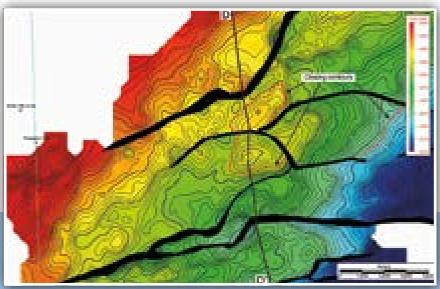
VOL. 15, NO. 3 – 2018

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



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Generating Really Good Structural Maps

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GEOTOURISM
Indonesian Wonders

RESERVOIR MANAGEMENT
Leveraging AI for Production Optimisation

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INDUSTRY ISSUES
The Need to Retain Experience

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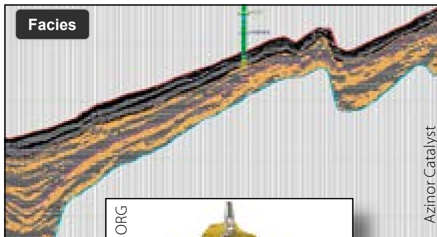

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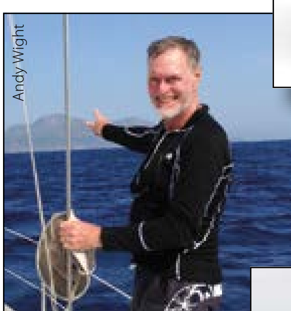

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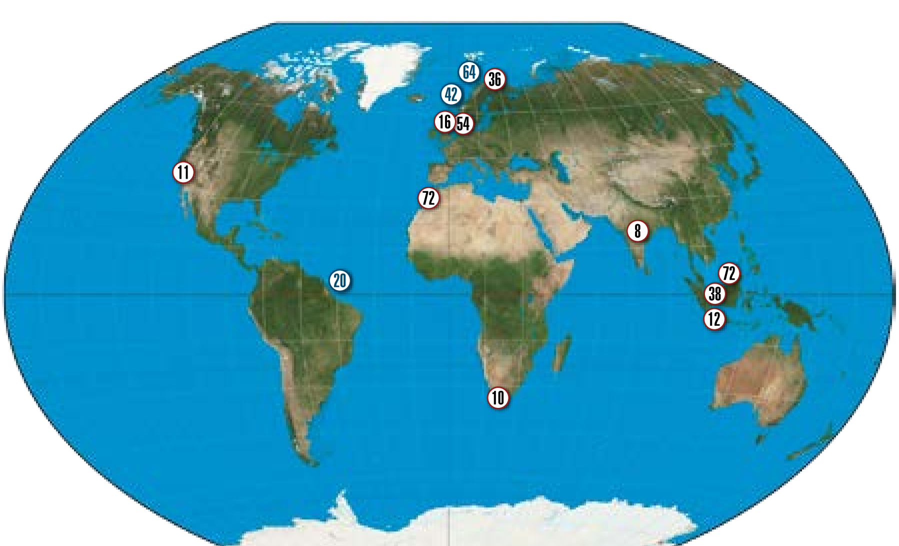

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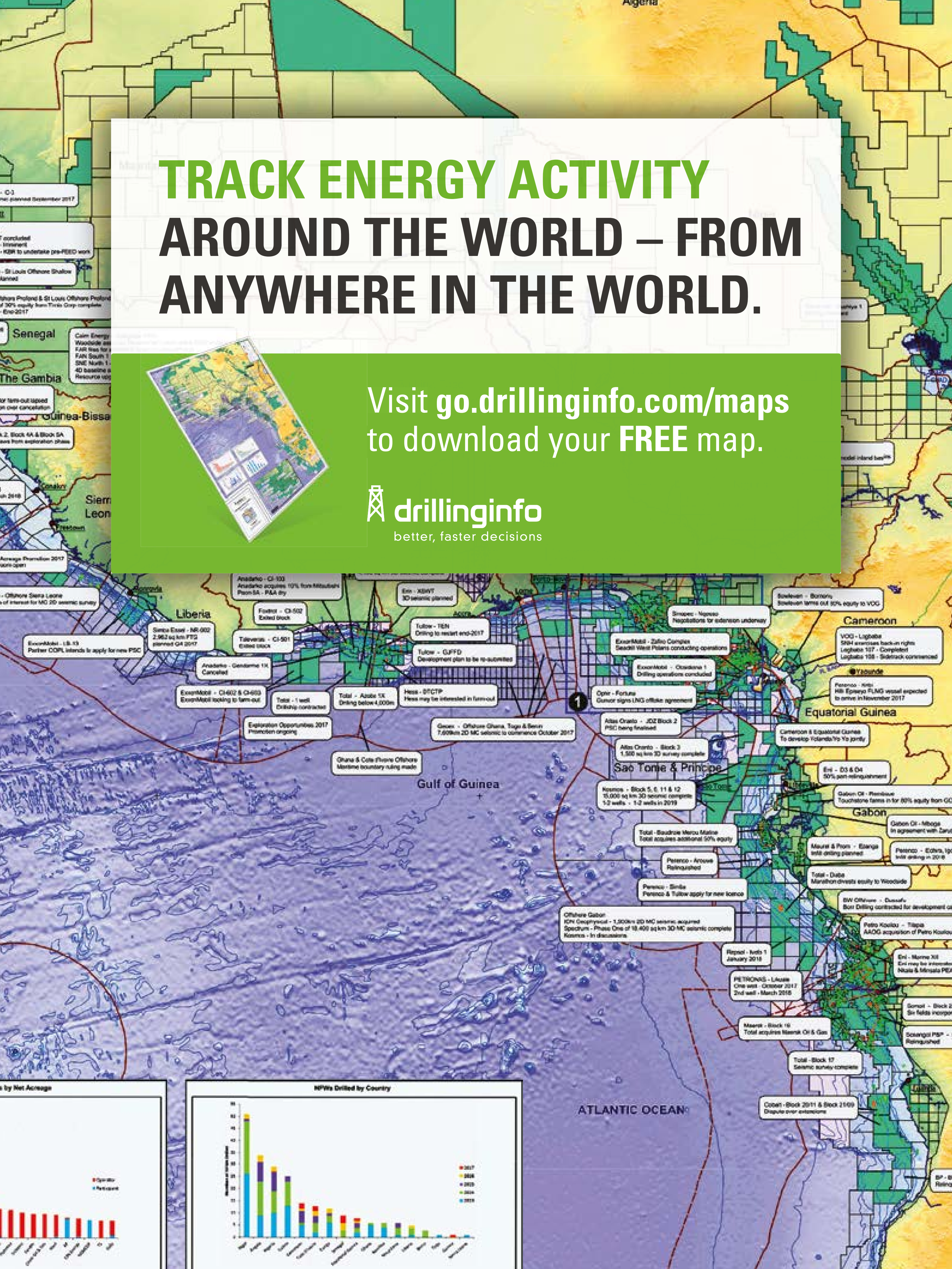
This edition of *GEO ExPro* focuses on Europe and South East Asia; New Technologies; and the Great Crew Change.



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A Poor Balance

A skewed demographic.

The demography of the oil and gas industry does not reflect the world. It is tilted towards an older age range, with a serious lack of middle management experience – those young professionals lost in previous downturns. Talking to recent entrants to the industry, it appears that we have not learnt a great deal; few recent graduates have been employed, while young professionals, let go in a flurry of cost-cutting, find they have to compete for jobs with people with maybe a decade more experience. Yet we must employ the younger generation, so they can learn from those with experience.

In addition to the imbalance in age demographics, we are seriously top heavy with men. Only 22% of people working in oil and gas are women, one of the lowest shares among major industries. It is commonly accepted that improving the gender balance would be beneficial to the industry, with a wider diversity of opinions resulting in increased creativity and teamwork, among other things, so this imbalance presents a considerable loss to the industry.

However, according to a recent study by the Petroleum Council and the Boston Consulting Group (*Untapped Reserves: Promoting Gender Balance in Oil and Gas*), the industry is an unwelcoming place for women. It is hard for them to establish and maintain a career in this male-centric industry. Common perceptions are that it is dirty, old-fashioned and male dominated; just google 'oil and gas work images' and see how many photos you scroll through before one features a woman.

At entry level almost equal numbers of men and women are employed in the industry, but this drops steeply by the executive stage, where on average just 17% are female. The study found there were big differences in the reasons men and women give for this. Over half the women in the survey believe they get less support, with a quarter of men thinking the same, while 34% of men believe women were not flexible, an opinion shared with only 24% of the female respondents. Interestingly, when asked questions that tested flexibility, women consistently scored higher than their male counterparts.

We have to realise that changing the demographic imbalance is *all* our responsibility. We need to change our mindsets, ask more questions and communicate our thoughts, wishes and ideas. ■

Jane Whaley
Editor in Chief

INDONESIAN WONDERS

Officially recognised as a UNESCO Global Geopark in April this year, the Ciletuh-Palabuhanratu Geopark in West Java offers a window on the complex processes involved when two tectonic plates meet.

Inset: Structural maps are important – so how can you tell if a map is good, bad or indifferent?

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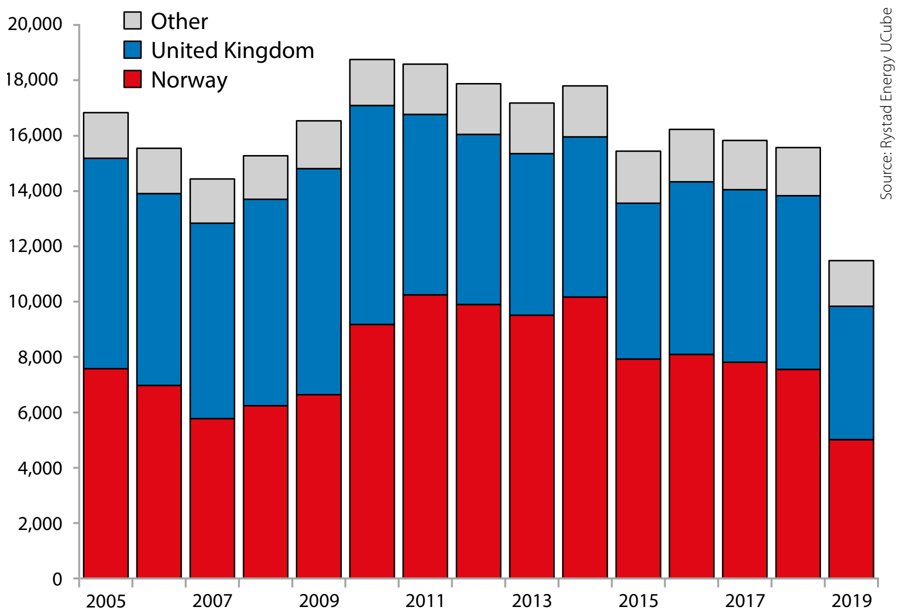
North Sea Project Pipeline Drying Up

RYSTAD ENERGY

In 2017, 360 MMboe of new oil and gas resources were discovered in the North Sea. This is just a fraction of what was found during the period from 2009 to 2011, when an average of 2,500 MMboe was discovered per year. Among E&P companies and suppliers, the low exploration success has raised concerns that we could be running out of new projects ready for development in the North Sea.



Resource development allocated to discovered, not yet sanctioned, fields for the North Sea (MMboe).

By tracking every discovery in the North Sea, Rystad Energy is able to analyse how not-yet-sanctioned resources, often referred to as contingent resources, have developed over the last 15 years (see figure above). In 2005, contingent resources were around 17 Bboe. This number declined to 14 Bboe by 2007, due to high sanctioning activities, before the oil price collapsed in 2008. From 2008 until 2010 the contingent resource volume increased as new fields were found, the key discoveries being Johan Sverdrup, Lancaster/Halifax, Culzean and Maria. In total, the contingent resources grew to 19 Bboe by 2010. This volume remained stable for the next five years, before dropping in 2015, when Johan Sverdrup was sanctioned. Since then the contingent resources figure has been stable at around 16 Bboe.

That said, over the next two years we might be in for a change. As the oil price remains high and E&P companies bring down costs and breakeven prices for new projects, sanctioning activity is expected to pick up in 2018 and 2019. Projects such as Johan Castberg, Johan Sverdrup (Phase 2), Troll West, Rosebank/Lochnagar and the Snorre expansion are all expected to be sanctioned over the next two years. By sanctioning these fields, contingent resources will be reduced by almost 5 Bboe, while at the same time the size of the sanctioned projects in the pipeline will drop considerably. This shows that we are starting to run out of viable projects in the North Sea. With the exception of Lancaster, Krafla/Askja, Wisting and Alta/Gohta, the landscape will be dominated by small subsea projects.

The fact that the number of large new development projects in the North Sea may start to decline should be a concern for anyone involved in the upstream sector. It shows yet again that we need to focus on exploration efforts and open up new areas to exploration. ■

Espen Erlingsen, Head of Upstream Research, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

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

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

India:
First Open Acreage Round

India currently imports 80% of its oil needs. As a result, in 2017 the Prime Minister, Narendra Modi, announced a new Hydrocarbon Exploration and Licensing Policy (HELP) to assist the country reach its target of reducing import dependency on oil and gas by 10% by 2022 by bringing about 2.8 million kilometres of virgin acreage in the country under exploration.

The main facets of the HELP policy include a single licence for exploration and production of all forms of hydrocarbons; an open acreage licensing programme; a new revenue sharing model; and marketing and pricing freedom for all crude oil and natural gas produced.

The open acreage idea is an important aspect; companies can make their own assessments of areas not currently under production or exploration and propose their own block outline through an ‘Expression of Interest’. Twice a year these will be accumulated and offered for auction, with the company that originally selected the area getting a five-mark advantage. Blocks will be awarded to the company which offers the highest share of oil and gas to the government as well as commits to undertake maximum exploration work by way of shooting 2D and 3D seismic surveys and drilling exploration wells.

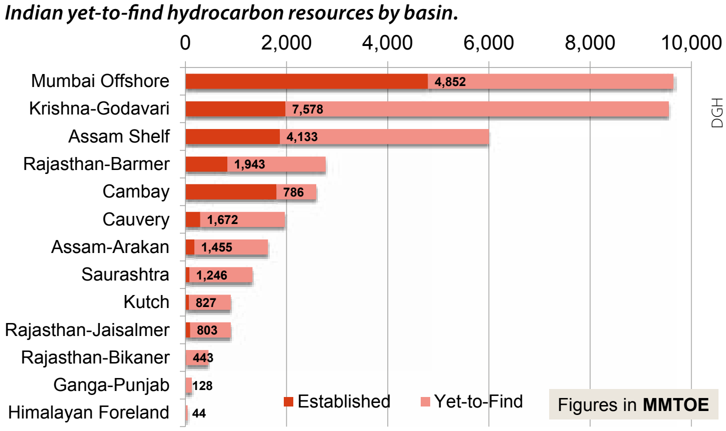
Domestic Success

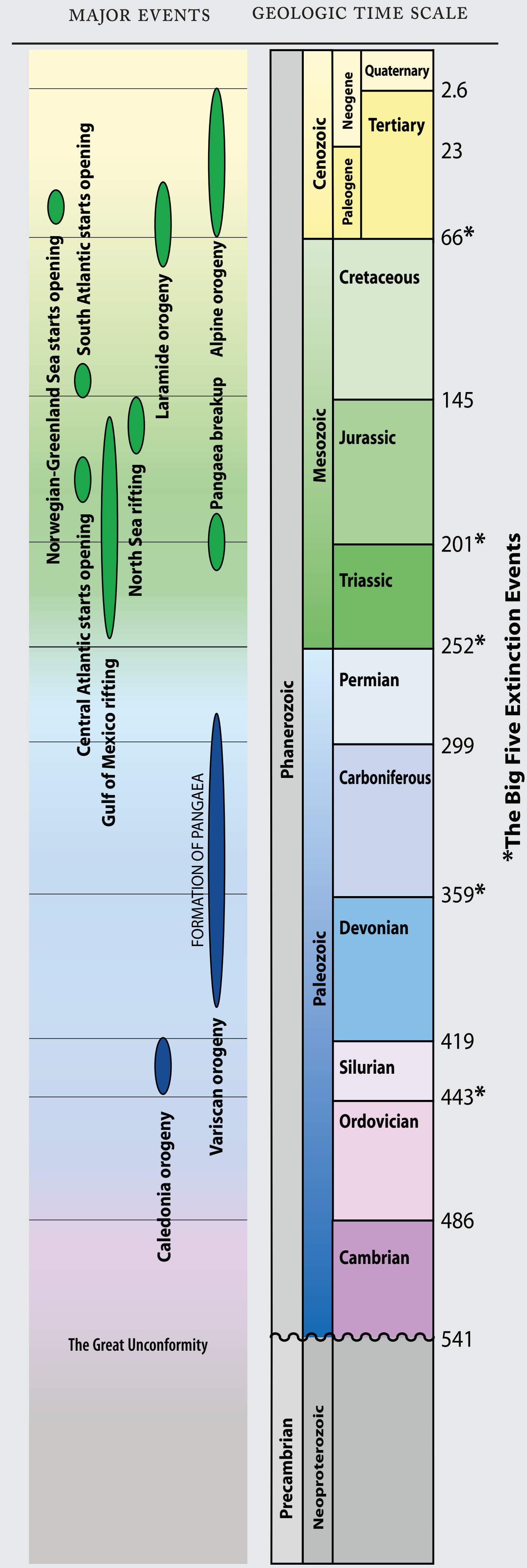
In the first Open Acreage round 55 blocks were offered, 46 on land and nine marine, covering a total area of nearly 60,000 km^2. The blocks were in ten sedimentary basins spread across the whole of India, from the Himalayan Foreland in the north to the southern Cauvery Basin, with 19 in the eastern Assam-Arakan Basin.

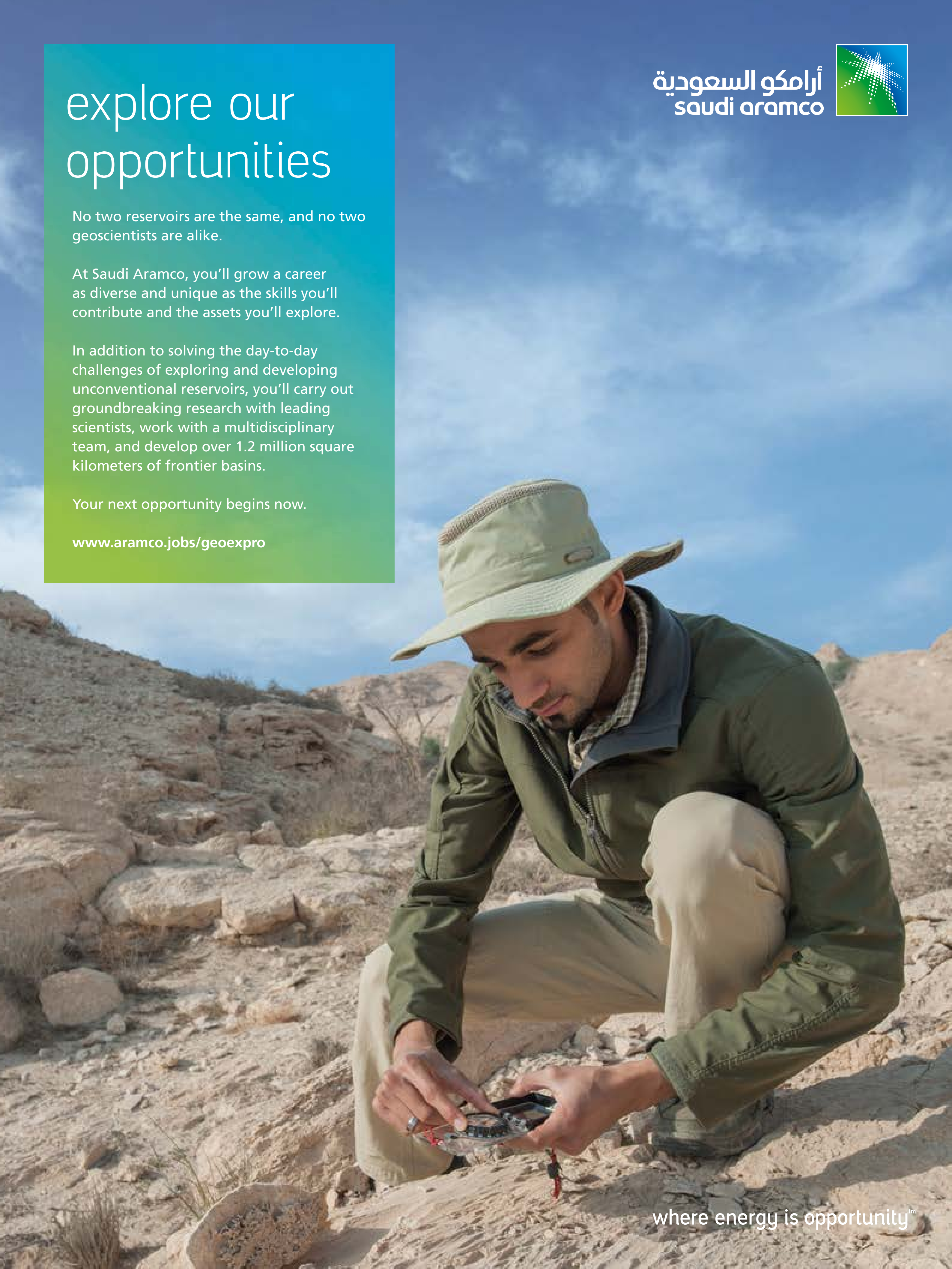
The round closed on 2 May 2018, and the Directorate General of Hydrocarbon (DGH), the upstream technical arm of the Ministry of Petroleum and Natural Gas, announced that 110 bids had been received, with every block attracting at least one bid offer. All the bids came from Indian companies, with no interest from international ones. They will now be evaluated, and the government says it will announce the awards of the blocks by June 2018.

Under the previous system of delineated block rounds, 254 blocks had been awarded for exploration and production since 2000, and 156 have already been relinquished due to poor prospectivity. ■

Indian yet-to-find hydrocarbon resources by basin.



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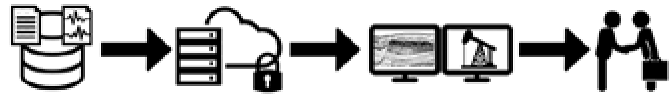
What is a Virtual Data Room?

A **Virtual Data Room (VDR)** is much more than an online repository of information and file sharing site. There are so many aspects to consider in advance of setting up a data room. YOU…



– may want to allow certain items to be downloaded but restrict the download of others.
– may not want to show all data in a concession but still indicate that data exists.
– may want to allow interpretation of subsurface data – or only allow a view of current interpretation.
– may want to subset existing subsurface data, perhaps by resampling seismic.
– may want a global audience of O&G new venture professionals to know of the opportunity or may prefer to run on an invitation-only basis.
– will want assurance that data will be treated as confidential by using confidentiality agreements
– will want a method of tracking any mistreated confidential data (e.g. watermarking with IP address of viewer).
– will want prevention of any robotic auto-download.
– will want all of this to be easily (EZ) set-up without a major effort (file reformatting etc.) on your part.

Fortunately, the **Zebra Data Sciences EzDataRoom®** services have been designed to address these issues leaving just one, albeit tricky, task for you – to decide what to include within your VDR. ■

New Surveys Awarded

Geophysical acquisition specialist **Shearwater** has recently been awarded several significant contracts. Three of the company's vessels were engaged in surveys in the Indian Ocean for the northern winter season. For the second consecutive year it has been awarded a contract by **TGS** to undertake a seismic survey on the Atlantic Margin in the Norwegian Sea, covering 5,135 km², which will be undertaken by one of Shearwater's high-end 3D vessels, using FlexiSource and a wide tow spread, for which all Shearwater vessels are designed.

*The survey ship **Polar Marquis** will undertake surveys in West Africa later this year.*

In May Shearwater was also awarded two 3D seismic acquisition contracts for clients in West Africa, one of which is for Genel Energy in the Sidi Moussa licene offshore Morocco, which will cover over 3,500 km². The other is for two surveys for an undisclosed client in West Africa, which are expected to take five months to complete and to cover approximately 10,000 km² between them.

Shearwater believes that these contracts are evidence that the seismic market is finally strengthening and improving. ■

AAPG ICE: A Unique Opportunity

Coming off a busy and successful **2017 International Conference & Exhibition (ICE)** in London, the **American Association of Petroleum Geologists (AAPG)** is excited to take the globe's leading international petroleum geoscience event to **Cape Town, South Africa, on 4–7 November 2018**. ICE 2018 will gather geoscientists and petroleum industry professionals from over 60 countries to build their knowledge and skills, discover technological innovations, and network with peers.

Attendees: become a leader and stay relevant by accessing the tools, content and contacts that will help you succeed in this constantly changing industry. By participating in and supporting ICE, you'll benefit through experiencing some of the most recent geoscience information available. It is this focus on science and community that provides the cornerstone for both personal and business opportunities at the event.

Exhibitors and Sponsors: The Cape Town International Convention Centre will simultaneously host both **ICE** and **Africa Oil Week. AAPG welcomes all attendees to visit the exhibit floor. Don't miss this unique opportunity to relay your message to a larger science and technology audience**.

Registration opens July 2018 and exhibition and sponsorship opportunities, as well as the technical themes of the meeting, are now available – see the AAPG ICE website for details. ■

AOW: Dedicated to Developing Partnerships

With over $194 billion forecast to be spent in the African upstream sector between 2018 and 2025, it is critical the industry has a platform where it can meet to ensure the investment deficit across the continent's O&G sector is met. **Africa Oil Week (AOW)**, an event dedicated to developing new partnerships and deal brokerage, has announced that 17 governments will be present throughout the event, to be held on **5–9 November 2018** at the **Cape Town International Convention Centre, South Africa**.

AOW's reputation as the premier transaction forum for the African oil and gas industry means that the programme is dedicated to seeing that finance and partnerships are committed to the region.

The event provides a platform for governments and private sector companies to engage collectively to develop new business activities. A new feature is the Prospect Forum, held together with AAPG: a platform for companies looking to broker commercial partnerships on prospects and data. It will be attended by governments, national and independent oil companies, service companies, investment banks, private equity funds and EPCs. ■

Ministerial Panel held at Africa Oil Week 2017.

Large Multiclient Data Library

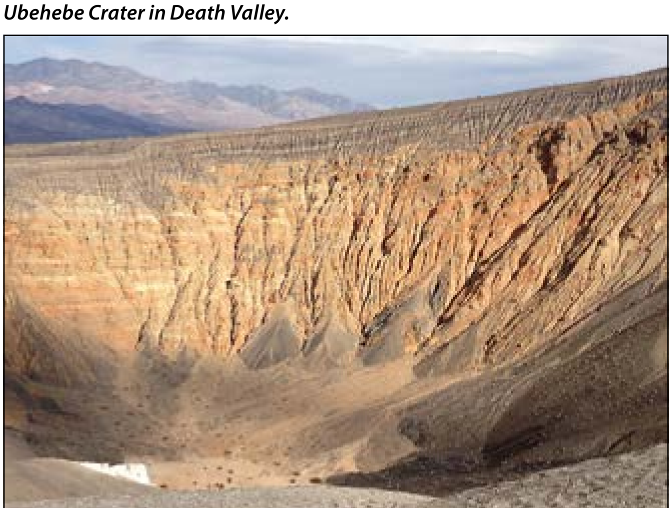
By acquiring Geokinetics Inc.'s entire US multiclient data library, **FairfieldNodal** has nearly tripled its **North American multiclient library** coverage, going from 3,532 square miles (9,148 km^2) in the Permian Basin to 10,460 square miles (27,092 km^2) in key US basins, including Appalachian and Powder River Basins. FairfieldNodal is an industry leader in seismic nodal technology and related services, specialising in revolutionary, true cable-free systems, both land and marine, as well as offering expert marine acquisition and data processing services.

This transaction is part of the company's aggressive plans to expand its multiclient data library, data-processing services and capabilities, reservoir analytics, and integrated solutions through partnerships and M&A. ■

The Road Ahead

The **Society of Exploration Geophysicists 2018 International Exposition** and 88th Annual Meeting, in **Anaheim, California**, will feature robust, cutting-edge education programming, including 151 technical programme sessions with over 1,080 presentations. There are also 14 Continuing Education courses, five Business of Applied Geophysics Plenary sessions, Ancillary Education sessions, including a Career Workout Workshop, 2018 SEG Distinguished Instructor Short Courses, and 23 postconvention workshops.

Ubehebe Crater in Death Valley.



A brand new hot topic, 'Machine Learning and Data Analytics for E&P', will be highlighted, with five oral and five poster sessions as well as the special session, Recent Advances and the Road Ahead, which will discuss the recent advances and future opportunities and challenges of Data Analytics and Machine Learning for geoscience applications.

Join over 6,000 colleagues from more than 70 countries in sunny southern California, a beautiful location offering a wide variety of nearby geological wonders, from Newport Beach, Inglewood, the San Andreas Faults and Ubehebe Crater in Death Valley to areas rich in the history of oil drilling such as Signal Hill.

Early bird registration ends 21 August. Register today at the SEG website. ■

Indonesian Wonders

Officially recognised as a UNESCO Global Geopark in April this year, the Ciletuh-Palabuhanratu Geopark offers a range of geological wonders, many the result of ongoing subduction.

MEGA ROSANA
Padjadjaran University, Indonesia.

The Ciletuh-Palabuhanratu Geopark lies in the south-west corner of Java, an island in the Indonesian archipelago and part of a long volcanic arc extending from northern Sumatra to Timor Leste. These islands are the result of the continuing northward movement of the Indo-Australian plate at a rate of a few centimetres a year, and its subsequent subduction beneath the Eurasian plate, which started in the Cretaceous. This movement has resulted in a rare geological diversity which includes important features demonstrating forearc evolution. These range from ancient ophiolitic complexes to very recent phenomena such as hot springs and geysers, and they naturally divide the park into three very geologically different areas: the mountainous northern Cisolok region, with evidence of the most recent magmatic activity; the central Jampang Plateau; and in the south, the geologically significant Ciletuh area, dominated by a huge natural amphitheatre.

Shifting Magmatic Belt

The Geopark's northern area of Cisolok and Palabuhanratu (named after the goddess who, according to local legend, was the Queen of the Indian Ocean) reflects the tectonic evolution of the whole island and demonstrates the progress of a belt of volcanic activity from south to north. The coastal area is dominated by older volcanic rocks, probably Miocene in age, while there is plentiful evidence of present-day volcanic activity in the north, including geothermal systems and active volcanos such as Mt. Salak in the mountainous northernmost region, part of the Gunung Halimun-Salak National Park.

Although there are many hot springs along the Indonesian magmatic arc, only one is at sufficient pressure to release water as a geyser, rising up to 5m high. This is situated on the Cisolok River in this northern section of the geopark, and is a popular tourist destination, along with nearby hot springs and fumaroles. The water is close to boiling point and there

Ron Agusta

Looking across Ciletuh Bay from the Jampang Plateau towards the ophiolite complex on the opposite headland.

is plentiful evidence of the alteration of rocks in the vicinity of the hot springs, related to hydrothermal mineralisation, as well as surface deposition of hydrothermal fluids. Because the hot water passes though the limestone of the Citarete Formation, it has a high calcareous content, which is deposited at the surface as sheets and layers of dramatically shaped travertine, formed through rapid precipitation of calcium carbonate.

Moving further south, the central area of the Geopark is dominated by the Jampang Plateau, with evidence of slightly older tectonic movements. The rocks here are mostly from the Jampang Formation, with volcanic breccias and lava flows, as well as volcaniclastic sandstones and mudstones and intercalated limestones, all deposited in the Late Oligocene to early Miocene in a marine environment. In the Pliocene to Pleistocene, this area underwent uplift to form the plateau, which has since suffered erosion and peneplenation, leaving the majority of it at about 700m above sea level.

A UNESCO Global Geopark

The Ciletuh-Palabuhanratu Geopark lies about 135 km south of the Indonesian capital of Jakarta, and covers an area of 1,261 km^2, encompassing 74 villages with a total population of about half a million.

UNESCO Global Geoparks are areas where sites and landscapes of international geological significance are managed with a holistic approach to protection, education and development, combining conservation with sustainable growth, all of which has to be demonstrated before the park can be awarded this highly prized status (see *GEO ExPro*, Vol. 14, No. 1). For many of the communities in the Ciletuh-Palabuhanratu Geopark their main income is derived from fishing, but it is expected that tourism, which is already becoming common in the northern part of the park, will provide an increasing source of revenue as tourists seek out not only the spectacular scenery, untouched beaches and fascinating geology and geomorphology, but also the thrills associated with adventure sports such as surfing, paragliding, rafting, canoeing, rock climbing, snorkelling, diving, fishing and forest trekking.

The area is culturally diverse, with a number of villages following traditional Kasepuhan farming and harvesting techniques, with traditional music and dance also being an important cultural feature. Local communities are encouraged to become involved with initiatives related to Geopark conservation, education and promotion through a community empowerment programme.

Much of the plateau is given over to tea plantations, dating back to the era of Dutch colonisation of Java. Fruit such as durian and dragon fruit are also grown.

Awang waterfall – Java's Niagara.

Oldest Rocks in West Java

The Ciletuh region, the southern part of the Ciletuh-Palabuhanratu Geopark, is in many ways the most geologically interesting, as it contains remnants of subduction that occurred in the Cretaceous, including rocks that were deposited within a deep trench created during the process. These are the oldest formations found in West Java and include ophiolites, composed of peridotite, gabbro and basalt, as well as metamorphic and sedimentary rocks mixed together to form mélange subduction complexes, both very rare rocks in this region. There is also evidence of pillow lavas. The Oligocene-Early Miocene tectonism uplifted the area, and subsequent erosion in the southern part of West Java exposed the Cretaceous basement.

These rocks are overlain by Tertiary sediments, the oldest of which are Middle Eocene volcanogenic turbidites and breccias containing basaltic material, deposited in deep water and representing the onset of a renewed phase of subduction. These are the oldest sedimentary deposits in West Java. There are also thick sandstones, possibly deposited in a large prograding delta system in the Late Eocene, while the Oligocene is represented by terrestrial sandstones, reefal and foraminiferal limestones and volcanogenic sediments deposited in fluvial to deeper water marine environments. There was a major phase of subduction-related explosive volcanism in the Early Miocene, possibly associated with the emergence of the island arc.

