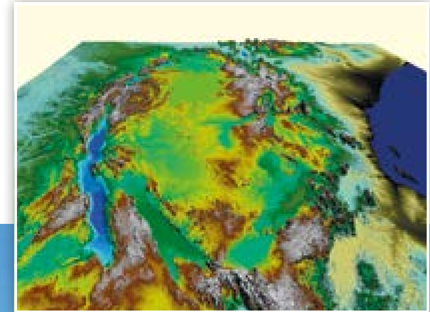
VOL. 11, NO. 5 – 2014

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



Exploration:
The East African Rift System

geoexpro.com

GEO TOURISM

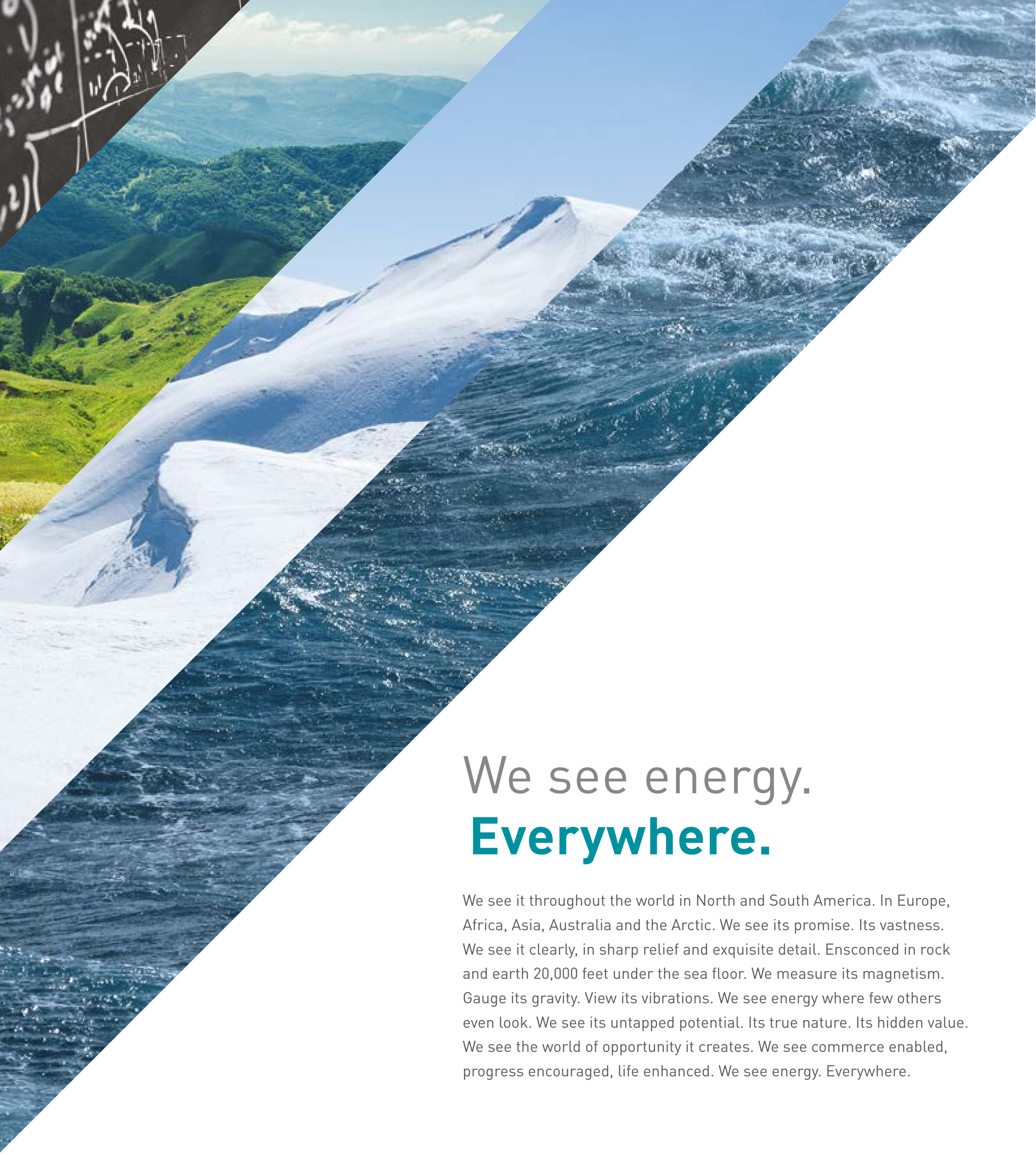
Milos:
An Aegean Gem

TECHNOLOGY EXPLAINED
Modelling: The Power of Movement

EXPLORATION
Whale Hunters Seek Elephants

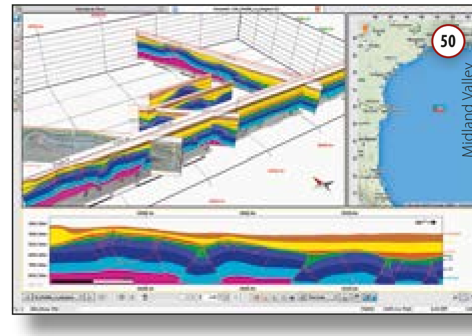
RECENT ADVANCES IN TECHNOLOGY
Testing Broadband

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT



GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



Kinetic modelling unlocks geological systems.

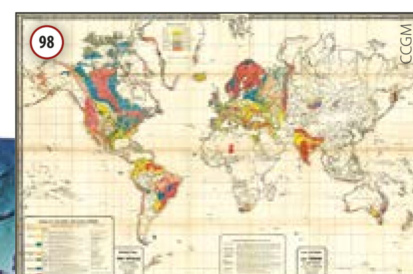
CONTENTS Vol. 11 No. 5

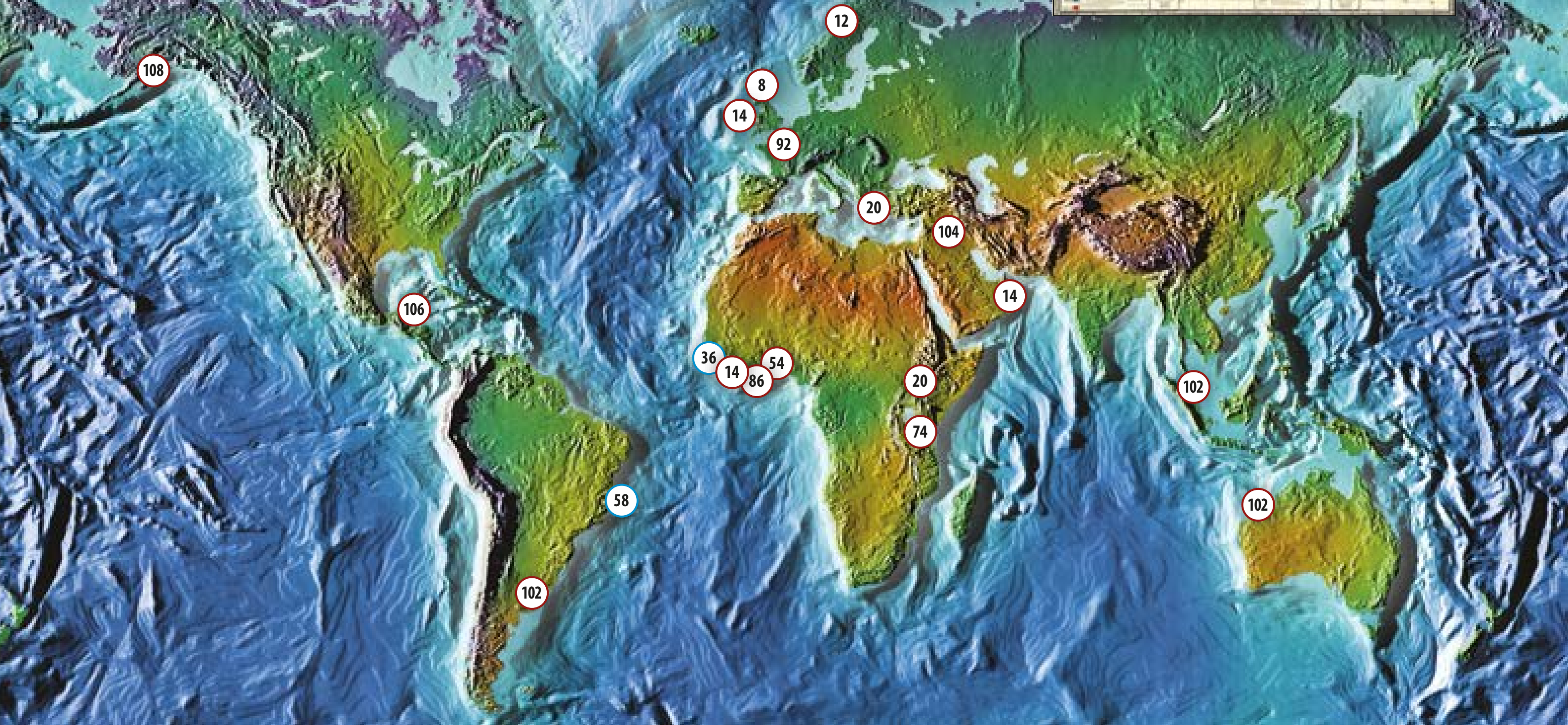
This edition of *GEO ExPro* Magazine focuses on North West Europe, Africa, Modelling and Mapping

COLUMNS

FEATURES

One of the oldest geological maps of the world: Marcou, 1861.






Polarcus®
Are you ready for new horizons?
We are.
POLARCUS ADIRA
With a wealth of operational experience, an industry leading seismic fleet, and a passion for geophysical excellence, we have what it takes to tackle the most complex projects, wherever they are.
Imaging tomorrow's energy™

Feelings Before Facts

Elephants hiding in East Africa?

The discovery of hydrocarbons can be a wonderful bonus to a country, or a mixed blessing – or in some cases, the root of decades of fighting and war. For 27 long years Angolans, for example, fought a bloody civil war, fuelled by revenues from oil, conveniently located offshore and therefore accessible to foreign companies without them having to set foot in the war-ravaged country. With peace, production increased and now the country produces about 1.7 MMboepd: yet about 35% of the population still lives below the poverty line.

Undeterred, the craving for oil wealth and the desire to be 'the next Norway' continue unabated. As do high community expectations in many countries, surrounded by myths about local oil riches. This is particularly true in East Africa, where recent discoveries have fuelled long-held beliefs that the region is rich in oil and gas reserves, the knowledge of which has been reputedly suppressed by companies and oil-rich Arab countries. The fact that the majority of the recent discoveries have not been in areas which have historically seen most exploration seems to slip past unnoticed; the myth of riches and conspiracies is far more attractive. These misconceptions help fuel local disagreements and underwrite regional armed conflicts, as seen in much of the Horn of Africa.

Africa does not have a monopoly on conspiracy theories. In September, the Scots decided in a closely fought and sometimes contentious referendum to remain part of the United Kingdom – and immediately social media were awash with talks of a rigged election. The London government, it was said, had made sure the pro-independence movement lost the vote because there had been a recent discovery of a giant field off Scotland – news that would be suppressed until after the referendum. Interestingly, 45% of Scots voted for independence, and in a poll just before the election 42% of voters said they thought the government was probably covering up a secret oilfield near Shetland. There is no evidence for this discovery or its concealment, but as so often with these 'urban myths', many people prefer to put their feelings before the facts.

Of course, there is also no evidence that the story was *not* covered up, which is why conspiracy theories and stories of 'rivers of oil' beneath East Africa endure. ■

Jane Whaley
Editor in Chief

SUN, SEA – AND SARAKINIKO

The island of Milos emerged out of the Aegean in a series of ash falls and eruptions less than four million years ago. With mountainous volcanic plugs, microstructures in layered pumice and multi-coloured cliffs, not forgetting excellent Greek tavernas and sparkling blue seas, it is a geologist's dream holiday location.

Inset: There are still plenty of underexplored areas in the East Africa Rift system.

GEO ExPro

www.geoexpro.com

GeoPublishing Ltd
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
+44 20 7937 2224

Managing Director
Tore Karlsson

Editor in Chief
Jane Whaley
jane.whaley@geoexpro.com

Contributing Editors
Thomas Smith
Thomas.smith@geoexpro.com

Ken White
ken.white@geoexpro.com

Halfdan Carstens
halfdan@geo365.no

Rasoul Sorkhabi
rsorkhabi@egi.utah.edu

Paul Wood
sciwrite@btinternet.com

Editorial enquiries
GeoPublishing
Jane Whaley
+44 7812 137161
jane.whaley@geoexpro.com
www.geoexpro.com

Marketing Director
Kirsti Karlsson
+44 79 0991 5513
kirsti.karlsson@geoexpro.com

Subscription
GeoPublishing Ltd
+44 20 7937 2224
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
kirsti.karlsson@geoexpro.com

GEO EXPro is published bimonthly for a base subscription rate of GBP 60 a year (6 issues).
We encourage readers to alert us to news for possible publication and to submit articles for publication.

Cover Phtograph:
Main Image: Jane Whaley
Inset: GEO International

Layout: Bookcraft Ltd.
Print: NXT Oslo Reklamebyrå

issn 1744-8743

Transport the Last Stronghold

Oil demand growth is expected to pick up, but only slowly

There is a considerable risk in oil price forecasting as the oil price outlook for 2015–16 will be clouded by geopolitical unrest in major oil-producing countries.

Oil prices are expected to be somewhat weaker in the last quarter of 2014 as some of the politically-related locked-in volumes will return to the market. After some time, however, investment cuts will weigh on oil supply growth and the market will become gradually tighter.

The North American oil boom, mainly driven by the shale/tight production in the US, is expected to grow at a healthy rate. The resurgence of North American oil production and a flexible output by OPEC's *de facto* leader Saudi Arabia will continue to be vital to balance the market and offset the substantial supply disruption we have seen in the Middle East and North Africa region. Thus, the oil market looks well balanced in the near future, but the tide can easily turn. The nuclear talks between Iran and the West are slowly progressing, but it is still too early to say when we will see more Iranian barrels in the market. The risk of political supply disturbances has risen sharply this year due to growing unrest and risk of a division of Iraq and instability in Libya. The US and EU sanctions on Russia are not expected to have any significant short-term impact on oil supplies, but may put the start-up of much-needed new capacity expansion projects on hold.

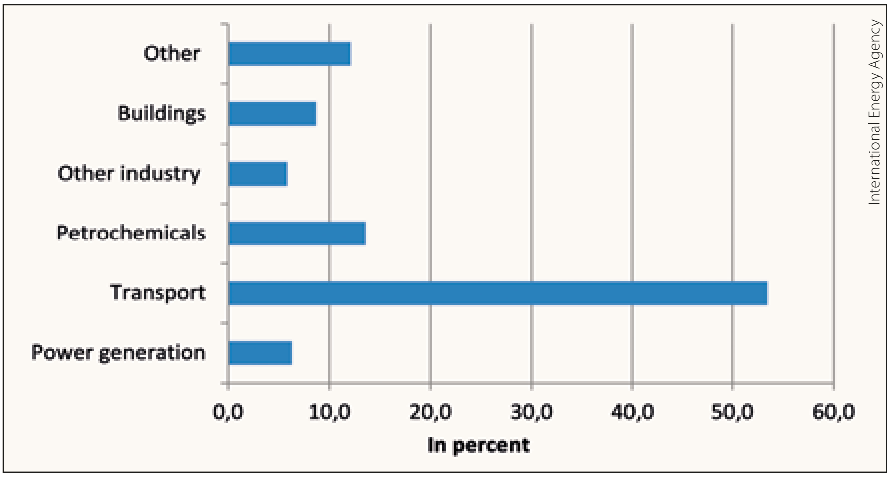
In addition, galloping cost growth and flattening oil prices have squeezed oil companies' margins. Consequently, new and more expensive oil projects have been put on hold and this will curb supply growth, but with an expected lag of two or three years.

Oil demand growth has shown clear signs of weakness, but it is expected to pick up again with economic growth. China will continue to be the main driver, but at a slower pace than before. Meanwhile, the oil demand growth outlook for both the Euro area and Russia looks more subdued as sanctions will weigh on the growth potential. In addition, Japan is expected to reduce its demand for oil as some nuclear power stations will restart. The focus on pollution and green energy is expected to increase before the UN climate summit in Paris next year, and efficiency standards and fuel switching are expected to have a growing impact on the oil market in the future.

How quickly these new environmental policies will be felt in the oil market depends on when technological breakthroughs lead to a big shift in the transportation sector. This currently accounts for about 60% of global oil consumption, and the use of energy in this sector has so far been more or less shielded from competition.

Thina Margrethe Saltvedt

Oil demand split by sector. Transportation still uses over half the energy supply.



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

Scotland Decides

The issue of Scottish independence has divided a nation – and worried an industry

Since oil was first discovered in the cold, stormy waters of the UK North Sea, people in Scotland have pointed out that the majority of the resource lies in Scottish, rather than English, waters. As a result, the whole of the United Kingdom has benefited from this bounty – and 'Scotland's oil for Scotland's people' rapidly became a rallying cry for Scots who felt it was time to break the centuries-old tie with Britain. On 18 September the Scots got their chance to decide, in a referendum with the simple question "Should Scotland be an independent country?"

The debate was about much more than oil. Nationalism, self-determination, taxation and anti-establishment feeling all played their part, but crucial to the discussions was the economy; and key to that is oil. The oil and gas industry is the UK's largest corporate taxpayer and a major industrial investor, employing thousands of people. Many different figures for remaining reserve potential were flung around during the run-up to the referendum, with 'Yes' campaigners (those in favour of independence) claiming that there was 24 Bboe remaining in Scottish waters, which would lead to revenues of about £1.5 trillion (US $2.45 trillion). By contrast, consultants Wood MacKenzie said that the figure for the whole UK is more like 15.3 Bboe, 84% of which would come under the jurisdiction of an independent Scotland.

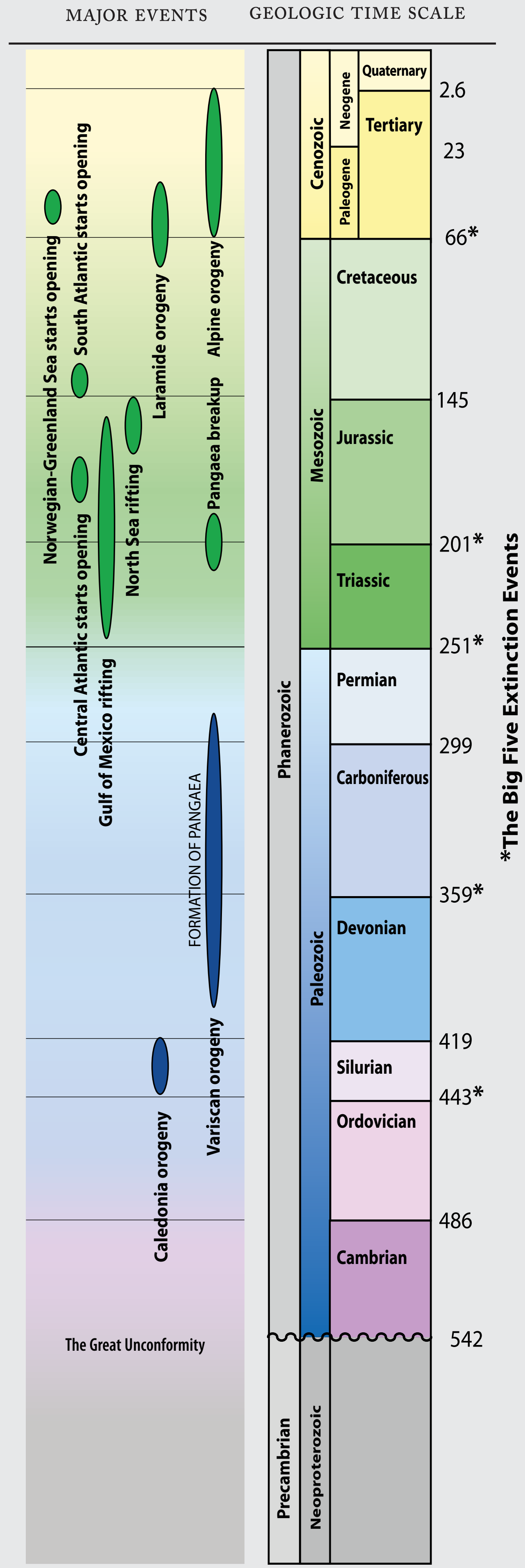
Industry Unease

There was definite unease in the industry, not at the thought of an independent Scotland, but of the disruption and uncertainty which would result in the interim. The issues were daunting. What currency a newly independent Scotland would use was not clear, while offshore borders would have to be negotiated and an entirely new fiscal regime established. For the oil industry these matters are all key to ongoing investment, as would be the setting up of new hydrocarbon laws and regulating bodies. As Wood MacKenzie warned, 'prolonged disputes could cause uncertainty and negatively impact the investment plans of companies active in the area.'

Much of the remaining UKCS resource is in mature fields, or in difficult deepwater environments. Tax reliefs and allowances have been implemented by the UK government to assist with the associated complex and challenging issues, but with apprehension in the industry as to whether a Scottish government would continue such benefits, a number of projects have been temporarily put on hold. With costs ever-increasing, yet production dropping, the thought of a prolonged period of uncertainty was causing a lot of unease and inertia in the O&G industry during the run-up to the referendum.

In the end, the Scottish people decided by a narrow majority to preserve their union with the UK, with 55.3% voting against independence and 44.7% for it. Financial markets, as well as the oil and gas industry, breathed a sigh of relief. ■

Jane Whaley



Women in Charge

2014 was a landmark year for women in the oil and gas industry.

The American Association of Petroleum Geologists (AAPG) was formed in 1917, the European Association of Geoscientists and Engineers (EAGE) in 1951 and the Petroleum Society of Great Britain (PESGB) in 1964. Women were involved in each organisation almost from the start – but it is noticeable that very few women have held major office in these august bodies. It is therefore interesting to note that in 2014 all three of these important oil and gas industry organisations have been led by a woman: Gladys Gonzalez as President of the EAGE, Randi Martinsen, the AAPG, and Oonagh Werngren, the PESGB.

Still Below 20%

According to Robbie Gries, AAPG Past President, six women were elected into the AAPG as early as 1919, when they were working on well sites, collecting core information and examining samples with microscopes. Their presence was probably due to the shortage of manpower in WW1; only one of them continued membership for more than a couple of years. Between the two world wars, the percentage of women in the organisation remained low, and by 1986, the first year for which there are clear records, 10% of the membership was female. Even today, when approximately 50% of all geoscience graduates are woman, that figure is still less than 20%. Robbie was herself the first woman AAPG president, serving in 2005, and Randi is only the second.

Statistics from the EAGE and the PESGB also point to a present female membership of about 19%. It is not clear when the first woman joined the PESGB, but its first female council member served in 1978, 15 years after the founding of the society. Rosemary Johnson Sabine was the first female president, in 1994, and Oonagh is the second, after a gap of 20 years. And Gladys is the first ever female president of the EAGE – also the first Latin American.

Oonagh Werngren is 2014 President of the PESGB. She is also Operations Director for Oil & Gas UK and has 30 years' experience in the industry.

All three 2014 presidents have put getting more women into the geosciences and the industry at the top of their agenda, as well as encouraging them to be more proactive in the societies. Deirdre O'Donnell, Managing Director of specialist oil and gas recruitment company Working Smart, believes that woman now make up approximately 15-20% of the industry workforce, with a growing percentage under the age of 35, which is very encouraging.She thinks the main challenge still appears to be the retention and development of these women to take on senior level management roles and board positions.

Both Randi and Robbie believe that they owed their initial employment to 'affirmative action' in the '70s, so are gender short lists and quotas the answer to increasing diversity? Are female employees putting themselves forward to get the diverse skills required to be successful in today's industry, so enough women are promoted into the middle ranks to be involved in succession planning?

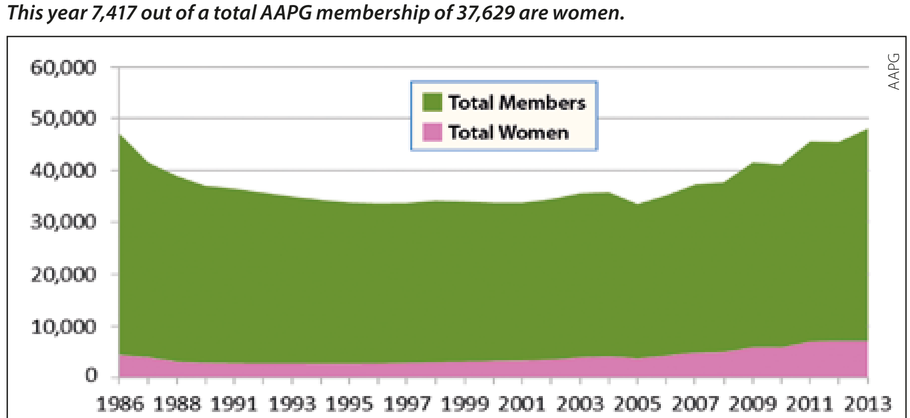
Randi Martinsen, President of AAPG since July 2014, is a certified petroleum geologist with 40 years' experience (domestic and international) working in industry, consulting and teaching.

Advice from the Presidents

What advice can these three successful women Presidents give to the next generation of female geoscientists? Gladys says: "The message I want to pass on from my own experience is that if you are determined and obtain the skills, the opportunities will come." Similarly, Oonagh believes "that women can have a very successful career in the oil and gas industry and manage a good work life balance. You just have to have the confidence to apply for a role and ensure you get the right experience early on in your career".

But maybe Randi has the real key: "A sense of humour goes a long way!" ■

This year 7,417 out of a total AAPG membership of 37,629 are women.



Making an Educated Guess

An online game shows that using input from a knowledgeable crowd can lead to better decisions.

JONNY HESTHAMMER, Atlantic Petroleum Norge, and **HANS GEBAUER,** Geonova

In a recent experiment, university students and oil industry staff, including non-explorationists, tried to predict whether exploration wells on the Norwegian Continental Shelf would succeed or fail – and they predicted well! The experiment, named 'WellBet', is based on an established economic theory known as 'prediction market theory'.

WellBet is about making an educated guess on the outcome of prospects to be drilled. It is run with geoscience students at the University of Bergen and a team from Atlantic Petroleum, where not only exploration experts participate but also team members who are typically not directly involved in the drilling process.

Both groups, students as well as employees, are doing surprisingly well in predicting the outcome of drillings. The questions that arise are, firstly, how is this possible, and secondly, is it useful for companies?

Prediction markets utilise inputs from many different participants in game-like environments. In theory, the prediction gets better and better the more people place their bet. This phenomenon is also called "wisdom of the crowd". Several scientific studies in different industries and markets have shown that combining the knowledge of many – via market-based aggregation mechanisms – can lead to surprisingly accurate results, even though the participating individuals are not accredited experts.

Extending WellBet

In order to find out more, the WellBet experiment is now being extended, thanks to sponsorship from Atlantic Petroleum. Since May, members of the online geoscience community Geonova have been able to make their own predictions, bringing this fun experiment to a broader audience – again with remarkable results. All you need to do to participate is to create a user account. Each prospect is presented with a standard set of publicly available information. Your bet is immediately compared to the other bets. When the prospect has been drilled, and the result has been published in a press release, we can all see how the community prediction compares to the actual outcome.

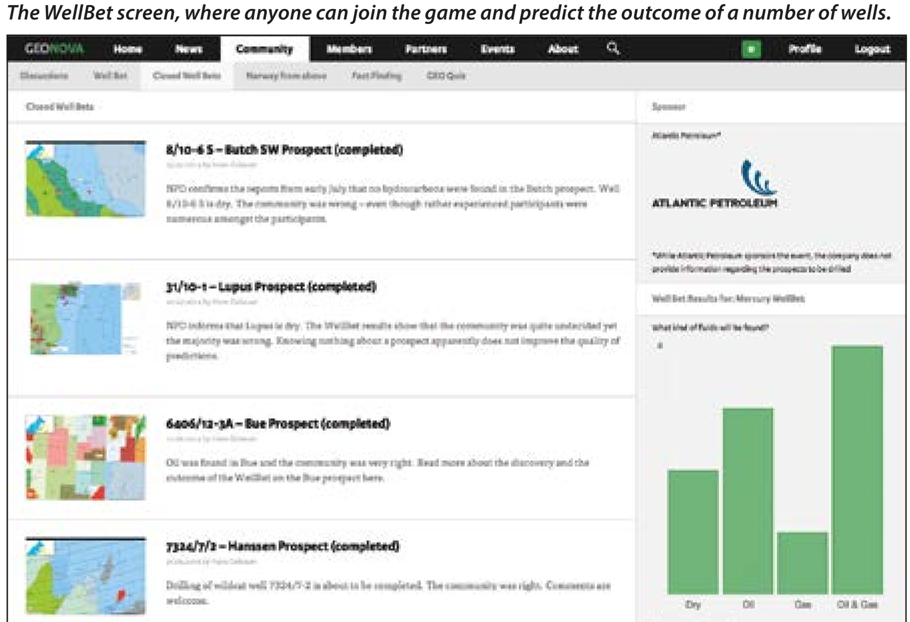
So far, 10 WellBet prospects, all located on the Norwegian Continental Shelf (NCS), have been presented on Geonova and a total of 650 bets placed by members of the community. Most participants were in the age group of 40+ with a background in the oil and gas industry, although they indicated that they possessed little detailed knowledge about the actual prospects. The success rate for predicting technical and commercial discoveries as well as phase, i.e. three different parameters, is 53.33% which must be considered very good – and at the same level as the university students, whose score is currently at 54%. The overall discovery success rate – predicting technical and commercial discoveries but not the perhaps most difficult parameter, phase – is somewhat higher at 60%. Interestingly, the very important farm-in success rate – the rate at which the community predicts correctly a commercial success or commercial failure – lies at 70%. It is thereby at the same remarkably high level as the groups of geoscience students and oil industry employees of Atlantic Petroleum Norge.

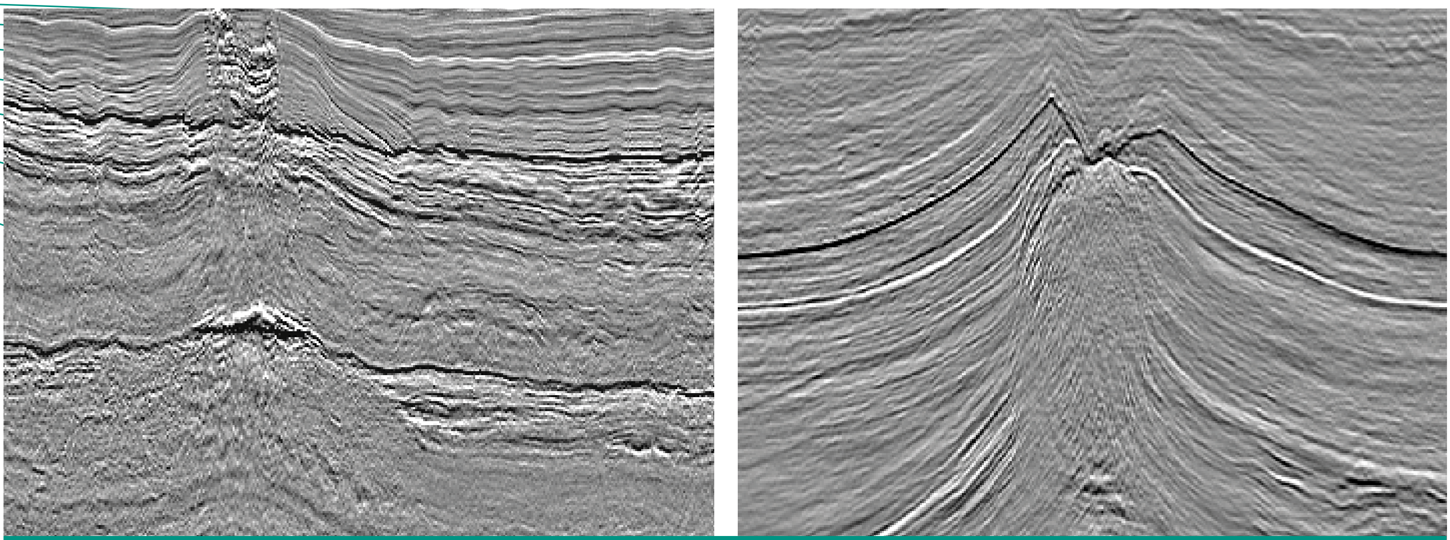
The prediction market mechanism seems to be providing highly valuable information, although more data is needed to generate resilient results. WellBet could in fact prove helpful for small oil companies with limited capital available for drilling. It seems that taking input from a knowledgeable crowd into consideration can lead to better decisions.

It remains to be seen how the community will perform over time. Based on the results of the first bets in WellBet run in the three different groups, we can state so far that non-experts can have a relevant say in finding oil, and we should watch closely how WellBet accuracy develops with increasing numbers of participants.

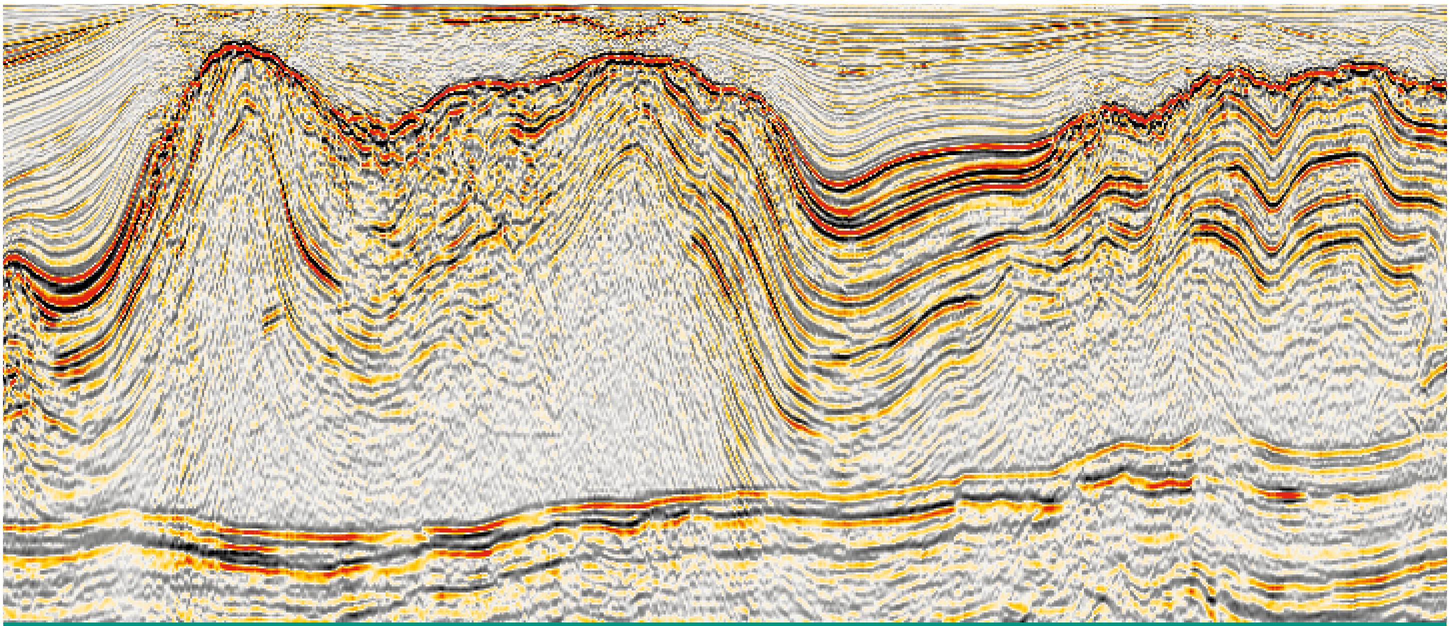
You can support this experiment and have lots of fun by placing your bets on Geonova at www.geonova.no/well-bet. ■

The WellBet screen, where anyone can join the game and predict the outcome of a number of wells.





SHarp - AVO Friendly Broadband



Pre-Salt Kirchhoff PSDM

Data courtesy of Dolphin Multi-Client

Offshore and Deepwater Challenges Remain

KEN WHITE

Ireland

The Minister of State at the Department of Communications, Energy and Natural Resources opened the 2015 Atlantic Margin Licensing Round on 18 June 2014 advising that applications for Licensing Options are to be submitted by 16 September 2015. The acreage proposed consists of 995 full blocks and 93 part blocks, and covers an area of approximately 256,700 km^2. Three regions have been delineated, with specific rules applying to each of them. Applications should not comprise more than four complete blocks in Region 1 (Donegal, Erris and Slyne Basins), six complete blocks in Region 2 (Porcupine and Goban Spur Basins) and 10 complete blocks in Region 3 (Rockall Basin). Licensing Options are available for a maximum of two years and may not be extended. However, a three-year Licensing Option may be offered if the application is wholly or partly located in an area which is recognised as being environmentally sensitive.

The Atlantic margin offshore Ireland is a difficult operating environment where deepwater challenges are coupled with environmental and financial constraints that significantly impact drilling costs. Not surprisingly, the area is ranked as seriously underexplored – yet tax provisions relating to hydrocarbon exploration and production are to be revised upward in favour of the state. With this round, the marginal tax rate on oil and gas production will rise to a maximum 55% from 40%. To improve the image of offshore prospectivity, the government is offering enhanced data quality and moving to de-risk the exploration effort by acquiring and making available 18,000 km of 2D seismic data.

Liberia

With Liberia battling the outbreak of the deadly Ebola virus, the National Oil Company of Liberia launched the 2014 bid round at the beginning of August and already the bid submission date has been revised to 14 November 2014. Four undrilled offshore blocks are offered. Blocks LB-6 and LB-7 in the Liberia Sub-basin, where water depths range from 20 to 3,000m, were part of the Liberia Basin 2007/8 bid round but were never awarded. Blocks LB-16 and LB-17 in the Sierra Leone-Liberia Basin, with water depths down to 3,000m, were awarded in the 2004 Bid Round and are again available.

The Narina-1 wildcat drilled on LB-09 in January 2012 encountered a combined total of 31m of net oil pay in the primary objective Turonian fan system and underlying Albian reservoirs with no oil/water contacts observed – the first well to prove a working petroleum system in the central Liberian basin. Recent advances in deepwater technology have opened up the region to a new phase of exploration. According to the National Oil Company of Liberia (NOCAL), a full working petroleum system in the Liberia Basin is evident and this is shown to continue along trend beyond Block 17 with the Mercury discovery in Sierra Leone.

The first exploration period of three years requires 3D seismic, while the second and third periods, each of two years, require the drilling of one well in each period.

Oman

The Oman Ministry of Oil and Gas (MOG) are offering two offshore and three onshore blocks covering a total of 76,416 km^2 for international tender. The 2014 bid round includes offshore Block 18 (Batinah Coast) and Block 59 (Arabian Sea); and onshore Block 43A (Dhahirah), Block 54 (Karawan) and Block 58 (Qatbeet). The deadline for the submission of sealed bids is 31 October 2014. Block 18, with water depths of between 30 and 3,000m, was previously held by Reliance Industries. It includes three wells drilled by Wintershall and Reliance, including Batinah Marine-B1 which resulted in oil and gas shows. Offshore Block 59 is the largest on offer and is undrilled; water depths range between 0 and 3,600m. There are seven wells on onshore Block 54, four of which were drilled by the Occidental, Mubadala and Mutsui consortium between 2008 and 2010. Both blocks 43A and 58 are considered underexplored and include one well drilled in each block; Amoco Oman Gas drilled Jebel Sumeini-1 in 1988 and PTT Exploration and Production Public Company (PTTEP) drilled Wassa-1 in 2009, in blocks 43A and 58 respectively.

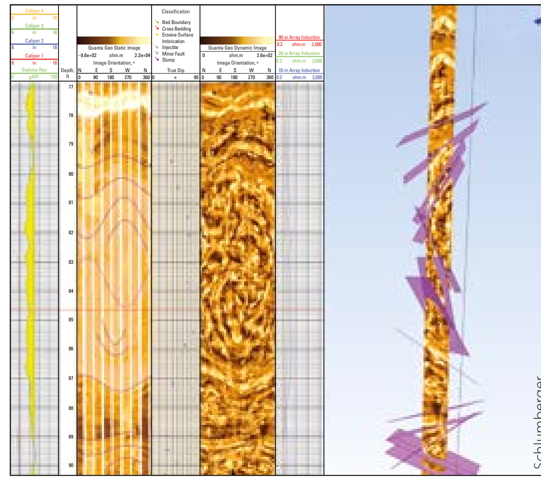
International oil companies and independents have gained a more prominent role in reversing Oman's oil production decline but the government seems keen to restrict output at 950,000–960,000 bpd because the state wants to be able to sustain production levels from difficult-to-access resources for a period of time. Independents have overall been very successful in Oman but the authorities are shifting investors' focus towards its offshore acreage, which remains largely untapped.

Core-like Images from Quanta Geo

Schlumberger recently launched the **Quanta Geo*** photorealistic reservoir geology service, the industry's first microresistivity imager that produces oriented, photorealistic, core-like images of the formation in wells drilled with oil-base mud (OBM). Quanta Geo's high-resolution array of 192 microelectrodes overcomes the electrically resistive barrier imposed by OBM. Interpretation of the images identifies geological features and predicts reservoir trends in 3D with a high degree of certainty, enabling better understanding of reservoirs and more confident decision making.

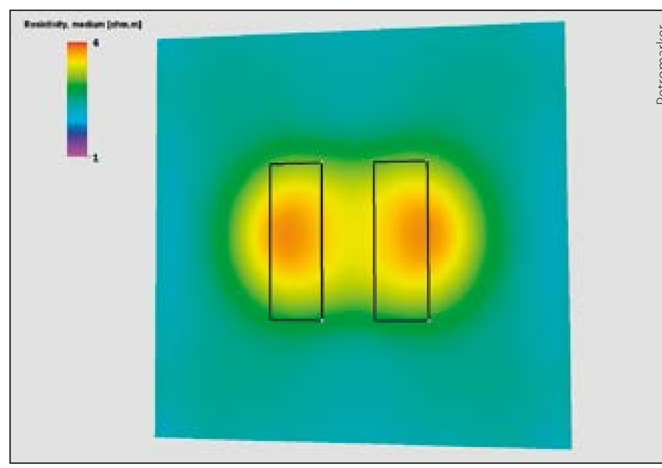
Data acquired by the Quanta Geo service can be easily rendered into an image which resembles a whole core. Geologists interpret these images in the same manner as they would perform continuous core description, with the added benefit that these images cover a longer continuous interval and are precisely oriented, enabling extraction of key reservoir parameters such as the structural dip, or the identification of sand body type, extent and orientation. ■

**Mark of Schlumberger*



PetroMarker's 2D and 3D Code Development

PetroMarker, together with **Scripps Institution of Oceanography** in La Jolla, California, has developed a time domain version of the Occam 2D code, which allows inversion of PetroMarker CSEM data along a profile. PetroMarker also collaborates with **Lawrence Berkeley Labs** (LBL) in Berkeley, California, on improvements to their 3D TEM inversion code. These improvements include the ability to use larger 3D datasets with a broader range of offsets for more accurate depth and lateral positioning of hydrocarbon targets. So-called gradient depth weighting is used to get more accurate depth positioning. Recent tests show that it is possible to separate two closely adjacent reservoirs, thanks to PetroMarker's technology which uses stationary pulsing and short offsets. In the synthetic example given here, even two reservoirs as close as 1 km may be differentiated 2 km below the seafloor. PetroMarker's improved 2D and 3D workflows offer the possibility to import and export SEGY and other formats to and from other geophysical applications, facilitating easy integration of the data into existing client infrastructure and workflows. ■



PROSPEX: Bigger Than Ever!

