and phase distribution within and among the clinker grains, indicating a homogeneous finely-ground raw feed (no evidence of segregation) and uniform burning conditions.

- The ferrite is abundant and exhibits bright reflectivity indicative of burning in an oxidising environment.
- Aluminate is present in the cubic form and no prismatic alkali-modified form of aluminate (NC_8A_3) was noted.

Conclusion

In summary, the microscopical examination of the sample is consistent with clinker used to manufacture Class G oilwell cement. X-ray diffraction with Rietveld refinement is consistent with the microscopical observations, and allows a secondary confirmation of the quantification of crystalline phases.

As demonstrated in this study, clinker microscopy is a useful quality control tool for the production of oilwell cement clinkers, which have special characteristics necessary for use in the construction of oil, water and gas wells, and pipelines.

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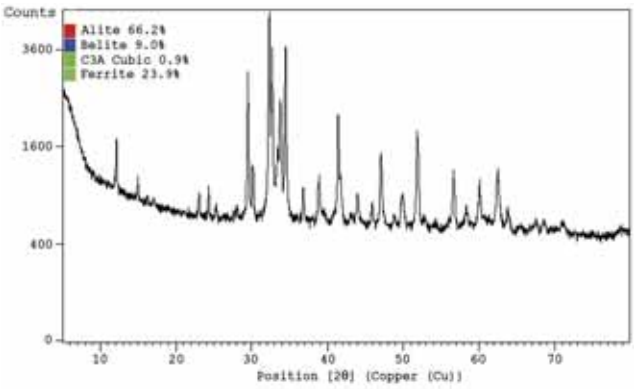


Figure 6. *X-Ray Diffraction pattern of Class G oilwell cement clinker sample.*

Table 2. Results of Point Count Analysis and XRD-Rietveld.

Clinker Phases	Phase Abundances (%)	
	Microscopical Point-Count*	XRD (Rietveld)
Alite (C_3S)	70.6	66.2
Belite (C_2S)	8.6	9.0
Ferrite (C_4AF)	20.0	23.9
Aluminate (Cubic C_3A)	0.8	0.9
Aluminate (Ortho C_3A)	None	<0.3
Free lime (CaO)	None	<0.3
Periclase (MgO)	None	<0.3
Alkali sulfate	None	<0.3

*A total of 3780 points were counted in accordance with ASTM C13563.

floating around

Mike Churchill, Churchill Drilling Tools, UK, discusses how operators can make time and cost savings without impacting well control.

A comprehensive and compliant downhole barrier implementation strategy is absolutely paramount for any well operation. This is even more critical in deepwater, where the risk factors and complexity are often multiplied many times over. Within the confines of both external and internal regulatory controls, the operator has a range of options from which to choose the most appropriate way to protect the rig and crew from gas in the formation.

This article reviews how a different approach to non-return valves (NRVs), commonly referred to as floats, in deepwater drill strings has delivered significant time and cost savings without compromising the fundamentals of well control.

Background to the float in the string

When the string is in open hole, there are a number of protection barriers normally in play aside from the mud weight and the BOP at the surface. Floats placed inside the drill string, often just above the bit for maximum bit plugging protection, should close out any risk of influx from the formation when the pumps are off. Pumps being off is most common for making and breaking connections. Critically, however, when major issues arise, pumping may either be impossible or undesirable, in which case the loss of the circulation as a barrier makes it vital that the floats are in working order. No intervention will be required from the crew, the floats should shut as soon as there is any reverse flow and hold any influx at bay. Typically, a pair of floats will be installed for insurance against the potential failure of one.

Whenever the string is being lowered into hole, the operator will see that the floats are working by correct displacement of annular fluid from the hole. This should occur at a volume equal to the volume of pipe being inserted into the hole. Whilst this is a very useful positive indicator, there is also a significant downside. When running into hole (RIH) 'fully floated,' the pipe is prevented from self-filling. This creates a void of air at the top of the string that gets longer and deeper with each stand that is run in. Unless the pipe is filled from the top, the hydrostatic differential pressure on the pipe (with air on the inside, but mud at great depth on the outside) will cause it to be crushed. Top filling the pipe is analogous to trying to pour water into a drinking straw. It is perfectly possible but can be very slow and messy depending on the technique. Mud spillage on the rig floor adds cost and safety risk. Moreover, slow filling the pipe can add many hours to the RIH process, especially in deepwater.

The use of a ported float is sometimes considered. Ported floats contain a small bleed hole, allowing for a slow equalisation of pressure and gradual filling of the pipe. However, by definition, ported floats are not proper barriers and, even assuming the ports do not plug with cuttings from the hole, the fill rate is unlikely to be fast enough to remove the need to top fill completely.

Therefore, whilst floats offer invaluable protection, they also introduce additional complexity, time and cost, especially to the RIH process.

The increasing importance of floats in the string

When drilling deepwater and high pressure, high temperature (HPHT) wells, the escalation of safety concerns has increased the requirement for running floats outside the cased hole in any phase that is exposed to the formation. This has extended to contingency scenarios and even, perhaps, contingency-on-contingency scenarios. For example, it could be anticipated that there will be a secondary flow path into the bottom hole assembly (BHA) that bypasses the installed floats. This could be the opening of a bypass valve above the floats to cure losses, for example. A risk assessment may conclude that floats should be placed above the valve in certain situations.

At this point it is worth discussing the drop in check valve (DICV). This is a standard piece of well control contingency equipment, which is also a

non-return valve. Unlike the conventional float, which is permanently installed in the sub, the DICV is dropped into a landing sub only when the additional barrier is actually needed. The landing sub would typically be placed above the BHA and any conceivable leak path. Whilst very effective in an emergency, it is costly to use because, once dropped, it restricts access to tools in the BHA and restricts pumping at full flow until it is fished back out. Deployment of the DICV is, therefore, something to be avoided if at all possible.

A multiple level contingency scenario could be where stuck pipe was unable to be freed and required severance of the lower part of the drill string. This would consequently result in the loss of float protection. However unlikely the eventuality, the realisation that in certain scenarios of contingency there might be no float between the rig and the formation may present itself as a cause of major concern in the planning stages.

Another driver for float demand is the narrow pressure windows that are commonly being tackled and addressed with techniques such as under balanced and managed pressure drilling. Where the barrier of mud weight over balance is removed, maintaining a rigorous float regime becomes even more critical to protect against deviations in the pressure that may lead to problems.

The self-filling float solution

Non-pumpable, self-filling floats have been available for a number of years. Essentially, the float is dormant during RIH but, when pumping begins, the hold open mechanism is dislodged and the float becomes active. While quite useful, it does mean that shallow hole testing of the measurement while drilling (MWD), for example, is not possible because pumping to test the MWD at the beginning of the RIH would activate the float and prevent any further self-filling from taking place. The inability to pump and test can be extremely costly if it means that set-up issues are only discovered when on bottom, particularly so in deepwater operations.

In 2012, Churchill Drilling Tools (Churchill) launched the first dart-activated self-filling float. This overcame the previous hold open limitation by giving full pumping capability. When approaching activation depth, a dart dropped and pumped into the sub would shear out and activate the system. However, while floats previously would be placed just above the bit, in this new configuration they have to be above the MWD to give the dart a thru-bore to reach the sub. Whilst this new development was recognised by operators as a time-saver, uptake in the initial phase was fairly limited. This was, perhaps, due to perceived insufficient benefit in return for the costs and risks of procedural changes in a US$100/bbl oil environment.

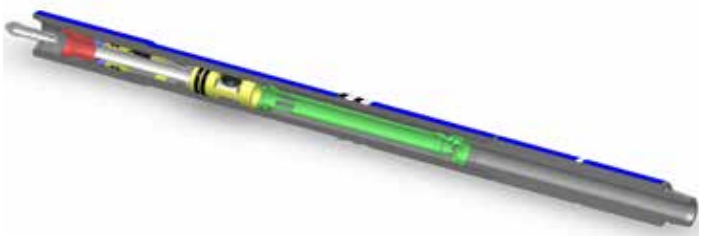


Figure 1. *The Churchill self-filling float immediately prior to dart activation.*

Deepwater case histories

Step forward four years later and a completely different environment for this simple technology has emerged. In 2016 - 2017, demand for the self-filling float in deepwater operations illustrates that a number of rigs now see the cost benefit of making the change in procedure. Across 10 different deployments, self-filling RIH has been performed down to measured depths ranging from 13 000 - 21 000 ft. This has meant that RIH to the casing shoe or to the completion is being done at full speed, with activation of the float only taking place just before the permanent barrier is about to be removed.

In these runs, the tool deployed in 6 ¾ in., 8 ¼ in. and 9 ½ in. versions at angles of up to 40˚ and activation shear-out pressures in the 600 - 700 psi range. A typical sequence of top-filling every 10 stands or 1000 ft of pipe RIH, might take up to 20 min. depending on the top-filling methodology. With median activation at depths of approximately 18 000 ft, recorded time savings have been up to 6 hrs per RIH. In each case the flapper float format was selected by the operator.

The system is also available in the more rugged, poppet type format, where centrally-mounted high strength closing springs and tungsten carbide pistons with a ceramic seal interface provide a very robust design. In the majority of cases, however, operators prefer the flexibility of thru-bore access, provided in the flapper type format.

Development

A new addition in the float market is a large bore version of Churchill's self-filling float – the Double Upper Reserve Activating (DURA) drill float. This allows a dormant flapper float to be run even higher up the string within the drill pipe for some potentially critical contingencies. The first of these is as a back-up to the primary floats, which may require a trip for replacement if damaged during drilling. Activating the DURA Drill Float™ could save a replacement trip and/or allow a much safer exit from the hole. There would be the option to activate the dart sub NRV for this kind of situation. However, as previously noted, this has much less flexibility than the DURA Drill Float solution as drill ahead pumping will be lost.

The second scenario is where the primary floats have become bypassed by a flow path into the string above them. This could be due to a number of factors such as circulation bypass, tool failure, twist-off or stuck-pipe severance, at the extreme. In all of these contingency scenarios, the DURA Drill Float will provide the option to recover to floated state without losing pumping capability.

Conclusion

The current popularity of this technology shows that operators are taking a flexible approach to minimise the costs of string float strategies. By doing this, they are able to fully meet their safety obligations and at the same time deliver improved performance. This time shift in uptake suggests that solutions for the current low cost environment can sometimes be found in innovations that were made in the previous higher oil price era.

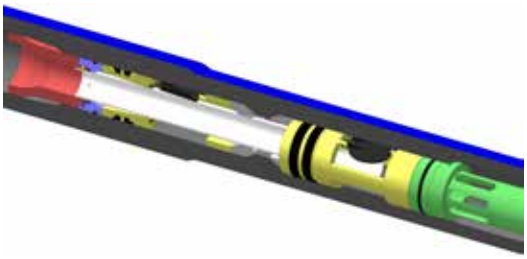


Figure 2. *The self-filling float in flapper configuration.*

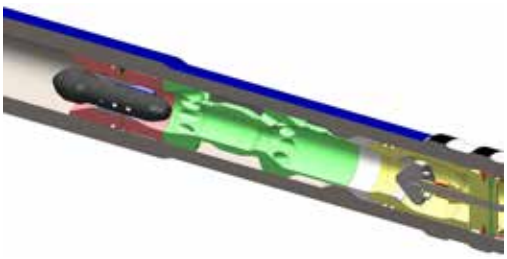


Figure 3. *The self-filling float in poppet configuration.*

INCREASING DRILLING EFFICIENCY WITH TELEMETRY

Paul Cooper, PhD, Halliburton, USA, shows how high-speed telemetry can help increase drilling efficiency.

Because new wells are becoming more complex, large amounts of measurement/logging-while-drilling (M/LWD) and formation evaluation data are necessary to enable exploration and production (E&P) operators to make timely decisions and achieve greater production at the lowest cost per barrel of oil equivalent (BOE). Drilling dynamics data are needed to help optimise the rate of penetration (ROP) and reduce well time. Pressure and wellbore stability data are necessary to deliver the well safely and help minimise operational risks and avoid issues, such as lost circulation, poor hole cleaning, and stuck bottomhole assemblies (BHAs). Additionally, rock and fluid properties data are needed to help understand the reservoir and accurately place the wellbore within the reservoir to maximise production. To realise the full benefit of these real time measurements, the capabilities of telemetry systems need to increase in parallel. As such, Halliburton introduces the JetPulse™ high-speed telemetry service, which delivers consistent, high data rate transmission of real time drilling and formation evaluation measurements, enabling operators to make quicker decisions at any point in the well plan to help achieve accurate well placement, improved well control, and increased drilling efficiency.

Engineered for high performance

The new system was engineered for high performance, incorporating the latest technological developments, including an integrated downhole generator, which provides power to the BHA and allows operators to drill long sections in a single bit run. The generator has been run with lost-circulation material (LCM) concentrations greater than 100 lbm/bbl and is the most LCM-tolerant high-speed telemetry system in the industry. Additionally, the system can be configured in a battery-only mode, which helps remove any LCM limitations from the telemetry system.

Durability and reliability are also key considerations for achieving longer runs, particularly because high-speed telemetry systems are typically used in offshore and deepwater environments where the cost of nonproductive time (NPT) is extremely high. Multiple valve concepts were evaluated before a valve design and material was selected that is sufficiently durable to deliver the number of cycles necessary. Design choices were made to help maximise the overall reliability of the system, such as minimising the amount of electronics and reducing the number of internal connectors.

