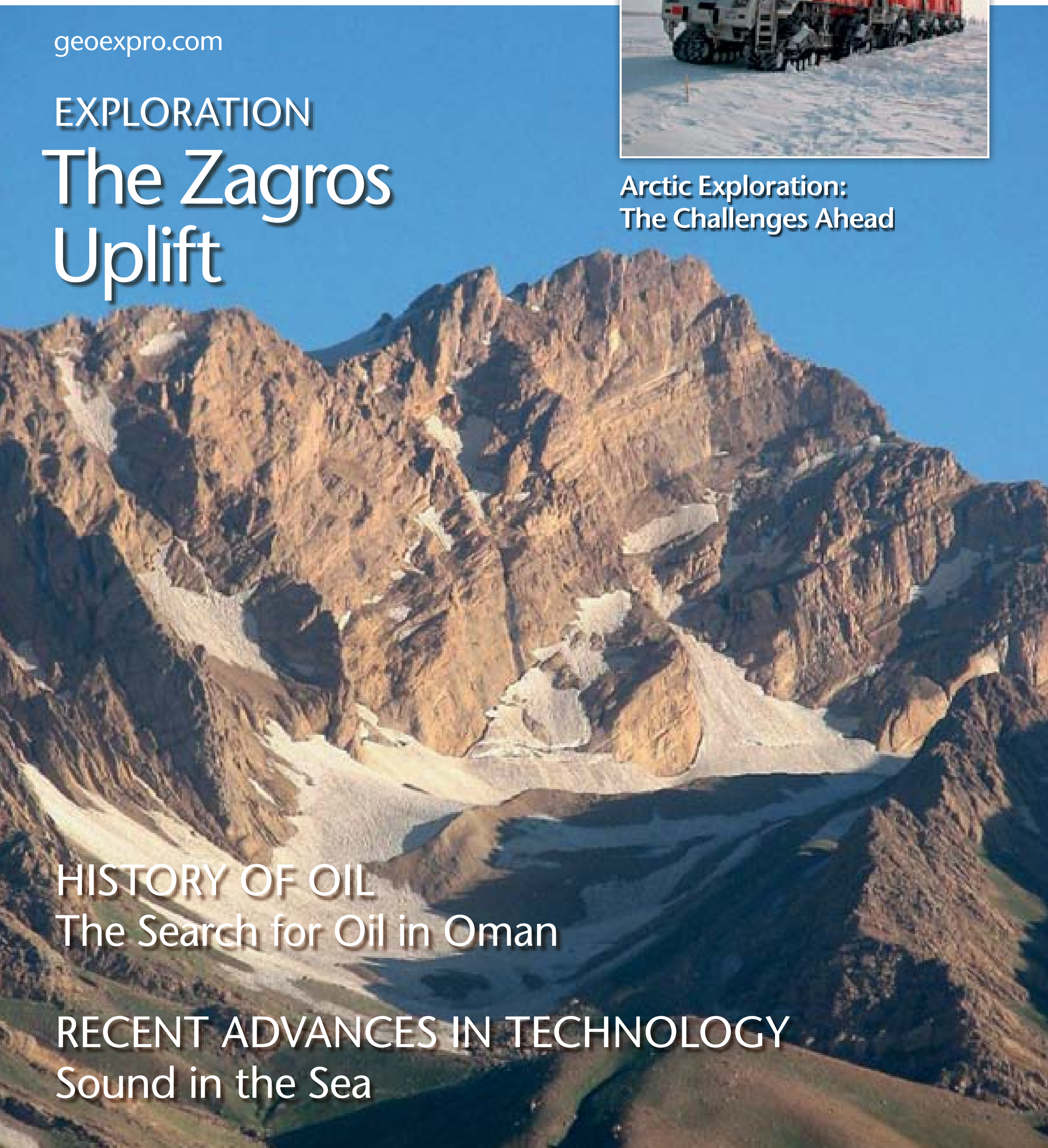
VOL. 9, NO. 1 – 2012

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

geoexpro.com



EXPLORATION
The Zagros Uplift

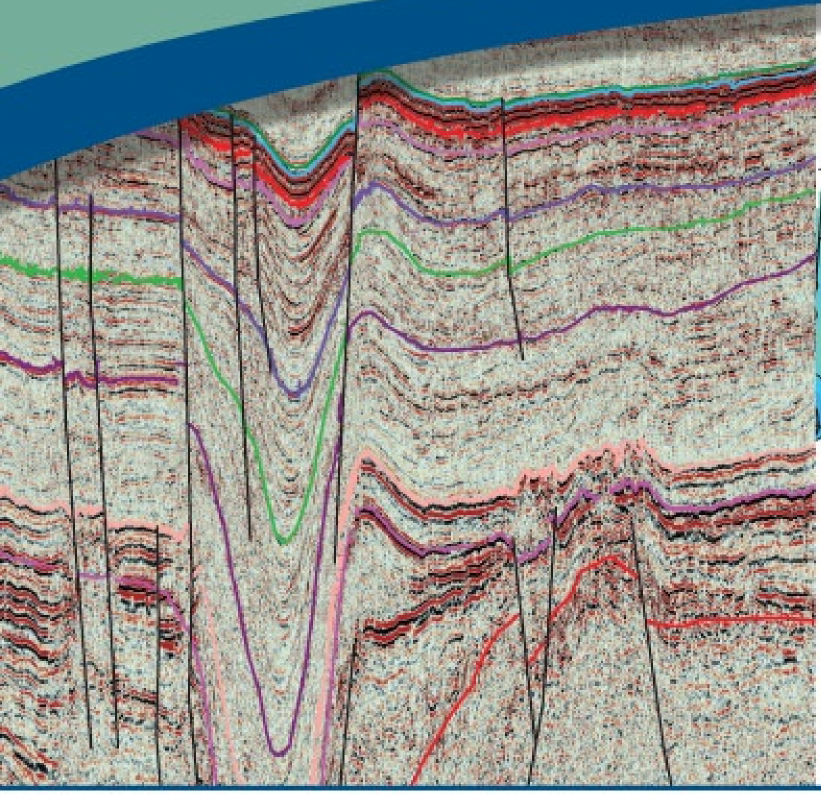
Arctic Exploration: The Challenges Ahead

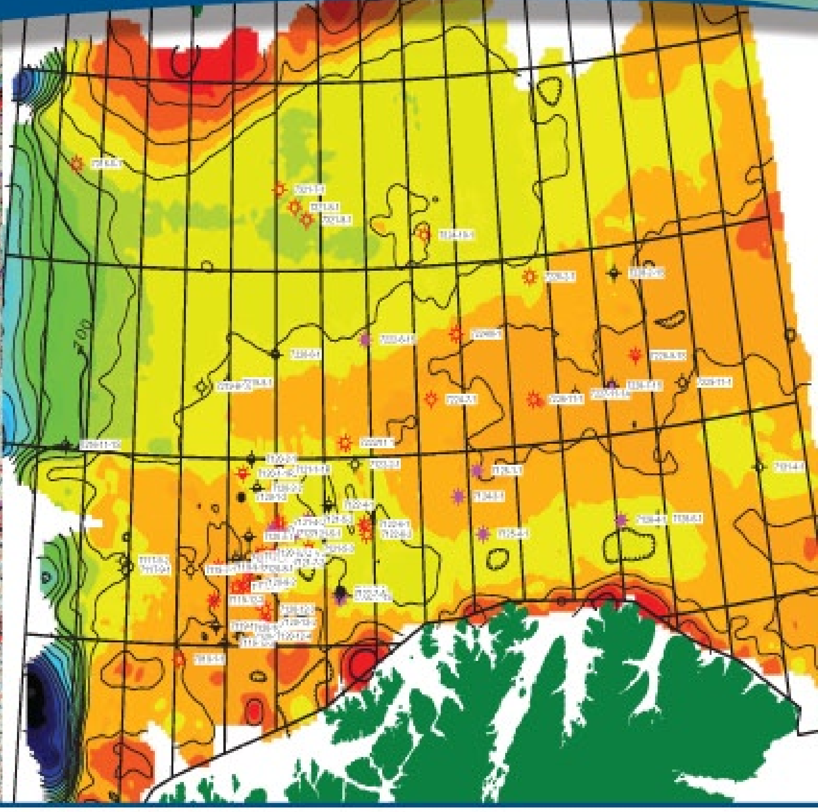
HISTORY OF OIL
The Search for Oil in Oman

RECENT ADVANCES IN TECHNOLOGY
Sound in the Sea

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT

Norway Barents Sea - 22nd Round



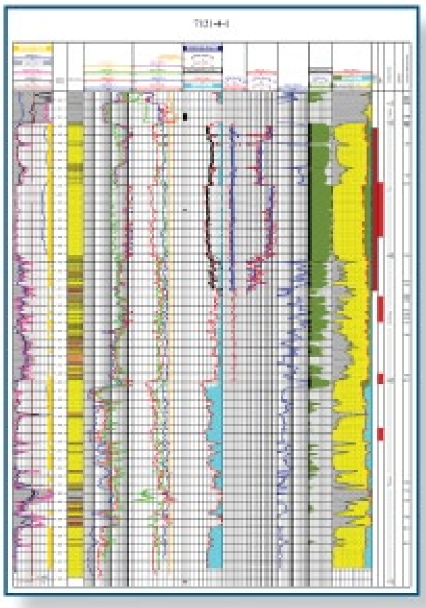


Regional Prospectivity Study

TGS' detailed regional overview of the Barents Sea provides an integrated approach to understanding and predicting hydrocarbon potential. Using interpretation derived from geophysical, geological, petrophysical and source rock analysis, basin models have been created that allow G&G teams to:

- Effectively predict reservoir quality and thickness at both present day and maximum burial
- Accurately predict maturity at a range of intervals and on a regional basis
- Apply risking on source and reservoir in a regionally consistent manner
- Rank areas in the 22nd round and guide future strategy

Approximately 120,000 km of seismic data has been interpreted to produce TWT and depth maps of 16 horizons. Reservoir distribution and quality maps have been produced for 10 regional reservoir intervals.



