VOL. 14, NO. 2 – 2017

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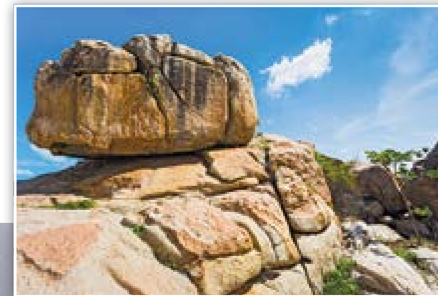

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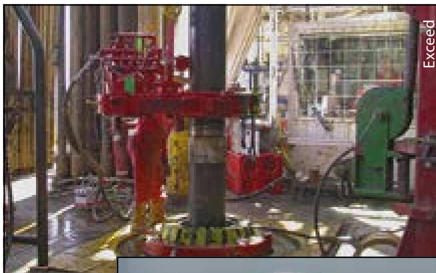

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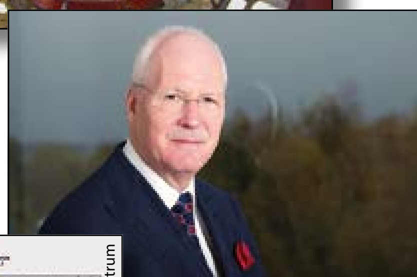

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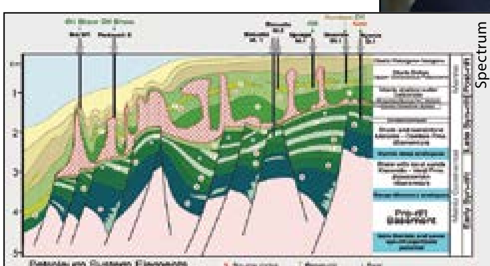

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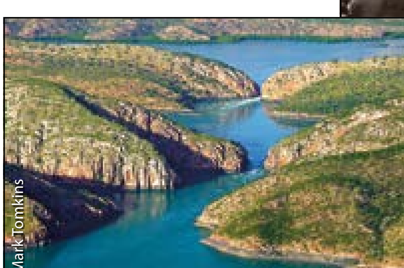

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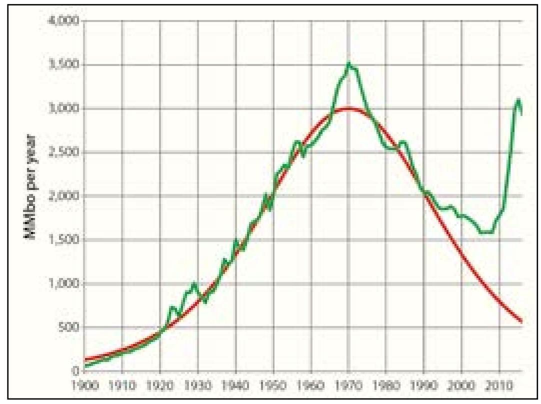
Expect the Unexpected



US Lower 48 states oil production (green) compared to Hubbert's prediction (red).

Ever since M. King Hubbert first outlined his peak oil theory, suggesting that the rate of petroleum production tends to follow a bell-shaped curve, it has been the source of much debate. Even though US Lower 48 states annual oil production did indeed peak in 1970, as he had predicted, the anticipated steady and inevitable decline has not followed, having been abruptly reversed in recent years by the rapid increase in production as a result of exploiting unconventional resources. Broad estimations about the industry's future always have a high chance of being proved wrong, because it is almost impossible to second guess the technological, political and societal changes that feed into a topic of such global significance as energy supply.

In recent years, however, the discussion has migrated to the topic of peak oil demand, rather than production. The conversation had been about finding sufficient resources to supply an ever-increasing population, coupled with rapid economic and technological developments in Asia. A world falling out of love with fossil fuels, the growth of alternative, renewable sources of energy and concerns over carbon emissions are all issues which were not considered when production was the primary concern.

Predicting peak oil demand is proving as contentious as foretelling peak oil production. Statoil believes that demand will start slowing between the mid-2020s and late 2030s, while Ben van Beurden, CEO of global giant Shell, said at the recent IHS CeraWeek that we should be ready for oil (though not gas) demand to peak between 2025 and 2030, and that "the most difficult challenge… is to have a meaningful discussion with the public on energy transition. The discussion is not rational, it is emotional." Not everyone agrees with this forecast. The CEO of Chevron is cited as saying that the idea of peak demand is merely "wishful thinking", and the International Energy Agency recently said that lack of new investment means that oil supply could struggle to keep pace with demand after 2020.

Predicting the future of oil is a difficult and controversial game and many experts have been caught out in the past, ever since David White, chief geologist of the US Geological Survey, forecasted that the peak of US petroleum production would soon be passed, possibly within three years. That was in 1919. ■

Jane Whaley
Editor in Chief

Gravity base structures, such as those supporting the Brent Bravo platform, are among the biggest and most impressive feats of engineering in the oil and gas industry. Designed to withstand the rigors of the stormy North Sea, they were constructed of thick concrete reinforced with steel bars. Having produced nearly 4 Bboe over 40 years, the Brent field is now the location of one of the first major decommissioning projects in the world.

Inset: Results from Vietnam's first ocean bottom seismic survey demonstrate that higher density full azimuth seabed data can be used to enhance our understanding of fractured basement reservoirs.

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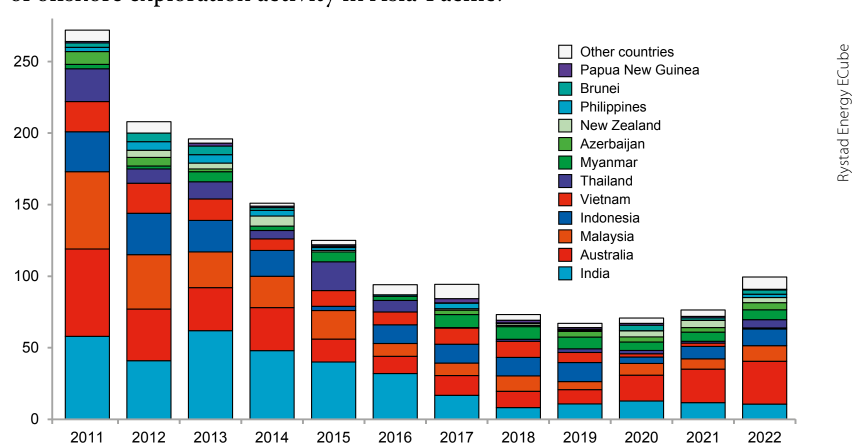
Asia-Pacific: Decline in Drilling

The resurgence of offshore exploration in the Asia-Pacific region is dependent on more acreage.

Since the peak year of 2011, offshore exploration activity, measured as the number of exploration wells drilled, in the Asia-Pacific region has dropped by more than 40%. This is very much in line with the global trend. In Australia, the number of exploration wellbores has dropped from around 90 in 2008 and 60 in 2011 down to 12 offshore exploration wellbores completed last year. The same trend has been observed in India where the number of wells drilled has gone down from a level of 60 wells per year to 32 in 2016. In comparison, offshore exploratory drilling activity in China has increased by 10–20%, and CNOOC has reported plans to drill 126 exploration wells in 2017, compared to 115 in 2016.

With the backdrop of a forecasted oil price recovery towards $97 per barrel Brent in 2021 (source: Rystad Energy Oil Market Trends Report, February 2017), and an expected 7–10% annual growth of global E&P offshore expenditure from 2018 onwards, two key questions are when and how fast will we see a resurgence of offshore exploration activity in Asia-Pacific?



Number of offshore exploration wells completed in the Asia-Pacific region outside China.

As shown above, a significant increase in exploration activity is not expected before 2022 and beyond. This is partly due to a steep decline in the awarding of new exploration acreage. In the Asia-Pacific region, annual awarded acreage has fallen from more than 350,000 and 500,000 km^2 in 2013 and 2014, respectively, to around 60,000 km^2 in 2016. An additional observation is that discovered volumes per exploration well were reduced by 75% from 2010 to 2016, indicating that a higher degree of exploration success along with attractive, new exploration acreage is needed to ensure growth in exploration activity.

The activity level during the next three to four years will be partly driven by the drilling of prospects where activity has been postponed during the current downturn. Increased activity will, however, depend on an uptick of awarded exploration acreage to E&P companies. Outside China, Australia is likely to be one of the key countries behind increased offshore exploration activity in the region, primarily in Western Australia/North West shelf. The Great Australian Bight off Australia's south coast could also become a growth region for exploration, but further drilling here is currently postponed until 2019 with BP's Stromlo prospect as the first high-impact well to be drilled in the area. In the longer term, New Zealand could contribute to growth, where a risked estimate of 7 Bboe is yet to be found. The results of the deepwater Barque gas-condensate prospect in Clipper, with potential drilling in late 2018, will be a good indicator of the area's potential.

Nils-Henrik Bjurstrøm and David Mullins, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand = 1 x 10^3
MM: million = 1 x 10^6
B: billion = 1 x 10^9
T: trillion = 1 x 10^{12}

Liquids

barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day

Gas

MMscfg: million ft^3 gas
MMscmg: million m^3 gas
Tcfg: trillion cubic feet of gas

Ma: Million years ago

LNG

Liquified Natural Gas (LNG) is natural gas (primarily methane) cooled to a temperature of approximately -260 °C.

NGL

Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

Reserves and resources

P1 reserves:
Quantity of hydrocarbons believed recoverable with a 90% probability

P2 reserves:
Quantity of hydrocarbons believed recoverable with a 50% probability

P3 reserves:
Quantity of hydrocarbons believed recoverable with a 10% probability

Oilfield glossary:
www.glossary.oilfield.slb.com

Large Areas To Be Made Available in Gulf of Mexico

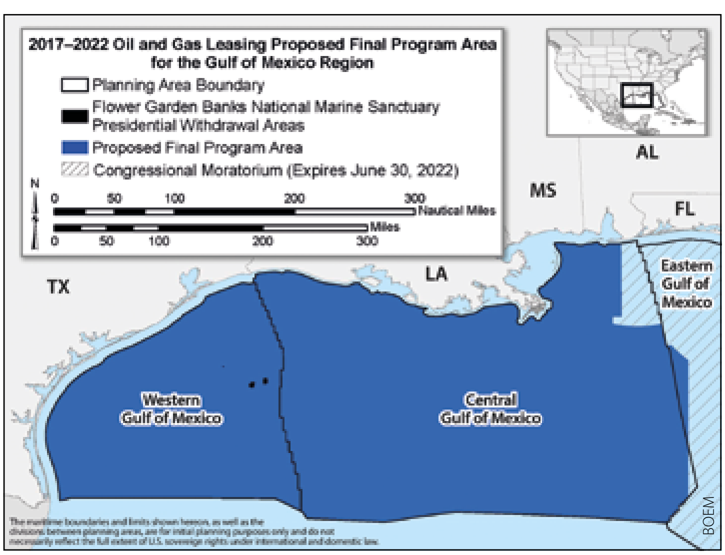
The United States Department of the Interior announced in early March that it will offer 73 million acres in the Gulf of Mexico – nearly 300,000 km² – for oil and gas exploration and development. The proposed region-wide lease sale has been scheduled for August 16, 2017 and will include all available unleased areas in federal waters of the Gulf of Mexico. It includes acreage in offshore Texas, Louisiana, Mississippi, Alabama and Florida. Lease Sale 249 will be the first offshore offering under the new five-year Outer Continental Shelf Oil and Gas Leasing Program for 2017–2022, in which two Gulf lease sales will be held each year. Most interest is expected to be in acreage in the Central Planning Area.

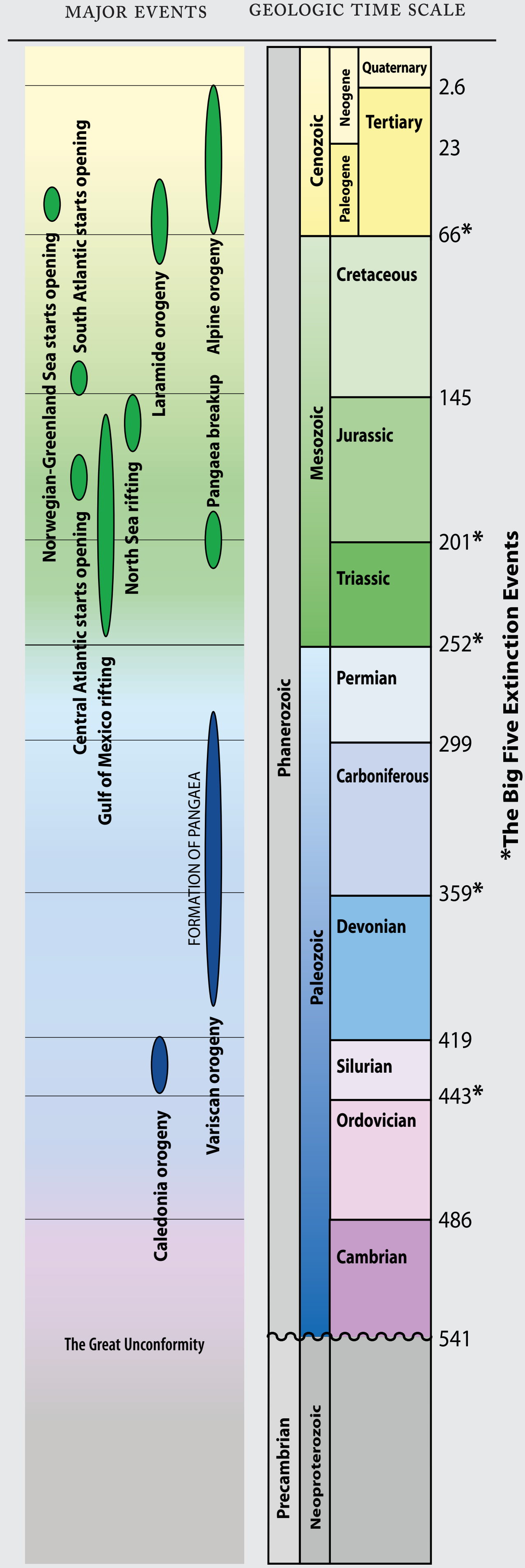
A total of 13,725 unleased blocks are included in the sale, which extends south to the Mexican border. However, everything within 200 km of the Florida coast will remain off limits until at least 2022, unless Congress amends the Gulf of Mexico Security Act which bans oil and gas activity in that area. The terms include stipulations to protect biologically sensitive resources, mitigate potential adverse effects on protected species and avoid potential conflicts associated with oil and gas development in the region.

Water depths in the acreage to be offered range from just 3m to 3,400m. For areas in less that 800m of water, it is suggested that leases will be offered for a five-year initial period, plus three years for drilling below 7,600m TVD SS, while in waters of 800–1,600m there will be an initial seven-year period. Leases in over 1,600m of water will have a ten-year initial period.

After protesters disrupted a number of offshore lease auctions, all lease sales are now routinely livestreamed. Lease Sale 249 is scheduled to be livestreamed from New Orleans on August 16, 2017.

According to the US Bureau of Ocean Energy Management (BOEM), the Gulf of Mexico Outer Continental Shelf contains in the region of 48.46 Bb of technically recoverable oil and 141.76 Tcf recoverable gas. It is estimated that 211 to 1,118 MMbo and 0.547 to 4.424 Tcfg could be developed in the leases offered in the next five-year program. There is one remaining GoM lease sale to be held in the current (2012–2017) program, which has already awarded more than 2,000 leases, covering nearly 300,000 km². The BOEM estimates that more than 97% of the leased offshore area of the US is in the Gulf of Mexico. ■



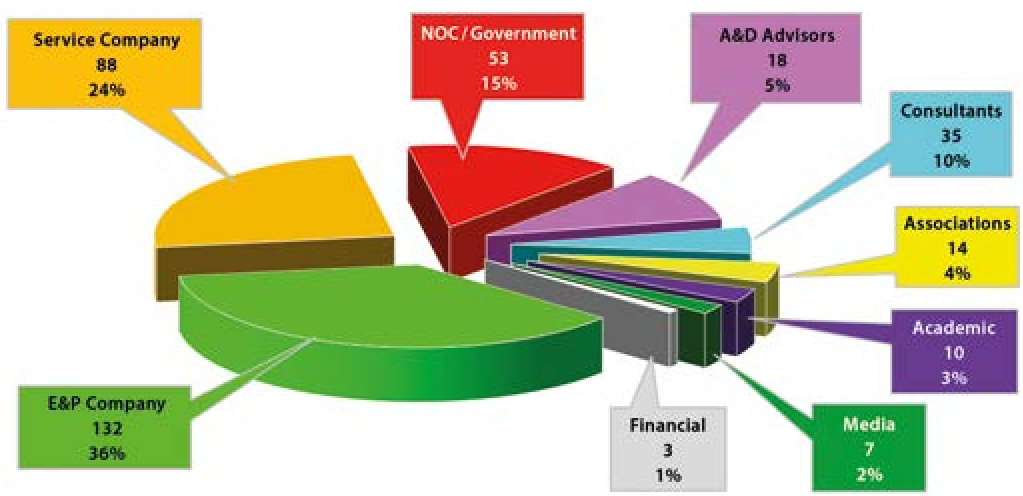


Green Shoots of Recovery?

Global Upstream A&D: is it two steps back… one step forward – or are we beginning to see signs of recovery?

The Global APPEX A&D conference held annually in London in early March has just finished. Why is this significant? Because, as one of the major events in the global upstream deal-making calendar, there was clear evidence that the 'green shoots' of a new cycle may be around the corner. Hopefully after two steps backwards (as the saying goes), and two years of price uncertainty, the first stumbling step forward has perhaps now been taken in E&P recovery, hopefully with the second pending!

The mood was warily optimistic but the presentations cautious, with speakers not wanting to tempt providence by calling an upcycle too early, but the early evidence is positive. Investors are starting to be able to raise money again for international and near-term cash flow assets, which in turn will lead to a measure of associated upside exploration, this time hopefully balanced and appropriately risked as true upside and not the 'raison d'être'! Gone are the days where listed companies will be dashing off to put all the money raised on the a 30/1 outsider in the first horse race of the day, as one might argue has been done all too often over the last decade. The evidence of this failed E&P formula is clear to see on pretty much every E&P company market around the world, save for a very precious few.



APPEX attendees 2017 according to sector: a wide range of organizations are interested in seeing an increase in M&A activity.

Skills Gap

A 'back to the future' approach to E&P is perhaps a more appropriate formula, as E&P companies have done before. By measuring exploration risk against available cash flow, with low overheads and good quality technical G&G work, and with promoted exploration farmouts to minimize risk, companies should be able to extend their ability to achieve the quantum value leap. The evidence of this successful formula was evident at APPEX, attended by several Small Cap companies that have achieved this balance, and which, having successfully survived the low oil price, are now poised and ready for an upcycle.

The consensus of conference presentations and comment also suggested confidence that the oil price would likely oscillate between a floor and ceiling price of US$45–$65 bo over the next year or two as resource play thresholds and OPEC production maintained some equilibrium. Thereafter, some questions were voiced about conventional production decline, which has been significantly under-resourced during the downturn, and the ability of resource plays to fill the potential undersupply after 2020–23.

Although there are plenty of pundits predicting that oil will, in time, become the dirty fuel that coal is now considered to be, the big question is when alternative sources of energy will take over from hydrocarbons. This may be dependent on such things as battery technology and finding fuel sources that are able to fly 350 passengers from London to Sydney in 18 hours. If the alternatives are unlikely to be in service until after 2030 at the earliest, then large new sources of oil and gas need to be found. Although new technology will no doubt play its part, the dilemma is how such new reserves will be discovered with the huge gap in qualified and experienced technical people, particularly geologists and geophysicists, left by the last major crash between 1984 and 2003. There are simply not enough of them to replace the G&G experts who will retire in the next few years.

Maybe some answers to these questions will have become clearer by the time of the next regional APPEX, which will be held in Athens in September, 2017.

Mike Lakin, Envoi Ltd. ■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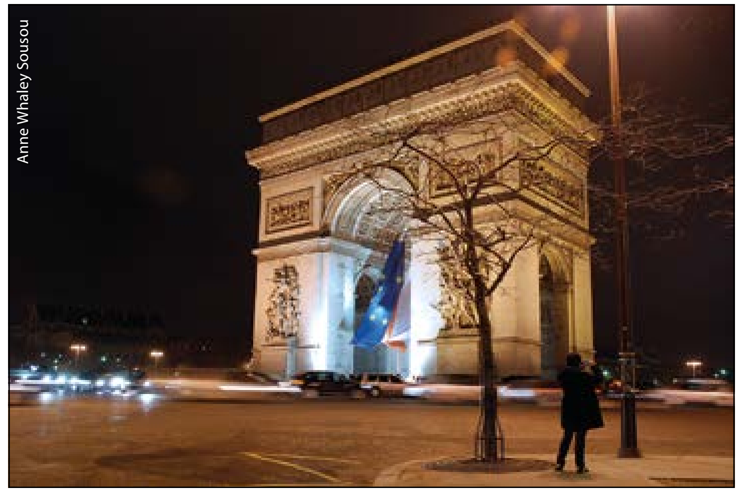
Paris is Always a Good Idea!

Audrey Hepburn said it in a 1950s movie and it is a sentiment that has been repeated many times since. So we should all be excited about this year's **79th EAGE Conference and Exhibition** including SPE EUROPEC, which is being held at the **Paris Expo Porte de Versailles** on June 12–15, 2017.

What better place for delegates to meet for the largest multi-disciplinary geoscience event in the world with the vital theme of **Energy, Technology, Sustainability – Time to Open a New Chapter?** It is an opportunity for the international geoscience and engineering community to consider the new reality of a persistent low oil price environment and the need to think of new and more efficient techniques and solutions.

EAGE's annual meeting includes a large conference – in total over 1,000 technical oral and poster presentations – and a technical exhibition presenting the latest developments in geophysics, geology and reservoir/petroleum engineering. Around 6,000 people from almost 100 different countries visit this event annually.

To catch up with all details and for registration, please refer to the EAGE website. ■


Anne Whaley Sousou

Shaping Africa

A recent Ernst & Young report states that the total O&G deal value for Africa in 2016 was US$ 4.9 billion, with 92% of the deals being upstream. The majority were made in the last quarter, suggesting a return of confidence in the industry and an expected upturn in operational activity in the region in the ensuing months. This forecast upswing sets an optimistic tone for the 16th **Africa Independents Forum**, a key event on the international oil and gas calendar, which will get underway at the **Waldorf Hilton Hotel, London** on May 24–25, 2017.

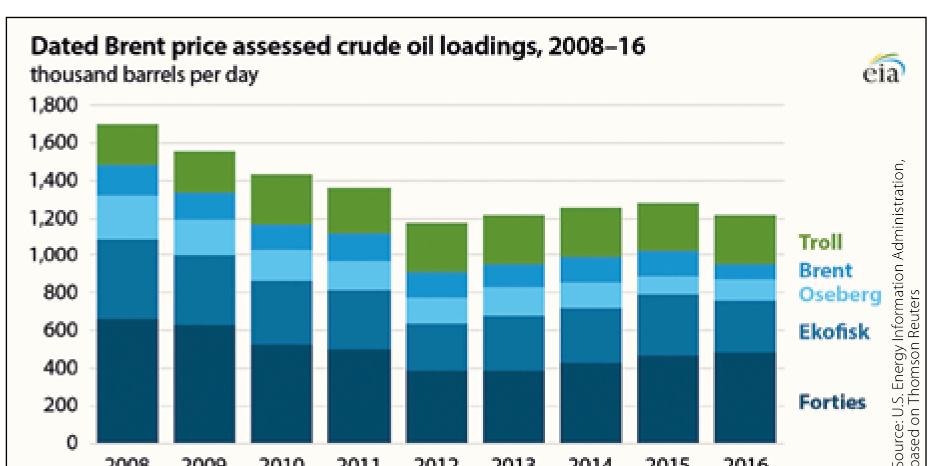
This annual gathering of Africa's oil and gas upstream industry is an essential platform for reviewing the state of the industry and exchanging ideas on game-changing opportunities for the future. Showcasing Africa's premier projects and upstream operators, the forum provides plenty of scope for networking and to present projects, propose new ventures and firm up partnerships and investment deals.

Based on the theme of 'Shaping the Continent's Future in Upstream Oil & Gas', this year's program focuses on developing and driving change in the industry. In-depth presentations explore solutions that move beyond survival tactics to establish best practices that better equip the industry to weather uncertainties and withstand shocks whilst maintaining optimum performance. ■

Brent Benchmark Adds Troll

The price of **Brent crude** has been avidly watched as the basis of comparison for crude oil prices around the world since the 1980s, but the method for assessing the Brent global benchmark crude oil price is scheduled to change in 2018. The price reflects transactions involving physical cargoes of several specific grades of crude oil from four fields in the North Sea, but declining production from these has prompted the price reporting agency, Platts, to decide to include crude oil from a fifth field in the mix from 2018.

Originally the benchmark was based solely on cargoes of Brent crude, but as that field declined (see page 16) oil from the UK Forties field and Oseberg in Norway were added in 2002, followed by Norwegian crude oil grade Ekofisk in 2007. Now an additional North Sea crude from the Troll field, about 60 km off the coast of Norway, will be included in the mix, adding about 29% more crude oil volume to the current Dated Brent (BFOE) price assessment.



Shah Deniz Developments

With 40 Tcfg in place, **Shah Deniz** is one of the largest gas-condensate fields in the world. Discovered in 1999, it is located in the Caspian Sea, 70 km south-east of Baku, the capital of Azerbaijan, in water depths ranging from 50 to 500m, and started producing in December 2006. Since then it has undergone a series of improvements and production capacity is now nearly 1 Bcfgpd, with gas delivered by pipeline to a number of countries including Azerbaijan, Georgia and Turkey.

Expanding the project still further, **Shah Deniz Stage 2**, or Full Field Development, is a giant project that will add a further 565 Bcfg a year to the field's output, and is designed to bring Caspian gas resources to markets in Europe for the very first time via a pipeline route known as the **Southern Gas Corridor**. The project includes the construction of two new bridge-linked offshore platforms, the first of which was safely towed out and installed towards the end of 2016.

Operator BP have now announced that the second platform left the construction yard in mid-March and the transportation, launch, positioning, pile installation and final completion activities of the jacket structure are expected to take around 75 days, depending on weather conditions. ■

The first Shah Deniz 2 platform before it was transported out to the field.

Seismic2017 Program Announced

Seismic2017 is the first conference in **Aberdeen** to focus on seismic acquisition, processing and interpretation. The Seismic Technical program features eight operator presentations and case histories from Apache, Shell, EnQuest, Maersk, BP, TAQA and Chevron. The conference will also provide more in-depth information about the 40,000 line kilometers of new and legacy seismic data from the Rockall Trough and Mid-North Sea High Areas that the UK Oil and Gas Authority has recently released.

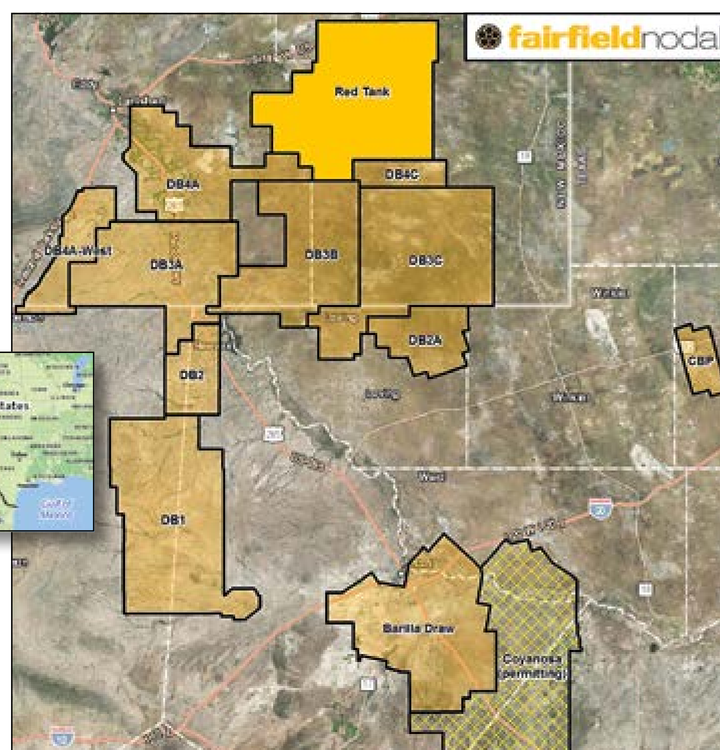
The conference takes place on May 11, 2017 at Aker Solutions in Aberdeen International Business Park and is organized by SPE and supported by EAGE. Bookings are now open and there are still limited exhibitor and sponsorship opportunities. Further details on the SPE website. ■

Targeting the Delaware Basin

For more than 30 years **FairfieldNodal** has innovated, acquired, processed, and licensed seismic technology, and it is well known as an acknowledged leader in ocean bottom seismic (OBS) and in developing, manufacturing, and deploying exclusive, nodal data-acquisition systems. With this proprietary technology, it has also built and licensed a large, multi-client library of data for the **Permian Basin**, extending across areas in Texas and New Mexico.

