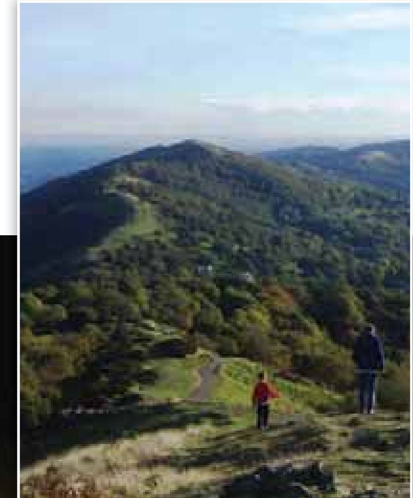
VOL. 8, NO. 3 – 2011

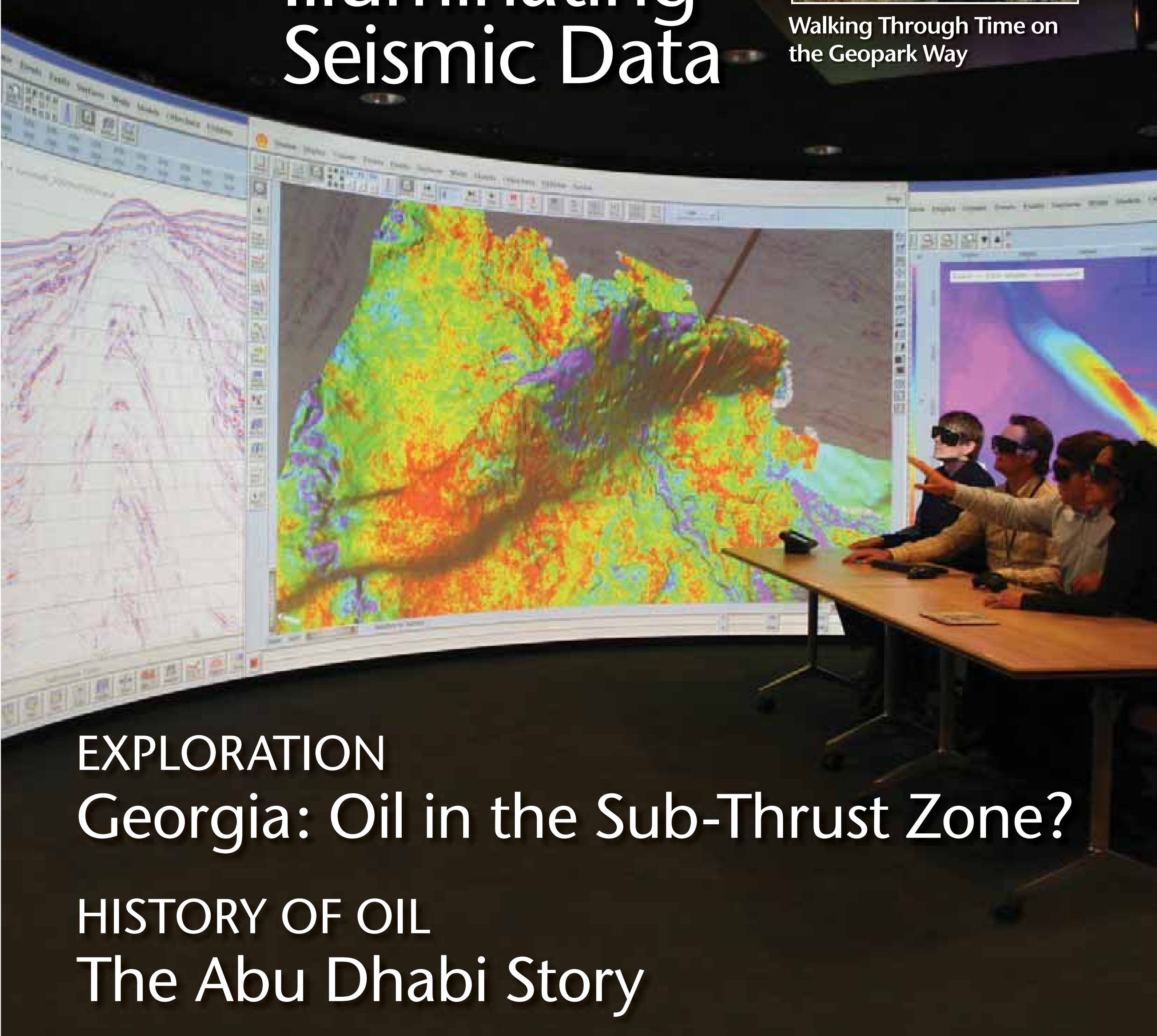
GEO ExPRO

GEOSCIENCE & TECHNOLOGY EXPLAINED



Walking Through Time on the Geopark Way

geoexpro.com



TECHNOLOGY
Illuminating Seismic Data

EXPLORATION
Georgia: Oil in the Sub-Thrust Zone?

HISTORY OF OIL
The Abu Dhabi Story

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT

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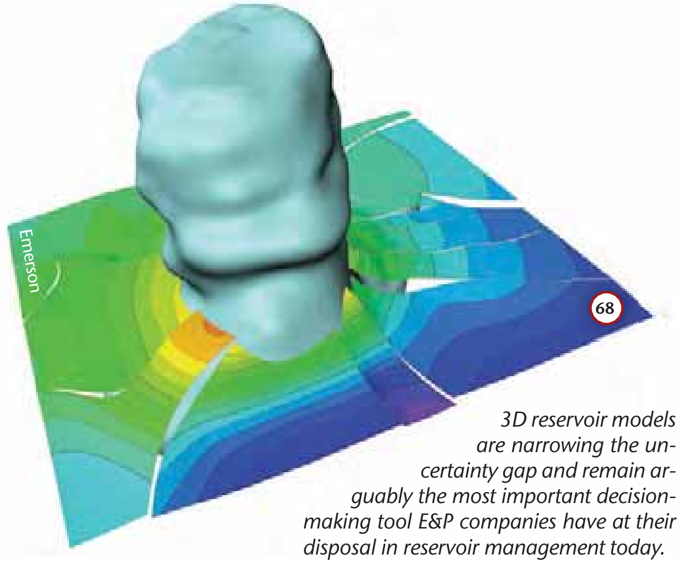
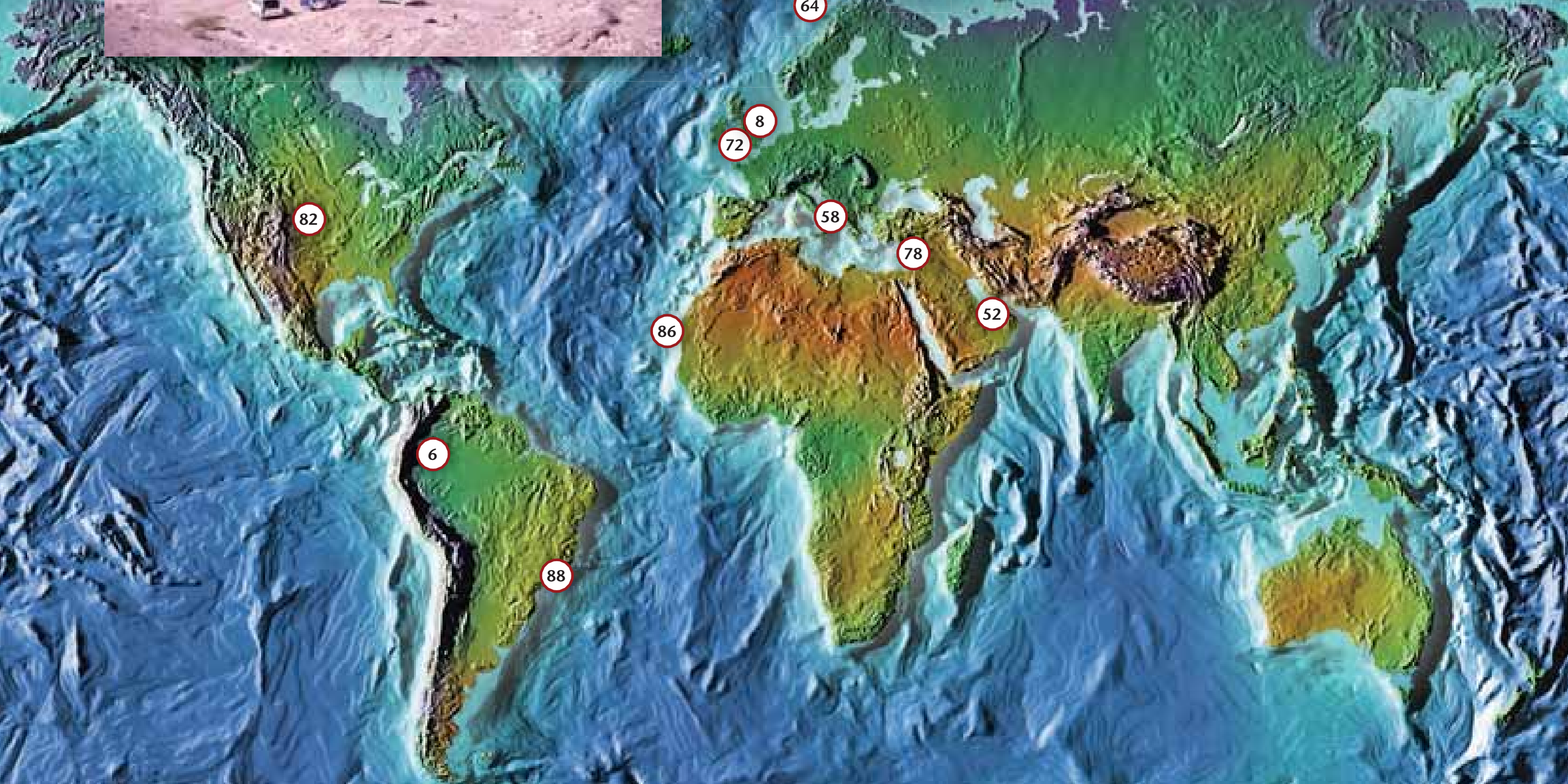


3D reservoir models are narrowing the uncertainty gap and remain arguably the most important decision-making tool E&P companies have at their disposal in reservoir management today.

COLUMNS

History of Oil: Early exploration in Abu Dhabi relied heavily on geophysical surveys to locate potential oilfields.

FEATURES



One Year On

The first anniversary of the Macondo disaster in the Gulf of Mexico has been marked in a number of ways. Foremost it has been an opportunity to remember the eleven men who lost their lives. But it has also been a chance to take stock of the progress which has been made in ensuring that no other families will have to endure such tragedy.

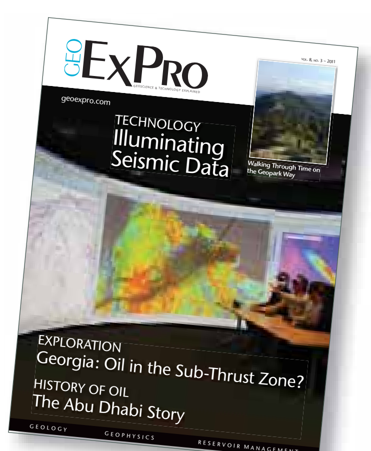
One of the major positives to have come from the disaster is the fact that oil companies are actively working together and sharing knowledge in order both to prevent future major oil spills and to be able to deal with them if they do occur. Well containment systems have been designed which can be deployed rapidly and effectively in a variety of scenarios, not just in the Gulf of Mexico but throughout the world. Major steps forward have been taken to improve response procedures, and the technology is designed to be made available to all operators, should the need arise.

Many observers considered that lack of regulatory control had a part to play in the tragedy, and the US government has responded by reorganising the agency responsible. Other countries have also looked hard at their systems, realising that they too were allowing companies to drill in deep waters without asking the right questions about the abilities of either companies or agencies to deal with a disaster of this scale.

Oil spill recovery preparations and procedures

The oil and gas business probably boasts some of the best scientific intellects in any industry. These are brains which have developed the technology required to visualise rocks buried beneath salt and to identify separate sedimentary layers just tens of centimetres thick, or which can discover ever more innovative ways of squeezing the last drop of oil from a field – topics discussed in this issue of *GEO ExPro.* The industry should ensure that some of these brains are also exercised on planning for the avoidance of disasters such as Macondo in the future. Lack of forethought and funding should never again allow us to bury our heads in the sand and pretend that accidents cannot happen.

JANE WHALEY
Editor-in-Chief



ILLUMINATING RESOLUTION

Evaluation teams rely on high quality seismic to locate the remaining hydrocarbons. Revolutionary new seismic acquisition techniques are now helping geoscientists get high resolution images that illuminate the subsurface completely.

Inset: The Abberley and Malvern Hills Geopark Way is a long distance walking trail that brings to life the fascinating geological story of this beautiful rural part of central England.

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Progress in Colombia

Reforms and security are paying dividends in Colombia

After years of decline, Colombia's upstream oil and gas industry has been revived through a series of government regulatory reforms, partial privatization of the state oil company Ecopetrol, and a much improved security situation, all making the country attractive to foreign investors.

The government reforms that were started in 1999 are beginning to show some real results. Now, Colombia's upstream sector is seeing record levels of exploratory and development drilling. Foreign investment in the oil sector was $2.95 billion in 2009 and over $3.5 billion in 2010. In early 2010, Colombia conducted its latest bidding round that included 255 exploratory blocks covering 526 km^2 in both frontier and established producing areas.

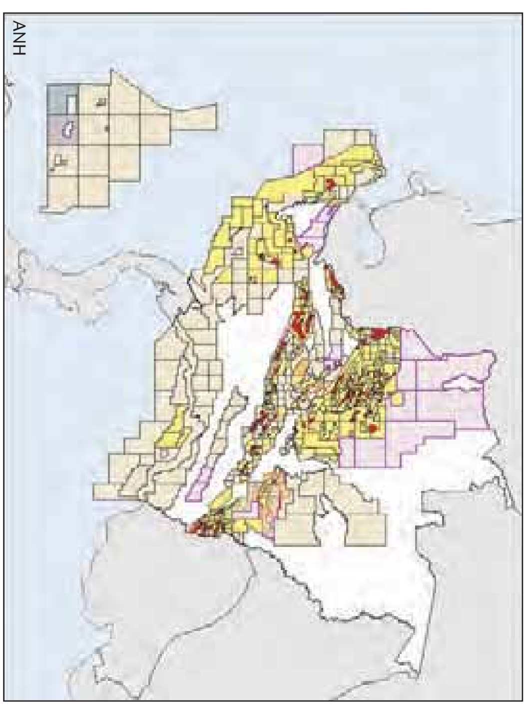
The steep rise in oil production which has occurred since 2007 has been through increasing investment in existing fields, particularly the country's largest, the Rubiales field, that contains heavy crude below 15° API. Production has increased from 12,000 bopd in June 2007 to exceeding 100,000 bopd by the end of 2009.

A recent parade of discoveries is also encouraging. Over the past year, Ecopetrol, along with various partners, have found six new fields in the Magdalena River Basin heavy oil province, a region that produces 40% of the country's oil. According to Ecopetrol's President, Javier Gutierriz, "recent discoveries ….help us meet our goals of increasing reserves and continuously boosting our production by more than 12% a year until we reach one million barrels equivalent by 2015." Independent oil companies recently claimed three light crude oil discoveries in various basins along the Andes foothills and one in the eastern side of the country.

Similar to the oil sector, natural gas production has risen substantially since 2007. BP and Chevron are the largest natural gas producers in the country. A large portion (43%) of Colombia's gas production is re-injected for enhanced oil recovery, but the country is producing more than the amount required for domestic consumption. Ecopetrol claims three new gas discoveries in 2010 and independents are claiming two substantial onshore gas discoveries.

Considerably more drilling programs are planned for the rest of 2011 to follow up on the recent oil and gas discoveries and to probe newly leased acreage. Oil production for March, 2011 reached 884,000 bpd, a 15% increase over last year. Ecopetrol's Javier Gutierriz also announced in March that "the company is on track to produce 1.45 MMboepd by 2013". That exceeds their target previously quoted above, making Colombia an increasingly important player in the world oil and gas industry. (For details about the country and producing basins see *GEO ExPro* Vol. 5, No. 3.)

THOMAS SMITH



Colombia's licensing situation: yellow - areas undergoing exploration; purple - ANH evaluation; red - areas under exploitation; white - areas available for contract.

ABBREVIATIONS

Numbers
(U.S. and scientific community)

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

Liquids

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

Gas

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

Ma: Million years ago

LNG

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

NGL

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

Reserves and resources

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

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

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

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

Increase in UK Tax on Oil Profits

The recent increase in tax on UK oil and gas profits has damaged the industry's confidence

In the UK 2011 Budget George Osborne, the Chancellor of the Exchequer, announced a major increase in the rate at which profits from UK oil and gas production will be taxed. The rates were increased from 75% to 81% on the older, mature fields subject to Petroleum Revenue Tax (PRT) and from 50% to 62% on fields not subject PRT. Since then, a number of representations have been made to the Government, arguing that this will have a major impact on the industry in the UK.

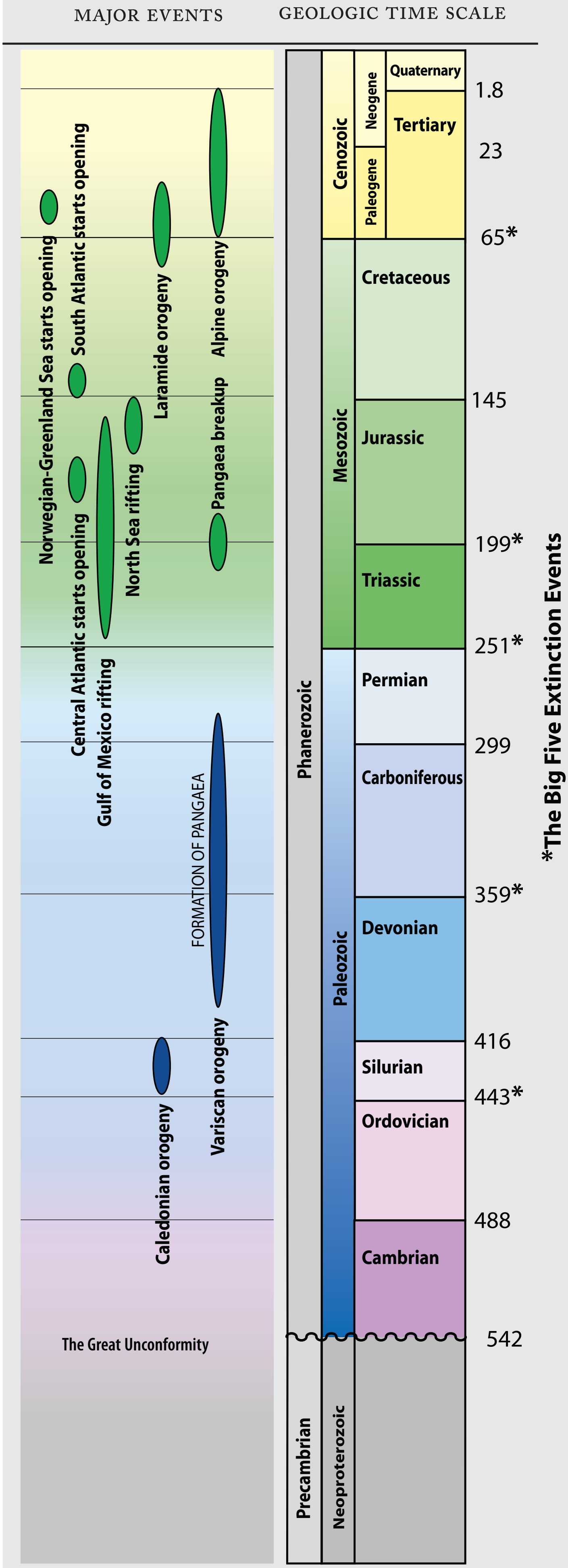
This is the third upward adjustment to the industry's corporation tax rates in nine years, when all other UK sectors have seen corporation tax rate reductions. Almost £2 billion was wiped off the market values of North Sea oil and gas producers on the announcement of the tax change. UK Oil and Gas claimed that "overnight, exploration and production companies in the UK lost nearly a quarter of their value as a result of the tax changes. Not only do investors have to factor in the higher tax environment, but they also perceive the UK as a much riskier place to do business in."

A new study entitled *'The Effects of Budget 2011 on Activity in the UK Continental Shelf'* by Professor Alex Kemp and Linda Stephen of the University of Aberdeen has attempted to quantify the effects of this change by examining the economic effects of these increases on fields and projects which could be developed over the next 30 years as well as on existing fields. It demonstrates that the tax changes will lead to substantial long term reductions in field investment and production of oil and gas. The study suggests that with oil prices of US$90 per barrel, 70 fewer new field or developments projects would commence when compared to pre-budget estimates, with a reduction in total oil and gas production of 2.25 Bboe – nearly 10% less than the pre-budget estimate. Total field expenditure would be reduced by about £52 million – about the same amount as the overall increase in tax revenue to the Government. The study also anticipates that reductions in post-tax returns will discourage companies from pursuing exploration prospects and may also reduce the ability of the industry to finance exploration and development projects.

The Government and the industry are trying to find a way forward and among other things have been discussing alterations to the tax system which could encourage investment in the less profitable fields and minimise the effects on investment, production, energy security and jobs.

JANE WHALEY

George Osborne, the UK Chancellor of the Exchequer, announced major increases in tax on profits from North Sea oil.



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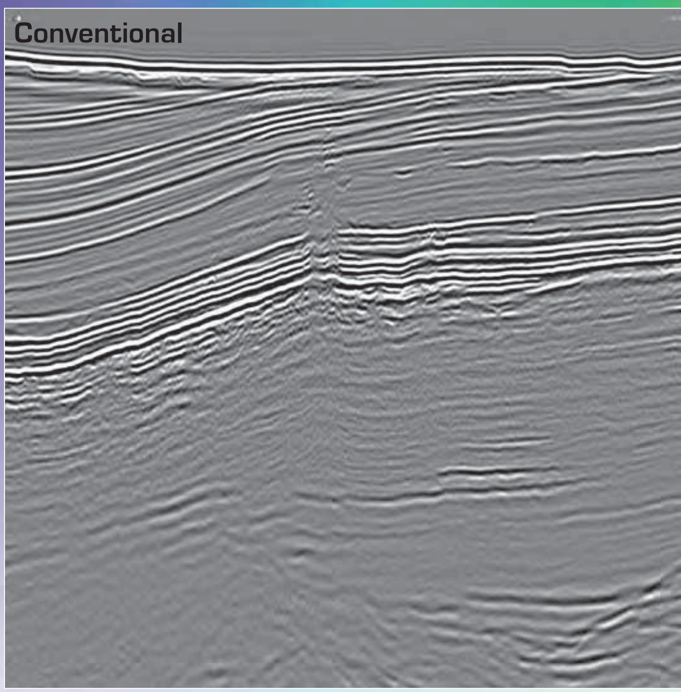

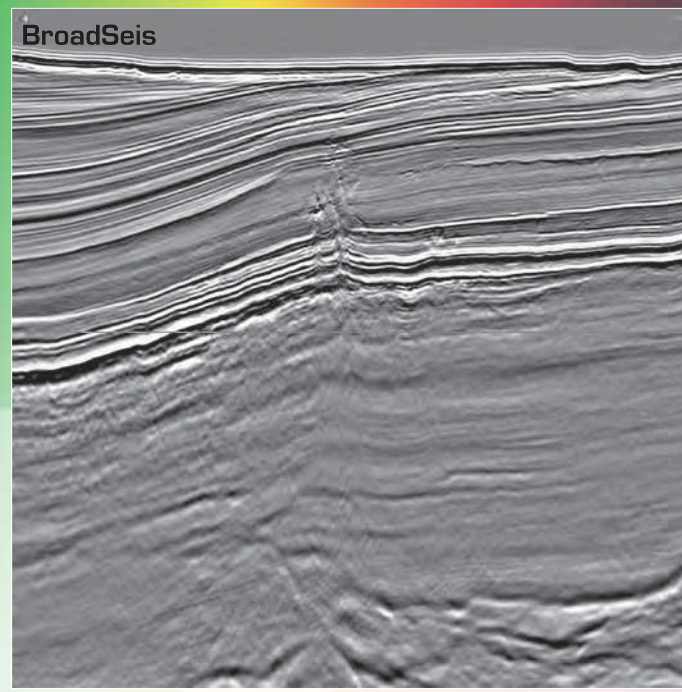

West of Shetland – sub-basalt.

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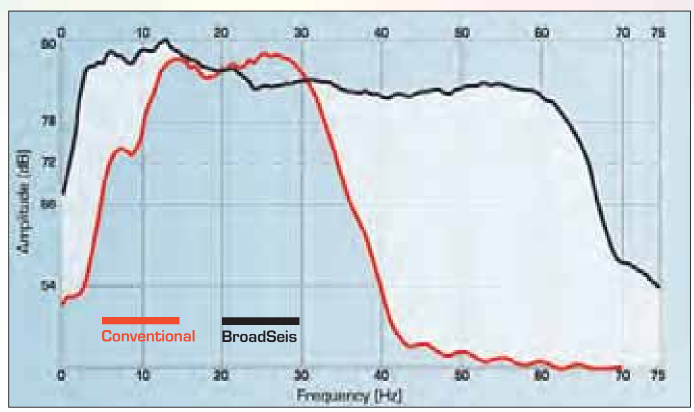

*Patents pending

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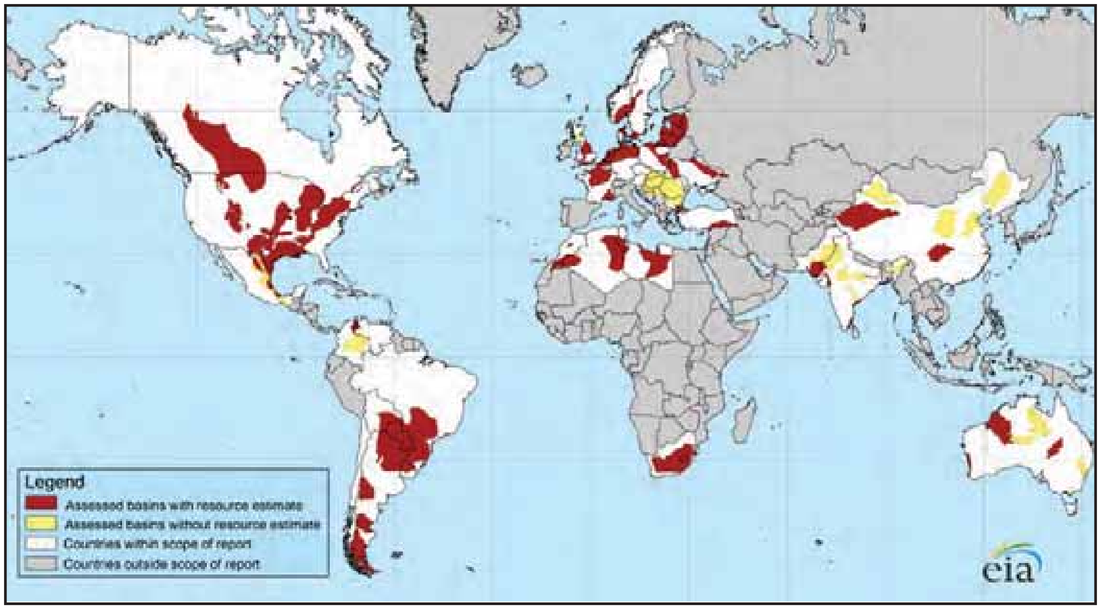
Assessing the World's Shale Gas Potential

A new report commissioned by the US EIA suggests that the world's total shale gas resource is 6,622 trillion cubic feet of gas – and that's a conservative estimate.



Since companies first began looking at shale gas and the technologies required for its exploitation in the US in the 1970s, the industry has moved fast. By 1990 deep shale gas production from the Barnett Shale in North-Central Texas was a commercial reality and by 2005, the Barnett Shale alone was producing almost half a trillion cubic feet per year of natural gas. According to the US Energy Information Administration (EIA), shale gas production in the United States increased from 0.39 Tcf in 2000 to 4.87 Tcf in 2010 – more than 20% of US dry gas production.

Having had such an impact on US production, it is important to have an idea of the total potential reserves of shale gas globally. A new independent report commissioned by the EIA was published in April, the aim of which was to gain a better understanding of the potential internationally through the development of an initial set of shale gas resource assessments. These covered the most prospective shale gas resources in a group of countries, selected because they had sufficient geological data for analysis. In total, the report looked at fourteen regions and assessed 48 shale gas basins in 32 countries, containing almost 70 shale gas formations.

Vast Potential

This study showed beyond doubt that the total shale gas resource potential in the world is vast. The technically recoverable reserves of the 32 countries analysed came to 5,760 Tcfg, without including the US estimated reserves of 862 Tcf. This combined total of 6,622 Tcf can be compared with estimates of roughly 16,000 Tcf for the world's technically recoverable natural gas resources (USGS, *World Petroleum Assessment 2000*). And problems with accessing accurate data meant that Russia, the Middle East and South East Asia are not included in the shale gas estimate. In addition, according to the EIA, the methodology used for the report means that estimates probably tend to be conservative and are expected to increase as more geological and technological knowledge is obtained.

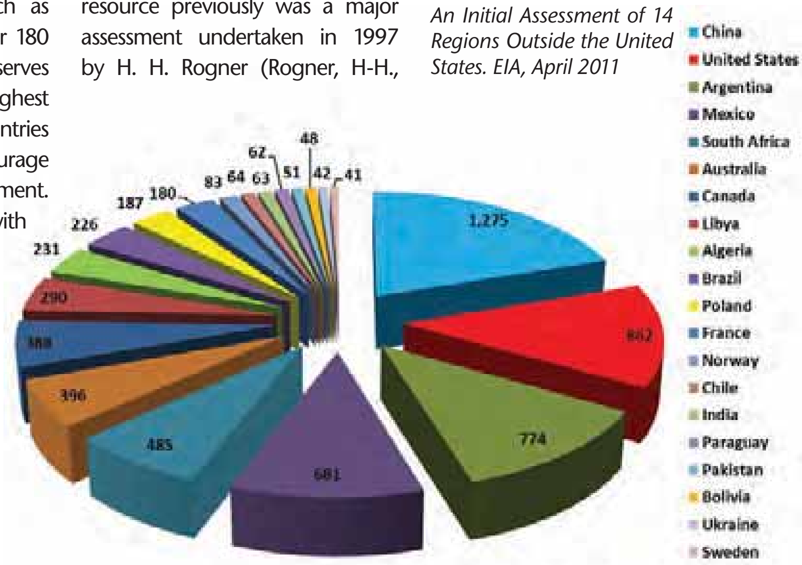
The results could have an interesting impact on a number of countries, particularly those which at the moment are heavily dependent upon imported gas, if their estimated shale gas resource is substantial relative to their current gas consumption. Countries such as France and Poland, with over 180 Tcf estimated shale gas reserves each, are among the twelve highest resource estimates for the countries analysed. This could encourage them to consider development. Similarly, South Africa, with a shale gas resource base estimate of 485 Tcf, could find its import/export gas balance significantly altered through shale gas development.

The report is also of significance to countries such as Canada, Brazil and China with high shale gas resource estimates of over 200 Tcfg, but which already produce substantial quantities of conventional gas. Since they have good infrastructure and supply lines, development of the shale gas would be relatively easy, but could lead to competition with other natural gas supply sources within the country.

The only attempt to quantify the overall size of the world's shale gas resource previously was a major assessment undertaken in 1997 by H. H. Rogner (Rogner, H-H., *Annu. Rev. Energy Environ*. 1997). The EIA study results in a risked shale gas in-place of 25,300 Tcf, which is considerably higher than Rogner's estimate of 13,897 Tcf for the same geographical areas. The most striking difference in the figures for the two reports are from Europe, Africa and North America, with for example, Rogner estimating the total shale gas in place for Europe to be 549 Tcf, considerably less than the EIA assessment of 2,587 Tcf.

JANE WHALEY

World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States. EIA, April 2011



Technically recoverable shale gas resources in Tcfg for the 20 countries with the highest reserve estimates according the EIA report.

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Disturbing Times

Political unrest and natural disasters tighten the oil balance

We expect a faster tightening of the oil supply/demand balance as a consequence of the recent cut in oil production and export from Libya, and a robust growth in global oil demand. In addition we expect the political fear premium will remain high for the coming months. The risk that oil production and export could be seriously hampered or even halted if the unrest in the Middle east and North Africa spreads to vital oil producing countries, will continue to support oil prices.

The Middle East alone accounts for around 30% of the world's aggregate oil production and North Africa for around 5%. The lion's share of Libya's 1.56MMbpdof oil production has come to a halt. We do not expect the production to return to the level we saw before the unrest started as the future political situation is highly uncertain and the disruption may have also resulted in longer term damage to oil production.

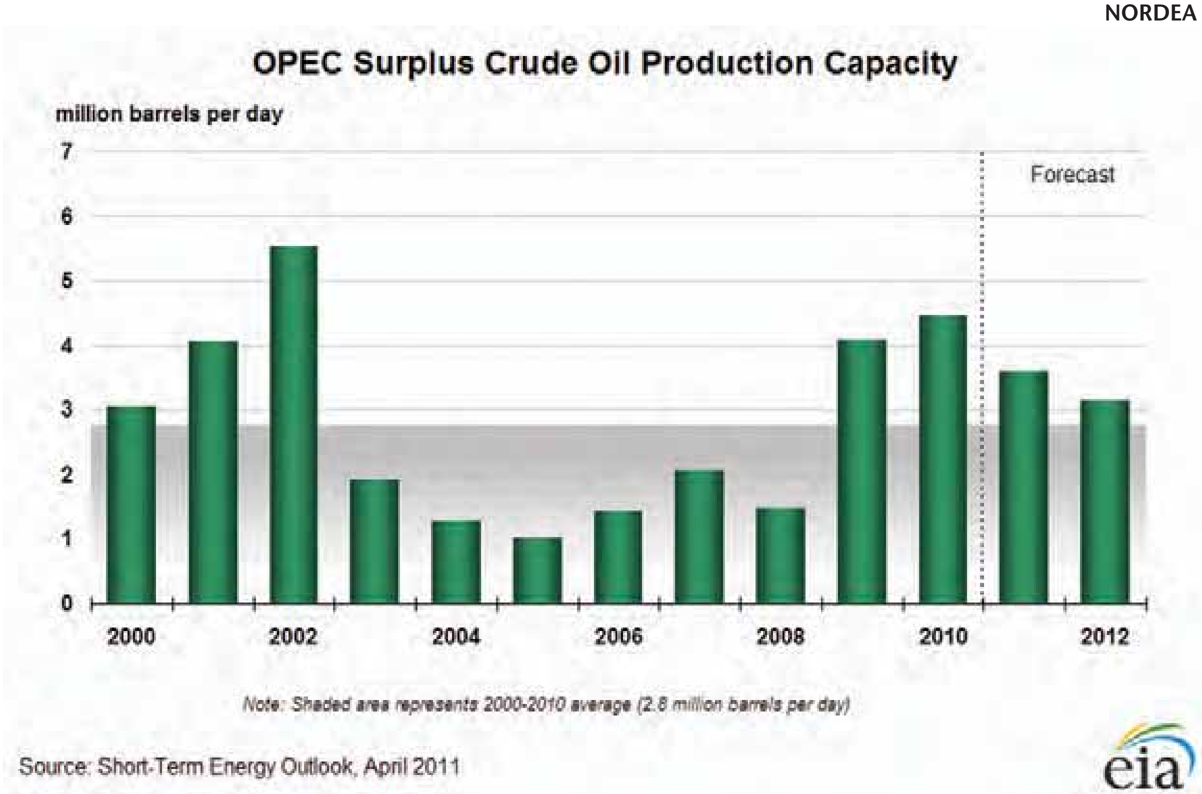
OPEC countries will have to increase production to offset a large share of the losses from Libya. The recent decrease in production by that troubled country has cut the spare capacity available to OPEC substantially and has reduced OPEC's flexibility and buffer in case of further contagion or supply side disturbances in the region. OPEC spare capacity, according to IEA, was around 5.15 MMbopd in January, with Saudi Arabia accounting for around 3.5 MMbopd alone. Saudi Arabia is the world's biggest exporter of oil, accounting for around 12% of the world's oil production, so a significant cut in the Kingdom's oil production would have very serious consequences for the oil market.

Adding to the risk of further production disruption is the presidential election in Nigeria on 9 April. Violent attacks on oil installations and the kidnapping of oil workers have shut in more than 20% of Nigeria's oil production. We expect the violent attacks to continue following the election, which may cause short term disturbances to oil production.

The implications of the tragic earthquake and subsequent tsunami and nuclear problems in Japan are still highly uncertain. In the short term we expect the power demand to have been dampened by the destruction of private houses and business on the coast of Sendai where the tsunami hit Japan, but when the reconstruction begins the demand for power will increase. We expect that the shut down of nuclear power will be replaced by a mix of crude oil, fuel oil and LNG. The total increase in oil demand following the nuclear power plant disruption is expected to be in the range of 200 – 300 Mbpd, not a significant increase when compared to Japan's total energy consumption of 4.4 MMbpd.

The natural disasters in Japan have led to the shut down of seven nuclear reactors in Germany, as well as the suspension of approval for new power plants across China for safety reasons. We expect that tougher safety regulations and an extended start-up period for nuclear power plants around the world in the coming months may lift demand for oil, natural gas and coal further to meet the energy needs any delays may cause. Going forward, this sets the stage for increased demand for oil, natural gas and coal and an upside risk to our oil price forecast in the second half of 2011 and moving into 2012.

THINA MARGARETHE SALTVEDT PH. D
NORDEA MARKETS



INOVA in Successful Oman Survey

Ensuring its growing reputation as a leading provider of land geophysical technology, INOVA Geophysical Equipment Limited recently completed a high productivity Vibroseis 3D seismic survey test in Oman for Petroleum Development Oman (PDO). Undertaken in conjunction with Chinese geophysical service company BGP, the survey used a range of equipment, including INOVA's ARIES II recording system, Vib Pro source controllers, and AHV-IV Vibroseis vehicles.