PESGB and **DECC** bring you the 12th show in their highly successful series of Prospect Fairs – the UK's leading networking event for exploration and development. The show has gone from strength to strength. In 2013 we saw over 80 exhibitors and 981 attendees, in addition to a full two-day programme of 'prospects to go', overviews from governments and presentations by explorers and consultants. This year there is a special session on onshore prospects, prompted by this year's 14th Landward Licensing Round.

But don't just take our word for it, here are what some attendees and exhibitors said last year:

"PROSPEX is the industry benchmark conference, where you meet all the right people."

"This show always has a buoyant and optimistic mood."

"The exhibition was a constant hum of activity!"

"A yardstick for activity within a region."

Registration is now open and includes admission to the exhibition and conference, all-day refreshments, luncheon and a networking wine reception – head to *www.pesgb.org.uk* for more details. **PROSPEX 2014** runs on 10–11 December 2014 at the Business Design Centre, Islington, London. ■

SeaBird Exploration

THE FLEET

SeaBird's Seismic Operations benefit from both Seismic and Marine being managed in-house, providing a fully unified crew.

SeaBird is an Industry leader in Shallow water 3D, deep water 3D, high end 2D and source vessels. SeaBird operates a Global fleet of seismic vessels.

SeaBird has a growing Multi-Client Library in strategic regions.

SeaBird is the provider of choice in high security regions. Security is a key element of SeaBird's HSSEQ philosophy.

SeaBird's SeaArc and SeaNet proprietary software connects all aspects of SeaBird's HSSEQ management system.

SeaBird operates to the highest Industry standards, with accreditation/certification to ISM / ISPS, OGP, ISO 9001, 14001 and OHSAS 18001.

Seabird is an active member of the IAGC.

WWW.SBEXP.COM

3D VESSELS

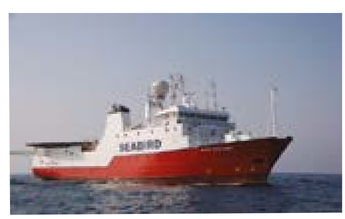
GEO PACIFIC
3D Long Offset Vessel.
Configured for 8 x 6000m or 6 x 8000m deployments. 4 Sercel G-Gun Sub-Arrays. Capable of dual source, wide tow configurations.

VOYAGER EXPLORER
3D Long Offset/Source Vessel.
Specialised in four streamer shallow water 3D acquisition. 4 Bolt 1900 LLXT Sub-Arrays. Capable of dual source, wide tow configurations.

2D VESSELS

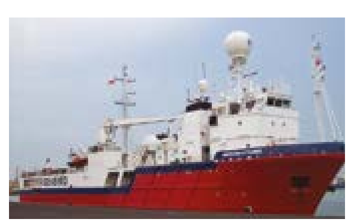
AQUILA EXPLORER
2D Solid Streamer Long Offset/ Source Vessel.
Equipped with 12,000m of Solid streamer and 6 Bolt 1900 LLXT Sub-Arrays. Capable of dual source, wide tow configurations.

HARRIER EXPLORER
2D Solid Streamer Long Offset/ Source Vessel.
Equipped with 12,000m of Solid streamer and 6 Bolt 1900 LLXT Sub-Arrays. Capable of dual source, wide tow configurations.



HAWK EXPLORER
2D Long Offset/Source Vessel.
Equipped with 12,000m of Sercel ALS streamer and four Bolt 1900 LLXT Sub-Arrays.

MUNIN EXPLORER
2D Solid Streamer Long Offset/ Source Vessel.
Equipped with 12,000m of Solid streamer and 6 Bolt 1900 LLXT Sub-Arrays. Capable of dual source, wide tow configurations.



NORTHERN EXPLORER
2D Long Offset/Source Vessel.
Equipped with 12,000m of Sercel ALS streamer and four Bolt 1900 LLXT Sub-Arrays.

OSPREY EXPLORER
2D Long Offset/Source Vessel.
Equipped with a 12,000m streamer and 6 Bolt 1900 LLXT Sub-Arrays. Capable of dual source, wide tow configurations.

ATC Moves to Copenhagen

OTC's **Arctic Technology Conference** (ATC) is part of the successful series of events which includes the flagship Offshore Technology Conference in Houston, OTC Brazil in Rio de Janeiro and OTC Asia in Kuala Lumpur. Anchored by 14 of the energy industry's leading engineering and scientific organisations, OTC's cutting-edge conferences, products and exhibitions have fostered development of the world's oil and gas resources since 1969.

ATC is the industry's most focused, comprehensive technical conference and exhibition for Arctic E&P professionals. It offers an unparalleled technical platform for the exchange of expertise for the safe and responsible development of the Arctic, with a technical programme developed by a collaborative expert committee representing every discipline. International scientists and engineers share their ongoing research and experiences in six key Arctic themes covering both a technical and socio-economic point of view.

The conference has had three successful years, attracting a focused group of some 1,500 E&P professionals from 26 countries, with an exhibition that boasts 80 exhibiting companies. Previously held in Houston, ATC 2015 will move to the Bella Centre in **Copenhagen** 23-25 March. Copenhagen's geo-strategic location provides easy access for European Arctic professionals while also drawing experts from North America and around the globe. ATC will return to St. John's in Newfoundland, Canada in 2016 and the plan is to alternate between continents every year. ■

Northernmost Well Ever

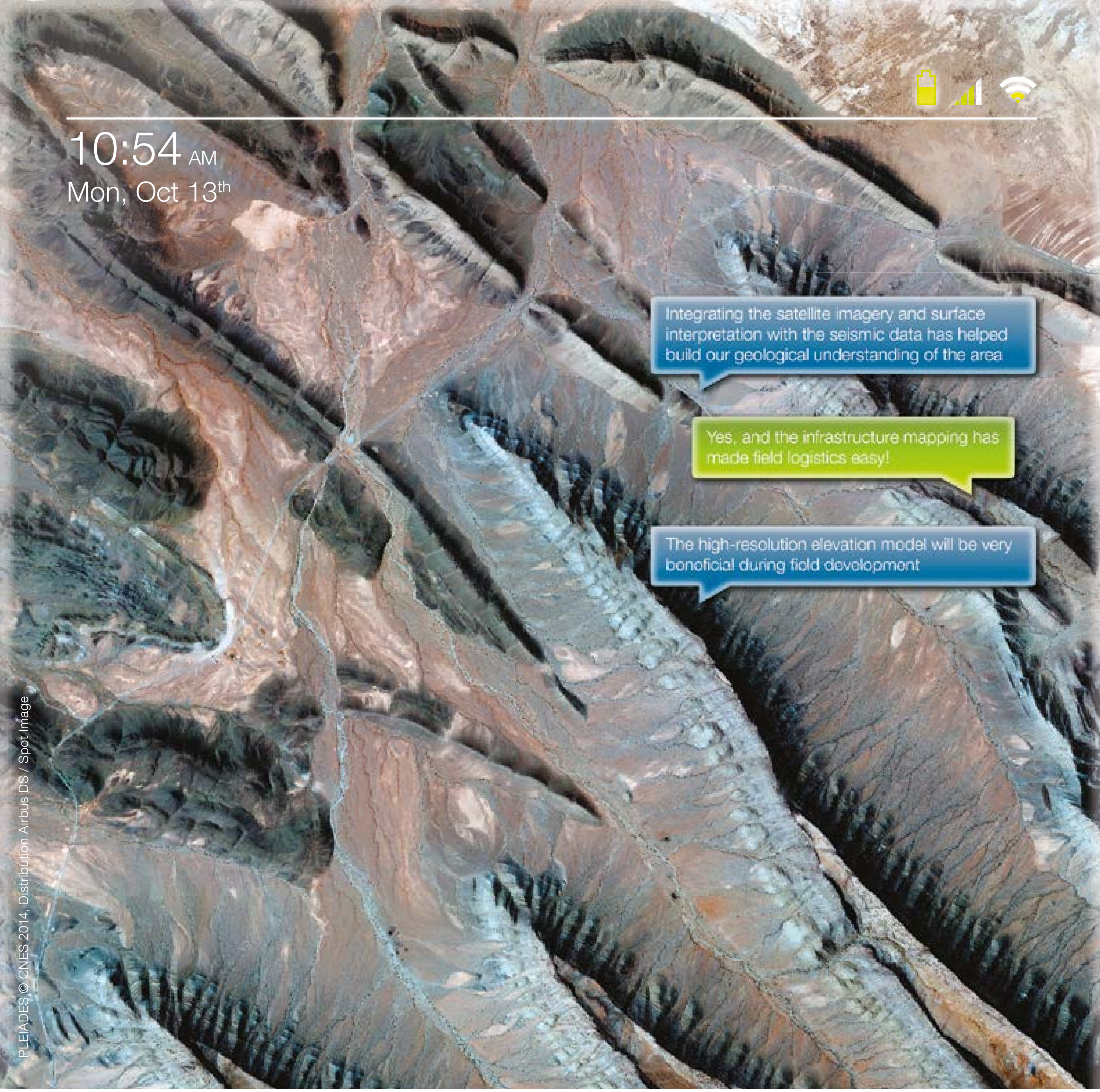
The most northerly well ever drilled in the world, **Universitetskaya-1**, was completed in record time on 26 September – and found the first oil and gas-condensate field in the new **Kara Sea** oil province. **Rosneft** announced that the field, called Pobela (Victory), could have a resource base of **733 MMbo** and **12 Tcf**, although their major partner, ExxonMobil, was not prepared to substantiate that figure. Taking only one and a half months to drill to over 2,000m in 81m of ice-free water, the operation involved detailed ecological and environmental studies and precautions, including two groups of blowout preventers and an independent submarine locking device, which in case of minor risks will seal the well.

However, the future development of the field is up in the air as the sanctions against Russia have now come into play and US technology that is considered vital for the safe exploitation of these Arctic fields will not be available. ■

Aker Geo Becomes First Geo

On 11 July 2014 **Aker Solutions ASA** and **Aker Solutions Holding ASA** entered into a demerger plan to effect the announced split into two companies: new **Aker Solutions** and **Akastor**. Akastor will be an oil services investment company. On 12 August the demerger plan was approved by the respective general meetings. As a consequence of the demerger, Aker Geo AS will be developed as a standalone company under the Akastor umbrella, and in October 2014 change its company name to **First Geo AS**.

Apart from the name change, ongoing business at First Geo AS will continue as normal, maintaining a strong position among the largest subsurface consultancy companies in Norway. Under the Akastor umbrella First Geo AS benefits from added support and a strong drive to develop the business further by extending their service and product portfolio. This means that First Geo will remain a significant, trustworthy vendor of subsurface knowledge for E&P companies in the future. ■


10:54 AM
Mon, Oct 13th
Integrating the satellite imagery and surface interpretation with the seismic data has helped build our geological understanding of the area
Yes, and the infrastructure mapping has made field logistics easy!
The high-resolution elevation model will be very beneficial during field development
PLEIADES © CNES 2014, Distribution Airbus DS / Spot Image

Sun, Sea, and Sarakiniko

JANE WHALEY

The volcanic island of Milos is a horseshoe-shaped gem rising out of the azure waters of the Aegean Sea, where the geological tourist will never be bored.

What do you want on a holiday?

Beautiful quiet beaches? Milos has more beaches than any other Greek island, ranging from small coves with volcanic sand to long white stretches backed by mulitcoloured cliffs. Plenty of sunshine? With a Mediterranean climate, you are sure to be happy. Stunning scenery? Steep rocky cliffs and inlets, beautiful white hilltop villages and a central mountain rising to 750m with wonderful views in all directions will definitely satisfy. Peace and quiet? With the western half of the island virtually inaccessible except by boat, and no large hotels or package tours, even the most unsociable tourist will be able to get away from it all. Some antiquities to excite the imagination? As the place where the famous Venus de Milo was discovered, and with evidence of habitation dating back over 3,000 years, you are not going to be disappointed.

And for the geotourist? Something to wonder at round every corner. Let me take you on a short geological tour of this beautiful island.

Jane Whaley

White Neogene submarine layered ash flows have been intruded into by darker Quaternary lava flows. At the base of the cliff the intruded andesite has formed hexagonal columns.

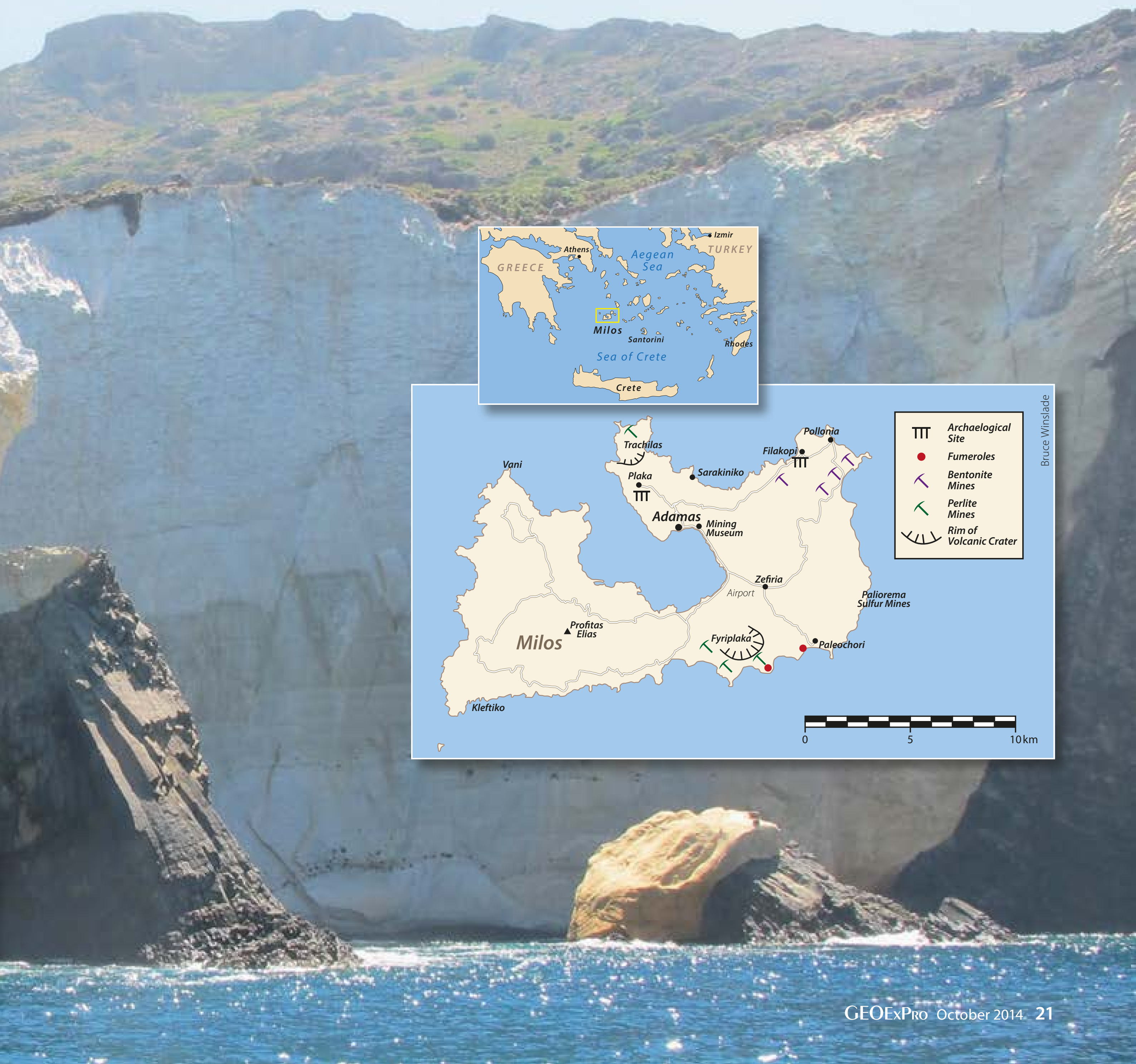
Plugs and Craters

The best way to arrive at Milos is by boat – about three hours by fast ferry from Athens – as this allows you to slowly appreciate the scene as you sail through the large bay in the centre of the island into the small main town of Adamas. At a first glance, this bay resembles a classic flooded caldera, the centre of an extinct volcano, as in the similarly shaped volcanic island of Santorini 100 km to the east, but the bay was created through faulting and erosion.

Rising above Adamas, the whitewashed houses of the village of Plaka can be seen winding up to a castle perched at the top of a steep-sided 200m high hill. This is a Lower Pleistocene volcanic plug, the result of magma rising through the Earth but cooling in situ rather than erupting, and exposed when the softer surrounding ash and other sediments eroded away.

Volcanism was initially centred in the western half of the island, when undersea volcanic explosions resulted in large domed structures, the oldest being the rhyolitic Profitis Elias complex (3.08 Ma), followed by the deposition of a series of predominantly submarine volcanics including ignimbrites and tuffs with ashy layers. These are overlain by sub-aerial Quaternary andesitic to dacitic (depending on silica content) lavas, tuffs and pyroclastic flows.

The eastern half of the island is slightly younger, with primarily Late Pliocene–Quaternary volcanics overlying probably Mesozoic crystalline basement. There were a number of main centres of activity, including Filakopi in the north-east, which formed about 2.66 Ma. in a submarine environment, unlike the northern Trachilas and southern Fyriplaka complexes, which date from between 0.5 and 0.1 Ma., by which



time much of the present day island of Milos was above sea level. Both of these exhibit visible crater rims composed of successive layers of ash, sand and lava flows, with evidence of occasional marine inundations.

Multicoloured Cliffs

The headland to the south-east of the Fyriplaka crater is an exciting stop for the visiting geotourist. Composed of Lower Pleistocene brecciated lava flows overlain by 'green lahar', a volcanic mud and debris flow, the rocks have been highly altered by hydrogen sulphide-rich gases escaping to the surface via vents known as fumeroles. These are easily spotted; apart from the unmistakable 'bad egg' smell and the steam rising from them, the vents are surrounded by bright pink, yellow and light green crystals and are hot to touch. You can still see the old kaolin mining galleries here. Fumeroles are present in a number of other locations in Milos.

Brightly coloured rocks, the result of geothermal and hydrothermal alteration, can be seen at a number of coastal locations, one of the most spectacular being Paleochori in the south-east. As well as the hydrogen sulphide which is responsible for these colours, the gases causing this phenomenon can be rich in arsenic, carbon dioxide and methane. They reach the surface via fractures and vents, which are also present offshore.

Pirates and Pumice

One of the most visually stunning places to visit on Milos is Sarakiniko on the north coast, where the stark, dazzlingly white rock formations contrast vividly with the gaudy colours of Paleochori. These are formed from thick beds (up to 100m) of white diatomite and pumice tuffs, alternating with thinner layers of greyer pumice tuffs and pale yellow, shallow marine Pliocene limestone. Differential wind and water erosion has sculpted these soft layers into pillars, mushrooms and other shapes, in which almost horizontal layering and bedding is clearly seen, together with minor faulting and slumping evidence of earth movements.

The people of Milos have taken advantage of the soft nature of the rocks underlying much of their island by digging into it to make stores and boat houses, known as *syrmata*, sealed by brightly coloured wooden doors.

There are no paved roads in the western half of the island, but many boats offer tours around the coast to the 'pirate cove' of Kleftiko on the south-west tip of Milos – a recommended trip, as the western coast offers much for the geologist to wonder at, at (see photo, page 20). Kleftiko itself is very picturesque, with caves and arches carved out of Neogene tuffs, large and sheltered enough for pirates to hide their boats in, and best explored by swimming in the clear turquoise water.

Important World Source

Unlike the rest of Greece, the Miloan economy is booming, and did not suffer in the recent recession. This is not due to a massive influx of geotourists, although geology is indeed responsible, as volcanic processes have produced a range of rare metals and minerals. These resources have been exploited since 9,000 BC, when Neolithic man used the obsidian found near Adamas and in the east of the island for tools and

A Recent Creation

Milos is the south-westernmost island in the Cyclades Group, which includes Mykonos, Paros and Santorini, and lies about 150 km from Athens on the mainland, and the same distance north of the large island of Crete. It is part of the South Aegean Volcanic Arc, which resulted from the subduction of the African plate under the Eurasian plate and which extends almost 500 km from mainland Greece to Turkey. Miocene to Pliocene extensional tectonics created a pattern of horst and graben structures, including the central bay, and controlled the volcanic and hydrothermal activity.

Volcanic activity commenced between about 2 and 3 Ma, and much of the island originally formed underwater, coming to the surface as a result of regional uplifting processes about 1.4 Ma. Except for some Late Mesozoic metamorphic units outcropping along the south coast, and Lower Pliocene conglomerates and limestones south-east of Profitis Elias, the island consists almost entirely of Neogene and Quaternary volcanics.

The volcanic rocks on the southern edge of the Fyriplaka crater have undergone intense alteration by acidic solutions generated from hydrogen sulphide-rich vapours escaping through fumeroles, creating needle-like sulphur crystals at the edges of the vents.

weapons. Commonly called 'volcanic glass', obsidian is formed when viscous high temperature lava cools very rapidly.

Milos is the world's most important source of perlite, which forms when volcanic ash cools rapidly, trapping water. Perlite expands 20 times in volume when heated to about 950°C, becoming light and porous and making an excellent sound and heat insulator. It has been extracted through open cast mining in Milos since the 1950s. Disused mines are found on the island, but careful environmental reinstatement means that they blend in well with their surroundings. Bentonite, a plastic clay generated from the alteration in situ of volcanic ash, has similar insulation properties, as it swells when coming into contact with water. It is used in oil drilling and civil engineering projects.

As hot volcanic fluids rich in molten metals made their way to the surface, they cooled and metals such as manganese formed, along with smaller amounts of silver and lead. From 1890 to 1928 manganese was extracted at Vani, on the north-west point of Milos, and exported directly onto ships at the mine. It is an interesting spot to visit, with plenty of evidence of the mine workings remaining, but is a remote spot, so a pair of hiking boots is recommended.

As already noted, alteration of the volcanic deposits by hydrothermal activity produces sulphur, which has been exploited in Milos since the time of the ancient Greeks, only stopping in 1958 when it became easily obtained as a byproduct of petroleum refining. At Paliorema on the east coast one can explore the deserted mines, where the old galleries used in sulphur extraction can be seen climbing up the walls of a steep ravine, with the rocks showing the typical bright colouration of hydrogen sulphide alteration.

Proud Heritage

The people of Milos are rightly proud of their geological heritage, and also grateful for the employment and wealth it has brought them. There is an excellent mining and geology museum just outside Adamas, well worth a visit, as well as an interesting archaeological museum in the town, where you can learn about the long history and the many interesting archaeological sites of the island. A number of geological routes have been identified and described on annotated maps, obtainable from the museum or online (*www.miloterranean.gr*), a commendable and really useful initiative.

There are also, of course, beautiful beaches, colourful villages, excellent Greek food and many a taverna in which to rest after all that hiking and geology.

As I said, what more could you ask for in a holiday? ■

Important clay minerals, like kaolin and bentonite, are mined in Milos.

Shining blindingly white in the Greek sun, the ravine, cliffs and pillars of Sarakiniko show clear evidence of recent tectonic movement.

Complex Mesozoic greenschist outcrops at Paleochori, highly altered by fumarolic activity, resulting in multicoloured cliffs.

A Quaternary volcanic plug is at the centre of the highest point on Milos, Profitis Elias, surrounded by Pliocene to Quaternary pyroclastic lava flows with a number of cones and extrusive centres. In the foreground are the Neogene tuffs that form the cliffs and caves of Kleftiko, a safe haven for pirates in the past.

HALLIBURTON | Landmark

Exploration in the East African Rift System

Billions of barrels of oil have been discovered in the East African Rifts in recent years, but it remains highly underexplored with only two rifts partially explored so far.

IAN DAVISON, IAN STEEL, MATTHEW TAYLOR, EOIN O BEIRNE and THEODORE FAULL
GEO International Ltd.

The East Africa Rift System (EARS) consists of the Main Ethiopian Rift in the north and a broadly rifted zone in northern Kenya and south Ethiopia which continues southward into a Western and Eastern Rift Branch separated by Lake Victoria (Figure 1).

The western branch of the EARS and the broadly rifted zone of north Kenya and Ethiopia have seen an unprecedented amount of hydrocarbon exploration in the last twelve years since Heritage Oil made the Turaco-1 discovery in the Albertine Graben in 2002. Over 4 Bb STOIIP have been proven in the Albertine and Lokichar rifts, with more than 20 oil fields discovered in these two basins (Figure 1). The commercial volume threshold has now been reached, but a pipeline to the Indian Ocean and/or an oil refinery are still some years away.

Rift Architecture and Fill

The rift system is distinctly segmented, as is each individual rift, where the major bounding faults switch polarity up to five times (Figure 2). The switch in polarity sometimes coincides with the location of Precambrian basement shear zones or earlier Karoo age (Permo-Triassic) rift structures intersecting the EARS.

Footwall traps in rotated fault blocks were the principal targets in early exploration, as can be seen in Figure 3. However, hanging wall traps have proved to be one of the most successful targets in the EARS, with discoveries in both the Albertine and Lokichar rifts (e.g. Ngamia, Mputa and Kingfisher). This trap type is usually considered to be high risk because of lateral fault seal concerns, especially in areas that are still seismically active such as the EARS. The critical success factor appears to be a prolific and active source to charge traps, so that even if the fault seal periodically leaks, more oil charge replenishes the structure. In this context it is notable that extensive surface seepage is associated with the Albertine and Lokichar Basins and may be an important exploration indicator for other potentially effective basins. Other successful traps are compressional anticlines that appear to have formed due to slight compressive inversion of the rifts (e.g. Waraga-1 in Figure 4).

Most of the basins in the western branch of the EARS have similar geological histories to the rift segments with proven hydrocarbons. These rifts

Lake Manyara fault escarpment.

Benjamin Croce

are filled by fluvial deltaic and lacustrine clastic deposits with limited volcanics. The eastern branch of the EARS was, and is, much hotter than the west with large thicknesses of extrusive lavas infilling the rifts. Sandstone sequences are present in all the rifts, and these can reach a kilometre in thickness near the main sediment entry points (e.g. Buringa-1 and Ruzizi-1 wells in the northern Lake Tanganyika Basin), where there can be hydrocarbon seal problems. In the volcanic areas of the eastern branch and the central broad overlap zone, sandstones often have a large proportion of volcanic detritus which can be detrimental to reservoir quality. However, reservoirs with 15% porosity can still produce at economic flow rates in an onshore situation.

Rift Ages

The earliest volcanics in the EARS are located in the broadly rifted zone where the eastern branch and the main Ethiopian Rift overlap in northern Kenya and Ethiopia. These are dated as Eocene (ca. 45 Ma) and preceded faulting and uplift.

The extensional basins are believed to have been initiated in the Early Oligocene (ca. 30 Ma) based on dating of the Loperot shale located near the base of the Lokichar Basin. The

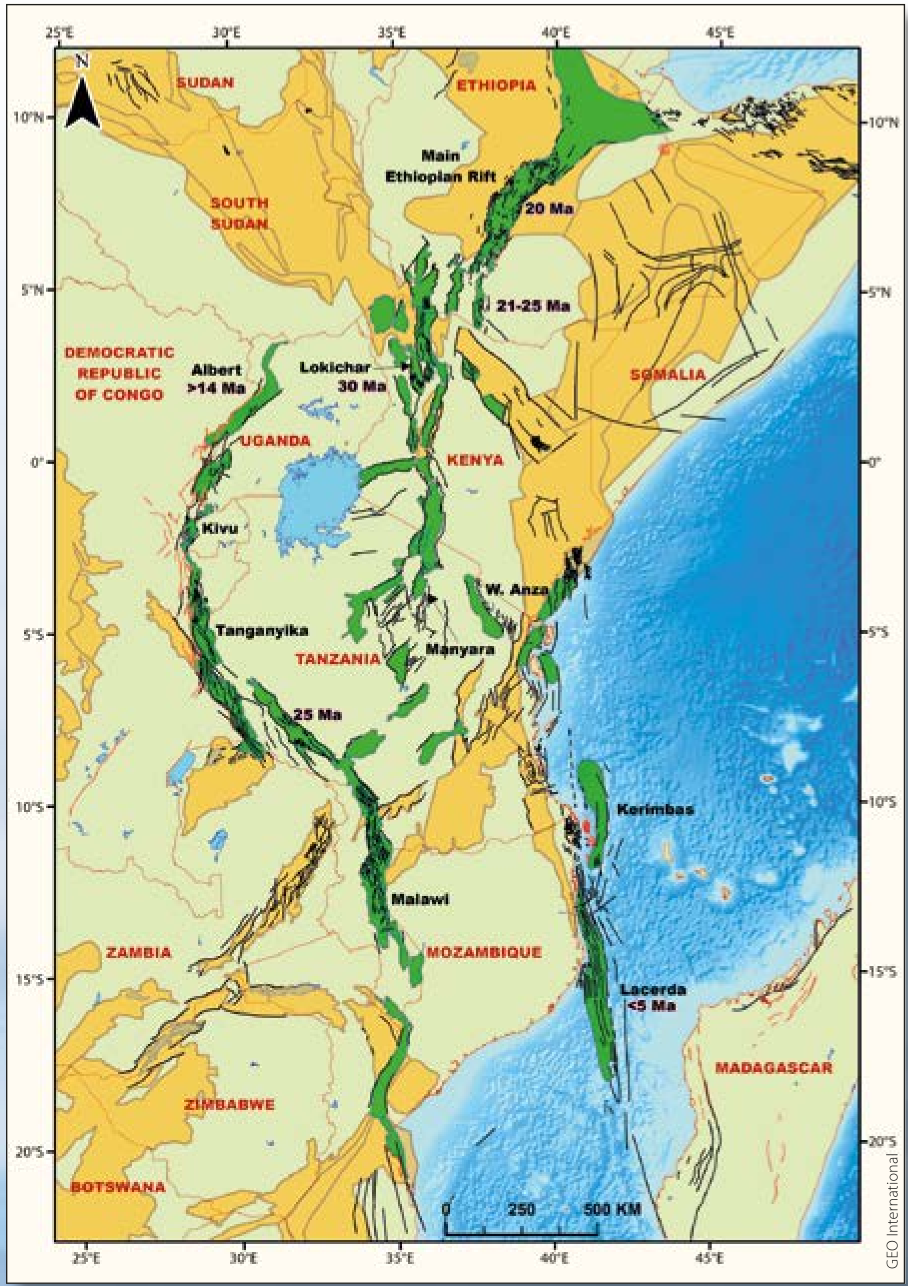
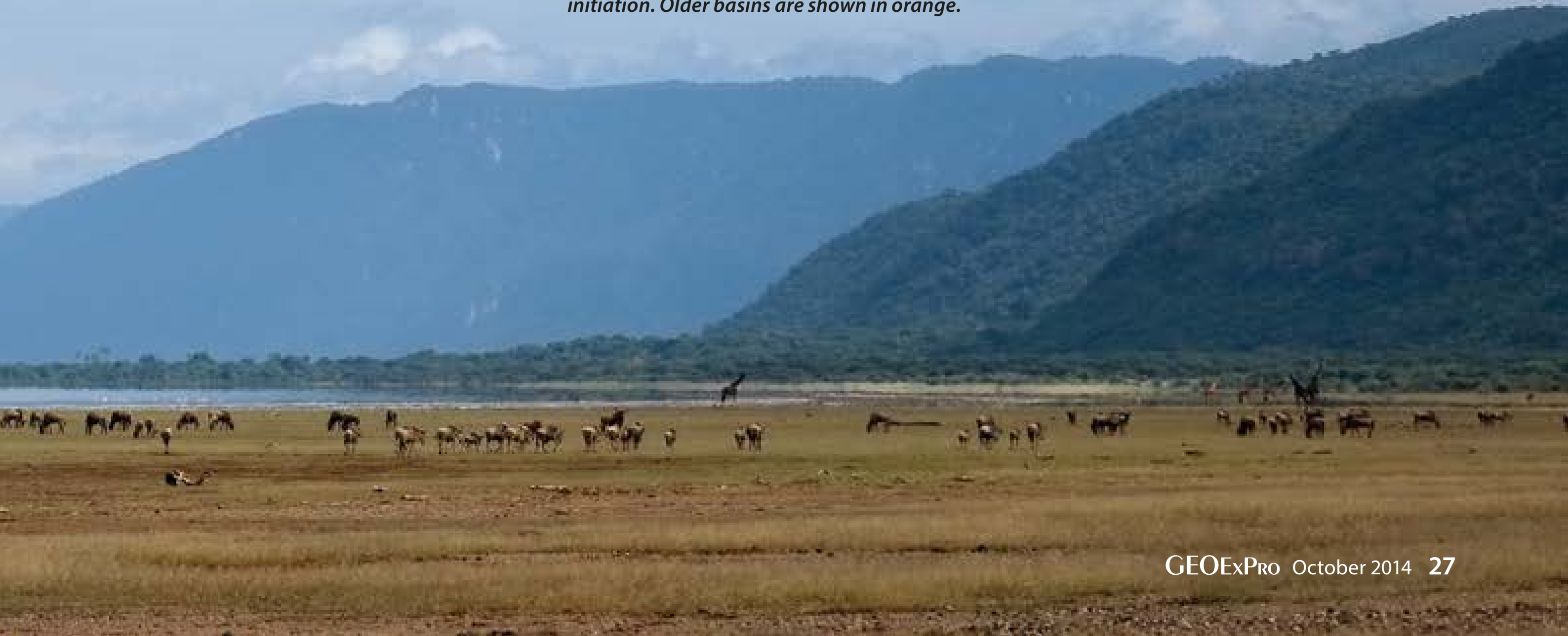


Figure 1: Map of the East Africa Rift system in green, showing the main fault patterns and ages of rift initiation. Older basins are shown in orange.



main Ethiopian Rift initiated in Early Miocene times (ca. 20 Ma) shortly after the main outpouring of the Afar Plume volcanics. The initiation of rifting in the western branch of the EARS is poorly defined because the deepest strata in the rifts have not been drilled. However, late inversion of the Albertine Rift has exposed a large upper section of the stratigraphy, where mammalian fossils and geochronological ages of the tuffs can be used to constrain the age of the rift to be older than 14 Ma. The eastern branch propagated southward into the offshore area in the Kerimbas and Lacerda rifts between Mozambique and Madagascar (Figure 1) where the seafloor has been downfaulted, and rifting is probably less than 5 Ma.

Source Rocks and Maturity

Favourable conditions for source rock development include a rapid rifting phase with a hot humid climate and reduced wind conditions. In such conditions lakes will be deep, fresh to slightly alkaline, and with stable stratification suitable for preservation of organic material. Oligo-Miocene precipitation rates reached up to one metre per year, which favoured deeper lakes. Hot humid conditions will also promote dense vegetation growth and large amounts of organic material will be washed into the basin. The dense vegetation inhibits surface erosion and clastic sediment run-off, which further enhances the source rock potential by diminishing clastic dilution. Intense chemical weathering enhances the nutrient content of the run-off water to promote organic productivity, especially of phytoplankton and cyanobacteria, which are common in present-day African lakes. Some of the lake bottom sediments contain up to 20% TOC in Lake Tanganyika, where water depths were greater than 200m. The lacustrine algal matter generally produces a waxy crude with a fairly high pour point of 40°C, which may require complex production techniques with heated and insulated pipelines.

There is a general problem with predicting source rock maturity where there are variably high heat flows and associated volcanism. Heat flow can be so great that the source rocks can be overcooked within a few hundred metres of burial (e.g. the Main Ethiopian Rift has a geothermal gradient > 200 °C/km in the volcanic segments). Outside the volcanic segments the geothermal gradient is still high and source rocks can be mature at 1–2 km burial. Oil slicks have been recorded in the Abijata, Shala and Awasa lakes of the Ethiopian Rift. However, analysis of slick oil at Cape Kalamba on Lake Tanganyika indicates it was produced by hot springs streaming through shallow organic-rich sediment deposited in the last 25,000 years. Thus, the presence of oil slicks does not guarantee a working hydrocarbon system. All the western branch rifts are predicted to have mature source rocks in the oil generation window.

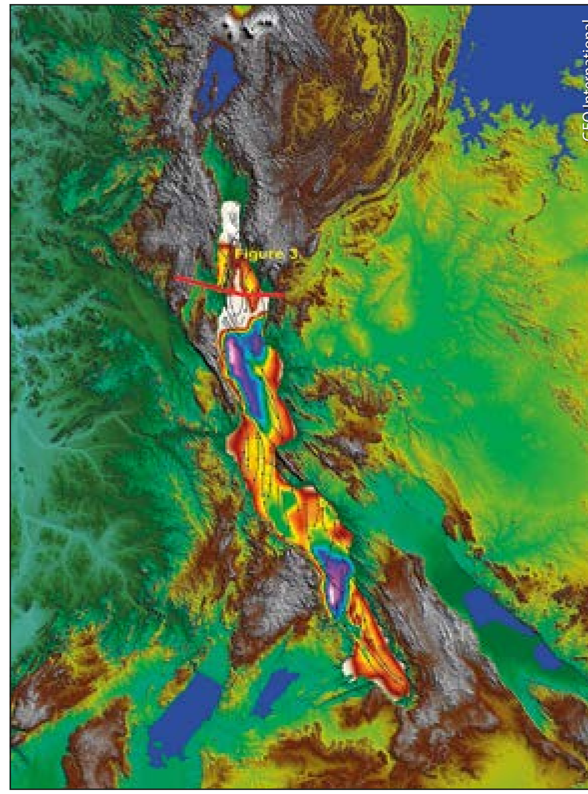
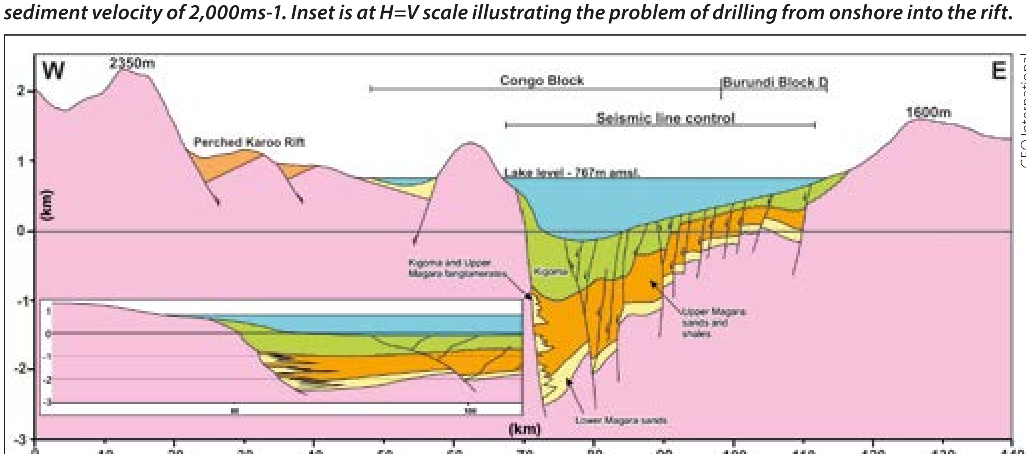


Figure 2: Map of the Tanganyika Rift showing the surrounding topography, the rift fault pattern and the gridded sediment thickness interpreted from project PROBE seismic data (orange shallow to purple deep). Location of cross-section in Figure 3 also shown.

Future Exploration

The East African Rift System is rightly attracting significant exploration interest because it is a very large accessible onshore basin system, and yet has only recently yielded large hydrocarbon discoveries. It remains highly underexplored with only two rifts partially explored so far. Differentiating effective segments of the rift should benefit from relatively intense fieldwork and geochemical exploration methods, neither of which have been applied in much of the rift system to date. Effective prospect maturation can be achieved

Figure 3: Cross-section through the Lake Tanganyika Rift. Depth conversion of seismic data is based on an average sediment velocity of 2,000ms-1. Inset is at H=V scale illustrating the problem of drilling from onshore into the rift.




Geometric Freedom™
starts here.
It's a new way of thinking that opens up a whole new world of possibilities.
Suddenly, you're free to design the seismic survey of your dreams. Anywhere, any time, any way you want.
Forget the limits of fixed intervals. Banish the idea that obstacles are obstacles. These cable-free nodes go wherever you need them—on land, in transition zones, in shallow water or deep—so you can optimize subsurface illumination and spatial sampling in the most cost-effective way.
Solve your most complex challenges without compromising a thing. And get better data no matter where in the world you need it.
Put the power of Geometric Freedom to work for you, with the ultimate nodal technology.
fairfieldnodal
fairfieldnodal.com

with potential field methods such as airborne Full Tensor Gravity Gradiometry (FTG) supplemented with 2D seismic, without the need for expensive 3D seismic (see article on page 74). The combination of appropriate technology and good quality geology has the scope to generate high quality, relatively low cost prospects; and the EARS can deliver play fairways attractive to both smaller and larger companies.

Whilst access is relatively good, with host governments encouraging exploration, there are significant challenges, some specific and some more pervasive. In rift segments with present-day lakes there are some unusual hazards associated with volcanic activity. Around Lake Kivu and in the southern Albertine Rift, for example, CO_2 gas accumulation can be a serious problem. A large build-up of this gas within the mud at the bottom of Lake Kivu can periodically vent and spread across the lake as a density current (being heavier than air). With over two million people living in the lake basin, this could cause mass fatalities. Experimental drilling is being considered to vent the CO_2 before a catastrophic build-up and release can occur. This may also pose a very serious limitation on being able to drill within the Lake Kivu Rift. The Turaco-3 well in the southern Albertine Graben also encountered anomalously high amounts of CO_2 gas and is located near a magmatic segment of the rift, where several hot springs (Figure 5) and volcanic craters are present.

Present–day lakes also inhibit access due to their depth and the lack of ways to bring in floating drilling vessels. Lake Tanganyika, the largest, is 645 km long and up to 1,500m deep, with storm wave heights reaching 6m. Seismic acquired over the lake reveals exciting prospectivity, but clearly drilling will be problematic in the deepest parts of the lake, unless accessible by long reach wells either from shore or possibly from artificial islands in shallow water areas (Figure 3 illustrates the problem).

The western branch of the EARS is considered to be the most attractive; but the main Ethiopian Rift and eastern EARS branch are almost undrilled, and some wells are now required to test whether these hotter rifts have working petroleum systems.

More pervasive access issues relate to production and export options, especially for waxy crudes. Much of the western EARS branch runs at least 700 km inland, and long pipelines to the coast would be required.

Exploration is continuing at a rapid pace, with a high success rate achieved in the Lokichar and Albertine Rifts. The EARS remains highly underexplored, and a combination of geological analysis and modern technology will allow relatively low cost pre-drill analysis. It ought to inspire the smaller, exploration-driven company, for if they can find the oil (and clearly it is there to be found) then history tells us the larger companies will come along to develop it.

Footnote: GEO International Ltd. has compiled a large exploration database on all the interior African Rift systems.

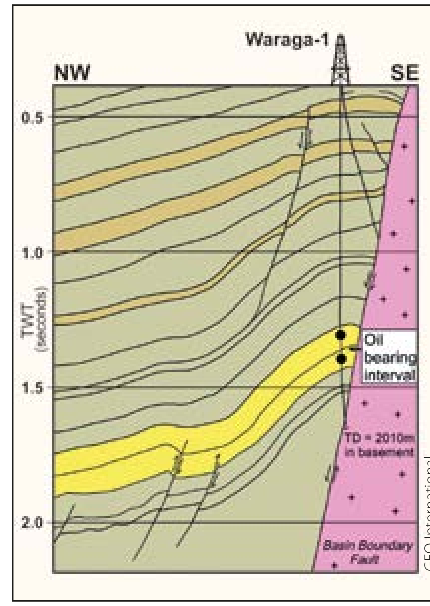


Figure 4: Cross–section through the Albertine Rift Basin showing an example of a successful hanging wall trap, Waraga-1 well.