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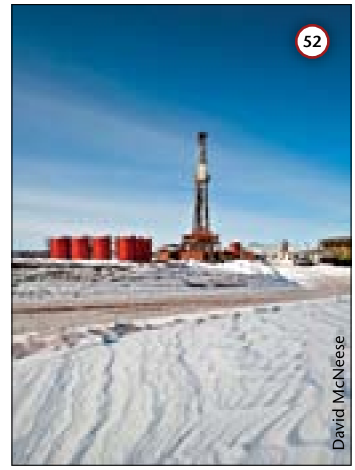
The Bakken is one of a growing number of shale formation success stories, thanks to new, innovative technologies



David McNeese

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This edition of GEO ExPro Magazine focuses on the Middle East and New Technologies

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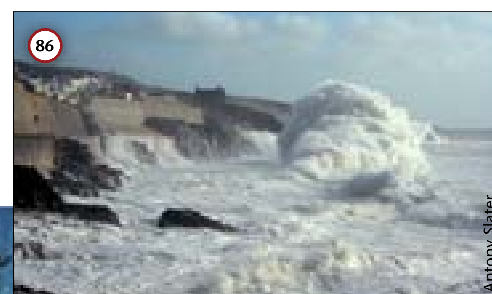
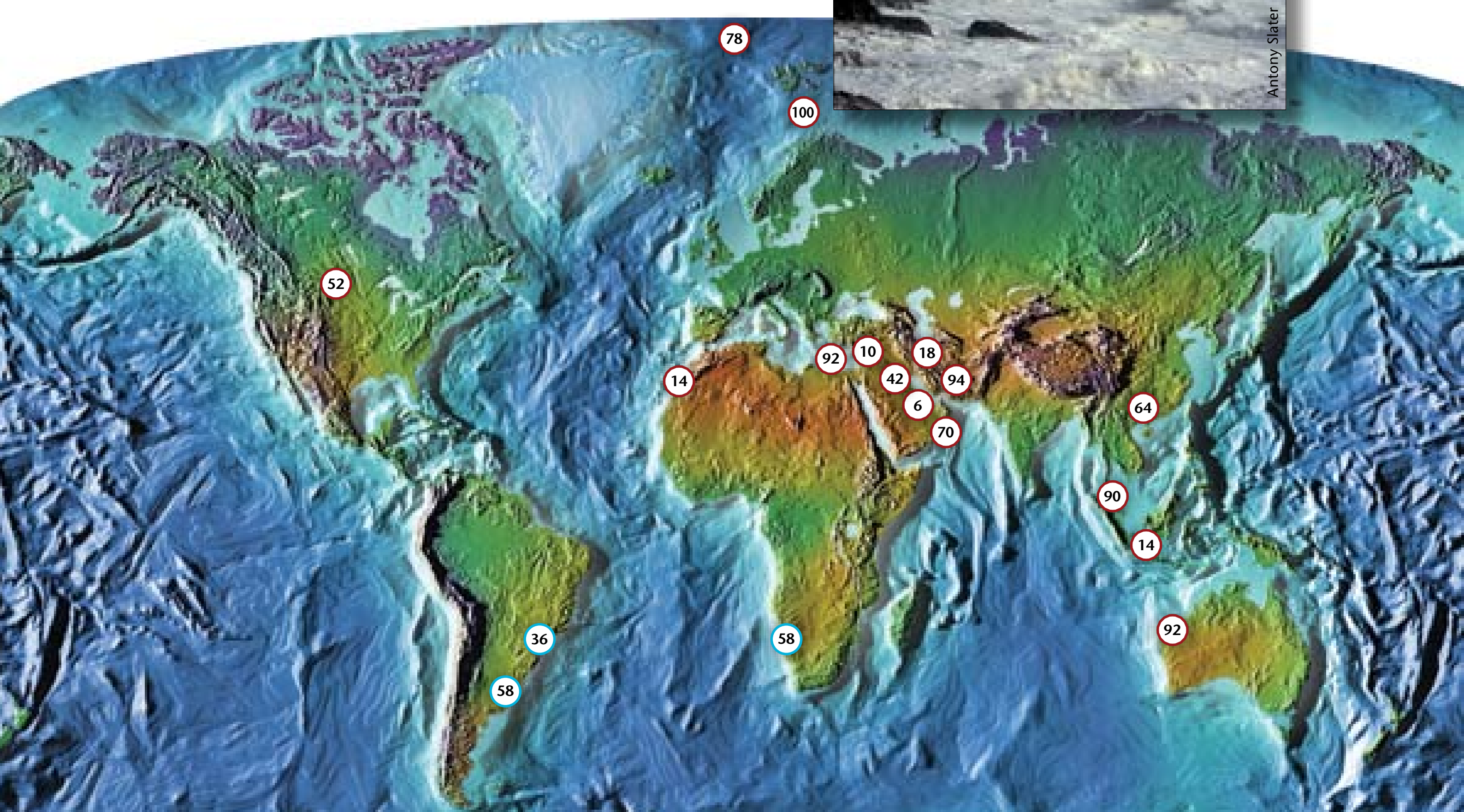
What governs the way that sound travels through the sea?



Antony Slater



All Eyes on the Middle East

The site in Bahrain of the first well drilled in the Persian Gulf.

The Middle East has been a cornerstone of the oil and gas industry for over a hundred years. Oil was first found in the area in Iran in 1908, while in 1932 the earliest discovery in the Persian Gulf was made in Bahrain, now the location for GEO 2012, the biennial Middle East geosciences conference. Since then, the region has kept much of the world well supplied with hydrocarbons and, according to the BP Statistical Review, it still is believed to hold 54% of the earth's known oil resources and over 40% of gas reserves. In 2010 the average production was 25 million barrels of oil per day, providing the world with 30% of its total energy needs. With the eyes of the media on much of the Middle East at the moment, the important role the region plays in the economy, wealth and stability of the whole world is unmistakable, and there seems little reason to doubt that Middle Eastern oil and gas will continue to play as significant a part during the next century as it did in the last. So in this issue of GEO ExPro Magazine we pay homage to that contribution and look at several key aspects of the oil industry in the Middle East, including the influence of the formation of the Zagros Mountains on the accumulation of hydrocarbons in the area, and the history of the development of the oil industry at the opposite end of the Arabian Gulf, in Oman.

Crucial to the success of the industry in the Middle East, as well as elsewhere, has been the continuing development of and use of new technologies to find and extract the highest possible yield from each hydrocarbon accumulation, and we also look at some of the new technologies available to help do just that. The utilisation of CO_2 as one of the most efficient and effective of the improved recovery mechanisms available to us is discussed, as is the development of the most advanced workstations for geological modelling. As ever, it is fascinating to watch how this vibrant industry is continually developing.

JANE WHALEY
Editor in Chief

THE ZAGROS UPLIFT

Jurassic and Cretaceous carbonate sediments exposed in High Zagros, Zard-Kuh (3,972m). With a length of 1,500 km and summits higher than 4,000m, the Zagros Mountains in south-west Iran were produced by the tectonic collision of the Arabian plate with Eurasia, and exhibit the sedimentary record of this part of the Middle East dating back to the Cambrian. This mountain-building process influenced the generation, migration and entrapment of the largest oil reserves on Earth. These mountains have also played an enormous role in the geomorphology, climate, and cultural history of south-west Iran.

Inset: "Everyone says that their part of the world is the final frontier – but believe me, the Arctic really is." Alastair Fraser, Professor of Petroleum Geology at Imperial College, discusses the petroleum systems and distribution of hydrocarbons in the Arctic and analyses the challenges ahead.

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Shaping the Future of Geoscience in the Middle East

GEO 2012

The Middle East plays a pivotal role in the oil industry, and so GEO 2012, the 10th Middle East Geosciences Conference and Exhibition, promises to be an exciting event, with a wide selection of current research and technology from both new and traditional areas of petroleum geoscience. The conference, which is held every two years in Manama, Bahrain, has been growing steadily since its inception in 1994. It had a total attendance of just over 3,500 in 2002, rising to 4,628 at the last conference in 2010 – and organisers expect over 5,000 attendees at GEO 2012, which will be held from 4 – 7 March at the Bahrain International Exhibition and Convention Centre.

"Over the last two decades, GEO has established itself as the premier forum for presenting and learning about best practices, new developments and applications in geosciences in the Middle East region," explains Intisaar Al Kindy, GEO 2012 Chairperson. "The theme of the conference, 'Shaping the Future of Geoscience in the Middle East' focuses on the current challenges facing hydrocarbon exploration and production, with emphasis on future technology and opportunities. The conference also aims to highlight the increased environmental challenges in the region by sharing best practices in exploring and producing hydrocarbons in the most environmentally responsible manner. Undoubtedly, this conference is very well attended by decision makers, senior executives and the most talented scientists and engineers in the hydrocarbon industry."