The field test was designed to acquire data to validate the capabilities of INOVA recording technology in acquiring a range of data. In difficult mountainous terrain, such as in Oman, where the vibrator movement varies significantly between seismic vehicles, it is important to be able to successfully record both Distance Separated Simultaneous Sweep (DS3) and Distance Separated Simultaneous Slip-Sweep (DS4) data effectively, and on this project, production numbers for DS4 reached over 830 vibration points per hour. Increasing surface sampling with high-channel count acquisition systems is important as it increases productivity by reducing equipment-related downtime and minimizes the impact of harsh operating conditions.

TGS Buys Stingray

TGS announced in April that it had acquired Stingray Geophysical Limited, a UK-based company providing seismic Permanent Reservoir Monitoring (PRM) solutions to the global oil and gas industry. Stingray possesses unique fibre-optic sensing technology for seismic PRM and other oil and gas applications.The 4D seismic market, of which PRM is an integral and increasing part, was estimated to be over USD 1 billion in 2010, and, according to Stingray, is expected to exceed USD 2.5 billion within four years. New PRM installations are anticipated to trend towards optical rather than electrical solutions due to the expected increase in reliability and flexibility that this technology offers, especially in deep water.

Robert Hobbs, CEO of TGS said in a released statement, "The age of 'easy to find' oil is over, forcing oil companies to increase investment in their existing fields to extend production and increase recovery factors. The combination of TGS and Stingray will leverage both companies' strengths to create a powerful PRM offering to the industry."

KADME GeoTracker System for Statoil

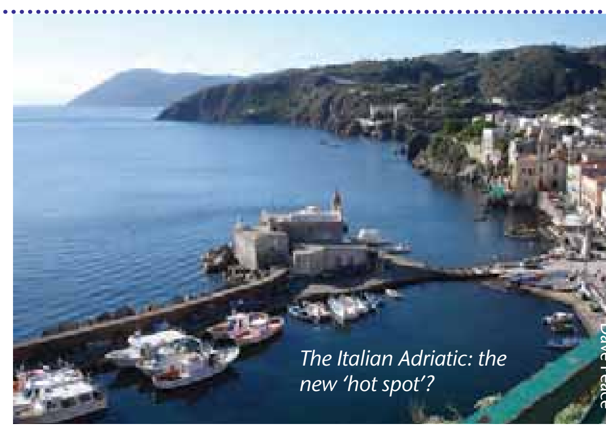
Since establishment in 2002 KADME has grown to become a leading provider of Information Management software and services to the oil and gas industry, with an excellent track record in the planning, deployment and management of information systems up to the scale of multi-terabyte National Data Repositories. Its flagship product is Whereoil™, a search engine which helps find and manage all the data for a project in whatever form, including in proprietary software like Petrel® or SMT Kingdom®, squirreled away in a PC or in a country's National Data Repository.

Statoil ASA has now chosen Whereoil to power its GeoTracker system to monitor and track well reporting. The system will be customised for Statoil's internal data flow, ensuring data passes through the necessary quality control steps and is successfully transmitted globally to regulatory authorities, corporate data stores and other data repositories. GeoTracker will also enable Statoil users to automate data flow tasks based on predefined, country-specific rules.

Spectrum Gets 'Technical'

In recent months Spectrum's technical experts have substantially increased their presence at a variety of industry events including PETEX, APPEX and SEAPEX. New technical papers have been published and presented on areas of core competency, sparking a series of Spectrum-hosted seminars.

Following the great success of its Frontier seminar in Houston, the first of Spectrum's UK Frontier seminars took place in London in March. Designed to provide oil companies with valuable geological and geopolitical information from strategic global frontiers it revolved around four exploration hot spots – East Greenland, the Italian Adriatic, East Mediterranean and Australia. Topics addressed the exploration opportunities along with the political, economic, environmental and technical implications of operating within these hot exploration regions. Over 50 oil and gas industry professionals attended, including Senior Geophysicists, New Ventures Managers and Exploration Directors from some of the world's leading oil and gas companies. Participants agreed out that 'focusing on regions which were likely to be of interest to Exploration Managers, as opposed to covering all areas of the globe, was a smart way of organising the seminar."



The Italian Adriatic: the new 'hot spot'?

These events will now take place on a regular basis Houston, London, and other locations.

GEO ExPro Reunites Old Friends

"The man in the left is probably Don Bowes, an Australian postgraduate student who studied with them." So ran the caption to a photo from the Geological Society archives in the Geo-Profile of renowned geologist Dr. Joe McCall (*GEO Expro*, Vol. 8, No. 1). And a few weeks later the *GEO ExPro* postbag included a note from one Dr. Don Bowes, now Emeritus Professor in the Department of Geographical and Earth Sciences at the University of Glasgow in Scotland, confirming that it was indeed him in the photo. He was very interested to hear what Joe had been up to since they had been students together and asked to be put in touch. Joe in turn was thrilled to hear from his old friend, who he thinks he last saw in Australia something like 40 years ago.


EXPRO PROFILE

Janet Watson and John Sutton were contemporaries of Joe McCall at Imperial College, London. The man to the left is probably Don Bowes, an Australian postgraduate student who studied with them.

students, and taught petrology, structural and economic geology, also supervising various doctorate theses on the PreCambrian Archaean rocks of Australia."

"I also developed a great interest in

and in pipes, but not in kimberlites."

Eventually however, it was time to come home. "Well, the family, now with three children, returned to England," Joe continues. "Within a week, I had left for Iran, to undertake regional geological mapping of the Makran range in the south of the country. We used helicopters to identify areas of interest and would drop off the geologists so they could map a traverse and be picked up at the end point. We mapped an area the size of England in only two years. We had just completed the field work when the revolution happened in 1978 and the Shah was deposed. Luckily for us, the new government decided to support the project, so I was able to complete the write-up – although, having watched the revolutionaries burning banks and other buildings in Tehran, most of this was done back home in Hereford."

There followed three years in Canada.

A First in Asia

Producing hydrocarbons from the challenging environments of high pressure and high temperature (HPHT) reservoirs calls for innovative solutions for drilling, completing and production wells. Halliburton, one of the leaders in this technology, define a high bottom hole temperature as between 150° and 175°C and high pressure as 10,000 – 15,000 psi. However, recent developments mean that we are now extracting hydrocarbons from ultra HTHP environments, with bottom hole temperatures above 200°C and pressures exceeding 20,000 psi, pushing technological limits.

One such project involves two offshore blocks in the South China Sea, the first ultra-high-pressure/high-temperature drilling project in Asia. Major oil service company Halliburton has been awarded a contract to supply equipment and services for this, involving the drilling of at least two highly complex wells, scheduled to start in the third quarter of 2011. Halliburton will provide several ultra-HPHT technologies for drilling, completions, cementing and testing, including the industry's first M/LWD sensors rated to 230°C and 25,000 psi, as well as the industry's first multi-cycle DST tools rated to 260°C.

3D Contract for Dolphin

'New kid on the block' Dolphin Geophysical has been awarded its first 3D contract, moving the company into operational mode. Dolphin, based in Bergen, Norway, aims to become one of the leading and most cost effective marine seismic companies in preparation for the next decade of oil and gas exploration.

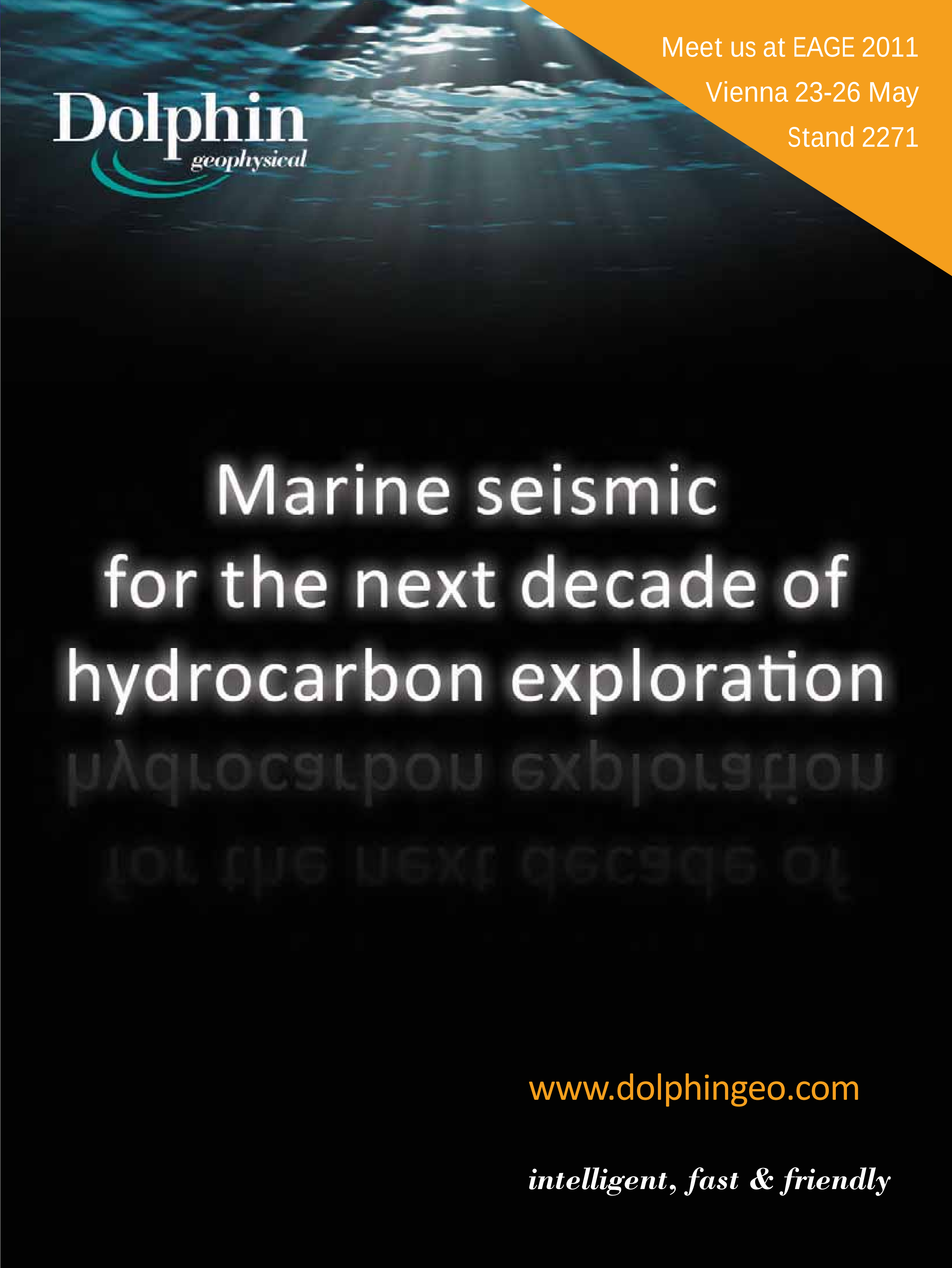
This first 3D contract, signed in early April, is with TGS-NOPEC for the charter of the high-capacity 3D seismic vessel Polar Duke, built in 2010. The project will start in May and continue for a minimum of three months. Dolphin also recently signed a contract with ION's GX Technology Group for a three month 2D seismic acquisition survey offshore West Africa using the Polar Explorer, with acquisition commencing in April 2011. The vessel has been fully equipped with ION's suite of integrated navigation and seismic acquisition equipment including OrcaTM and DigiStreamerTM, and the survey will add up to 7,500 km of new seismic data to ION's West Africa package.

Rainwear and Petroleum Exploration

What do rainwear, hiking boots and finding petroleum have in common? The global company, W.L. Gore and Associates, is famous for making the GORE-TEX® membrane, used in waterproof, breathable clothing and footwear. Each microscopic pore of the GORE-TEX® membrane is about 20,000 times smaller than a drop of water, and 700 times bigger than a water vapour molecule.

The proprietary passive diffusion sampler used in GORE® Surveys for oil and gas exploration features a similar membrane technology so that gases can pass into the adsorbent material in the sampler, but water cannot. Gore's versatile sampler can be placed in soil, sediment or water to detect more than 90 compounds, in the range from C_2 to C_{20}, emitted by charged reservoirs in a parts-per-trillion range. This technology can find and map gas, condensate and oil both onshore and offshore, in all terrains, geographies and climates. Since their introduction 15 years ago, GORE® Surveys have been used successfully in more than 57 countries with climates ranging from frozen tundra to dry desert to tropical jungle, for deep reservoirs, in transition zones and in water depths up to thousands of meters.

And, as any student geologist will tell you, good hiking boots and rainwear are an important requirement in the training of a future exploration manager!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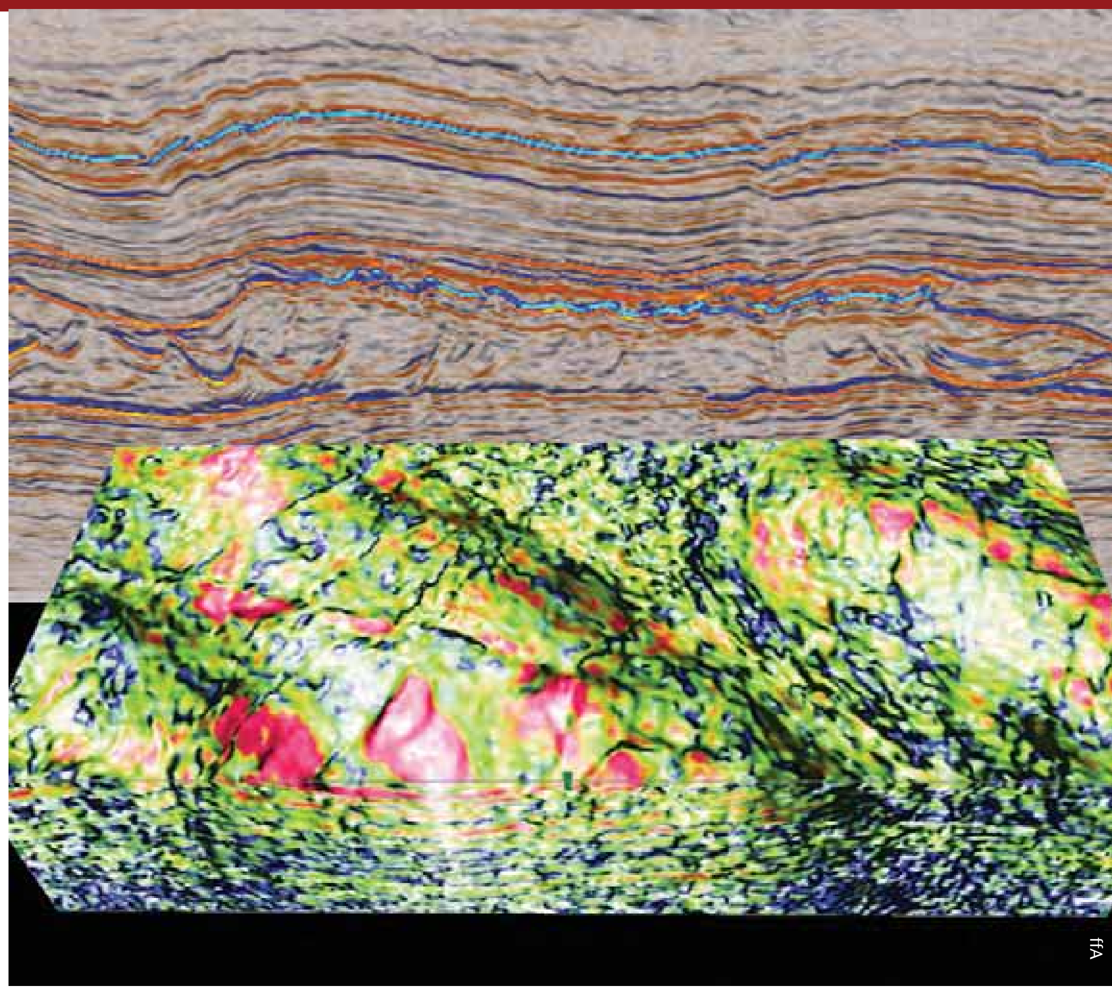
ILLUMINATING RESOLUTION

PAUL WOOD

The latest developments in high-tech seismic vessels and 'mega' channel counts both on and offshore have driven a revolution in seismic data acquisition.

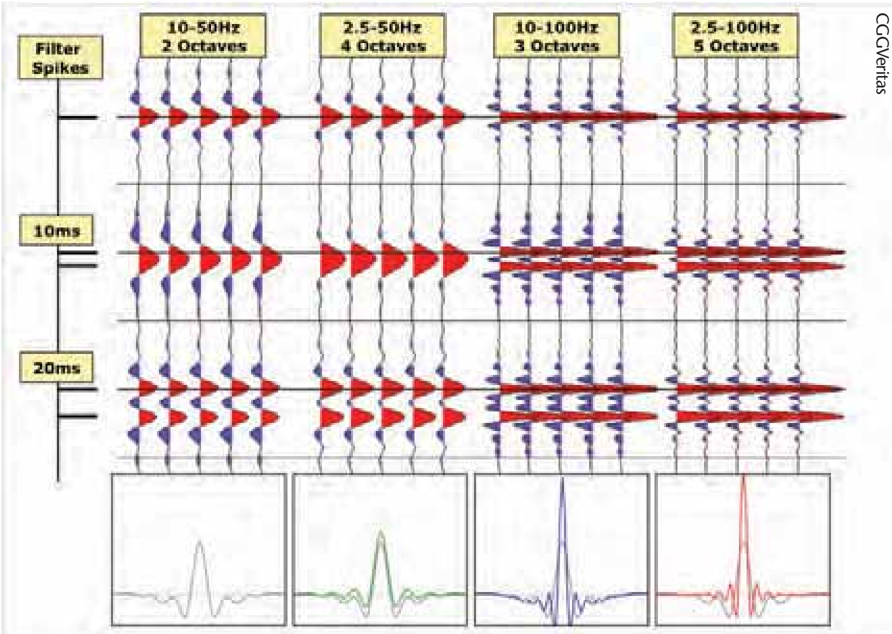


Improved resolution will be vital in future to extract the maximum information from the subsurface, as shown in this sub-salt image from the UK North Sea. (Previously published in First Break Vol. 28, No. 10).

The concept of using sound waves for exploring the subsurface is almost 100 years old. Inspired by the sinking of the Titanic in 1912, Canadian inventor Reginald Fessenden came up with the idea of using sound waves to detect the sea bed and icebergs. J. Clarence Karcher in the United States developed the principles into a reflection seismograph in the 1920s. In Europe, Ludwig Mintrop worked on refraction seismic, which he then took to the U.S. These early pioneers, and those that followed them for nearly 50 years, were restricted to two-dimensional or 2D seismic, recording profiles or cross-sections through the Earth.

3D Seismic Improves Accuracy

In the 1960s it was realised that 2D seismic did not provide sufficient detail or accuracy, especially when seismic was to be used for guiding the development of oil and gas fields. So three-dimensional (3D) seismic was born, with the first survey recorded by Esso (now ExxonMobil) in the U.S. 3D not only provided an image of a volume of the



Increasing the number of octaves in a seismic wavelet provides better resolution and more precise interpretation.

subsurface rather than just cross-sections, it also allowed seismic processors to place sub-surface features such as dipping geological layers, faults and structures in the right location. Geoscientists soon found that maps of their oil and gas fields based on 2D were not correct. By the 1990s, 3D was seen by most operators as an essential tool not only in field development, but for exploration as well.

3D seismic requires data to be recorded over an area of the Earth's surface, in order to image a volume of the sub-surface. This is relatively easy on land, where shot lines can be laid out at right angles to receiver lines, or Vibroseis sources moved along between lines of cables and receivers covering several square kilometres. But offshore, early 3D surveys had to be acquired with seismic vessels that towed only a single airgun array source and cable of hydrophone detectors (streamer). The first marine 3D surveys were essentially very closely spaced 2D lines, but this was inefficient and inaccurate. Gradually, marine systems evolved, first with seismic vessels that could tow more than one streamer and source array, and then with spreads that used multiple vessels. Sophisticated positioning combined the emerging GPS technologies with acoustic networks linking the cables.

Seismic technology developments were also driven by new thinking and research into acoustic wave sampling. Leo Ongkiehong of Shell and Ian Jack of BP, among others, promoted the idea that the seismic signal should be measured with receivers as closely spaced as possible along the cable, in order to recover the highest bandwidth (range of frequencies) reflected from targets in the sub-surface. Gijs Vermeer (then of Shell) introduced 'cross-spreads', a method of sampling the seismic wavefield fully by recording data from all shot-receiver distances (offsets) and directions (azimuths) within a survey. The twin goals of the seismologist became illumination and resolution – sampling the acoustic reflections from subsurface targets as completely and finely as possible.

3D Geometry Evolution

When marine acquisition moved from 2D to 3D, the main drivers were economic – how to acquire as much data as fast as possible. Vessels started to deploy two streamers and then two airgun arrays in order to record four lines simultaneously. In the 1980s, seismic company GECO used two vessels in the 'quad-quad' system, acquiring 16 lines at a time. The feathering (displacement of streamers by currents) also required traces to be 'binned' – plotted at their correct shot-receiver location using the navigation data – so marine seismic was being recorded as a 3D volume rather than many 2D lines.

This technique allowed large 3D surveys to be acquired much faster than previously possible. But because each airgun array only fired once every four shots, the data were not being fully sampled. Noise caused by spatial aliasing – not recording sufficiently often along each individual cross-section in the 3D volume – was contaminating the data. Subsequent marine acquisition developments aimed to return to the ideals of Jack and Ongkiehong, improving sampling while maximising coverage.

Q-marine Integrated System

Towards the end of the 1990s, WesternGeco, now a Schlumberger company after the merger of GECO, Western Geophysical and other seismic providers, decided that the answer was to combine a number of acquisition technologies into a fully integrated and revolutionary system that would maximise resolution and minimise noise. This concept became the Q-Marine system that was deployed at the start of the new century. It is based on four main components - calibrated source, positioning, single sensors and steerable streamers.

In order to relate the seismic response to geology and hydrocarbon reservoir characteristics, the source signature – the shape of the outgoing signal – must be known accurately. Q-Marine has a source controller and measurement system that ensures every recorded shot can be calibrated with a notional signature. The calibration philosophy is continued into the positioning system, with acoustic networks down the streamers giving an accurate measurement of the location of each receiver for each shot. Within the streamers, the sensors, closely spaced hydrophones, are recorded individually and the effect of perturbations removed automatically. The streamers are steerable using devices called Q-Fin and are filled with a solid gel neutrally buoyant material, rather than liquids such as kerosene used in the past. These measures increase resolution and reduce noise in the recordings. Steerable streamers also allow the desired coverage to be obtained more accurately, important for time-lapse of 4D surveys that repeat the geometries of previous acquisition. The Q-Marine system is now available on most of the WesternGeco fleet. With 3.125m receiver spacing, a typical spread could have 30,000 channels.

Revolutionary Vessel Designs

Also in the 1990s, another merge of seismic companies created Petroleum Geo-Services or PGS. From the start, the main focus of PGS was high resolution 3D. It considered that the key to obtaining the best resolution combined with efficiency was a high channel count with as many streamers as possible. PGS grabbed the headlines with ▶


PGS

PGS new Ramform 'W-class' seismic vessel.

their novel Ramform designs, delta-shaped seismic vessels based on 'stealth' designs that generated little noise but had wide 'back decks' that could deploy many streamers. These were introduced in the mid 1990s and in the intervening years have gone through several generations, with ever wider back decks, streamer numbers and streamer lengths. PGS is now building its latest offering, the Ramform W-class, which will have a staggering 26 x 12,000m streamer capacity. PGS, like many seismic companies, has also embraced the solid streamer. Their entire marine fleet is now equipped with these gel-filled streamers.

CGGVeritas has also aspired to higher marine channel counts and noise reduction. It has introduced the Sercel Sentinel® solid streamers. Sentinel streamers are filled with a polymer foam rather than the gel of other solid streamers. CGGVeritas believes these foam streamers are the quietest available. Streamer positioning is achieved and measured with Sercel's integrated steering, depth control and acoustic Nautilus™ system.

CGGVeritas, like other seismic companies such as Polarcus and WesternGeco, has also introduced the distinctive low-emission ULSTEIN X-BOW design of seismic vessels to further reduce acquisition noise. Their vessel 'Oceanic Vega' can deploy up to 20 streamers, with the maximum so far deployed being twelve streamers of 8,100m length.

Improving Land Resolution

CGGVeritas is also well known as a land acquisition specialist and with its 'super-crews' has come close to realising the Vermeer ideal of cross-spreads. Modern land acquisition systems like Sercel's 428XL have been field proven at more than 80K channels and can use new technology detectors like MEMS (Micro-Electro-Mechanical Systems) accelerometers. Wireless systems aim to take mega-channel systems into rugged and remote territory. In a recent survey in the Middle East, CGGVeritas recorded 25,000 live channels per Vibroseis 'shot', each into a 36 line spread of 5km x 4.2km. Source and receiver sampling was 7.5m, yielding exceptionally high fold and resolution. Super-crews also use techniques to improve production, such as recording more than one Vibroseis source simultaneously and have matched or even exceeded marine production rates. After a survey conducted by a CGGVeritas joint venture in Oman, Petroleum Development Oman's Chief Geophysicist Bob Sambell said "A reasonable estimate (is) the expected additional discoveries would pay the cost of the survey a hundred times over".

WesternGeco has also developed the UniQ system, taking the Q-Marine concept onshore. As with Q-Marine, UniQ integrates a number of proprietary technologies into a seamless system. The point receiver system has a notional channel count of 150,000, though it is scalable beyond this if required. At each receiver, a GAC (Geophone Accelerometer) unit contains the sensor, with end-to-end cables connecting to power and digitising boxes. This eliminates geophone cables, saves weight and increases the efficiency of land crews.

The GAC accelerometers reduce distortion and extend bandwidth, especially at low frequencies, compared to geophones. The hardware is combined with processes like DGF (Digital Group Forming), a software solution to tailor noise rejection to local conditions. As array-forming is a processing step, UniQ allows for a range of geometries including random detector placement.


WesternGeco

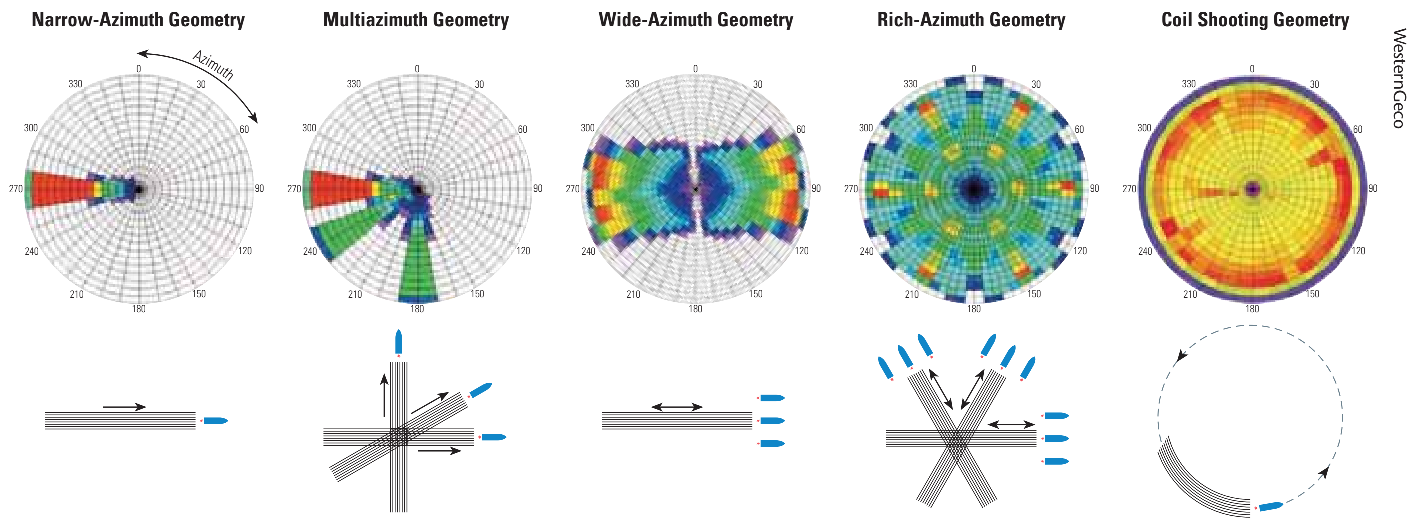
GAC sensor unit from UniQ land acquisition system.

Capturing All Azimuths

Whereas on land all azimuths can be captured by laying out an appropriate spread, this is more difficult for marine. This was recognised in the early days of marine 3D when discussions sprang up as to whether one should shoot 'dip' (as far as possible in


CGGVeritas

Equipment for a CGGVeritas 'super-crew' ready to go!



Various marine acquisition geometries – colours show number of traces (fold) in each offset and azimuth range with dark blue the lowest and red the highest fold.

the direction of the main geological dip), or 'strike'. In the Gulf of Mexico, completely different images were obtained by shooting across a salt dome, where seismic energy could be distorted, or just along its edge, where it might be possible to 'undershoot' overhanging salt, revealing hydrocarbon traps. This highlighted the need to record both dip and strike; in fact, as many azimuths as possible. The problem was that 3D with only a few cables still had limited azimuths except on very short offsets. Widening the spread with more streamers improved the situation and in the 1990s, when exploration was moving beneath the salt, several different techniques developed. These included shooting several lines in different directions (Multiple Azimuth, or MAZ), or with multiple vessels, perhaps with extra shots from across and behind the spread (Wide Azimuth or WAZ).

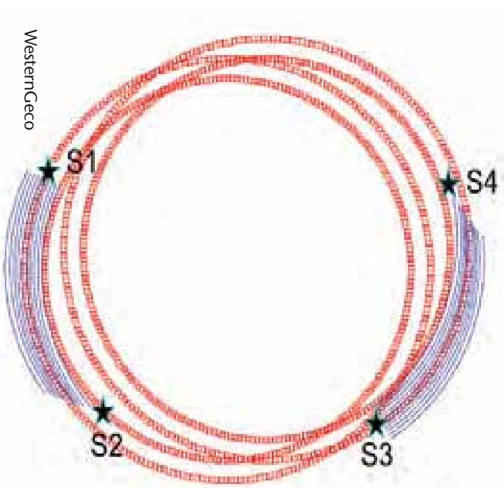
None of these methods sampled all azimuths for all offset ranges, though. Offshore, this could only be obtained by very closely spaced ocean bottom sensors, today still prohibitively expensive for high-resolution 3D. One answer came from reviving an idea of Bill French's from the 1980s, to sail in circles round salt domes. At the time, the hardware was not really up to the job, but this Full Azimuth (FAZ) technique has now been taken up by WesternGeco as 'Coil Shooting'. A 3D survey is covered by a series of overlapping near-circles until the desired sampling is obtained. These methods have been described in more detail in the series of *GEO Expro* articles by Landrø and Amundsen from April 2008 onwards. WesternGeco has now expanded the idea in 'Dual Coil Shooting' to capture very long offsets of 12-15km. This returns to the multi-vessel concept, using two vessels at opposite sides of the coil and two extra source vessels.

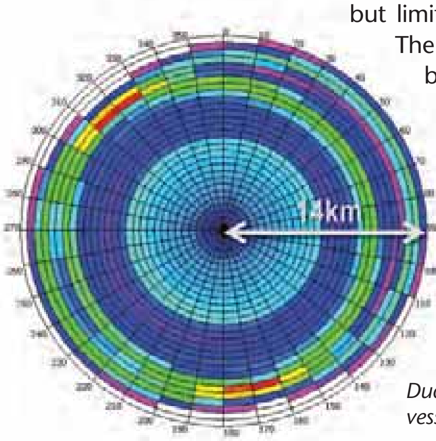
A different approach to improve coverage is being tried by PGS who recognise that, with very wide towed spreads, the source sampling in the crossline direction is sparse. Short offsets in particular and therefore shallow data are not fully recorded. PGS has developed a technique called HD3D that improves this sampling by interleaving adjacent sail lines. This method improves coverage and means that they can remove surface multiples, the seismic energy reflected from the sea-air interface, more effectively.

Ghosts Limit Bandwidth

In spite of all the attempts to record fully and finely sampled data, multiple signals called ghosts are a fundamental limitation in extending the seismic bandwidth towards both high and low frequencies. Maximising bandwidth is important for higher resolution and for techniques such as seismic inversion – determining geological properties directly from seismic – and stratigraphic prediction. The hydrophones, pressure sensors in the streamers, record the seismic signal reflected from the subsurface, but also, slightly later, the same signal that has bounced back from the sea surface – the ghost. The ghost is reversed in polarity and cancels out at frequencies dependent on the streamer depth - creating 'notches' in the recorded seismic spectrum. Towing the streamer shallower can achieve higher frequencies but limit the lower ones and vice-versa.

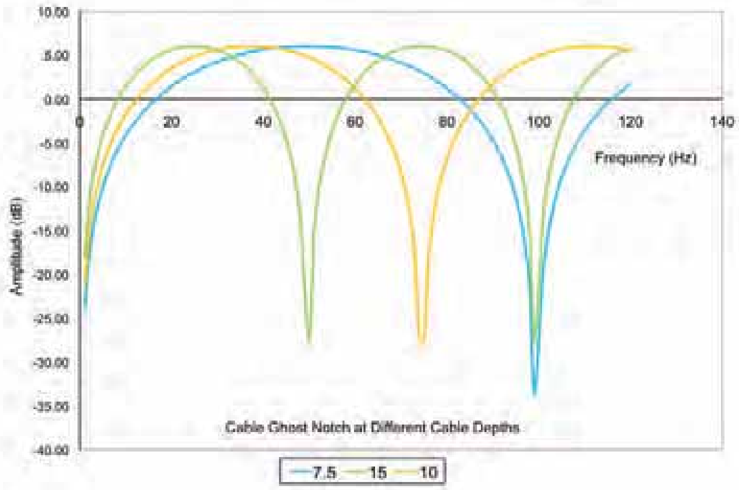
The goal, to extend the spectrum in both directions, is now being approached by different seismic companies in different ways with a set of new technologies. WesternGeco have introduced DISCover (Deep Interpolated Streamer Coverage). The Q-Marine system allows not





Dual coil configuration: two receiver vessels and two source vessels.

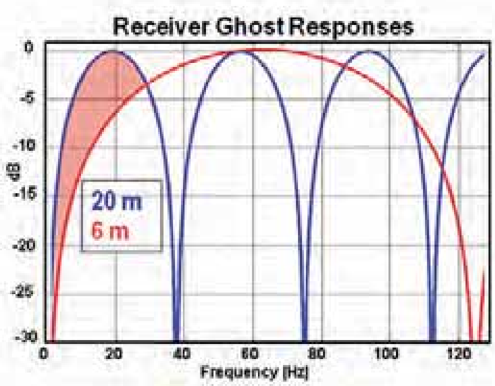
only many cables to be towed, but permits the precise positioning of those cables both laterally and in depth. The DISCover system uses cables towed both shallow, to capture high frequency data, and deep, for the low frequencies. It may seem at first that this could be a costly and operationally difficult solution, but the trick lies in only using sparse sampling on the deep cables, with perhaps only one deep cable for every four shallow ones. This works because the deep cables are only sampling low frequencies which can be interpolated between the cables without losing resolution. An ▶



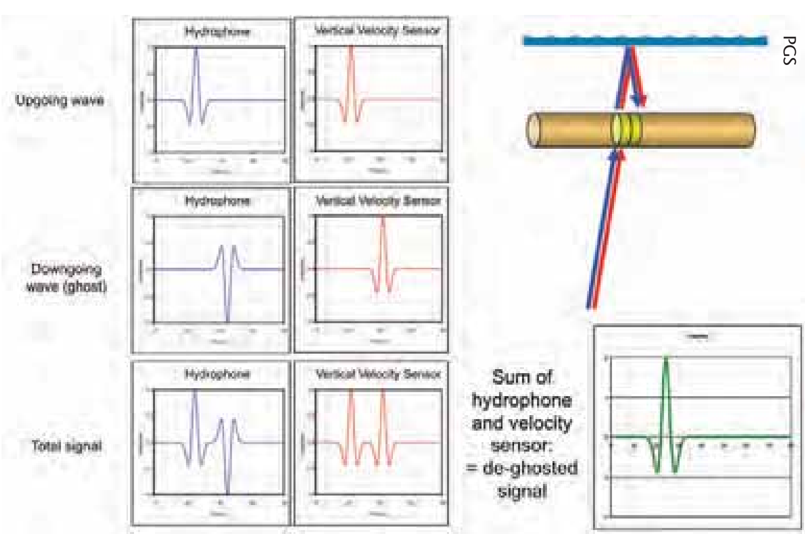
CGGVeritas

Notches in the amplitude spectrum caused by ghosts at different streamer depth lead to compromises in data quality during survey design.

Improvement in low frequency response in WesternGeco's DISCover system when adding deep cable signal (blue) to shallow (red).



WesternGeco



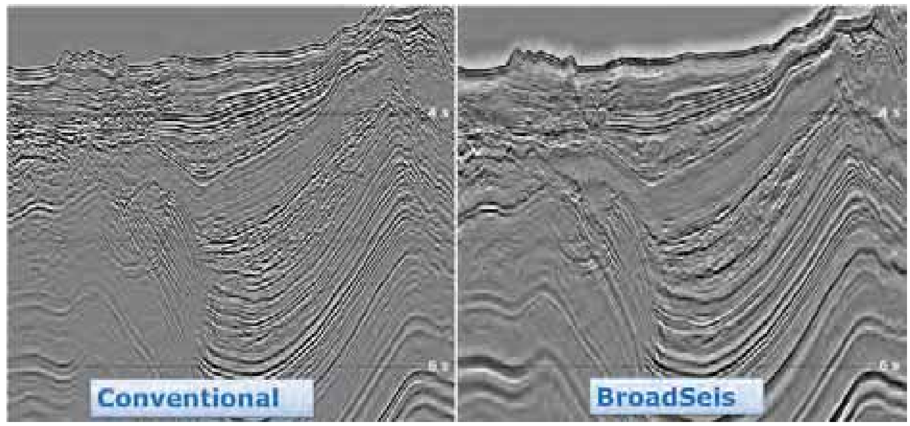
PGS

Separating up- (signal) and down-going (ghost) energy with dual sensors - signals sum but ghosts cancel out.

analogy is in modern surround-sound hi-fi systems that have several small speakers for directional sound, but only use a single bass 'sub-woofer' for the low frequencies.

