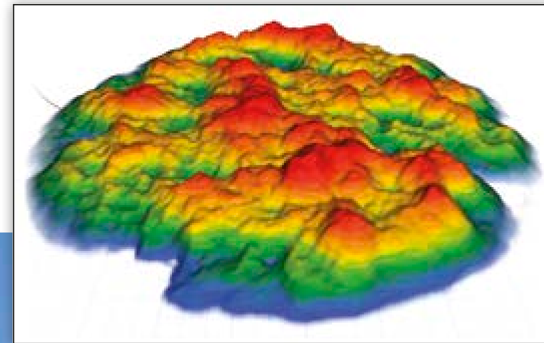
VOL. 10, NO. 6 – 2013

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



NEW TECHNOLOGIES
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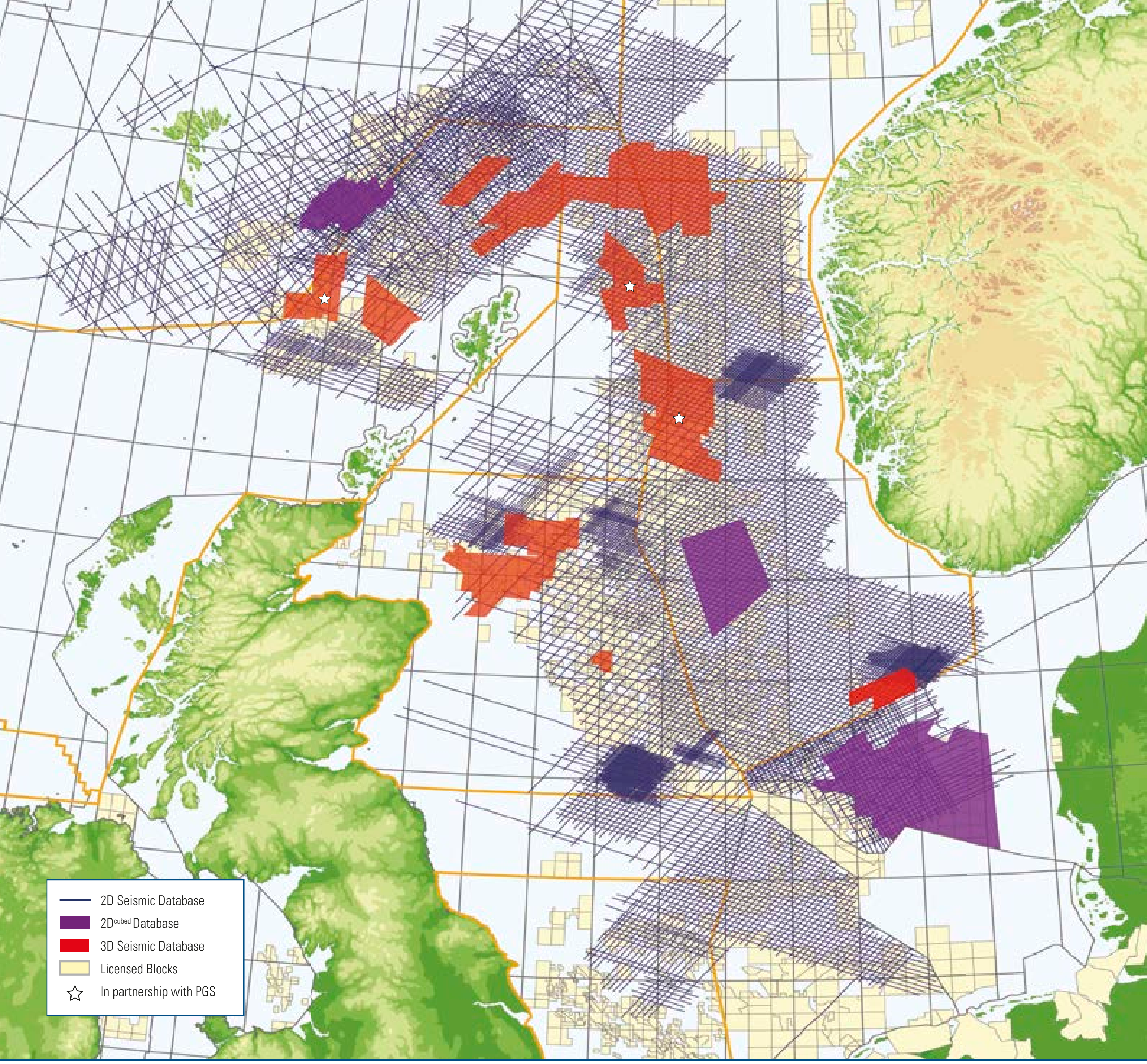
EXPLORATION
Norway: Small is Also Beautiful

GEOTOURISM
Romania: The Salt Mountain

GIANT FIELDS
Wytch Farm Ploughs Ahead

UNCONVENTIONAL EXPLORATION
Monitoring Gas

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT



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The salt mine in Slanic Prahova, Romania

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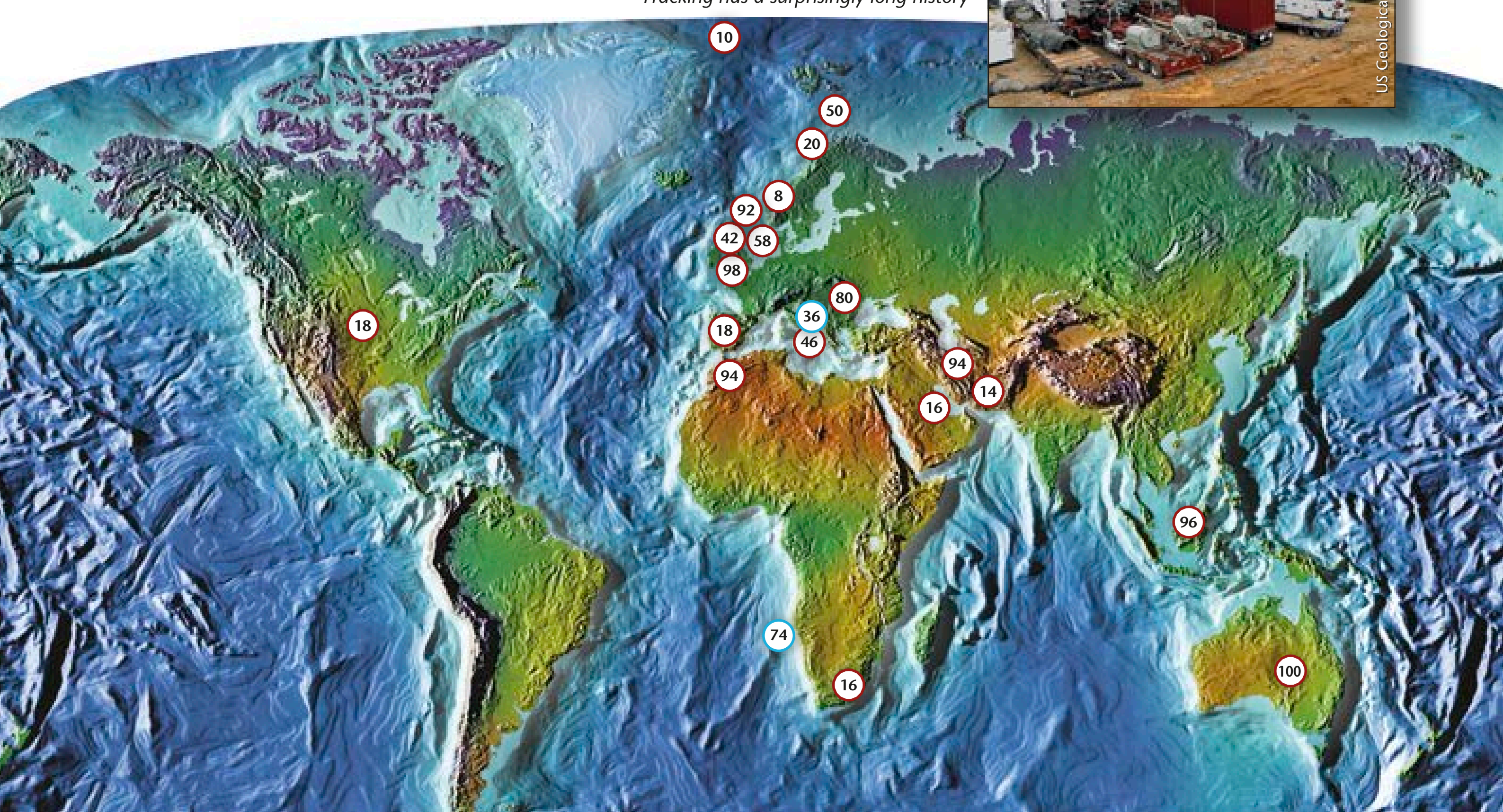
Fracking has a surprisingly long history



Maturing Nicely

The Seaquest drilling rig, which made the first commercial oil find on the UKCS in 1969.

Following the discovery of gas onshore the Netherlands in 1959 and offshore the UK in 1963, and then oil in the North Sea a few years later, the hydrocarbon industry in North West Europe virtually exploded with activity and excitement. Over 45 Bb of oil and gas equivalent have since been pumped from reservoirs below the UK and Norway alone, bringing with them many jobs, billions of dollars, the development of hitherto struggling centres like Stavanger and the Shetland Islands, and an influx of high technology companies and innovative intellects.

Fifty years on, most people feel that the major fields have been found, although we still have surprises like the 2010 >3 Bbo Johan Sverdrup discovery on the Norwegian continental shelf. Frontier areas in North West Europe, like the Barents Sea and the Atlantic west of the UK and Ireland, may yet yield major resources, and technology will be crucial in unlocking important new plays, but this will require concentrated effort, considerable financial input and possibly government incentives.

The landscape is changing. Whereas the golden years of exploration offshore North West Europe were dominated by majors and giant fields, many more companies are now involved, including small operators with strong expertise in either an area or a technological challenge, such as heavy oil or high temperature/high pressure reservoirs. They come from all over the world, including many NOCs, a demonstration of the increasing growth in that sector. Much of their efforts will be directed towards developing smaller fields, and in enhancing recovery and extending the life of older fields.

In this edition of *GEO ExPro* we look at some of the new technologies driving these endeavours, like predicting reservoir pressures in frontier regions, vital for planning new drilling and for understanding migration, and the use of 4D gravity data to enhance recovery from fields nearing depletion.

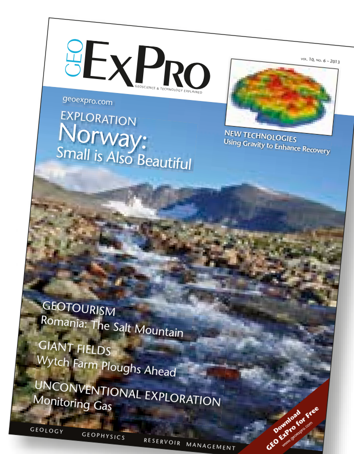
The wild waters off North West Europe have been the location of many pioneering and innovative technologies in the oil and gas industry, now mainstream and used throughout the world. The techniques and knowledge being developed in this mature area to keep the oil – and the oil dollars – flowing now will prove vital for the long-term future of the industry.

JANE WHALEY
Editor in Chief

NORWAY: SMALL IS ALSO BEAUTIFUL

Norway is the largest oil producer and exporter in Western Europe, owing its abundant resources in part to the large quantities of reservoir rocks built up on the Norwegian continental shelf after millions of years of erosion by rivers and ice.

Inset: 4D gravity data can be used to image water influx into a reservoir as gas is depleted.



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

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Early Stage Engagement:

Winning Social Acceptance For Shale Gas

Hamish Wilson, Technical Director at **SLR Consulting**, reviews how early public engagement can pay dividends in securing public acceptance for seemingly controversial drilling projects.

I live on the Isle of Wight, a lovely spot. I have seen in the press that drilling activity is planned off Compton Bay – a beautiful beach and very unspoilt. Given all I have read in the press, drilling is going to pollute the water, cause earthquakes and create global warning. Hypothetically, it is easy to conceive how an 'anti' group could form, gain support and cause an upset, resulting in permission to drill being rejected.

The Balcombe debacle for Cuadrilla in Sussex is an example of what activists can achieve. It isn't hard to predict that *all* onshore exploration drilling in the public's perception will likely involve fracking; if this is so, *all* drilling will face public opposition. Yet companies still start the regulatory consenting process, getting EIA's and holding the mandated public consultation meetings, only to be surprised when met with vehement opposition along with grossly misleading articles in the local and national press with the result that projects are delayed.

The disappointment about Cuadrilla and Balcombe is that the events were predictable and therefore possibly preventable. There were articles in the press from local residents some months before the rig appeared, in which strong objections to drilling were expressed. Although there were undoubted tactical reasons why the well had to be drilled when it did, the Balcombe protests have set back the shale gas cause in the UK.

What's To Be Done?

I believe there are three areas the industry needs to look at.

Firstly, oil and gas developers should embed social and environmental processes into mainstream technical decision-making and risk management. Currently risk management is devolved to environmental departments. Yet social disruption can delay a project just as much as a dry well, or reduced reservoir performance. So we should consider including social and environmental risk into our stage gate decision processes.

Secondly, the collective industry should take a proactive stance towards the national media. The dominance of material in the press presents a largely negative view of onshore oil and gas, with opposition groups becoming very effective at using the media to campaign against a set of activities. To address this imbalance, the industry needs a strategic PR campaign to actively promote a more realistic picture. Collectively we have failed to get across some of the good points about oil and gas exploration in the UK, and have yet to show openness and willingness to engage about the impact schemes may have.

Thirdly, we should engage local stakeholders early. It is clear that the current regulatory compliance processes, and social consultation approach embodied in the planning regulations, is insufficient to win public acceptance. Therefore regulatory compliance must be separated out from winning public acceptance. Regulatory compliance is clear, but if the public cannot be convinced, time and resource will have been wasted.

Currently, methods for public consultation consist of telling the public that a certain activity is going to happen. As the public, we are shown pictures of the location of the well and asked if we like it. But despite its title, this approach is not about public consultation, it is public 'telling'.

Winning Trust

I propose an alternative approach which involves engaging with local people early, before technical decisions have been taken. This takes time and effort and requires talking to people in their homes and offices – and being patient. My estimate is that it normally takes two years to build an effective community engagement programme – which can be done at the same time as the EIA process. A major concern in the UK is that a local, potentially rational, decision-making process will be overrun by emotive opposition from national groups whose *raison d'être* is campaigning. Local public engagement would be much easier, and go much smoother, if it were done in the context of effective industry messaging.

To conclude, I believe the oil and gas industry in the UK and elsewhere should base engagement on the sound principle of treating others as you would expect to be treated. Imagine if shale gas were found in your village or town and think through how you would expect to be treated. I would expect industry representatives to talk to me, explain the process, explain the risk and listen to my concerns. But then, most importantly, I would expect the company to *do* something about my concerns and thus win my trust. ■

Compton Bay, Isle of Wight

Successful Polar Petroleum Potential Conference

The Arctic region is characterised by unprecedented challenges related to its harsh and sensitive environment, which affects both the operability and cost of data acquisition, exploration drilling and production. In addition, in the Arctic where well data and even seismic data are scarcely available in some areas, the use of other geophysical and geological techniques, such as potential field data, shallow drilling for stratigraphic information and the use of wide scale plate tectonic models, become relatively more valuable than in mature areas.

These were among the highlights discussed in the well over 200 oral and poster presentations at the third Polar Petroleum Potential, known as the 3P Arctic Conference and Exhibition, held in Stavanger in October. With around 650 attendees from more than 30 nations, the meeting represented a solid increase in size over the first event in Moscow in 2009 and the second one in Halifax in 2011, and demonstrates the high interest in the Arctic region.

In his presentation on Arctic exploration in the opening ceremony, Bob Gistri with ExxonMobil referred to their joint venture with Rosneft in the Russian Arctic and the need for long-term focus and commitment, pointing out that ExxonMobil has been in the region for 90 years. An interesting observation was the variability of the length of the drilling seasons, with a significant increase experienced in 2011–12 compared to previous years, whereas the 2013 season was exceptionally short!

Through three parallel oral sessions, presentations were focused on all the circum-Arctic countries and regions. The Barents Sea session was in particular very well attended – unsurprisingly, since the conference was held in Norway, but probably also as a result of recent discoveries in the Norwegian sector including results confirming recoverable oil and gas in a Permian play for the first time in this area. Other regions covered in the programme included the west and east side of Greenland, the Canadian and Russian Arctic and the Alaskan onshore and offshore basins.

Across these geographical regions, topics discussed included Arctic petroleum systems and resources, tectonic and palaeogeographical models, geophysical techniques and technologies for Arctic operations, as well as climate variability resulting in increased access to the region. Presentations on unconventional resources were included in a separate session for the first time at 3P Arctic, with most presentations describing various aspects of gas hydrates found in the area.

The 3P Arctic exhibition was exclusive to companies working in the Arctic, offering products, services, data, technology and techniques that relate to or have been developed for the sedimentary basins, petroleum systems and rocks of the region. Naturally, a number of companies promoted non-exclusive seismic and other geophysical data. "The right people are attending this conference" according to the representative from one of the exhibitors.

The organisers (AAPG, the Norwegian Geological Society and the Oslo Society of Exploration Geophysicists) are emphasising that 3P Arctic is driven by science and exploration considerations, not by politics: 'the science not politics' mantra. They believe that is one reason why the conference has built an enviable reputation as the leading geo-scientific event for the High North. 3P Artic 2015 will be held in St Petersburg in Russia.

TORE KARLSSON

3P Arctic included a competition for students who submitted abstracts for posters. Eight were accepted and the authors were given financial travel support and free full conference registration.

ABBREVIATIONS

Numbers
(US and scientific community)

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

Cornerstone

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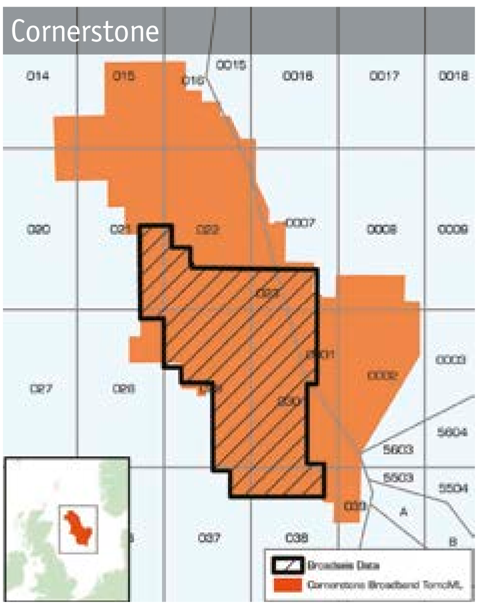

New broadband subsurface information with the benefits of dual-azimuth coverage and a state-of-the art PSDM model will be available in June 2014.

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Mark Richards
mark.richards@cgg.com
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John Mckenzie
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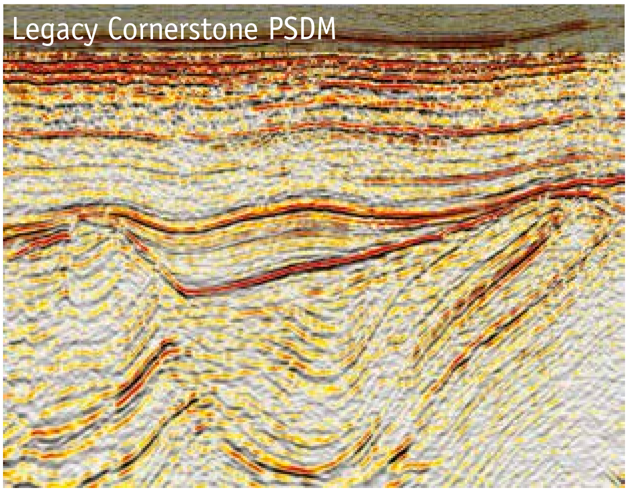

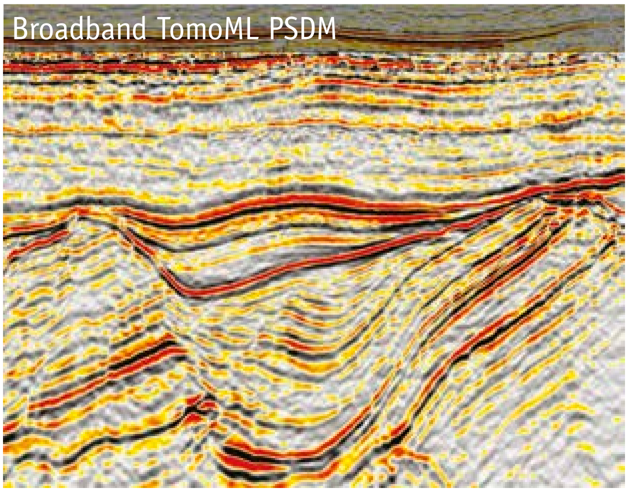

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Passion for Geoscience

The Azolla Biosystem

The amazing *Azolla* plant could provide a gateway to the future.

The Past

2004 was a landmark year in our understanding of past climate change. Reduced ice cover allowed the Arctic Coring Expedition (ACEX) drillship *Vidar Viking* to core a deep hole in sediments close to the North Pole, opening a window into a greenhouse world completely unlike today's, when turtles and alligators inhabited lush forests a few hundred miles from the North Pole. Then, 50 million years ago, the free-floating freshwater fern *Azolla* repeatedly spread across the Arctic Ocean surface, sequestering enormous quantities of atmospheric CO_2 and triggering the shift from a greenhouse climate to our modern icehouse world with its year-round snow and ice at both poles.

Azolla was able to accomplish this because of its symbiosis with the cyanobacterium *Anabaena*. *Azolla's* leaf vacuoles provide an oxygen-free home for *Anabaena*, which draws down atmospheric nitrogen. This fertilizes *Azolla*, making it one of the fastest growing plants on the planet, doubling its biomass every two to three days even though its only requirements are air, light, freshwater and small quantities of nutrients. *Azolla-Anabaena* is the only known symbiosis in which the cyanobacterial partner is maintained throughout the plant's reproductive cycle, resulting in their co-evolution and the extreme efficiency of the *Azolla-Anabaena* superorganism. This amazing plant, and its effect on CO_2 and climate, was discussed previously in *GEO ExPro* Vol. 4, No. 4.

The Present

Could this unique plant help us weather the perfect storm that threatens humans and many other species today: the related threats of imminent climate change and shortages of land, food, freshwater and energy as our population passes seven billion? Alexandra and Jonathan Bujak have designed a natural biological system – the *Azolla* Biosystem – to do this.

The biosystem can be used outdoors, or as an indoor modular system, which facilitates control and automation. The Sequestration Module converts atmospheric CO_2 directly into *Azolla* plants that can be grown in containers, ponds or stacked trays of shallow water. The resulting biomass is then transferred to the other modules: the Carbon Capture Module removes selected amounts of *Azolla* from the biological cycle by converting it into dense carbon products, and the remaining biomass produces biofertilizer, livestock feed, food and biofuel in the other modules. The biosystem is highly flexible because the size of each module can be adjusted for local needs, and processes such as algoil generation and hydroponics (growing plants in water with nutrients, rather than soil) can be integrated into the biosystem, providing food and renewable bio-oil and gas anywhere in the world, irrespective of the local climate.

Azolla can remove impurities from our waste water including harmful chemicals from industrial discharge and also extract radioactive material from water used in nuclear facilities.

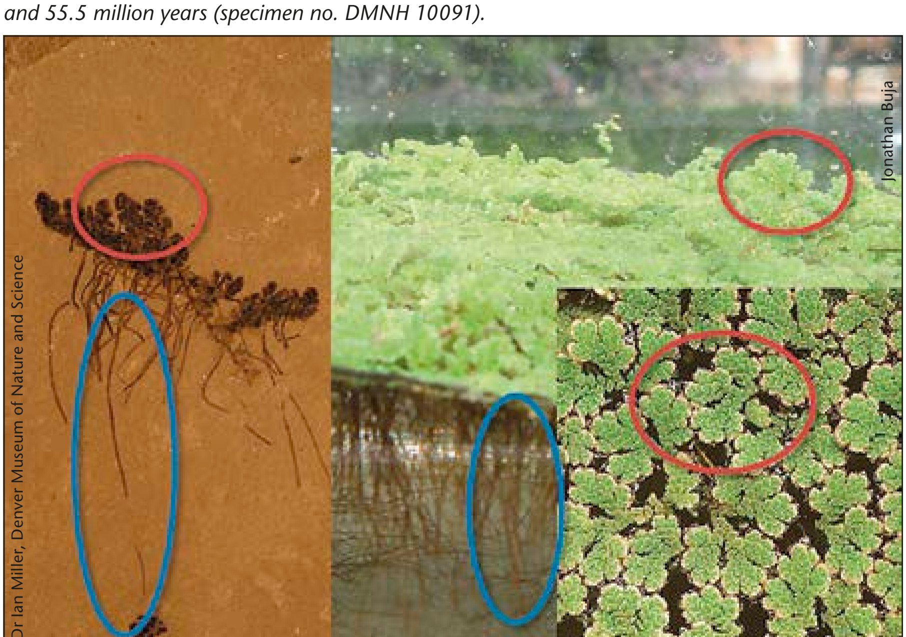
The Future

The biosystem resolves the main problem that plagued the 2009 and 2012 Copenhagen and Doha Summits on Climate Change: why should developing countries forego their opportunities in the 21st century in order to help resolve the problems created by developed countries in the 20th? The billions of pledged 'climate change dollars' can help developing countries to progress using the biosystem's synergy, thus turning the perfect storm into a perfect opportunity, for example by replenishing soils and providing livestock feed and food in regions such as East Africa that experience repeated famines. And the biosystem could also be a catalyst for other essential changes in the 21st century – greening of the growing megacities, or re-establishment of families and communities through urban agriculture.

The *Azolla* Biosystem is an incredibly efficient nano-assembler that has evolved for millions of years and it is ready to use now. It is a gateway to the future that only needs our determination to make it work and attain its full potential.

Alexandra and Jonathan Bujak's book 'The Azolla Story' will be published in 2014. ■

Fossil azolla (left) has leaves (circled in red) and tendrils (circled in blue) that are identical to those of modern azolla (right). The fossil is from the Green River Formation of Colorado, dated between 50.5 and 55.5 million years (specimen no. DMNH 10091).



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Licence Opportunities That Could Shape 2014

Egypt

According to an official source from the Egyptian General Petroleum Corporation (EGPC), the company will invite the first tender for tight oil exploration in the country early in 2014. Apparently a technical committee has been formed with members from the EGPC, Ganoub El Wadi Petroleum Holding Company and the Egyptian Natural Gas Holding Company to choose locations to be proposed for the tender. Egypt is said to have 114 Bb of tight oil reserves, of which 4.6 Bbo can be extracted.

India

The government is considering an April 2014 launch of the 10th New Exploration Licensing Policy (NELP X) with the minister of petroleum and natural gas indicating some 270,000 km^2 will be available. Media sources suggest the offering will probably comprise 23 onshore, 20 shallow water and 25 deepwater blocks. Some consideration is allegedly being given to revising fiscal terms to make the offer more attractive to investors.

Libya

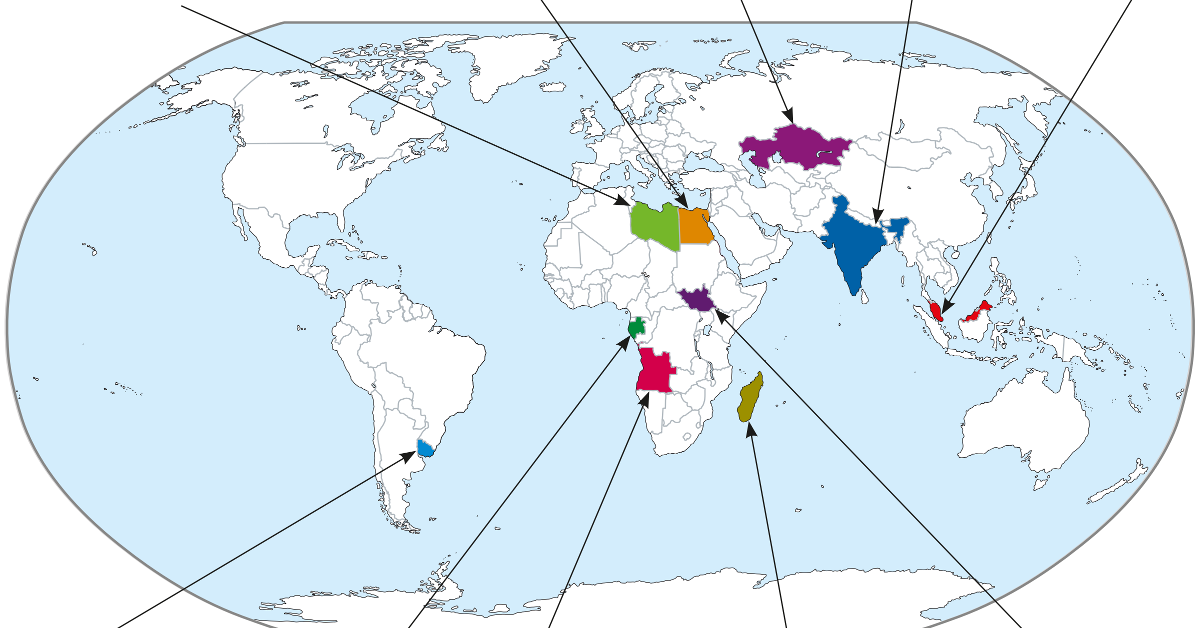
Nuri Berruien, chairman of state-owned National Oil Corp., has indicated an intention to hold the next bidding round for exploration rights in mid-2014. The auction would be the North African country's first since the ousting of Muammar Qaddafi in 2011. The country is reassessing the terms it offers foreign companies to explore for oil as the OPEC member seeks to entice more partners and boost crude output while resolving worker protests that are curbing exports. It is understood that any new acreage offering will have to consider the technology required to develop any hydrocarbons and that the focus will be on underdeveloped acreage.

Kazakhstan

The first onshore licensing round since 2008 is reportedly to take place before the end of 2013, in which three blocks are planned to be offered initially, with a further six to be included in 2014. This could mark a change as since 2008, foreign companies had to team up with state KazMunaiGaz to enter the country's upstream. There are currently no plans to offer offshore acreage, considered by the industry to be more prospective.

Malaysia

Malaysia launched its Exploration Opportunity 2014 at the end of October, offering four blocks offshore Peninsular Malaysia, (PM-403, PM-327, PM-337 and PM-331), four in Sarawak, (SK-335, SK-332, frontier deepwater block 2D and SK-317A) and three in Sabah (V, T both ultra-deepwater blocks and SB-306). A data room will be open until March 2014.



Uruguay

ANCAP has indicated Uruguay Round III will be held in 2014 and that it will probably comprise 12 blocks. Spectrum has acquired 4,000 km of 2D spec data over the potential blocks.

Gabon

The authorities in Gabon have launched a long-awaited licensing round but as negotiations started several months ago, 11 companies have already been awarded 13 blocks. A total of 43 were proposed by companies. It is expected that the national oil company will hold a working interest of around 10–15% and that the state will have a carried interest of 15–20%.

Angola

Lúmen Sebastião, Sonangol's head of resource evaluation, has reiterated plans to launch a licensing round onshore Angola, probably first quarter 2014. The precise date and the blocks to be offered are still being confirmed, but the round will offer acreage in the Kwanza and Congo Basins. The current suggestion is that seven blocks will be offered in the onshore section of the Kwanza Basin, with each covering around 1,000 km^2, while three blocks, each covering around 700 km^2, are likely to be offered from the recently demarcated Congo Basin.

South Sudan

South Sudan plans to auction licences for a yet-to-be determined number of new petroleum exploration blocks. "We are now working on a concession map, and this will lead us to the initiation of the licensing for the new annexed blocks, and we are hoping that by the end of this year we will have a licensing round," Mohamed Lino Benjamin, director general of petroleum at the petroleum and mining ministry, told a regional East African oil and gas conference.

Madagascar

OMNIS is expected to launch a bid round in early 2014 following the processing and interpretation of the 13,000 km of 2D seismic acquired off the western coast by BGP in May 2013.

If Iran Strikes a Deal…?

THINA MARGRETHE SALTVEDT, PH.D

After years of frustration and stalemate in the negotiations on Iran's nuclear programme between Iran and the six world powers (the five permanent members of the UN Security Council plus Germany), it is way too early to talk about a breakthrough. However, the proposal tabled by the Iranian foreign minister in October, and the seriousness displayed by Iran to address the concerns of the western world over the military potential of the country's nuclear programme, could suggest that changes are underway.

Optimists had hoped that the negotiations would lead to a temporary agreement whereby the world powers would grant minor sanctions relief in exchange for a freeze on the nuclear programme. After three days of intensive diplomatic efforts the parties left the negotiation table empty-handed, concluding that progress had been made but that there were still issues outstanding.

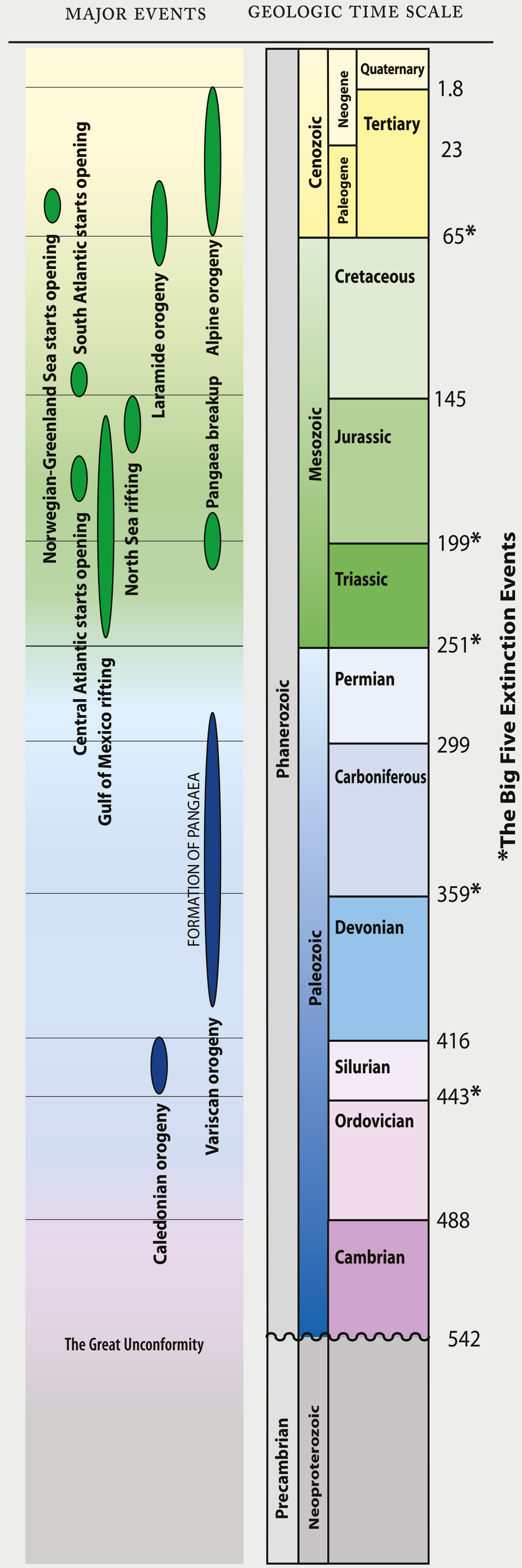
Iran wants to succeed in what it considers the first important step in a process that it hopes to finalise in 6 to 12 months. The initial stage is intended to establish an agreed framework between the six powers and Iran to define the 'end state' of Iran's nuclear programme and the common goals for the negotiations. In practice, this means that the Iranian government wants the West to recognise the country's right to extract uranium in limited volumes for its nuclear programme. Once the parties have reached an agreement on this, they can make concrete plans for limiting Iran's uranium enrichment and gradually lifting the sanctions which have crippled the Iranian economy, with resultant galloping inflation and double-digit unemployment.

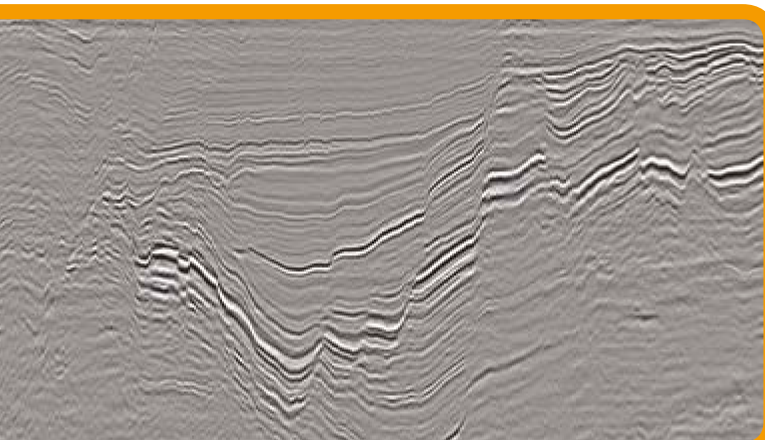
Oil exports account for 80% of the country's total export revenues and for 50–60% of government revenues. Since the end of 2011 Iran's oil production has plunged from 2.5 MMbpd to just 900,000 bpd in July this year, and in August 2012 it moved below the level of arch-rival Iraq for the first time since 1989.

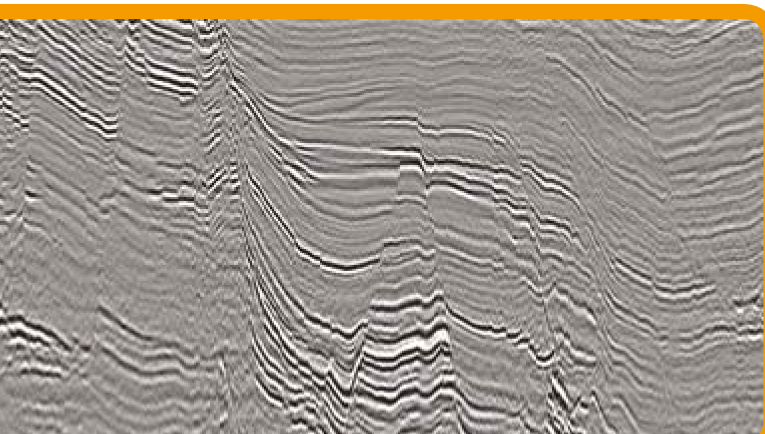
Less Volatile Oil Price

Even if Iran and the world powers succeed in striking a temporary deal, the hurdles to be overcome to reach a long-term agreement are very significant. We do not expect to see any major changes to Iranian oil exports until well into 2014 at the earliest, but it is interesting to consider the effects on the oil market and price if the sanctions were lifted.

Let's assume that Iran succeeds in convincing the West that it will reduce its uranium enrichment and financial sanctions are lifted. Iran would then be able to boost its production to 2.9 MMbpd, which is its total production capacity in 2014 according to the IEA. If these barrels were released in the market without any production cuts by the other OPEC members, prices could drop US$3–5/barrel. However, it is unlikely that Saudi Arabia, the de facto leader of the cartel, would allow the market to be flooded with oil, so we would expect it to cut its production, thus increasing its reserve capacity and providing a more solid buffer in the market without reducing its oil revenues too dramatically. Oil prices would only change marginally, but the market would be more balanced and oil prices less volatile. ■

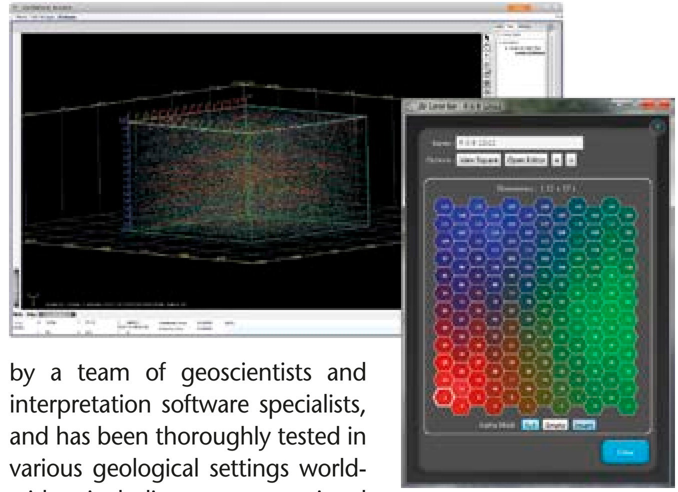






Paradise Arrives!