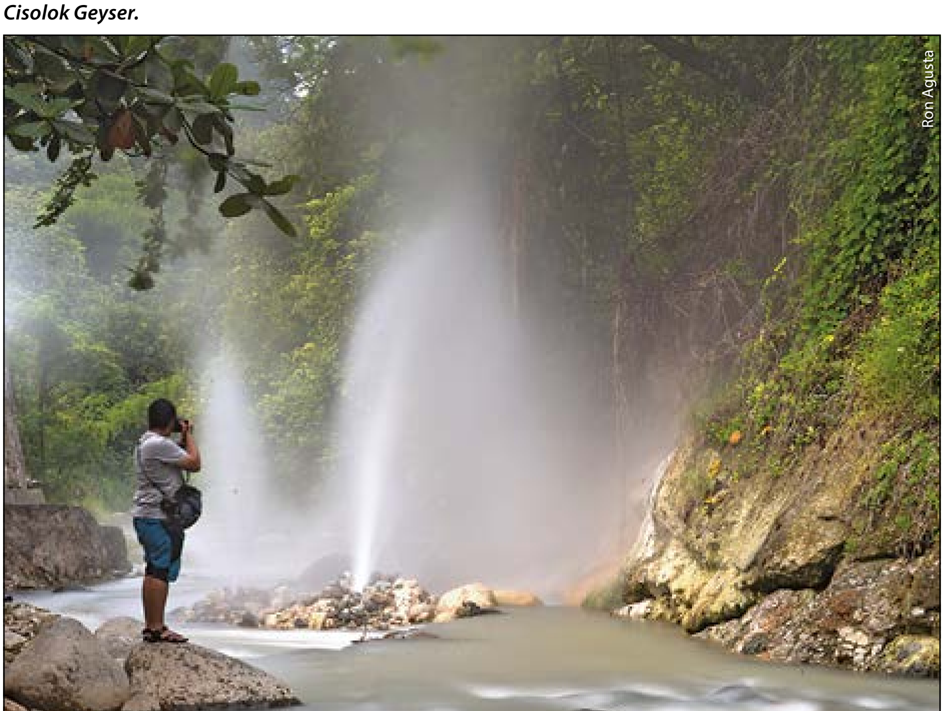
One of the most distinctive features of this area is the horseshoe-shaped Ciletuh amphitheatre, which opens out to the sea at Ciletuh Bay. Encompassing 135 km^2, the amphitheatre is the result of the gravity-induced collapse of part of the Jampang Plateau in the Pleistocene, triggered by tectonic movement along faults. This has resulted in steep cliffs up to 500m high around the valley, which feature many spectacular waterfalls. In the dry season the clean surfaces behind these provide excellent exposures of the flat-bedded nature of the sediments of the Jampang Formation in this area – and also offer good practice walls for climbing enthusiasts.

Many Interesting Geosites

A number of geosites of interest have been identified throughout the Ciletuh-Palabuhanratu Geopark, including the Cisolok Geyser and the Ciletuh amphitheatre, already discussed. The sites include features covering geomorphology, fossils, sea caves, unique rock formations, waterfalls, sedimentary structures and rocks of geological significance, such as the ophiolites and mélanges found south-west of the Ciletuh amphitheatre. The small peninsula of Sodongparat is an example of a site identified for its geological significance, because of its good outcrops of peridotite, gabbro, amphibolite and plagiogranite, demonstrating that it represents part of the oceanic crust uplifted due to subduction.

Gunung Badak on the southern side of Ciletuh Bay is another good location for finding evidence of the Cretaceous plate movement, as the rocks are a classic 'mélange' complex composed of breccias, sedimentary and metamorphic

Cisolok Geyser.



Batu Kodok, or the Frog Rock, one of many interesting rocks carved by erosional forces found on the south-west coast of the Geopark.

Seren Taun is a traditional harvest festival.

rock. At this site it is also possible to find peridotite from the upper mantle, along with oceanic crust in the form of gabbro and pillow lava, together with marine fossils. Close by is Pasir Luhur, which is significant in being the only place in West Java where metamorphic rocks can be seen in outcrop.

The Eocene sedimentary rocks which form the west coast of the Ciletuh area have been subjected for many years to the forces of the wind and the sea. As a result, they are carved into spectacular shapes, many of which have been named after the animal or mythological creatures which they are thought to resemble, including a frog, a rabbit and a dragon. The best way to appreciate these formations is by taking a boat trip along the coast to the south of Ciletuh Bay.

What's Keeping You?

Despite Java being the most populated island in the world and home to more than half the population of Indonesia, much of the Ciletuh-Palabuhanratu Geopark is relatively remote and hard to reach, particularly in the south, with very little tourist infrastructure like information boards and signage associated with the geosites. It is a very unspoiled corner of the island and, in keeping with its status as a geopark, is not only fantastic to visit from the geological point of view, but also shows great biodiversity and contains a number of national parks and conservation areas. These include the Pangumbahan Turtle Park, where female Giant Green Sea Turtles come ashore and lay their eggs in a protected environment. The forests in the surrounding area contain macaques, leaf monkeys, wild boars, otters, monitor lizards as well as many fascinating birds.

With fascinating geology, beautiful landscapes, sandy beaches, excellent surfing, the popular Citarik river for rafting and a diverse range of animals and birds both on and offshore: what more could you ask for? ■

The steep-sided Ciletuh amphitheatre is a result of gravitational collapse.

Unlocking the Triassic

Exploring play potential in new areas of the North Sea.

HENRY MORRIS and MATT ENGLAND, Azinor Catalyst

Although the UK North Sea is becoming increasingly mature as an exploration province, the search for hydrocarbons continues, albeit with new focuses. One of these in recent years has been the Triassic play. Statistics show that the Triassic is one of a few underexplored plays able to deliver substantial resources with a high commercial chance of success: 40% , according to Westwood Global, with an average discovery size of 95 MMboe. When we look at exploration wells in the last eight years and at play-based creaming curves we see that the Triassic is very underexplored. Although not a frequent target for exploration, Triassic prospects are generally low risk and high reward.

This article highlights how the use of new data and best practice techniques can help companies unearth opportunities and value. While new seismic helps define traps previously too deep to be well imaged, it is the integration of this data with a regional basinwide understanding of the Triassic geology which provides detailed insight into reservoir quality, one of the key risks in the play. The big picture informs the local detail!

Triassic Stratigraphy

Triassic deposition is interpreted to have occurred in a dryland fluvio-lacustrine setting (McKie & Audretsch, 2005; McKie 2014; Cope, 1992). The overall depositional setting for the Lower Triassic was one of relatively arid conditions, with ephemeral terminal fluvial systems discharging into desiccated and evaporitic playas as terminal splay systems. In contrast, facies associations in the Middle to Upper Triassic suggest a dry land depositional system which was typically wetter than in the Lower Triassic, allowing the formation of well developed river courses which sourced perennial lakes and marshes (McKie, 2014). Fluvial channel facies are typically fine to medium grained and characterised by a low clay content, while lake margin terminal splay facies are finer grained, and more argillaceous and micaceous (Akbokodje et al., 2017). These depositional textures retain a primary control on porosity evolution through burial. Consequently, well-sorted, clean, fluvial sandstones provide the most important Triassic reservoir targets in the North Sea.

The Triassic stratigraphy of the South Viking Graben is poorly understood compared to the Central Graben, owing to fewer well penetrations in the axial parts of the basin. Along the basin's Norwegian eastern margin detailed chemostratigraphic, sedimentological and petrographic analysis means we are able to update our understanding of age and facies and integrate this with recent seismic interpretation. This is having important implications on our understanding of the expected reservoir quality of these units, and may in part explain the poor reservoir properties observed in at least some of the Triassic wells along the flanks of the South Viking Graben. Despite the greater depth of burial in the basin axis, better reservoirs can be expected in these more basinal locations where we would expect a high dominance of fluvial channels throughout the Triassic.

New Eyes, Improved Clarity

In addition to new insights into the depositional settings and facies types, new broadband seismic data provides much better imaging of the deep trapping mechanisms. Figure 2a shows the large untested Boaz tilted fault block prospect on vintage data. Well 16/8a-10, drilled in 1988, reached total depth in the overlying Middle Jurassic Sleipner but did not reach the Triassic sands. In the adjacent blocks to the east in Norway lies the Eirin field, which flowed gas condensate from the Triassic. In the vintage seismic it is difficult to interpret below the Sleipner coals, which is why the industry has historically struggled to gain confidence in defining the Boaz trap. With new broadband seismic

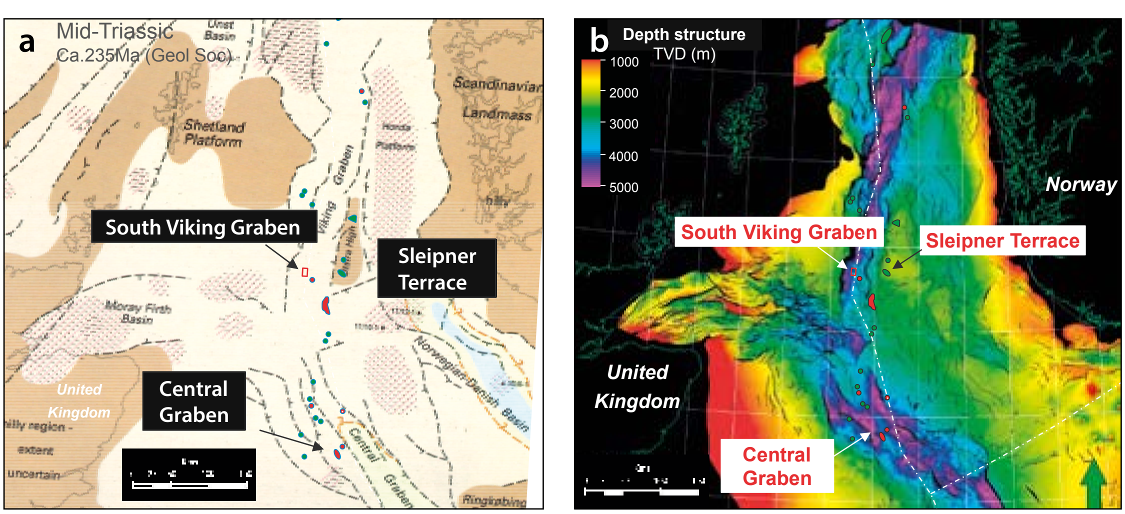


Figure 1: (a) Palaeogeography of the Mid-Triassic (modified from Geol. Soc. Memoir No.13, 1992); (b) Top Triassic two-way-time map.

data (Figure 2b) there is far greater clarity at depth and we can now correlate new prospects to known discoveries – Boaz to Eirin and to surrounding wells. We now have the ability to not only map the top of the Triassic directly but also to define important intra-Triassic reflectors and deeper stratigraphy, such as the Permian.

The next challenge is reservoir quality. Big Data such as regional 3D seismic allows for a detailed understanding of the basin history and architecture. This is fundamental to making the correct analogues when comparing new basins with better known critical wells and fields within the same play. The closest Triassic fields to the South Viking Graben are those on the Sleipner Terrace in Norway (Figure 1). Slater et al. (2016) show that if you take Norwegian core data from the Sleipner Terrace (Figure 3, right), and project to depths of known structures (~4,500m) within the South Viking Graben, sandstone porosities will be degraded and provide only poor conduits to fluid flow. The dotted line represents the mean porosity, indicating porosities of below 10% at a depth of 4,500m. However, if you take the UK trend (Figure 3, left), predominantly driven by wells in the Central Graben, the indication is that porosities and therefore permeabilities will provide good quality reservoirs that can flow hydrocarbons. Porosities on this trend average 15–20% for depths around 4,500m, and could be expected to have a reasonable permeability.

Further to the primary facies control, reservoir quality is controlled by opposing subsurface processes that can either degrade the reservoir, or act to preserve porosity. To understand the rock properties, we need to understand the regional forces acting on them. Degradation is caused by two main controls: mechanical compaction (controlled by vertical effective stress) and chemical compaction (pressure solution and quartz cementation, primarily temperature controlled). Preservation is assisted by three key controls inhibiting quartz cementation: presence of clay grain coatings, early migration of hydrocarbons and overpressure. Understanding the rates and timing of all these controls is the key to forward predicting new areas of effective reservoir quality.

By comparing burial history models for the South Viking Graben to the better known Sleipner Terrace and Central Graben, we see that the South Viking Graben undergoes rapid burial from the Upper Jurassic period, unlike the Central Graben and Sleipner Terrace (Figure 4). Rapid burial creates overpressured reservoir bodies and causes earlier entry into the hydrocarbon generation window than in the other two areas. Both of these physical processes

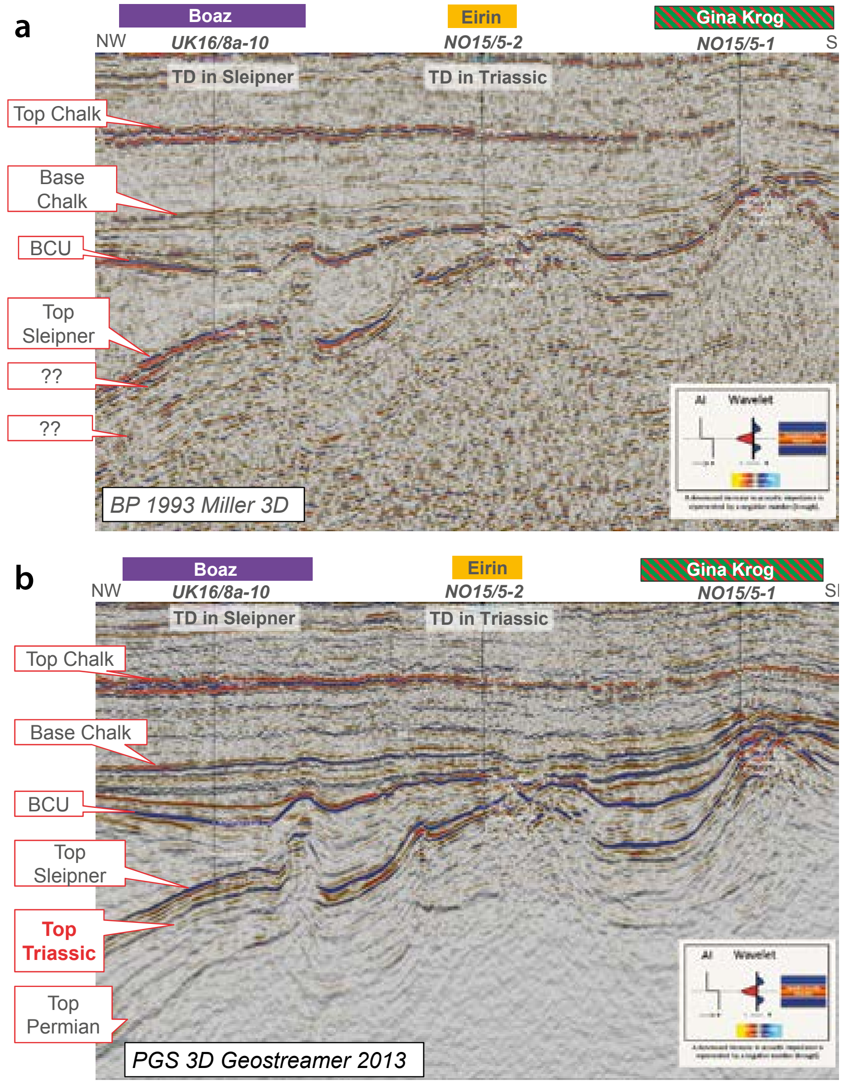
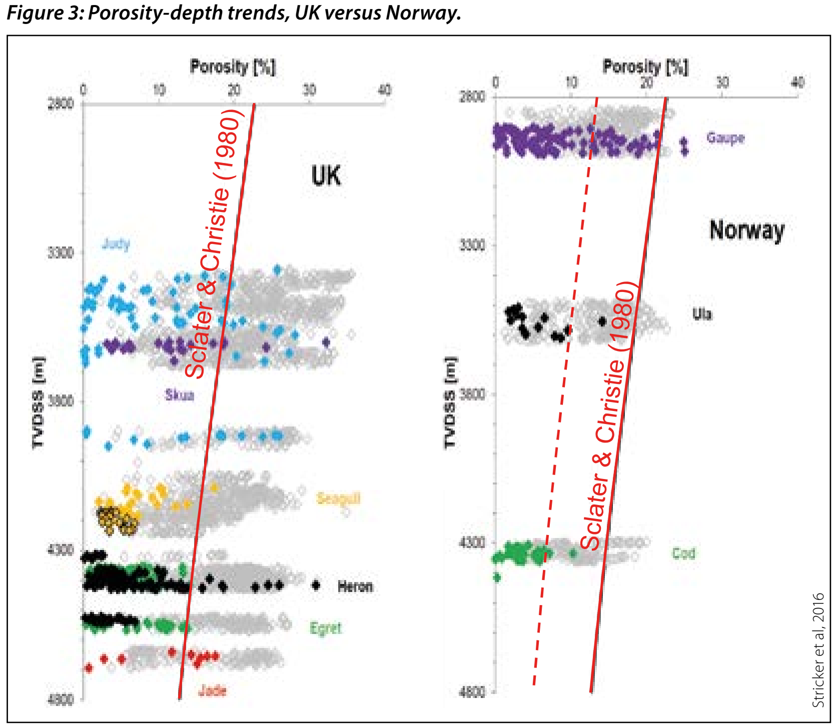


Figure 2: (a) Vintage seismic; (b) Recent broadband seismic.

Figure 3: Porosity-depth trends, UK versus Norway.



will assist in preserving porosities and permeabilities. In addition to high sedimentation rates in post-Triassic times, the low thermal gradient in the South Viking Graben, along with regional gravity maps, indicate that it was a longstanding depocentre prior to the Triassic. The net effect of this is that, while the rocks may have been buried quickly, they have been exposed to lower temperatures than other rocks at equivalent depths in the Central Graben, for example. This has positive connotations for reservoir preservation.

It also illustrates that the South Viking Graben is more analogous to the Central Graben than to the Sleipner Terrace area, and in the Central Graben reservoir quality is known to be good at a considerable depth. The regional basin modelling and loading of the South Viking Graben rocks mean that the physical processes acting upon this area would allow for preservation of adequate reservoir qualities, unlike those indicated from the trends identified from the Norwegian Sleipner Terrace; the Sleipner Terrace area is an inappropriate dataset for guiding trends within the Viking Graben.

Quantitative Predictions

Observations from the Triassic show that from a rock physics viewpoint it is actually very well behaved, and sands are almost always softer, i.e. lower acoustic impedance (AI), than the encasing shales. This is due to the sandstone structure maintaining a relative consistent framework, while the shales through time have undergone a larger degree of change. This is shown in Figure 5: highly porous sands are soft (low AI) while tight low porosity shales and silts are hard (high AI). When a formation behaves in this way it is incredibly useful – the seismic can be inverted to acoustic impedance, and from this we can get an indication of porosity and then permeability through rock physics transforms built around the data and relationships presented.

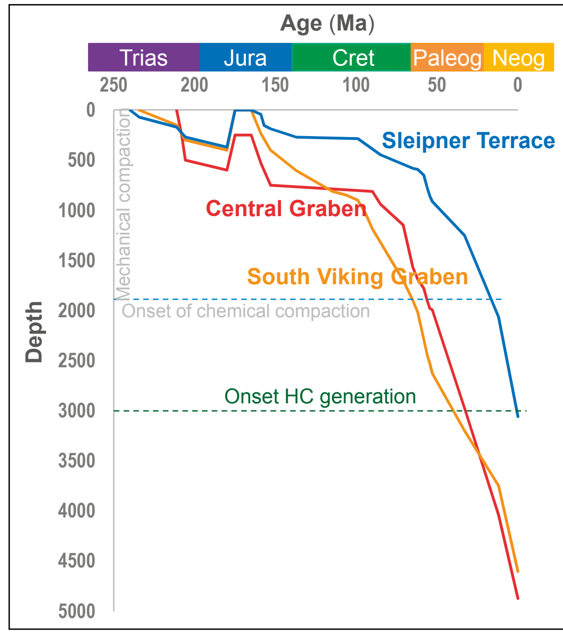


Figure 4: Burial history curves from the South Viking Graben, Central Graben and Sleipner Terrace.

Rock physics models and transforms give us the ability to convert seismic reflection data and seismic velocities into petrophysical properties (facies, porosity and permeability), as shown in Figure 6.

Bridging Basins

By driving for Big Data and detailed understanding, the industry can support pushing plays beyond previously recognised conventional boundaries, extending them into new sub-basins. Big regional datasets and high-powered computing allow us to build large regional maps and isochores crossing several basins, letting us bridge basins and draw on more distal analogues. New data and integrated studies provide clarity and new insight into the subsurface.

We can clearly see the benefits of using the data to extend the Triassic play from the more conventional Central Graben area north into the Viking Graben and possibly beyond. The Triassic section, in particular, shows very few anomalous rock properties and this can, and should, be taken advantage of in both exploration and production predictions. ■

Figure 5: (left) Porous rocks (sands) are continually softer than the surrounding shale. (right) Crossplots show clear trends between impedances and rock porosity and permeability.

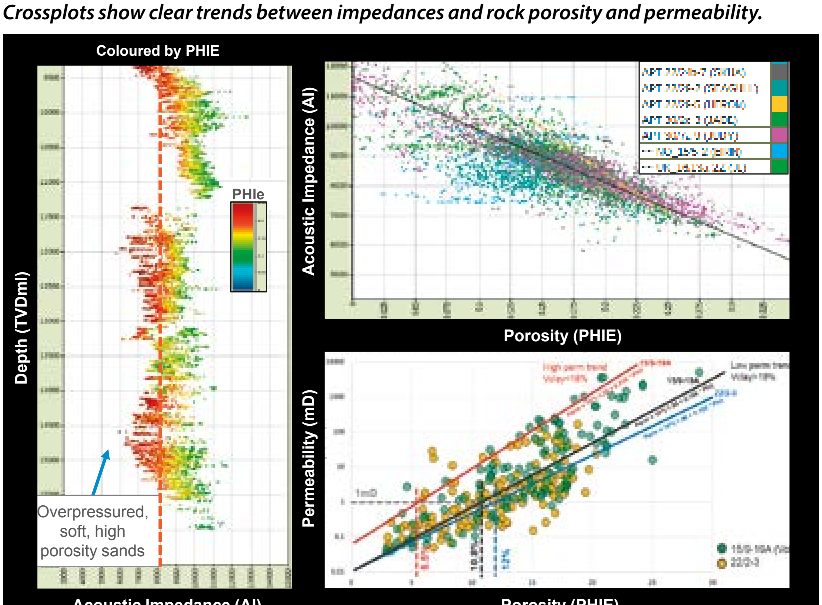
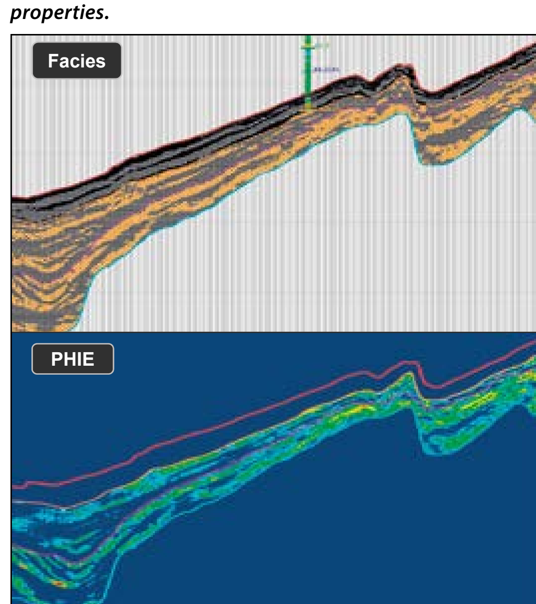
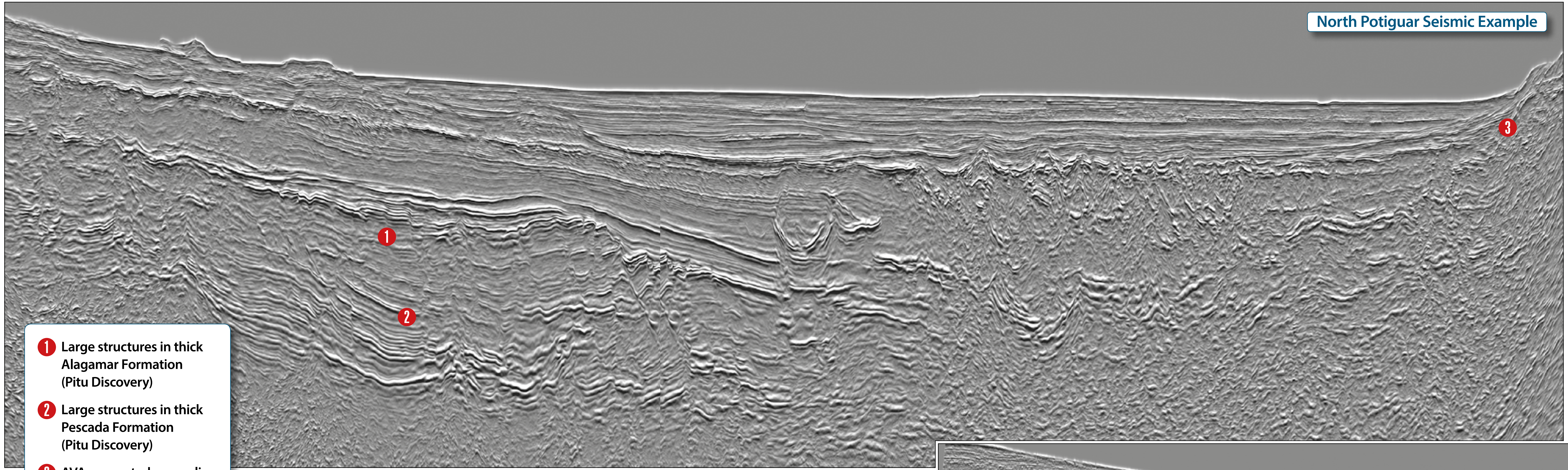


Figure 6: An example of seismic compared to petrophysical properties.



Brazil Regional Prospectivity: Highlights for Future Rounds

Spectrum

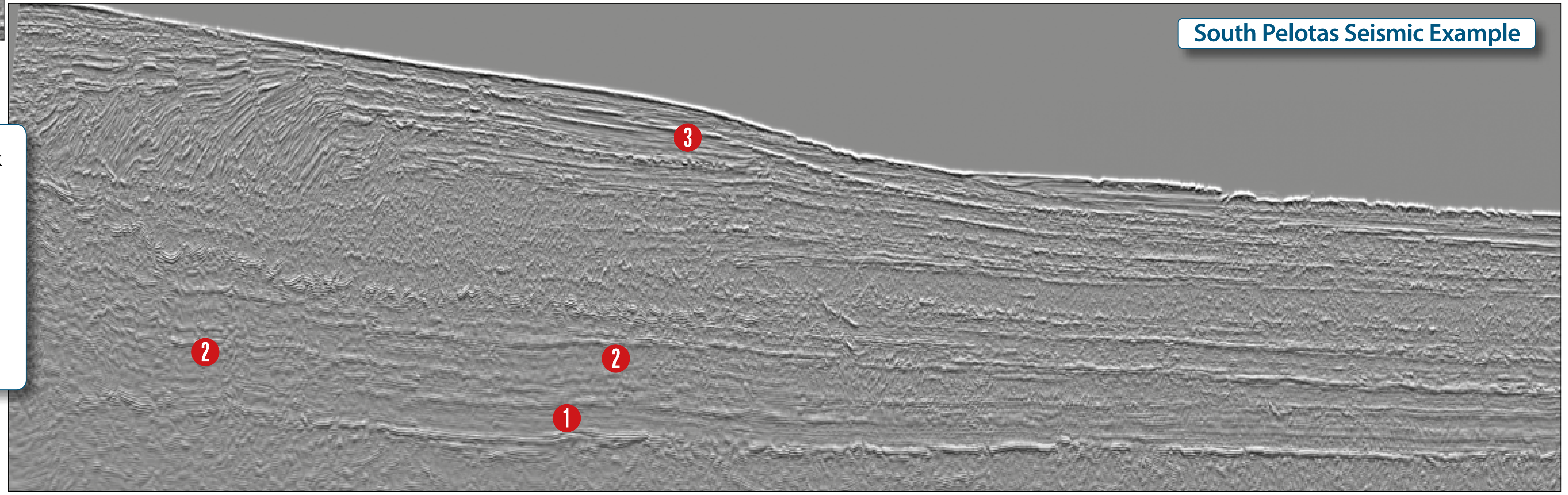


1. Large structures in thick Alagamar Formation (Pitu Discovery)
2. Large structures in thick Pescada Formation (Pitu Discovery)
3. AVA supported anomalies onlapping onto guyot

The recent Brazilian licence rounds have been extremely successful but also extremely competitive as the industry has focused on areas with well-established and prolific petroleum systems, such as the Santos, Campos and Sergipe Basins. In the latest round, blocks were also awarded in the less explored East Potiguar Basin where recently acquired 2D seismic data revealed the continuation of the Pitu oil discovery play fairway but within thicker and larger syn-rift structures.

In anticipation of future rounds, regional seismic datasets provide excellent coverage of open blocks (Figure 1) offering great insights into their prospectivity.

1. Aptian source rock modelled mature for oil
2. Basin Floor Fans with draping structures
3. BSR



Prospectivity Highlights of Open Blocks in Brazil Main Basins

KARYNA RODRIGUEZ, NEIL HODGSON and RICHIE MILLER, Spectrum

Foz do Amazonas Basin

Foz do Amazonas is the most northern of the Brazilian equatorial margin basins. The ANP 11th Round presentation quoted in-place volumes of 14 Bbo and 40 Tcfg, demonstrating huge hydrocarbon potential.

The recent Liza discovery by Exxon in Guyana has opened up a very prospective play fairway along the margin. Exploration targets have shifted from the complex and high risk slope channel bypass deposits in French Guiana to the more Liza-like distal basin floor fans.

Aptian and Cenomanian/Turonian source rocks have been identified with TOCs of up to 10% and 3.5% respectively. Also, a number of low stands are known in the Upper Cretaceous, when sands would have been transported via the slope channel systems into the deeper water areas of the basin. Liza-like basin floor fans have been interpreted on superb quality 3D seismic data. Spectral decomposition analysis indicates that these are disconnected from the shelf and also have a similar flat geometry to that observed in the Liza discovery. The 3D also indicates multilevel prospectivity (Figure 2), including thick syn-rift sections above a clear basement image, a thick and extensive Santonian channel and fan sequence, and a series of Late Cretaceous canyons with infill associated with a decrease in acoustic impedance and clear AVA anomalies.

Para Maranhao/Barreirinhas Basins

On the south-eastern side of the Amazon Cone, in the Para Maranhao Basin, new and reprocessed seismic data has revealed Amazon Cone specific and Foz do Amazonas look-alike play systems. The Amazon Cone has loaded the underlying crust, generating a structural dip to the south and east. Onlapping this structure are Early Cretaceous basin floor fan clastics sealed by Late Cretaceous mudstones. Well-defined Liza-style plays can be identified in the Cretaceous section as well as Ranger analogues with clear carbonate build-ups on volcanic mounds. All of the plays are expected to be charged with hydrocarbons potentially sourced from Albian and Cenomanian Turonian (syn-rift and sag) source rocks modelled to be oil mature, with thermal maturity models constrained by detailed crustal architecture studies by Royal Holloway University. A detailed interpretation carried out by Pedro Zalan has indicated significant Early to Late Cretaceous syn-rift inversion structures and Tertiary plays in drape, onlap and structural configurations with numerous apparent DHIs (Direct Hydrocarbon Indicators).

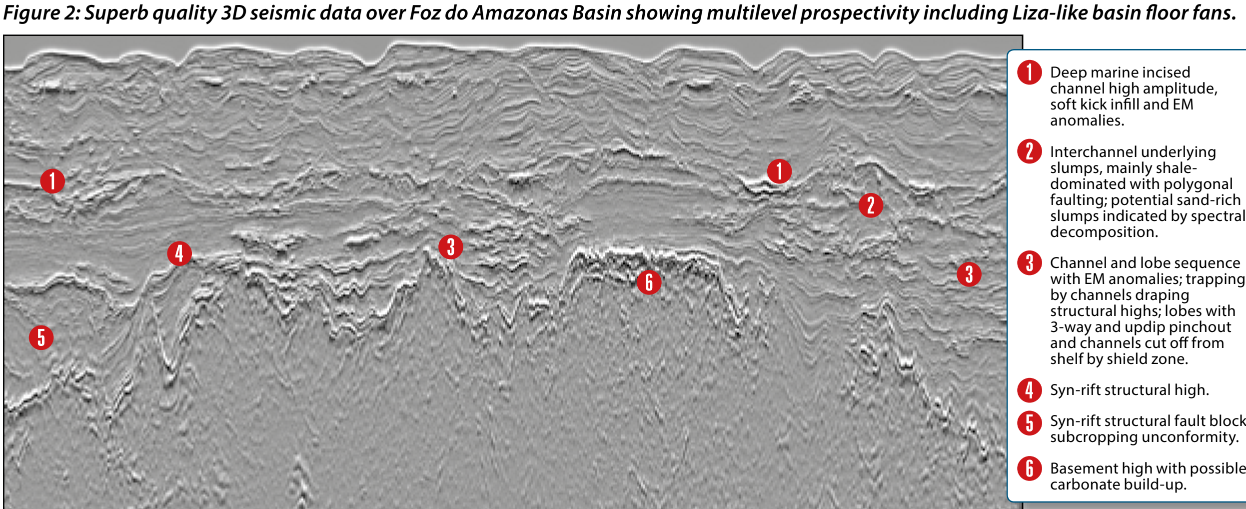
Ceara/Potiguar Basins

Two main play types have been confirmed. The 'Rift' play follows the Potiguar oil basin off the shelf. It is the same play as Pitu, with clear structures in a thicker Alagamar sequence and well-defined horst blocks at Pescada Formation level seen towards East Potiguar. The 'Drift' Late Cretaceous-Tertiary play is a turbidite sand play on-slope in bypass-canyonhead plays, base of slope fans and onlap against guyots, many with amplitude anomalies showing brightening in the far angle stack. Recent seismic in East Potiguar clearly shows that there is enough sediment overburden in the area for the syn-rift source rocks to be in the oil window. In the case of the mapped structures, these would be directly over mature source rock, taking away the risk associated with long-distance migration.