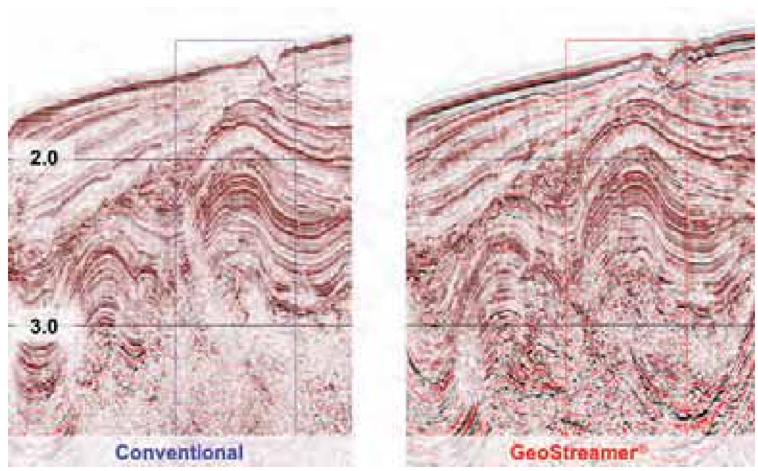
CGGVeritas approaches the problem in a similar way, but using variable depth streamers in a system called Broadseis™. As with the other seismic companies, solid streamers and streamer control have now improved to the stage where their positioning is much more accurate. At the longest offsets in a cable, high frequencies are most attenuated, so Broadseis increases streamer depth with offset, recovering high frequencies near the vessel but aiming to maximise low frequencies further away. With a curved streamer shape, the system records a broader band of signal than previously possible, with frequencies down to 2.5Hz. The exact geometries can be optimised for each survey and, together with the special processing needed for this system, are proprietary to CGGVeritas.

The PGS solution to the bandwidth problem is called GeoStreamer®. This uses a different technology from the other two companies, relying on two component receivers hitherto limited to land or sea bed seismic systems. If two different sensors are used at the same location, they act in different ways. Pressure sensors (hydrophones) and velocity sensors (similar to land geophones) both record the seismic signal (upgoing wave) as positive polarity, but the ghost (downgoing wave) as negative for the hydrophone and positive for the velocity phone. Summing the recordings of the two sensors removes the downgoing wave (de-ghosting), leaving only the signal. Because the ghost is removed, the high frequencies remain and the streamers can be towed deeper, enhancing low frequencies as well. With a deeper tow, the acquisition system is also not as susceptible to noise generated in bad weather.



CGGVeritas Data Library

CGG Veritas legacy data set from NW Australia and equivalent Broadseis™



PGS

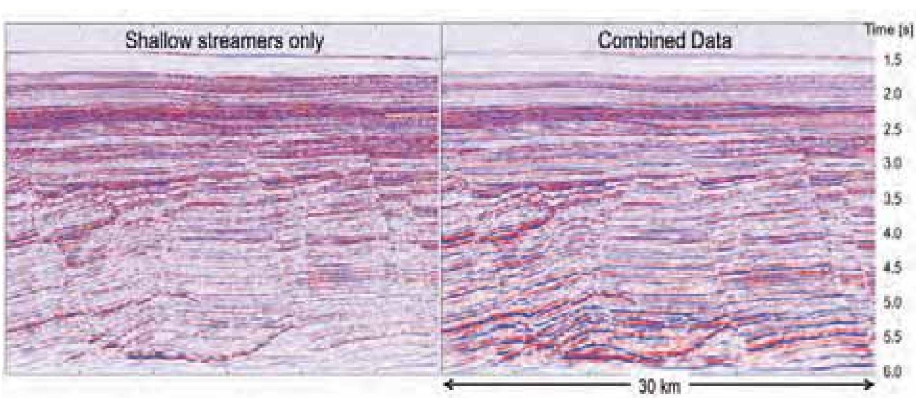
PGS conventional and GeoStreamer® acquisition offshore West Africa.

PGS has now equipped about half of its marine fleet with GeoStreamers and has observed a 4 to 5 fold boost in low frequencies and an overall improvement in the frequency range of some 60%. This has improved results from advanced signal processing such as seismic inversion. An additional benefit of the dual sensors is that the information needed for PGS's surface multiple removal processing, SRME, is measured directly.

Future developments?

The past two decades have seen significant advances in the technologies needed to meet the twin goals of a fully illuminated and high resolution image of the subsurface. What will the next twenty years bring? For the offshore, Landrø and Amundsen had a go at crystal ball gazing in the fourth part of their *GEO ExPro* articles in 2008, citing ocean bottom surveys that use autonomous underwater vehicles, or a 'net' of detectors towed behind a vessel. On land, CGGVeritas expect that systems deploying 200,000 single sensor channels will soon be deployed. True wide-azimuth acquisition and processing should help unlock unconventional hydrocarbons by focussing on 'sweet spots'.

In a 1992 article in SEG's 'The Leading Edge', Woody Nestvold, Shell Chief Geophysicist asked "3D seismic – is the promise fulfilled?" His answer was a resounding 'Yes'! But how much more has it been fulfilled today! The resolution revolution is still in progress – we can only imagine what it may bring in the future. ■



WesternGeco

Improvements in WesternGeco DISCover technology when adding data from deep streamers.

The Best Place to Find Oil…

There is an old adage that runs "The best place to find oil is in an oil field!"

The Forties Field in the UKCS is a well-known example of a mature North Sea field being kept going by innovative petro-technical folk, working in multi-disciplinary teams, deploying "Know How" *and armed with the right technologies.*

Apache Corporation

DAVID BAMFORD

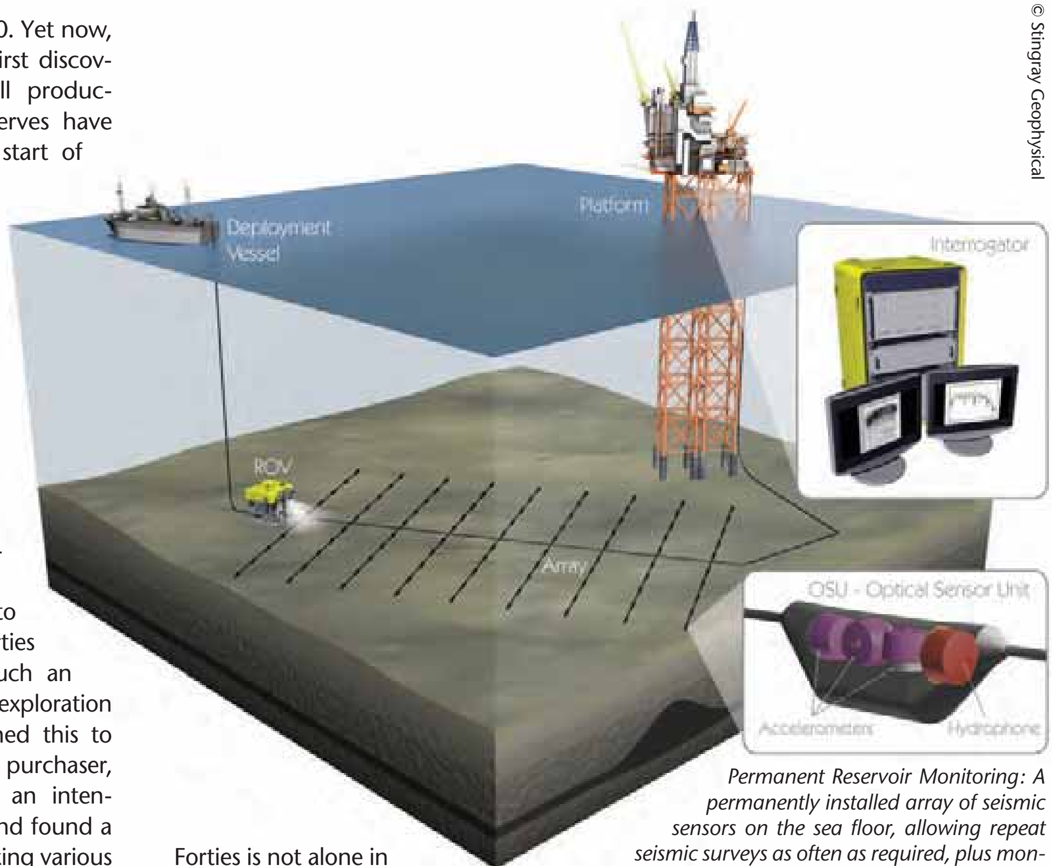
As global exploration gets more difficult, there is a major prize to be gained by increasing flow rates and improving recovery factors in existing fields. In any petroleum province which is very mature in exploration terms, such as the North Sea, it would be better for companies to stop 'wildcat' exploring and focus on enhancing production in and around existing oil & gas fields.

The Forties Story

When production from Forties commenced in 1975, it was predicted that the field would stop producing by the early 1990s. In 1990, it was expected to be shut down by the year 2000. Yet now, over forty years since it was first discovered, the Forties Field is still producing, and the recoverable reserves have increased by 35% since the start of production, even though the area of the field as defined by the oil-water contact has remained approximately the same (see *GEO ExPro* Vol. 7, No.3). Plateau production of 500,000 bopd was reached in 1978, lasting until 1981, and progressively declining to 77,000 bopd in 1999. At this point the field had already produced 2.5 billion barrels and still had nearly 60 producing wells.

With production down to 35,000 bopd, BP sold the Forties field in 2003. It had been such an iconic field for UK North Sea exploration that some commentators likened this to 'selling off the family silver'. The purchaser, Apache Corporation, initiated an intensive re-evaluation of the field and found a further 800 MMbo. By undertaking various efficiency measures and installing new equipment, it has brought new life to the field which is now producing 70,000 bopd and is expected to be still pumping oil for the next twenty years.

Forties is not alone in benefitting from an integrated approach to improved recovery; the Statfjord Field in the NOCS is a similar example, with its recovery factor now headed towards 70%.



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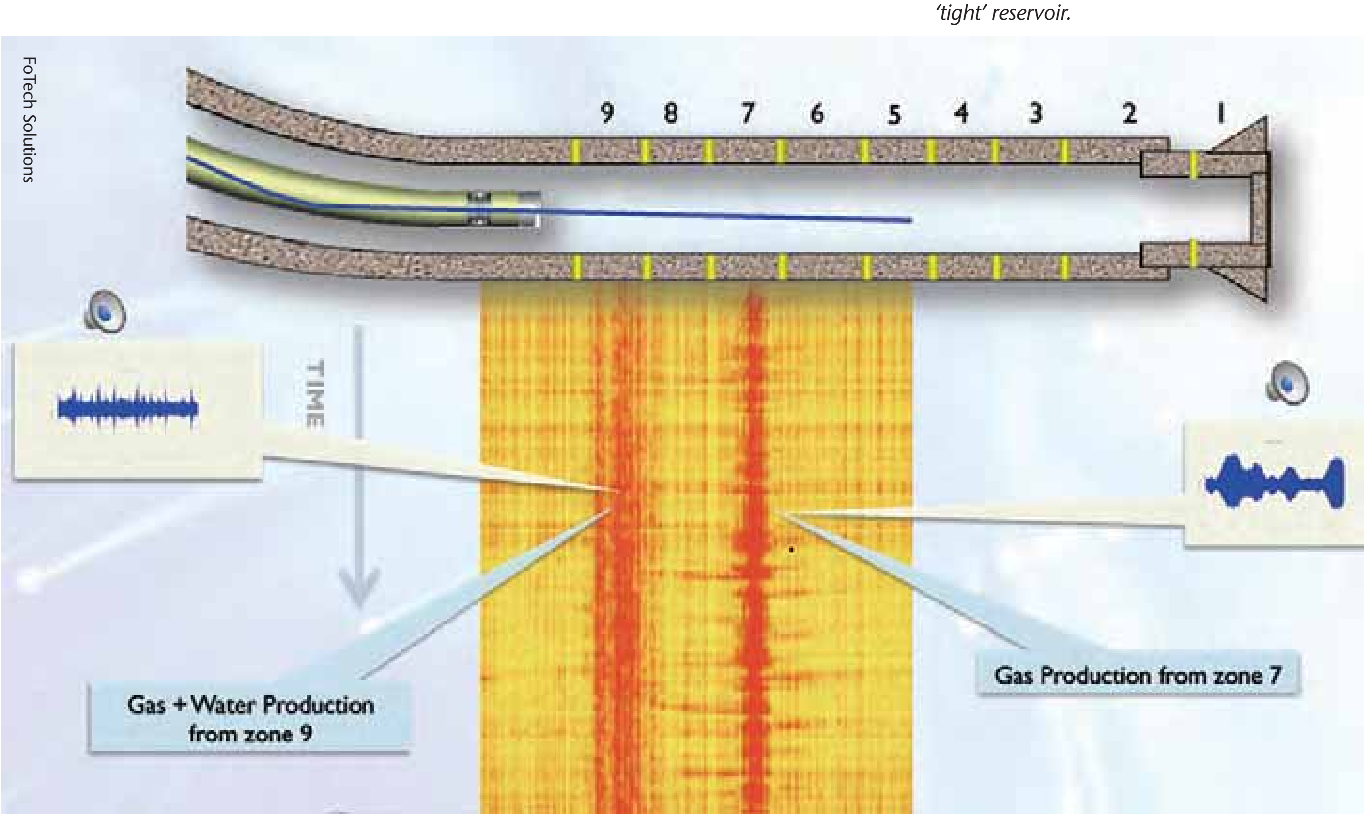
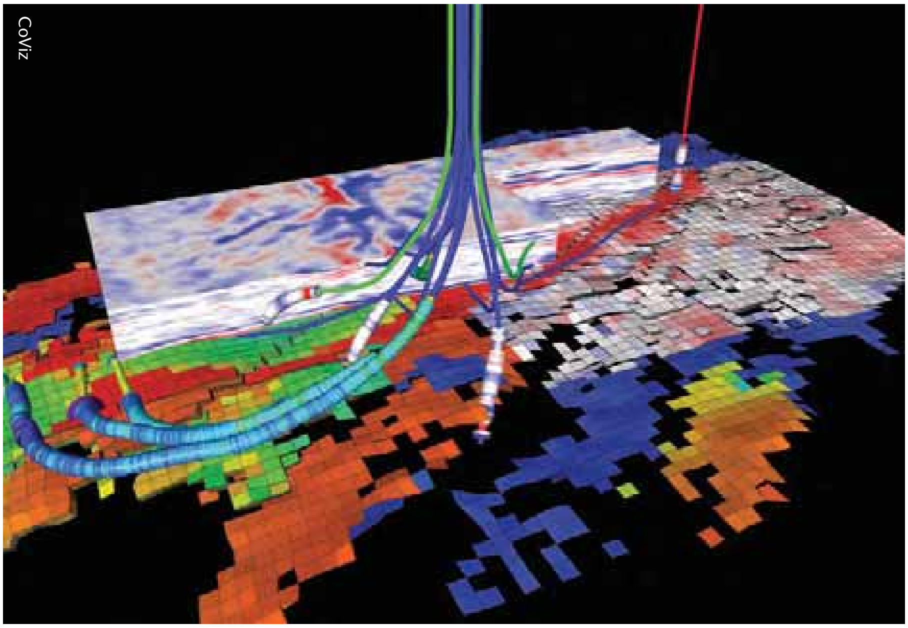
Permanent Reservoir Monitoring: A permanently installed array of seismic sensors on the sea floor, allowing repeat seismic surveys as often as required, plus monitoring of micro-seismic events.

'Listening' to the reservoir: a fibre optic cable (depicted as the thin black line, delivered through tubing) records the sound of gas and water production from completion zones 9 and 7 in a 'tight' reservoir.



FoTech Solutions



Integration of sub-surface data and interpretations with drilling in a Collaborative Working Environment. (Images published with permission of the owner)

Technologies to Improve Recovery

Broadly speaking, we can divide the technologies that can help other fields be similarly transformed into those to do with the reservoir and wells, and those to do with the top-sides.

Reservoir and well enhanced oil recovery (EOR) themes include:

- recognising where there are reserves of undeveloped or unswept hydrocarbons – key technologies are reservoir monitoring (using 4D seismic/permanent seismic monitoring), production monitoring, reservoir simulation, history matching.
- mobilising these reserves towards the well bores – key technologies include fraccing, enhanced recovery (EOR) mechanisms (Microbial, WAG, CO_2 floods etc).
- moving these mobile hydrocarbons into and along the well bores – completion, pumping and flow monitoring technologies are key.

The broad 'top-sides' themes include improving operational efficiency (such as 'debottle-necking'), monitoring and improving operational integrity, safety and cost reduction.

The 'Digital Oil Field' then provides an enabling framework in which these key technologies can be deployed for optimal efficiency and effectiveness – key aspects include automation and collaborative working environments.

Especially offshore, delivering both production performance and recovery factor improvements requires an integrated field development plan: it is not a matter of simply introducing a single technology.

Big Prizes?

How big is the prize to be gained by increasing recovery factors?

Sandrea and Sandrea estimate the global recovery factor, (the percentage of the total conventional oil volume likely to be produced in the world's oil fields), to be 22% of the oil in place. Using a value of 2,158 Bbo for the ultimate recoverable volume and a 22% recovery factor, the estimate global STOIIP is 9,800 Bbo. This 22% global recovery factor compares to previously published estimates in the range of 27% to 35%, which were probably over-optimistic.

Typical recovery factors vary world-wide. Average recovery rates for the North Sea are stated to be about 45%, the highest in the world, compared with 39% for the USA and 23% for Saudi Arabia. Examples of individual fields with high recovery factors are Statfjord (North Sea) and Prudhoe Bay (Alaska) with 66% and more than 47% respectively.

Turning to Enhanced Oil Recovery in particular, Awan *et al*. have surveyed all North Sea EOR projects initiated in the 30 years 1975 to 2005, and have also reviewed all microbial EOR projects undertaken world-wide. Approximately 63% of the North Sea projects were on the Norwegian Continental Shelf (NCS), 32% in the UKCS, the rest in Danish waters: Statoil has been the leader in conducting EOR field operations in the North Sea. Awan *et al*. conclude that microbial processes, CO_2 injection and water-alternating-gas (WAG) injection are the most relevant technologies. Moving the current recovery factor for the NCS of approximately 45% to the 50% target (for oil; the target is 75% for gas) established by the Norwegian Ministry of Petroleum and Energy would yield approximately an additional 4 billion barrels of oil.

A 22% recovery factor means that 78% of the world's oil will be left behind once all the oil fields are shut in and abandoned, and only 3% of the world's oil is currently produced as a result of Enhanced Oil Recovery (EOR) technologies. Yet experience with one EOR method – the injection of CO_2 – in the USA and elsewhere, shows that this can result in increases in recovery of between 7 and 15% following initial recoveries using water-flooding.

Hence, by comparing the UKCS with West Texas, Gluyas has estimated that an

A downhole 'robot', a Well Tractor, is able to reach the toe of a deviated or horizontal well and carry out operations throughout the entire length of the wellbore.

additional 2.7 to 8 billion barrels of technical reserves could result in the UKCS from CO_2 injection, corresponding to an increase of recovery factor in the range of 4 to 12%.

Provided the CO_2 supply can be found, the US Department of Energy has estimated a minimum of 30 billion barrels is recoverable with CO_2 EOR in the USA.

Range of Technologies Needed

It should be emphasised that increasing recovery factors depends on a range of technologies – surveillance, 'smart' wells, EOR etc. Nevertheless, worldwide, just a 1% increase in the global recovery factor represents almost 90 Bbo, equivalent to replacing roughly 3 years of production at current levels.

Wherever serious studies have been undertaken, truly astonishing volumes of oil can be contemplated from increasing recovery factors using technologies that are known today. Oil and gas companies can of course choose from many investment options, economically distinguishable from one another by their net margin per barrel (or per Mcf) at some 'benchmark' price, for example $70/barrel. The available options include service contracts in Iraq; EOR projects on existing fields; improved primary/secondary recovery projects in existing fields; 'full cycle' deep water projects (from exploration through to production); and 'full cycle' Shale Oil (for example onshore USA).

Certainly, it seems reasonable to believe that the current approximately 10% of all existing discovery volumes that has actually made it to production is very much a lower limit. In many instances, a rising oil price will ensure that primary, secondary and tertiary recovery projects are economic, although in some instances it may be necessary for governments to give tax incentives to help improved recovery projects – for example those based on CO_2 EOR – to bring them into existence.

However, for major economic players such as the USA and western Europe, such support would have the significant political advantage of reducing both dependence on imported oil and the outwards flow of funds.

Finally, it will be noticed that all of the technologies that have been illustrated in this short review are from relatively small, entrepreneurial, companies, as a matter of fact all of them supported by some form of private equity. "Breakthroughs" to higher recovery factors depend on the contribution of such ventures.

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Squeezing the Last Drop

Halfdan Carstens

Farouk al-Kasim, an Iraqi with ten years experience in one for the world's most prolific oil provinces, went on to serve the Norwegian government for 23 years and was instrumental in establishing the Norwegian Model.

HALFDAN CARSTENS

May 10 1968: Well 7/11-1 in the Norwegian sector of the Central Graben, the first well on the Cod prospect, was reported as a discovery with hydrocarbons in Palaeocene sandstones. But an appraisal well a few months later was disappointing and the discovery was declared non-commercial at the time*. These are the dry facts – one year before the giant Ekofisk field was found, opening up the North Sea as an oil province.

This not-so-promising conclusion about the Cod discovery came from a young, albeit very experienced, geologist. Farouk al-Kasim had just arrived in Norway in the spring of 1968, having fled his home country of Iraq. At that time, Norway did not have an oil industry as such, and only a few wildcats had been sunk. Iraq, on the other hand, had made several supergiant discoveries, and al-Kasim knew all about them.

Petrolem System Identified

Carrying out this important evaluation was his first assignment for the Norwegian authorities. The government was, at this time, completely devoid of geoscientists with experience of the oil industry. Norway consists predominantly of hard rocks, and no one had ever thought of looking for oil under the North Sea until Phillips Petroleum began to show interest in 1962.

Al-Kasim's expertise was therefore highly appreciated amongst bureaucrats in the Department of Industry. Without hesitation he was offered a temporary job. "My conclusion was that Cod was a marginal discovery, but it was nevertheless very important. It demonstrated beyond doubt that the North Sea had a working petroleum system. While the oil had been generated in the central part of the basin, the flanks would be the right place to explore," says al-Kasim about his conclusions.

Today we all know that he was spot on. But at the time he certainly did not have even the faintest idea that he would end up playing a key role in the Norwegian oil adventure.

Celebrated Geologist

35 Bboe have flowed from multiple Norwegian oil and gas reservoirs since then. The giant Ekofisk was the first to be put on stream in 1971. Statfjord, Gullfaks, Snorre, Oseberg, Troll and others were to follow. Two years later, in 1973, both Statoil and the Norwegian Petroleum Directorate (NPD) commenced operations in Stavanger.

"When the NPD – and Farouk – went to work in 1973, it was assumed that Ekofisk would produce 17% of the oil reserves in place. Instead, Ekofisk, may go on for another fifty years and could recover 50%," writes Gunnar Berge, former Director General, NPD, in his foreword to al-Kasim's book "Managing Petroleum Resources", published in 2006. To make a long and complex story short, it is now well known that al-Kasim was instrumental in improving the recovery percentage through water injection. Without this move, Ekofisk would have been closed several years ago.

Al-Kasim was with NPD from day one and stayed on until 1991 as resource director. Since then he has worked as a consultant travelling the world. His mission has been to give advice to governments about how to manage their petroleum resources. It was time to capitalize on his ten years experience as an exploration and production geologist in one of the world's richest oil provinces, as well as his in-depth knowledge about the Norwegian Model.

Then, after more than 15 years outside the spotlight, in 2009 al-Kasim was portrayed in the Financial Times. "Almost forgotten", and virtually unknown amongst the ▶

Farouk al-Kasim is a petroleum geologist by education and profession, but his time is now devoted to giving advice to countries that are planning how to manage their petroleum resources. His expertise is highly sought after, and he is constantly on the move to countries all over the world.

* *Cod was later declared commercial and produced some 66 MMboe from 1977 to 1998.*

GREATEST VALUE CREATOR

"Farouk is perhaps the greatest value creator Norway has had," says [Willy] Olsen [former Statoil manager]. And with good reason. Most of the oil found in the world is never recovered: the average extraction rate worldwide is around 25%. Norway averages 45%, and for that, Olsen gives al-Kasim much of the credit: he pushed the government to increase extraction rates; insisted that companies try new technologies, such as water injection in chalk reservoirs or horizontal drilling; and threatened to withdraw operating licences from companies that balked. "It is this culture, a culture of 'squeezing the last drop out', which he cultivated," says Olsen.

Financial Times, August 29, 2009

younger generations, his name was revived. In January this year, the Geological Society of Norway staged the "Farouk seminar", a tribute to his dedication to improving oil recovery.

The Norwegian Model, as it is now called, is based on a threefold division of responsibility – politics (Ministry of Oil and Energy), management (NPD) and business (Statoil). The idea of a Directorate model dates back to the 19th century when it was realised that the state has rights to its strategic resources such as waterfalls, forests and minerals. It follows that the state also needs the expertise to exploit these resources.

Fascinated by Burning Gas

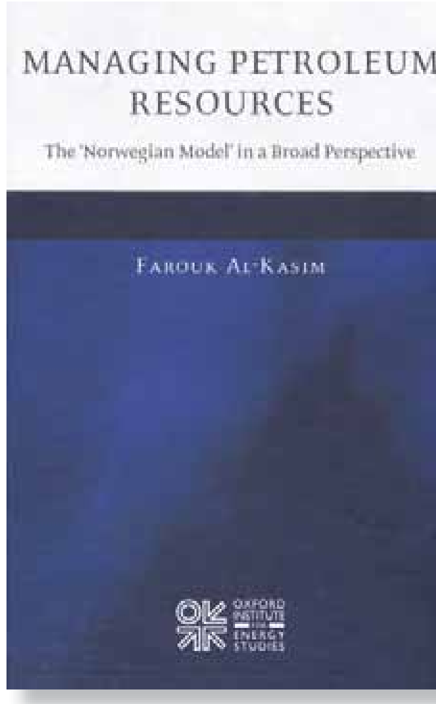
Farouk al-Kasim was born in southern Iraq in the middle of the 1930s and grew up in the hot and steamy town of Basra on the Arabian Gulf. The supergiant Kirkuk had already been discovered (1927), but most of the country was unexplored. Iraq Petroleum Company (IPC), a consortium consisting of the five largest oil companies in the world, dominated the Iraqi oil industry, and most of the production came from Kirkuk, although it was only in the 1950s that production reached a level of 100,000 bopd.

"At school, the challenge was to end as one of the "top hundred" in the entire country. The reason was obvious. We would all get a grant to study abroad, and then get a job for the purpose of replacing the foreign experts. This was part of the "Iraqi-fization" that the government had decided upon," explains al-Kasim.

"As a young boy I was fascinated by the burning gas in the desert. I had always wondered how oil and gas had been formed. I wanted to be part of that industry."

At only 16, al-Kasim went to London and the prestigious Royal School of Mines at Imperial College to study petroleum geology. To his surprise, they were only teaching hard rock geology. At the same time, however, a sedimentologist was hired, and petroleum geoscience was incorporated. For field work they travelled to the Jura mountains in France where both sandstones and carbonates are found.

In London al-Kasim also found a courageous Norwegian girl working as an au pair. They married and together returned to Iraq in 1957, where he landed a job with the Iraq Petroleum Company (IPC). With his new family Farouk al-Kasim was about to start his career.



Farouk Al-Kasim's book Managing Petroleum Resources *(Oxford Institue for Energy Studies, 2006) is considered a reference work in resource management. With the Norwegian Model as a background he describes in detail how to avoid the "oil curse".*

Major Discoveries in Iraq

IPC operated supergiant fields like Kirkuk, Zubair and Rumaila and had an exploration license covering the entire country. There was a strong need for geologists. Al-Kasim's first assignment was to assist in the drilling operations as a well-site geologist in the middle of the dry and hot desert.

After few years he was transferred and started on a new career as a production geologist on Zubair and Rumaila, where the team's first task was to assess the reserves. "We did a thorough job during three dedicated months spent studying both logs and cores. The outcome was that the reserves were increased by as much as 25%, because we included several thin zones that had previously been overlooked," al-Kasim explains. "This was a perfect example of the fact that geologists have an important role throughout the entire value chain. It actually became a turning point in my career," he adds.

His next undertaking was a sedimentological and petrophysical study of the Upper Cretaceous Mishrif Formation, which later turned out to be the most important carbonate reservoir in Iraq. His conclusion showed that the formation increases in thickness northwards and eventually led to the discovery of West Qurna, with recoverable reserves of 43 Bbo – more than has been produced from all the Norwegian oil and gas fields in total so far.

"My greatest achievement those days, however, was the discovery of another giant, Dujaila, just south of Baghdad. We predicted that the reefs would become younger towards the north as it seemed that the sea transgressed from the south. The first well on that structure was exciting, indeed, and it came in as a discovery. The theory was proved, and I now look upon this as the highlight of my geological career, by far."

In 1965, at less than 30 years old, al-Kasim was assigned the position of Area Geologist for northern Iraq, and in 1966 he was given the same job for southern Iraq. "For me, personally, this was a breakthrough, as it was now accepted that geologists had as important a role in production as in exploration".

Life was easy. The family, now including three children, had a prosperous lifestyle belonging to Basra's upper middle class, and his career was moving steadily forward. He was now number five among the technical staff in the company and among the highest-ranking Iraqis. He had certainly no plans to leave his country.

Perfect Timing

But the family's youngest son was born with cerebral palsy, and the Iraqi health care system had no way of treating him. In fact, it was suggested that their son should be taken away from them and put into an institution, as "he would always be a nuisance to them". No way – that was certainly not an option. Instead, the family – in complete silence, as the government looked upon al-Kasim as a valuable asset it could not afford to let go – decided to move to Norway, where their son could receive the health care he needed.

As it happened, and as the story has been told many times, the Iraqi petroleum geologist, having nothing better to do while waiting for the evening train to his wife's home town on the north-west coast, knocked on the door of the Ministry of Industry to get addresses of oil companies exploring on the Norwegian continental shelf.

The timing was good. Norway had only three employees in what was called the Oil Office at the time. One of them was a geologist, but he had no experience of the oil industry. Al-Kasim, on the other hand, had eleven years of relevant experience from one

"Farouk Al-Kasim has played a significant role in the development of Norway as one of the largest oil and gas exporters in the world. His influence on Norway's policies and the resource management strategy has been considerable."
Willy Olsen, former director of Statoil.

Halfdan Carstens

of the world's richest oil provinces, as an exploration as well as production geologist. In addition, he had been exposed to the arrogance of international oil companies, something very useful when he later had to deal with them directly as a director in NPD.

The next few months were spent studying electrical logs and seismic data to evaluate the Cod discovery, sharing an office with Fredrik Hagemann who would later become the first boss of the Norwegian Petroleum Director. Al-Kasim's superiors must have been pleased with his work. After only three months he got a permanent position with the Ministry, and when NPD was founded four years later he became its first resource director.

Avoiding the Oil Curse

Al-Kasim's next task was to evaluate the petroleum potential of the Norwegian sector of the North Sea, following 13 exploratory wells. His detailed study led him to believe that the North Sea had an active petroleum system.

"It's only a matter of time before a significant discovery will be made," he concluded.

His reasoning made sense, as three wells had encountered hydrocarbons, one with a significant column. In fact, 25/11-1 was the second well on the Norwegian shelf, completed in 1967 by Esso, and now known as the discovery well of the Balder field, finally put on production in 1999. The situation one year before Ekofisk was therefore that, in addition to oil, both reservoir and source rocks had been proven.

"You didn't need to be a genius to predict that a commercial discovery had to be made. Nevertheless, the international oil companies were not convinced, something I found very strange. The explanation might be that they were not thinking in terms of petroleum systems."

One year later, in 1969, well 2/7-2 found Ekofisk (*GEO ExPro*, Vol. 8, No. 1): Al-Kasim was proved right.

Al-Kasim's reputation as an experienced petroleum expert grew fast, and in 1971 he was a key member of a small group putting together White Paper no. 123. This is now considered the most important political document in Norwegian oil history as it established the Norwegian "trinity" model. Partly because of this, Norway has succeeded in taking full advantage of its oil and gas resources.

"Norway has avoided the oil curse that has been so destructive in many oil-rich countries," al-Kasim says.

Ekofisk and Troll

Al-Kasim's reputation is closely tied to his insistence on securing improved recovery in the Ekofisk field. The idea of water injection was his, but before it was implemented in full, several years were spent on research and a pilot project.

"A key learning element from Ekofisk is that we need to have the future in mind when new fields are being developed. It is necessary to leave space for options not considered at an early stage. This is now part of the Norwegian regulations and makes responsible reservoir management possible," al-Kasim says.

The development of Troll was another fight. Troll is a huge gas field with a thin oil leg. Too thin to be produced, almost everybody said, including both Shell and Statoil. Norsk Hydro had a different opinion. It was their idea that the oil could be produced with horizontal wells. Al-Kasim supported the initiative strongly, and it is generally accepted that he played a significant role in getting the Minister of Energy to make the decision to designate Troll as an oil field in addition to a gas field. Troll is today the largest oil producer on the Norwegian shelf.

The North Sea Lab

Managing petroleum resources is Farouk Al-Kasim's expertise. He is concerned with squeezing the last drop out of the oil reservoir, and he knows that this has to do with a lot more than geology, geophysics and reservoir engineering. It has also to do with making the right decisions at the right time, based on sound knowledge. And it has to do with a genuine desire to maximize the resources, at the expense of fast profit, if necessary.

Using the Norwegian continental shelf as his laboratory, Farouk al-Kasim has shown that petroleum resource management matters. ■

SOUTH-WESTERN BARENTS SEA:

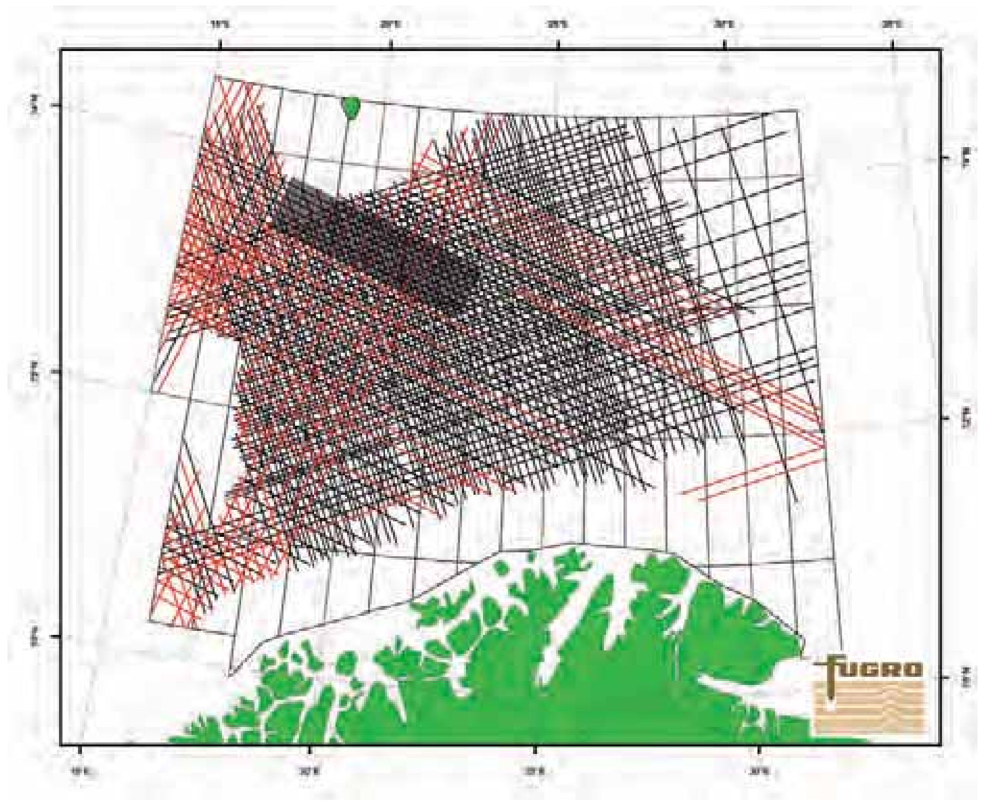
Improved Imaging with Long-offset Data

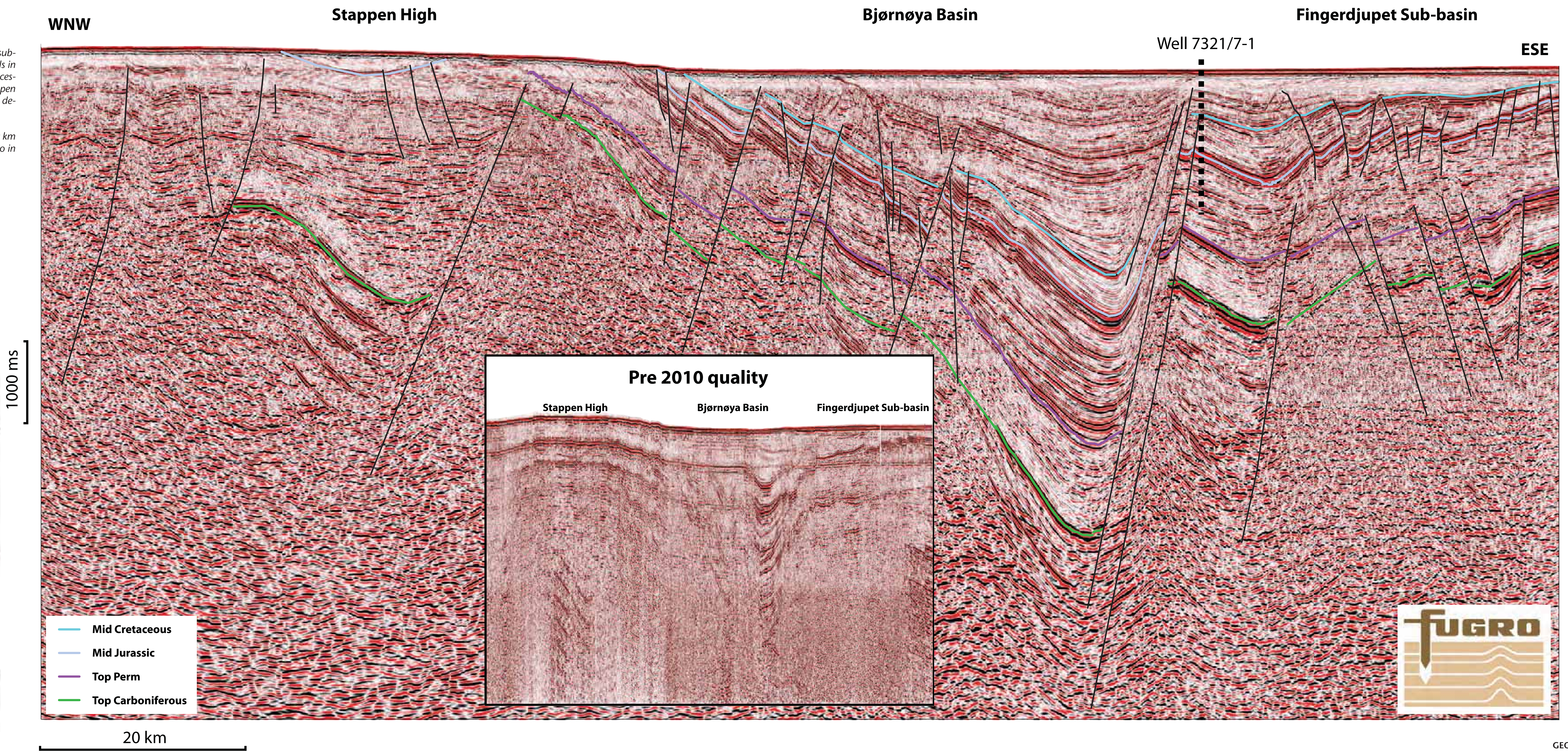
The influence of the Stappen High on the petroleum potential of the Sørvestsnaget Basin, south-western Barents Sea has been revealed by newly acquired 2D data.