For more information please visit *www.geointernational.co.uk/studies/african-interior-rift-basins/* ■

Figure 5: Sempaya Hot Springs south of Lake Albert.


Don't miss the world's most focused and comprehensive Arctic event.
OTC's Arctic Technology Conference (ATC) is part of the successful series of events which includes the flagship Offshore Technology Conference in Houston, OTC Brazil in Rio de Janeiro and OTC Asia in Kuala Lumpur. Anchored by 14 of the energy industry's leading engineering and scientific organizations, OTC's cutting-edge conferences, products and services exhibitions have fostered development of the world's oil and gas resources since 1969.
If your job is to discover and effectively and safely produce the vast energy resources in the Arctic, you need to participate in the event that has the industry and society credibility to bring it all under one roof: ATC.
ArcticTechnologyConference.org
COPENHAGEN
23-25 MARCH 2015
BELLA CENTER
DENMARK
ARCTIC TECHNOLOGY CONFERENCE
AN OTC EVENT
SM
SPONSORSHIP AND EXHIBIT OPPORTUNITIES AVAILABLE.


bridgeporth
Let your exploration take-off with Bridgeporth
With a fleet of aircraft and an expert team of geoscientists, Bridgeporth provides airborne acquisition, processing, and interpretation services for a variety of high resolution data, whether it's gravity, magnetics, LiDAR, hyperspectral, photometric, or radiometric.
Choosing Bridgeporth gives you access to unparalleled expertise spanning the entire hydrocarbon and minerals exploration time line, from frontier discovery through to asset identification and development.
To learn more about how Bridgeporth can help get your exploration off the ground:
please visit us online at www.bridgeporth.com
or contact us at sales@bridgeporth.com

Inside the Rock

For the first time, geoscientists can produce 3D images of rock features at a wide range of scales — from millimetre through micron and down to nanometre size — and peer into the rock's porous structure, seeing what is there and how it can be produced most effectively.

ALEXANDER NADEEV and DENIS KLEMIN, Schlumberger

Digital core analysis has become a useful addition to the petrophysics and reservoir engineering toolbox. The integration of digital and laboratory evaluations of rocks provides more and better engineering data than either alone, and that information can be delivered faster than ever before. The new Schlumberger DHD* (direct hydrodynamics) multiphase compositional pore flow simulation is a step-change improvement in the simulation of flow in porous media that can lead to improved recovery of hydrocarbons in the field.

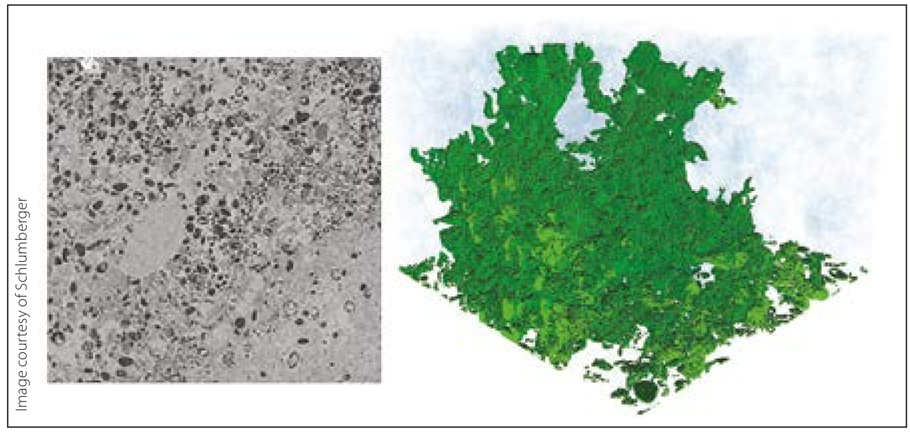
In the 1980s, attempts were made to use processed images of cores to generate petrophysical data. For example, researchers digitised thin section 2D images of core from a well and then evaluated them for size, shape, texture and structural information. This resulted in a large array of statistics about the pore space. From this, researchers developed correlations to the permeability of the rock. This approach required several months of data acquisition, image processing and analysis, and the results were limited by 2D porous structure. Transferring the methodology to another well created additional challenges. Digital analysis of core images to provide useful geological and engineering information had a long way to go.

A whole-core sample is positioned for CT imaging using a dual-energy multislice scanner – the start of the process.

Image courtesy of Schlumberger

New Ways to Know the Rock

Widely recognised components of routine physical core analysis, combined with the latest in digital analysis technology, comprise the earliest stages of the process that culminates in DHD simulation. These different working parts — whole core X-ray computed tomography (CT), micron-scale CT (microCT) imaging, and focused ion beam scanning electron microscopy (FIB-SEM) — can be integrated rapidly to produce an actionable digital rock model. Analysis that previously took weeks or months can be completed in hours or days. Having the power to leverage a working model, one which analyses both rock and fluid properties and involves both physical and digital interpretation, puts operators in a position to better plan for a range of reservoir engineering strategies.



Simulation of tracer flow through Edwards White (outcrop) carbonate. The sample is somewhat heterogeneous, as indicated in the 2D cross-section of a microCT scan (left). A tracer test, shown at first breakthrough of the tracer, also indicates a high degree of heterogeneity in the flow (right).

Simulating core flow for a given reservoir using DHD simulation gives operators more options than ever, enabling the study of multiphase flow from individual pore-scale events all the way up to complex scenarios. The simulator uses density functional theory encompassing a multiphysics envelope. With the ability to track how fluids will move through pore throats, this new introduction of digital-meets-physical analysis can consider the effect of mixed wettability, complex rheologies, and changes in saturation as water drives production. Phase transitions can be observed as pressure drops beneath the fluid bubble point. This ability to change properties based on reservoir pressure or temperature condition is important because these transitions can lead to major differences in production efficiency.

Rock and Fluids Measurements Meet

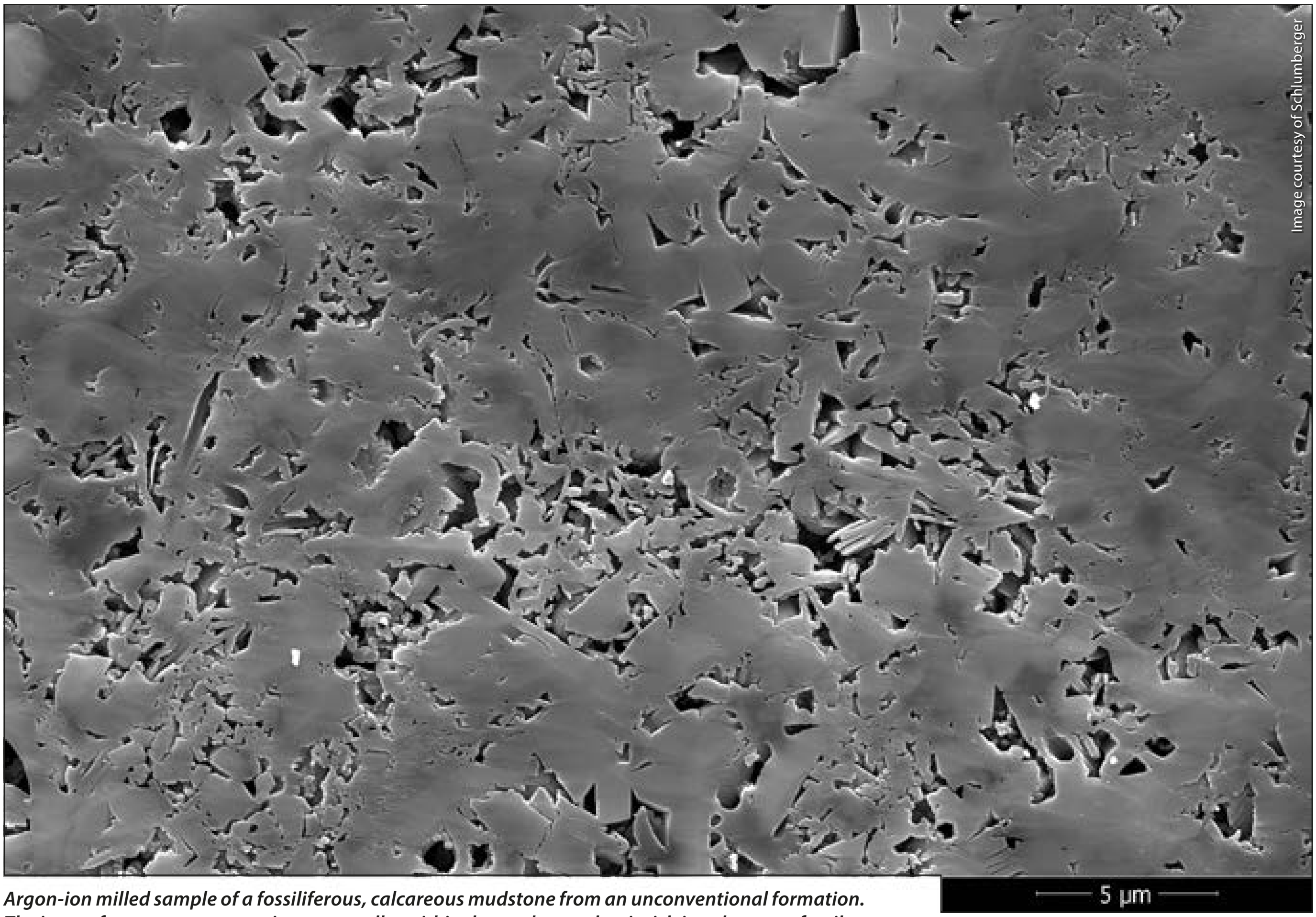
At the Schlumberger Reservoir Laboratory in Houston, the process of analysing rock and fluid properties follows three basic steps in one workflow: characterisation, simulation, and validation. All of this is made possible through the use of CoreFlow* digital rock and fluid analytics services.

Characterisation constitutes measurements of basic fluid, rock, and fluid-rock properties, including PVT data, rheology, fluid-fluid and rock-fluid interactions, and rock morphology. Simulation comprises building digital models to explore rock-fluid and fluid-fluid dynamics. During validation, the results are authenticated through laboratory tests and core analysis — first with well-defined samples, then progressing to more complex examples. The physical laboratory testing component helps to refine the DHD modelling, thereby enhancing and confirming the digital measurements.

Whole core CT scanning is a typical start for the process. At this stage, operators are able to select samples for additional core analysis and imaging, while the whole core (e.g. 4" diameter) is still in the liner. The 0.5 mm slice resolution from this imaging allows for the selection of a representative core sample with greater speed and ease, helping operators determine areas of interest for their reservoir evaluation. The rock sample obtained from this evaluation can be analysed to determine physical properties and is also used during digital analysis.

To create a core flow model, the

CoreFlow services SEM analysis typically provides key insights into the petrology of conventional and unconventional formations.



Argon-ion milled sample of a fossiliferous, calcareous mudstone from an unconventional formation. The image focuses on an organic matter pellet within the mudstone that is rich in calcareous fossils. The skeletal structures of these fossils provide a framework that preserves high porosities within the rock.

samples then undergo another round of imaging at higher resolution based on the formation's geological properties. Operators working with conventional reservoirs, like sandstones and carbonates, can determine flow characteristics by using microCT imaging and analysis. Using microCT plugs taken from the original core, micron-scale resolution images can be captured to show pore and grain characteristics (see page 33, top image). The digital porosity and simulated permeability can be compared with routine analysis measurements on the mini-plug. The use of the same plug enables operators to compare physical and digital results on a one-to-one basis, without risking possible miscalculations because of slight differences from sample to sample.

Because flow in unconventional reservoirs includes pores hosted by organic matter, instead of the larger pores found in conventional reservoir types, higher-magnification imaging is necessary to get the most accurate look at a sample. SEM provides 2D images that can reveal features as small as nanopores, in addition to offering a closer look at mudstone texture, which is useful in evaluating producibility. Further insight into pore connectivity can be determined by obtaining 3D images in an FIB-SEM.

Reservoir Characterisation Answers Revealed

Both microCT and FIB-SEM 3D images can be converted to digital rock models that distinguish between minerals and the porous flow paths. These models are combined with a digital model of the reservoir and injection fluids to enable the DHD simulation of flow. This is the industry's first simulation to combine digital rock models, complex compositional digital fluid models, 3D wettability distribution, and set-up of boundary conditions to simulate fluid flow through porous media. The simulator output can be compared with a laboratory measurement, such as relative permeability, and then extended to additional simulations that would be difficult, time-consuming, or prohibitively expensive to do in the laboratory. This scenario evaluation provides operators with actionable results to optimise field development plans, including identification of the most important parameters involved in displacement efficiency.

DHD simulation measures capillary pressure, relative permeability, recovery efficiency, and flow heterogeneity. This kind of dynamic modelling and comprehensive reservoir understanding based on fundamental physics has not been possible in the past. DHD simulation provides the reservoir characterisation answers necessary for reserves estimation, and offers an unmatched level of detail in modelling that can be used to improve production scenario planning decisions for optimised hydrocarbon recovery. ■

**Mark of Schlumberger*

Guinea-Bissau:

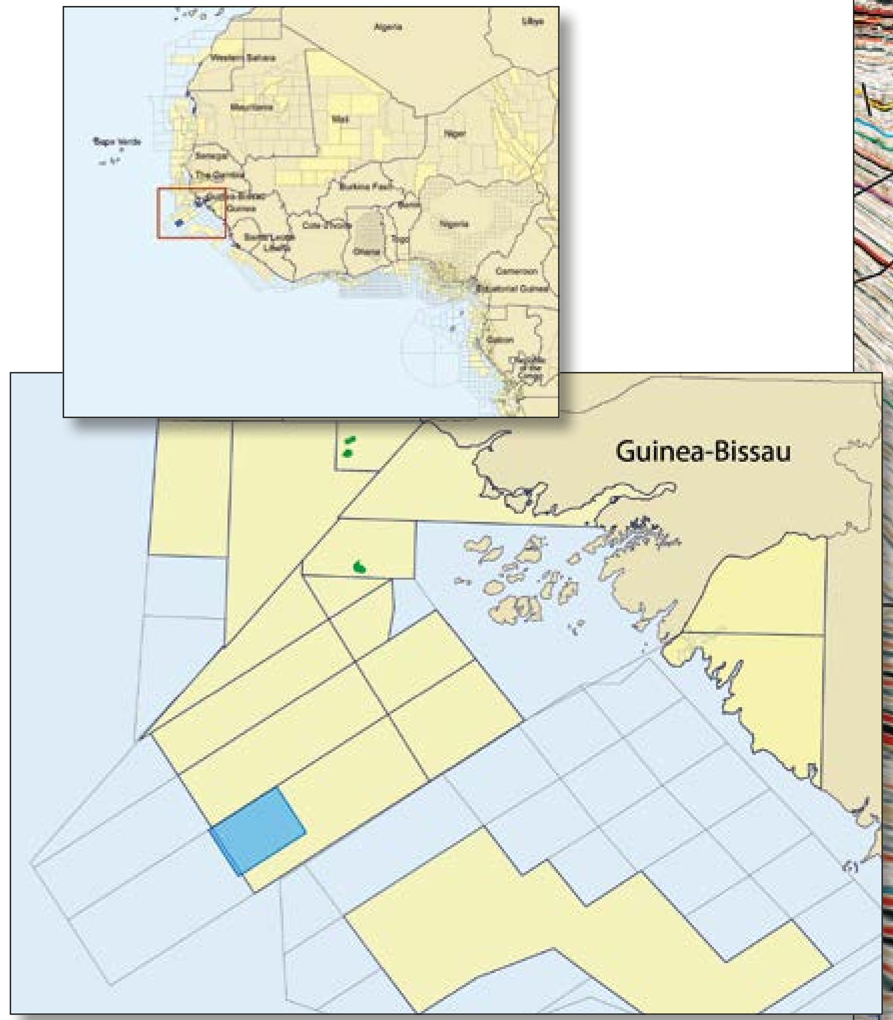
New Insights into the Geology and Deepwater Exploration Potential

Polarcus

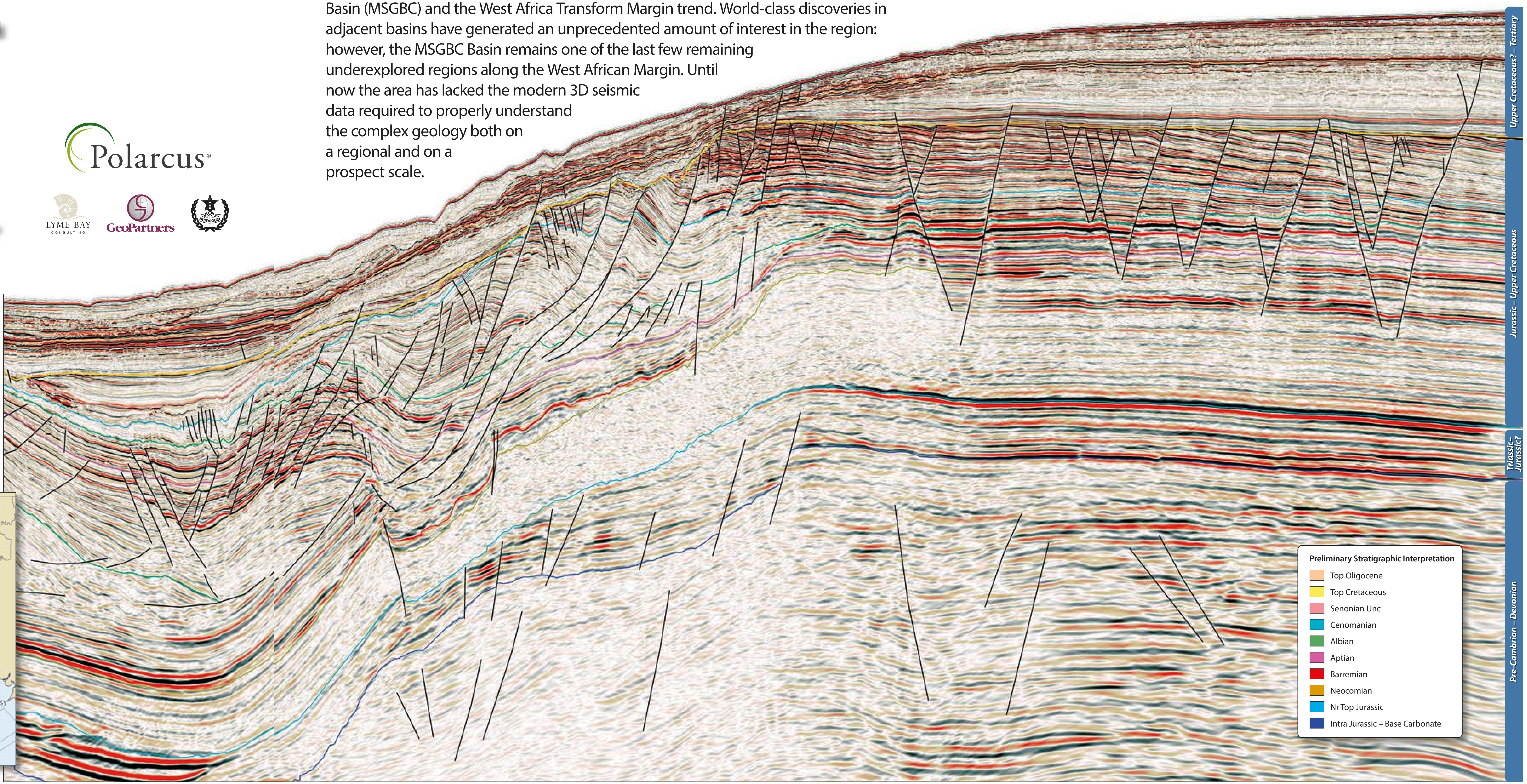
LYME BAY CONSULTING

GeoPartners

Guinea-Bissau lies at the confluence of the Mauritania-Senegal-Gambia-Bissau-Conarky Basin (MSGBC) and the West Africa Transform Margin trend. World-class discoveries in adjacent basins have generated an unprecedented amount of interest in the region: however, the MSGBC Basin remains one of the last few remaining underexplored regions along the West African Margin. Until now the area has lacked the modern 3D seismic data required to properly understand the complex geology both on a regional and on a prospect scale.



SW-NE In-Line showing the collapse of the Guinea platform margin.



Guinea-Bissau: Improved Imaging and New Insights

A detailed reconnaissance study of Polarcus's 3D multi-client data has revealed a complex shelf to basin sediment transport system feeding into classic deepwater West African plays

TONY PEDLEY, Polarcus and GERRARD SPEAR, Lyme Bay Consulting

The MSGBC Basin is the largest of the offshore north-west African Atlantic Margin basins, covering some 600,000 km^2 and extending almost 1,500 km along the margin from the Cap Blanc Fracture Zone in northern Mauritania, south through Senegal, Guinea-Bissau and Conarky to the Guinea Fracture Zone in the south. The basin can be divided into a number of sub-basins aligned in a north-south direction and delimited by east-west fault systems related to syn-rift tectonics. The sub-basins between the fracture zones have similar overall architecture yet each sub-basin has a different sedimentary and tectonic history. This, in part, is related to presence or absence of salt.

Polarcus, in collaboration with Petroguin and GeoPartners Ltd, acquired in 2013 approximately 2,380 km^2 of broadband multi-client 3D seismic data within Block 7B, offshore Guinea-Bissau. The data provides significantly improved imaging and provides new insights into the exploration potential of the area and the wider region.

Project Description

Polarcus acquired this multi-client data in this geologically complex area using the *Polarcus Naila*, towing a 10 x 100m x 8,100m ultra-quiet Sentinel® solid-streamer spread and a 25m alternating shot interval, delivering 81 fold data and a 6.25 x 25m acquired bin size. The data has been processed by DownUnder GeoSolutions through a state-of-the-art true-azimuth 3D SRME and Pre-Stack Time Migration flow.

Interesting Structures

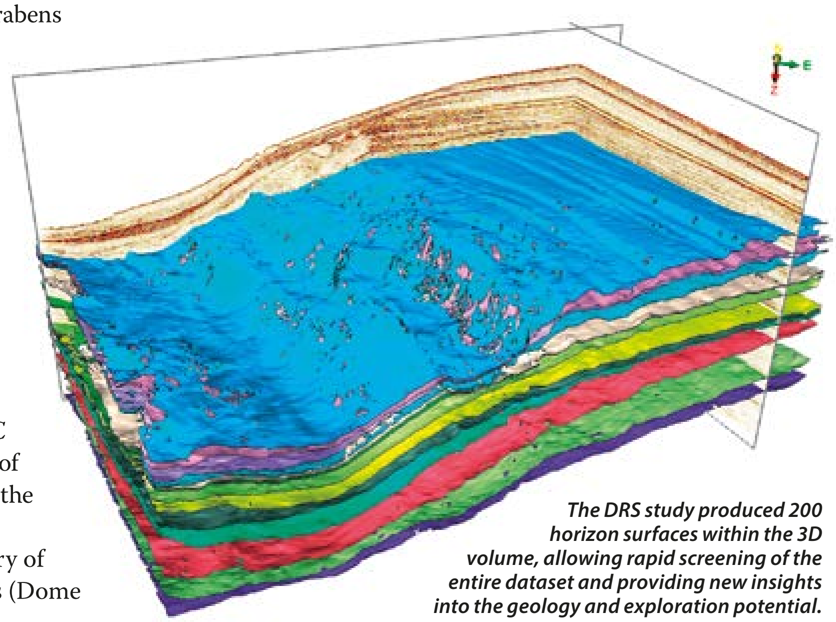
Guinea-Bissau Block 7B lies within the Casamance sub-basin, the southernmost of the MSGBC Basins. The Polarcus 3D covers the shelf to basin transition in the south-western area of the block, with water depths ranging from 150m to 1,500m. The foldout line shows a typical cross-section, exhibiting the variation in structural and stratigraphic character across the shelf-slope break.

Break-up of the Pangaea supercontinent in the MSGBC Basin area began during the Late Permian to Early Triassic. The syn-rift sequence consists of Triassic to Lower Jurassic clastic sediments deposited in a series of grabens and half-grabens as the region extended, in some areas with the development of evaporites. The overlying post-rift sequence consists of Jurassic to recent clastic and carbonate units, with reefal facies in the Lower Cretaceous, and the possibility of laterally extensive Upper Cretaceous turbidite deposits as recognised in Senegal to the north. The carbonate shelf was eventually shut down by clastic input from deltas prograding from the east. The salt layers which are characteristic of other areas of the MSGBC Basin thin towards the south-eastern part of offshore Guinea-Bissau and interplay with the Upper Cretaceous fan systems.

The Casamance sub-basin has a history of exploration with a number of discoveries (Dome Flore, Dome Gea, Sinapa) and several wells encountering oil shows (PGO-3, PGO-2, BASS-1). Exploration to date, using only 2D seismic data, has been focused on the more shallow water near shore areas, where a variety of clastic and carbonate reservoir horizons have been encountered by historic drilling. Reservoir quality is good to excellent in several of these wells; however, to date no wells have been drilled in the deeper water areas. The wells in the northern part of the basin targeted deep anticlinal structures and those in the central part of the basin sought salt-related traps.

Two Geological Regions

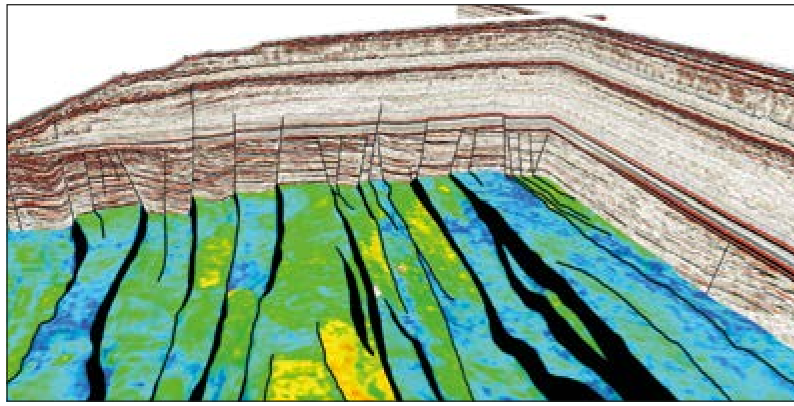
To evaluate the geology and gain insights into the prospectivity of Block 7B, Lyme Bay Consulting Ltd applied their Detailed Reconnaissance Study (DRS) workflow to the Polarcus 3D dataset. The DRS builds a geological representation based on the underlying seismic data, a GeoModel, which calculates and correlates the relationship between 3D seismic points according to the similarity of the wavelets and their



The DRS study produced 200 horizon surfaces within the 3D volume, allowing rapid screening of the entire dataset and providing new insights into the geology and exploration potential.

distance from each other. This process automatically tracked every reflector within the seismic volume where a relative geological time/depth was computed for every point, producing a horizon for each and every reflector within the dataset. Attributes were then calculated from the original input seismic and overlain on the horizons to deliver a high resolution reconnaissance tool to enable identification of structural and stratigraphic features within the 3D volume.

Offshore Guinea-Bissau can be broadly divided into two geological regions: a shallow water relatively tectonically quiescent area, and a deeper water highly deformed collapsed margin.



A series of laterally extensive north-north-west – south-south-east trending normal faults affecting the Lower Cretaceous sequence beneath the regional Senonian unconformity.

The shallow water platform area is characterised by the Guinea Plateau, a large marginal plateau clearly seen on the free air gravity and bathymetry maps. This consists of Jurassic and Lower Cretaceous carbonates overlain by Cretaceous to Tertiary clastic sediments. The Tertiary sequence displays well developed polygonal faulting due to fluid overpressure and expulsion. Beneath this a series of north-north-west – south-south-east trending grabens, half-grabens and horst blocks can be seen throughout the Cretaceous sequence below a regional Senonian Unconformity (see image above) which has removed some 1–2 km of strata from the outer margin of the bank. Within the Cretaceous sequence faulting can be seen to be generally laterally extensive; deeper in the Mesozoic section the DRS has, however, illustrated a different tectonic fabric with less laterally extensive faulting, displaying a more north-south orientation.

Seaward of the Guinea Plateau, the Mesozoic and Tertiary sediments have been heavily deformed by structures (slumps, listric faults, folds, etc.) generated by the gravitational collapse of the sedimentary cover along the margin. The collapse led to a highly complex interplay of tectonics with multiple levels of detachment.

Several Play Types

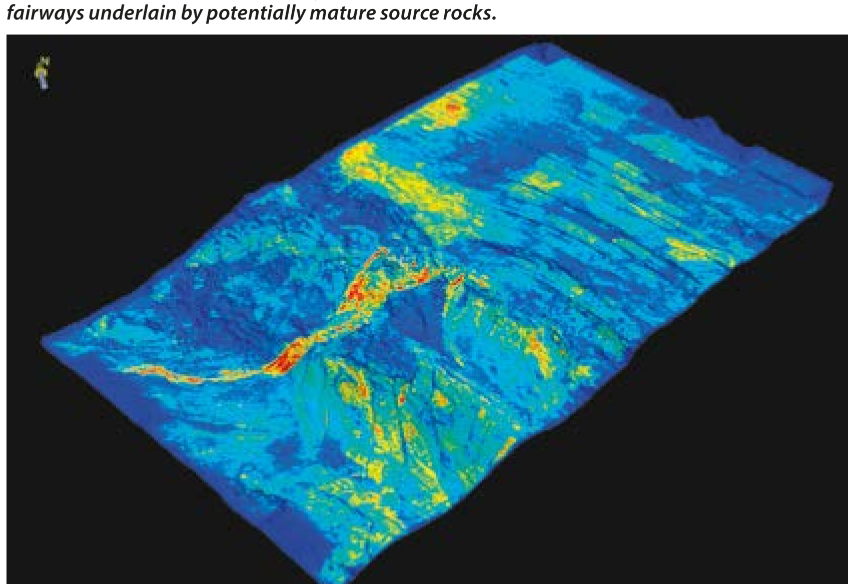
The main play types expected within the 7B Block are: Upper Jurassic and Lower Cretaceous marine carbonates (providing both source and reservoir) with the potential also for a Lower Cretaceous lacustrine source, Lower Cretaceous (Aptian-Albian) clastics with Cretaceous-Jurassic source, and Upper Cretaceous (Cenomanian-Turonian) clastics with a Cretaceous source. The presence of a working petroleum system is suggested by numerous oil seeps and surface geochemical samples as well as the nearby well results and discoveries.

Frequent structural closures can be observed on the 3D data. A key to evaluating the prospectivity of the deeper water areas, however, is understanding the potential for clastic input into any potential play fairways. The DRS study has shown clear evidence of a number of channel systems throughout the Cretaceous sequence on the margin slope to basin area (see image below). A major depositional system has been recognised extending from the area of the shelf-slope break into the deeper marine offshore area. A number of other smaller scale distributory systems have also been recognised, generally consisting of channel systems, in places showing amalgamation and deflection against structural relief.

Historic seismic data has not been of sufficient quality, or had adequate coverage, to allow proper investigation of the plays beyond the shelf slope break. The basin-ward extension of the reservoirs encountered by historic exploration has therefore, to date, been unknown. Analogy to other deepwater basins in West Africa and elsewhere suggests these facies may be potentially excellent reservoirs. The DRS study provides clear evidence, hitherto unavailable, of potential reservoir sands being delivered to the basin over an extended period of time. Both structural and stratigraphic traps have been identified and the new seismic data and DRS study provide fresh encouragement that the deepwater may contain all the necessary elements of a successful petroleum system.

Selected references available on www.geoexpro.com ■

Development of a Cretaceous slope to basin channel system. A succession of such features highlights the potential for delivery of clastic sediments into intra-slope and base-of-slope play fairways underlain by potentially mature source rocks.



The Quantification of Uncertainty in Reservoir Management

NIKKI JONES

New developments in history matching improve uncertainty quantification and risk assessment in reservoir management.

Improving the analysis of risk in field management is the Holy Grail of reservoir modelling and in recent years history matching has become a vital tool in this process. As explained by Jon Saetrom, Chief Science Officer of Resoptima, an independent technology company delivering software solutions and consultancy services to the oil and gas industry, the main purpose of history matching is "to generate geological and reservoir simulation models which honour both static and dynamic data measurements and can provide reliable predictions regarding the future state of the reservoir." The assumption is that if a reservoir model reacts in the same way as the actual wells when under historical constraints, then it will behave the same way as the actual wells under future constraints; but if it does not correctly predict past observations, then it is very unlikely that the reservoir model will accurately predict future production data. "Using methods and tools which can help improve the model predictability is therefore key to better reservoir management," Jon concludes.

Building Models – and Uncertainties

The process of data accumulation begins as soon as a prospect is identified, with magnetic and gravimetric data plus seismic analysis feeding into a basic model of the geological history, with some regional estimates of the reservoir's potential quality. More data comes at the appraisal stage as the first well is drilled, when the development geologists and petrophysicists put together a static model. Each stage in this process inherently carries a level of uncertainty due to this wide range of data, so subsurface teams generate multiple equally plausible static geo models, which try to give an estimate of the uncertainty.

At this stage, for practical reasons the geologist traditionally provides one geo model on which the engineers will develop a dynamic model ready for simulation and history matching. This initial step results in a huge loss of potential subsurface data and an appreciation of subsurface uncertainty and their relationships is lost.

The engineers assess the ranges of uncertainty in the single model and eliminate what are perceived to be those with least influence, driven by a need to reduce the number of uncertainties so as to decrease the computing power and time needed to achieve a history match during simulation. Finally, the history matched result is often achieved through 'altering' the model to fit the data – similar to the traditional curve fitting approach – potentially leading to a model that is geologically implausible. Thus the process of 'anchoring' to a single base case model, eliminating uncertainties established in the modelling process in order to cut down on computational time and focusing on the history match at the expense of the underlying geology, results in a poor ability to accurately predict the future field development.

The single history matched model is used to simulate the field's response to production, taking into account, for example, pressure changes, fluid dynamics and other active

Uncertainty in reservoir modelling – base case model. Each branch of the tree represents different modelling choices; e.g. choice of seismic processing vendor, different geological concepts, well-log interpretation, choice of lithofacies modelling technique, etc. Each leaf represents individual reservoir models – all honouring the same data measurements. Hence, making decisions based on one single base case model is a big leap of faith.

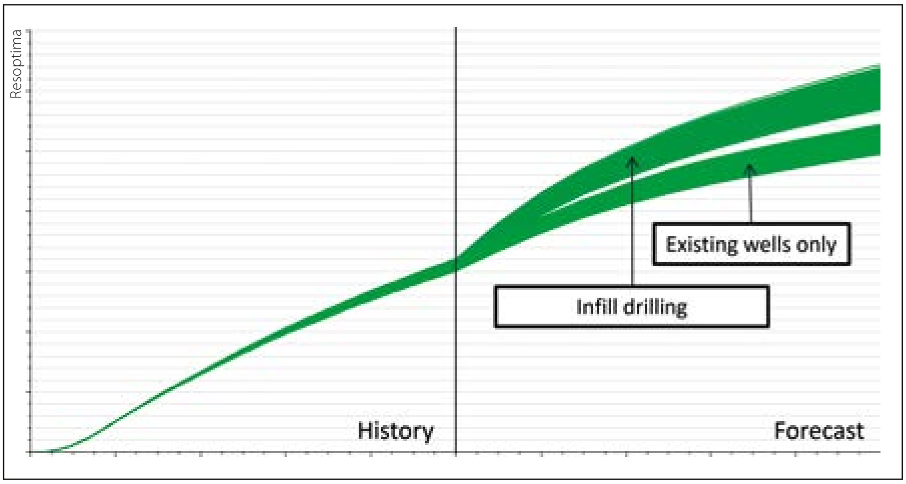
well data. Actual behaviour during production is matched to the best fit dynamic model and once a good match is achieved, the model is run forward in time in order to make projections of production and pressures. The model will help to identify where there is missed oil and a need for infill drilling, whether investment in new drilling is required, or whether field depletion and water cuts make further investment unviable. If the predictions made by this single reservoir model are unreliable, the consequences for an oil company can be quite dramatic when the cost of drilling a single well can be $100 million or more.

The Range of Uncertainty

The ideal solution would therefore be to develop a system that allows many more models to be history matched and provide a greater – and more accurate – range of the uncertainty space.

The E&P industry has been working on this since 2001, adopting the improved algorithm Ensemble Kalman Filter (EnKF), which is widely used in many fields such as weather forecasting and the car industry. In the ensemble-based approach, the full range of geo models is taken forwards, capturing key uncertainties in connectivity and reservoir quality where previously there was just one. Hence, with this approach there is a natural link between geologists and engineers, which can greatly improve how teams collaborate together building the range models and populating the static and dynamic properties. Each model realisation is geologically sound and represents one possible outcome of the various modelling choices – one leaf node in the uncertainty tree. Hundreds of uncertainties are captured and taken forwards to the history matching stage. This results in a set of reservoir models which are geologically consistent and honour the dynamic production data, which ultimately leads to improved predictability.

Since its launch in 2010, Resoptima has been working on a suite of software aimed at improving reservoir management. In 2013 it launched ResX, the industry's first commercial software platform for computer-assisted history matching and production forecasting using ensemble-based methods. ResX uses the latest developments in data-assimilation techniques to generate highly reliable reservoir models honouring both static and dynamic data. Taking advantage of high performance computing facilities by running flow simulations in parallel, results can be obtained in a highly efficient manner. This new and innovative solution enables data-driven decisions by utilising the increasing volume and detail of data captured in the E&P industry, allowing companies to generate reliable future production



Reservoir management under uncertainty. Multiple reservoir models are generated, all honouring both static and dynamic data (in the historic period). Even if the set of models all honour the same data measurements, there is still significant uncertainty in the production forecast. However, by using multiple models it is a straightforward task to quantify the prediction uncertainty and assess the risk of various investment decisions (in this case, infill drilling).

forecasts with a thorough quantification of uncertainty, and focus on making the right decisions to maximise recovery, while minimising financial risk.

"The workflow streamlines the process from geo modelling to flow simulation. This means that we can easily test different geological concepts or alternative modelling uncertainties and quickly see the response in production profiles," Jon explains. "Using the ensemble methodology, we are able to capture the prior uncertainty in a model by sampling static uncertainties such as porosity, permeability and net-to-gross, with dynamic uncertainties derived through the integration of production data."

"The application of an ensemble-based approach through ResX allows E&P companies to drastically improve the reliability of their reservoir models, quantify the uncertainty in future production forecasts, and use simulation of future production scenarios as key input to investment and operational decisions," says Tore Felix Munck, Managing Director of Resoptima.

Geologically Sound Matches

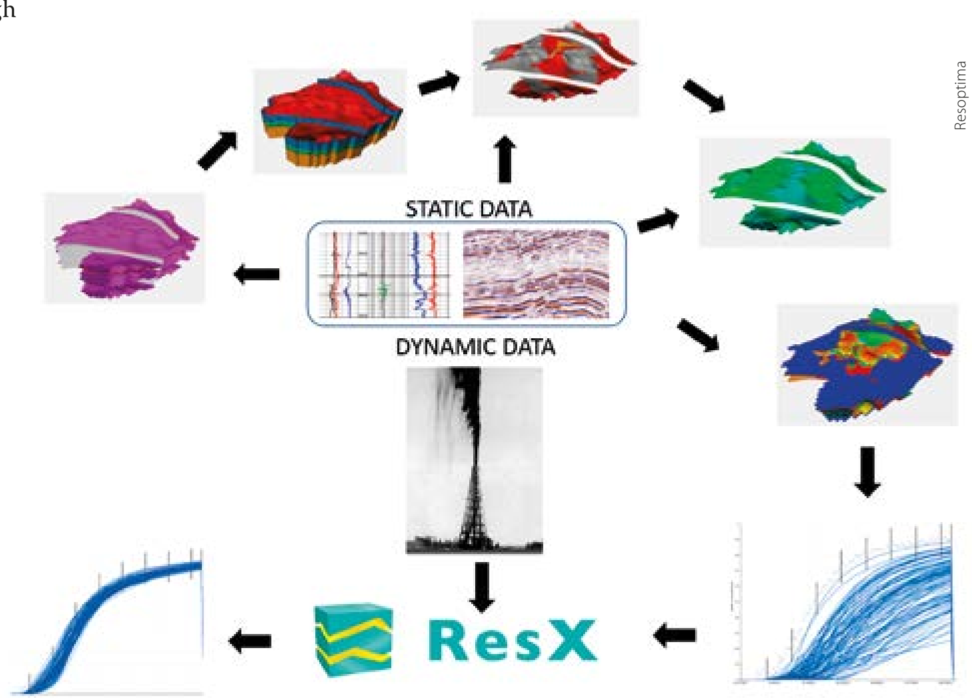
In addition to providing high quality and predictable history matches, the company believes that ensemble-based history matching greatly speeds up the time required for the matching process. It also scales very well with model size and complexity, making it ideal for large super fields with many years of production history. With efficient use of computer resources and man hours, ensemble techniques provide for competent end-to-end workflows that lead to an increased confidence in reservoir development planning and an optimisation of decision-making processes, potentially resulting in substantial cost savings for exploration and production companies.

ResX was commercially released in October 2013 and the technology has been well received by the industry. "Since its initial release, the technology has been used by several well established E&P companies. We clearly see a demand for tools which streamline the reservoir modelling and history matching process, and we are currently working closely together with the industry to further improve the technology," Tore says.

Ensemble-based history matching in reservoir modelling has proved it can provide high-quality, geologically sound and reliable history matches, with superior results when compared to other methods, and a thorough quantification of uncertainty. The method can easily be scaled to fit large, complex models and it provides reservoir models with a high degree of predictability, resulting in improved reservoir management.

Whether this means that for reservoir engineers the search for the Holy Grail is over remains to be seen. However, since this is a business where the wrong decision can easily mean a loss of $100 million or more, any effort which can improve the uncertainty quantification and risk management is likely to be welcomed throughout the industry. ■

Ensemble-based history matching using ResX. An automated workflow streamlines the process, moving from geological modelling (structural modelling, grid building, facies modelling, petrophysical modelling and water saturation modelling), conditioning on static input data (i.e. seismic and well logs) to flow simulation and dynamic data conditioning using ResX.



Whale Hunters Seek Elephants

JANE WHALEY

Atlantic Petroleum is a small independent E&P company with big ambitions. With a strong concentration on technical expertise and some very creative geoscientists, it is looking at some exciting exploration licences on the Norwegian Continental Shelf.

The Faroese are known worldwide as great seafarers and fishermen and for centuries they have hunted the whales that inhabit the wild waters surrounding their islands. But in 1998 a group of them decided to look for a new quarry – elephants (of the hydrocarbon variety, obviously!).

Calling themselves Atlantic Petroleum, the eighteen Faroese investors obtained their first licence in their native waters in 2000, using the initial Faroese licensing round as a basis for entering into partnerships with strong international oil and gas companies. They soon began to move further afield, farming into acreage West of Shetlands, Ireland and the UK North Sea.

"We like to find good prospects in proven places," explains Susanne Sperrevik, Exploration and Business Development Director for Atlantic Petroleum's Norwegian arm. "We are a full cycle E&P company with a North West European focus, and we are looking for growth through licensing rounds, farm-ins and acquisitions."

Jumping into Norway

By 2012, Atlantic had been party to a number of discoveries in the Central North Sea, had participated in drilling off Ireland and had been awarded significant acreage in the 3rd Faroese Licensing Round. In addition, after farming into a number of producing fields, production from the UK was bringing about 2,000 boepd net to the company. Then, in November 2012, Atlantic expanded its portfolio considerably through the acquisition of Emergy Exploration, newly pre-qualified to work in the Norwegian Continental Shelf.