Geophysical Insights, the Houston-based geosciences company, chose SEG 2013 in September to announce the commercial launch of **Paradise™**, a geosciences analytic software platform. Paradise executes and manages workflows based on Self-Organizing Maps (SOM) and Principal Component Analysis (PCA). Geoscientists who have applied Paradise over a two-year period of testing are reporting the potential to reduce risk when exploring for hydrocarbons. The platform enables rapid analysis and comparison of different aspects of seismic and engineering data, while revealing complex and subtle relationships in the data. The suite features guided workflows, interactive world maps, 3D imaging, and a unique 2D colour mapping capability that is integrated and interactive with 3D imaging. Over three years in development, Paradise has a scalable, client-server architecture that has been built to take advantage of multi-processing and to manage very large files. The software suite was designed by a team of geoscientists and interpretation software specialists, and has been thoroughly tested in various geological settings world-wide, including unconventional plays. Paradise enables geoscientists to work independently or collaboratively across an oil and gas enterprise. ■

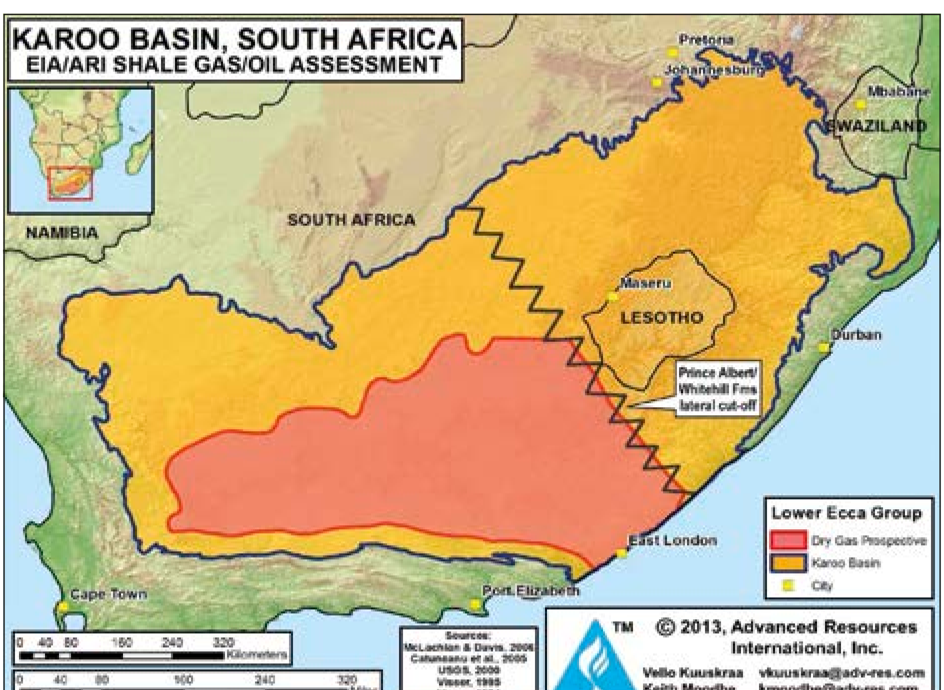


South African Shale Permits

South Africa expects that exploration for **shale gas** will soon commence in the country, as the Mineral Resources Minister Susan Shabangu recently announced that permits will be issued in the first quarter of 2014. According to the most recent report from the EIA, South Africa has reserves of **390 Tcf** of technically recoverable shale gas resources, much of it in the Karoo region in the southern half of the country. Royal Dutch Shell, among others, has applied to explore the region.

South Africa lifted a ban on fracking in 2012, and further opened the door to exploitation of the resource by recently publishing regulations on the process, under which drillers will be required to meet American Petroleum Institute standards regarding the type of equipment and chemicals they use. The regulations also include measures to protect wildlife in the region as well as to safeguard water resources.

South Africa currently imports 70% of its crude oil needs, and hopes that by exploring for shale gas reserves it will eventually become more independent in its energy needs, and also greener, as a large percentage of its present supplies come from coal-fired plants. ■



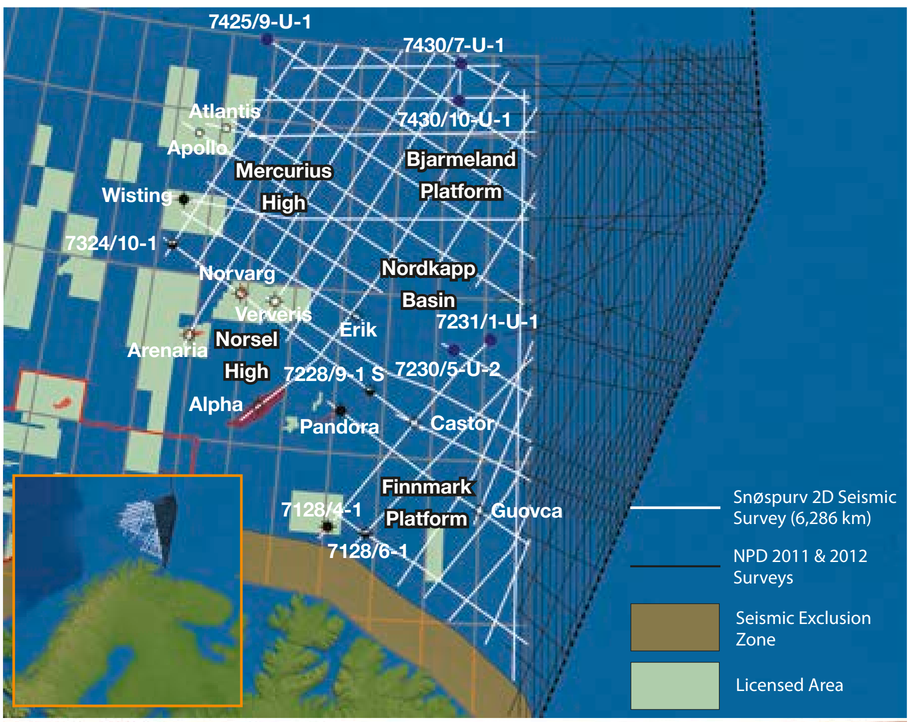
Unlocking Energy

'Unlocking Energy through Innovation, Technology and Capability' is the theme of the 7th **International Petroleum Technology Conference** (IPTC), which will be held in **Doha, Qatar** in January 2014 under the Patronage of His Highness Sheikh Tamim bin Hamad Al Thani, Emir of the State of Qatar. IPTC conferences are the largest multi-society, multi-disciplinary oil and gas events in the eastern hemisphere, rotating annually between Asia-Pacific and the Middle East, and are a collaborative effort between AAPG, EAGE, SEG and SPE.

The scope of the conference programme and associated industry activities address the technology and relevant industry issues that challenge industry professionals and management around the world. The 2014 event will include over 100 exhibitors from more than 27 countries – marking a substantial increase from the last conference, in Beijing. There will be a nine-stream conference, featuring 67 technical sessions with over 400 technical presentations, which is expected to draw some 7,000 attendees. ■

Snøspurv 2D Seismic Survey

6,286 KM - Barents Sea - Norway




Final velocities and Radon demultiple not yet applied

- Searcher Seismic and Seabird Exploration have acquired the 6,286 km Snøspurv 2D regional seismic survey covering the Bjarmeland and Finnmark Platforms.
- The survey provides well-ties to 24 planned and completed exploration wells, including Norvarg, Gouvca, Wisting, Atlantis and Apollo and provides the critical link to Barents Sea South East which is now open for exploration.
- The Snøspurv Seismic Survey is designed to enhance the seismic resolution of the prospective Triassic-Jurassic sections of the Bjarmeland and Finnmark Platforms.
- Data will be available from Q4 2013 for participating companies.

SeaBird Exploration

SEARCHER SEISMIC

P: +47 9521 1634 E: sales@searcherseismic.com W: searcherseismic.com

Zagros in the Pyrenees

In late September 2013 a **Zagros Petroleum Geology Workshop** was held in Sort, Catalonia, Spain, attended by around 30 people including delegates from major oil companies. The workshop comprised technical presentations from oil companies, consultants and academics working on the petroleum geology of the Zagros Mountains, mainly Iraqi Kurdistan, as well as field trips to examine analogue exposures of fractured carbonates, sharing knowledge in an informal and relaxed setting. There was also plenty of Catalonian culture and local cuisine to experience.

A range of subjects was covered, from regional scale issues to field appraisal and development. Topics included comparison of the Zagros fold and thrust belt with the Pyrenees, geodynamic analysis of the Zagros foreland and the role of salt tectonics in fold and thrust belts, plus a range of field-specific presentations on fracture, in-situ stress and flow characterisation, dolomitisation and evaluation of fracture porosity for reserve estimations. During the field trips comparisons were made between structures and lithologies in the exposed Pyrenean fold and thrust belt and the Zagros Belt. There was also a visit inside a salt diapir to look at flow textures and shear bands. Carbonate facies from reef to shelf and slope environments were also examined.

This successful workshop, run by **GeoScience** Ltd and **Geoplay Pyrenees** Ltd., will be repeated in the next year or two, so keep an eye on www.geoscience.co.uk and www.geoplay.cat for information.

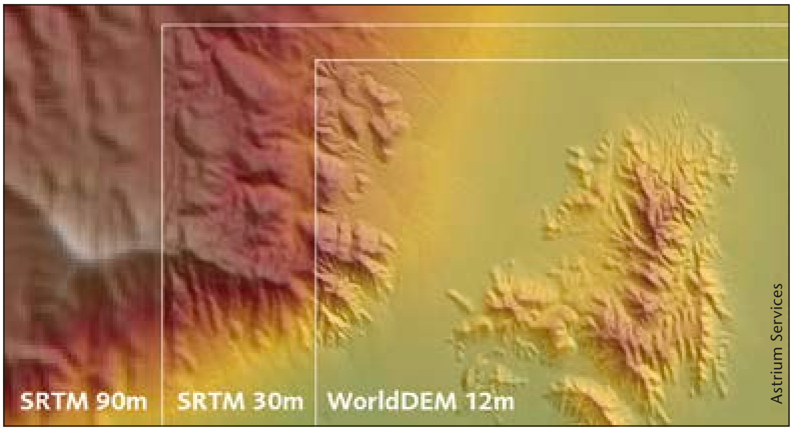

GeoScience Ltd

World Digital Elevation Model

From 2014 onwards, **Astrium Services** will be able to offer a worldwide, homogenous digital elevation model, which will be available off-the-shelf for all land masses of the earth including polar regions. **WorldDEM™**'s resolution and accuracy will surpass that of any satellite-based global elevation model available today and will replace the common data set for SRTM (Shuttle Radar Topography Mission). This new unique elevation data base will open up fresh opportunities for oil and gas projects in terms of accuracy, reliability and availability.

Astrium Services offers a comprehensive portfolio of elevation models thanks to its unique radar and optical satellite constellations, allowing quick acquisition of various input data for either stereo-photogrammetric or radargrammetric generation of digital elevation models. Its GEOElevation Suite consists of different products for serving different requirements, from 30m down to 1m grid spacing, and can support a range of oil and gas projects, from feasibility studies to detailed planning in preparation for field development.

Comparison of the new WorldDEM data set and SRTM data



Astrium Services

Shell Pessimistic on Unconventionals

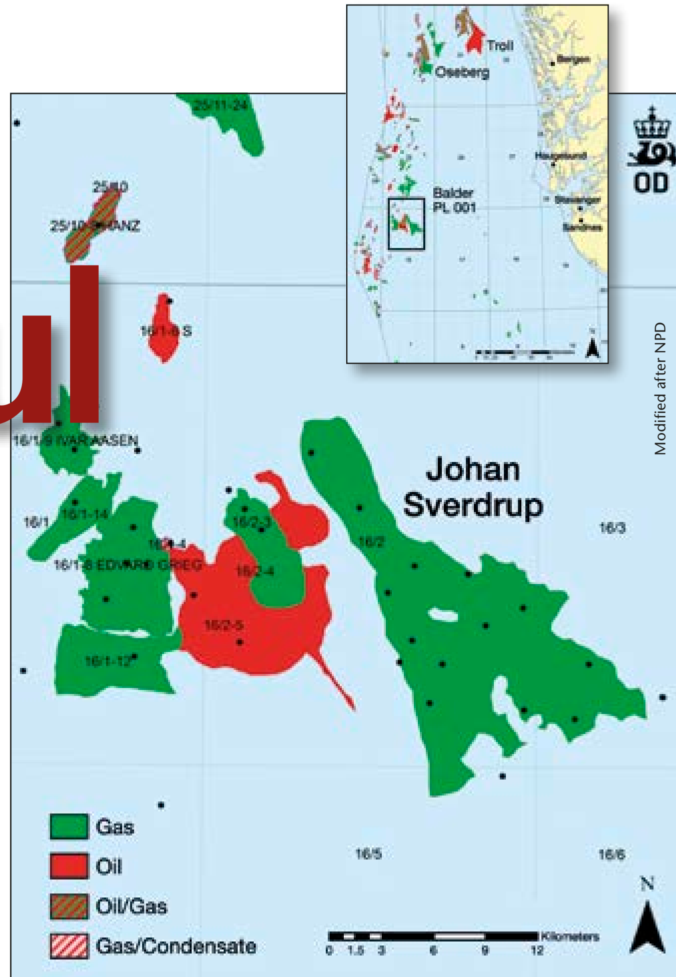
Like a number of other majors, Europe's largest oil company, **Shell**, entered the US **shale gas** arena relatively late in the game. Despite having spent at least $24 billion, it has yet to prove a good investment, as the company's North American upstream business has struggled to turn a profit. In August Shell announced a strategic review of its US shale portfolio, after posting a 60% fall in profit for the second quarter of this year, having had to write-down over $2 billion on the value of its North American liquids-rich shale assets.

Outgoing Shell CEO **Peter Voser**, in an interview with the *Financial Times*, admitted that he regretted the 'huge bet' on US shale, saying "Unconventionals did not exactly play out as planned… We expected higher flow rates and therefore more scalability for a company like Shell." He cites the main problem to be US gas prices, which recently hit a 10-year low. "Therefore you are hit with more than $3 billion of depreciation whilst you don't have the revenues against it," he added. He believes that much of the US shale boom could be 'hyped', and other companies may easily face similar disappointments, and also suggested that shale gas exploration in the rest of the world was at an early stage and may yet yield 'negative surprises'.

Small Is Also Beautiful

While one giant and several major discoveries have stolen the media headlines, the future bread and butter for the Norwegian continental shelf will to a large extent be the discovery and development of small and medium-sized fields.

HALFDAN CARSTENS



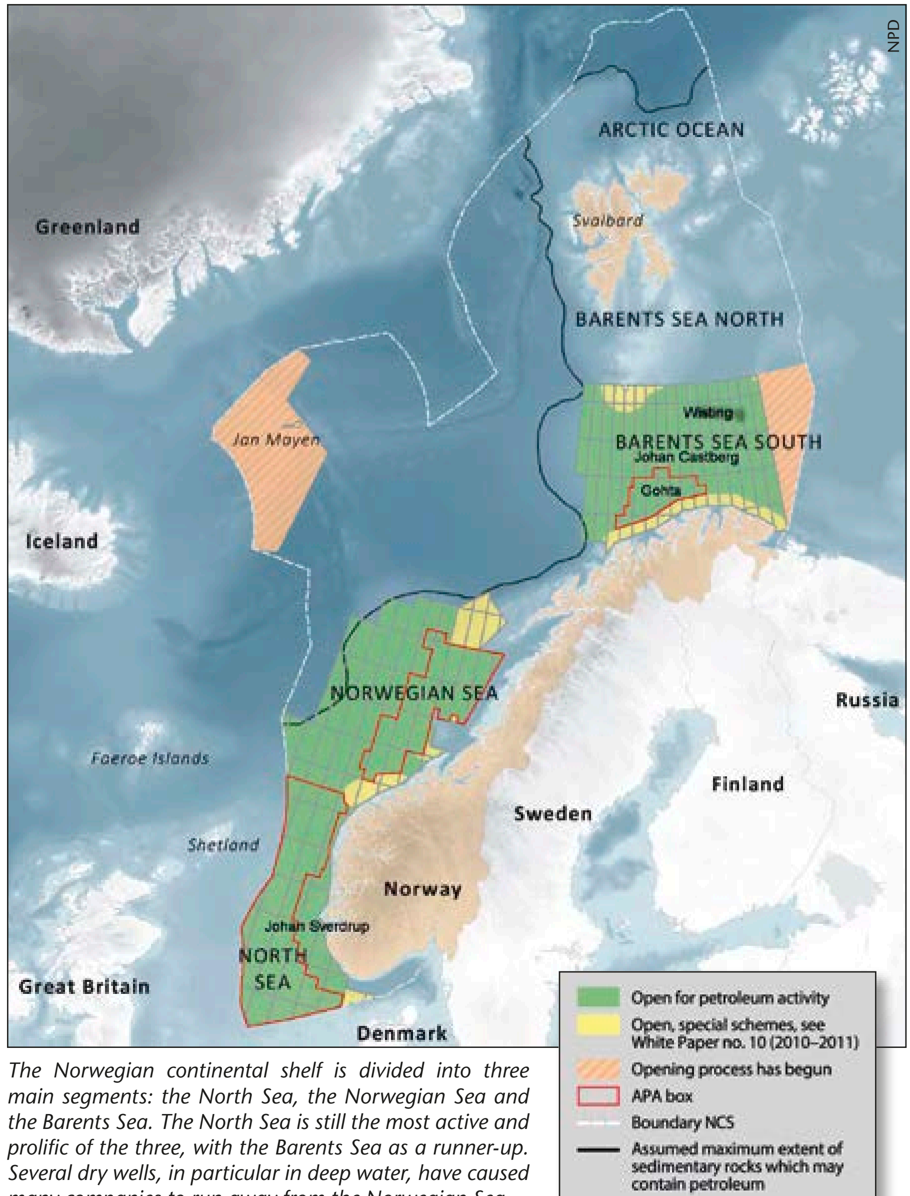
The discovery well of the Johan Sverdrup field was made in 2010 (16/2-6) on a prospect named Avaldsnes, followed by Statoil with well 16/2-8 in 2011 drilled on the Aldous prospect. The latter proved that two apparently separate closures were actually a single closure and field.

The Svalbard archipelago stands out as an excellent place to learn about the Barents Sea rocks.

© Snorre Olaussen/Hans Arne Nakrem

Some spectacular discoveries have been made on the Norwegian continental shelf (NCS) in the last three years. Avaldsnes and Aldous, later proven to be one single accumulation and renamed Johan Sverdrup, after the father of Norwegian parliamentarism, made world headlines in 2010 and 2011 when Lundin Norway and Statoil found this supergiant on the Utsira High, a mature part of the North Sea. It was the world's largest oil discovery of 2010.

The size of the discovery is not yet fully known, but it is believed that it contains some 3 Bb of recoverable oil, possibly much more, in a superb sandstone reservoir of Jurassic age (net to gross close to 1, porosities between 25 and 30%, and permeability of several Darcys). Recently, Statoil has said that the recovery factor might exceed 70%. It ranks as one of Norway's largest discoveries ever.



The Norwegian continental shelf is divided into three main segments: the North Sea, the Norwegian Sea and the Barents Sea. The North Sea is still the most active and prolific of the three, with the Barents Sea as a runner-up. Several dry wells, in particular in deep water, have caused many companies to run away from the Norwegian Sea.

Credit to Lundin

From a historical viewpoint it is interesting to note that the acreage was originally licensed to Esso Exploration and Production Norway. Four blocks on the Utsira High, including Block 16/2 which contains Johan Sverdrup, belonged to PL 001, previously awarded to the Americans in 1965.

In 1967 the company made the very first oil discovery on the NCS in this licence (well 25/11-1), but it was declared uncommercial. Later it was reclassified as an appraisal well on the Balder field, and was put on stream in 1999. Esso never came close to recognising the huge prospect further south in subsequent exploration. The reason for this is not known, but it is true that the oil companies' focus in the early 70s was the Tampen Spur further north, where the Statfjord field is located.

Norsk Hydro, however, was only 400m off when the company drilled its first well on the NCS in 1976. Well 16/3-2 targeted both Paleocene and Jurassic sandstone reservoirs in a presumed stratigraphic trap without hitting pay. More than 30 years later the information from this well, including knowledge about excellent quality Jurassic sandstones, was important when the prospect was generated by the Lundin team.

In 2013, exploration director Hans Chr. Rønnevik and managing director Torstein Sannes of Lundin Norway got the *Gullkronen Honour Award* for taking "the risk to drill the prospect despite dry wells in the area and industry scepticism", thereby giving full credit for the surprising find to Lundin. The jury also said that "they form a small and extremely powerful management team that in the years gone by has proved pivotal in finding resources worth 400 billion NOK for Norwegian society – one as the explorer, the other as the manager and business developer".

The main reservoir in Johan Sverdrup and nearby fields is Jurassic sandstone. Several wells on the Utsira High, however, have also hit oil in weathered and fractured basement rocks of Precambrian and Caledonian age. The first production test was made in 16/1-15 in 2011, which made the Norwegian Petroleum Directorate state that this "is the first successful full-scale production test of a reservoir that consists of cracked and porous bedrock on the Norwegian continental shelf". In other words, a new play model had been defined.

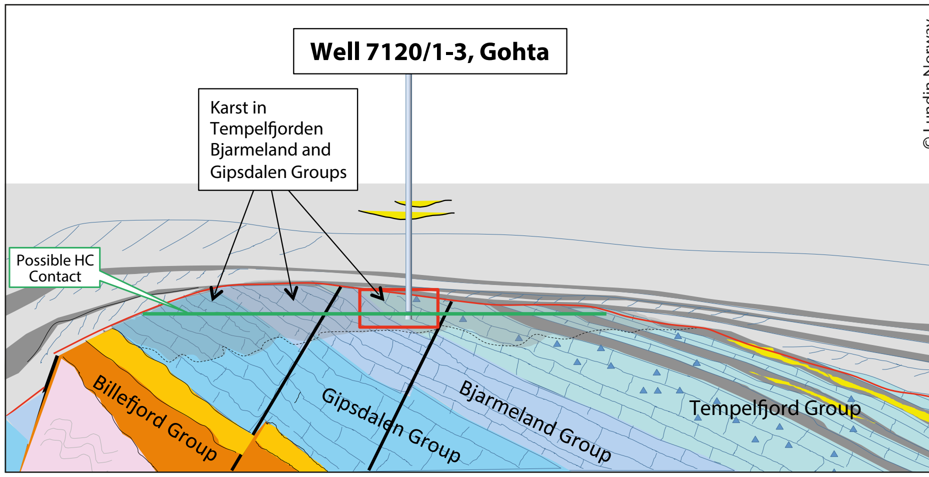
The basement pay is now part of the Edvard Grieg field, which will come on stream in 2015.

New Life for the Barents Sea

Following the breakthrough with this giant discovery in 2010, a high number of small, medium and large discoveries have been made on the NCS. Most noteworthy are several finds in the Barents Sea, turning this huge area into a hotspot.

The frenzy started during spring 2011. Statoil drilled well 7220/8-1 and found both oil and gas in a structure that has two separate flat spots, thereby indicating the presence of gas above oil. Now we know that Skrugard, as it was initially called, proved some 250 MMboe. Less than a year later another discovery was made in a structure nearby. This one, Havis, has even more hydrocarbons, 286 MMboe, and the two discoveries are now known as Johan Castberg (named after a Norwegian politician).

Finding this field was a great relief for the Norwegian oil industry. With close to 100 exploration wells drilled in the Barents Sea, only two finds had turned into producing fields: Snøhvit with 1,300 MMboe (predominantly gas), which came on stream in 2007; and Goliat with 240 MMboe (mostly oil) with production start-up due in 2014. Most of the super majors have abandoned the area, leaving it to Statoil, Eni and many medium and small oil companies to continue the exploration efforts.



Gohta was the first discovery in Permian rocks on the NCS.

Two Surprises

This year has brought two surprises which have changed the game completely. Optimism is back, and the oil companies are flocking to virgin acreage.

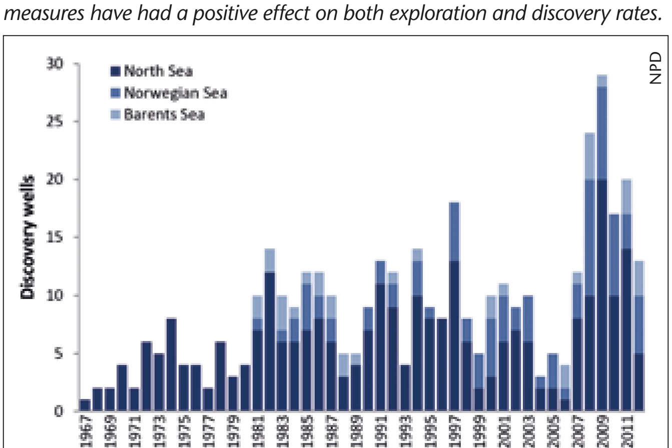
The first was when Austrian company OMV hit oil in Jurassic rocks only 250m below the seabed. The oil is reservoired in a well-defined structure, known as Wisting, and the presence of hydrocarbons was indicated by a strong CSEM (controled source electromagnetic) anomaly. Most explorationists, however, did not believe in the prospect because it was buried only under some few hundred metres of shale, arguing that any oil would have been biodegraded due to temperatures in the reservoir of only 10°C.

After announcing a 60m oil column, and a reserve estimate of up to 160 MMbo, OMV quickly stated that the licence may hold some 500 MMbo of recoverable oil when including nearby prospects, while TGS, having shot multiclient seismic in the area, indicated that a new oil province had been discovered that may very well host several billion barrels of oil. This was substantiated by EMGS after acquiring multiclient CSEM. According to their experts, the area is flush with strong electromagnetic anomalies indicating the presence of hydrocarbons in commercial quantities.

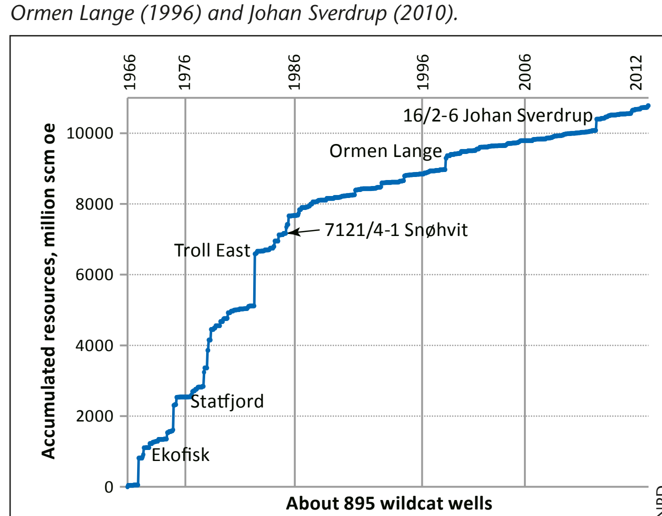
The second surprise for the Norwegians was when Swedish Lundin Norway once again made an interesting discovery. While oil was found in Permian carbonate rocks in the 1970s on the UK side of the North Sea continental shelf, this play model had not worked on the NCS. That changed with the drilling of the Gohta prospect (7120/1-3) in the Barents Sea, a prospect previously tested down-flank by Shell in 1986. The well hit pay in karstified carbonates on the western, down-faulted segment of the Loppa Ridge and flowed more than 4,000 bopd and is therefore the very first discovery in Permian rocks on the NCS.

Preliminary reserve estimates indicate close to 250 MMboe. The play may result in more nearby discoveries, and it is no wild guess to suggest that it will also be explored in other parts of the Barents Sea.

Radical changes were made in Norwegian oil policy in 1999, 2003 (licensing in mature areas) and 2004 (tax regime) in order to boost exploration. All these measures have had a positive effect on both exploration and discovery rates.



The creaming curve of the NCS clearly illustrates the importance of the first 15 years of exploration. Following the $10 barrel in 1986, the curve flattened remarkably. Two steps stand out after 1986: the discoveries of Ormen Lange (1996) and Johan Sverdrup (2010).

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The four oil and gas discoveries mentioned above have turned everybody's eyes north, meaning that the seismic companies are eager to increase their databases in advance of the 23rd licensing round, which is expected to close by the end of next year. In the meantime, particularly in the far north, several key wells will be drilled, which may confirm a petroleum province that was all but forgotten only some years ago. It is a common belief that if it had not been for Statoil, which has continued its efforts in spite of numerous disappointments including dry wells and technical discoveries, the Barents Sea might have been left before reaching the successful outcome achieved today.

Production vs Resources

The spectacular discoveries on the Utsira High and in the Barents Sea have taken the headlines. But more than 25 true wildcats have been drilled on the NCS every year since 2008, with an all-time high in 2010 and 2011 with 35 wildcats. This high level of exploration activity has resulted in a series of discoveries – in fact, three of the past five years accounted for the largest-ever number of finds on the NCS. Technical and commercial finding rates have therefore averaged about 55 and 40% respectively over the past 15 years, which helps to explain why more than 50 oil companies are actively involved, with more on their way.

One example is the discovery of Garantiana in the North Sea in PL 554 (Block 34/6), due east of Snorre. This is the third time in the history of the North Sea that this acreage has been explored, and in 2002 Conoco drilled a dry well in a separate fault block to the west. Bridge Energy was the sole applicant for the new prospect, which attracted their interest because of an apparent flat spot, but the geoscientists had to spend some time finding partners. Last year it became known that about 45 MMbo had been found in Lower Jurassic sandstones, now with Total as the operator.

Despite these discoveries, the resource growth does not outweigh production from year to year. On average, the amount of oil and gas discovered annually on the NCS exceeded annual production during the first 30 years, but this reflected low output and large discoveries. Resource growth over the past 15 years has been substantially smaller than the volume produced, reflecting high levels of output (1.7 MMbopd in 2012) and a smaller average discovery size. However, a more detailed analysis of the latest 15-year period shows that the picture is more nuanced. Over the past five-year period, resource growth has been almost on a par with production. The main reason is Johan Sverdrup, which was discovered in 2010.

Targeting Satellite Fields

The high discovery rate is also caused by drilling satellite structures close to some of the giant fields that were discovered in the 1970s and 1980s. Gullfaks, with original reserves of about 2,500 MMbo recoverable, is a good example of how an area has developed after its initial discovery. According to Statoil, infrastructure-led exploration yields highly commercial finds which can be brought on stream quickly. The size of each of these finds may be less than 10 MMbo, but they all prolong the life of the field and make effective use of the production facilities already in place.

The big surprise this year on Gullfaks was the discovery of between 40 and 150 MMbo in hitherto unknown reservoirs above the Jurassic sandstones. Oil has leaked upwards, and a new look at the formations that have been drilled through – on their way down to the billion barrel field – confirmed that oil is plentiful in the overlying Tertiary and Cretaceous sandstone and carbonate beds.

Bright Future

The mature, proven areas that are included in the yearly APA licensing round still have a good remaining potential, in particular in the North Sea, but also in the Barents Sea. Lately the Norwegian Sea has had many disappointments, resulting in diminishing interest.

The frontier provinces are promising in the Barents Sea, while lots of disappointments in the deep water of the Norwegian Sea have resulted in low interest.

Altogether, this means that we can expect the Norwegian Continental Shelf to continue to experience hectic activity in the years to come. ■

The Gullfaks Field in the Norwegian North Sea first began producing in 1986, but received a new lease of life when up to 150 MMbo were discovered this year in previously unconsidered rocks above the main reservoir.

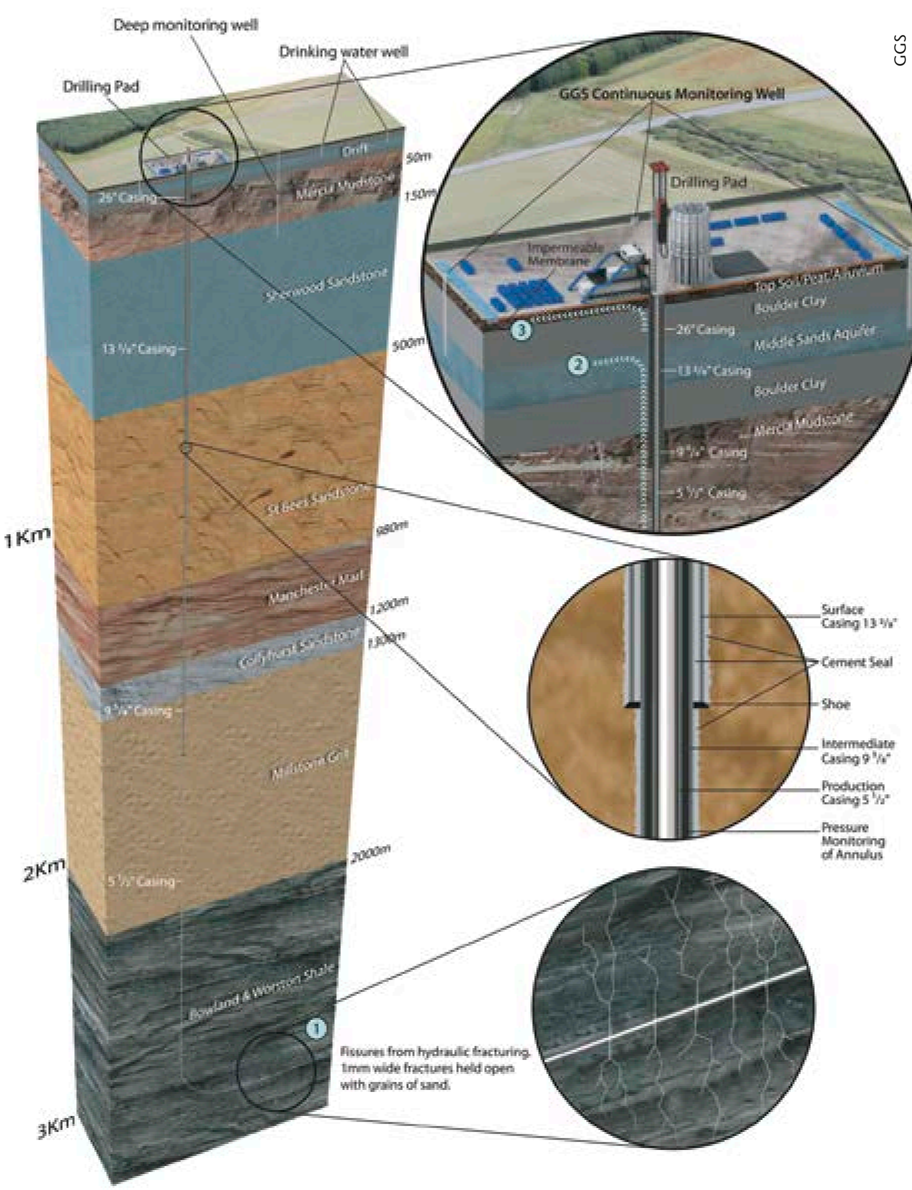
The source rocks (March 13) and play models (April 2) of the Barents Sea will be discussed in two forthcoming seminars hosted by the Geological Society of Norway.

Solutions for Monitoring Gas

In the face of widespread fears in the public about potential pollution as a result of fracking, we take a look at standards and best practices for environmental monitoring of onshore hydrocarbon exploration and development.

PAUL WOOD

Environmental monitoring requirements for shale gas in north-west England need to demonstrate no contamination at (1) subsurface fracking, (2) shallow aquifers, (3) surface locations.



GGS

In the past few months, a great deal of publicity has been given to the issue of the production of shale gas. In North America, the increase in gas production from unconventional reservoirs has helped drive down prices, while in the UK the Department of Energy and Climate Change (DECC) has made an initial evaluation of a large potential shale gas resource across the north of England (*Geo ExPro*, Vol. 10, No. 4). The gas produced from unconventional sources is one of the least environmentally damaging fossil fuels known. Yet the production of shale gas is controversial, mainly because of perceived environmental effects from the main technology needed to release the resource – hydraulic fracturing of the reservoirs, or 'fracking'.

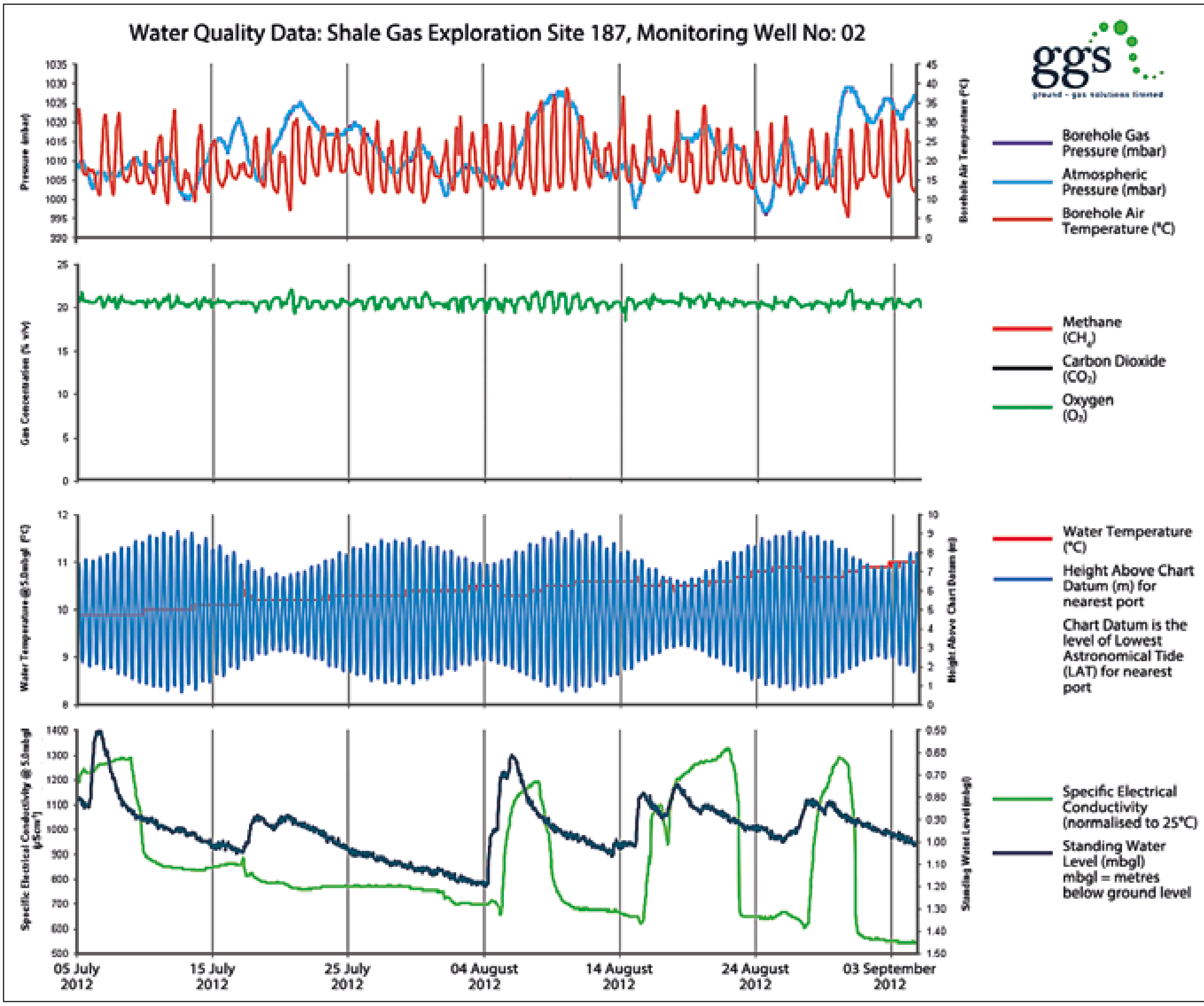
Environmental Issues

One of the fears of campaigners against the process is the release of gas or the chemicals used in fracking, either unintentionally or because of poor practice. This could be into the atmosphere or the ground water, possibly contaminating local water supplies. If the correct procedures are followed, in particular with the use of properly cemented casing strings and the protection of drill sites from accidental fluid release by containment, then it is very unlikely that the production of shale gas will lead to environmental damage. Many cases cited (notably in the USA) have, after investigation, pointed to pre-existing sources such as shallow biogenic gas being responsible for contamination.