The long-offset Norwegian Barents Sea Regional survey dataset gives improved subsurface imaging across the Barents Sea, revealing new and untested play models in less explored and frontier areas. This exciting long-offset seismic line reveals successive erosion down to Mesozoic strata on the Stappen High. In this way, the Stappen High is shown to have played an important role as a provenance area for sand deposits (reworked Nordmela and Stø formations) to the surrounding basins.

The Norwegian Barents Sea Regional survey (NBR) consists of more than 56,000 km of high quality 2D seismic data that have been acquired and processed by Fugro in co-operation with partner TGS.

Norwegian Barents Sea Regional survey (NBR) includes data acquired in 2006-2010 (black lines) and the 2011 (red lines). The gray zone indicates approximate position of the regional line.





Exploration in the Sørvestsnaget Basin

OLAV A. BLAICH AND GUSTAV A. ERSDAL, FUGRO MULTI CLIENT SERVICES

Since petroleum exploration in the Norwegian Barents Sea commenced in 1979, a total of 87 exploration wells have been drilled. Most of those outside the Hammerfest Basin have failed to prove commercial petroleum reserves, although shows have been encountered throughout the Norwegian Barents Sea. This limited success is usually attributed to the Cenozoic regional uplift and erosion, which affected the entire platform, causing seal failure and leakage from potential former petroleum accumulation. The western margin of the Barents Sea reveals a relatively complete Cenozoic succession with less erosion and uplift, implying that this area is more likely to have retained trapped petroleum.

Fugro commenced the acquisition of the Norwegian Barents Sea Regional survey (NBR) in 2006. So far, more than 56,000 km of high quality 2D seismic data have been acquired and processed in co-operation with partner TGS. The long-offset NBR dataset gives improved subsurface imaging across the Barents Sea, revealing new and untested play models in less explored and frontier areas. This improved imaging is exemplified here by the northern part of the Sørvestsnaget Basin and the Stappen High areas.

The Late Cretaceous/Early Cenozoic structuring and evolution of basins and marginal highs along the western part of the Barents Shelf were related to the opening of the Norwegian-Greenland Sea and the formation of the predominantly sheared western Barents Sea continental margin. The Vestbakken Volcanic Province and the northern part of the Sørvestsnaget Basin formed in a pull-apart setting related to the releasing bend at the margin, forming extensional faulting and local depocentre (Faleide *et al*., 1991, 1993). In this regime, lacustrine/restricted marine facies are prognosed, and under such conditions sediments with source-rock potential often develop (Rasmussen *et al*., 1995). Although non-commercial, the well 7316/5-1 located in the Vestbakken Volcanic Province proved the existence of

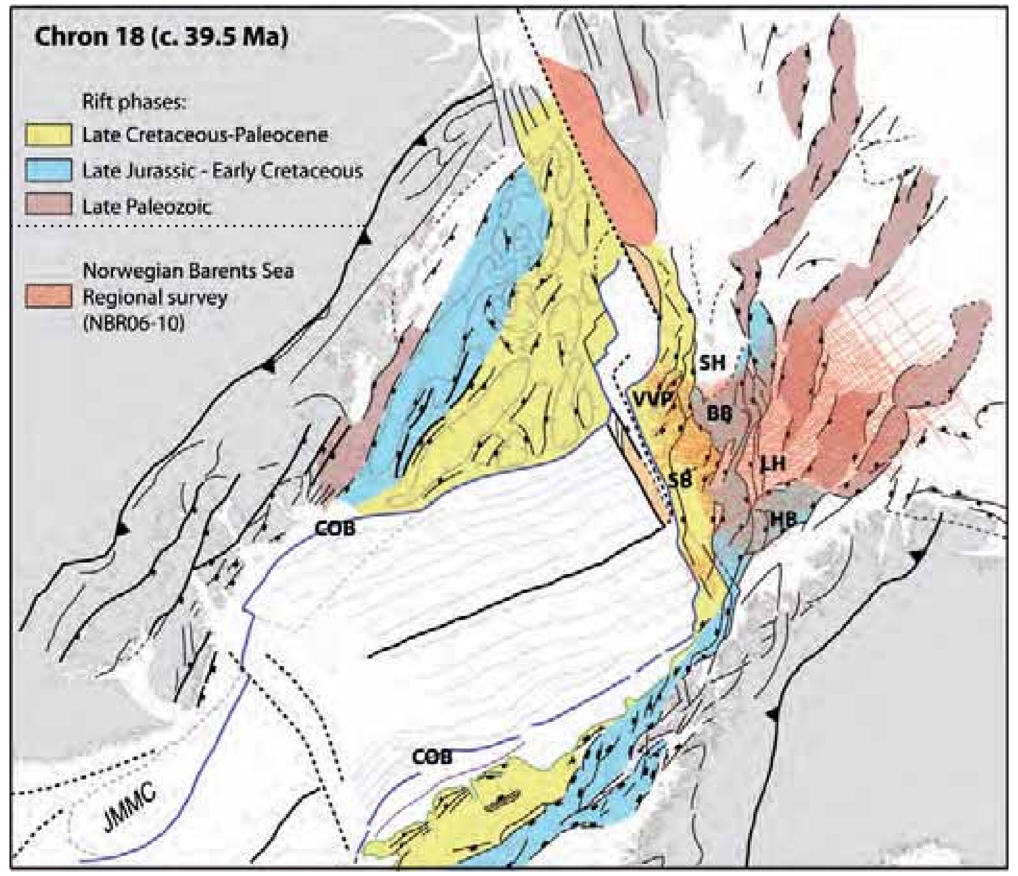
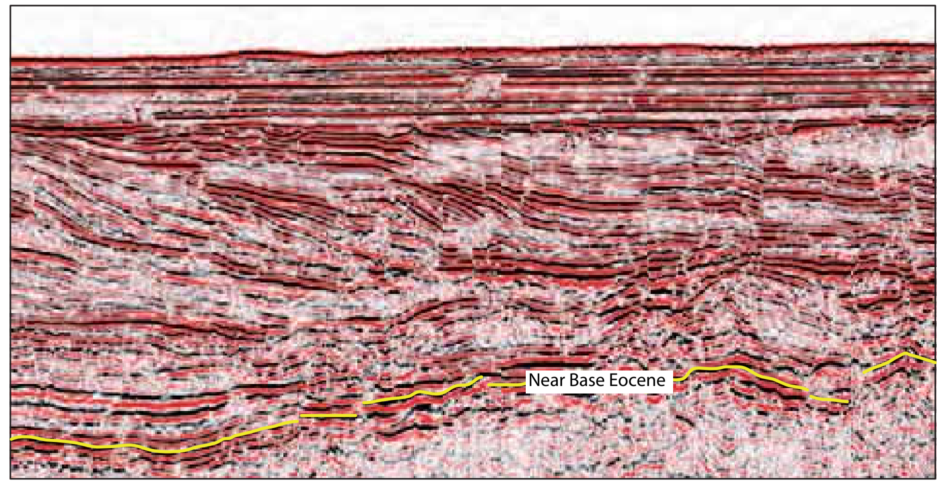
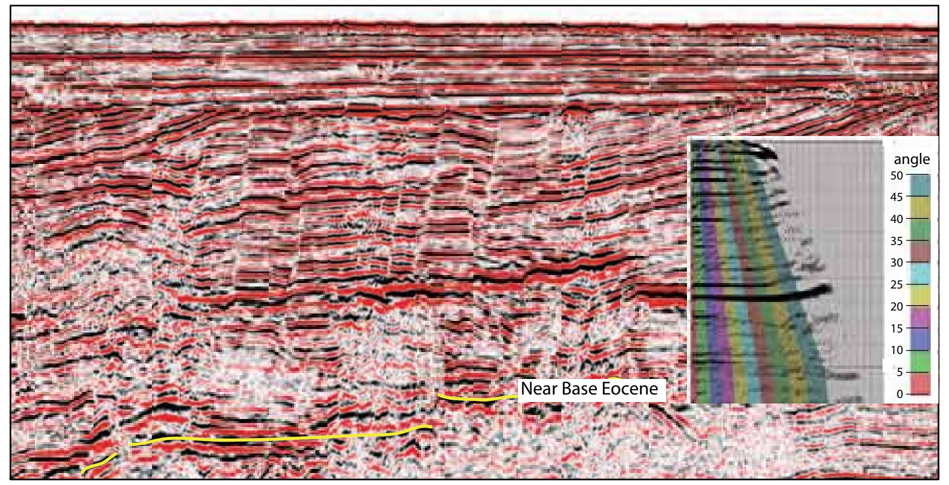


Plate tectonic reconstruction to chron 18 (c. 39.5 Ma) of the North-East Atlantic, modified from Faleide et al. *(2010). The Norwegian Barents Sea Regional survey (NBR06-10) is also indicated on the figure (red lines). BB, Bjørnøya Basin; COB, continent-ocean boundary; HB, Hammerfest Basin; LH, Loppa High; SB, Sørvestsnaget Basin; SH, Stappen High; VVP, Vestbakken Volcanic Province.*

Sørvestsnaget Basin



Seismic example showing a band of high seismic amplitudes interpreted as Middle Eocene submarine fan. Well developed seismic clinoforms are observed above the submarine fan, indicating that the northern part of the Sørvestsnaget Basin received large amounts of erosional products from the Stappen High.

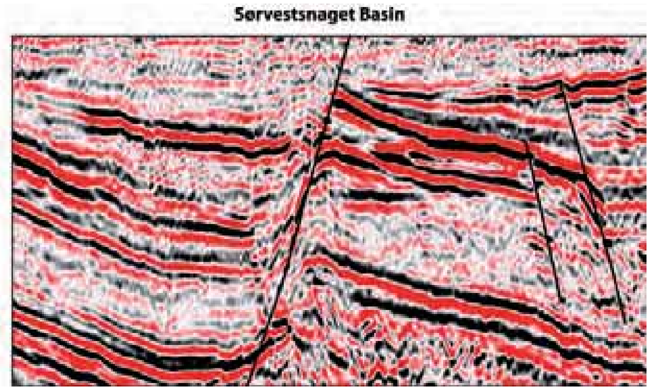


Seismic example showing a band of high seismic amplitudes interpreted as Middle Eocene submarine fan. The CDP gather from the long-offset NBR data reveals increase amplitude with angle.

minor gas accumulations in Middle Eocene submarine fan sandstones, and in this way, documented the existence of a Cenozoic petroleum play (Ryseth *et al*., 2003). On the other hand, the depocentre in the southern part of the Sørvestsnaget Basin is related to Middle-Late Eocene large-scale salt diapirism (Breivik *et al*., 1998), implying a different depositional setting. After the initial continental breakup and the onset of sea-floor spreading, the Vestbakken Volcanic Province and the Sørvestsnaget Basin subsided rapidly and received large amount of erosional products from the Stappen High to the north-east.

The Stappen High was uplifted during Late Cretaceous/Cenozoic time due to tectonism and volcanism, acting as a regional high on the Western Barents Shelf (Faleide *et al*., 1993). Based on newly acquired long-offset better-resolution seismic data from the NBR survey, successive erosion down to Mesozoic strata is imaged on the Stappen High. In this way, the Stappen High can be seen to have played an important role as a provenance area for sand deposits to the surrounding basins. In particular, well developed seismic clinoforms are observed in the northern part of the Sørvestsnaget Basin, indicating south-southwestwards progradation of shorelines from the Stappen High during Middle and Late Eocene times. Furthermore, the Middle Eocene gravity-driven deposits in submarine fan and high-density turbidites form the most significant reservoir sandstones in the Sørvestsnaget Basin, and most likely consist of reworked Jurassic sandstones (reworked Normela and Stø formations) eroded from the uplifted Stappen High. Although dry, the well 7216/11-1S located in the southern part of the Sørvestsnaget Basin proved the existence of significant Middle Eocene reservoir sandstones which are age equivalent to submarine fan sandstones proved in the Vestbakken Volcanic Province (Ryseth *et al*., 2003).

The geological understanding of the south-western Barents Sea continental margin will be further enhanced by the 2011 seismic survey program (NBR11), where 12,000 km of long-offset, high quality 2D regional seismic data will be acquired by Fugro in co-operation with TGS.



Seismic example showing a robust rotated fault-block with possible DHI.

Marine Seismic Sources

PART VIII: FISH HEAR A GREAT DEAL

Christine Reisæter Amundsen (10)

To understand how human-generated sounds affect fish it is necessary to understand how and what fish can hear, and how they respond to different types of sounds.

MARTIN LANDRØ AND LASSE AMUNDSEN

Lasse Amundsen is Chief Scientist Exploration Technology at Statoil. He is adjunct professor at the Norwegian University of Science and Technology (NTNU) and at the University of Houston, Texas.

Martin Landrø is professor in Applied Geophysics at NTNU, Trondheim, Norway.

The majority of fish species are known to detect sounds from below 50 Hz up to 500 or even 1,500 Hz. A smaller number of species can detect sounds to over 3,000 Hz, while a very few can detect sounds to well over 100 kHz.

In a somewhat vague and unclear manner, fish are termed as either *hearing generalists* or *hearing specialists*. Hearing generalists are fish with the narrower bandwidth of hearing – typically able to detect sounds up to 1 or 1.5 kHz. Specialists have a broader hearing range, detecting sounds above 1.5 kHz. Furthermore, where specialists and generalists overlap in frequency range of hearing, the specialists generally have lower hearing thresholds than the generalists, meaning that they can detect quieter sounds.

Fish species with no swim bladder, like the ray, tend to have relatively low auditory sensitivity.

Lukas Blazek/ Dreamstime.com

Fish species with either no swim bladder (e.g. elasmobranchs, the collective name for sharks, skates and rays) or a much reduced one (many benthic species living on, in, or near the seabed like flatfish) tend to have relatively low auditory sensitivity, and generally cannot hear sounds at frequencies above 1 kHz. The sound pressure threshold can be as high as 120 dB re 1 μPa (hereafter dB) at the best frequency. Such fishes are therefore "hearing generalist" species. Fish without swim bladders are only sensitive to the particle motion component of the sound field.

Fish having a fully functional swim bladder have increased hearing sensitivity, especially when there is some form of close coupling between the swim bladder and the inner ear. These transmit oscillations of the swimming bladder wall in the pressure field to the inner ear. With the ability to perceive also the pressure component of sound these fish are referred to as "hearing specialists".

In the clupeids, (common food fish like herrings, shads, sardines and anchovies), the coupling takes the form of a gas-containing sphere (prootic bulla) connecting the swim bladder to the hearing system. This considerably lowers their hearing thresholds and extends the hearing bandwidth to higher frequencies up to several kHz.

In otophysan fish (e.g., the carps, minnows, channel catfishes, and characins; the majority of freshwater fish worldwide), a bony coupling is formed by the Weberian ossicles. These bones allow them to use their swim bladder as a sort of drum to detect a greater range of sounds, and create a super-league of hearing-sensitive fish.

Goldfish are otophysan fishes and therefore possess Weberian ossicles that allow sound pressure waves impinging upon the swim bladder to be carried directly to the ear, leading to sensitive hearing (wide-frequency range and relatively low thresholds of around 60 dB). Goldfish hear above 3 kHz, with their best hearing between 500-1000 Hz.

Alexstar/Dreamstime.com

Fish Sensory Systems

Fish have evolved two sensory systems to detect acoustic signals: the ear and the lateral line.

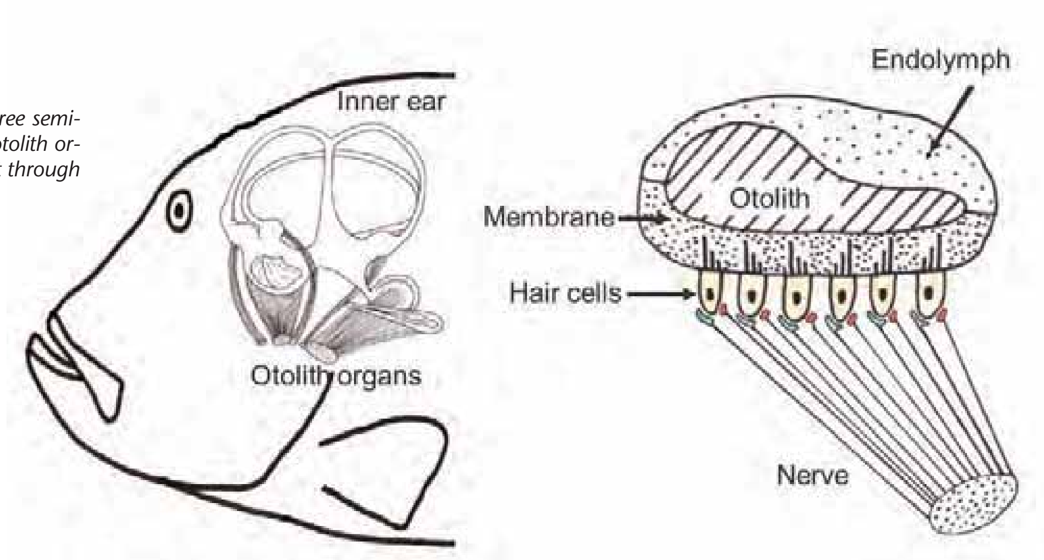
Fish do not need an outer or middle ear, since the role of these structures in terrestrial vertebrates is to funnel sound to the ear and overcome the impedance difference between air and the fluids of the inner ear. Since fish live in water, and have the same density as water, there is no impedance difference to overcome. Fish do have an inner ear which is similar in structure and function to the inner ear of terrestrial vertebrates. The most important similarity between ears of all vertebrates is that sound is converted from mechanical to electrical signals by the sensory hair cells that are common in all vertebrates. Extreme high intensity sounds are able to fatigue or damage these cells, resulting in temporary or permanent hearing loss. However, fish continue to add sensory hair cells throughout their lives. In addition, there is evidence that fishes can repair sensory cells that have been fatigued due to sound exposures that cause a shift in auditory thresholds.

Fish will move along with the sound field from any source. While this might result in the fish not detecting the sound, the inner ear also contains dense calcium carbonate structures – the otoliths – which move at a different amplitude and phase from the rest of the body while stimulating sensory hair cells. This system with relative motion between the otoliths and the sensory hair cells acts as a biological accelerometer and provides the mechanism by which all fish hear.

However, in fish with a swim bladder the acoustic sound pressure can indirectly stimulate the fish's inner ear via the bladder. For the stimulation to be efficient, the swim bladder either must be close to or have a specific connection to the inner ear. In one form, a gas bubble makes the mechanical coupling; in another the inner ear is directly connected to it by a set of small bones called the Weberian ossicles. Since the air in the swim bladder is of a very different density to that of the rest of the fish, in the presence of sound the air starts to vibrate. This vibration stimulates the inner ear by moving the otolith relative to the sensory epithelium. In these cases the fishes are sensitive to both particle motion and pressure modes of sound, leading to enhanced pressure detection and a broadened frequency response range.

The lateral line consists of a series of receptors along the body of the fish enabling detection of hydrodynamic signals (water motion) relative to the fish. It is involved with schooling behaviour, where fish swim in a cohesive formation with many other fish and for detection of near-by moving objects, such as food.

Left: The inner ear with three semicircular canals and three otolith organs. Right: Schematic cut through an otolith organ.



Lasse Amundsen

SOUND IN WATER

Any sound source in water produces both oscillations of water molecules - particle motion - and pressure variations - sound pressure. Particle motion can be either described as acoustic displacement, particle velocity, or particle acceleration.

Sound pressure is the parameter with which most are familiar, since it determines the "loudness" of a sound to humans and mammals. Far away from a sound source, in the far field of the source, the ratio of sound particle velocity (V) and sound pressure (P) is constant, equal to the water impedance. But moving closer than around 1/6 of the wavelength, into the sound's near field, this simple relationship breaks down. The V/P ratio strongly increases with decreasing distance to the source, thus inducing high levels of particle accelerations. However, when a fish is free to swim away from the sound source, it will likely be in the far field of the source. For a frequency of 1 Hz, the far field distance is around 250 m.

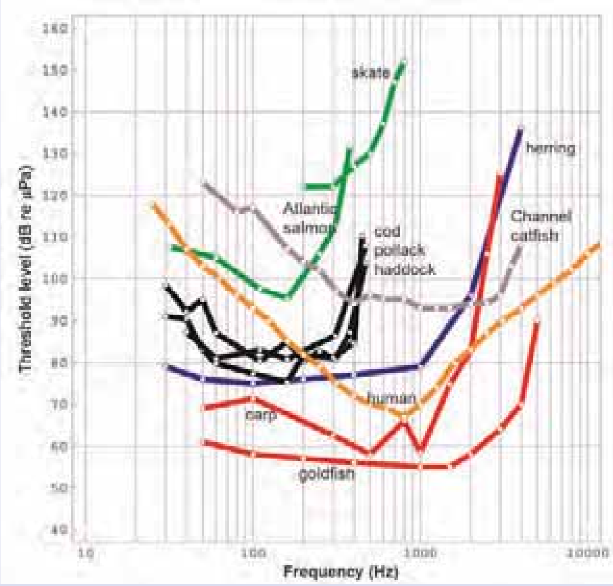
Per Eide Studio/Norwegian Seafood Export Council

The cod has been shown to detect sound pressure at the higher frequencies within their hearing range. At low frequencies, below about 100 Hz, however, the cod is particle motion sensitive. Its swim bladder appears to serve as an accessory hearing structure: oscillations are transmitted through the surrounding tissue to the inner ear, even though there is no apparent specialized anatomical link to the inner ear.
The cod possibly detects ultrasound. Astrup and Møhl (1993) indicate that cod has ultrasound thresholds of 185 to 200 dB @ 38 kHz, which likely allows for detection of odontocetes' clicks at distances up to 10 to 30 m (Astrup, 1999).

FISH AND HUMAN HEARING

Audiogram curves give the faintest sounds that can be heard at each frequency, and fall in two main categories: hearing generalists like skate, salmon and cod, with medium hearing ability, and hearing specialists like Atlantic herring and gold fish. Hearing generalist species have a narrower hearing frequency range (less than 1500 Hz) and higher hearing threshold (above 100 dB) than hearing specialist fish (up to 8 kHz and down to 60 dB). The level at which fish respond to a sound stimulus can be significantly above the detection threshold.

The human auditory system is most sensitive to waterborne sound at frequencies from 400 Hz to 2,000 Hz, with a peak at approximately 800 Hz and at a sound pressure level of 67 dB. The most sensitive frequency range is also the range having the greatest potential for hearing damage.



Audiograms

For fish to hear a sound source, the generated sound pressure level should be higher than its auditory threshold and background noise levels from natural sources and anthropogenic sound.

Traditionally, studies of hearing have used behavioural or electrophysiological methods. The qualitative behavioural methods are based on conditioning the fish with acoustic signals in conjunction with either reward (food) or punishment (electric shocks). The electrophysiological methods insert electrodes into either the midbrain or auditory end organs of the test fish to record neuronal activities in response to acoustic signals. This requires invasive surgery. A decade ago, a non-invasive auditory brainstem response (ABR) method where electrodes are placed on the skin of the fish's head was developed to obtain audiograms of fish, similar to those we described in (*GEO ExPro* Vol. 7, No. 6) to test marine mammals. It has now become a standard method for fish auditory physiology research.

Fish lacking the swim bladder or having a swim bladder that is not in close proximity or mechanically connected to the inner ear are sensitive mainly to sound acceleration. Their audiogram shows a sharp upper frequency limit for hearing at 200-300 Hz. This response is typical for fish species like flounders, flatfish, demersal fish (such as bullheads and sculpins), wolf fish, mackerel, salmonids, redfish and eels. The European plaice is known to be significantly sound sensitive into the infrasonic band (less than 20 Hz) and this probably holds for many of these fish species.

Cod, haddock and pollack have similar hearing capabilities and sense sound in the frequency range 0.1-450 Hz. For sound intensities close to threshold cod fish are sensitive to sound pressure in the frequency range 100-450 Hz and to sound acceleration for frequencies below 100 Hz. For sound intensities above the threshold value cod fish will detect both sound acceleration and sound pressure over a substantial frequency range, 20-150 kHz. Sound pressure thresholds in cod fish in the frequency range 60-300 Hz lie in the range 80-90 dB.

The herring family has a upper hearing frequency limit of 1-8 kHz, with an optimum range of 0.6-2 kHz. These hearing specialists are also sensitive to sound pressure towards lower frequencies. Sound induced escape responses can be triggered from sound pressure by infrasonic sound down to 5 Hz.

Recent studies have demonstrated that the inner ear of the herring subfamily shad is specialized to sense ultrasound in the range 20-120 Hz, with threshold values in the range 150-160 dB for frequencies at 80-100 kHz. The sensitivity is sufficient for the shads to sense attacking dolphins' ultrasonic clicks, which can have sound pressure up to 220 dB @ 1 m. The other subfamilies of herring do not have ultrasound hearing.

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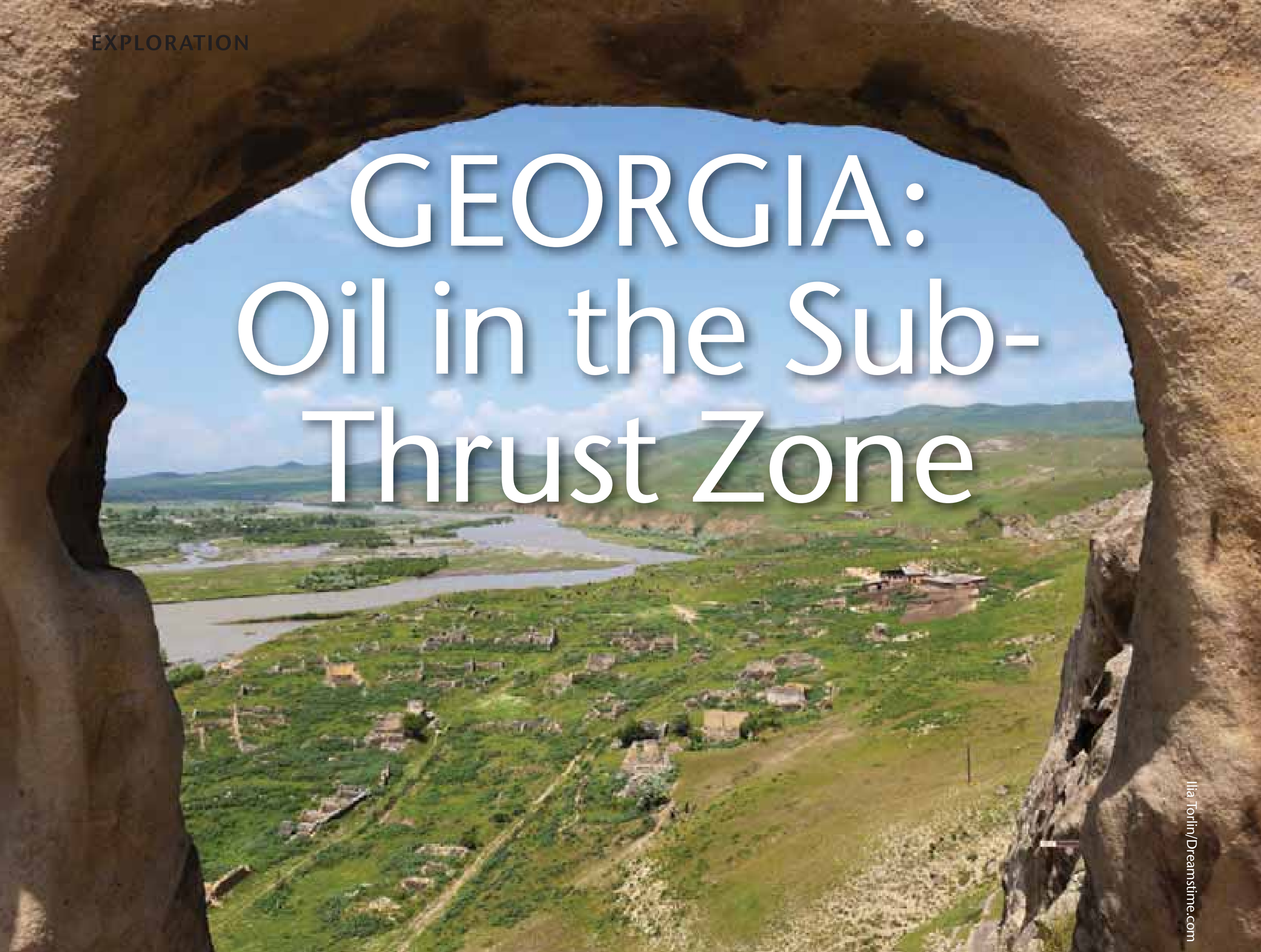


GEORGIA: Oil in the Sub-Thrust Zone

Ilia Torlin/Dreamstime.com

JANE WHALEY

A beautiful country, flanked by mountain ranges and famous for fine wine – but Georgia's primary contribution to the hydrocarbon industry is as a corridor for oil and gas travelling from the Caspian to European markets. Or so it was thought – until modern seismic techniques and recent exploration revealed oil bearing structures in the sub-thrust zone, only poorly imaged on the older Soviet era data.

Village ruins near the ancient cave city of Uplistsikhe in eastern Georgia.

Over a million barrels of oil a day flow through Georgia – but not a drop comes from the Eurasian country. Much of the vast oil and gas reserves of Azerbaijan on the Caspian Sea is exported via three main pipelines which pass through it, but Georgia itself produces less than 1,000 bopd, which is exported, not via the pipeline infrastructure, but by rail and the Black Sea port of Batumi.

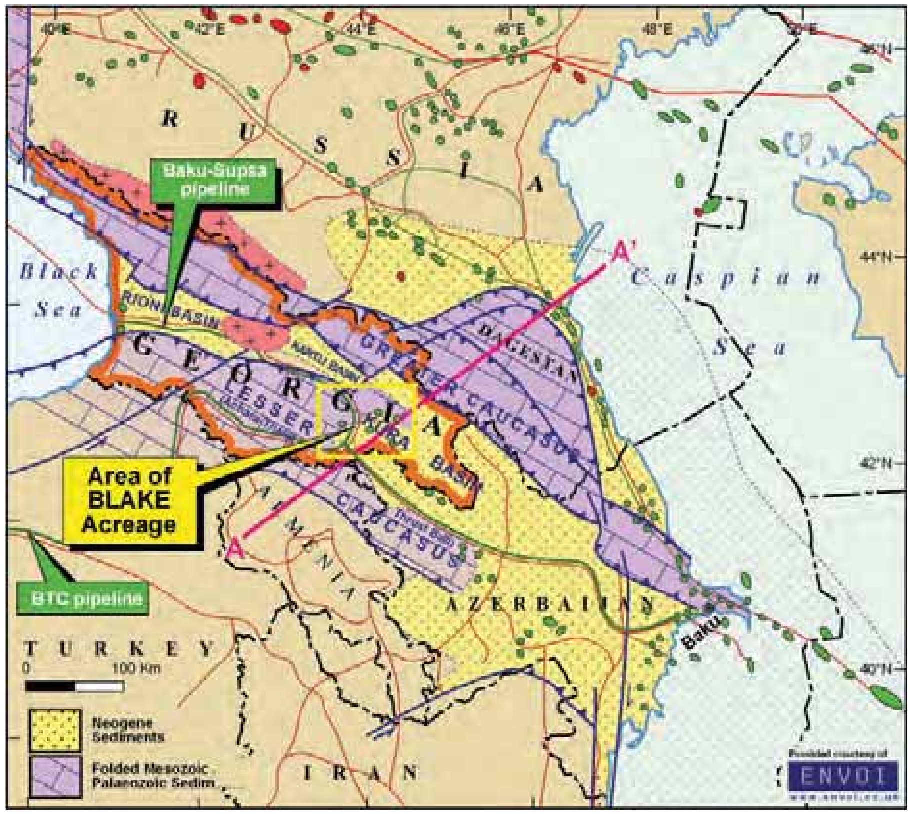
"Much of Georgia lies in the Southern Caspian petroleum system; the very same system which has sourced the giant discoveries in Azerbaijan," says Vincent McDonnell, CEO of Blake Oil and Gas, one of a handful of companies actively exploring in Georgia. "Only 220 MMbo have ever been produced from the country, but we believe that it offers considerable potential."

Long Regional History

Hydrocarbons have been recognised in the region for centuries – in fact Marco Polo noted in the 14th century that oil was being collected from oil seeps in Georgia and used for heating and lighting. In 1846, more than a decade before the Americans made their famous Spindletop oil discovery in Pennsylvania, Azerbaijan drilled the first oil well in the Caspian region in Bibi-Heybat. By the beginning of the 20th Century, Azerbaijan was producing more than half of the world's supply of oil.

In 1865 alone, more than 100 shallow (i.e. <100m deep) wells were drilled in eastern Georgia, and by 1869 some 15.7 Mbo had been produced from this area. Three further fields were discovered in Georgia before World War II, but exploration thereafter was sporadic, resulting in a total of only 18 oil and gas discoveries to date, of which the Samgori-Patardzeuli and the Ninotsminda fields are the best known.

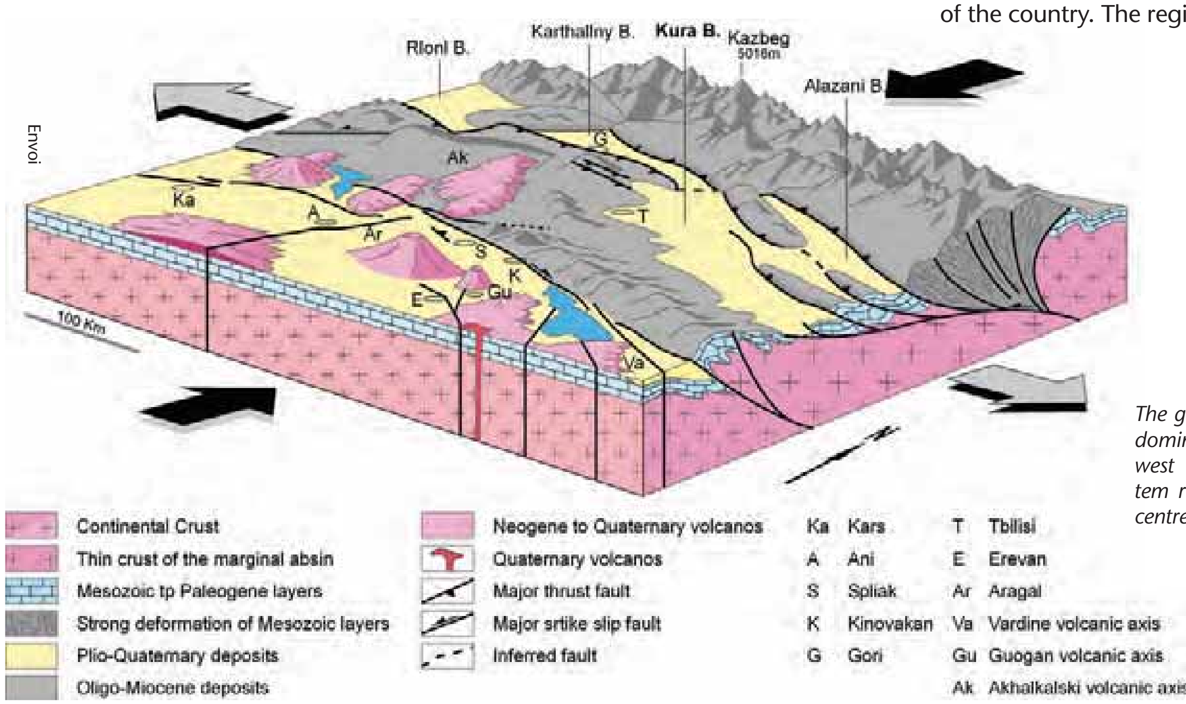
"Fifteen of the known discoveries in Georgia are in the Kura Basin, in the eastern half of the country and which extends into Azerbaijan and the South Caspian Basin. This is the area which we believe holds the greatest potential," says Vincent. "The basin is a Late Tertiary back-arc feature, but we are interested in the older sediments, particularly the Upper Cretaceous carbonate rocks. These have been very prolific oil and gas producers on the other side of the Greater Caucasus Mountains, where more than 200 Cretaceous fields exist, with individual wells flowing at rates greater than 15 MBopd. Prior to the civil strife in Chechnya, fields such as Karabulak-Achalukskoye and Malgobek-Voznesensko-Alkhasovo, among others, were producing over 300,000 bopd. They may seem a long distance away, but the geology is the same – it was all the one basin before the North Caucasus mountains popped up."