Effective downhole data management

In addition to the physical mud pulser, software engineering efforts focused on ensuring consistent downhole data delivery during long runs, and that the data are optimised to enable operators to make the right decisions at the right time. The conditions for signal transmission vary significantly during the course of a drilling run, and the signal from downhole is attenuated as it travels up the drillstring. The choice of signal modulation is important to help ensure consistent data delivery during the entire run. The JetPulse service uses differential pulse position modulation (DPPM), creating pressure-drop pulses in the bore of the drillstring and encoding the data in the time intervals between these pulses. This DPPM encoding is less affected by changes in depth than phase-shift keying (PSK) encoding schemes and has provided consistent data rates during long runs in a broad range of drilling conditions. When it is necessary to adjust to the effects of varying mud properties and drilling noise, it is possible to downlink to the BHA tools using Geo-Span® downlink service during a run, which helps ensure reliable signal detection at surface and consistent data delivery.

The JetPack 3D™ data management service provides additional features to help optimise the data delivered while drilling the well. Just as high-tech companies stream large amounts of movie and television show data and use compression to optimise the available bandwidth to deliver high-quality videos to customer homes, the JetPack 3D service uses compression to increase the effective amount of useful data delivered to surface at the wellsite. Various compression techniques are available to tailor specific data types. Imaging tools measure a formation property azimuthally around the borehole (e.g. density, resistivity) and use a difference-encoding algorithm to transmit high-quality azimuthal images in a relatively small number of physical bits. Interpretive compression is used to transmit a mathematical representation of a set of data rather than the raw data, reducing the bandwidth consumed without impacting the decision making based on these data. For example, downhole standoff data from a caliper tool can be used to generate an ellipse representing the borehole, and the ellipse parameters can be sent to the surface to provide an understanding of the downhole stress directions. Axial compression can be used to compress any general curve data by accumulating several measurements of the same type, compressing them, and sending the data as a single block. The correct choice of compression techniques for the tools in the BHA can provide greater than a fourfold increase in the amount of useful data received at surface.

The type of data necessary for optimal decision-making changes depends on the position of the well plan and the drilling activity at any given time. The JetPack 3D service enables the operator to configure different data sets based on expected needs along the well plan. During drilling, the operator can switch between these data sets to deliver the most relevant data at any given time.

Table 1. Measured depth and effective data rates of wells.

Location	Measured depth (ft)	Effective data rate (bits per second)
US Land	2100	35.3
Gulf of Mexico	9700	13.7
Central Asia	10 900	15.2
Brazil	11 300	10.9
US Land	12 000	12.4
Central Asia	12 700	26.0
Central Asia	19 300	14.6
Norway	20 000	10.3
Central Asia	20 100	24.0
Gulf of Mexico	22 900	9.4
Gulf of Mexico	27 900	5.6

Figure 1. *The JetPulse™ high-speed telemetry service provides consistent, high data-rate transmission of real time drilling and formation evaluation measurements to deliver the right data at the right time, helping ensure reliable and fast decision making.*

Delivering the right data, at the right time, for better decision making

The JetPulse service is currently being used at multiple locations globally; Table 1 shows performance data. It has delivered data rates greater than 20 bits per second at more than 20 000 ft measured depth. Additionally, it has demonstrated the necessary endurance to operate downhole for longer than 600 hours and delivered hole sections of more than 14 000 ft in a single run. Using the service, operators can consistently receive the necessary data to drill and place wells efficiently. For example, an operator in the Middle East was geosteering through thin reservoirs. The JetPulse service transmitted density images, multiple resistivity images, and geosignal data. Through subsurface insight, the operator was able to accurately

place the well in the target reservoir while maintaining high ROPs and reducing well time.

Case study: managing ECD with high-fidelity pressure data

An operator in Asia recently deployed the JetPulse service at a location where high formation pressure existed in the zone above the targeted reservoir section and a high overbalance existed in the production zone. To drill wells successfully in such an environment, decisions to adjust drilling parameters and equivalent mud weight (EMW) or equivalent circulating density (ECD) need to be made quickly to help avoid unwanted fracturing and/or becoming stuck. If the mud weight is too light, high-pressure water can flow out of the wellbore; if the mud weight is too heavy, undesired fractures in the formation can occur. The JetPulse service was able to provide high-fidelity, real time pressure-while-drilling (PWD) data updates for the drilling team without sacrificing the data density of measurements for formation evaluation data to assist the geologists with lithology analysis. The data flexibility provided by the service allowed the operator to use a transmission option focused on pressure data when necessary, delivering pressure updates with a 1 psi resolution every 5 seconds. Decisions to adjust the EMW could be made before the well was fractured or unwanted formation fluid flowed into the well. With the right data at the right time, the operator was able to anticipate potential problems and react quickly to the dynamic drilling environment before any NPT was incurred. The operator reached the gas production zone within budget and without fracturing the well or allowing unwanted formation fluid to enter.

Case study: lost-circulation cement solution

Wells drilled in the southern North Sea region in Norway frequently encounter severe lost-circulation events in both the overburden and the reservoir. Overburden drilling includes narrow drilling margins between the fracture gradient and pore pressure, and multiple severely depleted zones often exist in the reservoir. A cement-based lost-circulation solution was deemed necessary to carry sufficient mud weight for wellbore stability in the overburden without encountering excessive losses. The challenge during this process was providing a solution that could be pumped through a directional BHA without tripping out of the hole. The high-LCM tolerance of the JetPulse service allowed a lost-circulation solution based on FracCem™ cement to be pumped through the BHA. During 19 FracCem cement operations, more than 2800 bbls were pumped through the BHA with concentrations ranging from 120 - 220 lbm/bbl. No damage or plugging occurred during these operations, and in seven cases, the operator drilled directly to the section total depth after the cement operation, eliminating the need for a trip and reducing the overall well time.

Summary

The JetPulse high-speed telemetry service is able to provide higher physical and effective data rates in a broad range of complex operating environments in offshore, deepwater, and mature fields, allowing operators to make better real time decisions to overcome the challenges faced while drilling current wells. By delivering the right data at the right time to make the right decisions, new technology can help operators maximise production at the lowest cost per BOE while increasing drilling efficiency and maximising the value of their assets.

ENHANCING EOR

Ismarullizam Mohd Ismail, Tendeka, UK, shows how EOR in heavy oil wells can be improved through the use of an autonomous inflow control device (AICD).

As heavy oil reservoirs age and fields become mature, the optimisation of oil recovery becomes essential if oil production targets are to be met.

For many years, inflow control devices (ICDs) that restrict flow by creating additional pressure drop have been used to mitigate this problem. They are, however, passive in nature and once water or gas breaks through, the choking effect cannot be adjusted without intervention. The viscosity difference between heavy oil and water gives an unfavourable mobility ratio, which results in quicker water breakthrough. The velocity difference between water and oil allows water to flow much faster and will flood the wellbore and impair the oil production from oil producing zones. The Autonomous Inflow Control Device (AICD) is designed to choke back flow of less viscous fluid, and therefore chokes back the flow of water compared to oil, thus resulting in reduced water cut.

The functionality of an AICD is similar to a passive ICD in that it helps to create a more even inflow along the horizontal section prior to water breakthrough. Moreover, the AICD also has a self-regulating, adjustable design to provide greater production choking where water breakthrough occurs. This chokes production from compartments producing large amounts of water, leading to greater oil recovery and lower water cut. The AICD can also be retrofitted and deployed as an inner string in an existing well that has already been flooded to control the inflow of the water. This leads to greater oil recovery by reducing water production.

Applications

In sandstone reservoir applications, the AICD valve is typically assembled as part of the sand screen joint in the lower completion. However, for carbonate reservoir applications, the AICD can act as a standalone sub with a debris filter assembled before the inlet of the valve. The reservoir fluids can enter the completion through the sand screen filter and flow along the annulus between the filter and base pipe into the inflow control housing where the AICD is mounted. The fluids then flow through the AICD and into the production stream, moving to the surface together with the production from the rest of the well.

An experiment with oil, water and gas was performed to define the performance of the AICD in heavy oil operations. The performance is shown through the differential pressure across the AICD versus the flow rate through the device. The experiment was carried out using 106 cp oil, 34 cp oil and water. Figure 1 shows a typical flow rate profile for heavy oil and water through an AICD. It illustrates flow rate through the valve increasing with oil viscosity ranging from 1 cp water to 36 cp heavy oil and 106 cp heavier oil. The mobility ratio between water and heavy oil in this test ranges from 36 to 100 times. This implies that

water travels faster at a similar pressure gradient compared to oil and leads to a reduction in water flow at a similar pressure drop.

There is stringent due diligence to be performed before the implementation of the AICD. Reservoir simulations are used to evaluate the potential of an AICD application. A segmental dynamic and static model is commonly produced to simulate representative reservoir properties and allow evaluation of the well with and without the AICD.

Commonly, for wells without inflow control, the water is channelled from the down-dip through to the high permeability section, to the producer well and bypasses the oil up-dip. The AICD will improve the water sweep by balancing the inflow from high permeability sections and creating the pressure drop at high mobility water sections. Furthermore, the AICD will allow a low mobility heavy oil to be produced and recover the oil up-dip.

Not all heavy oil horizontal well applications will show benefits from this technology. However, a sizeable mobility contra caused by permeability difference and good pressure support will usually benefit from these technologies.

Annular isolation is critical for compartmentalising the reservoir during AICD completions. This allows for different choking pressures at high mobility water sections or compartments and more production from low mobility heavy oil sections or compartments. Generally, the swell packer placement is dependant on the permeability contra and saturation contra that exits between intervals in the wells. Limitations on the number of compartments may be imposed by well operability factors, such as zone length, open hole drag and previous operational experience. Sensitivity analysis to optimise the quantity and location of zonal isolation devices is essential for this technology.

The flow rate and the well length will determine the total flux rate through a single AICD valve. The flow rate through the valve for a given pressure drop increases with viscosity, as it is dependent on fluid mobility. The initial/maximum oil/liquid production targets are used along with the reservoir fluid data to determine the quantity and size of AICDs required to ensure the maximum well deliverability is achieved. This will favour applications in longer horizontal wells compared to shorter vertical wells.

The evolution of water cut over time, typically low water cut levels are seen at the initial stages of the well, is a critical factor for maximising the oil production. During this time, AICDs should be used to optimise the drainage and reduce the likelihood of water coning and ensure that inflow between the zones is balanced. Generally, heavy oil reservoirs have a high Darcy permeability. This provides a period window to extract oil from high saturation pockets until the water saturation increases highly along the entire wellbore. At this later stage, operating the well at higher total liquid rate will help in the attempt to recover more oil.

As a field's water cut increases, this can cause the formation of emulsion in its wells. It will increase the flowing pressure loss and consequent reduction in the well production rate. Due to the viscous properties of emulsion, the AICD will not apply a higher pressure drop to flow the emulsion if it forms in the annulus. A bypass valve will be needed if downhole chemical injection is planned to treat the emulsion and scaling. The bypass valve can be installed as part of screen assembly in the lower completion or run as a separate sub.

Case study

AICDs have been implemented in m≠any brownfield wells as a retrofit solution after water cut increases were experienced. Retrofit installations to date have been in wells where the water cut has typically reached up to 96%. One of the first AICD retrofit installations in a heavy oil environment was to control water cut, it also showed a significant increase in oil recovery (Figure 2).

The results of the installation from 2014 have shown significant water cut reduction from an average 96% water cut before the AICD string installation to around 93.6% water cut after the AICD installation. This is a significant reduction in water cut for a well that is producing a total liquid rate of 1000 m^3/d.

The water cut reduction has increased the oil production from 43 m^3/d to 55 m^3/d. The results of these wells have shown an increase in oil production of approximately 28% after installing the AICDs. Based on the positive results of the initial well, there have been many more wells within the field completed with AICDs as a retrofit solution or primary completion for new wells.

Conclusion

The implementation of AICDs in various heavy oil fields worldwide to control water has shown a general trend of reduced water cut. The viscosity difference between heavy oil and water provides a favourable mobility ratio well suited to this technology and has been shown to enhance oil production. As the water is restricted upon breakthrough, the overall recovery of the well is improved when compared to operations using conventional methods and passive ICDs. ■

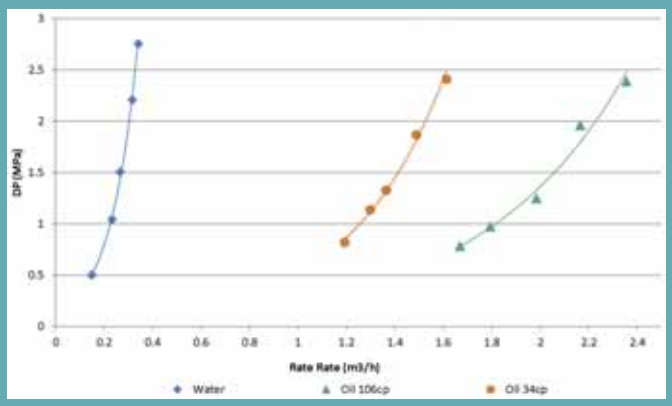


Figure 1. *Heavy oil testing: single phase volume flow of oil, water and gas through the AICD as a function of differential pressure.*

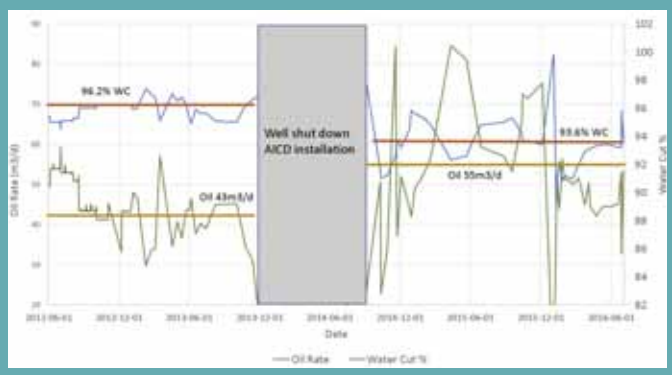


Figure 2. *AICD oil rate and water cut performance in an existing/retrofit well.*

time for a fresh approach

Giles Edward, M-Flow, UK, explains how new innovation and fresh thinking in multiphase metering will enable a shift in focus; moving from meters and onto the power and impact of accurate, reliable and qualitative data.