The **Red Tank** multi-client survey, which commenced in February, is a continuation of this project, and is being undertaken in the heart of the New Mexico portion of the prolific **Delaware Basin**, where there is significant interest at the moment. This high-resolution 3D survey adds more than 984 km^2 to the company's regional database of 6,625 km^2.

Acquisition parameters are designed to target the Bone Spring through Wolfcamp Formations, providing operators with the crucial information they need to make the right decisions in these highly productive zones. To ensure that their customers will have the best image possible, FairfieldNodal will be processing the data using a variety of the latest techniques for noise removal, signal conditioning, azimuthal analysis and imaging. ■



New Overseas Markets

BGP, a leading Chinese geophysical company, has been operating in **60 countries** for more than **200 clients**. At present, BGP has 53 overseas branches distributed throughout the Middle East, Africa, Central Asia, South and North America, and South East Asia, supporting 65 land crews and six seismic vessels, as well as 19 data processing and interpretation centers all over the world. In 2016, BGP made an historic breakthrough in developing six new overseas markets and signed several big contracts with international E&P companies in Indonesia, Saudi Arabia, Kuwait, Oman, Nigeria, Algeria, among others. BGP will continue to strive to provide the best service for clients based on leading technology and operational excellence. ■

Building Resilience, Driving Growth

Popular Aberdeen-based conference **DEVEX** has released its technical program and this year it features 20 operator case histories and presentations. Following the theme, **Building Resilience, Driving Growth**, it features presentations from BP, Shell, ConocoPhillips, TOTAL, Repsol Sinopec, Maersk, Premier Oil and Engie and will provide an ideal opportunity to share subsurface technical knowledge and experiences which will be pivotal as our industry begins to move forward after the shocks of the past two years.

Richard Arnold is the 2017 Devex chairperson.

In addition to the strong technical program, BP's Clair Core will be on display, expert-led masterclasses will take place on both days and yet again, the Young Professionals event will include a panel of industry professionals. There's a diverse exhibition and a variety of networking and training opportunities for all levels of experience, including an exclusive Collaboration and Leadership Lunch and a networking reception.

With the generous support of conference partners and sponsors, DEVEX 2017 has continued with the objective of allowing the first 300 delegates who register to attend free of charge. There is a limited number of 'at cost' places that can be purchased so delegates can take advantage of this low-cost training opportunity.

The conference takes place on May 9–10, 2017, at the **Aberdeen Exhibition and Conference Center**. ■

Unconventional Event

The **2017 Unconventional Resources Technology Conference (URTeC)** is coming this summer to **Austin, Texas**, on 24–26 July. The one must-see event of 2017 for unconventionals is hosted by the **American Association of Petroleum Geologists, the Society of Exploration Geophysicists**, and the **Society of Petroleum Engineers**, with the goal of cross-educating engineers and geoscience professionals, vastly improving their interdisciplinary knowledge base and their decision-making.

This year's program includes hundreds of presentations, both oral and e-papers, as well as short courses, networking receptions, and core exhibits with examples from around the world. As always, the event will feature a sold-out exhibit hall demonstrating the latest technology for unconventional plays in order to capitalize on the improving industry outlook for 2017 and beyond.

URTeC remains the most vibrant and vital event that every upstream energy professional should attend because its collaborative platform and innovation exchange sustain and propel the industry's ongoing success. For more information, visit the URTeC website.

URTeC 2017 will be held at the Austin Convention Center.

Brent
An Aging Giant

The Brent Field, one of the most significant oil and gas discoveries ever made in the UKCS, celebrated its 40th anniversary in November, 2016. Having produced nearly 4 Bboe and given its name to one of the industry's major pricing benchmarks, this aging giant is preparing to close down.

JANE WHALEY

Discovered in 1971, the Brent field opened up the Northern North Sea sector of the United Kingdom continental shelf (UKCS) and was one of the first UK fields to come on stream. It lies about 180 km north-east of the Shetland Islands, close to the border with Norway, and when discovered was estimated to contain 1.8 Bb recoverable oil. Since that time it has produced over 2 Bbo and 5.7 Tcf, and at its peak in the early '80s it was producing more than 0.5 MMbopd, supplying 13% of the UK's oil and 10% of its gas needs. Since its discovery, Brent has been a 50:50 joint venture between Esso and Shell, with the latter as operator.

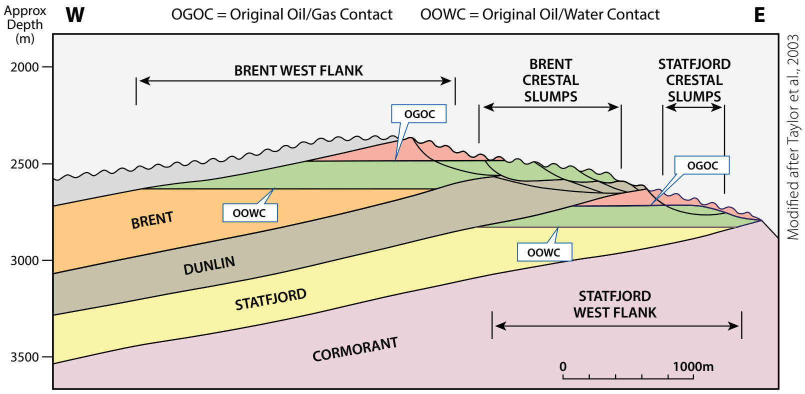
Classic North Sea Petroleum System

Brent proved to be the archetype for many of the fields in the area: a tilted fault block unconformity trap with bounding faults that allowed migration from the Kimmeridge Clay, the most prolific hydrocarbon source in the North Sea.

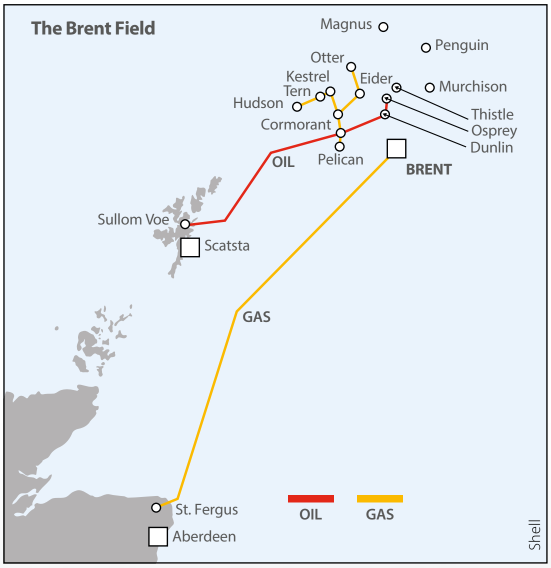
The field, approximately 16 km from north to south and 5 km across, is located in the central part of a 65 km-long fault terrace on the western margin of the Viking Graben, the northern extension of a 1,000 km rift system extending northwards from the Central North Sea Graben. Two major east-west oriented faults divide the northern area of the field into a wide graben and horst feature, creating three separate production areas, whilst a structurally complex zone along the crest of the field, known as the Brent

Schematic view of the four Brent platforms, with Brent Alpha (left) in the south and Brent Bravo, Charlie and Delta stretching over a distance of 10 km to the north.

Shell



Schematic cross-section over the Brent field.



and Statfjord Slumps, forms a fourth production area.

There are two main reservoirs. These are the Middle Jurassic Brent Group, which is, in economic terms, the most important hydrocarbon reservoir in north-west Europe, and the Lower Jurassic/Triassic Statfjord Formation. The latter comprises an upwards-coarsening fluvial sandstone sequence, ranging in thickness from 270m to 300m from south to north. The mud and siltstones of the Dunlin Group separate it from the approximately 240m-thick interbedded sandstones, siltstones, shales and coals of the Brent Group, which were deposited within a shallow marine and coastal plain environment. The Group consists of five formations, known as Broom, Rannoch, Etive, Ness and Tarbert – hence the name.

The hydrocarbons are trapped in a simple fault-bounded, monoclinal structure, dipping about 8° to the west, with in addition some crestal truncation unconformity traps caused by the slumping. The Statfjord Formation is also trapped in the east by faulted Lower Cretaceous mudstones. Seal is provided by a series of mudstones or calcareous mudstones and marls overlying the unconformity surfaces.

The main source rock is the Upper Jurassic Kimmeridge Clay formation,

migrating from both the Viking Graben and the East Shetland Basin, where it has an average TOC of 5.6%. It could be also migrating vertically up the steep, faulted eastern scarp or along the shallower western dip slope of the block, and there is also evidence for lateral migration along the major fault terrace.

Highest Performing North Sea Field

To access the light, sweet crude which is now an industry benchmark, four platforms – Brent Alpha, Bravo, Charlie and Delta – were constructed between 1975 and 1978 in a line running roughly 10 km south-south-west to north-north-east over the field. This was a major engineering feat, since at the time Brent, in water depths up to 150m, was one of the deepest offshore oil fields in the world. Brent Alpha is a steel jacket, while the others have concrete gravity base structures weighing more than 300,000 tonnes each. From the seabed to the top of the platforms, they stretch up over 300m, including the 'topsides', which has the equipment for drilling, producing and processing oil and gas, as well as the accommodation block and helipad. Brent Delta, for example, could accommodate 161 people on board at any one time.

A fifth installation, the floating Brent Spar, which served as a storage- and tanker-loading buoy, was constructed in 1976, loading the first tanker of crude from the field in December the same year. In the late '70s three enormous gas compression modules, containing what were at the time the world's largest offshore reciprocating compressors, were built to re-inject gas into the reservoir. Initially transported by tanker, from 1982 most of the oil was pumped via a 147 km-long pipeline to Sullom Voe in Shetland, while gas was piped 450 km to Scotland.

As oil output began to decline in the 1980s, Shell created a development plan designed to switch the main production from oil to gas, because the high solution gas: oil ratio meant that substantial gas reserves remained in situ. The Brent redevelopment project cost £1.2 billion and involved depressurizing the entire reservoir in order to release solution gas from the bypassed and remaining oil and making extensive modifications to three of the four platforms, thus extending the field's life beyond 2010. In 2000 Brent was externally benchmarked as the highest-performing North Sea field, and by 2001 it was producing record levels of gas.

Brent B, the first Brent platform to be commissioned, was built in Stavanger, Norway and towed out to its location on the field in August 1975.

Detailed Planning Required

When the Brent Field was discovered, it was expected to have a total life span of 25 years. With careful management, continuous investment and the use of cutting-edge technology, that has now been extended to 40 years. But with an estimated 99.5% of the economically recoverable reserves in the field produced, it is time to commence the long, complex and technically demanding task of decommissioning.

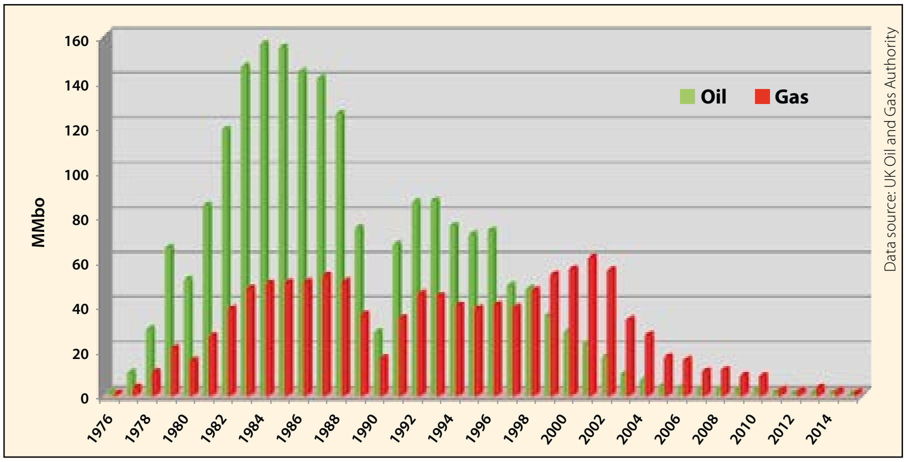
Production from Brent Delta stopped in December 2011 and all 48 of its wells have now been plugged and abandoned. Both Alpha and Bravo ceased producing in November 2014, while production from Charlie is expected to finish within the next few years.

Decommissioning fields and pipelines in the UKCS is a tightly defined regulatory process overseen by the government's Department for Business, Energy and Industrial Strategy (BEIS). It requires that decommissioning is carried out in a way that is technically achievable and economically responsible, while having minimal impact on the environment or involved communities. The safety of those working on the project is of paramount importance.

The decision to decommission a field is therefore not an easy one, and Shell and Esso only took this after many other options of how to re-use the platforms – from carbon capture and storage facilities, to wind farms and even offshore prisons and casinos – had been considered. However, after consultation with BEIS, it was decided that the age of the infrastructure, distance from shore, the lack of demand for re-use, as well as the cost of modernizing the facilities, put alternatives out of the question; decommissioning was the only viable option.

Shell began the long-term planning of this task back in 2006. From early in the process this included an independent review group which objectively looked at all the scientific and engineering methods which could be required, involving many meetings with stakeholders. Much had been learnt from the decommissioning of the redundant Brent Spar 20 years ago, when both the operator and the UK government had determined that the safest place to dispose of it was deep in the Atlantic, but an outcry from the public, activists and several European countries halted that plan. Eventually, in 1999, after a long series of discussions and many imaginative suggestions, the solution was to use the lifted, cleaned and broken up installation as the base for a ferry quay in a Norwegian fjord. This proved effective but far more expensive than originally planned and many valuable lessons, particularly on engaging with communities and the recycling of materials, were learnt from the experience.

Brent Charlie in high seas: the rough weather in the Northern North Sea is one of the many challenges to be overcome in planning the decommissioning of the Brent field.



Brent oil and gas production.

Recycle or Leave?

Shell have now submitted two detailed decommissioning programs to BEIS, one to cover the Brent platforms and the 154 wells, and the other dealing with the pipelines and other subsea infrastructure. Plans must include the removal to shore and subsequent recycling of the platform's topsides, the recovery of associated debris from the seabed and the removal of trapped oil, among many other issues.

Contracts to remove, transport, reuse and recycle the platform topsides have been awarded and include the use of a giant vessel, Allseas *Pioneering Spirit*, which at 382m long and 124m wide is the largest construction vessel ever built (see page 71). It will lift the topsides in one go and transport it to shore. The target is to recycle at least 97% of the topsides material.

For the base of the platforms, the plan is to cut the upper portion of the Brent Alpha steel jacket and recycle it, but working out how to deal with the heavy concrete gravity base structures of the other platforms was less easy. Each base comprises a cluster of concrete storage tanks and not just their weight but their contents had to be taken into account. As well as containing sand ballast, they had been used for oil storage, but assessing their contents was difficult since they are deep underwater and have very thick walls. Help came from a surprising source – NASA. Special gold-painted 'sonar spheres' the size of a bowling ball were designed to access the cells and take sonar images of the cell sediment so that Shell could identify their physical characterization.

The final recommendation, which has yet to be officially approved, is to leave in place the giant concrete structures, as well as the Brent Alpha footings, the drill cuttings and cell contents, due to the technical and safety issues as well as the huge cost involved in attempting to recycle them. Although it is difficult to predict how and when these structures will eventually collapse, studies suggest that the visible part of the legs will remain in place for up to 250 years, the section under the sea may last another 300 to 500 years, while the oil storage cells are expected to remain largely intact for at least 1,000 years.

Pipeline infrastructure in the field includes 28 lines totaling approximately 103 km and thousands of tonnes of steel, concrete and rocks, as well as several subsea structures. A range of options is being considered for the pipelines, depending on their age and condition, including complete removal, cutting and sealing the ends, leaving in place with a covering of rock or trenching and burying them.

Complex Project

Given the harsh marine environment of the Northern North Sea and the complexity and relative age of the structures, retiring the Brent field was always going to be a challenging technological project, requiring careful implementation and considerable innovation, which is expected to take until the mid-2020s to complete. As one of the first major decommissioning undertakings in the world, many eyes will be on this project and despite the steep learning curve it is expected to set an example for the industry to follow.

Over its 40-year life, the Brent field has generated more than £20 billion in tax revenues (in today's money), delivered a significant amount of the UK's energy needs, provided tens of thousands of highly skilled jobs and considerably increased technological knowledge and competence within the oil and gas industry throughout the world. We have much to thank it for.

Acknowledgement:
Many thanks to Shell for assistance with this article.

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The concrete pillars supporting Brent B, C, and D will probably be left in situ.

Shell

Vietnam
Improved Images of Fractured Basement

Detecting basement reservoir fractures on Vietnam's first ocean bottom seismic survey in the Cuu Long Basin.

JIM KEGGIN and WATHIK ALAARAJI, Seabed Geosolutions, Malaysia; **JOE ZHOU**, CGG, Singapore

It is estimated that two billion barrels of oil will be produced from fractured basements in Cuu Long Basin. Can we detect these fractures on seismic data? Can we distinguish good reservoirs from bad? Can we extend the life of producing fields? Results from Vietnam's first ocean bottom seismic (OBS) survey demonstrate the benefits of higher density full azimuth seabed data to enhance our understanding of fractured basement reservoirs.

Fractured Granite Reservoirs

The 'buried hill' basement play in the Cuu Long Basin is unusual in the fact that the shale source rocks are younger than the fractured reservoir. The concept is described by Cuong & Warren (2009) as illustrated in Figure 2, and an example of this fractured granite can be seen in onshore outcrops similar to those seen in Figure 1. In some fields, these fractured reservoirs can be extremely productive, whilst others struggle to be economic. PetroVietnam's prolific Bach Ho oil field has exceptional reservoir characteristics, whilst the Dai Hung Field with similar structure and fractured basement failed to produce economically. Since fracturing varies enormously both between and within basement structures, it is essential to understand fracture development in order to identify the most productive areas and implement successful appraisal and development programs.

Can Seismic Detect Fractures?

Large scale faulting and fracturing can be seen and mapped on conventional towed streamer 3D data, but the quality of the fracture image has always left uncertainty in the interpretation (Figure 3a). Furthermore, small scale fractures are below seismic resolution and cannot be seen directly on

Figure 1: Fractured granite basement outcrop in Na Trang.

the 3D seismic image.

Prevailing theory, modeling and industry experience all suggest that both small and large scale fractures can be detected by comparing seismic data that has been acquired in different directions – a phenomenon called azimuthal anisotropy. The concept is illustrated in Figure 4, which shows sound waves traveling faster in the direction parallel to the fracture orientation and slower when travelling orthogonal to the fractures. The difference between the fast and slow velocities indicates the magnitude of the fracturing, and the direction of the fastest velocities indicates the orientation of the faulting. Azimuthal anisotropy occurs on both compressional wave seismic (PP) and on shear wave converted wave seismic (PS), the effect being considerably larger on the PS data. In both PP and PS, the effect is greatest at higher incidence angles and longer offsets.

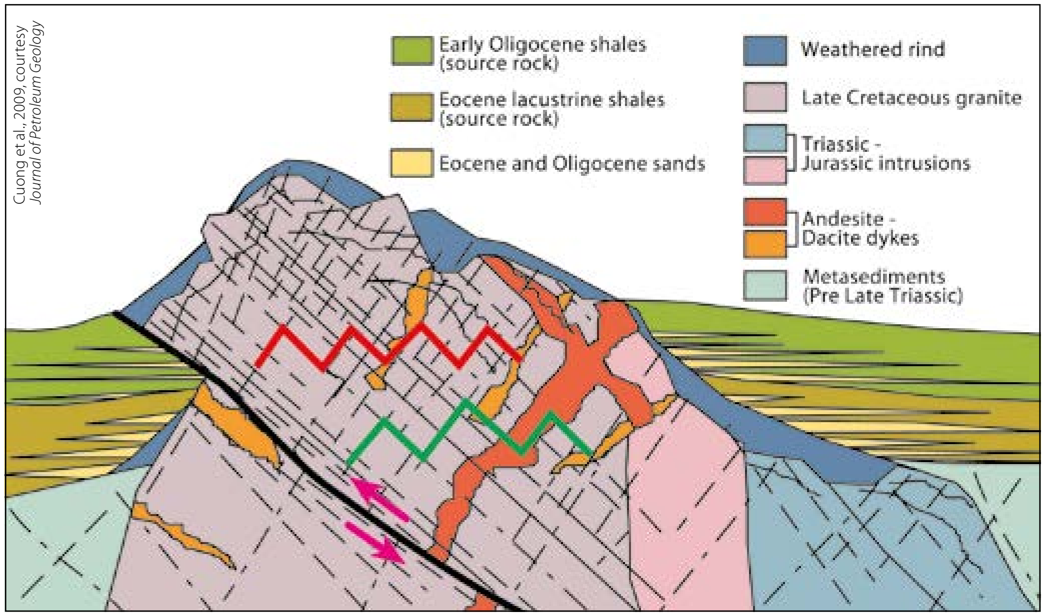


Figure 2: Cuu Long fractured basement play.

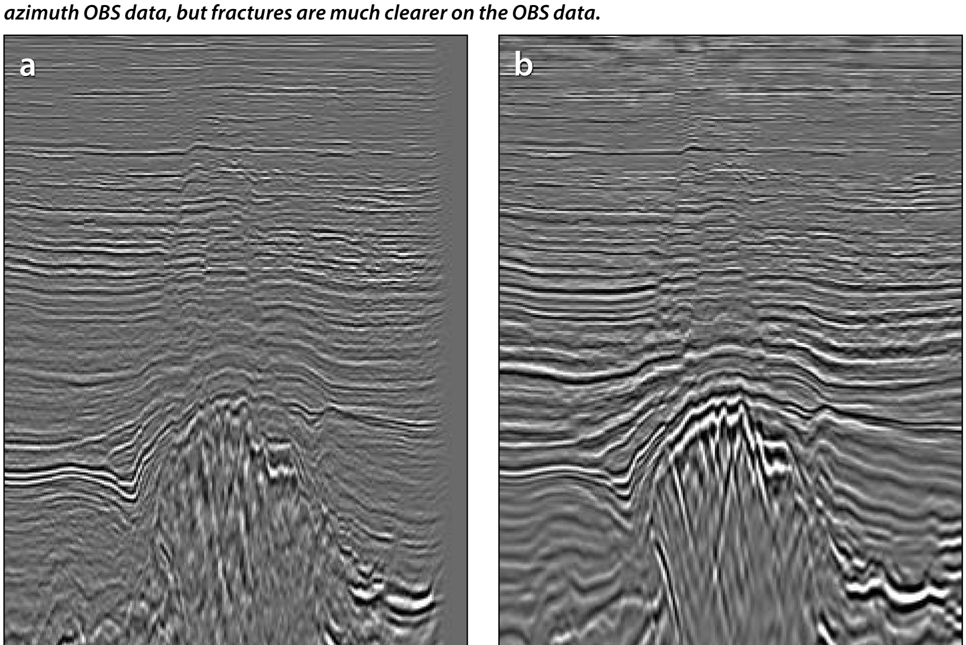
There are several measurements that can be made that will help describe the scale and direction of the anisotropy. Direct measurement of velocity can be made from seismic travel times on both PP and PS data. However, since reflectivity depends on seismic velocity, variations in amplitude at far offsets is also a measure of azimuthal anisotropy and fracturing. Modeling studies using well data from a Cuu Long producing field predict azimuthal amplitude variations at the top basement reflection of 14% for PP data and 28% for PS data. These predictions are for 30 degree incidence angles.

What Kinds of Seismic Data are Needed?

In order to compare seismic attributes from different azimuths, it is undoubtedly essential to acquire seismic data that sample the full azimuth and offset range. The dilemma is that until recently, all 3D images consisted of single azimuth towed streamer data that produce measurements in one direction only; furthermore, these data measure the PP wave field, not the PS wave field where the azimuthal effects are likely to be the greatest. It is optimal to acquire both PP and PS data that fully sample all azimuths and all offsets – i.e. full azimuth seismic – to enhance our understanding of fractured basement reservoirs.

Although it is possible to acquire full azimuth data using the 3D towed streamer method, there are several reasons why ocean bottom seismic should provide the highest quality dataset. Since seismic receivers and sources are independent of each other, there is more flexibility in how to sample azimuth and offset. High fold, well sampled data yield a better direct image of the faults and fractures through improved illumination and noise attenuation. In addition, towed streamer data contain only PP data recorded in the water column. Ocean bottom receivers, which contain three component

Figure 3: (a) 3D towed streamer data 2009 Kirchhoff PSDM; (b) 3D full azimuth OBS data 2016 Kirchhoff PSDM. Large scale fracturing and faulting can be seen on both single azimuth towed streamer and full azimuth OBS data, but fractures are much clearer on the OBS data.



geophones in addition to a hydrophone, generate PS data recorded on the horizontal component geophones. Finally, the combination of the hydrophone signal with the vertical component geophone signal gives us a broadband, high resolution image that is rich in low frequencies.

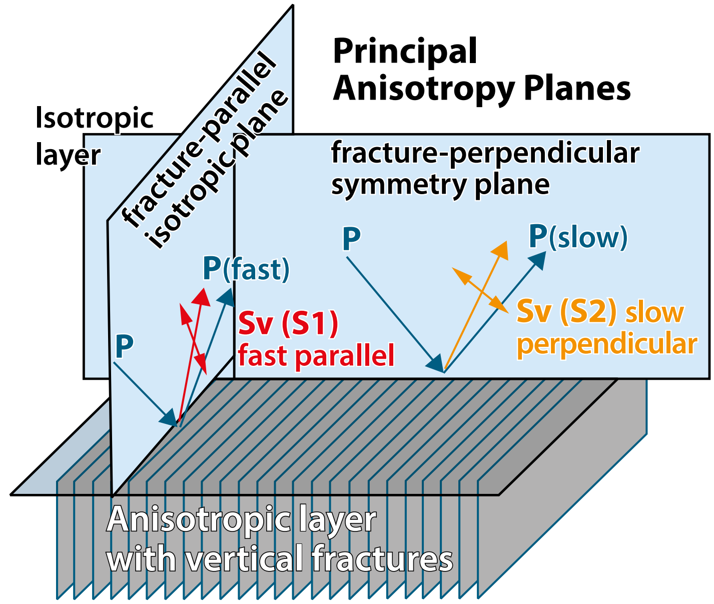


Figure 4: Diagram showing fast and slow directions caused by fracturing.

Bach Ho Ocean Bottom Seismic Survey

Vietnam's first OBS survey was acquired over VietsovPetro's Bach Ho Field by Seabed Geosolutions in 2015. The survey was designed to record data from all azimuths and offsets out to 6 km and beyond.

The 850 km^2 survey, which was large enough to image the entire basement structure, was completed in five months. Seabed Geosolutions used the Sercel Searay Ocean Bottom Cable (OBC) system with an orthogonal shooting geometry that allowed the recording of full azimuth data. Trace density was significantly higher than the legacy towed streamer 3D, with 576 fold in the 0–5 km range compared to the vintage 2009 data which was single azimuth, 50 fold with a 5 km streamer. Processing was performed by CGG in Singapore using a state of the art pre-stack depth migration sequence outputting azimuth sectored PP and PS stacks for analysis.

The improvement in data quality due to both OBS acquisition and advanced processing resulted in a much clearer picture of the basement faulting on the PP stack, where large faults in the granite can be picked with much more confidence, as illustrated in Figure 3b. In addition to the improved basement image, the combination of OBC hydrophone and geophone data has improved the resolution of the shallower section.