But such is the pressure of public opinion (reinforced by the popular press) that it is becoming very difficult for other countries to follow the North American 'shale gale'. In France there is a ban on fracking and in the UK, in spite of governmental support, the leading UK shale gas operator, Cuadrilla, has only managed to frack a single test shale gas well. Even Cuadrilla's conventional operations are disrupted by protestors. There is no doubt that if shale gas exploration and production is to become commercial in Europe, it will be with strict regulation and the need to win the 'hearts and minds' of people potentially affected by the operations.

Independent Gas Monitoring

Enter Ground Gas Solutions Ltd., (GGS), a



Monitoring at one site showed no abnormal gasses but periodic influxes of saline water represented by increased conductivity (green line, bottom graph). This was correlated with tidal variations (blue line third graph down).

private company based in Manchester, UK. GGS was founded in 2009 by Simon Talbot and John Naylor, who had both previously worked in landfill monitoring and contaminated land regulation and investigation. They set their company up as an independent specialist gas monitoring service that could provide both regulatory requirements and advice to operators. Initially GGS did not work for the energy business but provided a wide range of specialist monitoring and risk assessment to, for example, residential and commercial building developers, landfill operators, local government authorities and even the operator of the Forth Road Bridge in Scotland. These services include other continuous monitoring techniques, such as groundwater and air quality monitoring and monitoring of greenhouse gas emissions and radon gas.

In their previous work, Simon and John had realised that, with the industry practice as it was then, there were two key aspects of environmental monitoring which were not being executed rigorously. The first of these was the need to take baseline studies, in particular to demonstrate whether any environmental effects detected pre-dated an operation. The baseline had to be measured over a sufficiently long period to account for any significant environmental fluctuations. As an example of this, in one case a regular influx of brackish water in groundwater at a site was shown to be correlated with tidal variations.

Continuous Monitoring

Another problem with the monitoring processes was that sampling was done at periodic intervals by an individual visiting a site and taking measurements. This could only give 'snap shots' in time and even if done on a regular basis could miss highly variable and irregular natural fluctuations in gas concentration. So GGS decided to develop continuous monitoring methods in order to measure concentrations of the most important gasses used in environmental monitoring. These are methane, carbon dioxide, oxygen, carbon monoxide and hydrogen sulphide, together with total Volatile Organic Compounds (VOC). Atmospheric pressure and borehole temperature and pressure are also typically measured. These measurements are usually taken once per hour but can be up to every three minutes if required.

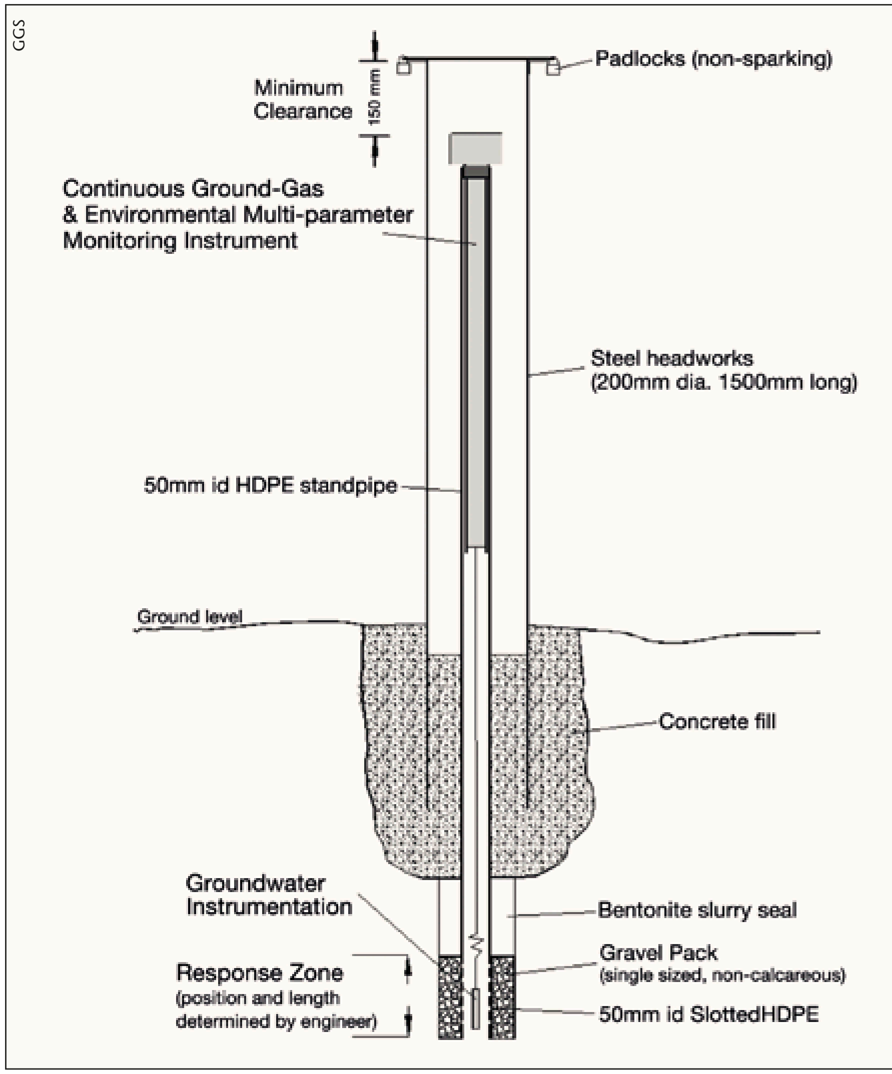
In order to differentiate itself in the field of environmental monitoring, GGS developed the GGS DataPack®, a unique report format that takes the continuous monitoring data and presents them in an easy to read graphical format. This provides regulators and other bodies with a clear and precise report to improve understanding of the ground-gas processes and risks at a particular site. This is now an industry standard for this type of presentation.

Developing Best Practices

In 2011, GGS started to work together with Cuadrilla Resources Ltd. in the UK to provide independent continuous gas monitoring services in their shale gas exploration and extraction programme. As has become abundantly clear with the public and press involvement, it is likely that the demonstration of no or As Low As Reasonably Practicable (ALARP) environmental impact of shale gas extraction will have to go beyond mere regulatory compliance in order to satisfy public opinion. It will be essential that an independent body is involved in any monitoring.

Monitoring will also have to differentiate between gas that may originate from deep reservoirs (thermogenic gas) or shallow biogenic gas that may come from peat or other non-reservoir sources. As Simon Talbot says, "If you have methane recorded in near-surface soils, it's very important to take samples to fingerprint it with isotope analysis." So GGS and other operators also take samples at sites and then use specialist laboratory analysis to characterise the natural geochemistry of the sites. In some of the cases where operators were accused of contamination in the US, this had not been done, so it was difficult to refute the claims.

GGS is working with Cuadrilla and other operators to develop industry best practices and standards for shale gas development. Cuadrilla also believes this will be essential in order to maintain a licence to operate in this controversial field. Cuadrilla former CEO Mark Miller says that GGS' services "will allow us to collect background gas levels and compare them before, during and after operations. Continuing with our open



Continuous monitoring and shallow borehole installation

and transparent communications with the community, we will make this data available to the public".

Pioneering Work

As a result of its groundbreaking work on continuous ground-gas monitoring as applied specifically to shale gas development, GGS has also been requested to advise other onshore UK operators. It so happens that GGS' Manchester headquarters is fairly and squarely in the centre of the Bowland Shale Gas resource evaluated by the UK DECC (*Geo ExPro,* Vol. 10, No. 4). The company's unique technology and pioneering work in the field give it the potential to become a leader in independent gas monitoring and risk assessment that will undoubtedly become a requirement in any future shale gas work in the UK and elsewhere. ■

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Broadband Seismic Technology and Beyond

PART VI: Towards a Ghost-Free Solution

PGS launched the 'ghost-free' GeoStreamer GeoSource solution in 2011: a time- and depth-distributed source using sub-sources operated at specific depths and time delays, attacking the source-ghost effect in seismic data.

LASSE AMUNDSEN, Statoil and
MARTIN LANDRØ, NTNU Trondheim
Guest Contributor: **EIVIND FRØMYR,** PGS

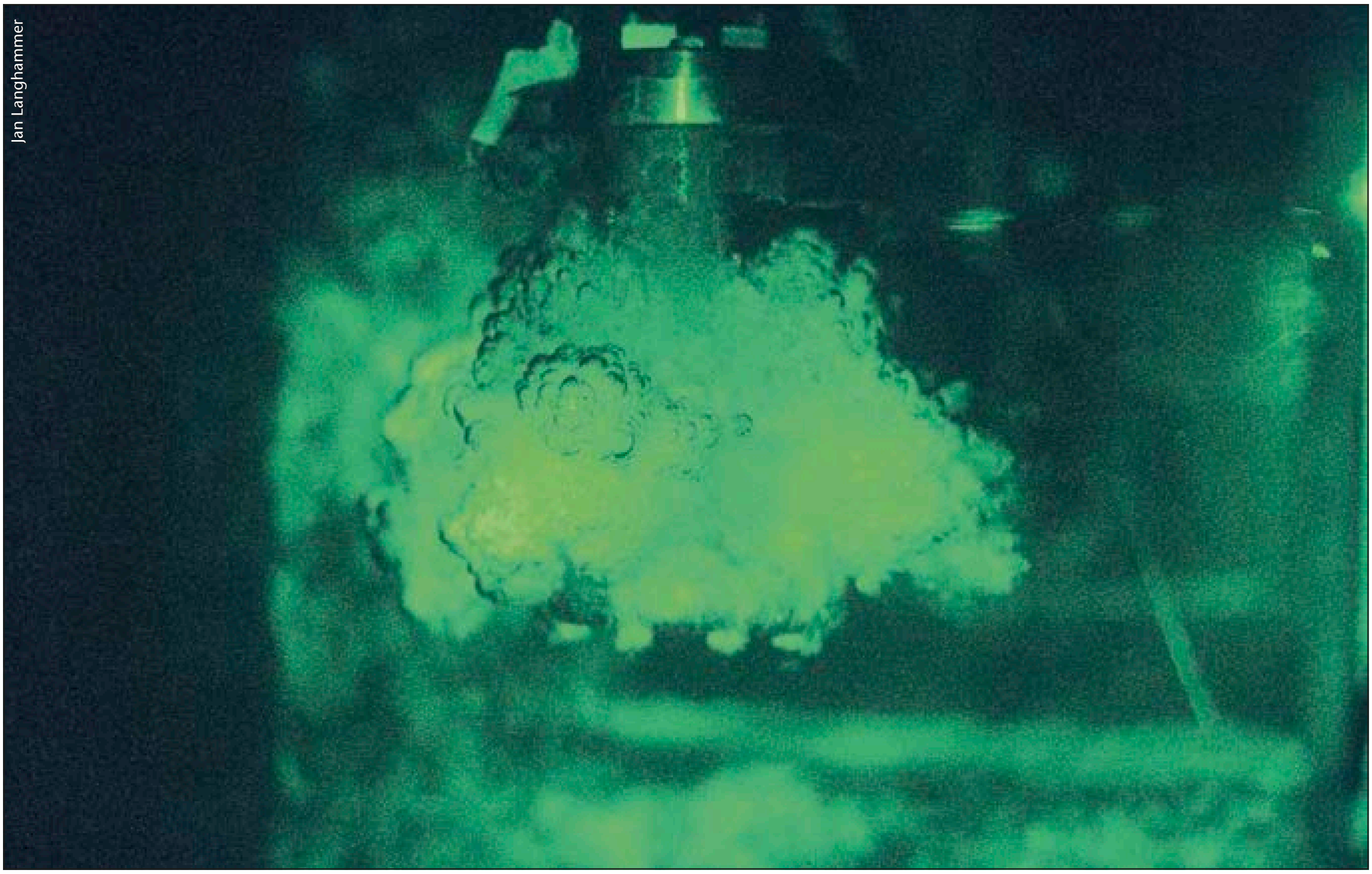
"Our greatest weakness lies in giving up. The most certain way to succeed is always to try just one more time."
Thomas Edison

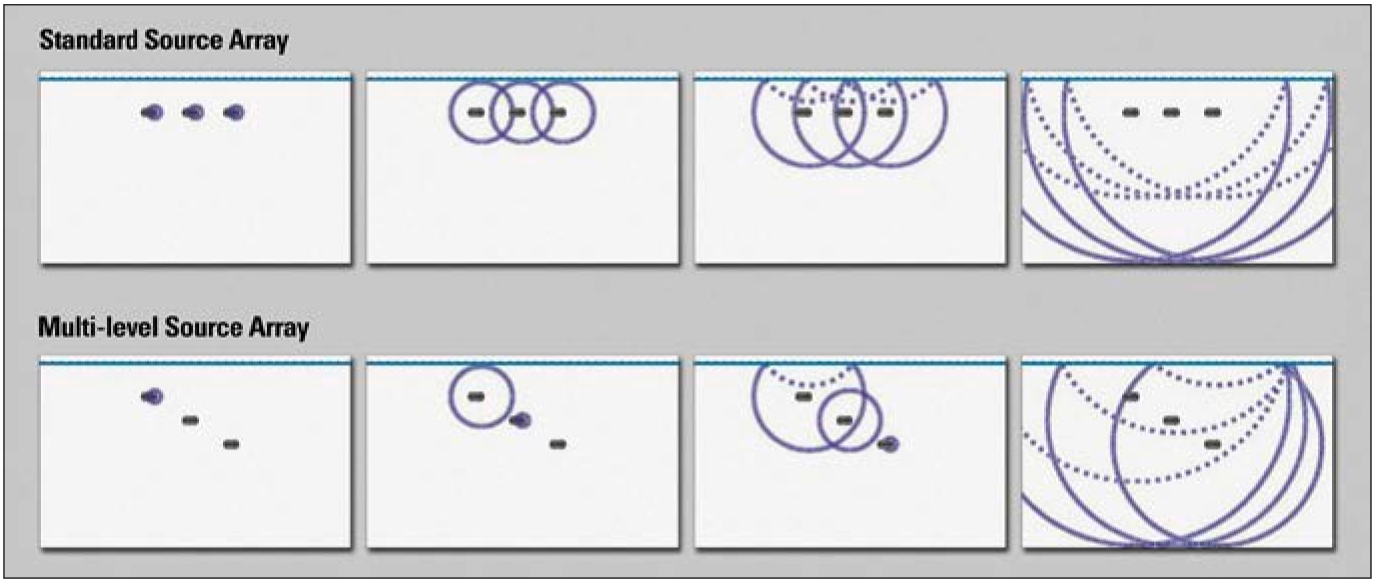
The marine air-gun source was widely adopted by the seismic industry in the 1960s and soon became the source of choice because of its flexibility and superior safety over explosive sources. The physics of the source is governed by the interaction of the various elements such as number and volume of the guns, and the pressure and depth in terms of hydrostatic pressure. The interaction with the sea-surface which acts as a perfect reflector creates the well-known ghost effect, and this affects effective bandwidth as well as the radiation pattern of the source.

Towards a New Paradigm

Conventionally tuned air-gun arrays consist of numerous single guns and clusters (two or more guns that are fired close together) of different sizes. When fired synchronously, the difference in bubble periods leads to destructive interference and hence primary energy is enhanced and bubble energy is attenuated. While this is desirable from the point of view that we seek a sharp pulse with minimum

Photo of the bubble created by a small air gun in a water tank, taken after several bubble oscillations. A laser beam was used as light source. Work done as part of Jan Langhammer's PhD thesis at NTNU.





Wave patterns from standard source versus multi-level arrays; with all guns at the same depth the ghost (dotted line) has the same energy as the down-going direct wave (solid line), while with a multi-level source only the down-going direct wave builds up constructively and the ghost effects are consequently reduced.

trailing energy to represent the various echoes from the subsurface, it has the undesirable consequence that it reduces the effective amount of low frequencies. Peak to bubble ratio remains one of the key parameters in marine air-gun design together with absolute strength and source radiation pattern (*GEO ExPro*, Vol. 10, No. 1).

With the advent of broadband receiver solutions (Carlson et al.) the industry has started focusing on source solutions that will further increase the bandwidth of seismic data. This is driven by the need for low frequencies for improved deep penetration as well as the recognition of the value of the complement of both low frequencies as well as high frequencies in inversion and estimation of elastic parameters in the earth. New processing techniques like full waveform inversion have further emphasised the need for even lower frequencies all the way down to 1 Hz. In this context, it is paradoxical that we adopt methodologies on the source side which intrinsically diminish the low frequencies through the attenuation of the bubble characteristic of tuned arrays. The industry has, up till now, applied the criterion of peak-to-bubble maximisation in order to create a high resolution wavelet without regard to what it does to the low frequency response. This ignores the fact that the presence of low frequencies greatly reduces the side-lobes of the seismic wavelet and therefore significantly improves the effective resolution power, given that the high frequencies are there.

Optimising Low Frequencies

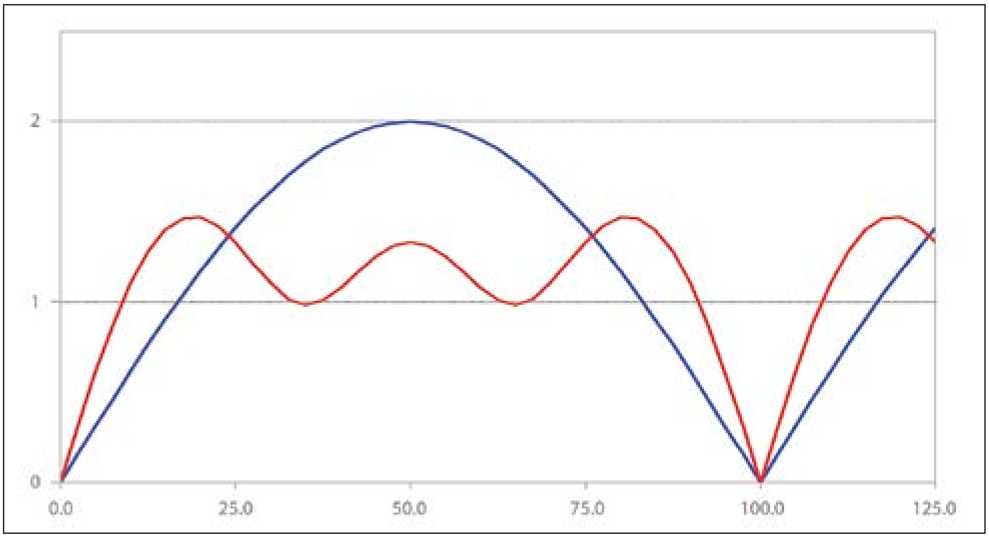
As indicated in the introduction, the response or strength of air-gun sources is determined by number of guns, volume and pressure, approximately as cube root of the last two. The Rayleigh-Willis approximation describes the bubble period in terms of the factors above and in addition as being inversely related to hydrostatic pressure. This fact is crucial when we attempt to improve the low frequency response of source elements consisting of traditionally tuned arrays, although the second element which determines the air-gun response is the interaction with the free surface, i.e the ghost effect, which means that low frequency response will improve with increasing depth. The net effect can be close to a zero sum game for tuned arrays, albeit somewhat dependent on the nature of the array. In fact if one looks at the response of a single gun of considerable size when the bubble energy is not attenuated, the low frequency energy is best preserved at shallow depths.

Below the frequency of the source-ghost notch, the source spectrum can be shaped to optimise low frequency response as far as signal to noise allows it. Such procedures can be guided by the ghost function. Going across the source-ghost notch is more challenging, just as it is on the receiver side. If we consider source solutions with tuned arrays as a basic building block, there are a couple of methodologies that can be used to de-ghost the source. The ghost reflection can be attenuated by spreading it out in time, or over-under techniques can be used to de-ghost the source, in a similar manner to the techniques used for over-under streamers (*GEO ExPro,* Vol. 3, No. 1).

Synchronised Multi-level Source

The source ghost can be attenuated using a beam steering technique originally developed some 60 years ago for dynamite land acquisition (Shock, 1950). The principle is to detonate charges at various depths in a sequence that constructively builds the down-going wave at the expense of the up-going wave. This way the energy of the ghost (surface-reflected down-going wave) is reduced compared to that of the primary pulse. One can adapt the beam steering approach to air-gun arrays in the marine environment. We place guns, clusters of guns or sub-arrays at different depths and fire them sequentially. Contrary to the land dynamite case, the speed of sound in water is well known and varies little at the depth considered, and the trigger-time accuracy is in the order of a fraction of a millisecond. This technique is quite straightforward to implement and requires only minor modifications of the existing gun arrays.

A conventional air-gun array is made of several sub-arrays each containing a number of guns, or clusters of guns. All guns are at the same depth (typically between 5 and 10m) and fire simultaneously. This provides constructive down-going energy but also constructive up-going energy, and the ghost therefore has the same energy as the direct wave. The multi-level source concept puts guns, clusters or sub-arrays at different depths and fires them sequentially so that only the down-going waves build up constructively, as shown in the figure to the right. The up-going wave does not build constructively and the ghost effects are consequently reduced. The pure ghost effect will favour low and high frequencies whereas the middle frequencies are attenuated.



The ghost signatures for the two schematic sources (blue = standard source, red = multi-level source).

An important issue to consider with the multi-level source is the radiation pattern. The illustration clearly shows that a direction other than down-going also benefits from the beam steering. Although conventional source arrays have a radiation pattern and are far from being isotropic, this issue is more pronounced with the multi-level source. Array modelling is required to ensure the spectral benefits are not offset by unintended consequences.

Beyond the change in ghost behaviour, the air-gun signature is also affected by this new design. First, the source ghost is an effective attenuator of bubble pulses. Consequently, we expect the multi-level source to deliver a lower peak-to-bubble ratio (PTB) than a conventional source. Secondly, since the guns are towed deeper, they operate under higher hydrostatic pressure, which reduces the size of their bubble. Smaller bubbles mean less low frequency content, which can partly offset the gains demonstrated in the ghost signatures illustration. Thirdly, the reduced diversity in bubble sizes requires less parameter modifications to play with in array design and bubble pulse attenuation. Therefore, modelling is the key to ensuring an effective multi-level source array design.

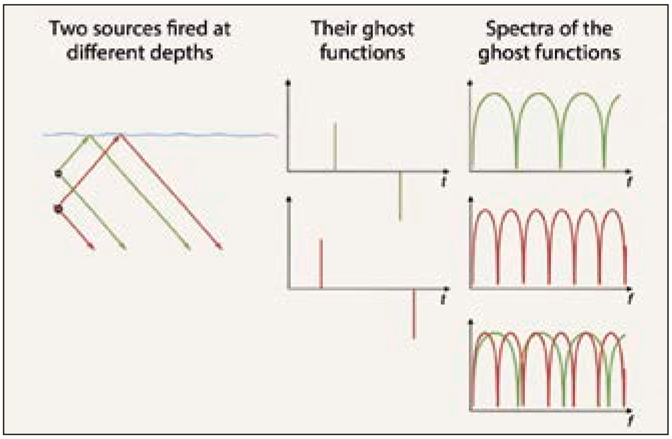
A Fully De-Ghosted Source

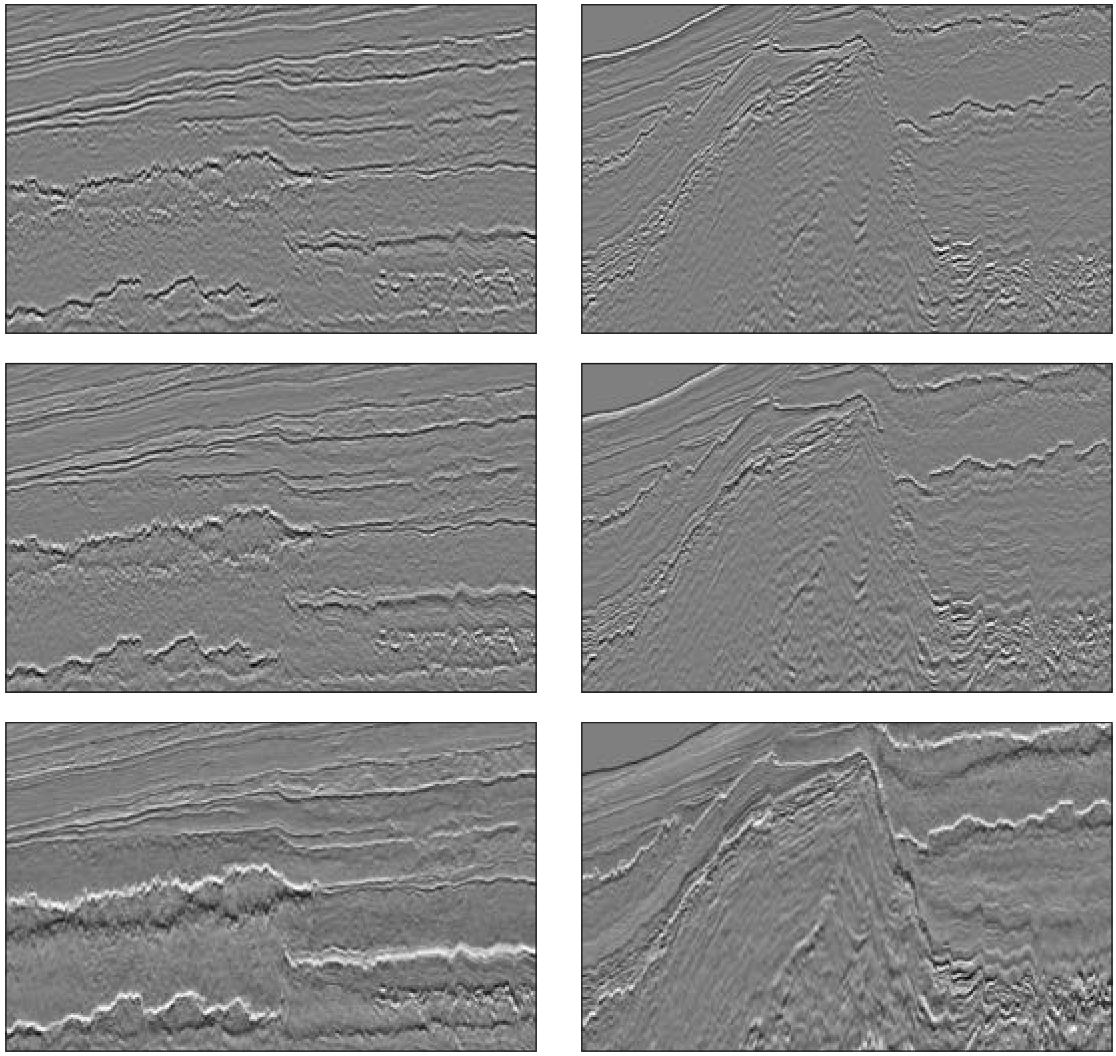
The fact that a synchronised multi-level source just attenuates the ghost and creates an anisotropic radiation pattern encourages us to look for alternatives. What springs to mind is the over/under principle applied earlier for de-ghosting of streamers. One could achieve this by shooting a survey twice, using a shallow source and then a deeper source, but this would be quite costly. Alternatively, a deep and a shallow source could be fired in turn at the same surface location but this would then reduce the fold by 50% which is also highly undesirable. A fully blended solution with a randomised firing scheme offers an attractive alternative (Parkes et.al), as de-blending techniques have been in rapid development over the last decade (see e.g. Van Borselen et al.).

The GeoSource is a time- and depth-distributed source. The source array is divided into sub-sources, each of which consists of one or more conventionally tuned sub-arrays towed at different depths. A typical configuration is two sub-arrays at 9m depth and a single one at 5m, which creates a high degree of complementarity in the frequency domain. The arrangement of the sub-arrays is such that air in the water from the arrays fired first can only affect the subsequently fired arrays at very high angle, thus not impacting the emitted wave-field directed into the earth. At least one sub-source is fired with a time delay that is varied in a random fashion from shot to shot within a typical 1 sec. window. The randomised fire time delays allow us to separate the wave-fields emitted by the sub-sources, and the depth distribution of the sub-sources allows us to recombine these wave-fields in such a way that the source ghost is removed (Posthumus).

The methodology allows the source ghost to be removed in a robust way at an early stage in the processing, i.e. pre-stack. When combined with GeoStreamer, the resulting image is broadband and ghost free. After the source response has been compensated for, the wavelet in the resulting data has a flat amplitude spectrum without notches, and the phase spectrum is zero.

The intrinsic source response, which is now ghost-free, remains in the data. The form of this response is well-known and results from the oscillatory nature of air-gun bubbles. Due to inaccuracies in numerical modeling towards the very low frequencies, accurate near field measurements are needed to calibrate the modelled results. This applies to any source





Comparison of seismic from a conventional source with conventional streamer, a conventional source with GeoStreamer and the combination of GeoStreamer and GeoSource. It demonstrates the potential for de-ghosted ultra-high resolution seismic. The data was acquired in the Møre margin area of the Norwegian Sea, which is a notoriously difficult imaging area. The GeoStreamer data (centre) were shot in 2010 using a conventional airgun array at 9m and a dual sensor streamer at 25m. From the GeoStreamer data the total pressure field was reconstructed at a depth of 12m, to simulate conventional streamer data (top). The GeoStreamer GS data (bottom) were shot in 2011 using the GeoStreamer at 25m and a time and depth blended source with two sub-sources at 10m and 14m. It has had all the acquisition-related effects removed, thereby representing an improved response of the earth.

configuration trying to preserve the low frequency integrity.

Due to the randomised firing scheme it may also be possible to reduce the shot-generated noise towards the lower frequencies. GeoSource is an acquisition-based methodology and does not make any restricting assumptions about sea state. The challenge lies in the source separation, especially in shallow water and in the presence of strong diffractions.

GeoSource exhibits some similarities to, but also differences from a synchronised multi- level source. Due to complete de-ghosting, the radiation pattern is much more uniform and it represents a more robust alternative for source de-signature.

Challenging the Old Paradigm

Both solutions described above are based on tuned sub-arrays. The main contributor to low frequency response, the bubble, is intrinsically attenuated. Alternative array designs and tuning strategies may offer new opportunities to boost the low frequency part. One strategic element in such novel designs will be an accurate representation of the far-field signature through high quality near-field measurements. Technology is moving rapidly in this direction and will offer new opportunities. Alternative sources such as marine vibrators may complement our search for more low frequencies. The rapid development of techniques like full waveform inversions compels us to keep up the good work.

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Croatia:

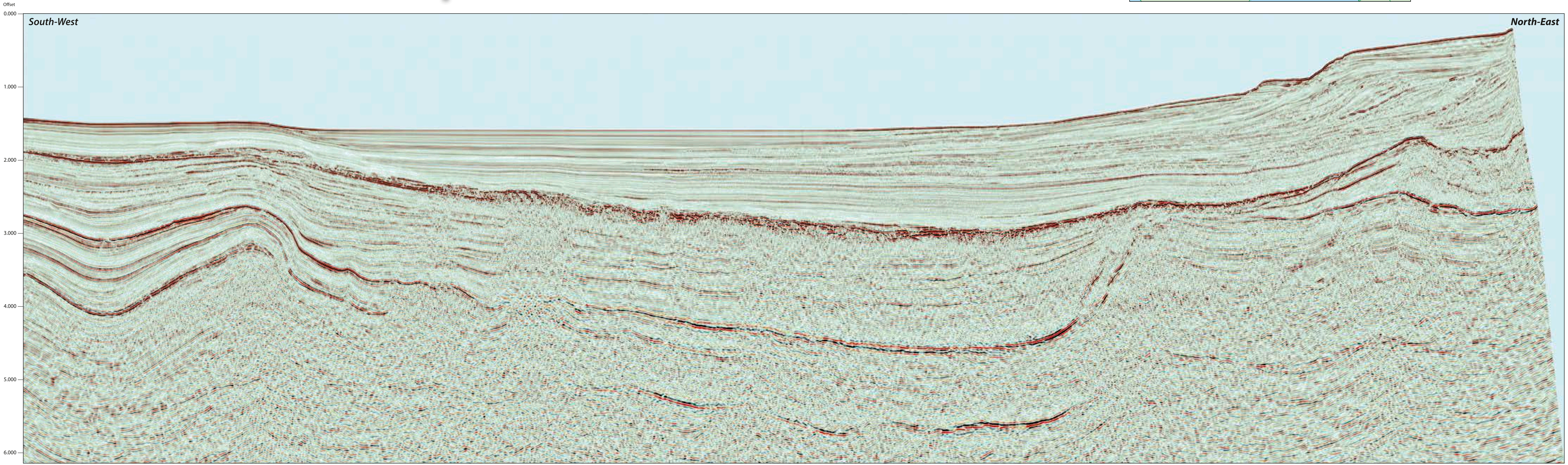
A New Oil Province at the Heart of Europe

As the autumn sun blazes down on the calm azure-blue seas of the eastern Adriatic, Spectrum is acquiring a unique seismic dataset offshore Croatia that is revealing a new oil province at the heart of Europe. At the time of writing more than 50% of the acquisition of >12,000 line kilometres of new long-offset 2D data is complete. Early results from fast-track processing are already startling and reveal new, untested hydrocarbon systems and plays ready for explorers to seize the opportunity of a forthcoming Q2 2014 Croatian licensing round.

Location of line shown in foldout

Spectrum

A fast-track processing sample of the newly acquired Croatian 2D seismic. Line length 86 km.



A New Wave of Exploration Offshore Croatia

NEIL HODGSON, HOWARD NICHOLLS, ANNA MARSZALEK, PETER BROWNING-STAMP and **STEVE MADDOX**, Spectrum

Proven hydrocarbon systems, shallow waters and proximity to hungry energy markets: is it time for Croatia to emerge from the shadows of its neighbour on the other side of the Adriatic Sea?

The Adriatic is the most prolific hydrocarbon province in the northern Mediterranean, with over 20 biogenic gas fields and a number of thermogenic oil fields in production. Exploration activity in the Adriatic, however, has been heavily skewed in the past between Italy and Croatia, such that whilst the Italian Adriatic is relatively well explored, the eastern Croatian margin remains comparatively untouched. This is about to change as the Croatian authorities are committed to holding a licensing round in Q2 of 2014, ushering in a new wave of exploration offshore Croatia.

As an exploration arena, the Adriatic is attractive. There are proven hydrocarbon systems, most of the basin is in less than 200m of water (only deepening in the south to about 1,000m of water), and it is located in Europe, close to significant energy markets. The Northern Adriatic is already endowed with Plio-Pleistocene biogenic gas fields, whilst to the south a number of Mesozoic oil discoveries have been made offshore Italy, demonstrating a working Mesozoic oil system.

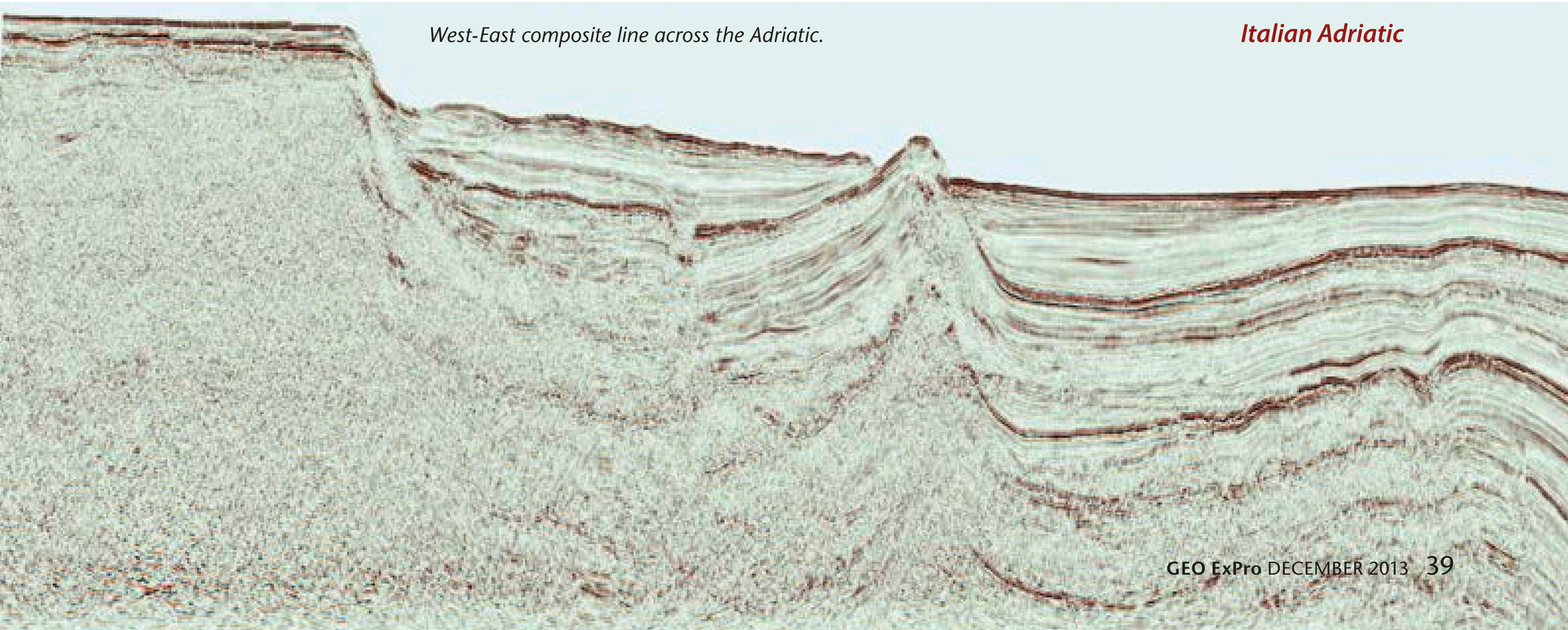
However, of late, exploration activities in Italy have slowed due to time-consuming consents and regulatory issues, while activities in Croatia had all but stopped, as the indigenous oil industry was restructured and privatised. The forthcoming Croatian licensing round will, however, rejuvenate activity, and this will be facilitated by Spectrum's on-going seismic acquisition of more than 12,000 line kilometres of long-offset 2D data and the availability of a re-conditioned well dataset.

Improved Data Quality

The dichotomy of historic exploration intensity across the Adriatic was in part due to the quality of the available seismic data on the Croatian margin, which were acquired in the 1970s and 80s, since when, seismic acquisition and data processing techniques and capabilities have developed significantly. Longer streamers are now used, producing seismic data of much higher fold, allowing improved noise cancellation from the data, and also imaging far deeper into the subsurface than ever before. Spectrum's programme uses an 8.1 km streamer length, rather than the legacy data's 3–4 km. Advances in data processing de-multiple techniques such as Surface Related Multiple Elimination (SRME) and Hi-resolution Radon are also far more effective than technologies available in the 1970s and 80s. In addition, the use of Pre Stack Time Migration (PreSTM) and dense automatic velocity analyses using second and fourth order updates gives better imaging, and provides higher quality gathers for velocity estimation and production of AVO-friendly products.

To take advantage of these technological advances Spectrum are also reprocessing ca. 9,000 km of older legacy data from which good uplift in quality can be expected. This reprocessed data will be particularly useful in the shallow water areas close to the environmentally sensitive coastline and around the existing production infrastructure, which are being avoided by the new acquisition.

Importantly, the new seismic dataset being acquired in Croatia is being tied to data available on the Italian margin, allowing for the first time a pan-Adriatic understanding. The



West-East composite line across the Adriatic.

figure below shows such a dip-line composite. Interestingly, the large four-way structures seen on the line in the centre of the basin are both undrilled.

Hydrocarbon Geology of the Adriatic

The Adriatic is a uniquely structured basin comprising a double foreland between opposing thrust fronts. The great nappes of the eastward verging Apulian thrust belt forming the Apennine Mountain belt onshore Italy frame the west of the Adriatic. To the east in Croatia, a west-verging Dinaride thrust belt forms the island chain of the Dalmatian coast and the Dinaric mountains.

Compression from both east and west has unsurprisingly thrust and folded the foreland Adriatic, generating a number of promising structures comprised of Miocene to Jurassic-aged carbonates. The new seismic, tied to the key wells that Spectrum are conditioning, will allow the structural restoration of the Mesozoic section. Additionally it will also allow the mapping of depositional facies belts within the repeated carbonate platform sequences running parallel to the coast along this margin. This will allow the identification of many new shelf margin carbonate plays previously obscured due to poor seismic resolution.