Pernambuco Basin

Pernambuco is an unexplored offshore basin with indications of light oil. Legacy seismic shows the extension of Alagoas-style potential in channel-fill sediment plays,

Figure 2: Superb quality 3D seismic data over Foz do Amazonas Basin showing multilevel prospectivity including Liza-like basin floor fans.



rifted basin fill and faulted Palaeozoic sediments. Indications of salt-related traps are expected to be confirmed by the survey currently being acquired by Spectrum in this area. Significant potential is also inferred in post-rift carbonate build-ups associated with palaeotopographic highs formed by outer basement highs, salt diapirs and magmatic structures. Brute stacks from the new survey are already indicating the presence of several basins with thick sediment accumulation over potential source rocks.

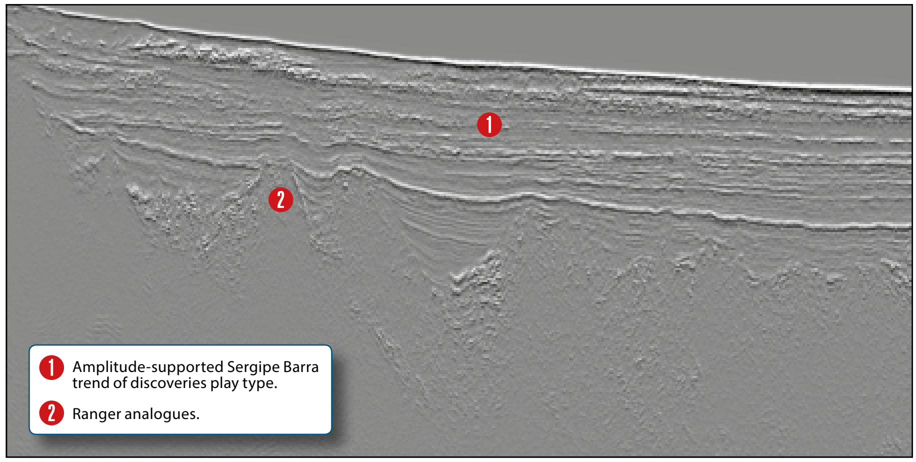


Figure 3: Ranger analogues and amplitude-supported Cretaceous channels and submarine fans analogous to Sergipe recent multibillion barrel discoveries.

Sergipe Basin

Evaluation of modern, high quality seismic data in Sergipe has led to the confirmation of the extension into open acreage of proven turbidite channel systems of Mid to Late Cretaceous and Early Tertiary ages. Untested basin floor fans dipping landward and pinching out towards the Mid Oceanic Ridge are associated with AVA anomalies similar to those of the discoveries. Integration of available seismic and potential field data has resulted in the identification of multiple as yet untested play types in this basin. With calibrated amplitude support and pre- to syn-rift analogies in the successful targets in the conjugate Gabon margin, modern tools are available which confirm that the undrilled potential offshore Sergipe easily surpasses the discovered resources to date.

Camamu Basin

Extensive amplitude anomalies associated with a decrease in acoustic impedance in the same setting as the multibillion barrel discoveries in Sergipe extend into Camamu. Interestingly, a series of volcanic features with potential carbonate build-ups on the crest (Figure 3), very similar to the recent Ranger discovery in Guyana, are observed.

Santos/Campos Basins

With increased competition from oil companies in the Santos Campos basins, success in one of the most prolific play types in the world will come from a good understanding and integration of the micro and macro scale characteristics of the prolific Barra Velha Formation reservoir, which indicate a shallow water lake depositional model. This, together with access to a good quality regional dataset outside the old salt polygon area, should allow identification of the more subtle unexplored traps (Figure 4), which may be overlooked by campaigns aiming to only explore clear analogues to discoveries. Huge additional potential is indicated by this model, painting a very exciting future for a well-informed exploration campaign.

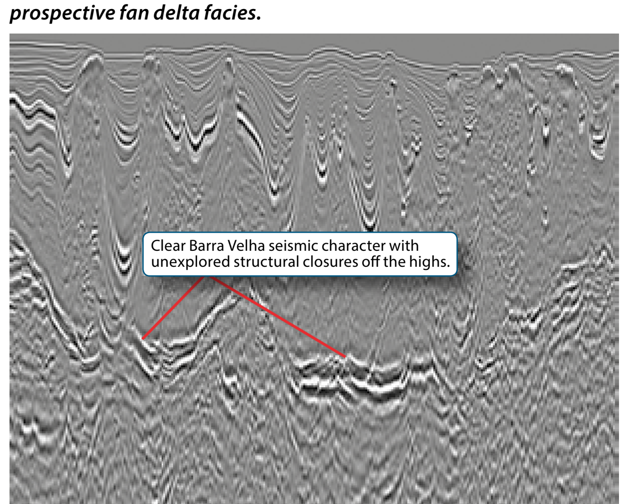
Pelotas

The Pelotas Basin is one of the world's last remaining unexplored basins with significant Tertiary and underlying Cretaceous deltas, where both display abundant evidence of coarse clastic reservoirs. Pelotas has proven source rock in offset wells and conjugate basins, oil seeps proving a working hydrocarbon system and one of the world's biggest gas hydrate deposits demonstrating the presence of abundant methane. Additionally, the high quality seismic acquired in 2013 shows abundant structures with both structural and stratigraphic traps. This basin has truly awesome multibillion barrel potential and perhaps the forthcoming licence round will give her a time to finally shine.

Conclusion

There are open blocks in both frontier and mature settings with plays to suit different exploration strategies and portfolio types. There is huge untapped oil potential along the whole Brazilian margin and regional seismic data, such as the 304,145 km of 2D and 19,017 km^2 of 3D offered by Spectrum, provide the evaluation tool of choice that will allow these basins to be evaluated, ranked, accessed and success delivered. Never before has so much acreage been covered by seismic data available to so many, imaging the plays that work and lighting the path for future glory. ■

Figure 4: RTMPSDM seismic section from Spectrum's 2017 acquisition campaign. Barra Velha seismic character extending into the present-day low areas. Unexplored structural closures have been mapped off the structural high blocks. Small-scale faulting indicating syn-Barra Velha deformation and presence of the more prospective fan delta facies.



Hot Spot

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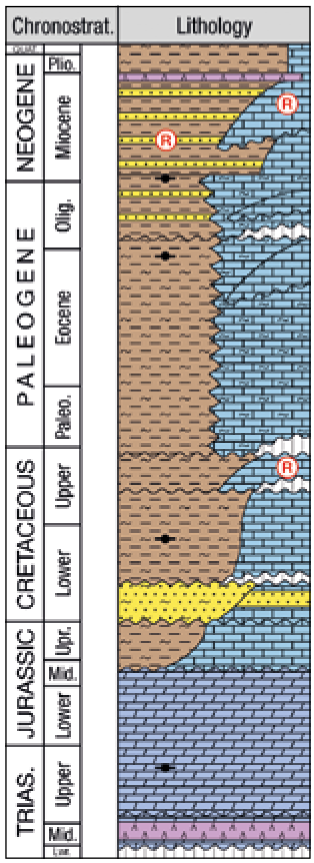
East Mediterranean Gas:
Big Fields, High Success Rates



Stratigraphic column for Cyprus.

Ultimately recoverable reserves of 79 Tcf in ten gas discoveries across Egypt, Israel and Cyprus in 16 years define the East Mediterranean hotspot.

Two fields dominate: Egypt's supergiant Zohr (30 Tcf) and Israel's giant Leviathan (22 Tcf). Technical success rates exceed 60%, with commercial rates projected to reach 50%. Gas markets have been secured and production phases entered, with gas from Zohr heading ashore just 2½ years after discovery. Tamar exports via pipeline to nearshore Israeli facilities. Development plans are in place to pipe gas ashore from Israeli fields Leviathan, Karish and Tanin. No firm plans are yet announced for the Cypriot discoveries Aphrodite and Calypso, although Aphrodite may be routed to Egypt. The Gaza Marine discovery offshore Palestine is stranded.

Big Players, Major Politics

Noble Energy and the Delek Group dominate Israeli E&P, although recent exploration licence awards went to Energean and a new Indian entrant.

ENI operate Zohr and have partially monetised it through sales to BP, Rosneft and Mubadala. ENI and Total found the Zohr lookalike 7 Tcf discovery Calypso, offshore Cyprus, following technical success but commercial failure at Onesiphorus West. Attempts to drill Cyprus Block 6 prospect Soupia have been abandoned due to a maritime dispute with Turkey, which has shot 3D itself and identified prospects in the region. Noble operate the Cypriot Aphrodite discovery with partners Shell and Delek. ExxonMobil also have licensed acreage offshore Cyprus.

Lebanon's attempts to extend the Levant Basin play northwards resulted in awards to a consortium of Total, ENI and Novatek but re-awakened a maritime border dispute with Israel. Meanwhile, Greece has announced bids for wildcat acreage offshore Crete from Total, ExxonMobil and Hellenic Petroleum, probably chasing a similar play.

Levant Sandstones and Herodotus Carbonates

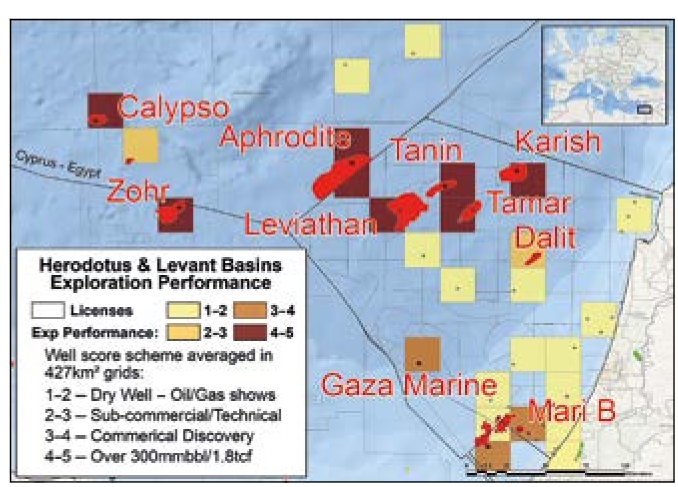
The high success rates in the Tertiary Levant Basin reflect seismic DHIs and low risk play elements. Rapid Late Cretaceous deepening of the basin led to the replacement of carbonate-dominated sedimentation by deep marine clastics, including north-east-directed sand-rich turbidite reservoirs from the Nile Delta deposited into shales, generating biogenic gas and forming the seal. East Mediterranean gas, predominantly from the Oligocene, is biogenic, 95–99% methane and has very low condensate yields. Access to source is widespread; up to 800 Tcf of gas is estimated to have been expelled offshore Israel alone, though source is not guaranteed: Eni drilled two dry wells off Cyprus.

Locally continuous turbidite fans form high quality Lower Miocene reservoirs with up to 25% porosity, even at depths of 5 km. High flow rates per well are a significant factor in commercialising gas at such depths. Traps are structural, commonly large, faulted 3-way dip closures. Interbedded flooding surface shales seal gross columns over 100m high vertically and cross-fault. Crucially, rock physics allows direct detection of gas-water contacts on seismic.

By contrast, the Herodotus Basin play features shallow water carbonate build-ups and promontories seeded around the long-lived Eratosthenes High as it keeps pace with basin deepening. Biogenic source rocks onlap the build-ups in direct juxtaposition with older and contemporaneous reservoirs. The carbonates are ultimately killed off by the Messinian salinity crisis. Miocene to Cretaceous reservoirs are thick (430m connected net pay at Zohr), from reefal to lagoonal and tidal flat environments, with high energy facies forming excellent reservoirs. Traps are formed by the morphology of the build-up. A critical factor is the height of the gross column (>600m at Zohr), related to the geometry of the Messinian evaporites seal at top carbonates as they thin onto the Eratosthenes High. Zohr and Calypso are isolated build-ups with large vertical closure, while Onesiphorus West is a promontory to the Eratosthenes High with limited encompassing salt seal and restricted column height.

Politicians, geologists, economists and geopolitical stakeholders alike are focused on the future of this world-class gas play.

Jon Ford, NVentures



The Need to Retain Experience in O&G

BALAKRISHNAN KUNJAN

"Through layoffs or job cuts, they've shed some 440,000 jobs globally since 2014. Retirements among workers who started their careers in the 70s and early 80s have winnowed the workforce by tens of thousands more."

From *Accenture Strategy – The Talent Well Has Run Dry* (2017)

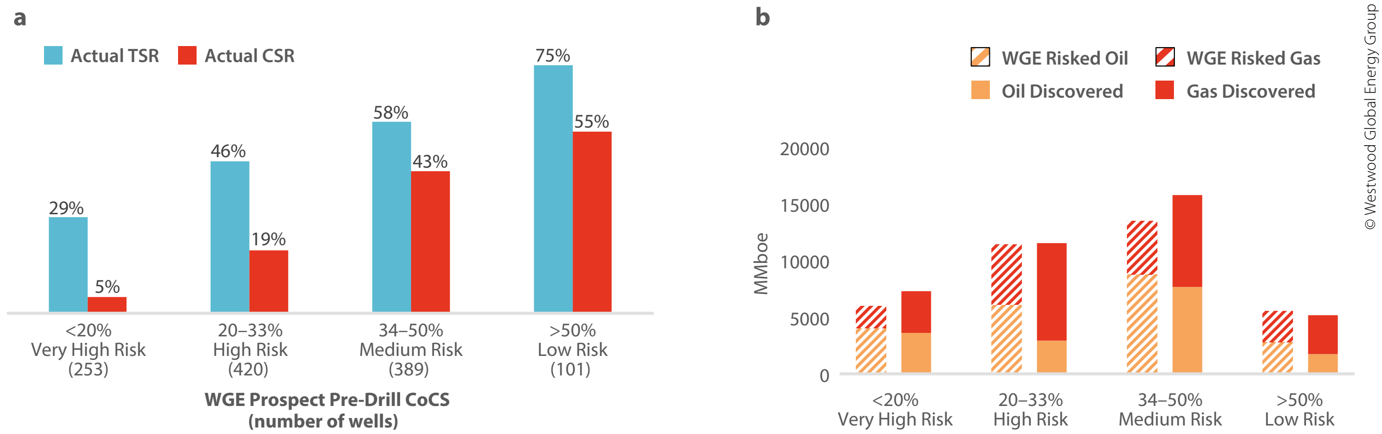
Why, now more than ever, is there a need for experienced personnel?

Our industry has become more complex in many ways over the last couple of decades. Not only has the search for hydrocarbons become more challenging, the environment within which this exploration has to be carried out is challenged by many uncertainties. This article does not argue against the increasing role of young people in our industry, but instead that in the transition phase of getting more of the youth exposed to the rigours of this industry, the experience of those who have been through the many complexities in the business will be crucial in the handover period. Management and company boards need to have a planned strategy to ensure they keep, or attract back, some of those who are about to or who have left the industry.

Predicting Our Future is Complex

The oil and gas business globally is facing tremendous challenges on many fronts, the likes of which have not been seen before. There are uncertainties in many facets of our business, including in supply and demand with regard to the role of shale oil vs OPEC production, the challenges from renewables, the growth of electric vehicles, geopolitics, environmental, climate change and government policy issues. Projections of the future trajectory of our industry are thus vexed and complicated and there are many different predictions, but there is general consensus that, at least within the near term of the next two decades, oil and especially gas will continue to play a significant role in the energy mix. However, the hundreds of billions of dollars in delayed investment due to the low oil prices since 2014 and the attendant lowest discovery rates globally in decades, have left a hole to be filled as supplies dry up. This has set the stage for an impending anticipated increase in exploration and development where the requirement for experienced personnel will be critical.

In the midst of all the turmoil, there are increasing signs of improving technological breakthroughs that promise to make the exploration for and extraction of hydrocarbons more effective and efficient, including Artificial Intelligence, Machine Learning and Big Data Analytics. BP, for example, is a leader in this area. The combination of AI and Machine Learning can lead to quicker and more optimised answers within domains that are amenable to using these technologies. Our industry is capable of capturing huge volumes of data,



Pre-drill risking: CoCS and volumes. (a) Global 2012–2017 prospect risking (1,163 wells). TSR: technical success rate, CSR: commercial success rate; (b) Global comparison of pre-drill risked volumes and post-drill outcomes 2012 – 2017. Average CoCS = 37%, but there is strong evidence of overestimation of CoCS in high risk category prospects (<20% CoCS). Only 1 in 6 discoveries in the <20% CoCS category are big enough to be likely commercial. There is also a tendency to overestimate oil versus gas pre-drill.

from seismic to downhole realtime monitoring data, which if handled with the right kind of fast and efficient processing hardware and software can lead to beneficial real time solutions.

Despite the best technologies, the best data and the best brains, there are still limits to what we can achieve in this business. Globally, the chance of commercial success (CoCS) averages 30–40%. The figure above highlights our current 'limits to success'. The details are interesting and point to various areas in which experience/ techniques/ technologies can be used to potentially improve our chances of success. There are issues related to both CoCS predictions as well as volumes, as the WGEG charts show. Some improvements could come from the areas of technology mentioned before, and there is a whole area here for discussion and elaboration beyond the scope of this article. Suffice to say that experience plays a key role in determining how good a person or team is at risking and volumetric predictions.

Technology Versus Experience

There is a move towards utilising more high-end technologies in O&G and various facets of the industry are already showing benefits from this. Eventually, ongoing technological advances will lead to greater penetration of new technology in our business. It is, however, very important at the current mid phase of transformation to recognise what is technologically possible and what isn't. It is easy to be over-excited about the dazzling array of possibilities, but it still comes back to the 'limits of success' to our exploration results noted above.

The figure below is my attempt to capture conceptually what is amenable to technological penetration and what is still going to be dependent on hard-earned human experience. Experience becomes very important when the situation is not well defined, is very ambiguous, and in the early parts of evaluation where a great deal of data is still not available. It is in situations like these where the incomplete nature of information requires 'filling in the gaps' and where experienced hands are indispensable. The data and information available will vary from poor to good and this will drive the degree to which automation is possible. The more nebulous the dataset, the more probabilistic the nature of assessment – the more the call on extensive prior experience.

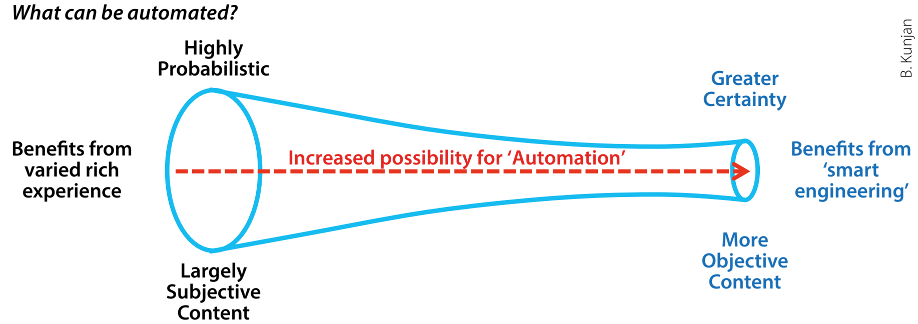
I can draw on examples in exploration processes to illustrate the point here. Currently, in seismic interpretation you can propagate interpretations that can automatically produce surface maps. You do not necessarily have to understand geology to do this. In areas with good data, accurate time structure maps, fault maps and isochrons can be quickly and efficiently created: a time-saving and sound outcome. However, to understand the nature of the forces acting on the structure that determine the growth history and control on sedimentation requires interpretational skills beyond what machines can currently do. It is these latter skills that have an impact in the COS (Chance of Success) and volumetric predictions.

In each area of the industry, from exploration to production, it is important to analyse which tasks can benefit from automation and which still require a great deal of real life experience. Usually, it is the highly subjective, highly probabilistic areas of our business that are hard to replicate with technology – at least for now.

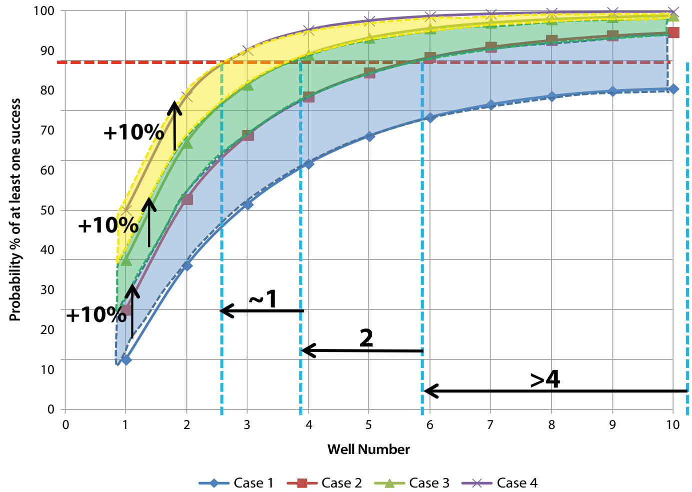
Technology, Specialisation and the Silo Effect

One unintended consequence of the penetration of technology is the tendency to drive professionals towards specialisation. Unless management is vigilant and provides experienced

What can be automated?



Making a call 'on limits to perfection': benefits obtained from greater effort to increase portfolio certainty of success reduce at higher end CoCS portfolios.



Step increase of 10% between each set of Cases

B. Kunjan

COS% for different cases				
Case 1	Case 2	Case 3	Case 4	
30	40	50	60	
27	37	47	57	
24	34	44	54	
21	31	41	51	
18	28	38	48	
15	25	35	45	
12	22	32	42	
9	19	29	39	
6	16	26	36	
3	13	23	33	
				Average
17	27	37	47	COS

oversight, professionals tend to specialise in particular fields and associated software in which they become experts. The positive in this is the development of great expertise in a particular field and/or software. The negatives I have seen are that, unlike professionals of the pre-technology era, there is loss of awareness of the total subsurface challenge that is being addressed.

I have seen reservoir modellers turn on and off fault transmissibilities to match production without referring back to the seismic interpreters to check why some faults helped and others did not. Another example is where petrophysicists have interpreted the existence of a considerable column of oil because it is supported by shows. They did not look sideways and pay more attention to the MDT pressure points that show a very limited moveable oil column. This total approach to solving a subsurface problem appears to come with having varied experience. In my early Exxon days, my very experienced mentors would ask the question, 'does it all hang together?'

The Limits of Perfection

The figure above shows that there are reducing benefits to trying to attempt higher levels of certainty. It shows four different portfolios with ten wells each that have COS increasing by 10% each going from Case 1 to Case 4. The Y axis shows the probability of attaining at least one success at the point of each well being drilled in each of the four campaigns. The shaded areas between the curves shows the 'certainty gained' going from one portfolio to the next. Alternatively, you could use the measure of the increased number of prospects needed to be drilled before attaining 90% certainty of at least one success.

For small companies with limited resources and for those who want to be fleet-footed in the business, it is important to know when to make the call that sufficient work has been done to achieve one's exploration goals. This is an area that calls upon a great deal of experience. There are many elements to this decision and those who have drilled more and varied prospects have a better chance of making this call.

Losing Experience and Talent

In the midst of all these concerns, we have lost a great deal of experience and talent from the industry. The final figure shows the age demographics in our business. The peak age group is around 33 years old. The older age groups drop off at a constant pace till you reach 60 years old, after which the number of mature people reduces drastically.

It is critical that companies are aware of this and try to maintain experienced personnel as long as they can. Management have to work out ways to entice lost experienced talent back into the business. These experienced personnel should be mentors to younger people and pass on their skills while the younger generation is still learning.

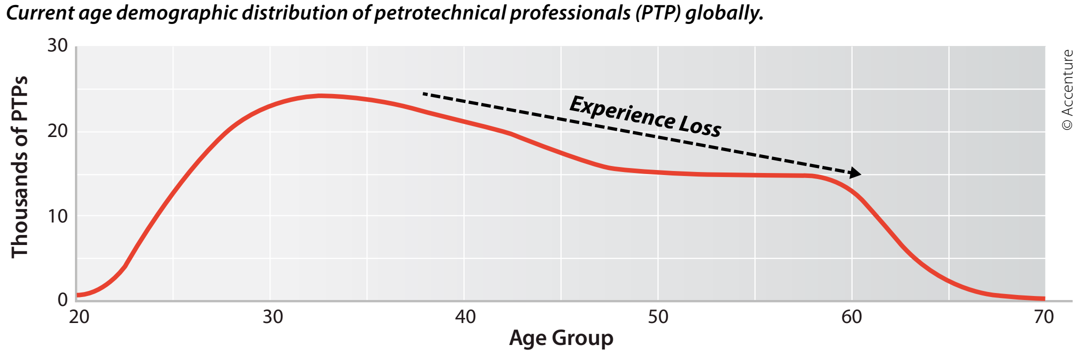
From my own experience, having worked in many mostly small to moderate sized companies, I have come across errors made because the data has not been interpreted with eyes that have seen a great deal more than the less experienced personnel. Many mistakes have been made in past downturns in terms of losing experience and hence ending up with expensive errors being made.

We can, at least partially, avoid it as long as we can entice the 'elders' to remain or to rejoin our teams.

Acknowledgements:

Many thanks to Westwood Global Energy Group (AAPG ICE 2017) and Accenture Strategy (The Talent Well Has Run Dry – 2017) for permission to reproduce figures used in this article. ■

Current age demographic distribution of petrotechnical professionals (PTP) globally.



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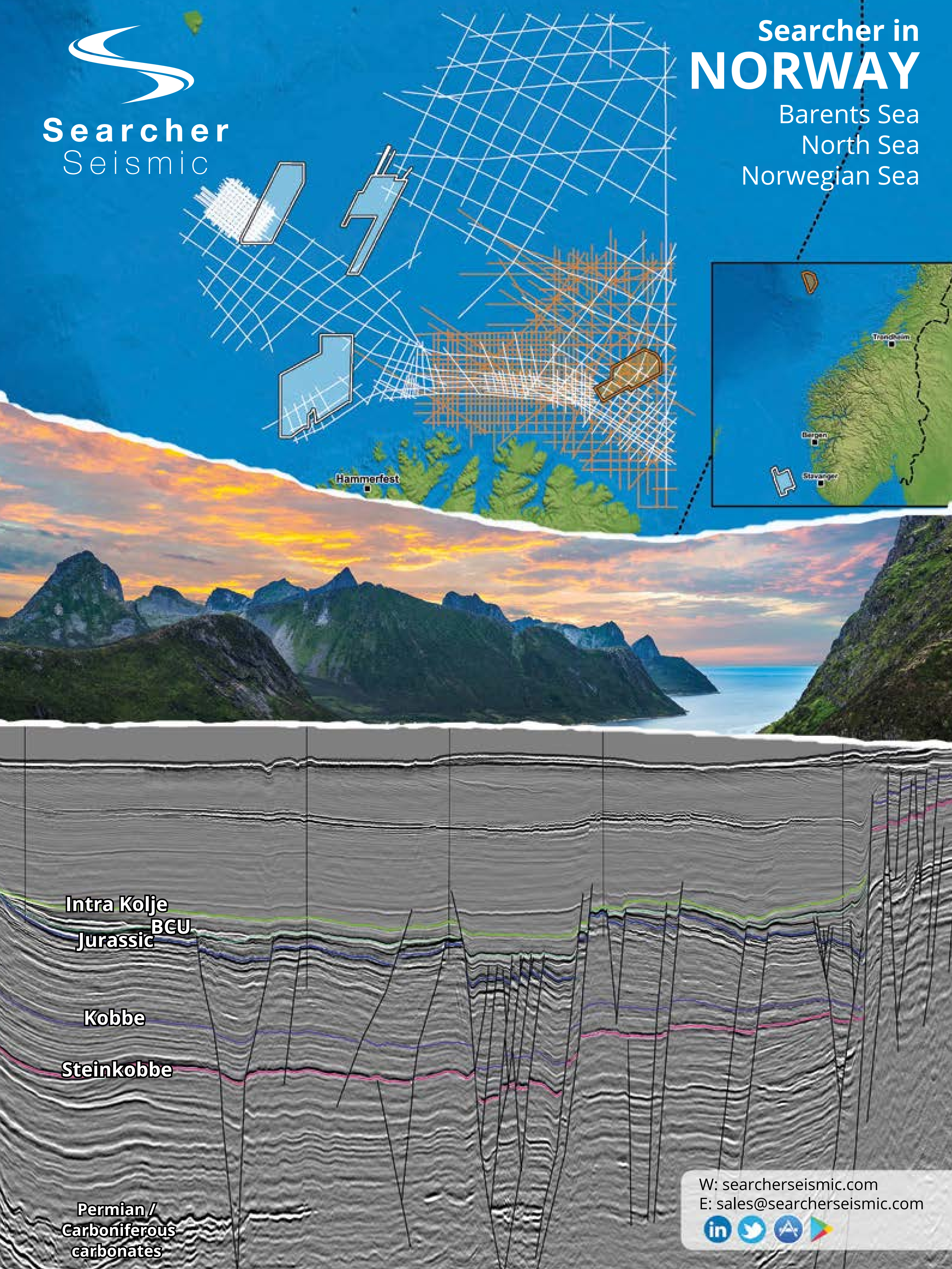
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See Your Reservoir at the Surface!

A newly developed method for detecting petroleum seepage uses a closed system with real-time analysis of sea water and bottom sediments.

GER W. VAN GRAAS, MONA ULAS, JAN ROGER SCHØNNING, ORG Engineering, Norway; and **JOACHIM RINNA** and **JON ERIK SKEIE**, AkerBP, Norway

The use of surface geochemical exploration methods is based on the concept that all petroleum accumulations suffer some leakage to shallower intervals and eventually to the surface. This leakage can be detected directly by sampling and analysing the petroleum compounds in surface sediments, the water column or in air. The seepage process can also cause changes in the mineralogical and environmental conditions, which can be detected using a range of other chemical, physical and microbiological methods.

In recent years, the most commonly used approach to surface geochemical exploration in offshore areas has been the collection of gravity core samples that are then taken ashore for analysis of any petroleum components in the sediment. In deeper water (>100m), collection of gravity core samples can lead to the loss of light components due to the pressure drop experienced when moving the core to the surface. The onshore analysis of the sample material means that results are often available only 6–8 weeks after completion of the sampling cruise, which can be a concern in an exploration project.

How the New System Works

To mitigate some of the weak points of the gravity core approach, ORG has developed a new approach in recent years. It is based on a sub-sea unit (SSU) equipped with a pump, camera and a range of sensors for environmental analysis and the detection of polyaromatic hydrocarbons (PAH). The SSU is lowered onto the seafloor and pumps a sediment suspension through a closed system up to the vessel, where the flow is passed through a silicone-membrane gas filter and the released material is analysed by a selected-ion flow-tube mass spectrometer (SIFT-MS) with a cycle time of approximately two seconds. A sample of the pump flow is passed through several sensors on the SSU for measurement of environmental and PAH parameters.

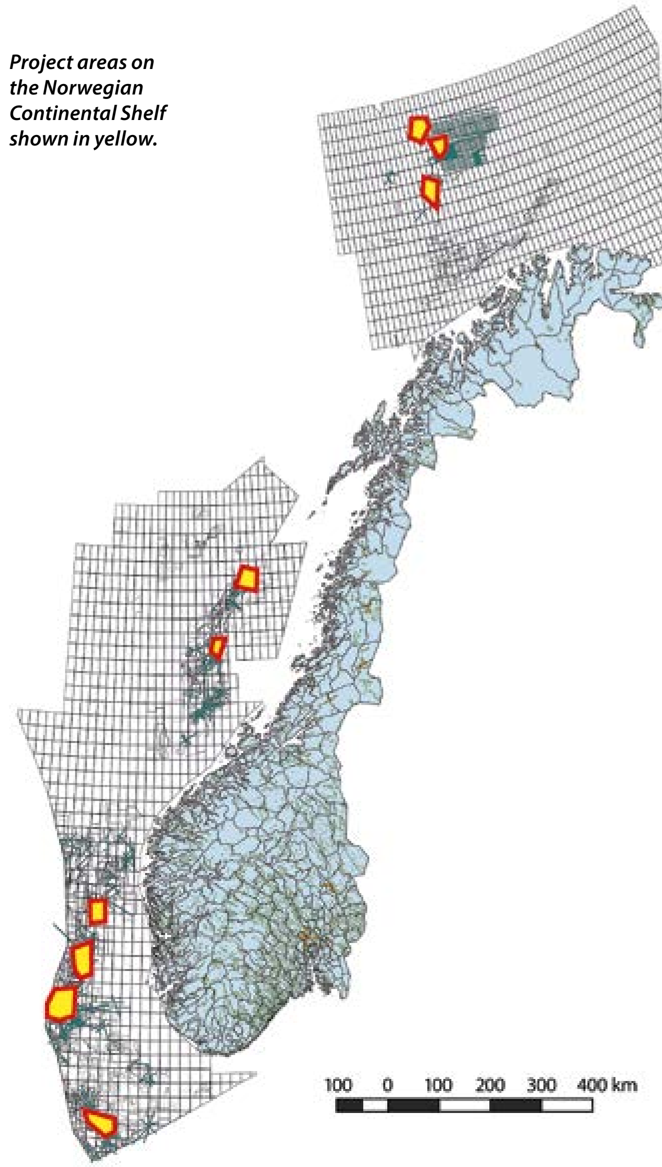
The mass spectrometer measures and reports the concentrations of C_1–C_{12} hydrocarbons in the gas from the gas filter. Obviously, the sensitivity of the method will be strongly controlled by the compound solubility in water and the efficiency of the gas filter in extracting the hydrocarbons from the water. Further testing is underway to optimise this transfer.

The mass spectrometer and the environmental sensors collect data continuously, starting when the vessel arrives on position with the SSU suspended about 10–15m above the seafloor and pumping only sea water. Data collection continues after it has been lifted from the seafloor during transit to the next sample location. To reduce this very large dataset to more manageable numbers, average data values have been calculated for several time intervals and these have been compared in order to find the most representative values. Some of these intervals cover the time during which the SSU is positioned on the seafloor, while others represent time when the unit is suspended in the water column close to the bottom and pumps only water.

The two-metre-high sub-sea unit is equipped with sensors for measuring environmental parameters and the analysis of polyaromatic hydrocarbons.

ORG

The vessel is also equipped to collect gravity cores, which can be used for a broad range of chemical and microbiological analyses. The sediment material in the suspension flow can be collected on board the vessel for later analysis. Tests are ongoing to evaluate if this material is equivalent to sediment samples from gravity cores.



Project areas on the Norwegian Continental Shelf shown in yellow.