Diverse Themes

Following the opening ceremony on Sunday March 4, there will be a Plenary Session entitled 'Shaping the Future of Geoscience in the Middle East', with invited speakers including Abdulla Al Naim, Vice President Exploration, Saudi Aramco, and Andrew Gould, Chairman and CEO, Schlumberger. This will set the tone for the more than 360 technical papers and posters which will be presented at the conference, with topics ranging from reservoir characterisation, technologies to solve complex reservoir challenges, advances in geophysics, integration and next generation technologies, and harvesting unconventional resources, to new play concepts in exploration, human resources, and environmental and safety issues in the industry. There will also be a number of half-day panel sessions, in which participants will give their opinions on some of the over-arching matters of concern to geoscientists, including emerging trends in research and development, geoscience and the environment and 'producing the last drop'. These sessions will be led by key players in the industry, and the delegates will be invited to join in the concluding discussions.

GEO 2012 also offers learning opportunities, with seven short courses available, covering a number of technical aspects of geoscience. There are also three fields trips, which will be held after the close of the conference. Two of these are in Oman and one in Abu Dhabi, giving delegates the chance to develop their knowledge of the geology of this important region.

The conference is organised with the support of the American Association of Petroleum Geologists (AAPG), the European Association of Geoscientists and Engineers (EAGE), the Society of Exploration Geophysicists (SEG), the Dhahran Geoscience Society (DGS), the Bahrain Geoscience Society (BGS), the Geological Society of Oman (GSO), Qatar Geological Society (QGS) and the Emirates Society of Geoscientists (ESG), together with a committee of senior regional and international industry figures.

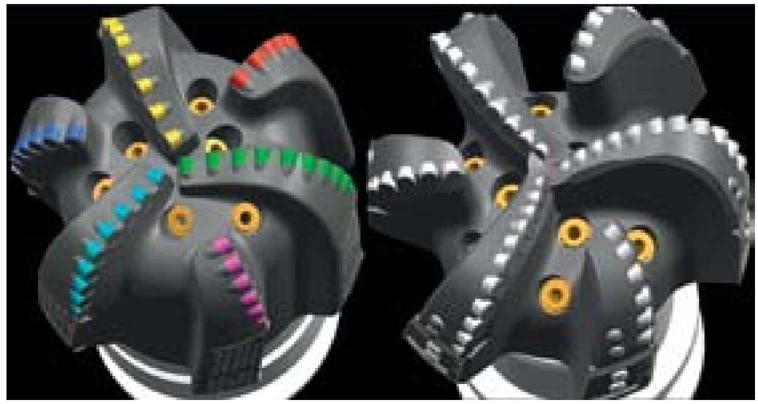
Bahrain, an independent island state in the Arabian Gulf about 25 km east of Saudi Arabia, was the location of the first discovery of oil in the Gulf, in 1932. This field, Awali, is the only one in the country and is still producing, although it peaked at about 77,000 bopd in the early 1970s and is now reported to be producing approximately 42,000 bopd. Revenues from oil and natural gas currently account for approximately 25% of GDP, but the country is also an important regional financial centre.

JANE WHALEY

Attendees at the GEO conference come from all over the Middle East and beyond

Longer Runs at Higher Speeds

Maximising fixed cutter bit performance in shales and carbonates



Conventional matrix bit (left) compared to high blade standoff of SteelForce™ bit design.

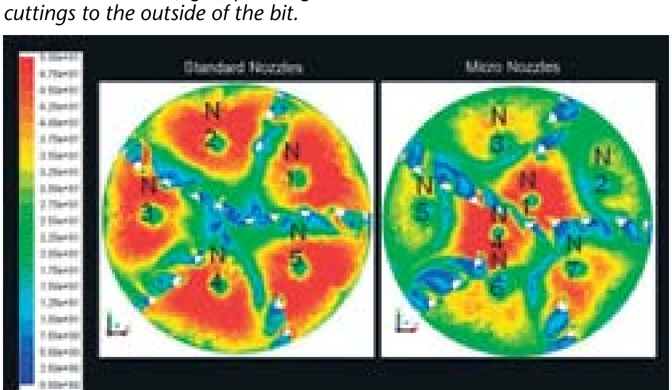
Fixed cutter bits – generally termed PDC bits for their poly-crystalline diamond cutters – have been achieving high rates of penetration (ROP) for decades, helping operators reach target zones as quickly as possible. However, fast drilling creates several challenges, especially in larger hole diameters that are usually drilled with water-based mud. The cuttings must be cleared from the bit face rapidly or the ROP suffers due to bit balling. The bit blades must resist solids accretion, and the cutters must remain sharp over long intervals. The bit design must match the formations to be drilled. To address these needs, operators typically choose between tungsten carbide body bits, known for longevity, and steel body bits, known for speed but more susceptible to erosion. Another factor is formation type: drilling in shales and carbonates is less abrasive than sandstone or hard rock. In these more forgiving conditions, a properly designed steel body bit can change the equation, allowing operators to benefit from both speed and longevity.

Bit Cleaning Facilitated

In the Anaima field in Oman, the carbonate and shale formations are not particularly abrasive, but frequent bit balling was slowing the ROP to an average of 65–70 ft/hr (21m/hr). The fluid flow across the face of the bit could not prevent cuttings from lodging between the blades. The operator had been using mostly tungsten carbide bits. A switch to steel body fixed cutter bits showed some gains as the ROP rose to an average of 100–105 ft/hr (32 m/hr).

The lessons learned from this improvement were applied to a new fixed cutter steel body design. The fine tuning paid off; while drilling the 12¼″ interval, the operator set a field record of 5,360 ft in 23 hours at an ROP of 233 ft/hr (71m/hr). When the operator reached total depth (TD) for the interval, the new SteelForce™ bit was pulled and graded 1-1 – equivalent to nearly new condition.

The improvement in cleaning capacity is confirmed by analysis of the fluid flow with each nozzle type. The fluid flow on the conventional matrix bit (left) has high velocity on the outside and stagnant flow on the inside. The micro nozzles (right) push higher flow in the centre and evacuate the cuttings to the outside of the bit.



This success was accomplished primarily by resolving the bit cleaning issue. The steel body bit has several characteristics that make this possible. Steel is more ductile, or flexible, than tungsten carbide, so the blades of the steel bit can extend further from the body, creating improved flow paths for the fluid emerging from the bit nozzles. The high blade standoff design of the steel compared to standard matrix bit facilitates cleaning for a faster ROP, and the strong blade design combats drillstring vibration. Tungsten carbide, which is much more brittle than steel, lacks the ductility necessary for extended blade construction.

Another success factor is the use of micro nozzles, allowing for an increased number of smaller nozzles to replace the standard number of conventional ones. While the diameter of the nozzle orifice typically remains consistent with established drilling practice (i.e., up to $^{16}/_{32}$″ opening), the smaller nozzle casing takes up less space. More nozzles can be installed on the bit, increasing the cleaning efficiency without reducing the total flow area needed to optimise bit hydraulics.