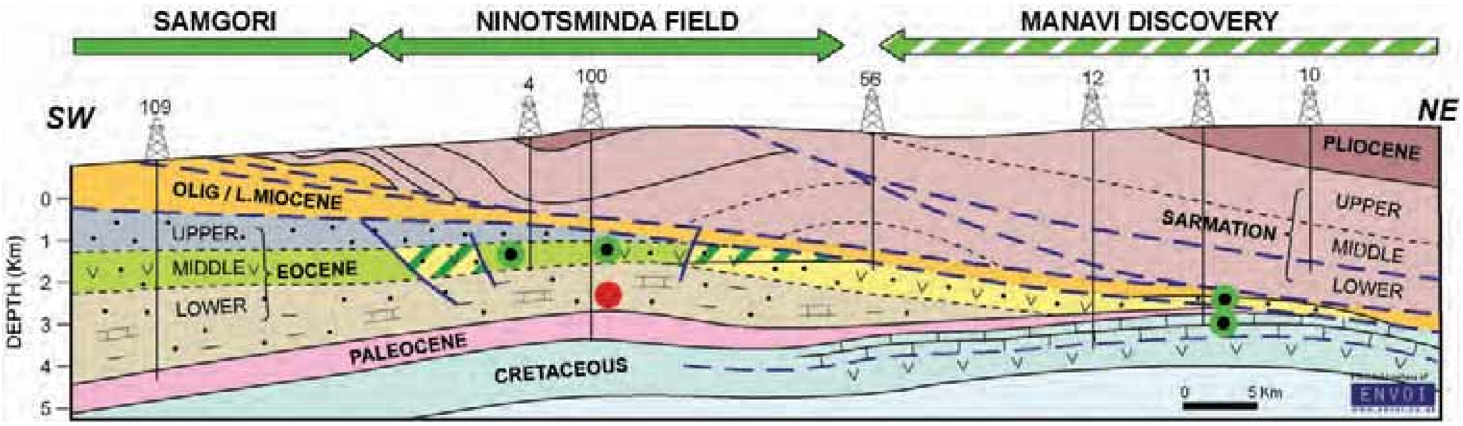
Georgia is bounded to the West by the Black Sea. The Greater Caucasus Mountains rising to the north form a boundary with the Russian province of Chechnya, while Turkey, Armenia and Azerbaijan lie to the south and east.

Intramontane Basins

The geology of Georgia is dominated by an east to west trending Neogene foreland basin system running through the centre of the country. The region marks the final ▶



The geology of Georgia is dominated by an east to west trending basin system running through the centre of the country.



Schematic cross-section south-west to north-east across the Samgori-Ninotsminda field and Manavi discovery.

zone of convergence between the Eurasian and Afro-Arabian plates and the development of the Alpine mountain system, which began during the late Mesozoic and continues today. The central basin originated in the Mesozoic as an inter-arc basin which underwent late Mesozoic and Palaeogene transformation and became a relatively passive foredeep environment as the Afro-Arabian plates moved progressively northwards.

This foreland basin system is split into two intramontane basin systems. Rioni in the west, bordering the Black Sea, is separated from the eastern Kartli and Kura Basins by the Dziruli Massif, which is composed of acid intrusive and metamorphic rocks covered by Upper Triassic-Cretaceous sequences. To the north is the predominantly carbonate Greater Caucasus thrust belt with the volcanic rocks of the Lesser Caucasus Mountains to the south, both of which exhibit complex nappe features.

Sedimentation in the Rioni Basin started in the early Jurassic, with maximum subsidence taking place in the Miocene and Pliocene. Volcanics, volcaniclastics and carbonates were deposited in the Cretaceous and the main reservoirs units of the Rioni Basin are the Upper Miocene molasses. Potential traps have been identified in structural closures such as anticlines and faulted anticlines, as well as stratigraphic plays related to facies change, but to date the basin has not proved very prospective.

The Upper Kura or Kartli Basin, which is the western end of the Kura Basin lying in Georgia, is composed of Palaeozoic igneous rocks and Carboniferous limestones, unconformably overlain by Jurassic to Quaternary sequences. It has a similar depositional history to that of the Rioni Basin.The entire Kura Basin today is under inversion and compression, resulting in a number of fault-bounded, east to west trending, high relief features, which have been the main targets in the northern part of the basin, where younger megasequences have been overthrust over Mesozoic rocks. They have resulted in the Samgori-Patardzeuli fields, which were discovered in the 1970s and have produced approximately 200 MMbo so far.

MAJOR PIPELINE ROUTES

At a length of 1,768 km, the Baku-Tbilisi-Ceyhan (BTC) Pipeline can rightly claim to be one of the great engineering endeavours of the new millennium. It transports offshore Caspian oil from the Sangachal terminal near Baku, via Georgia to the Ceyhan marine terminal on the Turkish coast of the Mediterranean, from whence it is exported by waiting tankers to European markets. About 350 km of the pipeline, which has a capacity of a million barrels a day, pass through Georgia, where there are two pumping stations.

Construction of the pipeline, which is buried throughout its length, commenced in 2002 and first oil reached the Ceyhan terminal on 28 May, 2006. It is an incorporated joint venture company with 11 shareholders, managed by its largest shareholder, BP.

Two other pipelines pass through Georgia: the nearly 700 km Baku-Tbilisi-Erzurum or South Caucasus line, which transports gas from Shah Deniz to Turkey, and the 833 km Baku-Supsa or 'Western Early Oil Route', which terminates on the Black Sea on the Georgian coast.

Pumping station on the Baku-Tbilisi-Ceyhan pipeline in Georgia.

BP p.l.c.

Vincent McDonnell is CEO of Blake Oil and Gas, which has promising acreage in Georgia.

New Play Opened

"I have been involved in Georgia since 1994, initially working for JKX Oil & Gas – at the time the first Production Sharing Contract (PSC) in Georgia was signed," says Vincent McDonnell. "This covered the Ninotsminda field, later acquired by CanArgo Energy Corporation, a US AMEX listed company where I worked for ten years. CanArgo added two further large high potential blocks to its portfolio in the Kura Basin, close to the capital, Tiblisi. In addition to the undoubted potential in the shallow Tertiary Caspian system, where CanArgo discovered oil in a structure analogous to the Samgori-Patardzeuli-Ninotsminda complex of fields, our work in the area has also opened up a new oil play fairway in the South Caucasus in Cretaceous fractured carbonates."

"The acreage includes the undeveloped Manavi and Norio discoveries: the former partly underlies the Ninotsminda field and was identified on new seismic acquired in 2000. The Manavi 11 exploration well drilled in 2003/04 proved up the deeper Cretaceous hydrocarbon system, which is directly analogous to the prolific fields to the north of Georgia in the southern provinces of Russia. The subsequent M12 appraisal well found a 148m hydrocarbon column of 40.5° API oil which remains to be tested. We also expect to be able to produce significant gas from the field, due to the very high gas-oil ratio." The Norio discovery, where 46.8° API oil has been flowed to surface, comprises a stacked reservoir analogous to the adjacent Samgori and Ninotsminda fields, but larger.

"Unfortunately, political and economic developments, including the Georgia-Russia five day war in August 2008, the global financial crisis, and the collapse of the oil price, meant it was difficult to find sufficient funding for exploration and development, culminating in CanArgo filing for Chapter 11 in 2009. After a corporate re-organisation and refinancing these promising assets, including the producing Ninotsminda field, the Manavi and Norio oil discoveries and significant leads and prospects, are now owned by Blake Oil and Gas."

"Independent consultants have estimated that the blocks could contain combined reserves and upside contingent resources of 835 MMboe recoverable, with a further upside of 957 MMboe recoverable in unrisked prospective resources" Vincent adds.

Geochemical studies suggest that the primary source for Tertiary and Mesozoic reservoirs is Oligocene to Middle Miocene aged "Maykop Formation" organic-rich black mudstones, which can be as much as 2,500m thick in the region and which contain TOC s of between 1.5% and 10%. Peak generation seems to have occurred during Miocene-Pliocene, after the development of the major anticlines and traps.The Maykop is the primary source for the hydrocarbon charge of the Kura Basin, South Caspian Basin and the North Caucasus.

Modern Seismic Reveals Potential

"During the Soviet era, most of the obvious structures with surface expression in Georgia were drilled, and many found hydrocarbons," Vincent explains. "However, the seismic at the time was not able to effectively visualise the deeper horizons. As a result, the structures tested were generally small and detached by faults from the deeper and larger structures located in the sub-thrust zone which can be seen on modern seismic data. There is therefore significant future exploration and development potential in the Georgian Kura Basin."

"Georgia is a good place to do business," he adds. "It has a supportive government, and PSCs have good terms; the first 50% of production goes to the company for the recovery of expenses, with the remaining split with the state. It is also very beautiful, flanked by two impressive mountain ranges, with friendly people – who incidentally make very fine wine!"

"We've done the difficult job and found what appear to be large quantities of hydrocarbons in this hospitable and beautiful country. Come and join us!"

Further information about the Blake acreage in Georgia can be found at www.envoi.co.uk ■

The Abu Dhabi Oil Discoveries

In the 1930s Abu Dhabi was a poor fishing village on the edge of the desert, but the discovery of oil has revolutionised the Emirate. It is thought to possess the sixth largest proven oil reserves in the world and is now extremely rich.

Iraq Petroleum Company

A seismic party crossing the desert, Abu Dhabi 1971

MICHAEL QUENTIN MORTON

Abu Dhabi is often described as the world's richest city but in the 1930s the opposite was true. Situated on an island, it was a simple fishing village with a fort. Although the local economy had once prospered on the pearl trade, cultured pearls from Japan destroyed the market for natural ones, ruining the trade and bringing poverty to the population. The rest of the emirate comprised mainly sand, with settlements and date plantations around the oases of Liwa and Al Ain.

1930s and 40s: The First Moves

The ruler, Sheikh Shakhbut bin Sultan al Nahyan, was eager to find a good water

Situated on the south-eastern side of the Arabian Peninsula, the emirate of Abu Dhabi has a land surface of 67,340 square kilometres, about the same size as West Virginia. Almost 200 islands fall within its territory and the mainland is predominantly desert. The capital city of the same name is also the capital of the seven member United Arab Emirates (UAE), which was formerly known as the Trucial States (or Trucial Coast). Abu Dhabi contains 95% of the oil and 92% of the natural gas resources of the UAE.

Location map of United Arab Emirates and its major oil fields (from Granier B., Al Suwaidi A.S., Busnardo R., Aziz S.K., Schroeder R. (2003) – "New Insight on the Stratigraphy of the "Upper Thamama" in Offshore Abu Dhabi (U.A.E.)" Carnets de Géologie/ Notebooks on Geology*, Article 2003/05.)*

supply. He had heard about Major Frank Holmes' work drilling for water in Bahrain and thought the same might be done on Abu Dhabi island where only brackish water was recovered from shallow pits. He agreed enthusiastically to the British political officer's suggestion that a water survey should be carried out and a request was duly made to the Iraq Petroleum Company (IPC), whose partners included the Anglo Persian (renamed Anglo Iranian in 1935) Oil Company, the forerunner of BP.

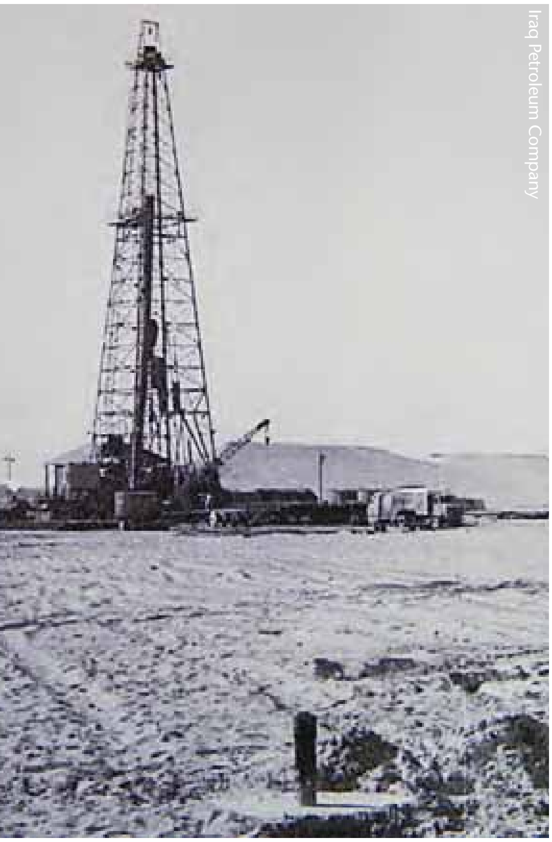
Even so, when Anglo Persian geologist Peter Cox arrived in Abu Dhabi in 1935, he was surprised to find a lukewarm Sheikh Shakhbut: it seemed that the Sheikh was now more interested in oil than water. Shakhbut was well informed about payments that other rulers had received from oil companies, and was keen to discuss an oil concession. On 5th January, 1936 William "Haji" Williamson, on behalf of IPC, obtained a two year option for Abu Dhabi on a down payment of 7,000 rupees and 3,000 rupees a month (approximately £27,000 and £12,000 at today's values). IPC created a subsidiary company, Petroleum Development (Trucial Coast) (PDTC), to explore the area.

The first survey of Abu Dhabi began in the same year. A PDTC survey party visited the Buraimi Oasis and studied the largest and most promising anticline of the region, Jebel Hafit, but everything pointed to future difficulties for oil exploration. Field geologists relied on mapping and plane tabling exposed rock formations and most of the interior of Abu Dhabi was covered in sand; only Jebels Hafit and Dhana and a few coastal outcrops were exposed. The oil company would have to rely on the "new" science of geophysics rather than geology to unlock the secrets of this land, but the technology would not be available until a decade later. Undeterred, PDTC obtained a 75-year concession for the whole territory on 11 January 1939.

World War II intervened and exploration was put on hold. Once the war was over gravity surveys were started in 1946 and continued moving inland until 1950, when the going became too difficult for the company's vehicles because of the huge sand dunes. After a break of three years, these surveys resumed with special equipment, including helicopters. By now, land transport had improved and crews were able to complete the gravity coverage of Abu Dhabi using vehicles such as Dodge Power Wagons equipped with low profile balloon-tyres.

1950s: Win Some, Lose Some

PDTC began drilling for oil at Ras Sadr in 1950 and Jebel Ali in 1951, but both wells proved dry. PDTC's focus shifted to western Abu Dhabi but progress was hampered by a boundary dispute with ▶



Murban No.1 Well.

Saudi Arabia. The Buraimi Dispute, as it was known, closed parts of Abu Dhabi to oil exploration.

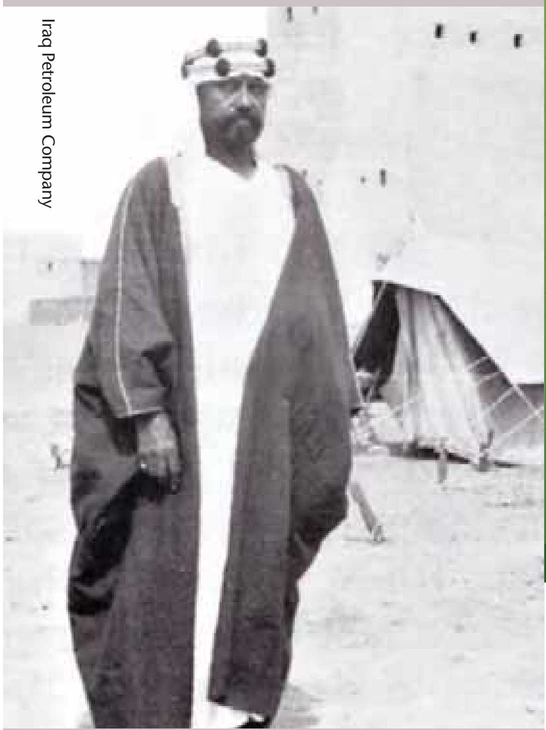
As a result of this dispute, PDTC was forced to drill the Murban No.1 well several miles off the seismic crest. The well struck traces of light oil and gas at a depth of about 10,000 ft (3,048m) but drilling ended abruptly at a depth below 12,500 ft (3,810m) when the well suddenly blew out with high-pressure sour gas, killing a petroleum engineer and brittling the drill string. The well had to be plugged and abandoned. Analysis indicated that the oil show had in fact come from a Cretaceous rock interval known as the Upper Thamama.

The disappointing findings from this well pushed exploration westwards towards the region where the productive Jurassic Arab reservoirs might be found. When arbitration proceedings over the Buraimi Dispute broke down, PDTC continued its drilling programme in Abu Dhabi where two more seismic structures were discovered, Gezira and Shuweihat. Both were drilled but proved dry.

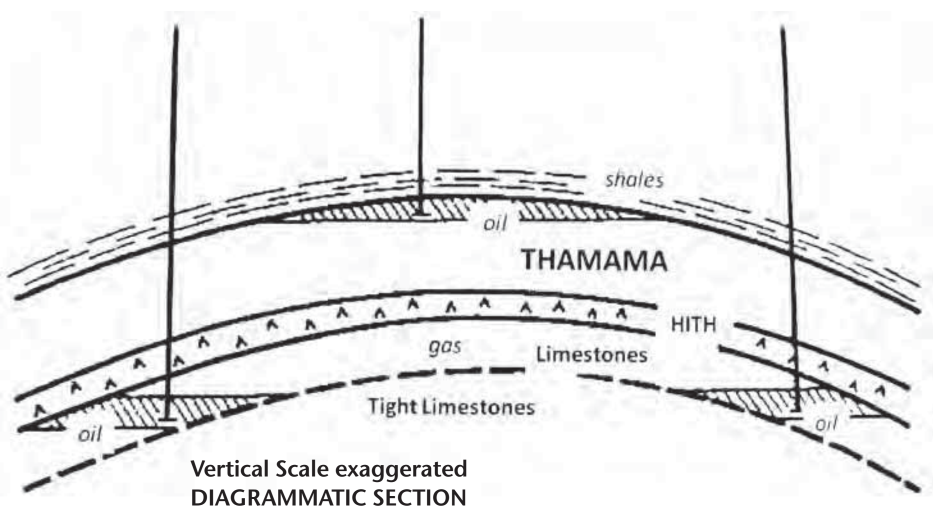
Meanwhile, Abu Dhabi Marine Areas Ltd. (ADMA) had obtained an offshore concession. ADMA was jointly owned by British Petroleum and Compagnie Française des Pétroles (later Total). The company brought Jacques Cousteau on his research ship Calypso to the Gulf to map the sea bed geologically. There followed a seismic survey conducted by GSI Ltd. from their vessel mv Sonic, the results of which led to the location of the first test well being selected. In 1958, using a marine drilling platform, the ADMA Enterprise, drilling began on the Umm Shaif field and oil was struck at about 8,755 ft (2,668m). The field, a super-giant about 300 km^2 in size, came on stream in 1962, producing oil from the top of the Lower Cretaceous Thamama group (I and II), from the Upper Jurassic Arab D carbonates and Middle Jurassic Araej and Uwainat limestones.

This was followed in 1959 by PDTC's onshore discovery well at Murban No.3. The oil field (now known as Murban-Bab) was delineated by seismic surveys in light dune terrain and was about 450 km^2 in size. Oil came from several porous limestone zones of the Lower Cretaceous Thamama

'Haji' Williamson was an Englishman who had lived for many years in the Middle East and had a good reputation among the sheikhs of the Gulf. He was the guide and interpreter for the first PDTC survey of Abu Dhabi in 1936. Major Frank Holmes was a concession hunter who had helped to obtain oil concessions in Al-Hasa, Bahrain and Kuwait (see "The Emergence of the Arabian Oil Industry," *GEO ExPro*, Vol 7, No. 6). Although often cast as rivals in the competition to obtain oil concessions, Haji and Holmes were in fact of much the same ilk: both were individualists who saw the Arab point of view, which sometimes made British officials suspicious of their influence. In the 1930s, both were involved on behalf of PDTC in negotiations for oil concessions with the sheikhs of the Trucial Coast.



William "Haji" Williamson in 1934.



Vertical Scale exaggerated
DIAGRAMMATIC SECTION
UMM SHAIF FIELD

One important feature of the Umm Shaif discovery was that it confirmed the presence of oil in the Cretaceous Thamama Group, whereas most of the previous oil strikes in eastern Arabia had been in the Jurassic Arab Zone limestones.
S. Elder, The Journal of the Institute of Petroleum *vol. 47, p. 310, October 1963.*

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Ruler of Abu Dhabi, Sheikh Shakhbut bin Sultan al Nahyan (centre), with IPC General Manager C.M. Dalley on his left, after turning the valve at the newly-built oil terminal at Jebel Dhanna to symbolise the first flow of oil, 21 March 1964.

group. The field went on stream in 1964. By 1979 average daily production was 60,270 bopd and by 1980 cumulative production had reached 630 MMbo. In 1962, the company discovered the Bu Hasa field and ADMA followed in 1965 with the discovery of the Zakum offshore field.

1960s and 70s: Facing the Future

In the early 1960's PDTC relinquished much of the Trucial Coast area but retained Abu Dhabi and changed its name to the Abu Dhabi Petroleum Company (ADPC). In 1965 ADPC signed a 50-50 oil-sharing agreement with Sheikh Shakhbut. ADMA agreed the same terms in 1966. On 6 August 1966, Shakhbut was succeeded by his younger brother, Zayed. In 1971, Sheikh Zayed became president of the newly created UAE and the Abu Dhabi National Oil Company was created. In December 1974, the company gained a 60% interest in ADPC and ADMA, which were reincorporated as the Abu Dhabi Company for Onshore Oil Operation and Abu Dhabi Marine Operating Companies.

Oil in the UAE Today

In addition to the oil fields mentioned, the main producing fields onshore are Asab, Sahil and Shah, and offshore are al-Bunduq, and Abu al-Bukhoosh (ABK). Oil production in the UAE was in the region of 2.3 MMbopd in 2010, and it possesses the sixth largest proven oil reserves in the world; but plans to boost production to 3 MMbopd have not yet materialised.

In recent years the focus has turned to gas as increasing domestic consumption for power, desalination and reinjection of gas into oil fields increases demand. Gas extraction is not without its difficulties, however, as demonstrated by the sour gas project at Shah where the gas is rich in hydrogen sulphide content and is expensive to develop and process.

Acknowledgements: Thanks to Alan Heward and Peter Morton for their assistance with this article.

Michael Quentin Morton's father D.M. ("Mike") Morton was Head of the Geological Department of the Abu Dhabi Petroleum Company (ADPC) between 1961 and 1966. Mike's biography In the Heart of the Desert *is published by Green Mountain Press (ISBN: 095522120X).* ■

Another line is fired: Party 19 in the Abu Dhabi desert, 1971. Party 19 was one of three seismic crews on contract from General Geophysical Company each with about 120 people and 36 vehicles of various kinds, including six mobile shot-hole rigs. In a typical day, about 1,500 shot–holes were drilled and over 1,000 geophones laid out and connected by cables to recording instruments. These geophones and cables were picked up and relocated several times each day. The field data was recorded and processed in a large computer complex in London. Starting in 1960, Party 19 surveyed the Bab and Bu Hasa areas, moved south-eastwards to Asab and subsequently covered most parts of Abu Dhabi. The crews completed operations in 1971 and their equipment was shipped to Saudi Arabia.

Abu Dhabi city at night, November 2010.

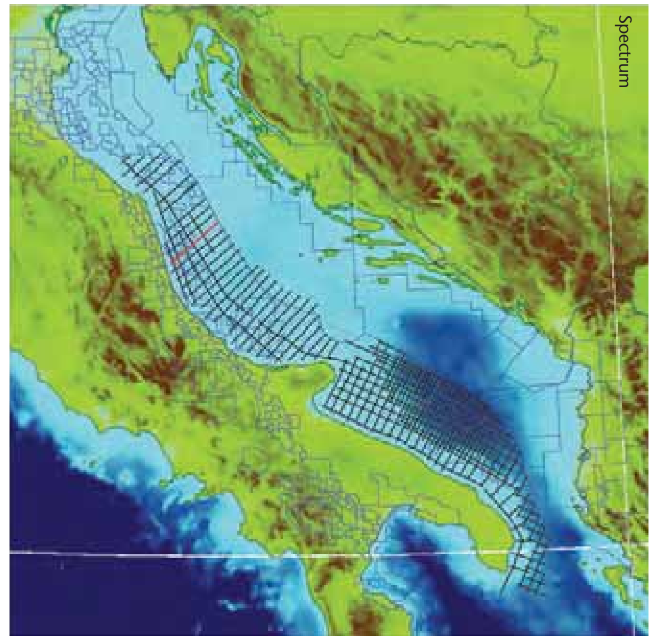
ITALIAN ADRIATIC SEA:

Filling in the Gaps in this Prolific Region

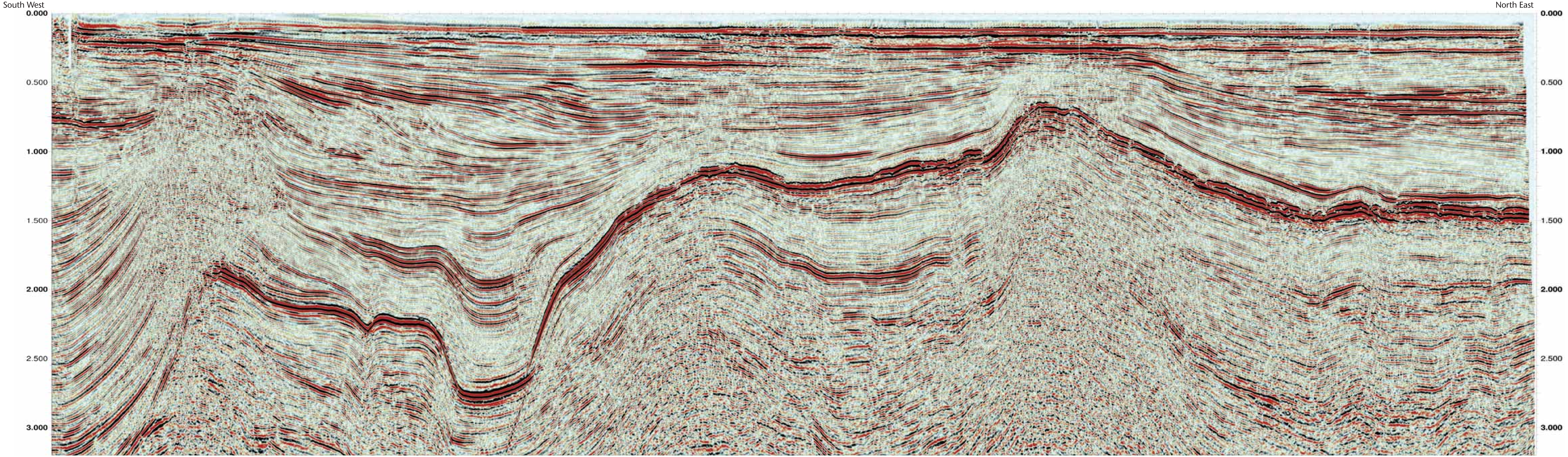
This approximately 70 km. wide, west to east PSTM seismic line is located within Zone B in the northern part of the Italian Adriatic Sea with much of the line in currently unlicensed acreage. The line was in acquired in 1967 and was reprocessed by Spectrum in 2011 resulting in improvements in seismic resolution and continuity in both the shallow and deeper sections.

The line is an excellent example of the enhancements made by the reprocessing, with clear improvements from water bottom right down to the oldest deeper section. In the shallower gas-prone section of the Plio-Pleistocene there are some obvious amplitude anomalies associated with interesting stratigraphic leads, and in the deeper section there are several clear large scale structural rollovers that appear very interesting for future exploration.

These older reprocessed lines will be interpreted and the main leads and structures mapped by SDX to help guide interested companies to the best areas to licence in the future.



Map showing the area covered by the Adriatic Reprocessing survey off the East coast of Italy, with the line of section highlighted in red.



Exploration in the Italian Adriatic

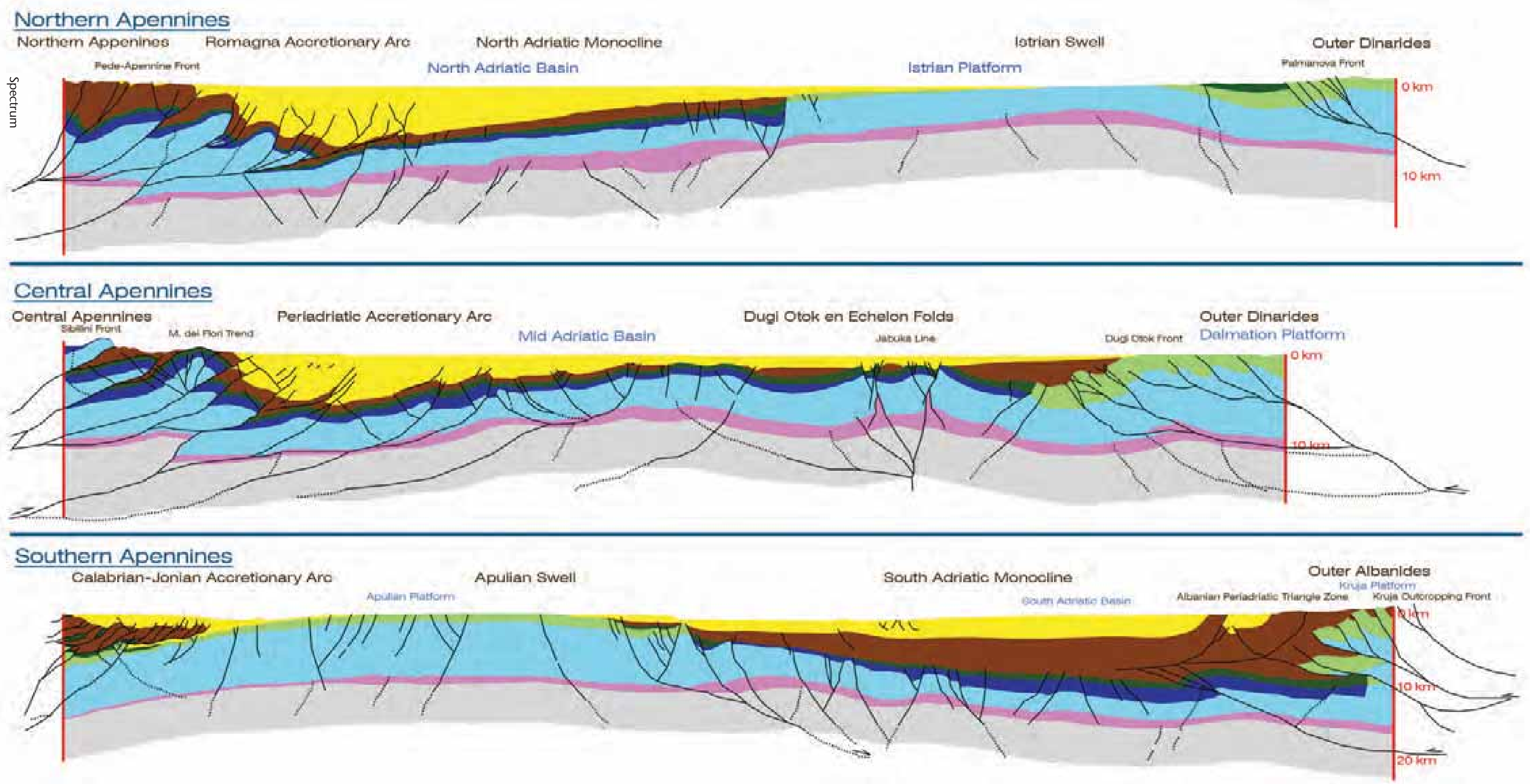
GARY SCAIFE AND RICHARD SPOORS, SPECTRUM; DAVE PEACE, GREENFIELD EXPLORATION

Italian exploration for oil and gas has been very successful in the past 50 years both onshore and offshore, with a number of large oil and gas discoveries being made. However, more recently Italy has been thought of as a mature region in terms of hydrocarbon potential with perceived limited remaining prospectivity. This has resulted in the region being overlooked by exploration companies and a significant lack of new investment as they have been lured to other parts of the world.

Italy has a large and rapidly growing domestic gas and oil market, and a good pipeline and hydrocarbon infrastructure in place. Despite this there has been a gradual decline in domestic production over the last 15 years, meaning that Italy now imports much of its gas from North Africa.

The country continues to have one of the best fiscal and tax regimes in the world for exploration companies, so it is surprising that more companies are not exploring for oil and gas in Italy. One of the reasons for this reduction in interest is the lack of modern regional seismic data and difficulty in accessing available older vintage regional data which together have made it difficult for interested exploration companies to make a regional evaluation.

In order to help address these issues, Spectrum and S.D. Exploration Services (S.D.E.S), specialists in offshore Italian exploration, have undertaken a significant project involving the reprocessing, interpretation and evaluation of a unique regional dataset covering the Italian Adriatic Sea.



Simplified Geological Cross-Sections of the Adriatic Region

High Exploration Potential Offshore Italy

The Italian Adriatic Sea is the most successful exploration area offshore Italy. Numerous gas discoveries have been made in the shallow Pliocene and Tertiary section. This is particularly evident in the prolific Zone A region in the northern part of the Adriatic, where numerous gas fields have been in production for many years, providing Italy with a modest amount of domestic gas , but new production is needed to help fill the increasing gap in gas supply. In the more southerly regions of the Adriatic Sea, especially south-east of the Gargano peninsula, the geology changes and exploration has been more focused on the deeper oil plays in the Cretaceous and Jurassic carbonate section with some success, while the shallower Tertiary gas plays have been largely overlooked.

There is a modest amount of current exploration activity in the Italian offshore Adriatic but there is still a huge amount of the region (approximately 70-80%) remaining unlicensed and lying fallow. Seismic data, however, implies that the open acreage still contains many more oil and gas deposits waiting to be discovered. There are structures observed on the reprocessed seismic which remain undrilled, many of which have associated DHI's. One of the reasons for the open acreage is that it has not been very easy for interested exploration companies to access large volumes of regional 2D data. Consequently companies have not been able to properly review the excellent opportunities that exist in the Italian Adriatic Sea.

The only regional seismic database was acquired 35 to 45 years ago. This data has never been reprocessed, until Spectrum recently reprocessed approximately 8,500 kms of this old regional dataset using modern seismic data processing techniques. The enhanced dataset, which is available to interested parties, ties numerous wells in the region to provide valuable regional stratigraphic control. SDES will compile an interpretation & evaluation report including local well control, which will be available to purchasers of the reprocessed seismic data.

The study area contains both structural and stratigraphic play styles that vary significantly from the northern to the southern Adriatic. A number of very interesting play types and leads can be observed on the seismic section on pages 58 - 60.

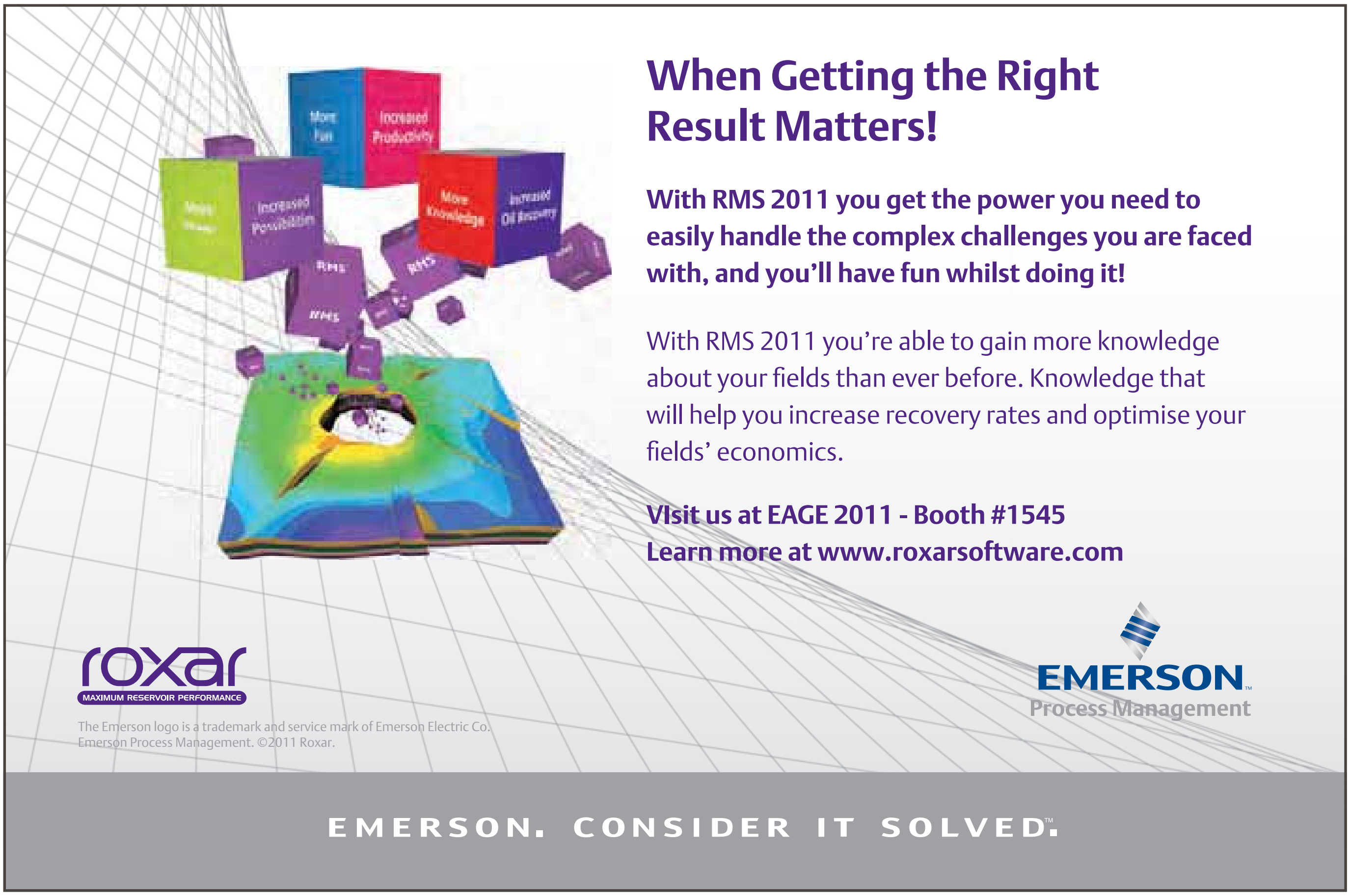
Extrapolating New Plays

The main structural elements of interest are traditionally associated with the Apennine over thrust front and the structures and play types that surround the over thrust in the basin. There are a wide variety of proven gas and oil plays associated with the thrust front and its related structuring varying from reservoir sands within the over thrust units to sands around/over/pinching out around the thrusts. There are also ripple fold plays in front of the thrusts and stratigraphic plays similar to the discoveries at Barbara, Anna-Maria and Andreina gas fields.