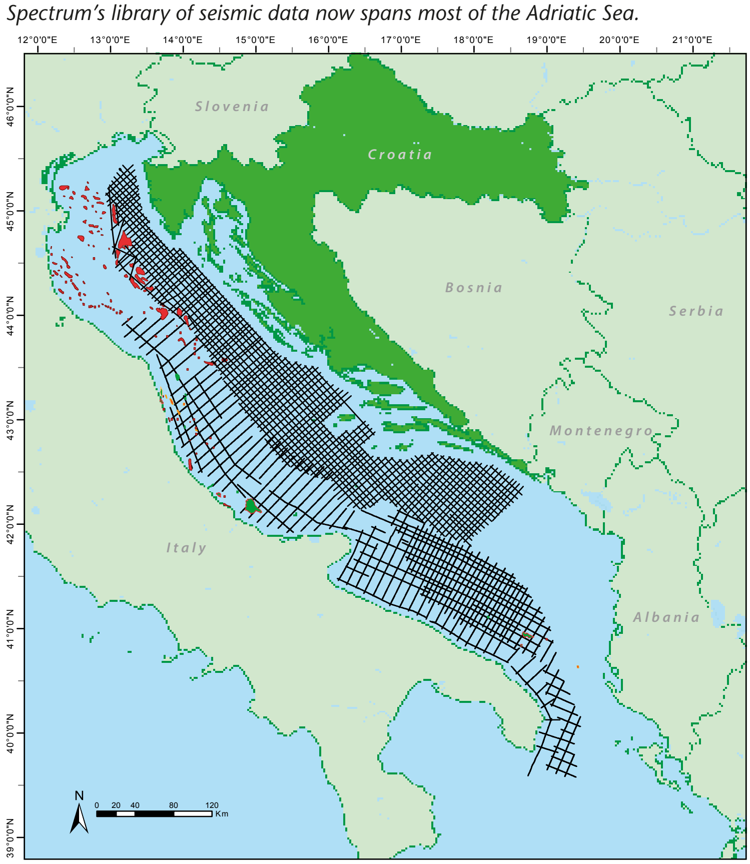
The younger Tertiary clastics derived from the Po valley of Italy and the Neretva River of Croatia have built deltas onto a seabed topography influenced by the underlying structure. This interaction between structure and sedimentation has resulted in abundant stratigraphic and structural plays. Although many have been exploited in the north, where there are 20 gas fields on production in the Po valley basin, data from the new acquisition indicates that the Neretva River delta looks promisingly untapped in central-south Adriatic.

The new seismic is also revealing the presence and distribution of an extensive salt diapir province offshore Croatia. Interaction of this Triassic salt with both the Mesozoic carbonates and clastic plays of the Tertiary has resulted in numerous untested plays in the basin.

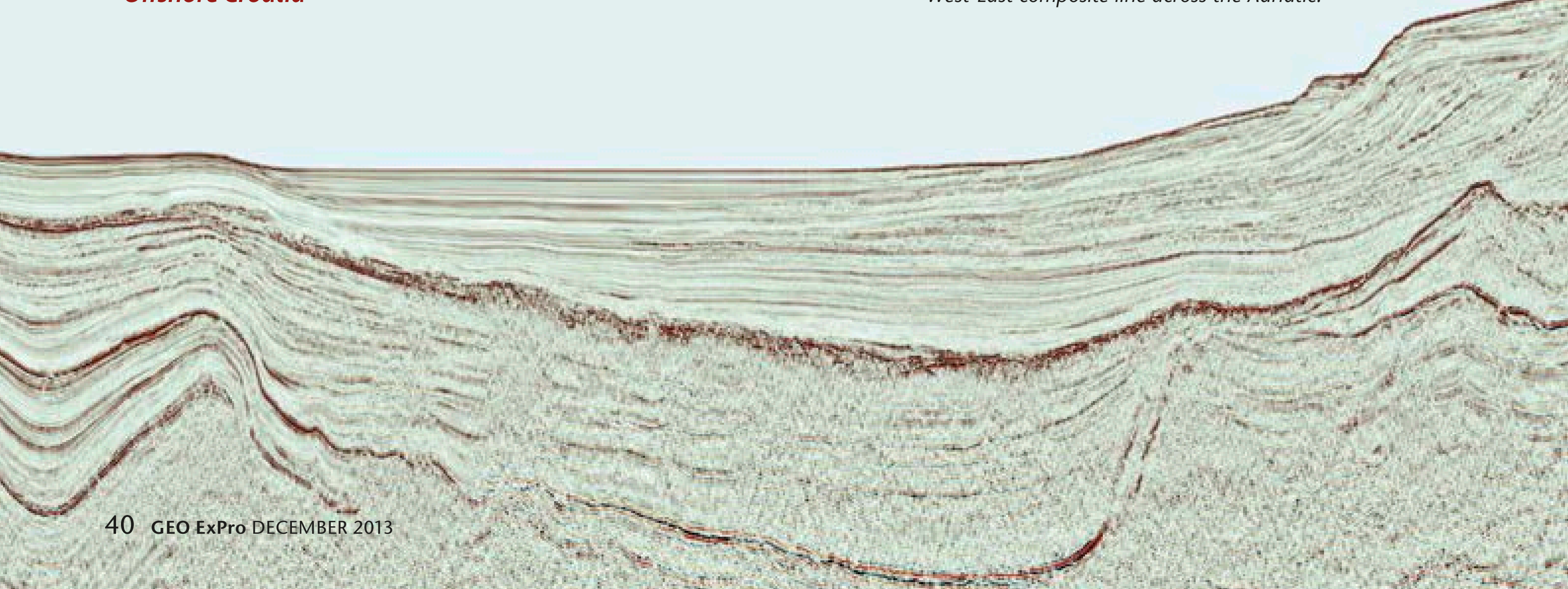
It is interesting to speculate on the association of oil source rocks and salt provinces, as globally there is often a causal association between these two. The main oil-prone source rock in the Adriatic is the Upper Triassic, which was deposited in a restricted shallow sea environment and characterised by marine Type II kerogen. This is a dominant source rock both for accumulations onshore Italy and to the east onshore Croatia and Albania. In both the adjacent thrust belts Triassic source rock and oil-stained carbonates are exposed, and oil was recovered from the Triassic of the Vlasta-1 well, offshore Croatia.

Spectrum's new seismic will be fully processed in Q1 2014, ready for the licence round to open in Q2 2014. The early results of this survey are startling and reveal new, untested oil and gas plays, which will ignite a new era of exploration offshore Croatia, at the heart of Europe's future prosperity. ■

Spectrum's library of seismic data now spans most of the Adriatic Sea.



Offshore Croatia

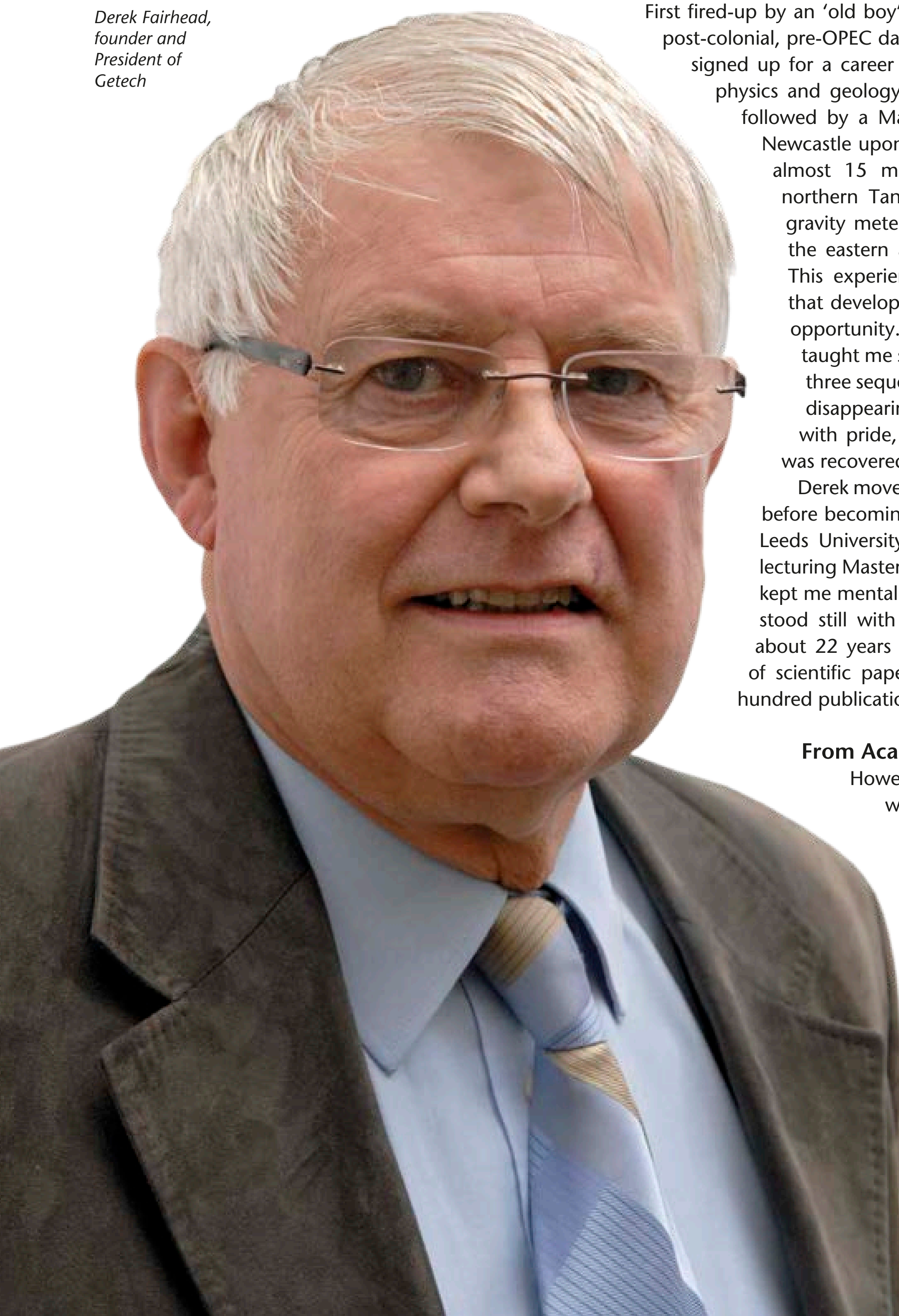


West-East composite line across the Adriatic.

Mapping Out a Career

For almost 50 years, **Derek Fairhead**, founder and President of **Getech**, has studied the earth's gravity and magnetic data. Now, close to retirement from the rapidly expanding AIM-listed company he has helped to build, he reviews a career that has successfully combined academia and business and has ridden the technological and economic waves of change in the oil exploration industry.

NIKKI JONES



Derek Fairhead, founder and President of Getech

First fired-up by an 'old boy' talk at his grammar school – in the post-colonial, pre-OPEC days of the early 1960s – Derek eagerly signed up for a career in oil exploration. A joint degree in physics and geology at Durham University in 1967 was followed by a Masters and a Ph.D. in geophysics at Newcastle upon Tyne University. The latter involved almost 15 months of fieldwork – literally – in northern Tanzania and southern Kenya, using a gravity meter to measure the gravity field across the eastern arm of the East African Rift System. This experience as a young man was the seed that developed, many years later, into a business opportunity. "It was a really exciting time, it really taught me self-reliance," he says as he points out three sequential photos, showing his Land Rover disappearing in a flash flood: they are displayed, with pride, on his office wall. "The Land Rover was recovered!" he beams.

Derek moved into academia in 1972 as a lecturer, before becoming Professor of Applied Geophysics at Leeds University in 1994. Apart from his focus on lecturing Masters students for nearly 40 years – "They kept me mentally young, since it was as though time stood still with the students perpetually remaining about 22 years old!" – he became a prolific author of scientific papers and has clocked up well over a hundred publications in his career.

From Academia to Business

However, by the mid-1980s academic life was "losing its gloss", and so Derek took a year of sabbatical leave to study at El Paso University, Texas, as a Fulbright scholar. Here a small flame was ignited and fanned by the experience of giving lectures directly to a large number of American oil exploration companies. The discovery that they had boxes of data, hidden away and forgotten, gave him the idea of putting together continental scale gravity compilations, by collecting, computerising and merging these

data into a comprehensive unified digital database. Such a database could then be marketed back to oil companies. He invited Professor Tony Watts, an expert in offshore gravity studies who at the time was at Columbia University, New York (now Professor of Marine Geology and Geophysics at Oxford University), to complement his own onshore expertise in order to form the nucleus of a new research group. The aim was to promote such compilation studies to oil companies for funding.

Despite the low oil price in 1985–86 and the consequent restricted oil exploration budgets, nine oil companies came on board to fund the initial three-year gravity mapping study of Africa. Research was conducted primarily using data amassed in the colonial period by the British and French geological surveys, national surveys, academia, and by oil companies, collected from specific areas of exploration. By the end of the study 19 oil companies were sponsoring the study, and Getech was born as an enterprise attached to Leeds University. Within ten years (ie. by 1995) the company had mapped the whole world. However, the oil price crash of the late 1990s rendered the company apparently valueless and in consequence, in 2000, the University of Leeds allowed the R&D group to 'spin off' from the University as a limited company.

The success of the initial African project resulted in oil and mineral companies requesting similar studies of South America, then East and West Europe, followed by north Central Asia and South East Asia. As part of these studies Derek and Getech linked up with the Russia Academy of Sciences, and were able to gain access to hitherto restricted gravity data (albeit at 10 km grid resolution) collected by the Soviet military; similarly, Chinese gravity data at the same resolution was secured by partnering with educational establishments. Parallel to the gravity compilations, the company undertook magnetic compilations that covered the world.

The Chinese relationship led to Derek being awarded with an honorary professorship at the Ocean University of Qingdao, China, in 1993. Further awards came from the Bureau Gravimetrique International in 1994 for 'outstanding works on the earth's gravity' and, in 1999, a special commendation award from the Society of Exploration Geophysicists.

Simple Business Model

Between 2000 and 2005 Getech boomed, boosted further by the development of new satellite technology that was able to more accurately map the gravitational field of the oceans.

"Our business model was simple," Derek explains. "We decided we wanted to bring all sources of data together to create a global database. This was branded, in the 2010s, as 'Globe, a live earth platform'. It contains the world's most extensive library of global gravity and magnetic data as well as global and regional geological and palaeogeological studies. Currently ten oil companies are sponsoring the Globe study."

Why would oil companies give Getech access to their own proprietary gravity and magnetic data? "The answer is that they do not have the time to collect region-wide information themselves since they are focused on their time-limited exploration blocks. The value of their data is, however, preserved by Getech only releasing products on a broader grid scale that does not compromise the high resolution proprietary nature of the original data," explains Derek. "For companies, our analysis of the resulting gravity and magnetic compilations helps to define where the sedimentary basins and sub-basins are located, and in recent times our geological expertise has brought a greater understanding to the evolution of the basins. With these data products and studies, therefore, companies are able to identify areas of interest and then use new seismic studies to refine their search for the 'sweet spots'. These companies may also use some of the more advanced technological developments that have been made over recent years, such as Full Tensor Gradiometry (FTG) and Controlled Source Electro Magnetics (CSEM), both of which enable them to further de-risk prospects prior to drilling, giving greater certainty in their quest to discover hydrocarbons. However, both methods are expensive options, with CSEM easier to apply in marine environments rather than on land."

In 2005 Getech was floated, raising approximately £2.5 million net for the company, which allowed the company to buy the impressive Kitson House just outside Leeds. It is a fitting office environment, since the house was originally the family home of the Kitsons, whose entrepreneurial son Sir James Kitson worked with George Stephenson to build some of the earliest steam locomotives. Derek is clearly proud of the historic associations of the building, plus its semi-rural setting which provides an unusually spacious working environment for the 80-strong, young, multi-ethnic team.

Retirement? What Retirement?

It appears that Derek's potential retirement next year is unlikely to be an endless round of golf, although "knocking a ball around a course – plus the 19th hole – is a great way to relax," he enthuses. Independently from Getech he has already moved one step closer to the drill bit by becoming a part owner in a fledgling UK oil company, focusing on conventional onshore UK opportunities. He also plans to continue in a consultancy role with Getech, using the extensive worldwide contacts and networks which he has built up over a life-time of working in the industry.

Will he miss his creation, Getech? "Yes, but one has to step back at some time," he says. Asked about the future of the company, Derek indicates the most likely scenario is that it will be taken over by one of the much larger oil contractors now that Getech has surfaced on their radar valued at over £20 million. "But if this does not happen, the future remains extremely bright for Getech, as we are already planning various ways to expand our operations."

Either way, with Derek currently 69 years old, there are clearly no regrets: Derek is heading for new ventures and challenges. ■

Kitson House, near Leeds, headquarters of Getech.

A Fresh Look at the Oil and Gas Potential of Greece

With a working petroleum system in place, proven by the Katakolon discovery and a number of oil shows, seeps and gas leaks, Western Greece is ready to be explored.

ØYSTEIN LIE, JÖRN FÜRSTENAU
Petroleum Geo-Services (PGS)
SPYRIDON BELLAS, GEORGIOS TSIFOUTIDIS
Greek Ministry of Environment, Energy and Climate Change

Greece is preparing for a new offshore licence round. The nearby Italian and Albanian discoveries and fields may be valid analogues since they share much of their geological history with offshore Greece.

Exploration Activity in Greece

Exploration work in Greece began in the late 1930s. In the 1960s, the Greek state and its advisor I.F.P. conducted geologic studies that resulted in the drilling of two exploratory wells targeting the top carbonates and the pre-Triassic evaporite sequence (IGRS-IFP, 1966). In the late 1970s the Prinos oil and gas field was discovered and then in the 1980s more exploration work carried out by the Public Petroleum Corporation of Greece (DEP, DEP-EKY) led to the Katakolon and Epanomi oil and gas discoveries. In 1995 the First Licensing Round was launched with further onshore and offshore exploration work and surveys in four concession areas continuing until 2000. The 2012 'Open Door Invitation' for blocks onshore Ioannina, offshore West Patraikos Gulf and Katakolon in Western Greece attracted several international and domestic operators and partners. Currently, Greece has offshore oil and gas production in the Kavala and Prinos fields in the Northern Aegean Sea.

Geological Overview and Petroleum Systems

Western Greece belongs to the **Hellenides**, part of the Alpine Mediterranean Orogenic Belt (Alpes, Dinarides, Albanides and Hellenides). The External Hellenides consist of north-north-west to south-south-east trending geotectonic zones that are part of the fold and thrust belt system of Western Greece (Marnelis et al., 2007). After vast deposition

Petroleum Geo-Services (PGS) in collaboration with the Greek Ministry of Environment, Energy and Climate Change conducted a 12,500 line km offshore 2D MultiClient GeoStreamer GS™ seismic survey during late 2012 to early 2013, which included the Ionian Sea, West Peloponnese, and south of Crete with total area coverage of 225,000 km^2 (Figure 1). GeoStreamer GS acquisition technology increases data bandwidth and improves illumination of deeper targets. Marine gravity and magnetic data were also acquired and will be integrated into the interpretation work.

At least 6,000 km of key legacy data lines are being reprocessed to complement and enhance the new seismic coverage in shallow/coastal areas and tie with onshore stratigraphy. Seismic data processing of the PGS data continues with the PSTM stacks available by the end of 2013. All of the data, including vintage 2D data, will be conditioned and matched into the Greece MegaProject which will form the basis for the seismic interpretation and data packages for the 2014 bid round.

of Triassic evaporites and platform carbonates, basin development began in the Early Jurassic due to crustal extension affecting the southern Tethyan margin. To the west, play types are controlled by thrust belt tectonics and related foreland basins, while to the south and south-western offshore play types are controlled by the Hellenic accretionary prism, including the forearc and Mediterranean ridge of the Hellenic subduction zone.

The **Ionian** geotectonic zone is the outermost deformed part of the External Hellenides fold and thrust belt. It comprises three stratigraphic sequences documenting the evolution of the Ionian from a neritic carbonate platform environment to a pelagic basin that are attributed to pre-, syn-, and post-rift stages (Karakitsios, 2003). The lowermost sequence consists of a thick Triassic evaporite series, in parts brecciated, overlain by Upper Triassic to Lower Jurassic shallow-water limestones. The syn-rift sequence reflects a general deepening of the area, i.e. the formation of the Ionian Basin, with shales (Posidonia) and limestones being deposited into differentiated basins with half-graben geometries and subject to differential subsidence. The post-rift sequence consists of Lower Cretaceous to Eocene basinal limestones and paleo-margin ward thickening brecciated limestones overlain by a clastic succession of uppermost Eocene to Lower Miocene (Flysch deposits, Bellas et al., 1995; Bellas, 1997), a Mid-Miocene molassic series and younger sediment cover (Figure 2).

The **Katakolon** oil discovery located in Upper Cretaceous to Paleocene/Eocene carbonate reservoirs of the Ionian Zone is sealed by Plio-Quaternary shales (Figure 3). The Albanian Marinez discovery may serve as an analogue here, extending the area of interest from Western Peleponnesus in the south up to the northern tip of Western Greece.

North-west Greece offers folded and well-sealed anticlines. Similarities are seen in the Albanian Delvina gas condensate discovery in Cretaceous-Paleogene carbonate reservoirs, which are trapped in Oligocene Flysch sealed fold-belt anticlinal structures (Figure 4).

The **Apulian** geotectonic zone, including the Apulian Platform and the Paxi (or Pre-Apulian) zone, is the westernmost undeformed part of the External Hellenides and is being overthrust by the Ionian geotectonic zone to the east. The Paxi zone on the eastern margin of the Apulian carbonate platform is composed of three primary packages. The first is alternating strata of Upper Triassic to Middle Jurassic dolomite, limestone and anhydrite deposits overlain by Upper Jurassic to Lower Cretaceous slightly cherty and marly limestones deposited contemporaneously with the Ionian Basin development (Figure 5). The second is Cretaceous through Paleogene to Lowermost Miocene locally brecciated shallow-water carbonates with slope and basinal marlstones, sands and shales. The third package consists of Langhian to Recent molassic sediments which are alternating marl, sand and shale. Main tectonics occurred at the Miocene/Pliocene base. The Apulian Platform and its marginal areas offshore Northwest Greece offers several targets. Further to the north of the platform the Italian Rospo Mare heavy oil discovery is found in karstified limestones of the actual platform and the Italian Aquila oil discovery is structurally trapped in redeposited carbonates off the Apulian platform margin.

The south of **Crete** is a frontier area exhibiting the complete

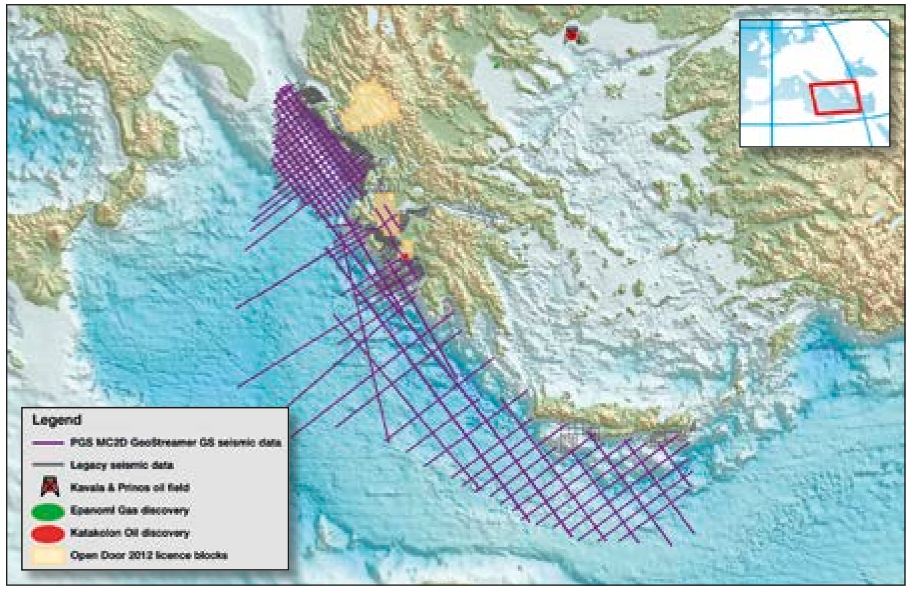


Figure 1: A map of Greece illustrating the 2D GeoStreamer GS™ seismic data (purple), the legacy data (grey), the 'Open Door Invitation' blocks (orange), in addition to oil and gas discoveries and the producing field.

Figure 2: A stratigraphic column of the Western Greece, Ionian zone. (After Bellas et al., 2012)

Geologic time	Geology/Formation	Source	Reservoir	Seal
Plio-Pleistocene	Clays/Sandstones/Conglomerates			X
L. Miocene-E. Pliocene	Marls/Clays/-Sandstones		●	X
E. Miocene	Shales/Sandstones	◆		X
Oligocene	Flysch (Claystones prevail/Silt-Sandstones alternations)			X
L. Cretaceous-Eocene	Breccias Limestone		●	
E. Cretaceous	Pelagic limestones with intercalations of cherts & marls (VIGLA)	◆		
M.-L. Jurassic	Posidonia Shales	◆		
E. Jurassic	Shallow-water carbonates		●	
L. Triassic	Evaporites - Breccias (Andrite & salt with intercalations of Dolomite, limestone & shales	◆	●	X

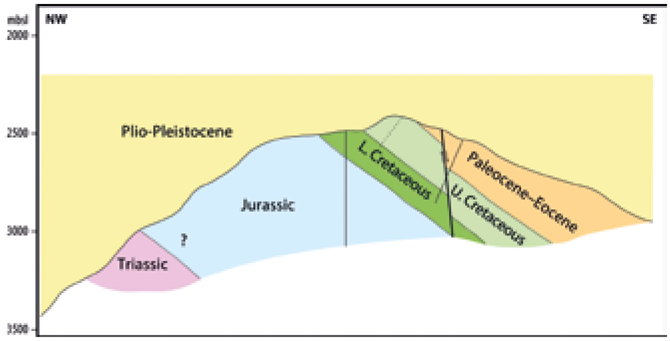
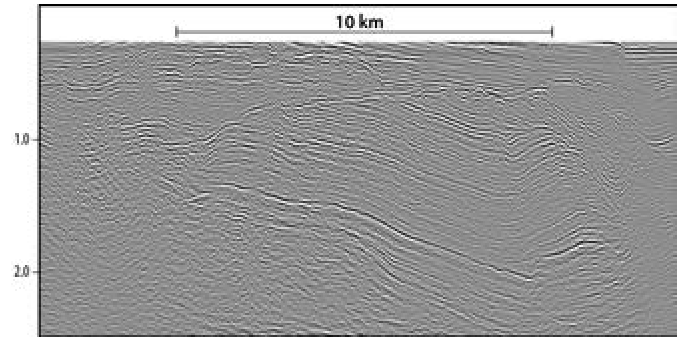


Figure 3: A schematic cross section through the Katakolon discovery. (Modified from Public Petroleum Corporation, 1995)



An analogous example (preliminary reprocessed PSTM seismic stack) from the North Ionian area.

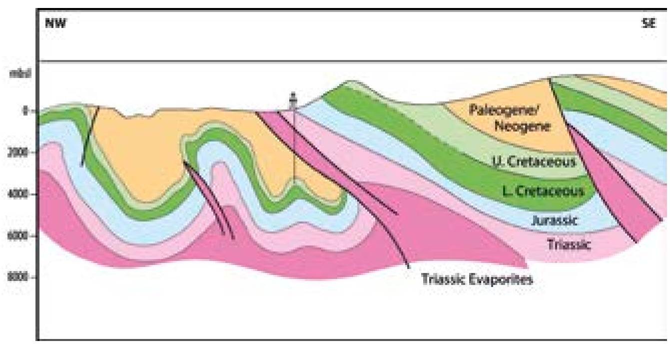
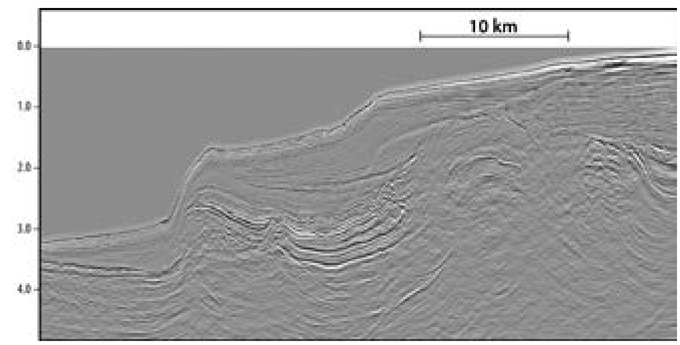


Figure 4: A schematic cross section through the Delvina discovery. (After Prenjasi et al., 2011)



An analogous example (preliminary PSTM seismic stack) from the North Ionian area.

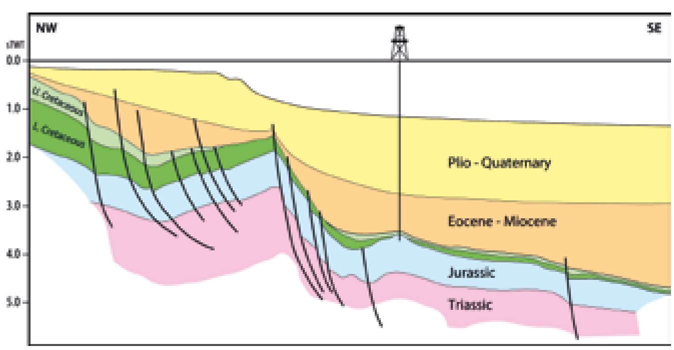
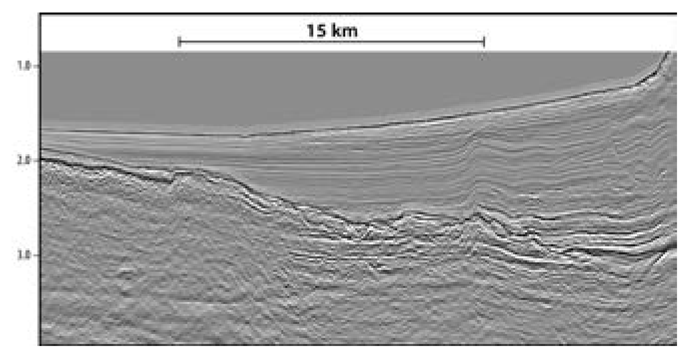


Figure 5: Interpreted cross section through the Aquila discovery. (After Casero, 2004)



An analogous example (preliminary PSTM seismic stack) from the North Ionian area.

lateral succession of an ocean-arc boundary: from the Mediterranean Ridge forming the outer part of the Hellenic accretionary prism with all its wedge-top basins to the forearc basins of the Hellenic trench system and finally the Hellenic fold and thrust belt. Mesozoic to Pliocene to Recent sediments, including Messinian evaporites, are found directly south of Crete. Published descriptions of mud volcanoes as well as gas emissions and their geochemistry indicate active thermogenic systems with potential for hydrocarbon accumulation.

2014 Bid Round

Greece is now preparing for an offshore licence round, expected to be launched in Q3 2014. The country offers political stability and an EU transparent framework for hydrocarbon exploration. Interpretation of the new geophysical data will be the basis for delineation of exploration blocks, which will cover all the areas from Western Greece (Ionian Sea) to the south of Crete. The oil and gas legal framework offers an investment-friendly platform and incorporates current developments and international best practices. The lease duration is 25 years with extension possibilities of five plus five years and a standard tax and royalty-based fiscal regime. ■

Acknowledgments:

The authors would like to thank YPEKA (Greek Ministry of Environment, Energy and Climate Change) and PGS for permission to publish this paper. Thanks to PGS colleagues in Operations, Data Processing & Technology, and MultiClient, who have worked with the Greek data. A thank-you should also be extended to GeoEnergy, which is reprocessing the legacy data.

For more information: www.ypeka.gr/Default.aspx?tabid=765&language=en-US and www.pgs.com/en/Data_Library/North_Africa___Middle_East/

References:

A complete list of references will be available on www.geoexpro.com

Pressure Prediction in Exhumed Basins

Predicting pressure in basins that are exhumed or contain rich source rocks is difficult. We look at a case study from the Barents Sea region

A. EDWARDS, J. HELLER, S. CLANCY, N. WHITFIELD, and S. O'CONNOR, Ikon Science

The dominance of gas over oil in the Norwegian Barents Sea has been one of the major factors in slowing the development of the region. The lack of oil has often been attributed to the exhumation and erosion during Cenozoic times that affected the Norwegian Barents Sea, removing as much as 2,500m of sediment. For example, during exhumation the cap rocks could have fractured over large areas, allowing oil to escape from the reservoir rocks below them. At the same time the decreased pressure from above allows dissolution of gas from the oil, while the expansion of the gas forces the oil out of the reservoirs.

Fracturing of cap rocks (as opposed to membrane leakage) is, at least in part, due to elevated pore pressure. The potential of high pore pressure also becomes a drilling risk, bringing uncertainty into the selection of a mud weight programme and influencing well design. Therefore, a full understanding of the pressure regime becomes a prerequisite for exploration in the Barents Sea, both for planning new drilling and for understanding the effects on trap failure and petroleum migration.

This article presents a series of steps giving an integrated approach to pressure prediction in the East Barents Sea. Multiple techniques and data types are used to predict pore pressure, including seismic amplitudes, provided by Searcher Seismic (to visualise structure and unconformities); Apatite Fission Track data (AFTA) (to understand exhumation history), supplied by GeoTrack, Melbourne; and log data and drilling reports to understand well histories. This is the first stage before seismic interval velocities can be used to predict pressure along 2D lines of seismic velocities that will over time extend into the Russian Barents Sea.

Step 1: Seismic Acquisition

The first stage is to acquire the seismic data to aid visualisation of the chosen area, which is the Finnmark Platform (Figure 1).

Step 2: Understanding the Geological History

Figure 2 shows the seismic amplitudes and the structural positions of two wells, 7125/4-2 (Masøy Fault Complex) and 7128/4-1 (Finnmark Platform). The 7125/4-2 well lies in a more basinal position and is dominated by Jurassic/Triassic sands and shales and contains the main Barents Sea source rock (Hekkingen Formation). The 7128/4-1 well is in a structurally higher position, and penetrated the Permian carbonates, shown in Figure 2 as the strong reflectors, and the Carboniferous including coal horizons beneath. A pronounced unconformity is present in the shallow section. The stratigraphy at the unconformity in each well suggests relative exhumation by

The Barents Sea – a tough environment to work in.

Bernard Cooper

300ms or approximately 400m.

To the east of 7128/4-1, not shown on Figure 2, lies a dry hole, 7128/6-1. Using a combination of AFTA and Vitrinite Reflectance (VR) data, it has been possible to re-construct the burial history of this well (Figure 3), and doing so gives us an understanding of the exhumation on the Finnmark Platform. Exhumation is represented as erosion of 1,200m of section on the unconformity at the top of the Triassic beginning at 35 Ma. This erosion is shown to have occurred in two episodes with 500m eroded 35–30 Ma and 700m eroded between 10 and 5 Ma. This was followed by only minor re-burial of several 100s of meters (200ms TWT on Figure 2). Therefore, from the assessment of exhumation, the 7125/4-2 well has been much less affected, i.e. is closer to its maximum burial depth and has some source rock preserved.

Knowing the geological context of these wells is an important step for pressure prediction. Overpressure distribution is governed by fluid retention and hence an understanding of pressure loss from sequences is critical in understanding how overpressure builds up and dissipates (Yardley et al., 1995). For all realistic permeability and seal thickness, all pressure would dissipate in less than 1 Ma. Deming (1994) concluded that to maintain pressure over geological time requires nano-darcy permeability. These shales are unlikely to have permeability of this magnitude.

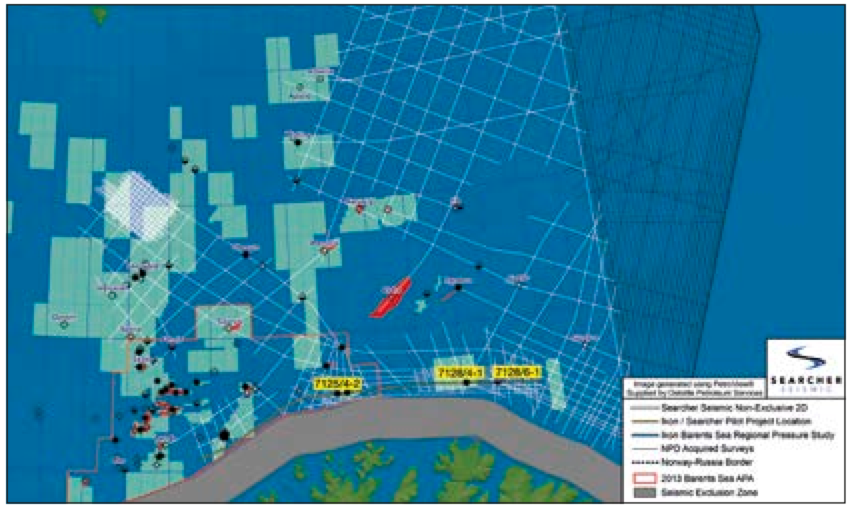


Figure 1: A series of 2D lines extending west–east towards the Norway/Russian boundary. These data have recently been derived by Searcher Seismic, Perth, as part of an acquisition process in the Barents Sea in 2013.

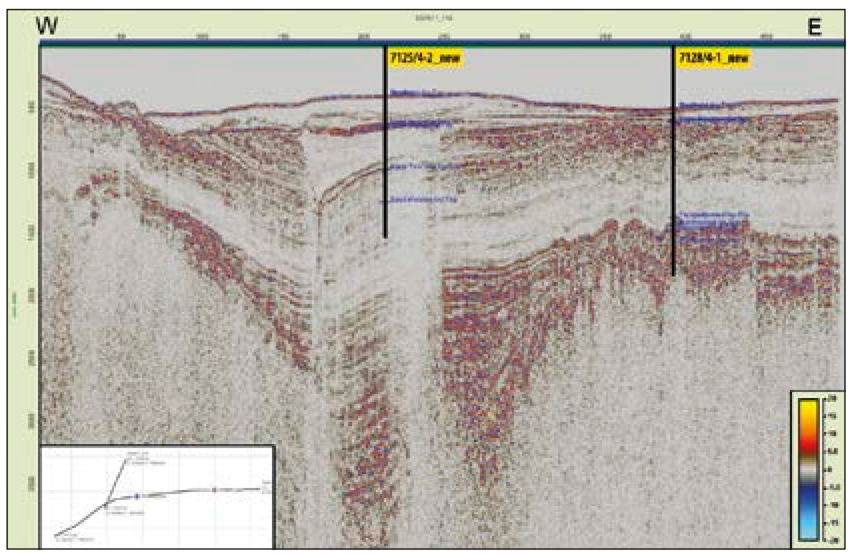


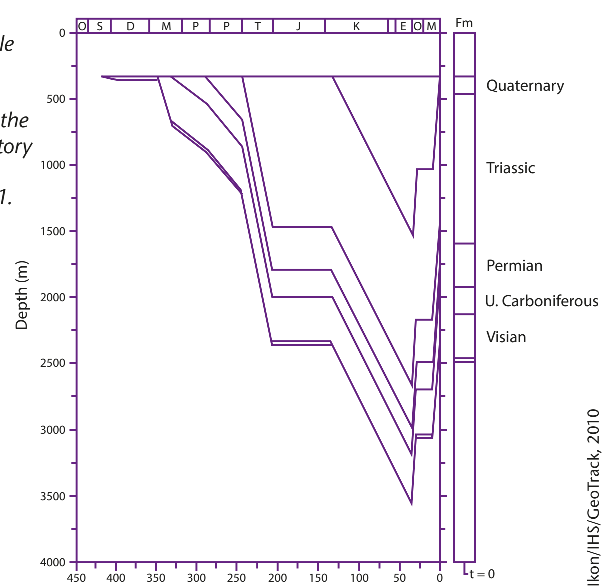
Figure 2: A seismic line running west–east from the recent Searcher Seismic survey of the East Barents Sea. Two key wells, 7125/4-2 and 7128/4-1, are shown.

Step 3: Pressure Prediction

In porous intervals such as the Lower-Middle Jurassic Stø Formation in the Hammerfest Basin, direct pressure tests can be used to measure reservoir pressures. This is not possible in impermeable lithologies such as shales. The challenge therefore is to reconcile pressures that are measurable with those that have to be inferred from rock properties in shales. A set of standard techniques exists for this latter task, which rely on detection of anomalously high porosity for depth of burial, whereby porosity is preserved at depth in shales as pore pressure increases. Data used to detect this porosity include sonic, density and resistivity log data as well as seismic interval velocity. These data are compared to those values expected at a given depth assuming the rocks are normally compacting with hydrostatic pore pressure, which is much more complicated if the rocks are not at their maximum burial depth. This is the case in exhumed basins such as the Barents Sea, where up to four phases of exhumation are possible, depending on the area (Green et al., 2004; Green and Duddy, 2010).