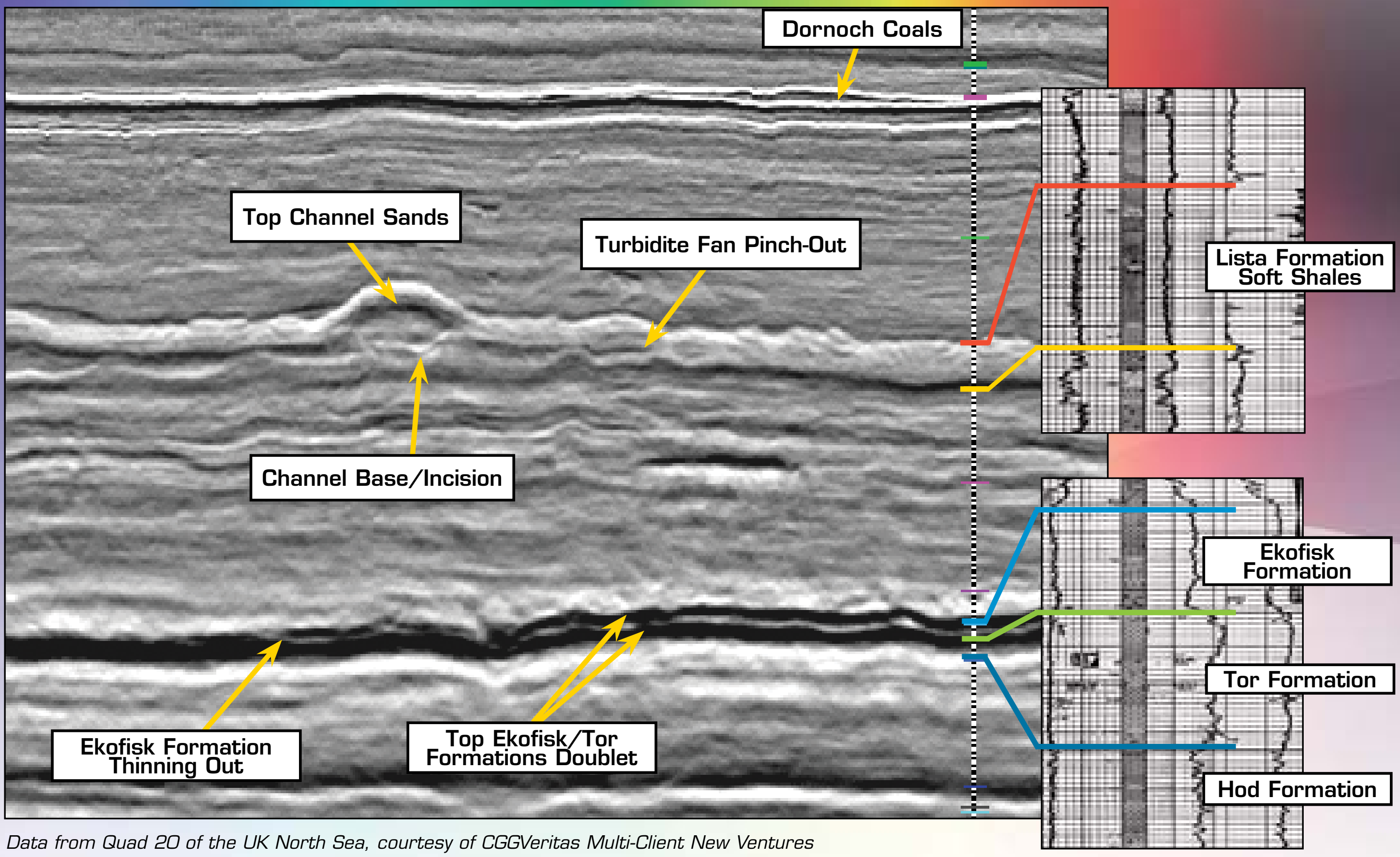
To combat erosion and potentially abrasive formations, the new steel body fixed cutter bits are coated in a special hardfacing that strengthens the outside surface with carbide pellets, helping to extend the life of the bit so that it can compete favourably with tungsten carbide bits. In addition, each bit has an anti-balling coating that changes the electrical potential of the steel to a strong negative. This repels the negative ions in the drilling fluid so that a lubricant barrier of water forms on the surface, preventing the bit from balling.

The cutters, like the rest of the bit, are designed to extend bit life without sacrificing ROP. Traditionally, cutters provide abrasion and impact resistance, but thermal degradation can cause damage through the differing expansion coefficient of the materials in the cutter. The ability of a cutter to manage the frictional heat generated during the drilling process allows it to stay sharper longer and wear at a slower rate.

Each bit is designed specifically for the application. The combination of these optimised features means that the steel body fixed cutter bit will drill farther faster, and reduce the cost per foot drilled. ■

DR. MARC DAVIDSON,
BRAD DUNBAR and ZEINOUN KLINK;
HALLIBURTON DRILL BITS & SERVICES

BroadSeis - Enhancing Interpretation



Data from Quad 20 of the UK North Sea, courtesy of CGGVeritas Multi-Client New Ventures

BroadSeis Data Empowers the Interpreter

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Force Majeure in Syria

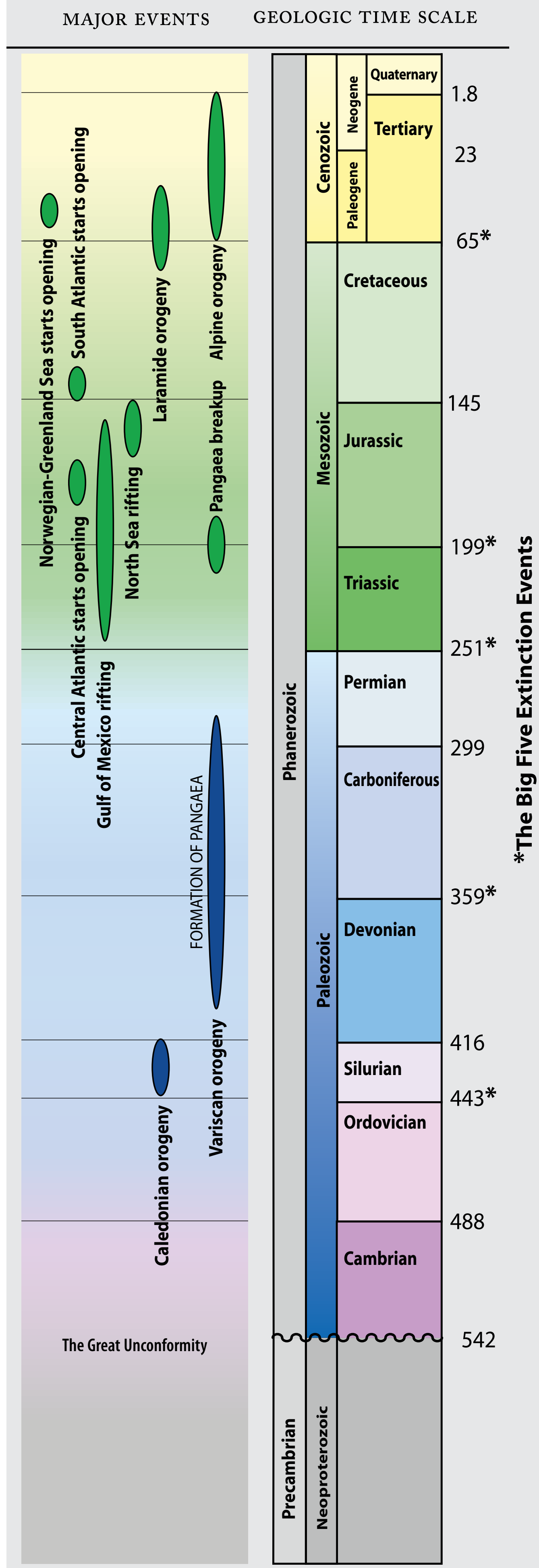
The much-vaunted Arab Spring, which has brought new life to the Libyan oil industry, where production is reportedly already nearly back to pre-revolution volumes, is having a less satisfactory impression on the business elsewhere in the Middle East. This is particularly evident in Syria, where in December last year Gulfsands Petroleum had to declare force majeure on its 50% owned Block 26, where it is operator. This is because in the latest round of EU sanctions on the country the Syrian state oil company, General Petroleum Company (GPC), is on the list of proscribed organisations. As with all Production Sharing Agreements in Syria, Gulfsands are partnered on Block 26 by GPC as the Syrian government representative, and, as Gulfsands themselves announced, "The fundamental effect of the additional sanctions is to preclude the Group (Gulfsands and its subsidiaries), until further notice, from engaging in activities, including funding activities, connected with the production, delivery or sale of crude oil from its Block 26 fields."

This effectively means that Gulfsands cannot expect to see any foreseeable future revenue from the block. The company focusses on the Middle East and North Africa and although it also holds interests in Tunisia, Iraq and the Gulf of Mexico, the bulk of its production income comes from Block 26.

There are two producing oil fields within the PSC area, which lies in the extreme north-east corner of Syria, bordered to the south by Iraq. Khurbet East was discovered in June 2007 and commenced commercial production only 13 months later, while the Yousefieh field, a few kilometres to the east, was brought on-stream in April 2010. Gulfsands have an intensive programme of further exploration on the block planned, with seismic having revealed further prospects and successful wells indicating that the main field area has potential for expansion. In the first half of 2011 Block 26 was producing 24,100 bopd. However, by October 2011 this had dropped to about 6,000 bopd on the instructions of the Syrian Oil Ministry, due to reduced availability of crude storage capacity within the country.

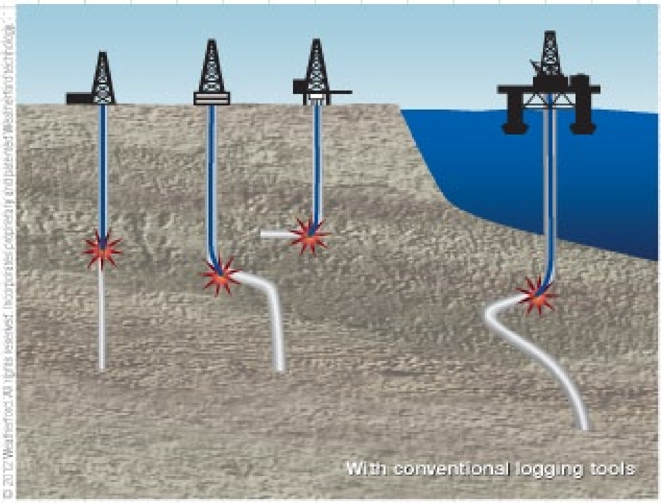
Shell, Total and Canadian company Suncor Energy have all also suspended operations due to the situation in Syria, and Emerald Energy, a wholly-owned subsidiary of Chinese state-owned Sinochem which owns the other 50% in the Block 26, has agreed to the issuing of the force majeure. Gulfsands intends retaining its 100 Syrian staff, hoping that the present troubles will subside and they will be able to resume operations. In the meantime, GPC may continue to produce oil from the block itself, and Gulfsands should be compensated for anything produced during the operation of the force majeure. ■

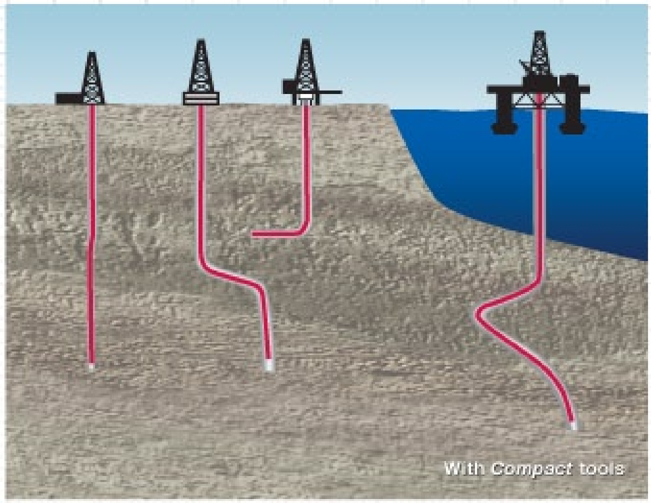
Gulfsands Block 26 lies in the north-east of Syria, about 600 km from the capital, Damascus.