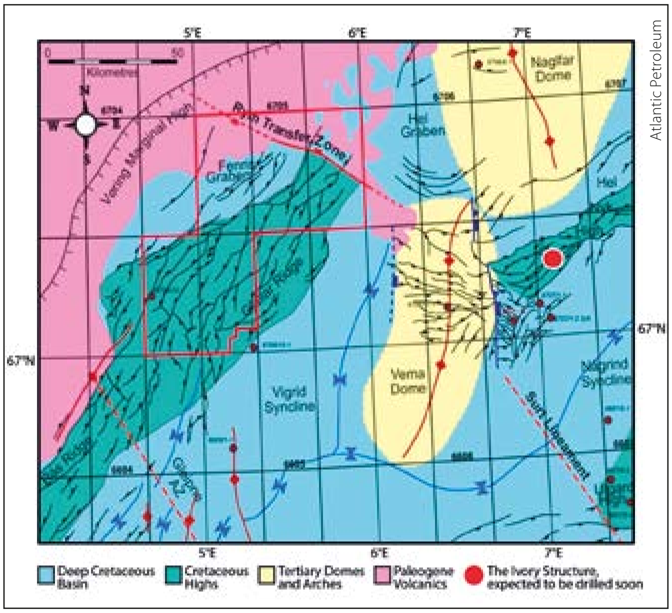
"In less than two years in Norway we quickly built a promising portfolio in the country, with two awards in the 22nd round; two in APA 2013, two extensions and six farm-ins," says Susanne. "Through these we jumped enthusiastically into the deepwater Vøring Basin, a proven gas province, building a position around new planned infrastructure."

The Vøring Basin is part of the Atlantic passive margin in the Norwegian Sea, several hundred kilometres north of Trondheim, with water depths which vary from 800 to 2,000m. Drilling in the basin did not start until 1997, but since then it has been the site of a number of discoveries, including the giant Ormen Lange gas field, which has recoverable reserves of about 14 Tcfg.

"The area has a number of proven gas plays, but we believe there could also be potential for oil," Susanne explains. "Whilst the discoveries in the acreage near us are all gas, some do have oil shows.

"In the basin there are many large structural closures, formed when it was inverted in the Early Tertiary, which could also have stratigraphic upside. We have identified multiple targets, mainly upper Cretaceous deep marine fans sourced from East Greenland. The Nise Formation looks particularly interesting, as does the Kvitnos Formation, which can be up

The Norwegian Sea as seen from the Faroes.



Atlantic Petroleum

Map of the Vøring Basin in the Norwegian Sea showing the main geological provinces and structural elements.

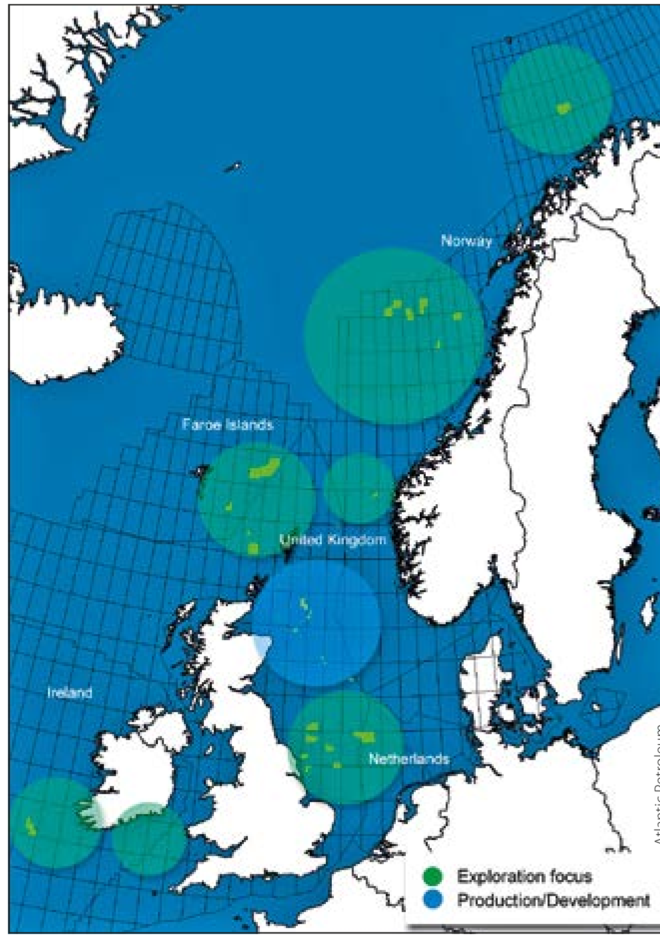
to 1,000m thick in this area, and the Lysing Formation also shows promise. Probable source rocks are the gas-prone Lower Cretaceous, although we see some oil-generating potential in wells further away.

"We believe that while the 'easy' targets are already drilled, the basin is essentially underexplored," Susanne explains.

Technical Expertise

Atlantic Petroleum believes that what it brings to any partnership is technical expertise. "We are not operators, at least for the moment," explains Aris Stefatos, Technical Director based in Norway. "We are basically a small technical company with less than 30 employees – but many of them are geologists, geophysicists and engineers. We have some excellent, very creative geoscientists, who are very open-minded and eager to try new things.

"We prefer to take between 10% and 30% interest in



Atlantic Petroleum

Overview map showing Atlantic Petroleum licences and activity.

licences, depending on the opportunity, and we are now partnered with more than 30 reputable companies. Because of our technical expertise we like to be active partners in our licences and through our technical support to contribute to the decision-making process. Our geoscientists are very good at using modern techniques such as EM to identify clear DHIs (Direct Hydrocarbon Indicators), through which it is possible to significantly reduce the exploration risk."


Jonny Hesthammer

Norwegian Ivory

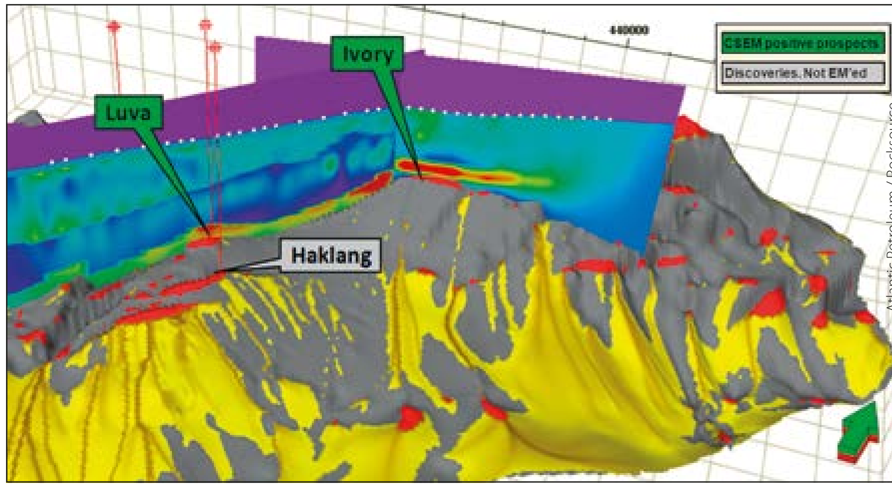
The company hopes it has moved one step closer to finding its elusive Norwegian Sea elephant by farming into the Ivory prospect in PL 528/528B on the Nyk High in the Vøring Basin, which is due to be drilled later this year. It is located next to, and will test the same play as, the Luva gas field, now known as Aasta Hansteen (1.66 Tcfg), and the Haklang (6707/10-2A) gas discovery.

"Ivory has had many changes of partnership and it's been a long road to drilling – people have been hunting this elephant for some time!" explains Susanne. "Now, it is finally going to be investigated by the drill bit. Our targets are the deep marine sandstones of the Kvitnos and Lysing Formations, with identified upside in Nise 1. Seal is considered the main risk for Kvitnos and Nise 1 and reservoir quality for Lysing. Our partner Rocksource currently carries a pre-drill resource range estimate of 50–230 MMboe for the primary target only. Ivory will be the first well on this block, and since it contains a number of other interesting structures and potential stratigraphic traps, significant additional prospectivity in the block will be de-risked if it discovers hydrocarbons."

So why has this promising-looking structure never been drilled? "The Ivory prospect is a large structure with multiple levels, leading to a very complex seismic picture," Aris explains. "There was a lot of shadowing and noise on the data, making it difficult to clearly identify seismic flat spots similar to those found in the neighbouring Luva and Haklang discoveries, but if you looked closely it was possible to see a number of flat spots, pull-downs and similar events.

"Earlier this year, we secured access to electromagnetic (EM) data over this and the neighbouring licences and our technical staff has spent several months analysing the data together with other available geological and geophysical information. Although we only have 2D data, the results from these studies are encouraging as they provide multiple evidence of a good strong response over a resistive area covering about 85 km^2. What is particularly exciting is that if this response is related to hydrocarbons, the column must be much bigger than it would appear from the seismic," he adds.

The Ivory prospect is only 15 km from the Statoil-operated Aasta Hansteen development, which is due to go on stream in 2017. If Ivory discovers hydrocarbons, they could easily be tied into this existing infrastructure, which would establish the Aasta Hansteen field as a hub for gas in the area, thus allowing the establishment of a new gas province.



Both Ivory and Luva (Aasta Hansteen) are associated with clear EM DHI responses that fit migration modelling results.

Big Ideas

"So far, we have only drilled one well in Norway: Langlitinden on block PL659, which proved to be an oil discovery but with relative tight sands," Susanne says. "However, over time we plan to increase our activity on the Norwegian Continental Shelf to drill three or four wells a year."

Atlantic Petroleum is listed on the Copenhagen Stock Exchange and on the Oslo Børs and has technical offices in London and Bergen, with the head office in Torshavn in the Faroes. With cash flow from production assets funding exploration activities, which gives it a lower risk profile than pure play exploration companies, and with an attractive asset base of exploration opportunities, this company seems to be going far.

"With our core of technical and operational expertise, we are open to anything big and exciting!" adds Aris. "A small company with big ideas!" ■

Aris Stefatos, Atlantic Petroleum's Technical Director, and Susanne Sperrevik, Exploration and Business Development Director, Atlantic Petroleum Norway

The Power of Movement

EUAN MACAULAY and JENNY ELLIS, Midland Valley

Kinematic modelling and analysis unlock many secrets of geological systems, providing a structurally valid framework for further analysis and risk assessment, ultimately reducing uncertainty in hydrocarbon exploration and production.

Timing is critical in the formation of any petroleum system: if the key elements are not in place at the correct time, hydrocarbons will not form or accumulate. Understanding how these systems evolve through time is therefore essential for maximising the likelihood of success and providing information on which to base future decisions regarding the development of a resource. Kinematic modelling gives us the tools to 'see' into the past, allowing for a robust analytical study and therefore provides us with a way to better understand the evolution of petroleum systems and to develop realistic geological models.

4D Thinking

For more than thirty years, geoscientists at Midland Valley Exploration have used restoration and balancing techniques to unravel the geological evolution of petroleum systems, and to extract unseen information from available data. In consultation projects, this approach has facilitated the identification of new plays and additional resources, helping make informed decisions, improving well planning, and reducing risk associated with hydrocarbon recovery.

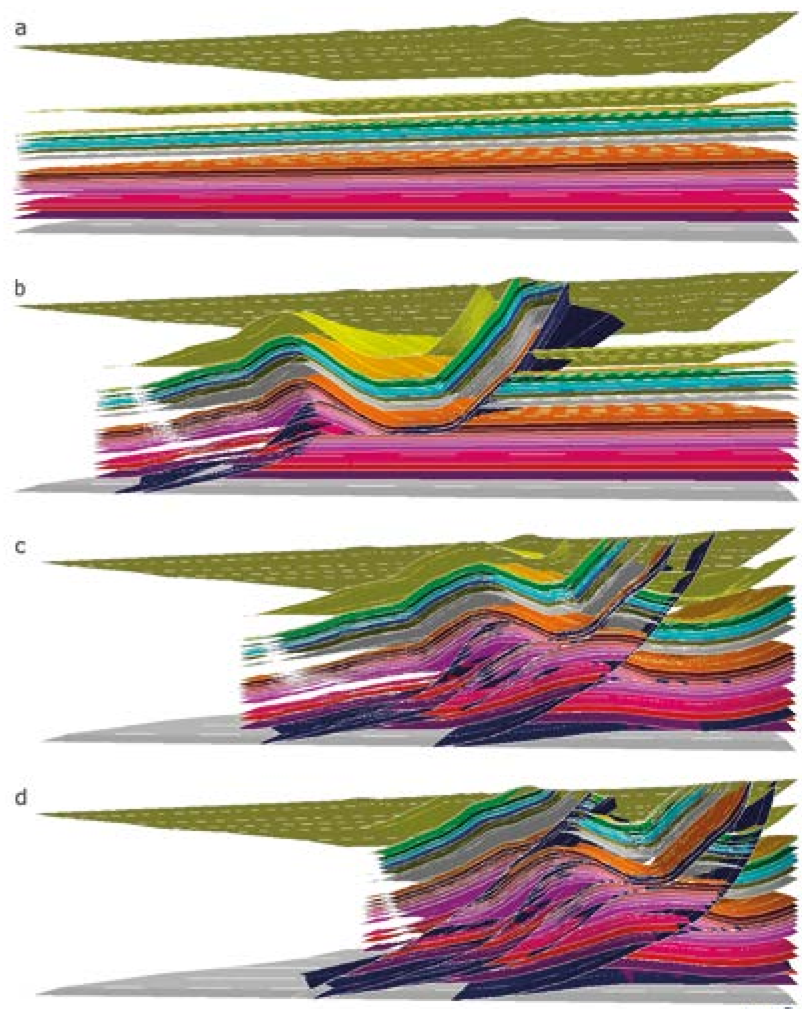
The key tool for investigating the past is Midland Valley's Move™ software, which has been developed by geoscientists working in close collaboration with software developers. The innovative approach, driven by geoscientists, has remained central throughout the development of Move. This has ensured that every tool is efficient and easy-to-use, therefore allowing users to quickly generate and analyse two- and three-dimensional models and see evolution through time (the fourth dimension). The result is a software package that can be used to test and differentiate between alternative interpretations; identify key geological events; predict palaeo-basin architecture; analyse sediment dispersal and salt movement; and provide the ability to model strain and fracture systems. Collectively, these tools and techniques have the ability to solve many of the geological problems commonly investigated in the oil and gas industry, offering unparalleled insight into the geological evolution of petroleum systems.

Questioning Interpretations

Interpretations remain a geoscientist's best estimate of the truth. They need to be as accurate as possible to ensure that the right decisions are taken in the development and management of a prospect, or in planning further exploration. Strong emphasis must be placed on the importance of developing structurally valid interpretations based on geometric and geological principles, rather than the artistic skill and panache of the interpreter.

A typical workflow for testing interpretations in Move uses a combination of back-stripping and restoration techniques. This allows the user to identify locations of geometric, structural and geological inconsistencies, which may indicate whether a model is incorrect, or needs to be revised or potentially discarded. Successive iterations of the workflow and subsequent adjustments of the model produce a structurally

This model demonstrates the timing and relationships (a–d) of complex 3D geometries in the Bolivian fold and thrust belt. (Repsol-YPF are acknowledged for providing data).



Midland Valley

valid interpretation. This modelling procedure highlights possible alternatives and enhances understanding of geological evolution in the area of study.

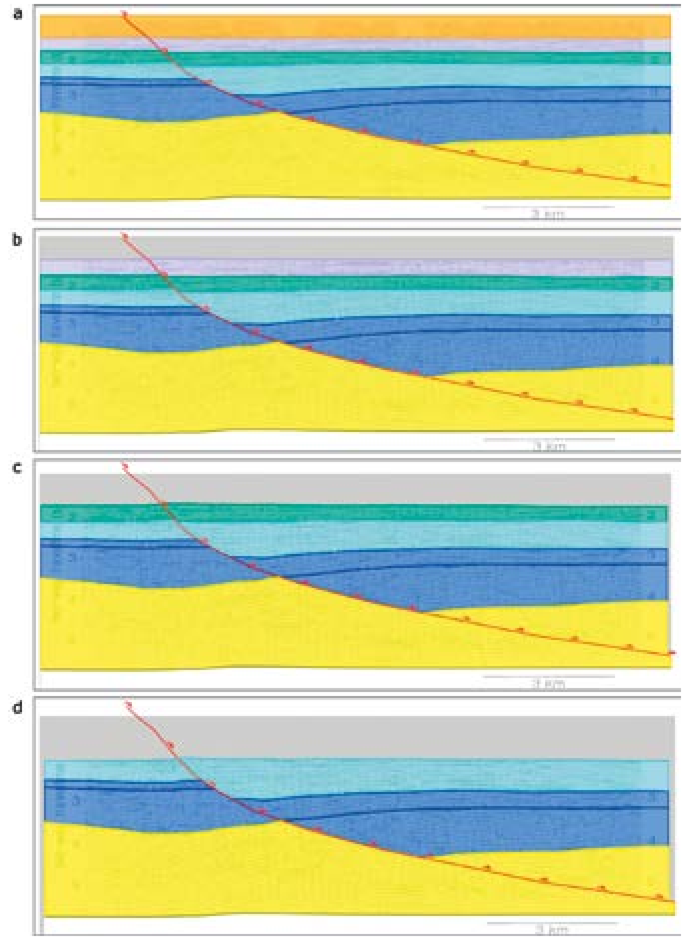
Visualising the Puzzle

Building a geological model typically involves piecing together different datasets and developing a solution that accurately honours the available constraints. Invariably, there will be pieces of this geological puzzle that are missing, and the interpreter is required to extrapolate between constraints into areas with little or no data. Numerous tools and techniques have been incorporated into the software to assist users in building geologically and structurally feasible models and reducing difficulties associated with integrating different datasets and extrapolating into unknown areas.

Realistic 3D surfaces can be generated quickly and easily using a number of algorithms from any positional constraint, including well data, 2D interpretations and surface intersection angles. In 2D, users can also develop interpretations and fill in the missing pieces by using several geological projection techniques. Horizons can be constructed using established fold geometry relationships, and developed to honour dip data and positional constraints. Geometric fault construction techniques, such as the constant heave method, can be used to predict fault geometries at depth where they are not as constrained by geological or geophysical data. Alternatively, users can interactively investigate faults at depth by forward modelling hanging-wall horizons, and then comparing them to observed geometries.

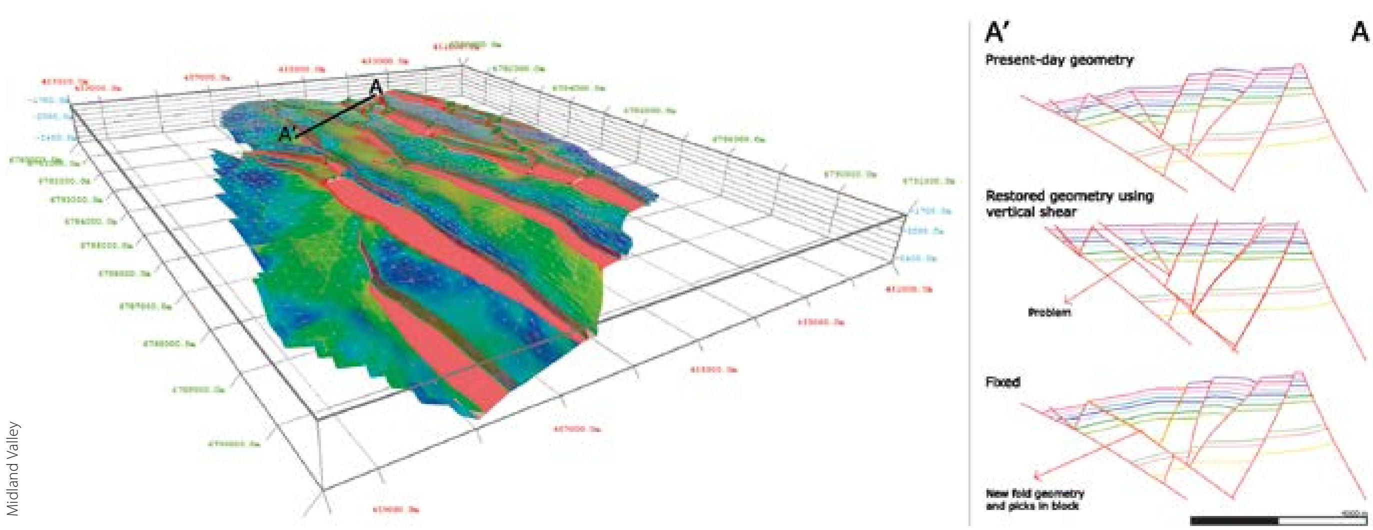
Collectively, these techniques and tools allow users to make predictions relating to unknown areas that are based on geological and mathematical principles, rather than speculation and guesswork. The result is more confidence in geological models, and an ability to objectively evaluate datasets in order to better understand the uncertainty attached to a model and therefore reduce the risks.

Once a structurally valid model has been constructed, the sequential restoration of deformation, sediment compaction and isostasy reveals the geometries and positions of key horizons through time. This provides a window into the past, which allows the evolution of petroleum systems to be investigated; for example, faulting and folding can be restored and modelled through a variety of kinematic and geomechanical algorithms. The kinematic algorithms can be



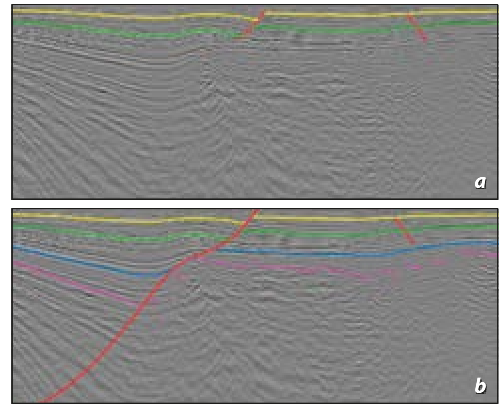
Kinematic modelling is used to reveal timing relationships regarding juxtaposition, migration and charge associated with the footwall trap in a Listric normal fault from the Gulf of Mexico (a–d). Data from Xiao and Suppe (1992).

Combined 2D and 3D analysis for an extensional example from the Gullfaks field, North Sea. Using an interpretation of seismic imaging, block restoration and jigsaw fit, the mismatch between horizon and fault geometries is highlighted. During the subsequent adjustment of the interpretation, an alternative scenario involving fewer faults was developed, which increased the extent of the reservoir unit and led to other resources being identified along strike.



used to restore both 2D and 3D models, and rely on geometrical relationships to maintain line-length, area and/or volume.

In contrast, the geomechanical algorithm considers the rock properties (Young's modulus and Poisson's ratio) and handles non-plane strain situations. The selection of the algorithm depends on the structural setting and the objectives of the restoration. Since Move uses mathematical models of reality, it is normal for a variety of restoration algorithms to be tested and compared. This makes it possible to assess the implications of different algorithms and develop an understanding of the uncertainty with the defined deformation history (see image on page 64).



How do you interpret at depth where seismic imaging is poor? Geometric models permit realistic fault and bed shapes to be predicted at depth where information is limited (a–b). *(BP/GUPCO are acknowledged for providing data from the Gulf of Suez.)*

Identifying 'Sweet Spots'

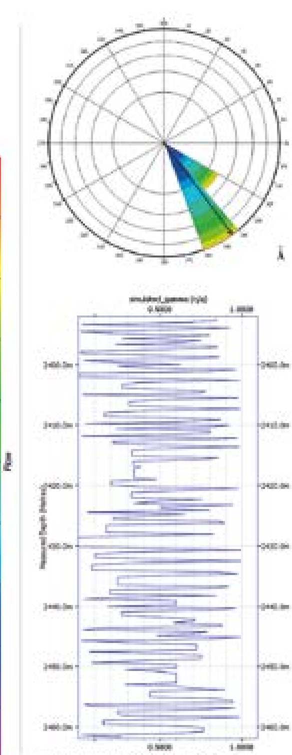
The amount of additional analyses and potential applications that can be carried out in this software is vast. Here we give an example of the development and analysis of sediment models based on the geological evolution determined from conceptual models, and interpretations tested through restoration.

For hydrocarbon reservoirs hosted in turbidite deposits, Move can be used to simulate turbidity flows. This aids in the assessment of sediment distribution and reservoir quality attributes, and ultimately can lead to the identification of optimal package thicknesses, grain size distributions and sand fractions: 'sweet spots' in the reservoir units that should be targeted for drilling.

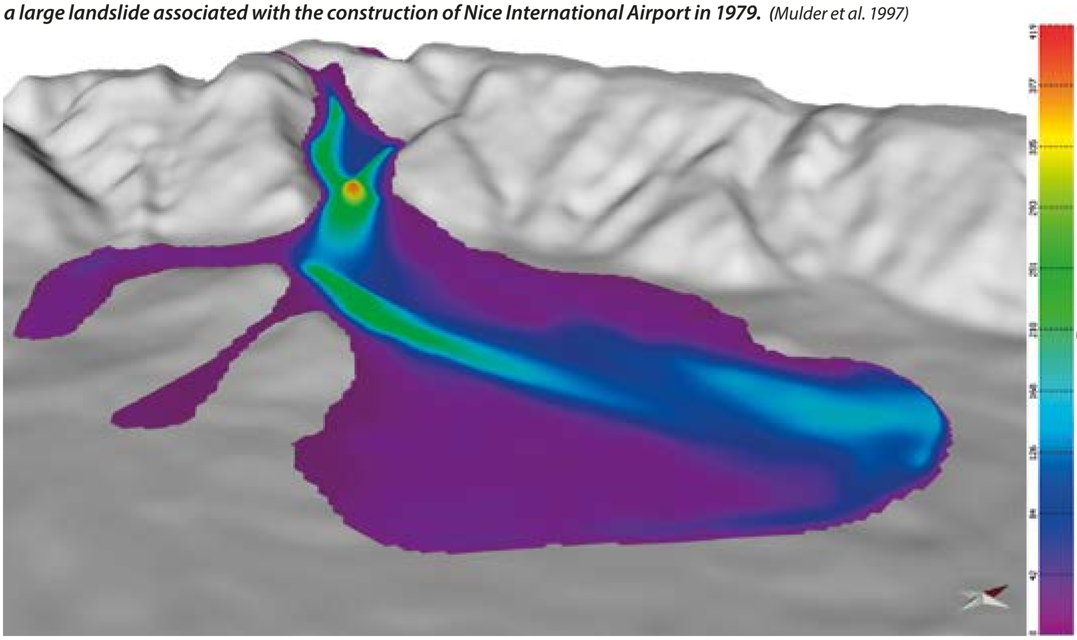
The workflows within the Sediment Modelling module are very flexible and can be tailored to investigate specific aspects of turbidite deposition, including the number of turbidity currents, the location of entry points into a basin, and the initial sediment composition. Initially, this requires the construction of a palaeobathymetric surface which can be generated using the 3D Kinematic Modelling module tools to restore deformation, sediment compaction and isostasy. Turbidity flows can then be run across this surface to investigate sedimentation: for example, to test basin entry points, predict the amount of sand, determine the net:gross relationship and distribution, or simulate multiple scenarios and compare the predicted sediment attributes to observed data from wells to identify the best-fitting flow or flows (inverse modelling). As with many of the workflows within Move, the ability to quickly carry out modelling and analysis means that multiple models can be tested and evaluated, providing more insight into the spatial distribution of reservoir units and reducing uncertainty within a hydrocarbon play.

Dynamic Solutions

In the past, traditional paper maps, sections and elaborate isometric diagrams were the cutting edge of geosciences and offered fascinating new insights into geology. As technology has advanced, the ability for geoscientists to investigate the sub-surface and constrain the geological evolution of an area has vastly improved. The powerful modelling and analysis tools within Move have the potential to be a significant asset to all geoscientists working in the oil and gas industry, enabling the user to visualise and test ideas, generate solutions, effectively communicate concepts, and interact with geological models in a flexible and dynamic manner. ■



Sediment flow run over the present-day bathymetry south of Nice, France (The GEBCO_08 Grid, version 20100927, courtesy of http://www.gebco.net). This model is inspired by a turbidity flow that developed from a large landslide associated with the construction of Nice International Airport in 1979. *(Mulder et al. 1997)*



The Deepwater Niger Delta:

An Underexplored World-Class Petroleum Province

Regional, deep-penetrating 2D seismic data is imaging new petroleum potential in this prolific province.

PAUL BELLINGHAM, CHRIS CONNORS, RICHARD HAWORTH, BARBARA RADOVICH and AL DANFORTH, ION Geophysical

The Niger Delta system is one of the world's largest Tertiary deltas and one of its most prolific hydrocarbon systems, containing an estimated 68 Bboe and producing approximately 3 MMboe per day. The evolution of the delta has created an almost perfect petroleum system with the thick Akata shale oil-prone source rock overlain by a substantial succession of progressively shallower facies in a sand-prone delta system. The load of the thick delta rocks causes gravitational collapse on the underlying, overpressured Akata shale, forming structural traps in both up-dip extensional and down-dip contractional systems (Figure 2). As always though, the devil is in the detail, and the complex relationship between timing of maturation and timing of structuration in the different structural domains creates exploration risk and the need to understand the development of the system as a whole. ION's NigeriaSPAN data is being used to pull together this integrated story.

The Niger Delta prograded into the South Atlantic during the Cenozoic, after break-up in the Albian/Aptian (Figure 1). The fit of the South American continent demonstrates the entire offshore area has to be underlain by Cretaceous oceanic crust. During break-up, several rift basins opened in Central Africa and these topographic lows have focussed sediment flux and deposition into the Niger Delta area since that time.

Quality Data Important

A key to making a full evaluation of the Niger delta system has been the availability of long-offset (10km), long-record (18s TWT), regional seismic data that have been pre-stack depth migrated. Many of the NigeriaSPAN lines were also acquired using a deep-towed cable and source, which also helps to improve image quality. Beyond careful planning and acquisition, the use of ION GXT's latest imaging and velocity modelling capabilities has provided the results seen here. Depth imaging enables the interpreter to view complex structures with true depth perspective and to see the regional links between the different provinces.

This improved imaging allows one to see detail in places within the mobile shale structures, which can help constrain the extent of brittle vs. ductile deformation (Figures 4 and 5). What may previously have been interpreted as shale structures with a diapiric origin are at once transformed into low angle shale-cored thrust sheets. What has been interpreted as a single mobile Akata shale formation becomes layered sequences of shale bodies with differing mobilities separated by regional detachment zones that are fundamental to the present-day structural shape of the offshore Niger Delta.

Seismic recording buoys ready for deployment on a deepwater survey.

The Main Play

Initial offshore exploration was an extension of the onshore successes in a shallow water region with a continuation of the extensional, growth fault structural regime (Figure 3). Large listric faults with throws mainly down to the basin (SW) provided a rich environment for structural traps within the Lower Miocene and younger stratigraphy (Figure 2). Successes came thick and fast with a string of medium-sized oil, gas and condensate fields discovered along this coastal belt.

During the past decade drilling has progressed into deep water, to 2,000m and beyond in the inner fold and thrust belt, with several major discoveries. Among these are Bosi, Agbami and Nnwa, all associated with a thick (>100m) Akata source rock and with production from often stacked deepwater turbidite reservoirs of Upper Miocene age. Reservoirs are often of very high quality and acoustic effects of fluids are often visible on seismic. The structures of the inner fold and thrust belt have been difficult to image in past datasets, showing only thick sections of seismically opaque facies commonly interpreted as shale 'diapirs' with only thin sediments. Deep-tow data here reveals several deep areas of stacked thrust sheets, within the Paleogene strata (Figures 2 and 4), with associated floor and roof detachments interpreted throughout the delta.

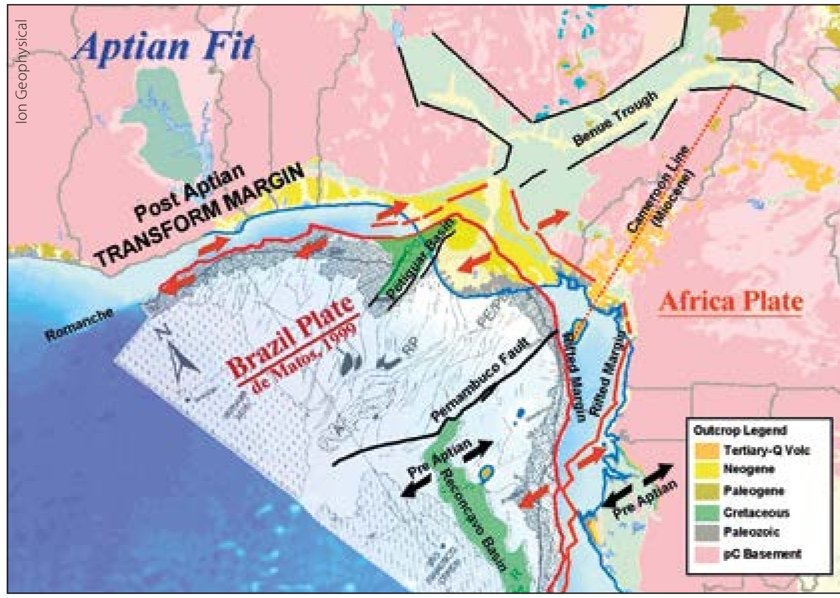


Figure 1: Tectonic map showing the restored fit of the Brazilian plate at Aptian time. Surface geology shown on the African plate, major Cretaceous rift basins and break-up direction shown.

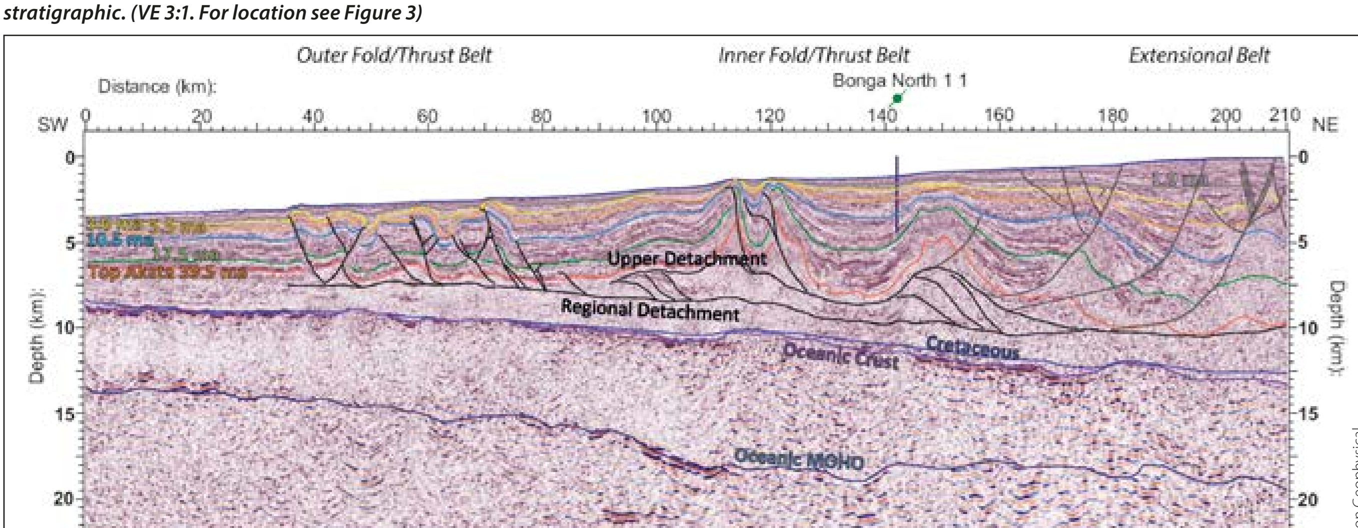
New Plays, New Risks

To continue to grow the resource of the Niger Delta, new plays must be proven and demonstrated to be economic. The old adage to 'go deeper' applies in two senses: extending exploration out to the deeper water and the outer fold belt, and exploring the deeper stratigraphy in the proven areas. Both carry challenges and risks, but offer huge potential.

Early exploration in the deep water between 2002 and 2005 proved disappointing and much less successful than earlier efforts in the shallower parts of the delta. Exploration from 2005 through 2009 was somewhat more successful with a string of finds in the southern part of the delta (Pina, Etan, Zabazaba and Kuro). All of these discoveries are on the inboard side of the outer fold and thrust belt, and highlight some of the key risks in this play where only a significant-sized accumulation will prove economic. These risks include:

- Maturation and source potential: The thinner sediment package in the outboard clearly limits maturation – this means maturation is probably more recent. Also, the Akata shale unit clearly thins as well, decreasing total potential.
- Migration: If detachment faults act as any kind of barrier to migration then the outer fold and thrust belt can

Figure 2: Regional PSDM seismic line (NG2-4500) across the main provinces of the Niger Delta. The extensional domain, inner fold and thrust belt and the outer fold and thrust belt are all shown. Thrusts and detachment faults are mapped, clearly demonstrating the younger nature of the outer fold and thrust belt compared to the inner belt. The deeper of the two main detachment zones is the one which extends out to the outer belt. The Bonga field in the inner fold and thrust belt is located close to this line and the structural high is well imaged here; trapping at Bonga is both structural and stratigraphic. (VE 3:1. For location see Figure 3)



only directly access a much thinner section of source than the inner belt. This means the outer belt may be more dependent on longer distance migration.

- Timing of trap formation: The outer fold belt is a younger feature than the inner belt (compare Figures 4 and 5) and will only trap the most recent migrated hydrocarbons.

Successful deeper drilling within the established inner fold and thrust belt relies on identification of reservoirs through good imaging. Figure 4 demonstrates the clear presence of reservoir character stratigraphy at lower Miocene levels, and these targets are gradually being exploited but remaining potential is high.

Further potential also exists in defining combined structural/stratigraphic traps on mobile shale structures. Several successful wells have targeted this play, such as the Bonga field (Figure 2). Structural development occurred throughout the Miocene, sometimes continuing to the present day, and the associated pinch-outs have largely been ignored. Ultimately they will provide a rich if somewhat more uncertain harvest.

The NigeriaSPAN data have been used to image two major detachments within the Akata shale that have not previously been imaged, which appear to control the overlying structural development. The upper detachment is constrained to the inner fold and thrust belt, and the lower detachment underlies both inner and outer fold and thrust belts (the outer being the younger of the systems). By post-Cretaceous times, basement tectonic control had ceased to be an influence on the overall morphology; the South America plate had long since departed. What remains to control the structural evolution is sediment loading and mobile Akata shale, and to understand the twinned thrust belts requires high quality imaging of this formation across the whole system. The deposition, burial and deformation of this unit appear to control the success of the various petroleum plays.

Acknowledgement: *The authors wish to thank ION Geophysical Inc. for permission to show the data, and also the Department of Petroleum Resources (DPR), Nigeria and Mabon Ltd. for their partnership and cooperation in this effort, including utilisation of selected well data for control.* ■

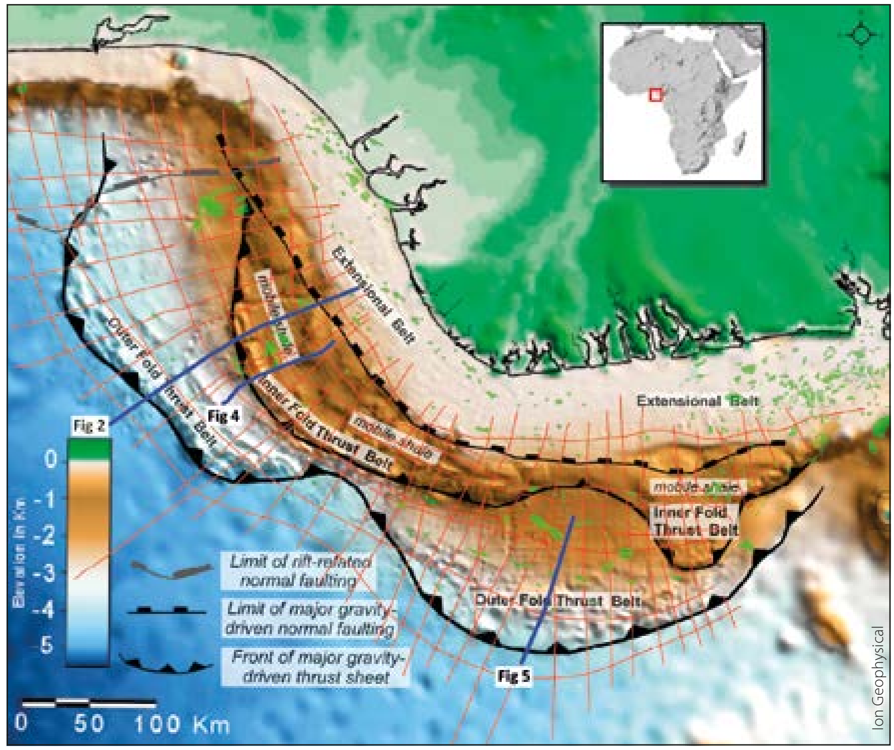


Figure 3: NigeriaSPAN layout over structural elements map with location of displayed seismic lines. Bathymetric map from Corredor et al. 2005 AAPG Bulletin, v. 89, no. 6.

Figure 4: Seismic zoom into inner fold and thrust belt (NG2-4650). Note complex and long-lived deformation and Akata shale unit thickened by thrusting and duplexing. (VE 2:1. See Figure 3 for location.)

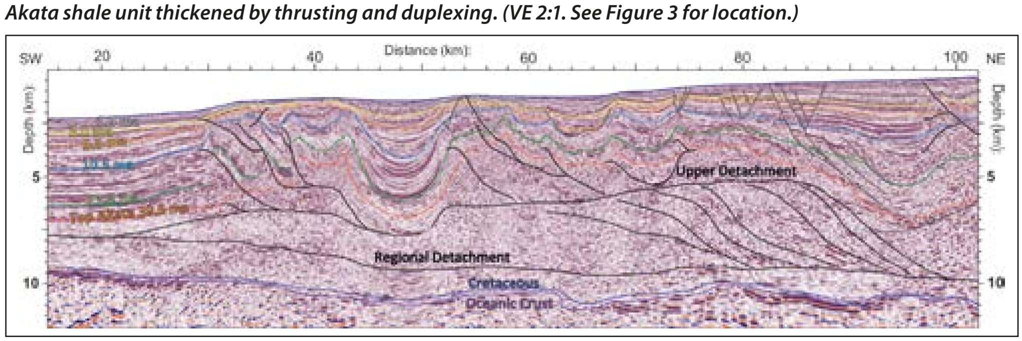
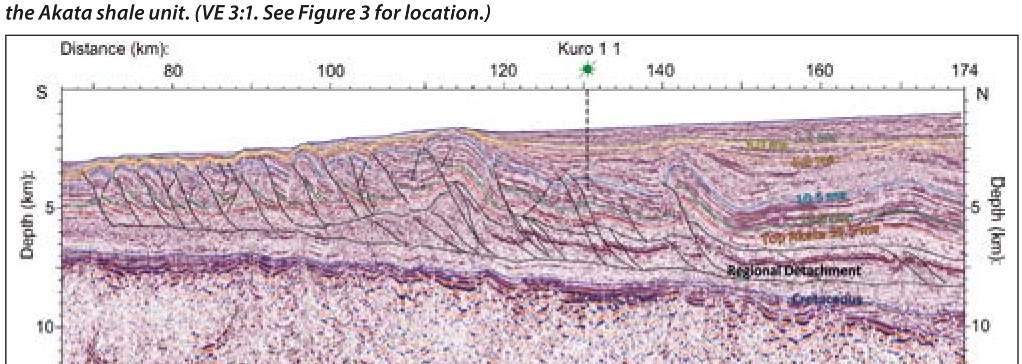


Figure 5: Seismic zoom into outer fold and thrust belt NG2- 5475. Brittle deformation can clearly be seen within the Akata shale unit. (VE 3:1. See Figure 3 for location.)