The key factor to successful prediction of shale pressure is to understand what processes are causing the

Figure 3: Possible burial history reconstructions consistent with the thermal history reconstruction in well 7128/6-1.



Ikon/IHS/GeoTrack, 2010

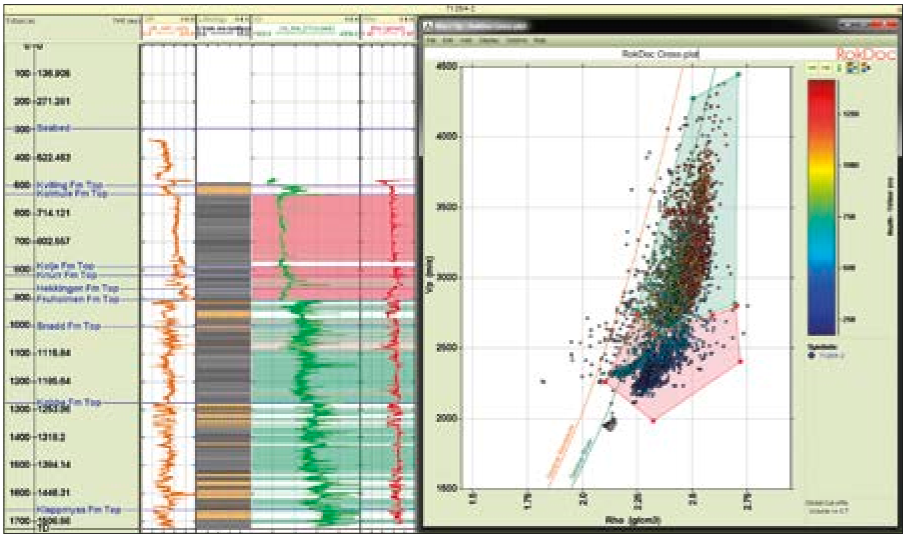


Figure 4: Vp/Rho cross-plot from well 7125/4-2. Only shale data is plotted as defined by a Vshale cut-off (green line is Gardner Shale). Two shale populations are suggested. Overall, the data is parallel to the Gardner, suggesting disequilibrium compaction or normal compaction is present. Red shale data plots at higher density for a given velocity. This could be lithological or imply diagenetic changes in the shale, reducing porosity.

pressure in the first place as this dictates which algorithm to use. One technique to identify these processes is to cross-plot log Vp and Rho data. What if the shales were affected by fluid expansion caused by gas? Gas generation and its expansion during exhumation could have occurred and this can significantly increase pore pressure. The main source rock in the Barents Sea is the Hekkingen Formation; however, the earlier analysis shows that on the Finnmark Platform this formation is largely eroded. Gas in well 7128/4-1 must have therefore migrated in. On the Finnmark Platform, Triassic source intervals are too shallow to generate hydrocarbons (Ohm et al., 2008), and the Permian Ørret Formation is only oil mature in a zone fringing the Loppa High and along the rim of the Finnmark Platform. Therefore gas is only likely to have affected pressures in 7125/4-2.

In this well, evidence from the Total Gas Analysis (%) shows increased levels through the source rock interval as well as in the Triassic shales, suggesting that there is gas in the system. Cross-plotting Vp/Rho shale data suggests there could be two populations of shale. Logs have a distinct break at this depth, perhaps related to a discontinuity. An overall trend parallel to the Gardner shale for the Jurassic and Triassic shale is suggested with no evidence for fluid expansion. There is a deviation off the trend in the deep Triassic shales (to higher density for a given velocity) and this is associated with density of 2.5 g/cc, i.e. low porosity. This deviation may reflect some chemical change in the shales, reducing porosity. This process can result in additional overpressure in other basins but the effect here is minor as the reduction in velocity is small. The overall interpretation is that the process of overpressure generation is disequilibrium compaction despite the low porosities in deep shales. This approach of using cross-plots is summarised in Swarbrick (2012).

Figures 5 and 6 show that in the shale intervals, the Vp and Rho logs are steadily increasing in magnitude with increasing depth. This is also true of the check-shots in 7125/4-2. This suggests that the shales are either normally compacting or have only small magnitudes of overpressure. In the first main shale package in 7125/4-2, Vp and Rho show sharp cut-backs, particularly at 800 to 900m TVDss. This interval corresponds to the Hekkingen Formation which is the source rock. These low log values can be interpreted to be elevated pore pressure, whereas, in fact, they represent a lithology effect. Interestingly, the deep resistivity tool seems to show a general reduction through this package, which could be interpreted as some pressure. Another lithology effect can be seen in 7128/4-1 in Figure 6. The Carboniferous interval has inferred high pore pressure. This is due to the 'soft' coals present.

Assuming disequilibrium compaction is considered primary, a velocity/effective stress relationship can be derived, and pore pressure can be calculated by solving for the Terzhagi (1934) equation. These interpretations for pressure in the shales are shown as the green profiles on the Pressure-Depth plots in Figures 5 and 6. Check-shots in 7125/4-2 are also used to produce a profile for pressure (blue profile). A single velocity/effective stress trend is used and based on a normal compaction relationship shown on these figures as the black line. This approach highlights the difficulty of predicting pressure where source rocks are present, as the Hekkingen Formation interval is inferred to have some overpressure. A single trend line for compaction therefore may not be sufficient where source rocks are present; that is, a second relationship is potentially required as the pressures in this interval may not be 'real' but rather caused by organic content in the shales making them slower (Passey, 1990). A possible solution is to use Vs data which will not have the gas effect. However, as a first-approximation this single model matches well history (and our geological prediction that the unconformity would let all previous pressure bleed off). Pore pressure has to be less than mud weight, as there are no well control problems such as kicks when thin sand units are present in the shale packages.

Looking Forward

The approach featured in this article highlights just how difficult predicting pressure is in basins that are both exhumed and/or contain rich source rocks such as those in the Barents Sea region. Unconformities allow time for pressure to return to hydrostatic. These discontinuities may also require multiple compaction models and velocity/effective stress relationships in order to successfully predict pressure. Velocity logs, and therefore by implication seismic interval velocities, can be affected by gas causing compressional wave slowing. Source rocks that are rich in Total Organic Content (TOC) can result in slow, less dense shales that appear 'overpressured' when they may not actually be so. The solution though, despite all these uncertainties and complexities, is to

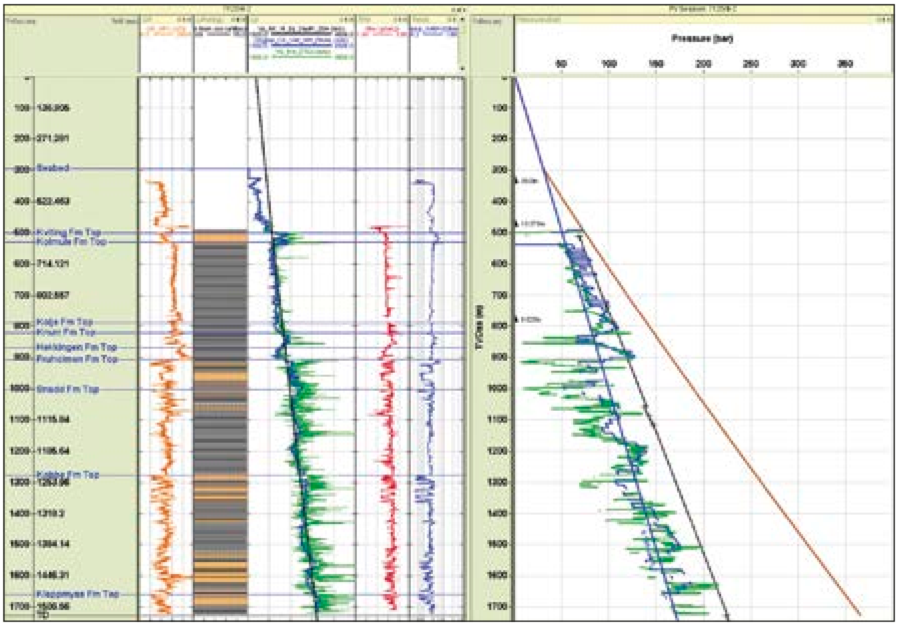


Figure 5: Well data 7125/4-2. Blue line = hydrostatic gradient: Red line = overburden. Black line represents the normal compaction curve. Vp, density and resistivity logs are displayed as well as pressure interpretation (Vp green, check-shots blue). The first shale package is the source rock Hekkingen Formation.

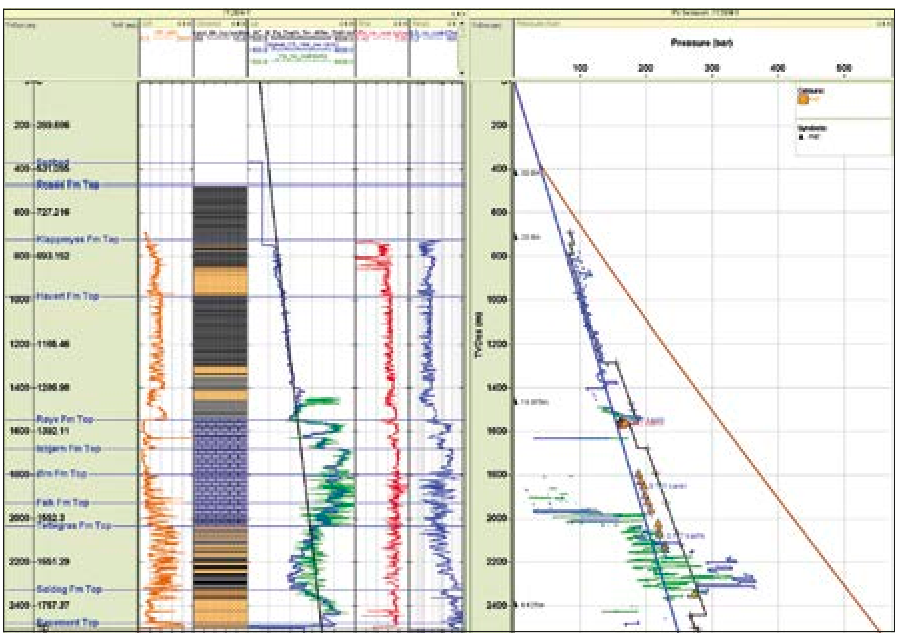


Figure 6: Well data 7128/4-1. Yellow triangles represent direct pressure tests in porous units. Fluids are interpreted. The source rock is absent here due to more significant exhumation. Note the very fast carbonate lithology – this is another added complication for pressure prediction in East Barents as carbonates do not have a porosity/effective stress relationship so cannot be modelled in the same way as shale using remote data such as seismic velocity. Note lithology effect of the Carboniferous coals giving inferred pore pressure.

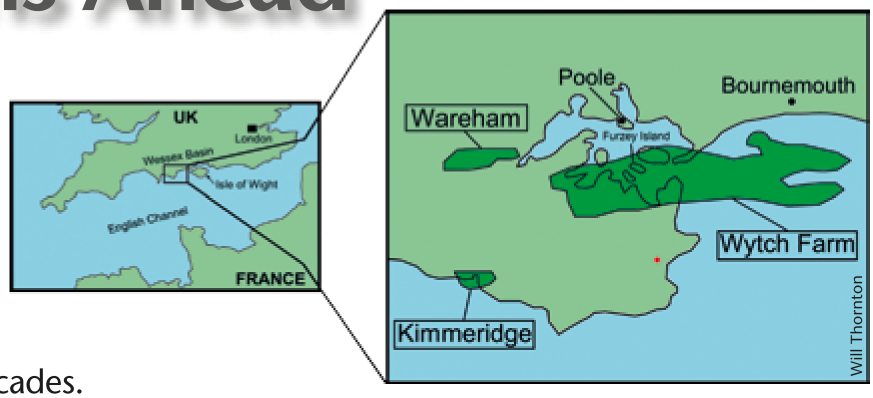
constrain pressure prediction by use of a geological model in exhumed basins.

Looking forward, the next stage is to use the processed seismic velocity data to interpret pressure below current well depths in this part of the East Barents Sea. When the shooting season re-opens, we hope to use some of these observations farther to the east into the Russian Barents Sea to produce pressure interpretation that will de-risk drilling in this new frontier area. For instance, as the Hekkingen Formation source rock becomes more deeply buried to the east, and consequently has higher maturities, fluid expansion may become a problem for pressure prediction and this will need to be factored in. ■

Wytch Farm Ploughs Ahead

WILL THORNTON

Celebrated as the largest onshore oilfield in Western Europe (~500 MMbo), the Wytch Farm field in Dorset, southern England, is an iconic field to the thousands of geoscientists and petroleum engineers who have worked and studied there over the last four decades. It is now heading for a productive old age.



Map showing location of Wessex Basin and Wytch Farm Oilfield (red dot shows location of photo on page 55).

Discovered in 1973, the Wytch Farm development has a long history of safe and successful production and has been the site of many landmark technical firsts and records for the industry. The facility, operated by Perenco since 2011, was previously under the stewardship of BP. Oil and natural gas (methane) are both exported by pipeline, while liquified petroleum gas is exported by road tanker.

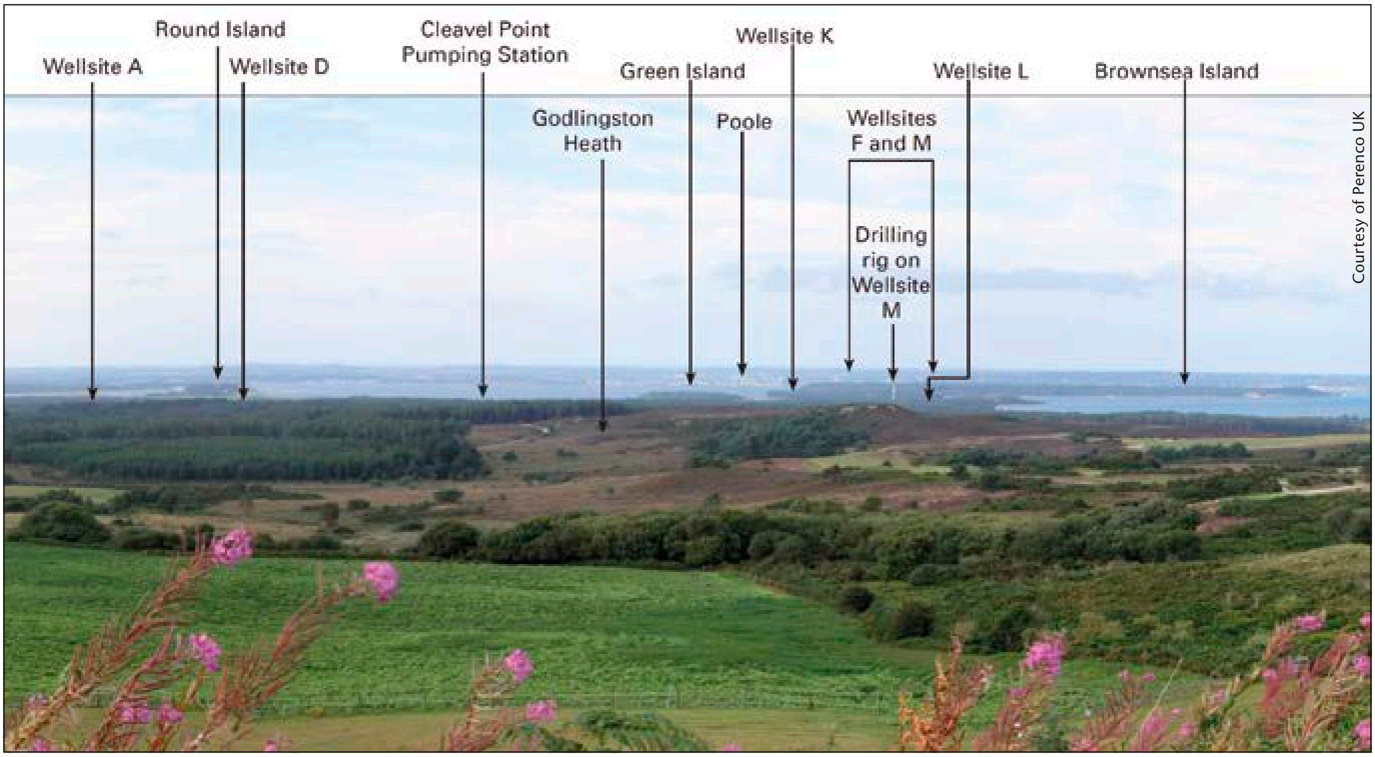
Sowing Seeds of Success

The discovery of commercial oil in the Wessex Basin was important not only for the opening of a new basin but because at the time of discovery the UK government was keener than ever to reduce dependency on overseas oil producers. Late in 1973, the doubling of crude oil prices by OPEC and a shortage of coal, caused by industrial action, resulted in the introduction of the 'Three-Day Week' electricity consumption reduction measure.

It was against this backdrop that the Gas Council (GC) – the E&P part of British Gas – was drilling exploration wells in the Wessex Basin. Natural oil seeps, earlier drilling and the Kimmeridge discovery in 1959 had provided evidence that the basin had a working petroleum system and that hydrocarbons may be trapped in seismically mapped faults, but the belief that the area was unlikely to be sourced by marine kerogens had slowed down exploration efforts.

However, following the identification of marine kerogens in a well on the Isle of Wight, the Wareham-1 well was drilled to test (Jurassic) Inferior Oolite and Bridport Sand targets. Initial interpretations of the well suggested that no significant reservoir sands were present. Geologist Vic Colter at the GC disagreed and argued that the log responses resulted from thick permeable intervals punctuated with hardbands, similar to those seen in the nearby Bridport Cliffs. It was this interpretation that

Aerial photograph of Furzey Island in Poole Harbour showing operations within planted areas.



View looking north from Godlingston showing panorama with oilfield sites hidden in the landscape. Wytch Farm is set in an environmentally sensitive area, and surface operations have been hidden in coniferous forests on Wytch Heath on the southern shore of Poole Harbour and at satellite fields in Wareham and Kimmeridge Bay. Since the photo was taken, the large visible rig has been replaced with a smaller more mobile rig. In 1995, the field won The Queen's Award for Environmental Achievement and it is interesting to note that in a time of increased public awareness of industry operations in the UK, the field remains largely unnoticed by the general public, just as the planners had hoped.

led the GC to drill the discovery well at Wytch Farm.

Good Husbandry Produces Bountiful Fruits

The first phase of development targeted the Bridport Sands and, to a lesser extent, the Inferior Oolite. Production was based on four well sites and ~6,000 bopd were extracted during the 1970s and early 1980s. The Bridport reservoir is a lower Jurassic structure at a depth of ~900m and is being depleted with conventional wells drilled from onshore drill sites. The Inferior Oolite contains small amounts of oil but in general acts with the Fuller's Earth to seal the reservoir.

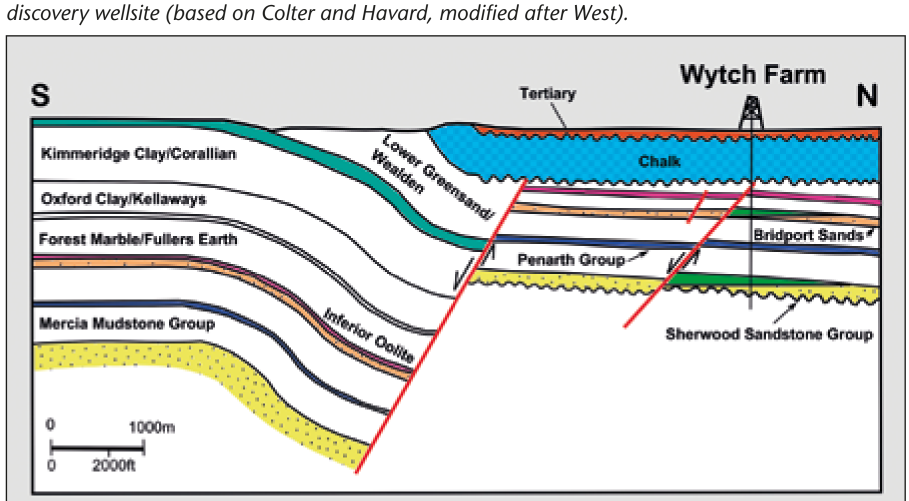
BP took over as operator in 1984 and, after upgrading the existing wellsites and constructing five new sites, saw extraction from the Bridport and recently discovered Sherwood reservoirs rise to approximately 60,000 bopd. It quickly became apparent that the main resources were trapped in the deeper Triassic Sherwood Sandstone formation, increasing the reserve base from around 30 MMbo to 378 MMbo, and a new phase of development began.

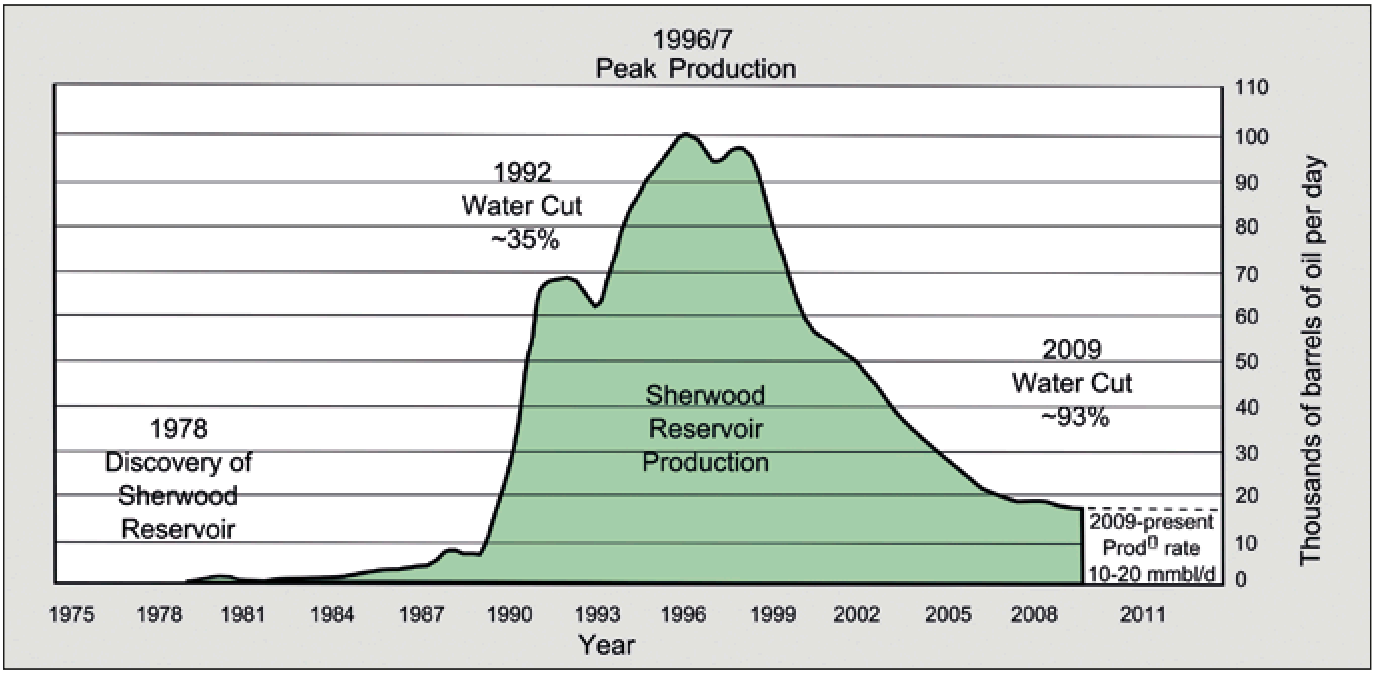
The Sherwood formation consists of a variable sequence of floodplain deposits, including lacustrine, sheetflood, channel-fill and aeolian facies, at a depth of 1,600m, and lies under Poole Harbour and out into the nearshore area. The reservoir is sealed by the Mercia mudstone. The next phase of development involved extended reach drilling from the mainland under Poole Bay, which required the construction of a wellsite on the Goathorn Peninsula. The investment increased the reserves base once more, this time to 500 MMbo.

Output peaked in 1997 at ~110,000 bopd and since then oil production has gradually declined. Production continues at levels of around 19,000 bopd and substantial oil reserves in the region of 43 MMbo are believed to remain.

As of June 2012, a total of 102 wells had been drilled at the combined oilfields

Simplified north–south cross section showing the main stratigraphic and structural elements at the discovery wellsite (based on Colter and Havard, modified after West).





Production curve showing Sherwood reservoir produced volumes. The field has combined reserves of 500 MMbo. It is believed that 43 MMbo reserves remain (based on Erwin Wahidiyat, modified after West).

from 13 wellsites. These comprise a combination of oil-producing and injection wells.

Winds of Change Bring New Seeds of Life

In 2011 BP agreed to sell its majority interest in Wytch Farm to Perenco (50.09%) for up to a reported £375m ($610m). Perenco, which became the new operator, describes itself as having 'particular expertise in the operation of oilfields that are approaching the end of their productive life'. Shortly after the divestiture of Wytch Farm by BP, Premier Oil opted to extend their equity to a 30.1% stake in the field. Other partners are Maersk Oil North Sea UK Ltd. 7.43%, Summit Petroleum Dorset Ltd. 7.43%, and Talisman Sinopec North Sea Ltd. 4.95%. BP further announced the sale of its interests in the Wareham and Kimmeridge fields – also to Perenco.

Citing the improvements in reservoir management that have taken place since the initial reserves forecasts, Perenco anticipate that it will be economic to operate the oilfields for 20 years more than was originally supposed. In September 2012, Perenco UK applied to Dorset County Council (DCC) for permission to extend the life of 39 planning permissions for the three oilfields. DCC's Planning Committee recommended approval of the applications on 6 September 2013, thereby extending the operational life of the oilfields beyond their original end-date of 2016 to 2037.

The plan for future development of the oilfields includes an operational phase, followed by decommissioning and restoration. The operational phase will include a period up to 2019 where the focus will be to increase or sustain oil production levels and will involve drilling new wells and the work-over of existing wells and facilities.

Following this initial phase of activity, from 2020 to 2037, efforts will continue to sustain production but with less emphasis on drilling projects and there will be significant work on the maintenance and integrity of the existing oilfield infrastructure, as Perenco and partners strive to maximise the recovery factor of the field.

Bumper Harvest for All

Since the Wytch Farm discovery there have been several other, albeit smaller, discoveries within the Wessex Basin (e.g. Humbly Grove, Stockbridge, and Albury) and a number of exploration companies continue to successfully explore the basin for further resources.

One such company is Egdon Resources (named after author Thomas Hardy's 'Egdon Heath'), based in Odiham, Hampshire. The company, which has been exploring the area since 1998, currently holds two licences in Dorset (PL090 and PEDL237) and has a full plan of operations for the coming months. Managing Director Mark Abbott explains, "We have just completed a 70 km^2 3D seismic programme to the south and east of Dorchester, mainly to evaluate the potential of some large Sherwood Sandstone prospects. We have also just commenced production operations from the Waddock Cross oilfield in PL090, which is a Bridport Sandstone field. Although we don't expect to find another Wytch Farm, our prospects range up to 30 MMbo and represent excellent drilling opportunities."

A recurring theme at Wytch Farm is that of change. A new injection of capital, the use of emerging technologies and a renewed vigour mean that Wytch Farm and the Wessex Basin will harvest the rewards for a few more seasons yet.

> "So do flux and reflux – the rhythm of change – alternate and persist in everything under the sky."
>
> *Thomas Hardy, Tess of the d'Urbervilles*

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THE UNITED REPUBLIC OF TANZANIA

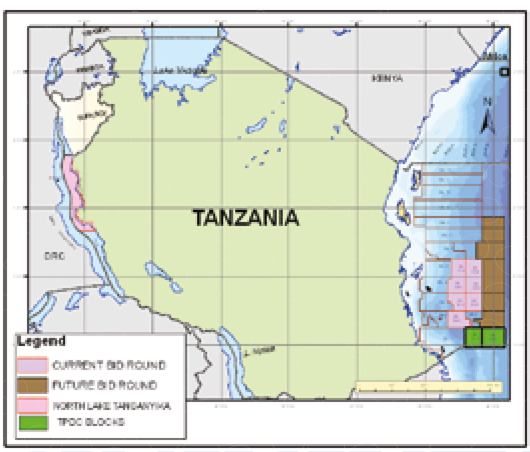
Announcing the 4th Tanzania 2013 Licensing Round

Deep Offshore | North Lake Tanganyika

The Government of the United Republic of Tanzania through Tanzania Petroleum Development Corporation (TPDC) is pleased to announce the 4th Tanzania Deep Offshore and North Lake Tanganyika Licensing Round. The delayed 2012 round will now be launched during the 2nd Tanzania Oil and Gas Conference and Exhibition.

When:	**Friday, 25 October 2013**
Where:	**Mwalimu Nyerere International Conference Centre Dar es Salaam, Tanzania**
Round Close:	**Thursday, 15 May 2014, Dar es Salaam**

4TH TANZANIA OFFSHORE AND NORTH LAKE TANGANYIKA LICENSING ROUND



The round includes the deep offshore sedimentary basins comprising of seven blocks (averaging 3000 sq km: Blk4/2A, Blk4/3A, Blk4/3B, Blk4/4A, Blk4/4B, Blk4/5A, Blk4/5B) and is located between 2000 m to 3000 m of water depths from 40°30'E to 41°40'E and 7°30'S to 9°00'S. Blocks 4/1B and 4/1C are reserved for the TPDC to execute exploration using a strategic partner. The blocks have excellent coverage of modern regional 2D seismic data available from ION Geophysical and WesternGeco.

The North Lake Tanganyika block is located offshore in the western arm of the east African rift system. Lake Tanganyika is the world's longest (650 km) and second-deepest (1500 m) and is covered by sparse 2D seismic data collected in the 1980s during the African Lakes Drilling Project. The data and copy of report will be made available.

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Tanzania Petroleum Development Corporation

Contact: Mr. Yona Killagane
Email: killagane@tpdc-tz.com

ION Geophysical, Inc.

Contact: Nick Blake
Phone: +44 7734 415105
Email: nick.blake@iongeo.com

WesternGeco

Phone: +44 01293 556000
Website: westerngeco.com

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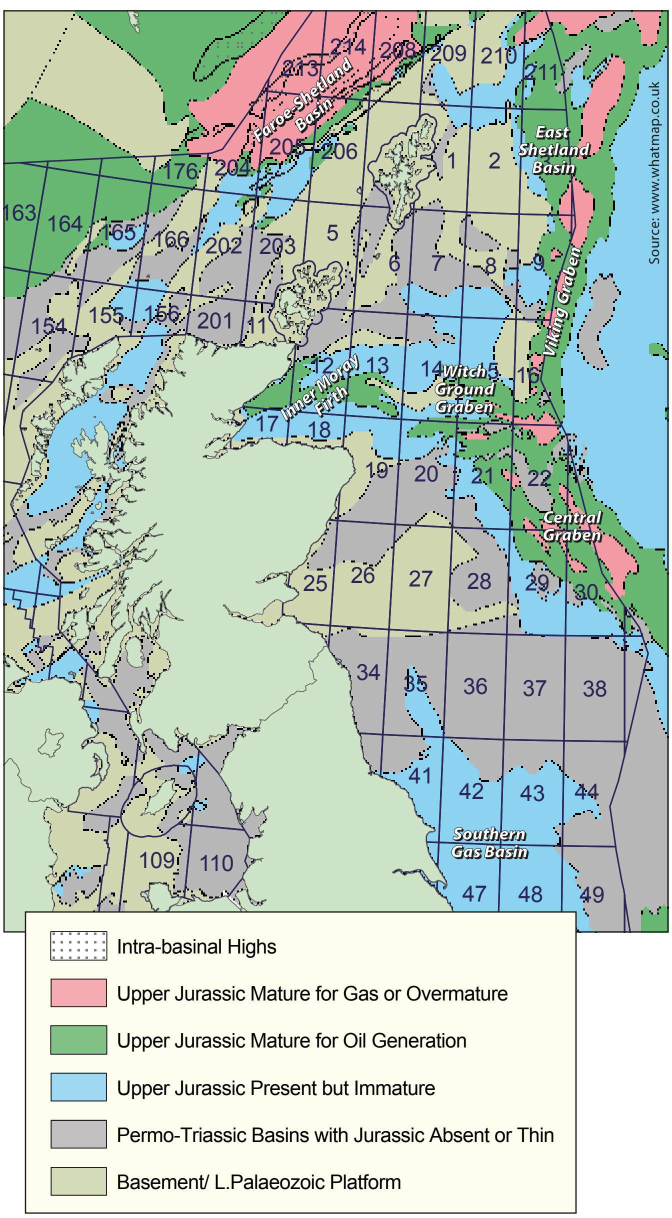
Exploration Trends on the UKCS

ALAN DRISCOLE,
Beagle Geoscience

With most of the 'easy' oil discovered, where are companies looking to find oil and gas reserves in the mature UK continental shelf?

Forty-eight years (and over 3,000 exploration wells) on from the first commercial discovery at West Sole, much of the United Kingdom continental shelf has long been considered a mature exploration province. Obviously, throughout this time the fortunes of the province have fluctuated along with the prevailing economic conditions and strategic considerations. These issues, along with a steady flow of technological advances, have driven exploration from the early large oil and gas discoveries to progressively more challenging prospects and hard to win reserves. In the current climate, with sustained high oil prices balanced by high capital costs, and not least by rig rates, a sharp focus has been kept by the industry on the technical risks of the UKCS prospect portfolio, with recent trends in exploration thinking reflecting the fine balance between prospect size, technical risks (of all aspects) and exploration costs.



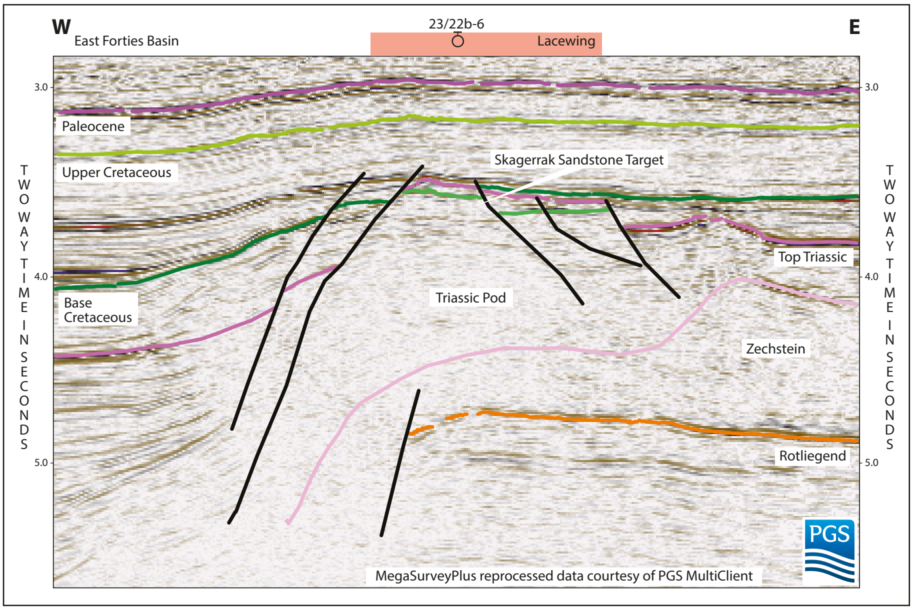
New Challenges

Despite an overall drop in exploration and appraisal drilling over the last few years – from 85 completions in 2009 to 45 in 2013 (to the end of October) exploration has held up surprisingly well, with 33 wells completed or currently operating this year, compared to between 25 and 37 completed each year from 2009 to 2012. With, by some measures, over 120 exploration and 50 appraisal wells planned or committed over the next three years, the nation's prospect portfolio looks healthy.

It goes without saying that within a mature exploration area all of the 'easy' oil and gas has been proven. The 'difficult' plays that remain provide a number of challenges. For those with large reserve potentials the challenges are generally technical and commercial. One of the most active areas with the potential to add significant reserves is the Central Graben HPHT/uHPHT province, with recent drilling including the Thunderer (30/2a-10) and Oakwood (30/1d-12Z) tight holes and the Lacewing gas/condensate discovery (23/22b-6Z). A considerable resource base is building in this province, with several large structures yet to be drilled to targets in Fulmar, Pentland and Skagerrak sandstones at depths in excess of 14,000 ft, with HPHT drilling in the Fisher Bank Basin (22/4b-6; White Bear) and planned in the Viking Graben demonstrating the willingness of operators to apply their experience to under-drilled deep basins. Up to fifteen exploration wells could be drilled on the HPHT play within the next few years.

Heavy oil provides a quite different set of challenges, particularly in sustaining commercial flow rates of viscous oil from an unconsolidated sandstone. EnQuest continued appraisal of Kraken in 2013 and plan to drill a large Heimdal pinch-out (Wayland's Smithy) next year. With several large heavy oil plays under development along the west flank of the Viking Graben, focus is shifting back to the Moray Firth in the search for large reserves, with wells planned on the shallow Norfolk pinch-out trap in block 12/16b and Bagpuss on the Halibut Horst in block 13/24a. Both wells have Lower Cretaceous objectives.

The risk of heavy oil partially explains the delay in drilling the Catcher prospect – a discovery that has acted as a play opener arguably along the entire western margin of the Central Graben from Quadrant 28 to 39. By demonstrating the viability of long distance lateral migration within Tertiary carrier beds and the potential for light, unbiodegraded oils at shallow depths, Catcher not only derisked several Cromarty and Tay amplitude plays on block 28/9 (most recently with 28/9a-6 proving oil in the Bonneville prospect) but opened up the adjacent margin, with five firm and two contingent wells bid in the 27th Round. These



The 2013 Lacewing gas/condensate discovery lies in the high pressure/high temperature (HPHT) zone of the Central Graben province, an area of increasing interest to operators.

wells will target not only Tertiary amplitude plays but deeper Fulmar Sandstones in small sub-basins away from the graben margin where migration and charge provide the challenge.

Further south along this margin, the Andromeda prospect is scheduled for drilling next year. This will be drilled updip of a 1973 Shell well which encountered oil pay in a Zechstein dolomite, with objectives also in the underlying Lower Permian Auk Sandstone. This is the principle reservoir in the Auk Field to the east. The Auk was also a deep objective for the recent Taggart/Rebus 22/23c-8 tight hole, showing a renewed interest in deeper, older reservoirs along the basin margins, where regional 3D coverage may aid derisking of oil charge.

3D Data Major Driver

The availability of regional 3D data sets covering almost all mature areas of the North Sea has been a major driver for exploration within the last few years. However, the inventory of Lower Tertiary channel/fan plays with amplitude support is being progressively drilled up, with some recent wells, such as 21/7b-4 (Cyclone) failing to prove hydrocarbons. Throughout the Outer Moray Firth and Central Graben more focus is being placed on the Upper Jurassic and Lower Cretaceous in subtle structural and stratigraphic plays. The Fulmar, for example, has a complex reservoir distribution, with strong structural controls and local erosion, not to mention the highly diachronous nature of the sands, making this a difficult play. However, recent success along both margins of the Forties-Montrose High have encouraged drilling, including Taggart and Seagull North (22/24e-12) this year and with several more wells slated within the near future.

The search for new plays has literally reached rock bottom in some areas, with 3D seismic used to identify permeable fracture zones cutting large basement closures. The Lancaster discovery has proven this concept, with 205/21a-4Z (2010) flowing light oil from two seismically defined fracture zones. Hurricane plan two further wells on this play, whilst EnQuest are drilling an appraisal well on Cairngorm (block 16/3d) to test an analogous basement fracture system.