One of the consequences of the tough and varying environments seen across the upstream sector – and exacerbated by the oil price's peaks and troughs – is that the oil industry has struggled to adopt a repeatable, data-focused oilfield development model.

At US$100 or more per barrel the drive was to find and produce more, but there was little incentive to promote financial and operational efficiency. However, the oil price decline, which began around June 2014, initiated a stream of cost reduction among upstream businesses and compelled extensive capital discipline.

Yet bespoke technology remains common, and the reality is that high oil prices de-prioritise efficiency and low oil prices stifle the short-term investment that is needed for a focus on optimisation.

While other industries have used data to focus on improved performance through reproducibility and tight process control, the oil industry has focused on one-offs to solve specific problems and struggled to benefit from an ethos of continual gains.

Data in a lower oil price environment

While profitability has always been an important metric, growth in production and reserves have often been the biggest priorities in the oil and gas industry.

The 'lower for longer' oil price scenario is widely considered to be the future, and the most forward-thinking companies now have plans for profitability under a variety of different low price scenarios. Moreover, the combination of low prices and the risk that interest rates may soon rise and elevate the cost of debt financing has increased the importance of free cash flow to a top priority. This makes the question the industry needs to ask itself even more pressing: can the upstream sector use this opportunity to move to a different and sustainable future?

Certain elements of the cost equation may have reached a floor. Oilfield services companies, for example, will try to walk back many of the price reductions that they conceded in the aftermath of the oil price drop. PwC estimates that this could add as much as 15% to the price of a barrel.

Moreover, the volume of experienced staff that were made redundant removed substantial amounts of familiarity, knowledge, and skills from E&P. These factors make it even more imperative to find and establish cost competitive behaviours.

The root of all asset value is access to reliable and accurate data at the wellhead. This drives reservoir understanding and production optimisation; and a thorough understanding of multiphase fluid flow is therefore vital in oil and gas operations.

Not least in the selection of an effective enhanced oil recovery strategy. Done well it is a key component of improving capital efficiency, lowering production costs, and reducing time to first oil.

There are positive signs out there. For one, the onshore shale revolution has implemented at large scale the sort of thinking which treats the oilfield as a reproducible industrial process, and GE's recent acquisition of Baker Hughes has resulted in sizeable strategic focus on more efficient well operations through improved digitalisation and data analysis.

However, in general, the upstream oil and gas industry's attempts to access asset value have been consistently restricted by a lack of access to reliable data in oilfield production.

Often the data is very expensive and uncertain, and continual interventions to sample, test, calibrate and maintain create a large operational footprint in terms of manning, cost and HSE exposure which disincentivises implementation. This has created an impasse, with the industry unable to benefit from the digitally driven efficiency gains that are normal elsewhere.

Figure 1. *M-Flow's multiphase meter.*

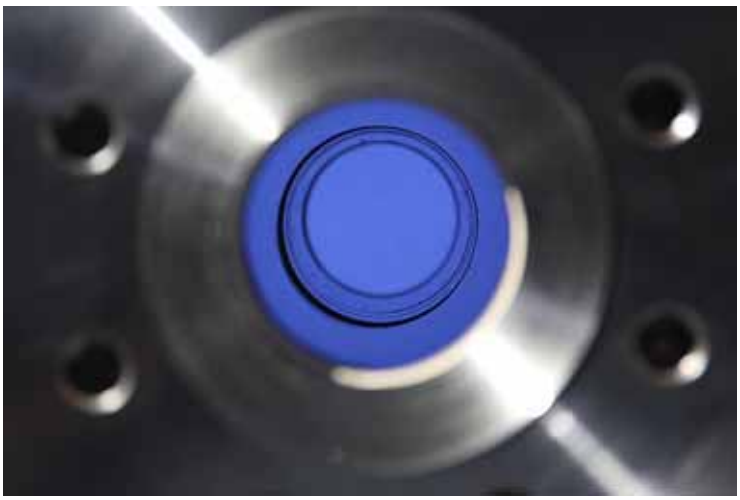


Figure 2. *Non-intrusive pipe view of the multiphase meter.*

Multiphase metering

The accumulated evidence suggests that there is rarely any question of the economic value of good data. Returns in improved production, revenue, and asset value through greater understanding of reserves are now widely accepted.

Nonetheless, when a mixture of fluids such as oil, water, and gas are transported through a pipe it has traditionally been extremely challenging to accurately measure individual phases without separating them. Complicating matters, the current multiphase market has been focused on meters that inherently embed uncertainty in flow rate measurement interpretation over accuracy and repeatability in parameters that can be directly measured.

Until recently the only alternative has been to use solutions such as sampling or well tests that provide incomplete or fragmented data that conveys limited value. Either option leaves producers unable to answer fundamental questions such as: Is the well running effectively? When and where did the water in the process come from? What does this mean for reservoir planning? Could the onset of damaging acid gas be avoided?

So although oil and gas companies have acknowledged the advantages of access to accurate and consistent data and using it to rationalise productivity in other points in the supply chain, for wellhead metering to date, there has been limited access to the means to deliver that data.

Identifying the capabilities that are critical to profitable growth

Unless companies examine more fundamentally the role that enabling digital technologies can play in improving their performance, they will limit the leverage they can get from innovation to improve productivity in the field.

By taking a step back, and re-thinking the challenges that have inhibited the growth of multiphase data for the production optimisation market, M-Flow has developed a technology solution that helps provide confidence at the wellhead. Delivering reliability, repeatability, and accuracy and simultaneously slashing capital and operational expenditure.

M-Flow has focused on understanding well performance through phase fraction measurement. This solution delivers through direct measurement the key parameters that quantify and signal production change, and can be combined with other measurement systems and data points to provide more complex understanding.

The company's carbon fibre construction creates a transparent window on the pipe flow, and makes it possible to deploy sensor systems fully protected from aggressive oil well fluids. This means that M-Flow's meters experience none of the harsh fluids-induced degradation or calibration change that are the main drivers for multiphase flow meter intervention.

Additionally, the non-metallic spool piece allows measurement of the full volume of fluid flow equally. The unique whole pipe measurement is made with microwave sensors and, when required, gamma density gauges. This avoids reliance on either spot or narrow chordal measurements that make the meter performance flow regime

dependent, and the complete, direct measurement removes the uncertainty of flow regime modelling.

Not only does this simpler solution deliver large capital cost savings but it also imposes almost no maintenance and recalibration burden. Additionally, it avoids lifecycle costs and reduces safety risks arising from putting manpower in the field.

To put this in context, typical annual multiphase flow meter service costs are often 25% of the original capital costs, meaning that within four to five years a multiphase flow meter installation will have doubled the total cost to the operator.

The evidence

The the advantages of the composite approach have been verified both in the oilfield and in industry tests through collaborative testing with international oil and services companies. This has included more than four years of cumulative field experience with zero downtime for maintenance or recalibration, even in heavy oil service.

In a water cut measurement trial conducted during a one year deployment with a supermajor, a study compared 64 key data sets logged by the M-Flow meter with a client lab analysis. Uncertainty of the meter over the full trial was shown to be +/- 0.14%. When the results from selected analyses were evaluated it was clear that the economic justification from the installation of accurate real time measurement was strong. In this case hypothetically paying back the return on investment in less than one day.

Conclusion

Wellhead multiphase and water cut measurement is a complex problem that requires accuracy and consistency across varying flow conditions. When data can be trusted, the focus can move away from data acquisition to how to use data to maximise production, improve asset value, and substantially reduce operating footprint and HS&E exposure.

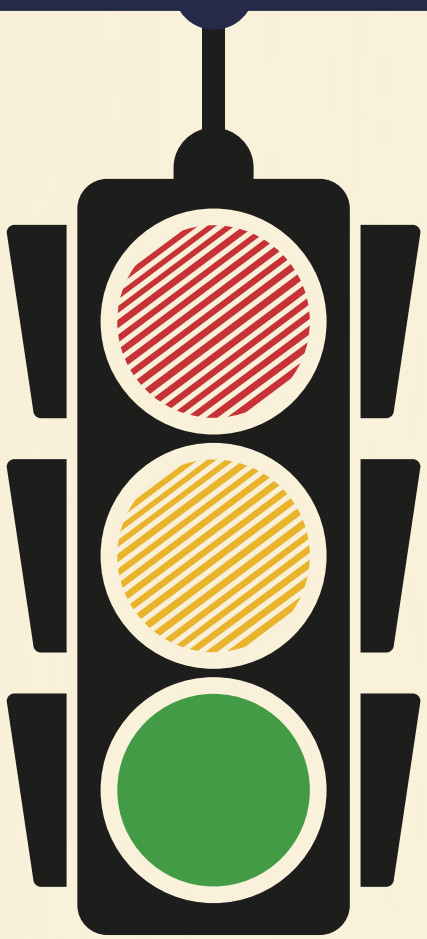
As oil companies focus on getting more from increasingly hard to find reserves, big wins are available in existing assets and infrastructure. From production allocation and flow assurance to well testing and custody transfer measurement, multi phase measurement can remove uncertainty throughout the upstream process and play a large part in asset development.

But if it is still uncertain whether the data's accuracy, repeatability and reliability are good enough to enable confident decision making, then it may be time to take a fresh approach to measurement.

Figure 3. *M-Flow field package.*

FORGING AHEAD WITH FLOW ASSURANCE

Lars Anders Ruden & Svein Eirik Monge, Emerson Automation Solutions, show how technology advances are securing increased flow assurance in offshore and onshore fields.



As profit margins remain tight, it has become more important than ever for operators to adopt cost-effective, flexible and innovative solutions so that wells perform at their optimal levels and that production goals are met.

The good news, however, is that whether offshore or onshore, advanced technologies are delivering. This article will look at how this is being achieved.

Flow assurance offshore

Flow assurance is an ongoing issue offshore with one threat to production – particularly in wet gas fields – that of formation water. Formation water not only displaces hydrocarbons but can lead to hydrates, scaling and corrosion and – in worst-case scenarios – well shutdowns.

Additionally, subsea tieback developments – in some cases up to 400 km long – that enable long-distance tieback opportunities for remote and marginal fields has only exacerbated the danger. This can lead to delays before the onset of formation water is detected and measured topside. In such cases it might be too late to react and save the well.

In the past, Mono Ethylene Glycol (MEG) tended to be the popular option in addressing formation water with operators making 'guestimates' on how much MEG was required. The downside of this, however, was that often too much MEG was applied.

In reacting to the need for more sophisticated and real time production information, Emerson has introduced advances to its Roxar Subsea Wetgas Meter in the form of a new salinity measurement system.

The salinity measurement system builds on wet gas meter developments that provide real time, accurate subsea measurements of hydrocarbon flow rates and water production, with such meters having been installed on fields such as the Ormen Lange field in the North Sea, offshore Egypt on the West Delta Deep Marine (WDDM) and West Nile Delta (WND) concessions, and the Gorgon project offshore Australia.

The new salinity system tells the reservoir engineer whether formation water is entering the flow. This subsequently helps the process engineer adjust injection rates of MEG, scale and corrosion inhibitors accordingly (without flooding the well as was previously sometimes the case with MEG). With many oil and gas wells being produced over a wider range of process conditions with increased exposure to saline water, there is an increased need to detect changing fluid composition and water salinity.

The system consists of a salinity sensor mounted flush with the wall of the meter and is based on microwave (MW) resonance technology. The MW technology ensures an instant response to changes to conductivity of the flow stream – in seconds, not minutes – and the ability to measure water conductivity down to ± 0.1 S/m and sensitivity in the range of ± 0.004 S/m.

Small pockets of formation water leaking into the flow can therefore be detected instantaneously with the salinity system providing quantitative and qualitative real time measurements in a wide variety of field conditions.

Outputs from the wet gas meter – enabled by the inclusion of the salinity system – include salinity, conductivity, formation water indicator, formation water flow rates and condensed water flow rates. All of these are crucial elements of a flow assurance strategy.

Flow assurance onshore

Topside multiphase meters are also an important option for establishing greater flow assurance in onshore production applications. Such meters provide the individual phase flow rates for oil, gas and water mixtures and negate the need for a test separator, manifold or line.

The result is continuous real time measurement – rather than periodic testing – of crucial information on well performance and the conditions that effect production flows.

Advances are also taking place to ensure that multiphase meters do not require expensive, large-scale deployments – as has often been the case in the past.

To ensure more flexible and accurate metering, Emerson has developed a new modular family of multiphase flow meters that can either be one component of an integrated well test system or provide cost-effective standalone wellhead measurement. The fact that such meters are so cost-effective also allows for the possibility of allocating one meter per wellhead.

The Roxar modular meters are based on a measurement technology platform that has been used in over 1500 meter installations worldwide. This includes advanced signal processing, field electronics and electrode geometry, as well as high-resolution sensors capable of capturing very small changes in the electrical properties of the multiphase fluid passing through it. The dual velocity system, cross-correlation capabilities and optional gamma system also provide measurements capable of handling multiple flow regimes.

Operators need only purchase the features they require and can select from a set of meters designed for: 1) trending water cut, gas breakthrough and flow rates from a single well installation; 2) generating high accuracy flow rates for oil, gas and water over a broader range of applications in a single well installation; 3) improving meter accuracy and robustness through the addition of a gamma source; and 4) providing flow back measurements, well testing and allocation metering in both single well and multi-well applications.