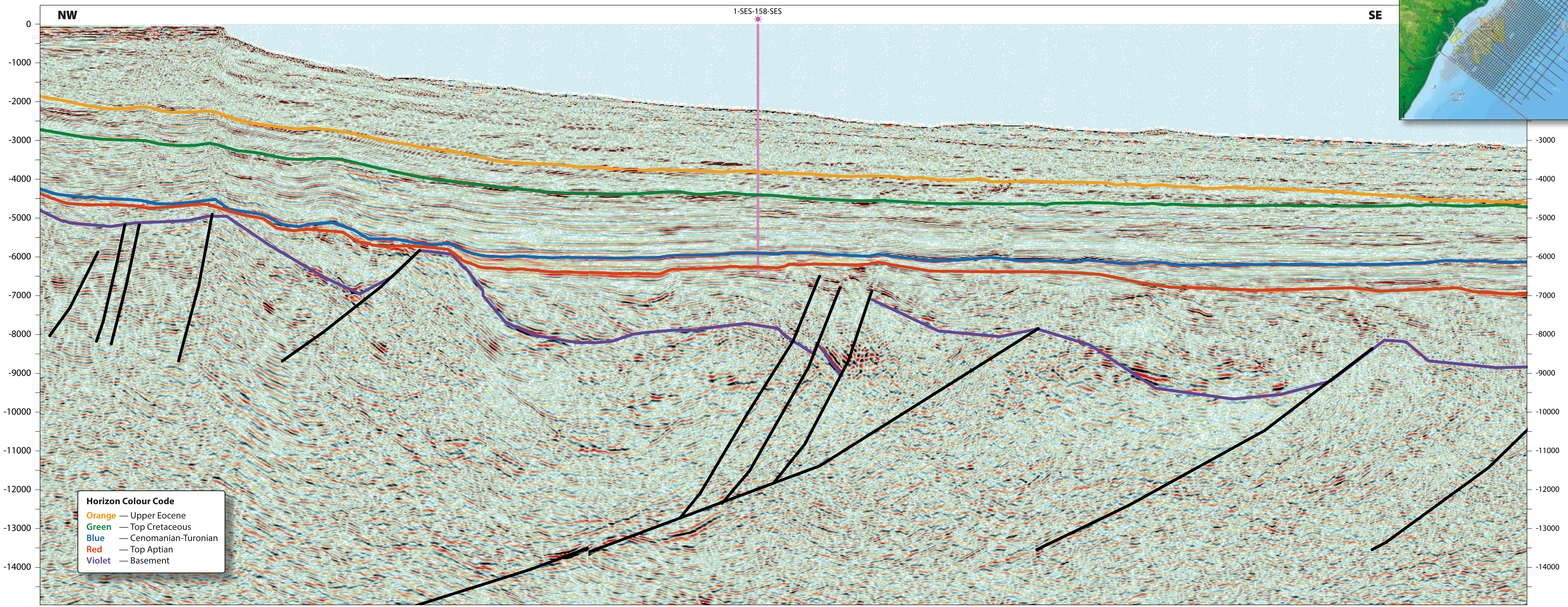


Sergipe Basin, Brazil:

DHIs from Calibrated AVO Stacks

Amplitude variation with offset (AVO) techniques are valuable tools that assist exploration, development and production teams to identify hydrocarbons in clastic depositional settings. The clastic reservoirs in the Sergipe Basin offshore Brazil are well suited for quantitative interpretation, best illustrated by the classic bright spot which can be observed on the accompanying section at a depth of 4,700m near the well bore. The recent announcement by the Brazilian energy regulatory agency ANP that the Sergipe Basin is likely to be included in Round 13 suggests that there will be considerable opportunity for additional prospecting in this basin. AVO techniques will prove to be important both for prospecting and for reducing drilling risk as the exploration cycle expands and progresses to development in the Sergipe Basin.

Pre-stack depth migrated section through the Barra discovery well



Spectrum

AVO Signatures Help Identify Hydrocarbons

MIKE SAUNDERS and DAN NEGRI, Spectrum;
CHRISTOPHER ROSS, Cross Quantitative Interpretation; **SCOTT BOWMAN**, Petrodynamics

In the relatively mature Sergipe Basin, AVO anomalies can be used to highlight prospective anomalies and eliminate leads and prospects without such indicators.

The Sergipe Basin is a relatively mature hydrocarbon province on the north-east coast of Brazil, comprising 44,370 km^2, both onshore and offshore. The onshore portion of the basin (12,620 km^2) is considered mature, with over 2 Bbo in place and 816 wells drilled since 1935. However, Petrobras has made several discoveries since 2010, including the 2010 Barra well (1-SES-158) and the subsequent Barra 1 appraisal well (3-SES-165). The wells targeted oil- and gas-charged Maastrichtian sandstones that display readily identifiable AVO anomalies on 2D seismic profiles.

Spectrum re-processed 8,200 km of seismic data in 2013, using modern pre-stack time and depth imaging algorithms. The 2D seismic data was acquired with an 8 km streamer in 1999, providing a wide range of reflection angles for quantitative interpretation. The re-processing illustrates clear images of stratigraphic features within the prospective section, and numerous potential AVO anomalies are evident. Two profiles near the 1-SES-158 Barra discovery well were selected and the digital logs from this well were incorporated into the analysis.

The Barra discovery well was drilled in September 2010, reaching a depth of 6,510m in 2,341m of water. Permeability and porosity conditions in the reservoir are excellent between 4,650m and 4,750m, where drill stem tests indicate gas and condensate are present in commercial quantities. The sandstones encountered in the Barra well are approximately 80m thick, and well tests indicate a high porosity gas-charged reservoir.

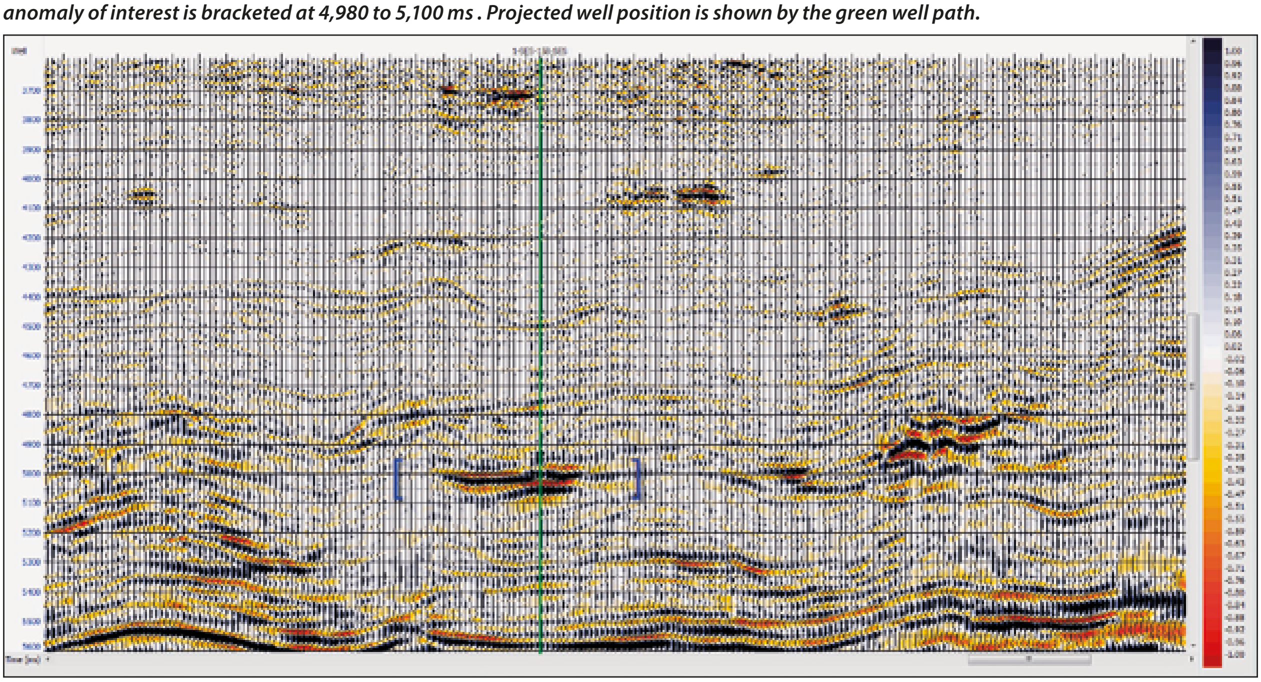
AVO Attributes

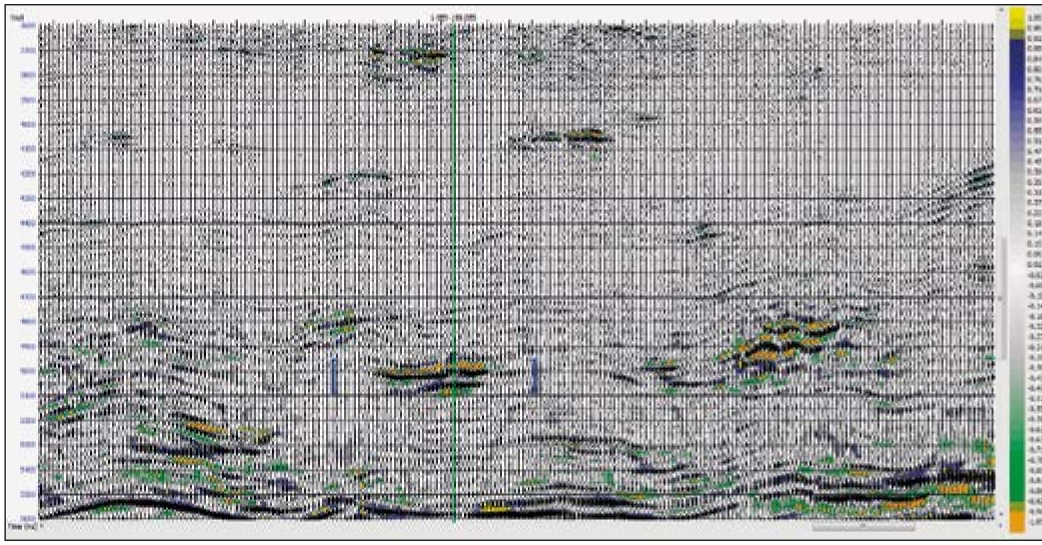
For mid to high porosity sandstones encased in shales or mudstones, gas and light oil saturated sandstones can be identified using amplitude versus offset (AVO) techniques with high-quality, long-offset seismic data.

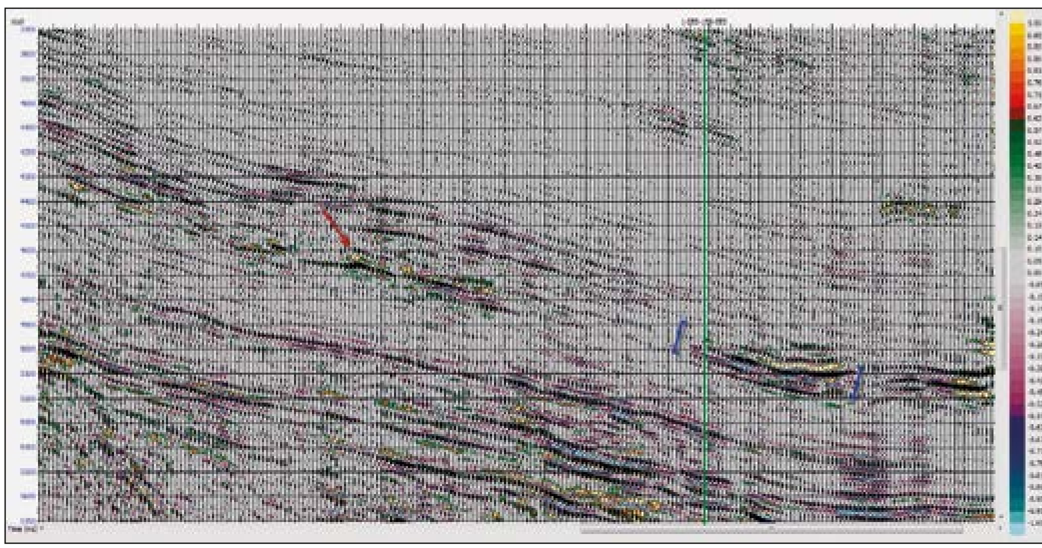
Examination of available well data shows that the sandstone in the Barra well does have 25% to 33% porosities, with velocities that are equivalent to or slightly faster than shale velocities and sand densities that are less than the shale densities. AVO modelling indicates a Class 2 to Class 3 AVO response depending on the thickness of the sand modelled. AVO attributes computed from the models indicate that the enhanced gradient (FNxF) and scaled Poisson's ratio change (SPR) attributes should be diagnostic for sands of sufficient thickness.

SPR change is the weighted sum of the AVO intercept

AVO conditioned stack using 4° to 32° after noise attenuation and residual move-out corrections. The multi-legged seismic amplitude anomaly of interest is bracketed at 4,980 to 5,100 ms . Projected well position is shown by the green well path.







Comparing the SPR and FNxF AVO for Line 21. Top: the SPR change AVO attribute is a fluid factor which illustrates hydrocarbon-saturated sands when properly calibrated. High porosity, gas-saturated sands produce an anomalous trough-peak (orange-yellow) SPR character, which is observed on the bracketed event. Bottom: the FNxF AVO attribute is a fluid-indicator that is positive for mid-to-high-porosity gas-saturated sands. For thick gas-saturated sands, a double positive (yellow-yellow) FNxF is observed in the down-dip portion for the upper leg of the anomaly.

and gradient, where the weighting is determined by the background V_p/V_s ratio of the geology. The SPR attribute is a fluid factor AVO attribute that should illuminate hydrocarbon-saturated reservoirs and marginalise wet- or brine-saturated reservoirs. The FNxF attribute is computed by calculating the difference between the far angle stack and the near angle stack, and multiplying the difference by the far angle stack. Angle ranges are used in place of offset ranges so they are optimised for the geology and objective depth.

For the purpose of determining whether AVO attribute stacks can identify potential hydrocarbon reservoirs, we look at 2D seismic profiles that tie the Barra discovery well. For each of these profiles we compute an SPR and FNxF stack, both of which should show visible anomalies for the high porosity, gas-saturated sands found in the Barra discovery well.

Seismic Examples

Line 21 is a strike line near the Barra 1 well. The top figure above shows the full stack in wiggle trace and the SPR change attribute in variable area. For a hydrocarbon-saturated reservoir the SPR attribute should show a minimum at the top of the reservoir signifying a relative decrease in Poisson's ratio (a decrease in V_p/V_s), and a positive SPR amplitude at the base of the reservoir assuming sufficient thickness to isolate the top and base of the sand. The event and overlaying attribute on the profile are quite similar to what has been described, with a strong negative SPR amplitude corresponding to the trough on the migrated stack amplitude and the positive blue-yellow SPR amplitude underlying the full stack peak.

In the lower figure this up-dip anomaly has the paired peak-peak character on the FNxF attribute, which typically corresponds to hydrocarbon-saturated reservoirs. This display also presents the known hydrocarbon-saturated reservoir with a single peak over a weak mix of positive and negative FNxF responses. The lack of a double peak in this instance might be attributed to the multi-legged nature of the event (a more complex sand body) and interference effects that may be negating the increase in amplitude versus offset on the base of the sand or other subjacent sands.

Hydrocarbon Charge Identified

Based on the available well data and the 2D profiles covering this basin, AVO anomalies from SPR and FNxF attributes can identify hydrocarbon charge in sandstone reservoirs, for thick sands with 18% or higher porosity. This screening process will not necessarily eliminate other geologies with lower V_p/V_s ratios: it will, however, highlight prospective anomalies and cull out leads and prospects that do not exhibit AVO signatures associated with hydrocarbons. ■

The Search for Oil in the South-Eastern Barents Sea

Broadband imaging improves the understanding of a prospective area on the Finnmark platform.

SYLVIA B. HAMMERSVIK and GUSTAV A. ERSDAL, CGG

For more than 40 years Russia and Norway were in dispute over a 175,000 km^2 area in the Barents Sea. On 15 September 2010 the foreign ministers of the two nations signed an agreement on where the offshore border between their countries should be drawn in the Arctic. During the spring of 2011 the agreement was ratified by the two parliaments and took effect from 7 July 2011.

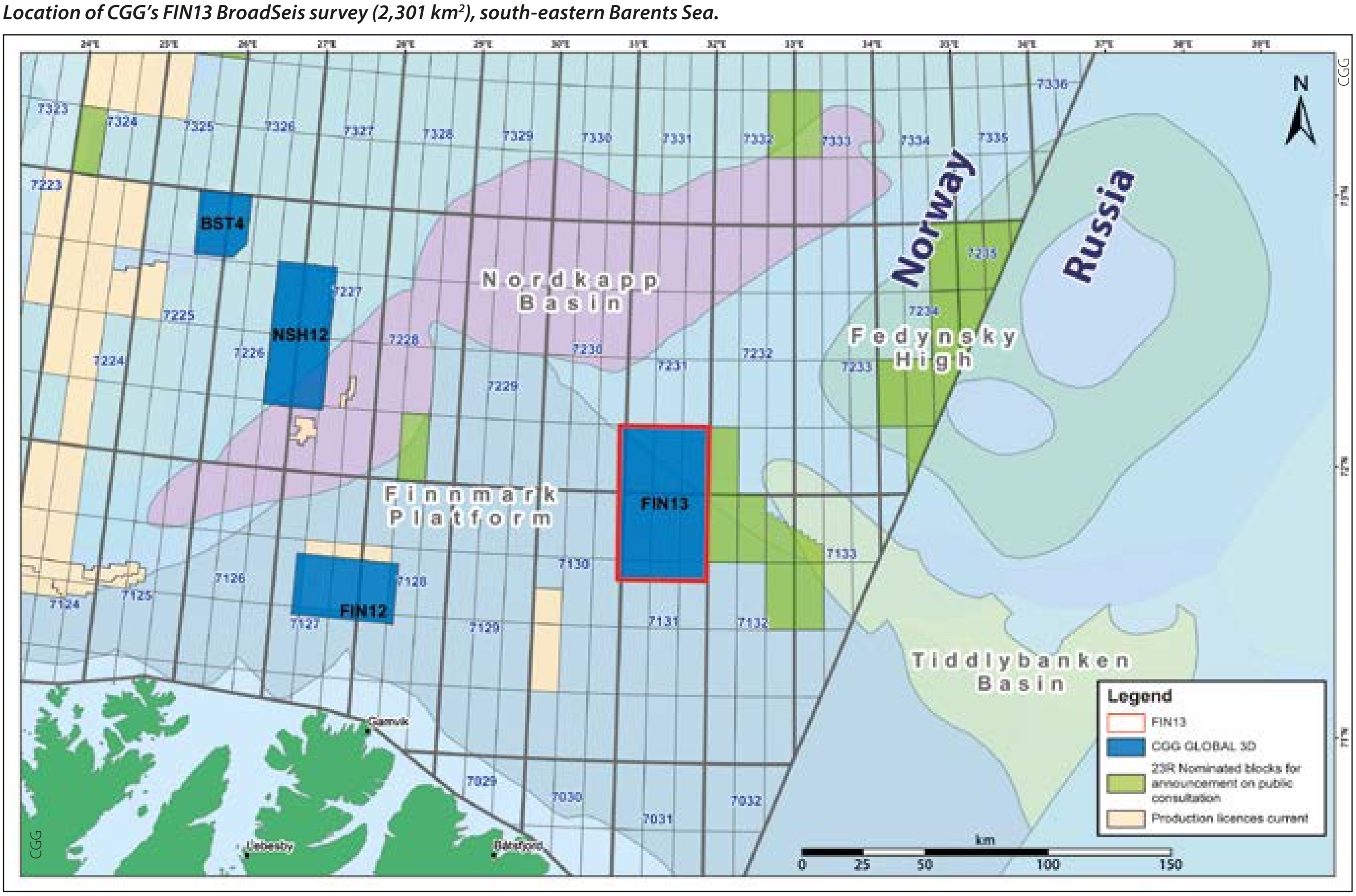
The ratification led to the opening of new areas for exploration on both sides of the border between Norway and Russia and several licences have already been awarded on the Russian side. Industry interest in participating in exploration on the Norwegian side is also significant, and the area is targeted for Norway's 23rd licensing round.

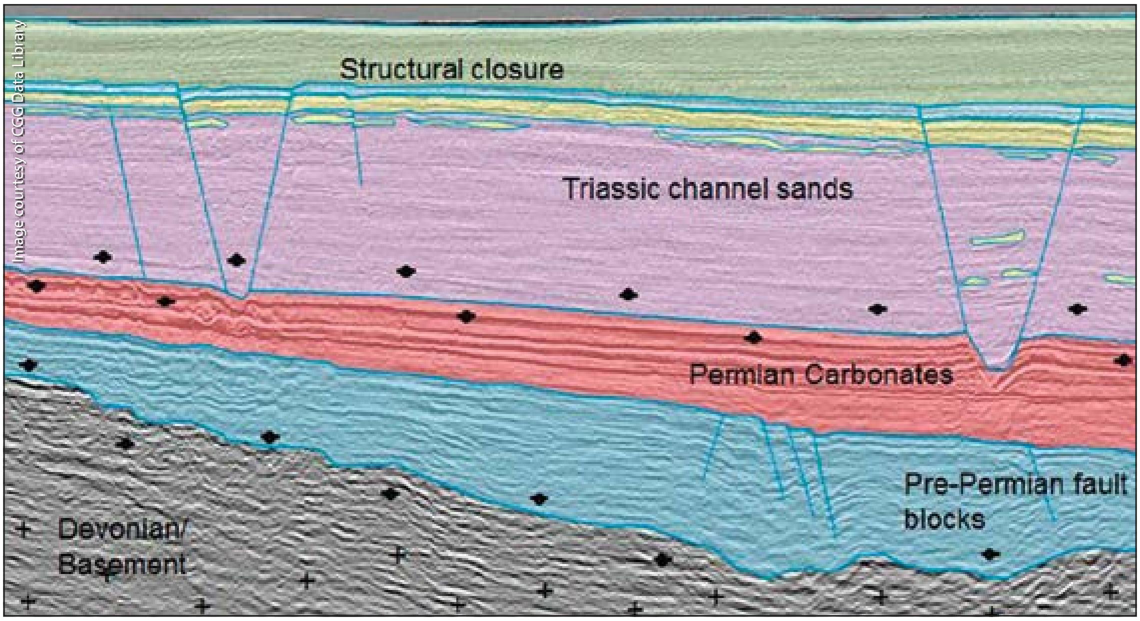
In the 2011/2012 seasons the Norwegian Petroleum Directorate (NPD) acquired a regular grid of modern 2D seismic data to complement the modest amount of vintage 2D data available at that time. In 2013 CGG acquired a large 3D seismic survey, FIN13, west of the former disputed area, covering the northern part of the Finnmark Platform and the western extension of the Tiddlybank Basin. This new survey was acquired with CGG's proprietary BroadSeis™ technology to produce broader bandwidths and deliver sharper wavelets without sidelobes. These provide more detailed imaging, allowing better identification of prospects and leads.

Structural Setting

The Timanian Orogeny centred in the Russian Barents Sea and the Pechora Basin had a major influence on the configuration of the eastern Finnmark Platform basement (Roberts and Siedlecka, 2002). The area experienced three major rifting events during the Late Palaeozoic, Middle Jurassic-Early Cretaceous and Early Tertiary (Faleide et al., 1993). The new seismic data reveal rotated fault blocks in

Location of CGG's FIN13 BroadSeis survey (2,301 km^2), south-eastern Barents Sea.





Geoseismic profile showing all levels of potential prospectivity within the FIN13 survey.

the Devonian/Carboniferous with a north-west oriented depression in the northernmost part of the Finnmark Platform. These depressions define the basin outline and hence the basin geometry, confirming it to be a north-westwards extension of the Tiddlybank Basin. The rifting phase in the Triassic caused a north-west to south-east trending fault zone to develop.

Multisource Province

FIN13 is situated in an area where both local and long distance hydrocarbon migration scenarios are possible. The south-eastern Barents Sea is considered to be prospective, but resources estimated are modest and generally dominated by gas (NPD publications). The source rock potential for both the long-distance and local migration is expected to range in age from Triassic to Devonian.

Several wells have been drilled in the eastern part of the Barents Sea and well results prove the area to be a multisource province with both oil and gas potential. The oil potential is thought to be significantly higher in the southern part of the area and possibly in the eastern extension of the Tiddlybank Basin, which may serve as a potential migration route for hydrocarbons into the study area and into the Finnmark Platform in general. In addition to the Tiddlybank Basin, the Nordkapp Basin is also considered as a possible source area for long-distance migration. Wells drilled on the Finnmark Platform confirm the presence of oil in Permian carbonates where the Carboniferous Tettegras Formation is most likely to be the source rock. This emphasises the importance of understanding the play models at all depths.

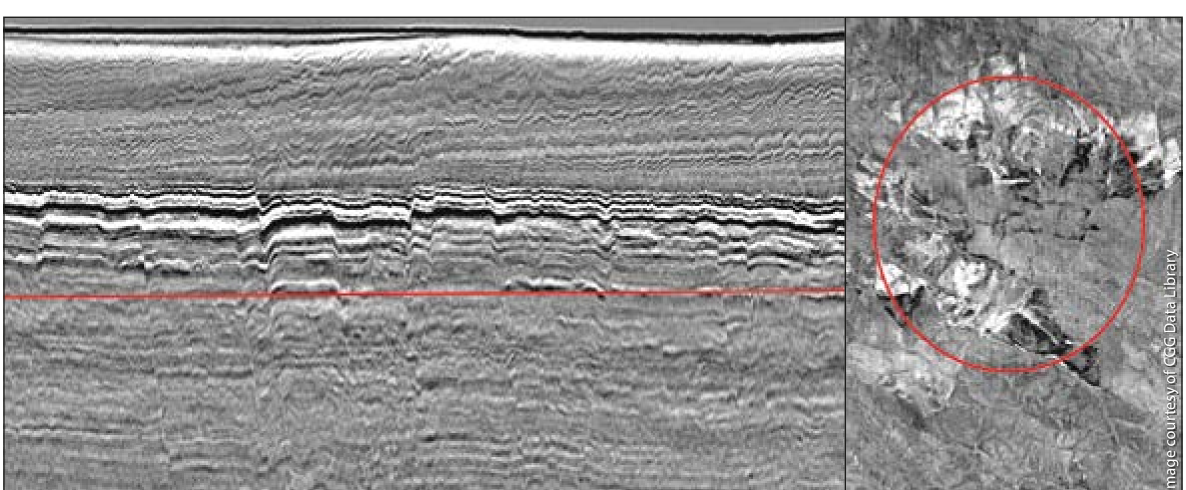
Play Models

Four play models have been identified within the survey area. The play models are located within the Palaeozoic and Mesozoic sections. They represent various depositional settings. A geo seismic profile through the survey displays potential levels of prospectivity. From this, one can see that faults are trending through all prospective levels, and might serve as structural traps. Stratigraphic traps are also present at each level.

Four-way closure and graben area

A four-way closure with a possible extent of up to 200km^2 defines the first play model. The closure is limited by a north-west to south-east oriented

Time slice through Carnian sand bodies, inside graben area and four-way closure.

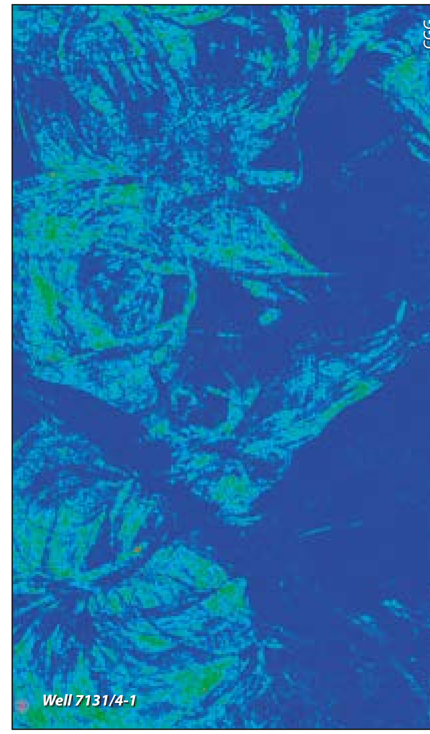


graben, formed prior to, or in, the Early Triassic. Potential reservoir rocks from the Early Triassic Snadd Formation to the Early Jurassic Stø Formation are identified within the structural closure and multiple targets are also observed within the area.

Triassic channel sands

Triassic fluvial sands were observed in well 7131/4-1 in the southernmost part of the 3D survey area and channels with this sand appear as amplitude anomalies on the seismic. This play represents both structural and stratigraphic traps. Anomalies deeper in the Triassic section may represent similar channel deposits.

The Carnian sandstone in the Snadd Formation is expected to have the best potential as a reservoir unit. The characteristic meandering pattern of the Carnian sand has been mapped throughout the whole study area and what are believed to be the most sand-rich facies are easily identified as high-amplitude events. The amplitude signature around the tie-in well is similar to that which we see throughout the survey. Based on the result of the core analysis from well 7131/4-1, one might expect good reservoir sandstone throughout the survey area.

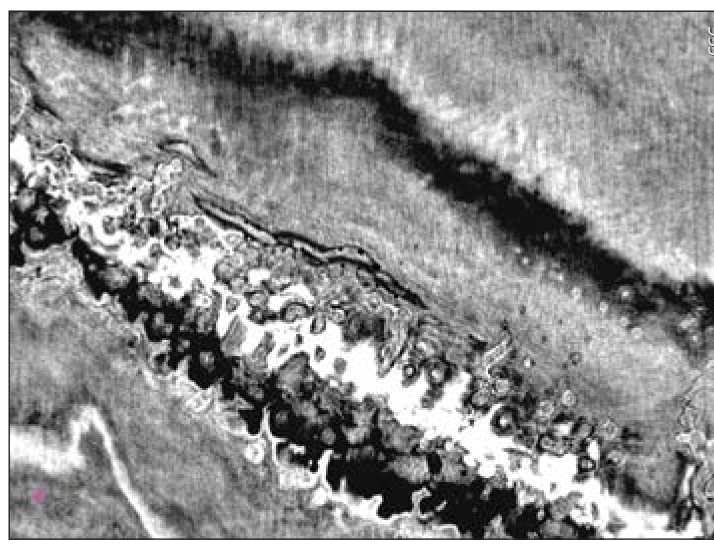


Amplitude map of the Carnian channel sands in Snadd. The light blue colour represents high amplitudes, indicating sand-rich depositions.

Permian carbonates

Reservoir potential is also present in the Palaeozoic carbonates, which can be observed as a north-west to south-east trending belt in the southernmost part of the survey. Time-slices through the Palaeozoic section at the Finnmark Platform indicate an extensive karstification of the carbonates. As demonstrated by the Gohta well in the western Barents Sea, karstification is one of the crucial processes enhancing the reservoir quality of carbonate reservoirs in the Barents Sea. In the FIN13 survey area, the karstification is seen as dissolution features at several depths, ranging from the top of the warm-water carbonates of the Gipsdalen Group to the top of the cold-water carbonates of the Late Permian Røye and Ørret Formations.

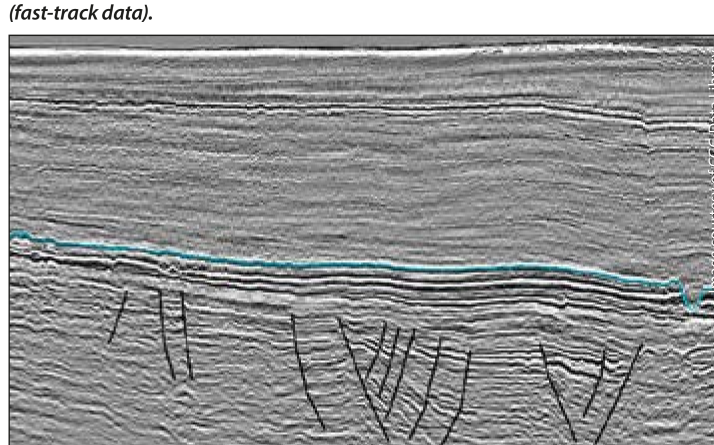
Time slice through the Permian carbonates, with an indication of karstification.



Rotated fault blocks in Pre-Permian

Rotated fault blocks formed during the rifting phase in the Late Palaeozoic, controlled by earlier-created zones of weakness. The rift system is seen as grabens and half-grabens in the Carboniferous to Early Permian, forming potential traps for hydrocarbons. Wells drilled on the Finnmark Platform and in the Timan Pechora region have oil and oil shows in Upper Permian carbonates, sourced from the Devonian. This may also be the case within the study area. In addition to serving as potential reservoir sections, the rotated fault blocks may also serve as kitchen areas in the deepest parts of the basin.

Rotated fault blocks in the Pre-Permian. Blue horizon is interpreted as Top Permian (fast-track data).



Geochemical Sampling Confirmation

Although only fast-track data is available, there are few indications of gas in the data and this supports the model of a petroleum system dominated by liquids rather than gas.

In 2014 CGG acquired a large surface geochemical sampling programme covering most of the south-eastern Barents Sea. The results from this programme will reveal additional information about the petroleum system and, it is hoped, confirm the liquid petroleum potential in the south-eastern Barents Sea. ■

Broadband Seismic Technology and Beyond

The answer, my friend, is hiding in the waves, the answer is hiding in the waves

(with apologies to Bob Dylan, and thanks to our colleagues in Lundin Norway)

PART XI: Which Technology to Choose?

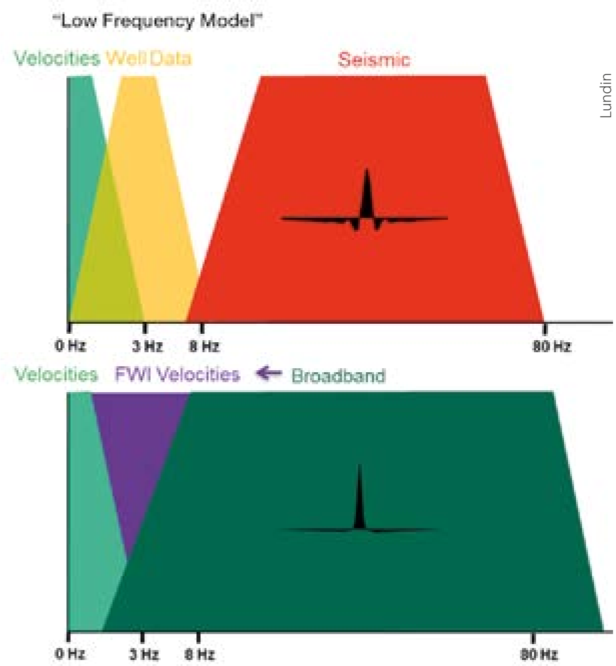
Using the Utsira High as a field laboratory for broadband testing

LASSE AMUNDSEN, Statoil and MARTIN LANDRØ, NTNU Trondheim

Guest Contributors: JAN ERIK LIE, VIDAR DANIELSEN and PER EIVIND DHELIE, Lundin Norway

In previous articles the focus has been on various broadband technologies and the principles behind them. Technical progress is vital and highly desirable, but how should the users choose between these technologies to find the best technology for a given field or exploration target? Lundin Norway has decided to use the Utsira High area offshore Norway as a broadband seismic field laboratory.

The same 2D line has been shot several times using various technologies, different shapes of the streamer and so on. Using these alternative set-ups, Lundin's geophysicists have tried to find what is hidden in the waves, including seismic waves, ocean waves, and the wave-shaped streamer. Their ambition is to prove that Bob Dylan is a genuine rocking geophysicist.

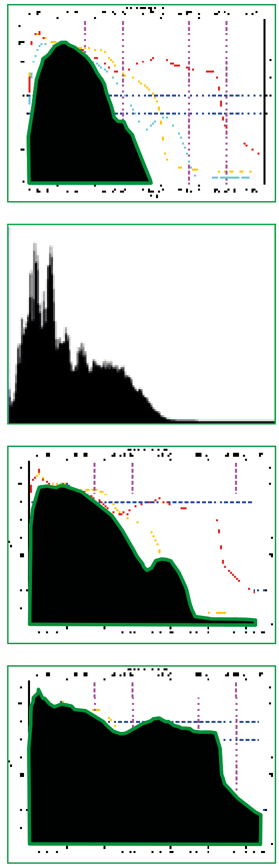


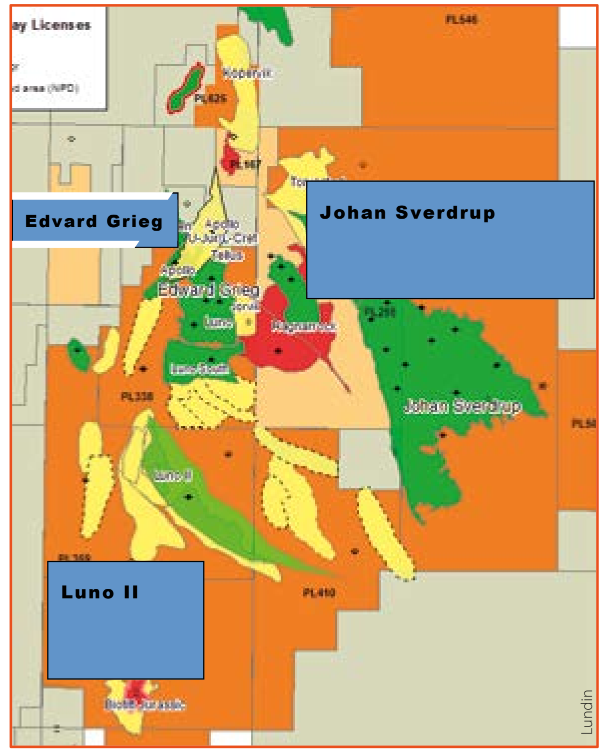
Lundin

Schematic view demonstrating the focus in broadband seismic acquisition and processing: filling the low frequency gap between 1 and 8 Hz and pushing the high frequency response above 80 Hz.

Martin Landrø

Amplitude spectra of seismic data acquired using various acquisition systems. Left column from top to bottom: conventional streamer (2007), OBC data (2008), Geostreamer (2009) and Broadseis/Broadsource (2012). Right: the Utsira High area, including the giant Johan Sverdrup field, Edvard Grieg field and the Luno II field.





Filling Frequency Gaps at Utsira High

The major objectives for broadband seismic data acquisition and processing are to increase both the low and high frequency content of the data. This is illustrated in the figure on the previous page, where the pre-broadband situation is sketched together with an idealised version of the broadband frequency response. We observe from this figure that the low frequency improvement is probably more critical and thus plays a more important role compared to the improvements on the high frequency end. This is because it is crucial to fill the gap between stacking velocities, well log data and seismic data.

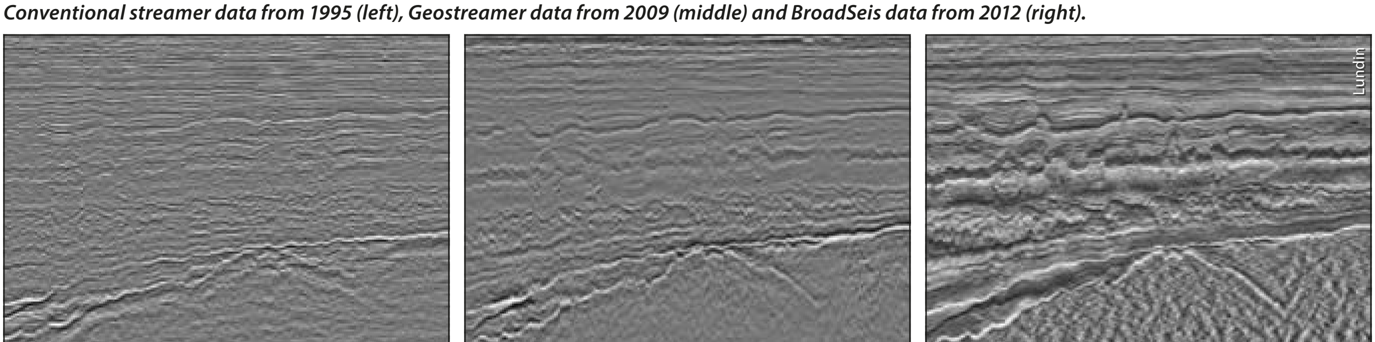
At the Utsira High both these challenges are important and early in the exploration phase Lundin's geophysicists embarked on a project aiming at understanding how these frontiers (low and high frequency content) could be met and actually measured and controlled. There are several challenges related to establishing a field laboratory like this. First of all, the technology is rapidly expanding and therefore it will never be fair to compare the results obtained by one contractor with those obtained by another contractor two years later. Furthermore, different contractors have different processing algorithms, causing different end results when the same data is used as input. Finally, weather conditions will always change between various acquisitions. Despite this, the main conclusion is clear and crisp: broadband seismic data is better than old conventional data. This is demonstrated in the figure top right where amplitude spectra from four types of acquisition are compared for the same 2D line at the Utsira High area.

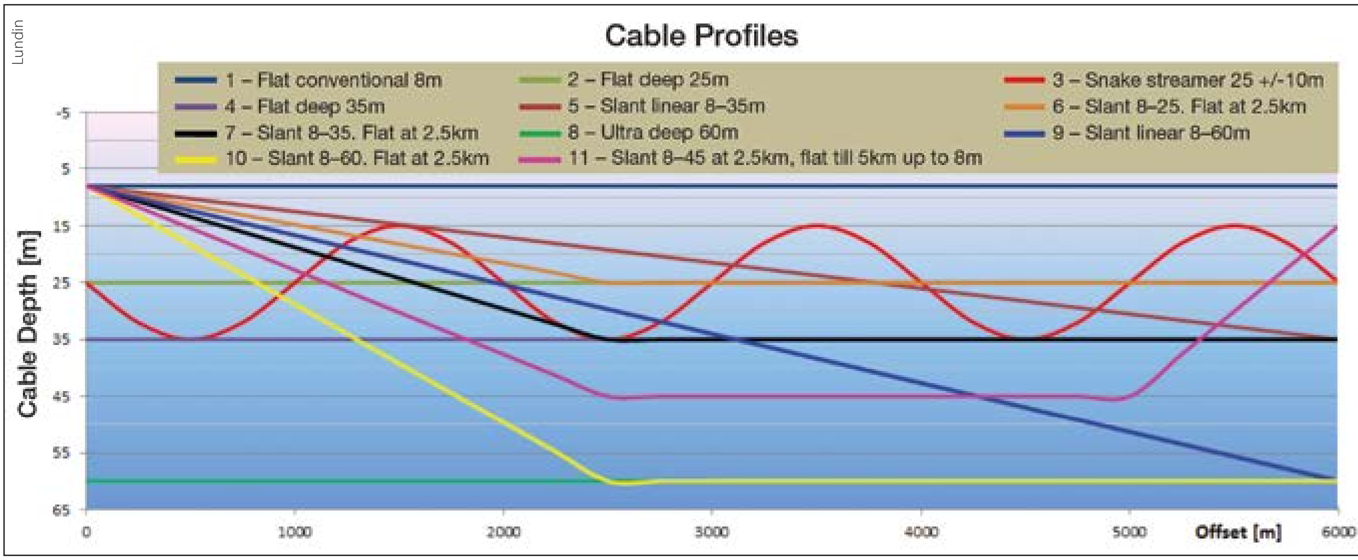
Another example illustrating the progress in broadband seismic is shown below, where we can observe distinct improvements in seismic imaging from 1995 to 2009 and finally 2012. We notice especially that the imaging of top basement (the lowermost clear reflector seen on these images) is significantly improved from 1995 to 2012.