There are a number of large multi TCF gas fields in the northern Adriatic gas province, such as the Porto Garibaldi-D'Agostino and Barbara fields, with the biogenic gas found in Pliocene turbidite reservoirs having been sourced from Pliocene-Pleistocene clays, together with deeper plays in the lower Tertiary section as well down to Miocene age.

In the central and southern part of the Italian Adriatic there are a number of oil fields that are sourced from the Burano Formation. This Upper Triassic oil source is a type II kerogen source rock with TOCs ranging from 0.1 to 0.6% and low API gravity. For example, the southern Adriatic Aquila oil field lies in a paleo-high located near the margin of the Apulian platform and produces from Cretaceous and Jurassic pelagic packstones and dolomitised mudstones sourced from the Burano Formation.

By applying modern seismic processing techniques many of the existing successful oil and gas play types can now be extrapolated into the large expanse of open acreage in the Italian Adriatic region. This availability of modern regional seismic data will hopefully stimulate hydrocarbon exploration in this forgotten petroliferous region.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A GROWING ATLANTIC PLAY

Recent discoveries in West Africa have highlighted the importance of the Upper Cretaceous throughout the Atlantic Margin. The Barents Sea is the Northern extension of this growing play.

RUPERT HOARE, WESTERNGECO; PAUL BATHURST AND HUGH NORTH, EXPLORATION GEOSCIENCES

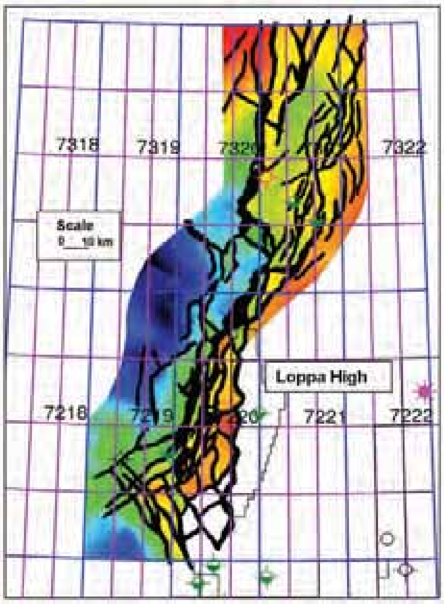
Sandstones of Upper Cretaceous age are proving to be a significant new play along the eastern Atlantic margin. Recent successes offshore West Africa, such as the Jubilee Field, along with other discoveries at Tweneboa, Teak, and Enyenre in Ghana, prove the presence of reservoir quality channel and turbidite sandstones of Turonian and Campanian age. Gross reservoir thickness can exceed 120m and the quality is demonstrated by the Mahogany 2 well in the Jubilee field, which flowed oil and gas at 4,448 bopd (39° API) and 5.1 MMcfgpd from Turronian aged turbidites. The nearby Enyenra 2A well found two Campanian aged channels containing at combined total of 32m of oil. With the Jubilee Field having booked reserves of 490 MMbo, and upside from other discoveries which could easily double this reserve, the potential of this interval is significant.

In the Norwegian Sea, drilling over the last few years has also demonstrated the presence of Upper Cretaceous aged sandstones. Among these are the Lange Formation (Turonian) sandstones, containing oil in the Sklinna accumulation (Block 6406/1), and the gas-bearing Nise Formation (Campanian) sandstones in the Luva discovery. The quality of the sands is extremely variable, with the Lange at Sklinna-being quite shaley, with porosity of 10-18%, while in comparison the Nise sands in well 6707/10-1 have porosity up to 30% and permeability of 1,000 mD.

WesternGeco

The West Loppa area of the Barents Sea, off northern Norway.

WesternGeco



Tectonic framework of the Loppa High region.

Over the past few years WesternGeco has acquired 6,145 km^2 of multiclient 3D seismic data in the West Loppa area of the Barents Sea. The initial West Loppa survey, shot in 2008, targeted the Triassic reservoirs in tilted fault blocks on the western flank of the Loppa High (*GEO Expro* Vol. 7, No. 3), where Statoil's Skrugard well has recently made an important discovery (see 'Exploration' Update, page 86.) The 2009 West Loppa Extension Survey first showed the presence of significant Upper Cretaceous fans further west in the Bjørnoya Basin, so in 2010 surveys were acquired to extend 3D coverage over this play.

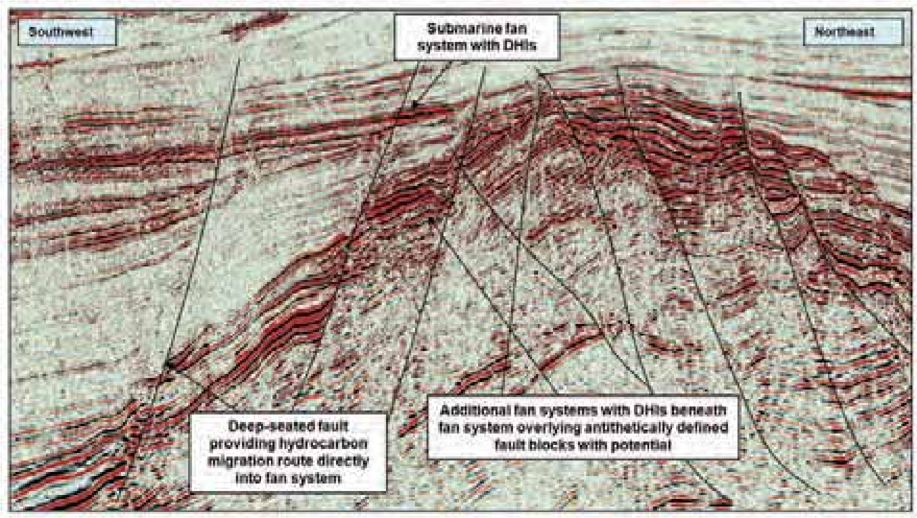
To date no significant hydrocarbon discoveries have been made in Upper Cretaceous sandstones in the Barents Sea, but good quality sands have been proven in the Hammerfest Basin to the south of the Loppa High. What therefore is the potential of this play on which Lundin will spud a well shortly?

Potential Reservoirs

Sandstones of the Knurr Formation (Hauterivian/Valanginian) are proven in well 7122/2-1, where a gross reservoir thickness 123m has a net/gross of 90% (10% porosity cutoff) giving a net sand of 111m, with a porosity of 18%. Additional sandstones are present in the Barremian Kolje Formation.

The sands are derived from erosion of the Jurassic and Triassic section from the crest of the Loppa High where today Paleocene aged sediments rest on Triassic rocks.

WesternGeco



Seismic line illustrating terraced nature of Loppa High with associated submarine fans.

Channel cuts within the southern flank of the Loppa High are visible on seismic data. These are the channels down which the erosive products poured and were deposited as debris flows or turbidites in the basin to the south. Well 7122/2-1 drilled through one such flow (fan) feature. The new WesternGeco seismic dataset displays similar fan bodies within the Upper Cretaceous section and the provenance of the sediment within these fans also appears to be the Loppa High.

The tectonic framework of the Loppa High region is dominated by two conjugate lineament systems that trend north-west to south-east and north-east to south-west. At the southern end of the Loppa High these two systems converge to provide a complex of down-thrown terraces to the west, and a subsidiary structural ridge with adjacent depositional centres. The Upper Cretaceous fans are clearly defined on the 3D dataset, often with bright amplitudes, and are seen to fill the lows in between and around the two high areas.

The excellent quality of the new data allows for good definition of the fan bodies, which can be mapped by amplitude extractions of the key Cretaceous section. The fans themselves appear to vary in gross thickness from 30-100m.

In addition to clear evidence of these fan systems, the seismic data provides considerable evidence of hydrocarbon presence in the form of gas clouds and direct hydrocarbon indicators. These are typically associated with deep-seated faulting.

Hydrocarbon Potential

With no hydrocarbons proven in this play to date, there are obvious risks and questions. Aside from the presence and quality of the reservoir, the main issues revolve around the migration of hydrocarbons into a reservoir and whether the resultis likely to be oil or gas.

Within the Barents Sea today, the two proven petroleum systems are of Triassic (Kobbe/Steinkobbe) age and Upper Jurassic (Hekkingen) age. Shale of the former is of high quality at outcrop on Svalbard (3-6% TOC), but in offshore wells drilled to date is generally of poorer quality at 1-3%. The Hekkingen shale is a rich source rock with TOC of 3-10%.

Within the Bjørnøya and Sørvestnaget basins in the southern part of the Barents Sea, rocks of this age are extremely deeply buried and have not been penetrated. Modelling predicts them to be in or through the gas window, and to have been through the oil window in the Cretaceous or early Tertiary.

However, thick, low-quality source rock intervals have been recognised within shales of the Knurr and Kolje Formations. TOCs are similar to the Kobbe at 1-3% and are considerably shallower within the western basins, seismic indicating depths of 2,000-4,000m. Within well 7199/12-1 Kolje shale contains kerogen type III and has hydrogen indices up to 200mg HC/gTOC. Generally, the shales are gas prone but some intervals show promise of oil. A similar Upper Jurassic lean shale, the Verrill Canyon Formation, is the source rock for much of the gas found at the Sable Island Field, offshore Nova Scotia, Canada. There the rock has ►

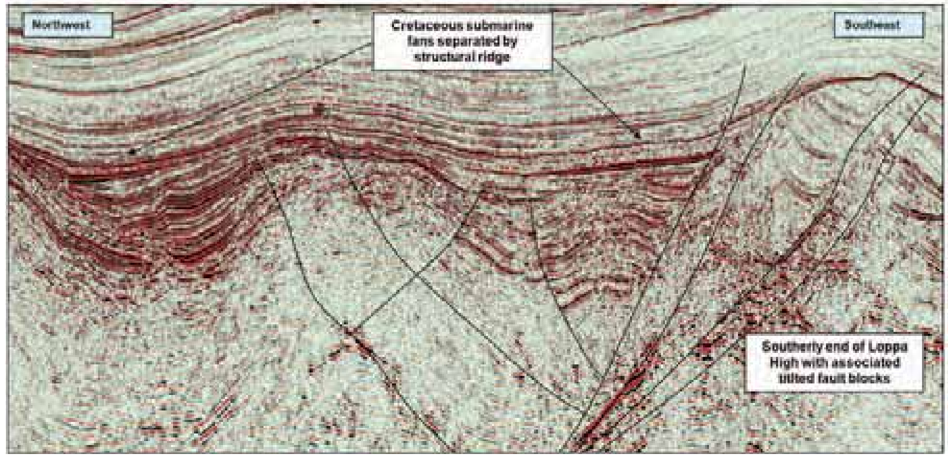
average TOCs of 1.25% and average hydrogen indices of 300mg/gTOC.

It would appear, therefore, that gas is likely to feature in any discoveries to be made. However, migration from the deeper Triassic/Jurassic sources – particularly along the flank of the Loppa High – occurred via faulting and fracturing. It is possible that early migrated oil could have been trapped in Cretaceous sands and still be present if the trap has not been breached.

Untested Cretaceous Fan Play

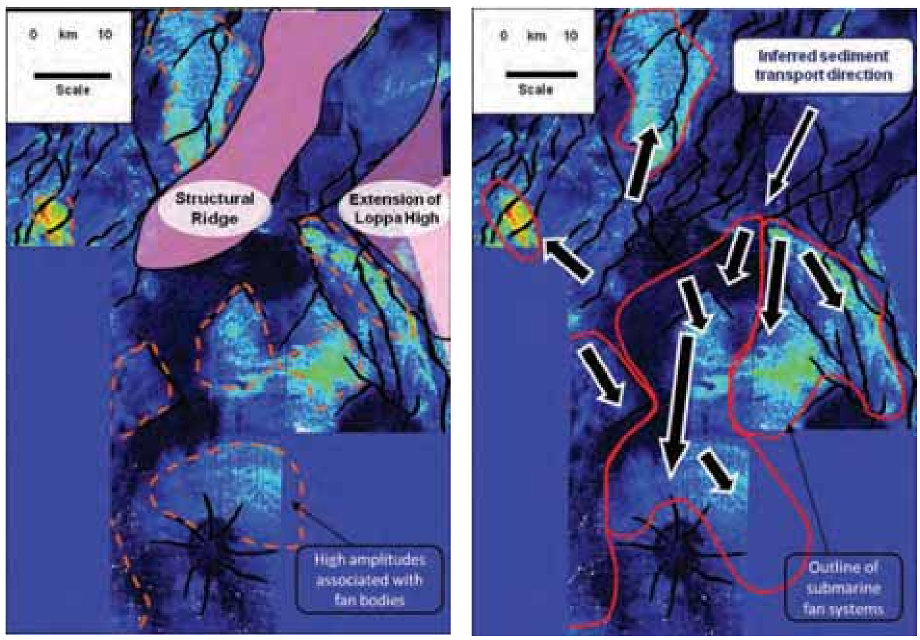
In conclusion, the WesternGeco 3D West Loppa dataset can be seen to have provided an insight into an untested Cretaceous submarine fan play within the Barents Sea region. Although drilling to date has yet to demonstrate the presence of reservoirs locally, the extensive nature of the fan systems provides a material opportunity. Taking a regional perspective, together with seismic evidence, it is suggested that such targets could be expected within the sequence identified as Upper Cretaceous in age. There would appear to be strong evidence of a working petroleum system within the region, from both regional well control and seismic data. The critical issue is whether the play is gas-prone and, if so, what degree of oil potential exists.

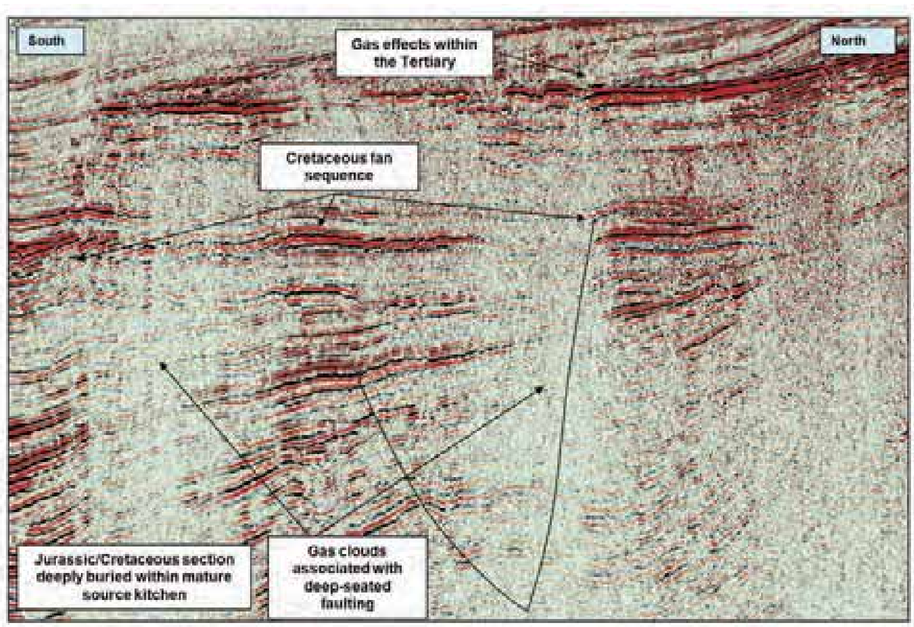
By integrating the wells drilled to date, together with the extensive 3D seismic database available, a coherent and consistent geological model of the region can be established which will help further elucidate this intriguing frontier region. ■



Seismic line illustrating multiple fan systems.

Vrms amplitude extraction maps (below) illustrating fan bodies and inferred transport direction.





Seismic line illustrating thickness of sediment in source kitchen with gas clouds and DHIs.

Leveraging Complex Geologies

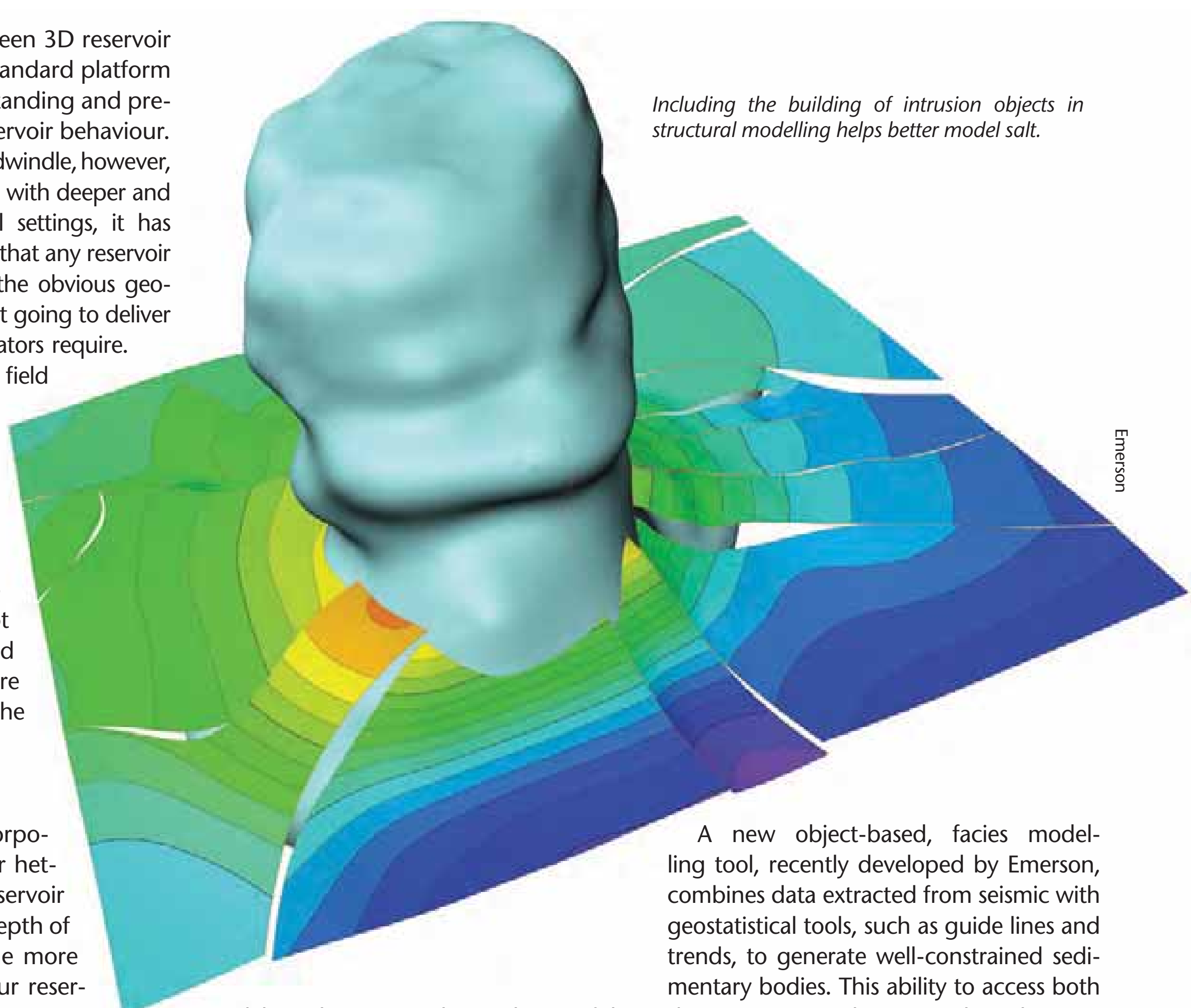
The ability of reservoir models to leverage seismic and accommodate complex geologies ensures robust and reliable models, improved decision-making, more justifiable investments, and improved field performance.

TYSON BRIDGER, EMERSON PROCESS MANAGEMENT

The last few years have seen 3D reservoir modelling become the standard platform for the mapping, understanding and predicting of oil and gas reservoir behaviour.

As reserves continue to dwindle, however, and as operators are faced with deeper and more complex geological settings, it has become increasingly clear that any reservoir models that oversimplify the obvious geological complexities are not going to deliver the vital information operators require. The result will be reduced field productivity and even, in the worst case scenario, misplaced wells.

Recent developments in 3D reservoir modelling, however, are ensuring that this oversimplification does not occur, by absorbing and interpreting ever more complex geologies into the models.



Including the building of intrusion objects in structural modelling helps better model salt.

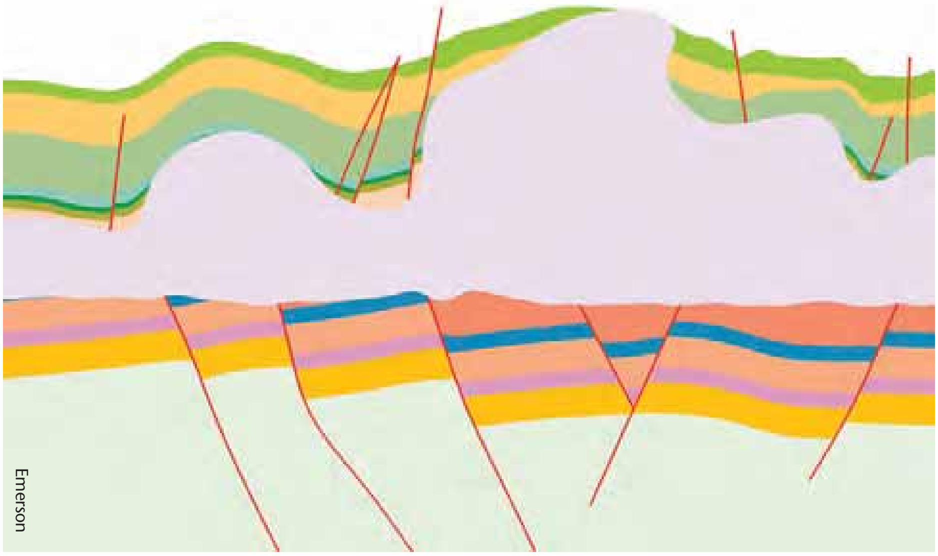
Emerson

Property Modelling

The better you can incorporate seismic and reservoir heterogeneities into your reservoir models and extend the depth of your static modelling, the more accurate and realistic your reservoir models are likely to be.

Integrating seismic data, however, can be a challenge. Take property modelling, for example – an area where seismic data can be combined with other data, such as well data, to generate accurate and well constrained reservoir models. In these cases, the resolution of the seismic is often too coarse to resolve the true geometries, scale can be a challenge, and uncertainty in depth can make it difficult to represent wells correctly. There is a need to integrate seismic more tightly into reservoir models.

A new object-based, facies modelling tool, recently developed by Emerson, combines data extracted from seismic with geostatistical tools, such as guide lines and trends, to generate well-constrained sedimentary bodies. This ability to access both deterministic and statistical techniques gives the modeller access to the grey area between seismic resolution and data-constrained statistical modelling. The net result is a realistic property model conditioned to well observations and with accurate volume calculations.



The top surface of a salt wall and diaper with over-hangs – a geological feature commonplace in sub-salt exploration.The section shows the deformed post or supra-salt section (in green) and the deformed salt body (grey) sitting on the rifted and eroded pre-salt section (pink and blue). Through reservoir modelling, a complex model can be handled as a single entity.

Another Emerson property modelling device is a multi-point statistics tool, which uses a pixel based (grid cell by grid cell) approach for building stochastic facies realizations. This allows the user to condition 3D training images of the interpreted heterogeneities in the reservoir, in addition to wells and seismic.

The Case of 4D Seismic

It is not just 3D seismic which is being incorporated into reservoir models. To date, 4D data has been primarily used in enhanced oil recovery programmes, but the expansion of reservoir modelling's seismic functionality has enabled 4D seismic data to be incorporated into the reservoir model, alongside existing data types such as geological, geophysical and simulation data. This has been achieved by combining observed and synthetic 3D and 4D seismic data with elastic parameters, where the synthetic seismic generated from the simulation model is compared to already observed seismic. This forward modelling of seismic is often referred to as petro-elastic modelling.

The new solution enables the analysis of observed and synthetic seismic attributes, the extraction of 4D geobodies, and the management of 4D vintages to identify production effects and obtain key information on the state of the reservoir. The differences between observed and synthetic elastic parameters are then used as input for improving geological and simulation models and production forecasts.

Incorporating 4D seismic into the reservoir model improves the quality of interpretations, structural and property models, simulation models, and well plans. It can also be the basis for a more quantitative use of 4D seismic data, especially towards history matching with both production data and 4D data.

Tackling Complex Structures: Sub-Salt

As well as incorporating 3D and 4D seismic into the reservoir modelling workflow, reservoir modelling is today playing an important role in addressing complex geological structures, such as pre-salt.

Pre-salt sequences come with significant challenges, as a result of being under two kilometres of salt and often at depths from sea surface of up to seven kilometres. Reservoir modelling is supporting reservoir management systems in both locating and extracting the oil.

One of the key benefits of building a 3D reservoir model in these geologies is the ability to have the entire geological section in one model from target to surface, tying all the elements of the structure together – vital to the model when looking at migration, trapping, pressure regimes, compartmentalisation and ultimately predicting reservoir presence.

Another geological challenge occurs when we observe the top surface of a salt wall and diaper with over-hangs – a geological feature commonplace in sub-salt exploration. The accurate handling of this through the reservoir model – not just of the shape of the salt but also the shape of the sediments as they intersect the salt structures – is essential to future reservoir management decision-making in extracting the oil in place.

While the major lineaments may be well-defined in pre-salt, the details of where the reservoirs are and how they communicate with each other are often controlled by second-order faulting. This requires accurate model building to capture fault linkages and complex fault populations. Whereas previously such geometries could only be modelled with specialist tools, today they are part of the general reservoir modelling workflow. This ensures that complex features, such as complicated fault inter-relationships and overturned beds, are not simply ignored in an attempt to simplify the model.

Populating the model with appropriate reservoir properties is another challenge in pre-salt. However, using structurally constrained grids, the combination of sampling of seismic into the geological grids, geostatistical facies modelling tools and geological QC tools, a realistic, if rather uncertain, facies models for the fields can be produced.

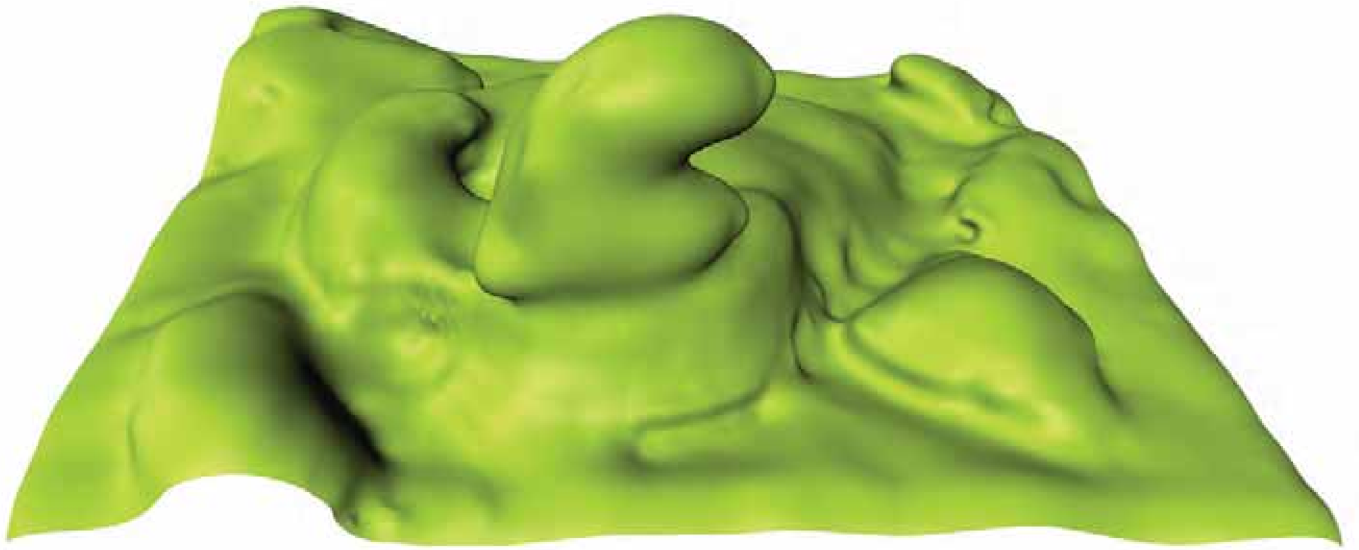
Further down the line, the ability to test multiple model variants of both facies models and fracture models against the accumulating production history and the increasing amount of available well data will allow the uncertainty levels in the models to decrease and subsequent confidence in our understanding of the petroleum system to increase.

Uncertainty Management

It is this focus on uncertainty management in reservoir modelling that is central to helping to better model complex geologies and petroleum systems.

Uncertainties in depth conversion, structural modelling, geological property modelling and dynamic reservoir simulation ▶

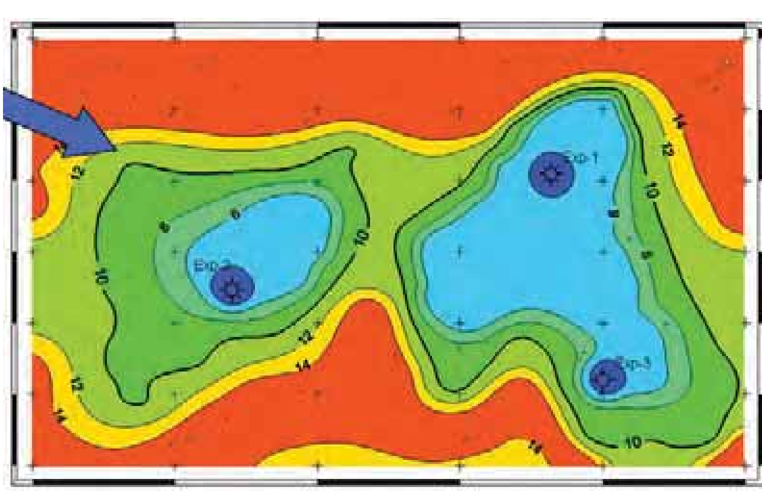
Emerson



The top surface of a salt wall and diaper with over-hangs – a geological feature commonplace in sub-salt exploration.

all need to be simultaneously evaluated, ensuring that the full impact of these often independent uncertainties is captured through realistic 3D static and dynamic reservoir models.

Today, integrated reservoir modelling systems are providing geoscientists with the possibility of identifying and quantifying uncertainties in their models (static and dynamic) and creating multiple realisations where the uncertainties are taken into account. The result is a better quantification of the uncertainties than the standard spreadsheet approach based on Monte Carlo simulation. Reservoir modelling is not only able to quantify the uncertainty in volumes and identify what factors affected this uncertainty, but can also generate maps and grids that illustrate the areas of structures that have the highest uncertainty.



Emerson

A velocity uncertainty map generated through the reservoir modelling workflow on a small marginal gas field, demonstrating low uncertainty near the well data and increased uncertainty away from the wells and lower on the structure.

Recent Developments

The twin needs of incorporating ever more complex reservoir geologies into the reservoir model, alongside the need to make the reservoir modelling more accessible and easier to use, have been the key drivers behind the latest version of the Roxar RMS 2011 reservoir modelling software.

This has seen an enlarging of the domain footprint of the reservoir modelling workflow. This has been achieved through enhancements to the seismic architecture to allow 4D seismic to be incorporated into the workflow, in combination with geological correlation improvements, such as True Vertical Thickness (TVT) and True Stratigraphic Thickness (TST) support.

Additional modelling functionalities include building intrusion objects in structural modelling to better model salt and a new grid data structure for improved performance, scalability and more flexibility in the grid geometry. The structural modelling improvements will also help handle overturned unfaulted surfaces as well as diapiric structures. The new release will also see a number of new QC tools, producing charts and maps to check consistency between the property models and the input data with just a few button clicks.

With two-thirds of the world's proven reserves lying in areas of the world with acknowledged issues with fracture-affected recovery, the developments in fracture modelling are an important tool in tackling complex, fracture-prone geologies. The software therefore integrates fractures into the reservoir modelling workflow through a DFN-based (Discrete Fracture Network) model which enables robust, fractured models to be built faster.

Finally, new usability features include updated data analysis charts and a new unified multi-viewer environment, making it easier and faster to create and update models.

All Models Are Wrong

"All models are wrong, but some are useful" – so said the famous statistician, Dr. George E Box.

While there will always be a certain degree of uncertainty, 3D reservoir models are narrowing the uncertainty gap and remain arguably the most important decision-making tool E&P companies have at their disposal in reservoir management today.

Walking Through Time: The Geopark Way

Herefordshire and Worcestershire Earth Heritage Trust

NATALIE WATKINS, HEREFORDSHIRE AND WORCESTERSHIRE EARTH HERITAGE TRUST

The view from Abberley Hill looking south to Abberley clock tower and beyond across the gently rolling Worcestershire landscape.

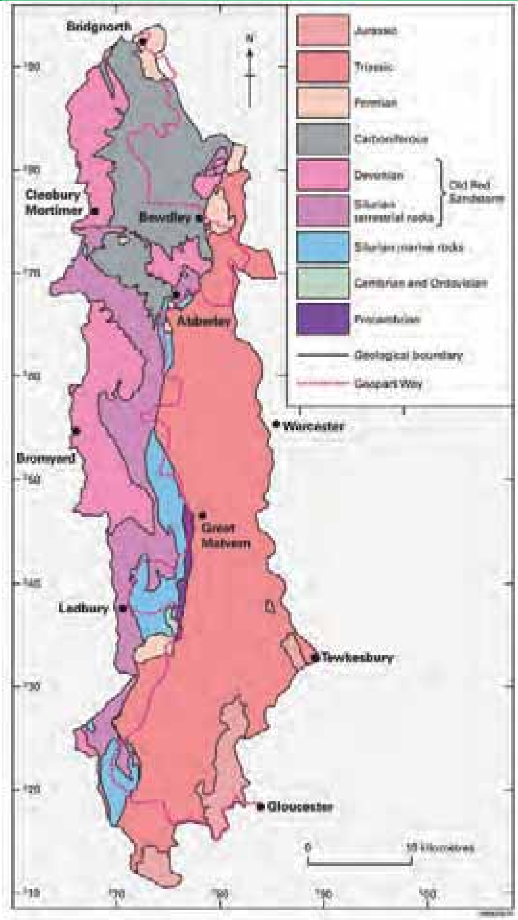
The Abberley and Malvern Hills Geopark Way is a long distance walking trail that brings to life the fascinating geological story of this beautiful area of rural England.

The Abberley and Malvern Hills Geopark is one of a new generation of landscape designations that has been created specifically as a result of the interest in the rocks and scenery within a particular area. The 1,250 km^2 of this Geopark spans four counties of the Western Midlands of England; Shropshire, Worcestershire, Herefordshire and Gloucestershire, in a strip of countryside 83 km long and at most 18 km wide. However, you will not see any large signs proclaiming your arrival, nor any wardens working for the Geopark. Instead, a partnership of organisations, encompassing the fields of geology, forestry, heritage, conservation and education as well local wildlife and landscape protection and management, decide strategic initiatives and day to day activities in the Geopark.

With aspirations to highlight and promote the geology, landscape and associated heritage within the Geopark to the local communities and to wider audiences, the Geopark Partnership has developed certain geotourism initiatives. Thus in 2006 the notion of a long distance walking trail that was born – a trail that could bring to life the geological story of the Geopark. The result; in 2009 the Geopark Way long distance walking trail and associated trail guide were launched.

Take a Walk Through Time

The wealth of geology and landscape features together with the associated heritage and wildlife within the Geopark



The Geopark Way winds through places of geological and natural interest from Bridgnorth in Shropshire travelling 175 km south to Gloucester.
Map derived from BGS Digital Geological Mapping, under permit IPR/106-50C. British Geological Survey © NERC.

presented a challenge in devising which course the Geopark Way trail should take – so many potential pleasing routes! However a desire to encapsulate the geological essence of the Geopark was of foremost importance, followed by a yearning to seize the opportunity to portray and illustrate how geology and landscape can significantly influence land use, history and the social fabric of a community. The end result, after several hundred miles of paths were walked and researched, was a 175 km (109 mile) trail winding its way from Bridgnorth in the far north of the Geopark, about 35 km west of the city of Birmingham, to Gloucester in the south. The route is not the quickest way between these towns but rather an exploratory journey through the Geopark, visiting sites of interest and reaching places off the beaten track.

The Geopark contains rocks which span over 700 million years and include some of the oldest found in England. They tell amazing stories of continental collision, of tropical seas, hot deserts, equatorial swamps and coastal lagoons and of vast ice sheets and polar deserts.

Imagine that you were transported back 700 million years to that piece of the Earth's crust which was to become the Geopark of today. You would have been in quite a different part of the world; about 60 degrees south of the Equator, close to the Antarctic Circle. You would find yourself in a place of violent geological activity, amidst volcanic mountains and subject to frequent earthquakes as the rock around you was slowly bent and buckled into a mountain chain; very different from today's landscape. And so the story of the rocks and landscape along the Geopark Way begins to unfold.

Geological and Industrial History

Starting at the town of Bridgnorth, Shropshire, the trail explores the Permian sandstone cliffs that separate Bridgnorth into a 'High Town' and 'Low Town'. Laid down in a landlocked desert, these rocks display the shape of ancient sand dunes, even revealing the predominant wind direction 300 million years ago. Cut into these fossilised dunes are a number of rock houses and caves, one of which was at the centre of an English Civil War siege.

From Bridgnorth the trail follows the River Severn southwards. It comes as a surprise to discover that a feature as large and as important as the River Severn is so recent an addition to the Geopark's landscape. Evidence to support the early stages of its formation, a mere 12,000 years ago, begins to emerge on the way down and through the National Trust property of Dudmaston Estate.