Change Lost Time to On Time

Weatherford's Compact™ logging tools and Assure™ conveyance options ensure logging jobs, while saving you time and money





Compact formation evaluation (FE) tools are half the size of most conventional wireline equipment and offer **eleven different conveyance options**. So now you can gain access to more hole sizes and log problematic wells with less risk of getting stuck.

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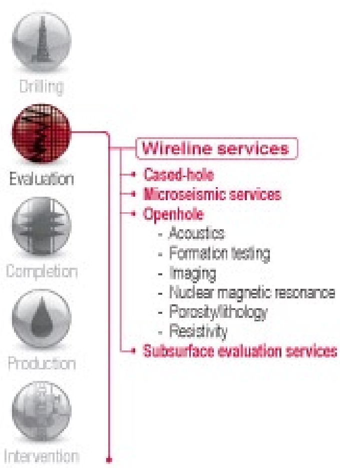


Advances in Deepwater Reservoir Monitoring

With the market for Permanent Reservoir Monitoring (PRM) continuing to grow along with deepwater field expenditure (Douglas-Westwood forecasts global deepwater CAPEX of US$225 billion between 2011 and 2015), TGS company, Stingray Geophysical, is currently engaged in a collaborative programme which will enable its fibre-optic seismic sensing arrays to be permanently installed in depths of up to 3,000 metres.

Already recognised by an Innovation Award from the Institution of Engineering and Technology, the FosarDeep™ programme is designed to take the benefits of Stingray's PRM systems into ultra-deepwater. Such benefits include proven system reliability to minimise the need for any costly retrieval or maintenance, sensitivity to the subtlest of changes in the reservoir, and the ability to acquire multi-component seismic and micro-seismic measurements frequently at a fraction of the cost of conventional 4D surveys to enable efficient reservoir management decision-making.

By considering the equipment and its delivery mechanism as an integrated requirement, FosarDeep meets many of the challenges that had previously proved an obstacle to PRM deployment beyond shallow waters. These include the pressures on subsea equipment that are sometimes as high as two tonnes per square inch (300 bar) and the ability to manage PRM systems and collect the data in real time at such depths. There are also challenging installation issues: currents of various strengths and directions in the water column; laying cables under risers, umbilicals and anchor chains; installing cables in seabed areas obstructed with subsea production equipment and flow lines; and in accurately positioning sensors on the seabed.

The FosarDeep programme will enable the installation of optical sensing arrays in water depths of up to 3,000 metres and with the ability to transmit the resulting signals over significant distances. FosarDeep will combine the lightweight sensing arrays, with the sensors and housing made more robust to withstand the high pressures, with an integrated installation system capable of installing arrays in these water depths. Partners in the project include fibre-optic cable and sensor manufacturers, Atlas Elektronik UK; VerdErg Connectors, who are underwater engineering specialists with particular expertise in ROVs and connectors; and the Optoelectronics Research Centre at the University of Southampton. The project was also partially funded by the Technology Strategy Board in the UK.

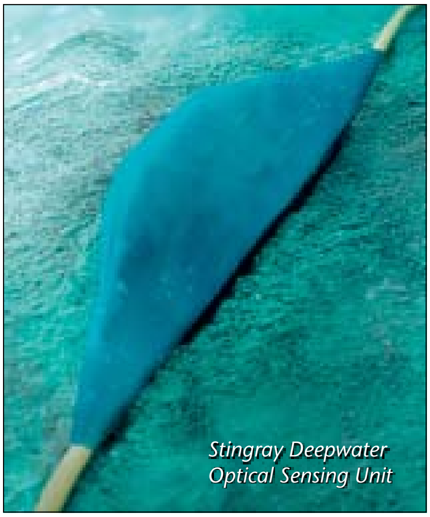
The rise in remote and unmanned platforms and the growth in subsea tieback technology have also spurred on Stingray's determination to deliver signals from the installed array to a host facility over long distances. Working with the University of Southampton, Stingray has achieved this up to a distance of 500 km – a significant development for operators as they look to optimise topside equipment use in deepwater fields.

In addition, the efficient optical architecture of Stingray's systems minimises the number of connectors required, improving reliability and reducing cost.

Finally, the efficient power use and low space requirements of the topsides recording system (potentially up to seven times smaller than alternative solutions) is also particularly attractive to deepwater operators, where platform space and power is at a premium.

With comprehensive equipment testing under way, FosarDeep is due for completion by the end of 2012. When in operation, the solution will have significant implications for deepwater reservoir monitoring, opening up oil and gas reservoirs previously considered inaccessible and providing deepwater operators with crucial information on production-induced changes in reservoir behaviour while significantly reducing engineering and reservoir risk in deep and ultra-deep water.

MARTIN BETT



Stingray Deepwater Optical Sensing Unit

ABBREVIATIONS

Numbers
(US and scientific community)

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

Liquids
barrel = bbl = 159 litre

boe:	barrels of oil equivalent
bopd:	barrels (bbls) of oil per day
bcpd:	bbls of condensate per day
bwpd:	bbls of water per day

Gas

MMscfg:	million ft^3 gas
MMscmg:	million m^3 gas
Tcfg:	trillion cubic feet of gas
Ma:	Million years ago

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

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

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

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

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

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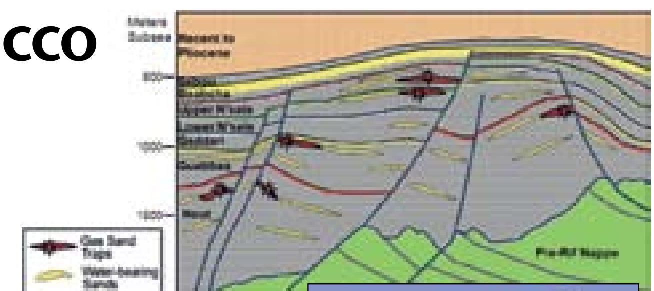
Wellsite Geosciences Service

Weatherford has introduced the Wellsite Geosciences Service, which brings advanced laboratory evaluation techniques to the field, essentially offering a mobile lab. The service incorporates four primary technologies, including the proprietary **GC-TRACER®** surface gas detector and **Source Rock Analyzer** (SRA), to enable in-depth analysis of formation rock and gas samples at the well site. The resulting near-real-time measurements have a range of applications, including estimating total organic content and mineralogically identifying brittle zones to optimise hydraulic fracturing, especially pertinent in shale plays, where such improvements can reduce costs and ultimately maximise production. The surface-based offering can also be used to ensure timely delivery of reservoir data in difficult high-pressure/high-temperature environments. This unique service is available through **Weatherford Laboratories**, the company's global network of geosciences laboratories. ■

Seismic Surveys in Morocco



Circle Oil recently completed a seismic acquisition programme over the Lalla Mimouna and Sebou permits in the **Rharb Basin**, in north-east Morocco. In all 154 km^2 of 3D seismic data with a 12.5m bin size were obtained, along with 22 line kilometres of 2D seismic in the Sebou block, the survey being undertaken by Prospectiuni. The company believe that the results from this survey will reveal a number of potential new drilling targets in the Rharb permits.

Circle's previous seismic campaign proved very successful, resulting in a highly successful drilling programs in the Sebou and Oulad N'zala blocls in 2008/09 and 2010/11, during which 10 gas discoveries were made from only 11 wells. Gross P50 reserves in these blocks are now put at 32.1 Bcfg. The Lalla Mimouna permit has gross unrisked resources of 62 Bcfg with six large 2D anomalies, identified from previous seismic, with further upside potential for up to 215 Bcfg (in place). ■

Free Phone App Tells Geological Time!

A free app for smart phones has recently been launched which provides geologists with an interactive reference tool detailing the subdivisions of geological time from the Pre-Cambrian to the Cenozoic and everything in between. The app, called **GETstrat**, is the brainchild of **GETECH**, the UK-based international petroleum consultancy best known for its unique global gravity and magnetic data holdings and services. It is a searchable version of the International Stratigraphic Chart, the global standard established by the International Commission on Stratigraphy (ICS) as the 'fundamental scale for expressing the history of the Earth'.