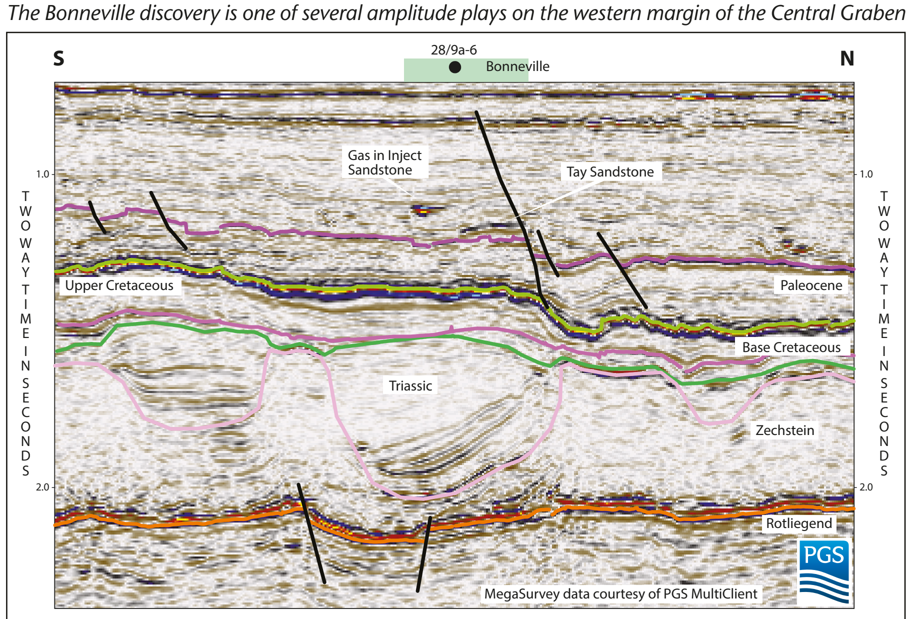
Finally, the focus west of Shetlands remains on large plays in deep water, with recent wells on Paleocene amplitude-supported stratigraphic traps and dip closures (Glenrothes and Cragganmore; 208/11-1 and 208/17-3), and Cretaceous and pre-Cretaceous fault structures, with Triassic gas/condensate proven in the North Uist structure (213/25c-1V).

The future of exploration in the UK sector lies in a continued push to HPHT prospects in the deep basins and into deepwater areas west of Shetland, with higher risk plays in mature areas requiring significant lateral migration along basin margins or with uncertainties over reservoir quality or trap integrity within basins.

Acknowledgments

*This review is based on detailed well reviews from the bi-annual **United Kingdom Discovery Digest**, prepared by Beagle Geoscience on behalf of Exploration Geosciences (UK) and Canadian Discovery. The map is from EG (UK)'s **WHAT Map**, and seismic examples, from the latest volume of the Digest, are reproduced here by the kind permission of PGS.* ■

The Bonneville discovery is one of several amplitude plays on the western margin of the Central Graben

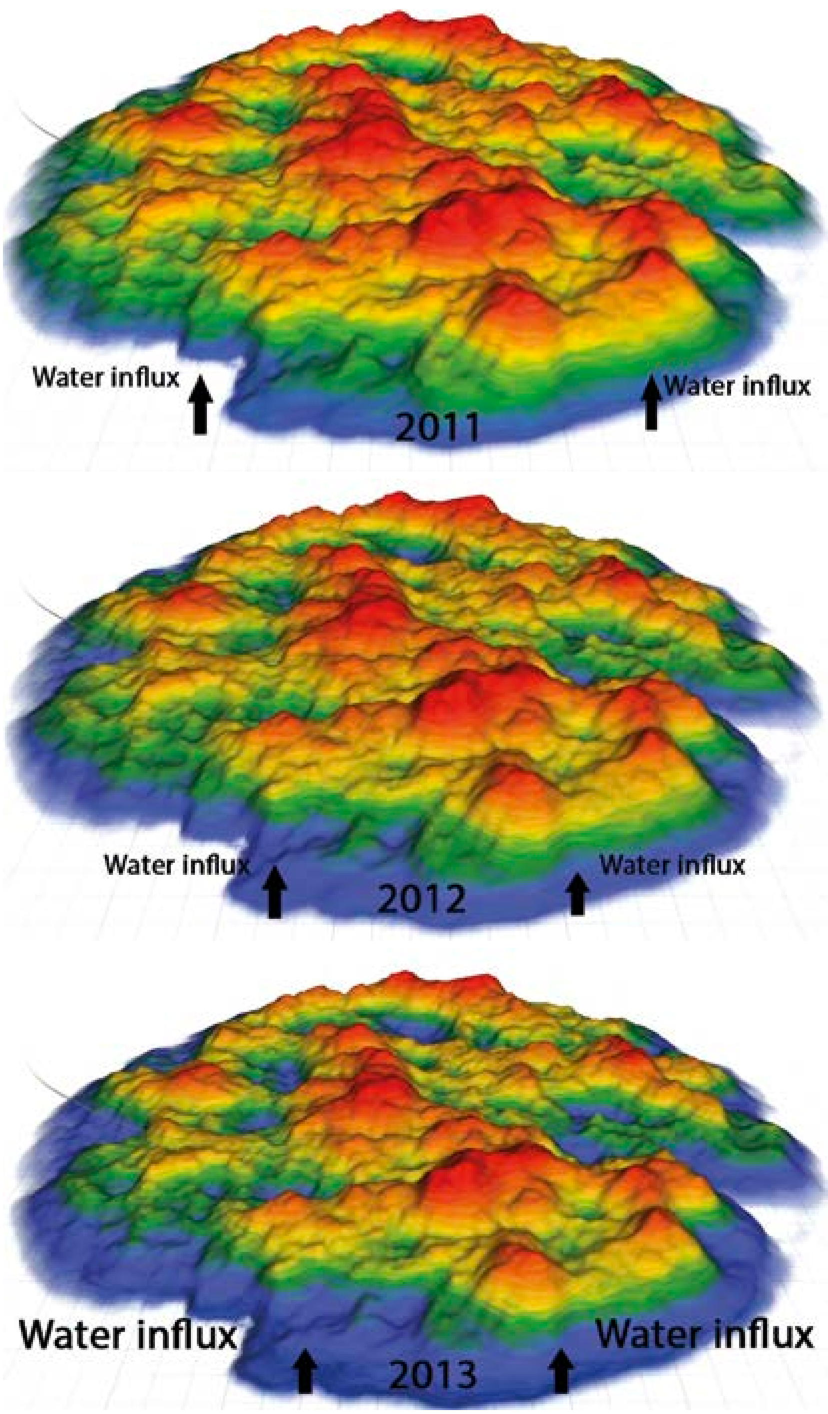


Using Gravity to Enhance Recovery

BJARTE FAGERAAS, MARTHA LIEN and REMY AGERSBORG, Gravitude AS

4D gravity data is a very useful additional and independent source of information for monitoring reservoirs

Conceptual picture of water influx in reservoir during gas takeout. Water replacing gas in the reservoir will lead to large density changes in the reservoir, which can be detected by time-lapse measurements of gravity at the seafloor.



Geophysical data available for reservoir characterisation and for the monitoring of offshore reservoirs is mainly represented by seismic and electromagnetic data. Gravity data is currently emerging as an additional and independent source of information after proving its value through numerous gas monitoring projects offshore. The increasing success of gravimetric surveys as an integrated part of reservoir monitoring programmes can be explained by new technological developments, enhanced software for data processing and experience from years of field case studies. With the superior acquisition design and data quality, important information related to reservoir performance such as the volume of available reserves, fluid flow, identification of depleted parts of the reservoir and seafloor subsidence can be found with greater confidence. This will lead to enhanced recovery of the reservoirs.

Gravity and Pressure Data

During a gravimetric survey, gravity and pressure data are measured at selected locations on the seafloor above the target of interest. Gravity data yield information about the density distribution in the subsurface and can be utilised to delineate subsurface structures and fluid distributions. By performing time-lapse gravity surveys, the changes in the density of the subsurface are monitored. The information revealed is seen to be highly valuable for identification of production-related changes in the reservoir such as water influx, fluid flow, pressure buildup and reservoir compaction.

Gas takeout will in general lead to pressure reduction. This effect may be counteracted by water influx from surrounding aquifers. Hence, uncertainties on the aquifer strength and potential influx mechanisms can be reduced by interpretation of gravity changes at different locations of the reservoir. Moreover, if evidence of pressure depletion is found in one region of the reservoir whereas other regions are not affected, this may indicate compartmentalisation or barriers to flow and provide information on fault block transmissivity.

The acquired pressure data provides accurate measures of seafloor subsidence and in several studies changes in seafloor elevation with subcentimetre accuracy have been obtained. The pressure data is also important for improving the accuracy of the gravity data by reducing noise introduced by density variations in the water column and providing valuable corrections to modelled astronomical tide effects.

Acquiring the Data

The layout design for the acquisition of gravity and pressure data is done by a pre-survey feasibility study where the focus is to ensure best possible illumination of the target area. Typically, this is performed in collaboration with the asset team of the field by optimising the gravity model towards the reservoir model. As a result of this study, it is possible to estimate the distance between and the number of seafloor locations, or stations, which will be needed for obtaining data within predefined uncertainties.

The acquisition itself is done by deploying a package of sensors at the different seafloor stations where the interval and frequency of the station visits will be determined by the main objectives of the survey. During data acquisition, the sensors are connected to the survey vessel through cables attached to a remotely-operated underwater vehicle (ROV) for continuous data recording. Compared to other geophysical services, the cost associated with operation and equipment is low.

A key factor for reducing uncertainties and to ensure acceptable 4D results is to have as accurate information about the location of stations and sensor tilt as possible. For the repeatability of measurements, efforts are taken to make the seafloor stations stable over time and state-of-the-art gauges for measuring tilt and automatic leveling of the sensor package are developed. We have already seen an exceptional improvement in data accuracy both due to improved data acquisition and processing. Today it is possible to obtain a level of accuracy in the gravity and pressure data which can enable the identification of as little as a one metre rise in the water gas contact under right conditions.

In addition to the spatial coverage of the data, the strength of the attainable gravity signal depends on factors such as the volumetric extent of the target, the density contrasts within the reservoir, and reservoir depth. For flow monitoring, a large density contrast between fluids will increase both the lateral and vertical resolution. Hence, this methodology is especially suited for monitoring gas reservoirs and also for CO_2 sequestration projects.

New Yet Mature Technology

Gravimetric data for offshore reservoir monitoring has proven valuable through years of research and field applications on the Norwegian continental shelf. The procedures for data acquisition and data processing were developed mainly by Statoil ASA and Scripps Institute of Oceanography at the University of San Diego. Until now, the technological development has been driven mainly for research purposes, but the technology has now reached a stage where it is mature and ready to be commercialised worldwide.

As a result, Gravitude AS was launched In 2012 by Statoil ASA as an independent technology company to bring this expertise forward and commercialise the services. Today Gravitude AS offers gravimetric surveys on the same basis as other geophysical services. The company aims at further developing this technology by offering a complete acquisition package including survey management, data acquisition and processing. The services can include detailed gravity/density modelling towards dynamic reservoir simulation models.

Affordable Data

Why is gravity data interesting and emerging as a preferred technology on several of the world's larger gas fields?

Deploying concrete stations from a survey vessel

Launch of ROV with gravimetric sensor package

Gravity data is well proven and works well on a standalone basis. Due to the low cost of gravimetric acquisition and processing, gravity data can be acquired more frequently than seismic data. The latter provides information about the elastic properties of the reservoir, and a prerequisite for accurate interpretations on other reservoir properties such as saturation and pressure is to get the density profile as correct as possible. Gravity data offers direct measurements of the density of the reservoir, and hence will be a very valuable tool for assisting and constraining seismic data interpretation. Another advantage of gravity data as compared to, for example, electromagnetic measurements is that it is relatively insensitive to existing seafloor installations such as pipelines and well paths, which makes it a viable option for mature fields at a late stage of production.

Gravimetric measurements provide a high lateral sampling density with coverage over the entire reservoir. Hence, in contrast to information such as well or core data, which provide point measurements at selected and restricted locations in the reservoir, gravity data offers information about both lateral and vertical variations within the reservoir. In contrast to active source geophysical data, the gravimeters do not require any ambient source to generate a signal; the signal measured is the fundamental gravitational force of the earth itself. No requirement for an active source coupled with a simplistic operational mode makes gravimetric surveys an affordable investment for most offshore reservoirs today. Moreover, the survey methods used are environmentally friendly with limited footprints and impact on the environment and animal life.

Gravity and pressure data are important tools for monitoring reservoir integrity and safety. Subsidence and uplift can be measured on subcentimetre scale and can be related to compaction and expansion in the reservoir. Compaction is one of the critical factors in managing reservoirs as it may have a potentially huge impact on the drainage properties. Surface deformation may be critical for installations on the field and by monitoring this it is possible to have an early warning system for any related hazards during operation.

Gravity Today!

High quality gravimetric services at low cost can be delivered all over the world by using state-of-the-art technology derived from gravity acquisition on the Norwegian continental shelf during the last decade by Statoil. An integrated package of sensors is used to measure gravity and pressure on pre-deployed concrete stations on the field. The package of sensors is handled by a ROV and depending on the size of field and weather conditions, a typical gravity campaign is one to two weeks. The processed data can be ready to be delivered within a week after a survey because of the fast and accurate measurement and processing of the data.

Since the beginning of development of the technology, there has been a large and continuing improvement in data quality for offshore gravimetric acquisition. Developments range from designing packages with state-of-the-art sensors, designing concrete stations, planning the survey operations, to processing of data, and today the repeatability of gravity data is as low as 1 μGal and subsidence can be measured on the millimetre scale! ■

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Contact information:
ngf@geologi.no
Tel: +47 73 90 44 68
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Applying Analogues for Success

Amongst the great challenges facing E&P professionals today is how to pool their collective experiences and talents in order to filter the feast of opportunities, from exploration acreage to prospect, field development and acquisition opportunities. This article suggests how the use of analogue data can help to reduce the risks and increase the chance of success.

DAVID JENKINS, C&C Reservoirs

A technical evaluation team must analyse all available data types – seismic, well logs, test and production data, cores and analogues – in making technical and business decisions in exploration and production. Often a lack of resources or time constraints mean this requirement is not fully undertaken; then the required due diligence suffers and consequently dry holes are drilled, field developments disappoint and acquired reserves are moved to the goodwill section of the acquisition. The question may still remain unanswered as to whether the opportunity was ever properly evaluated. A systematic way to reduce such unwelcome technical surprises and to better understand the opportunity is to use analogue fields and reservoirs for reference and benchmarking purposes.

Using Analogues

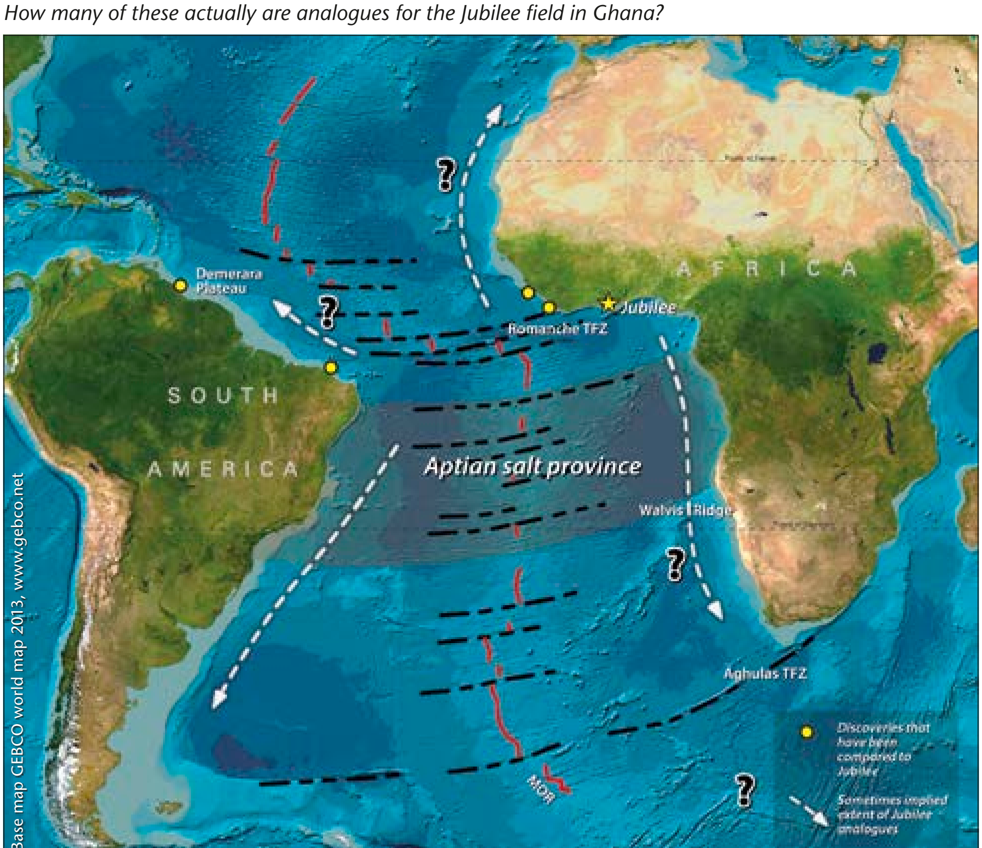
Existing oil and gas fields provide analogues, allowing for a direct comparison between an investment opportunity and the positive results (i.e. producing fields) which have been achieved from analogous exploration plays. Sadly the use of analogues is often haphazardly applied and with little rigour. A single analogue is often referenced because it looks similar on seismic data or with luck it is in the same basin and geographic region. How many times in recent history has the Jubilee field been used as an analogue for the numerous exploration opportunities up and down the West African and South American coasts – yet how many actually truly compare with Jubilee's setting?

The use of a single analogue carries inherent risk and is insufficient to benchmark or characterise an opportunity. Such ad hoc methods usually result in inappropriate analogues being applied for comparative purposes.

The basic critical element of any analogue database is consistency for all the technical parameters. Examples of such parameters which require absolute consistency are basin type, tectonic regime, structural setting, trapping mechanism, depositional system and environment of the reservoir, the reservoir lithology, reservoir properties and thickness, seal lithology and configuration. However, these are just the minimum technical parameters required. The development of an internal multi-analogue database with adequate technical parameters requires a significant amount of work and places itself beyond the capabilities of most E&P companies.

A major weakness to date has been the inability to directly characterise the opportunity being evaluated (new play, prospect or field development) against commercially available analogue databases.

How many of these actually are analogues for the Jubilee field in Ghana?



New Platform

Addressing this deficiency, C&C Reservoirs has developed a new platform, DAKS – Digital Analog Knowledge System – which enables the comprehensive characterisation and benchmarking of over 200 technical parameters collated in its 1,400+ analogue field database (FAKS) against

users' own data which is documented in the UFK (User Field Knowledge) module.

The UFK proprietary platform enables geoscientists and engineers to directly enter and store technical static and dynamic data of their subject of investigation. This allows for direct comparison and plotting of the opportunity's technical parameters against identical technical parameters from the analogue fields contained within the standardised global field and reservoir analogue dataset in FAKS. Users can further modify and customise the data model in the UFK to their own specifications by building their own unique data model. (Client Defined Data Models or CDDM). The new web-based UFK tool undertakes a statistical analysis of all the critical technical data associated with an opportunity and its analogues and generates these as P10-P50-P90 percentile distributions.

In peer assist and peer reviews, discussions currently tend to revolve around the experiences of the personnel involved and/or the one identified analogue, and often the critical risk elements are not fully understood or recognised due to lack of true benchmarking in these processes. The introduction of technology whereby an E&P opportunity can be directly compared with numerous global analogues allows for better and more focused analysis of the potential risks.

Using Global Analogues

A few examples of the advantages of applying such technology are discussed below.

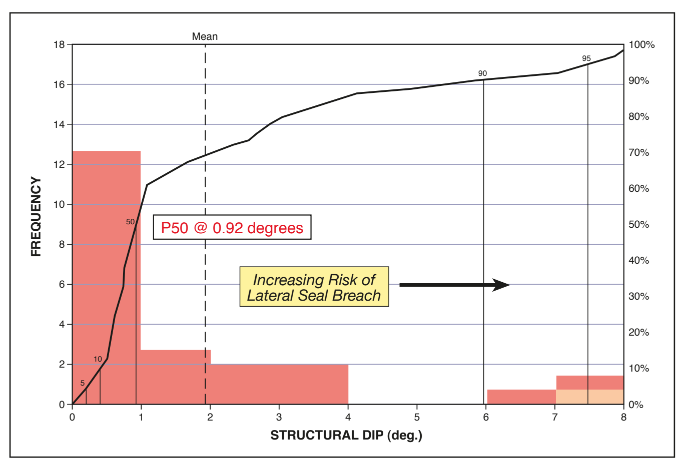
Play characterisation: In this example, a recent licensing round offered a large number of exploration blocks which had very sparse amounts of well and seismic data, but were aligned with a large regional producing trend. By using search parameters based on the tectonic structural setting of the blocks, FAKS enabled a characterisation of the play based on 60 producing, similarly-aged reservoirs, with a similar tectonic setting from within the region, i.e. true analogue data. Users have the option of selecting from a combination of up to 236 technical parameters for a tabulated full play characterisation, which allows screening economics to be run early in the evaluation cycle to determine MEFS (minimum economic field size). It can also highlight any potential production problems such as high viscosity oil, or high inert gas content, factors which can add to the complexity of any potential future field development and can risk increasing project costs.

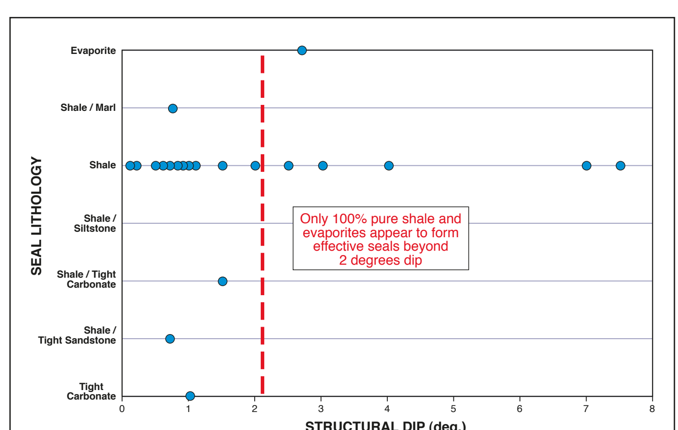
Prospect benchmarking: The UFK and FAKS tools allow for numerous field analogues to be used for benchmarking a prospect on a P10-P50-P90 distribution basis, automatically highlighting those prospect parameters which lie outside of the P10 and P90 values of the analogues. 'Prospect X', a Mesozoic lateral depositional pinch-out trap, was evaluated using FAKS and UFK. The full benchmarking process covered over 80 technical parameters and these were compared to the 36 closest analogue fields identified in the system. The exercise flagged that two technical parameters for the prospect, namely structural dip of the trap and the prognosed seal lithology, lay outside the normal P10-P50-P90 percentile distribution for the 36 analogues, as shown by the graphs below.

This analysis should now guide the interpretation team to focus on resolving the seal issue and address the question of whether the prognosed hydrocarbon column is likely to breach the shale/siltstone seal – ultimately determining if this risk is sufficient to deter drilling. This example demonstrates the benefits of this new technology for prospect benchmarking against global analogues and highlights how technical issues that might have otherwise been easily missed are now identified.

Post-mortem analysis: The input of the pre-drill and the post-drill parameters into the module allow for a direct comparison

Evaluating the risks at Prospect X, a histogram of the lateral depositional traps indicates that 90% of these types of traps have less than four degrees of dip, while additional analysis flags the fact that mixed lithology seals do not work beyond two degrees of structural dip.





against each other and against the global analogues (i.e. successful commercial accumulations).

Field development planning: Many performance uncertainties exist particularly in the early stages of a development. The UFK and FAKS modules allow for comparison between the proprietary field and analogue fields to provide quantitative envelopes to help in development planning and production optimisation.

Improved hydrocarbon recovery: Reservoir engineers can find all fields that share a similar set of geological and engineering parameters and which have gone through secondary and tertiary recovery production stages. The performance of production enhancement cases can be readily retrieved and reviewed. The engineer can then compare his field's performance versus these analogues fields and determine the most effective production enhancement methods and estimated performance for their candidate fields.

Mature and abandoned fields: When evaluating these types of opportunities available from host governments, reservoir engineers can enter all the available data into the UFK module and then determine whether specific technologies, such as horizontal and multilateral drilling, under-balanced drilling or gravity-assisted thermal recovery, used in analogue fields, might allow such technological solutions to create profitable investment opportunities.

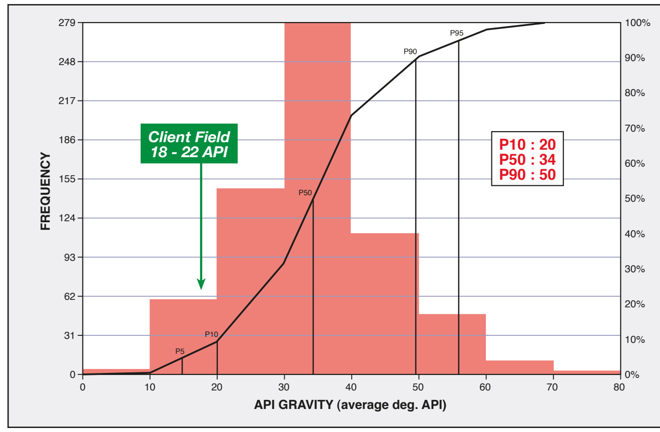
A recent peer review of a field redevelopment opportunity in Central Asia concluded that the shallow reservoir depth combined with the low temperature and the large number of structural compartments were the most critical factors. However, when the opportunity was benchmarked against the analogues, it was found that the two most anomalous parameters were oil gravity and viscosity.

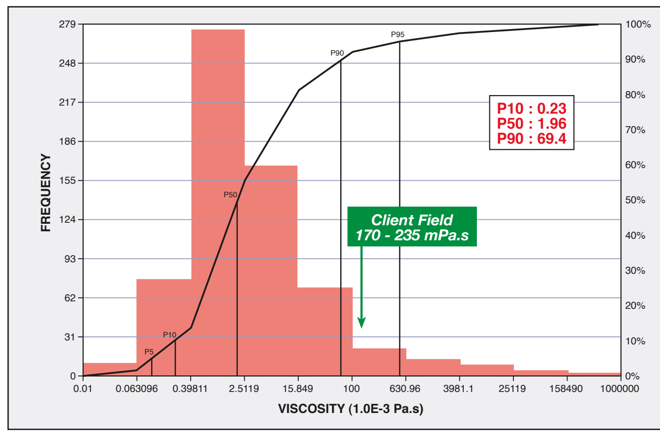
Further analogue analysis indicated that high recovery factors could be obtained from high viscosity reservoirs and that cyclical steam injection combined with closer well spacing had the highest probability of achieving the goal of higher recovery factors, as shown in the graphs and table on the right. Subsequently, the team revised its original proposed redevelopment plan, with a view to decreasing the well spacing to less than 500m in combination with steam injection and horizontal producing wells. The new redevelopment plan indicated that a multi-million dollar potential value had been added to the opportunity.

Portfolio Analysis: Several E&P companies, including a number of NOCs, are now able to enter all the static and dynamic data on their producing fields into the UFK module, allowing engineers to make a direct comparison between each field and to determine why some fields are comparatively under-performing. This allows determination of candidates for divestiture and candidates for additional investment.

Preparing for Surprises

In the complex subsurface world of exploration and production, there will always be surprises, welcome and unwelcome. DAKS technology gives geological and engineering professionals the opportunity to reduce the risk of such surprises by expanding their experience base to include the benchmarking of over 1400 commercial oil and gas fields across the globe. ■

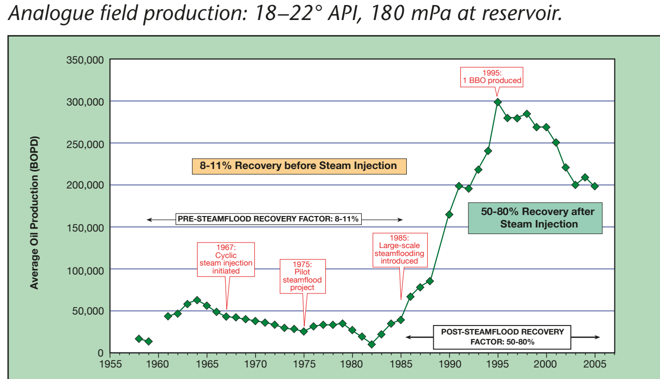




Key Field Parameters

Clastic Reservoir	Shallowest	Deepest
Depth	300–450m	390–600m
Gross Thickness	100–120m	85m
Net Thickness	38m	N/A
Stratigraphic Compartments	4	2
Oil Gravity @ reservoir	18-22 API	
Viscosity @ reservoir	170–235 mPa	
GOR	11–11.8 m3/t	
Reservoir Temperature	29–31 degrees C	
Initial Formation Pressure	4.3–5.2	
Drive Mechanism	Weak Aquifer	
Well Spacing	500m	
Secondary Recovery	Water Injection	
Tertiary Recovery	Hot Water (80c) Injection	
Well Count	864 Producers and 133 Injectors	

Analogue field production: 18–22° API, 180 mPa at reservoir.



Just How Good Are We at the Digital Oilfield?

We live in an age where phrases like 'Integrated Operations' and 'Digital Oilfield' have become part of our everyday parlance. But what do they really mean?

Dr JULIAN PICKERING
Digital Oilfield Solutions Ltd.
SAMIT SENGUPTA
Geologix Ltd.

Do these phrases mean the same thing to everyone, or have we created standards of working that only really work in our own discipline or company? How transferable are the elements that make up a digital oilfield implementation – people, process, technology – and just how good are we at managing the change when one of those has to be 'made to fit'?

The Digital Oilfield

In recent years there has been acute excitement about the concept of the digital oilfield. Ideas that were previously used in single areas – for example the people, process and technology triangle used in data management – have spread across disciplines and projects, and have had a far-reaching effect. However, changes like this take time and commitment before the real benefits can be felt. It is all too easy to be deterred by the front-heavy costs of a new implementation, not only in terms of technology but in managing the change from one way of working to another, and not see the long-term benefits.

The advantages of real-time technology are easier to comprehend from the outset, with a direct correlation between expenditure and benefit. The availability of high-speed connectivity on a rig allows operators to use various expert systems in labs and offices around the world for real-time analysis of well data, which, combined with audio, video and instant messenger links, provide us with a decision support system for a geographically disparate, multi-disciplinary team – the 'Digital Oilfield'. Well deployed, this team is able to maximise production, optimise recovery, and vastly improve reservoir management by allowing rapid decision-making and potentially avoiding expensive 'too late' interventions.

We all know what we want from our software solutions. We want the right data and we want it now, to improve our decision-making processes. We want better communication, improving health and safety standards and ultimately reaching the bottom line. We also know what we want from our Integrated Operations Centres – a one stop, high-technology centre where everything is provided to us in real-time and we can work collaboratively, across disciplines and across projects, communicating as close to face-to-face as humanly possible – again, ultimately reaching the bottom line.

Real-Time Operating Centre – the heart of the digital oilfield

Baker Hughes

The real challenge with the digital oilfield is that the fancy technology and smart RTOC's (Real Time Operating Centres) are easily achievable, constantly improving and easy to get hold of. A digital oilfield implementation may be transformational, but it is also one of the most complex projects that a company can undertake. It is easy for people to think of the digital oilfield as simply adding extra IT technology or a smart looking RTOC, but the reality is that changing the way in which people work has a profound impact across all areas of the business. Drag in the potential 'crew change' the industry is concerned about, and without competent planning and ongoing support, you could be looking at an expensive failure.

When a digital oilfield implementation comes together successfully, it is a major enabler for delivering efficiency, improved safety, remote operations and business value, and there are some excellent examples throughout the oil and gas industry. However, these projects can fail due to a lack of project preparation and a failure to understand the magnitude of the task to transform a company focused on more traditional operations. It is easy to launch into significant technology deployment projects without recognising the risks or potential value in advance, and this can cause a number of challenges to the team; indeed, in the worst case scenario, operational performance may actually decrease. The digital oilfield technology may prove to be unreliable and hinder drilling and production operations with a corresponding increase in NPT (non-productive time).

At its basic level, a digital oilfield implementation is just another project that requires a clear definition of scope, schedule and budget and adherence to them, but few people have the experience of managing a project that will influence the entire culture of a large organisation.

There are a number of excellent service providers who are creating products and services designed to guide an organisation through the design, development and implementation of the digital oilfield. Many of them provide Change Management as part of their service, and this is a great start. However, nothing can take the place of good, tailored and inspirational training within the organisation itself, given by professionals who have a thorough understanding of what constitutes success and indeed failure in a long-term transformational project of this type.

Round-the-clock monitoring of operations

The digital oilfield promotes collaboration

Why Conduct Digital Oilfield Training?

The digital oilfield is innovative because it changes the working culture in an organisation and enables people to perform more efficiently and safely – many published case studies attest to this. However, the innovation has come largely through the process and technology streams and there has been very little change in the way that people are developed. Training courses, if they happen at all, are rather dry and are delivered in a 'lecture style', with long teaching sessions and infinite numbers of slides. This does not prepare staff at all for what to expect in a digital oilfield adoption project.

No company would think of executing a drilling campaign or designing a process scheme without engaging professional and accredited staff, so why would they embark on a digital oilfield programme that could potentially change key work processes and even the organisational structure, without the same level of experience? Oil and gas personnel need to be professionally trained and given detailed knowledge of what a digital oilfield project looks like.

The situation is complicated further by the complexity of a digital oilfield project, which draws upon a broad range of skills that must all come together, including experience in well planning, drilling and production operations, as well as IT architecture design, not to mention understanding the processes involved in a 'cradle to grave' operation, and perhaps most importantly, understand people engagement and change management.

Few people can claim to be experts in all of these disciplines, but the digital oilfield project manager or coach must have a working knowledge of all of them and understand the essential role that each has to play in a successful implementation. The individual also needs credibility within the organisation, which may either be attained through seniority or the direct support of senior management. 'Bottom up' adoption projects tend to be very slow and can easily run out of momentum, whereas a 'top down' approach usually guarantees a more successful outcome.

Innovation in Training

There are a lot of 'learnings' that we can take from recent developments in education in schools, colleges and universities. Much of these have not been taken on board in professional training and development courses but they are very relevant to digital oilfield training.

There is little doubt that people learn more effectively if there is an element of enjoyment about the learning process. They have to want to learn or the experience will be very negative; this is particularly true in adult learning. Most of us tend to believe when we are 30+ that we have mastered the essential skills for regular life and we are only willing to learn new skills if there is a particular reason. If the objective is unclear or you do not share the goal then you are unlikely to throw yourself headlong into the learning process. Being told to attend a training course by your boss is probably one of the most negative ways to learn.

Training should be focused and relevant. It is very important to understand the expected audience and their learning requirements and abilities. There is little point in delivering a very technical course to senior managers or business representatives, as they will want to understand the business impacts of the digital oilfield rather than the technicalities. Similarly a business-oriented course has limited value to technical specialists. This may seem obvious, but all too often training courses have a subject title of 'Digital Oilfield'. It is true that some general background information is helpful for everyone but the primary objective of training is to raise competence in the area where the individual is going to contribute.

Modern education is directed at analysis and decision-making rather than absorption of facts. Students are expected to use the information available to make a reasoned judgement, which is far more appropriate to running a digital oilfield project or working in a collaborative environment. This can create a problem if they have only limited knowledge through a lack of experience, so instead, they must interact effectively with knowledgeable staff. To translate this into digital oilfield training, there should be more direction on how to manage a digital oilfield project rather than on giving a recipe for how it has been done successfully elsewhere. The digital oilfield is definitely a case of where one size does not fit all.

All About Change

Ultimately, the digital oilfield is about change – in the way we work, in the way we deliver on projects and, perhaps most tellingly, in ourselves. It is a daunting task – an elephant which we cannot imagine eating even one spoonful at a time. But with the right preparation and understanding of where the project is going, there is no reason why a digital oilfield implementation should not deliver on every level. ■

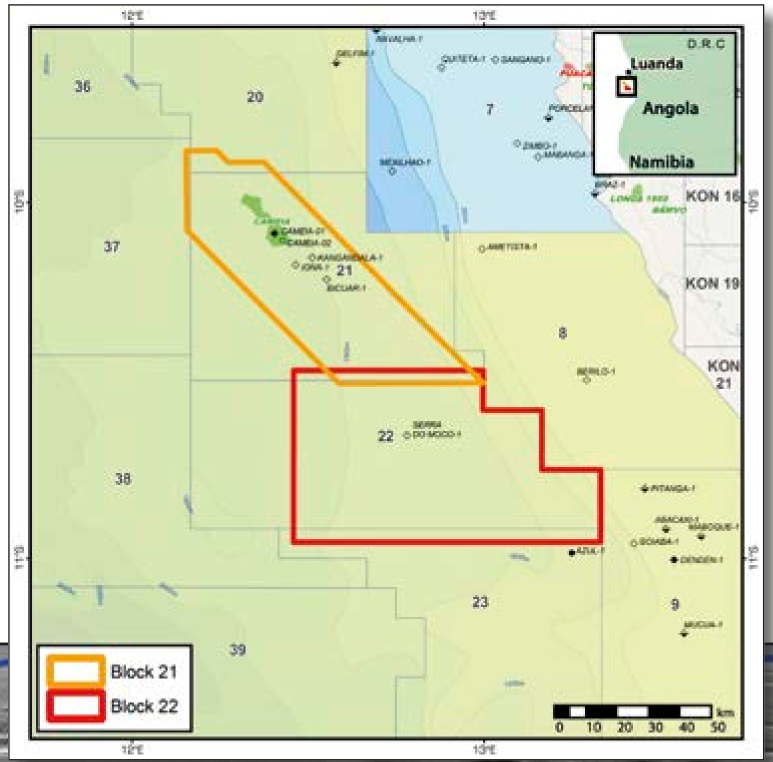
Angola

Kwanza Basin

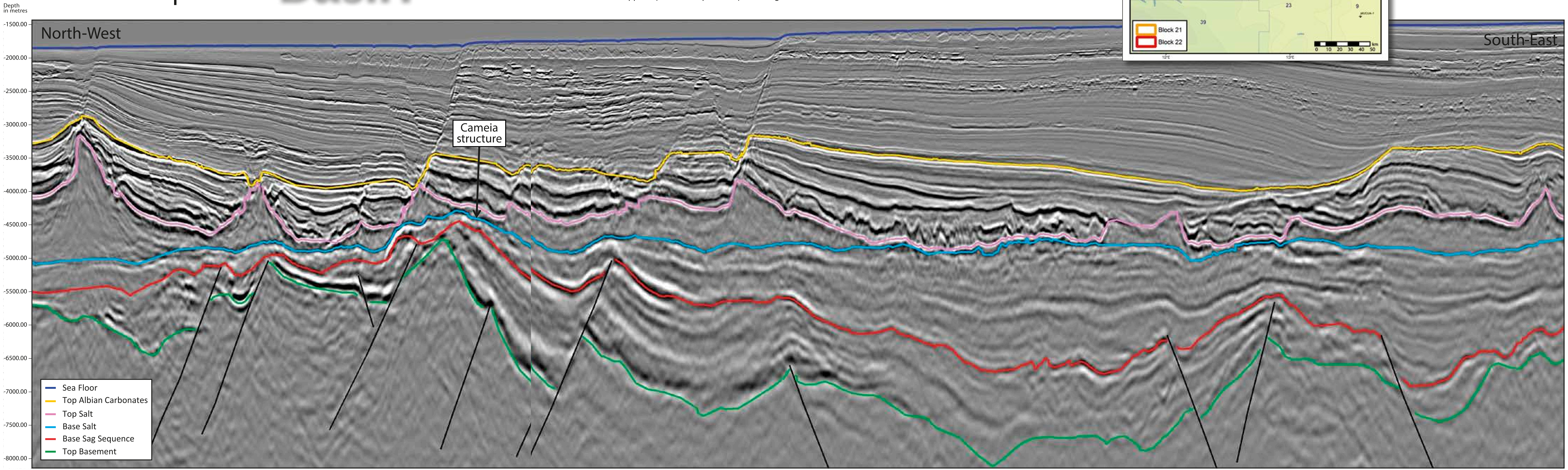
Sub-Salt Plays of the Ultra-Deep Water

The latest broadband seismic technology is being used in the Angolan deep offshore area as part of the oil and gas industry's efforts to unveil the sub-salt potential. Renewed interest in Angola's deep offshore pre-salt plays arose essentially from the success of the South Atlantic equivalent margin in Brazil, where the giant Lula field and more recently the Libra discovery were found. In Angola, the high-impact Azul and Cameia discoveries were found in similar pre-salt carbonate reservoirs. CGG recently acquired two broadband seismic 3D multi-client surveys around the Cameia discovery in the Kwanza Basin blocks 21 and 22, covering a total of 7,215 km², to help understand complex salt-induced structures and deep reservoirs below the Aptian salt.