Significant Variation

After some small-scale test projects in 2016, the system was operationally deployed in 2017, collecting data in seven different areas on the Norwegian Continental Shelf (NCS), with a total of over 1,500 measured stations. Project areas ranged from the Central Graben up to the Barents Sea, covering areas that have very different deep and shallow geology. These differences in geological setting can explain some of the variations that were observed, but there were also several common aspects in all the projects.

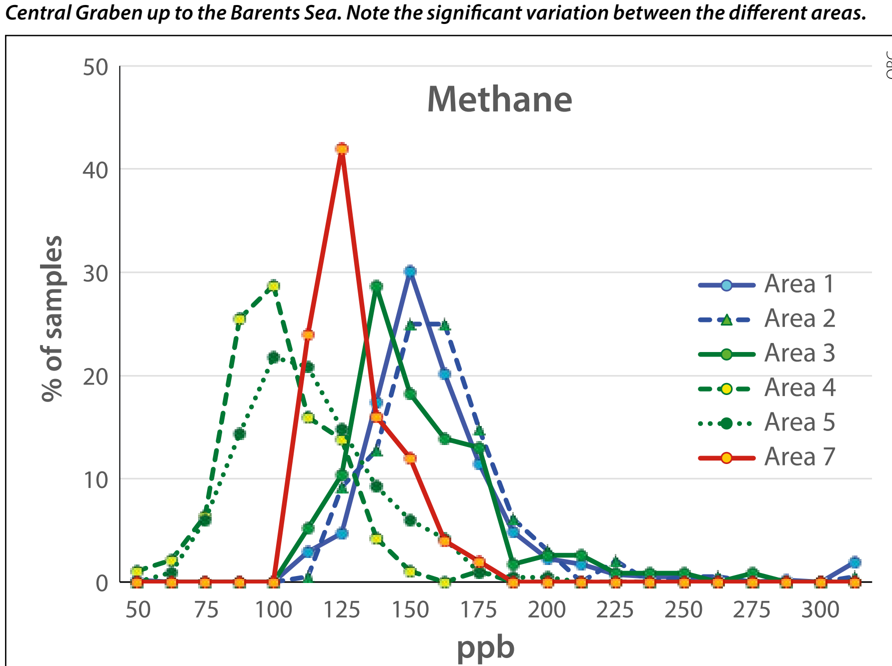
A comparison of different areas along the Norwegian Continental Shelf shows significant variations in the measured hydrocarbon concentrations. These variations are probably due to differences in the deep and shallow geology. It comes as no surprise that the highest concentrations come from places where active petroleum generation is ongoing at present.

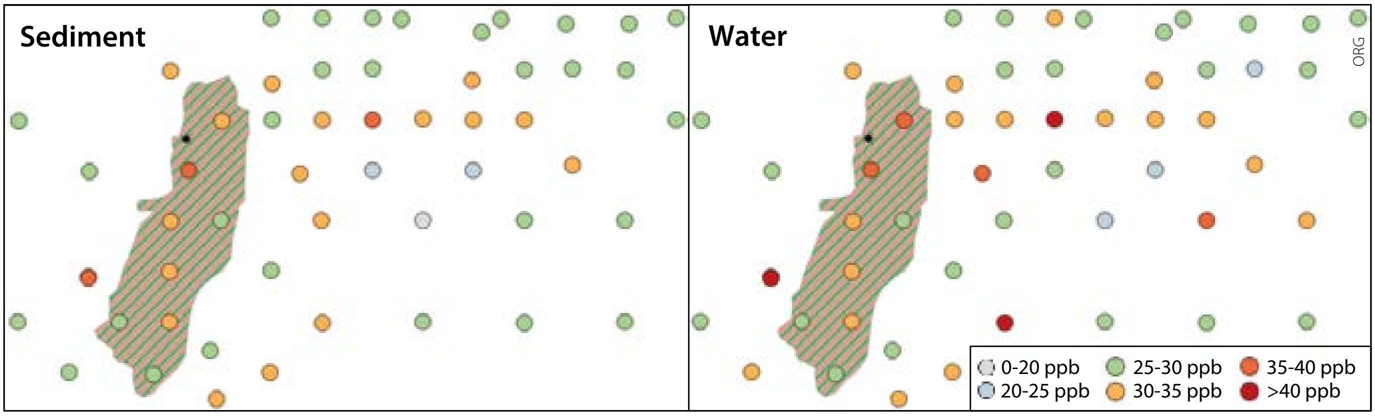
When comparing average hydrocarbon concentrations in the various sediment intervals with those from the water intervals, the values turned out to be very similar. While this correspondence was unexpected, it was observed in all measured components and in all the areas that were covered.

Two factors are thought to account for this. Firstly, to pump the sediment material up to the vessel, a certain volume of additional water is required to achieve a good flow. The exact volume of this excess (sea) water is not known but it can significantly dilute the sediment material, so the resulting hydrocarbon concentrations will be a combination of sediment and water values. The system is currently being modified to better constrain this dilution. Secondly, there is no reason why hydrocarbons seeping from the deep subsurface into surface sediments should remain there. In fact, seepage is expected to continue into the water column. As such, it is not surprising to find similar hydrocarbon concentrations in the water and in the sediment interval.

Both sediment and water data show geographical clusters of stations with anomalous measurement values. This gives added confidence to the assumption that these reflect real variations in the amounts of hydrocarbons present in the top sediment and in the water column close to the bottom. It appears that bottom currents do not effectively mix the water close to the sediment surface, at least not in the areas that were measured.

Methane distribution in different projects on the Norwegian Continental Shelf stretching from the Central Graben up to the Barents Sea. Note the significant variation between the different areas.





Average n-butane concentrations measured during a 10-minute period while pumping a sediment/water slurry (left) and a 5-minute period while pumping sea water before the sub-sea unit is positioned on the bottom. Reported values represent concentrations in the gas flow from the gas stripper. The map area measures 17 by 10 km and contains an oil and gas discovery (hatched outline).

Comparing Known Accumulations and Untested Prospects

The effectiveness of this method in identifying subsurface hydrocarbon accumulations can be assessed by evaluating the surface expression of known discoveries. Once more, there are significant variations between different areas: in one area all known accumulations are accompanied by anomalous hydrocarbon concentrations at the surface, while in other areas up to a third of the known discoveries are ambiguously detected in the surface measurements. The 'false negatives' can sometimes be explained, for example, by a lower pressure in the discoveries or a different nature of the (near) surface sediments, but further work is needed to better constrain this.

An example of how the surface measurements can be used to evaluate the petroleum charge risk of a given prospect is shown right. An untested prospect was densely sampled (central part of sample grid) and the resulting measurements show no significant anomalies over the structure, neither in the light components (gas indications; methane concentrations shown in the figure) nor in the heavier components (oil indications). Nearby wells with discoveries and shows were tightly sampled for comparison and do show multiple anomalous values. Given the shallow burial depth (<1 km), the lack of surface anomalies meant that the charge risk for this prospect remained unchanged.

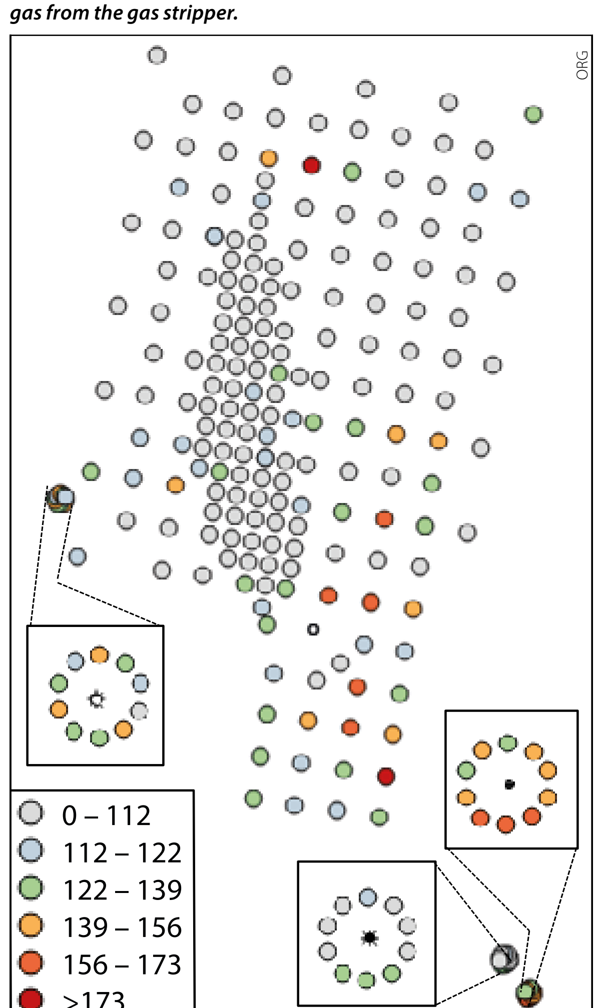
Further Work Needed

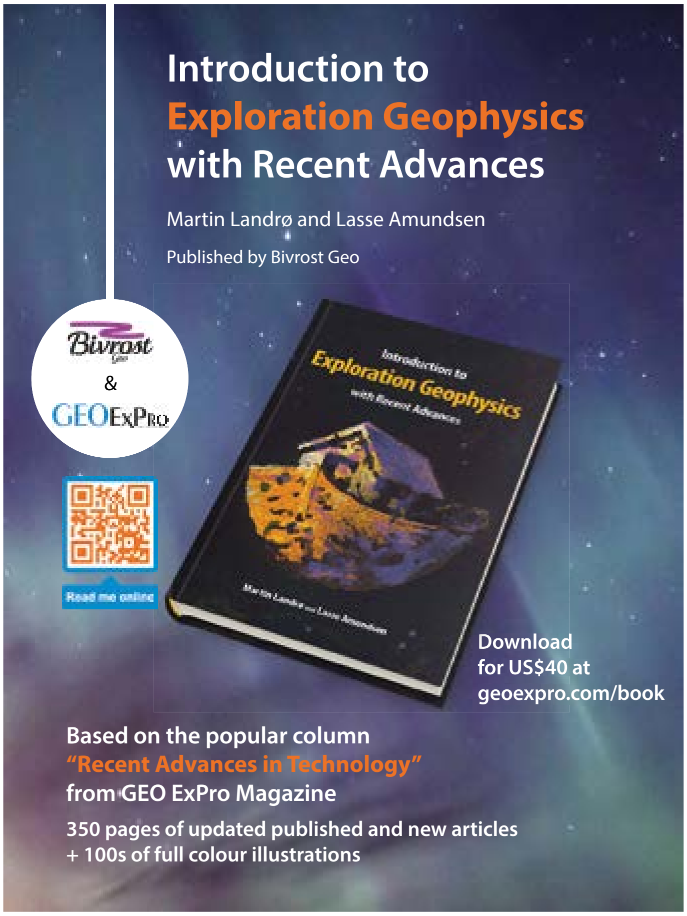
Based on the results from the 2017 projects, the new method has shown to accurately measure hydrocarbon concentrations in surface sediments and in the water column. Significant variations in the measured amounts are seen both within and between different areas on the Norwegian Continental Shelf and the results can help to better constrain the charge risk of undrilled prospects.

At the same time, the occurrence of clusters with anomalous hydrocarbon measurements is by no means well understood. Further work is needed to investigate the effects of changes in the deep geology and environmental variations in the shallow layers.

The lack of contrast between measurements in the sediment interval and in the water column suggests that it may be better to limit data collection to the water column in future projects, possibly as a first phase, before zooming in on the most promising areas. ■

Methane concentration data over an undrilled structure (dense part of the grid) compared with tightly sampled calibration wells with shows or discoveries (area enlarged in separate boxes). The map area measures 27 x 49 km; the radius of the sample circle around the calibration wells is approximately 250m. Methane concentrations are expressed as ppb in the gas from the gas stripper.

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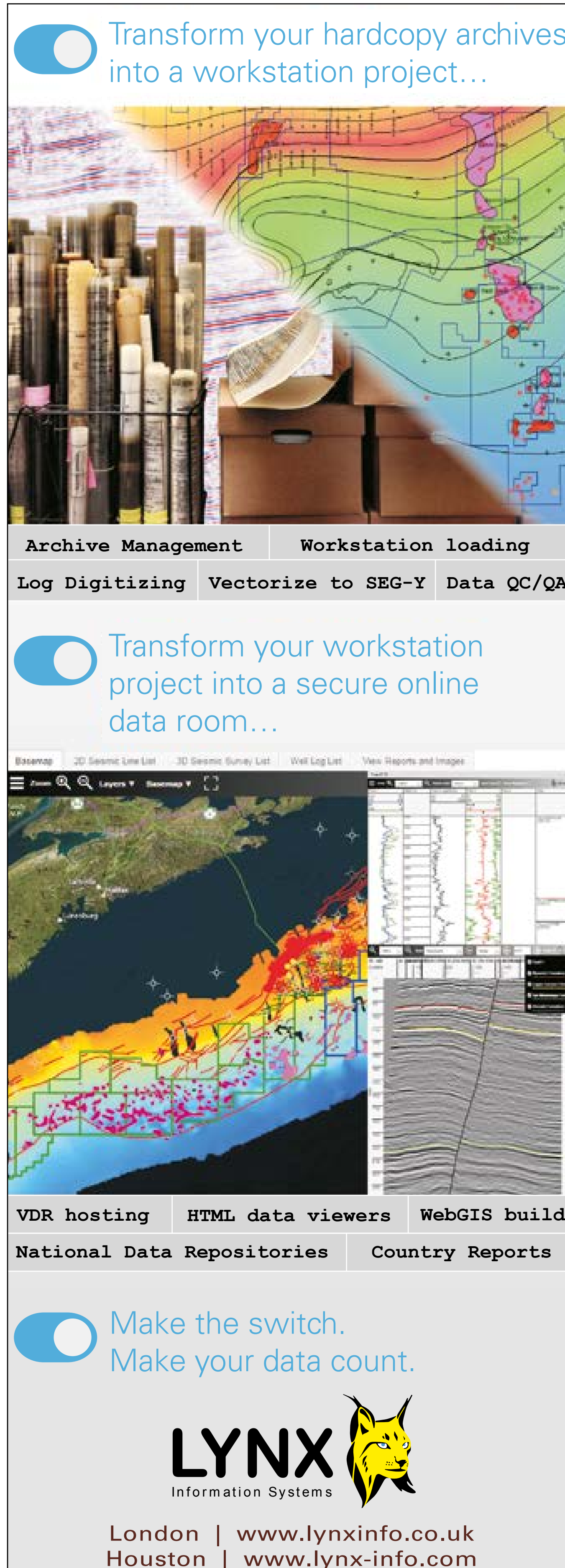
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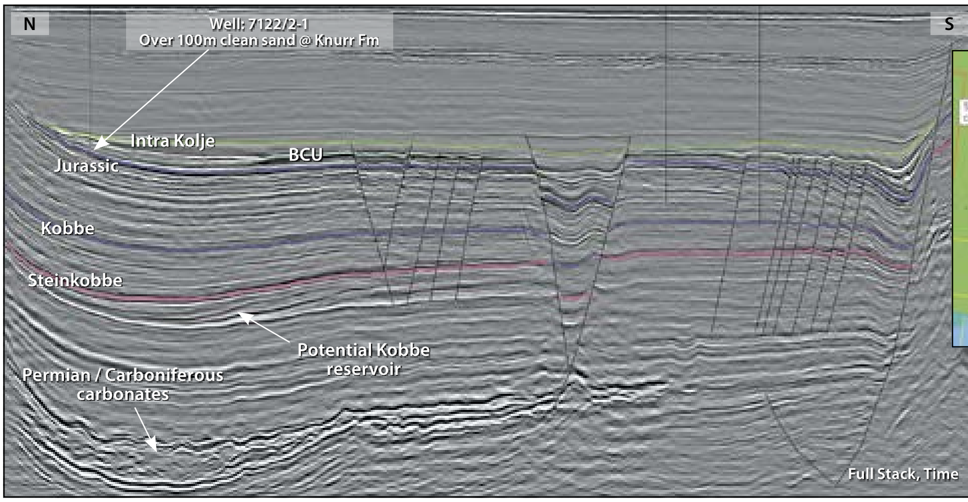
Hammerfest Basin's Unexplored Potential

New 3D seismic data provides a fresh insight into this prolific basin.

ERIK HENRIKSEN, SAID AMIRIBESHELI and KATHERINE G. FITZPATRICK; Searcher Seismic



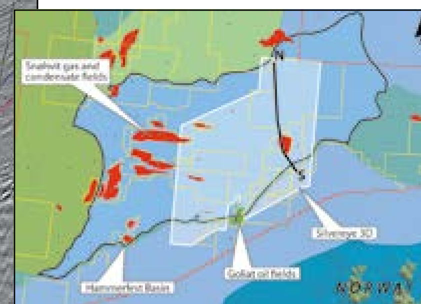


***Figure 1:** Regional north-south seismic line through the Hammerfest Basin with (inset) outline of the basin showing major fields.*

The Hammerfest Basin is an east-west trending graben located in the Norwegian Barents Sea. Sediments of Carboniferous to Cenozoic age cover the Caledonian basement, the thickness of which varies, but can exceed 10 km. Exploration began in the 1970s and the first exploration well was drilled in the basin in 1980. Since then a number of oil and gas discoveries have been made in this prolific basin. The classic Middle Jurassic play is well explored; however, the pre-Jurassic/uppermost-Triassic succession has only been penetrated by a few wells.

To be able to detect and delineate the remaining unexplored potential of various stratigraphic levels in the Hammerfest Basin, new 3D seismic data was needed. Therefore, between 2015 and 2016, about 4,500 km^2 of 3D seismic data was acquired by Searcher Seismic, demonstrating the clearest image yet of several depositional packages in the basin. This data with high quality broadband processing sequences supports the exploration of the deeper plays in the basin.

Petroleum Discoveries

A total of 44 wells have been drilled in the Hammerfest Basin, resulting in 18 oil and gas accumulations with an exploration success rate of over 50% for the basin. The Snøhvit field produces gas and condensate from Middle/Lower Jurassic reservoirs, while the Goliat field produces oil from Middle/Lower Jurassic and Middle Triassic reservoirs. Along the flank of the basin minor discoveries were made in the upper Jurassic (Hekkingen Formation) and in the lower Cretaceous Knurr and Kolje Formations (see Figure 1). Hydrocarbon show analysis indicates that considerable volumes of hydrocarbons have migrated into the basin. However, later isostatic uplift resulting in re-migration and leakage of hydrocarbons complicates the picture.

Searcher's 3D seismic, broadband processing and advanced multi-volumes blending techniques improve the possibility of detecting and delineating the remaining prospectivity within the basin.

Unexplored Potential

Significant remaining hydrocarbon potential exists in the prolific Hammerfest Basin. While most is currently expected to be found in the Mesozoic interval, potential may also exist in the Palaeozoic. In general, reservoir parameters of these deeper plays are slightly lower due to greater burial depths, predating the major Cenozoic uplift.

1. **Lower Cretaceous and Upper Jurassic Play:** There are minor discoveries (Skalle and Myrsildre) in the Lower Cretaceous-Upper Jurassic intervals. The 3D seismic indicates the presence of remaining potential along the flank of the basin. Turbidite fan systems can be identified on the seismic using AVA attributes (Figure 2). Analysis of the qualitative Extended Elastic Impedance attribute shows the presence of a strong AVA anomaly above and below the Base Cretaceous horizon (lower green) in the southern flank of the basin. This anomaly could be due to variation of lithology, porosity, thickness or hydrocarbons in the fan systems, providing supporting evidence that underexplored stratigraphic traps can work in the area. The strong AVA anomaly below the base Cretaceous marker here is an unpenetrated upper Jurassic sand (Hekkingen Formation), which may indicate additional potential in the area.

2. **Middle Jurassic – Uppermost Triassic Plays (Stø, Nordmela, Tubåen and Fruholmen Formations:** There is still undrilled potential in the classic Middle Jurassic-Uppermost Triassic fluvial to shallow marine reservoirs defined by structural traps. Several small to medium-sized horsts and rotated fault blocks define the traps in this area. The Bajocian Stø Formation

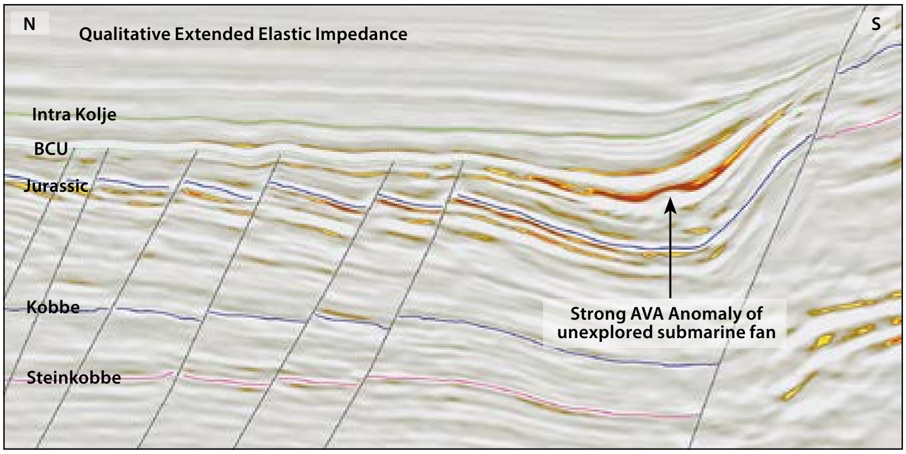


Figure 2: AVA attribute through Cretaceous and Jurassic fan.

is expected to represent continuous reservoirs, deposited in a lower to upper shoreface environment, whereas the uppermost Triassic typically consists of channelised complexes.

3. The Carnian Interval (Snadd Formation): 3D seismic clearly defines the outline of the Snadd Formation channel systems (Figure 3). There is clear evidence of sand deposition in the channels based on seismic character. The change in amplitude can be attributed to change of facies, porosity, interval thickness or hydrocarbon presence within the channel system. It is a challenge to separate the lithological effect from hydrocarbons within the channels at this depth. New multi-attribute blending techniques can help delineate the outline, geometry and possible content of the channels.

4. Anisian Interval (Kobbe Formation): The discovery of the Goliat oil field in the early Triassic Kobbe Formation interval proves both the Kobbe play and the Triassic petroleum system and supports this attractive additional play in the basin. Goliat produces from both the Kobbe and from reservoirs in the Upper Triassic/Jurassic Realgrunnen Group. Interestingly, minor oil was also proven in the Triassic Klappmys and Snadd Formations. The outline of the Kobbe reservoir and the source rock potential is uncertain but may have significant potential in other parts of the basin. New wells are expected following the recent APA awarded licences, which will further clarify the remaining potential. Figure 4 suggests that there is possibly local deposition of sand in the Kobbe Formation derived from the Fennoscandian shield to the south, indicating a good reservoir characteristic for the Kobbe in this area.

5. Palaeozoic interval, Siliciclastic and Carbonates: Although deeply buried, the Upper Permian sandstones penetrated by well 7120-12/2 show that reservoir porosity may also exist at this level. Permian and Carboniferous age carbonates are very well developed in the north-eastern part of the basin (Figure 5), and most likely consist of Paleoaplysina, Phylloid algea and Bryozoan type build-ups that grew in a distinct polygonal way and are interbedded with evaporites. The carbonate play, which has similarities with the Alta Gotha discoveries, is undrilled in this area.

Significant Yet-To-Find Volumes

In the Hammerfest Basin substantial volumes of hydrocarbons, both oil and gas, have been discovered in the classic Jurassic and Middle Triassic formations. Two fields, Snøhvit and Goliat, are in production and new discoveries expected, either stand-alone, or tied back to existing facilities.

However, broadband processed 3D seismic acquired by Searcher Seismic shows significant underexplored potential in the basin, revealing remaining hydrocarbon potential in undrilled Jurassic structures and significant yet-to-find volumes in the Middle Triassic and Upper Jurassic to Lower Cretaceous plays. Little is known of the Early-Mid Triassic Kobbe Formation, which represents an important part of the Goliat Field and may be a very attractive future target. Palaeozoic plays are as yet undrilled in most of the area. In addition, the seismic data may unravel well developed carbonate build-ups towards the north-east of the basin. ■

Figure 3:
Upper Triassic Snadd Channel complex.

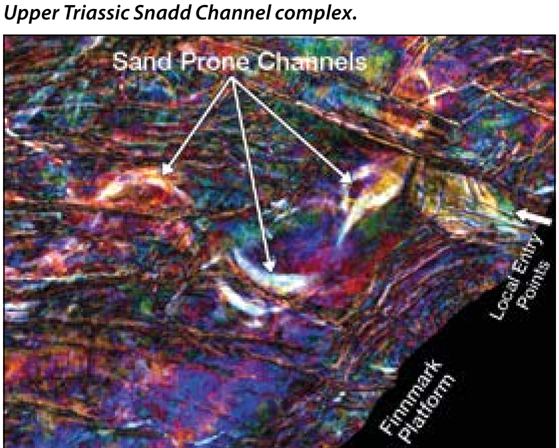


Figure 4:
Mid Triassic Kobbe fan system.

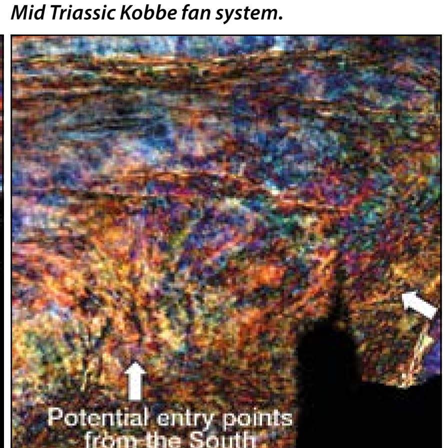
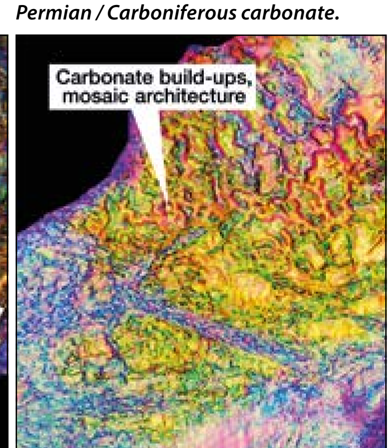


Figure 5:
Permian / Carboniferous carbonate.



Exploring South East Asia

Having spent most of his 43-year career in South East Asia, Andy Wight tells us about the exciting discoveries he was involved in and the people who helped make them.

JANE WHALEY

"The good thing about geology is that it's not really like a job. It's so enjoyable," exploration geologist Andy Wight explains. "In my career I had a lot of fun, met a lot of interesting people and saw some wonderful places."

Which makes it surprising to hear that when Andy first went to Bristol University, he was intending to study chemistry. "In the first year I chose geology as a subsidiary subject, mostly because I was good at geography. However, after a day spent in the chemistry lab in my first term, titrating horribly toxic substances, the following morning's geology class was a field trip down the Avon Gorge. It was a lovely sunny day, spent chipping away at rocks, and then we went for a cider afterwards. I thought "this beats chemistry!"

It Felt Like Home

Having rather drifted into the oil industry because that was where most of the geology jobs seemed to be, Andy spent several years working in Europe, first in Italy as a mudlogger, otherwise mostly in the UK, including helping delineate the Morecambe and Wytch Farm fields and working on Buchan in the North Sea. He was always interested in travelling further afield, however, so when in 1979 a job as an exploration geologist in Indonesia came up, he jumped at the opportunity.

Andy and his wife had previously had a vacation trip to India, but this was the first time they had been to the Far East. "We weren't sure what to expect," he says. "On landing, our first impression was how hot it was! But when we arrived at our house with two very tiny children we discovered that all the ladies of the company had got together and filled the fridge with food, which was a really lovely welcome." The company, IIAPCO, at that time was very much an old-style 'family'.

This positive initial impression was backed up by the experience of living in Jakarta. "Before we went out my wife, Gill, had said 'only a couple of years', but when we returned from our first annual leave, it just felt like home. It was amazing!" Jakarta was home to the Wight family for the next 24 years.

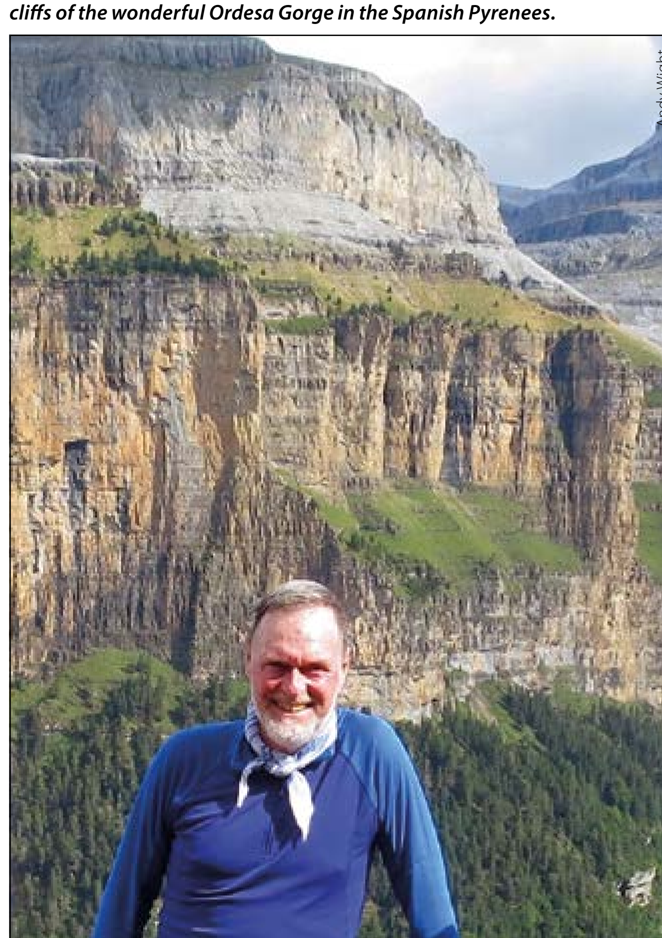
"We had a good life there, which was successful partly because we had to make our own entertainment," Andy says. "We spent a lot of our free time at the sports club, where each section – rugby, sailing, hockey, squash etc. – had to organise an annual show: themed nights, comedy nights, that sort of thing. It was great fun. Gill and I got into Scottish country dancing and through that met up with other clubs throughout the region, making lots of friends, many of whom we still see. Gill improved so much she actually ran teams and won medals at the annual St. Andrews 'Highland Gathering'."

Exciting Discoveries

However, his work looking for oil and gas with his many inspiring colleagues was at the root of Andy's love of South East Asia. "When I first arrived we were working on the SE Sumatra Offshore block, just off Jakarta, which the legendary Don Todd had obtained in 1966 ," Andy explains. "Although Don had left by the time we arrived in Jakarta, I interviewed him for SEAPEX years later when he was in his late 80s; it was a fascinating story."

American geologist Don (now in his 90s) was the first to realise the potential offshore Indonesia, entering the country in the early '60s with a hunch that pre-war onshore production indicated offshore oil. In 1966 he signed the world's first offshore Production Sharing Contract, for an area covering a large part of the Java Sea: 123,000 km^2 – almost the size of England! His small company, IIAPCO, shot a single seismic line across the basin, revealing a thick sedimentary section. The majors took notice, many soon taking blocks in Indonesia – but it was Todd and his partners who, in 1969, made the first discovery offshore Indonesia, coming on production a year later: an amazing feat.

Andy's carbonate experience shows on his climbs around the massive cliffs of the wonderful Ordesa Gorge in the Spanish Pyrenees.



Andy Wight

Andy Wight

Andy Wight with Don Todd, founder of IIAPCO and originator of the first offshore PSC.

"IIAPCO's block covered the Asri and Sunda Basins in the Java Sea. When I joined in 1979 we only had about seven fields and three rigs operating, but over the next few years we made some exciting discoveries," Andy continues. "One of my worst professional moments occurred not long after I started. The project was to delineate a sub-commercial find on a structure with four wells with fluvial sandstone reservoirs, with apparently straight-line correlations – but which I contoured as discrete point bars with an upside location based on a meandering fluvial system. My then boss reviewed my extensive report, insisted that sand contouring had to show concentric rings, rather than the irregular thicknesses typically found in point bars – and literally threw my precious report in the bin! My mentor, a great explorationist called John Wilson, encouraged me to recover from this setback. My work was not wasted, as it later contributed to a new point bar discovery, the first successful stratigraphic trap deliberately drilled in the Sunda Basin.

"It was an exciting period. The oil price rose dramatically from $3 to $15/b and lots of old prospects were being exhumed (literally)! Everything turned out differently from how we had expected – our success was a combination of luck and… luck! On one occasion an annual meeting was due and the 'big cheese', Dorman L. Commons, was due to visit. We had ten rigs running constantly and needed to find some prospects quickly. With structural prospects dwindling fast, we were under pressure to identify some 'subtle plays' to show him. Interpreting the reservoir sequence as transitional marine, I identified from the mapped patterns of highs and thicknesses what I thought was a coastline with mouth bars and beaches at right-angles to each other. To show my ideas at the meeting, using old-fashioned 'View-Graphs' I superimposed reservoir maps with thicknesses highlighted in blue onto structure maps with highs, conventionally shown in yellow. What do you get when you add blue and yellow? Green – which of course indicates oil! We identified a number of well locations – and discovered the Yvonne 'B' Field. This was all on poor-quality, widely spaced 2D seismic, but even when 3D was shot a few years later, the thick coal/shale sequence over the reservoir masked the underlying structure, making it impossible to image the sands."

New Ventures

With MAXUS (IIAPCO's parent company), Andy was involved in new venture studies covering over 20 basins and 46 blocks throughout Indonesia and South East Asia. One of his favourite trips was a field reconnaissance of Aru Island, south-west of Irian Jaya (now West Papua). "We spent two days surveying the island, with two teams and helicopters, looking for seeps," he explains. "When we first landed the local villagers arrived and, since it was a Sunday, insisted we came to church with them – quite an experience! There was a pulpit shaped like a ship's prow, covered in huge shells, and a little band, playing digeridoos! There were also kangaroos leaping around the airstrip, 4m-long saltwater crocodiles in the rivers – and literally hundreds of sharks in the sea! It was a fascinating place."

In 1989 MAXUS asked Andy to transfer to Dallas, but feeling well settled with his family in Jakarta, he turned that down and joined Sceptre, which had a couple of blocks in Kalimantan and Sumatra, later working for Petrocorp Indonesia, in the same areas, before re-joining Maxus in 1993.