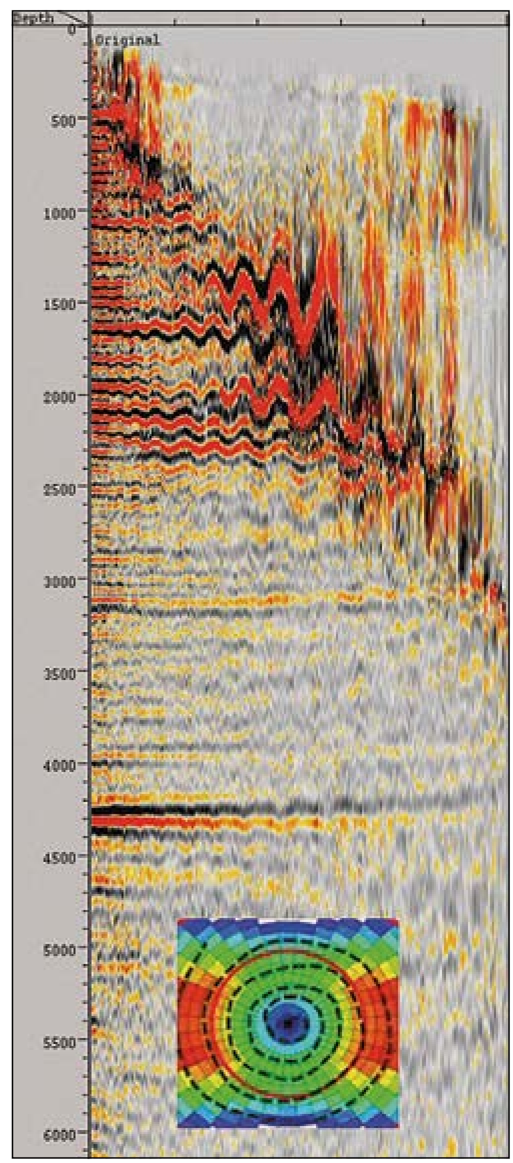
As well as improved full azimuth stacks, we can clearly see azimuthally varying velocities on both the PP and PS data. The PP 'snail gathers' shown in Figure 5 illustrate how far-offset travel times vary with azimuth. Comparisons of fast and slow shear wave travel times can be displayed in map form to show how anisotropy and fracturing varies along a particular seismic event. As can be seen, both PP and PS azimuthal anisotropy occurs at all levels, not just at the top basement. Figure 6 shows the difference in travel time between the fast and slow shear wave data for a shallower horizon at a depth of around 2 km. The variation in anisotropy is clear and makes geological sense, with the highest anisotropy being seen around the location of known faults.

Unfortunately, a similar analysis of the top basement is less clear since deeper travel times are affected by what occurs in the shallower section, and further efforts need to be implemented to unravel the overburden effects in order to reveal a reliable picture of fracturing in the basement. Recent advances in this field look encouraging for application in this dataset (e.g Boiero and Bagaini, 2016).

So far, only the effects of anisotropy have been considered on PP and PS travel times. What about seismic amplitudes? Can reliable anisotropy measurements be obtained at the deep top basement reflection from PP and PS amplitudes?

Ideally, it is best to measure and compare the amplitudes of the far-offset azimuth sector stacks where the expected azimuthal amplitude effects should be the largest, but these data are not always available. In this case, the amplitudes from full offset stacks of both PP and PS data were compared as shown in Figure 7. For the shallower horizon, it is comforting to see that the anisotropy maps for both PP and PS amplitudes look very similar in form to the maps produced from the shear wave travel time measurements, with areas of greatest anisotropy located around the position of known faulting. For the deeper event at the top basement, we also see azimuthal effects that relate to the structure, but there remains uncertainty as to whether these

Figure 5: PP 'snail gather' clearly shows how travel times vary with azimuth.



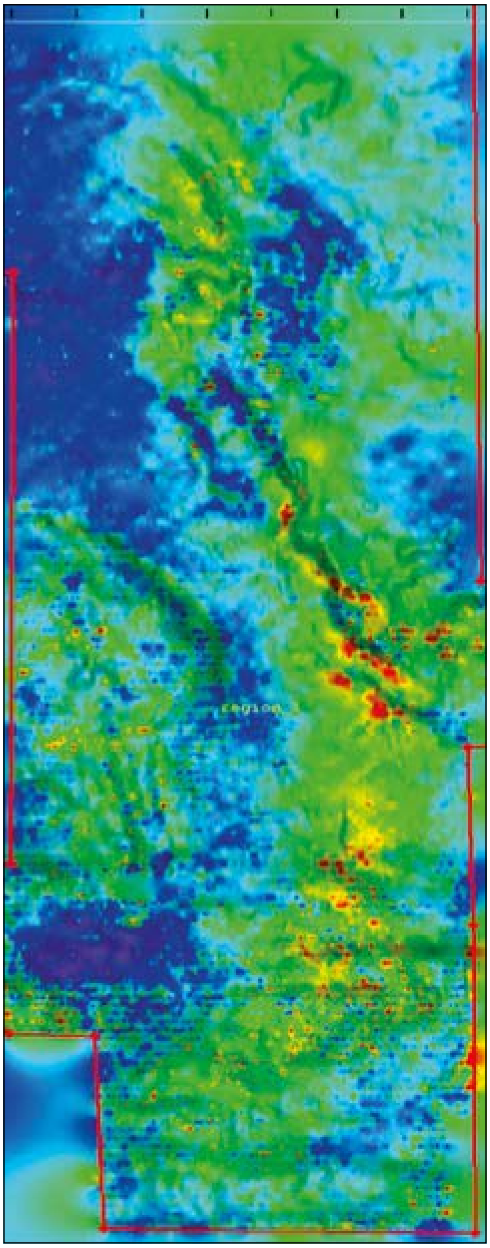


Figure 6: Shear wave splitting analysis shows clear time delays between fast and slow directions on the full azimuth OBS data.

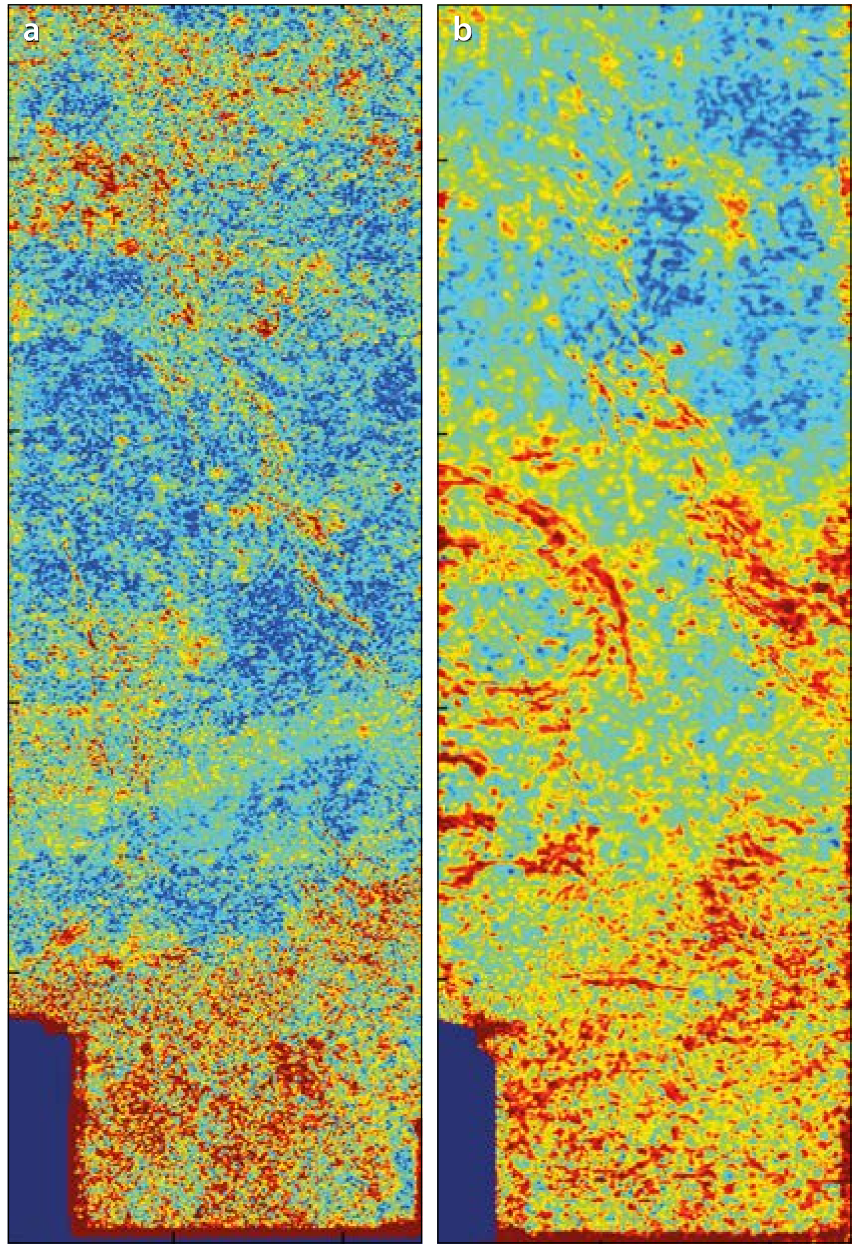


Figure 7: Magnitude of PP (a) and PS (b) azimuthal amplitude anisotropy. Difference in amplitude between the hottest and coolest azimuths in both cases.

azimuthal effects are due to fracturing, or due to variations in illumination or noise.

Enhanced Understanding

The higher density, wide azimuth ocean bottom cable data deliver improved images of basement fracturing and faulting, which enhance our understanding of the distribution of high quality basement reservoir.

Azimuthal anisotropy can clearly be seen on travel times and amplitudes of both PP and PS data. On the shallower horizons, the azimuthal effects occur around areas of known faulting, so the correlation beween anisotropy and faulting is convincing. On the deeper basement events, azimuthal effects can also be seen, but other factors such as azimuthal variation in illumination are limiting our ability to reliably map the basement fractures using anisotropy measurements. Further work to compensate for the overburden should result in better basement fracture maps in the future. Correlation of oilfield production data with these fracture maps will help confirm our predictions.

Acknowledgement: *Thanks to VietsovPetro and PetroVietnam for permission to publish this article.*

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Is There a G in Decommissioning?

Geological review and oversight is as important at the end of a well's life as it was during exploration.

JOHN SIMPSON and JOHN MCNAB, Exceed Ltd

"All penetrated zones with flow potential that have been identified as requiring isolation should be isolated from each other and from surface or seabed, by a minimum of one permanent barrier, or two as appropriate" (*Oil and Gas UK Guidelines for the abandonment of wells,* Issue 5, July 2015).

Sounds simple; however, the abandonment philosophy of a particular well is as unique as its exploration phase. Factors such as age, lithology, infrastructure condition, location and production lifecycle are some factors that combine to provide the challenge.

Like everything in life, information is key. Wells less than ten years old tend to have good records and have been engineered with abandonment in mind, but those greater than ten years old often have limited information and well abandonment was not usually a consideration in their design.

Some of the challenges that Exceed, which specializes in well management and decommissioning, has experienced in abandonment operations to date include lack of, or no cement behind casings, geological anomalies, lack of tooling for older wells, limited well access, pressurized annuli, challenging budgets – to name but a few.

Let's look at some of the technical challenges in a little more detail…

Cap That!

That low permeability seal withstood the test of time, the thickness and extent being sufficient to keep those hydrocarbons safely stored until we were ready to extract and use them. Now the hole we created must be plugged, in order to keep the remaining non-economically-producible oil and gas in the reservoir permanently.

Rock to rock is a description that immediately conveys the final requirements of the artificial seal; it must fill the wellbore, bonding with the caprock which was drilled through, and be of a sufficient length to ensure a competent seal.

The most commonly accepted plug material is good quality hard cement, which provides similar physical and chemical properties to the rock it is replacing. It should be impermeable, have a compressive strength comparable to the formation strength at the setting depth, be capable of withstanding both mechanical stresses and chemical conditions in the well, adhere to rock and metal (if required), will not shrink, and can be drilled out in case access is required. Cement, however, will typically be heavier than the fluids in place, such as drilling mud, and cement slurry will slump downwards and displace the mud upwards, leading to contamination, channeling and ultimately, poor sealing capabilities. To prevent this, a tested support is required, typically a mechanical plug set in the casing and tested.

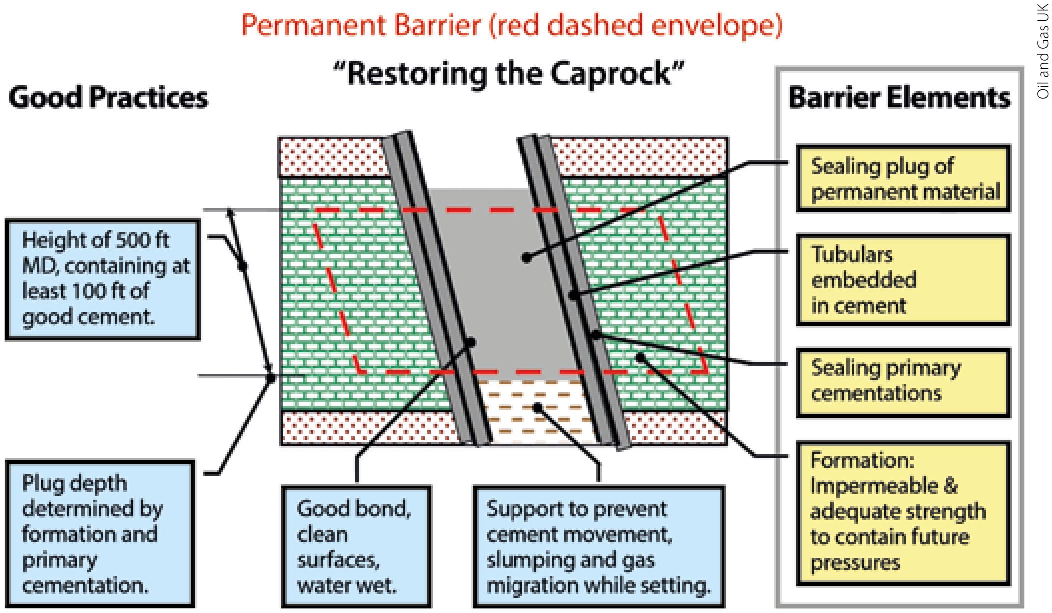
Alternative materials such as resins and grouts are acceptable, as long as their properties are at least equivalent to good cement. Sealing materials used in packers and plugs (rubber, synthetic materials, etc.) will degrade over time and therefore cannot be considered as a permanent barrier for well abandonment.

A weighted fluid such as drilling mud left in place cannot be considered a

Drillpipe make-up.

barrier; it may degrade over time due to settlement of weighting material, influx, cross-flow or chemical processes.

Casing Fully In Place: Where well history or logging confirms that there is good cement in place behind the casing at the caprock depth, proper abandonment can be achieved by simply placing cement inside the casing at that depth. With a tested mechanical plug as a base, the cement should be load tested with a drill bit or mill once set, to prove compressive strength has been achieved. This will also confirm top of cement and hence plug length, which has to comply with legislative requirements.



Schematic of a permanent barrier showing the barrier envelope (red dashed line) to restore the caprock, its barrier elements and recommended practices.

Casing Partially In Place: Where well history or logging confirms that there is no cement in place behind the casing at the caprock depth, a technique known as 'Perf, Wash, Cement' (PWC) may be used to place cement behind the casing. The lack of cement may have been caused by, for example, losses during the original cement placement operation, or contamination of the annular cement which lies adjacent to the caprock. PWC involves perforating the casing using TCP guns, thereby providing a flow path through which to displace the material in place behind the casing. Specialized tools will be placed across the perforations, enabling mud to be forced through the perforations, and for old mud or contaminated cement to be displaced out. Once the area between casing and caprock has been suitably washed, cement will be pumped into place, both outside and inside the casing.

If this technique has to be qualified prior to approval by the operator or governmental department, the internal cement will be drilled out to allow a cement bond log to be run to confirm competent cement in the casing to caprock annulus. In this case, the internal cement will have to be replaced following successful logging. Once this technique is approved, future operations may not require the drill-out and log operation to be carried out again.

As in the previous technique, the internal cement will have to be tagged to confirm compressive strength development, top depth and cement plug length.

No Casing In Place: Where logging confirms that poor cement is in place behind the casing at the caprock depth, but is sufficient to prevent circulation and therefore preclude the use of PWC, section milling would be utilized. This requires a specialized tool to be run to depth, and when mud is pumped downhole a series of knives are activated, and the casing and any cement between that and the caprock is cut away by rotation of the knives. The knives will extend to a maximum such that they cut to the open hole diameter, thereby removing all non-native material, except the milling mud. A section (hence the name) of casing/cement of some 60m will typically be removed. Once this operation is completed, an open hole cement plug will be placed, again with support to prevent slumping. Typically, the height of the plug will be about 150m – a total of 60m across the milled section and 90m above – which allows for any contaminated cement to be above the milled depth.

An alternative to the above, mainly for shallow formations, is to cut and pull the casing above top of annulus cement, and place an open hole cement plug at the required depth.

Collapsed Formations: An alternative to cement occurs where a particular formation has collapsed onto the casing, for example in shales or swelling salts. Where these can be pressure tested, they may be approved as permanent abandonment barriers in place of cement.

Other Geological Considerations?

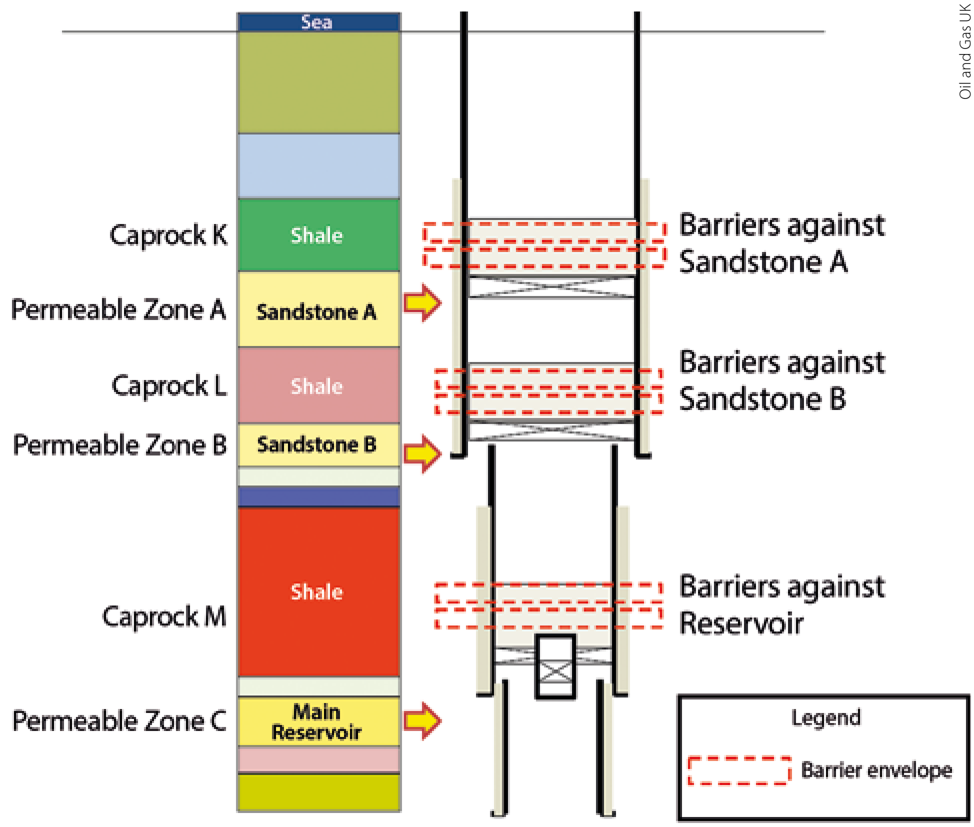
So what are the other geological trouble-makers in the well abandonment phase?

Moving salts and other mobile formations can cause significant problems. Exceed have come across several decommissioning projects, mainly in the southern North Sea, where access to the well is not possible via a standard intervention deployment method, due to casings and therefore tubing being crushed by the adjacent formation. This can have a huge effect on the complexity and ultimately the cost of the abandonment, as the lower formation still has to be isolated.

In an ideal world, the barriers in a well would include one double cement barrier above the reservoir and one shallow, environmental double cement barrier. Areas of the well where communication or cross flow between the zones is possible will require additional plugs or barriers. Exceed have come across wells that could potentially require as many as five double cement plugs. This ultimately adds time and cost to the project.

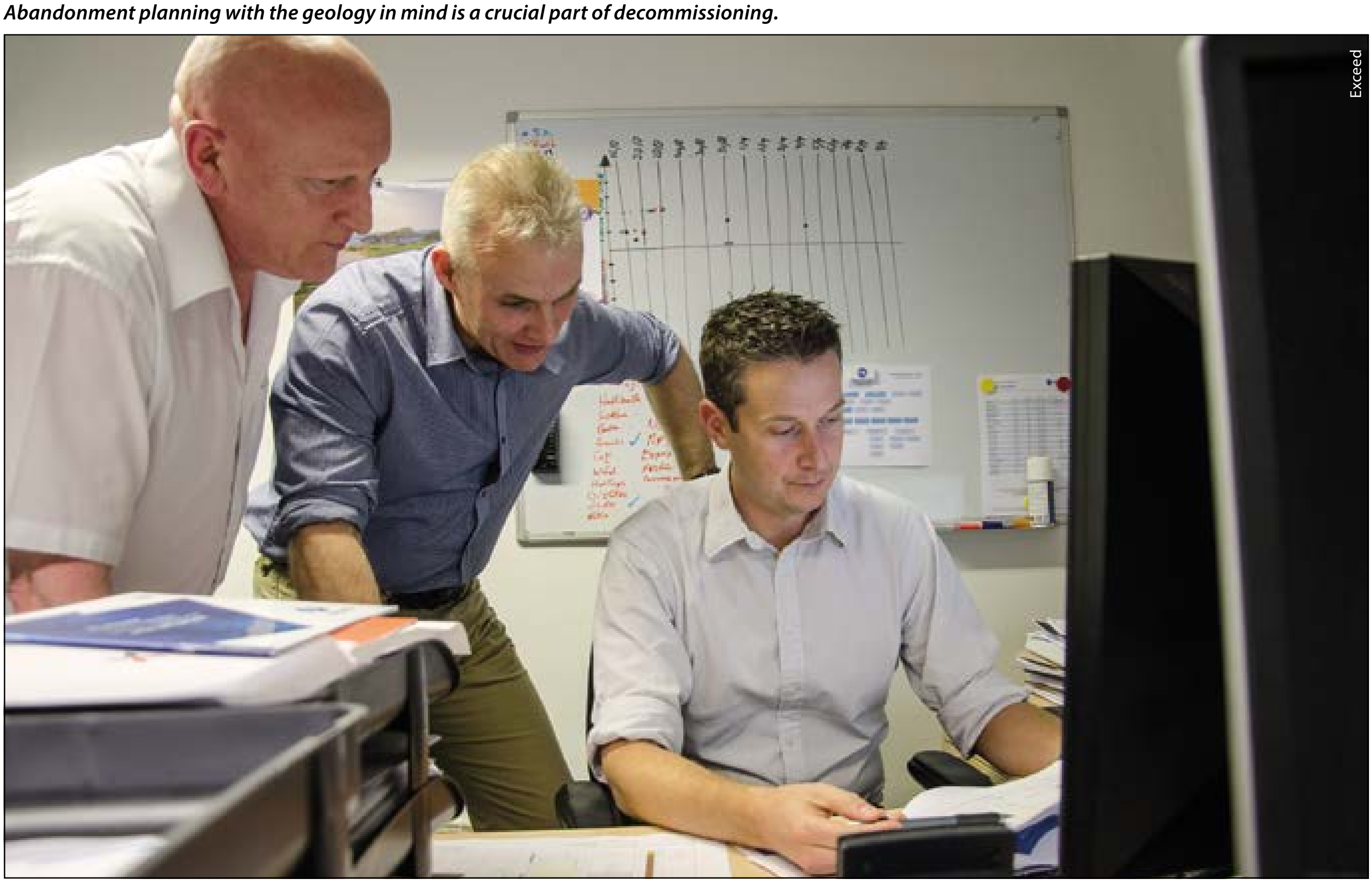
This may all seem straightforward and one would assume an old well file can be opened and the information will simply fall into our laps. If only that were true! Wells are now being considered for abandonment where there is little more information than a hand-drawn sketch. The life cycle data for the well may have been lost through numerous asset transfers while engineers who have worked on the wells have disappeared from the industry.

A fresh set of geological eyes are needed on these assets, guiding the engineers on potential risks, geological issues and possible solutions. The 'G' is not at the end of decommissioning, but right at the very beginning. All the issues noted above should be considered at an early stage of planning to prevent any surprises during operations. Contingencies can be planned and engineered in plenty of time, ultimately minimizing the effect on budgets. ■



Example of the position of permanent barriers determined by the actual geological setting relative to the zones with flow potential or caprock. The main reservoir and sandstones A and B are considered hydrocarbon-bearing and/or overpressured, hence require two barriers opposite a competent caprock.

Abandonment planning with the geology in mind is a crucial part of decommissioning.



Hunting for NULFs

Is using well data to hunt for those NULFs (Nasty, Ugly Little Facts!) that lead to breakthroughs in exploration thinking becoming a lost art?

JOHN DOLSON
DSP Geosciences LLC and Delonex Energy, UK

Thomas Huxley (1825–1895), in an address in 1870 to the British Association, famously quoted, "The great tragedy of science is the slaying of a beautiful hypothesis by an ugly fact." One of the key roles of a geologist is to sort through well and rock information to test old ideas with new data or find new ways to think about old data.

But are we losing the ability to teach the next generation of geoscientists how to use existing data to get new ideas? Are we allowing 3D computer or seismic images to trump hard work analyzing well data? Understanding how to interpret oil and gas shows in the context of migration and entrapment using well data is hard work. Well reports have to be read, logs and log analysis investigated, mud logs, head space gas, cuttings, biostratigraphical reports and petrography understood. None of this is glamorous work, but it has to be done.

Understanding Shows

Consider a case where company A had a multi-disciplinary team screening its acreage to decide what to retain. A block acquired in a company merger has a dry hole on it. Seismic shows the dry hole is a small 4-way closure. Maturation maps show it is over 50 km away from mature source rock. Concluding that no oil had migrated into this area, and with no other visible structural traps, the acreage was dropped. Company B was thrilled, because the 'dry hole' actually had 3.5m of pay on logs in a porous Jurassic sandstone. They recognized a seismically defined up-dip stratigraphic trap – and subsequently drilled the 1.4 Bbo-in-place Buzzard field discovery (Carstens, 2005; Dolson, 2016; Ray et al., 2010). The more careful analysis of the 'dry well' invalidated the pessimistic migration model and also de-risked reservoir issues.

Sound unusual? It isn't. A major complaint I hear from all oil companies is that far too many young geoscientists are drawn immediately to 3D seismic or computer simulations without a firm understanding of how to use well and geochemical data to test models.