This interpreted broadband seismic line runs from north-west to south-east through the recent Cameia discovery in Angola deepwater Block 21. It demonstrates the improved imaging of the pre-salt stratigraphic intervals with clearly visible sag and syn-rift sequences deep below complex salt-induced structures. The Cameia trap lies in a steeply rotated fault block capped by a thin evaporate layer and tight carbonates.



CGG



Exploring Further and Deeper

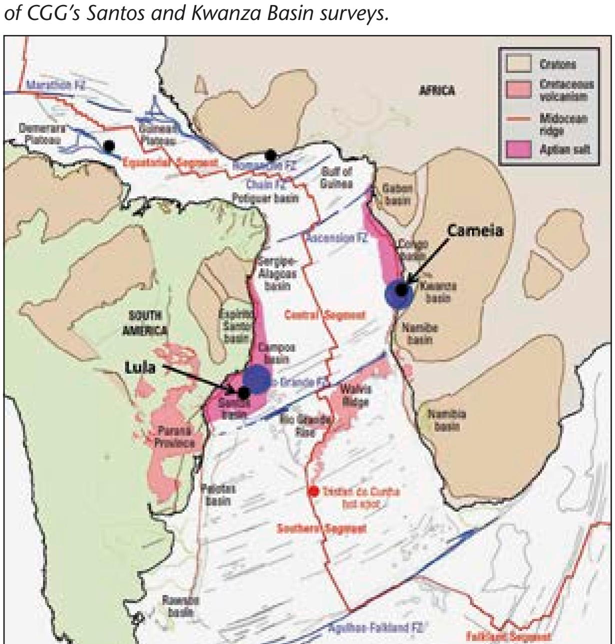
GREGOR DUVAL, JASWINDER MANN and LAUREN HOUSTON, CGG

Acquisition of marine seismic data using CGG's broadband solution, BroadSeis™, has greatly improved the imaging and interpretation of subsurface oil and gas reservoirs.

Pre-salt reservoir targets along the South Atlantic conjugate margin have been a major focus for hydrocarbon exploration with significant discoveries made within the Santos and Campos Basins offshore Brazil. Using these discoveries as analogues, the underexplored deepwater Kwanza Basin is emerging as a prolific pre-salt hydrocarbon basin.

The growing hydrocarbon potential beneath complex overburdens such as evaporites highlights the importance of recording a full range of frequencies when acquiring seismic data. The challenge of seismic imaging around and below complex salt bodies is well known and marine broadband techniques deliver improved results in combination with 3D, wide-azimuth and even full-azimuth survey designs. Beyond these illumination challenges, broadband seismic provides deep imaging due to its extra low frequencies and sharp resolution of small features with the higher frequencies. CGG has recently acquired a new multi-client seismic broadband 3D dataset offshore Angola in Blocks 21 and 22. The Block 21 dataset covers approximately 2,915 km^2 including the recent Cameia discovery. Data are still being processed but a fast-track pre-stack depth migrated volume has already been delivered. Block 22 benefits from full pre-stack time-migrated and depth-migrated volumes covering a total area of 4,300km^2.

Tectonic map of the South Atlantic with fracture zones highlighted (Bryant et al., 2012). The blue circles show the approximate locations of CGG's Santos and Kwanza Basin surveys.



South Atlantic Margin Equivalence

The South Atlantic rift basin evolved as a main branch of the Jurassic-Cretaceous rift zones between Africa and South America during the final stages of the break-up of western Gondwana. When juxtaposing the Africa and Brazil conjugate margins in a reconstruction of the initial opening of the South Atlantic (around 140 Ma) the Brazilian Santos and Campos Basins can be seen to be located adjacent to Africa's Benguela and Kwanza Basins. The tectonic history demonstrates the fact that the pre-salt play that led to the discovery of the giant Lula field in the Brazilian Santos Basin can be used as an analogue offshore Angola. The Lula oil field offshore Brazil was discovered in 2007 by Petrobras in water depth of approximately 2,000m. Hydrocarbons were encountered beneath the Aptian-aged evaporites within a lacustrine carbonate reservoir.

The figure at the top of page 78 displays a sample section from CGG's broadband survey acquired in the northern part of the Santos Basin in Brazil. It demonstrates the similarities existing between the Brazilian margin basins (Santos and Campos) and the Kwanza Basin in Angola which is shown below. The low frequencies at depth highlight deep rotated fault blocks, as well as the correlation of syn-rift sedimentary packages, the thickness of the sag sequence, and base and top of the evaporite section (i.e. salt domes and salt welds), all direct analogues of the geological features identified in Angola Block 21.

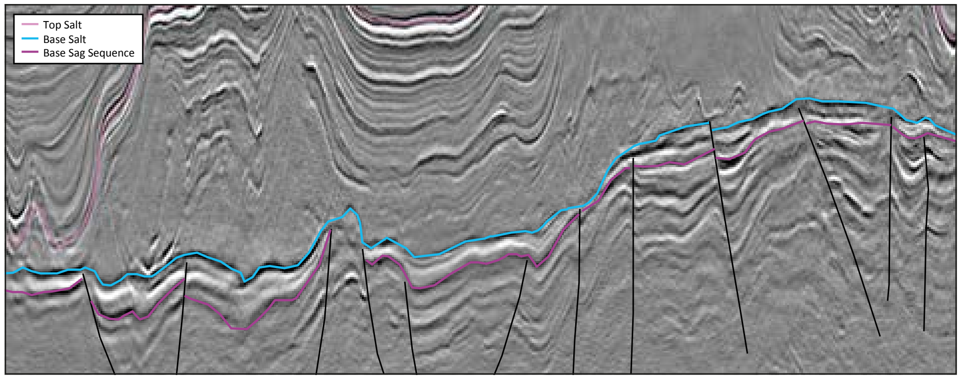
Kwanza Pre-Salt Discoveries

The first well discovering oil in the pre-salt section of the Kwanza Basin ultra-deep water (i.e. beyond 500m depth) was Baleia-1 in 1996. This well encountered good oil shows over a gross interval of about 120m. In 2011, as a result of recent deepwater discoveries in Brazil, Maersk drilled the Azul-1 pre-salt discovery in Block 23 and this was shortly followed by Cobalt's high-impact Cameia-1 discovery well in Block 21. The Cameia-1 well was drilled to a total depth of 4,886m into highly permeable fractured carbonates of Aptian age. A 360m gross oil column was encountered. It flowed at a restricted rate of 5,010 barrels of 44° API oil and 14.3 MMcf of gas per day. The oil leg is expected to extend into the deeper syn-rift section. Cameia is the first pre-salt discovery in Angola to benefit from broadband seismic coverage, which should help to better delineate the full extent of the oil accumulation.

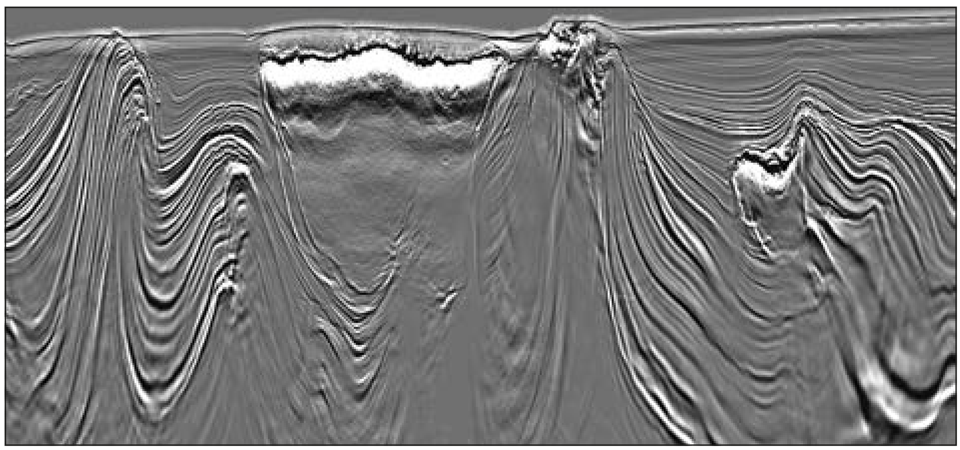
Salt Structures

Due to various episodes of relative uplift/subsidence of the

West African continental margin, sediments overlying the Aptian evaporites have slowly migrated down slope, with the salt acting as a ductile decollement layer. As a consequence, the post-salt sediment section is affected by a predominantly extensional regime in the shallower updip part of the Kwanza Basin whilst downdip the sediments underwent compression. The combination of gravity sliding processes and salt deformations has resulted in the variety of salt structures we observe today in the Kwanza Basin which makes seismic imaging such a challenge. Besides the obvious wavefield illumination complexities, broadband seismic helps to better image sub-salt sediments with the addition of the extra low frequencies, while at the same time allowing for a sharper definition of the edges of salt bodies due to the higher-frequency content, as seen from the figure on the right. For example, Angola Block 21 is located in a predominantly extensional area where smooth salt domes and local salt welds are seen on seismic data (fold-out image) whilst Block 22 covers an area dominated by compression stresses where detached salt diapirs, large canopies and overhanging sediments are observed.



Interpreted seismic section taken from CGG's Santos Basin Phase 6B broadband survey (fast-track PSDM volume) (courtesy of CGG Data Library).

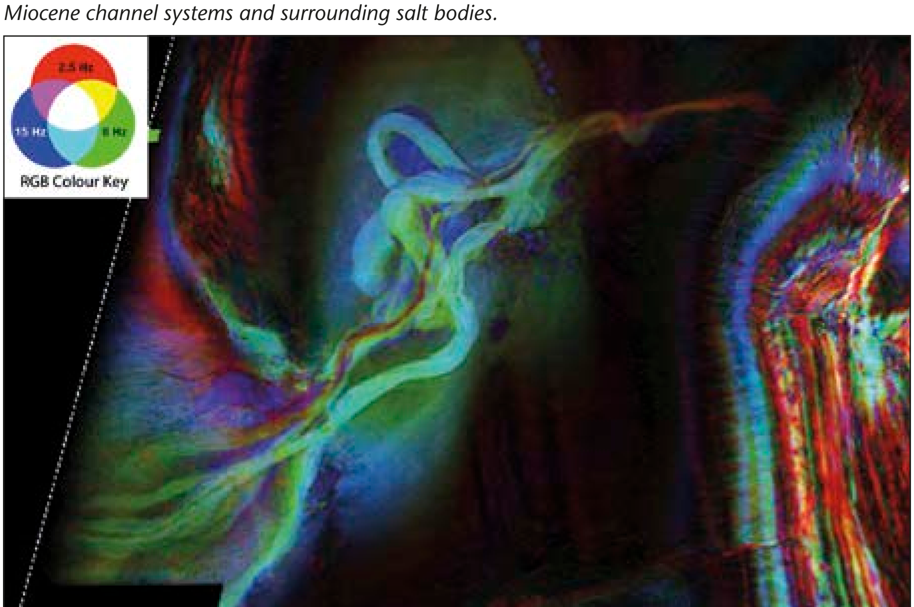


Complex salt structures seen within CGG's Angola Block 22 full PSDM dataset, showing salt tongues and detached diapirs and subsequent seismic imaging below (courtesy of CGG Data Library).

Mapping Channels

Deepwater turbidites deposited on top of the Albian carbonates and Aptian evaporites constitute another important target within the highly deformed sediments of the Upper Cretaceous to Tertiary section. These reservoir sands were only deposited locally on the Kwanza Basin margin, which means it is of high importance to accurately track turbidite channels and good quality sands that can potentially be trapped around or beneath salt-related structures. Broadband seismic data has brought a new level of understanding to the mapping of these facies. Using the full spectrum of frequencies (from 2.5 Hz to 125 Hz) we are now able to highlight greater details of the turbidite facies distribution.

Colour blend 3D visualisation of 2.5 Hz, 8 Hz and 15 Hz dominant frequencies, highlighting Upper Miocene channel systems and surrounding salt bodies.



The figure on the left shows an example of 3D frequency decomposition and colour blend from the Block 22 broadband dataset, where we can clearly identify a turbidite channel complex with various phases of sediment fill, meander growth and incisions. This kind of information is key to tracking reservoir sands around potential traps provided by salt structures and thus helping explorationists to find further oil reserves in West Africa. ■

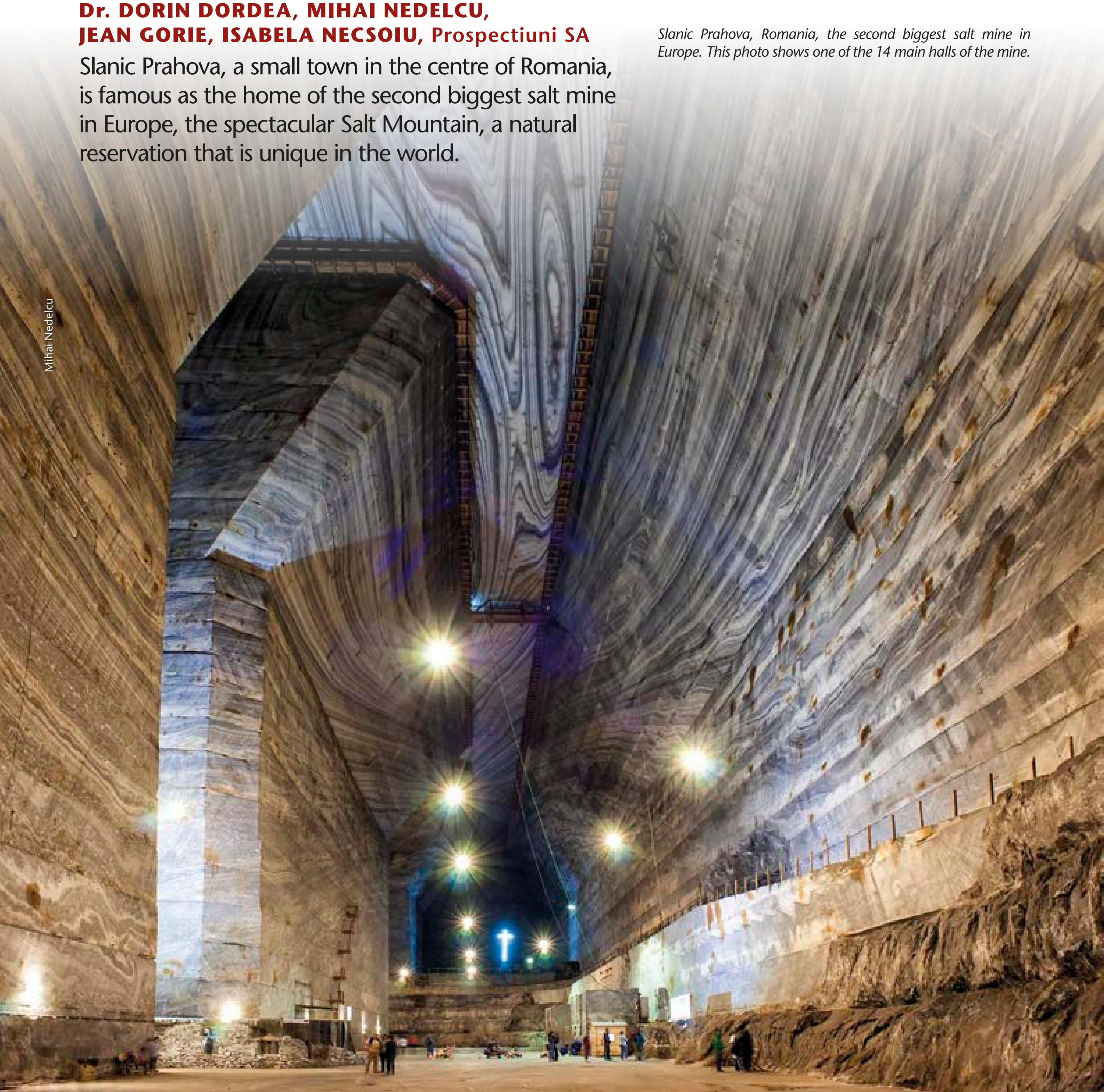
The Salt Mountain

Dr. DORIN DORDEA, MIHAI NEDELCU, JEAN GORIE, ISABELA NECSOIU, Prospectiuni SA

Slanic Prahova, a small town in the centre of Romania, is famous as the home of the second biggest salt mine in Europe, the spectacular Salt Mountain, a natural reservation that is unique in the world.

Slanic Prahova lies in the forested hills of the Sub-Carpathians, at an altitude of 413m and approximately 100 km north of Bucharest. Slanic is an all-season spa resort, which prides itself for its curative mineral waters, which have been used since 1885, but its main claim to fame is the spectacular Salt Mountain, the second biggest salt mine in Europe. This unique natural site also contains the 20m deep Bride Lake (or Bride Grotto), covering an area of 425 m^2, which appeared in 1914 after an old salt mine caved in. The resort is surrounded by gently rolling landscapes and offers guest accommodation including villas, hotels and private homes.

A mild climate with warm summers (the average temperature in July is 19.5°C) and relatively mild winters at about -3.5°C is a result



Mihai Nedelcu

Slanic Prahova, Romania, the second biggest salt mine in Europe. This photo shows one of the 14 main halls of the mine.

of the location of Slanic Prahova in a small despression not very far from the mountain peaks. The distinct beauty of this region, the numerous facilities with warm mineral water baths, cold lake baths and warm mud baths as well as the remarkable sights, make for a quiet and pleasant get-away. Situated between two main ridges of hills trending north-south, it blends in perfectly with the Sub-Carpathians landscape and is surrounded by large plateaus of pasture and woods.

A Long History

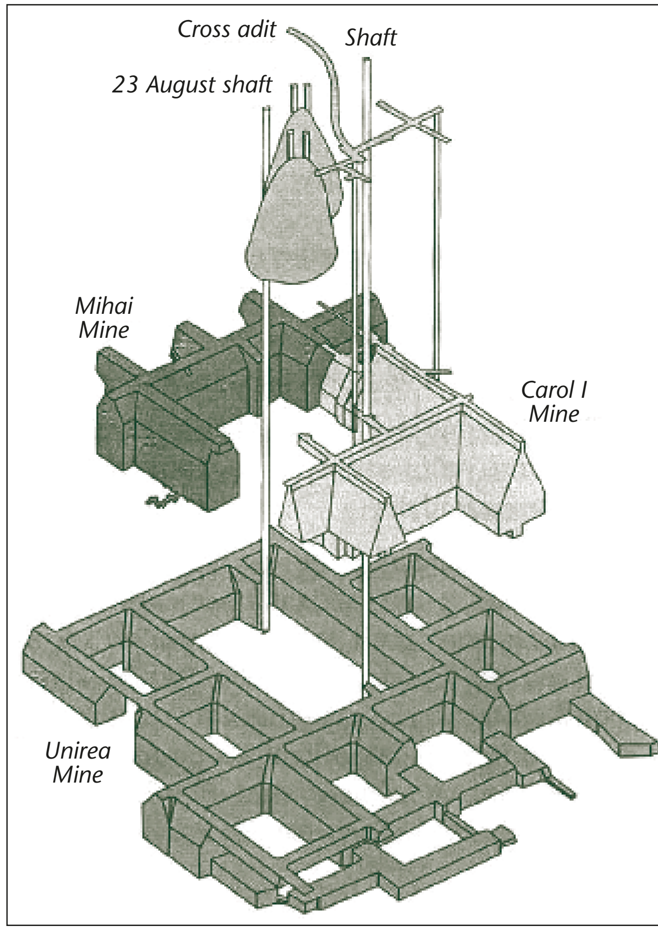
The salt deposits in Slanic have been exploited for more than three centuries – although according to official records that actually makes them amongst the youngest Romanian salt mines to be developed. The salt mining activities in this region started in 1688 and the first mine was opened in that year in the Green Valley. Between 1689 and 1800 three additional mines, shaped internally like a bell, were opened in the Baia Verde (Green Bath) area, and after the collapse of the ceiling and flooding of these old salt mines, three salty lakes appeared here; the locals refer to the salty lakes in the region as 'bai', or baths. Later on, between 1800 and 1854, two new mines were inaugurated on the western side of Slanic, which, following the same transformation process, resulted in today's Baciului Bath and the Bride's Grotto, the two salt lakes which serve the resort at present. These lakes are renowned for their curative powers, derived from the sapoprelic mud and the salty water.

In 1865, exploitation started in a new salt mine in the Voinoaia area, representing a big step forward in salt mining operations in the Slanic region as the bell-type exploitation mine was replaced by the systematic mine with multiple chambers. However, water infiltration and the poor quality of the salt here led to the re-exploitation of older mines from 1875 until 1881, when the Carol salt mine was opened. This was operational for 61 years, until 1935. In 1912 the Michael salt mine opened, with innovative new electric lighting. Since 1931 the mining method has been improved by using salt-cutting machines and explosives for blasting and cutting the salt wall, thus eliminating the manual operations of cutting and detaching the furrows. Michael closed in 1943, although currently this mine is reserved exclusively for small model plane competitions, and activity moved to a huge mine, named Unirea, which was opened under the older Michael and Carol Mines. This operated until 1970 when Victoria opened, followed in 1992 by Cantacuzino.

Spectacular Site

The Unirea mine consists of a total of 14 trapezoidal chambers, 55m high, and covers a total area of approximately 80,000m^2. A regular visitors' tour runs around the enormous pillar that supports the mine. One of the most spectacular halls to visit is the Genesis Hall, which resembles a huge cathedral, decorated with enormous salt statues of respected Romanian historic figures.

At the moment this mine also serves as an in-patient sanatorium, treating various respiratory diseases. Factors such as the constant temperature of 12°C all year round, the 50% humidity, the air rich in sodium ions, an atmospheric pressure of 18–20 mm Hg (higher than that at the surface) and the lack of any allergens, all create a special microclimate which has remarkable therapeutic effects for respiratory diseases. The efficiency of this microclimate was known over 100 years ago – in 1877 A. Bernard performed the first analysis of the properties held by the salt water lakes in the area. The first record of the therapeutic effectiveness of these lakes dates back to 1885, when an Austrian officer suffering from rheumatism came to Slanic on crutches and was cured through salt water baths therapy.



Layout of the Unirea salt mine

The Salt Mountain was declared a geological and geomorphological natural reservation in 1954, the protected area covering 20,000m^2. The Salt Mountain and the Bride Grotto are remarkable because they are the result of human action, or more precisely of the exploitation operations carried on inside the Salt Mountain until 1852.

Salty Facts

Although there are salt reserves throughout Europe, nowhere else on the continent are they richer or more heavily exploited than in Romania.

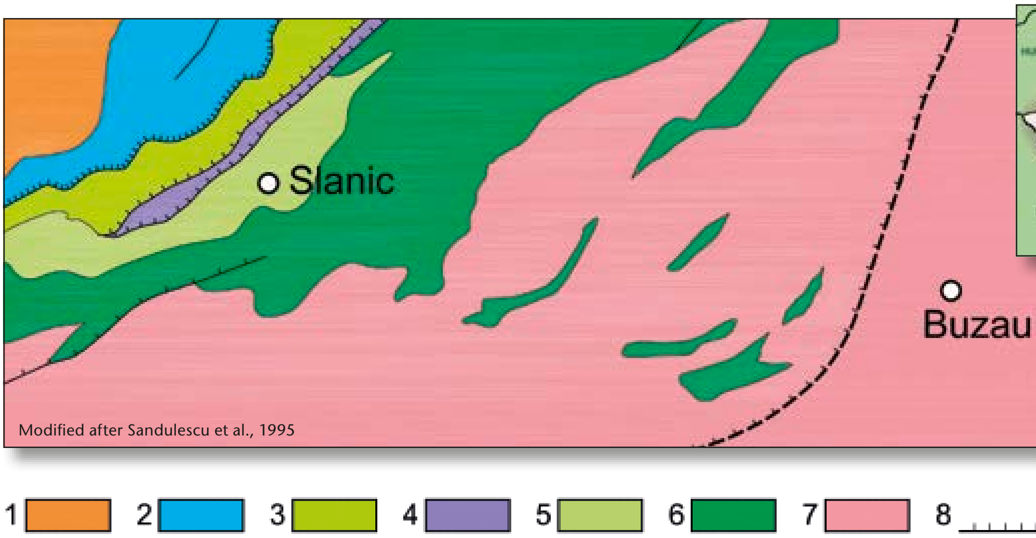
Covering a range of geological ages from the Palaeozoic to the Tertiary, the European salt deposits were formed as a result of evaporation processes in large lagoonal basins supplied with seawater for long periods. Consequently, a succession of carbonate rocks (limestone, dolomite), sulphates (gypsum, anhydrite), salt and potassium salts (KCl, $KMgCl_3$, or potash) covered by detrital deposits such as sand, clay and marl, accumulated

The lakes around the Salt Mountain are known for their therapeutic properties.

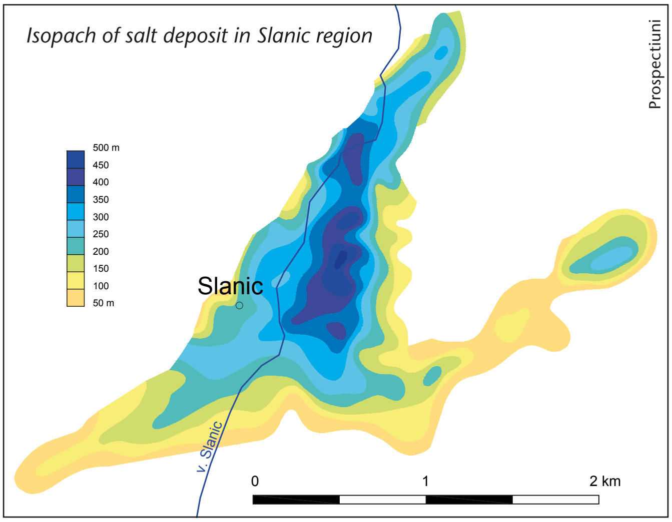
almost simultaneously with the slow subsidence of the sedimentary basins. As long as these basins are only slightly affected by the tectonics of the layers of the Earth, the salt and other evaporitic layers can be exploited through mining, but only if their thickness is considerable, and the exposure superficial. If instead, the area with salt deposits is affected by compressive tectonic processes (accretion, fracturing, overlapping, folding etc.), the salt plasticity (which contrasts with the surrounding detrital rocks) leads to massive accumulation – salt domes – which can become the object of greater interest in mining extraction. The Romanian salt deposits on the outskirts of the Transylvanian Basin (Ocna Dej, Turda, Ocna Mures, Ocna Sibiu, Praid etc.) and in the Sub-Carpathians (Cacica, Tg. Ocna, Slanic Prahova, Ocnele Mari) were formed in this way, i.e. as a result of compressive tectonic processes.

The Slanic Prahova area is situated in the south-western part of the Tarcau Nappe and comprises two elevated sectors (Valeni and Homoraciu Spur), compensated by two lowered areas (the Drajna and Slanic Basins). The Slanic Basin consists of a Cretaceous-Paleogene base, covered by Neogene deposits, predominantly of chemical precipitation (gypsum and salt). The Slanic Prahova salt reserves belong to the syncline bearing the same name, which developed over the Paleogene deposits of the external flysch of the Tarcau Nappe. The stratigraphic sequence of the Slanic syncline comprises an evaporitic (gypsum) formation of Burdigalian age, known in Romania as the Cornu Formation, plus deposits of Doftana Molasse and Slanic Molasse/Sandstone of Badenian to Mid Miocene age. The sequence ends with the Sarmatian and Pliocene deposits. The mid-Miocene Slanic Molasse includes marls and tuffs with globigerina, salt breccia, shales with radiolaria and marls with spirialis. The sequence shows one single cycle of sedimentation through evaporation. The deposit developed on three directions with maximum thickness in the central part.

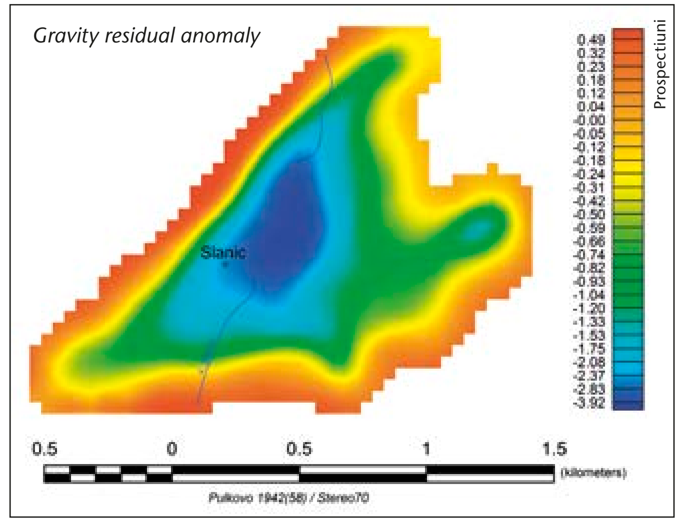
It is worth mentioning that the salt reserves in Slanic Prahova could provide salt for the entire population of Romania for 1,400 years (at the current level of population) or more than 700 years, if we take into account an increase in the population of 2% per year, while the total reserves from this area would cover the total salt consumption of the world population (at the current level) for 80 years from now. ▶



Geology of the Slanic area.
1: Ceahlau Nappe;
2: Bobu Nappe;
3: Convolute Flysch;
4: Macla Nappe;
5: Tarcau Nappe;
6: Sub-Carpathian Nappe;
7: Post-tectogenetic cover of Moldavides;
8: Foredeep.



Isopach of salt deposit in Slanic region



Gravity residual anomaly

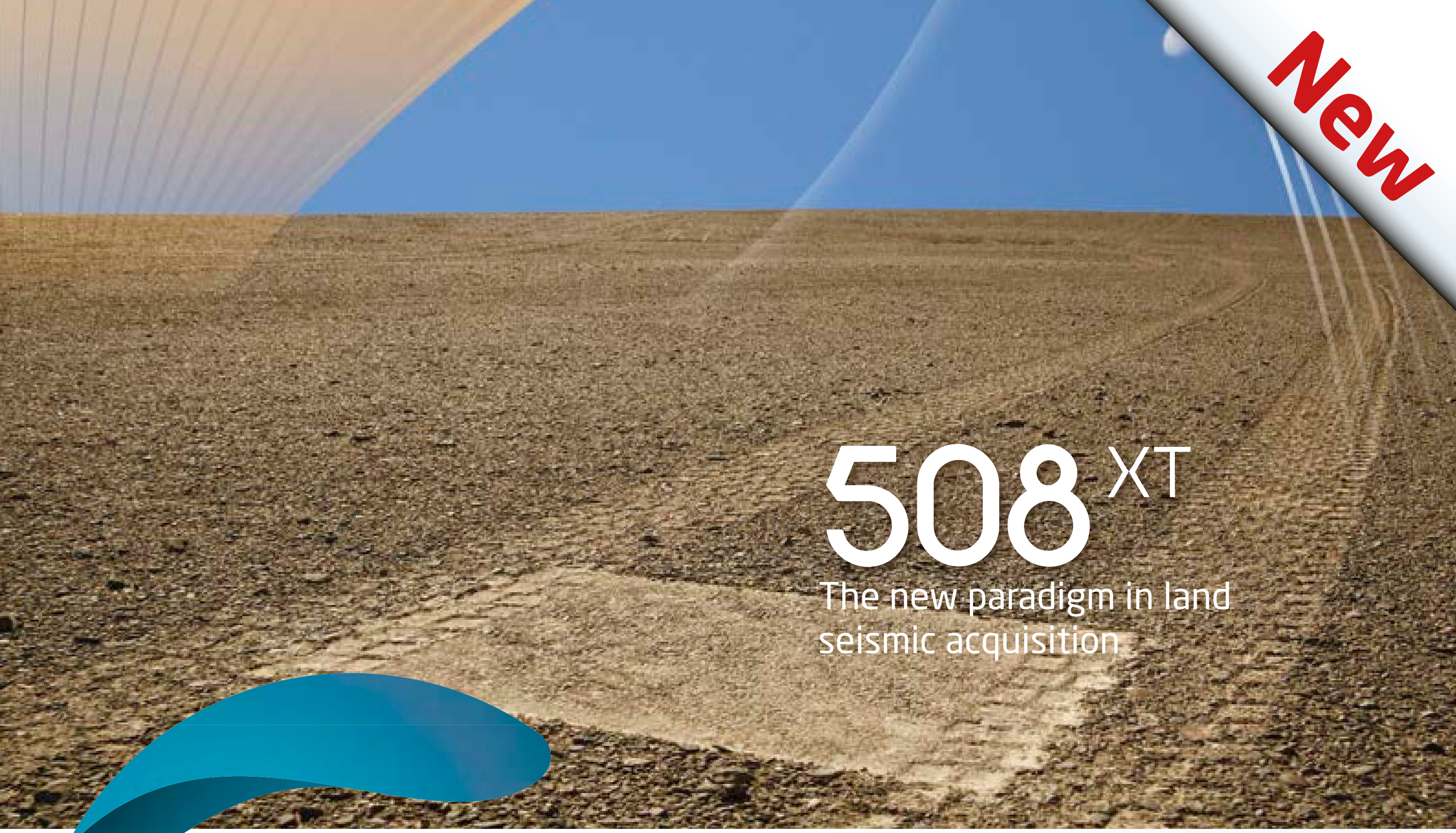
Salty Project

Recent gravimetric surveys carried out by Prospectiuni SA have led to the identification of new salt deposits in the Slanic Prahova region which could be exploited in the future. The company carried out an evaluation project of the potential of the salt deposits, targeting the expansion of the existing salt exploitation area. When the investigation started, the Badenian salt resources, known and exploited historically, were considered exhausted. Additional aims of the project were to clarify the relationship between the new salt accumulations and the adjacent deposits, to delimit the sectors with economic potential, and to obtain a deeper knowledge and a more accurate analysis of the structural elements.

Through the gravimetric surveys carried out in this project, which comply with the highest standards of efficiency and accuracy, it was possible to map with precision the main salt accumulation of variable thickness and extent, highlighting at the same time four new areas with economic potential, where the level of the reserves could be estimated. In order to support accurate quantitative estimates, the Prospectiuni gravimetric crew developed a three-dimensional simulation model (consisting of 335 prisms of square section, with the side of 100m) starting from the gravity residual anomaly. The correlation between the simulation model and the field observations proved to be very good.

The data obtained contributed to future investigations made by drilling, which accurately confirmed the advanced model and led to the promotion of new exploitable salt reserves. ■

The salt mountain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Unlocking the Earth

A Short History of Hydraulic Fracturing

MICHAEL QUENTIN MORTON

The recent shale gas boom is a reminder that the effective use of hydraulic fracturing in shale formations is a relatively new phenomenon. However, this ‘fracking’ (also called 'fracing' or ‘fraccing’ in the technical literature) has been around for longer than many people realise, and the use of unconventional techniques to extract oil and gas from the ground has developed over more than 150 years.

Fracking has come a long way since 1857 when Preston Barmore lowered gunpowder into a well at Canadaway Creek, NY, and dropped a red-hot iron down a tube, resulting in an explosion that fractured the rock and increased the flow of gas from the well.

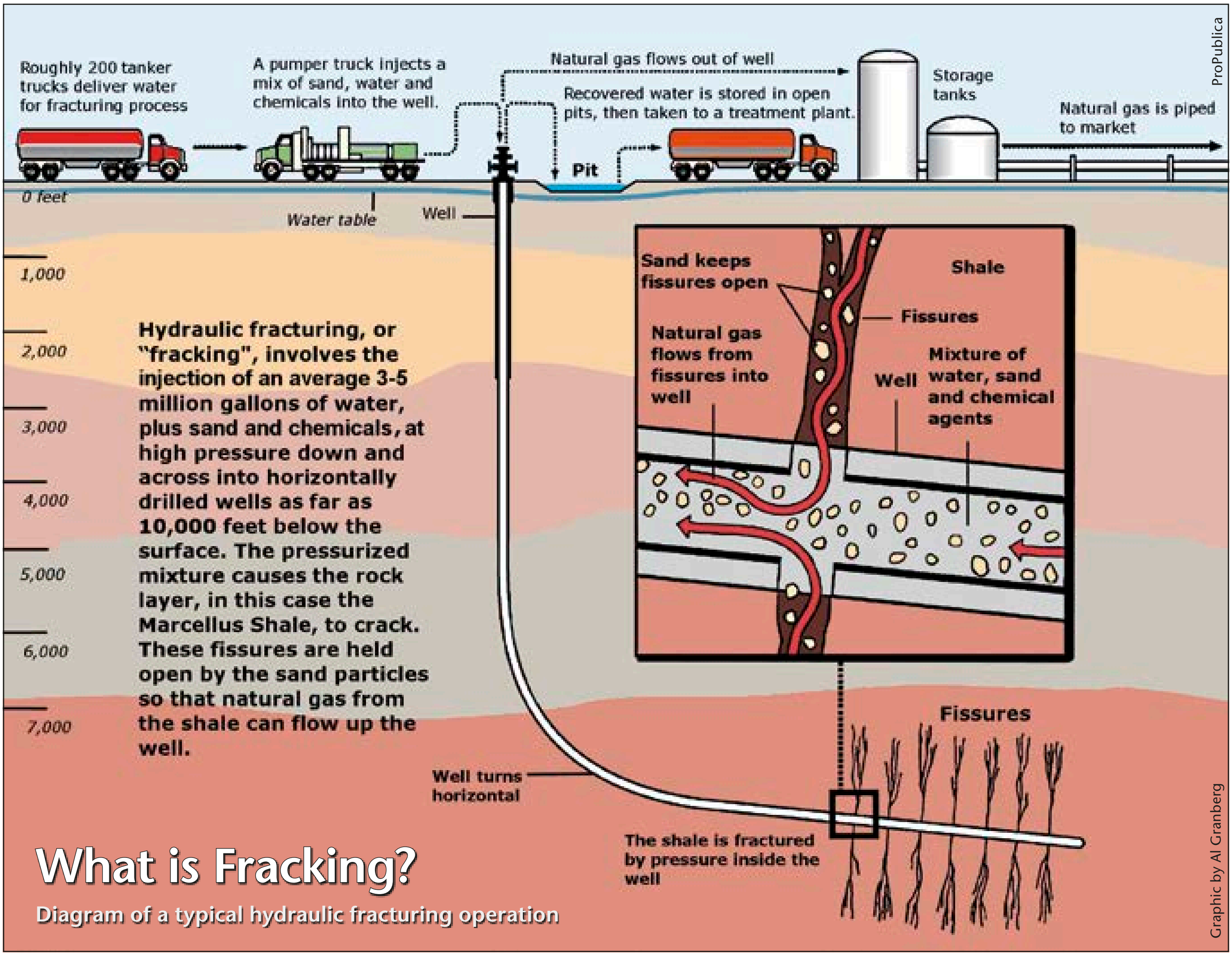
Hydraulic fracturing, as its name suggests, involves pumping water and sand at high pressure to fracture subterranean rocks. This might appear far removed from the mid-nineteenth century practice of ‘shooting’ a well, which used explosives instead of water, but the basic principle is the same. Drillers freed-up clogged or non-productive wells by creating underground explosions to loosen rock or debris. The effect was often the reverse of modern fracking: a column of earth, water and oil would shoot out of the well head, a spectacle for onlookers but hardly a reliable industrial process.

Courtesy of The Drake Well Museum, Pennsylvania Historical and Museum Commission

In 1865, Col. Edward Roberts and his brother developed a technique known as ‘super-incumbent fluid-tamping’, in which water dampened the explosion, preventing any debris blowing back up the hole and amplifying its effects. They also developed a nitro-glycerine ‘torpedo’, replacing the black powder and gunpowder that had previously been used. Their legacy lives on with the Tallini and Otto Cupler Torpedo Company, which still shoots wells with

Drilling for shale gas, Washington County, Pennsylvania, in November 2010.

Mark Schmerling, www.fractracker.org



modern explosives and rigorous safety procedures.

It was left to others to develop techniques to crack the rock: in the 1930s, experiments were conducted using acid instead of explosive, a technique known as 'pressure parting' and, in April 1939, patents were taken out for a device in which projectiles were shot through a casing into the rock formation.