One of the greatest challenges in unconventional fields today, however, is generating accurate flow rate and fluid information

Figure 1. *Field installation of the Roxar MPFM 2600 non-gamma meter.*

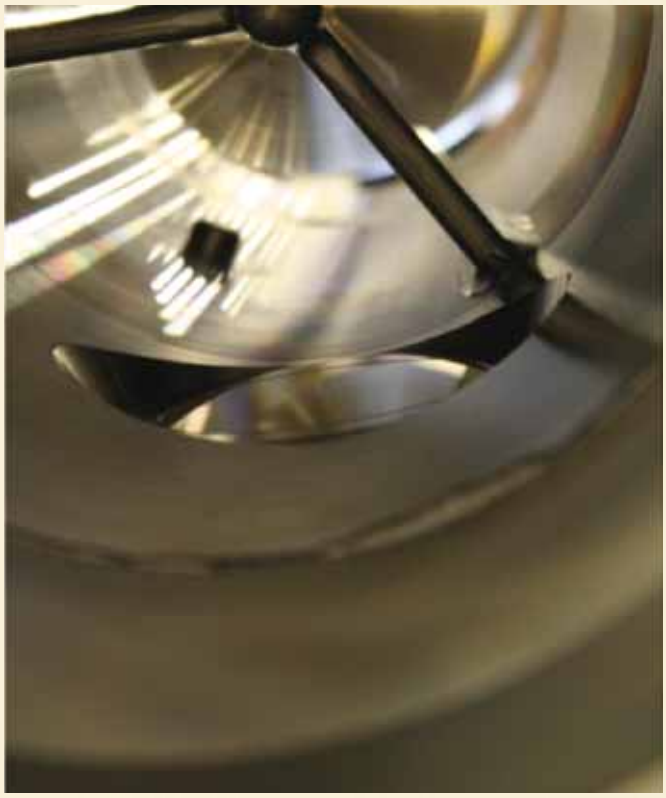


Figure 2. *The salinity system consists of a salinity sensor mounted flush with the wall of the meter.*

Figure 3. *The new modular Roxar meter has an internal diameter of just 35 mm (1.38 in.).*

from wells that have artificial lift, high gas fractions, high water cuts, unpredictable flow regimes, and low operating pressures.

It is with these specific characteristics in mind that a small size, modular flow meter specifically designed to address the flow profiles of North American shale and unconventional fields was launched.

The Roxar meter, which has an internal diameter of just 35 mm (1.38 in.), aims specifically to address the well characteristics of unconventional fields through improved algorithms and models, graphical views and trending software.

Through switching from one separator per well to one multiphase meter per well, operators can also reduce facilities capital investments at the well pad by over 50%. Other operator benefits include improved and more accurate well allocation; a reduced well pad footprint; and reduced environment exposure as tanks are pushed downstream to central facilities where they can be more efficiently monitored for regulatory and environment compliance, delivering operational excellence.

The meter can be used for applications such as flow back measurements, well testing and allocation metering, and can detect changes in flow rates and fractions immediately, providing accurate royalty payments and enabling precise actions to be taken.

Sustainable flow assurance strategies

Flow assurance strategies are all about negating production threats, providing an insight into operations, and maximising production offshore and onshore. It is also about technologies adapting to meet operator needs in today's cost conscious and bottom-line focused environment as these two technologies demonstrate.

SYNERGY OF EFFORTS

Dominique Guérillot and Alexander Darishchev, Texas A&M University at Qatar, present a joint industry funded project aimed at evaluating carbonate reservoir engineering workflows with oil and gas companies.

Oil and gas production from carbonate reservoirs is of significant economic importance in the Middle East, particularly in Qatar. For establishing accurate production forecasts and enhancing recovery, geoscientists and reservoir engineers build numerical models of reservoirs using computer-based workflows. In spite of continuous progress in software and computational capabilities, reservoir characterisation and data acquisition techniques, reservoir modelling and engineering workflows still require the special expertise and laborious work of multidisciplinary teams. Due to confidentiality clauses, the industry and academia suffer from a lack of realistic models for efficient collaboration and evaluation of advanced reservoir workflows.

The motivation behind the work lies in improving the following points:

- Static and dynamic reservoir engineering workflows for Middle East carbonate reservoirs.
- Field development plans (FDPs) with water injection.
- Enhanced oil recovery (EOR) projects.
- Carbon dioxide sequestration.

A joint industry funded project

One of the most efficient forms of collaboration between academia and industry is a joint industry funded project (JIP). With this kind of synergy, it becomes much easier to overcome real business challenges with shared costs and mitigated risks as each JIP member benefits from a customised work package developed according to its specific needs and concerns, and a complete portfolio of all other work packages as well. This form of academia-industry collaboration has been chosen for pursuing a start up focusing on high-resolution advanced Qatari and Middle East models for evaluating reservoir engineering workflows (JIP HAQEL™).

For the purpose of optimisation and benchmarking of various scenarios of field development with water injection and EOR processes, synthetic models such as SPE, PUNQ, Brugge, and Gullfaks are widely used. This provides an effective common work platform and helps create and elaborate innovative ideas and concepts. However, most existing models were originally designed for sandstone formations, and thus they are not suitable for carbonate reservoir systems, which are more complex in nature.

The proposed joint industry-funded project named HAQEL, which means 'field' or 'reservoir' in Arabic, looks primarily into improving static and dynamic reservoir engineering workflows with national and international oil and gas companies. This project has the following objectives:

- Build realistic synthetic models of Qatari and Middle East carbonate reservoirs.
- Benchmark innovative advanced reservoir workflows and assess uncertainties.
- Establish better practices in carbonate reservoir characterisation, modelling, simulation and engineering.

Target groups of carbonate reservoirs

Aside from some deeper gas and gas-condensate bearing reservoirs located in the Permian Khuff Formation (North field, Dukhan),[2] most producing reservoirs in Qatar and neighbouring countries are Jurassic to Cretaceous in age (analogous carbonate reservoirs can also be found in other regions of the world). After analysing the geological setting and the frequency of occurrence, the Upper Jurassic Arab C and D (or Arab III and IV) members of the Arab Formation and Lower Cretaceous Shuaiba Formation have been selected for preliminary studies as they contain an abundance of oil reserves in Qatar and neighbouring countries. As reported in literature, these carbonate reservoirs are characterised as being naturally heterogeneous and exhibiting complex reservoir behaviour. Multiscale input data has been collected from different producing fields and outcrops published in conference proceedings, journal papers, reports, monographs, and relevant data has been aggregated into synthetic case studies.

In Qatar, producing intervals of the Arab C and D consist of grainstone, packstone, wackestone and mudstone deposits, and generally, possess a better reservoir quality than the overlying Arab A and B. C and D can be divided into distinct major reservoir units with interbedded anhydrite layers. In contrast with the Arab C and D, the Shuaiba reservoirs are more heterogeneous in nature. They contain packstones and mudstones with interbedded argillaceous wackestones, networks of conductive faults and fractures; leached zones, significant transition zones due to capillary forces, and vertical and horizontal flow barriers even at a scale below conventional wireline log resolution. To better reproduce such complex formations, the facies and petrophysical properties can be simulated with advanced stochastic algorithms preserving the variability and honouring the input data. Hence, multiple realisations can be drawn to assess uncertainties. The reservoir fluid properties have also been inspired by actual Middle East fields producing light oils with an API gravity range from 18 - 42˚, medium to low viscosities, and medium to low sulfur content.

Such models are designed to reproduce complex formations and overall field and well behaviour as closely to the reported data as possible (Figures 1 and 2). These models are deemed to be representative enough, and thus cover a wider scope than any unique field case. These points are crucial for the development and evaluation of advanced reservoir engineering

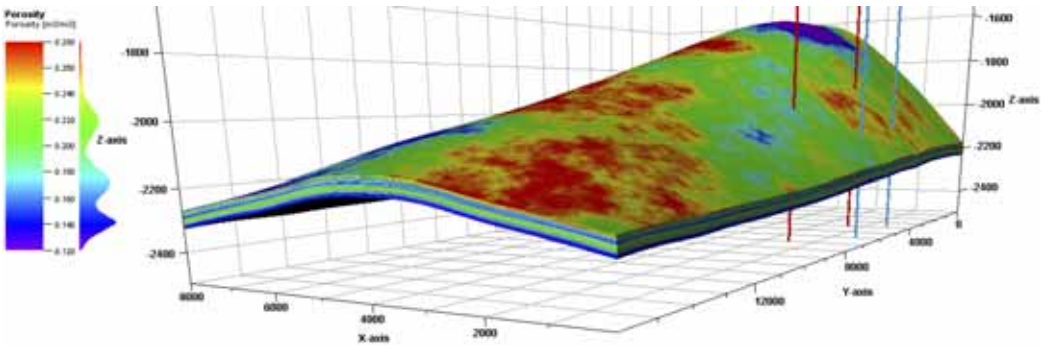


Figure 1. *A geostatistical realisation of porosity field of a typical Upper Jurassic reservoir (Arab D, Middle East).*

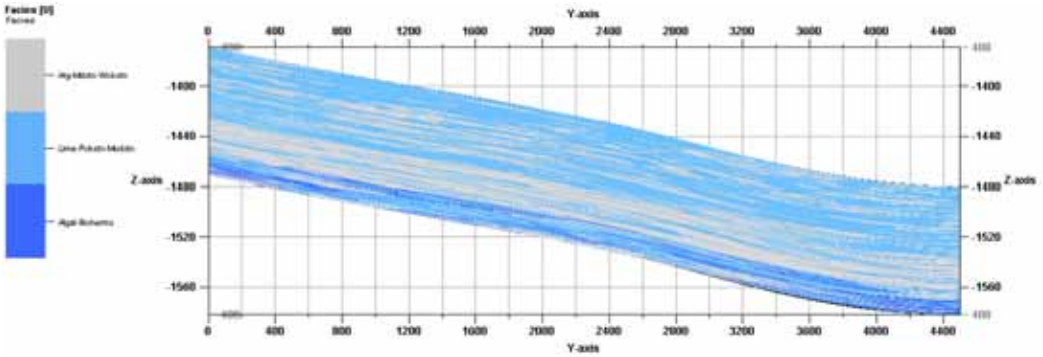


Figure 2. *A geostatistical realisation of facies distribution in a typical Lower Cretaceous reservoir (Shuaiba, Middle East).*

workflows in the framework of joint projects according to specific needs and concerns of each JIP member. Reducing the overall time and cost of projects allows for more insights to be gained and for decisions to be made more effectively. This would also be helpful in developing and implementing new ideas and concepts.

Workflow for elaborating synthetic realistic models of carbonate reservoirs

In comparison with routine reservoir engineering workflows, the proposed methodology includes advanced reservoir modelling and engineering workflows, high performance computing capabilities, multidisciplinary expertise and full access to technical databases and research libraries.

Several stages are envisioned to obtain more reliable production forecasts and uncertainty assessments in a convenient time framework. Geological models can be either directly used for elaborating high resolution sector models or upscaled for further processing with a reservoir flow simulator and optimisation tools (Figure 3).

During in-company meetings, several challenges have been identified for elaborating a portfolio of customised work packages according to specific interests and concerns of each JIP member, e.g. evaluating impact of flow barriers below the conventional wire-line log resolution, effects of rock alteration depending on injection water composition, mineralogy of reservoir rocks, kinetics of reactions, etc.

The following steps can be proposed for elaborating customised work packages:

- Gathering multiscale data on target reservoirs and analysing previous case studies.
- Building representative 3D models (full field or sectors).
- Selecting realistic ranges of paramaters of interest.
- Performing flow simulation and sensitivity studies.
- Evaluating impact of studied phenomena on production parameters and sweep efficiency.
- Assessing uncertainties, identifying the most influential parameters and mitigating risks.
- Drafting conclusions and recommendations for field development and enhanced recovery.

Preliminary remarks and perspectives

Carbonate reservoirs still require collaborative research and investigation due to their heterogeneous and complex nature. It is proposed that realistic synthetic models should be built using available published data on carbonate reservoirs of the Middle East, and especially Qatar.

During the initiating phase of this project, several studies were performed. The analysis of the geological setting and frequency of occurrence has shown that, as mentioned earlier, most of the oil-bearing reservoirs in Qatar and its neighbouring countries are aged Jurassic to Cretaceous, except some deeper gas and gas-condensate bearing reservoirs of the Permian Khuff Formation. Most of these reservoirs are composed of carbonates and are naturally heterogeneous. Two target groups (Upper Jurassic Arab D and C, and Lower Cretaceous Shuaiba) were identified and selected for building synthetic cases of static and dynamic models, and for elaborating customised work packages. The commencement of this project is planned for late 2017. It is designed according to specific needs and concerns of each JIP member. Bilateral advanced case studies can also be developed on demand for each interested member.

Finally, this will stimulate effective collaboration, allowing for knowledge and expertise to be shared, and will establish better practices in carbonate reservoir modelling and engineering.

Acknowledgments

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Disclaimer

The views expressed in this article are those of the authors and do not necessarily represent those of Texas A&M University at Qatar.