Two of the ground-breaking papers on understanding oil and gas shows were those of Schowalter (1979) and Schowalter and Hess (1982). Few younger geoscientists are even aware of these papers or understand how to distinguish a show along a migration pathway from live oil within an accumulation, or how to use water saturation (Sw) to determine position in a trap. Vavra et al. (1992) and Hartmann

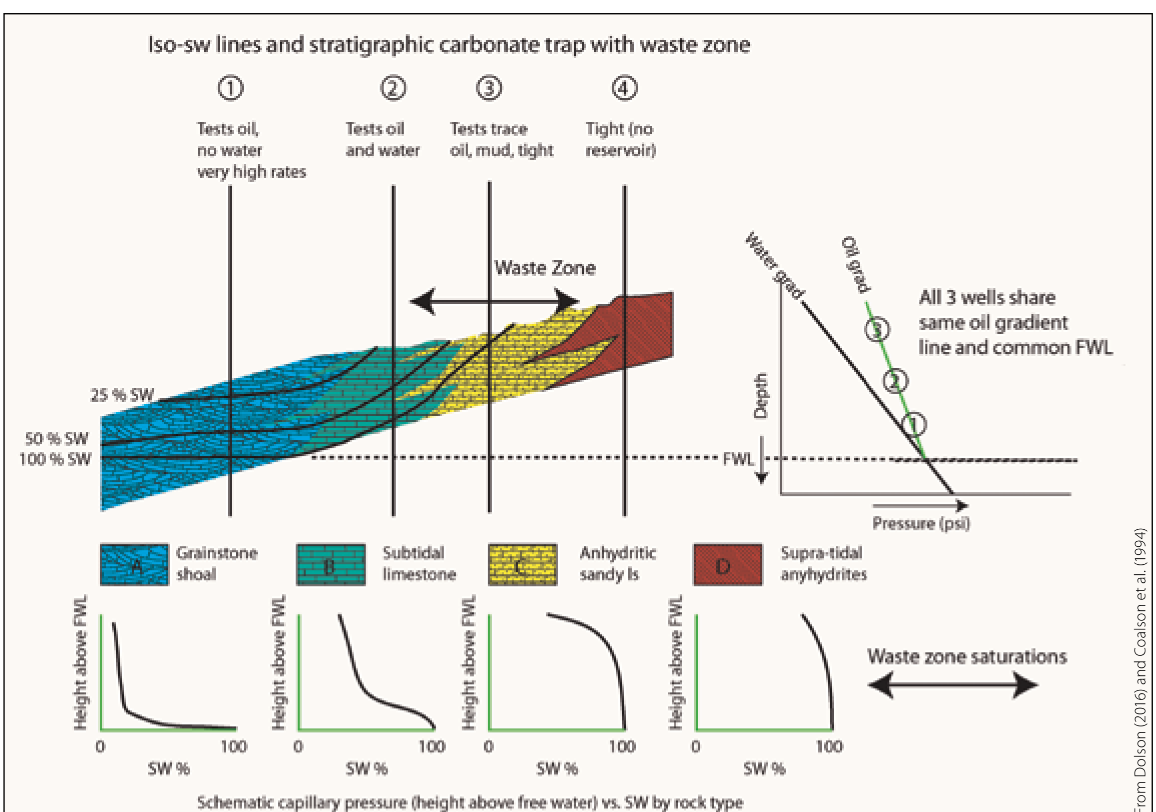


Figure 1: Water saturation (Sw) variation in a stratigraphic trap where test results can be misinterpreted and a commercial field missed.

and Beaumont (1999) are two additional papers that should be required reading for any geoscientist looking to understand how to interpret test data and shows in the context of capillarity and position in a column.

Consider Figure 1, a carbonate shoreline trap with degrading reservoir quality due to pore throat reduction up-dip into waste zones. How to interpret the test results depends not just on the sequence in which the wells are drilled, but the ability to integrate the petrophysical data. If well 3 is drilled first, it may be declared a dry hole with high Sw that looks wet in porous but low permeability rock. Drill well 1 first, and optimism abounds, but results in disappointment on the up-dip offset. Well 2 is more problematic. The key to recognizing a potentially large field here is the pressure and rock data, which shows the different facies as part of the same column. The fact that oil is actually recovered in wells 2 and 3 shows a trap with a column. If knowledge exists of the pore-throat sizes or capillarity, an astute geoscientist might be able to quantify the elevation above the free water level and speculate on where better facies might exist that would produce water-free oil, potentially even down-dip of wells 2 and 3.

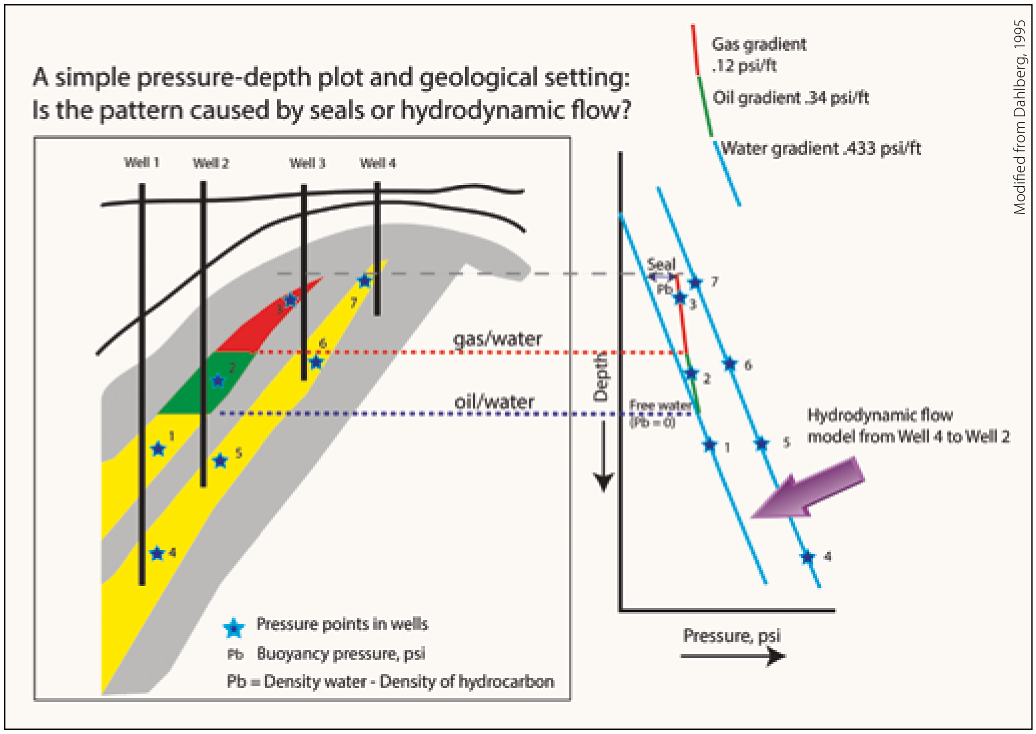


Figure 2: Simple pressure-depth plots can be used as a guide to understanding seals and traps.

Key Skills

Learning to understand test and show data to seek out those elusive 'NULFs' requires re-thinking porosity and permeability in a way that quantifies pore throat distribution. In Figure 1, the porosities may be similar in wells 1–3, but with radically different pore throat sizes and saturations at any point in the trap. Pittman (1992) and Winland (1972) determined a way to calculate pore throat sizes statistically using readily available permeability and porosity data. Once pore throat sizes are estimated, and with reasonable assumptions of interfacial tension, wettability and subsurface water/hydrocarbon densities, pseudo-capillary pressure curves can be made to estimate saturation-height functions. An example of this is shown for the Pennsylvanian carbonates in Colorado's Four Corners area in Dolson (2016). In addition, rocks with similar pore size distributions will have similar flow units. Understanding the geometry of these flow units and their saturation variations at any given point in a column is critical to understanding development scenarios (Ebanks et al., 1992; Gunter et al., 1997).

Without these skills as part of their fundamental 'tool kit', young geoscientists are doomed to miss a lot of plays, inappropriately plug a lot of wells and leave oil behind pipe for others to find. Worse, they may confuse oil or gas-water contacts (as at the base of well 2 at 100% Sw) with a free water level, failing to recognize the trap size.

Understanding pressures is another key skill. Integration of pressure data is critical to understanding connectivity and position in a trap. Figure 2 illustrates seal recognition from pressure data and how to use the slopes of the curves to calculate fluid density. However, in the absence of other data the pattern shown in the image could also be interpreted as the result of hydrodynamic flow.

In 37 years of consulting, I have seldom seen geoscientists make potentiometric surface maps to quantify the impact of hydrodynamic flow in tilting oil and gas contacts, despite the landmark work of Hubbert (1953), Dahlberg (1982, 1995) and England (1994). Many geoscientists do not recognize the presence of tilted oil and gas columns caused by an upward flow of expelled waters from over-pressured areas towards the basin flanks. Numerous recent examples of tilted contacts in deep basin settings show the potential to underestimate trap size due to tilting (Ferrero et al., 2012; Muggeridge and Mahmode, 2012; O'Connor and Swarbrick, 2008; Riley, 2009; Robertson et al., 2013). (For a case history of a tilted gas-water contact from deep basin water flow see the online version of this article.)

FIS and Migration Modeling

Many advances have been made in capturing new information in old wells, particularly Fluid Inclusion Stratigraphy (FIS) (Dolson, 2016 and Hall, 2008). Mud log, mud gas and cuttings data provide the first step in detecting hydrocarbons but in some cases shows are suppressed and hydrocarbons

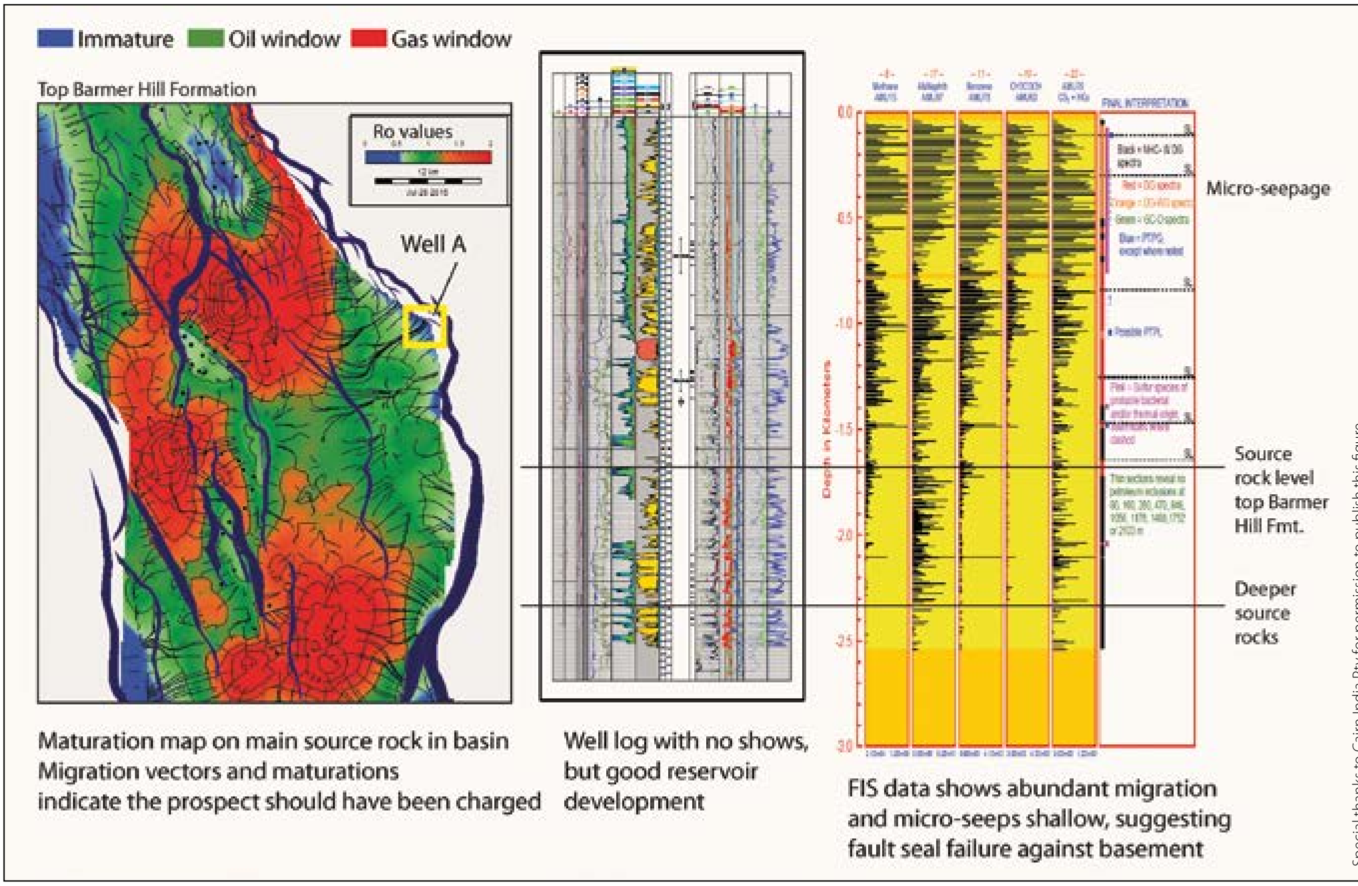


***Figure 3:** Fluid inclusion stratigraphy vs. mud log shows, Barmer Basin, India (Dolson, 2016). This dry hole was attributed to lack of charge due to complete absence of shows in the mud log, but FIS data proved migration had occurred and poor seal was the most likely cause of failure.*

missed. Fluid inclusions often provide new insights, such as the temperature of emplacement of fluids, API gravity, salinities, proximity to pays, migration pathways, seals and even biomarkers useful for source-to-oil correlation.

The example shown in Figure 3 is from a well where there were no mud log or sample shows. FIS data, however, showed abundant migration and evidence for micro-seepage at the surface. These data provide new insight plays and prospects.

Modern petroleum systems software performs very powerful 4D and 3D migration and maturation modeling – but how rigorously are the models tested against well data? Calibration is essential, and requires carefully analyzing and capturing well information in ways that can be displayed in the models, as in Figure 4. Proper shows analysis is a time-consuming but critical role for a geologist.

Another useful technique is to quickly and qualitatively convert depth seismic depth images into reservoir-seal pairs (in meters of seal capacity) based on amplitude variations (www.zetaware.com). Figure 5 models migration off the west coast of Africa. While only a crude representation of the real subsurface data, these solutions give a good feel for how migration might work, and can be developed quickly.

While much more sophisticated models can be run using more quantitative rock property modeling, pressures, hydro-dynamics, and other data, they are time-consuming and expensive to build, particularly if in a 3D seismic volume. Worse, all models involve multiple assumptions on fluid phase, seal capacity, fault leakage, pressures, etc., adding complexity to the model but not necessarily insight. A good discussion of the main benefits and pitfalls to petroleum systems migration modeling is that of He (2016).

The Young Geologist Skill Set

Just some of the skill sets needed for young geoscientists are summarized here:

- Understand the rocks: go look at cores and cuttings.
- Think of rocks in terms of pore-throats, capillarity, Sw and position in a trap.
- Understand pitfalls in log analysis or formation damage due to unusual minerals and/or shaliness.
- Build and refine oil and gas show databases that can be mapped and visualized quantitatively.
- Post-appraise key dry holes carefully, looking for anomalous shows.
- Simulate migration scenarios, first conceptually, and then with appropriate software.
- Build appropriate seal and pressure maps and integrate them into migration models.
- Supplement mud log shows with FIS, thin sections or classic fluid inclusion studies to help ground-truth migration and entrapment.
- Systematically use geochemical analysis of source rocks and reservoired hydrocarbons to try to understand migration pathways and source to oil correlations.

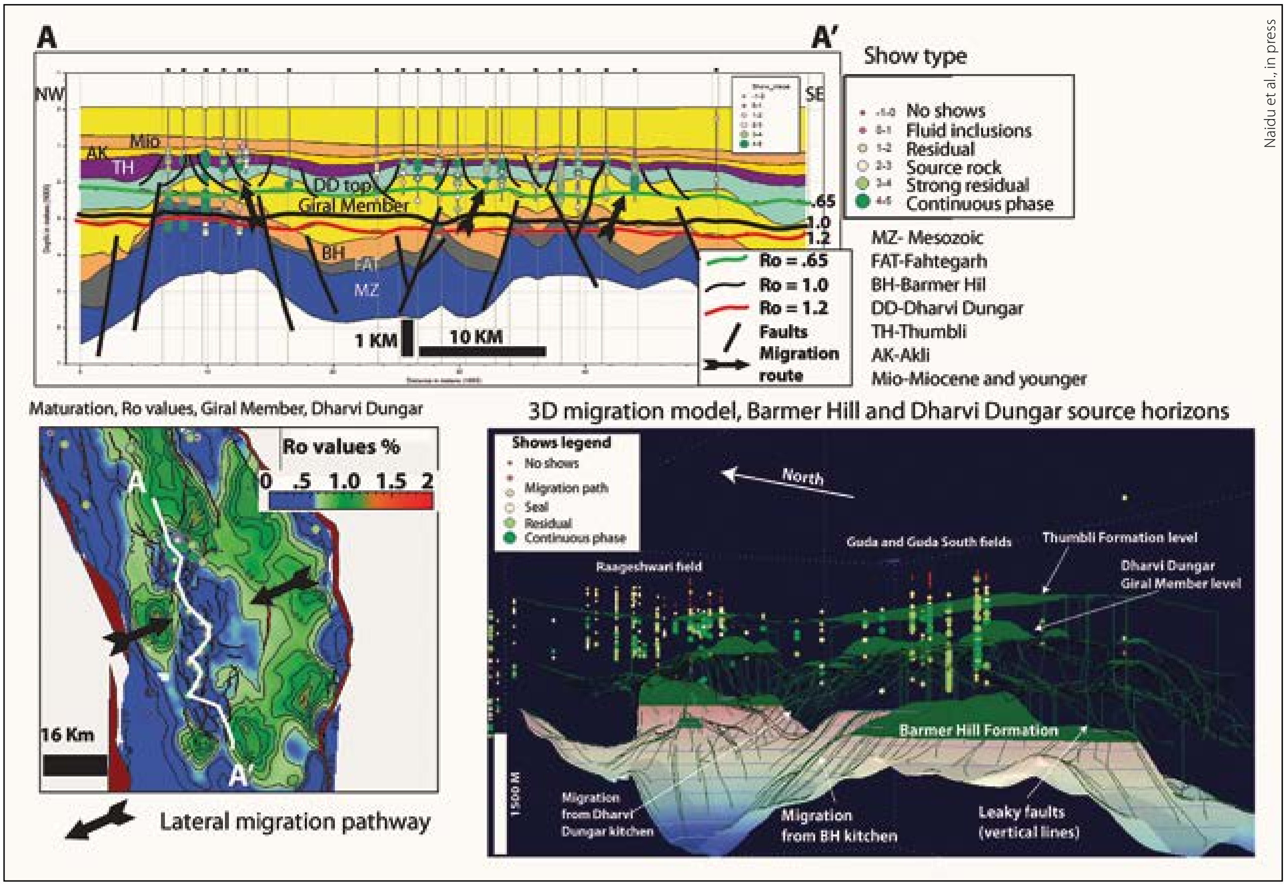


Figure 4. Trinity 3D migration model, maturation kitchen and shows data, Barmer Basin, India. The source system charging the Thumbli Level (TH) reservoirs is thermally immature across the crest of the field and vertical migration is required to charge this interval.

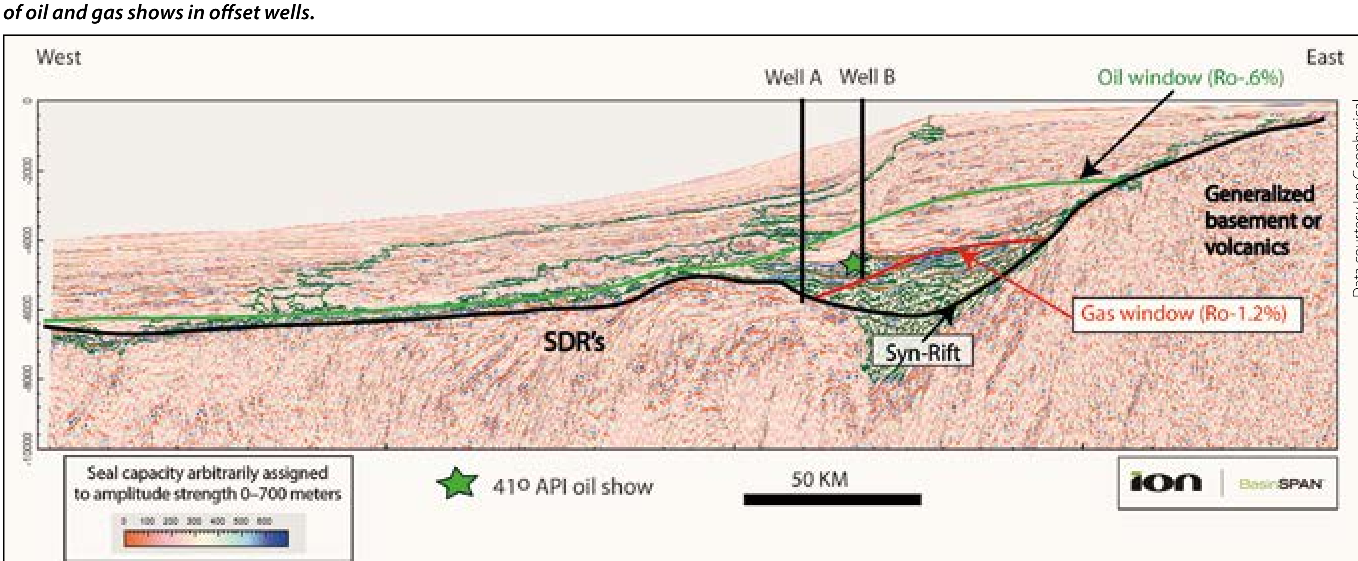
Most importantly, young geoscientists should be taught to become skeptics who search for data that does not fit existing paradigms. They need to be rewarded for the hard work of integrating data properly to test their models and play concepts. They must go back to basics, challenge conventional wisdom and continuously scour for data that yields the 'NULFs' that lead to new plays.

(For a longer version of this article please see geoexpro.com.) ■

Acknowledgement:
Cairn India Pty and Ion Geophysical have been particularly helpful for permissions to use some key figures. The author is also indebted to Zhiyong He and Jeff Corrigan for review of this manuscript and many productive discussions over the years regarding calibration and construction of petroleum migration models.

References available online.

Figure 5: Seismic depth section modeled in Trinity software for migration from syn-rift and early rift source rocks. Testing the model requires calibration of oil and gas shows in offset wells.



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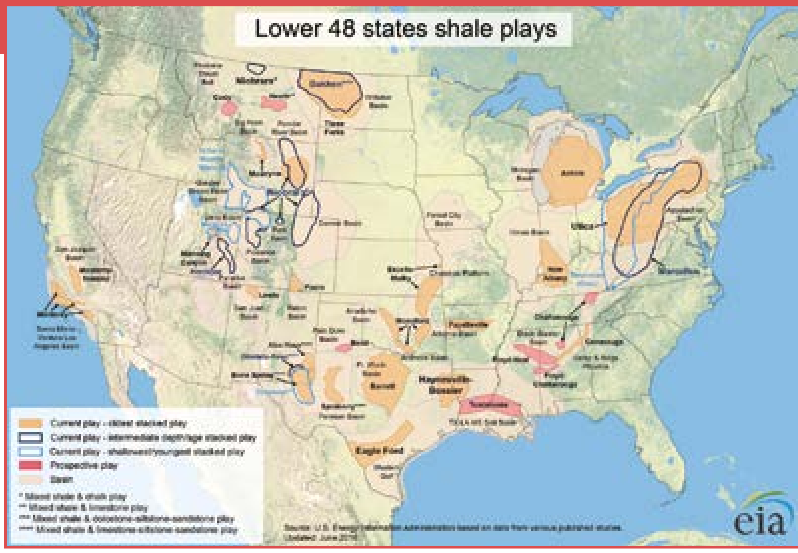

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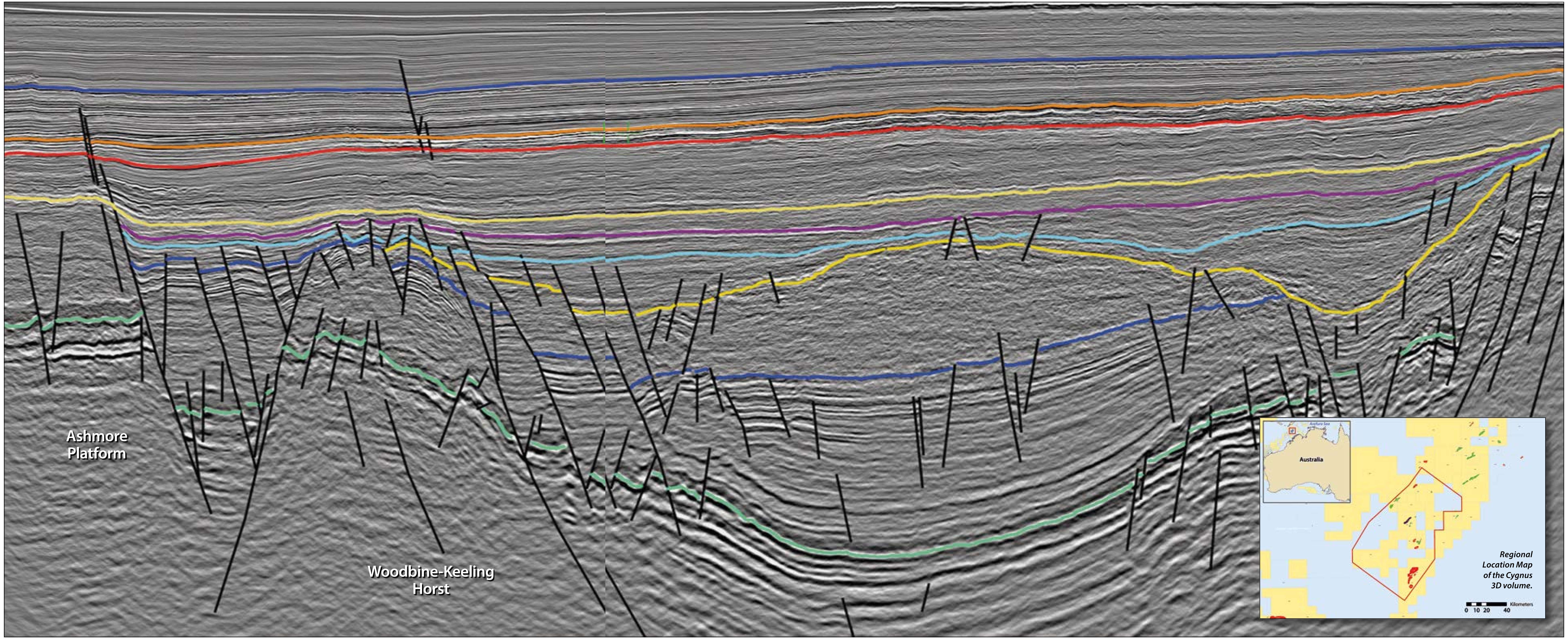
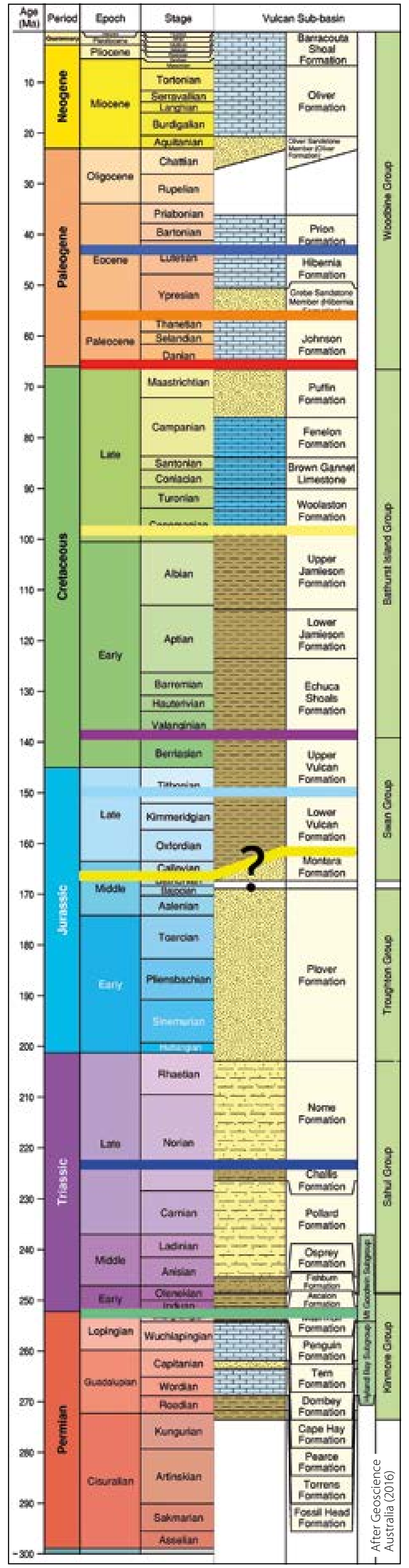
New Imaging of the Vulcan Sub-basin

Polarcus, in collaboration with Spectrum and DownUnder GeoSolutions, is acquiring a 7,200 km² RightBAND™ multi-client 3D seismic survey over the Vulcan Sub-basin, offshore north-west Australia. Historically, sub-optimal acquisition and processing strategies of the legacy data across the basin have not been able to address the geological and geophysical challenges, limiting understanding of existing proven plays and the evaluation of future upside. The broadband survey is being acquired by the *Polarcus Naila* using an XArray™ configuration of 10 x 112.5m x 8.1 km with a triple source and continuous recording.

West–east Pre-SDM in-line across the southern Vulcan Sub-basin from the Cygnus multi-client 3D dataset.





The Vulcan Sub-basin

The Cygnus survey is located in the southern Vulcan Sub-basin, one of the most prospective areas of the Bonaparte Basin, containing oils that are normally very light. Integrated processing techniques shed light on this area, which has been historically hard to image.