The Advent of Fracking

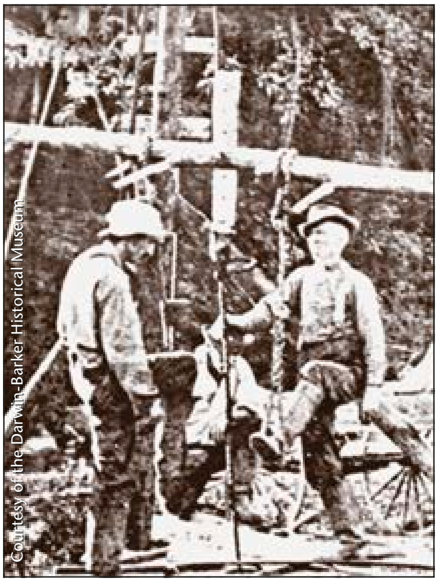
In the 1940s, Floyd Farris of Stanolind Oil proposed that fracturing a rock formation through hydraulic pressure might increase well productivity. This was followed in 1947 by the first application of the 'Hydrafrac' process at the No.1 Klepper well in the Hugoton Field, Kansas. One thousand gallons of naphthenic acid and palm oil (napalm) were combined with gasoline and sand to stimulate the flow of natural gas from a limestone formation.

In 1949, Halliburton Oil Well Cementing Company obtained an exclusive licence (subsequently extended to other qualified companies) for the hydraulic fracturing process. In the first year of operations, 332 oil wells were treated with crude oil or a combination of crude oil, gasoline and sand. The wells on average increased production by 75%. From 1953, water was also used as a fracturing fluid, and various additives were tried to improve its performance. By 1968, fracking was being used in oil and gas wells across the United States, but its application was limited to the less difficult geological formations.

The Fracking Breakthrough

Fracking was transformed when it was combined with horizontal drilling and other new technologies, such as 3D seismic imaging. Horizontal drilling wells extended the range of fracturing sideways along a rock formation rather than contacting it vertically. Millions of gallons of water mixed with sand and chemicals were then injected at high pressure into the well to fracture the

The Barmore well in 1858.



rock. This mixture (or 'proppant') filled the fissures and propped them open, allowing trapped oil and gas to flow out.

Shale rock presented a particular challenge because of the difficulty in accessing the hydrocarbons in these tight formations. In the mid-1970s, the US Department of Energy (DOE) and the Gas Research Institute (GRI), in partnership with private operators, began developing techniques to produce natural gas from shale. These included the use of horizontal wells, multi-stage fracturing, and 'slick' water fracturing (*GEO ExPro* Vol. 9, No. 2).

Between 1981 and 1998 a Texas company, Mitchell Energy and Development, experimented with these techniques in testing the Barnett Shale formation. Commercial success came when the company combined them with slick water, a low viscous mixture that could be rapidly pumped down a well to deliver a much higher pressure to the rock than before. A merger between Mitchell Energy and Devon Energy in 2002 brought a rapid increase in the use of fracking with horizontal drilling. With other companies involved, fracking spread to shale exploration in Texas, Oklahoma, Arkansas, Louisiana, Pennsylvania, West Virginia and the Rockies.

Fracking 'Quakes

As public awareness of fracking has grown, so have concerns about the process, especially the large volume of water used, the resulting wastewater, air pollution and the consequences of injecting chemicals deep underground. Opponents point to the possible contamination of aquifers by chemicals associated with fracking or by the escape of methane gas. According to geologists, it is unlikely that the gas will rise far enough to reach the shallow aquifers that supply drinking water, although some researchers disagree. It appears that, at production sites, fracking causes lower leakages of methane than had been feared. In a number of cases, landowners and farmers have claimed that leaks from holding ponds, spills and underground ruptures have polluted their water.

The first commercial hydraulic fracking site at Duncan, Oklahoma, in 1949.

A hydraulic fracturing operation at a Marcellus Shale well, Pennsylvania.

Microearthquakes (less than magnitude 3 on the Richter Scale) are an integral part of fracking. They carry a very low risk of destructive effects – virtually all observed microseismic events associated with fracking are of a magnitude -0.5, well below levels that are noticeable to the public. Small earthquakes in south Texas have been linked to increased extraction of oil and brackish water in the shale boom, but not directly to the fracking process. Low-level seismic events between 2009 and 2011 in remote areas of the Horn River Basin, British Columbia, were caused by fluid injection during hydraulic fracturing in proximity to pre-existing faults, but only one of these events could be 'felt' at the earth's surface and no damage or injury was caused.

Most earth tremors attributed to fracking are associated with the injection of wastewater into wells deep underground. This can change the fluid balances in rocks and the stresses in the Earth's crust near a fault. Generally, these so-called 'disposal wells' carry a small risk of induced seismicity and, in

relation to their large number, there have been few recorded seismic events. However, a 5.7-magnitude earthquake in Oklahoma in 2011 has been linked to the disposal of wastewater from oil production. It appears that some areas in the mid-western United States are prone to a process called 'dynamic triggering' whereby distant earthquakes might trigger minor earthquakes along faults which have been 'critically loaded' by disposal wells. If strategies are devised to minimise the impact of these wells on underground fluid balances, then the risk of induced seismicity will be reduced.

The Hamster's Wheel

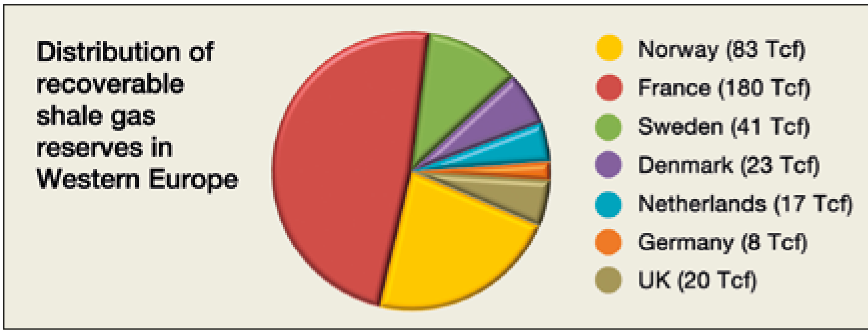
The International Energy Agency (IEA) estimates that, over the next five years, the US will account for a third of new oil supplies. The growth in US production is largely attributable to a steep rise in the recovery of shale oil, in which fracking has played a major part, unlocking major shale rock formations such as the Bakken in North Dakota and Montana.

The tables are turning. The US is likely to change from the world's leading importer of oil to a net exporter and, according to the IEA, will be self-sufficient in its energy needs by 2035. It has also led to a refocusing of US foreign policy, away from an historical reliance on the oil-rich countries of the Middle East.

The natural gas boom initiated by fracking has had a number of consequences (*GEO ExPro*, Vol. 10, No. 3). In the United States, with low prices resulting from the development of unconventional gas, producers are currently active in preserving leases for future development. Today's story is more about fracking for liquids – natural gas liquids (aka condensate) and oil. Commodity prices and economics are driving relentless activity in the Eagle Ford Basin in south Texas, the Permian Basin, the Williston Basin in North Dakota, and the Utica Shale in western Pennsylvania and eastern Ohio. Like a hamster on a wheel, the producer has to keep production numbers up, or even rising, in order to satisfy investors.

Fracking in Europe

Europe's reserves of 639 Tcf compare favourably with America's 862 Tcf, but there are other factors to consider. European geology tends to be more complicated, with the shale buried deeper underground and therefore more expensive to extract. According to Deutsche Bank, a well in Europe might cost as much as three-and-a-half times more than one in the US.



EIA ARI World Shale Gas Resources

The American gas industry is less restricted than in Europe, with hydraulic fracturing being exempted from the Safe Drinking Water Act. This contrasts with France, where there is a moratorium on fracking while an assessment of the risks is carried out. But some countries have forged ahead: in Poland, for example, exploration licences have been issued to 20 firms, test wells have been drilled, and commercial production is likely to commence in 2014.

In the United Kingdom, until the occurrence of two small earthquakes (3.2 and 2.4) in Lancashire in 2011, fracking was not widely known. In fact, the process has been going on since the 1970s, with 200 wells fracked onshore and even more in the North Sea. Various experiments have been tried: the Lidsey oil well, for example, was fracked in September 1991 using as the fracturing agent microbial acid, otherwise known as Marmite, a yeast and vegetable extract. In theory, Marmite (and molasses) would be food for special bacteria, which would excrete acid to dissolve the carbonate rock. Unfortunately, it also fed the indigenous bacteria to produce hydrogen sulphide gas. The well was also fractured with a typical sand frack before the Marmite treatment, and is still producing today.

Unanswered Questions

Although the global potential of shale gas is vast, it is uncertain how much can be produced. And, although shale gas is cleaner to burn than conventional fossil fuels, its overall impact on global climate change is difficult to predict. Environmental concerns persist: in China, drilling for oil has begun in the earthquake-prone Sichuan region; in South Africa, the government has lifted a moratorium to allow fracking in the Karoo region, raising fears of damage to its ecosystem. Whatever fracking's real benefits, one thing is certain: the arguments over its future risks and impact are set to rumble on.

Acknowledgements:
The author wishes to thank Peter Morton, Julie Shemeta, Eric Vaughan and Steve Wolhart for their assistance. ■

West Sussex, England, 1991: the fracking fluid in the tanks is pumped into the well using Marmite in the fracturing process.

Eric Vaughan

Aberdeen
The Granite City

An oil boom city, Aberdeen's growth since the 1970s into one of the main global hubs of the oil industry has shaped and defined the modern city.

PAUL ARCHER

Union Street.

Aberdeen ('the mouth of the Dee' in Scots Gaelic) is the third most populous city in Scotland, and lies in the north-east of the country. It is an old city – a settlement is thought to have been on the same spot for over 8,000 years, the Romans were there, the Normans founded the port and it has had a university since 1495. Robert the Bruce laid siege to Aberdeen castle in 1308 during the Wars of Scottish Independence, eventually destroying it and massacring the English garrison inside. When the railway line was finished in 1850, Aberdeen became more successful as it meant fish trains could go between Aberdeen and London and it became Scotland's largest fishing port.

Aberdeen owes its distinctive appearance to the local grey granite that many of the buildings are made from, giving it the nickname 'Granite City' or the 'Grey City'. It grew up around the typical local industries of fishing, shipbuilding, papermaking and textiles, although by the end of the 19th century the granite itself was a major business; Aberdeen was the world centre for the granite trade, employing thousands of men cutting, polishing and sculpting the stone, which was sent around the world. Aberdeen's famous 'Granite Mile', Union Street, remains the heart of the city.

However, it was the discovery of oil in the North Sea which defines the city these days. Although it had been speculated about for many years, only in the 1960s, when the sheikhs and leaders in the Arabian Peninsula started to realise the value of their supplies and the political implication of this, did it become economical for the major oil firms to start to tackle the relatively challenging deep waters and inhospitable conditions of the North Sea. The first discovery was the Forties field, 180 km north-east of Aberdeen, in November 1970 (*GEO ExPro* Vol. 7, No. 3). The city, being the nearest port, and with an extensive dock area, was the natural base for the developing industry, and since then oil – and oil money – has been flowing and is expected to carry on flowing for quite a few years yet.

Booming Economy

The oil industry is thought to have created over half a million jobs in the Aberdeen region over the past 40 years, and it still employs 47,000 people. The surge in jobs bolstered the local economy throughout the 1970s and 80s, funding the development of the city with new schools and housing and it is estimated that over £175 billion has been paid in taxes directly due to the oil industry. The industry is thought to have invested over £200 billion into the region itself so it is no surprise, then, that Aberdeen is one of the wealthiest places in the UK, and is the only UK city to have actually grown its economy during the present recession.

However, it is not all good news. The rise in house prices that accompanied the boom now means that the younger generation struggle to afford properties and typical industries in the city have been squeezed. For example, electricians can earn three times as much by working on the rigs than they would back in Aberdeen and the average salary for oil workers is £64,000 per year – more than double the UK average. In addition, the city's infrastructure, which was rapidly thrown together at the beginning of the boom, is now starting to decay and although expensive cars roam the streets, the city has a run-down appearance that is not reflective of its wealth.

Ten years ago, extraction of oil in the North Sea cost approximately $5 per barrel, which was comparable to West Africa or the Caspian Sea, and investment from the big firms declined as they shifted their energy and money elsewhere towards discovering larger finds to boost their reserves. This year, however, has seen an increase in investment from £11.4 billion in 2012 to £13 billion and deepwater drilling has become more attractive. By 2017, it is estimated that 2 MMbopd a day will be extracted, which is up from the current 1.5 MMbopd today.

Another reason for the increase in investment is down to

Panorama of Aberdeen.

tax breaks. UK Chancellor George Osborne made a £2 billion tax raid back in 2011, which meant that the North Sea's marginal tax rates were raised to up to 81%. This was eased this year by a series of tax allowances designed to promote exploration in more challenging fields, making it more attractive for the firms to return, and helping boost Aberdeen.

Energy Capital of Europe

As reserves in the North Sea decline Aberdeen has attempted to rebrand itself as 'Energy Capital of Europe' – moving away from the reliance on oil and focusing on energy services and renewable energies. The expertise in the industry is now becoming a valuable commodity. Firms based in Aberdeen who cut their teeth in the boom years and generated huge amounts of specific expertise are now selling that expertise overseas as they bring their knowledge to new spheres. As offshore fields are being explored in deeper and deeper water, Aberdeen has become a world centre for innovation and the execution of the technology that makes the modern offshore energy industry possible. It is thought that British companies have a 45% market share of the global subsea business, worth just under £9 billion – and many of these businesses are based in Aberdeen.

The city has mapped out a 20-year plan to reinvent itself without the reliance on oil. By investing in projects to liven up the city's appearance and improving support for the arts, they hope to make the city more desirable. Technology will play a key part with many tech firms deciding to base themselves there as well.

Recently described as 'the City the Credit Crunch forgot', Aberdeen now thrives with over 800 shops, five major shopping centres and restaurants from all over the world, plus a wide range of entertainment and events, museums, art galleries and fashionable café bars, as well as a long beach only a mile or so from the city centre. ■

Aberdeen Harbour, with the grey granite buildings of the city behind.

The world's most significant discoveries brought to you by IHS and GEO **ExPro**

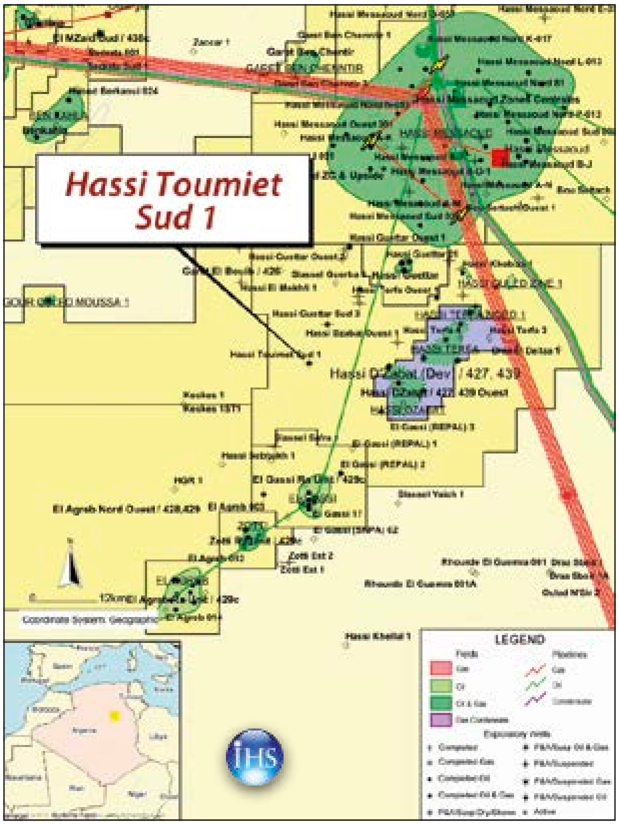
KEN WHITE

Algeria: Sonatrach taps high potential oil play

Described as one of the company's most important finds in the last 20 years, Sonatrach has made an oil discovery with an estimated 1.3 Bbo in place in the region of Tamguid Messaoud, some 112 km from the giant **Hassi Messaoud** facility. The find is believed to be **Hassi Toumiet Sud 1**, that was drilled to a total depth of 3,700m in the Hassi Dzabat block 439, on the Hassi Messaoud (El Biod) High. According to Energy Minister Youcef Yousfi, Sonatrach would have to use non-conventional methods to extract 50% of the reserves from the new field, adding an extra 10% to costs.

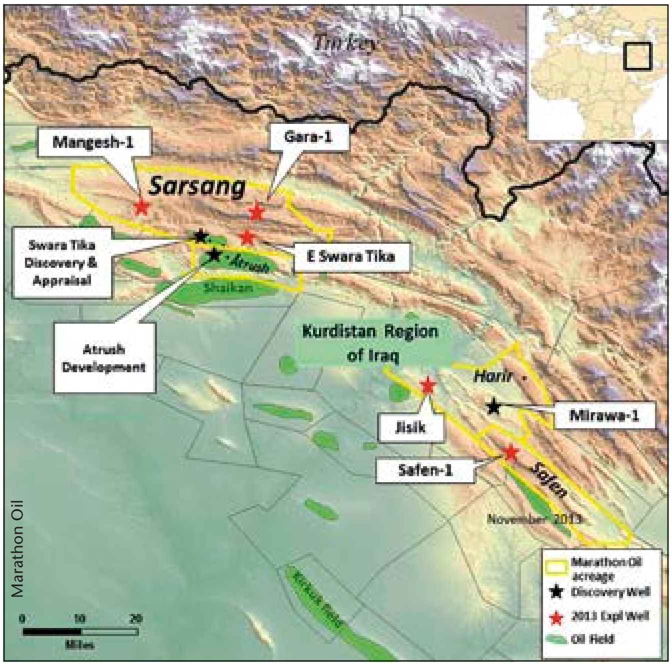
Algeria remains one of the largest natural gas suppliers to Europe but has been concerned about declining oil reserves for some time. While the Cambrian reservoirs stay an important target, Sonatrach has been keen to exploit the Ordovician reservoirs, which constitute a new and main objective not just in the satellite discoveries that surround the Hassi Messaoud oil and gas field but in the whole area. Eroded at the Hercynian unconformity in this giant field, the Ordovician reservoirs (mainly the Hamra Quartzites) form a ring around the Hassi Messaoud dome and represent an oil play with high potential. This latest find adds further weight to this understanding.

Hassi Messaoud, which lies about 560 km south-east of Algiers, originally had 38 Bbo in place and has been producing since 1957. ■



Iraq: Marathon high-risk high-reward success

Demonstrating the importance of the **Kurdistan** region as a potential major hydrocarbon province, and underlining a strategy to explore high-risk, high-reward prospects, Marathon Oil's second attempt on the Harir Block has proved an important strike. The **Mirawa 1** exploratory well was drilled to a depth of 4,260m and encountered significant oil and natural gas columns from 1,767m to TD, with gross intervals of 300m of oil shows in the Jurassic and 800m of gas shows in the Triassic. The well encountered light oil of 39–45° API in two Jurassic carbonate reservoirs. Three drill stem tests were conducted, with flow rates between 3,200 and 3,900 bpd, while three other formation tests confirmed the presence of gas and condensate reservoirs in the Triassic. Choked drill-stem tests flowed at approximately 20–30 MMcfgpd and one of the formations also flowed at 1,700 bpd of condensate.



The Mirawa prospect is a four-way closure above reverse faults, and has Cretaceous, Jurassic and Triassic reservoir targets. The Harir Block is estimated by Marathon to have upside potential of 5 billion barrels of oil in place, despite the first well drilled earlier in 2013, Harir 1, being abandoned after failing to flow at commercial rates. Total farmed into the licence in 2012 and current interests are Marathon Oil (operator 45%), Total (35%) and the Kurdistan regional government (20%). Marathon next plans to drill the Jisik prospect in the Harir Block.

Some estimates put oil reserves in Iraqi Kurdistan in the region of 45 Bbo. Negotiations between the Kurdistan regional government and Baghdad as to how much oil can be exported from the region to international markets without having to pass through the central government appear to have reached a stalemate. ■

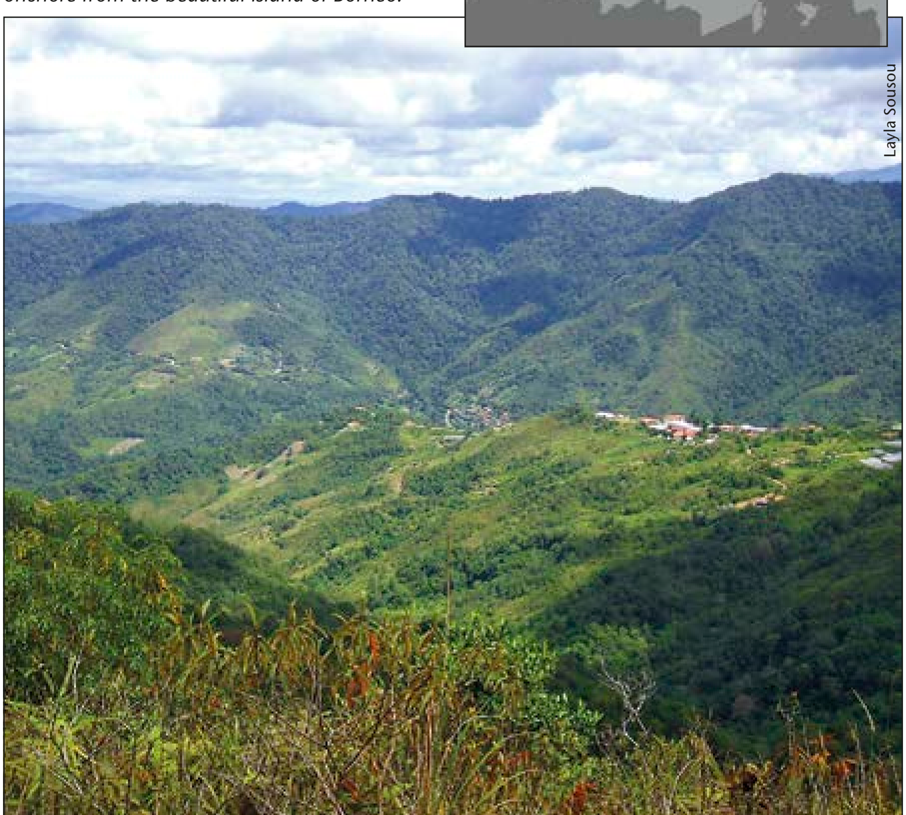
Malaysia – Mubadala find hints at significant gas column

In the same week that the company marked first gas from the Ruby field in Indonesia, **Mubadala Petroleum** also confirmed an important gas find in Block SK320 with the first in a three-well campaign.

Located about 250 km north-west of Bintulu in **Sarawak**, in the Malaysian part of Borneo, in a water depth of 108m, the **Pegaga 1** wildcat was drilled to a total depth of 2,029m and encountered a 247m gas column in the carbonate reservoir of Cycle IV-V. The well was targeting the carbonate Middle to Upper Miocene stratigraphic play, the most prolific in the Central Luconia Province. The well flowed gas to the surface but, significantly, pressure data indicates the possibility of a substantial gas column still not penetrated by the drill bit. The operator plans to conduct further drilling to determine the volumes of the discovery and the gas quality.

Pegaga 1 is the second successful gas well for the joint venture partners in Block SK320 after the M5-2 well drilled in 2012. The remaining two wells in the current programme for which the Songa Venus S/S is being used are Sintok 1 (likely spudded) and Sirih 1. Mubadala holds a 75% interest in the licence and the remaining 25% is held by Petronas (see *GEO ExPro* Vol. 9, No. 4 for more information about the petroleum geology of this area). ■

The Pegaga 1 discovery lies about 250 km offshore from the beautiful island of Borneo.



Into His Mind

Wegener's Jigsaw
Clare Dudman: Sceptre, 2003

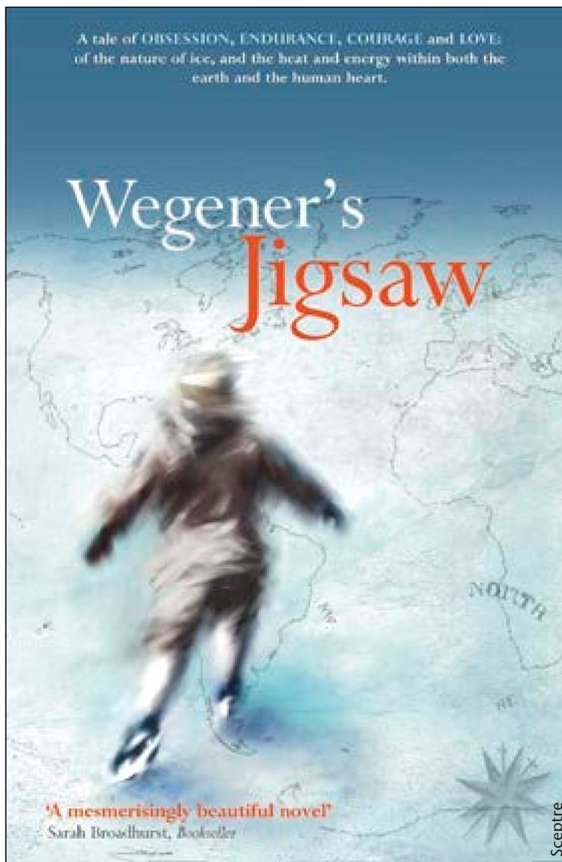
Author **Clare Dudman** uses diaries, letters and published papers to create a novel that takes the reader into the thoughts and life of the revolutionary German scientist, **Alfred Wegener**.

Dr. Alfred Wegener made his first expedition to Greenland in 1906 to study polar air circulation. Upon his return, he accepts a position as tutor at the University of Marburg. Feeling frustrated with his career in meteorology, he visits the school's library. While browsing titles, he finds a book protruding from the shelf and pulls it out. Two words catch his attention: 'Africa' and 'Brazil'. He finds it to be a fascinating compendium on fossils showing identical species from either side of the ocean. The prevailing theory was that the continents were once connected by land bridges that have sunk, thus sharing similar flora and fauna.

Author Clare Dudman writes of Wegener's thoughts shortly after perusing this book, "I stop. My pen blots the page. I watch the ink spreading through the paper. I shut my eyes. There is another way to form a supercontinent. Behind my eyelids the white outlines of the continents slide together to form one unbroken jigsaw. The idea of land bridges is an unnecessary complication. It is much simpler just to assume that the land masses have moved. It explains the fossil similarities just as well. I know it is right."

The theory of **continental drift** is taking shape in Alfred Wegener's mind.

Whether or not that was how Alfred Wegener first came up with the idea that continents can move around is immaterial. Clare Dudman conveys Alfred's actions, thoughts and voice persuasively as the reader is transported to a different time, into the thinking of this great scientist.



Sceptre

His Life's Journey

The book, *Wegener's Jigsaw* (US title: *one day the ice will reveal all its dead*), allows the reader to join Alfred Wegener on his journey through a very remarkable life. Growing up in Berlin, Alfred's early explorations and fascination with science would guide the rest of his life. He set early hydrogen ballooning altitude and endurance records. Dudman poignantly follows his college days and his first Greenland expedition. There, the reader can feel the cold, hunger, and sometimes desperation that Wegener felt as well as his remarkable accomplishments such as using balloons to measure the atmosphere and surviving long treks across Greenland's icefields in the winter's darkness. Learn about his theory on how craters were formed on the moon, how ice flows, how raindrops form; live in the trenches during WWI; and enjoy his family life with three daughters and his remarkable wife, Else. Be with Wegener while he develops his Continental Drift theory and listen to his detractors, all the while remaining determined to prove his theory. Finally, take his journey back to Greenland to learn, map, and explore beyond any previous Arctic expedition. This is a story that is sure to inspire and thrill.

The Author

Clare Dudman was born in North Wales and educated at Leicestershire comprehensive schools, the University of Durham and King's College London. She has a PhD in chemistry and is now an editor with the Writers Workshop. Clare actively gives talks and writes about her research, having written four novels and numerous short stories.

In writing her book *Wegener's Jigsaw*, Clare was inspired not by literature, but by Arthur Holmes's *Principles of Physical Geology*, where she learned about Continental Drift. She says, "Scientific books can be powerful – just as powerful as any others because the ideas are concrete: Charles Darwin's *Origin of Species* must have changed many lives, and he in turn was changed by Thomas Malthus's *Essay on the Principle of Population*."

It is obvious from the start that the author researched into everything she could find. To her surprise, she found very little written in English for the general reader and how little Wegener's important ideas are known today. She was able to piece together her information for this book from various German sources. Particularly helpful were Wegener's many papers and biographies written by his wife, Else Wegener, and German author, Ulrich Wutzke. To add Wegener's voice to this novel, Ms. Dudman uses his expedition diaries and recoded comments from various conferences on Continental Drift.

The novel is based on real events but fictionalised by altering some details to add structure to the story. The book concludes with an extensive reading list about and by Dr. Wegener.

THOMAS SMITH

Imperial College

Petroleum Geology Course Centenary

Petroleum Geoscience has been taught at Imperial College in London for 100 years. **Professor Richard Selley**, who has spent much of his career at IC, tells us about the course and the centenary celebrations.

Tell us about the history of the Imperial College petroleum geology course

Petroleum geology began at Imperial College (IC) in a small way with a course of lectures in 1911. This was so popular that a four-year degree course in Oil Technology was established in 1913. Vincent Illing, a 23-year-old Natural Science graduate from Cambridge, was appointed to run the programme. The course taught all aspects of petroleum exploration and production, from plane table topographic and geological mapping to how to build a drilling rig ('make sure that the timber is well-seasoned') and all aspects of drilling, reservoir evaluation and production. A postgraduate course in petroleum reservoir engineering began in 1955. Postgraduate courses in Petroleum Geology and Exploration Geophysics followed. Today these three courses are run in an integrated 12-month M.Sc. programme.

Is it the oldest course in the world?

No – two courses predate it: the University of Pittsburgh (1910) and the Missouri School of Mines (1912).

Vincent Illing, the father figure of the Imperial College course.


Imperial College archives

How was the centenary celebrated?

On 23–24 September 2013, a symposium of lectures was held at IC. Speakers included the Lords Browne and Oxburgh and many IC staff and distinguished alumni. Apart from an account of the history of oil technology by alumnus and long-serving staff member Mike Ala, the talks focused on the future of petroleum geoscience and technology. After the first day a grand dinner was held in the Earth Science gallery of the Natural History Museum, attended by participants and alumni from all over the world. Two had flown in from Lagos especially for the occasion.

How has post-graduate petroleum geoscience training changed?

Needless to say there have been many changes to the course over the century. Topographic surveying and geological mapping are no longer included. There are still field courses, but little microscopic study of cuttings and cores. Computers have revolutionised the industry, so much time is spent on basin modelling, seismic mapping and reservoir definition and production modelling. Projects are an important part of the course, culminating in the Barrel Award, a team project recently appropriated by the AAPG as the International Imperial Barrel competition.

How important is a post-graduate degree these days?

In the old days a three-year B.Sc. used to be sufficient to be employed by an oil company, especially if followed by a year or two working on the rigs as a mud logger. Today a Master's degree is generally essential.

Is there enough industry involvement in training?

The IC course is integrated with industry throughout. Many students, both British and foreign, are sponsored by companies. The PESGB also sponsors students. Industry provides data for both the Barrel Award project and for the some 80 solo projects that conclude the course. This involves close liaison between students, staff and industry sponsors, enabling sponsors to talent-spot the brightest students.

Should we not just be learning 'on the job'?

Major companies often have carefully constructed career development paths for their new recruits. Smaller companies without these programmes value IC recruits because they are already so well trained that they 'hit the deck running' and contribute from day one. Both routes enable advancement to Chartered Engineer and Chartered Geologist status.

Masters or doctorate: which helps most?

A new Ph.D. has spent the last three or four years focused on one small area of research; thus the broadly-trained Masters graduate is generally the preferred recruit. The exception to this rule is where a company may wish to recruit specialist geochemists, micro-palaeontologists, etc.

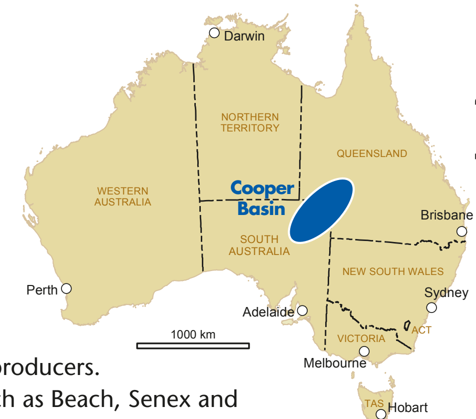
Does the department engage in research as well as teaching?

Yes, indeed. At present the department carries out research across the whole spectrum of petroleum exploration and production, ranging from sediment supply into sedimentary basins, via organic geochemistry of source rocks, to reservoir characterisation, production technology and carbon capture and storage. In the past the department carried out fundamental research into petroleum generation and migration, and unravelled the complex story of petroleum generation and migration in the Wessex basin. Research in this department identified the shale gas resources of the UK nearly 30 years ago. ■

Australia's New Oil Heavyweight

DAVID UPTON

Australia has a surprising new heavyweight in oil production – the western flank of the Cooper-Eromanga Basin.



Energy Resources Division DMITRE

Oil production from this arid and remote region 800 km north of Adelaide has jumped by 47% over the past three years to almost 10 MMb, based on data produced by consultancy EnergyQuest for the year to June 2013. Production is still climbing sharply and looks set to reach 12 MMbo this year, making the western flank a bigger oil producer than the famous fields of Bass Strait, and second only to BHP Billiton's Pyrenees FPSO off the North West Cape.

It is a remarkable revival for an area that was considered by many explorers to have yielded all its recoverable oil for Santos in the 1980s and 1990s.

In the late 1990s, the State Government of South Australia forced Santos to relinquish large tracts of the Cooper-Eromanga Basin. The company had held a near-monopoly for decades, but the government was keen to introduce new players with new ideas. The western margin was let go on the basis it had little left to give. The fact that oil prices were less than $US20 a barrel made the decision easier than it might appear today.

New Ideas Reap Rewards

Beach Energy and Stuart Petroleum (now part of Senex Energy) had other ideas about the potential of the neglected western margin. Both companies had noted the eastern margin of the Cooper, which included Australia's largest onshore oilfield at Jackson in southwest Queensland, had produced about twice as much oil as the western margin. They reasoned the western margin had simply not been adequately explored. The eastern flank play relied on Permian-sourced oil in the Cooper Basin migrating upwards into Jurassic age reservoirs in the overlying Eromanga Basin. The new explorers applied for acreage on the western flank up-dip from Permian source rocks, and in direct communication with Jurassic reservoirs. Of key importance was finding areas where the Triassic regional seal at the top of the Cooper Basin had been eroded away before the deposition of the Eromanga sediments.

Beach was the first of the new explorers to hit success with an oil discovery at Sellicks-1 in PEL-92 in 2002.

The routine use of 3D seismic has been a game changer for the new western flank explorers, which also include Drillsearch and Cooper Energy. The success rate for all exploration wells drilled on 3D seismic has climbed to a remarkable 56% across the Eromanga basin, with even higher rates in parts of the western flank. 3D seismic has also made it possible to identify subtle stratigraphic traps in the form of palaeo river channels, with Senex being the leading exponent of this play type. The Brisbane-based company has embarked on a massive campaign of 3D seismic surveys across several thousand square kilometres with the aim of creating a production line of drillable stratigraphic prospects.

The new boom in oil production is generating rivers of cash for the western flank producers. Companies such as Beach, Senex and Drillsearch have been catapulted into the ranks of Australia's top 200 companies thanks to profit margins in excess of AUD75 a barrel.

Low Cost Production

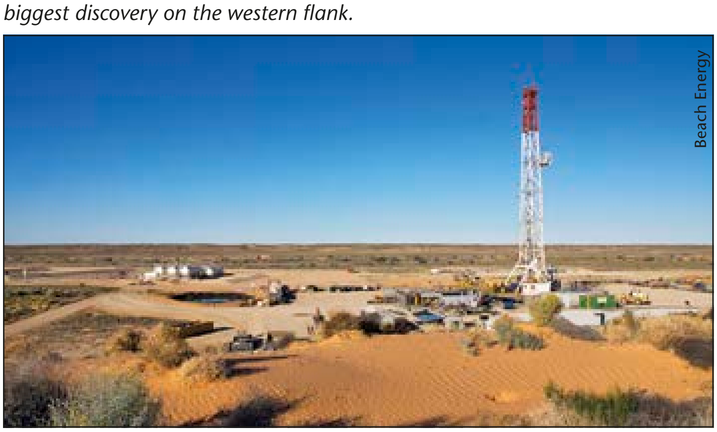
While fields are typically small to moderate in size, they are being developed at low cost by laying flowlines to the Cooper Basin's central gas processing centre at Moomba. Santos built a major liquids pipeline from Moomba to a liquids processing and export facility at Port Bonython on South Australia's Spencer Gulf in the 1980s.

With such attractive financial returns, an increasing number of junior overseas explorers are keen to find ways to grab their own share of the Cooper Basin oil boom, including Canadian Bengal Energy, along with Holloman Energy and Discovery Energy Corp, both based in Houston. Acreage in the heart of the western flank is tightly held, but the state government recently released two areas in the south-west and south of the Cooper Basin that offer some exposure to the oil play that has generated so much recent success.

Explorers are also taking another look at the eastern flank. Beach is about to shoot a 3D seismic survey in a large and overlooked area where, until the end of last year, only eight wells had been drilled across the entire area, with no discoveries. Earlier explorers were mesmerised by the Tookoonooka asteroid impact structures that dominate the area. Beach is counting on 3D seismic to unravel the complicated structures in the area and identify potential traps for Permian-sourced in overlying reservoirs of the Eromanga basin.

If successful, it will be another major new chapter in the Cooper-Eromanga oil story and ensure that onshore production takes an even bigger role in the Australian petroleum scene. ■

Drilling of Bauer-6 in August last year. The Bauer oil field in PEL 91 is Beach's biggest discovery on the western flank.



Beach Energy

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

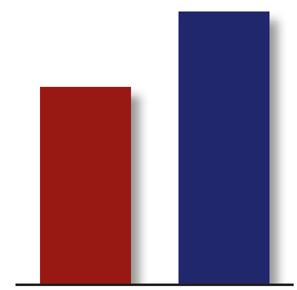
Historic oil price

Oil in Demand

Despite the accepted need to reduce greenhouse gas emissions, oil production is set to increase for the next 30 years, according to the US EIA.

Worldwide consumption of petroleum and other liquid fuels will increase from today's 87 MMbpd to 115 MMbpd in 2040, driven by rapid economic development in the emerging economies of the non-OECD region, with the larger part coming from Asia, says the US Energy Information Administration (EIA). Meanwhile, demand among the more mature economies of the OECD regions remains flat or will decline, according to the IEA's International Energy Outlook 2013.

OPEC member nations are expected to provide almost 50% of the growth in world liquids supply up to 2040. OPEC's additional output is estimated to be 14.1 MMbpd, of which 12.0 MMbpd will come from OPEC countries in the Middle East. The most significant non-OPEC contributors to production growth are Brazil, Canada, the US and Kazakhstan, which together are anticipated to account for 87% of the total increase in non-OPEC liquids supply.



Worldwide Oil Consumption

According to the BP Statistical Review of World Energy (2013), the US has shown a steady growth in production since 2009 (7.263 MMbopd), with a 13.9% increase from 2011 to 2012 (8.905 MMbopd). The IEA outlook states that growth in petroleum and other liquid fuels production in the Americas will be particularly strong in years to come, reflecting contributions from deepwater pre-salt resources in Brazil, heavy oil in Canada, and tight oil in the United States. In fact, it is projected that by 2025 liquids production will balance consumption in the Americas. US production of liquid fuels will also surpass that of Russia by 2015.

Some of this will come from US shale oil; the EIA's assessment of technically recoverable shale oil resources is as high as 23.9 Bbo in the Lower 48. The largest play, the Monterey/Santos, may contribute as much as 15.4 MMbo.

The output of conventional oil from the Middle East has also grown steadily since 2009, reaching 28.27 MMbopd in 2012, in spite of a severe reduction in Iran from 2011 to 2012.

HALFDAN CARSTENS

World liquid fuels production from 1990 to 2040 by region and type.