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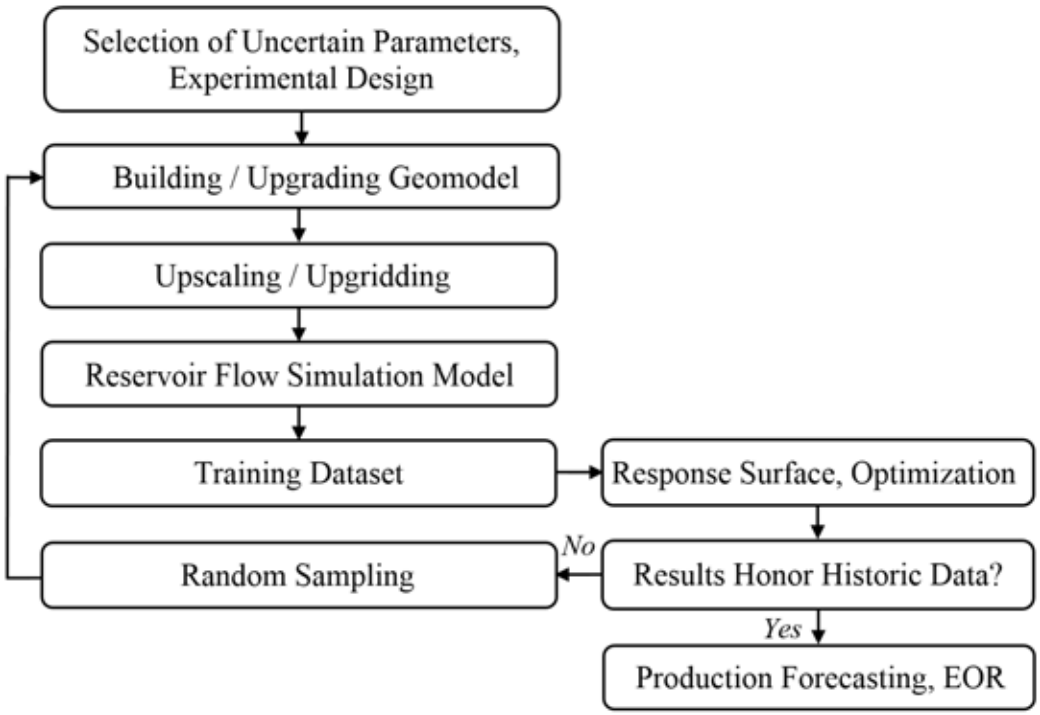

Figure 3. *An example of workflow for production forecasting and optimisation.*

Considering Compressor Technology

Joseph Lesak, NEUMAN & ESSER USA, examines a new medium to high-speed compressor designed to offer technical and economic benefits for operators.

According to the EIA, North American natural gas production is expected to climb by 4.9 billion ft^3/d next year. Due to this increase in output, the compression industry has an obligation to improve technology to handle this growth. Increased volume of flow is required to maximise profit, and engine and motor drivers will need to push their horsepower limits and efficiencies to keep up. The design and production of compressors better equipped to handle these horsepower increases is essential.

A new design

In 2000, NEUMAN & ESSER (NEA) created its first high-speed frame, the 320hs, for the natural gas storage market. This frame was also used across other applications, such as gas boosting, industrial gas generation, gas pipelines and various residues and hydrocarbon gas mixes. Operators wanted a cost-efficient frame that could be skid packaged and installed with lower labour requirements compared to foundation-mounted systems. The challenge posed by the industry was clear: since it is possible to customise compressor strokes and cylinder sizes, why not create a new frame that is a true fit for larger midstream applications?

NEA entered the North American midstream compression market in 2011 targeting various natural gas and CO_2 for EOR applications. With the continued exploration of shale gas in North America, it was felt that the company needed to improve its product line in order to better compete in this competitive market. In this regard, the company optimised its compressor line to utilise the high-speed capability available in its portfolio. NEA frames were already available with a large range of strokes, and the flexibility offered a good fit for engine drive applications. After studying the larger engine drive applications and gaining more feedback from customers, the company worked to develop a new optimised frame for midstream service, known as the 560hs.

The team decided on the need for a compact compressor, but one with high rod load capabilities in order to pair easily with the larger engines used in this industry. The decision was taken to utilise

the crankshaft, main bearings, crosshead and piston rod derived from an existing API 618 running gear to handle higher loads, but with reduced throws. These features along with the robust nodular iron crankcase enable the 560hs to handle higher gas and inertial loads. Discussions with end users, rotating engineers, and packaging partners helped to garner key design points for consideration.

Design considerations

This new compressor design offers various benefits. The system will have the standard NEA feature of a one-piece frame casting including the crosshead. Since alignment of the frame is the most important step in the packaging process, a one-piece design eliminates wasted labour aligning bolted joints and ensures true perpendicularity and flatness in reference to the feet and main bearing journals. This robust casting also prevents frame twisting. Stringent FEA studies by NEA in Germany have proven this frame design to be the preferred option in terms of both safety and cost-efficiency. The one-piece frame eliminates bolting and gaskets between the frame and crosshead distance piece.

The main bearings feature a split design in the 90˚ or vertical arrangement. The company's R&D team studied bearing simulations and found this increased reliability when compared to a conventional split in the 180˚ position. This design, along with the tri-metal material, enhances the strength of the bearing and its operational lifetime.

In addition, the new frame has an improved foot mount design for skid installation. To ease transportation, width limits were also considered. The length of the 4-crank frame enables transportation without special road permits with installed cylinders and distance pieces.

The original intention of the one-piece frame construction was to ensure perfect perpendicularity of the rod axis compared to the crankshaft axis. In previous designs, the frame part holding the crosshead was bolted to the part holding the crankshaft. The flanged connection of these two parts was a risk because of manufacturing tolerance, clamping force variations and a permanent source of trouble due to oil leaks. The typical reason for this two-piece construction was that parts of this size were hard to mill on the machines available at that time. The introduction of the 5-axis milling machine and associated manufacturing process enabled the development of a precisely manufactured one-piece frame. By the early 1970s, the company had adapted its complete range of frames to the one-piece construction – consequently, the design and manufacture of the 560hs is based on more than 40 years of experience with this feature.

The company's new philosophy has always been to ensure a quick exchange of parts. Some of these parts have constant wear such as piston rings, packing rings or cylinder bores and are known as routine spare parts. Other components are not usually viewed as routine spare parts, but can be subject to wear under unintended conditions. Therefore, the 560hs uses a crosshead liner that is easily replaceable. In the highly unlikely occurrence that a major damage event happens to the crosshead, the liner ensures the crankcase is protected.

Optimisation of the compressor performance begins and ends with the cylinders. The NEA cylinder line-up is customisable and able to efficiently maximise the flow. Power losses are minimised through the combination of optimised compressor valve selections, cylinder clearances and flow paths. To minimise gas leakage or fugitive emissions under all operating conditions,

Figure 1. *NEA performs hydraulic bolting on all critical connections. This includes main bearings, connecting rod bearings, piston rod to crosshead, distance piece to frame, distance piece to cylinder and compressor anchor points.*

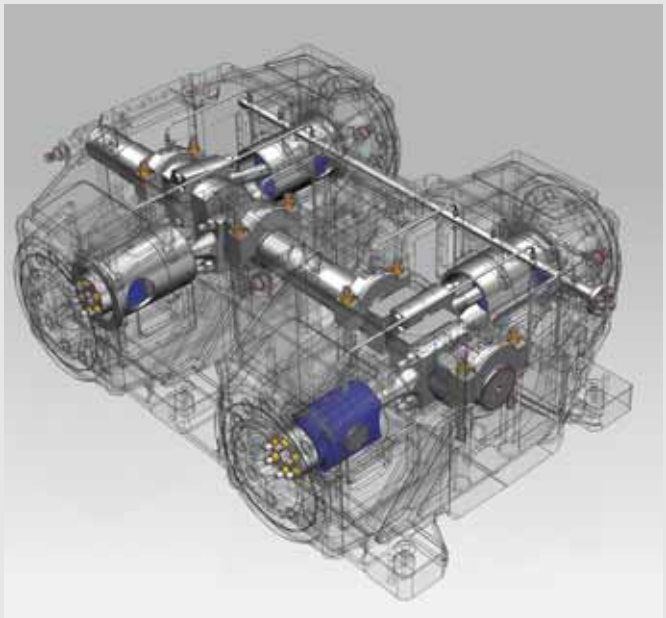

Figure 2. *The one piece frame construction of the 560hs includes the crosshead assembly. Due to the lack of joint bolting, it achieves enhanced precision in drive train movement. Any frame twist or deformation is eliminated by the rigid construction.*

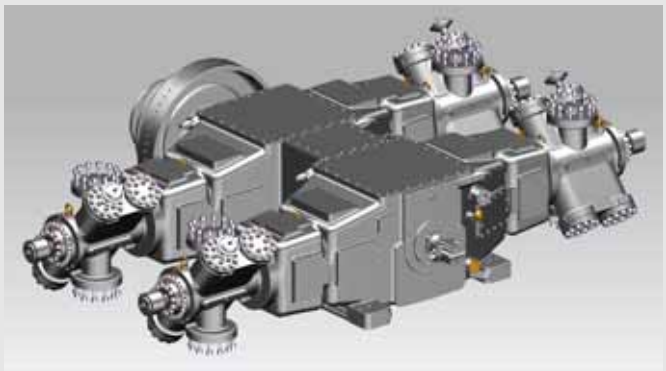

Figure 3. *There is an over 30% decrease in maintenance and capital parts when utilising a 4 throw instead of a 6 throw configuration. When adding up the financial costs as well as the downtime to properly maintain and replace these parts, the impact on the operation's overall performance can be significant.*

optimised pressure packing designs are incorporated. Due to a close collaboration with STASSKOL, a manufacturers of sealing elements for oscillating and rotating systems, the use of innovative component design is guaranteed. Finally, the complete cylinder line can be supplied in air-cooled or liquid-cooled versions. This ensures no limits in applications and compressed gas components.

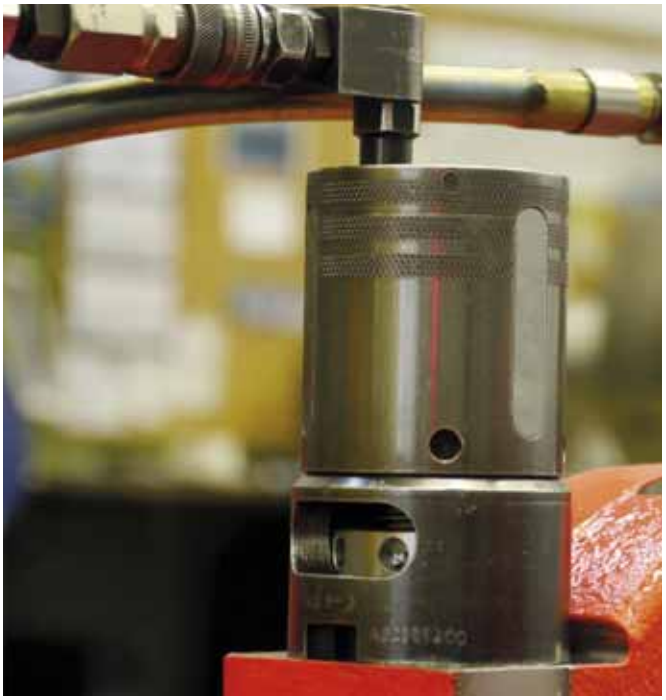

Figure 4. *NEA compressors, including the 560hs, are designed to ensure all dynamically stressed connections are hydraulically bolted to 1200 bar or 17 400 psi.*

Hydraulic bolting

Hydraulic bolting has been a standard feature on long stroke, large horsepower NEA API 618 compressors for some time and the 560hs is no exception. Hydraulic bolting improves joint strength, ease of maintenance and most importantly, safety. Accurate bolt loading with speed and uniformity is one of this compressors key cost saving features. Easy to handle tooling and the elimination of pinch points increases the safety rating.

The compressor has hydraulic bolting on all dynamically loaded connections. The most critical connection is the piston rod to crosshead, which has the highest load concentration under pure dynamic conditions. In addition, this connection must be disconnected over the years when maintenance on wear parts is required. A reproducible, narrow tolerance connection is vital for the performance of the machine. The connecting rod bearing on the big end and all crank bearings will have their best performance and reliability, when they are equally supported on their circumference, which is ensured by the bolting tension. Finally, for safety reasons, the distance piece to frame connection, the cylinder to distance piece and anchor point connections are all hydraulically bolted up to 17 400 psi.

Conclusion

Natural gas is a clean and sustainable energy solution for North America. The ongoing growth of this market will continue to fuel demand for industry for efficient and reliable compression systems. New systems, such as the 560hs, are designed to meet this need now and for the future.

SUBSEA TECHNOLOGY Q&A

OILFIELD TECHNOLOGY INVITED WILD WELL CONTROL AND EXPRO TO SHARE THEIR INSIGHTS ON SUBSEA TECHNOLOGY. THEIR FEEDBACK COVERED AREAS INCLUDING SUBSEA INTERFACES, INTERVENTION OPERATIONS, AND P&A OPERATIONS.

NICK JACKSON & THOMAS WILKE, WILD WELL CONTROL

Intervention operations

One of the challenges of operating from assets designed with a specific duty is trying introduce additional equipment and systems for performing additional activities. These assets have standard systems that are typically used for only one function. For example, the BOP and marine riser are used solely for conveying pipe during the drilling and completion phases. Additionally, intervention workover control systems (IWOCS), which have been around for as long as subsea completion equipment itself, are used specifically to control the subsea infrastructure. With that said, how can all of the necessary equipment be installed onto a dedicated drilling asset and have that asset perform riserless intervention and abandonment operations?

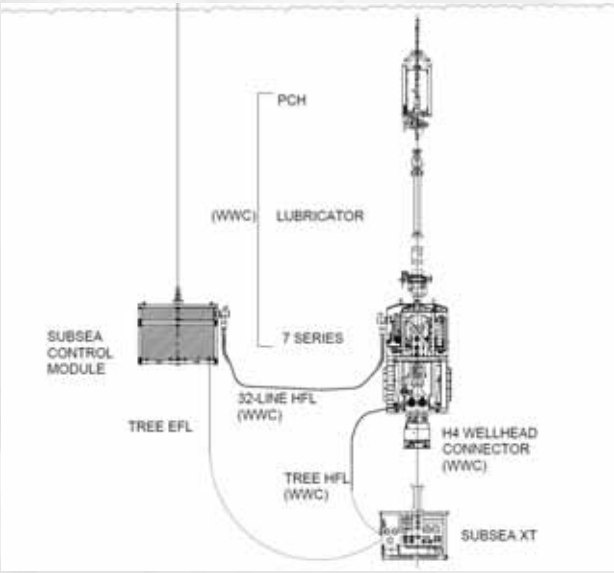

Figure 1. *Wild Well 7Series Riserless Intervention System Layout.*

Figure 2. *IWOCS control centre.*

The answer: Innovation. Wild Well's approach to the installation concern is to perform the work using new technology. When a riserless intervention package is employed on a drilling asset, all of the systems to support the lighter package must be installed on the vessel, including the control system.