Testing Streamer Configurations

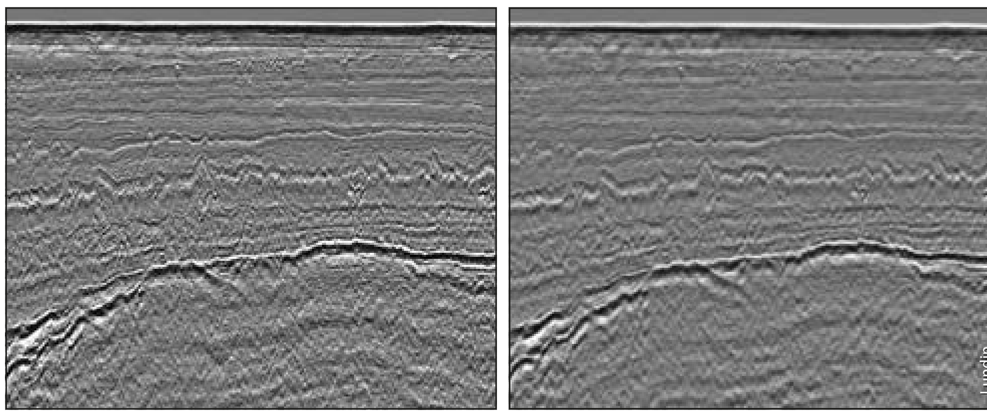
In 2013 Lundin initiated a huge practical experiment to be conducted at the Utsira High. Together with a seismic contractor, they tested 11 different streamer configurations at the same time. The same 2D line was shot over and over again using the same source configuration but with different shapes of the streamer. Maybe the most spectacular (and the most difficult for the contractor to achieve) is the 'snake' configuration, where the streamer has a sinusoidal shape varying from 15 to 35m. This extensive experiment gives a unique insight into how various towing configurations might impact the final imaging result. A comparison between

Conventional streamer data from 1995 (left), Geostreamer data from 2009 (middle) and BroadSeis data from 2012 (right).





Various streamer configurations (11 in total) were tested.



Comparison of the 'snake' streamer configuration (left) and a streamer towed at 8m depth. It is hard to spot any major differences between the two seismic profiles.

the snake configuration and a conventional streamer towed at 8m depth is shown on the right, and it is actually hard to spot any major differences.

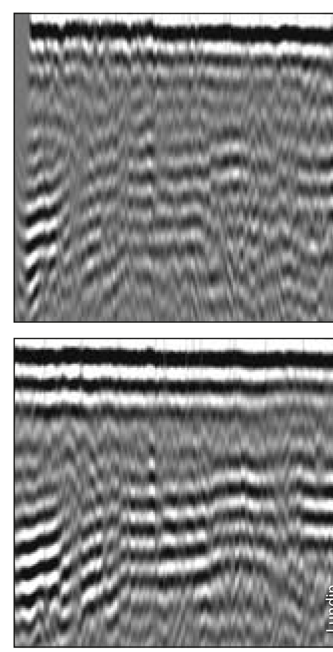
A clear difference is observed, however, when the low frequency response is considered. It is evident from this test that a streamer deployed at 60m depth gives a far better low frequency response compared to a streamer towed at 8m depth. For more advanced use of seismic data, as for example Full Waveform Inversion (FWI), this advantage is crucial. Another benefit demonstrated with this comprehensive test is that a slanted streamer configuration with more notch diversity is preferred over a flat or less slanted cable.

Processing Developments

Alongside the rapid developments in seismic acquisition, major improvements have also been achieved on the processing side. When the acquisition deviates from the conventional flat streamer into, for instance, a slanted configuration, there is need for adjustments and modifications of the processing algorithms, simply to correct for the fact that the streamer depth is changing with offset.

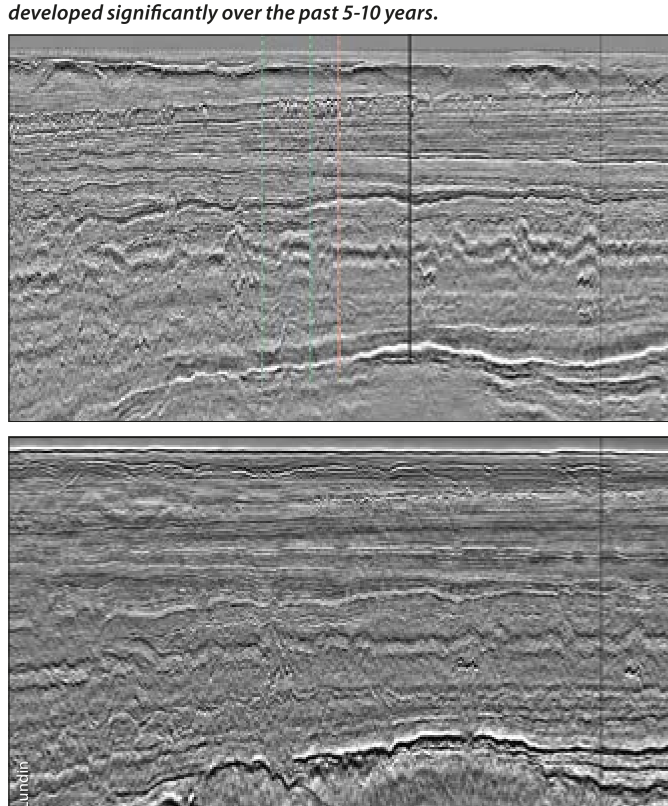
However, the major and most certainly the most important new processing step that is a must in broadband seismic processing is de-ghosting. As described in earlier articles in *GEO ExPro*, the receiver ghost notch frequency depends on the streamer depth (f=c/2z; f = frequency, c = sound velocity in water and z = streamer depth). For old data this receiver ghost notch was not harmful, since a streamer depth of 8m corresponds to 94 Hz, which is normally outside the frequency band of interest. However, when the streamer depth is changed to, for instance, 25m, this ghost notch occurs at 30 Hz, which is in the middle of the useful seismic spectrum. Therefore, there is a strong need for effective and accurate ways to remove the ghosts from data acquired using a deep towed streamer. Since different vendors prefer to use different streamer configurations and some vendors measure particle velocities in addition to pressure, the de-ghosting algorithms used will also differ.

There has also been a significant research effort aiming at increased understanding of



Comparison of 8m (top) and 60m (bottom) streamer depth for the low frequency response (0-1-3-4 Hz bandpass filter has been applied). A more continuous and stronger response is observed for the deep-towed streamer data.

ghost effects in seismic data and especially on developing robust and effective de-ghosting algorithms. The example shown right probably demonstrated this time evolution more than differences between various vendors in processing skills. It is, however, interesting to notice major differences especially for the deeper data when it comes to image quality.



Same input data (8m streamer depth) and different de-ghosting schemes from different vendors compared. Note that the processing has been done at different times, demonstrating that de-ghosting algorithms have developed significantly over the past 5-10 years.

The Answer is Hiding in the Waves

There is no doubt – the marine seismic industry has changed significantly over the last decade. Today more and more marine seismic streamers are towed at between 20 and 40m. This is a huge change, and it might actually be the beginning of a new era in marine seismic. As technology is improving, new efficient ways of towing both source arrays and streamers will be found. The oil industry is facing severe changes in the years to come, and cost savings and other challenges might slow down the broadband revolution. Despite this, there is a huge reward waiting for the organisations that are capable of understanding and exploiting information that is still hidden in the waves.

One thing is sure: geophysics rocks, and the waves will continue to propagate. We just need to understand how and why. ■

References:

Lie, J.E., Jorstad, A., Danielsen, V., Nilsen, E.H., Dhelie, P.E., 2014: Broadband seismic – the interpreter's dream come true?; EAGE meeting in Amsterdam.

The Operations Geologist

Bjørn Cato Ellingsen is an Operations Geologist with First Geo (formerly Aker Geo) in Stavanger. He tells us about the various skills and tasks involved.

The operations geologist's role is multi-faceted and not easily defined to a certain set of tasks. Perhaps the best way to describe it is that an operations geologist acts as a link: a link between subsurface and drilling departments, geo-scientists and engineers, wellsite and office. Most of the tasks addressed will be in conjunction with others; whether it is logistics of personnel and equipment or pressure calculations. Hence, a key element of the job is communication. In any pending task that necessitates the contribution of others, the ability to communicate clearly and without ambiguity increases efficiency and precision.

The importance of communication skills is underscored by the variable nature of tasks that may arise. One moment you might be discussing an atypical gamma-ray or porosity log response for a given lithotype at a particular chronostratigraphic level with a fellow geologist, the next investigating the apparent disappearance of a cuttings shipment.

The operations geologist ('ops geologist' in everyday lingo) plays a key role in the interface between subsurface and drilling departments. Having one foot in both camps, it becomes essential to understand the purpose and need for each set of data requested by the geoscientists and what is feasible or not from an engineering perspective. Any geologist or petrophysicist knows that you can never have too much data or information. This need, however, must always be balanced against what is practically achievable with regards to well design and ultimately reasonable financial cost.

Bjørn Cato Ellingsen has been with First Geo since 2008. Before that he worked for Geoservices Norway.


First Geo

Tasks for Different Phases

The specific tasks undertaken by the ops geologist will naturally vary with whichever phase the current project is at. During the planning stage there is an assessment of available regional and/or local data, meetings and discussions on strategies and goals in addition to specifying in detail what data will be collected and plans for different 'what-if' scenarios in relation to that. At this stage it is also important to keep close communication with contractors and personnel to ensure that the required manpower and equipment is available for the drilling phase of the project. When all plans are in place, relevant documents written and the well is spudded, there is a change in the daily routine of the ops geologist.

During the drilling phase most of the ops geologist's attention will be focused on assessing current information. There will be a lot of data and reports coming in that need to checked, distributed and filed. The ops geologist is a natural contact point for many at this stage, and although the routinely close communication with the wellsite has priority, there will be a significant amount of e-mails and telephone conversations from a fairly wide range of involved personnel during the course of a day. The sheer amount of data, reports, meetings, e-mails and phone calls makes it necessary, if not essential, to establish fairly rigid routines. Personally I employ the use of a check-list where I can tick off all the routine tasks done during a day, as a sort of quality assurance system for myself. That way there is less room for oversights when an unexpected situation arises that demands your attention or input. Obviously there will be around-the-clock operations at the wellsite during this phase, which can sometimes translate into long days and nights for the ops geologist.

After the drilling phase has been completed and all the information gathered, there is a post-drill stage where the different contractors author and submit their final data, reports and summaries. These are assessed, analysed and integrated by several disciplines, thereby becoming part of the accumulated knowledge upon which to base future decisions. The ops geologist will at this stage typically author and/or quality check a geological final well report (FWR) in conjunction with the geologists who worked at the wellsite.

As I said, it is challenging to rigidly define the role of an operations geologist. A geologist will always be a geologist first and foremost, but in addition to being a scientist with the required theoretical knowledge, the typical ops geologist will also draw upon technical insights and often extensive practical experience. In many ways the 'link' is the most valid analogy: a link that strives to bridge theory and practice through effective communication. ■

Western Tanzania: The Lake Rukwa and Lake Nyasa Rifts

WILL THORNTON

Independent explorer Heritage Oil focuses on regions which may have been overlooked and where it can participate as an early entrant. We look at its exploration efforts in two blocks in Tanzania, considered analogous with the Lake Albert Basin in Uganda.

Tanzania is located at the intersection of several East African countries and its population of around 47 million consists of more than 120 ethnic groups. Bordered by Kenya and Uganda to the north, Rwanda, Burundi and the Democratic Republic of the Congo to the west and Zambia, Malawi and Mozambique to the south, the country's eastern border is formed by the Indian Ocean. The name 'Tanzania' derives from the names of the two states, Tanganyika and Zanzibar, that joined in 1964 to form the United Republic of Tanzania.

The Tanzanian economy is dominated by agriculture, with the industry accounting for around 80% of employment. Currently hydrocarbon production is limited to natural gas from the Songo Songo gas field, located offshore in the Indian Ocean, on Songo Songo island, about 15 km from the Tanzanian mainland and 200km south of the commercial capital Dar es Salaam. Production commenced in 2004 with the gas being transported by pipeline to Dar es Salaam, where it is converted to electricity. A new gas field is being brought on stream in Mnazi Bay, south-eastern Tanzania, with first gas expected to be delivered Q1-2015.

Heritage Oil is an independent exploration and production company with producing assets in Nigeria and Russia and exploration assets in Tanzania, Papua New Guinea, Malta, Libya and Pakistan, looking for areas where it can participate as an early entrant. The company has two blocks in Tanzania, which are considered to have analogues with the Lake Albert Basin in Uganda.

Exploring Rifts

In 1997 Heritage Oil began to explore in the Albert Basin, Uganda, on the western arm of the East African Rift System (EARS). By 2008 drilling in the Kingfisher area had resulted in exploration success and individual well flow rates of over 14,000 bopd caught the eye of the watching industry. Current reserve estimates for the Albertine Basin stand at 1 Bbo, with upside for 2 Bbo – though upside estimates of up to 3.5 Bbo have been quoted. The Kingfisher well was a game changer and opened a new fairway in the African Rift Basins. Since its discovery, stimulation of exploration activity has resulted in the African rift basins becoming nearly 100% licensed.

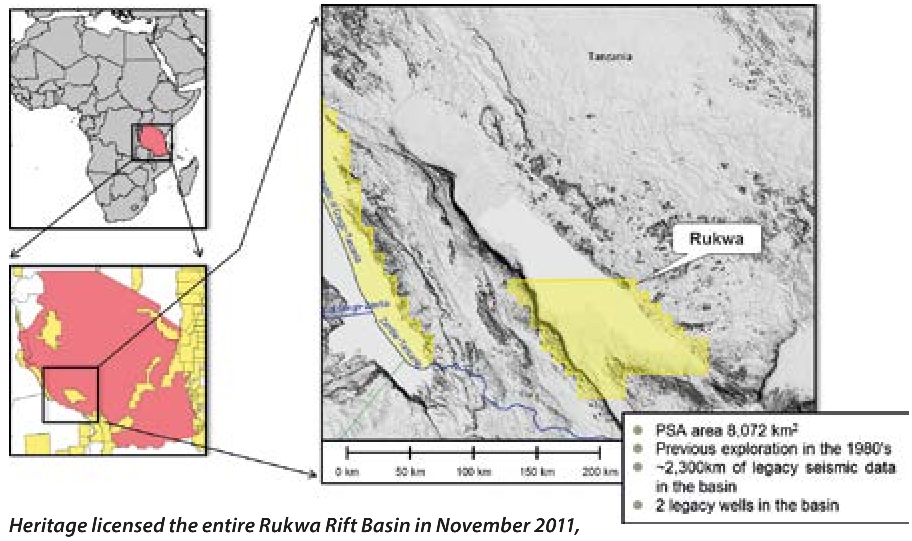
Following its Albertine Basin success, Heritage was keen to apply its geological and operational skills

Children playing next to a pirogue, Lake Nyasa (also known as Lake Malawi).

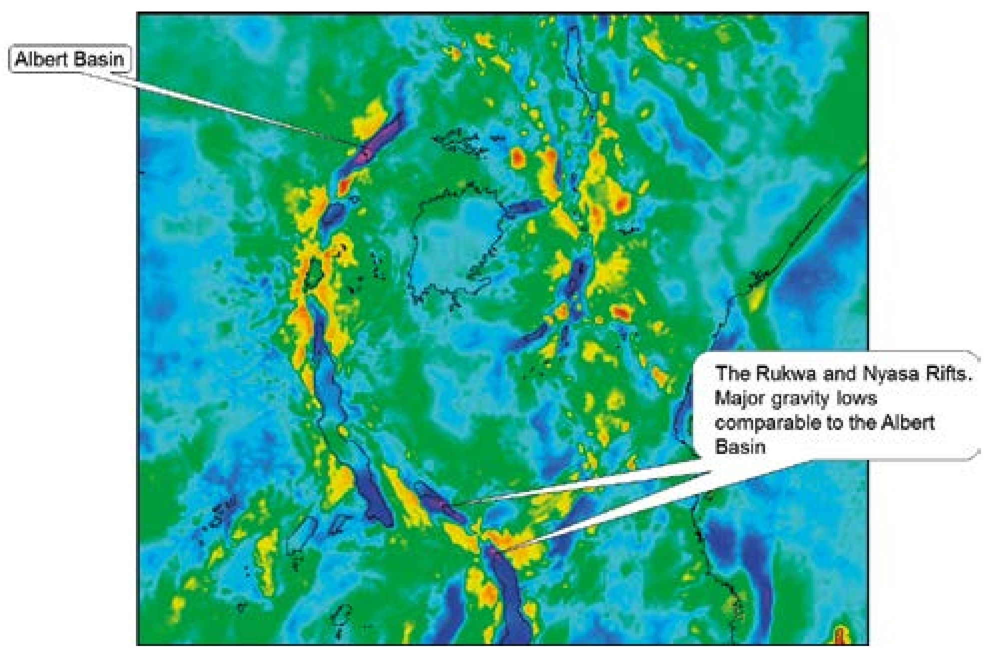
to exploring in similar African rift basins. As part of the screening process it used the global gravity database to look for basins with thick low density sequences, which may be geologically similar to Lake Albert. This pointed them towards the Rukwa Rift and the northern end of the Nyasa Rift, where gravity lows comparable to the Albert Basin are present.

As a part of operations in Uganda, Heritage reviewed the operational logistics of drilling in an offshore rift-lake location. Outline cost for drilling in a comparatively shallow (<50m) lake was in the order of $85 million – just to mobilise the rig/barge into the lake; for deeper waters the costs were considerably higher. The conclusion was to keep rigs onshore or in very shallow water and this increased the interest in Rukwa, the shallowest of all the major lakes.

Bob Downie, Senior Geologist with Heritage Oil, explains why the licences attracted Heritage: "Our experiences in the Albert Basin in Uganda showed that the petroleum system is entirely contained within the Neogene section, so we were very encouraged in that not only do the Rukwa and Nyasa rift basins have thick Neogene Lake Bed sequences but also have underlying Cretaceous and Karoo, providing secondary potential for reservoir and source rocks."



Heritage licensed the entire Rukwa Rift Basin in November 2011, and the original PSA included all of the shallow Lake Rukwa and adjacent areas (2 blocks). Following geological studies, the northern block was relinquished to allow focus on the more prospective southern areas. Early in 2012, Heritage licensed the Kyela PSA, which is entirely onshore at the north-east end of Lake Nyasa (or Lake Malawi).



A search for basins with thick low density sequences, similar to Lake Albert, pointed Heritage towards the Rukwa Rift and the northern end of the Nyasa Rift.

Neogene Source Rocks

Exploration in the Rukwa Basin by Amoco in the mid-1980s resulted in the acquisition of ~2,300 km onshore and offshore legacy seismic data. Two wells were also drilled in 1987 – Galula-1 and Ivuna-1. Legacy data delineated a major depocentre with up to 4,500m of Plio/Miocene to Recent section. Heritage considers this an underexplored basin with missed potential.

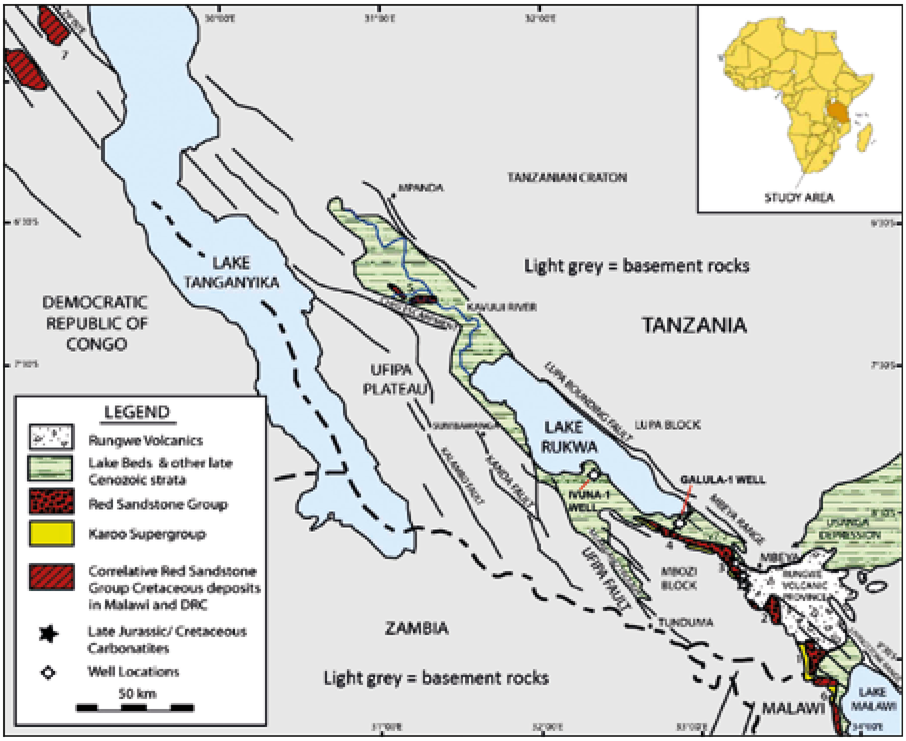
A frequent criticism of the source rock potential of Lake Rukwa has been that the present-day shallow water depths would be inconsistent with deposition and preservation of source rocks. Bob Downie elaborates: "Our studies clearly show that the Neogene palaeo-Lake Rukwa was deep for significant periods of its history. Deep water represents a high probability of source rock deposition and preservation."

Geochemical analysis of Ivuna-1 cuttings clearly indicate that oil-prone Type I kerogen comprises 80–95% of total kerogen and supports the proposition that the deep water dysaerobic conditions existed for significant periods during the Neogene. Ivuna-1 is on the basin margin and it is likely that the source quality and thickness will increase into the basin depocentre.

Source rocks are one thing but what about maturity? Bob Downie again: "Our current mapping and velocity models suggest that the base of the Lake Beds in the basin depocentre is up to 4,500m. The legacy wells both showed high geothermal gradients of 39°C/km and modelling suggests the possibility of oil generation from depths > 2,200m. With this in mind we can define a kitchen within the Lake Beds."

Potential Reservoirs and Seals

The legacy well data and outcrops prove the existence of medium-coarse grained



Geological map of the Lake Rukwa and Lake Nyasa (Lake Malawi) area, showing surface outcrops, key bounding faults and well locations. *(Modified from Roberts et al. (2010), DOI 10.1016/j.afrearsci.2009.09.002)*

quartzitic Lake Beds sands with good potential as reservoir. Downie and co-workers consider the probability of effective reservoirs being present in the mapped leads as being highly likely. Shales with seal potential were penetrated by the legacy wells and similar shales, at similar stratigraphic levels, can be recognised in both legacy wells. With this in mind, Heritage considers the probability of effective seals as being good.

If all this is true then it is important to try to understand why the initial wells failed. The team at Heritage believe that Ivuna-1 could have never worked, as it was drilled 40 km from the main kitchen area, in a migration shadow zone. Galula-1 was more favourably located but the structure was not closed to the south-east and was located in a proximal, sandy, non-sealing facies. Also, faults in this area appear to be non-sealing.

From the legacy seismic it was recognised that Rukwa had structures of probable strike-slip origin, giving rise to the possibility that structural traps similar to the Albert Basin Kingfisher field may be present. In fact, the legacy seismic suggested a number of leads of this type associated with the main basin margin fault, proximal to the depocentre, in areas that were poorly covered by the legacy seismic.

In order to remedy this deficiency in seismic coverage Heritage acquired an additional 601 km of seismic. 460 km of this were acquired in the offshore areas using the same OBC technology as applied to Lake Albert, and 141 km were acquired using conventional land dynamite technology. The focus was to image structures right up to the basin margin fault. The results were successful and prospects defined by roll-over structures against the fault were proved at a number of locations.

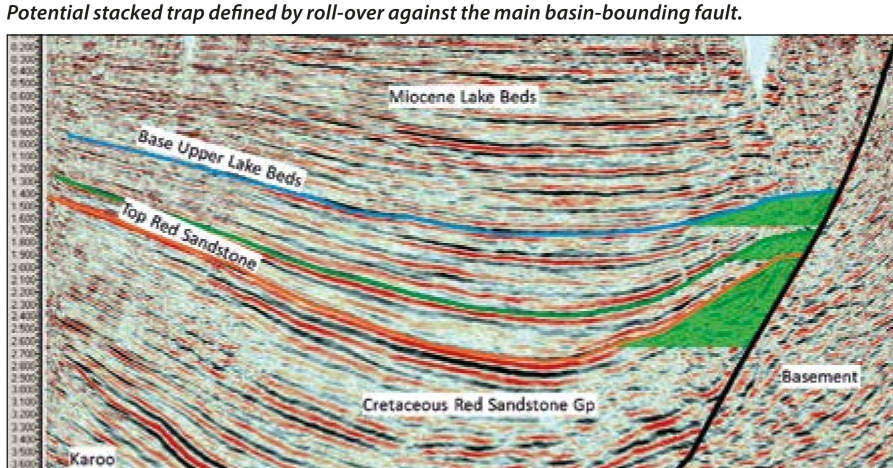
Exploration – Kyela, Lake Nyasa

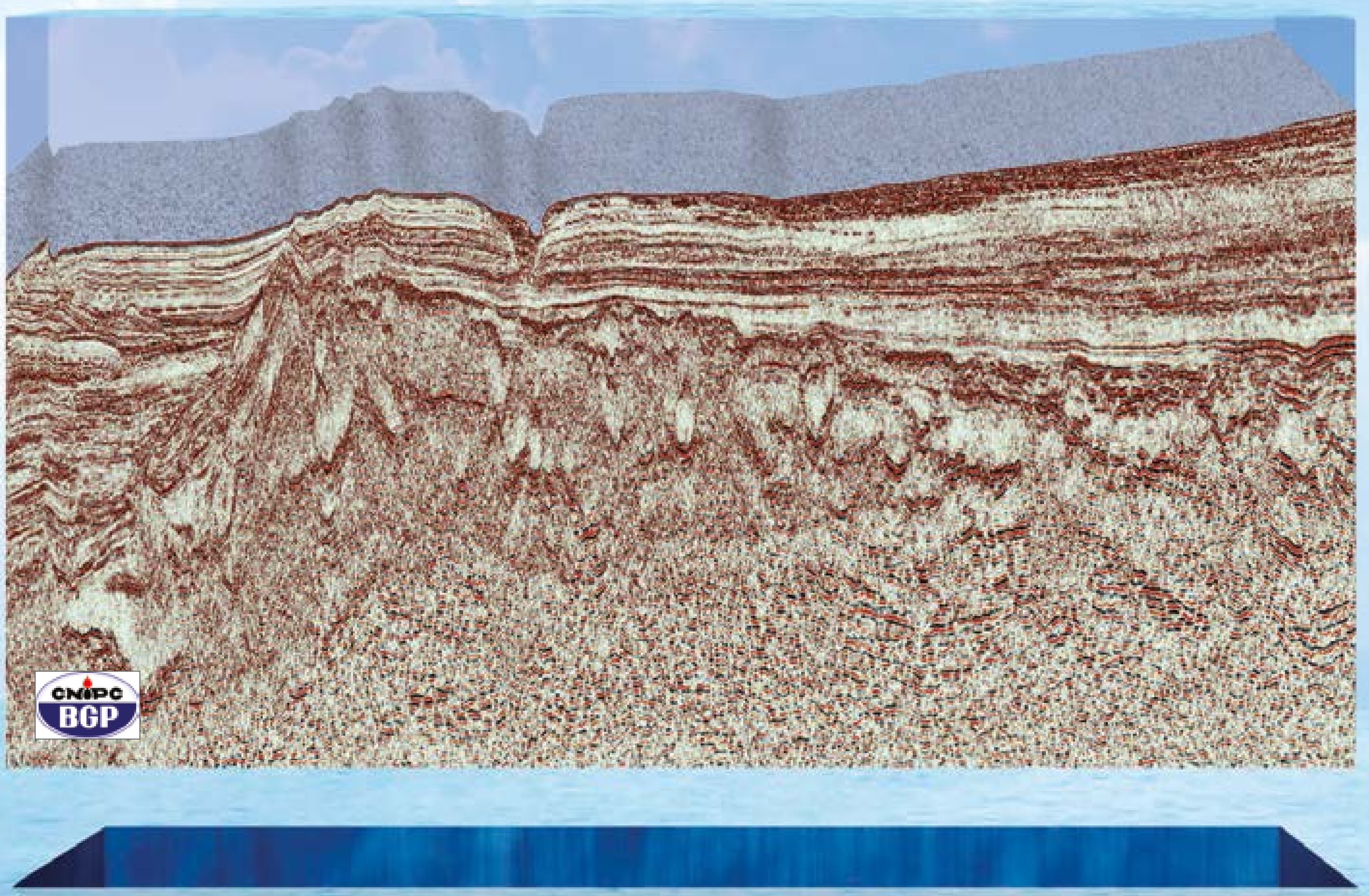
This onshore area north of Lake Nyasa has never previously been targeted for hydrocarbon exploration, but Heritage was drawn to it by the recognition of a major gravity low. The possibility of a major depocentre was confirmed by published seismic maps from the immediate offshore area, which show up to around 4 seconds of section.

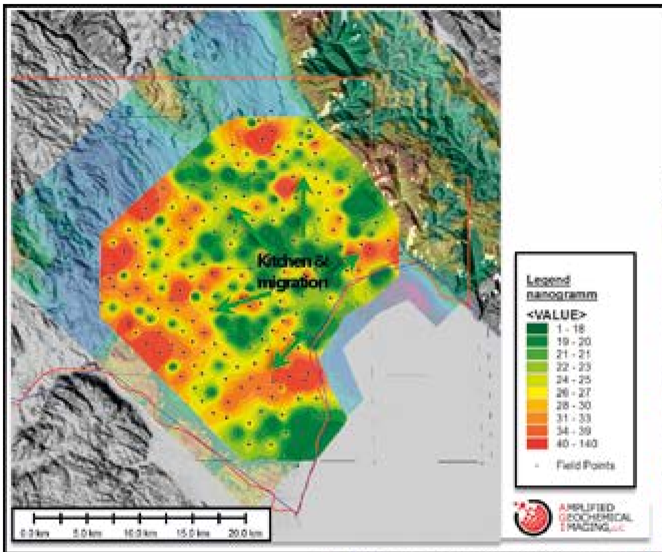
As the first phase of the exploration campaign, Heritage acquired a Full Tensor Gravity (FTG) survey, by Arkex, completed in September 2012. The results were very revealing, confirming the presence of the main depocentre, extending from onshore to offshore. The data suggest the presence of flanking structural highs and intra-basinal highs. Some of these are very large with the 'A' Lead being around 50 km^2.

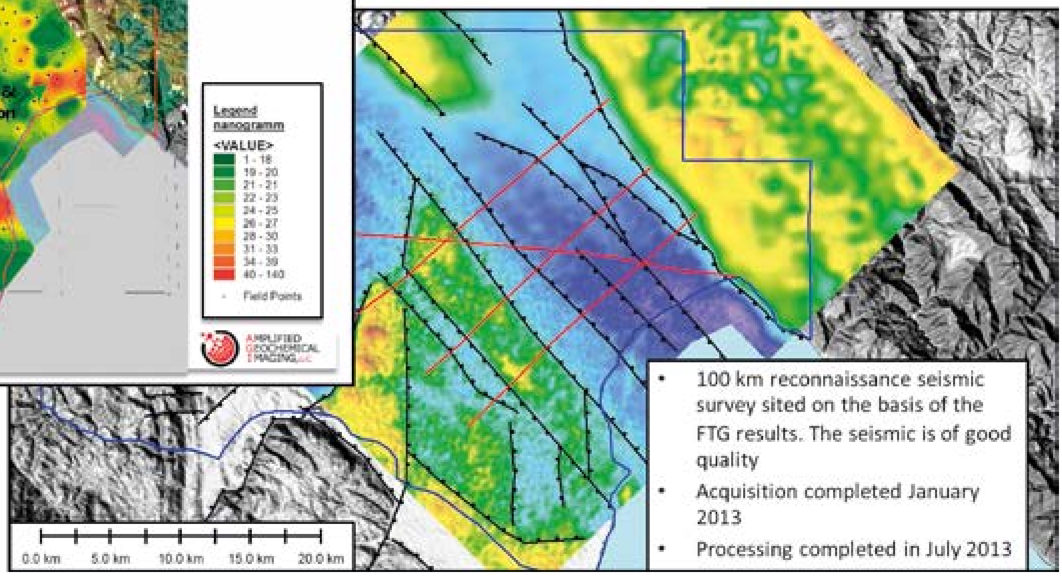
As a result of the FTG a 100 km reconnaissance seismic programme was sited and acquired, which proves reflectors down to over 4 seconds and validates the gravity highs shown by FTG as potential structures. The seismic thus provides clear evidence that sufficient thickness of section exists to promote potential source rocks into the oil window. In order to validate the presence of a kitchen, a geochemical microseep was commissioned from AGI across the main depocentre and onto the flanking highs. This survey showed that the basin centre was characterised by low hydrocarbon signals, whereas the flanks had high signal, exactly as might be expected if hydrocarbon generation

Potential stacked trap defined by roll-over against the main basin-bounding fault.









Satellite map showing results of FTG survey overlain with structural interpretation and location of seismic reconnaissance survey. Inset: same area with results of the geochemical microseep analysis and interpretation of kitchen area.

had occurred in the basin centre with migration to the basin flanks.

A second seismic infill programme is planned, to convert the gravity leads to seismically defined prospects.

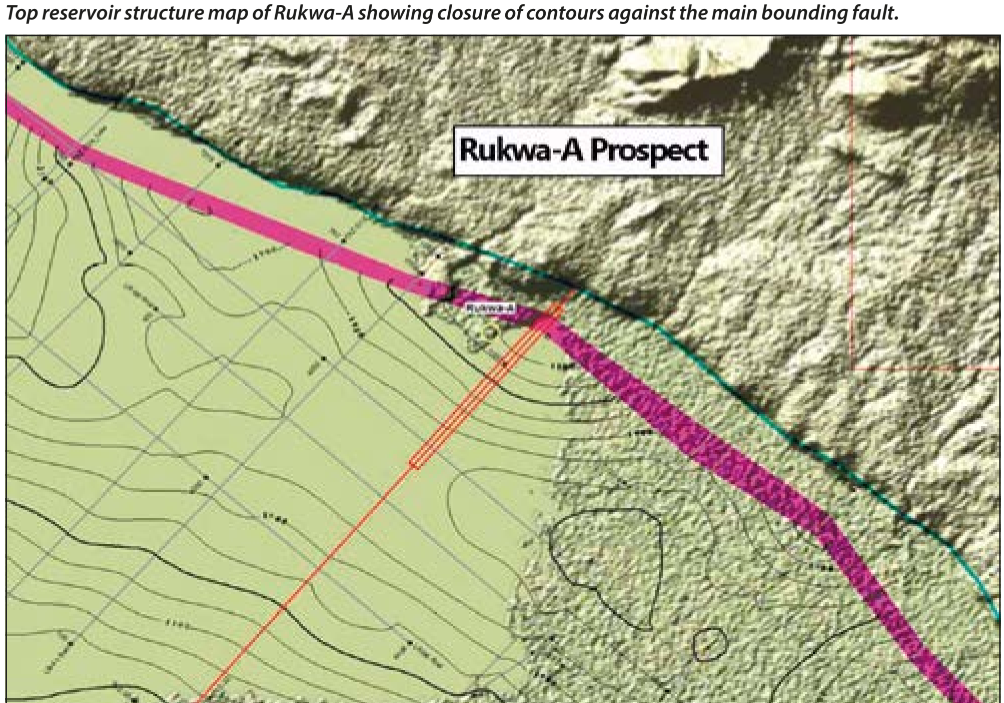
Looking Ahead

At Rukwa, Heritage has completed the mapping of the combined seismic dataset and has defined five prospects associated with inversion structures along the main boundary fault. The largest of these prospects, Rukwa-A, located at the south-eastern end of the lake, has an unrisked Pmean resource of 225 MMboe (management estimate). The greater part of the structure lies offshore, but the location of a suitable land spit means that the prospect can be tested from a planned onshore vertical well.

Meanwhile, Bob Downie and colleagues believe that the initial geophysical and geochemical surveys of Kyela have proved that this frontier area has clear hydrocarbon potential, with depth of section, potential structures and geochemical anomalies all revealed. The seismic data, however, are insufficient to define a well location and Heritage is planning for an infill seismic campaign to define a well and identify a drilling site location.

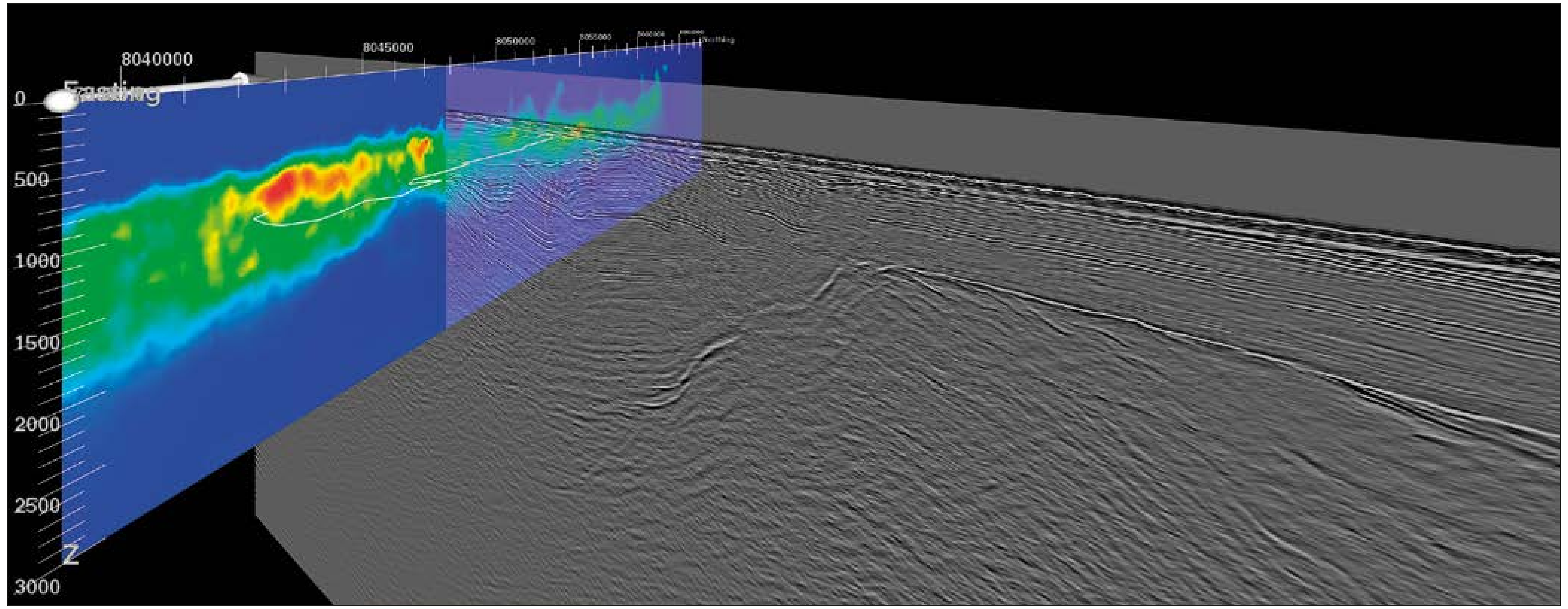
The pursuit of hydrocarbons in these blocks will present many scientific challenges, but the geological and geophysical studies undertaken by Heritage to date all point to the clear hydrocarbon potential of both areas. Further geophysical studies will be required in Kyela to delineate drill sites and ultimately the presence or absence of hydrocarbons will be proved by drilling. Nonetheless, Heritage is excited about the similarity of these basins to the proven African Rift Valley plays of the Albert and Lokichar Basins of Uganda and Kenya, and look to extend the proven play into these two underexplored basins. ■

Top reservoir structure map of Rukwa-A showing closure of contours against the main bounding fault.

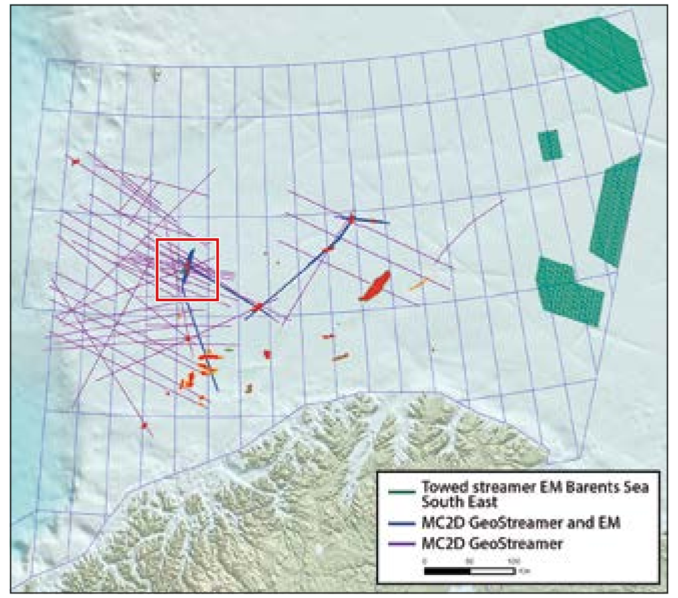


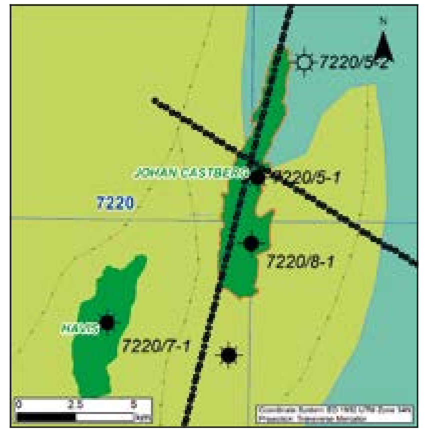
Towed Streamer EM for Success

Marine CSEM has been used extensively to improve the chances of success in the search for hydrocarbons due to the fact that accumulations of oil and gas are characterised by increased resistivity. PGS' Towed Streamer EM system allows EM data to be acquired with the same efficiency as towed streamer seismic data, resulting in the possibility of cost effective regional-scale surveys. Acquisition rates of 150 km per day are not uncommon and the system can also be used simultaneously with 2D GeoStreamer, providing the ultimate exploration tool in frontier areas. While the efficiency claims are obvious, there are also a number of technical advantages to the towed streamer EM system, as summarised in the following article.

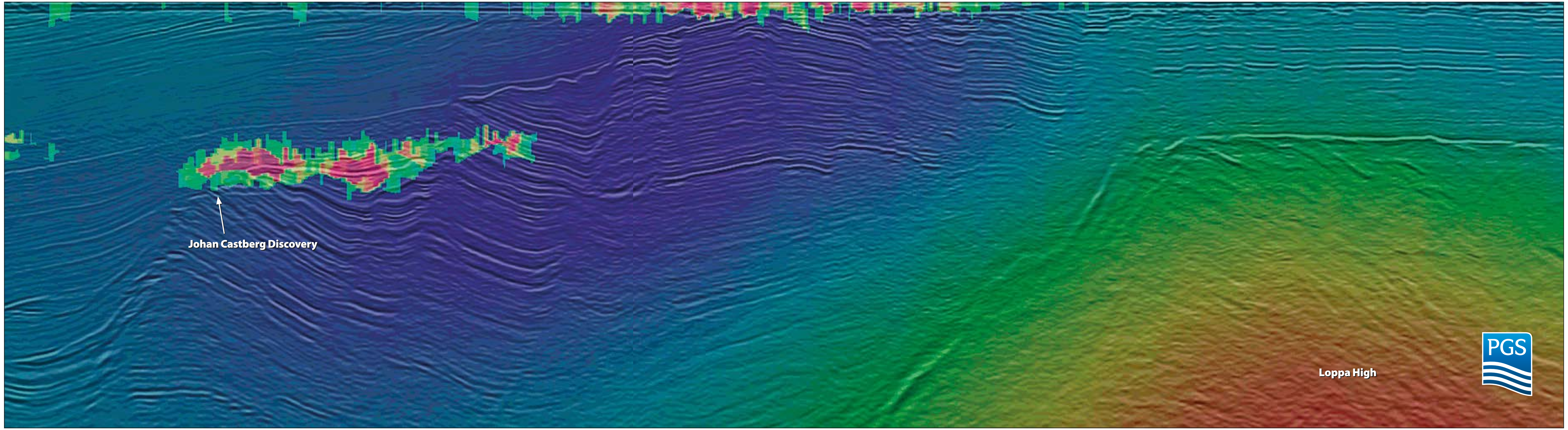


Close-up of Johan Castberg area.