GETstrat has a searchable format with additional information of value to the geological community, such as displays for eustacy and magnetostratigraphy. In development, as an accompaniment to the app, is a new micro-site, www.getstrat.net, intended for the geologically-minded to test their knowledge of the International Stratigraphic Chart, as well as links to the ICS, its sub-commissions and GETECH to find out more about their activities. ■

New Surveys for Spectrum

Spectrum, the Multi Client specialist company, continues to expand its range of seismic datasets with new acquisitions. It has recently announced the commencement of two new surveys. The first, in partnership with CGGVeritas and GeoData Ventures, is a 2D survey covering several open acreage blocks in the Sumba Straits, **Indonesia**, an area that has attracted significant industry interest. The prefunded program is planned to cover 1,325 km and will commence early January 2012, with CGGVeritas providing acquisition and processing services. Final deliverables are expected to be available in March 2012.

A second survey, this time in partnership with the National Petroleum Corporation of Namibia (NAMCOR), as well as CGGVeritas, will cover held and open blocks in the deepwater Orange Basin, offshore **Namibia**. The program includes the acquisition of around 7,000 km of long offset data and will be acquired by Seabird Exploration. The data will be processed through full pre-stack time migration and include added-value products such as angle stacks and AVO products.

Only fifteen wells have been drilled so far offshore Namibia in an area covering more than 500,000 km^2. Seven of these are in the Kudu gas field which was discovered by the first exploration well, Kudu 9A-1, drilled in 1973. Due to the frontier nature of the area, a 'Fast Model' Pre-Stack Depth Migration (PSDM) sequence will be provided as part of the standard deliverables for the project, expected to be available in June 2012.

In addition to the new data, over 20,000 km of high-quality 2D Multi-Client data from offshore Namibia is already available through Spectrum, in eight individual surveys. ■

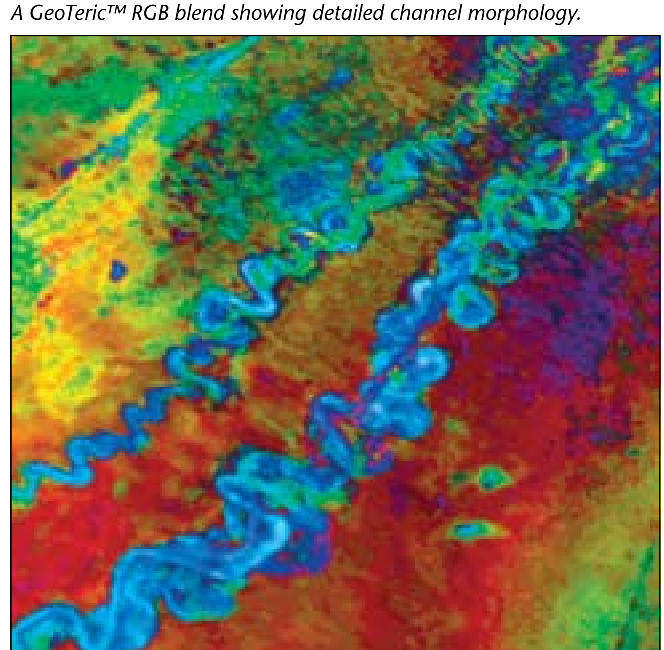
New Workflow Software

ffA provides innovative 3D seismic analysis software and services to the oil and gas industry, with the aim of extracting geological features from 3D seismic data objectively and more rapidly than with conventional techniques. To further that aim, it celebrated the beginning of 2012 with the global launch of its new seismic interpretation workflow software, **GeoTeric**™. The software directly translates geophysical data into geological information, by focussing on bringing out the geological expression captured in seismic data.

GeoTeric accesses the best post-stack techniques for reducing the noise level in seismic data whilst preserving or even enhancing the information content, before using an extensive and flexible range of techniques for examining the geological information with the best possible resolution. This information is then visualised, using the highest dynamic range 3D seismic visualisation system on the market, in order to reveal all features, both dominant and subtle, in the data. It can then be analysed and converted into forms to be taken into the next stage of the workflow. GeoTeric contains ffA's Adaptive Geobodies™ technology, an intuitive, highly interactive and very robust tool for geobody delineation.

ffA believes that GeoTeric bridges the gaps between seismic processing, interpretation and 3D modelling, giving geoscientists and engineers the power to make better decisions with higher confidence, in less time. ■

A GeoTeric™ RGB blend showing detailed channel morphology.



The Zagros Uplift

"We climbed for most of that day, conquering step by step the Morvarid Pass, only to drop down again, having reached the top; and as evening fell we came down on the lovely valley of Deh Diz, with its single sentinel poplar and a ruined castle in the distance, and the long ridge of the snowy Kuh-e Mangasht beyond. Our camping-place this time was in an orchard of pomegranates, beside a clear mountain stream, on a grassy terrace strewn with rocks and boulders."

Vita Sackville-West, Twelve Days in Persia: Across the Mountains with Bakhtiari Tribe (1928)

RASOUL SORKHABI, Ph.D.

The quote above from a famed British writer's travelogue is an expression of mankind's natural attraction to the majesty and serenity of high mountain landscapes. The Zagros Mountains form an important segment of the Alpine-Himalayan orogenic ('mountain-building') system that originated from the closure of the Neo-Tethys Ocean and the collision of Africa-Arabia-India continental plates with Eurasia. Studies of Zagros are important for a variety of reasons. Firstly, this active mountain range of colliding continents provides a natural laboratory to investigate how mountains of similar type form. Secondly, the foreland basins of Zagros are home to some of the world's largest oil and gas reserves, and Zagros outcrops exhibit these subsurface petroleum source-reservoir-cap rocks for direct observations at reservoir scale. Thirdly, the Zagros uplift exerts enormous impacts on the climate, landscape development, ecology, earthquake hazards, and cultural history of south-west Asia.

The Anatomy of Zagros

Anatomy helps us to understand the pathways of evolution, in geology as in biology. Mapping of the Zagros Range over the past century has led geologists to divide these mountains into several tectonic belts which run, for most part, parallel to one another along the north-north-west to south-south-east strike of Zagros. These belts are separated by major, generally north-east dipping, thrusts or reverse faults. Internal structural complexity in each tectonic

A summit of Zard Kuh ('Yellow Mountain' in Persian), 3,972m, in the High Zagros, exposing Jurassic and Cretaceous carbonate sediments dipping north-east.

Dr. M. Fakhari

zone definitely exists and detailed examination of many areas remains to be conducted. Nevertheless, the following description drawn on from the works of Jovan Stocklin, Norman L. Falcon, Manuel Berberian, and Mehdi Alavi offers a simplified framework of Zagros, useful for understanding its geologic history and architecture.

The Urumieh-Dokhtar magmatic belt (50-80 km wide) lies to the north-east of Zagros and is composed of plutonic and volcanic rocks which largely formed from the subduction of Neo-Tethys oceanic floor beneath the Central Iran block. Magmatic activity began in the Middle Cretaceous and climaxed in the Eocene (50-35 Ma) but it has continued sporadically to the present day. In places, these igneous bodies are thrust north-eastward over the Central Iranian Plateau. The south-western boundary of the Urumieh-Dokhtar belt, mapped as a thrust zone, is considered by some geologists to be the 'suture zone' (continental plate boundary) between the Arabian and Asian plates.

The Sanandaj-Sirjan belt, named after the two towns to the north-west and south-east respectively, is a highly-deformed and relatively wide (about 150 km) zone which consists of overthrust Paleozoic and Mesozoic sediments (mostly deformed and metamorphosed), and volcanic and granitic rocks. The tectonic origin of this belt is related to the closing of Neo-Tethys.

The High Zagros or Zagros Imbricated Zone is a topographic high and a relatively narrow zone (up to 80 km) of imbricated thrust faults. This zone is bounded on the north-east by the Main Zagros Thrust (or Main Zagros Reverse Fault, initially called "Zagros Crush Zone"), which many geologists have regarded as the Arabia-Asia suture zone because its hangingwall are the Cretaceous-age ophiolites (ocean-floor volcanic rocks) and deep ocean sediments of Neo-Tethys. There is apparently little seismic activity assignable to this thrust zone today. However, the north-western strands of the structure, mapped as the Main Recent Fault, show right-lateral strike movements of up to 200 km. The High Zagros is thrust over the Simply Folded Belt along the High Zagros Thrust, which is exposed to the surface.