The company pushed to utilise the same control conduit that supports its 7Series riserless intervention system to host pass-through functionality for operating the third-party completion hardware already installed on the wellhead. The controls are 'daisy-chained' in this arrangement where the control system connects to the 7Series, which routes hydraulic supplies to the third-party equipment. Electric supply is routed directly from the control system to the subsea tree. The well access arrangement is depicted in Figure 1.

The gain is reducing the typical IWOCS equipment to a topside interface provided by the completion hardware provider. The added complexity of installing the typical IWOCS system on a drilling rig adds cost to the end contractor: the cost associated with another system, mobilising the system and people, installation of the system (in many cases requires significant structural modifications to the vessel), and the operation of a dedicated one-trick system.

The success of this approach saves the end customer time in mobilisation of assets, provides efficiency in operations as pass-through systems do not require independent deployment sequences, and reduces operating headcount, all of which result in reduced overall operating costs.

P&A operations

Efficiency, in a market where costs are heavily dictated by the overall time spent on a particular scope of work, is the advantage of using unconventional methods to meet customer demands. Wild Well has worked to bring this characteristic into the deepwater P&A process with use of the DeepRange tooling and 7Series system.

The two systems work together to provide a solution for the permanent abandonment of subsea wells requiring isolation of the outer annuli (the voids of concentric space between wellbore casing strings). Efficiency in the operation comes from the nature of how the tooling systems work together: one trip in with the tool, multiple perforation, circulation, cementing, and testing sequences all performed without the need to mobilise any additional assets to complete the abandonment. The latter portion of the statement is in regard to a typical cut-and-pull methodology

of performing permanent abandonment of subsea wells, where the method ultimately requires the use of a drilling BOP to complete.

The efficiency of these systems does not mean a lesser quality abandonment is performed on behalf of the particular client. On the contrary, the abandonment is as equally robust or more than the traditional cut and pull. The process methodology of based on the premise of leaving the wellbore casing strings and suspending casing hangers intact. By limiting the alteration of these casing strings to perforations only, the structural integrity of the wellbore remains intact. As a side note, the perforations are conducted with full well control integrity by way of the 7Series in place and the well does not have to be overbalanced with heavyweight fluids.

These systems have been used to conduct nine consecutive P&A operations in the Gulf of Mexico. The system was used to successfully abandon wellbores that not only had one outer annuli to address, but up to three annuli in total (typically referred to as B, C, and D annuli). These were accomplished in just 21 days, which includes the time for the rig to arrive on location and set its dynamic positioning systems. The single annuli well (typically the B annulus) operations were completed in 13.5 days under the same start-to-finish conditions.

Robust and operationally more efficient, less invasive to the wellbore, fully regulatory compliant – these factors all act in favour of the solution, which can be provided to operators with deepwater P&A needs across the globe.

Subsea interfaces

In previous years, almost every piece of subsea equipment has been custom designed to meet the client's needs and expectations. This has led to the development of horizontal and vertical trees, each with their own unique interface (i.e., internal tree caps with crown plugs, dual crown plug tubing hanger, dual bore vertical trees, and enhanced vertical trees with tubing hanger spools for annular access).

As a result, custom intervention packages are built to interface with each type of subsea tree. These packages can consist of only a connector or include a full well access package with valves and blowout preventers (BOPs) for riser-based intervention. These custom intervention/well access packages are typically not used on a frequent basis and therefore are not well maintained. This means that mobilisations are time consuming and very expensive, neither of which are beneficial to the client.

With the slowdown in deepwater drilling, many operators have turned their attention to intervention in order to increase the productivity of their wells. This could include sliding a sleeve to open a new zone, logging a zone to perform a water shutoff, changing out a defective subsea tree, or stimulating a well with chemicals. All of these activities make it necessary to interface with the non-standard subsea tree.

Wild Well's subsea department has worked to develop tooling/adapters that can standardise the tree interface and allow a standard H4 drilling connector to interface with any type of tree interface. These adapters are much more cost-effective than trying to maintain a custom well access package and allow the operator to choose what type of intervention package is best suited for the job. These adapters can be used with a riser or riserless system.

Furthermore, they give the client access to the annulus and production of the well in case circulation of the well is needed. For instance, when abandoning a well with a riserless system, the system must circulate cement into the production tubing and 'A annulus'. For subsea to continue to be a viable service, companies and operators will have to continue to push the envelope and increase overall efficiency.

Figure 3. *The 7Series subsea intervention system.*

Figure 4. *Standardised subsea interface connector.*

Figure 1. *NGLS programme of work.*

Figure 2. *Subsea landing string assembly.*

CARLY GRAHAM, EXPRO, UK

Intervention operations

With no specific standard relating to subsea well intervention equipment in place, the upcoming API 17G standard is intended to address this key area and provide robustness and integrity for landing strings. A committee of subsea matter experts have been formed, including representatives from Expro, to agree and deliver this new standard – driving the industry to recognise the importance of landing strings and their role in well integrity and their safety critical element in barrier philosophy.

In preparation for this, Expro has embarked upon a programme of work within its Next Generation Landing String (NGLS) projects, which meets the integrity, compliance and robustness demanded from API 17G.

The use of landing string technology will lower well commissioning and intervention costs, by minimising rig times and optimising rig utilisations through installing/completing in one run, improving efficiencies during operations for the operator.

- Functionality – including enhanced functional capability of the valves. The enhancements, through compliance to the upcoming standard, improve the integrity of the equipment through meeting the vigorous validation requirements within the standard, which are applicable across all of Expro's products.
- Structural integrity/operability – delivered through validation of finite element analysis against physical tests, will provide more accurate curves and improves structural and fatigue capacities. This in turn leads to improved operating windows and ability to perform in harsher environments.
- In riser monitoring system – monitors the bend and tension that the subsea equipment is experiencing subsea, which is fed back into the global riser analysis to provide more accurate data to manage fatigue life.
- Safety integrity levels – measures the amount of risk associated with safety related functions within the system.
- Life cycle management – delivers a system that ensures equipment has the same integrity from installation through to the end of its operational lifespan.

Collectively, the NGLS programme of work ensures compliance with the upcoming API 17G standard, thereby reducing risk and enhancing safety.

SHEDDING LIGHT ON SRBs

Paul Hennessey, atg UV Technology, UK, discusses how ultraviolet irradiation can replace chemical disinfection for water injection.

Since the introduction of sea water or produced water injection to enhance oil production back in the early part of the last century there have been microbiological problems 'enhanced oil recovery' (EOR). The main one has always been sulfate reducing bacteria (SRBs) which consume dissolved sulfates in the sea water converting them into sulfides which generate hydrogen sulfide or sour gas which then has to be stripped. Hydrogen sulfide, in turn, creates corrosive conditions which increase maintenance costs and in some circumstances can lead to plugging of the reservoir through the formation of insoluble iron sulfide (FeS). SRBs are very common in water but only become active in anaerobic conditions such as those down hole. Other bacteria can be equally troublesome. Once established, the bacteria proliferate and many excrete extracellular polysaccharides which stick the cells together to form adherent slimes or biofilms causing blockage of porous rock strata, reducing yield and defeating the object of injection. The obvious solution was disinfection and the biocide of first choice was chlorine, which was and is widely used for drinking water supplies. Chlorine gas dissolves in water to form hypochlorite ions and these can be simply and economically produced offshore by electrolysing sea water (electrochlorination).

The traditional approach is to inject a very high dose of chemical biocides (e.g. hypochlorite or glutaraldehyde) at both continuous dosing and batch dosing intervals – 'shock dosing' – to kill the bacteria present in the injection water. The problem with chemical biocides and shock dosing is that the concentration of biocide falls between the doses and natural genetic variation in bacterial cells means that some are naturally immune to specific chemicals. Bacteria multiply at alarming rate – given the right conditions they will double in number every twenty minutes – and this makes them fiendishly adaptive. In a very short time the resistant cell strain will become dominant and the biocide becomes ineffective. Changing to an alternative biocide is the obvious solution but this leads to escalation in this war of attrition. The bacteria become resistant to the next

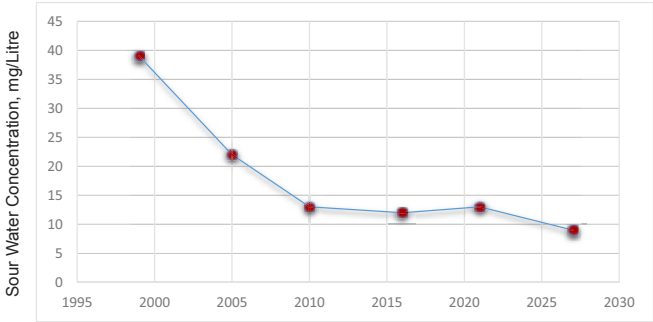

Figure 1. *UV treatment has been proven to improve well integrity and has been shown to reduce the H_2S content in the returning produced water – an indication of reduced SRB activity.*

Figure 2. *Inline, 1500 m^3/hr medium pressure UV chamber provides a compact disinfection solution.*

Figure 3. *Containerised produced water treatment plant used in the US shale gas sector.*

biocide, necessitating another alternative. There are many chemicals that can be used – quaternary ammonium compounds ('quats'), glutaraldehyde, acrolein – but they are toxic and this can have a significant impact on the resulting environmental impact factor (EIF) of downstream water when looking to discharge produced water into the environment. In addition, biocides require special handling procedures, are expensive to purchase and require shipping and storage offshore. Several North Sea oilfields have changed from biocides to nitrate treatment. This encourages the growth of nitrate reducing bacteria (NBRs) which suppresses SBR growth. Whilst this reduces souring, it does nothing to help with the fouling problem; to solve this problem, disinfection is necessary.

The advantage of UV

This is where UV scores as a disinfectant. Ultraviolet radiation in the UV-C band has a wavelength around 254 nm which is very close to the absorbance wavelength of the amino acid bases which form the 'rungs' of the DNA double helix. UV radiation fuses adjacent amino acid groups making it impossible for the molecule to replicate and permanently damaging the thymine strand of the DNA helix. This means that bacteria exposed to UV radiation are not actually killed but cannot reproduce and effectively die at their next natural, reproductive cycle. Unlike biocide disinfection, UV treated bacteria cannot evolve or mutate to then produce a resistant strain.

UV is a broad spectrum that inactivates a wide range of micro-organisms. The technique, which is widely used in applications like drinking water treatment, pharmaceuticals and wastewater is entirely chemical-free with no health and safety or environmental issues. All it needs is an electricity supply and replacement lamps and quartz sleeves every 1 to 3 years. The water flows through a reaction chamber housing the UV lamps (which look like fluorescent tubes) that generate UV-C radiation. The hydraulic design of the reaction chamber ensures that all the water is exposed to equal intensity of radiation with no short circuiting.

Back in 1987 in the Norwegian sector, ConocoPhillips were dosing 500 mg/l of biocide upstream of their fine filters and a further 1000 mg/l into their injection pumps. Shock dosing was for four hours once a week. To combat bacterial resistance they alternated hypochlorite with quats every week. Hypochlorite soon proved ineffective and by 1993 they were alternating quats with glutaraldehyde and then glutaraldehyde with formaldehyde, shock dosing up to three times a week. A combination of rising costs and sheer inconvenience of shipping and storing significant amounts of chemicals offshore prompted them to look for a different solution. atg UV undertook a series of laboratory trials to ascertain the effectiveness of a single pass UV disinfection system against SRBs in sea water.

The UV intensity (or 'fluence rate') produced per unit area by a UV lamp is normally measured in mW/cm^2. Multiplying this by the hydraulic retention time in the reaction chamber in seconds gives the effective dose (or 'fluence') in mJ/cm^2. Different microorganisms have a different sensitivity to UV-C light. Some like pseudomonas and SRBs require a relatively low dose whilst viruses and plankton need a higher dose but, typically, a single pass through a UV system will achieve a 3 log to 5 log (99.9% to 99.999%) reduction of most microorganisms. Tests were carried out at UV doses of 20, 40 and 80 mJ/cm^2 against SRB challenges of 0.2x106 and 1.1x106 MPN (most probable numbers). In all cases a dose of 40 mJ/cm^2 reduced the SRB count to less than 10 cfu (colony forming units)/ml.

On the basis of these results, ConocoPhillips installed four UV disinfection systems the largest of which treated 700 000 bwpd at Eldfisk 2/7E with a programme consisting of UV dosed at 40 mJ/cm^2,

followed by electrochlorination at a low level residual dose of 0.2 mg/l Cl_2. The disinfection process was now continuous and much more controllable. SRB levels were reduced to below the limit of detection regrowth between shock doses of biocide was eliminated. Offshore delivery and storage of biocides was eliminated with reduced health and safety implications and a lower environmental impact. In addition there was a financial saving of over £5000/d in biocide costs. Other installations include Ekofisk, where a treatment programme covered 600 000 bwpd.

One criticism that has been levelled at UV is that, whilst the operation of biocide dosing systems can be easily monitored by chemical analysis, there is no comparable method for determining the performance of UV. This problem threatened the future of UV in drinking water treatment in the USA and was resolved by the US EPA whose 2006 Ultraviolet Disinfection Guidance Manual has generally been adopted internationally. The efficacy of UV disinfection is dependent on the dose of radiation required to handle the microbiological load and the UV transmissivity of the water – this is a measure of how much of the applied radiation is absorbed by the water. The lower the transmissivity the higher the applied dose has to be to achieve the required dose. But the critical factor is how the UV dose is delivered and that depends on the design of the UV reactor. The US EPA guidelines require validation of equipment by independent third party bioassay to the EPA protocols using the log inactivation of specific challenge microorganisms passing through a UV reactor, in combination with known UV254 nm dose-response relationships, to determine a corresponding Reduction Equivalent Dose (RED) and, thereafter, a validated dose for target pathogens. Minimum required REDs derived during reactor validation are expressed in terms of a UV254 nm equivalent dose. Once the RED for the specific reactor type has been validated then the control system has to maintain it over the full range of works flows and UV transmissivities by monitoring UV intensity in each reactor and automatically adjusting the dose. Not all UV reactors are capable of achieving this.