Entering into the Wyre Forest Coalfield you pass back in time onto Carboniferous strata. Along with exposures of Carboniferous cyclothem lithologies, the trail encounters evidence of the social and industrial impact that the availability of natural resources had on local communities. These industries date back centuries and include coal mining, brick making, stone quarrying and iron smelting. In the 19th and 20th centuries commercial scale coal mining took place. There is abundant evidence of this industrial history still to be seen on the ground, in the style of Highley town, and the fabric of some local communities. ▶

Former tramway cutting along which coal was transported from Highley mine to the railway, cut into Carboniferous Highley Sandstone.


Natalie Watkins

The Geopark Way passes along the Malvern Hills ridge line, made up of Precambrian rocks.

Leaving the coalfield, the trail passes over a succession of Permo-Triassic sedimentary rocks before encountering the Quaternary wind-blown sands that cover the lower terrace of Hartlebury Common. This local nature reserve is celebrated not only for its geology, but as a lowland heath and as a common with a social history spanning at least 2,000 years.

The Precambrian Ridge

Next the trail veers westwards and crosses over the East Malvern Fault where the topography becomes more dramatic as the Silurian limestones and shales of the Abberley Hills come into view. The East Malvern Fault defines the line of hills that run through the centre of the Geopark. It had several phases of movement and the immense pressures and forces at work during these episodes of uplift, folding and faulting stand recorded in the structure of the rocks seen today. Along this part of the trail you can find fossils and occasional bentonite layers and there are old pits, quarries and abandoned lime kilns; collectively telling a compelling story of this series of rocks.

The Silurian hills then give way to the dominating landscape feature of the Malvern Hills, a 21 km (13 mile) long ridge line forming the centrepiece of the Geopark. Composed of Precambrian-aged rocks, the geological history of this meta-igneous suite of rocks is yet to be fully understood. The Geopark Way visits several sites on the hills to capture the essence of their geological history; some peppering the science with tales of folklore and the Victorian Water Cure phenomenon that placed Malvern on the map.

Leaving the Malvern Hills the horizon changes as the Cotswold Hills come into full view. Into Gloucestershire the trail passes over the inlier of May Hill with its distinctive crown of Jubilee (Queen Victoria) trees, before entering into Huntley Quarry Geological ▶

A group of walkers taking a breather in Wellington Heath, whilst on a guided walk along the Geopark Way as part of the Malvern Walking Festival 2010.

Huntley church, near the southern end of the trail, is built from the wonderful combination of Triassic red sandstone and Jurassic limestone.

Reserve to explore the fault and fold structures clearly seen in the quarry face.

The final leg of the trail leads you over the relatively flat plains of late Triassic and early Jurassic sediments, visiting sites which unveil the River Severn's formational history, before arriving at the final destination of Gloucester cathedral. This wonderful building of oolitic limestone marks a fitting end to a traverse across 700 million years of Earth history.

A New Perspective

The story of the rocks along the Geopark Way can be followed in the guidebook, delivering a totally new perspective on long distance walking. The trail guide conveniently splits the trail into 18 comfortable day walks and comes with a supplementary booklet detailing public transport routes, tourist amenities and attractions and countryside sites within the Abberley and Malvern Hills Geopark.

Since its launch in 2009 several thousand people are believed to have walked along sections of the Geopark Way. Some of these walkers did so through the Malvern Walking Festival, which in 2009 featured the Geopark Way in its festival programme; walking the full 109 miles over a period of 9 days. The nine days were well attended, so much so that sections of the Geopark Way were included in the 2010 walking programme and will feature again in 2011. A fine example of how a geotourism initiative can reap benefits to the wider tourism economy.

Since the launch of the Geopark Way trail in 2009 funding was secured to develop three (which we hope one day will be a complete series) circular trails, each incorporating a section of the Geopark Way linear trail. These free trail leaflets (also available as downloads) prove very useful tools in introducing people to the concept of Earth science exploration as a leisurely and enjoyable form of recreation. Each trail leaflet offers a great walk, along with a healthy sprinkling of geology.

All of these trails feature as guided walks in a new initiative: GeoFest. First run in 2010, GeoFest is a three month festival of events and activities that highlights and promotes the many attributes of the Geopark. Events include children's activities at museums and visitor centres, guided walks, talks and 'meet the expert' sessions where people are invited to quiz geologists about their rock, fossil and mineral specimens. GeoFest 2011 runs from 1st June – 31st August 2011.

With a growing understanding, demand and appreciation of geotourism, evolving out of what was once a niche market, there is much potential for growth in the Abberley and Malvern Hills Geopark. Linking and integrating geotourism to the already established tourism industry is one avenue, as is developing pure geotourism ventures to attract more visitors to the area. Although such initiatives are dependent on sponsorships or funding, the enthusiasm of the Geopark partners will ensure that each year more visitors to and residents of the Geopark take pleasure in all that it has to offer.

Don't take my word for it though – come and find out for yourself.

Natalie Watkins is Trails Manager with the Herefordshire and Worcestershire Earth Heritage Trust, one of the founding partners of the Geopark. Further details can be found at www.EarthHeritageTrust.org and www.Geopark.org.uk

SYRIAN OFFSHORE Exciting New Frontier

The ancient city of Palmyra in central Syria was an important trading post.

STEVEN BOWMAN AND TORIL LEITE JENSEN, CGGVERITAS

With the announcement of the 2011 Syrian International Offshore Bid Round, interested oil and gas exploration companies have an exciting opportunity to assess the hydrocarbon potential of this highly prospective region.

The Eastern Mediterranean is a tectonically complex region with offshore Syria located above the plate tectonic boundary between the African and Eurasian plates defined by the Latakia Ridge System. Further to the east the Dead Sea transform fault system separates the African and Eurasian plates from the Arabian plate with a triple junction situated onshore in north western Syria.

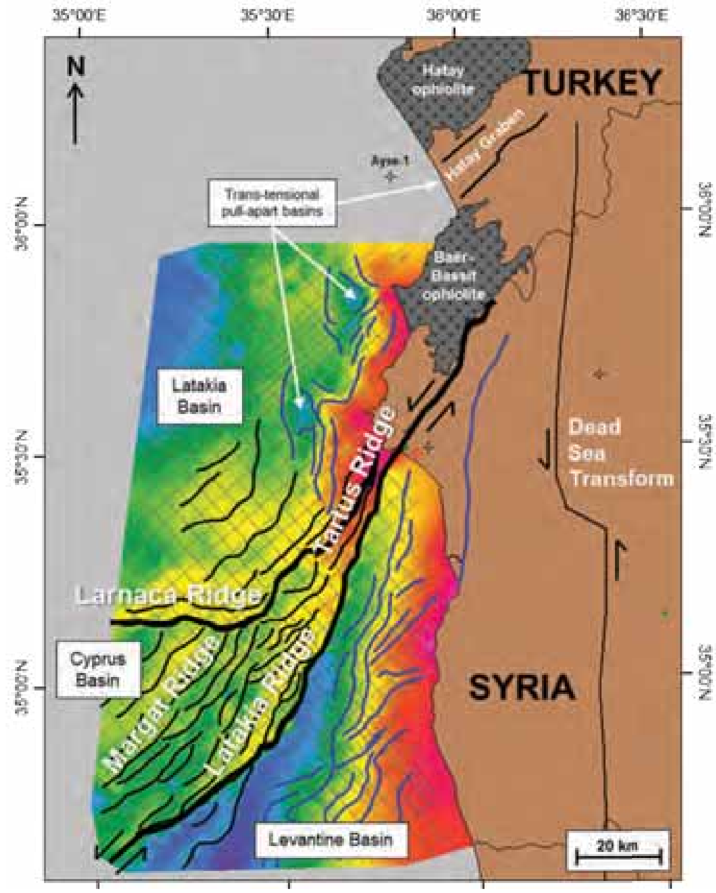
True Frontier Area

This underexplored region has recently become the focus of increased industry interest due to three major biogenic gas discoveries, Tamar, Dalit, and Leviathanin the offshore southern Levantine Basin. The discoveries were made in high-quality Lower Miocene turbidite reservoirs with total combined recoverable reserves of approximately 25 Tcf gas. Several exploration and appraisal wells have been drilled within the offshore southern Levantine Basin resulting in six gas discoveries.

Offshore Syria, however, can be considered as an area of true frontier exploration given that no wells have yet been drilled. The closest offshore well is Ayse-1 located just over 10 km to the north of the Syria-Turkey maritime border. It was drilled in 1981 within the Iskenderun Basin and was declared as a dry hole.

Four wells were drilled onshore Syria east of the city of Latakia, within 5 km of the coastline, as part of a drilling campaign by the Syrian Petroleum Company during 1981–84.

The first of these four wells to be drilled was Fidio-1 which was declared as being dry, although small amounts of gas were encountered within Lower Cretaceous carbonates.



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Structural lineaments offshore Syria displayed on the Late Cretaceous unconformity time structure map, illustrating the Latakia Ridge System that defines the Levantine, Cyprus, and Latakia Basins. Compressional faults are displayed in black and extensional faults in blue.

The Latakia-1 well encountered gas shows within Upper Cretaceous and lower Tertiary carbonates and oil shows were present within fractured Lower Cretaceous clastics. The Latakia-2 well recovered combustible gas from Eocene and Oligocene carbonates and heavy oil and gas shows were encountered within Upper Cretaceous carbonates.

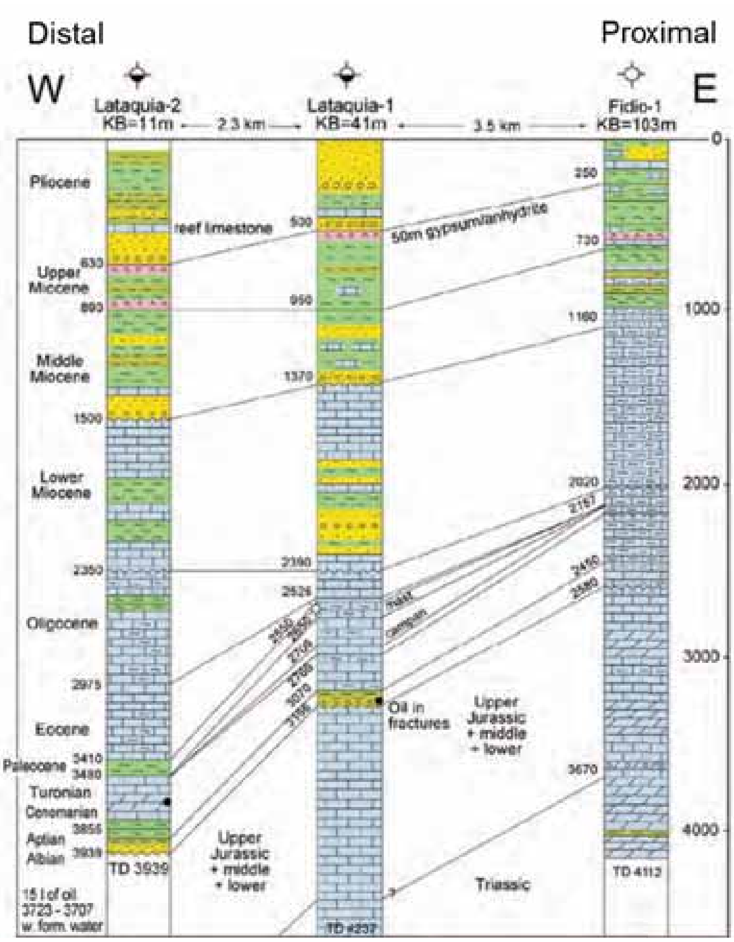
The Latakia-3 well was drilled above the Latakia Ridge System further north of the other three wells, all of which had been within the northern extension of the Levantine Basin. It was declared as dry, although heavy oil shows and asphalt were encountered within the deepest section of the well and gas shows were recorded at several intervals within the Oligocene and Eocene.The Cretaceous – Tertiary section encountered was repeated up to four times or more, indicating that the area has been intensely faulted and compressed.

Three Sedimentary Basins

Three sedimentary basins, Levantine, Cyprus, and Latakia, have been identified from the seismic data, each with a unique structural and stratigraphic history. The basins are defined by large structural lineaments, the Latakia, Larnaca and Tartus Ridges, that define the Latakia Ridge System. They developed as compressional fold-thrust belts during the middle to Late Cretaceous, contemporaneous with plate-tectonic convergence between the African and Eurasian plates. Compression continued through to the Late Miocene prior to a reorganization of the plate-tectonic stress regime which led to the establishment of sinistral strike-slip conditions that created significant uplift and deformation.

The Levantine Basin is interpreted as having developed during the Middle Jurassic.The main phase of sedimentation offshore Syria occurred from the Late Cretaceous onwards within a foreland basin setting that developed ahead of the Latakia Ridge System as a result of lithospheric loading from the emplacement of late Maastrichtian-aged ophiolites. This is a relatively new interpretation of the data based upon the results of the first ever deepwater exploration wells to be drilled within the Eastern Mediterranean in the offshore southern Levantine Basin. The Cenozoic section is believed to be much thicker offshore Syria than previously thought, with a major unconformity that was initially assigned a Late Jurassic age now assigned to the Late Cretaceous.

The Cyprus Basin developed above the Latakia Ridge System following the emplacement of ophiolites. It is a broad ▶



Well correlation panel through the Latakia-1, -2, and Fidio-1 wells. The wells provide a roughly East-West transect from a proximal to a distal setting within the northern extension of the Levantine Basin.

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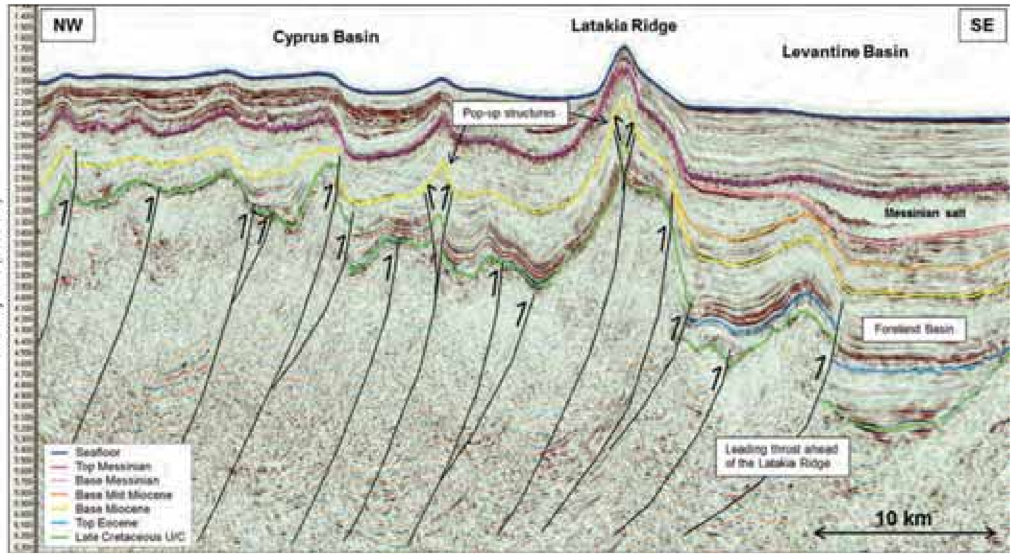


Seismic section across the southern Latakia Ridge displaying the Cyprus and Levantine Basins situated on either side.

zone of deformation defined by thrusting and folding that was subsequently reactivated during the Early Pliocene under sinistral strike-slip compression leading to the initiation of back-thrusting that formed large positive flower and pop-up structures. This late-stage deformation produced several potential hydrocarbon traps often with stacked reservoirs.

The youngest of the three basins is the Latakia Basin, where sedimentation is interpreted to have been initiated during the Early to Middle Miocene, above an ophiolitic basement analogous to the Iskenderun Basin further to the north, offshore Turkey. The north-western part of the basin is characterized by thick diapiric Messinian salt whilst the eastern part of the basin is characterized by deep trans-tensional pull-apart basins that initiated during the Pliocene.

Working Petroleum System

There is significant evidence for a working petroleum system offshore Syria.

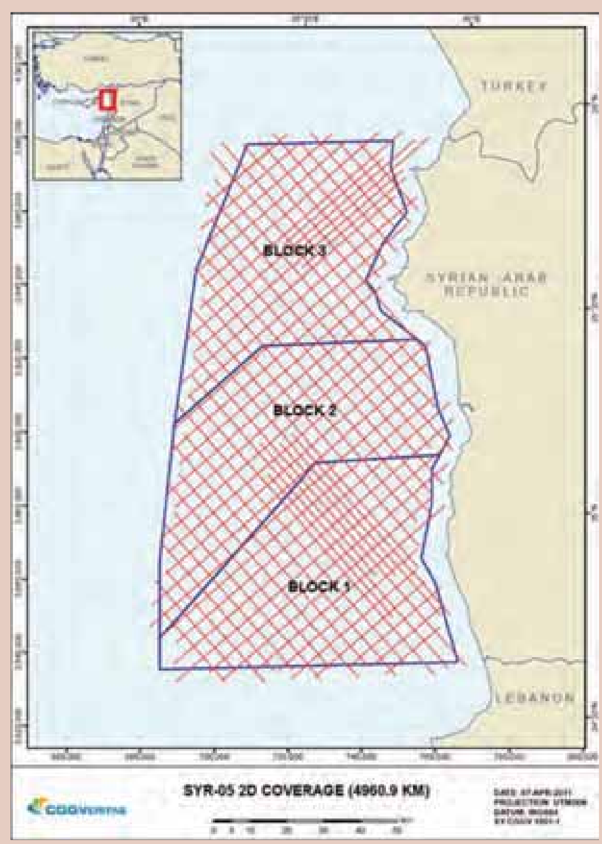
Numerous oil and gas shows have been observed in wells along the Levant Margin, and seismic observations reveal the presence of multiple Direct Hydrocarbon Indicators in the form of gas chimneys, flat-spots, and bright-spots, some of which may represent billion-barrel/ or multi-Tcf exploration

BID ROUND TERMS

The Bid Round, which was announced on March 24, 2011 by the Syrian Ministry of Petroleum and Mineral Resources and the General Petroleum Corporation (GPC), invites international oil and gas exploration companies to explore, develop and produce hydrocarbons from three offshore blocks in the Mediterranean Sea, according to a production sharing contract. The size of the area is 9,038 km^2, and the blocks are approximately 3,000 km^2 each. Bidders may submit their offers for one or more offshore blocks and a separate offer for each block is required.

CGGVeritas acquired 5,000 km of long-offset multiclient 2D seismic data offshore Syria in 2005 in water depths ranging from 500 to 1,700 m. To participate in the Bid Round, it is conditional to license at least 3,000 km of seismic data exclusively from CGGVeritas according to the provisions described in the technical part of the Tender Book. In addition to the original survey data, CGGVeritas is offering an interpretation package and report, gravity data, seep data (in collaboration with FugroNPA) and a reprocessed seismic dataset, currently in production.

As part of an exclusive contract with the Ministry and GPC, CGGVeritas is also providing the technical support for the Bid Round. CGGVeritas will co-host roadshow events and data reviews with the Round organisers in Damascus and London for companies interested in the official available technical data. The closing date for the Bid Round is 5th October 2011 at 14.00 hrs Damascus local time.



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CGGVeritas database of multi-client long-offset 2D seismic data offshore Syria acquired in 2005 along with the three blocks to be offered in the second Bid Round.

targets. Ocean Basin Screening carried out by FugroNPA using satellite imagery reveals the presence of several good, repeating oil slicks, interpreted as naturally occurring oil seeps that correspond to geological features observed on seismic.

Prospective reservoirs range in age from Triassic to Pliocene-Quaternary and include Lower Miocene deepwater turbidite sands analogous to those encountered in the Tamar, Dalit, and Leviathan discoveries. The complex evolution of each of the three sedimentary basins has produced an array of potential structural and stratigraphic trapping mechanisms including thrust fault anticlines, tilted fault blocks, salt-influenced traps, carbonate reefs, and basin margin onlaps/pinchouts.

Looking Ahead

Following successful reprocessing test results, CGGVeritas is currently reprocessing the entire 2005 data set. The latest processing techniques have been applied with the aim of attenuating multiples, increasing the signal-to-noise ratio, enhancing reflector continuity, and improving imaging of steeply dipping reflectors. The results are extremely encouraging and provide a much clearer and more easily interpretable image. Similar results are expected to be achieved across the whole survey with significant uplift in the imaging of DHIs and sub-Messinian salt structures and stratigraphy.

There is no doubt that recent findings have enhanced Syria's hydrocarbon prospectivity. Should Syria deliver on its hydrocarbon potential, the country has the infrastructure in place to meet export requirements. There are two oil export terminals, one in the port of Tartous and the second in Banias. The first serves a domestic pipeline bringing 250,000 bopd from Syrian Peroleum Company's north-eastern fields. The port of Tartous also has a large Free Zone Area with storage facilities for service companies to set up base. The second oil terminal, in Banias, serves a 100,000 bopd pipeline from Al-Thayyem and other fields.

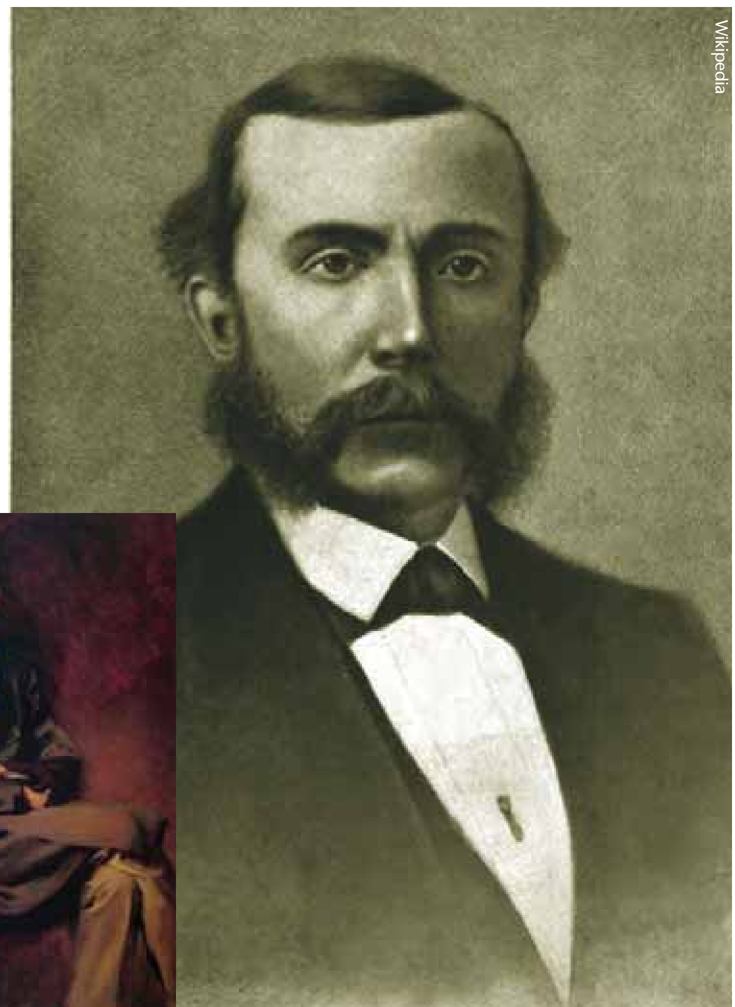
AUTHOR'S NOTE

A full version of this Syria article including a comprehensive description of the regional geology will be published in GeoArabia Vol. 16. No. 3: Bowman, S.A. 2011. Regional seismic interpretation of the hydrocarbon prospectivity of offshore Syria.

More information about the Round can also be found on the following websites: www.gpc-sy.com and www.cggveritas.com/syria ■

JOHN D. ROCKEFELLER: The First and Richest Oil Tycoon

In this second part of the Standard Oil story, we profile **John D. Rockefeller**, the man who founded the world's first large oil company, which was forced by the US anti-trust law to dissolve into several independent companies exactly one hundred years ago.



John Davison Rockefeller in 1872 at age 33 (far right), and at age 78 (right) as portrayed in 1917 by John Singer Sargent. Despite his wealth, Rockefeller did not lead a lavish, entertaining lifestyle; he abstained from alcohol and tobacco, and was a regular church-goer. He was a meticulous accountant. "As I began my business life as a book keeper," he once remarked, "I learned to have great respect for figures and facts, no matter how small they were."

RASOUL SORKHABI, Ph.D.

John Davison Rockefeller was born on 8 July 1839 on a farm in Richford, New York. His father, William Avery Rockefeller (1810–1906), "Big Bill," was notorious for keeping mistresses and leaving his family to embark on extended trips for various businesses including selling herbal medicines. Nevertheless, he taught the young John how to be clever at both earning and spending money. Rockefeller's mother, Eliza Davison (1813–1889) was a devout Christian and was largely responsible for holding the family together and raising her six children with a sense of discipline and diligence. Although his family moved a few times in the eastern USA, John attended good schools and was studious. While living in Strongsville, a suburb of Cleveland, Ohio, he decided to quit school and instead take a ten-week college course in business. At age 16, he got a job as a book keeper in order to support his family.

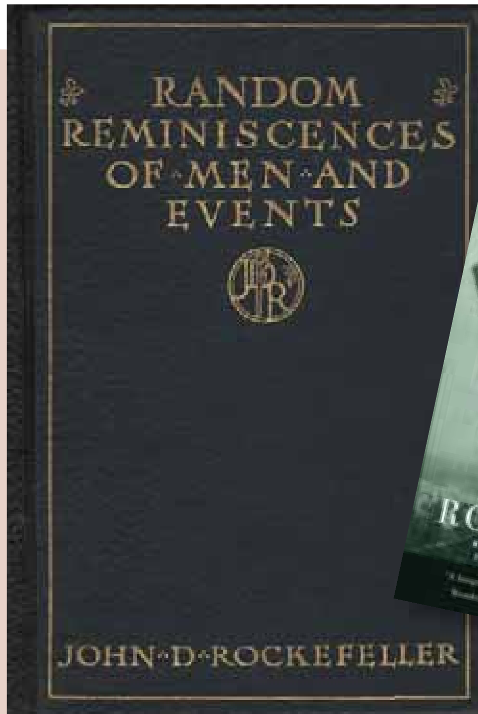
In 1859, the year Drake drilled his famous discovery well in Oil Creek, Pennsylvania, Rockefeller entered a wholesale foodstuff business with Maurice Clark, with a start-up capital of $4,000. During the American Civil War (1861–65), Rockefeller continued his prospering business and did not fight (possibly because as the eldest son he had to support his family) although he was sympathetic to the North's anti-slavery ideals; Rockefeller instead donated money to the Union Army and paid for a substitute soldier to fight on his behalf.

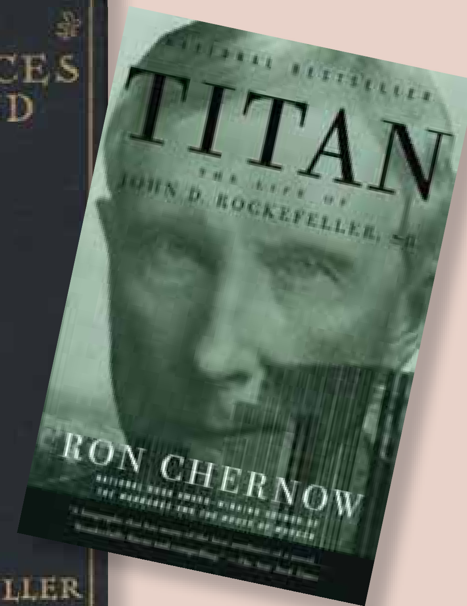
Petroleum was increasingly replacing whale oil as the major lighting fuel and, as Pennsylvania's Oil Region was booming, Rockefeller and Clark, together with Clark's two brothers and a chemist Samuel Andrews (all Englishmen) started an oil refinery in 1863 in Cleveland. Two years later, Rockefeller bought the Clark brothers shares for $72,500. Rockefeller and Andrews named their refinery Standard Works, implying that their objective was a steady flow of quality oil to clients. Indeed, Rockefeller, as he later recalled, had plans to do oil business "on a larger scale." They set up an office in Oil City, Pennsylvania. In 1866, Rockefeller's younger brother William joined him and they built another refinery in Cleveland; a year later, however, this new refinery was absorbed by Rockefeller and Andrews, leading to a bitter relationship between the Rockefeller brothers for the rest of their lives. In 1867, Henry Flagler and Stephen Harkness entered partnership with Rockefeller and Andrews. This was the nucleus of Standard Oil of Ohio that was officially founded in 1870 in Cleveland. Flager, like Rockefeller, played a vital role in the company's successes and described their fellowship in his famous motto: *"A friendship founded on business is better than a business founded on friendship."*

The Standard Oil Trust

Standard Oil of Ohio was principally a downstream company and did not want to get involved in risky oil exploration and drilling. Instead, the partners focused on an aggressive "horizontal integration" of other oil refineries under the umbrella of Standard. In its defense, Standard argued ▶

Despite his fame, Rockefeller did not like publicity, and wrote only a brief autobiography, *Random Reminiscences of Men and Events* (in a response to Ida Tarbell's book) which was first published as a series of articles in the monthly magazine *The World's Work* during 1908–09 and in a book form in 1909 (reprinted in 1933 and later in an illustrated volume in 1984). His official biographies include Allan Nevins' *John D. Rockefeller: The Heroic Age of American Enterprise* (1940) and *Study in Power: John D. Rockefeller, Industrialist and Philanthropist* (1953). Ron Chernow's *Titan: The Life of John D. Rockefeller, Sr.* (1998) is a definitive, up-to-date biography to read.





that mushrooming refineries (some of poor quality) in north-eastern US had led to chaotic business, unnecessary competition, and unreasonably cheap oil prices, and that Standard actually saved the oil industry during its infancy. Nonetheless, the company's "standardising" of the oil industry involved practices that were later found to be unethical. Many refineries in the Oil Region (some of which were also oil producers) despised Standard, as they were forced out of business.

In those days, railroad companies were competing to carry oil barrels from or to refineries. Standard struck secret deals with the Lake Shore Railroad of New York and the Southern Improvement Company in Pennsylvania to the effect that Standard would ensure to ship at least a certain amount of oil on their trains daily but that the railroad company would give a special discount ("rebate") per barrel to Standard but not to other refineries. Moreover, as the railroad company charged other refineries more per oil shipment, it should give a portion of the price difference ("drawback") to Standard! These rebates and drawbacks made Standard's oil cheaper than that of its competitors in the Oil Region, and in Cleveland and New York.

Standard's overall plan was to either buy out its competitors or force them out of business, and thus monopolize the oil market. To achieve its objectives, Standard spied on other companies' transactions, artificially sold cheaper petroleum products in the competing territories, or simply asked other refineries join its enterprise (some of which gladly did).

During the 1870s and 1880s, Standard rose to be the predominant company, controlling nearly 90% of refineries, pipelines, transportation and marketing of oil in the USA. In 1882, it consolidated the power of its numerous subsidiaries and stockholders in the form of the Standard Oil Trust governed by nine trustees (including Rockefeller and other founding members). Out of the Trust's 700,000 shares, Rockefeller owned 191,700. In 1885, the headquarters moved to New York City.

In response to protests against Standard's practices and growing power, however, Senator John Sherman of Ohio initiated an anti-trust legislature in 1890 that demanded the dissolution of the Standard Oil Trust. Rockefeller was lucky, though: two years previously New Jersey had passed a law that permitted large corporations to operate in that state while also holding shares of other companies operating outside the state. Rockefeller and partners simply renamed their Trust Standard Oil Company of New Jersey and registered it there.

Rockefeller's Legacy

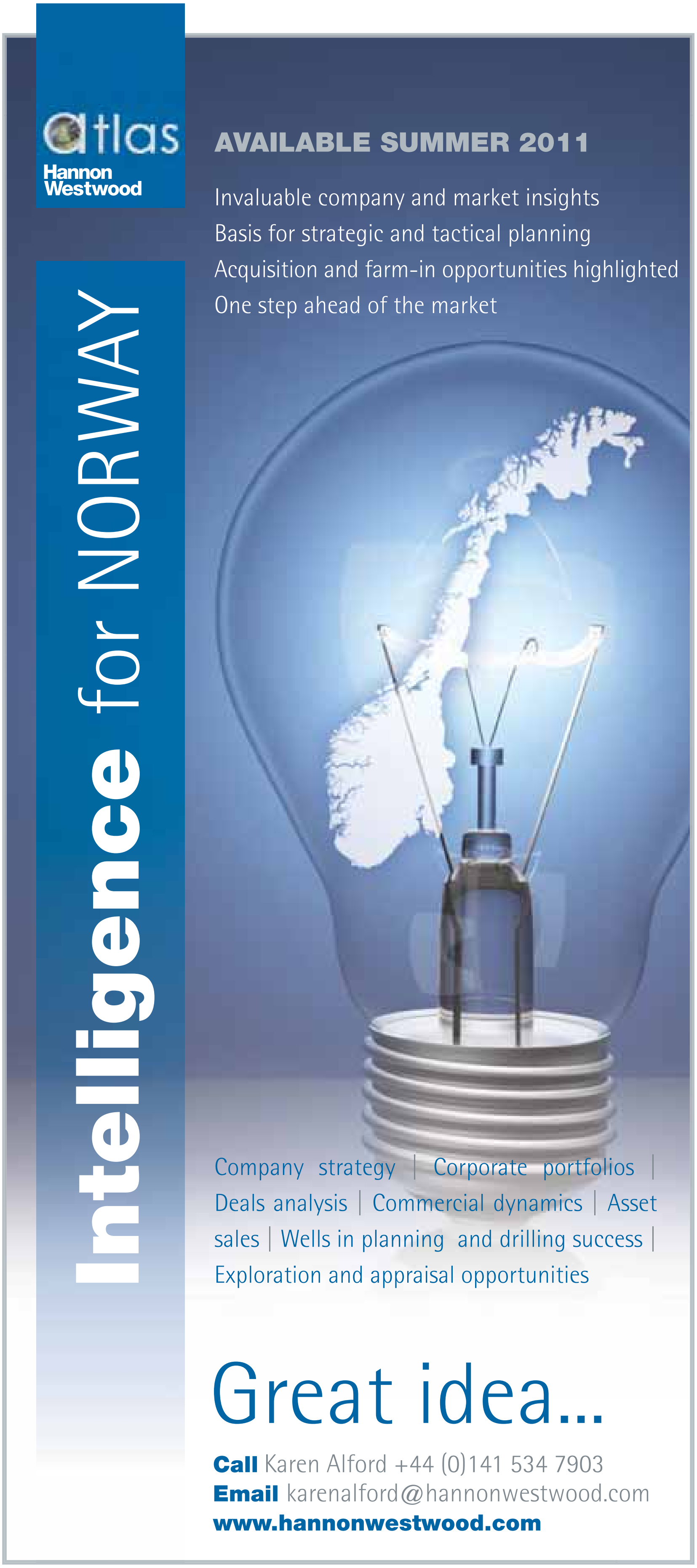
In 1897, Rockefeller retired from Standard, although continued to hold his majority shares and influence in the company for the rest of his life. He even expanded his business activities to other industries during his four decades of retirement.

Rockefeller was an avid donor to charities, even when he was a young boy, and is renowned as one of the world's greatest philanthropists. He used his fortunes to establish the University of Chicago in 1890, Rockefeller University in New York City in 1901, and in 1913 the Rockefeller Foundation in New York, a major supporter of research and service in the areas of education, arts, science, health, and food internationally.

After Ida Tarbell published her expose in *The History of the Standard Oil Company* in 1904 (see *GEO ExPro*, Vol. 8, No 2), she wrote an article for the *McClure's* magazine entitled "*John D. Rockefeller: A Character Study*," in which, while admiring Rockefeller's philanthropic activities, Tarbell described the man as simply "money-mad."

Rockefeller married Laura Celestia Spelman (1839–1915) in 1864, at the age of 25. They had four daughters and one son (the youngest), John Davidson Rockefeller, Jr. (1874–1960), who took over the family's businesses.

Rockefeller died on 23 May 1937 at age 97 in Ormond Beach, Florida and was buried in Cleveland, Ohio, the city he called home and where he had built a house for his parents and siblings, a house for his wife and children, the largest refinery of his day and the first headquarters of the Standard Oil Company. ■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HALFDAN CARSTENS/JANE WHALEY

NORWAY: A Decent Discovery – Finally!

It was no surprise. Most geoscientists that knew the data had predicted an oil discovery. It was, nevertheless, a relief to get the confirmation when well 7120/8-1 found oil in Jurassic sandstones. The good news was all over the Norwegian media. Huge headlines. Interviews. The Barents Sea was once again in the limelight. A medium sized oil discovery was to blame. Well 7220/8-1 (midway between the 72nd and 73rd parallel) had encountered oil and gas in Jurassic sandstones.

According to the operator, Statoil, this breakthrough discovery is one of the most important finds on the Norwegian continental shelf in the last decade. The Skrugard prospect was Statoil's first priority in the 20th licensing round on the Norwegian continental shelf, which was awarded in April 2009.

After having drilled more than 80 wells in the south-western Barents Sea, this is the third discovery that may end up as a producing field. **Snøhvit**, with approximately 1 Bboe, recoverable gas and condensate in Lower and Middle Jurassic sandstones of the Stø and Nordmela Formations, operated by Statoil, has produced gas since 2007. Similarly **Goliat**, reservoired in Triassic sandstones with 220 MMbo recoverable, operated by Italian Eni, is now being developed. According to the Norwegian Petroleum Directorate, **Skrugard** may contain between 160 and 250 million barrels of oil (See *GEO Expro*, Vol. 7, No.3).

So what's the fuss?

It's not even a giant! Well, the answer is already partly given. While most of those 80 wells had oil shows, very few have been flowing gas or oil. The south-western Barents Sea was opened up for exploration in 1980, and two commercial discoveries up to now are far below the initial expectations. Not only explorationists were disappointed - politicians were in particular dissatisfied.

One early morning, April 1, this was all changed. The news was out, and Statoil, with Eni and Petoro as partners, could claim they had made "a significant discovery". The well had proven a gas column of 33 metres and an oil column of 90 metres, and it was said that the oil could easily be produced. The Norwegians, along with the oil companies exploring in the far north, took a big sigh.