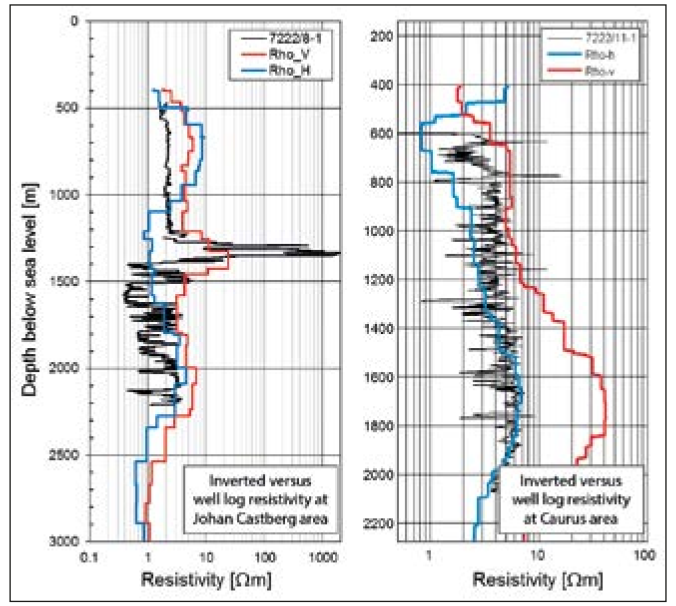




This survey line is about 110 km long (about 50 km shown here) and traverses the Loppa High as a 2D profile.
Warm colours (yellow to red) in the smooth background resistivity denote regions of increased resistivity (red is > 100 Ohm m).



Example comparison between the measured resistivity at wells in the Johan Castberg and Caurus areas and the resistivity recovered via anisotropic inversion.



See the Big Picture – and the Details

ALLAN McKAY, JOHAN MATTSSON and JONATHAN MIDGLEY, PGS

Using a towed streamer EM system makes it possible to use the same data to determine resistivity on a scale of a few hundred kilometres, and at the scale of the reservoir.

As part of the practical interpretation of CSEM data, the definition of anomalous zones of resistivity is one step in the overall workflow to determine the origin of high resistivity regions. However, the subsurface resistivity can vary by several orders of magnitude due to both lithology and fluid effects. In complex geological settings such as the Barents Sea the variation of resistivity that is possible means that it is important that we are able to determine the main regional factors controlling the variation of subsurface resistivity. Being able to define the background trend in, for example, electrical resistivity and anisotropy, is crucial in the robust interpretation of the subsurface and definition of areas considered anomalous. In essence we wish to be able to determine the subsurface resistivity at both the regional and reservoir scale.

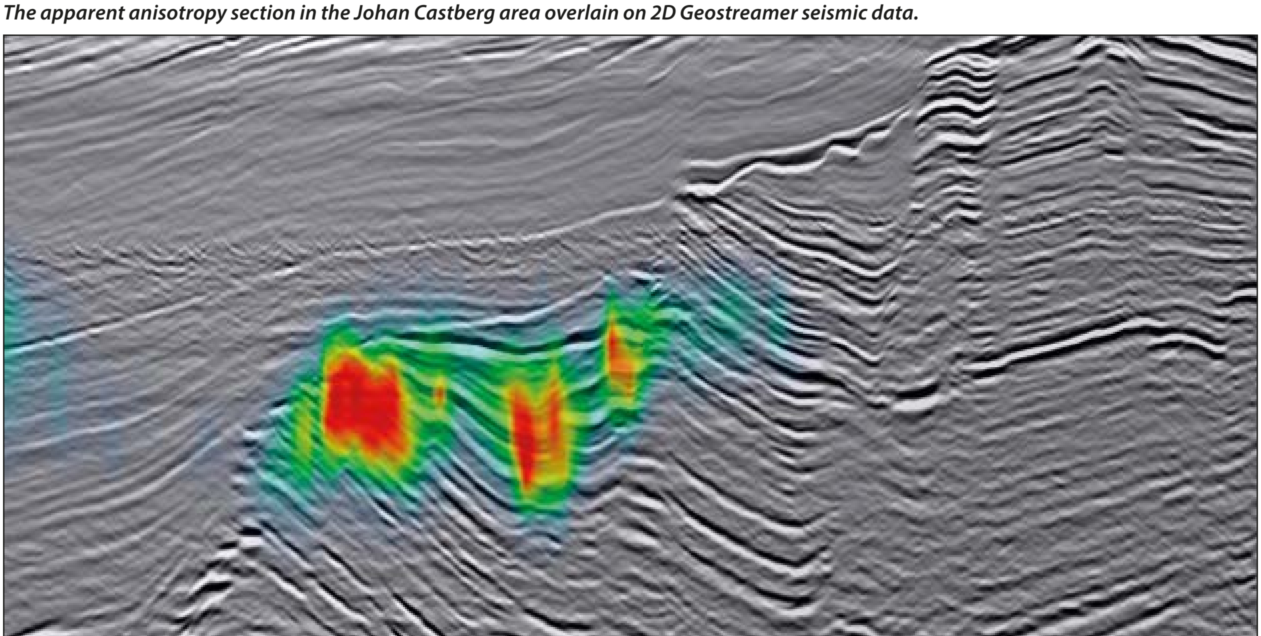
Large and Small Scale Resistivity

The fold-out figure on the previous page demonstrates the large scale of resistivity determination that is now possible given that CSEM acquisition has been integrated with acquisition of broadband dual-sensor seismic data. The resistivity along the survey profile has been determined using unconstrained anisotropic 2.5D inversion, and is overlain on the full stack broadband dual-sensor data that was acquired at the same time. The horizontal component of resistivity is shown, and this is taken to represent the bulk background resistivity.

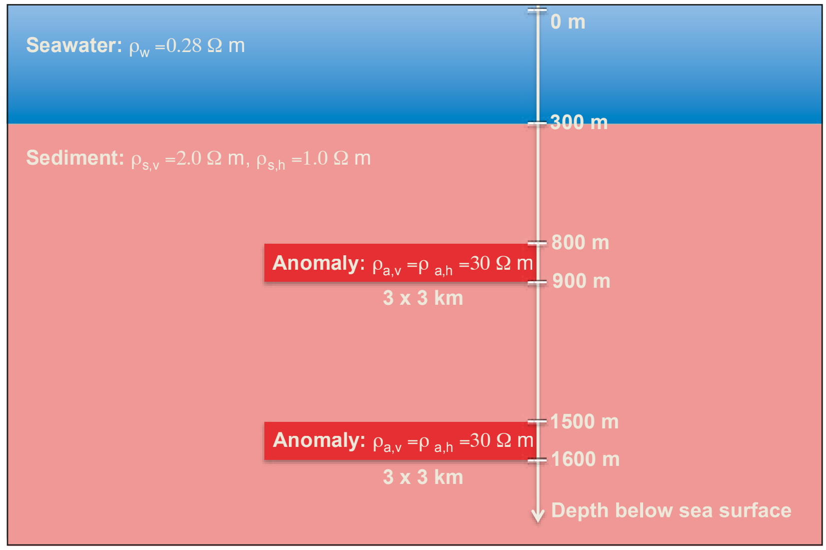
In the western part of the survey line the distinctive Bjørnøyrenna fault block terraces leading into the Bjørnoya Basin can be seen, while east of the Loppa High is the Bjarmeland Platform. The Loppa High is clearly one of the major units of resistivity on this survey line. In addition, a distinct structural difference in resistivity is observed – east of the Loppa High is generally more resistive than west of it. Each end of the profile indicates moderately resistive tertiary sediments: at the extreme western edge of the profile the increase in resistivity appears to be associated with an obvious gas-cloud zone.

However, defining the background resistivity is only one piece of the puzzle – we also need to determine the resistivity at the reservoir scale. Shown below overlain on the seismic is the electrical anisotropy (ratio of vertical to horizontal resistivity) in the vicinity of the Johan Castberg discovery, determined using unconstrained inversion along a 20 km profile traversing Johan Castberg. The survey line crosses the short axis of the field (about 1.5 km wide) over the surface location of the 7220/5-1 appraisal well completed in 2012. There is a strong correspondence between high electrical anisotropy determined from inversion, and the Johan Castberg discovery. The strongest apparent anisotropy is restricted to the precise lateral location of the field, and is remarkably well registered in depth given that we have used unconstrained inversion. At the appraisal well location the top reservoir level is 1,276m below mean sea level; the oil water contact is at 1,395m and the apparent anisotropy anomaly is between 1,200 and 1,500m. Clearly, towed streamer EM data can be used

The apparent anisotropy section in the Johan Castberg area overlain on 2D Geostreamer seismic data.



to determine resistivity on a scale that ranges from about some tens of metres to 200 km.



Geometry of the resistivity structure in the modelling example.

Spatial Data Density

PGS' towed streamer EM system allows for dense data sampling along the survey line and along the streamer cable itself. A typical transmitted electric current sequence from the source has a duration of 120s – representing a 'shot'. With a towing speed of 4 knots, the system will move about 250m during this time. The acquired potential differences in the 72 electrode pairs in the streamer are deconvolved with the electric current sequence for every shot, which means that the resulting frequency responses of the earth are estimated every 250m. The electrode pairs are evenly spread along the 8 km streamer, which gives an average offset separation of about 100m. This is the highest spatial data density in the current version of the towed streamer EM system.

Are there any advantages to this data density compared to a more sparse acquisition? In particular, what happens with the subsurface resistivity image estimated from inversion when the frequency responses are decimated and are only obtained every 1,500m along a survey line? This is illustrated for a relatively simple resistivity structure in the following modelling example.

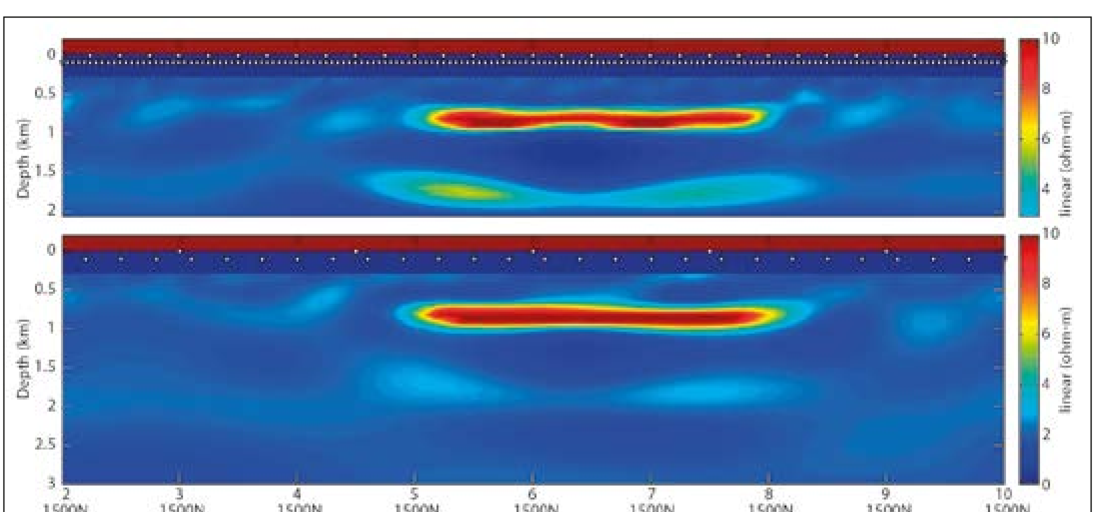
Consider a half space of an anisotropic background sediment with two high resistive anomalies. The subsurface model is located below a 300m layer of seawater of constant resistivity.

An electric current source is towed 10m below the sea surface along a 21 km long survey line, with a streamer cable at a depth of 100m and with receiving electrode pairs every 100m. A 120s long source sequence is transmitted at every shot. The resulting frequency responses are then calculated at the frequencies of 0.1, 0.3, 0.5, 0.7 and 0.9 Hz for every offset and shot point.

This synthetic data set is inverted using a 2.5D finite element inversion code called MARE2DEM with the vertical resistivity result shown in the top figure below. It can be seen that the top anomaly has been recovered rather well with a resistivity of 8–10 Ωm, whereas the lower anomaly is less well recovered but still visible. The horizontal extent of the top anomaly matches the model in the figure above very well, with an accuracy of 100m. The accuracy of the thickness is poorer since an unconstrained inversion was used, only preserving the product of anomaly thickness and resistivity value. In this case the recovered thickness is therefore roughly three times the true thickness, hence, a resistivity of about 10 Ωm.

The 2.5D inversion is now run with a spatially decimated data set where the shot and offset separations are 1,500m and 300m, respectively. The result is shown in the second figure below, where it can be seen that the lower anomaly has now almost disappeared. The top anomaly is still well recovered to within the same accuracy as with the denser data set.

The denser spatial sampling which can be achieved with a towed streamer EM system is demonstrated to be advantageous for a higher and more accurate vertical resolution of the subsurface and potentially allows the detection of deeper anomalies that would otherwise be missed. ■

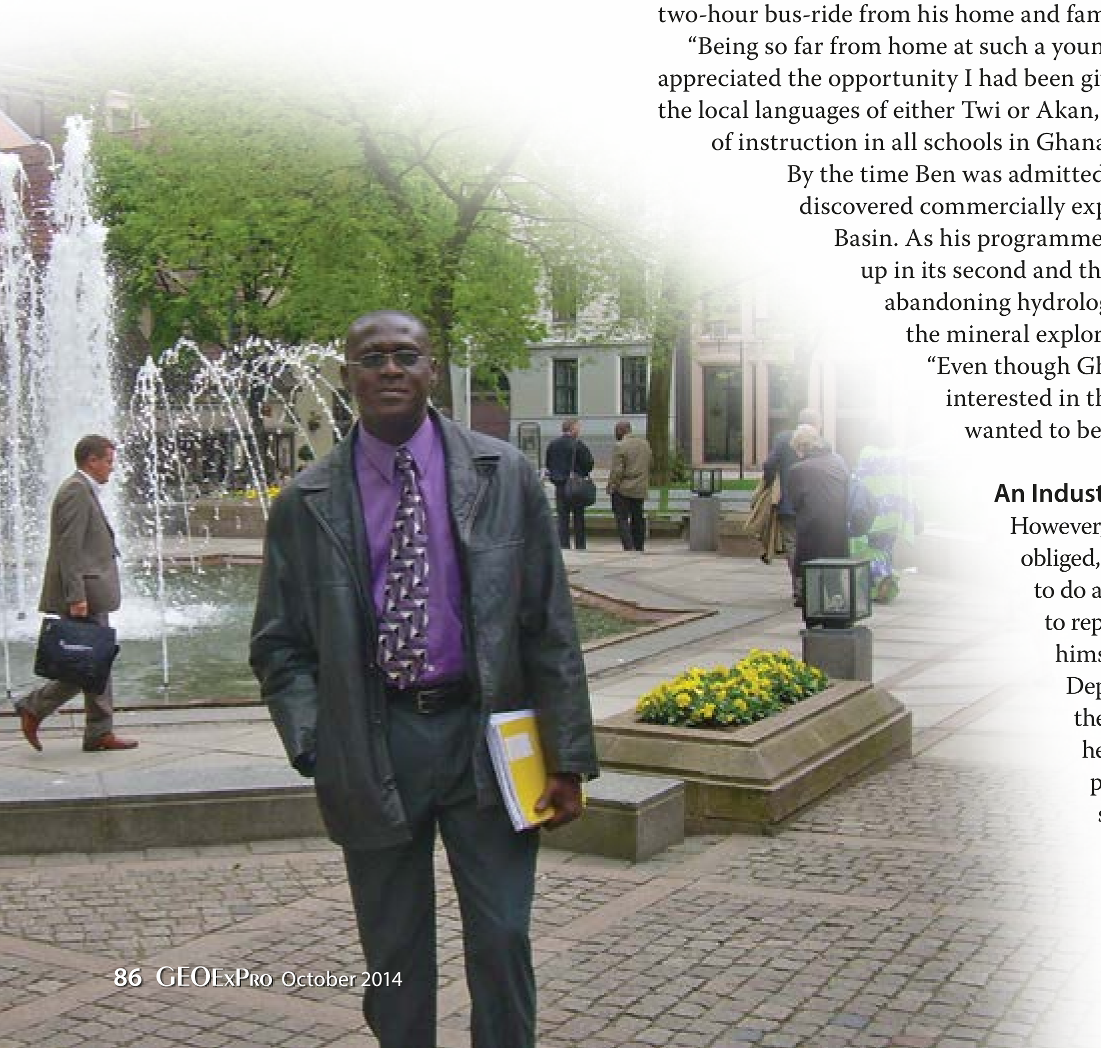


The inversion results with a shot spacing of 250m and offset separation of 100m (a) and a shot spacing of 1,500m and offset separation of 300m (b).

Ben Asante: Riding the Wave

NIKKI JONES

Benjamin Asante, until recently a senior geoscientist at the Ghana National Petroleum Corporation, has ridden the wave of Ghana's national development. Although his story is full of significant and unusual personal firsts, it also reflects the rapid economic and social development of a post-colonial African state.



Even in the international oil industry, the career of Benjamin Kwame Asante, Lead Geophysicist at the Ghana National Petroleum Corporation (GNPC), is remarkable. It's a story of life-long learning and personal determination, combined with the luck of being in the right place at the right time. As Ghana's oil industry has taken off, Ben has found himself at the forefront, gaining rapid first-hand experience of the technicalities of oil exploration and production, and moving fast into management and an advisory role to government. For most people that would be career enough, but now a student again at GIMPA Law School, Ben has a whole new career in mind.

Hydrology, Not Seismology

Ben's early interest in Earth Sciences came from observing the daily trips to the village well.

"Fetching water was every child's job from the age of six or seven," he explains, "and we carried it on our heads. But in the dry season the water was so dirty we had to leave it for a day to settle before it could be boiled. For anyone living on the coast, there was the added problem of salt contamination due to seawater encroachment."

This early experience led to an interest in hydrology and in 1984, Ben was admitted to the University of Science and Technology to study Geological Engineering. The journey from village to university was itself atypical since school was not compulsory at the time. Fortunately Ben's parents believed in education and he was lucky enough to benefit from the fact that certain prestigious mission schools were still in existence. Following primary and middle school at the Begoro Presby primary and middle schools, Ben took his common entrance exam early and was admitted to St Peter's, a Catholic Secondary school at Nkwatia-Kwahu, about 150 km north of Accra. The school was run by a German Roman Catholic priest with Ghanaian and other ex-pat teachers and was a great opportunity for a young lad – but a long two-hour bus-ride from his home and family in the east.

"Being so far from home at such a young age was hard, but I really appreciated the opportunity I had been given," says Ben. "At home we spoke the local languages of either Twi or Akan, but English was the official means of instruction in all schools in Ghana and I learnt very quickly."

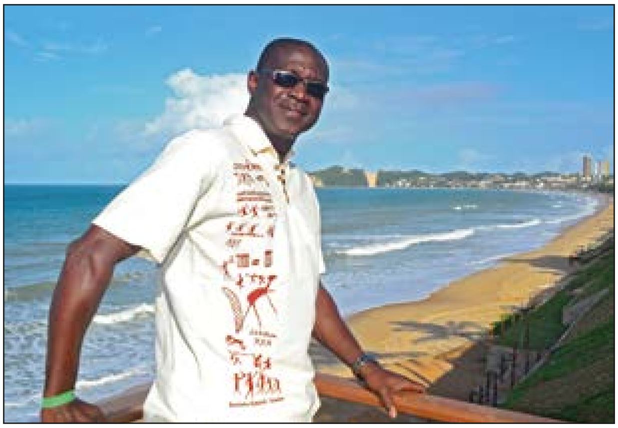
By the time Ben was admitted to university, Ghana had already discovered commercially exploitable oil reserves at the Saltpond Basin. As his programme of study at the university opened up in its second and third years, Ben found himself abandoning hydrology and increasingly drawn towards the mineral exploration and geophysics options.

"Even though Ghana has many minerals, I wasn't interested in the hard rocks," he says. "I decided I wanted to be part of something up and coming."

An Industry with a 'Buzz'

However, on graduating in 1988, Ben was obliged, as were all Ghanaian students, to do a year of national service in order to repay the costs of tuition. He found himself posted to the Geological Survey Department in Accra. Frustrated with the lack of 'action', after three months he managed, through a network of personal contacts, to get himself seconded to GNPC, the four-year-old national oil company. Along with two fellow mates he became one of the 'service personnel', working in the field on a very small allowance, with little control over his career.

With a staff of less than twenty involved in exploration, there was 'quite a buzz' and Ben was quickly given responsibility for surveying two areas. Within a year he had approval to do well-site duty on drilling rigs. Periods on board a seismic vessel were interlaced with training sessions.


Ben enjoys travelling, as can be seen from this photo of him in Brazil.

"It was great to be employed by the national oil company, working from an office in Accra," he says. "I was involved in everything – not just the quality control on the seismic vessel during acquisition, but on guide vessels and on land as community liaison at certain times. I was, and have continued to be, involved in a range of activities: seismic data interpretation, negotiations, policy formulation, promotion of the hydrocarbon potential of Ghana, management roles and mentoring of junior colleagues."

Promoting Ghana's Potential

In 1991 Ben travelled abroad for the first time – a personal trip to the UK – and two years later he was awarded a Norwegian government scholarship (NORAD), to the University of Trondheim in Norway, to do a post-graduate diploma in Petroleum Exploration and Production.

"By then I was used to being the only black person on a seismic vessel. In Norway I was mixing with students from Nigeria, Kenya, Uganda, Tanzania, Madagascar and Bangladesh, as well as the locals," says Ben. "Part of the industry is about learning to adapt, to accept cultures and the different way people do things. I only remember one incident of discrimination, out at some country bar. Generally we were well looked after and given a very good reception."

The year in Norway not only introduced Ben to snowball fights and skiing but the course covered all aspects of exploration, environmental issues and policy making. At the end of 1993 he returned to Ghana and married his long-standing partner, Grace, who has her own career in shipping and freight management. Ben has two children – a girl and a boy.

At GNPC, Ben's career moved fast. He was soon promoted from Assistant Geophysicist to Geophysicist Officer, a role that broadened his experience of giving presentations, management and training. In 1998 he was promoted again to the role of Senior Geophysicist and later to Lead Geophysicist.

His promotions involved an increasingly active role in the promotion of Ghana's hydrocarbon potential to foreign investors, as well as the drafting and review of the state's petroleum laws. "It was so fascinating, giving presentations at local and international conferences and also meeting other professionals and parliamentarians to review and formulate policies for the petroleum industry in Ghana, and defending petroleum agreements."

As Senior and later Lead Geophysicist, Ben was working closely with foreign companies – Kosmos and Tullow, Hunt, Nuevo, Devon and Dana Petroleum and many more – who, in the '90s and early 2000s, were actively exploring the offshore sedimentary basins in Ghana. At this stage they were mostly limited to not very deep waters. However, Dana's commitment to Ghana was sufficient for them to offer Ben a three-month attachment to their office in Aberdeen in 2001, a great learning experience that encouraged him to think about further studies. However, in 2003 Dana folded as a company – truly unfortunate timing since oil was discovered in the Jubilee field not long after. "They sent us a congratulatory email when the news came out," says Ben, "but clearly it was a painful experience for them."

First Oil

Kosmos's discovery of the Jubilee field in 2007 finally confirmed Ghana as a source of commercially recoverable oil (although Ghana was already producing some 400 bopd from the Saltpond field). Because of the dynamic communication with wells in the next block where Tullow had exploration rights, unitisation was necessary. It took two years for a plan of development to be agreed and during this period Ben acted as coordinator with the Ministry of Energy and parliament. He had an office at the Presidency as a member of the Oil and Gas Technical Committee set up by the President. First oil was achieved in December 2010.

Soon after, Ben was part of the team hosting Ghana's first international oil and gas conference after the Jubilee discovery, with attendees from the UN, the World Bank, Norway, Trinidad & Tobago and the West African sub region. He was subsequently invited back to Norway to study the management of their oil industry and its revenues. Returning home, he became part of the team that travelled around Ghana having regional consultations with the public as to how they wanted the oil revenues to be used and the priority areas into which the oil monies should be channelled. This public consultation led to the formulation of the Petroleum Revenue Management Act for Ghana and a review of Ghana's oil and gas laws, tackling difficult subjects such as 'local content' employment policies.

"I'm really proud to have been part of it," says Ben. "Travelling around the country and talking with ordinary people about their priorities and expectations led to the establishment of a heritage fund and a stabilisation fund, both of which should help Ghana avoid the 'resource curse'. We need an equitable distribution of revenues. It's been positive so far, although we're seeing too much fire-fighting at the moment. Ghana needs to stick to the national development plan that came out of the stakeholder consultations.

"Local content is a difficult issue for a country like Ghana," says Ben. "Expectations have been high and we have had to manage the people's expectations. We have really had to stress that the industry will not bring a great increase in employment and people should help develop other sectors of the Ghanaian economy so as to avoid the 'Dutch Disease'. All oil-related contracts are published so it's a fairly transparent process. If a Ghanaian company is within ten per cent of the optimum bid, we still consider them – this was stipulated in the Petroleum (Local Content and Local Participation) Regulations. The purpose of the local content and participation regulations, known as L. I. 2204, is to promote the maximisation of value-addition and job creation through the use of local expertise, goods and services. The inclusion of local businesses and financing in the petroleum industry value chain and the retention of capital and expertise in Ghana are essential for the country's development. The position at the moment is that companies such as Schlumberger, Baker Hughes, Halliburton etc. are almost the only companies that can provide services on the rigs – the same is true for seismic companies. But we want Ghanaian companies to develop and build capacity so that they are providing some of the essential complex services as well as those already mastered – the fabrication work, pipes and steel works, recruitment, maintenance of the FPSO and general servicing. This would bring more employment. Ghanaians are certainly learning fast."

For some, helping to lay the foundations of Ghana's oil industry might have been career enough but in 2012, Ben decided to go back to the University of Aberdeen to do a Master's degree in hydrocarbon exploration (exploHub). "We were a cohort of just five students and the second batch to go through this new course at the University of Aberdeen," says Ben. "It was intensely practical – much field work, and lectures from industry leaders. It was a really worthwhile year and it has enabled me to do much more mentoring of colleagues back in Ghana."

A New Career

Ghana is now pumping 100,000 bpd and is aiming for 250,000 by the end of the decade. Ben's career, like Ghana's development, is full of significant milestones – but they are not over yet. Rather than coasting towards retirement as the Lead Geophysicist and a key policy adviser to government and probably a consultant to the GNPC or the Petroleum Commission, Ben is now embarking on a whole new career – this time, in law. He has been admitted to the Bachelor of Laws (LL.B) programme at the faculty of law at GIMPA, Ghana, and started his three years of study in September this year. Although he is interested in general law, he expects he will specialise in petroleum and corporate law.

"I never thought I would be going through entrance exams and interviews at this stage of my career, but I just fancy the profession – and it's one way to make sure I am still needed when I reach retirement age!" he says.

With such a rare skill-set, it seems unlikely that Ben Asante would ever have found himself unemployed. It will be interesting to see where this next step in education takes him – possibly closer to a direct role in politics? Given such a remarkable career, it seems the options are fairly limitless. ■

Ben graduated in 2013 with a M.Sc. in hydrocarbon exploration from the University of Aberdeen.

Geologists at War

WILL THORNTON

2014 marks the centenary of the beginning of World War One. The Great War, as it was generally referred to in Europe, heralded a major shift in political power across the Western World, Asia and Africa. It also witnessed the emergence of the modern oil and gas industry.

The 'war to end all wars', as author H. G. Wells famously described it at the time, began in Western Europe late in the summer of 1914, following the assassination in Sarajevo of Archduke Franz Ferdinand of Austria, heir to the Austro-Hungarian throne. The fighting went on to include most of the major economies of the world until peace, in Europe at least, came with the signing of the 'Armistice of Compiègne' in November 1918. By then the establishment of new forms of fighting, made possible by mechanised weapons, resulted in many of the processes and institutions that are still recognisable in the modern oil and gas industry.

Armies on all sides of this new conflict rapidly discovered the importance of scientific know-how, and geologists and mining experts were attached to general staffs and ad-hoc military organisations. The tasks they were allocated were extensive. From the outset all sides needed access to essential natural resources, not least potable water, and there was an increased need to locate oil, metals and other strategic minerals for the war effort – and as military targets on the opposing side. Geological map-making was part of tactical terrain intelligence, while seismography was used to detect anti-tunnelling, subterranean caches of poison gas. Other tasks included analysing the strength of fortifications and facilities, examining local sand and rock for concrete, and studying the landscape for the mobility of vehicles. Fourteen geologists of the Geological Survey of Great Britain were seconded to the military to undertake this type of war service, many being despatched to the front.

Geologists were not passive in this process. R. A. F. Penrose Jr., President of the GSA in the United States, for example, wrote *What a Geologist can do in War*, a briefing document for commanding officers in the American military about the many ways geologists could be used on the front line.

Trench Warfare

The war in Europe began as a battle between gentlemen officers, supported by a professional infantry and cavalry, but

Geology as a tactical weapon: during WW1 large quantities of explosives were detonated in strategic locations to create craters or rock falls. This photo, taken in 2007, shows talus from landslides caused by explosions in 1917 at the foot of Mt. Lagazuoi in the Dolomites.

Michmuch06

Soldiers of the Lancashire Fusiliers fixing bayonets prior to an attack in 1916. Entrenchment challenged engineers and geologists throughout the war.

quickly became a war of attrition as both sides dug in and the largely volunteer and conscripted armies began the slow process of trying to nullify each other.

To do this they built a network of trenches, separated by a neutral zone ('No Man's Land'), running in a line from southern Belgium south-eastwards into eastern France – and by mobilising millions of men and women into the war effort. The 'Western Front', as it became known, produced a new form of warfare, with the opposing armies of the Allies (UK, France, Russia, Belgium, Canada and later Italy, USA and Japan) facing their enemies of the Central Powers (the German, Austro-Hungarian and Ottoman Empires) in close proximity. A bloody stalemate ensued.

Trench warfare on the Western Front brought a series of engineering problems that could best be solved by an understanding of geological principles, and the scale of the theatre of war meant that both sides were to encounter a variable geology. As the stalemate progressed the trench networks became more and more sophisticated, in both design and use, evolving for specific purposes: communications trenches to facilitate the movement of men and ordnance, and the dreaded front-line trenches, where snipers and shelling were a constant threat. The geologists and engineers employed in their construction had to deal with a landscape that changed rapidly, as boggy uplands rolled into dry, chalk valleys. As the killing continued, the pleasant pastures of central Europe were flattened by an endless bombardment, turning fertile soils into a quagmire of mud and blood.

Mountains and Bogs

Like the other combatants, Germany had no specialist geological corps before hostilities began, but by the end of the war, over 100 geologists were serving in advanced positions on the Western Front. Possibly one of Germany's greatest victories early in the war, the Battle of the Mazurian Lakes, has been partly attributed to earlier terrain surveys that established which of the shallow lakes had hard bottoms, and were thus passable, and which were soft and boggy. The Russian Second Army were routed in the mud and the Germans manoeuvred around them on firmer ground.

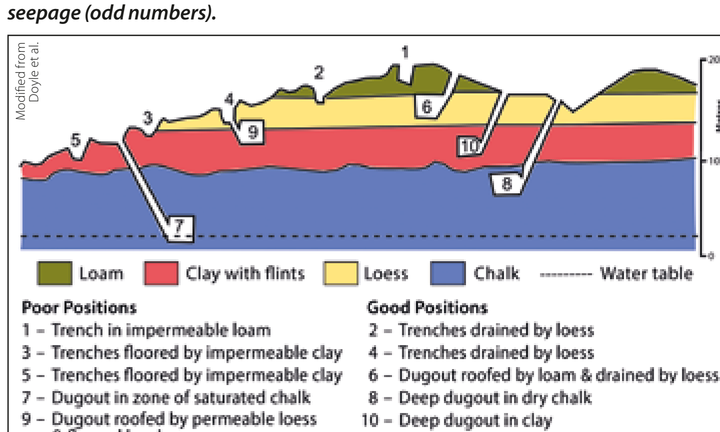
The 'Western Front', where the entrenched armies of the Allies fought the armies of the Central Powers, became a wasteland and the final burial place of tens of thousands of men from both sides.

While the armies on the Somme floundered in the muddy wastelands and millions died from violence and disease on the Russian Front, further south in the Alps, in the picturesque and remote mountains and valleys where the armies of Italy faced the forces of Austro-Hungary, a new engineering challenge was encountered.

Italy had entered the War on the side of the Allies in 1915 and the Central Powers decided it would be prudent to secure the most important mountain routes, including the 2,100m high Falzarego Pass, overlooked by the near vertical cliffs of Mount Lagazuoi (2,700m). It was almost impossible to attack an enemy sheltered in the steep cliffs, so trench warfare was adopted, along with tunnelling. Large quantities of explosives were detonated in strategic locations to form a breach in enemy lines.

In the Alps the Austro-Hungarian army had instituted a special unit of war geologists – the *Kriegsgeologen*. The Italian army are also reported to have employed many professional geologists at the time.

The construction of dugouts and trenches on the Western Front in relation to the underlying geology. Good positions would be well drained and dry (even numbers). Poor positions would be liable to flooding through inadequate drainage or water seepage (odd numbers).



The Italian tunnel under Mt Lagazuoi (see photo, page 92). Today a tourist attraction, in 1916–17 these excavations were for a deadly purpose.

Lochnagar Crater, Ovillers-la-Boisselle, caused by the detonation of 27,000 kg of explosives at the start of the Battle of the Somme, 1916.

Mining, Tunnels and Explosions

Both sides knew it was possible, by undermining the position of your enemy or by causing a rock fall, to use geology as a tactical weapon. In the Dolomites more than 30 explosive operations were attempted by both armies. In 1915, to reach the Italian position in the middle of the southern cliff of Mount Lagazuoi, the Austrians started to construct a tunnel on the northern slope of the mountain. Adopting a similar strategy, the Italian soldiers tried to undermine the Austrian positions. Mt. Lagazuoi is composed of the Triassic Cassian Dolomite Formation, a marine reef complex, and although fractured and deformed by tectonics the rock was much harder to excavate than anyone had expected, with tunnelling rarely progressing at speeds greater than 10m a day.

In January 1917 the miners of Austro-Hungary detonated 16,000 kg of explosives, forming a 45m deep crater on the top of Mt. Lagazuoi. In June 1917 another explosion below the mountain top formed a debris cone still recognisable at the base of the cliff today (see photo on page 92).

Operations like those in the Italian Dolomites were one thing, but the use of tunnels and explosives was to reach new heights on the Western Front, where successful military mining beneath enemy earthworks and fortifications required an understanding of subsurface geology, including hydrogeology. Today the Flanders landscape is scarred by the tell-tale pockmarks that demarcate the location of some of the larger explosions. Many remain as gardens of remembrance for the soldiers whose remains still lie somewhere buried in the now verdant landscape.

A chilling example of the abilities of the miners can be found in the tale of the Butte de Vauquois, a large chalk hill where once the small village of Vauquois stood atop. In September 1914 the invading German Army captured it and began to shell French supply routes to Verdun. The French Army attacked several times but lacked the strategic advantage of topographic height and suffered enormous casualties. The hilltop, with its ruined village, became a no-man's land. The French then began building tunnels through the bedrock towards German lines. Soldiers from coal-mining areas dug the excavations that were then filled with explosives and ignited, creating massive craters on the surface. The Germans responded with their own tunnels and explosions under the French lines.

Eventually almost 40 km of tunnels riddled the Butte de Vauquois. More than 500 French and German mines had been exploded here by September 1918, splitting the hill in two with a row of craters. Thousands of soldiers on both sides were killed, with 8,000 completely missing, presumably buried in collapsed tunnels and trenches.

First World War battlefield trench at Vauquois, with craters from German and French mines in the background.

One of the largest military mining operations in history was at Messines Ridge, where sub-surface conditions were especially complex. Australian Tannatt Edgeworth David, Professor of Geology at Sydney University and discoverer of the Hunter Valley coal field, was instrumental in planning the system of mines in this battle in 1917. It culminated in the most lethal, non-nuclear explosion ever, killing 10,000 people and reportedly heard as far away as Dublin.

The Need For Oil

As often seems to be the case, a new style of warfare

Welsh/Australian geologist [Sir] Tannatt Edgeworth David successfully petitioned the Australian government for the formation of a geological corps (pictured), a unit he led with the initial rank of major. He ran the operation which mined Messines Ridge in 1917, culminating in the most lethal, non-nuclear explosion in the history of war.

Tank advancing with infantry, Vimy, 1917. The increased use of mechanised war machines had great significance for the development of the oil industry.

resulted in a new style of weapon. In the Great War it is the emergence of mechanised weapons of mass destruction – tanks, ships and aircraft – that are of most importance to our story.

Although at the beginning of the War the British Expeditionary Force had made swift advances using cavalry, the inadequacy of horse-borne transportation and militarisation was quickly recognised and the rapid development of the internal combustion engine as the warhorse of choice followed. In 1911 the Royal Navy had begun converting their ships from coal to oil; in 1916 the first tanks entered the battlefield of the Somme; and the Royal Flying Corps that had formed at the beginning of the War pioneered the way for the formation of the Royal Air Force.

Prior to 1914, British and German companies had negotiated joint participation in the Turkish Petroleum Company, which held prospecting rights in Mesopotamia – the war ended that partnership. But a growing importance was placed on oil, and the British government, already controlling oil in Persia via the Anglo-Persian Oil Company, recognised that oil had become absolutely vital and that resources in Mesopotamia would be crucial in the future. Security of the oil resource became a key focus in the war effort.

The Allies had a superior position with regards to access to oil resources and by the end of the War this was beginning to tell. An attempt to capture Allied-controlled oil fields in Baku failed and the Allies were able to rely on a good supply of oil to support the war effort.

The Legacy

The increasing use of mechanised war machines had great significance for the development of the oil industry and the professionalisation of the geological disciplines involved in finding and producing the life blood of the modern army.

At the beginning of the war the US government had formed the National Petroleum War Service Committee (NPWSC) to ensure adequate oil supplies. The mobilisation effort saw a study of the oil industry's ability to meet the growing demands generated by the Allies' reliance on American oil. The oil companies had no experience of working together but agreed to collaborate with the government to ensure that vital petroleum supplies were efficiently deployed to the armed forces.

After the war, momentum began to form for a national association to represent the entire industry in the post-war years. In 1919 the NPWSC was reborn as the American Petroleum Institute (API).

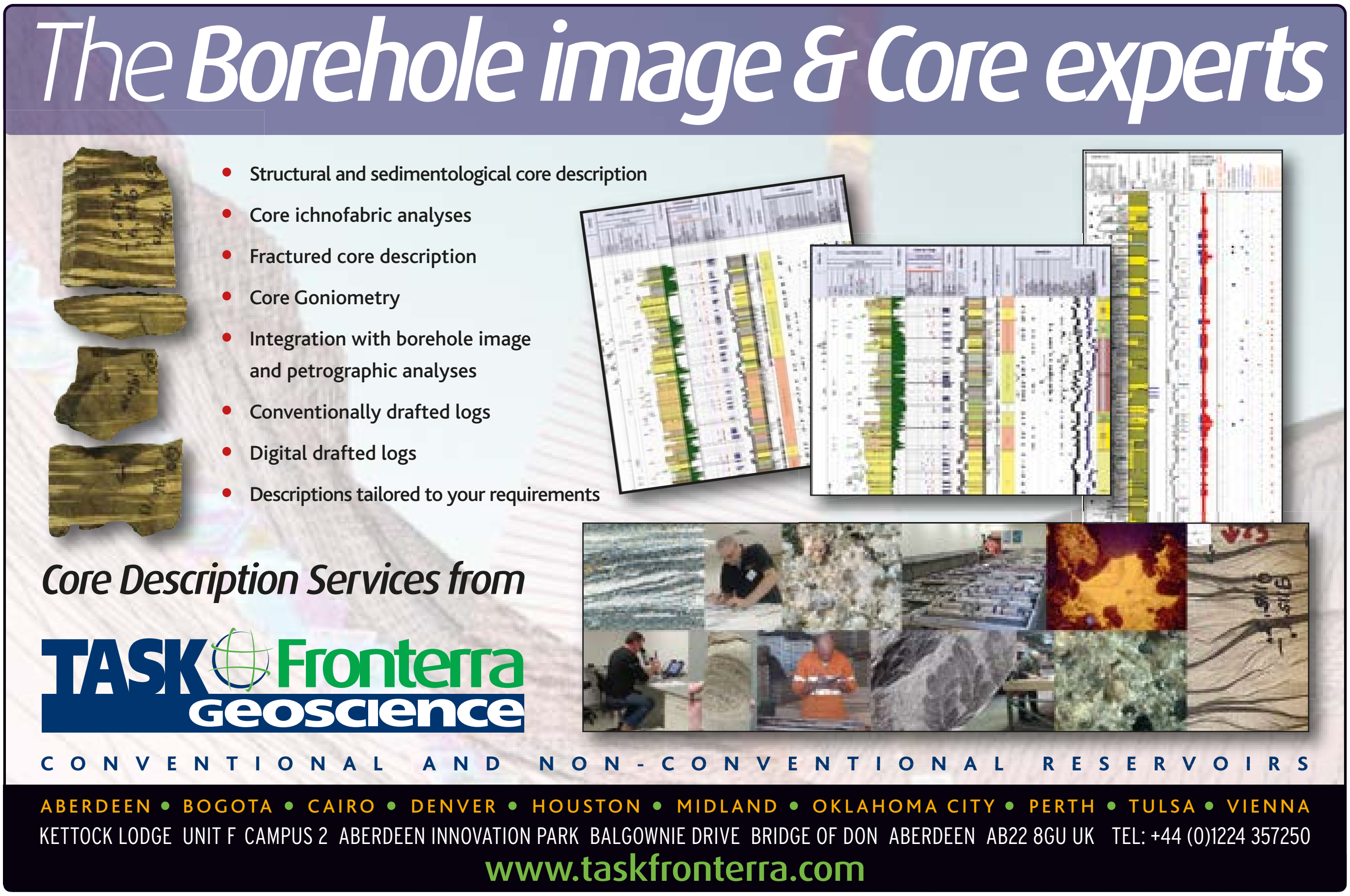
The annals of history tend to be populated with the famous and great but it is perhaps the quiet work of the men and women of the Great War and the years immediately following that really defines the industry we work in today. Before the war there was no reliable information about the production, refining and transportation of petroleum products; by the time it ended the institutions and structures of the modern industry were well established.

It is an eternal truth that 'necessity is the mother of all invention'. It was the changing face of warfare to an increasingly mechanised type of conflict that led to the invention of the modern oil and gas industry as we know it today. ■

Acknowledgement: *Many thanks to Bruce Winslade for assistance with this article.*

References available online.

German Albatros D.IIIs parked in a line at La Brayelle, France 1917. The red-painted aircraft of Manfred von Richthofen ('The Red Baron') is second in line, with boarding step-ladder in place. Increased use of planes in the war opened up the possibilities of aerial geological surveying.