A recent study by a major oil and gas operator compared the costs of supply, transportation, handling, storage and injection of acrolein into 300 000 bwpd against those of a chemical free, UV disinfection package. The result was dramatic. Based on a five-year operation calculation the biocide would cost £3.5 million compared to £130 000 for UV.

In a recent joint industry project between Shell and atg UV Technology in Europe, UV was trialled on the re-injection of produced water to maintain well pressure at five injector wells. In 2016 they were experiencing problems with microbial induced corrosion (MIC) and fouling by biofilms. They were dosing glutyraldehyde continuously with weekly shock dosing of tetrakis hydroxymethyl phosphonium sulfate (THPS). The biocide regime was not working and, due to local environmental regulations, the dose rates could not be increased. Shell undertook a trial on one stream using UV at 60 mJ/cm^2. The trial is continuing but results so far indicate a significant reduction of SRBs after UV. The aim of the trial is to reduce the continuous biocide dosing by 90% and to significantly reduce the requirement for shock dosing. This should have an annual cost saving of £145 000 when compared to biocide treatment.

There is a footprint saving as well. A typical atg UV disinfection package for well injection treatment and SRB reduction is supplied either as a modular skid package arrangement or within a standard 20 ft DNV certified offshore container. The package is designed to be fully turnkey and is both simple to operate and easy to install into existing pipe work with minimal disruption. A small amount of biocide such as hypochlorite is still advised to maintain residual protection, and occasional shock dosing with chemicals may still be needed to flush pipework downstream of the UV package.

However, as the UV system is used as the primary disinfection solution, post-treatment with chemicals does not require the complex monitoring equipment that would be necessary if biocides were used as a primary disinfectant for everyday operation. In addition, when holistically analysed, the UV treatment also reduces the cost and complexity of treating produced water for discharge due to a reduction in both residual biocides and disinfection by-products such as halogenated hydrocarbons.

A number of UV packages are currently being trialled for well injection water, produced water reinjection, produced water discharge and recently have received government-backed funding to complete a UV trial for the treatment of flowback water produced from shale gas wells during hydraulic fracturing operations.

Figure 4. *Conoco Phillips, Ekofisk 4650 m^3/hr seawater injection plant, Norwegian North Sea.*

Figure 5. *6000 m^3/hr Seawater UV disinfection plant used for pipeline hydro testing and flooding water.*

Fighting CORROSION with fibre

Grace Bull & Stephen Forrester, NOV, and Qiang Fu, BP, reveal how fibreglass solutions can help reduce a platform's weight and susceptibility to corrosion.

When the word 'innovation' is used in the oil and gas industry, it frequently refers to the modern developments in software and technology, which include drilling automation, Big Data, and algorithm-driven predictive analytics, that are revolutionising the way wells are drilled and explored. Outside of these areas, however, innovation is still occurring on a large scale in the realms of weight control and corrosion prevention. National Oilwell Varco (NOV) worked with BP to develop a solution to manage weight and corrosion on the Clair Ridge platform, a project that transformed from a simple fibreglass pipe installation into an opportunity to develop, from concept to execution, a comprehensive solution that employed a wide range of composite offerings across the entire platform.

Reducing weight and preventing corrosion have long been problematic to the offshore oil and gas industry. Placing these concerns in a historical context, weight control has become more critical to offshore topside development over the past several decades, as the size and complexity of structures has continued to increase. The issues that arise from improper weight control are manifold – reduced personnel safety, loss of long-term structural integrity, inaccurate centre of gravity, and inefficient operating schedules, to name a few – and must be dealt with to allow platforms to achieve maximum operational efficiency.

Corrosion – the breaking down or destruction of a material, especially metal, through chemical reactions – has similarly been a major issue for the oil and gas industry since the offshore market's rise to prominence in the 1970s. External corrosion of offshore structures is caused by seawater, which has an average salinity of 3.5%. As salinity increases, oxygen solubility decreases, in turn allowing the seawater to erode metal and protective coatings at an average rate of 2.5 in. (60 mm) per year. Corrosion affects nearly all aspects of oil and gas field development, at every stage of equipment lifecycles, leading to far-reaching consequences if left unchecked. It has become increasingly apparent that the impact of corrosion on safety, the environment, and project economics is significant enough to warrant research and development into new ways of preventing or delaying corrosion and corrosion-related failures.

Clair Ridge case study

Located in the North Sea, BP's Clair Ridge facility is the second development phase of the giant Clair Field. Clair Ridge has two bridge-linked, fixed-steel jacket platforms and topsides. The complex design of the facility involved linking a drilling and production platform with a quarters and utilities platform to streamline operations.

Primary objectives

When NOV's work on the Clair Ridge project began, BP's primary objectives were simple: reduce the platform's weight and its susceptibility to corrosion through the installation of fibreglass pipe. An engineer from Pipex px®, part of NOV's Fiber Glass Systems business unit, was sent to work in BP's London-based design offices to provide onsite technical specifications for the project. After this design phase, NOV mobilised to the worksite and, per a determined work scope, installed approximately 9843 ft (3000 m) of Bondstrand® glass-reinforced epoxy (GRE) pipe systems throughout the platform to reduce weight. Then, almost 29 528 ft (9000 m) of phenolic fibreglass-reinforced polymer (FRP) grating was installed across the platforms, providing an anti-slip surface while eliminating additional amounts of excess weight and, as an added benefit, the persistent fear of seawater-related corrosion. Finally, 278 safety gates and four phenolic FRP structures to create stairwells and landings were designed and installed. Beyond reduced weight and increased corrosion resistance, longevity was an important advantage, as composite materials have a significantly longer lifecycle than steel and other corrosion-prone metals while providing similar strength. The life of the composites installed on the Clair Ridge platform is expected to range from 30 to 60 years.

Figure 1. *The Clair Ridge platform, a state-of-the-art facility where BP will begin recovery of 640 million bbls of oil and deploy their LoSal® EOR technology for the first time.*

Figure 2. *Almost 2.6 miles of the MARRS® OFFSHORE handrail system was installed throughout the entire Clair Ridge facility. The handrail system meets strict NORSOK safety requirements and is dramatically more corrosion resistant than steel.*

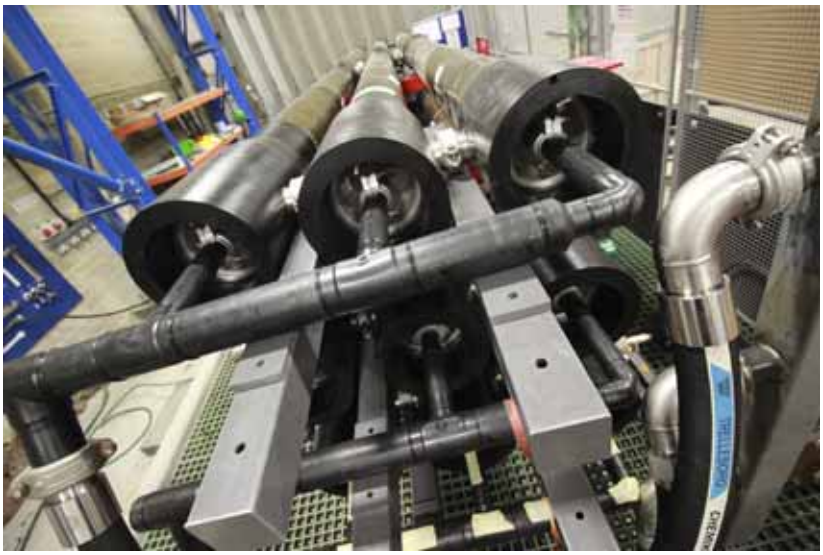

Figure 3. *NOV designed, manufactured, and tested 290 composite pressure vessels for the Clair Ridge platform, working in BP's office and at the shipyard to ensure quality, performance, and corrosion resistance.*

Phenolic FRP composite materials and GRE pipe systems were the clear choices in these applications, as both options provided similar strength to steel but weighed significantly less, were more resistant to internal and external corrosion, and ensured negligible combustibility, conductivity, smoke, and toxicity risk. Further benefits of using these composite materials were reduced future maintenance requirements, extended asset service life, and enhanced safety in the harsh North Sea environment where the Clair Field is located. Additionally, safety on the platform benefitted by eliminating the need for 'hot work' repairs, which would be necessary with a traditional metallic solution.

BP, satisfied with the weight reduction and corrosion resistance from implementing these technologies, sought additional ways of achieving these objectives throughout the platform. NOV suggested a complete redesign and application of the handrails as the next step in the process. Approximately 2.6 miles (4.2 km) of NORSOK-compliant handrail systems and almost 12 000 compression-moulded fittings based on 600 proprietary designs were installed as a result of this inquiry. The MARRS® OFFSHORE handrail system was designed and rigorously tested to ensure that it met the required strength, toughness, and fire reaction performance and safety standards for offshore oil and gas installations as dictated by NORSOK. A continuous round top rail eliminated sharp corners and provided an operator-friendly, warm-to-touch safety rail. The corrosion-resistant material ensured long-term structural integrity, and the nature of phenolic FRP materials enabled a significant weight reduction over standard steel railing systems.

Industry-wide issues

In the final part of the project, NOV sought to help with the industry-wide problem of leaking offshore seawater reverse osmosis (SWRO) pressure vessels. BP had developed, over the past several years,

a waterflood enhanced-oil-recovery (EOR) technology that involved injecting modified water into a reservoir to increase recovery rates. The technology, which BP calls LoSal®, is designed to use low-salinity water in oil reservoirs to allow oil molecules to flow more freely toward producing wells. In typical high-salinity water, such flow is often inhibited by the way oil molecules bind to clay particles. Using this EOR technology in Clair Ridge is expected to cost-effectively yield an extra 40 million bbls of oil over the lifetime of the project.

Some of the most vital pieces of equipment for BP's technology investment included the LoSal skids on which the SWRO pressure vessels are incorporated. These pressure vessels had initially been scheduled for deployment and installation on the Clair Ridge platform earlier in the project, but the original vessels suffered from leaking nozzles, delaying delivery. Despite this setback, BP had committed to a delivery schedule for the SWRO pressure vessels and needed a supplier who could complete the successful manufacture of all 290 vessels, as well as permeate collars and FRP supports, to extremely stringent tolerances within a short timeframe.

Although this final phase of the project was of considerable complexity and size, issues compounded by the extremely restricted time schedule, NOV determined that it was feasible given the company's experience in this domain. To manufacture the pressure vessels to the required specification parameters while simultaneously maintaining repeatable quality and production flow, two computer numerical control (CNC) machines were custom designed and built from the ground up. These machines automatically performed precision drilling of both holes and internal recesses and could clamp and rotate the pipe through 180°, re-clamping into a secondary position and continuing to drill additional holes. The vessels underwent factory acceptance testing in a secure, high-pressure test area at 118 bar to ensure adherence to design specifications. Finite element analysis of GRE materials investigated the material shear limit at the machined end cap groove and machined side port penetrations were analysed to determine maximum stress and deflection of GRE material when under operating conditions, which simulated the biaxial nature of helically wound material. After verifying all results through destructive testing, the completed composite pressure vessels, measuring 22.3 ft (6.8 m) long with an 8 in. diameter, were delivered to BP in sets of twos and threes with up to six titanium side ports (nozzles) each.

Results

The scope of the project, which had transformed from simple fibreglass pipe delivery into a major turnkey package solution, showcased the wide breadth of application for composite materials and solidified the role of these materials in addressing weight and corrosion issues. BP saved more than 700 tonnes of weight on their topside modules due to the combination of advanced design and manufacturing solutions provided. Everything used, from the fire-performance phenolic FRP structural products to GRE pipe systems and pressure vessels, was significantly more resistant to rust and the corrosive effects of the harsh North Sea environment. These improvements were vital to BP, as the Clair Ridge development is expected to extend production life of the field until 2050.

Conclusion

Sometimes, the most difficult issues that the oil and gas industry faces can be addressed through a combination of engineering ingenuity and dedicated technical expertise. The size of offshore structures has necessitated that more attention be paid to weight control, with the issue being of such importance that engineering and construction is now governed by stricter design philosophies and standards. Corrosion on structures of such size and complexity is a similarly problematic issue, particularly as operators seek to drill in more challenging, unexplored frontiers and eliminate the threat of assets having to be prematurely replaced. This project brought together fibreglass product solutions, comprehensive engineering services, and technical authority to deliver major results, thus reinforcing the belief that sometimes, one has to break tradition to achieve success.

Figure 4. *GRE pressure vessels during skimming of outside diameter to allow for the pipe to be positioned within the CNC machine for precision drilling of holes and internal recesses. Production ran for 24 hours a day, 7 days a week to meet strict project deadlines.*

Figure 5. *One of two custom CNC machines built to manufacture the pressure vessels to BP's specification parameters while maintaining repeatable quality and production flow.*

All eyes on the asset

Alison Mackey, Baker Hughes, a GE Company, USA, outlines the value of using a digitised approach to asset performance management for reciprocating compression equipment.

For decades, many in the gas compression industry have pushed through the downturns with little to no equipment monitoring, leaving a substantial amount of data and money on the table. It is no secret that the oil and gas industry has generally been slower than most to adopt digital initiatives, especially in the gas patch. As the industry learns how to do more with less, many companies are gathering data in an effort to understand the 'whats' and 'whys' of events, and increasingly to predict future occurrences and plan for what to do. Adopting a digitised approach to asset performance management (APM) can enable operators to reduce unplanned downtime in oil and gas production and transmission.