TONY PEDLEY, Polarcus; **RICHARD PALMER**, Polarcus Geophysical Consultant

The Vulcan Sub-basin is a north-east to south-west trending Mesozoic extensional depocenter located in the western Bonaparte Basin between the Ashmore Platform to the north-west and the Londonderry High to the south-east (Figure 1). It extends south-westwards to connect with the Heywood Graben in the Browse Basin, opening north-eastward to the Nancar and Timor Troughs. The sub-basin comprises a complex series of horsts, grabens and terraces which developed as an intra-continental graben in response to extension in the late Callovian.

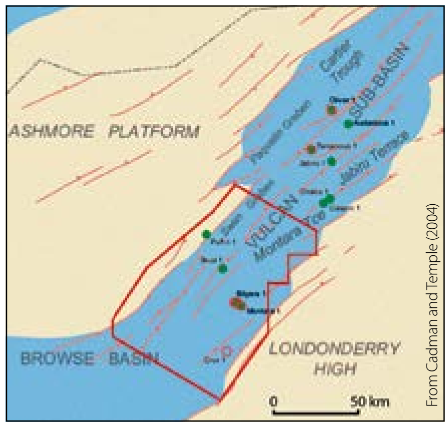


Figure 1: The Cygnus 3D volume with structural elements and selected well locations.

The Callovian Unconformity marks the base of the syn-rift sequence, which is of critical importance as it contains the source rocks that provide the majority of hydrocarbon charge to reservoirs above, below and also within the syn-rift sequence. Widespread marine conditions prevailed during the syn-rift phase with deposition of shales of the Lower and Upper Vulcan Formations. The Jabiru, Challis and other intra-basinal horsts were partially to fully emergent at this time, and sand-rich fan deltas were shed from the Londonderry High and exposed horsts into the adjacent depositional lows, the Montara Formation forming from footwall erosion of exposed horsts and rotated fault blocks at the base of the syn-rift sequence.

Deposition of the Upper Vulcan Formation was terminated by the Valanginian unconformity, marking the end of the syn-rift and a transition to passive margin conditions. Post-rift thermal subsidence commenced and resulted in widespread flooding of the continental margin. With continuing subsidence, Aptian to Albian marine sediments of the Jamieson Formation transgressed the area. A combination of restricted sediment supply and increasing water depth resulted in the accumulation of Upper Cretaceous fine-grained carbonates of the Woolaston and Gibson Formations. Continued deposition of a mixed carbonate–clastic ramp continued, until a sea-level fall led to the deposition in the Maastrichtian of the low-stand clastic fans of the Puffin Formation across the southern part of the Vulcan Sub-basin and adjacent Ashmore Platform.

The Tertiary succession is characterized by the establishment of a sub-tropical carbonate platform as the Australian plate moved northward, climatic warming culminating in the development of tropical carbonates and reefs. This carbonate deposition was interrupted in the Early Eocene and Miocene by glacio-eustatic sea level lowstands, allowing prograding sand-prone deltas of the Grebe and Oliver formations to be deposited.

Established Petroleum System

The main source rock intervals recognized in the area to date are the marine-dominated Lower Vulcan Formation and more terrestrial fluvio-deltaics of the Early-Middle Jurassic Plover Formation, with the Lower Vulcan Formation considered to be the dominant source rock interval for both the oil and gas generated in the region.

Clastic units within the pre- and syn-rift sequences host the majority of the identified petroleum accumulations. Reservoirs range in age from Triassic to Cretaceous with the main exploration targets being sandstones in the Upper Triassic Challis and Nome Formations, fluvio-deltaic sandstones of the Middle Jurassic Plover Formation, Oxfordian fan-delta, shoreface/barrier bar sandstones of the Montara Formation, Tithonian submarine gravity flow fans of the Upper Vulcan Formation and submarine fans of the Upper Cretaceous Puffin Formation.

Plays occur in stratigraphic traps, pinchouts, unconformity truncations, tilted fault blocks, horst blocks and anticlines, although to date most exploration wells in the region have been sited on narrow intra-basin horst blocks, tilted fault blocks or the major structural highs that form the margins of the basin-bounding terraces and flanking platforms.

The Vulcan Sub-basin contains all of the critical elements needed to produce a successful petroleum system. High quality sandstone reservoirs are capped by regionally extensive and highly effective seals in areas with proven source rock presence, and hydrocarbons generated from these source rocks were able to migrate into a variety of robust fault bound traps.

Seismic Imaging: Historic Problems

Issues such as repeated episodes of fault reactivation, remigration, and poor seismic definition of potential traps which resulted in many wells being drilled off structure, have meant success rates in the Vulcan Sub-basin are historically poor, particularly given the large amount of legacy 3D seismic data coverage that exists. The area therefore has long been considered difficult for seismic imaging, with the lack of adequate data hindering full evaluation of both the known and yet to be found plays. A number of factors have contributed to this problem, including:

- Shallow carbonates and seabed reefs leading to signal penetration issues;
- Shallow high velocity hydrocarbon related diagenetic zones;
- Coherent noise – multiples and refractions;
- Complex faulting leading to poor reflectivity, reverberation/ shallow water multiples and ray path distortion;
- Fault shadows;
- Poor signal to noise ratios;
- Limited depth of source penetration.

Seismic Imaging: Solutions

Acquisition azimuth in the dip direction was critical in order to avoid any ambiguity with respect to the pre-processing testing, evaluation and parameter decisions, enabling a highly effective processing sequence maximizing the incremental improvements achieved. This also resulted in an accurate initial time velocity model. Previous surveys were acquired north-east to south-west, making processing parameterization in this complex area difficult and uncertain.

Triple source acquisition with shot interference removal was applied, increasing the spatial resolution of the data to assist pre-processing data integrity.

8.1 km streamers were critically important to image the structure of the deep, steeply-dipping horst blocks. These long far offsets properly processed ultimately provided far angle stack data, 34–46°, which has never previously been available for interpretation and high quality AVO/inversion processing. Figure 2 illustrates the quality of the pre-stack data at the Crux location with shallow primaries all the way out to 8 km.

Broadband acquisition and processing technologies with DUG Broad deghosting were applied prior to demultiple, with notional signatures for each shot derived from recorded near-field hydrophone data used in debubble and zero phase processing.

Demultiple processing, improved sampling and long offsets enabled a cascaded demultiple sequence to be carefully designed with a total of seven passes including 3D SRME, shallow water demultiple, interbed multiple elimination, Tau-P and parabolic radon.

High fidelity velocity model building for depth migration, five hybrid iterations of tomography, including reef replacement and incorporating interpretation along the western margin of the Swan Graben to constrain rapid lateral velocity changes were undertaken.

Depth migrating with a 75° maximum dip and 6.5 km half aperture for accurate migration of steeply dipping faults, together with data output to 14 km, make the dataset suitable for regional basin studies.

Usable far angle data – the holy grail: historically 4.5 km streamers have been used in the area. To demonstrate the effectiveness of this vintage data, the Cygnus 3D PSTM raw 34–46° far angle stack data has been used to simulate this 4.5 km limited offset data (Figure 3a). This illustrates that reasonably reliable data was previously only achieved on the critical 34–46° far angle stack to a depth of ~3.0 km (~2.2s in time). Now, with 8.1 km offsets, a 34–46° far angle stack has reliable data over the important Jurassic to Triassic interval down to the top Permian, in some locations reaching ~6.5–7.0 km depth (~3.8s in time) (Figure 3b).

The combination of the integrated solutions outlined above has produced a step change improvement in imaging in the Vulcan Sub-basin, allowing detailed investigation of the complex sub-surface for the first time, leading to new understanding of both the known, proven plays, and the potential for new plays never before imaged. ■

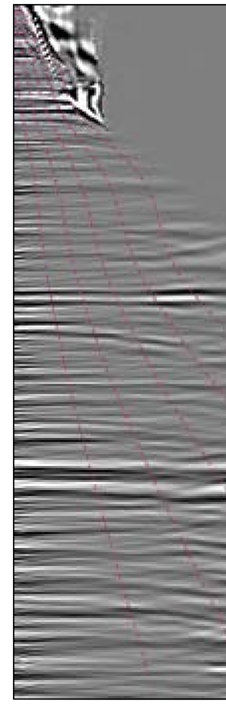
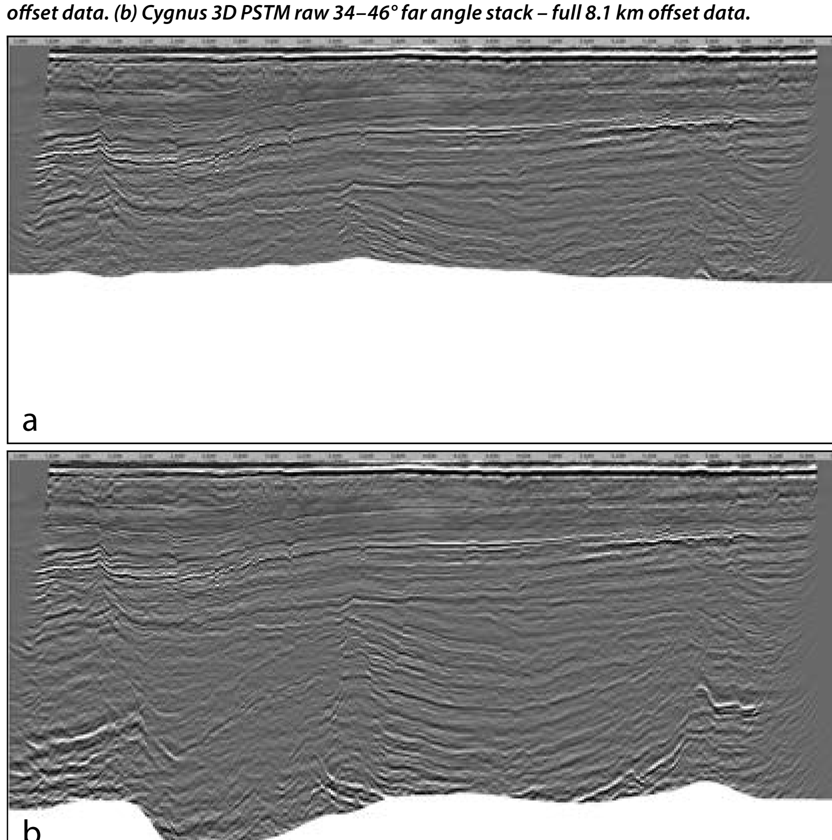


Figure 2: PSDM gather located on the Crux Discovery.

Figure 3: (a) Cygnus 3D PSTM raw 34–46° far angle stack – simulated historical 4.5 km limited offset data. (b) Cygnus 3D PSTM raw 34–46° far angle stack – full 8.1 km offset data.



Francis Gugen
Advocate for Change

JANE WHALEY

Francis Gugen has had a long and varied career in the O&G business, including as regional CEO of Amerada Hess in North West Europe, Chairman of seismic operator Petroleum Geophysical Services ASA and founder of a number of successful companies. He is a member of POWERful Women and of the Energy Transition Forum and believes that the industry needs to be more proactive in dealing with the changes ahead of us.

"Energy has to be one of the most fascinating businesses to be involved in," says Francis Gugen. "It is the biggest industry in the world; we undertake remarkable engineering feats with amazing results that the world needs; the politics and financial organization behind it is complex and fascinating. Everyone should be excited by what we do."

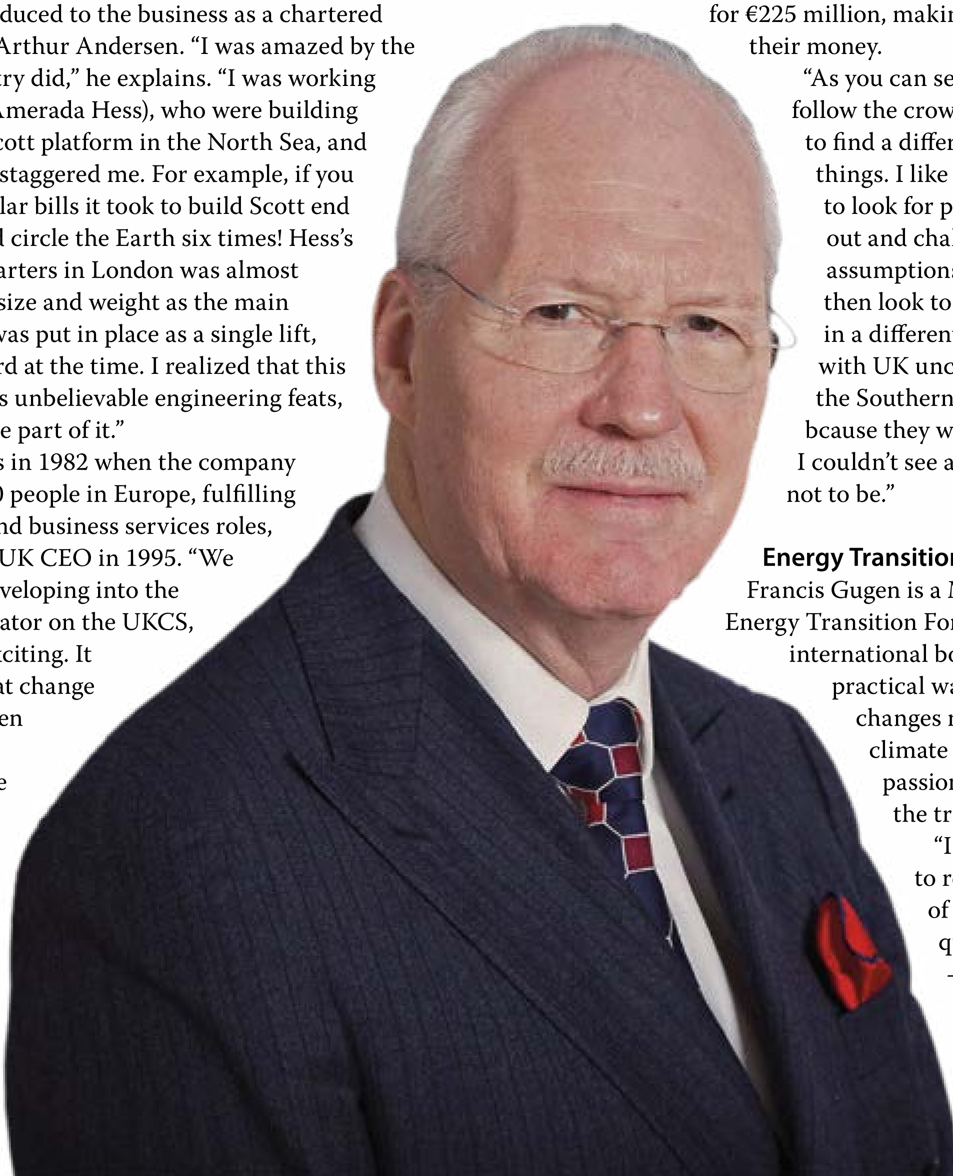
Challenging Assumptions

Francis arrived in the oil and gas world via a bilingual upbringing and education in France and England and a foray into production engineering, before becoming an accountant. He was first introduced to the business as a chartered accountant with Arthur Andersen. "I was amazed by the things this industry did," he explains. "I was working with Hess (then Amerada Hess), who were building the $1.5 billion Scott platform in the North Sea, and the statistics just staggered me. For example, if you put all the US dollar bills it took to build Scott end to end they would circle the Earth six times! Hess's company headquarters in London was almost exactly the same size and weight as the main platform; which was put in place as a single lift, which was a record at the time. I realized that this industry performs unbelievable engineering feats, and I wanted to be part of it."

He joined Hess in 1982 when the company only had about 20 people in Europe, fulfilling various finance and business services roles, rising to become UK CEO in 1995. "We grew very fast, developing into the third largest operator on the UKCS, and it was very exciting. It was a time of great change – I remember when we created an IT department in the '80s with one of the first Wang computers; we were well ahead of the times! A key part of the role of a CEO is to look out from the company and build relationships, as that's how the opportunities will be found."

Leaving Hess in 2000 because he felt ready for a change, Francis set up IGas Energy, a company focused purely on UK onshore unconventional resources. "Those were early days for unconventionals – everyone thought I was mad, including me!" he says. "But we are now a leading onshore producer/shale player in the UK with one of the largest gross acreage holdings in England." He was also a co-founder of CH4, set up to look at the then unfashionable Southern North Sea, which was successfully sold some three years later for €225 million, making investors 7.5 times their money.

"As you can see, I don't tend to follow the crowd; I always want to find a different way of doing things. I like to gather facts, to look for patterns and seek out and challenge the hidden assumptions behind them and then look to do things profitably in a different way. I got involved with UK unconventionals and the Southern North Sea precisely bcause they weren't popular and I couldn't see any reason for them not to be."



Energy Transition

Francis Gugen is a Member of the Energy Transition Forum 2.0, an international body looking for practical ways to affect the changes needed to manage climate change. He talks passionately on the topic of the transition ahead of us.

"I believe the transfer to renewable sources of energy is coming quicker than we think – though oil will have one 'last hurrah'. The pace of change is increasing rapidly. These transformations need to happen, and we as an industry must be involved in the journey. In the Energy Transition Forum we are looking at ways of making this shift in a practical way. It's no good aiming for perfection, however nice that would be – it would take too long, we haven't the time.

"I believe that in this industry we don't ask enough questions – and don't forget, it's that question you didn't ask which is the important one. What are the challenges in front of us on this transition journey; what should we be doing to address them? Are we thinking ahead? Politics is changing; have we passed the apogee of globalization and what will that mean to us all? In my experience, being curious and looking for, rather than resisting, change is often a good way to make money!

"The world is being reinvented all the time," he continues. "Artificial intelligence, the 'internet of things', battery science, 3D printing; these will all dramatically make a difference to our lives and those of our children and grandchildren. Technology is moving so rapidly, and I think the energy industry in particular will change hugely in the next ten years. We cannot perpetuate the past into the future. That would be a failure of imagination akin to that of the IBM President who in 1943 predicted that the world would only ever need five computers!

"Ways of doing business are also changing. Bitcoins and monetization of unutilized energy capacity are two diverse examples of new business mechanisms. We must put the parts of the energy conversation together and stop looking at it in little boxes. We also need better logistics and should let players from other industries come into O&G and shake it up."

Diversity is Key

"I was brought up sharing a number of European cultures and languages," says Francis, who as well as French and English, also speaks good German and some Spanish. "I think this gives me a different perspective on life, possibly making me tend to look for a different way of doing things."

Coming from this background, it is no surprise that he is an enthusiastic believer in diversity in the workplace, so that people from different backgrounds, countries and cultures can bounce ideas off each other. He is a founder member of POWERful Women, a UK government-born initiative which seeks to redress the paucity of women at energy's top table by bringing together a mix of industry, academic and political leaders. "At the moment, only some 6% of senior managers in energy are female. However, I don't encourage and promote the idea of more women in positions of authority in the O&G industry because I think men are bad managers or to be 'nice' to women," he insists. "I strongly believe that redressing the gender imbalance is a way for the business to be more successful and to make money. If we are going to embark on major changes in the world's biggest industry, we need diversity of viewpoints. From my own experience I have learnt that a board with a number of women on it is one which listens better, is more collaborative and tends to better learn from its mistakes.

"To increase diversity requires an acceptance that the culture of the industry needs to change, which isn't easy.

Back in the 1990s I was Chair of CRINE, a UKCS cost-reduction initiative, designed as a collaborative effort to find ways of reducing waste and inefficiency in the UKCS. This had a radical impact on the safety, efficiency and economics of developing and operating North Sea fields, but ultimately didn't work as well as it should have because we failed to change the culture of the industry. In this industry we do have a reputation for being quite slow to adopt new technologies, however much we need to do so to progress – though to be fair to ourselves, when you consider the costs involved in drilling wells, a mistake can be very expensive, so we understandably tend to be a little conservative."

Range of Interests

Although most of Francis Gugen's working life has been involved in the oil industry, he has interests in a range of other areas, including being Chair and founder of an innovative company called Fraudscreen, which produces an honesty index using data analytics to enable clients to distinguish 'will pay' from 'won't pay' customers. He is also Chairman of Raft, a world-renowned medical research charity that helps people who have suffered severe tissue damage such as burns.

"I have been involved for many years now with this wonderful charity, which was formed just a couple of weeks after the Piper Alpha disaster in the North Sea in 1988, in which 167 people lost their lives and many suffered terrible burns," he explains. "RAFT (Restoration of Appearance and Function Trust) develops pioneering new treatments for people who have suffered damage to skin or bones through accident, disease or birth abnormalities. The treatments that the plastic surgeons undertake can sometimes save lives and often make significant improvements to a patient's quality of life and independence. RAFT scientists have potentially found methods of closing wounds without skin grafts, for example, and they also developed a therapeutic bed, based on hovercraft technology, which allows burns patients to 'float' on air. About 25% of UK consultant plastic surgeons have been trained by RAFT. The charity has now spawned SML, a biotech company to set up to commercialize some of its research and to attract philanthropic investment.

"I like the fact that this charity is science based. It makes things happen – and I like to make things happen rather than just talk about them."

Industry Ambassadors

"Energy has dramatically changed the world and we in the oil and gas industry have played an important role in that change – we should be proud of that. We also need to tell the world what we do, but in easy language and using simple imagery that everyone can understand – like my description of the Scott platform. We don't use this sort of imagery, and we need to learn from other science-based industries like pharmaceuticals and telecoms, who communicate what they do much more effectively. Everyone working in the oil and gas industry should be an ambassador for what they do."

And he adds: "Remember that famous comment that Sheikh Yemeni made in 1980; 'the Stone Age didn't end because we ran out of stones.' The world is changing fast, and the energy industry is changing with it. Be sure that you are all part of this journey." ■

Francis Gugan was an invited speaker at the Petex 2016 Forum 'What is the new normal? Just another cycle or a structural change in the hydrocarbon industry?'

Time-Lapse Seismic and Geomechanics

MARTIN LANDRØ and LASSE AMUNDSEN

Ekofisk, discovered in the Norwegian North Sea in 1969, was one of the first fields where time-lapse seismic proved to be an excellent tool for monitoring and mapping overburden and other geomechanical changes in a producing field.

A stone is ingrained with geological and historical memories.

Andy Goldsworthy

Studies at the Ekofisk field (Figure 1) have shown how reservoir compaction led to seabed subsidence of approximately 30–40cm a year over a long period (1986 to 1998), before the subsidence suddenly dropped to 15–20cm per year. Doornhof et al. (2006) explain this as a result of the chemical reaction between water and chalk. In 1987 a major campaign to inject sea water into the chalk reservoir had begun, the amount of water injected per day reaching a maximum level in 1996–1997. After a certain volume of a reservoir has been swept by water, chalk weakens to a given limit before the process slows down, which explains these changes in subsidence rate. In addition to this chemical process, we can observe that the average reservoir pressure started to increase again in 1994–1995, so possibly the sudden drop in subsidence in 1998 was caused by a combination of these two effects.

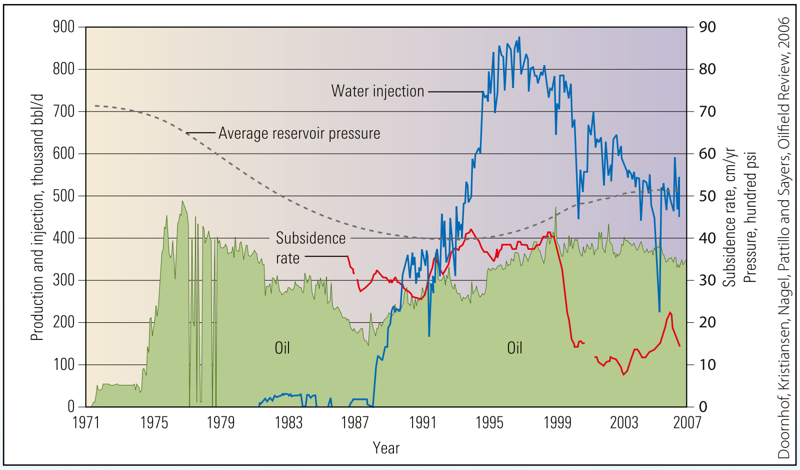


Figure 1: Ekofisk production and subsidence history. From 1987 to 1999 subsidence was between 30 and 40cm per year, corresponding to a total seafloor subsidence of more than 4m over this period.

Furthermore, when subsidence is compared to reservoir compaction, the compaction rate is found to be higher than the subsidence rate; often a difference of 40–50% can be observed between the two, which means that overburden rocks are being stretched. Looking at seismic surveys over an area away from the crest of the field in the period from 1989 to 1999,

The Ekofisk Complex.

BoH/Wikimedia Commons

Guilbot and Smith (2002) found that the top reservoir moved downwards by 4m, while the corresponding seabed subsidence was only 2.4m, meaning that the overburden rock had been stretched by 1.6m. From rock physics it is well known that such stretching will reduce the P-wave velocity of the rock, and hence will introduce an overburden time shift.

Guilbot and Smith (2002) used 4D traveltime shifts to conclude that the overburden at Ekofisk had been stretched and that the chalk reservoir rock was compacted due to production. A 4D traveltime shift means that the traveltime between two seismic horizons (representing geological interfaces in the subsurface) has changed. Guilbot and Smith found that the time shift for the overburden was up to 18 ms between 1989 and 1999. The overburden thickness at Ekofisk is approximately 3 km. This time shift was positive, meaning that the average P-wave velocity in the overburden had decreased between 1989 and 1999. For the same period they found a negative time shift of up to 10 ms for the Ekofisk reservoir formation, which was not a huge surprise since it was well known that the seafloor at Ekofisk had undergone severe subsidence. The compaction of the reservoir was also well known, and it was understood as well that the subsidence was less than the compaction at reservoir level, and hence the overburden has been stretched. What was new and exciting in Guilbot and Smith's findings was that time-lapse seismic could be used to quantify compaction and thus to create maps that show that some reservoir compartments are more compacted than others. This initiated new research on how to couple geomechanical modeling with time-lapse seismic measurements.

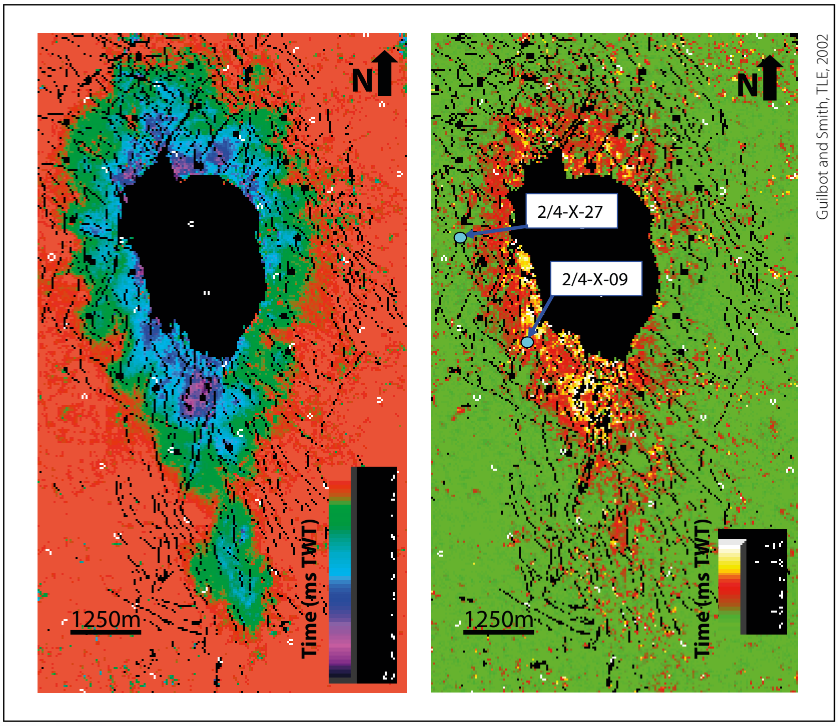


Figure 2: 4D time shifts for top reservoir interface (left) and for the Ekofisk Formation (right). The black area in the middle is caused by the gas chimney problem at Ekofisk, leading to lack of high quality seismic data in this area. Notice that some areas of the reservoir zone (right) are more compacted than others.

Reservoir Compaction and Velocity Changes

When the reservoir rock compacts, the over- and underburden are stretched. This stretch is relatively small (of the order of 0.05%). However, it produces a small velocity decrease that is observable as time shifts on time-lapse seismic data.