The Borehole image & Core experts
Structural and sedimentological core description
Core ichnofabric analyses
Fractured core description
Core Goniometry
Integration with borehole image and petrographic analyses
Conventionally drafted logs
Digital drafted logs
Descriptions tailored to your requirements
Core Description Services from
TASK Fronterra Geoscience
CONVENTIONAL AND NON-CONVENTIONAL RESERVOIRS
ABERDEEN • BOGOTA • CAIRO • DENVER • HOUSTON • MIDLAND • OKLAHOMA CITY • PERTH • TULSA • VIENNA
KETTOCK LODGE UNIT F CAMPUS 2 ABERDEEN INNOVATION PARK BALGOWNIE DRIVE BRIDGE OF DON ABERDEEN AB22 8GU UK TEL: +44 (0)1224 357250
www.taskfronterra.com


IPWEEK
International Petroleum Week 2015
10–12 February 2015
InterContinental Park Lane London
www.energyinst.org/ip-week
Quote GeoExpro
to save £100
on booking fees
For more information about speaking or sponsoring at IP Week, please email Sheetal Ruparelia at:
e: ipweek@energyinst.org
Hosted by:
energy institute
Follow us on Twitter @energyinstitute #ipweek
Connect with us on LinkedIn
In partnership with:
PETROLEUM REVIEW
Gold Sponsors:
HORIZON ENERGY
PLATTS
McGRAW HILL FINANCIAL

Maps for Understanding the Earth

Set up over 100 years ago, the Commission for the Geological Map of the World has been an important factor in the drive for standardisation in geological mapping and nomenclature. JANE WHALEY

How often have you wondered where you can find a reliable geological map of a region? Or maybe you want a broad look at the tectonic stresses or magnetic anomalies around the globe, or a geological hazards map of a continent? And when you find something, can you be sure of the scientific accuracy of its content? If, like me, you spend hours trawling the internet, it may be time to take a look at the many products produced by the Commission for the Geological Map of the World (CGMW) (www.ccgm.org).

Mapping the World

It appears that Jean-Etienne Guettard (1715–86) produced the first geological map, his 1746 *Carte Minéralogique* covering France and England, although William Smith's 1815 map of the geology of England and Wales, at a scale of five miles to the inch, is recognised as the first modern geological map of a whole country. Very soon, national geological surveys had been established in many countries, all producing their own maps, using a huge variety of techniques, formats, naming conventions and colour schemes.

The next logical step was to try to set up some standards and then combine these regional views into a geological map of the world. The first attempt was remarkably early, in 1843, when Ami Boué produced a *Carte géologique du globe terrestre*, at a scale of 1:58,000,000, although since much of the globe had yet to be visited by geologists, there were, unsurprisingly, many omissions. Twenty years later, Jules Marcou produced a 1:23,000,000 world geological map, leaving unmapped regions – most of Africa, Arabia, Asia and Australia – blank.

Eventually, through the International Geological Congress, it was decided to set up international commissions to look at 'geological graphic representations and terminology'. These morphed into the establishment of the Commission for the Geological Map of the World (CGMW) in 1913, but with the outbreak of World War One, little was done to further its aim of producing a geological map of the world at a uniform scale of 1:5,000,000. Over subsequent years and after much discussion, a *Geological Atlas of the World* was initiated in 1965 and published in 1985, which included 22 sheets featuring separately the geology of each continent and ocean. This has been out of print since 2004, but high definition scans are available. The first *Geological Map of the World* displaying both continental and oceanic geology was published by the CGMW in 1990 at the scale of 1:25,000,00. This map is now in its third edition, and in its revised issue in July 2014, at the scale of 1:35,000,000, for the first time the geology is enhanced by a physiographic background. CGMW is responsible for a large range of other regional maps, covering not just surface geology, but also tectonics, ore deposits, natural resources and climate.

Community Support

The not-for-profit commission, which is based in France, is responsible for designing, promoting, coordinating, preparing and publishing these small-scale thematic Earth Science maps of the globe, continent, major regions and oceans. To produce them the organisation relies on the support of the international scientific community, as well as cooperation with geological surveys, universities, oceanographic institutes and also industry. The mapping activity is financed by the membership fees from the various geological surveys, plus grants from organisations like the International Union of Geological Sciences and UNESCO, and sponsorship by industrial partners.

Crucial to the process of generating accurate and informative maps is the General Assembly of the Commission, where each suggested cartographic idea is assessed, progress on existing projects analysed and decisions are made as to future plans. The Assembly is held every two years, either at UNESCO headquarters in Paris or during the International Geological Congress, convened every four years. Members of the General Assembly are drawn from throughout the world; 75 participants from 23 countries, ranging from the USA and Russia to Cameroon and Switzerland, took part in the 2014 meeting.

Jules Marcou's 1861 world geological map.

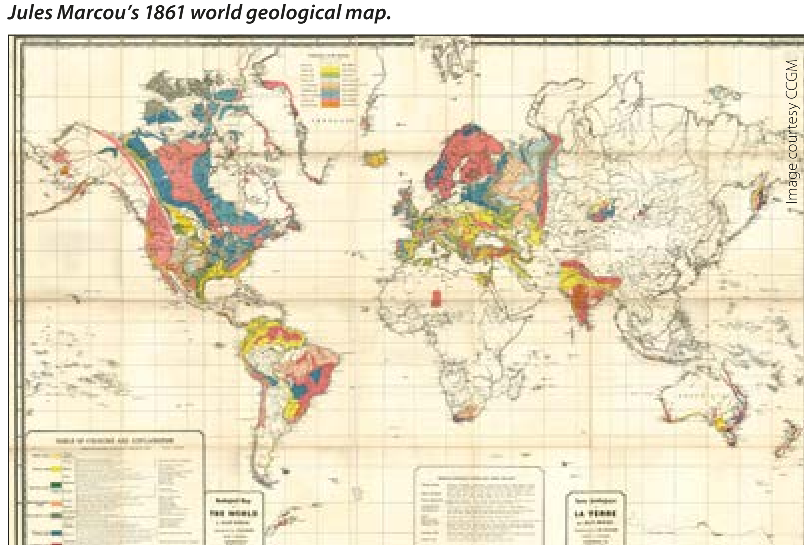


Image courtesy CCGM

Although the Assembly is principally responsible for determining which cartographic projects are undertaken, overseeing the work there is an executive bureau, which also includes representatives from throughout the world and from different Earth Science fields. Before their publication, all maps are submitted to expert review in order to ensure the best scientific quality to all CGMW releases.

An important remit of the CGMW is the development of international standards in geological mapping, working closely with organisations like the International Commission on Stratigraphy and the International Union of Geological Sciences. The standard stratigraphic and geological colours used in most official maps are also those set down by the CGMW.

Range of Products

The Commission's products range broadly in scale and theme. They include, for example, hydrogeological, physiographic, structural and gravity maps of the world at 1:50,000,000, in addition to the world geological map. There are also more detailed maps, including one on the geology of the Pyrenees (1:400,000) and a geological map of the Bosumtwi impact crater in Ghana at 1:50,000. CGMW has also published a number of map-based atlases including, for example, an atlas of *Messinian Salinity Crisis Markers in the Mediterranean and Black Sea* and one of *Paleotectonic Maps of the Middle East*, both of which should be of interest to geologists in the hydrocarbon industry. The commission does charge for its products, but they are relatively nominal sums, ranging from €5 to €50 ($6–$64).

Part of the CGMW's role is to 'research and adopt digital cartographic techniques and disseminate information about them'. Digital mapping has been used in the preparation of the maps since 1990, with every effort being made to comply with the different, rapidly evolving softwares available in the market, taking into account the different demands of the users.

The geological and physiographic maps of the world and a number of other products are available digitally, with data in various formats, and the organisation is committed to extending its offering of digital maps in the near future. However, as Clara Cardenas from the CGMW points out: "It is important to note that small scale printed maps are always in demand, especially for educational purposes. A digital image of a map supplements its printed version, but never replaces it, in particular when it comes to a global vision of the geology of our planet, continents, oceans or major regions." ■

The most recent edition of the Geological Map of the World.

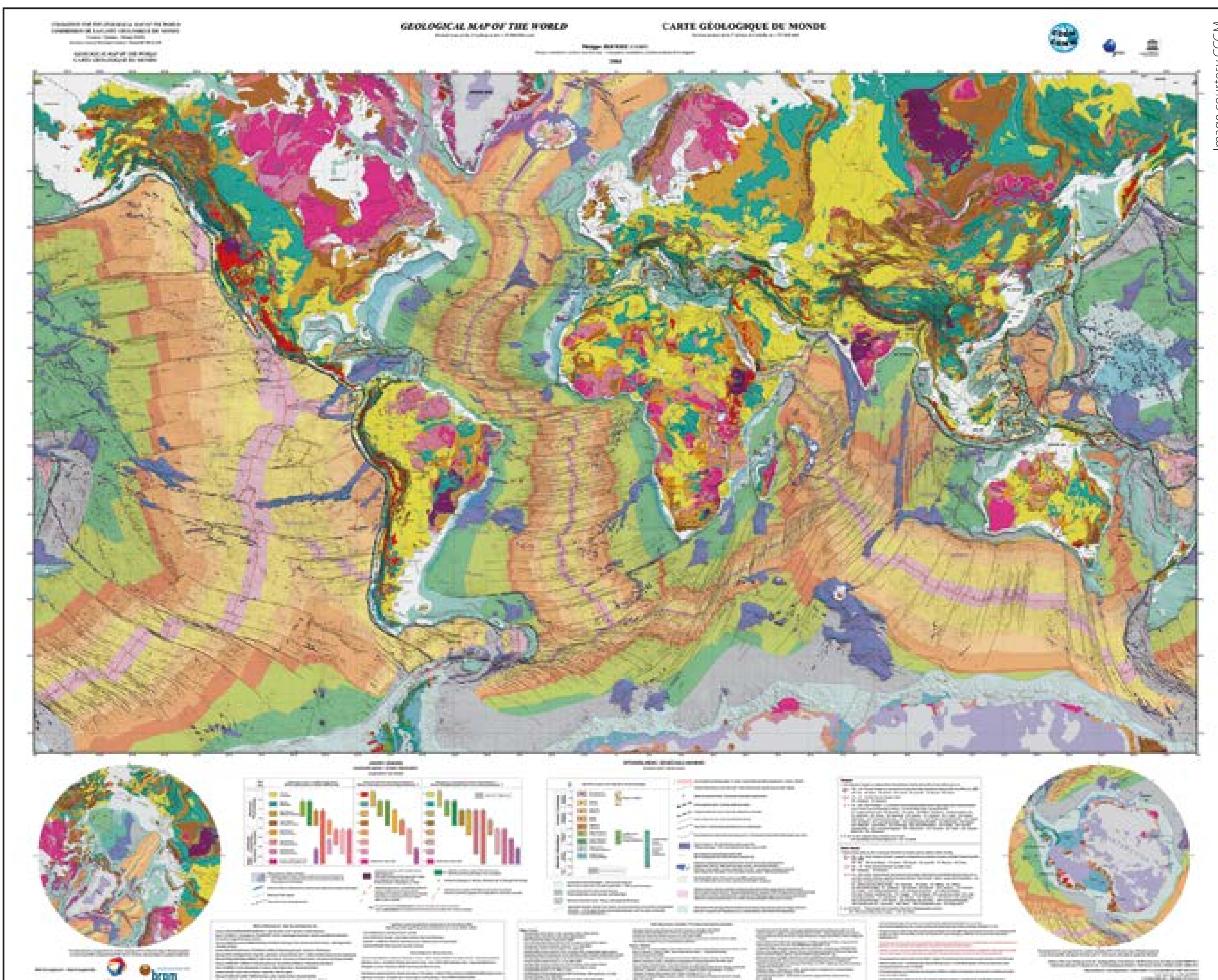


Image courtesy CCGM

KEN WHITE

Malaysia: Second Deepwater Gas Find

For the second time in 2014 **Shell** has confirmed a deepwater gas discovery in **Block SK318** offshore **Sarawak**, results that are seen as very positive indicators for the gas potential of the area. The latest find, **Marjoram 1**, was abandoned early July at a depth of 3,900m. Located in 800m of water, the well was targeting a gas prospect within the Cycle IV/V and Cycle 1/II Miocene carbonate; the new gas accumulation is probably in the former.

Shell signed two exploration and production sharing contracts with Petronas in April 2012 for deepwater blocks 2B and SK318, both offshore Sarawak. Block 2B is located some 300 km offshore in water depths ranging from 300 to 2,000m, while Block SK318 is about 200 km offshore in water depths of between 200 and 1,000m. Under the agreements, Shell will undertake an aggressive drilling campaign to comprehensively explore an area totalling an estimated 9,000 km^2. The minimum work commitment includes the acquisition of 3D seismic data, five electromagnetic surveys and the drilling of five exploration wells in order to de-risk the challenging deepwater environment in the waters of North Luconia. Shell is operator and has an 85% interest in both contracts, with Petronas holding the remaining 15%.

The focus of exploration has moved to deeper water in Central Luconia, following major discoveries by Petronas in the area. Petronas is building a floating LNG (FLNG) development in the Kumang gas cluster in Central Luconia, which could be the world's first FLNG plant to come onstream when it begins operations in late 2015. ■

Argentina: Significant Reserves Below Las Mesetas

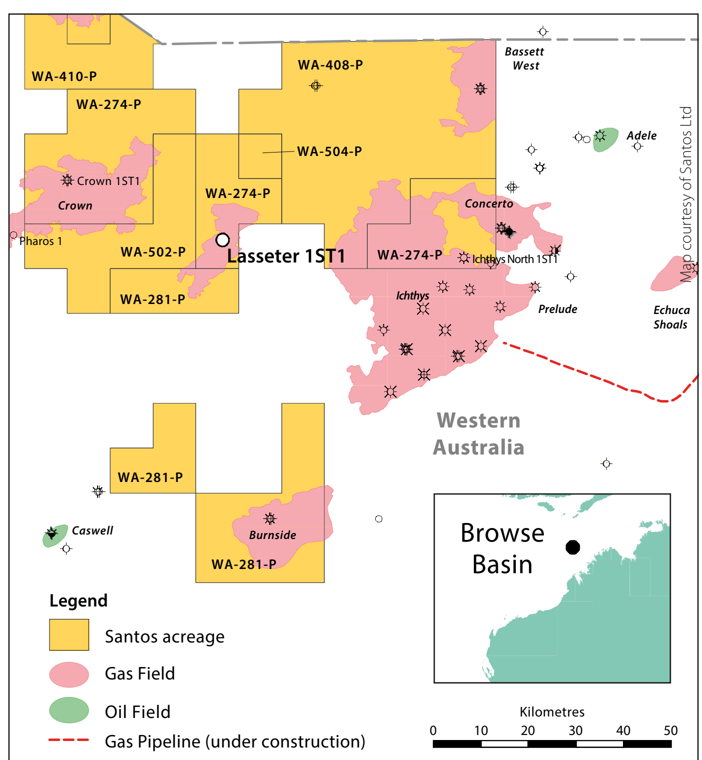
YPF has made what it describes as the largest conventional gas/condensate discovery in the province of Santa Cruz in the last 20 years by drilling beneath already mature formations in the **Las Mesetas Field**. The well, **YPF. SC.LCM.xp-778**, was drilled to a final depth of 2,770m in the Los Perales-Las Mesetas Block in the **San Jorge Basin**; 2P resources are estimated at 65 Bcf plus 2 MMbc. Modern seismic allowed YPF to identify the unevaluated areas and as this lies in the basin's western section, the company plans to investigate this potential with new exploration wells and 3D seismic. YPF estimated that the discovery will have a production potential of 7 MMcfgpd and 370 bcpd from the Castillo Formation (Chubut Group).

This is the latest in a series of discoveries made by the company in the past year. The provinces of Mendoza, Neuquen, Chubut and Rio Negro have all played hosts to discoveries since the start of 2014, dramatically increasing production potential in both conventional and unconventional hydrocarbon resources. In 2012, Repsol YPF lost its licence to produce oil in the Los Perales-Las Mesetas field following the expropriation of Repsol's shares in YPF and the subsequent nationalisation of 51% of the YPF shares. ■

Australia: Santos Building Reserves

Although not tested, **Santos** has claimed its **Lasseter 1** wildcat in **WA-274-P** in the **Browse Basin** off **Western Australia** as a significant gas/condensate discovery. The well, located in 404m of water, was targeting gas within multiple units as a follow-up to the 2012 Crown discovery, which lies around 35 km to the north-west. Lassiter 1 is around 480 km north-north-east of Broome, which puts it in the vicinity of two FLNG projects. Drilled to a total depth of 5,329m, the well intersected a gross hydrocarbon column of 405m and net pay of 78m over the Jurassic Lower Vulcan and Plover intervals, between 4,880 and 5,285m. This interpretation has been confirmed by pressure and sample data that confirm excellent mobility in the higher porosity sands in the Lower Vulcan. Initial analysis confirms a condensate to gas ratio in the range of 10-25 bo/Mcf. The structure lies primarily in WA-274-P, with possible down-dip extension into WA-281-P to the south-west and is also in close proximity to the June 2013 Bassett West discovery, in which Santos is partner.

The two FLNG projects in the Browse Basin are Shell's Prelude project that is under construction and will be located 475 km north-east of Broome and Woodside's Browse project. A final investment decision on Browse, described by Woodside as the foundation of its next phase of growth, is expected in 2015 after the company dropped plans to build an onshore LNG plant. ■



A Beautiful Country
The Geology of Lebanon

Dr MUNIM AL-RAWI
Carta Design Ltd.

This book is in large format, making it suitable for presenting text along with photos and maps. The list of contents includes eight chapters, references, index and author's biography, but lacks a list of figures.

The book starts with a review of Lebanese geological literature, which has an intimate association with the development of natural resources. This starts with the earliest published observation on the geology of Lebanon, by Bottes in 1833, and includes the publication in 1955 of Louis Dubertret's important *Carte Géologique du Liban*. The author concisely reviews petroleum exploration in Lebanon from the late 1940s to 1974, mentions the pioneering work of the late Ziyad Beydoun during the civil war from 1975 to 1990, leading to the author's own work from 2000 to present, heralding the dawn of offshore exploration in Lebanon.

A brief and informative review of the plate tectonics and regional setting of Lebanon and the surrounding Levant region is found in Chapter 2, including an excellent discussion of gravity anomalies both on and offshore Lebanon. This is followed by a comprehensive discussion of the structural elements of Lebanon, describing the two major topographic mountain chains of Mount Lebanon and Anti-Lebanon, which are separated by the Bekaa Valley. This chapter also includes full descriptions of the faults associated with the Levant Fracture System, folds and monoclines. All these structural features of Lebanon are supplemented by excellent cross-sections and photographs.

Chapters 4 and 5 deal at length with the lithostratigraphy of Lebanon from the Jurassic to the Pliocene succession, described thoroughly and supplemented by numerous field and petrographic photographs, charts, palaeogeographic and sediment thickness maps, all reflecting the tectonic development of Lebanon.

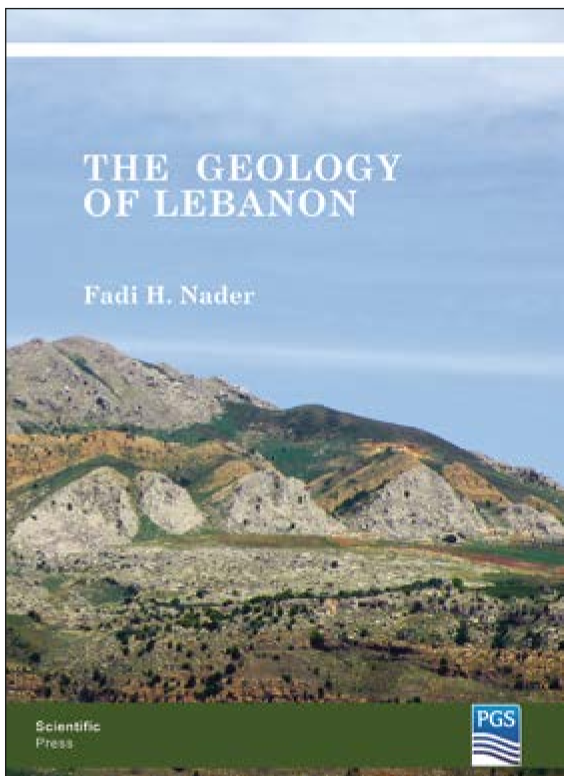
A short review of the elements of the hydrogeology of Lebanon is given in the next chapter, with a concise account of the major aquifers in Lebanon, supported by rainfall maps and excellent photographs of karst features and springs.

Chapter 7 is a short account of mining and then a comprehensive review of petroleum exploration in Lebanon, which is treated in a very systematic way. It covers the historical background, from the earliest work of the IPC in 1947–48, the activities of various companies from 1963 to 1971 and a review of seismic surveys offshore Lebanon from 1970 to 2010, when the earliest offshore legislation was initiated. It then moves on to onshore hydrocarbon prospectivity, including drilling activities from 1947 to 1967, correlated to adjacent parts in Syria. Petroleum systems in eastern Palmyra Basin, Syria are discussed, supplemented by an excellent Triassic isopach map of the Levant region (compiled from Wetzel, 1974, and Beydoun and Habib, 1995). Petroleum systems onshore Lebanon are covered in depth with excellent maps, cross-sections and photographs. The section on hydrocarbon prospectivity offshore Lebanon again highlights the Levant Basin as the current frontier gas province, and provides up-to-date data and discussion on the subject including maps, cross-sections, charts and seismic profiles.

Finally, the concluding comments in Chapter 8 describe Lebanon as "a beautiful country, rich in easily accessible features which demand to be visited, studied and understood".

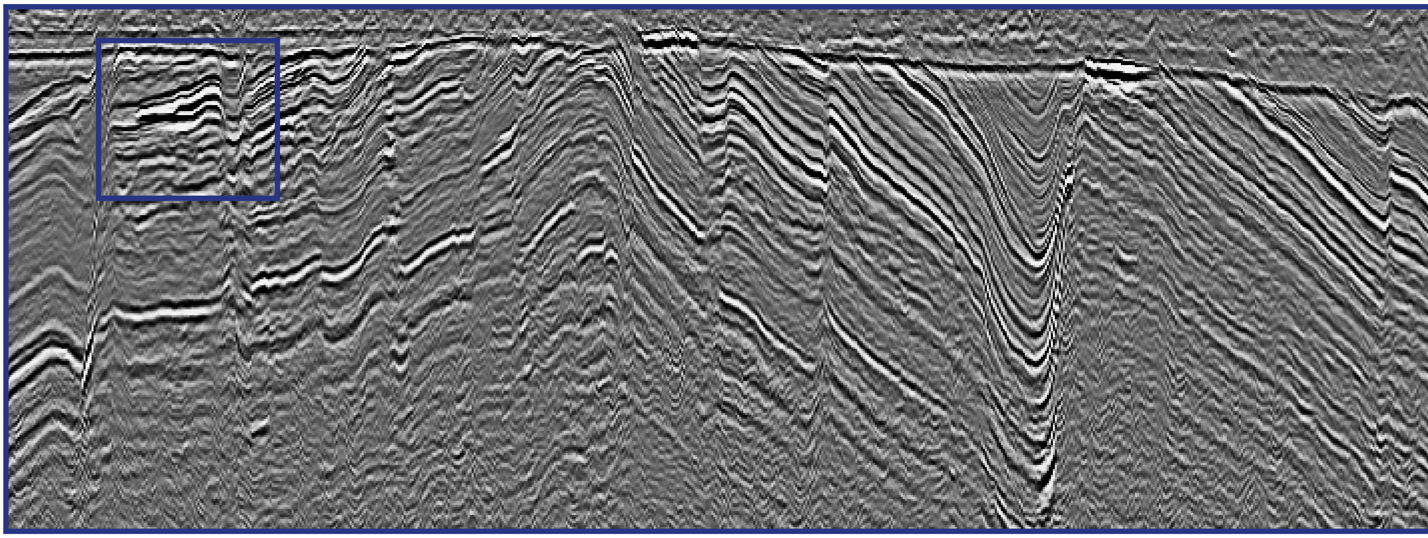
This short book brought me, as an interested reader and worker on the petroleum exploration of the Middle East, to a quick understanding of many aspects of Lebanon geology as well as petroleum exploration. The compiled map on page 85, for example (Triassic isopach map of the Levant region showing the location of oil and gas fields, the extent of the Kurrachine evaporates, and the location of the wells producing from Triassic reservoirs), is an important reference for the exploration of the Triassic play in northern Jordan, southern Syria and the Golan Heights. The references list is comprehensive and very informative, particularly the published work of the author of this book from 2000 to 2011.

I highly appreciate this work by Dr. Fadi H. Nader, and strongly recommend this wonderful book to students of geology as a textbook on Lebanon, as well as a reference for exploration in the Levant region. ■



The Geology of Lebanon (2014)
Fadi H. Nader
Scientific Press Ltd.

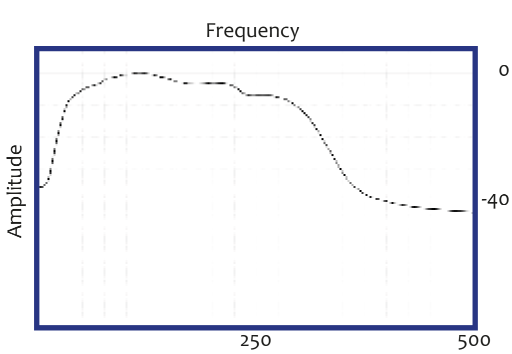
Super High Resolution Hoop



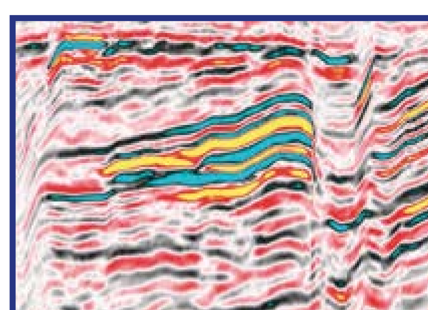
300 ms

Detailed reservoir mapping

This specially designed 5 600 km super high-resolution survey in a 2 × 8 km grid will give detailed imaging of the shallow Jurassic, Triassic and Cretaceous prospects in the Hoop area of the Norwegian Barents Sea.



The survey is acquired with a 2 km streamer and is broadband processed at 1 ms. This gives the seismic data both ultra high resolution, which will resolve reservoirs down to 10 meters in thickness, and high-fold angles for advanced pre-stack analysis work.



100 ms

Please contact us for more information

Tor Åkermoen
tor.akermoen@mcg.no

Per Kulseth Dahl
per.dahl@mcg.no

Lars Ivar Leivestad
lars.ivar.leivestad@mcg.no

www.mcg.no

Ronda Uno

Mexico's first exploration licensing round is a landmark event in the history of oil exploration in Latin America

IAN DAVISON and THEODORE FAULL, Earthmoves Ltd.

Mexico's oil industry is opening up to the private sector after a 76-year state monopoly, and eyes are now focused on one of the world's most promising continental margins. The oil boom of the early 2000s is now a distant memory as well-established oil fields such as the Cantarell complex and Golden Lane trend are in a rapid decline, and oil production in Mexico has fallen to its lowest level in 24 years at 2.44 MMbopd.

To kick-start the process of building up Mexico's oil production, the Comisión Nacional de Hidrocarburos (CNH) announced the first ever exploration licensing round (Ronda 1) for foreign companies. The block maps were recently posted on the CNH website *www.energia.gob.mx/webSener/rondauno/*. Companies are invited to submit exploration work programme bids on 109 exploration blocks (see map); and production and appraisal plans on 60 blocks with existing fields. They have been asked for feedback on the terms and fiscal conditions between November 2014 and January 2015, with data packages made available from January 2015. Bids must be submitted by the end of April and bid results are expected in September 2015.

Round Highlights

The highlights of the round are the 11 deepwater blocks in the offshore Burgos Basin and Perdido Fold Belt, where a succession of important oil discoveries have been made in both the USA and Mexico. Pemex have made five major finds in the last two years, each with 100 to 500 MMbo in place (Trion, Supremus, Maximino, Vespa and Exploratus). In the US sector, five wells are expected to come online in 2016 producing 100,000 bopd and 200 MMcfg/d from Paleogene Wilcox Formation reservoirs on the Great White Field. These sandstones are also well developed in the Mexican sector, and deformed in a gravity fold belt which developed after the basin floor fans and channels were deposited. Hence, the reservoirs are draped over the fold crests, leading to a very high exploration success rate.

The onshore and shallow water Tampico-Misantla and Chicontepec basins, which host the Golden Lane string of discoveries on the Tuxpan carbonate platform, contain over 110 Bb STOIIP. Five blocks are available in the Mexican Ridges Fold Belt, which extends down from the deepwater Burgos to the Veracruz Basin.

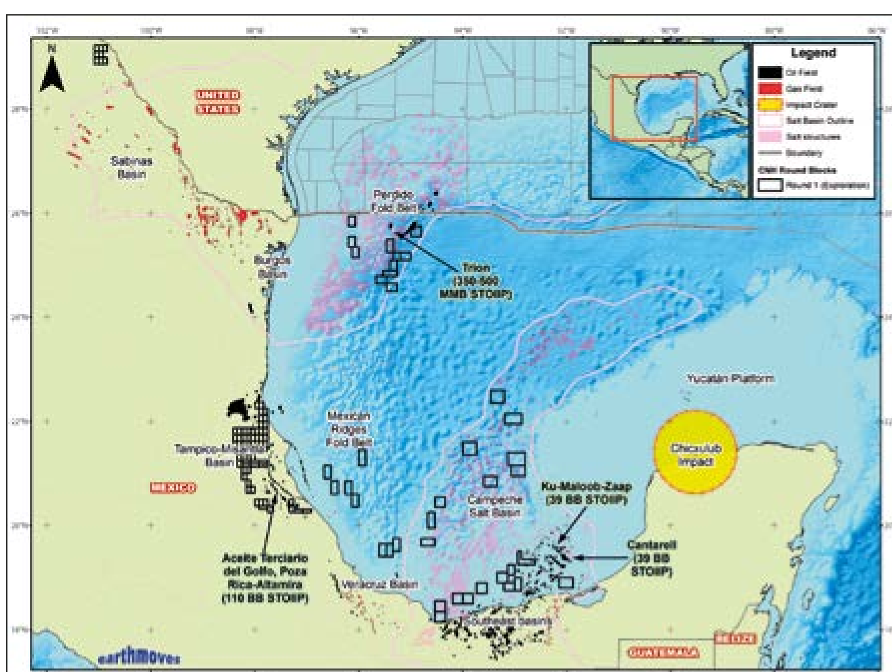
To the south, a massive salt basin stretches 800 km from the south-eastern basins to the northern reaches of the Campeche. The Campeche Basin has numerous oil slicks emanating from the crests of shallow salt structures, indicating a widespread active petroleum system. Only two wells have been drilled in the Campeche deepwaters so far, and the nine blocks on offer will be hotly contested.

Unconventional shale oil and gas projects are just beginning in Mexico, and the onshore Tampico-Misantla and Sabinas Basins have a large number of attractive opportunities.

Meteorite Impact

Mexico's most productive and largest fields lie in the South East Basin, owing their existence to the Chicxulub meteorite impact, which hit at 66 Ma. The bolide has been calculated to be approximately 10 km wide and produced a crater 170 km in diameter and 4 km deep. The impact caused a destabilisation of the carbonate platform edge and large thicknesses (> 300m) of carbonate breccias were redeposited in deeper waters followed by several rebounding tsunami deposits. Finally, an iridium-rich ash fall-out was deposited on top of the breccia which seals the Cantarell oil field (39 Bb STOIIP). This is a very complex area with allochthonous salt sheets and two phases of folding and thrusting, and many complex traps are present that have yet to be tested.

Most of the prospective exploration blocks are already covered by 3D surveys, which will accelerate the exploration process and lead to exciting new discoveries in the coming years. ■



Ireland–South Porcupine Basin

Multi-Client 3D & 2D Data

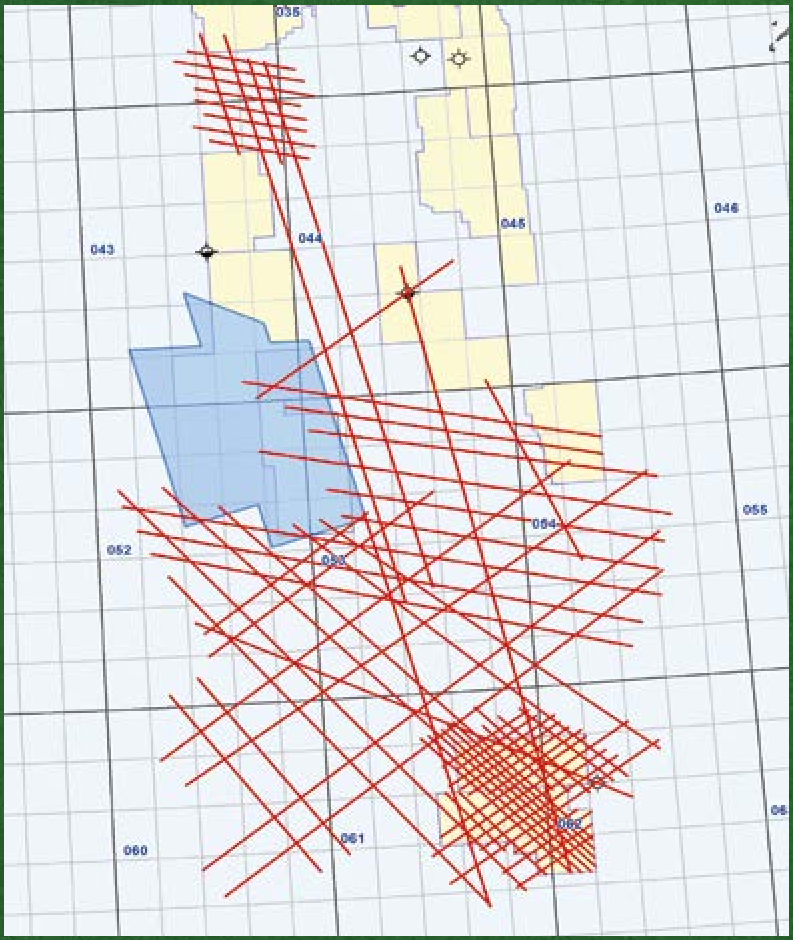
Polarcus and ION Geoventures are pleased to announce a major new multi-client seismic program comprising 4,300 sq. km of 3D data and 5,500 km of 2D data in the South Porcupine Basin, offshore south-west Ireland. The South Porcupine Basin is an under explored Mesozoic rift basin with multiple exploration plays. The new data provides coverage over the Drombeg exploration prospect and the attractive adjacent open acreage, allowing evaluation of this highly prospective area for the forthcoming 2015 Atlantic Margin Oil and Gas Exploration Licensing Round. These new *RightBAND™* data are being processed by GX Technology through a WiBand™ Pre-STM processing flow and data will be available for evaluation in Q4 2014.

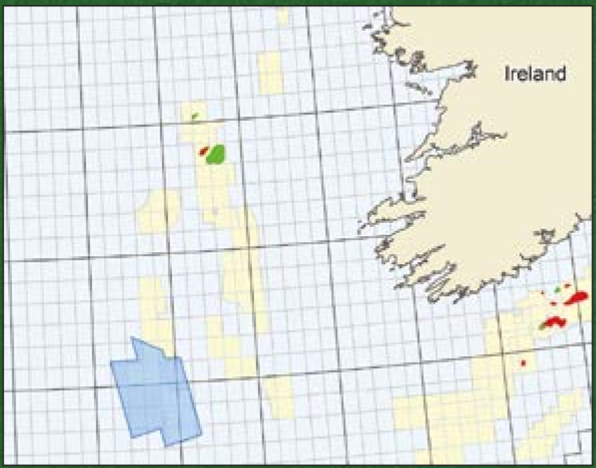
For further information contact:

Tony Pedley
tony.pedley@polarcus.com
+44 788 44 81747

Zyg Sarnowski
zyg.sarnowski@geopartnersltd.com
+44 1252 761314

Phill Houghton
phill.houghton@iongeo.com
+44 1784 497475





www.polarcus.com/mc

SeaBird Exploration ion GeoPartners Polarcus®

A 25-year Anniversary

Shortly after midnight on 24 March 1989, the *Exxon Valdez* supertanker ran aground on Bligh Reef in Alaska's Prince William Sound. More than 250,000 barrels of oil were lost.

The *Valdez* spill was the largest ever in US waters until the 2010 *Deepwater Horizon* accident. A massive clean-up effort was instigated immediately, with more than 11,000 Alaskan residents involved.

While the vessel carried some 1.25 MMbo, 'only' a fifth of this ran into the water. The oil was on its way from Prudhoe Bay, the largest oil field in the US, which originally contained approximately 25 billion barrels of oil in place.

What actually happened was that the *Exxon Valdez* departed from the Trans Alaska Pipeline terminal at 9:12 pm on 23 March. A little later, the vessel encountered icebergs in the shipping lanes and it was decided to take the tanker out of the lanes to go around the icebergs and to turn back into the shipping lanes when it reached a certain point. However, it failed to make that turn back and the ship ran aground at 12:04 am on 24 March.

According to ExxonMobil, it was "one of the lowest points in its 125-year history". Economically, the company spent US$4.3 billion in compensation, clean-up payments, settlements and fines.

According to others, it was one of the worst environmental disasters in US history due to the enormous toll on the wildlife, landscape and people of southern Alaska. Roughly 2,000 km of shoreline and 28,000 km^2 of ocean (almost five North Sea quadrants) were polluted through the action of currents and storms, killing as many as 3,000 sea otters the first year. Some of us also remember depressing photos of birds soaked in oil. However, sea otters in the most affected parts of Prince William Sound have now recovered to their pre-spill numbers, according to US Geological Survey research biologist Brenda Ballachey.

In 1992, the US Coast Guard declared the clean-up complete. Others say that oil is still found trapped between and under the boulders on beaches in the Gulf of Alaska. Author Marybeth Holleman has her own opinion: in a CNN broadcast she says that "thousands of gallons of *Exxon Valdez* oil still pollute the beaches; this oil is still toxic and still hurting the ecosystem near the shore", and that "the Sound's coastal ecosystem is permanently damaged".

So even after 25 years, the long-term effects of this spill are still being debated.

Halfdan Carstens

Groups of otters feeding together in Prince William Sound in June, 2007. The USGS believe that sea otters have now recovered to their pre-spill numbers.

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.

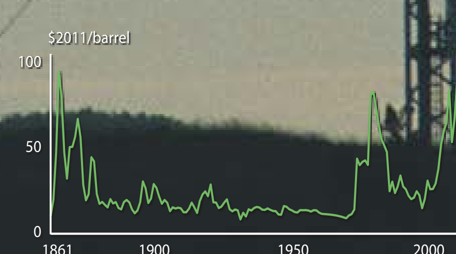
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

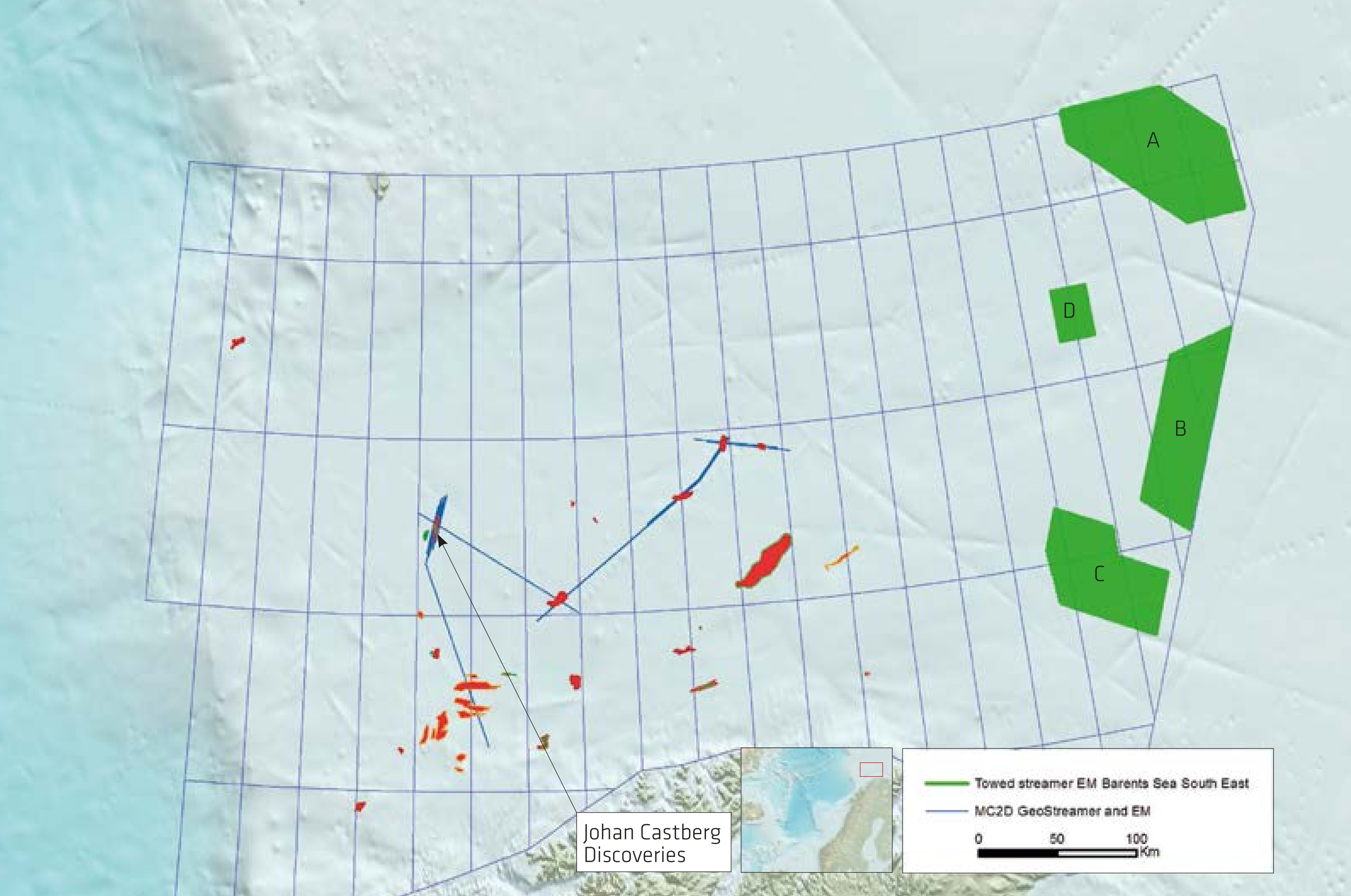
Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm^3) of oil equivalents

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

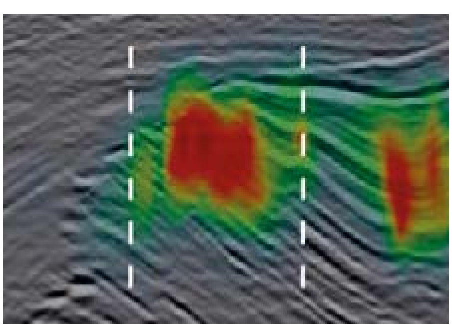
Major field
Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price





BARENTS SEA SOUTH EAST



Johan Castberg Discoveries

PGS has now acquired in excess of 9,000 sq km of high-density Towed Streamer EM data in 2014 during the Barents Sea South East survey; this is comprised of areas A, B, C and D.

Data has been processed onboard and the inversion and interpretation of the data will be built on the experience gained with the regional EM survey acquired over the Johan Castberg discoveries in the Barents Sea in 2013.

For more detailed information on PGS' Towed Streamer EM technology please read the PGS article on page 80.

JOSHUA MAY Tel: +44 1932 376406 joshua.may@pgs.com
RUBEN JANSSEN Tel: +47 67 51 45 61 ruben.janssen@pgs.com

A Clearer Image

www.pgs.com

MultiClient
Marine Contract
Imaging & Engineering
Operations