Location of the Zagros Mountains in the plate tectonic framework of the Middle East. The plateau of Iran is sandwiched by the Zagros on south-west and the Alborz and other ranges to the north and north-east. The northern belt initially formed by the closure of the Paleo-Tethys Ocean during the Triassic-Jurassic (but was reactivated in the Cenozoic). The Zagros belt was produced by the closure of Neo-Tethys. The south-east boundary of Zagros is often considered to be a fault zone in the Strait of Hormuz (the 'Oman Line'); its north-west boundary, however, is not clearly defined as it merges with several other mountain structures. Geographically, the Urumieh Lake may be considered as the north-west end of Zagros, which then makes this mountain range about 1,500 km in length, but some geologists, on tectonic grounds, extend it some 500 km further north-west to the East Anatolian strike-slip fault - Arabian plate velocities with respect to a fixed Eurasia from Sella et al. (2002, Journal of Geophysical Research, 107,B4: 2081) and Vernant et al. (2004, Geophysical Journal International, 157: 381-398)

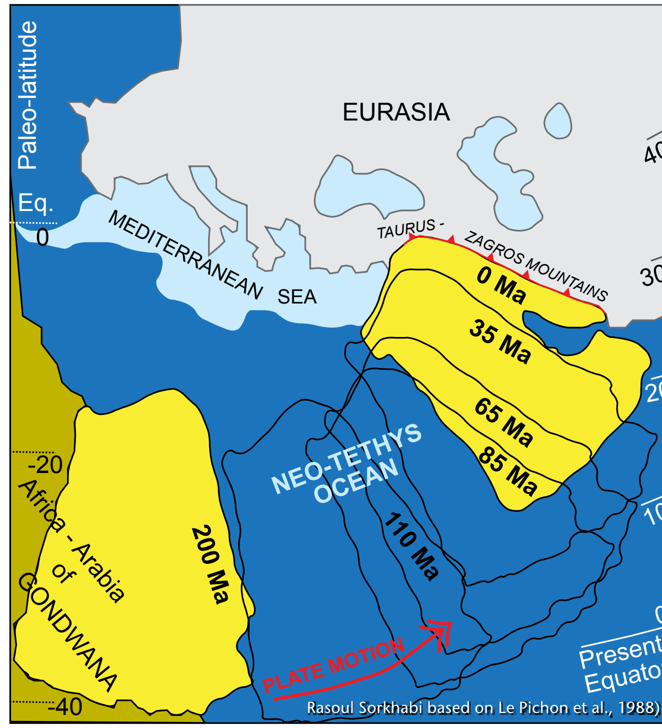
The Simply Folded Belt (also called the Zagros Folded Belt), at up to 300 km the widest zone of Zagros, is dominated by numerous large 'whale-back' and small anticlines as well as localised thrust faults which trend NNW-SSE parallel to the general strike of Zagros. These anticlines are renowned for their petroleum accumulations. The folding mainly occurred during Late Miocene and Early Pliocene times. This belt has also been affected by highly active, north-south trending wrench faults (strike-slip faults across the zone), the largest of which is the Kazerun Fault. The Simply Folded zone is divided into two arc-shaped areas or salients, the Lurestan (or Posht Kuh) arc to the north-east and the much larger Fars arc to the south-west. The Mountain Frontal Fault (Flexure) marks the south-west boundary of the Simply Folded Belt.

Associated with the Simply Folded Belt, there are two particular blocks, the Kirkuk embayment to the north-west and the Dezful embayment to the south-east, which deserve special attention because they contain a large number of oil fields. Although these embayments or promontories have anticlines and thrust structures like the Lurestan and Fars salients, they have experienced much less uplift and erosion. Bounded by active strike-slip faults, they appear as re-entrants in front of the Simply Folded Zagros, and their origin is a matter of debate among geologists studying Zagros.

The Zagros Deformation Front (also

called the Zagros Foredeep Fault) separates the Zagros orogenic belt from the foredeep basins of the Mesopotamia-Persian Gulf which currently receive enormous amounts of sediments from Zagros as well as from the Taurus Mountains in southern Turkey.

As in many other fold-and-thrust belts, the faults that have sculptured the Zagros Mountains are joined at depth to a basal docollement (detachment) fault. In the case of Zagros, this basal decollement is often considered to be the ductile (low-friction) layer of Hormuz Salt at the base of the Phanerozoic sediments. The uniform features and parallelism of anticlines in the Simply Folded Belt indicates such a common detachment horizon at depth. This notion suggests a 'thin-skinned' tectonic style in which the deformed sedimentary cover is detached from the underlying Precambrian basement. While this appears to be the case especially in the Simply Folded Belt, it is conceivable that basement faulting in the High Zagros and beyond has also taken place at deeper levels but that these structures have not emerged to the surface. This is supported by the distribution of earthquake hypocentres. Moreover, the areal extent of the Hormuz salt in the entire Zagros region is not well known; it is possibly absent or insignificant in the north-western parts of Zagros.



Counter-clockwise plate motion of the Arabian Plate from its position in Gondwana at 200 Ma (Early Jurassic) across the Neo-Tethys Ocean to the Cenozoic collision with the Iranian block (Eurasian Plate) to produce the Zagros Mountains. Le Pichon et al. (1988, Geological Society of America Special Paper 218, p. 111-131), who analysed this plate motion history, estimate about 5,700 km of Neo-Tethys ocean floor subduction (since 190 Ma) and 1,020 km of continental collision between Africa-Arabian and Eurasian plates (since 110 Ma).

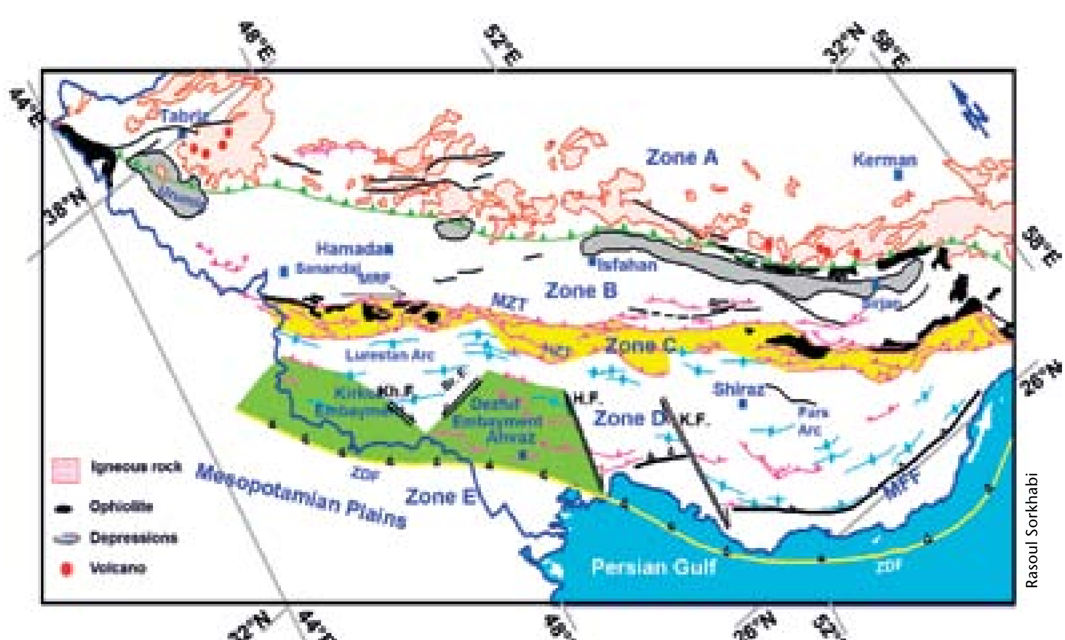
Acts of a Zagros Drama

Precambrian basement rocks have not been exposed in Zagros and previous suggestions of Proterozoic metamorphic rocks or granite bodies have been refuted by new data. The deepest wells drilled in the Zagros basin have not reached the Proterozoic basement. The oldest rocks exposed in the High Zagros are of Lower Cambrian sediments at the base of major thrust zones indicating that these structures have cut through the entire Paleozoic-Mesozoic succession. Besides these, the emergent plugs of the Hormuz Salt, abundantly in the Simply Folded Belt, have brought debris of Infracambrian sediments and metamorphic rocks to the surface.

The story of Zagros may be described in five acts of a geologic drama spanning the past 500 million years or so.

Act 1, the longest, is the deposition of vast amounts of sediments on the passive-margin, continental shelf and slope of the Tethys Ocean when Arabia was part of the supercontinent of Gondwana in the southern hemisphere. The thickness of these Paleozoic-Mesozoic sediments is 4,000-7,000m.

Act II begins in the Middle Jurassic when Africa-Arabia started to split from Gondwana and the Tethys oceanic floor,



Structural map of Zagros (between latitudes 38° N and 26° N) showing the major tectono-stratigraphic zones and bounding faults. Zone A: The Urmieh-Dokhtar magatic arc; Zone B: Sanandaj-Sirjan belt; MZT: Main Zagros Thrust (Reverse Fault); MRF: Main Recent Fault. Zone C: High Zagros 'Imbricated Zone'; HZT: High Zagros Thrust. Zone D: Simply Folded Belt. MFF: Mountain Front Fault (Flexure). Kh.F: Khanaqin Fault. Br.F.: Bala Rud fault. H.F.: Hendijan Fault. K.F.: Kazerun Fault. ZDF: Zagros Deformation Front (also called Zagros Foredeep Fault). Zone E: Mesopotamian-Persian Gulf foreland basin (Quaternary plains on the Arabian platform). (Modified after Mehdi Alavi, 1994, Tectonophysics, 229, p. 211-238 Manuel Berberian, 1995, Tectonophysics, 241, p. 193-224).

A fabulous Landsat image (taken on 2 February 2002) of large 'whale-back' shaped anticlines in the Simply-folded Zagros. Such anticlines, home to enormous oil and gas reserves, are large folds produced by Hormuz Salt movement at the base and compressional stresses of the Arabia-Asian collision. The town of Khormuj (with a population of about 35,000) and the Mand River (both in the Province of Bushehr, Iran are visible in the figure. A salt dome has intruded through the crest of the anticline.

being denser, began to subduct beneath the Central Iranian continental block. The partial melting of the subducting oceanic slab produced an Andean-type igneous arc on the Iranian block. In the Late Cretaceous, compressional stresses produced the first deformation in Zagros, notably in the obduction (overthrusting) of ocean-floor slivers onto the marine sediments.