The Reciprocating Compression division of Baker Hughes, a GE Company, (BHGE) regards APM as an important part in helping customers manage their data at the asset level and the business level – improving performance, throughput, reliability and the overall bottom line. The APM solutions BHGE delivers, along the full value stream of oil and gas, provide solutions by offering real time machine performance, data trending and analysis. They range from small, simple, physics-based analysis like measuring the deviation in discharge temperature to indicate a future potential issue, to broader analysis, such as creating a 'digital twin' to optimise the equipment in real time without ever touching the equipment. This operator is given a range of opportunities, customisable to each package and project, depending on how critical the asset is and how many sensors or personnel are available.

The value of APM

For asset-intensive operations, APM connects data sources and uses advanced analytics to turn that data into actionable insights, while fostering collaboration across an organisation and minimising total cost of ownership. The APM system utilises data from the compressor, engine and other package assets by running cloud-based analysis to give customers insights into how the machine is running, flagging potential problems and providing solutions to any issues. Data collected from the engine and package control panels is pushed through to the cloud via a small data collector at the site. The data can then be analysed in a variety of formats, depending on the criticality of the asset.

Many groups can benefit from APM systems. End users can benefit from increased reliability and managing maintenance across a site. Fleet users find benefit in downtime reduction and maintenance and parts strategy across hundreds or thousands of assets. Operators have an enormous amount of knowledge about their equipment, but are not always able to be onsite or forewarned before a failure occurs. Furthermore, operators often spend countless hours (and dollars) sending technicians to site for false alarms. Misdiagnosed repair often incurs significant expense in downtime, lost production and equipment or service cost. For example, an operator might misdiagnose issues with throughput or efficiency to a turbocharger. The operator is essentially making a 'best guess' at fixing an issue, due to the fact that the turbocharger does not have a host of sensors. This 'best guessing' can end up costing the operator up to US$200 000 in lost production

and US$25 000 in repair costs. APM can help a technician arrive more prepared. The technician can remotely view alarm history after an unexpected shutdown, notice a misfire, and make sure to grab the correct set of tools from the maintenance shop before driving out to site.

Operators have an ongoing, pressing need for reliable discernibility in regard to issues with their equipment. When operators have access to data at their fingertips, they are better prepared for a variety of situations. With proper monitoring and assessment, they can reinforce their diagnoses with data, saving time, frustration and expense.

Case study

BHGE works with a variety of companies that range from data-starved to data-rich (or data 'swamped'), but many of them lack a central system with the power to perform analysis beyond the basics. APM systems give customers the ability to use their data and equipment to the fullest potential that would not otherwise be possible without a great deal of work and effort from the customer.

In a recent application of APM, sensors identified machine stress in a turbine at one of the world's largest exploration companies. The customer was notified of this stress by the Rapid Response team in BHGE's Industrial Performance & Reliability Center and subsequently initiated regular briefings on the situation. The customer was able to contemplate a range of potential root causes and plan an inspection of the turbine before it failed, rather than waiting until a hard alarm was tripped at the customer facility and relying on a reactive approach to maintenance. This approach enabled the company to replace the turbine in its next planned downtime rather than months later at the turbine's scheduled date of replacement. If the turbine had failed prior to replacement, the company would have lost millions of dollars in downtime.

Another recent example concerns a reciprocating engine in power generation. An analytic system identified early valve wear in an engine cylinder head and was able to flag the issue before it led to camshaft damage. Past experience has shown BHGE that to continue running would have resulted in camshaft failure (a long lead-time item) and tens of thousands of dollars in repair cost.

Conclusion

There is a lot to be gained from harnessing data to improve the ability to plan maintenance schedules and more effectively manage equipment deployment. Offshore, a 36% reduction in unplanned downtime has been observed when a predictive, data-based approach is implemented compared to those that rely on a reactive method.

APM gives a package view, integrating both the engine and compressor control systems into one global view. In the future the industry will also see a focus on condition-based maintenance and sensible alignment of maintenance intervals of all the equipment on a compression package. BHGE maintains a focus on developing analytics that have the biggest impact on package reliability – driven by industry feedback.

APM and digital solutions are designed to work for both the operator with a few assets and the largest gas production companies in the world, and bring value beyond simple data collection. The analytical capabilities of APM systems, together with customer engagement and collaboration efforts, translate into optimisation, efficiency and overall productivity.

Figure 1. *APM helps operators and technicians understand the issue or failure before heading to site.*

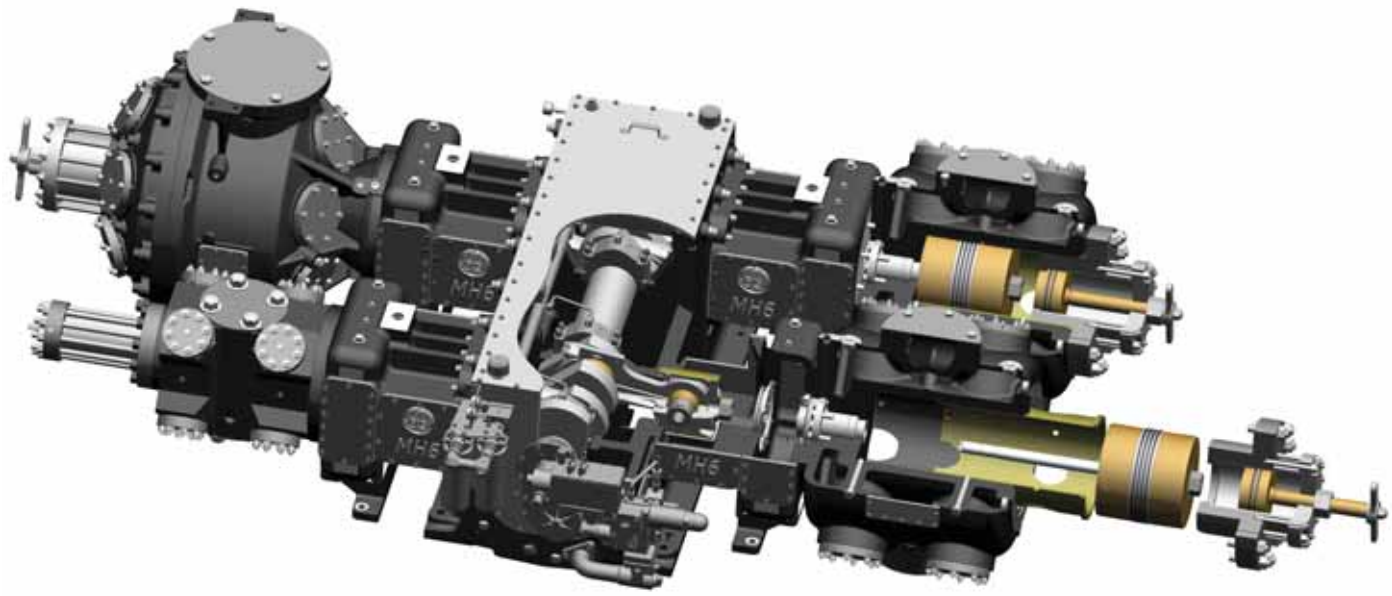

Figure 2. *Equipment insights from real time data via APM connects customers with their assets remotely.*

ADDING VALUE WITH ANALYTICS

Andy Young, Pioneer Energy, USA, explains how data analytics software allows operators to evaluate performance at remote well sites.

The oil and gas industry, like many others, is collecting and storing ever larger volumes of data. Although there is value in this data, it is often difficult to unearth using conventional analysis tools such as spreadsheets. To address this issue, new data analytics software platforms are being introduced specifically to deal with time-series data.

Because these new data analytics software platforms are dedicated to just one specific function, analysing time-series data, they are much easier to use than a general-purpose tool such as a spreadsheet. In the hands of a process expert, usually an engineer, data analytics software can quickly yield answers to questions regarding operations – leading to improvements in safety, uptime and throughput.

Pioneer Energy in Lakewood, Colorado is a service provider and original equipment manufacturer solving gas processing challenges in the oilfield with a range of standard gas capture and processing units for tank vapours and flare gas.

Pioneer Energy's VaporCatcher™ line of units captures hydrocarbon vapours from crude oil tank batteries and extracts natural gas liquids (NGLs) at high yields, instead of sending these valuable commodities to combustion or venting to atmosphere. This significantly reduces emissions, meets EPA Quad O compliance standards and provides a significant economic return. The company's FlareCatcher™ line of equipment provides flare gas capture and processing at the well site, producing NGLs and pipeline quality lean methane, and enabling producers to achieve regulatory compliance.

Oil and gas fields in North Dakota, Montana and Colorado use these systems at production well sites to capture methane and natural gas liquid streams. Pioneer Energy provides a turnkey solution, operating and monitoring these geographically dispersed units from its headquarters in Colorado. The company's operations and design teams monitor the equipment and analyse the results to deliver continuous improvement.

The FlareCatcher is powered with a natural gas generator, which is inside the white enclosure on the front of the trailer as shown in Figure 1. The fuel gas for this generator is provided by any of the refined energy products made by the system, and this usage represents only about 5% of the total energy of the gas processed by the equipment.

The system has auxiliary (backup) batteries which are charged with a conventional battery tender powered by the primary generator or a solar panel. The auxiliary power system is required to keep communications alive during periods when the system is not running due to maintenance, a component level failure, or insufficient gas flow from the site. Once the shutdown condition

has been remedied, having communications available with headquarters allows remote startup.

Acquiring data from afar

Pioneer currently has systems installed in the Western US, but future sites could be located onshore or offshore anywhere in the world with cellular or satellite connectivity. Alternatively, a local radio network could be installed to get the data to a network hub.

Well site data from the systems is sent to local data centres. This is a critical element of Pioneer's modular architecture as it leverages specialised resources. Data centres have extensive redundancies built into their power and networking services, absolutely required for operating critical hardware remotely. Pioneer uses one data centre in Denver and one in Dallas, and is investigating virtualisation to add dynamic scaling and load balancing to field data gathering.

Currently, all analogue data is being transmitted at one-second intervals. Discrete data is transmitted as it changes.

While the company had data coming in from field sites to the data centres, they had no sophisticated data analysis tools. If engineers found themselves with some free time, they could manually load historical data into an Excel spreadsheet and calculate a few basic metrics. But Excel is not suitable for calculations of reasonable complexity, so much of the data gathered was not being utilised to the greatest extent possible. The company needed to find a way to better analyse data from its far flung operations.

Adding analysis

After reviewing various data analytics software packages, Pioneer selected Seeq's visual data analytics application because it most closely fit the software the company had envisioned. It had all the required components: a graph database, time series optimisation and a clean browser-based interface – as well as advanced data analytics and information sharing capabilities.

The software enabled Pioneer to optimise the data stream. Engineers are able to define simple computations to be performed at the edge to determine what data needs to be streamed elsewhere for analysis, and what data can be archived locally at the sites.

Seeq is currently being used to analyse and understand historical data, and to generate and define new rules for operating parameters (Figure 2). Applications are manifold. In a continuous improvement cycle, all data has potential value if it can be unlocked and leveraged. Seeq provides an environment for experimentation and learning, and its visual feedback is the appropriate way for engineers to analyse complex data in a reasonable amount of time.

For example, key components of Pioneer's technologies are advanced refrigeration system designs that can be very sensitive to changing operational conditions. Seeq has allowed Pioneer to isolate these effects, identify their causes, and develop simple operational rules to extend the life of capital investment.

One of Pioneer's core value offerings is the ability to operate systems remotely. If software helps identify a problem with equipment in the field, corrective action can be taken quickly. For instance, Pioneer uses air-cooled cascade refrigeration systems. During hot days, discharge temperatures and pressures can rise to elevated levels, leading to hardware failure. Detecting this with advanced metrics and predictive analytics allows operators to intervene and turn down the system throughput until the condition has cleared.

All data from the well site is streamed to a centralised, secure data centre, where the Seeq server resides and accesses all field data. From there, the interface is made available via a web proxy server. Technicians and engineers can access the data anywhere there is a network connection, including at the well site itself with a cellular hot spot.

Installation and startup

Two on-site training sessions were performed in addition to remote installation and code development help sessions.

Application engineers identified an unusual issue causing an installation failure. Pioneer had made Seeq accessible through a web proxy server, which involves multiple port forwarding and security rules. Due to the many operations tools running on the server, there was a port conflict. A quick live session identified the issue. Other than this issue, installation and startup proceeded as planned without a hitch.

Results

The single biggest outcome of the Seeq installation is improved operational intelligence. The simple to use yet powerful visualisation and analysis tools shed light on otherwise complex processes. At this point, Pioneer is looking to increase Seeq's uptake and adoption throughout the organisation as a key design and operations tool.

Conclusion

Analysing time-series data to improve operations is a goal for many companies in the oil and gas industry. Like many other firms, Pioneer Energy has long relied on spreadsheets for analysis, but found this tool cumbersome for the task.

In search of a better solution,the company investigated and found new data analytics software platforms specifically designed to analyse time-series data were now available. These platforms were investigated in depth, and the selected solution was found to significantly reduced the time required for analysis.

Figure 1. *The FlareCatcher unit produces NGLs and pipeline quality methane from flare gas.*

Figure 2. *Pioneer Energy's engineers can monitor equipment at remote well sites with Seeq's data analytics software, optimising the data stream at the edge to focus on the most relevant information.*

Coming up next month

December

- Regional Report: Global outlook
- Well control
- Drilling automation
- MWD/LWD
- Drilling fluids
- Cementing
- Artificial lift
- Riser design
- Oilfield tubulars

OILFIELD TECHNOLOGY EXTREME


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