"In 1987 IIAPCO had decided to review the Asri Basin, which lies immediately north of the Sunda Basin, but which after seven dry holes, had no indications of hydrocarbons. Due largely to the persistence of geologist Harlan Friestad, the play was kept alive and when the Intan-1 well was proposed, it was supported by CEO Charlie Blackburn, on the basis that although very risky, it could have the largest reserves.

"The well was a huge success and together with the even larger discovery at Widuri-1, these two fields transformed the company with the addition of around another billion barrels of oil. That year, I was fortunate to be reporting these finds to Dallas HQ where I met CEO Charlie Blackburn himself. Years later, after I had left Maxus, Charlie remembered me favourably from annual MAXUS exploration meetings in Dallas and his recommendation led to my return to the company as Chief Geologist. This meant I was able to see how all my earlier discoveries had developed, which was an unusually lucky opportunity."

Maxus was eventually taken over by YPF, then in 1999 by REPSOL, and Andy and his wife moved to Kuala Lumpur, before being transferred to the head office in Madrid, where he began working on Libya. "That was fun – I had done field work for my PhD in Libya," he says, "but eventually I wheedled my way back into the South East Asia team, because I felt there was plenty more I wanted to look at." On retiring, Andy returned to Kuala Lumpur as a consultant with Mitra Energy, evaluating opportunities for new ventures throughout South East Asia, finally leaving in 2014 "when virtually all exploration worldwide ground to a halt".

Tales of Adventure

Andy has lots of tales from his adventures in exploration: like the time early in his career in Italy, when one afternoon he took his wife to visit the rig, only to find it deserted, the mud pits empty and all the warning lights flashing, indicating an imminent blow-out; or when during his PhD he got caught in Libya, in the middle of the Sahara during the 1969 coup, and drove through 33 road blocks with his fossil samples hidden in the wheel arches.

There were also riots in Jakarta. "Our newly created New Ventures group, headed up by talented geologist Roger Wall and a team including the irrepressible Handoko Djuanda, had made successes in the East Java Sea and onshore Sumatra in the early 90s. However, in the 1998 Jakarta riots I was in a meeting with Roger when fires started appearing round the city. We suspected the army was behind it for political reasons," he explains. On another occasion, his office block in the Jakarta Stock Exchange was bombed; it was a tense time. "Indonesians are wonderful people, often misunderstood but you have to treat them according to their culture: they are hard-working, very pragmatic, and they don't like being dictated to unnecessarily. We trained many of them as wellsite geologists and they became very skilled; many of them are still good friends."

Andy has had a few non-professional hairy moments through one of his favourite pastimes – climbing mountains, particularly volcanoes. In Jakarta he jointly founded 'JavaLava', a group dedicated to climbing with like-minded people. "On one occasion we reached the top of Gunung Semeru and were looking down into the crater when it erupted, and we got rained on by a shower of breccia – luckily, the main blast went the opposite way. My wife Gill and I still love travelling; we've just come back from Costa Rica and last year we went to Oman where I did the Balcony Walk in Jebel Akhdar."

Potential in South East Asia

Where next in the search for oil and gas in South East Asia? "That's a question I always ask myself," Andy replies. "When reviewing outlying areas you think 'is there a previously undiscovered new source rock or reservoir, or a different type of structure'? I have discovered that small structures (usually a killer for management approval) are not always bad; for example, a tiny prospect I identified, initially undrilled due to its small size (2.4 km^2), has now produced over 50 MMbo. For Indonesia generally, the eastern islands are still underexplored, with low drilling and seismic densities. I always wanted to look further at a particular island where there's shallow oil production but also a potentially large structure play at a deeper level.

"So the answer is: there will always be something we haven't thought of. It may not be a whole new basin, but there's still potential out there in several other South East Asian countries, but," he quipped, "If I tell you where, I'd have to kill you!" ■

Two birds with one stone: Andy's interests in sailing and volcanoes coming together in the Greek Cyclades islands.

Exploring the Norwegian Atlantic Margin:
Møre and Vøring Basins

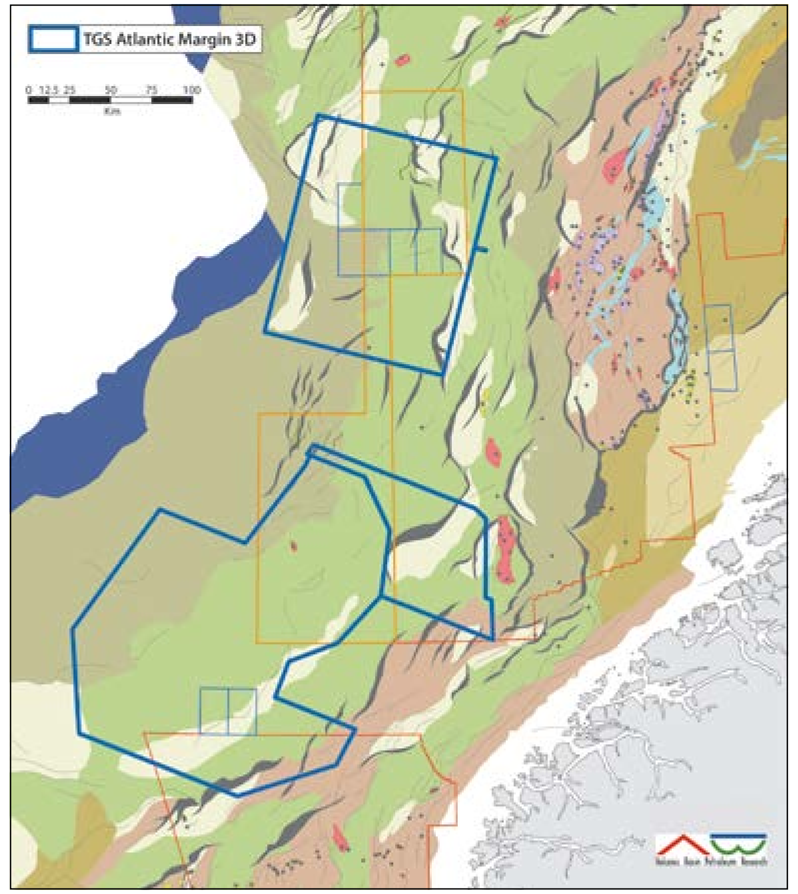


Figure 1: Location of the TGS Atlantic Margin 3D seismic project in the Norwegian Sea.

By the end of 2018 TGS will have acquired a total of 45,000 km^2 of high resolution 3D seismic across the Møre and Vøring Basins in the Norwegian Sea. This article summarises how the project has utilised the triple-source seismic acquisition technique, and how successful deblending technology ensures that these data can be used to explore shallow gas targets and image below the volcanic facies and the deeper Jurassic pre-rift structures. Consequently, new play concepts and ideas regarding prospectivity are being considered.

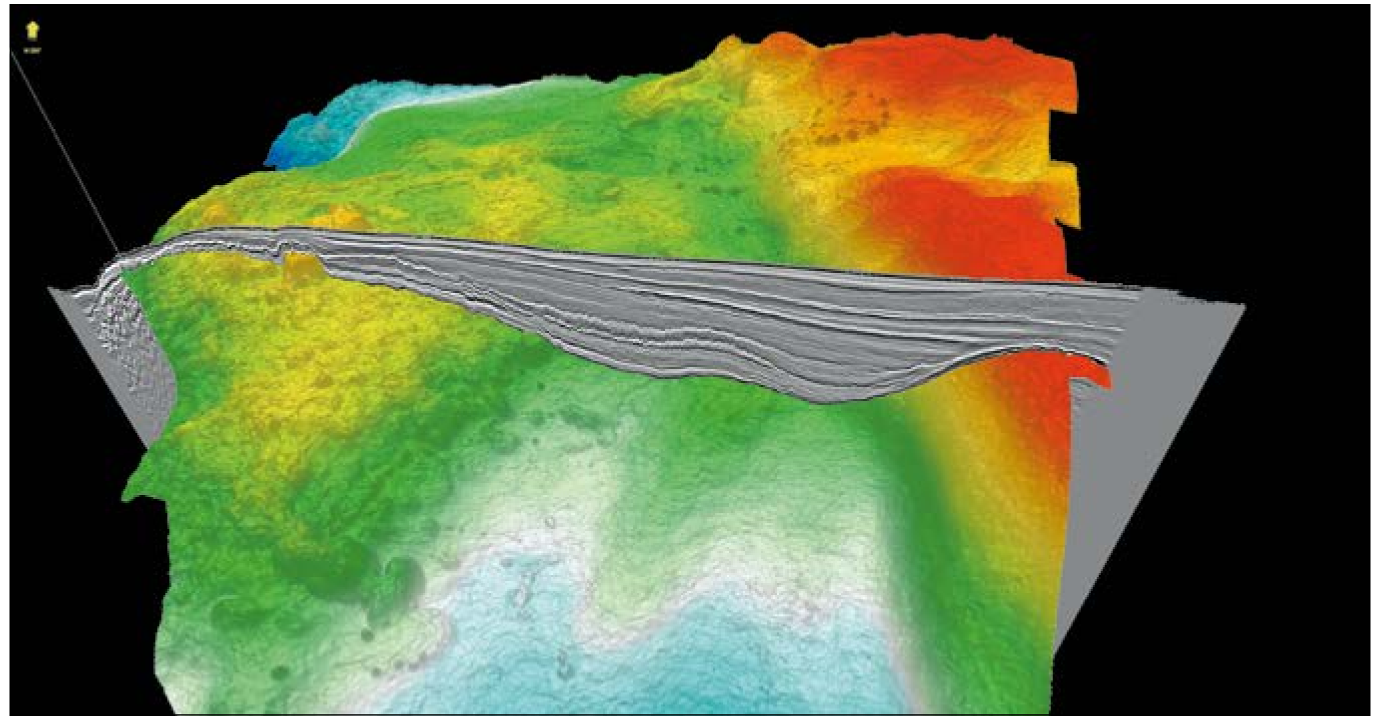


Figure 2: Top Eocene horizon across the Atlantic Margin North 3D in the Southern Vøring Basin. Structural highs are represented in red.

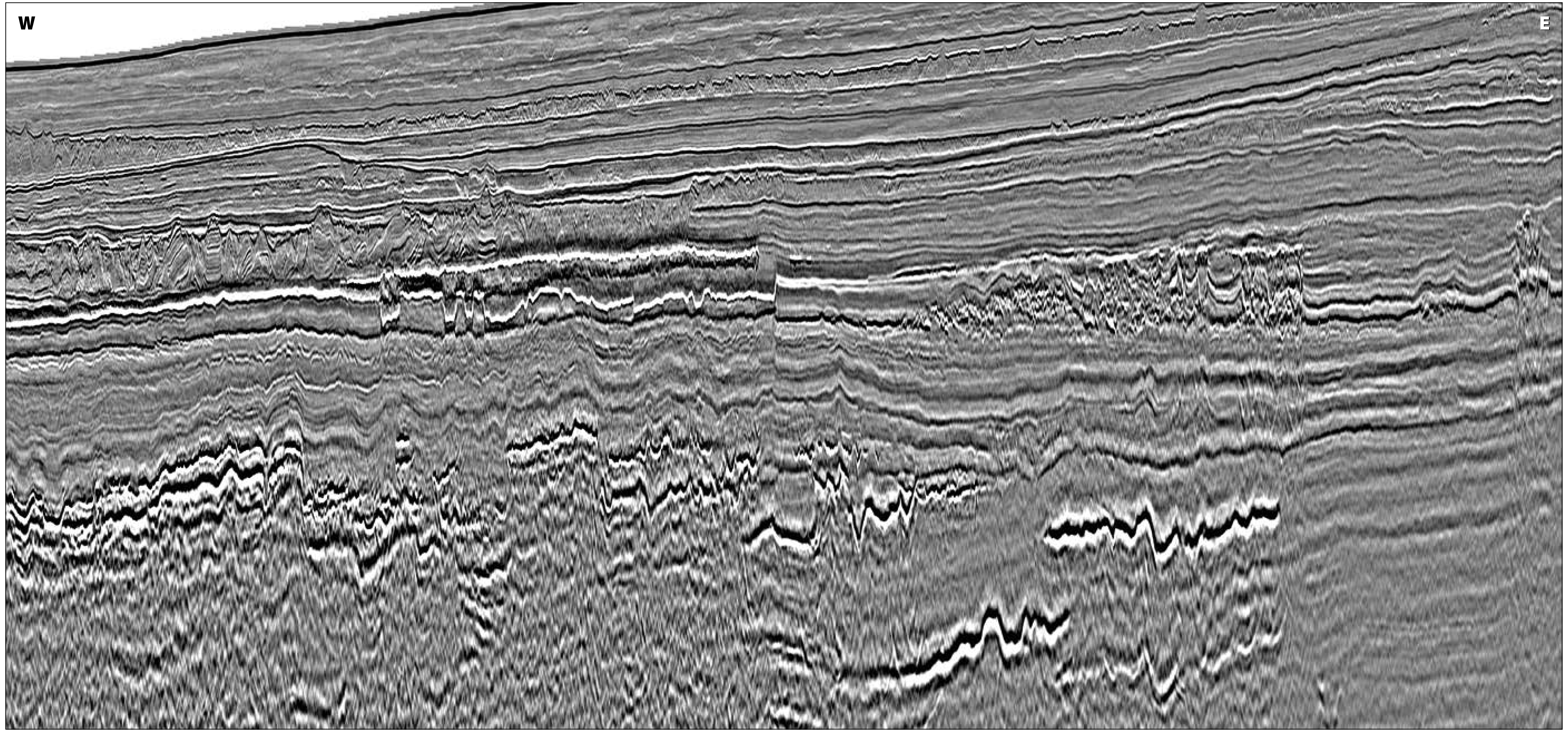
The Atlantic Margin (AM17) 3D seismic project in the Norwegian Sea covers vast deepwater areas off the coast of mid Norway (Figure 1). The area is still immature, with just a few wells targeting big dome structures created by Tertiary inversion.

The Møre and Southern Vøring Basins are challenging seismic terrains that include soft sediment deformation in the overburden, shallow gas, Holocene to Pleistocene seafloor slides, a volcanic sill intruded Cretaceous basin and sub-basalt targets within the Møre Marginal High. Figure 3 is from the Southern Møre Basin and shows some of the challenges that the region presents. In the centre we see two types of soft sediment deformations: to the left a low relief mud diapir and to the right a terrain of possible sand injectites. Both diapir types are often triggered by gas. The sill intrusions in the Cretaceous below have created migration paths and structural closures by altering the rhyology (stiffness) of the basin, and might have also intruded though a source rock. We observe many deep sills within the Blålange Formation, classified as a good marine source rock in the Helland Hansen well (6505/10-1). There are clear seismic imaging challenges with regard to volcanic sills and the side effects of these in data processing, but they also create positive effects like structural traps in an almost flat basin floor, aiding migration and even generating hydrocarbons.

Figure 2 shows the Top Eocene horizon picked in the AM17 dataset in the Southern Vøring Basin. The Helland Hansen two-part dome is seen to the right (east), before the line passes the 'Middle Dome' and into the rugged surface where hydrothermal vent systems and shallow sill intrusions create numerous structural closures in the west. A new play consisting of three-way closure and cross-cutting gas hydrates in the west, trapping free gas in Miocene beds over a vast area, is seen at the top of the seismic line.

TGS

Figure 3: Fast track PSTM seismic profile through the Southern Møre Basin.



Atlantic Margin 3D: Exploration Opportunities Redefined with New Seismic

With Norwegian gas production in decline and the European gas market expanding, the Møre and Vøring Basins in the Norwegian Sea represent great places to explore for new gas prospects.

BENT KJØLHAMAR, JAN LANGHAMMER, NICK WOODBURN, REIDUN MYKLEBUST and SIMON BALDOCK; TGS.

In 2017 TGS commenced the largest 3D seismic campaign in Europe. Known as the Atlantic Margin 3D, this project in the Norwegian Sea covers a region which is immature with regard to exploration drilling, although it is reasonably close to existing infrastructure. The technical drilling successes in the region so far have found oil and gas in Upper Cretaceous and Palaeocene units. The Ellida and Havsule wells indicate an active oil source is present in the Møre Basin, but the common expectation is gas. The Ormen Lange field, discovered in 1997, produces 20% of the natural gas consumption of the UK market. Recent gas prices in Norway have reached record highs, and interest in gas is rising.

To date, 34,000 km^2 of 3D seismic have been acquired, with a further 11,000 km^2 to be shot during the summer of 2018. The area offers a range of challenges to be tackled in data processing. In the west there are flow basalts and volcanoclastic deltas, with volcanic sills intruding into the main basin, while the eastern part exhibits soft sediment deformations, mud diapirs and sand injectites with many gas anomalies. To address these challenges, it was considered important to provide the industry with a high-resolution dataset that can correctly image the shallower gas targets, whilst also preserving lower seismic frequencies to image below the volcanic facies and the deeper Jurassic pre-rift structures.

Triple Source 3D and Deblending Technology

To realise the goal of efficient, high resolution acquisition, a triple source configuration was implemented. By going from two to three sources, vessels can support a larger total cable spread and still maintain the same crossline subsurface bin size. The cable spacing for this survey was 112.5m at the near offsets, which gives a crossline bin size of 18.75m when three sources are used. Further acquisition efficiencies were achieved by using multiple vessels, with up to four acquiring data simultaneously. In order to maintain CMP fold, the shot interval between each one of the three sources being activated was reduced to 12.5m. This acquisition design yields a high density, high fold 3D seismic dataset, well suited to creating high resolution images of shallow gas-related targets.

The 12.5m shot interval, combined with an average boat speed of 4.5 knots, means that a significant portion of each shot record is blended with – that is, overlain by – data from the previous or subsequent shots, setting up one of the key signal processing challenges of the project. There are approximately 5.3s of 'clean' record

Figure 4: A seismic profile through the Atlantic Margin 3D: (a) before deblending; (b) after fast track PSTM.

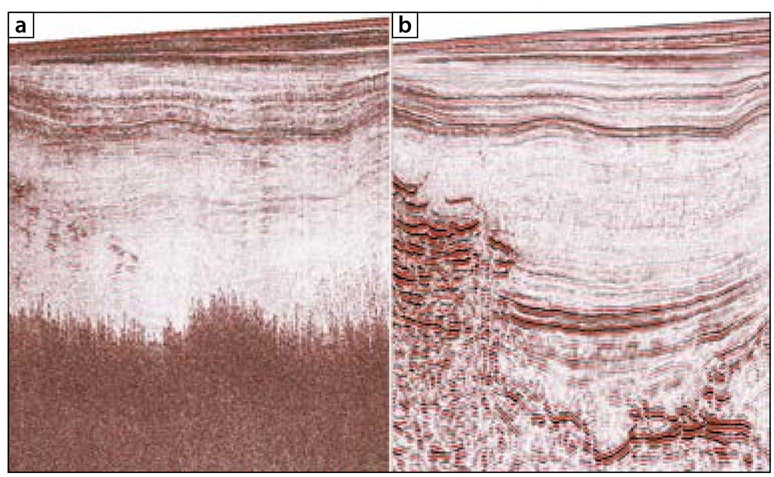
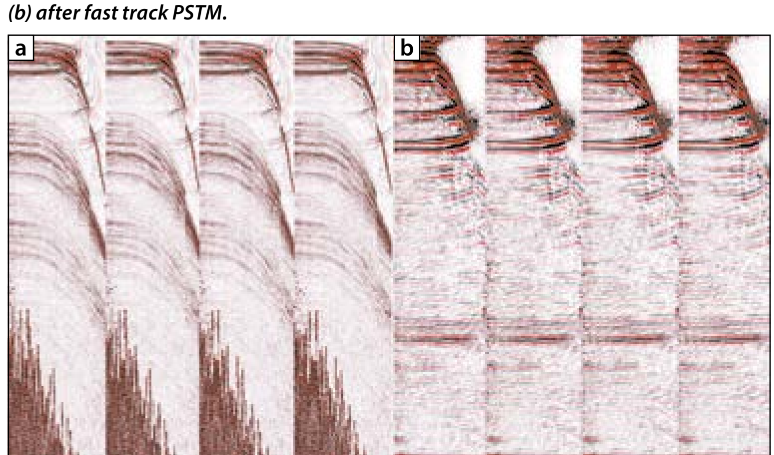


Figure 5: Example CMP gathers from the Atlantic Margin 3D: (a) before deblending; (b) after fast track PSTM.



before the subsequent shot arrives. In this interval the data that we wish to image has decayed to be as much as 40–50 dB weaker than the energy that overlays it. A combination of natural and random time dithers was also used to make the overlapping energy random in certain domains.

To deblend the data TGS has developed a multidomain coherency-based separation technique. The workflow consists of three steps. The first is a local weighted stack to remove the direct arrivals of the overlying shot, while the last step is a pass of multidomain noise attenuation to address any residual energy from the overlying shot. The key deblending step is the second one, in which a unique High Resolution Moveout Transform (Masoomzadeh and Hardwick, 2012) is used to build a model of the overlaying shot energy in the 2D CMP domain. Figures 4 and 5 demonstrate that data previously overlain by blended energy has been successfully recovered, revealing deep structures.

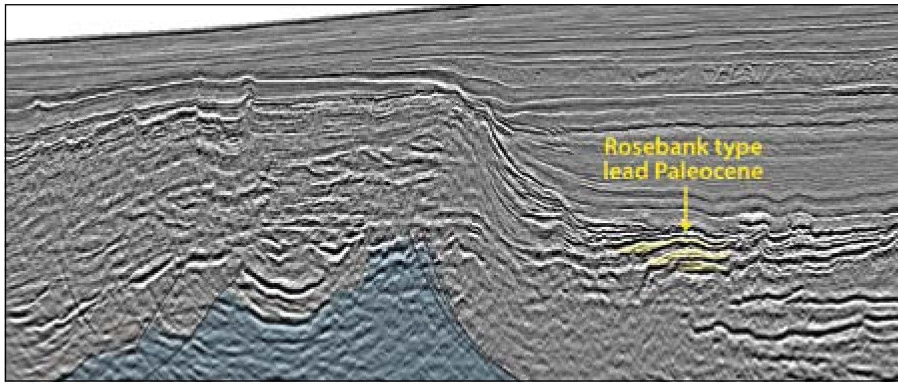


Figure 6: 3D seismic profile through the western Møre Basin. A stacked intra-basalt lead is highlighted.

New 3D Data – New Play Ideas

The area covered by the new 3D has water depths from 500 to 2,500m and the deep sedimentary Møre and southern Vøring Basins are filled with thick Cretaceous and Cenozoic successions. The dominant sedimentation process in the area is gravity flow deposits (turbidites). From the Cretaceous to Palaeocene these turbidite reservoirs were sourced from both the Greenland and Norwegian side. There are numerous leads in this proven play and now with the modern high-resolution 3D data the opportunity arises to evaluate intra-basalt leads (Figure 6).

An extension to the original Atlantic Margin 3D programme, supported by industry funding, will provide new 3D seismic close to and west of the Ormen Lange gas field. The main reservoir in this field comes from Palaeocene turbidites sourced from Norway. Over the Vigra High, 50 km west of Ormen Lange, we observe large thickness variations in the Palaeocene interval. AVO anomalies (class 3 trends) surround the deeper high in a doughnut shape. Several bright amplitude anomalies are also seen near Ormen Lange in the slope down and westward, suggesting stratified traps at a tie-back distance from the gas field.

Similar observations are made surrounding the drilled prospects Havsule, Solsikke and Edvarda – all drilled on top of the inverted domes and pronounced dry. It is a quite striking correlation that none of these wells have apparent brightening in any levels. From this we conclude that subtle highs existed already in the Late Cretaceous and Palaeocene, and not only in the Miocene (the main period for inversion), acting as barriers and controlling the turbidite fan systems. We suggest future drilling programmes should focus on the flanks of these domes.

Within the slope down from the Tampen area in the North Sea we observe large elongated mounds with a chaotic interior. Utilising the fast track PSTM data from the Atlantic Margin 3D data, we strongly believe we are looking at sand injectites of Eocene age. Gas is normally involved when we get injectites like this: our hypothesis is that gas and rapid loading from the Plio-Pleistocene created overpressure, simultaneously triggering the sand injectites and filling the stratified traps. An Eocene deltaic sand sourced from the Tampen area is likely to represent the mother bed.

In summary, improved imaging, resulting from triple-source acquisition and the subsequent deblending technology, is contributing to a much greater understanding of this underexplored region and can help to realise the full potential of this area of the Norwegian Continental Shelf.

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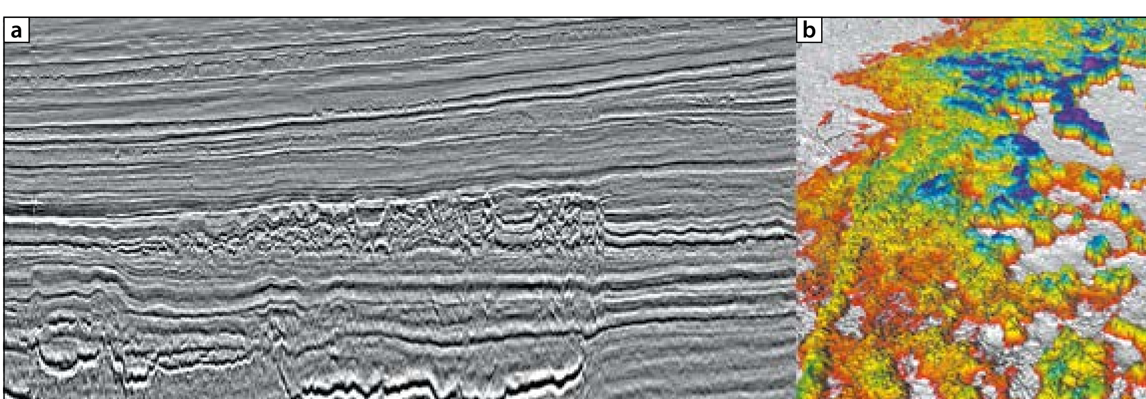
Figure 7: (a) 3D seismic profile through the Møre Basin highlighting possible sand injectites within the Eocene interval with a strong anomaly across the top. (b) Interpretation of the sand thickness mapped across potential sand injectites.



Leveraging AI for Production Optimisation

Solution Seeker, a Norwegian tech start-up and spin-off from the Norwegian University of Science and Technology, is developing the world's first artificial intelligence for real-time production optimisation. Starting in deep academic research, the company is now applying AI on a commercial scale, deploying the technology for major oil companies.

BJØRN-ERIK DALE and VIDAR UGLANE; Solution Seeker AS

In 2007, the Norwegian University of Science and Technology (NTNU) launched the Center for Integrated Operations in the Petroleum Industry (IO Center), focused on developing novel and innovative methods for oil and gas production optimisation. Among the IO Center partners were oil majors ConocoPhillips, Engie, Statoil, Total, BP, Shell, Eni and Petrobras.

The IO Center's research were split into short- and long-term production optimisation. Vidar Gunnerud, at the time a PhD student, led the short-term optimisation programme, which initially aimed at developing optimisation algorithms to run on top of multiphase flow and process simulators in real time. Having developed his algorithms, however, Gunnerud realised that third party simulators were both inaccurate and too slow for the purpose of real-time optimisation. In addition, they were hard to maintain. How could his advanced optimisation algorithms perform when running on these slow and inaccurate digital twins?

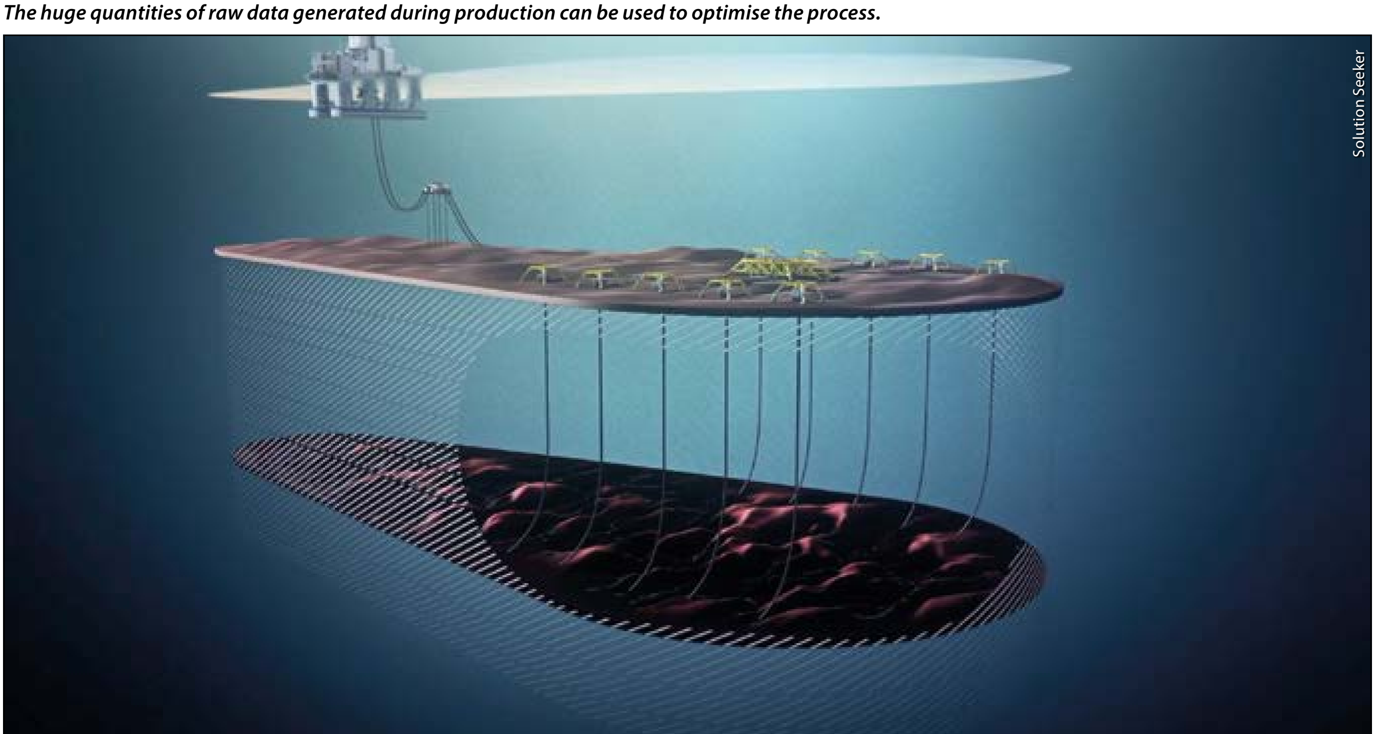
It was still early days in the fourth industrial revolution; 2007 was the year of the first iPhone, the year after Facebook and still two years before Uber. Few were yet to talk about big data and machine learning. All the same, Gunnerud and his professor Bjarne Foss at the Department of Engineering Cybernetics at NTNU rejected the assumption-based simulators and asked themselves "why don't we instead plug directly into the oil field itself, read all its data and see what is actually happening?"

During the programme five PhDs and 20 master's projects had studied real-time optimisation, and more than 50 scientific papers had been published on the topic. Three major inventions were made; namely how to build purely data-driven models, how to set up experiments to generate new data, and how to optimise from these models in practice. Based on these inventions, two of which were patented, Vidar Gunnerud, Professor Bjarne Foss and NTNU, through its Technology Transfer Office, set out to commercialise the technology, and on 31 January 2013 they formed Solution Seeker as an NTNU spin-off company – a company now well known on the Norwegian tech start-up scene.

From Algorithms to the NCS

ConocoPhillips and Engie became interested in the novel approach to production analytics and optimisation, and in 2014 they entered into a long-term collaboration with Solution Seeker to further develop these methods. The start-up was given live data access and followed the pilot fields over a couple of full year cycles, learning how to make the methods

The huge quantities of raw data generated during production can be used to optimise the process.



Vidar Gunnerud, founder and CEO of Solution Seeker.

work in a truly operative environment and understanding the real challenges and pain points both in the process and the work processes which the algorithms were to support.

Where oil and gas production differs significantly from other processes (such as refineries, petrochemical and power plants) is the high number of unknowns. Reservoir, well and flow dynamics are never fully understood, and they are continuously changing as the reservoir is drained, new wells are drilled or shut in, and the production system modified. Production data is typically sparse and noisy, with a great deal of inherent uncertainty in the measurements themselves. Furthermore, key sensors may fall out or drift over time. All this leaves the production team with the challenging task of continuously optimising and tuning the production settings in the face of uncertainty: identifying the optimal choke settings, gas lift allocation, well routing, pump speeds, etc. Typically there are tens or hundreds of production settings to be adjusted, and thousands, millions or even billions of relevant combinations to be considered. A successful real-time algorithm needs to be fast, accurate and robust to solve this stochastic optimisation problem and capture the full production potential within the limitations of the production system.

During 2015–2017, Solution Seeker obtained proof of concept of its methods while also developing new ones. Additional oil companies joined it: first Wintershall, then Lundin and most recently Aker BP. In close collaboration with its partners, the company is developing a full-stack 'AI as a Service' technology, called ProductionCompass, with a three-step data pipeline: from data mining to machine learning to optimisation.

How it Works

Through its data mining algorithms, ProductionCompass uses vast amounts of raw production data, capturing thousands of time series, continuously sampled and tracing them back over years. Leveraging machine learning techniques for automatic pattern recognition and classification, the production data is refined and distilled through advanced statistical analyses and compressed to high-grade information through proprietary and patented algorithms. It then builds estimation and prediction models by leveraging multiple real-time machine learning systems working in parallel. AI combines hierarchical neural networks, first principle physics, statistical models, and truly known parameters. This enables the technology to capture and analyse the dynamics of the production system and separate reservoir effects from the production control responses such as choke positions, gas lift rates, artificial lift equipment, and network routing of the wells.

Finally, leveraging the power of its predictive capabilities with up-to-date, fast and accurate models, ProductionCompass enables a continuous search for maximum with its optimisation algorithm.

A well-known issue of machine learning is the exploit/explore trade-off; should one exploit the existing knowledge, or should one explore for new data in order to improve the models and in turn exploit even better models in the future?

Because ProductionCompass captures and calculates the uncertainties through the whole data pipeline, from raw data to estimates to predictions, oil companies are able to exploit the upside potential in their systems while managing downside risk through the built-in tracking and stop-loss functionality. Furthermore, Solution Seeker's data scientists can design tailored experiments to provoke responses from the field in order to reveal dynamics and behaviour as yet unknown in the production history of the field.