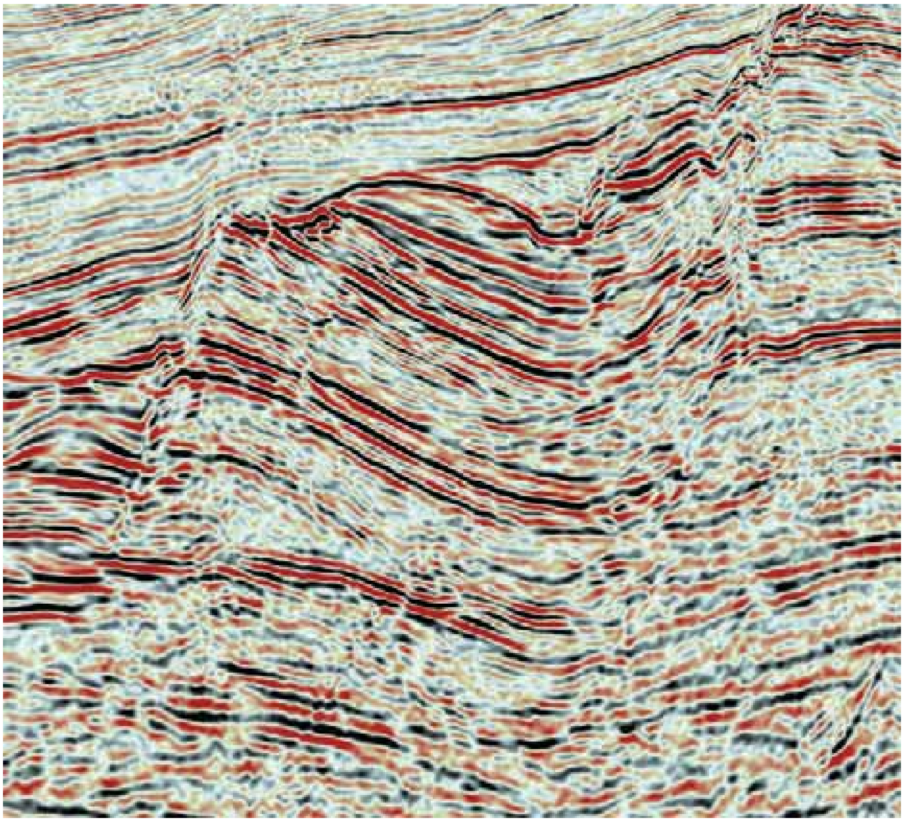
While the estimated volume of the discovery is said to be up to 250 MMboe, Statoil sees opportunities for further upside in the license for a potential total of 500 MMboe.

Moreover, the discovery belongs to a geological province that may very well have additional resources *(see pages 36 and 64*). Several more wildcats are expected in the near future in neighbouring licenses. Statoil is, nevertheless, cautious about claiming to have cracked the code for the entire area yet. "But we have confirmed that our exploration model is correct. This is a break-through, and an important step in understanding how the geology – and thus the hydrocarbon systems in the Barents Sea – works," says Tim Dodson, executive vice president for exploration in Statoil.

The structure is very well defined on seismic data. And because it is shallow, (the top of the reservoir is reported to be at approximately 1,200m below sea level, in water depth close to 400m), hydrocarbon indicators from both seismic and electromagnetic data work very well. We now know that there is a flat spot both between the gas and the oil leg and between the oil leg and the water. Moreover, rumours say the electromagnetic data gave a very favourable response. Geologists familiar with the area report that the risk of drilling a dry well was for those reasons considered quite low.

"If the volume estimates are confirmed, then this discovery could provide a basis for an independent development. Our ambition is to put this find into production as quickly as possible," says Tim Dodson, who has plans for both the drilling of a new prospect in the same license next year, and a possible appraisal drilling at Skrugard.

TGS



Rotated Jurassic fault block across the Skrugard prospect.

MAURITANIA: Resurgent Interest

After the 2001 discovery of the **Chinguetti** oil field in Block 4, 80 km off the Mauritanian coastline, Atlantic North West Africa was 'flavour of the month' for a while. Initial recoverable reserves for the field were put at 123 MMbo, and the nearby **Banda** field, discovered in 2002, was announced as having reserves of 3 Tcfg. Further excitement was generated by the discovery of the estimated 1 Bbo in place **Tiof** field in 2003 and the 1 Tcfg **Pelican** field in 2004.

Output, however, failed to match expectations. Although Chinguetti was put on stream in 2006 and reached its target rate of 75,000 bopd within two weeks, production began to decline rapidly as a result of geological and technical problems encountered when drilling. The field's 2P reserves estimates were first cut to 52 MMbo in November 2006 and then in 2007 to 34 MMbo. Production fell to 11,500 bopd, while a 2005 coup further undermined investor faith in the country's stability. The other fields have yet to be developed and the initial Chinguetti operator, Woodside, sold its assets.

Now however, interest appears on the increase again. Coup leader Colonel Ely Ould Mohamed Vall ceded power, as promised, in democratic elections in 2006 and 2007, and the country remains politically stable. A number of companies, including Malaysian national oil company Petronas, have bought assets and been investing in the country – and then in January this year Dana Petroleum announced another discovery.

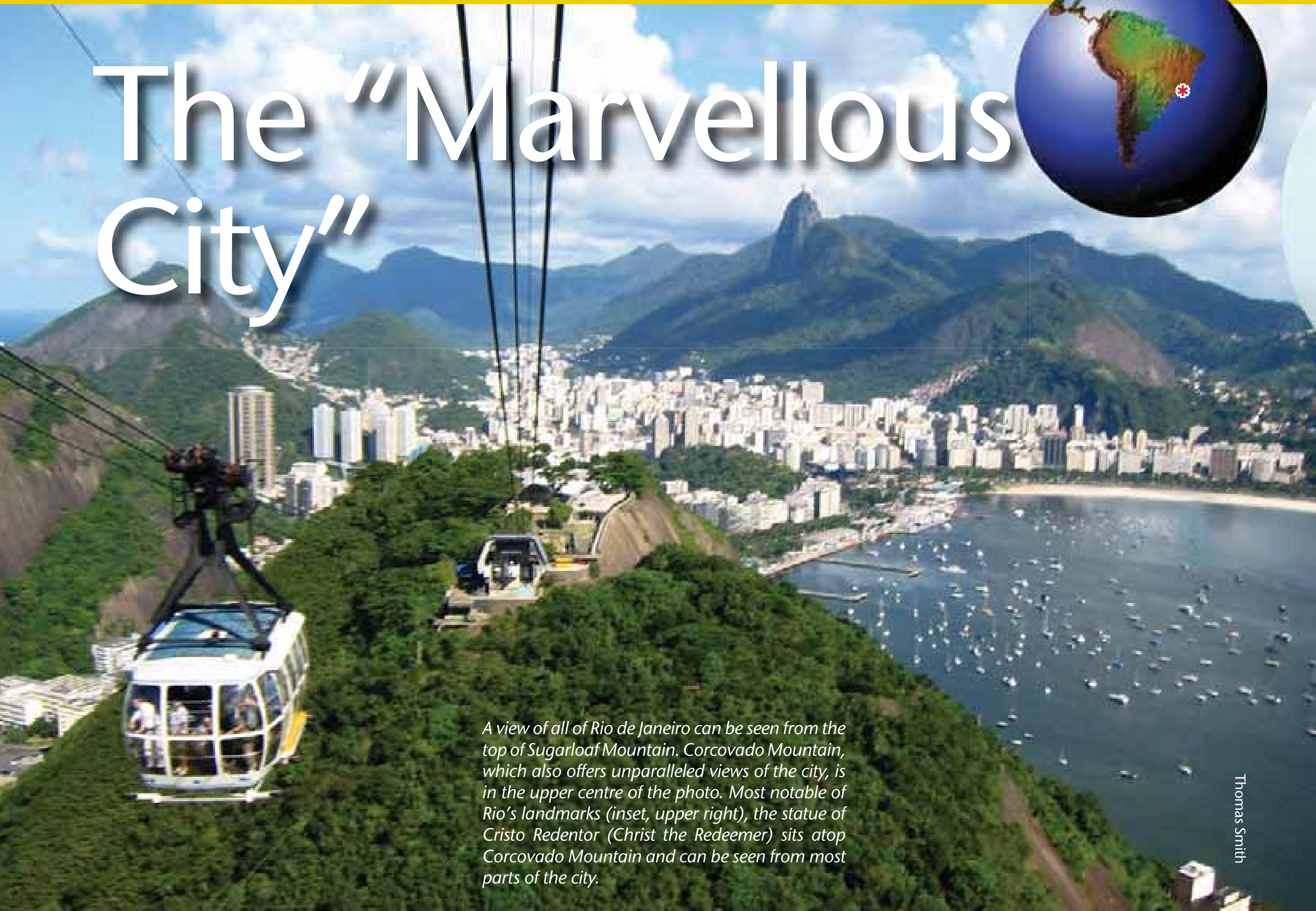
The **Cormoran** exploration well is located in Block 7, about 2 km south of the Pelican gas discovery in the same block and about 150 km north of Chinguetti, in deep water of approximately 1,630m. It encountered a number of good quality gas bearing sands, primarily in the Cretaceous, confirming this new play, as the Pelican discovery had been the first time significant volumes of hydrocarbons were discovered in a pre-Tertiary formation offshore Mauritania. The hydrocarbons reserves in Chinguetti, Tiof and Banda, by comparison, are found in submarine fan/channel reservoirs located 1,300m to 1,900m below the seafloor, part of a major Miocene delta complex.

Stabilised gas flow rates of between 22 and 24 MMcfpd were obtained during a test of one of the four separate gas columns encountered by the well, and 2P reserve estimates are in the region of 1 Tcfg.

The licence is operated by Dana with a 36% share. Other interested parties are GDF SUEZ (27.85%), Tullow (16.2%), PC Mauritania (15%) and Roc Oil (4.95%).

Rigzone

The "Marvellous City"



A view of all of Rio de Janeiro can be seen from the top of Sugarloaf Mountain. Corcovado Mountain, which also offers unparalleled views of the city, is in the upper centre of the photo. Most notable of Rio's landmarks (inset, upper right), the statue of Cristo Redentor (Christ the Redeemer) sits atop Corcovado Mountain and can be seen from most parts of the city.

Thomas Smith

THOMAS SMITH

The endless beauty of its people and its setting put Rio de Janeiro as one of the most visited cities in the Southern Hemisphere.

Flanked by steep granite mountains that rise from the sea, rimmed by famous beaches, and neighbourhoods connected by tunnels through the mountains, Brazil's second largest city, Rio de Janeiro, is like no other on the globe. Ever since the Portuguese founded the city in 1565, Rio has been an important commerce and administrative centre for the region. Now, this enchanting, multi-faceted city is in the middle of an oil related economic boom thanks to some of the world's largest offshore oil and gas discoveries in over 30 years. These discoveries are making Brazil a major player in the world energy picture and once again Rio de Janeiro finds itself another prominent role in the country's history.

Historically, while under the Portuguese, Rio was the administrative capital of Brazil and during the Napoleonic Wars, the King of Portugal moved his entire court to the city in 1808. In 1822, when Brazil became independent, Rio was again chosen as the capital. Primarily due to gold mining and a prolific coffee export industry, Rio de Janeiro became the largest and fastest growing city in Brazil.

When coffee growing moved south to more fertile acreage in the São Paulo area during the late 1800s, the city went into an economic decline along with a loss of political power. It would not be until the 1940s that Rio would rebound, when large steel, naval and oil plants were opened, in part with help from the Americans and British who were looking to Brazil as an ally during World War II. When, in 1960, the national capital was moved to Brasilia, tourism and petroleum became the major economic activities that are even more evident today.

Iconic Places and Events

Towering Corcovado Mountain with its statue of Cristo Redentor (Christ the Redeemer); the cable cars working their way up Sugarloaf Mountain (Pão de Açúcar); the infamous Copacabana and Ipanema beaches; Maracanã Stadium, one of the world's largest football venues; and the Sambódromo, the parade avenue used during Carnival – just a few of Rio's 'must sees'.

Corcovado Mountain, rising 710m above the city, offers breathtaking views. Atop the mountain is the most recognized of Rio's landmarks; the statue of Cristo Redentor. The 38m tall statue with outstretched hands is made from 1,038.5 metric tons of local granite. Corcovado Mountain is located in Parque Nacional de Tijuca, which preserves the last remaining Atlantic tropical rain forest around Rio and vicinity.

Sugarloaf Mountain (Pão de Açúcar) provides the other site for extraordinary views of the city and surrounding bays. Two cable cars are taken to reach the 396m high peak where a 360 degree panoramic view of the city, beaches, mountains, and bays can be enjoyed over a stout cup of Brazilian coffee. Rock climbers can be seen ascending some of the 350 established routes up the massive gneissic granite walls that formed over 570 million years ago.

But do not forget the beautiful beaches of Rio, namely Copacabana and Ipanema. Enjoy the sparkling water, gleaming sand, and walk the art deco sidewalks, called Portuguese pavement, constructed in a distinctive design for each area of the city. On Sundays, some of the coastal streets are closed to traffic and the locals fill these avenues throughout the day.

While each Sunday is an event, it pales in comparison to what the Guinness book of World Records calls the 'biggest popular party on the planet', the Carnival of Rio de Janeiro. This celebration occurs every year before the Christian tradition of Lent, in February or March. Parades, people dressed in masquerade, and street parties attract over 500,000 foreign tourists during the four day event.

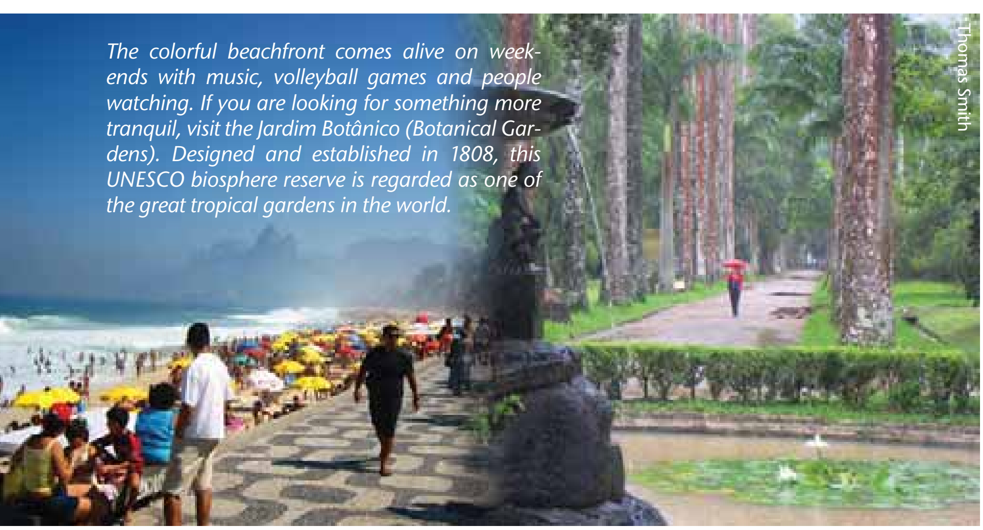
Two huge world events are coming to Rio. First is the 2014 FIFA World Cup that will feature the final match in the giant Maracanã Stadium and secondly, Rio will host the 2016 Summer Olympics, the first for a South American city.

Base for Oil Operations

The headquarters and extensive research facilities for the enormous state-owned oil company, Petrobras (third largest energy company in the world) are both located in Rio de Janeiro. Petrobras was established by the government in 1953 and has seen steady growth as Brazil's sole oil company. A Constitutional Amendment in 1995 ended the Petrobras monopoly allowing other companies to acquire acreage.

The 2007 discovery of huge subsalt reservoirs offshore (*GEO ExPro* Vol. 5, No. 5) has started a flood of new companies doing business in Brazil. Growing numbers of oil and oil service companies are increasing their operations in and around the city. Petrobras has enlarged port facilities in the beautiful bays around Rio to modernize and expand their deep water drilling capabilities. Production is just starting from the first of these new discoveries and potential is huge, giving Rio de Janeiro a bright economic future. With all this activity, local geoscientists are seeing increased opportunities in research and collaboration within the city, as well as Rio becoming a destination for international conferences.

Outside Rio, nearly unlimited exploration of the beautiful islands, bays, waterfalls, and mountains is close by.



The colorful beachfront comes alive on weekends with music, volleyball games and people watching. If you are looking for something more tranquil, visit the Jardim Botânico (Botanical Gardens). Designed and established in 1808, this UNESCO biosphere reserve is regarded as one of the great tropical gardens in the world.

Thomas Smith

Barrel Award Offers Great Opportunities

Jeremy Richardson, Director for AAPG Europe, tells us about the importance of working with students, and in particular the prestigious **AAPG Barrel Award Competition.**

Why is a professional organisation like the AAPG involved with students?
The AAPG has an unrivalled education programme worldwide, extending to a growing student and young professionals programme offering opportunities not only to learn in a traditional classroom style but to take part in field trips and, more importantly, to meet and network with the industry both as a whole and in specific groups. Our work with students contributes to our mission of promoting petroleum geosciences training and advancing the careers of geosciences students.

The team from the University of Texas at Austin received first prize at the Global Finals of the Barrel Awards this year.

What is the Barrel Award Competition?
It is an annual basin/prospect evaluation competition for geosciences graduate students from universities around the world. The university teams analyse a dataset (geology, geophysics, land, economics, production infrastructure, and other relevant materials) over an eight week period prior to their regional competition. Each team delivers their results in a 25 minute presentation to a panel of industry experts; the regional European competition is held in Prague each March. The winner from the European region competition goes to the Finals at the AAPG Annual Conference and Exhibition in the States, this year held in Houston.

The AAPG Imperial Barrel Awards gives graduate students the ultimate experience of learning and interpreting a dataset, coupled with the opportunity to meet and spend a couple of days with industry leaders and professionals. A fantastic opportunity for students and an equally useful few days for senior industry experts to view and interrogate future employees while watching them at work.

How many students are involved?
In Europe this year we had 17 teams competing for a place in the finals. There was a good spread of universities, from Tyumen, Russia in the east to Lisbon in the west. Over 85 students took part and we flew all the teams and their course leaders to Prague where they presented to 8 judges from Shell, Maersk, ExxonMobil, Baker Hughes, OMV, Petrom, Hess, Nexen and BG Group

Worldwide we had almost 100 university teams taking part from all the Regions; Africa, Middle East, Asia Pacific, Latin America and Canada plus all the sections within the United States. The biggest and most successful competition yet.

Who won the competition?
We have been very successful with our European teams in this competition; over the 5 years of the competition Europe has won on three occasions and come second twice. This year the European team from the University of Southampton was just nudged into second place by the team from the University of Texas at Austin with the Sultan Qaboos University from Oman taking a close third. All Universities have lived and breathed this competition for the past 3 months and all the 12 finalists in Houston made for a very close Finals competition.

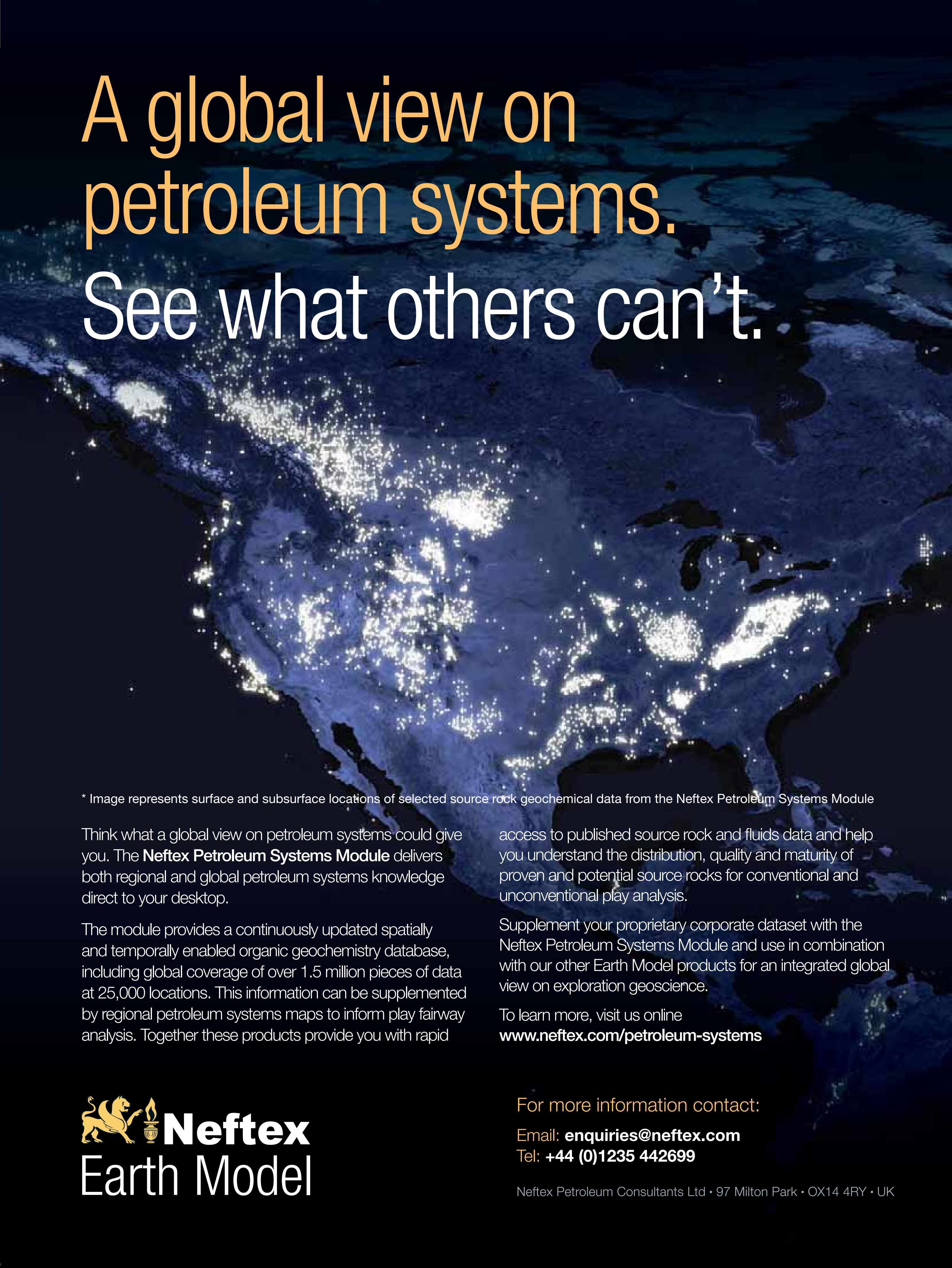
All sponsors of the competition are offered the chance to provide a judge for the competition. Some of those sponsors also cleverly choose to send along their recruitment or HR person to speak with the team members. Everyone is on the lookout for new young talent and I know that a lot of the Europe team members secured some holiday work and most members of each team go on to secure full time places once they have finished their education. So this is an ideal way to look at the future of our industry without the constraints of a formal interview.

That's a great success story, so where does the AAPG Imperial Barrel Awards go from here?
The simple answer is that it goes from strength to strength and grows. The trickier side of the question is how do we let it grow, encouraging more universities to take part and for the competition maintain the vital networking opportunities that we currently offer and that are so vital to the career of the students and the benefit of the industry?

And, not surprisingly, the answer comes down to money. The programme is hugely expensive and is funded by our generous sponsors and the AAPG. We are predicting a doubling of the number of universities entering the European Regional competition for 2012 and therefore two European teams will be going to the Global Finals (in Long Beach, California) next year. This means we need to raise double the sponsorship to ensure we give the students that valuable face to face interaction with the industry experts, judges and commercial Companies. There are huge benefits for organisations to sponsor this event, not the least of which is their satisfaction at putting something back into the education industry to promote and encourage our future geologists and geoscientists. I would be happy to run through a programme of benefits for any company that would like to become more involved.

How do students enter and how can someone find out more?
We have two websites, a sparkling new IBA website for the overall competition, which includes, rules and regulations, entry forms etc, which is at www.aapg,org/iba. Or there is a Europe website at http://europe.aapg.org/imperial-barrel-awards with more specific information on the European competition.

JANE WHALEY


A global view on petroleum systems.
See what others can't.
* Image represents surface and subsurface locations of selected source rock geochemical data from the Neftex Petroleum Systems Module
Think what a global view on petroleum systems could give you. The Neftex Petroleum Systems Module delivers both regional and global petroleum systems knowledge direct to your desktop.
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Huge Potential With Moderate Risk

With source rocks, reservoir rocks and traps in place, based on regional geological studies the previously disputed area between Norway and Russia in the Barents Sea may turn out to be a significant petroleum province some few years from now.

HALFDAN CARSTENS

"There is every reason to believe that the previously disputed area between Norway and Russia in the Barents Sea contains hydrocarbons."

This is the good news, according to Torbjørn Throndsen from Torena, a small company specialising in petroleum system analysis on a regional as well as prospect scale. Throndsen has himself in-depth knowledge of all aspects of source rocks on the Norwegian shelf following more than 30 years of consulting and oil company proprietary work.

"The bad news is that gas most likely will predominate," he adds.

Despite a recent discovery (Skrugard) further west in the Bjørnøya fault complex, in which up to 250 MMboe may have been proven, the previously disputed zone remains the Hot Spot of the Barents Sea. No official resource estimates do exist, but Statoil did at one time publish their own findings, stating that as much as 12 Bboe may be found on the Norwegian and Russian side combined.

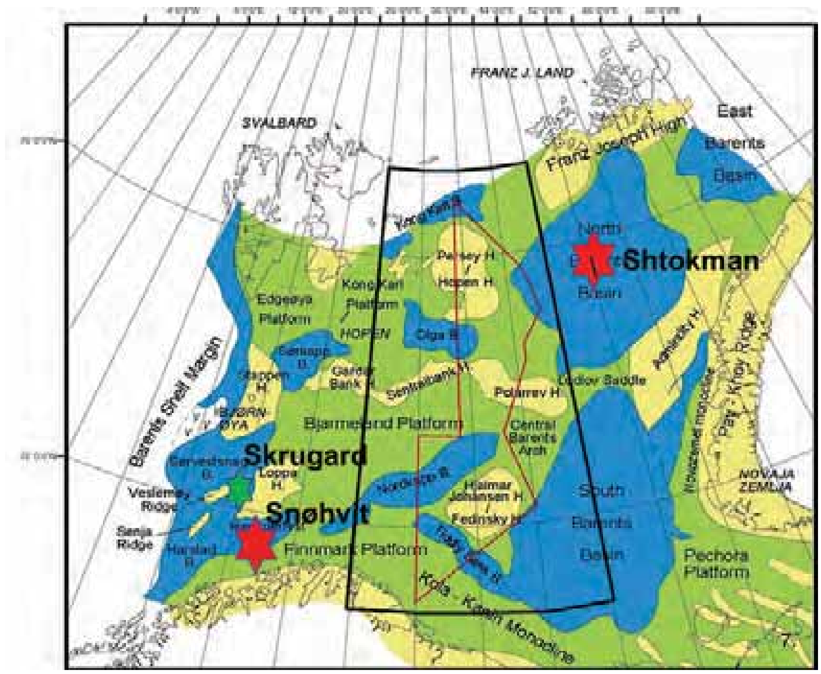
"Other companies also have a very positive view on the exploration potential of this area, as there are many strong indications that both source rocks and reservoir rocks are present," says Terje Hagevang, managing director of Sagex Petroleum. Sagex has done a comprehensive study on the petroleum potential of this area based on all available sources, including unpublished maps and seismic sections. Their expert team included Russian geoscientists and, in part because of this, their report must be looked upon as "state of the art", as no new data have come along since it was published five years ago.

In April last year an agreement was reached whereby the overall disputed area is divided into two parts of approximately the same size. One year later this agreement has been ratified by both the Norwegian Storting and the Russian Duma. In consequence, the Norwegian Government will initiate an impact assessment under the Petroleum Act, with a view to granting production licences for the area west of the delimitation line in the southern part of the Barents Sea (south of 74°30'N). If this is justified by the conclusions of the impact assessment, the Government will present a white paper recommending that these areas should be opened for petroleum activity.

In simple terms, the race is on. In all likelihood, exploration on the Norwegian side will happen first. But before the geophysical companies are allowed to carry out multiclient seismic surveys, and possibly also electromagnetic surveys as have been undertaken with great success further west, the Norwegian Petroleum Directorate will, for some unknown reason, do their own surveys using government money.

The geological province in question is huge by all standards. The original area was 175,000 km². If that number does not make sense, then combine the Viking Graben, the Central Graben and the Southern Gas Basin, and you will end up with the same areal coverage. Dividing the whole area into two equal parts means that both countries will have some 12-13 North Sea quadrants to explore.

In combination with the recent Skrugard discovery, and a number of other large and promising prospects to be drilled in the near future in the Norwegian sector west of the previously disputed area, Barents Sea exploration will continue to make headlines in years to come.



Sagex Petroleum

Structural elements of the Barents Sea, including the previously disputed area outlined in red. Also shown is the location of Shtokmanovskoye with 113 Tcf (3,200 Bcm) of gas (larger than both Groningen and Troll) and the recent discovery Skrugard with up to 250 MMboe - the largest oil discovery of the Norwegian Barents Sea so far.

CONVERSION FACTORS

Crude oil
1 m³ = 6.29 barrels
1 barrel = 0.159 m³
1 tonne = 7.49 barrels

Natural gas
1 m³ = 35.3 ft³
1 ft³ = 0.028 m³

Energy
1000 m³ gas = 1 m³ o.e
1 tonne NGL = 1.9 m³ o.e.

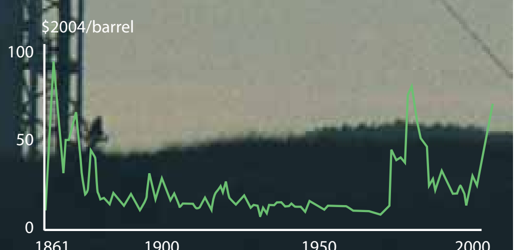
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm³) of oil equivalents

Giant field
Recoverable reserves > 500 million barrels (80 million Sm³) of oil equivalents

Major field
Recoverable reserves > 100 million barrels (16 million Sm³) of oil equivalents

Historic oil price



Libya – Flush with Oil

Libya has huge reserves of oil. With modest production and possibly vast resources, the North African country has the potential to serve the world with light crude for many years to come.

No other African country has more oil in the ground than Libya. According to the BP Statistical Review of World Energy 2010, the oil reserves amounts to 44 Bbo (most of it (80%) in the Sirte Basin) at the end of 2009. That is "slightly" (7 Bbo) more than Nigeria, but far more than all the other African countries put together. It is also some 3% of the world's total reserves. To put it briefly, we should all be aware that this North African country is very oily.

This fact becomes even more obvious knowing that the population in this huge country – 1.8 million square kilometers – has not yet passed 7 million. In comparison, Norway's population is about to turn 5 million, but the reserves, again according to BP, are only 7 Bbo. In other words, Libya has a lot to offer with respect to oil exports in years to come.

Again, for comparison, only six other countries in the world have higher reserves than Libya. Saudi Arabia ranks first with 264 Bbo, followed by Venezuela, Iran, Iraq and Kuwait, Yemen and Russia.

LIBYA
Oil exploration in Libya began in 1955, with the key national Petroleum Law No. 25 enacted in April that year. Libya's first oil fields were discovered in 1959, and oil exports began in 1961.

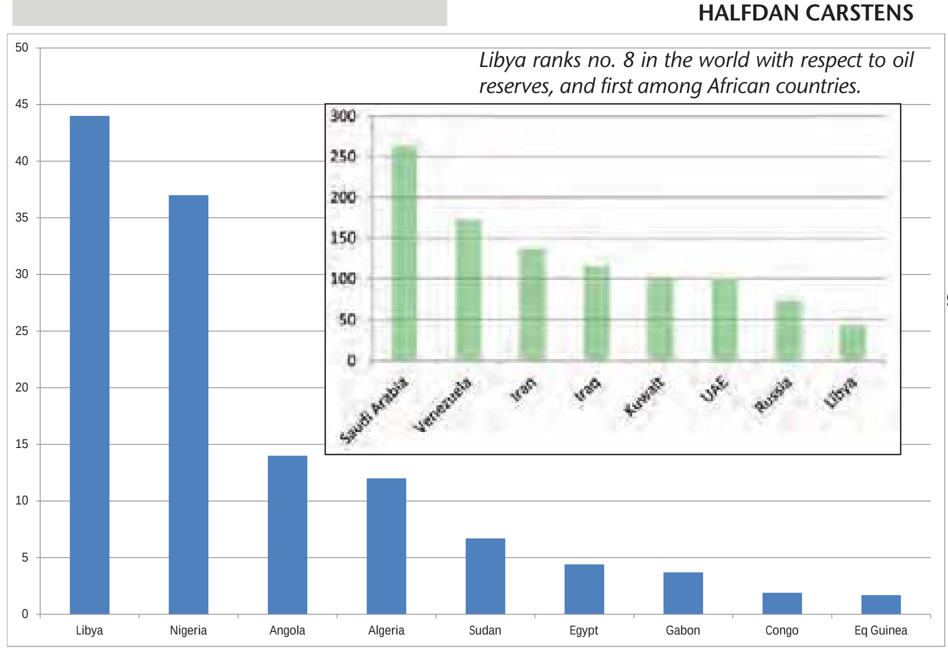
To complete the picture we also need to look at oil production. Using the same reliable source, Libya's oil production was 1.652 MMbopd in 2009 (domestic consumption 270,000 bopd), and it ranked only as the 4th largest producer in spite of having the largest reserves. Nigeria was in the lead, with Algeria and Angola as close followers. If we look at the whole world, Libya ranks as the 18th largest producer.

The above numbers all refer to oil reserves. The size of the oil resources is more speculative, as they depend on exploration maturity as well as sound resource estimates. Libya is, however, considered underexplored by many, probably reflecting the impact of sanctions formerly imposed on the country.

It is all too obvious that this makes Libya a particularly interesting venture. On top of that, Libya could be considered highly attractive both due to its low cost of oil production and its proximity to European markets.

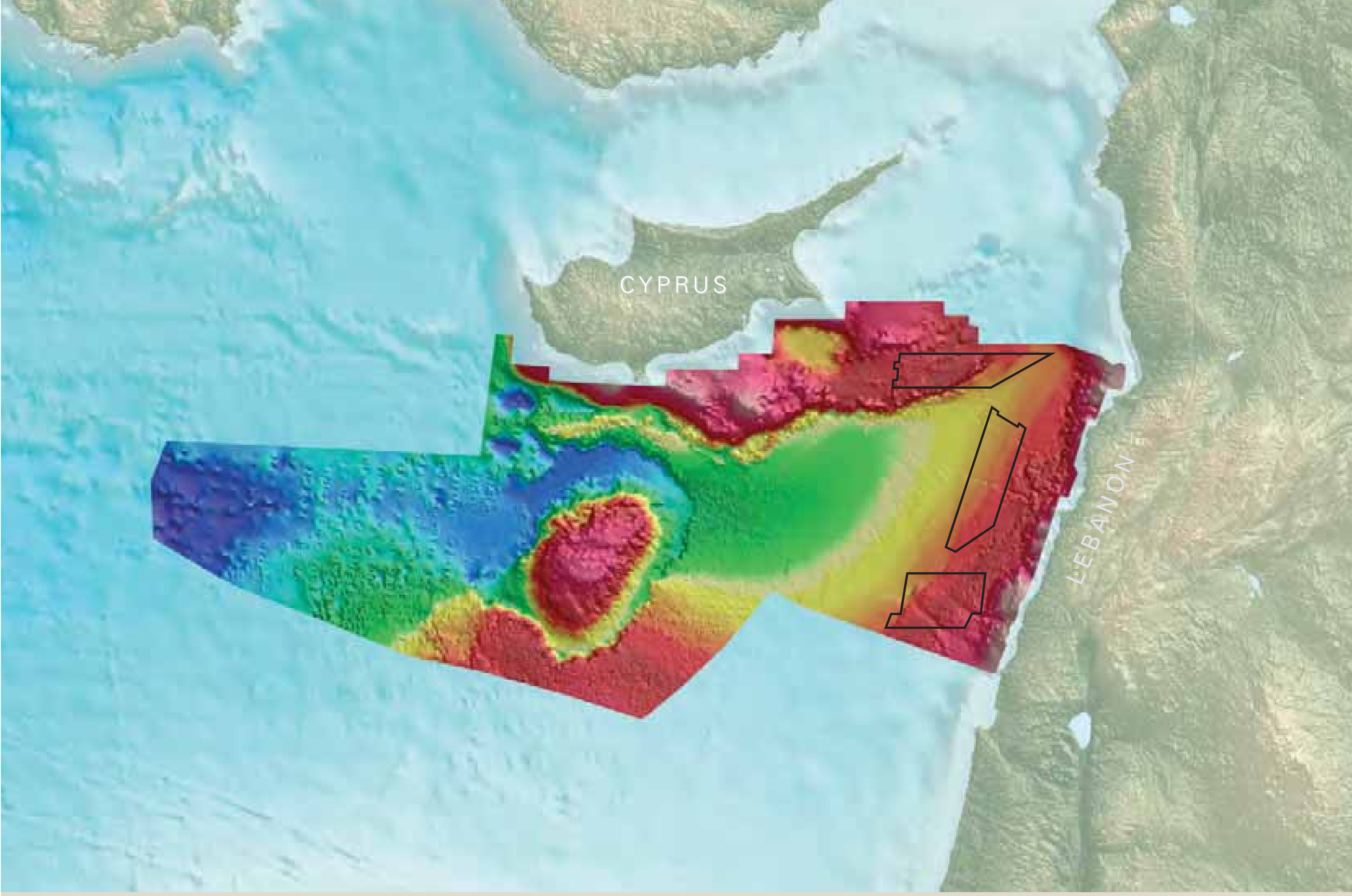
Libya's oil industry is run by the state-owned National Oil Corporation, which is responsible for implementing exploration and production sharing agreements with international oil companies. Along with smaller subsidiary companies, the NOC accounts for around 50% of the country's oil output. Major international oil companies operating in Libya include Eni, Statoil, Occidental Petroleum, OMV, ConocoPhillips, Hess Corp, Marathon, Shell, BP, ExxonMobil and Wintershall.

HALFDAN CARSTENS



Libya ranks no. 8 in the world with respect to oil reserves, and first among African countries.

BP Statistical Review of World Energy 2010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