A simple calculation can help us to understand why time-lapse seismic can detect such small changes. Assume that the velocity decrease caused by the stretching of the overburden

is -0.1%. As an example we can assume that the average velocity of the overburden thickness is 2,000 m/s, and that the overburden is 3,000m. After stretching, the velocity is 1,980 m/s. The difference in two-way traveltime is then (neglecting the length change of the overburden):

$$T_2 - T_1 = \frac{6{,}000m}{1{,}980m/s} - \frac{6{,}000m}{2{,}000m/s} = 0.03s = 30\,ms$$

which is well above detectable time shifts (less than 1 ms for high quality time-lapse seismic data). If the fact that the thickness of the overburden is also changed is taken into the equation, the following relation might be derived (assuming that the stretch *dz* is much smaller than the overburden thickness *(z)* and that the velocity change *dv* is much smaller than *v* – see Landrø and Stammeijer, 2004):

$$\frac{dT}{T} = \frac{dz}{z} - \frac{dv}{v}$$

When the rock is stretched, *dz* is positive, and *dv* is negative, which means that the two terms on the righthand side in this equation enforce each other. In the first example we found that the velocity change caused a 30 ms increase in two-way traveltime. If we assume that the reservoir compacts by 10m and that the subsidence at the seafloor is 7m, the total stretch of the overburden is 3m, and the first term on the right side in the equation is 3/3,000 = 0.001, corresponding to 3 ms, which is significantly less than the velocity effect in this case.

Guilbot and Smith (2002) show two maps of estimated reservoir compaction at Ekofisk, one without taking the overburden changes into account and one where the effect is included (Figure 3). The difference is significant, and it clearly demonstrates that the assumption of a constant overburden is not correct for the Ekofisk 4D case. Both in magnitude and spatial distribution, the two maps are very different.

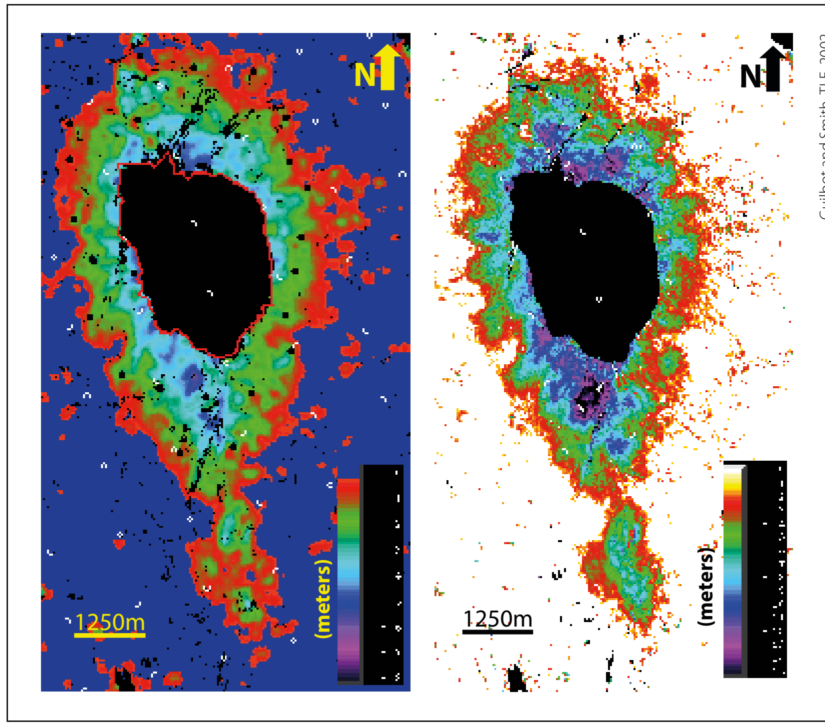
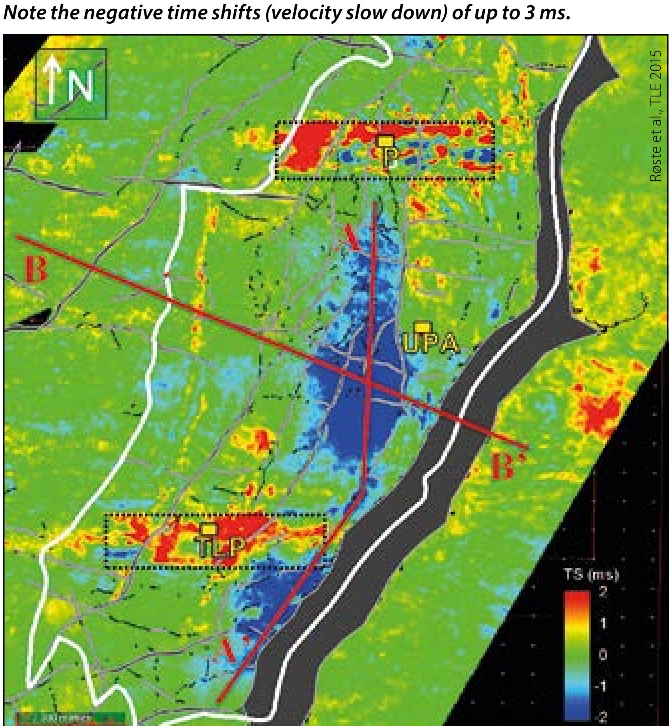


Figure 3: Estimated compaction of the chalk reservoir at Ekofisk between 1989 and 1999 neglecting overburden velocity changes (right) and including the changes (left). Notice that the two plots have different spatial distributions, not just a scalar difference between them.

Røste et al. (2005) assumed that the relative velocity change divided by the relative stretch is given as a constant, α. For the example given above $\alpha = -10$. Also in 2005, Hatchell et al. introduced essentially the same parameter, denoted *R*, where $R = -\alpha$. For a compacting reservoir, the P-wave velocity will increase and the thickness decrease, hence again, the α value will be negative. This factor is often referred to as the dilation factor. If α or *R* is known, we observe from the equation above that when the 4D time shift is measured, both the velocity changes and the thickness changes can be estimated.

Figure 4: Estimated time shifts for the Snorre overburden. Note the negative time shifts (velocity slow down) of up to 3 ms.



Compaction in Clastic Reservoirs

It is well known that highly porous chalk fields compact, but what about clastic reservoirs? In the North Sea both Elgin and Franklin, which are HPT (High Pressure and Temperature) fields, show significant compaction, although not as much as chalk fields. In a recent paper Røste et al. (2015) report that the Snorre field exhibits compaction and that overburden time shifts of the order of 3 ms have been observed between 1997 and 2009, as shown in Figure 4. Compared to Ekofisk, these time shifts are significantly smaller, by a factor of 6, underlining the fact that clastic reservoirs compact less than chalk fields. For a sandstone reservoir, the chemical effect (water weakening) is probably negligible, so it is fair to assume that the reservoir compaction is mainly pressure driven. Apart from this, the mechanism for the stretching of the overburden rocks is the same.

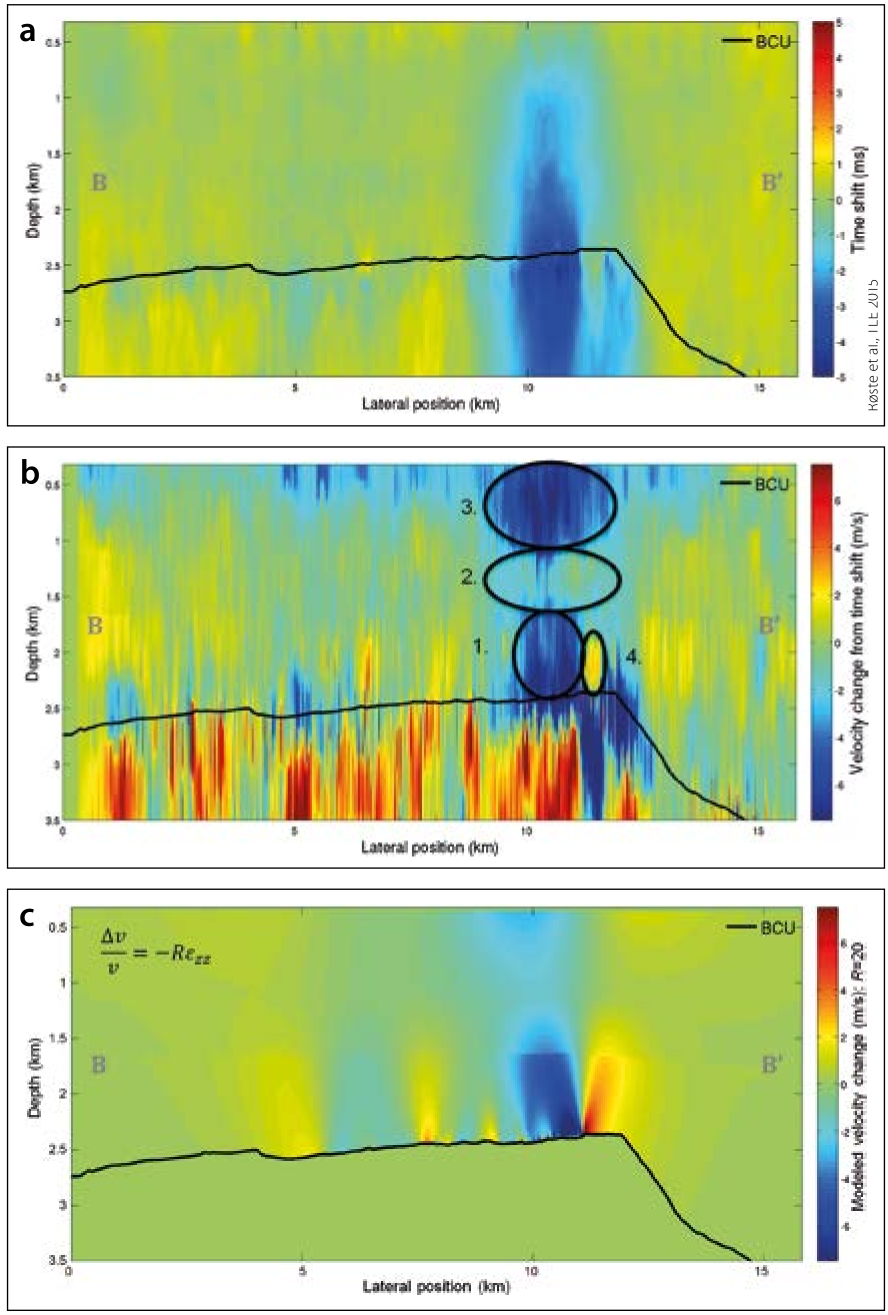


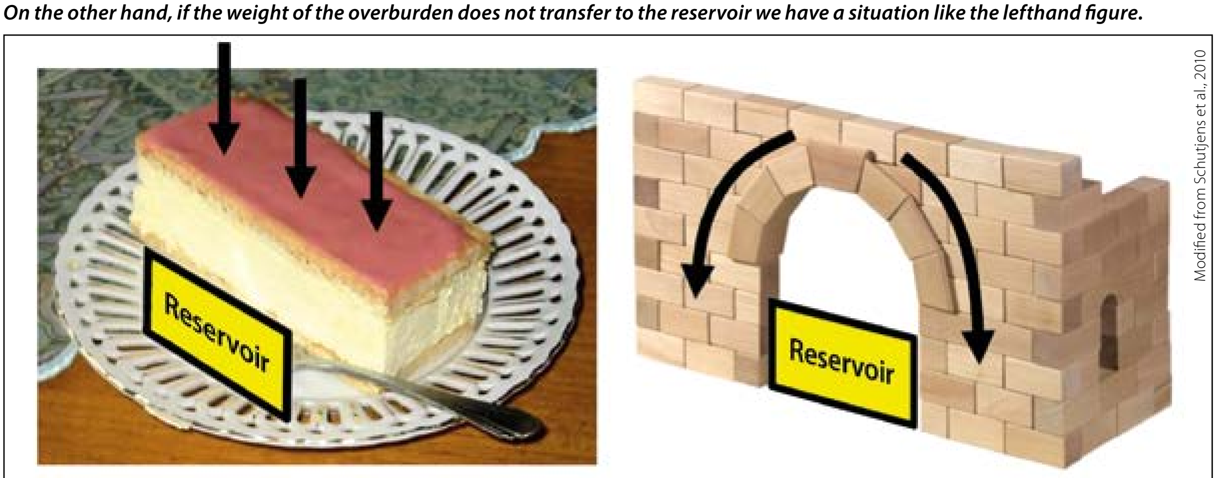
Figure 5: (a) Estimated time shifts between 1997 and 2009; note that the time shifts extend almost to the water bottom, which is at approximately 300m. (b) Estimated velocity changes. Notice four distinct areas (1–4), where 1 and 3 show a velocity decrease, 2 no change and 4 a velocity increase, probably caused by stress arching. (c) Estimated velocity changes – the velocity increase marked 4 in (b) is interpreted as a stress arch effect. Modeled velocity change (using geomechanical modeling) assuming α = -20.

A vertical profile showing that the time shifts reach nearly up to the seabed and that the width of the anomaly is more than a kilometer is shown in Figure 5. From the time shift estimates, it is possible to estimate velocity changes, which might be compared to geomechanical modeling. Notice the arching effect (the variation in overburden vertical stress caused by the reservoir compaction); stress arching occurs if the compaction zone is finite (for an infinite reservoir without edges there will be no arching effects) and some of the overburden weight is transferred to the sides of the reservoir, as illustrated in Figure 6. Due to the finite size of the compacting compartment, there will be edge effects where the vertical stress close to the edge of a reservoir increases, while there is a decrease right above the crest of the compartment.

Stress arching and in general stress changes in the overburden might cause problems for well bore stability, and there are several examples where wells have failed due to severe overburden stress changes. Hence, it is important and useful to monitor and map these overburden changes for a producing reservoir and, as these examples show, time-lapse seismic is an excellent tool for this.

References available online. ■

Figure 6: Stress arching: if the weight of the overburden is transferred to the sides of the reservoir (right) we get a stress arching effect. On the other hand, if the weight of the overburden does not transfer to the reservoir we have a situation like the lefthand figure.



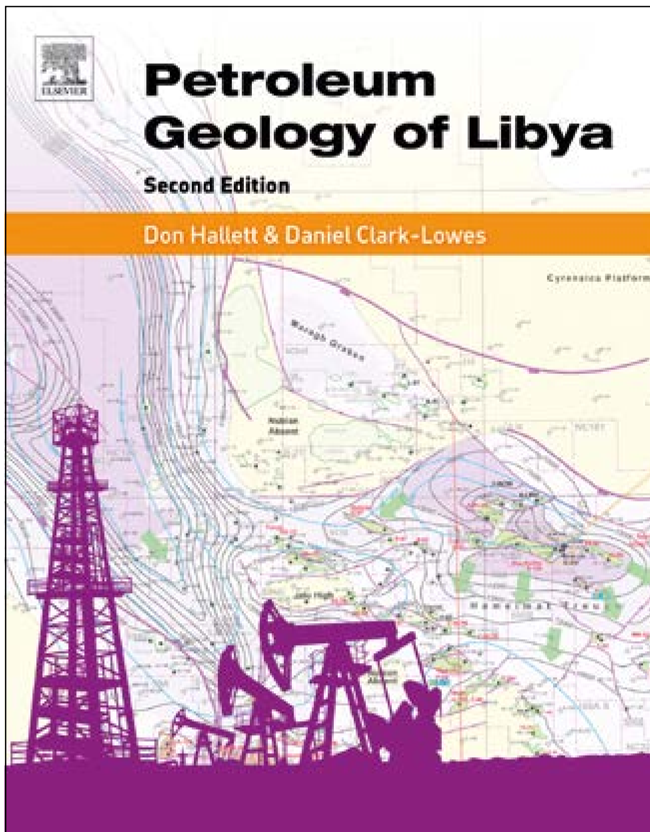
Petroleum Geology of Libya

Second Edition, 2016. Don Hallett and Daniel Clark-Lowes, Elsevier.

Professor RICHARD SELLEY, Imperial College, London

The first edition of *Petroleum Geology of Libya*, by Don Hallett, was published in 2002, so a second edition is welcomed. With Daniel Clark-Lowes as co-author, the book is written by two petroleum geoscientists with 40 years of experience between them.

Divided into eight parts, it commences with a historical review of Libyan petroleum exploration after the discovery of oil in a water well near Tripoli in 1926, followed by the story of petroleum exploration, detailed decade by decade down to the post-Qaddafi period.



Part 2 gives an excellent resumé of the plate tectonics history of North Africa in general and Libya in particular, while Part 3 describes Libyan stratigraphy – a challenging task that the authors attack with commendable vigor. The pre-oil industry terminology, largely proposed by pre-WWII geologists, principally Professor Ardito Desio working in the 1920s and '30s, was used in Raymond Furon's *Géologie d'Afrique* (1960) and the *Lexique Stratigraphique Internationale* (Burollet, 1960). However, when oil exploration began each company developed its own nomenclature for the rocks in its concessions. Barr and Weegar (1972) attempted to synthesize this chaotic stratigraphy. Hallett and Clark-Lowes bravely try to integrate these earlier stratigraphic terms with the Libyan Stratigraphic Code of the Qaddafi era, which itself had confused non-Arabic speakers and older geologists by changing the spelling of many of the stratigraphic terms and place names and over the years renaming some of the fields. The Hassaouna Formation became the Hasawnah, the 'h' and the 'a' in Sabratha were transposed to become 'Sabratah', Gialo became Jalu and so on. Amazingly, Russeger's 1837 term 'Nubian', which he applied to Lower Cretaceous Sandstones in Upper Egypt, has survived, although now used to describe any barren sandstone of uncertain age across the Saharan and Arabian deserts. Still alive in the 21st century, it has confused generations of stratigraphers; at one time more was written about the terminology of the 'Nubian' than about the rock itself. In this book it is used both as a stratigraphic term and as a facies and is applied to rocks that range in age from Triassic to Albian. The authors helpfully guide the reader through this terminological fluxoturbidite of Libyan stratigraphic and topographic nomenclature.

Structure and Petroleum Geology

Part 4 describes the geological structure of Libya, detailing the evolution of the Murzuk, Kufra, Sirt and Ghadames Basins and the arches that delineate them. These descriptions usefully extend into Tunisia, Algeria, Niger, Chad, Sudan and Egypt, and into the offshore Mediterranean basins; page 226 describes how the US Navy bombed a sea mount – the first hostile sea mount in history? The structural evolution is based on an extensive database of wells and outcrop sections, but does not integrate these data with the paleocurrent studies that have thrown much light on the complex evolution of the Kufra and Murzuk Basins. Part 5 describes the geochemistry of Libyan source rocks, proven and potential, sequence by sequence and basin by basin, illustrating how far this branch of petroleum geoscience has advanced. When the first oil was discovered in Libya no geologist had ever heard the word 'kerogen'.

Integrating the previous two chapters, Part 6 delineates the petroleum systems and play fairways of the Murzuq, Ghadames, Sabratah and Sirt Basins – intellectually one of the most challenging and worthwhile parts of the book. Part 7 describes the 15 major fields of Libya and Part 8 speculates on future petroleum exploration potential. Perhaps wisely, it omits any speculation about the potential for unconventional hydrocarbons such as shale gas and oil.

A Monument

The book contains many full color illustrations, though perhaps fewer seismic lines than one might have expected, probably for reasons of client confidentiality. Most of the figures are from previously published work, but some come from Nubian Consulting reports.

It concludes with a comprehensive bibliography and index. The former seems to include every paper ever published on Libyan petroleum geology, together with a number of unpublished oil company reports that presumably still survive in a few company offices, veneered by Saharan dust.

The *Petroleum Geology of Libya* is essential reading for anyone brave enough to explore for petroleum in this resource-rich country. This book may be a greater monument than the authors and readers realize. There was a short window of opportunity for geologists, largely though not exclusively Western ones, to explore the Sahara in general and its geology in particular. Wellard (1964) records that from 1789 to 1889 nearly 200 Western explorers died in the Sahara Desert. Only five survived to publish the results of their research. It was only in the last half of the 20th century, and the first decade of the 21st, that Saharan scientific research could be pursued in relative safety. As Raymond Furon said (1960): *"African geology is the work of only two generations, the work of a few brave men, who devoted their lives to their passion and many of whom died for their pains, sometimes murdered, sometimes victims of the desert or the jungle."*

At the present time and for the foreseeable future exploration in Libya for petroleum or any other resource, or even for pure science, may be a high risk endeavor. The authors of the second edition of *Petroleum Geology of Libya* have skillfully carved a monument to those who contributed to the knowledge of the petroleum geology of Libya. This monumental book may last for many years – though probably not as long as Ozymandias' statue.

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Getting stuck in Libyan stratigraphy is similar to being stuck in sand!

The Angle of the North

Shallow water oil is hidden in plain sight in North Gabon.

NEIL HODGSON, KARYNA RODRIGUEZ and ANONGPORN INTAWONG, Spectrum Geo Ltd.

The 5,000 km^2 of open acreage in shallow water off North Gabon sits adjacent to the site of one of the biggest discoveries in the world in 2014 – ENI's Nyonie-Deep discovery. One might expect that such a discovery would have made the surrounding acreage incredibly highly sought-after. Actually this area now suffers from one major drawback – the Nyonie-Deep discovery.

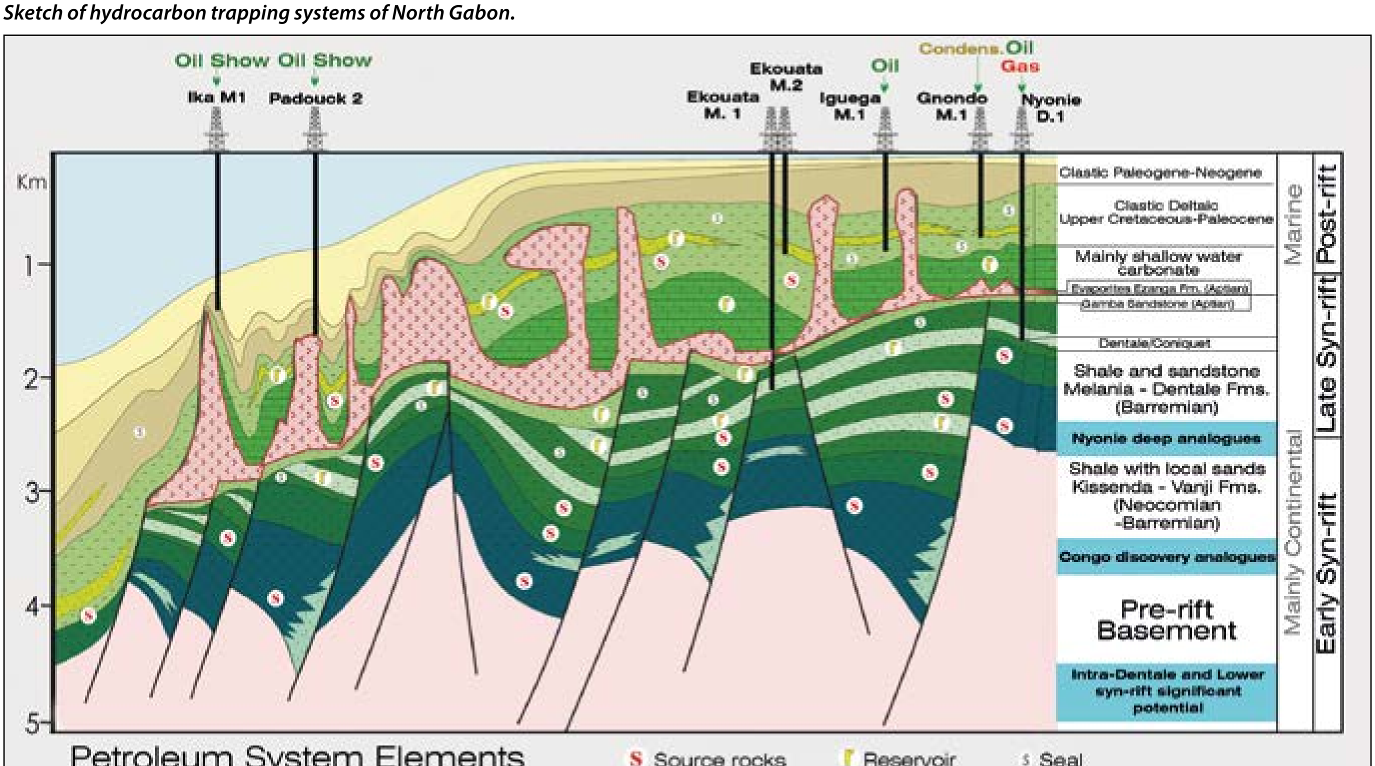
The issue at first glance is that Nyonie-Deep discovered gas in pre-salt syn-rift Dentale formation sandstone (locally called Coniquet Sandstone) that has low permeability. Gas in itself is not the hydrocarbon of choice in Gabon, which is at an early stage in its development of a gas export system, and the meme has grown from this discovery that the pre-salt of North Gabon is tight and gas prone. Nyonie redeems itself commercially by being a very large accumulation, estimated at 500 MMboe – and ironically gas is the only fluid producible from such low permeability sands.

So does this really write-off the whole of the pre-salt of North Gabon as being gas prone and tight? We argue absolutely the reverse – the pre-salt plays in the open acreage are likely to be oil-bearing in good quality sandstone. Our confidence in this model is such that Spectrum will undertake a 5,500 km^2 3D survey over the open area in 2017. So what angle do we work here? Firstly, variable heat-flow and source rock maturity can be evaluated to support the case for oil and secondly, despite the exploration immaturity and sample bias of the area, we believe that Nyonie-Deep has poor reservoir due to localized inversion. Bringing these two considerations to bear opens the probability that this unexplored area is ready to yield major surprises in the next wave of exploration.

Exploration Plays in North Gabon

As the figure below shows, traditionally two apparently separate systems are considered in North Gabon: a pre-salt syn-rift system with the lacustrine Melania and Kissenda source rocks, charging syn-rift Dentale fluvio-deltaic sands; and post-rift transgressive Gamba sandstone formation. An additional source rock, the restricted marine Vembo shale, is ubiquitously encountered sitting above the transgressive Gamba sandstone. Above the salt lie a number of deltaic clastic reservoirs such as the Ewongue, Anguille, and Cap-Lopez Formations, in drapes, turtle structures and stratigraphic traps generated by salt topology.

What is very clear on seismic is that the distribution of salt is very heterogeneous across the area. In the east it is very thin, or restricted to vertical diapirs, representing a salt body that has been mobilized by sediment loading, reactive fall withdrawal and gravity sliding, creating a clastic- (and to the east carbonate-) rich section. To the west, however, the salt is still present in extraordinary amounts as complex salt walls, domes, canopies and diapirs. As we shall see, this



Sketch of hydrocarbon trapping systems of North Gabon.

heterogeneous distribution is crucial for exploration.

The Case for Oil

The map of exploration wells drilled to date in the area adjacent to Nyonie shows that some 16 wells have been drilled in this open acreage. However, out of all these wells, only two have drilled into the pre-salt. Previous exploration strategies have targeted the post-salt section, where several oil discoveries (GLK-1, Iguega and Equata) were made. The post-salt is the dominant play system in the prolific Ogooue delta to the south, where there are a number of post-salt source rocks which can be buried deep enough – or with a high enough geothermal gradient – to generate oil.

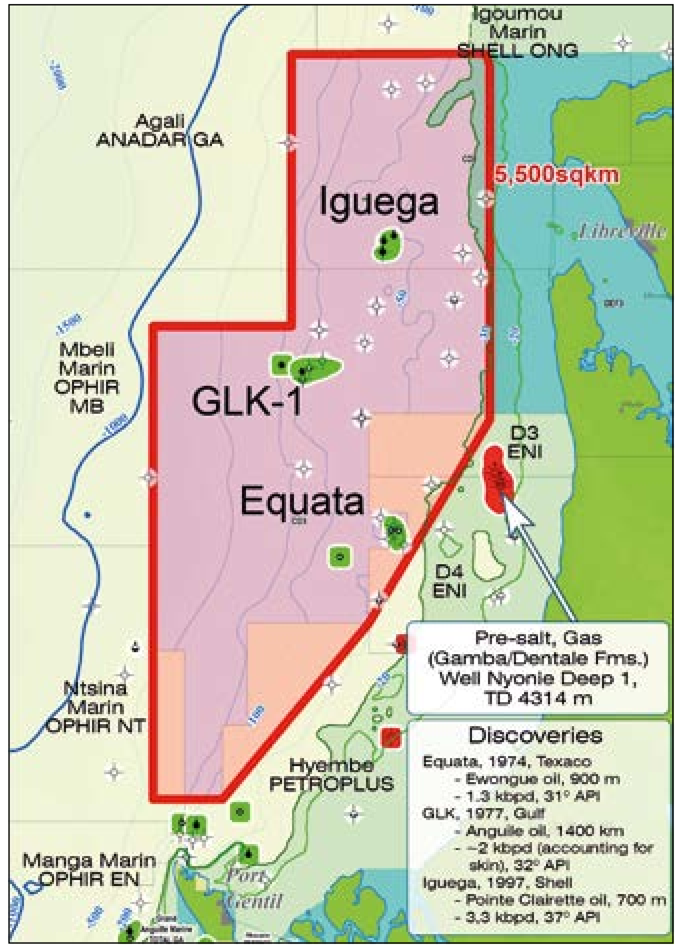
However, analysis of wells drilled in this region have revealed a number that have sported oil shows and sampled oil in horizons that lie stratigraphically below the lowest of the post-salt sources, requiring either complex downward migration or, more simply, demonstrate that oil is being generated in the pre-salt.