Learning to Leverage AI

As Solution Seeker has developed and deployed its methods, new uses for the technology appear. This is part of the lean start-up philosophy adopted by Gunnerud from day one – he and his team embrace a collaborative approach, working in partnership with the oil companies, with frequent interactions, rapid development and deployment of new methods, a direct feedback loop from the end users, and a pragmatic approach to problem solving.

One such case appeared when an oil company experienced severe slugging, which could not be explained by the simulators used by their third-party flow assurance advisors. Slugging was not a part of the current scope for Solution Seeker, but as it was so severe that production had to be reduced significantly, it overshadowed any other optimisation effort.

This slugging could not be explained by the simulators and the assumptions they rely on – but it was easily observable to the data mining algorithms reading the actual production data streamed directly from the field itself. By exploring and developing new machine learning algorithms, and applying them to the mined data, Solution Seeker was able to identify the problem and pin-point the troubling well, enabling the client to choke it back and regain control over the output and resume maximum production.

Maximising Production: Minimising Loss

Through its work to date, Solution Seeker and its clients have identified three main drivers for value capture: namely ensuring best practice based on existing knowledge; further optimisation based on data-driven prediction models; and freeing up engineer time to drive creative problem solving.

The Solution Seeker team.

McKinsey recently undertook a study for a major oil company on the NCS, showing an average 10% performance difference between the best and worst performing production team on the same field. Even for the very best performing field, the difference was 5%. By default, and before any optimisation, the AI learns; the data mining and machine learning algorithms learn from all the production teams' actions over the last few years – both those who were successful and those who were not. Hence it learns the best practice observed to date and avoids the mistakes of the past.

Based on this learning, ProductionCompass uses AI to build AI then builds prediction models. What is there between and beyond what we have observed? What is the better combination of production settings? By leveraging these prediction models into advanced mathematical optimisation algorithms, production is expected to improve from historic best practice by 2–5%.

Finally, as AI is superior at analysing production history, significant amounts of highly valuable time is freed up for the production engineer. This allows the production engineer to do what can be called creative problem solving, in which humans remain superior to machines. As an example, one of Solution Seeker's clients has several shut-in wells, and now the production engineer can spend more time figuring out how to restart these wells and further add to the production maximisation objective.

Scaling Globally

As oil companies globally start to adopt AI, Solution Seeker is preparing to scale its technology and operations. The first version of the technology will be made commercially available later this year, and the company is already in talks with operators from South and North America, to the Middle East and to Asia. With highly configurable software, powerful cloud computing and modern web technology, the company is looking forward to being able to efficiently serve clients globally. ■

Marine Vibrators: Part I

Early Developments and a Failure

If you want to find the secrets of the universe, think in terms of energy, frequency and vibration.
Nikola Tesla (1856–1943)

MARTIN LANDRØ and LASSE AMUNDSEN

In 1966 the marine seismic industry was blooming and acquiring a lot of seismic data by using a substantial quantity of dynamite. A combination of safety and environmental issues paved the way for a new source: the airgun, which was actually invented in 1960 by Stephen Chelminski, but came into practical commercial use 10 years later. Less well known is the fact that Conoco developed a marine seismic vibrator that was successfully tested in 1966 and also in later years. A marine seismic source competition developed during the late 1960s and the winner was the airgun: the marine vibrator lost.

Here we will explain how a marine seismic vibrator works, and why it might be getting closer to reality.

A Bit of History

In today's conventional acquisition two airgun sources, each defined by two or three sub-array elements spaced 6–8m apart, are fired sequentially at specified intervals, in a mode popularly called flip-flop shooting. After one source is fired, the reflected signals are recorded to the required time length for imaging the ground before the next shot can be acquired.

Before the airgun, dynamite was the common source for marine seismic operations, either placed on the seabed or directly into the water. Stephen Chelminski, who founded Bolt Technology in 1960, first acquired shallow seismic data using airguns in 1961 (Proffitt, 1991). In 1967 the concept of tuned airgun arrays – using airguns with different volumes – was introduced worldwide.

Today, a marine seismic source usually consists of between 20 and 50 airguns of different sizes. When the source is fired (i.e. the air is released), an acoustic signal is sent into the earth.

In the 1960s Conoco developed the first marine vibrator (Proffitt, 1991) and for a number of years there was competition between the two exploding sources, marine vibrators and airguns. According to Proffitt, it was the safety, simplicity and reliability of the airgun that made it the winner of this competition. During the '80s improved design and new developments for hydraulic marine vibrators were made.

Vibroseis – the First Land Vibrator Source

The first seismic vibrator source was developed in the 1950s by Conoco in order to replace the use of dynamite as a source for seismic land acquisition. Crawford et al. (1960) published a paper entitled 'Continuous signal seismograph', where they described the development of the first seismic vibrator, which they called Vibroseis. The figure below is taken from this paper, in which the combined use of a continuous signal and cross-correlation is described in detail. Notice the delay drum device in the figure. Crawford, Doty and Lee received the Reginald Fessenden award for this work from SEG in 1967. John Crawford is known as the father of vibroseis. Field work was essential in his work, and one of his best-known quotes is: "What field work teaches you is never to ask a man to do something that you couldn't or wouldn't do yourself."

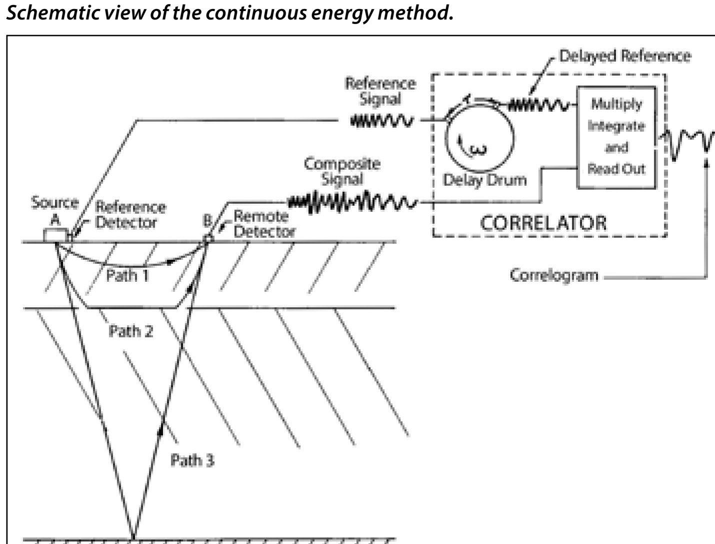
Launching Marine Vibrators…

In the late 1960s the marine vibrator sources were adaptations of land vibrators. Instead of generating a directive vertical force to the ground, marine vibrators were designed as a pulsating sphere (or similar shape) acting on water. In 1966 and for some years thereafter several marine vibrators were tested offshore, and demonstrated good results.

In 2002 Tyler Priest and Joseph Pratt interviewed Sam L. Evans about the competition between marine vibrators and airguns in this period. Sam states in this interview that the marine vibrator has a good signal but the vibrator signal length of 10–12 seconds followed by a listening period of 6–8 seconds makes the method slow and ineffective. When you tow seismic streamers you want the vessel speed to be around 4–6 knots (at least) to avoid drifting, so this lag makes the marine vibrator source less useful.

After the success of the vibroseis source onshore, Conoco spent several years finding ways to exploit this technology offshore. They cooperated with several companies including Olympic Geophysical and Ray Geophysical, and later Seiscom

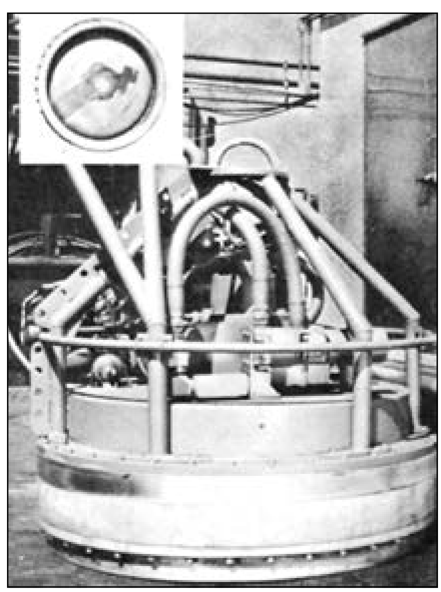
Schematic view of the continuous energy method.



Source: Crawford et al., Geophysics, 1960.

Delta. According to Evans, however, by 1972 or 1973 airguns had become the industry standard preferred marine seismic source.

From 1962 to 1970 SSC (Seismograph Services Corporation) and its subsidiaries (like, for instance, SSL) were the only service company that had the right (with a licence from Conoco) to operate the vibrator method on land (Lawyer, 2011). The figure on the right shows an old photo of the vibrator used by SSC in this period.



The Vibroseis high power transducer. (From Seismograph Services Corp., and Lugg, 1971.)

...And Losing the Battle

So why did the seismic vibrator win terrain for onshore applications in the late '60s, while the marine vibrator became a loser? The answer is probably complex and to some extent related to timing, random circumstances, but maybe mainly caused by the practical issues of a moving source emitting a long, randomised signal that required longer records for each shot and more processing efforts after acquisition.

Another reason could be that the mechanical life and long-term field reliability of the marine vibrator could not compete with the reliability of the airgun array. It was seen as an expensive, formidable engineering task to design a vibrator and its its associated rigging and handling gear for smooth, reliable operation in the harsh ocean environment..

So why are marine vibrators topical again today? First of all, there are offshore areas where the use of airgun arrays is not permitted, either seasonally or on a permanent basis. Environmental concerns related to noise pollution in the oceans are in focus, and hence there might be a need to develop sources with lower sound pressure level and sound exposure level than airguns. Research and development projects have been conducted by contractors and by industry consortia aiming to develop new marine vibrators that can compete with airgun arrays. We will discuss these developments in a series of articles. ■

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Super Producers: Revealing North Sea Injectites

Broadband data can reveal significant hydrocarbon potential in the Viking Graben area by providing superior images of complex structures like injectites.

NOÉMIE PERNIN, LAURENT FEUILLEAUBOIS, TIM BIRD and CYRILLE REISER; PGS

The North Sea Viking Graben has been a prolific hydrocarbon province, producing principally from Jurassic, Palaeocene and Eocene clastic reservoirs for more than 40 years. In this mature basin, many of these fields are in their later stages and experiencing declining production, so additional near-field step-out or extended-reach targets are in demand to augment production and prolong field life. The Tertiary injectites of the Viking Graben offer such an opportunity for relatively shallow incremental targets above producing reservoirs and adjacent to field infrastructure. Their complex, enigmatic geometries have made them a challenging play to understand and exploit in the past. However, the latest generation of broadband dual-sensor, towed streamer seismic data has enabled improved imaging and characterisation of these bodies, and the ability to de-risk lithology and hydrocarbon presence has enhanced the commercial relevance of even relatively modestly-sized features.

Super Producing Reservoirs

Injectites are created through post-depositional remobilisation of fluidised sands injected into the stratigraphy. Though often not large in area, these reservoirs are of particular interest due to their very high porosity and permeability and are often supported by a strong aquifer. For this reason, these features have been described as 'super producers'.

In the past, identification and characterisation of these Tertiary injected sands was challenging due to a lack of imaging resolution in legacy seismic data. This was exacerbated by the misleading interference of prominent side-lobe energy as the data was so limited in bandwidth. Recent broadband dual-sensor seismic data in the Viking Graben provides reliable, AVO-preserving pre-stack information and has significantly improved imaging and characterisation of these injectite targets, bringing clarity to known injectite fields such as Volund and Harding, as well as highlighting additional hydrocarbon potential for near-field exploration (Figure 1).

This improvement is the result of PGS having unified and processed its Viking Graben datasets using an advanced depth imaging workflow to create a GeoStreamer PURE pre-stack broadband depth dataset of around 18,000 km^2. The workflow consisted of anisotropic velocity model building and Kirchhoff depth migration including compensation for earth absorption, together with the implementation of the PGS complete wavefield imaging processing workflow, including FWI and separated wavefield imaging. This process offers a solution to many of the imaging challenges related to the varied geological setting, such as very shallow channels. The late Eocene injected sands were characterised and mechanically inserted as geobodies into the velocity model, which contributed to a final superior image of underlying features such as the targeted Palaeocene

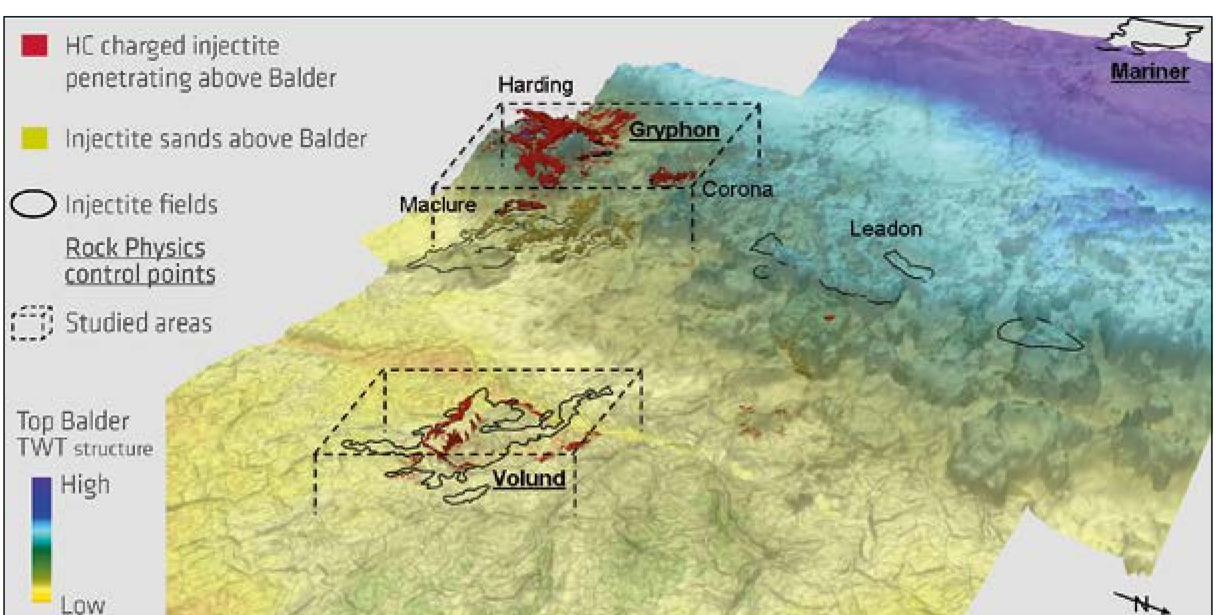


Figure 1: Key injectite features in the Viking Graben, North Sea.

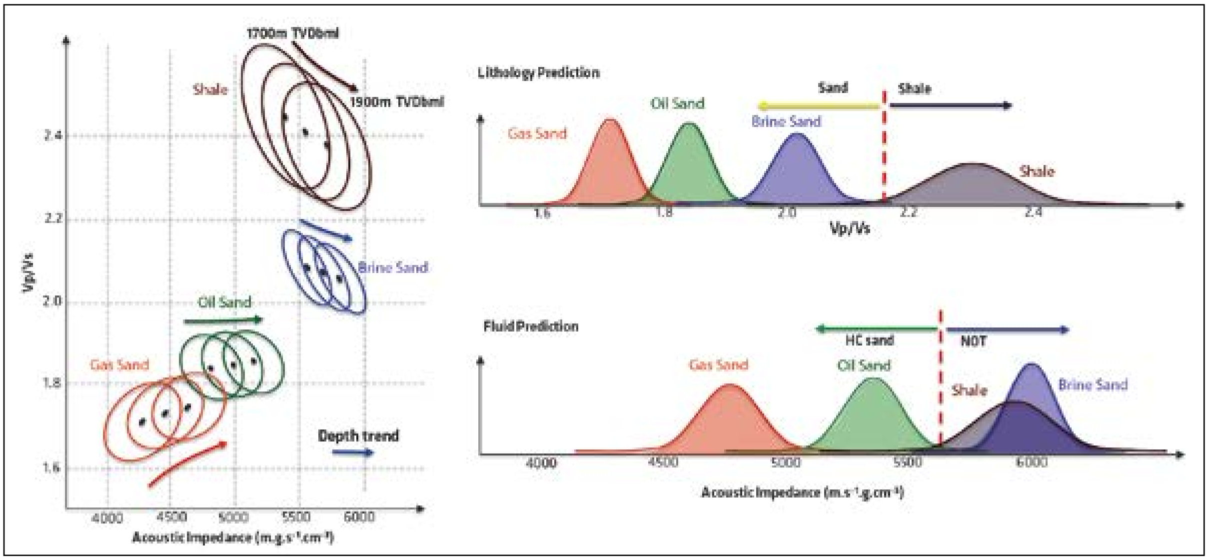


Figure 2: Rock physics analysis (depth trend analysis) and stochastic forward modelling of remobilised sandstones and shale lithologies performed on seven wells where Vp, Vs, density, and porosity logs were available.

injectites (Ciotoli et al., 2016).

In addition to this, detailed quality controlled AVO (amplitude versus offset) analysis was performed throughout the processing, along with reservoir-oriented processing, allowing a quantitative interpretation-ready pre-stack volume for the inversion.

Injectite Rock Physics to Assess Hydrocarbon Potential

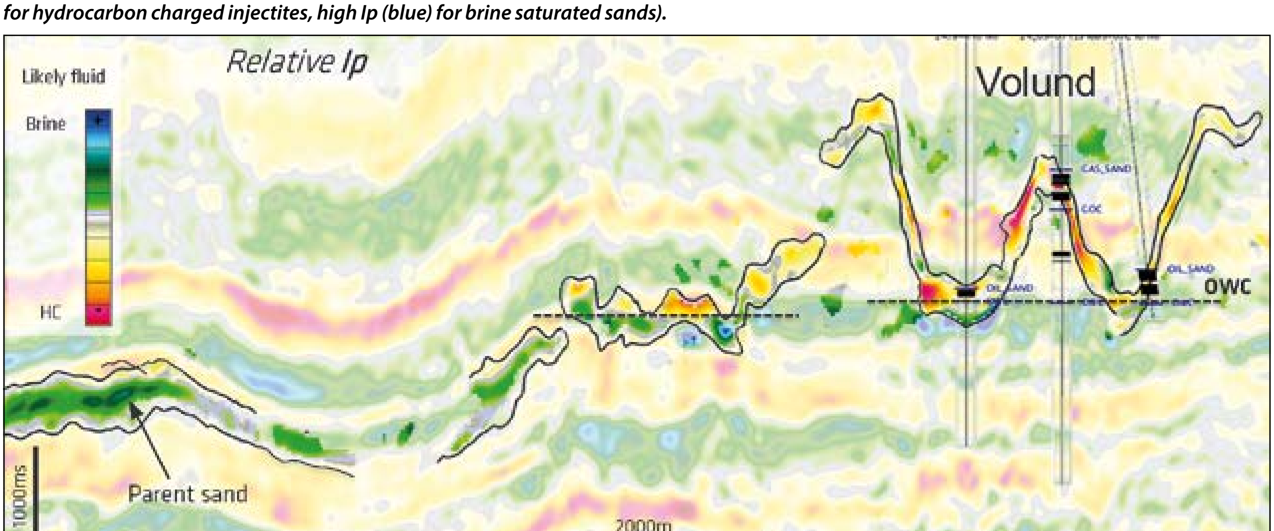
Tertiary injected sandstones from wells from both UK and Norwegian sectors in the North Sea were selected to perform a statistical depth-dependent rock physics analysis (Figure 2). Wells from the Mariner (Heimdal Formation Sandstone), Gryphon and Volund fields (Balder Formation Sandstone) were chosen. The fields are respectively located 1,100, 1,500 and 2,000m below the seabed. This allowed a good sampling of the sandstone characteristics with depth. Despite being buried at various depths, and being of different ages (Palaeocene-Lower Eocene sands), these reservoirs exhibit similar porosity values of around 34%.

Well results show that the GeoStreamer pre-stack AVO attributes can discriminate both lithology and fluids in many cases. In this context a lower Vp/Vs is expected for sand reservoirs compared to shale, while a low acoustic impedance within the sandy reservoir intervals indicates hydrocarbon charge and may be able to differentiate oil from gas. The combination of both Vp/Vs and acoustic impedance attributes is a requisite to accurately identify the hydrocarbon-charged injectites.

All Wells are Blind!

The availability of low frequency information delivered by broadband seismic data enables the derivation of seismic-driven pre-stack relative inversions without the use of any well input. Elastic properties can be estimated more reliably through a quantitative interpretation workflow (Ozdemir, H., 2009; Farouki et al., 2010; Reiser et al., 2012). The validity of the inversion results is confirmed with excellent well tie with the pre-stack GeoStreamer seismic elastic attributes (relative acoustic impedance and relative velocity ratio). Consistent fluid contacts were identified and mapped within the Volund complex (Figure 3). Figure 4 shows how these anomalies can be accurately mapped in 3D thanks to the reliable pre-stack elastic attributes

Figure 3: Relative acoustic impedance volume derived from pre-stack broadband dual-sensor streamer data showing parent sand and injected sands geometries of Volund field (Norway). Good well to seismic ties and oil-water contact observed matches with markers and rock physics analysis (low Ip (red) for hydrocarbon charged injectites, high Ip (blue) for brine saturated sands).



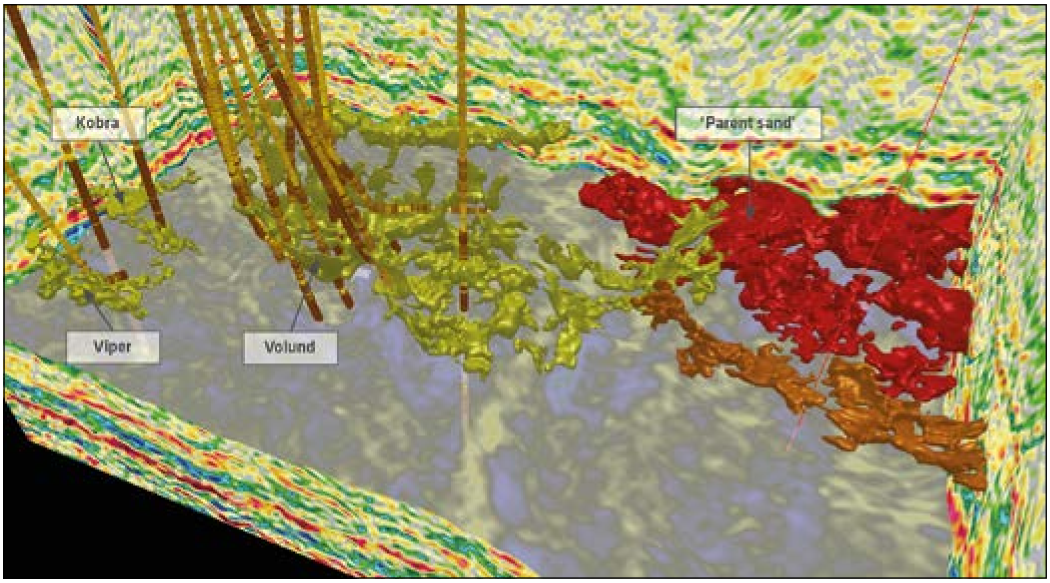


Figure 4: 3D geobodies volume extraction based on elastic attributes illustrating the Volund field and its satellites (Kobra and Viper) as well as the parent sand of the injectite features.

and highlights the Volund field and two of its satellites, Kobra and Viper.

A similar workflow was performed in the UK-Q9 sector on PGS MC3D Beryl GeoStreamer high-density (50m streamer separation) seismic dataset. In this area, the injectites are of Early Eocene age and located within extended reach of infrastructure associated with mature producing fields. These shallow injectites had been missed by earlier drilling campaigns that targeted deeper reservoirs and relied on vintage seismic data with more limited bandwidth and resolution. The improved imaging and the robustness of the pre-stack elastic attributes from the dual-sensor towed streamer broadband data proved to be essential to confidently identify, characterise and de-risk the injectite geometries (Figure 5). As a result, a number of prospects have been identified and assessed using lithology-fluid prediction to high-grade the most attractive anomalies where an oil-filled reservoir is predicted from the combined use of elastic attributes.

Improved Imaging and Characterisation

GeoStreamer seismic pre-stack depth migrated data significantly improves the imaging of the Tertiary injectite reservoirs of the North Sea. Our geological understanding of injectites has improved alongside awareness of their commercial potential, especially as shallow, near-field, step-out targets have been revealed. The robust pre-stack elastic attributes derivation for the Tertiary injectites studied in the UK/Norway Viking Graben also enables reliable characterisation of reservoir lithologies and the de-risking of fluid type. These attributes show very good correlation with well data.

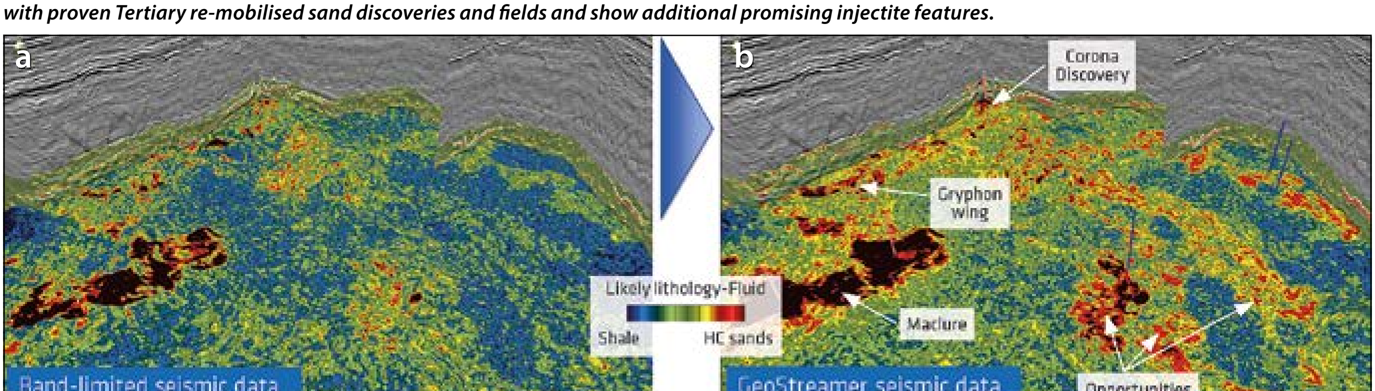
Rock physics analysis using appropriate key wells from the UK and Norwegian Viking Graben indicates that good lithology and fluid discriminations can be expected using elastic attributes, supporting the conclusions of the seismic inversion analysis.

The re-mobilised injected sandstones in the Tertiary of the Viking Graben exhibit extremely high porosity and permeability. Even modest-sized injectite features can represent attractive, relatively shallow, near-field objectives due to their known high producing rates and proximity to existing infrastructure. The new broadband data highlights many remaining untested injectite features that can be confidently characterised and de-risked using relative pre-stack attributes.

Acknowledgements: *The authors would like to thank PGS for permission to publish this work and colleagues for their support and fruitful discussions on this subject.*

References available online. ■

Figure 5: Minimum amplitude of relative Vp/Vs displayed on a regional Top Balder Horizon (100 ms extraction window above the horizon). (a) conventional frequency bandwidth: identification, characterisation and de-risking are significantly challenging, as band-limited elastic attributes are inadequate to confidently predict reservoir lithology or fluid; (b) shows equivalent case using broadband pre-stack attributes: low Vp/Vs values correlate with proven Tertiary re-mobilised sand discoveries and fields and show additional promising injectite features.



A Simple Guide to Depth Conversion: Part II

In Part I of this guide to the important subject of depth conversion we looked at the parameters involved. We now look at the steps in the process.

ASHLEY FRANCIS, Earthworks Reservoir

The key steps involved in depth conversion are:

1. Determine layer scheme.
The choice of layering will be determined by local geological knowledge. Layers generally are comprised of rocks of similar ages, lithologies or burial history. The boundaries for the layers are often chosen because they are important geological markers or major reflection events on the seismic. More layers are not necessarily better; sometimes simple single layer models work well. It depends on whether lateral velocity variations are present and represented by horizons that can be picked on seismic.

2. QC input data.
Quality control of the input data is important for depth conversion. Horizons should be picked on a consistent seismic event as far as possible: any mis-tie at wells is then representative of the true uncertainty in the depth conversion. Note that it is a poor strategy to force seismic horizon picks to match well markers in time, as then the QC information is hidden.

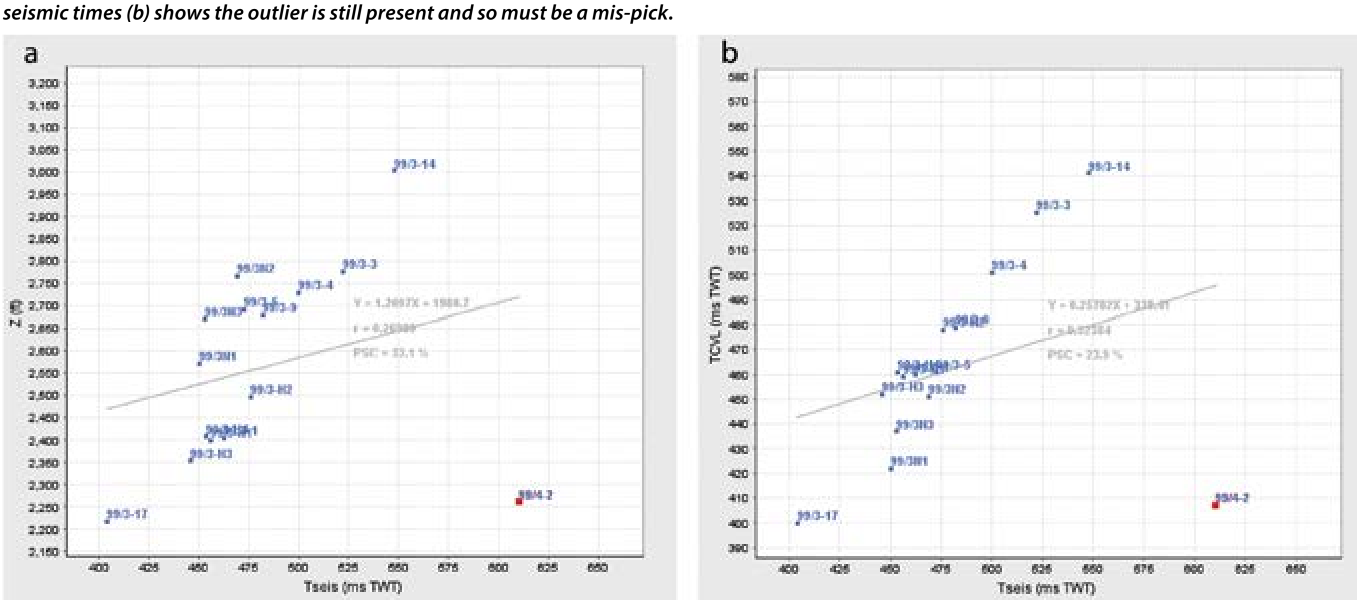
When using wells, the first step is to compare the calibrated velocity log times from logs to the seismic times picked as interpreted horizons. By cross-plotting the two, any mis-ties can be identified and corrected, with outliers possibly indicating potential issues (Figure 1).

3. Compare methods within layers.
Having checked the input data and layering then the usual approach is to test different methods in the layers, working from the top down. By fitting functions of different types (or using seismic velocities), the methods are compared by examining the depth residuals both within the layer and at the base of several layers as the depth conversion proceeds. The residuals are the difference between the depth predicted by the velocity model using the seismic time at the well marker and the actual depth observed in the well. A small mean residual difference (indicating an unbiased depth conversion) and a low standard deviation (meaning the method explains the depth quite well) are indications of a good depth conversion model. The spatial distribution of residuals should not show a strong trend, which would indicate a velocity variation unexplained by the model. The residuals are also a direct measure of the depth conversion uncertainty at any horizon.

4. Depth convert.
The depth conversion itself is simply a matter of multiplying out the various functions and stacking up the layers to get the depth at each horizon. At this stage a depth converted surface is arrived at, which is optimal but may not tie the wells exactly.

5. Residual tie to wells.
Finally, the depth residuals can be gridded up in order to arrive at depth converted surfaces that tie wells – useful for many purposes, including drilling prognosis and reservoir

Figure 1: A plot (a) of well depth and seismic time shows one point (highlighted red) as an outlier. This could be an unusual velocity. Plotting well and seismic times (b) shows the outlier is still present and so must be a mis-pick.



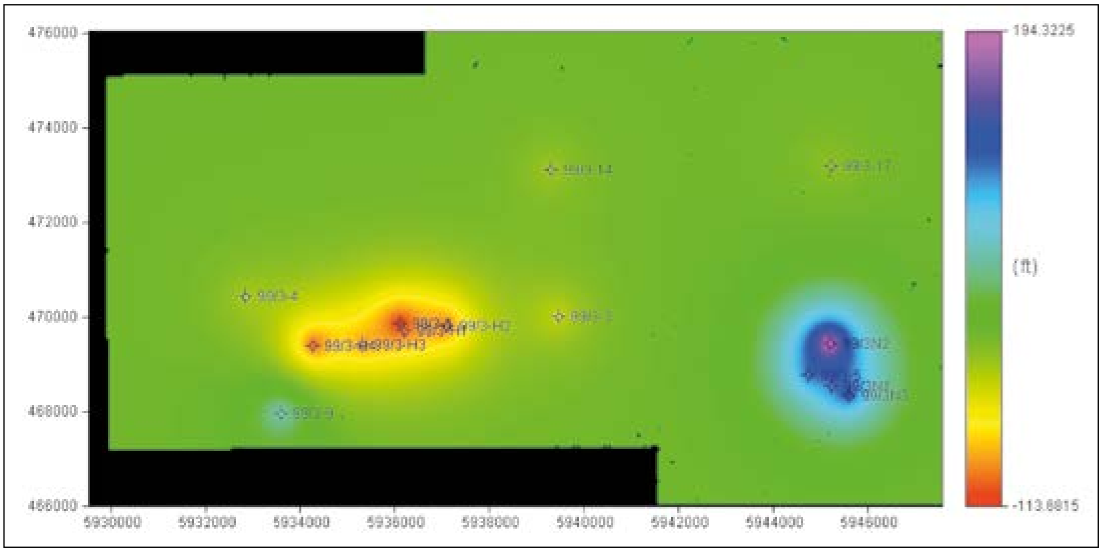


Figure 2: Typical residual map example. The choice of radius of influence in the gridding is ad hoc but significantly affects the area over which well misties are spread.

modelling. However, because the depth residuals are only known at wells and these are very sparse, the process of depth residual gridding is very subjective and results in spreading local well errors over an area in an arbitrary way (Figure 2).

Uncertainty

In a depth conversion context there are two main contributions to uncertainty. Firstly, uncertainty rises at a single point through there being multiple valid models and parameters by which we can depth convert, each model having a residual uncertainty; and secondly, there is the spatial uncertainty resulting from lateral prediction between data points and the spatial correlation/dependency model.

The impact of uncertainty due to choosing different valid models and parameters is assessed by doing just that – choosing different methods and building up a range of uncertainty from a variety of depth conversion models.

The second uncertainty is best handled by geostatistical analysis of the residuals and the residual mapping.

The uncertainty in depth for a single layer obtained from multiplying together time and velocity uncertainty in the layer is given by the following equation:

$$\left(\frac{\sigma_z}{z}\right)^2 = \left(\frac{\sigma_t}{t}\right)^2 + \left(\frac{\sigma_v}{v}\right)^2 + 2\frac{\sigma_t\sigma_v}{tv}\rho_{tv}$$

Where σ is the standard deviation and the letters *z*, *t* and *v* denote depth, time and velocity respectively. Note that the last term also includes *ρ*, the correlation between time and velocity. This clearly exists in models such as velocity functions and is expected to be a positive correlation.

The propagation of uncertainty through summing together a stack of depth layers in a multi-layer depth conversion is given by:

$$\sigma^2_{z1+z2} = \sigma^2_{z1} + \sigma^2_{z2} + 2\sigma^2_{z1}\sigma^2_{z2}\rho$$

Again, note that the last term includes *ρ*, the correlation between layer 1 and layer 2 thickness. In general, this correlation is negative because the boundary between two adjacent layers is shared in the form of a time surface. For this reason, an increase in time thickness in one layer must necessarily be a decrease in thickness of the other layer, hence they are anti-correlated. However, if residuals through a depth conversion are allowed to float (i.e. not be force-tied at each horizon) then these anti-correlations (as well as noise) will partially cancel. An alternative way of thinking about this is that simply summing the uncertainty for each layer together through the multi-layered depth conversion will hugely inflate the uncertainty at the final depth converted horizon. This is the strongest argument for not tying at intermediate horizons in a depth conversion to a deeper horizon.

Simple Guidelines Summary

1. Don't force horizon picks to tie wells during interpretation.
2. Always QC seismic times against well times by cross-plotting.
3. Seismic velocities may be useful but they are:
   a. Noisy.
   b. Subject to bias up to +/– 20%.
   c. Become less useful with depth and in high velocity areas.
   d. Variogram analysis and kriging are very good for analysis of stacking velocities.
4. Test multiple methods of depth conversion and consider different layer schemes and functions within layers.
5. Examine residuals and look for mean close to zero (no bias) and low SD.
6. V0 regression methods are usually just error residual corrections in disguise and should not be applied.
7. Velocity functions can become non-physical very quickly so QC the instantaneous velocities.
8. Look for unwarranted velocity inversions between layers.
9. Residuals should float between layers, not be tied. Only tie at the target horizon; intermediate horizons should be left untied.
10. Uncertainty propagation through depth conversion models is not trivial; floating residuals is a simple and robust way to deal with this.
    a. Uncertainties exhibit anti-correlation between layers.
    b. Correlation coefficients strongly influence uncertainty.
11. Depth prognosis uncertainty can be estimated from depth residuals and kriging.
12. GRV estimates and uncertainty can only be generated through geostatistical simulations. ■

How to Generate *Really* Good Structural Maps

The oil and gas industry has everything to gain from high-quality structural maps.

Dr FRANCIS RICHARDS
STAMP Structural Map QC

First things first: what is a structural map? In this article it relates to a deformed geological horizon, the mapping of which involves the interpretation of faults. Faulted horizons, such as the top of a reservoir interval, form the framework upon which exploration, appraisal and development initiatives are based. The quality of such maps impacts directly on our ability to make sound judgements on the size and geometry of a hydrocarbon trap and how any reserves may be distributed between compartments. Such decisions are vital to the success of E&P companies.

So how can you tell if your map is good, bad or indifferent? Basically, a map is only as good as the data used to construct it. The better the seismic used to define horizons and the faults that displace them, the better the map. Thus, a QC of the seismic data is effectively a QC of the final product derived from it. There is an undeniable logic to this statement and it is consistent with the almost universal practice of investing significant time and money in upgrading the quality of the seismic used to generate structural maps.

Accurate fault mapping is vital for understanding reservoirs.

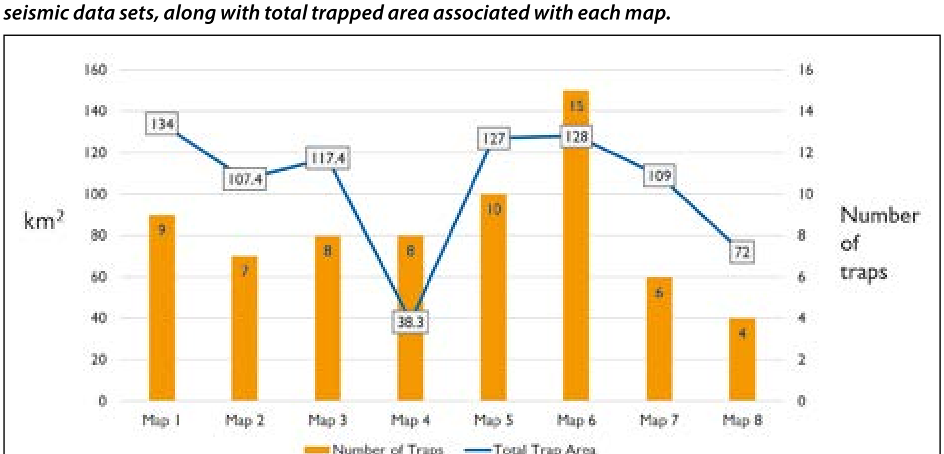
Interpretation = Variation!

However, I believe that analysis should not *finish* with the map but *start* with it. It is important to test the validity of a faulted horizon map, particularly one based on 2D data or 3D data with quality issues, where the results are contingent on 'interpretational leaps' taken in order to complete the map. These decisions are made by humans with different backgrounds, experiences, goals and personalities and lead to contrasting results. Time constraints and company process can also have a significant impact on the products of an interpretation.

Although research into the interpretation process is relatively limited, the results so far should concern businesses dependent on the outcomes. Bond et al. (2007) documented the variation associated with numerous attempts to interpret a single synthetic seismic line based on an inverted normal fault, demonstrating that, given interpretational freedom, individuals working with the same data see different things and are capable of producing an extremely varied set of results with a significant personal bias.

The production of a map obviously involves more than a single line; could this variation extend to the final 3D product – for example, a field-defining structural map? Again,

Figure 1: Graph showing the number of discrete traps identified by eight mapping teams using identical seismic data sets, along with total trapped area associated with each map.



there is relatively little research on this, but some insights were highlighted by Richards et al. (2016), who compared the results of multiple attempts to generate prospects by mapping out a reservoir using an identical 2D data set. The seismic quality was good and the faults affecting the reservoir comparatively simple; surely this would represent a good scenario for some consensus in the final product? The results showed quite the opposite, particularly when the trapped area derived from each map was compared. The number and respective size of the structural traps identified by each map, from a commercial perspective, was in some cases alarmingly variable (Figure 1).

On average, eight traps were identified by each team, with six of the eight maps pretty close to the mean trap population size. Two maps stand out as being anomalous: Map 6 with 15 traps and Map 8 with only four. The relationship between the number of traps and the total trapped area is not simple, since the map with the smallest trapped area (4) identified eight traps, while Map 6 with the highest trap count did not generate a significantly higher area.

The principal source of the variation could be traced back to how the faults were generated by linking individual fault cuts on each line to form a continuous fault trace. Areas where the density of fault cuts was particularly high effectively offered choice, so interpreters were able to define different fault trends and linkages.

Observing Displacement

Structural QC involves assessing the validity of a map by bringing to bear mechanical, geometrical and kinematic constraints. There are no hard and fast rules, and whilst specialist software can be extremely useful, it does not guarantee a rigorous analysis. Significant insights can be gained by making basic structural observations and simple measurements, and fault population statistics can also be used to good effect (Freeman et al., 2010).

Three short case studies are described below, with maps taken from relinquishment documents held by the UK Oil and Gas Regulator (OGA) and submitted by operators exiting blocks in the UK North Sea. Basic displacement analysis is applied to a major fault on each map and all three cases highlight a potential structural problem.

Displacement measures the finite movement along a fault – see Figure 2, which also indicates how this measurement can be estimated from foot-wall and hanging-wall contour intersections. Measurements made at regular intervals along

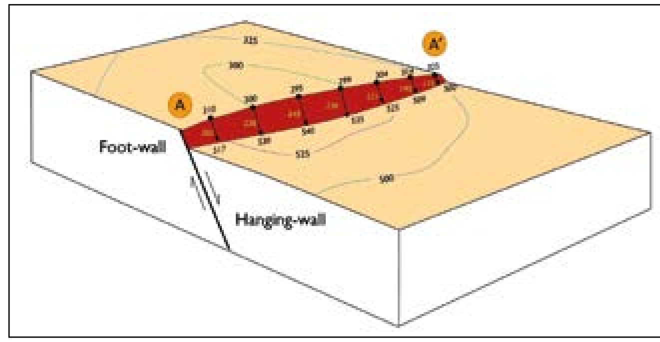


Figure 2: Block diagram showing displacement along a simple normal fault. Foot-wall and hanging-wall values are posted at regular intervals and displacement at each location is shown.

the fault are easy to display graphically and provide a relatively simple summary of how the fault behaves along its length.

Case Study 1: This top reservoir map (Figure 3) displays three sub-parallel normal faults dipping north-east. A graph of displacement generated for the central fault A-A' shows displacement increasing quickly from A to 400m but then dropping to zero before returning rapidly to a maximum of 500m. The point of zero displacement is clear on the map, located where the 5,000m contour passes straight through the fault without being deflected (by definition the horizon is not faulted at this point). Does the zero-displacement zone represent a place where the one mapped fault should be split up into two? This, however, is structurally problematic as it occurs where displacement from both sides is increasing and apparently approaching its maximum. For this reason, it is more likely the analysis has identified an interpretation error. The recommendation would be to check the seismic data and review the interpretation around this location.

Case Study 2: Here the structure is slightly more complicated, with two sets of normal faults intersecting at approximately 90° (Figure 4). Again, a displacement graph has been generated for one of the principal faults (A to A'). From A' the displacement increases slightly but then drops around point 7, probably associated with the intersection of two orthogonal faults observed on the map. Tracing the fault further south-west, the displacement drops to zero and then becomes negative, i.e. an apparent thrust fault. Could this be a result of structural inversion? An alternative is that the polarity of the fault has flipped and that separate faults with

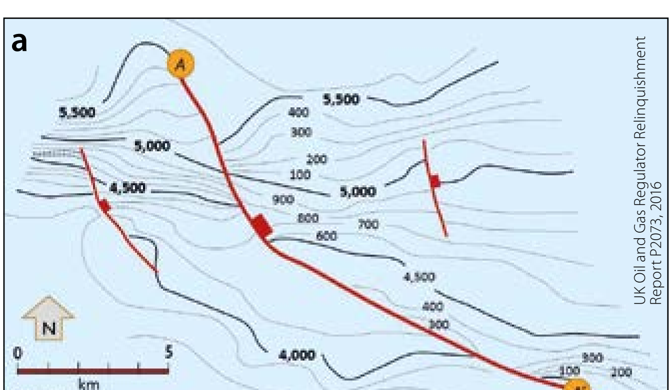
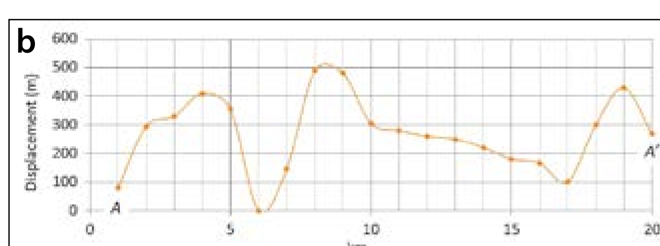


Figure 3: (a) Top reservoir map from a UK North Sea relinquished block report. (b) displacement calculated along fault A-A'. (This map was generated before the acquisition of new 3D data and may not reflect current understanding. No updated map of the same scale was shown in the report.)



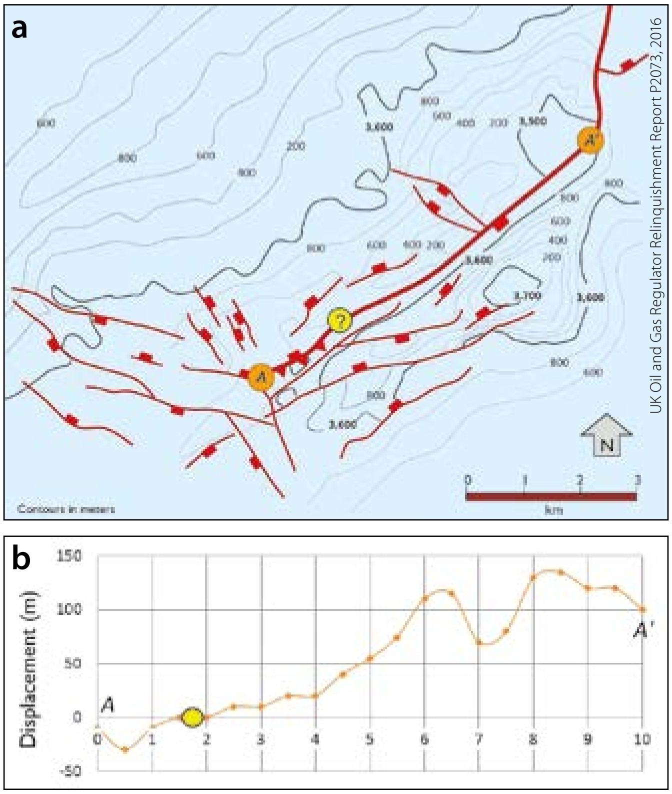


Figure 4: (a) Top reservoir map derived from a UK North Sea relinquished block report. (b) displacement calculated along fault A-A'.

opposing dips have been incorrectly joined together. From the map, it is difficult to argue which of the two alternatives is correct. Regional knowledge could be employed, but at this point the geoscientist would ideally go back to the seismic interpretation to find a solution. Observations like this, when iteratively integrated into the interpretation process, can be an invaluable aid to producing better quality structural maps that best honour the data but are also structurally realistic.

Case Study 3: In the final example (Figure 5) a different analytical style has been adopted. The width of the displayed faults can be seen to vary along strike, reflecting the estimated displacement along particular sections of the faults; the thicker the fault, the greater the calculated displacement. This approach was adopted as the quality of the map meant it was difficult to accurately read off contour depths over much of the map. The displacements were roughly estimated using colour variation on the original map and are only approximate. Although some caution is required using a map generated in this manner, it actually shows up some potential structural problems. Faults A, B and C show maximum displacements at their north-east tips. Displacement patterns like this are very unlikely as the strain gradient at the tip zones would be extremely high and would only form where faults are interacting with other faults or some other geological feature. It is probable that the interpreter has truncated these faults and that they extend much further north-east. It is also possible that this has been caused by limitations in data coverage, in which case, even without seismic data, it would make structural sense to extend these faults rather than cut them short as currently mapped.

In a Less Than Perfect World…

When faced with less than perfect data or data with significant gaps, interpretational decisions need to be made in order to complete the mapping of faulted surfaces. Under such conditions the results from one interpreter to another can vary significantly and the economic implications may be considerable. A timely structural QC of the interpretation has the potential to identify possible errors and help provide a valid structural solution. The short case studies here show how simple displacement analysis can be used to great effect to scrutinise faults.

There are many other types of analysis that can be equally effective, such as assessing the geometrical implications of fault shapes, undertaking strain analysis, geomechanical analysis or looking at fault population statistics. The trick is choosing the most effective and appropriate analysis for a given interpretation, taking into account the structural setting, size of area under investigation, degree of structural complexity and, importantly, the amount of time available. It is also essential that the QC is undertaken while there is still time to integrate the results back into the interpretation.

After analysing the maps discussed above, one is left wondering how much impact a complete analysis would have had on the assessment of the relinquished acreage. After all, structural maps not only define the size, shape and internal compartments of structural traps, they often play a large part in how we perceive the distribution of sediments and how fluids migrate through the subsurface. The analyses indicate that despite the relinquishments by previous operators, there is the potential to look again at many areas of the North Sea, reinterpret prospectivity in the light of new data and more rigorous structural techniques, and create new E&P opportunities.

Acknowledgment: The author would like to thank Nick Richardson (OGA) for taking time to review this article and for his advice and suggestions.

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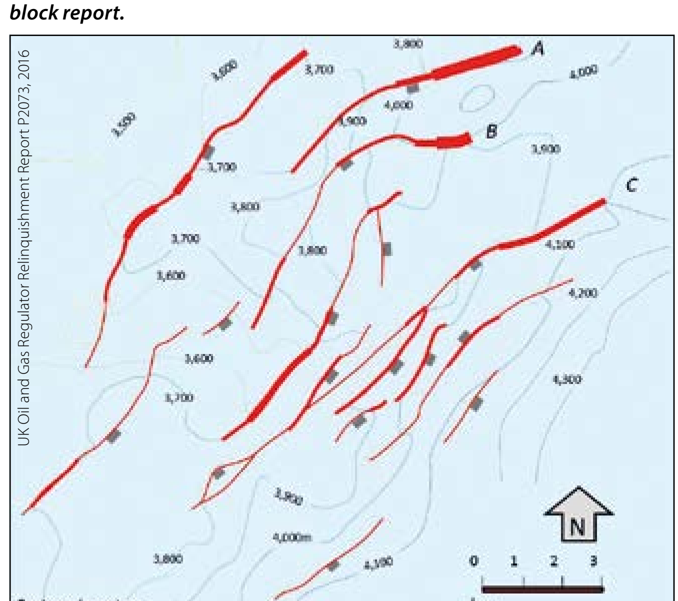
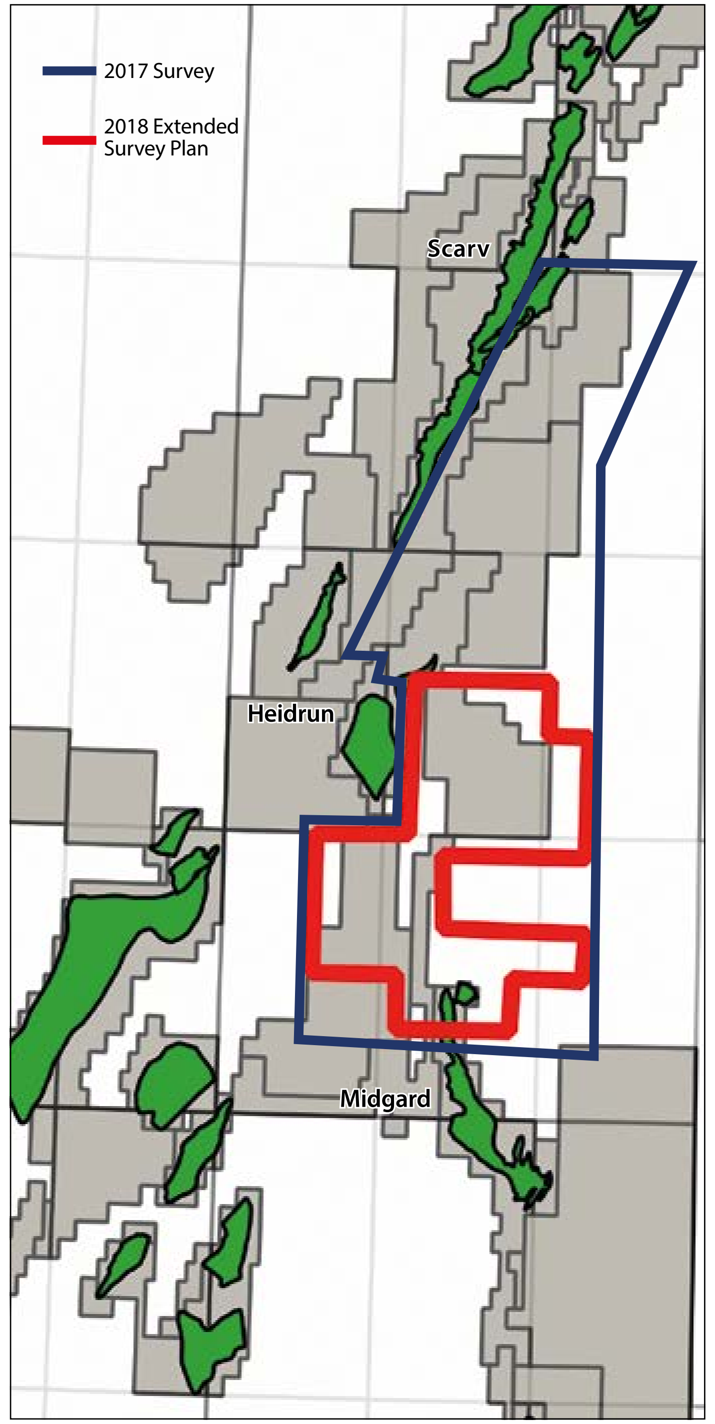
Figure 5: Top reservoir map derived from a UK North Sea relinquished block report.



A New Approach to Exploration

PetroMarker's unique 3D vertical EM technology acquires robust data for new opportunities in already-explored areas where the 3D CSEM data are inverted by the CGG EM team in Milan.



The exploration of the Haltenbanken area in the Norwegian Sea has over the years delivered several well-known fields such as Draugen in the south, up to Norne in the north, via Åsgard, Midgard and Heidrun, yet a significant portion of this productive area is still largely uninvestigated.

In 2017, PetroMarker carried out a 500 km² vertical 3D EM survey in the Norwegian Sea, from the Midgard field northwards to east of the Heidrun field.

2017 Survey Configuration

500 km² electromagnetic data survey area.

Water depths between 300m and 400m.

1.7 km between receiver positions.

1.7 km between transmitter positions.

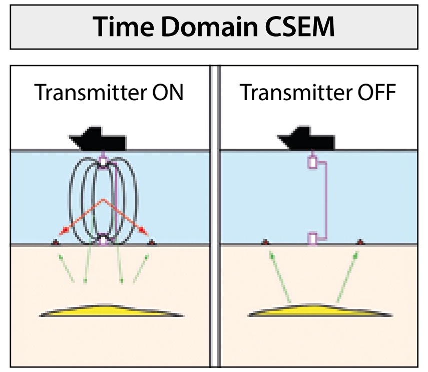
Denser grid with 1.1 km between receiver and transmitter positions around Novus.

PetroMarker's unique 3D vertical EM technology acquires robust data for new opportunities in already-explored areas.

PetroMarker was established in 2005, based on an idea to develop a new marine Controlled Source Electro Magnetic (CSEM) exploration technology with vertically oriented transmitters and receivers in a transmitter-over-receiver-grid configuration. These advances result both in a deeper recording ability as well as abundant near-offset data, which also give rise to an increased resolution of the subsurface resistivities when compared to earlier technologies.

To begin with the company provided 2D surveys, but in 2017 a dramatic improvement of the technology was launched, together with a substantial increase in receivers. With the resultant 3D ability, an alliance was formed with CGG Milan for the 3D inversion processing.

The main office is in Stavanger and the company has now both Norwegian and international shareholders. The aim is to become a supplier of marine CSEM 3D exploration data on a world basis.



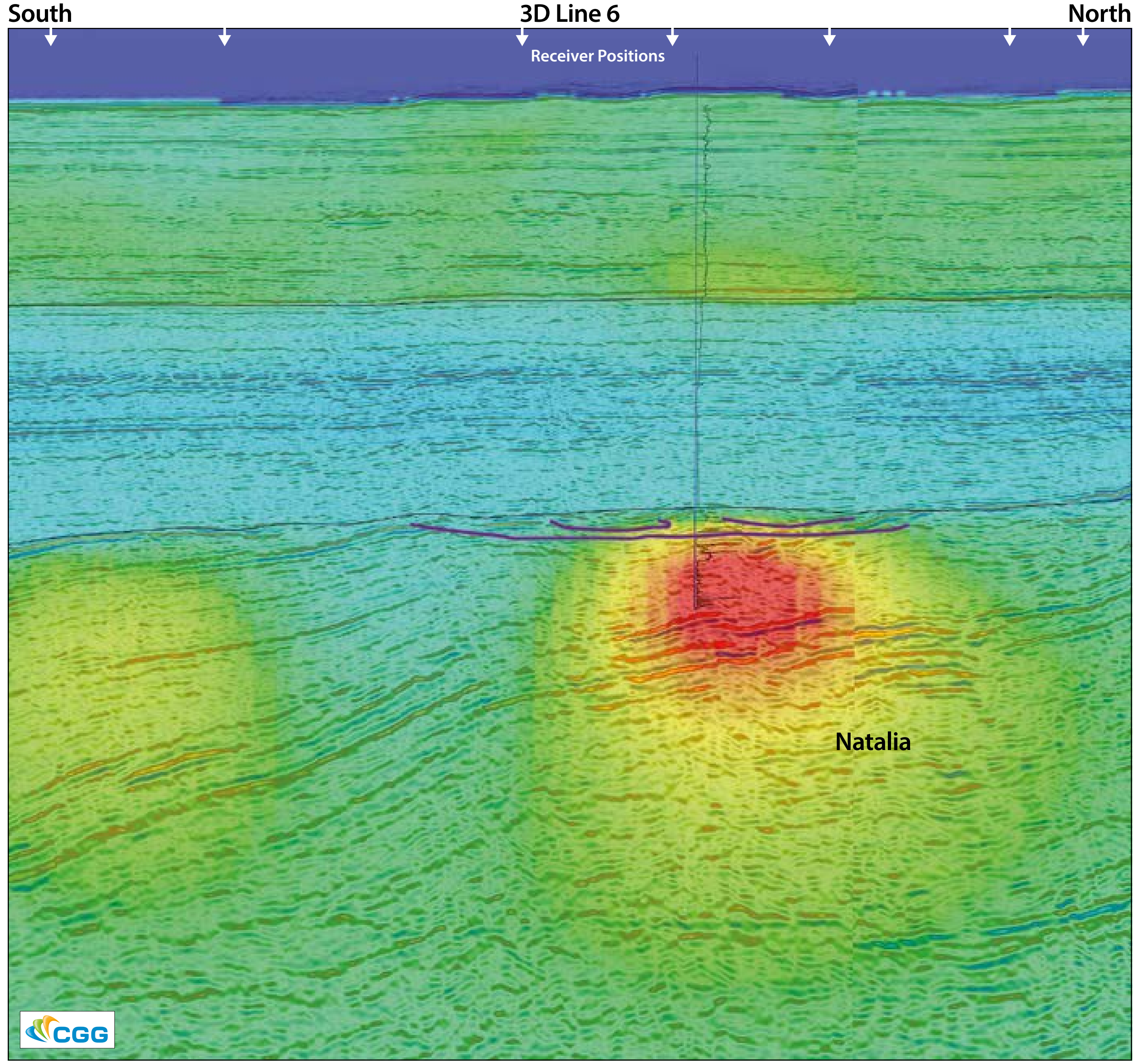
Natalia Discovery Shown by EM Data

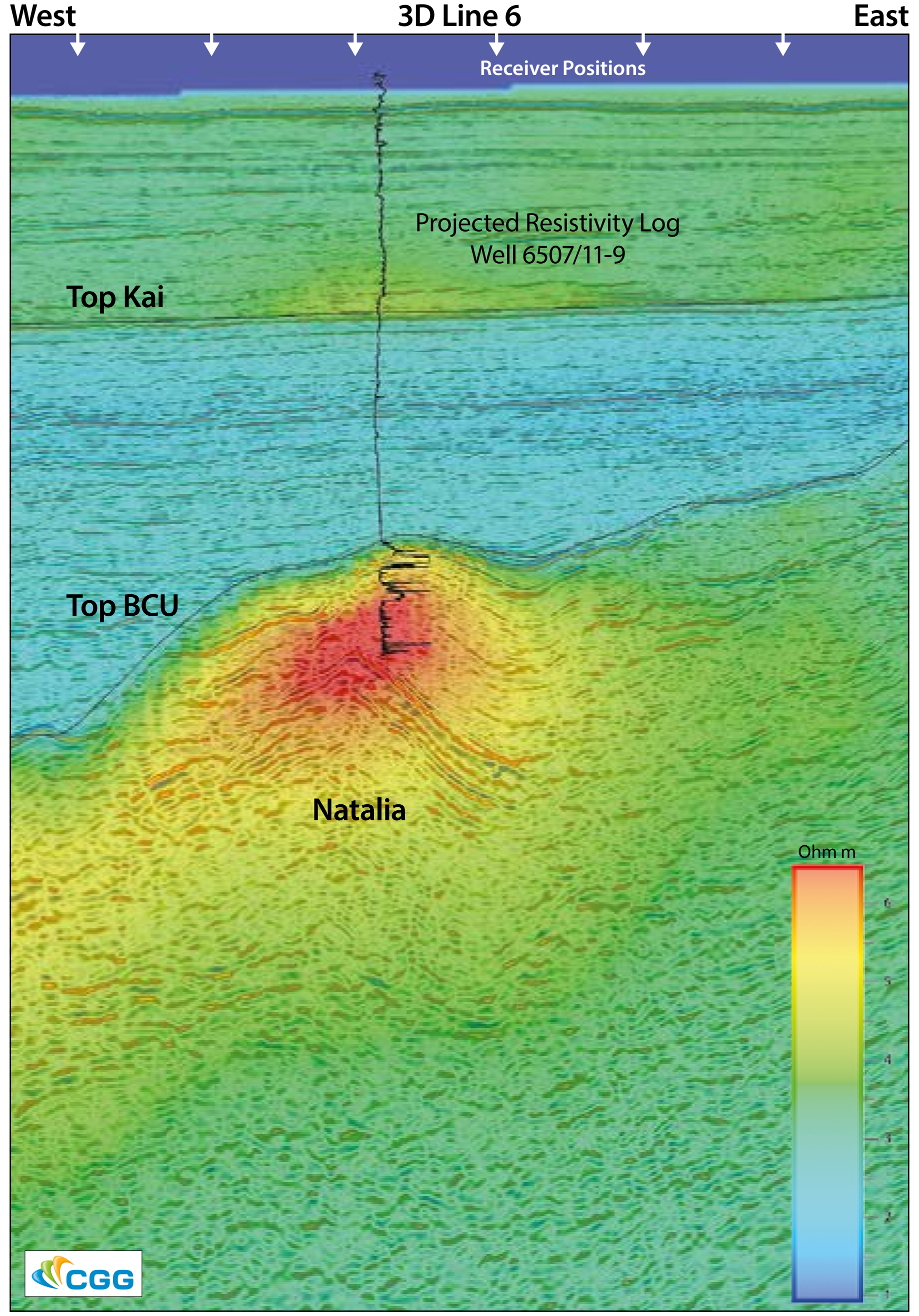
The discovery well proved about 40m gas column in the Jurassic Garn Formation, with a gas-down-to in the Not Formation at 2,637.8m.

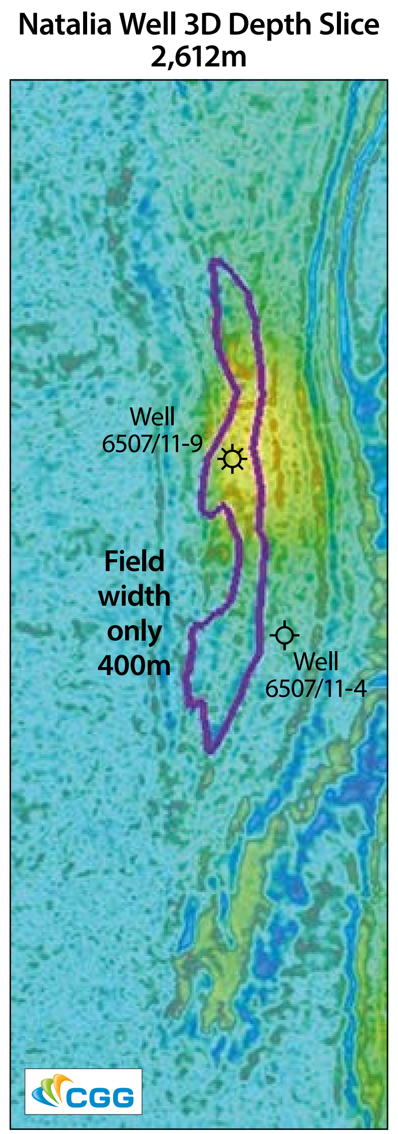
The hydrocarbon contact for the Natalia structure was expected to be between 2,637.8m and 2,645m if it had the same pressure regime and hydrocarbon system up-dip.

The updated seismic interpretation indicates that the structure spills to the north at 2,646m, which is in agreement with the expected contact.

The apex of the structure is mapped at 2,575m, which gives a corresponding column height for the entire structure of 60m.







Discovery well 6507/11-9 was drilled in 2008 on the Natalia prospect located in the Grinda Graben, about 5 km north of the Midgard Field in the Norwegian Sea. The structure is a small rotated fault block west-dipping north-west to south-east trending normal fault. The discovery prospect outline is only 400m wide where the EM anomaly was retrieved.

Verifying the Hypothesis

A new approach to exploration in the Haltenbanken area in the Norwegian Sea of the NCS.

ASLAK MYKLEBOSTAD, PetroMarker

In 2017, PetroMarker carried out a 500 km^2 vertical 3D EM survey in the underexplored parts of the Haltenbanken area of the Norwegian Sea, covering the area from Midgard and to east of Heidrun. The Midgard field and the Natalia discovery were used as data calibration points. The grid of transmitter and receiver positions varied according to the purpose of the survey; for example, a much tighter grid was used over the Novus discovery in order to improve resolution. PetroMarker's technology allows for such tailormade grids without generating operational issues.

PetroMarker's EM technology consists of a vertical source transmitting 5,000A, adjusted to the water depth, and an array or grid of vertical receivers set on the seabed, using vertical antennas both for the transmitter and the receivers. For the transmitter, two electrodes are used; the lower one is placed on the seabed, while the upper electrode hangs vertically above it suspended from the survey vessel. It is important that this alignment is strictly maintained to obtain the best possible data quality, so during pulsing the vessel is stationary and dynamic positioning is used to ensure this.