At first sight this is surprising as the Nyonie well entered the pre-salt at some 4,000m, where the geothermal gradient to the surface averages 33°C/km, and one expects the depth to the syn-rift to increase going west. So if the syn-rift source rocks under Nyonie were hot enough to generate gas, how could the same sequence be generating oil to the west? The answer to this may be the distribution of thick bodies of salt to the west, as the salt is a better conductor of heat than clastic wedges, so the presence of salt will cool the underlying syn-rift, and draw heat to heat up the overlying post-salt section. Available data on pre-salt geothermal gradients show that the pre-salt to surface gradient can be as low as 22°C/km in the west adjacent to thick salt. Whilst this aids the maturity of post-salt source rocks, it will retard the maturity of the syn-rift Melania and Kissenda source rocks, leaving them in the oil window.

Reservoir Complexities

Although the number of penetrations of the pre-salt is a fraction of that in South Gabon, there is enough core data to show that porosities in the pre-salt of North Gabon range from 5–20%, and permeabilities from 1–700 MD. This range is similar to that in South Gabon, although based on far fewer penetrations. There may also be some sampling bias, as the Nyonie poroperm is relatively poor, reflecting a different style of structure drilled so far in the north compared to South Gabon. In the south the prolific Gamba is the main target for exploration. This sandstone was deposited during the peneplanation of the first marine transgression of post-rift, eroding and reworking the upper parts of rotated Dentale Formation fault blocks. As such, the Gamba sands of South Gabon have never been buried and uplifted and consequently retain good poroperm characteristics.

However, the Nyonie-Deep structure comprises a large inverted fault block complex. The crest of this block was eroded significantly by the Gamba transgression, so that the Dentale reservoir is old, inverted and poor quality. Introduction of poroperm data from the inverted Nyonie reservoir introduces sampling bias to the analysis of this North Gabon acreage. The key to exploration of the pre-salt to the west of Nyonie is that the syn-rift fault blocks are less inverted and eroded, so that the Dentale can be expected to be better quality, with higher porosity and permeability, and the Gamba and Vembo Shale units will be thicker too.



Exploration density to date. Red shaded area is Spectrum's proposed 3D area.

Exploration Potential

Exploration of the pre-salt of North Gabon west of Nyonie has barely started, yet from the few penetrations to date we see good evidence for a working oil syn-rift system and are confident that good quality reservoir can be predicted in significant little eroded fault blocks and overlying units. The increase in presence and thickness of salt to the west has reduced the geothermal gradient locally to keep the Melania and Kissenda source rocks in the oil window.

Further west, into the salt domain, the post-salt sequences are very thick and complex and have not been fully explored due to the complexities of imaging plays even with early 3D data. The pre-salt systems may be working and even the post-salt provides attractive targets as the post-salt source rocks are likely to be generative.

Spectrum's exploration angle is the driving force that will lead it to acquire 3D in North Gabon in the next few months. This new coverage with long streamer 3D designed to image the pre-salt will unlock the potential of this overlooked play system. The future for exploration in North Gabon is bright and offers the promise of shallow water oil of a resource magnitude that is hard to find anywhere in West Africa. ■

The Mysterious Mister Rickett

MICHAEL QUENTIN MORTON

The story of Francis William Rickett is riddled with contradictions. Bluff and resourceful, notorious for his exploits in the world of oil in the 1930s, he remains an enigma today. Speculator and businessman he was, but he also had deeper links with oil companies and foreign governments than appeared in the press reports of the time. Above all, he lived in interesting times, and through his exploits we have a tantalizing glimpse into behind-the-scenes struggles for the control of oil.

There was a time when the petroleum landscape seemed incomplete without the secretive figure of Rickett passing through. His background was in the oil business, being primarily interested in concessions, and any other business he could lay his hands on. In the early 1920s he represented the heirs of the deposed Ottoman sultan, Abdul Hammid, who claimed the oil and mineral rights of Mesopotamia (as Iraq was once known). He also dabbled in Russian and Romanian oil holdings, and in everything ranging from the supply of uniforms for the Greek army to a loan for the city of Lille.

An Iraqi Connection

In 1922, when the Lausanne Conference of international powers was discussing the future of the Mosul *viyalet*

Francis W. Rickett pictured as Master of the Craven Hunt in September 1935.

Illustrated London News/Mary Evans

(district), Ricketts brought a high-powered Turkish delegation to London, claiming he had influence with important people including the British prime minster. He proposed that Great Britain should withdraw from Mosul in return for substantial oil concessions from the Turks, but was firmly nobbled by the foreign secretary, Lord Curzon, who also warned off other potential backers of the scheme.

One of those backers was the shipping magnate, Lord Inverforth, who was associated with Rickett in several business ventures. The most ambitious was a German-Italian-British project, British Oil Development Limited (BOD), which in 1932 obtained an oil concession covering 120,000 km^2 west of the River Tigris in Iraq. Three years later, after the Italians had taken a controlling interest, it was reported that Rickett was no longer involved in the company although he retained a major shareholding. The prospect of an Italian takeover alarmed the Foreign Office, and there was great relief in London when the British-led Iraq Petroleum (IPC) group eventually took over the concession. It was rumored that Rickett was attempting to obtain an oil concession for Basra, but this also went to the IPC group.

Ethiopia and surrounding countries and protectorates in 1935.

The Ethiopian Affair

In August 1935, Italian dictator Benito Mussolini was making threatening noises towards Ethiopia. The emperor of that country, Haile Selassie, was anxious to involve Britain and the United States in his defense, hoping that if one of their oil companies was operating a concession there, they might intervene in the event of an Italian invasion. The idea was not entirely fanciful – the Standard Oil companies of New York and Jersey were interested in Ethiopia, the latter having sent a survey party there in 1921. In July 1935 they formed a subsidiary, the African Exploration & Development Company, to pursue a concession, and the 46-year-old Rickett was dispatched to conduct secret negotiations with Haile Selassie on the company's behalf.

In August 1935, Rickett was not widely known. The English writer, Evelyn Waugh, was commissioned by the *Daily Mail* to cover events in Ethiopia and met him as just another passenger on the long journey down from Port Said. Rickett hinted that he was on a mission for the Coptic Church of Egypt, but spoke more openly about his pack of hounds, explaining that the coded cables he kept receiving were in fact messages from his huntsman in England. Although Waugh was suspicious, he had no inkling that Rickett was about to snap up the most astonishing oil concession of the time.

Haile Selassie in his palace at Addis Ababa in 1942.

In fact, none of his fellow travelers could really fathom what Rickett was up to and when they arrived at Addis Ababa, Waugh sent a letter to his head office in London asking for more information about his mysterious traveling companion – too little, too late. Waugh was soon sidetracked by another story, leaving the capital a few days later in order to investigate the case of a Frenchman and his wife who had been imprisoned for spying.

In the Dead of the Night

While Waugh was up country, Rickett was conferring with

US senators at a press conference to discuss Rickett's Ethiopian concession on September 3, 1938.

government officials in Addis Ababa at the dead of night. After a week of to-ing and fro-ing, papers were signed by which about half the nation's subsoil rights – an area of nearly 400,000 km^2– was made over to Rickett for a period of 75 years. He caught the morning train for Djibouti, breaking news of the agreement to two journalists before his departure. By the time he sailed into Suez, the story had made world headlines. Waugh, for his part, missed the scoop and was sacked.

Back in London, the British government was exposed to accusations that it was trying to exploit Ethiopia's natural resources at a time when Italy was about to invade the country. In Washington, too, there was consternation, and Standard executives at first denied any knowledge of Rickett's dealings. In the event, there was no British money involved and secretary of state Cordell Hull intervened to scotch American involvement in the deal.

Five months later, as Italian troops were advancing on Addis Ababa, Rickett still had the concession document in his safe and was trying to peddle it to Mussolini for $5 million. His efforts came to nothing, but anything Rickett did at that time was bound to attract the attention of a salivating press. He was dubbed the 'Lawrence of Oil' on account of his Middle Eastern connections. He also happened to be a wealthy man, owning a mansion in Berkshire and a castle in Pembrokeshire, with King Feisal I of Iraq as one of his house guests.

Friends in High Places

Rickett was certainly well connected around the world and, with his friend and traveling companion, Ben Smith, they made a fine pair of predatory speculators. Smith, who had acquired the monicker 'Sell 'Em Ben' from his days as a trader on Wall Street, was a notorious short seller. Described as an aggressive Irish-American, he was remembered as the trader who ran through a brokerage house in the crash of 1929 yelling "Sell 'em all, they're not worth anything". More recently, he had turned his mind to gold, having made a fortune in the Alaskan gold fields.

He was on good terms with the Maharaja of Jodhpur. When invited to stay at his palace for a few days, Smith and Rickett hopped on a plane and flew themselves from London to India. The plane, a Vultee 1-AD which belonged to Smith, was previously registered to the Cord Corporation owned by the famous American motor manufacturer, Errett Lobban (E.L.) Cord. Smith had used the plane during the Ethiopian venture to carry out aerial surveys on behalf of Standard Oil.

In those days, it was no mean feat for individuals to fly between England and India. Among other things, the Persian Gulf was closed to private aviators – not that such a minor detail would put off Messrs Rickett and Smith, of course, and they flew on regardless, taking advantage of a tail wind to assist them across Iran to reach their destination. On the way back, however, their luck ran out and they were forced to land at Sharjah on the Trucial Coast (today's UAE) where the British authorities kept a close eye on new arrivals. The unabashed Smith alighted from the plane and asked the British agent if he knew the whereabouts of any gold mines in the vicinity. But it was Rickett, with his oil connections, who set the alarm bells ringing. Within days of their leaving, he had been banned from traveling to the Gulf ever again.

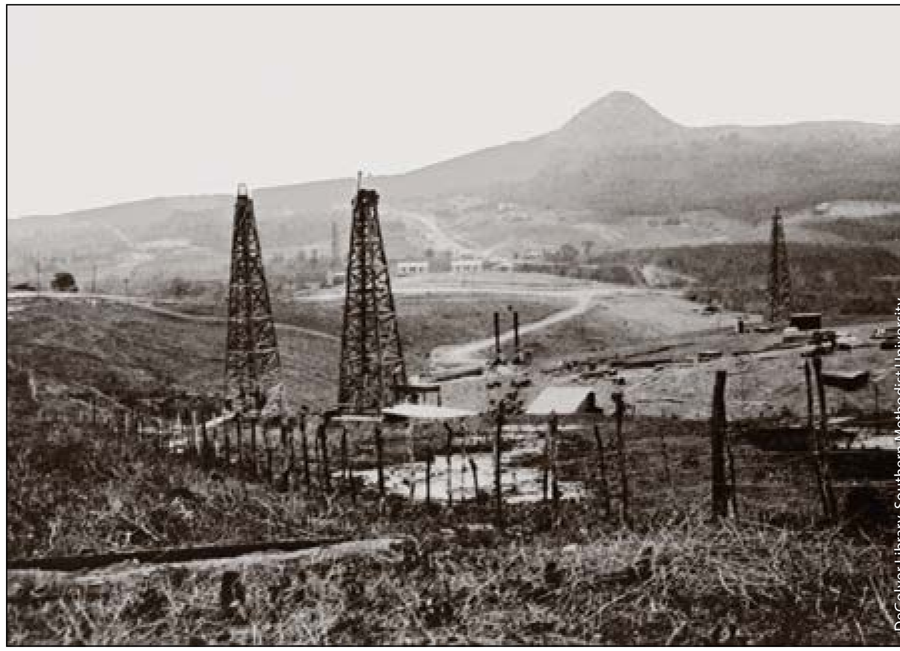
There was no doubt that the Ethiopian episode followed in his shadow. Although Western oilmen and politicians alike were wary of him, he did represent the spirit of free enterprise, and possessed a readiness to cut through official tape. Many tried to place obstacles in his way, but that did not prevent him from embarking on his next adventure with Smith – a foray into the Mexican oil business.

Mexico and the War Years

In 1938, Rickett was in his element. Following a period of labor unrest, Mexico's President Lázaro Cárdenas had confiscated all foreign-owned oil properties. Standard New Jersey and Royal Dutch Shell were the two biggest losers and imposed an oil embargo against Mexico, with the result that Cárdenas was urgently looking for buyers of his country's oil. Enter Messrs

Rickett and Smith who, with the backing of Lord Inverforth, flew down to Mexico City in order to negotiate a deal with the Mexican government. It was rumored that they were aiming to buy 25 million barrels of Mexican oil below the world price. For the Mexicans, the advantages of such a deal were plain: it would bring in some ready cash to keep operations going and enable them to make the first compensation payments to the deprived oil companies.

Rickett repeated the tactics he had used in Ethiopia, declaring that his real purpose was to prevent fascist dictators buying up cheap oil – he was saving the oil for the Western democracies. "My motives," he announced, "are patriotic!" Washington, however, thought otherwise. President Roosevelt, while recognizing a country's sovereign rights over its natural resources, demanded compensation based on the price originally paid for the properties and their development, less depreciation. Whitehall was not impressed either, and the City of London wrote letters in the British press denouncing Rickett's proposal. When Rickett tried to ship his first load of Mexican oil to England, he found that his bank account had been frozen.



DeGolyer Library, Southern Methodist University

A view of part of the oilfield at Amatlan State of Vera Cruz, Mexico, in about 1921.

Although Rickett was primarily a businessman, his treatment at the hands of the British and American governments may have colored his approach to politics. In late 1939, together with a group of American pro-Nazi businessmen, he was implicated in a plan to bring World War II to an early end. This was the time of the 'Phoney War' and General Wilhelm Keitel, the head of the German High Command, was sending out feelers for a peace treaty. The Foreign Office gave the plan no credence, and the British ambassador to Washington remarked that Rickett and Smith were "catspaws of the Nazi government". It seems that Rickett served out his war service as an ordinary seaman based on a naval patrol boat in the English Channel.

The One Who Got Away

In 1947, press reports from Cairo suggested that Rickett was in Turkey on a secret oil mission. "It's oil he's after again!" they proclaimed. But by 1950 he had fallen on hard times, having sold his Berkshire mansion and been made bankrupt. In November of that year, a French court sentenced him to eleven months' imprisonment in his absence for breaking currency laws. Ten days later, as police were still searching for his luxury yacht crewed by ex-Luftwaffe and U-boat men, Rickett turned up at Baghdad's best hotel. Like a pantomime villain, he appeared sleek and grey haired, dressed in a flowered dressing gown and holding a foot-long cigarette holder. He dismissed the prison sentence with a wave of his hand: "My lawyers are paid to deal with such annoyances," he said.

We do not know if Rickett ever served his sentence, and perhaps it is better kept that way. Certainly for Evelyn Waugh, who fictionalized him as the character Baldwin in his novel *Scoop*, the secretive businessman would always be remembered as 'the one who got away'.

Acknowledgements:
The author thanks Peter Morton for his kind assistance.

The novelist Evelyn Waugh, who met Mr Rickett on his secret mission to Addis Ababa.

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A Wonderful Wild Wilderness

Dr. DIANNE TOMPKINS, Associate Leisure Solutions®

The Kimberley National Landscape of Western Australia – wilderness, adventure and dinosaurs are waiting for you!

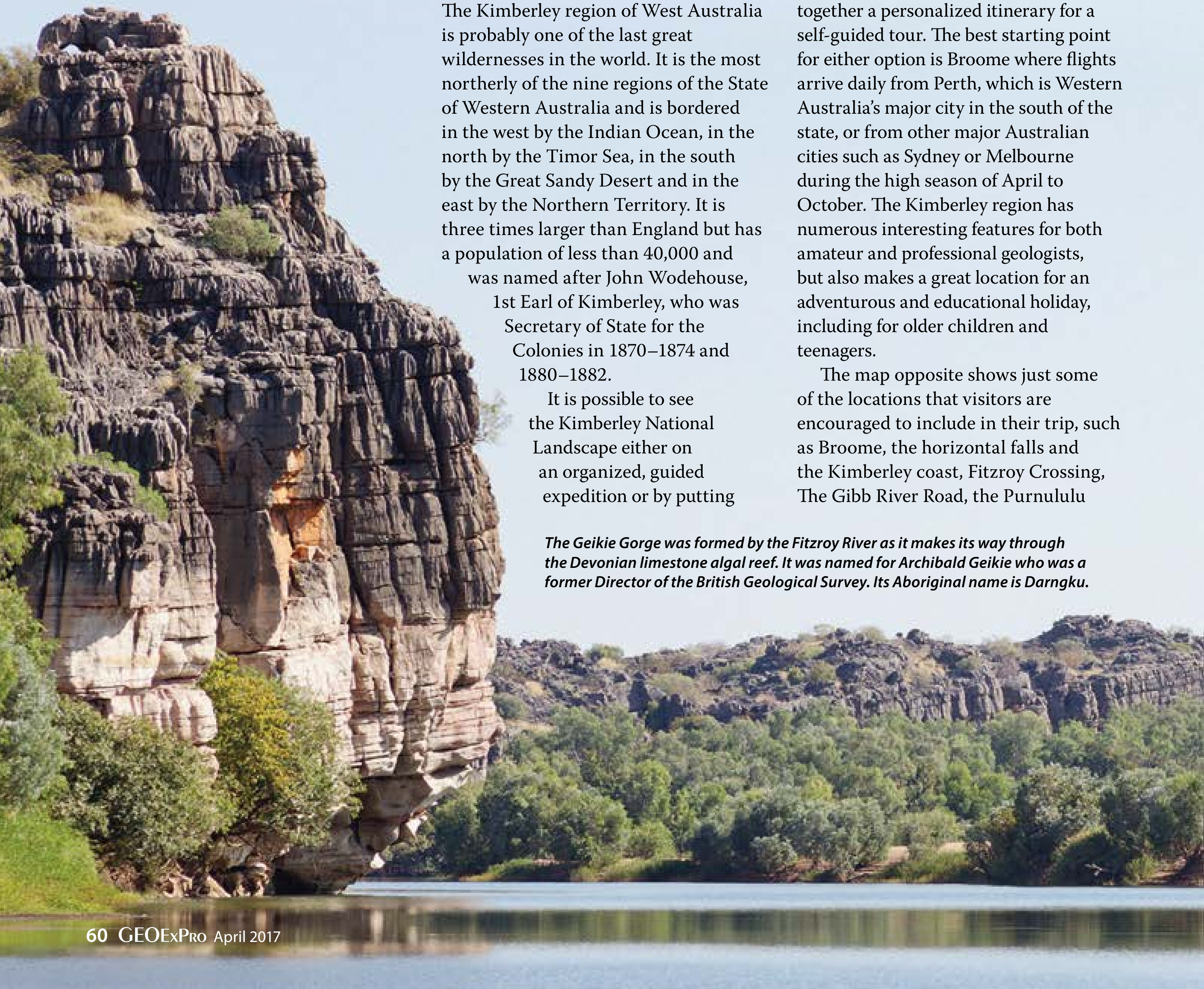
This is what I love about the Kimberley – wild gorges, fresh water and there's always a chance of a barra taking your lure…

Malcolm Douglas, a noted Australian wildlife documentary maker and crocodile expert (1941–2010)

The Kimberley region of West Australia is probably one of the last great wildernesses in the world. It is the most northerly of the nine regions of the State of Western Australia and is bordered in the west by the Indian Ocean, in the north by the Timor Sea, in the south by the Great Sandy Desert and in the east by the Northern Territory. It is three times larger than England but has a population of less than 40,000 and was named after John Wodehouse, 1st Earl of Kimberley, who was Secretary of State for the Colonies in 1870–1874 and 1880–1882.

It is possible to see the Kimberley National Landscape either on an organized, guided expedition or by putting together a personalized itinerary for a self-guided tour. The best starting point for either option is Broome where flights arrive daily from Perth, which is Western Australia's major city in the south of the state, or from other major Australian cities such as Sydney or Melbourne during the high season of April to October. The Kimberley region has numerous interesting features for both amateur and professional geologists, but also makes a great location for an adventurous and educational holiday, including for older children and teenagers.

The map opposite shows just some of the locations that visitors are encouraged to include in their trip, such as Broome, the horizontal falls and the Kimberley coast, Fitzroy Crossing, The Gibb River Road, the Purnululu



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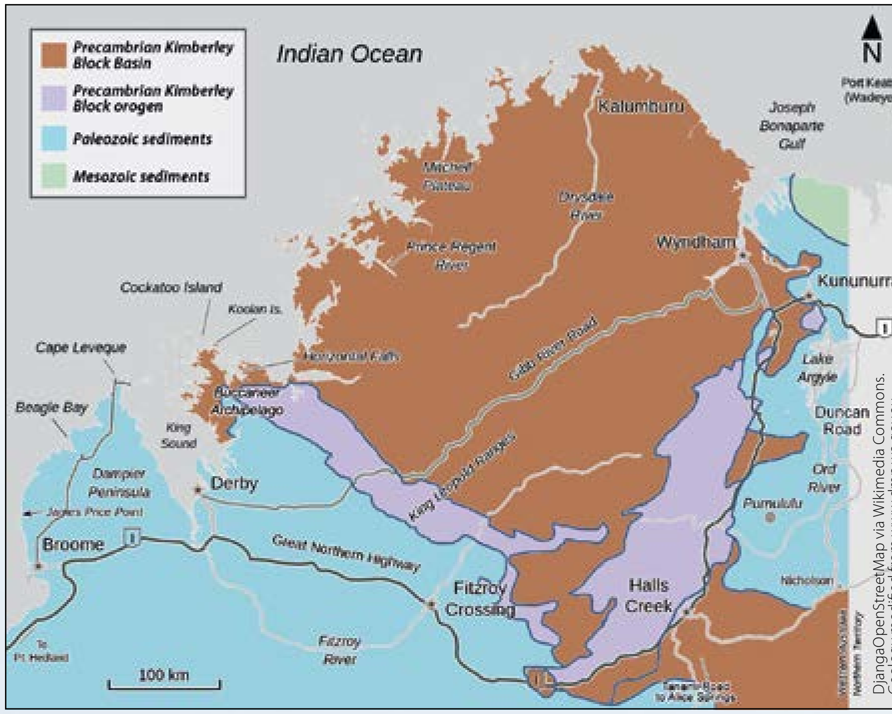
The Geikie Gorge was formed by the Fitzroy River as it makes its way through the Devonian limestone algal reef. It was named for Archibald Geikie who was a former Director of the British Geological Survey. Its Aboriginal name is Darngku.

National Park (a World Heritage Site), which includes the Bungle Bungles and Lake Argyle, to name but a few. A trip of around 10–12 days is probably enough time to get a taste for the area but a return trip will almost certainly be necessary to see this fabulous national landscape in its entirety.

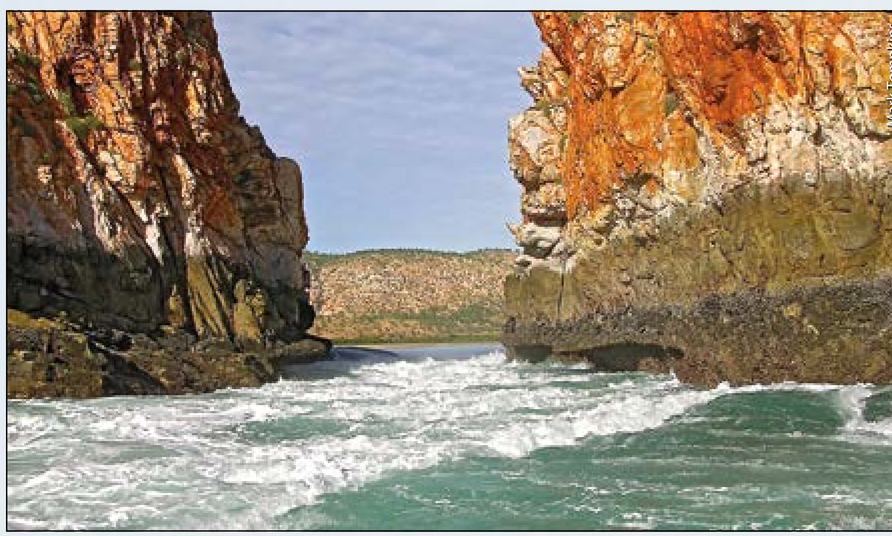
Geologically, the majority of the area comprises the Precambrian Kimberley Block, which is part of the larger West Australian Shield and is composed of ancient, 2.8 to 3.5 billion-year-old, molten rock that has cooled and then solidified. Sedimentary rocks are exposed around the edges of the basement and largely comprise Devonian barrier reef system deposits that formed before the sea level dropped in this area. Stunning outcrops can be seen in several places on the Gibb River Road trip, including Windjana Gorge and Geikie George.



The Kimberley Region showing simplified geology , the two major road trip routes and other features of interest.

The Incredible Kimberley Coastline

The Kimberley coastline is of particular geo-heritage significance as it is a spectacular example of a large-scale ria coast with a near-shore archipelago. As this coastline is located in a largely unspoiled wilderness setting, sedimentation and depositional processes are continuing as they have done for centuries, uninhibited by man's interference. It is however possible to take either a boat or a plane excursion from either Broome or Derby to see this pristine coastline. A flight from Derby can also take you over the Lalang-garram /Horizontal Falls Marine Park, an area which has been recently created as a new marine park jointly managed by local indigenous people and the



The horizontal waterfall is caused by some of the largest tidal changes in the world.

From space it is easy to see the striking shoreline patterns at Roebuck Bay, on the coast just south of Broome where small, straight streams reach the bay and their smaller tributaries give a feathered appearance to this shoreline. By contrast, the more typical meandering channel patterns of coastal wetlands appear on the top right. Almost no human-built patterns are visible in the scene, even though the town of Broome lies just outside the image on the top right.

Western Australian Department of Parks and Wildlife. This marine park is contiguous with another new marine park, the North Lalang-garram Marine Park.

There are only two horizontal falls landforms in the world and both can be seen off the Kimberley coast at Talbot Bay in the Buccaneer Archipelago. These 'waterfalls' are horizontal as a result of some of the largest tidal movements in the world. As the tide ebbs and flows so a huge volume of water is forced through two narrow cliff passages, which causes a variation in ocean level of up to 4m and produces this unique phenomenon.

Camels and Dinosaurs

Broome is the gateway to the Kimberley region and is only 2.5 hours flight from Perth. It is known as 'the pearl of the north' as it is home to one of the largest commercially harvested cultured pearl industries in the world. This business was started in the 1800s with Japanese, Filipino and Malay pearl divers arriving there to seek their fortunes, which has contributed to the multicultural nature of Broome still seen today. The town boasts over 20 km of magnificent white sand beach, Cable Beach, which takes its name from the telegraph cable laid between Broome and Java in 1889 that connected northern Australia with the rest of the world. Camel rides on Cable Beach are an exhilarating experience, while the 'Staircase to the Moon' is a fantastic site if you are lucky enough to see it. This natural phenomenon occurs when the full moon rises over the exposed tidal flats of Roebuck Bay, creating a beautiful optical illusion of a stairway reaching to the moon, which happens two or three days a month between March and October.

Of particular paleontological interest and a great day trip from Broome is a visit to some of the Cretaceous dinosaur footprints that are found at various points up and down the Kimberley coastline. A 30-minute hovercraft ride with an experienced guide will take you to see some of these prints, which were left by large sauropods roaming the area around 130 million years ago. The most recent footprints were found in September 2016 on Cable Beach itself by a family on a beachcombing outing.

Camel riding on Cable Beach – one of the best ways to see this beautiful stretch of coastline.

A Tale of Two Road Trips…

Driving inland from Broome, Derby and the Kimberley coastline, there are two main self-drive routes.

The first is the Gibb River Road from Derby to Wyndham or Kununurra. This is a four-wheel drive adventure that takes approximately eight days, depending on how often you stop and detour to see many of the natural wonders along the way. The driving conditions are challenging and the trip must be either very well planned in advance or else taken with a reputable guide so that everyone ends up safely at their destination. Setting off from Derby, this drive will first take you through Windjana Gorge National Park and the Napier Range via Tunnel Creek, which was once used as a hideout by the Aboriginal leader, Jandamarra. The trip continues through various gorges to the Leopold Range Conservation Park. After five or six days driving you will arrive at the El Questro Wilderness Park, which is a working cattle station and vacation destination where you can rest and relax prior to your arrival in Wyndham.

The second option is to take the Great Northern Highway (Highway 1) from Broome to Kununurra via Fitzroy Crossing, Halls Creek and the World Heritage listed Purnululu National Park including the Bungle Bungles. ▶

Dinosaur footprints.

Aerial photograph of the Bungle Bungles.

This is around 800 km of driving with numerous opportunities to stop or take detours to see the sights en route.

Fitzroy Crossing is on the floodplain of the fertile Fitzroy River downstream from the Geikie Gorge National Park and south of the Gibbs River Road excursion described above. Not far from the Crossing is the spectacular Geikie Gorge, part of the 350 million-year-old Devonian reef system outcropping on the south side of the Precambrian Shield. Halls Creek is on the edge of the Great Sandy Desert and is the closest town to the Purnululu National Park, listed as a World Heritage Site in 2003. It is also where the world's second largest meteorite crater is located at Wolfe Creek.

Also found within this National Park is the Bungle Bungles range, which was formed over 360 million years ago when rivers flowing from the north-east deposited Devonian sand and gravel. At the same time, gravel was eroding from nearby mountains and added to this fluvial deposition. The result seen today was the formation of spectacular banded beehive-shaped domes that represent what is left of this once-flat land surface. The Bungle Bungles have always been important to the local indigenous population and it was not until 1983 that their presence was advertised to the public at large, making them a popular tourist destination for adventurous visitors. A most informative booklet in the Bush Books series titled *Geology and Landforms of the Kimberley Region*, published in 2005 by Ian Tyler, can be obtained from the Western Australian Department of Parks and Wildlife.

From the Purnululu National Park, it is possible to drive still further north to Lake Argyle and then to the town of Kununurra, before Highway 1 heads east out of the Kimberley Region of Western Australia and into the Northern Territory. Created by the Ord River Dam, Lake Argyle is the biggest manmade lake in the southern hemisphere and at its peak holds around 32 MMm^3 of water (about 20 times the volume of Sydney Harbour). Cruises can be taken on the lake that is home to many different plants and animals including some 240 species of birds.

Adventure Destination

No matter which of the two roads you choose to travel, your journey through the Kimberley landscape will likely end either at Kununurra or Wyndham. Kununurra was established by the Ord River Irrigation Scheme and is the second largest town in the Kimberley region. Wyndham is the Kimberley's oldest town and was established in 1886 as a result of the Halls Creek Gold Rush. Both towns have regional airports from where it is possible to return to Perth.

The winter months of June, July and August are the peak seasons for tourists to visit the Kimberley Region. The summer months, especially November, can be extremely hot, while December and January can be very wet, the latter being the cyclone season when there is a high risk of flooding on the highway and many roads may be closed.

If you are looking for an adventure holiday with lots of geological features, wildlife and fun then the Kimberley Region is waiting for you…

Acknowledgments: *The input of Alan Briggs and Professor Ross Dowling OAM, Western Australia-based members of the Geotourism Standing Committee of the Geological Society of Australia, is recognized with appreciation.* ■

Advancing Geoscience in South East Asia

45 years old and counting, SEAPEX has a proud history of supporting the oil and gas industry in South East Asia.

South East Asia has been engaged in oil and gas production since before the beginning of the last century, initially in Indonesia and soon followed by Myanmar and Brunei. With the advent of offshore drilling, Malaysia came into the picture, with production later starting up in Thailand, Vietnam and the Philippines. Traditionally, the focus of the region has been on oil production, but there has been a constant, strong growth in gas production since the beginning of the 70s.

The South East Asia Petroleum Exploration Society, SEAPEX, which has a sphere of interest spanning from Afghanistan to New Zealand, was set up to look after the interests of oil and gas geoscience professionals in this region. Its objectives include advancing the science of geology and related earth sciences, with particular emphasis on petroleum and natural gas exploration, development and production in South East Asia, and promoting technologies related to exploring for hydrocarbons, as well as disseminating information on the topic. SEAPEX also aims to improve the awareness of oil and gas industry issues in the community.

Currently the group, which is based in Singapore, has over 1,000 active members and a number of Chapters which host regular meetings throughout the world, including London, Houston, Calgary, Ho Chi Minh, Manila, Perth, Kuala Lumpur, Bangkok, Jakarta, Tokyo and Auckland. The group prides itself on the social and networking side of the business as well as technical and industry intelligence. It is a non-profit organization.

Silver Years

SEAPEX is now over 45 years old. As described in Dick Murphy's account of the history of the organization, *Silver Years*, the "arrival of Allen Hatley and Frank Sonnenberg to Singapore in 1972 provided the impetus for the formation of SEAPEX. Both were old hands in the oil patch, both were articulate, and both recognized that the time was ripe for a professional society, based in Singapore, that would serve as a forum for the explosion of geological and geophysical knowledge resulting from the booming search for hydrocarbons in the South East Asia region." Their interest merged with that of Dick Murphy's, who was the President of the Geological Society of Malaysia (GSM) at the time and working for Esso. Eventually, after Frank, the first president, had been transferred and Allen, the second, was about to leave, Dick become President.

Recognition of Dick Murphy's contribution to SEAPEX has been made through the 'Dick Murphy Scholarship Award'. Now in its sixth year, this aims through SEAPEX to promote petroleum geoscience expertise in South East Asia. It is awarded to a South East Asia national (i.e. from Singapore, Malaysia, Indonesia, Thailand, Vietnam, Philippines, Brunei, Cambodia, Laos or Myanmar) in order to help with the cost of studying for a Master's degree in petroleum geosciences.

Membership over the years has fluctuated due to oil price, interest in the region and the movement of companies in and out of Singapore. They would often set up a regional new ventures hub in Singapore to look at opportunities and once they had established acreage in a country they would move their team there. The only company to have kept a presence in Singapore over the last three decades is Total, which has been particularly successful in the region.

After some boom times in the 1970s and 1980s the society went into a hole in the early 1990s but after some digging by the committee (and others), SEAPEX eventually 'rose from the dead', so to speak. The decision to run the evening meetings on the same day as the Singapore Scout Meetings (a regular gathering of upstream oil and gas operators in the Asia-Pacific region who meet to share accurate information about their E&P activities in the region) was the turning point for SEAPEX, with numbers growing significantly. The second Friday of every other month proved an important date for networking in the region, and soon the Thursday night and weekend became part of the agenda. Early birds now meet in Penny Black pub on Boat Quay on Thursdays ahead of the main Friday events.

Active Society

Since its formation SEAPEX has had 24 presidents, the current one being Ian Cross, who started his role in October 2016, taking over from Peter Baillie. Ian actually began his time on the SEAPEX committee as far back as 1990 and has been almost ever-present in the society since then. He is quoted as saying he felt like Ryan Giggs becoming manager of Manchester United when he became President after all his years of apprenticeship! According to SEAPEX

Map of SEAPEX regional chapters.

records the longest continual reign as President was John Bishop, from 1991 to 1997. Both Ian and John are also among the 19 who hold Honorary Life Membership, an award given by SEAPEX to individuals in recognition of their outstanding contributions to the organization and the oil and gas industry in the South East Asia region.

Each year SEAPEX allocates a portion of its budget to support educational, philanthropic and other causes and activities that advance the objectives of the society. In addition to the Dick Murphy scholarship, this helps fund field trips, gives support for conferences and allows invited speakers to give lectures at meetings.

SEAPEX publishes a quarterly news and views magazine, called the SEAPEX Press, which is distributed worldwide to members. This has been running since December 1997 and had its beginnings in a photocopied four-page newsletter. A competition was held to provide the name of the periodical, with a prize of a six-pack of beer! The SEAPEX Press rapidly went from 16 to 32 pages, and soon Mark Harris took over as Editor, a role which he still holds. After some 20 years in print it will go digital in 2017, which will undoubtedly stress some of the older members!

The London group hosted a large meeting the evening before APPEX this year as a prelude to the much-awaited bi-annual SEAPEX Exploration Conference in Singapore. This will be held on April 26–28, 2017, and dates have already been set for the next event in 2019. The society is also looking at running a joint Asia-Pacific event with the PESGB in mid-2018 in London. ■

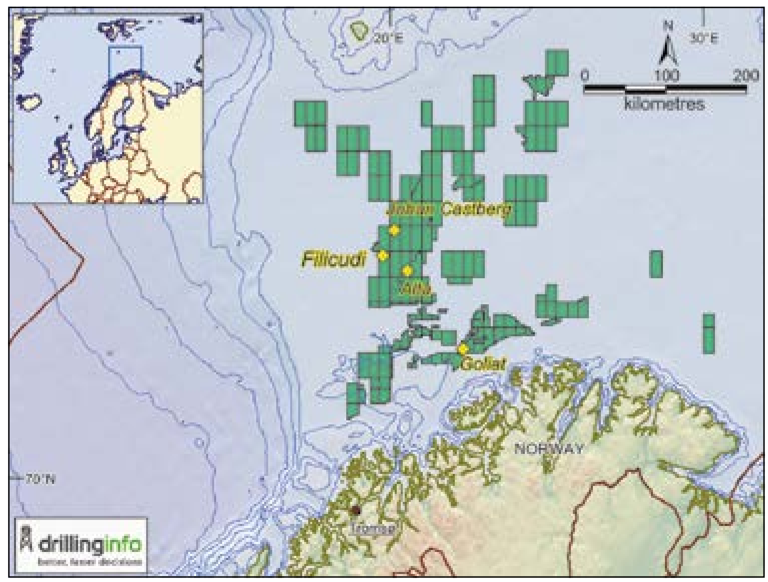
Current SEAPEX President Ian Cross on a recent visit to Vietnam.

Norway: Discovery on Trend with Johan Castberg

On February 13, 2017 **Lundin** announced that **Filicudi** (NFW 7219/12-1) in PL533 in the **Norwegian Barents Sea** had encountered a gross hydrocarbon column of 129m, intercepting a 63m oil column and a 66m gas column in the target Jurassic Stø and Nordmela Formations and in a Triassic secondary objective. Wireline logging and coring was undertaken, and a sidetrack has confirmed reservoir and hydrocarbons, with the sandstones described as being of high reservoir quality. As a result, the gross resource estimate for Filicudi is 35–100 MMboe, with Lundin reporting a significant upside potential that will require further appraisal drilling. The pre-drill mean prospective resource estimate was about 260 MMboe.

Filicudi was spudded on November 25, 2016 and reached TD at 2,500m by January 16, while appraisal sidetrack 7219/12-1A kicked off from 654m MD on January 22, and TD'd at 2,026m by February 14, 2017. The *Leiv Eiriksson* semi-sub was used in 323m water depth.

PL533 is on trend with and about 40 km south of the Johan Castberg field, which has proven volumes in the region of 400 and 650 MMbo, and 30 km north-west of the Alta and Gohta discoveries on the Loppa High in the southern Barents Sea. One well has already been drilled on the license, the Salina NFW (7220/10-1) which in 2012 discovered gas and condensate in the Early Cretaceous Knurr and Middle Jurassic Stø Formations, with estimated recoverable resources of 31–44 MMboe. Success at Filicudi has derisked other prospects in PL533, which has total gross unrisked prospective resource potential of up to 700 MMboe. Lundin plans to spud high-graded prospect Hufsa, which has gross unrisked prospective resources of 285 MMboe, in Q4 2017, with Hurri also being evaluated for near-term exploration drilling. Licensees are operator Lundin Norway AS (35%), Aker BP ASA (35%), and DEA Norge AS (30%). ■

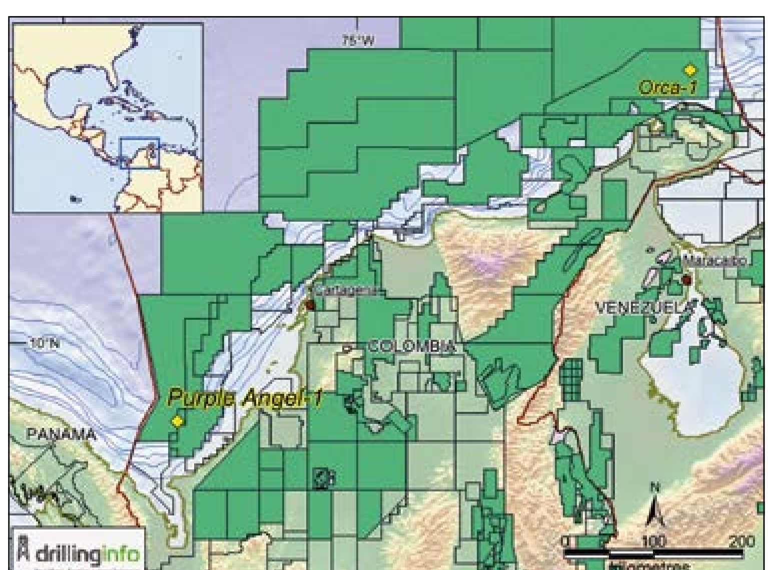


Colombia: Purple Angel Confirms Gas

In recent years, **Colombia** has become Latin America's fourth-biggest oil producer, behind Mexico, Venezuela, and Brazil, and it is now following that with a number of large gas discoveries. The state-owned oil company **Ecopetrol** reported in early March 2017 that its deepwater **Purple Angel-1** well, on the Purple Angel Block, has found gas, with registered gas pay intervals totaling an estimated 21–34m thickness. The well is situated about 50 km offshore in water depths of 1,822m, about 200 km south-west of Cartagena.

Anadarko spudded the Purple Angel-1 appraisal well on November 24, 2016, and the Dolphin Drilling vessel *Bolette Dolphin* reached a TD of 4,795m before moving offsite in late February 2017. Purple Angel-1 is located 4.7 km from the Kronos-1 discovery and confirms the extension of the reservoir and the potential of this new hydrocarbon province. Ecopetrol said that based on data from the two wells, the Kronos field is estimated to have a gas column of at least 520m. The original PTD was about 4,800m with Pliocene and Miocene targets. Kronos-1, in the Fuerte Sur Block, was drilled in 2015 and found evidence of natural gas, with 39–70m (net) of natural gas pay in the upper objective, though at the time it was deemed uncommercial.

Anadarko operates the Purple Angel Block and adjacent Fuerte Norte and Fuerte Sur blocks with 50%. Ecopetrol holds the remaining 50%. This well is part of a US$ 650 million exploration campaign by Ecopetrol which includes drilling five wells in Colombian Caribbean water. ■



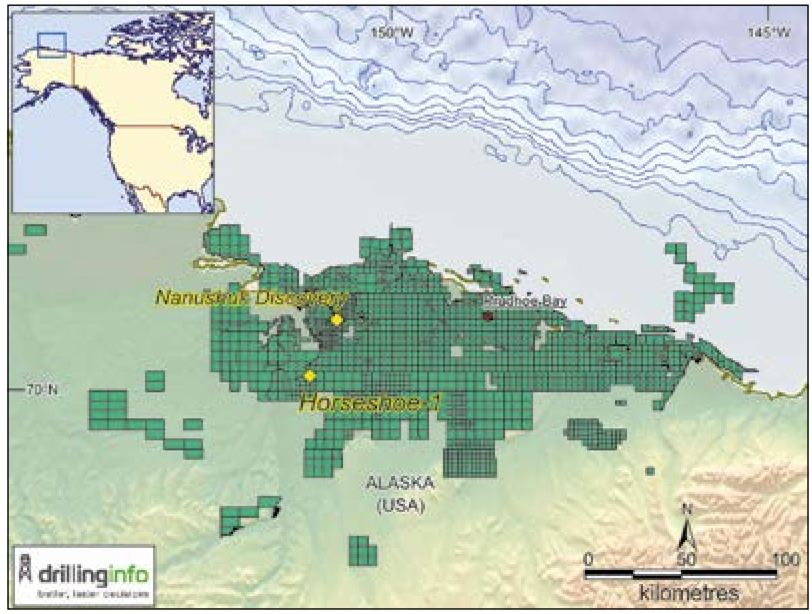
Alaska: Largest US Onshore Oil Discovery in 30 Years

Armstrong Energy and partner **Repsol** have made the largest US onshore conventional hydrocarbons discovery in 30 years, with the drilling of the **Horseshoe** 1 NFW and the subsequent Horseshoe-1A sidetrack, drilled on ADL 392048 in the North Slope region of **Alaska**. Both well bores were drilled during the 2016–2017 winter drilling campaign and the results verify the **Nanushuk** as an important emerging play.

Horseshoe-1 was drilled to a TD of 1,828m and encountered over 45m of net oil pay in several reservoir zones in the Nanushuk section. Horseshoe-1A sidetrack was then kicked off and drilled to a total depth of 2,504m, encountering more than 30m of net oil pay in the Nanushuk in the process.

The contingent resources identified in Repsol and Armstrong Energy's blocks in the Nanushuk play in Alaska could amount to ~1.2 Bb of recoverable light oil. The Horseshoe discovery extends the play more than 32 km south of the existing 2014 and 2015 discoveries achieved by Repsol and Armstrong in the same interval within the Pikka Unit. Preliminary development concepts for Pikka anticipate first production in 2021, with a potential rate of close to 120,000 barrels of oil per day.

Repsol holds 25% WI in the Horseshoe discovery and 49% WI in the Pikka Unit. Armstrong holds operatorship and the remaining working interest. (For more information on these and other recent Alaskan discoveries, see *GEO ExPro*, Vol. 14, No. 1.) ■



Decommissioning in the North Sea

The oil industry is set to spend over US$ 60 billion on decommissioning North Sea fields over the next 25 years. Greg Coleman, who managed financial aspects of decommissioning for BP Europe in the 1990s, discusses some of the issues involved.

What are the aims of decommissioning?

All companies and authorities want to achieve the maximum economic recovery of hydrocarbons from an oil or gas field, but there comes a time when this is no longer possible. We can stop pumping, but we cannot leave the infrastructure in place, so in the ideal world decommissioning involves the safe removal and disposal, preferably with reuse and recycling, of the platform and all associated pipes, seabed structures, material and debris. From the point of view of the oil company, timing and cost are the two vital issues: preferably as late as possible and in the most cost-efficient manner.

What are the triggers?

The main trigger is simply the oil price and where you expect it to be in the future. Decommissioning is usually discussed in times of low prices, when fields become uneconomic, but it's always a difficult decision. Your field might be losing $20 million a year, but if it is going to cost $100 million to decommission and you think prices will go up it may be best to wait, which was what happened in the '90s. However, that doesn't take into account the condition of wells and facilities. If they have not been maintained with a view to continuous long-term use, then as they get older things start to slide, and decommissioning may be forced on you.

One also has to consider the tax situation. In many countries a company can claim the cost of decommissioning a field against the taxes they have paid on production from that field. The government wants to ensure that decommissioning is done properly and with a well-planned, structured program in as efficient a manner as possible to minimize the tax rebate.

How long does it take?

For an offshore field in an environment like that of the North Sea, this is a long process, which usually doesn't physically start until a number of years after the decision has been made. Take the Brent field: from making the decision to decommission back in 2006, it took 10 years of planning and preparation before shut-in started, and will take another 10–15 years to complete the program. That means that Brent, which produced for 40 years, will take a further 25 to decommission.

What are the main challenges?

The biggest challenge is financial – only big companies have the financial capacity to take on these projects; the smaller ones now operating many of the more marginal North Sea fields cannot afford it. This has been taken into account in some of the change of ownership deals in recent years; the Magnus field, for example, is soon to be operated by Enquest, but the decommissioning liabilities remain with BP, who discovered the field in 1974. When the original deals were made the assumption was that the majors would be around throughout the life of the field.

Before physically dismantling the structures, all other options must be reviewed, such as using the redundant infrastructure for newly discovered resources nearby. Even when the decision has been made, the methods of breaking up the topsides and subsea structures, how and where they are transported to and the reuse and recycling of the

Greg Coleman is an ex-BP executive with 40 years in the industry, who is CEO of a small cap E & P firm. He was Head of Investor Relations, Group HSE and was the Executive Assistant to John Browne at the time of the BP-Amoco merger. He has had technical and management roles in the UK, Canada, Norway, Venezuela, Russia, Azerbaijan and Egypt.

material involve extensive discussions with a wide range of stakeholders.

Decommissioning is a new industry, and to date we have little experience of it. Only a few North Sea fields have actually completed the task, and the supply and service companies are still gearing up to the opportunity. Decommissioning is not really what people active in the industry want to do, so maybe a new generation of businesses and workers needs to develop?

The specially built decommissioning vessel Allseas 'Pioneering Spirit' can remove the topsides of a platform in a single lift. Here it is seen carrying the structure of the Norwegian Yme field platform.

Are there particular challenges in the mature North Sea?

Tax. There are very complex rules about tax payment and reimbursement and they can cause a lot of problems if not fully understood. Many companies have acquired assets without appreciating the decommissioning costs which they need to deal with – and $50 oil prices have brought a new perspective to acquisitions done when oil price expectations were nearer $100. When platforms were built in the North Sea in the 1970s and '80s, very little thought was put into what was going to happen to them when the oil ran out. Since then society's expectations, legislation and technology have all moved on and every offshore installation in the North Sea built after 1999 has been designed to be completely removed, but the oldest fields will be harder to decommission. The same applies to terminals, which will also have to be closed down. For example, the gas processing plant near Great Yarmouth on the east coast of England, which opened in 1968, is shutting down in the near future, as it is too expensive to repair.

There are many challenges in the environmental sphere and concerned NGOs are monitoring decommissioning developments. The primary aim is always to decommission in the most environmentally friendly way possible, but occasionally it is necessary to seek exemptions to 'clean seas' regulations because it is too expensive and potentially environmentally damaging to remove everything.

What business opportunities are there for service companies?

Contractors should do very well out of this if they plan properly and understand the scope of what has to be done. The total cost of decommissioning UK oil and gas infrastructure is estimated to be US$ 60 – US$ 120 bn and most of the work will go to contractors. In the subsurface area in particular, technology is going to be important and there will be plenty of opportunities. Maybe the winners will be new companies, with a different mindset. Decommissioning the North Sea will go on for 30 years or longer: a big investment which will be good for the UK and which will create an important exportable knowledge base. People now in E&P and wondering where their existing North Sea business is going should take advantage of this.

The infrastructure to bring all this steel, copper and sometimes radioactive material back to shore for reuse, recycling and disposal is not ready, so there should be plenty of opportunities in this area. At the moment the cheapest option is sometimes to take it abroad, but we need these facilities and the jobs and money they bring in the UK. Shell is modifying a port near Great Yarmouth specifically for recycling the Brent topsides, and more places like this will be needed, including ones with heavy lifting equipment and deep water capacity.

Has enough money been set aside by the industry?

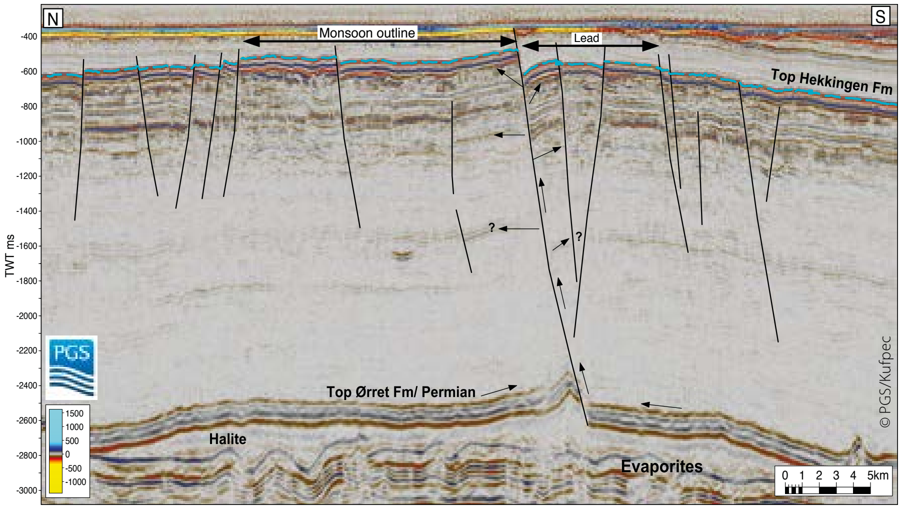
This is a major issue. BP have provided US$ 18 bn for this on their balance sheet and Shell have a nearly US$ 30 bn decommissioning liability. Having a pool of money ready to tackle decommissioning is important. For fields owned by smaller companies perhaps a financial arrangement could be put together whereby a deep pocketed organization, such as a sovereign wealth fund, would agree to underwrite the risk of a decommissioning project, in return for a fee.

How much should governments and other authorities be involved?

As tax payers it is important to all of us that decommissioning is undertaken in the most cost-effective way possible, so government has many roles in this, simultaneously maximizing resource recovery and tax contributions while minimizing the amount of tax refund for decommissioning. 2015 was the first year the UK government gave out more than they took in and that bill will continue to grow as decommissioning ramps up. ■

Arctic Hot Spot

It could turn out to be the discovery of the 21st century – or the duster of the year.



Seismic line across the Korpfjell prospect. While the potential reservoir sandstones are just beneath the seabed, the oil may have been sourced from the Permian at much greater depth.

Some 1.2 Bbo have reportedly been discovered in the Horseshoe-1 and 1A wells in Alaska's North Slope. If correct, this might be the biggest onshore discovery in the US in three decades. This North Slope find comes only a few months after Caelus Energy announced a potential supergiant Alaska oil discovery in the waters of Smith Bay (*GEO ExPro,* No. 6, 2016).

Both discoveries, even if they are huge, may, however, be dwarfed if Statoil has success with the Korpfjell prospect in the Barents Sea later this year.

According to American terminology, a major oil field has 100 MMbo or more in proven reserves. A giant field can recover more than 500 MMbo, while a supergiant has in excess of 5 Bbo reserves. In the best case scenario, the Korpfjell prospect has a potential for 10 Bb of recoverable oil. That's a lot of oil.

In comparison, Statfjord, the largest field in the North Sea, has so far produced exactly 5 Bboe, thereby qualifying as a supergiant. Korpfjell has the potential to be twice as big.

Korpfjell is situated in a license that was awarded in the Norwegian 23rd round and lies in the area of the south-east Barents Sea. This is very far north and only a few kilometers from the Russian border. It is definitely Arctic wildcatting.

The primary target is Jurassic sandstones with presumed excellent reservoir properties at very shallow depths (see seismic line above). Triassic sandstones with uncertain reservoir parameters constitute secondary targets. De-risking of the prospect will, of course, include detailed geologic analyses based on well and seismic data as well as 35 years of exploration experience. The geochemical and geophysical tool boxes have also been used extensively.

While 2D seismic has outlined the structure, 3D seismic will be necessary to understand the depositional systems and undertake AVO analyses. Published accounts (*GEO* 05/2016) indicate anomalies that reflect gas overlying oil (double flat spot), and suggest that the sedimentary sequence is 'flush with gas'. There is every reason to believe we do have an active petroleum system in the area. Unpublished accounts, however, are a bit more pessimistic. CSEM data acquired by EMGS and analyzed by a Russian company indicate that the Jurassic sandstones do not contain hydrocarbons, while the same data points to possible hydrocarbons in the Triassic.

Drilling will start in the second quarter this year. ■

Halfdan Carstens

Conversion Factors

Crude oil

1 m^3 = 6.29 barrels

1 barrel = 0.159 m^3

1 tonne = 7.49 barrels

Natural gas

1 m^3 = 35.3 ft^3

1 ft^3 = 0.028 m^3

Energy

1000 m^3 gas = 1 m^3 o.e

1 tonne NGL = 1.9 m^3 o.e.

Numbers

Million = 1 x 10^6

Billion = 1 x 10^9

Trillion = 1 x 10^{12}

Supergiant field

Recoverable reserves > 5 billion barrels (800 million Sm^3) of oil equivalents

Giant field

Recoverable reserves > 500 million barrels (80 million Sm^3) of oil equivalents

Major field

Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price