The receivers are equipped with an active verticality correction of the sensor dipoles (each receiver is equipped with four sensor dipoles). They are launched from the sea surface and retrieved by acoustic release. Horizontal sensors complement the recording suite.

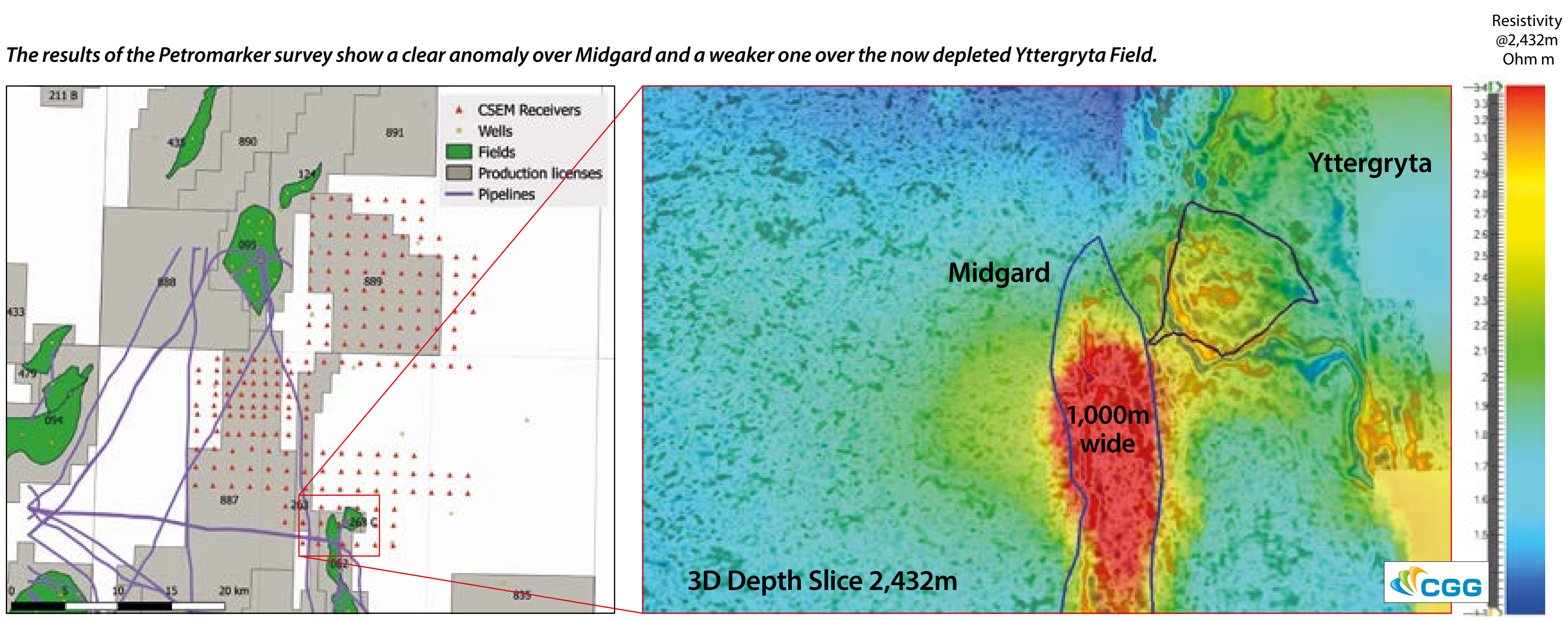
Surveying Midgard and Yttergryta

One remarkable feature of the technology is its application in the so-called 'near zone'. The volume of subsurface layers impacted by the pulsing signal is narrowly concentrated between the transmitter position and its nearby receivers. Most of the energy is therefore used to penetrate the layers, and the response is not disturbed by surrounding artefacts.

As indicated, the other important feature is the stationary pulsing. This means that the energy can be further concentrated by increasing the pulsing time on each location as required to optimise signal to noise ratio. The stationary approach also gives more freedom when operating close to existing installations.

To test these techniques, data were acquired over the northern part of the Midgard field and the now shut-down Yttergryta field. The calibration at Midgard was performed with 21 receivers on a 1.7 km grid, and 25 pulsing locations.

The results of the Petromarker survey show a clear anomaly over Midgard and a weaker one over the now depleted Yttergryta Field.



The presence of pipelines and other structures on the seabed was accounted for by omitting and/or adjusting certain points in the grid, but without affecting the operability of the survey, the quality and representability of the data, or the security of the field.

The combination of elongated reservoirs and deep water represents a good CSEM challenge for a conclusive verification of the new generation of PetroMarker's technology and equipment.

The width of the Midgard field in the area where the survey was undertaken is only about 1 km, but the EM anomaly registered both matches and follows the reservoir sandstones below the Base Cretaceous Unconformity (BCU). The higher resistivity above the Kai Formation was also clearly identified and agreed with the results of well 6507/11-1.

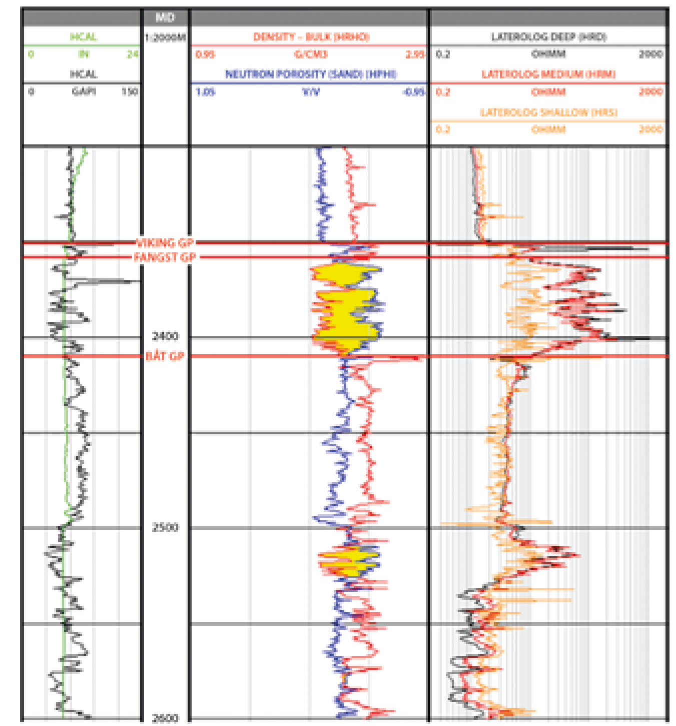
The multi-client 3D CSEM data were inverted by the CGG EM team in Milan. The results show a clear anomaly over Midgard and a weaker one over Yttergryta, as well as several other interesting anomalies in the dataset. The inversions, carried out by CGG's exclusive 3D time domain inversion codes, match the inversions carried out by PetroMarker's own software suite, and therefore confirm the robustness of the data. ■

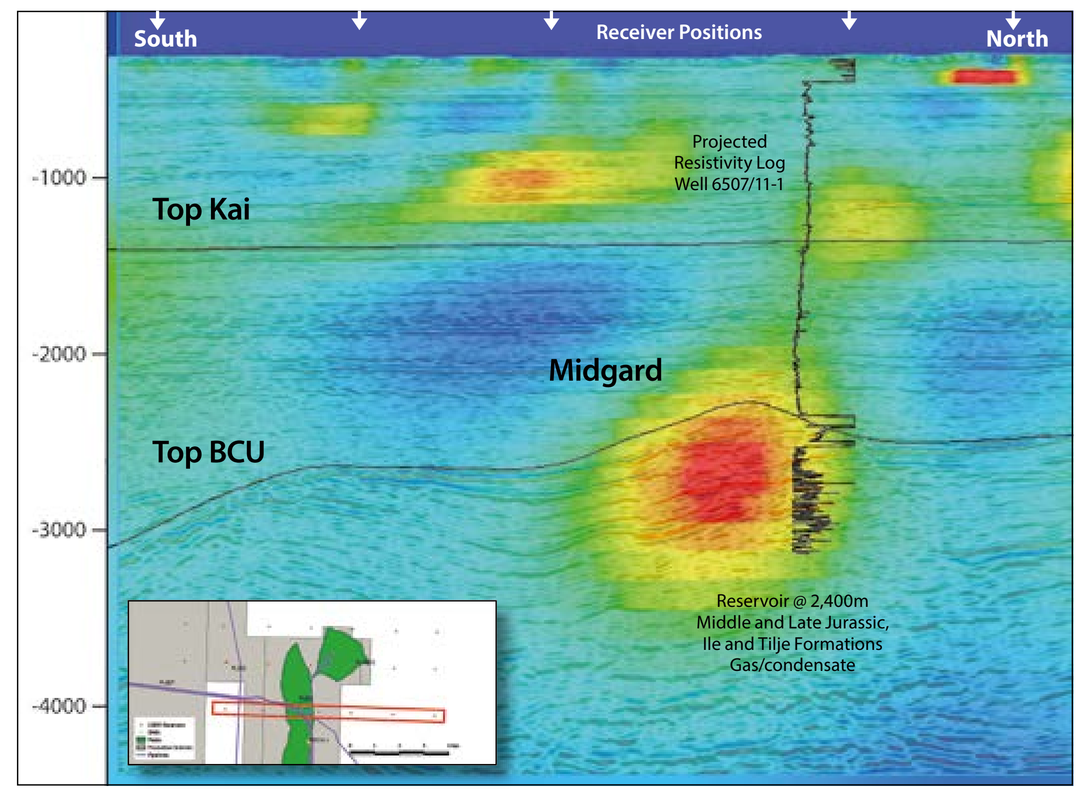
PetroMarker

Technical Advantages
Vertical EM components
No air wave or direct interference
Deeper penetration
Near zone focus
Finer details

Standard deliverables
Acquisition and inversion reports
2D unconstrained depth sections
3D unconstrained depth volume

Well 6507/11-1





The Earth Geological Globe

A 3D object from 2D data

CLARA CARDENAS, Commission for the Geological Map of the World

The Earth Geological Globe is based on the revised 3rd edition of the *Geological Map of the World*. As reported in *GEO ExPro*, Vol. 11, No. 5, the most recent printed version of this was published in 2014 by the Commission for the Geological Map of the World (CGMW). The Globe integrates data from this with state of the art geological knowledge of our planet at the end of the second decade of the new millennium and is aimed at educational and wider community use, providing a simplified geology of the continents and oceans in their entirety. It includes shaded physiography to provide a complete view of the geological setting of the earth in its most natural projection.

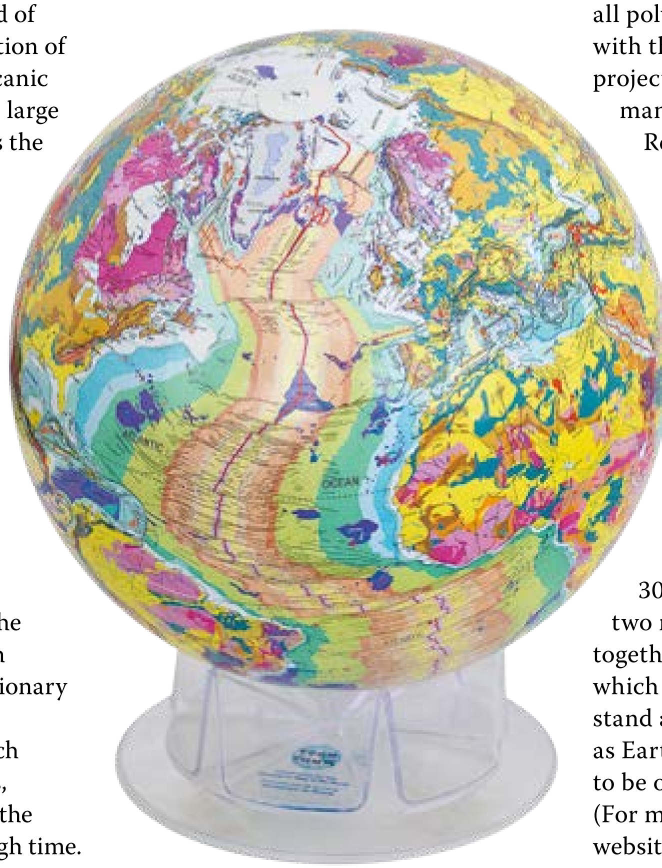
In addition to chronostratigraphic and lithologic information, an extensive set of geodynamic data on the continents and in the oceans is featured, including:

- The location of 'Large Igneous Provinces' (continental traps, 'oceanic plateaus') formed since the end of the Palaeozoic, with an indication of the mean age of the major volcanic episodes, which correspond to large magmatic pulses, and includes the extent of the Central Atlantic Magmatic Province;
- The Meso-Cenozoic ophiolites that underline suture zones;
- The limit of the continental shelf (< 200m water depth) and the boundary between continental and oceanic crust;
- The axes of active mid-oceanic ridges marking the boundary between two divergent lithospheric plates;
- Subduction zones formed by the convergence of two plates with associated sedimentary accretionary prisms;
- Various submarine features such as seamounts, oceanic plateaus, and hotspot tracks illustrating the progression of the plates through time.

The Globe is a major teaching aid that provides a clear visualisation of the main plates and sub-plates underpinning global tectonics and shows the real surfaces of the continents and oceans. For example, the surface area of Greenland, which appears as large as Australia in the Mercator projection, is shown in the globe at its correct relative size – four times smaller. The legend and explanatory notes in English and French are accessible via a QR code printed on the globe.

Merging Datasets

The starting point of the project was the original *Geological Map of the World* at 1:25 million scale, compiled by Philippe Bouysse, digitised in 2009 and successively upgraded to produce the graphic files of the 2010 and 2014 printed editions. In these versions the geodatabase consisted of three digital sets, one in the Mercator projection covering the areas between parallels 72° N and 72° S, and two others for the North and South Poles in the stereographic projection.



The GIS procedure to transform the spatial data of the 2D map into a 3D object required the merging of the three datasets and the restructuring of the geodatabase following a topological and set theory logic aimed at generating a single database using the same GCS_WGS_1984 Coordinate System. A style library was created to group all the symbols representing the graphic elements of the map (points, lines, polygons) and a STRM layer was also added to enable relief display.

This highly detailed operation was followed by the retro-projection of the geodatabase into two hemispheres. This part of the procedure required thorough geomatics and graphic work necessary to ensure precision and legibility to all vectorised symbols and texts. It also needed an optimal fit of all polygons and geodynamic features with the shaded relief at the particular projection required by the American manufacturer of the globe, the Replogle Globes Partners company.

Beautiful Product

The final stage involved the mechanical process of manufacturing the globe. The maps of the northern and southern hemispheres were printed onto a vinyl support by a specialised printing firm and then vacuum-formed onto plastic semi-spherical shells.

The resulting product is a 30 cm plastic globe delivered in two ready-to-assemble hemispheres together with a clear acrylic base on which the Earth Geological Globe can stand and be easily positioned since, as Earth itself, the globe is designed to be observed from all points of view. (For more information see the CGMW website.) ■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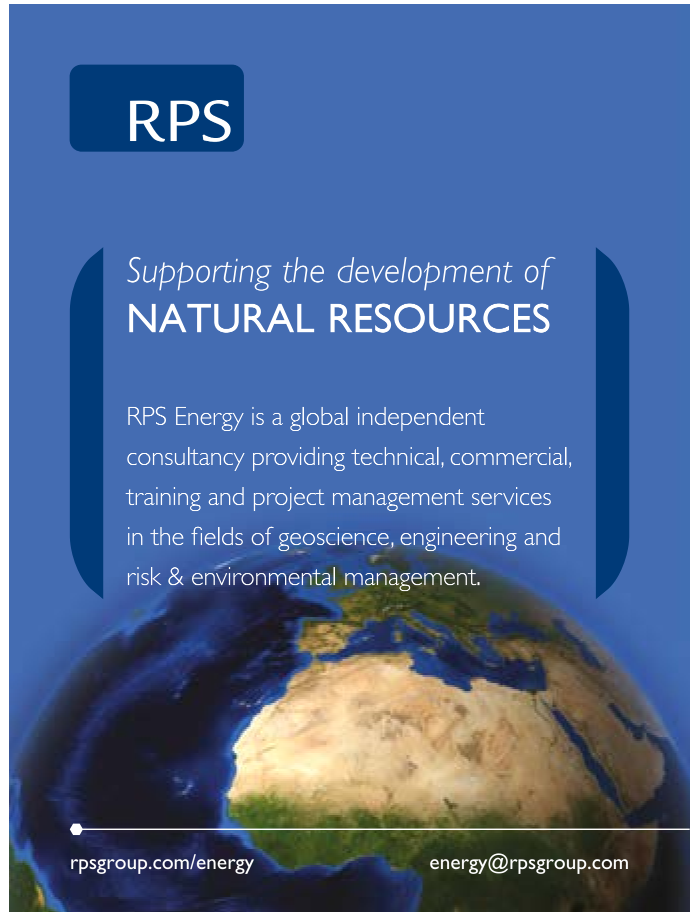
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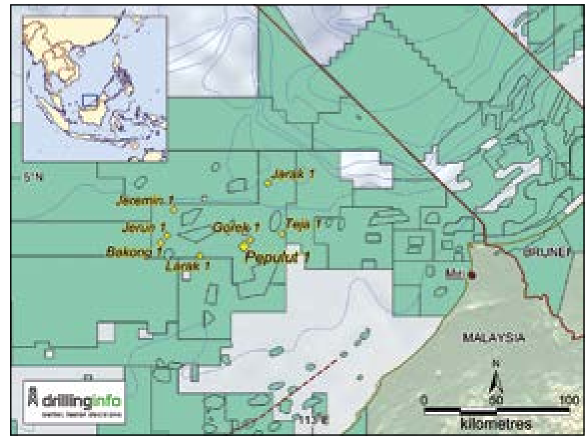
Malaysia: Successful Sarawak Block

In April 2018 **Sapura Energy** confirmed that the **Pepulut 1** vertical wildcat, the second of a two-well drilling programme located within its 4,354.6 km^2 **Greater Sarawak Basin SK-408** block was plugged and abandoned as a gas discovery after having been drilled in 84m of water to a TD of 2,640m within its objective Cycle V carbonate section. The unofficial potential resource estimate for the discovery had been placed at 350–400 Bcfg. The well was spudded on 17 December 2017.

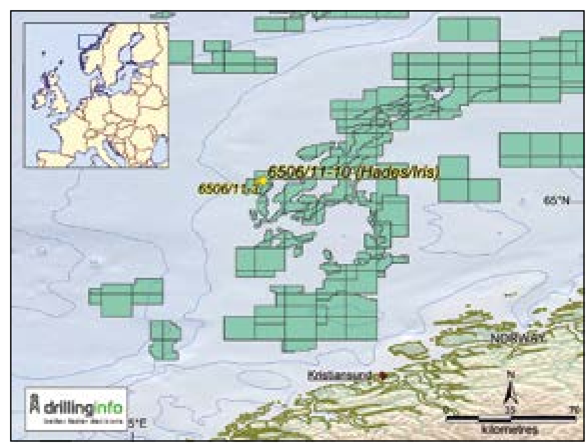
The first well of the drilling programme, **Jarak 1**, is understood to have been plugged and abandoned as a non-commercial gas well in late January 2018, having been drilled to a TD of 1,929m, also within its objective Cycle V carbonate section. The two-well programme completes Sapura's ten-well commitment within the block, eight of which are gas discoveries, namely **Teja 1**, **Gorek 1**, **Larak 1**, **Bakong 1**, **Jerun 1** and **Jeremin 1**. These wells are close to existing infrastructure supplying gas to one of the world's largest liquefied natural gas facilities at Bintulu, Sarawak. Equity in SK-408 is split between operator Sapura with a 40% interest in the block, with partners Shell and Petronas Carigali each holding 30%. ■



Norway: HPHT Discovery

The **Hades/Iris** new field wildcat **6506/11-10** was plugged and abandoned in April 2018 as a gas/condensate discovery. The well encountered a 35m gas/condensate column, with 15m of moderate to good sandstone reservoir in the primary target (Hades) Early Cretaceous Lange Formation, at 3,932m with estimated recoverable resources of 20–115 MMboe. The secondary target, Iris, in the middle Jurassic Garn Formation, was intercepted at 4,223m and had a total gas condensate column of 95m, with 85m of moderate to very good sandstone reservoir and a gas/water contact at 4,295m SSTVD. Estimated recoverable resources are 20–130 MMboe. The well TD'd at 4,536m MD.

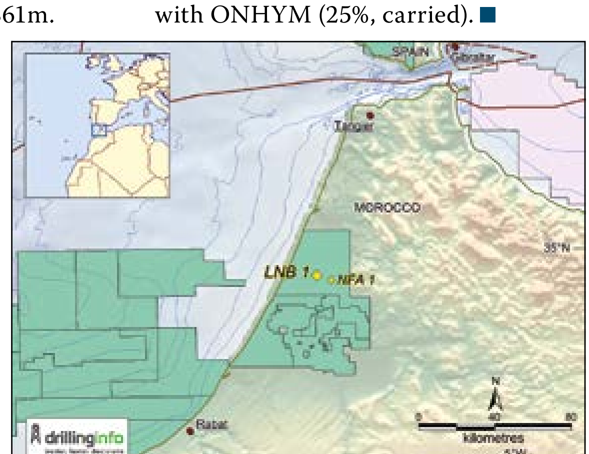
This high pressure/high temperature **(HPHT)** well, spudded in November 2017 in PL644 B in Norwegian Sea block 6506/11, is 8 km north of the Morvin oil and gas field, which has Middle Jurassic Ile and Garn Formation reservoirs. Current equity partners are operato **OMV (Norge)**, holding 30%, with Statoil Petroleum (30%), Bayerngas and Centrica JV, Spirit Energy Ltd (20%) and Faroe Petroleum (20%). ■



Morocco: New Petroleum System

SDX Energy has made a gas discovery with its **LNB 1** new field wildcat, located on the onshore **Lalla Mimouna** exploration permit in the **Gharb Basin**, northern **Morocco**. The well encountered 300m of over-pressured gas in the primary objective, the Tortonian Lafkerena section. The company has indicated that it may have a thermogenic source which could indicate a new petroleum system. The overlying secondary target in the Tortonian Upper Dlalha interval was also successful, with 2.6m net pay and average porosity of 33%. The Dlalha section will be completed, whilst the Lafkerena horizon will be tested. Company estimates put an unrisked, mid-case resource figure on the discovery of 10.2 Bcf of gas, with 55 Mbc.

LNB 1 was spudded in late March 2018 and reached a TD of 1,861m. The well is the eighth in the company's nine-well campaign in the Gharb Basin. The Lalla Mimouna permit comprises two contiguous blocks (Lalla Mimouna Nord and Lalla Mimouna Sud), originally awarded to Circle Oil in February 2010, who drilled three wells on the licence in 2015 (ANS 2, LAM 1 and NFA 1). SDX entered the permit in January 2017, through the acquisition of Circle Oil's Moroccan assets and operates the licence with 75% equity, in partnership with ONHYM (25%, carried). ■



Are We Doing Enough for Young Professionals?

To address the upcoming 'Great Crew Change' industry organisations are putting increasing effort into ensuring new entrants into the O&G business get access to information and training through initiatives like the AAPG's Next Generation Dealmakers Workshop, held in London during APPEX in March 2018. Ruairi McDonald, an AAPG Young Professional, helped organise the event.

Why did you join the AAPG Young Professionals?

The AAPG Young Professionals group provides graduates and early career (5–10 years) professionals with networking opportunities and technical seminars and workshops, in addition to AAPG's online publications, ICE and ACE conference discounts and a career job board. I joined to expand my network with young professionals across the upstream business chain, as well as to attend young professional events at conferences and professional learning opportunities.

Where did the idea of the Next Generation Dealmakers Workshop come from?

The idea was born out of a need for more young professional events within the European region, and specifically within upstream M&A, due to the changing face of the upstream industry in Europe through mergers, divestments and acquisitions over the last few years. APPEX serves as a headline event in the AAPG calendar, and appropriately was well aligned to run a M&A side workshop, targeted at young professionals who may want to understand the nuts and bolts of deal making in today's industry. The main objectives were to provide an affordable technical workshop and an educational overview of a typical M&A deal.

What did the Workshop cover?

The NGDM Workshop provided attendees with a full spectrum understanding of a M&A deal. It was kicked off by BP's William Zimmern (Head of Global Macronomics), who discussed the world's future energy outlook, highlighting the role of fossil fuels in the ongoing energy transition. A panel session with representatives from EY, WoodMac, Gneiss Energy and Saleve Energy Partners followed, rounding up recent and historic deals of significance. Subject-specific presentations from a range of oil companies, consultancies and experts discussed strategic fit and portfolio opportunity, subsurface geoscience, subsurface engineering, forward economic modelling and tax considerations and implications. Further panel discussions covered deal financing, with representatives from Gneiss Energy, Flowstream Commodities, Exotix, Rockrose Energy and Slaughter and May, and the important subject of 'Closing a deal', with contributions from Slaughter and May, Goldman Sachs and Faroe Petroleum.

What did you get out of the Workshop?

Being a subsurface professional, my main takeaways from the workshop and discussions were how these subjects fit into the overall integrated deal making process and, within each of these disciplines, what were the main levers for progressing an M&A deal – and what were the obvious 'show stoppers' to halt or pause such a deal.

The workshop also provided an excellent opportunity to network across disciplines, and with the main APPEX attendees.

Is the upstream industry doing enough to ensure the upcoming generation of geoscientists are ready to take over?

The upstream industry does an excellent job at providing professional graduate programmes and student internships, but I feel more support is needed for early career professionals (5–10 years' experience) from both industry and professional organisations.

The AAPG, one of the world's largest professional geological societies, lacks an official mentoring programme for young professionals, although it has been discussed for several years. Peer group professional organisations (PESGB, SPE) have seen widespread roll-out of such programmes, bridging the gap between early career and senior level professionals. Such a programme would act as another great advantage to joining AAPG as a young professional.

Since the beginning of the downturn, many early career professionals have been made redundant and find re-entering the industry very difficult. In most cases, they are up against professionals with 10–20 years' experience, if even considered, and graduate programmes are non-starters, unless changing career.

I think that the industry is missing out on an opportunity to capture experienced technical geoscience professionals, whilst building and preserving technical capability for the future. With thousands of dollars already invested into their early careers in the form of professional working experience, overseas assignments, technical courses, field trips, graduate rotations etc, one would think that such a talent pool would be sought after! It feels like a win-win for both out-of-work young professionals and upstream companies, but will require companies to re-think both their current hiring criteria and mindset approach to investing in young professionals. ■

Ruairi McDonald obtained a BSc in Earth Sciences from Glasgow University and an Msc in Petroleum Geoscience from Imperial College, London. He has worked as a geoscientist in the industry since 2010.

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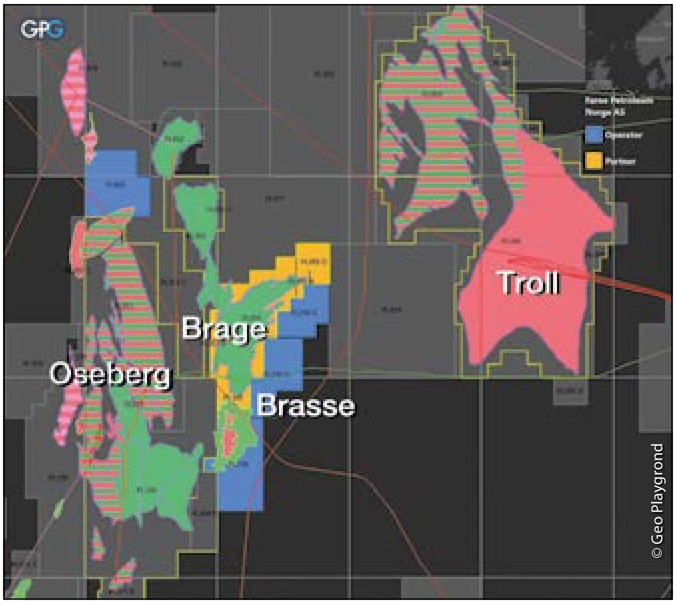


Faroe Petroleum's Brasse discovery was made very close to several giant fields such as Oseberg and Troll and is next to the Brage field. Faroe Petroleum's operated and partnered blocks are shown in blue and orange respectively.

Point Resources, a merger of three Norwegian companies, has acquired ExxonMobil's Norwegian-operated business, including the Balder, Ringhorne, Ringhorne East, Jotun and Forseti fields. The company's business model is simply to seek value creation in mature areas of the Norwegian Continental Shelf (NCS) with a focus on four core areas. There is no mention of frontier exploration. In just two years production has reached 40,000 boepd, and by 2022 total production is expected to increase to more than 90,000 boepd.

Another company that has had success with exploration in mature areas is Faroe Petroleum. Their 2016 Brasse discovery on the NCS was a company maker, and the location is stunning as it has prolific oil fields on all sides. Nevertheless, it took many years to have the prospect drilled, despite the fact that quite a few explorationists knew about it.

A key driver for near-field exploration may be the need to fill oil processing facilities due to declining production from fields that have passed plateau production. As an example, Aker BP is exploring near-field prospects and leads to mitigate production decline from the Ivar Aasen field on the NCS, which started producing just a year and a half ago. Small discoveries can result in high value contributions for mid-size companies.

Statoil has recently changed its strategy into a 'One North Sea' approach, in which the region is treated as one subsurface domain, the strength being that it allows plays to be chased across the border. The company believes that significant value remains to be unlocked on both the NCS and UKCS, making both provinces highly attractive to exploration, largely because of the 2010 discovery of the Johan Sverdrup field, which clearly demonstrated that giant discoveries can still be made in mature basins.

Moving away from North-West Europe, statistics based on global analyses reveal that discovered resources for the last five years were less than the amount of oil produced. In a long-term perspective this is of course very bad news as oil company values are reduced. However, and this is really important, the statistics also show that mature fields, both on- and offshore, grow significantly in terms of reserves as time goes by.

The lesson to learn is the same as we have experienced in the North Sea: exploration in mature areas, including near-field exploration, creates value for oil companies as well as the host state.

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.

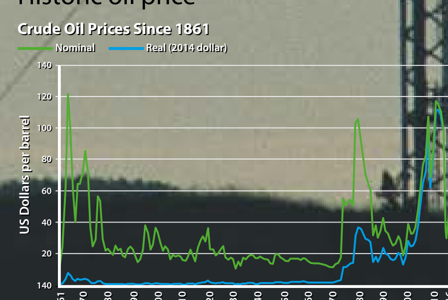
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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



multi-client seismic

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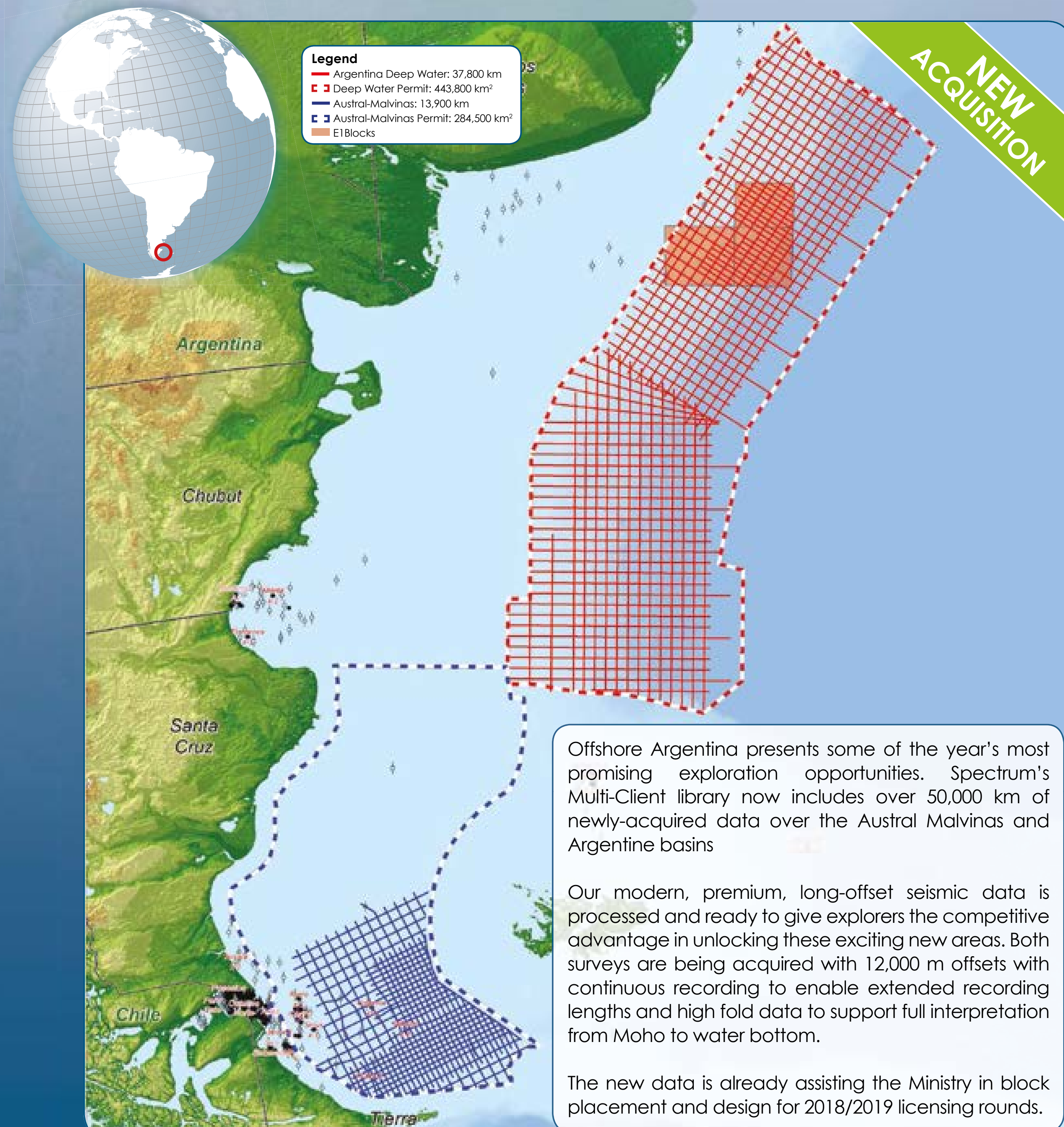

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