Act III is the head-on continental collision between Arabia and Central Iran, pushing the ophiolites further south-west. Geologists have no consensus on the age of the Arabia-Asia collision partly because of the scarcity of data (especially paleomagnetic-geochronlogic data from key areas) and partly because of different concepts of 'continental collision' for a geologically complex region. Suggestions for the timing of the collision range from latest Cretaceous to the Miocene. This event likely took place (or was completed) at the end of the Eocene, after which both the subduction-related igneous activity and the plate motion of Arabia substantially decreased and there is a widespread Oligocene unconformity in Zagros. It is notable that shallow marine sedimentation (notably the Asmari limestone) continued even after the continental collision, just as it is still continuing in the Persian Gulf.

Act IV is the rise of the Zagros Mountains by compressional stresses and crustal shortening and the south-westward sequential development of major thrust structures. Quantitative studies of the spatial and temporal development of the Zagros structures in various transects and by integrating geophysical and well data and detailed structural-stratigraphic mapping are critical for better evaluation of the subsurface petroleum systems in the Zagros basin. Since the Miocene the rifting of the Red Sea and the Gulf of Aden and the subsequent separation of Arabia from Africa have supplied renewed stress for tectonic deformation in Zagros. Recent studies have also postulated the 'slab break-off' of the subducted Neo-Tethys ocean floor beneath the Central Iran block after the continental collision. This break-off, is considered to have served as a force for an orogen-scale 'thermal uplift' of Zagros in the Neogene, and also as a heat source for the continued volcanic activity in the Urumieh-Dokhtar belt.

Act V (coeval with Act IV) involves the development of a long, wide foreland basin in front of the rising Zagros and the in-filling of this basin with sediments carried by rivers from these mountains. The 'antecedent' pattern of river drainage in Zagros is a remarkable feature. Many (but not all) rivers were already established before new mountains (mainly anticlines) popped up; therefore, the streams continued their flow and valley incision simultaneously with tectonic uplift of mountains. In his classic work *The Zagros Streams* (1965), Theodore Oberlander has documented this cooperation of erosion and uplift to produce spectacular sceneries in Zagros.

Why So Much Oil?

The reasons why the Zagros basin and the Arabian platform are so prolific for oil and gas have been discussed in a previous article in *Geo Expro* (Vol. 7, No. 1). Suffice it to mention a few points in relation to the Zagros tectonics. It is important to note that the Zagros foreland basin did not develop on a Precambrian basement (as it happened in the central parts of the Himalayas) but was superimposed on the shelf and slope sediments of Tethys. The thickness of Cenozoic sediments in

Zagros is 3,000-5,000m. The overburden of these sediments as well as the thickening of the basin by fold-thrusting deepened the organic-rich Mesozoic source rocks to the oil and gas generation window. Moreover, the upper parts of the Zagros foreland sediments are extensive evaporites (Gachsaran Formation) which provide an excellent regional cap rock for petroleum accumulation. Finally, the Zagros tectonic stresses have not only produced large anticlinal and thrust-fault traps for oil and gas pools but also contributed to the fracturing of carbonate reservoirs which dominate this region.

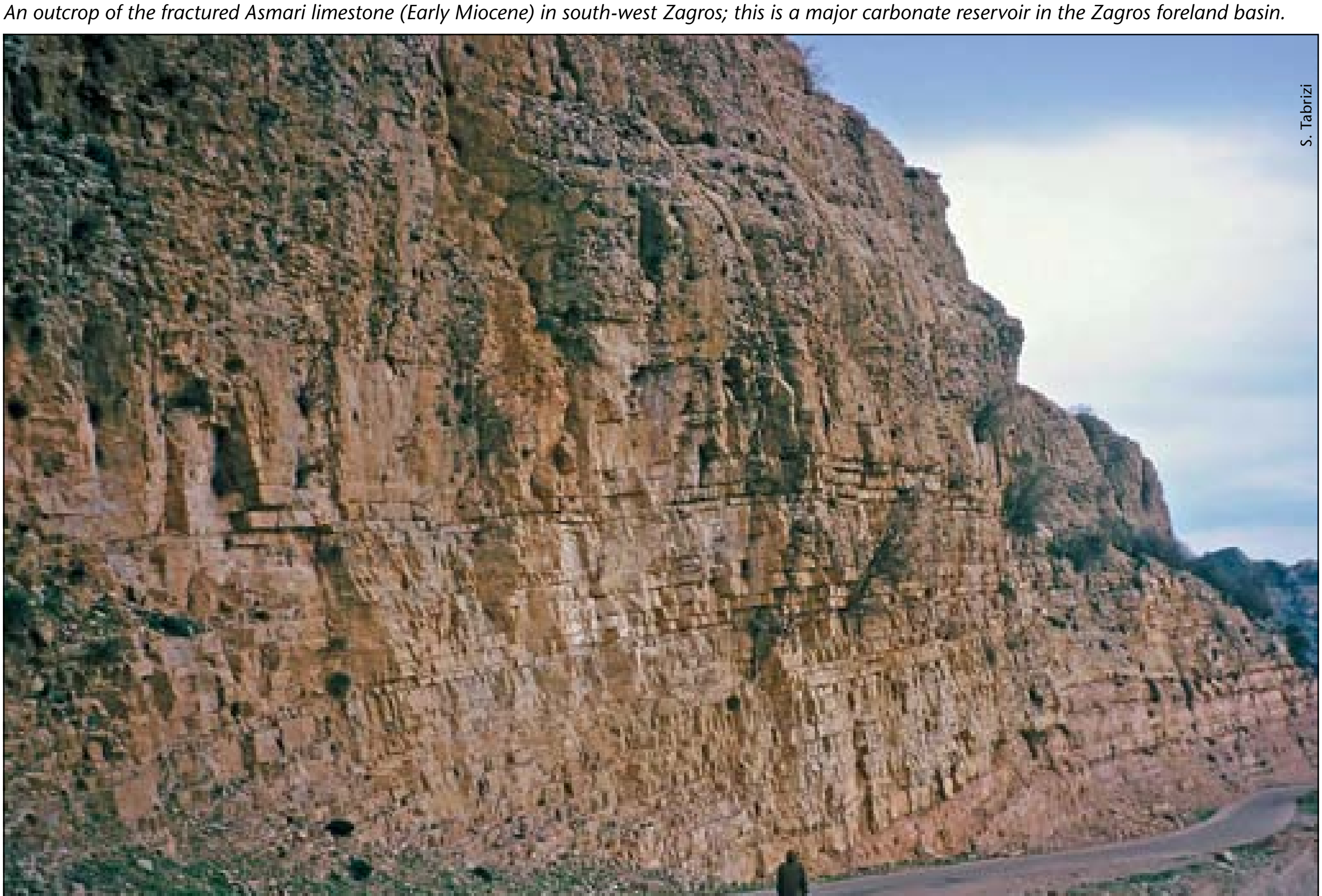
Environmental Impacts

The average altitude of Zagros in its northern and central parts is 2 to 2.5 km while in the south-east it is 1.5 km. Some of the highest summits in Zagros are Zard Kuh (4,548m), Mt. Dena (4,359m), and Oshtran Kuh (4,140m). The Zagros uplift has produced a lofty barrier in south-west Iran against the rain-bearing air currents from the Mediterranean and the Atlantis, thus producing rain shadow and a dry desert climate on the Iranian plateau, but a zone of high precipitation in the foreland. Precipitation is usually higher in the northern and central parts of Zagros, between 300 and 1,200 mm a year, but is reduced to 100-500 mm a year in the southern parts close to the Persian Gulf. Large rivers originating in the Zagros Mountains supply freshwater in that region. These rivers and streams have also created alluvial plains on which some of the earliest agricultural communities appeared some 10,000 years ago (shortly after the last glacial age). The majority of the Zagros rivers flow into the Persian Gulf, such as the Karun River (the longest) which passes through the city of Abadan (where the first refinery in the Middle East was built in 1909-1913). But some rivers drain the interior areas behind the High Zagros; for example, the Zayandeh River which flows through the famed city of Isfahan. Seasonal climate and pastures of Zagros have also motivated nomadic life, most notably of the Bakhtiari tribes about which Vita Sackville-West wrote in her 1928 travelogue.

In 1996, Patrick McGovern of the University of Pennsylvania Museum published chemical analysis of wine stains from 7,000-year old jars found from a mud-brick building in Haji Firuz Tappe (near Lake Urumie) in northern Zagros. This is the oldest winery on record, and it comes from a region where grape grew in the wild.

The story of Zagros has not come to an end. Numerous earthquakes are a (sometime tragic) testimony to the tectonic activity of the Zagros area. GPS measurements of a large network of geodetic benchmarks published in the recent decade indicate that structural shortening and strike-slip motions are taking place at rates up to 10mm/yr in Zagros; these data indicate that almost one-third of the convergence of the Arabian plate (about 2-3 cm a year) is deforming Zagros, the rest of convergence being taken up by the other parts of Iran. ■

An outcrop of the fractured Asmari limestone (Early Miocene) in south-west Zagros; this is a major carbonate reservoir in the Zagros foreland basin.



S. Tabrizi

Paul Wood

Working Under Pressure

PAUL WOOD

Richard Swarbrick with Nigerian trainee Folake Odesanya at the Ikon GeoPressure offices in Durham.

Richard Swarbrick's Ikon GeoPressure team in Durham predicts sub-surface pressures at regional and local scales, vital for the future pursuit of difficult hydrocarbons

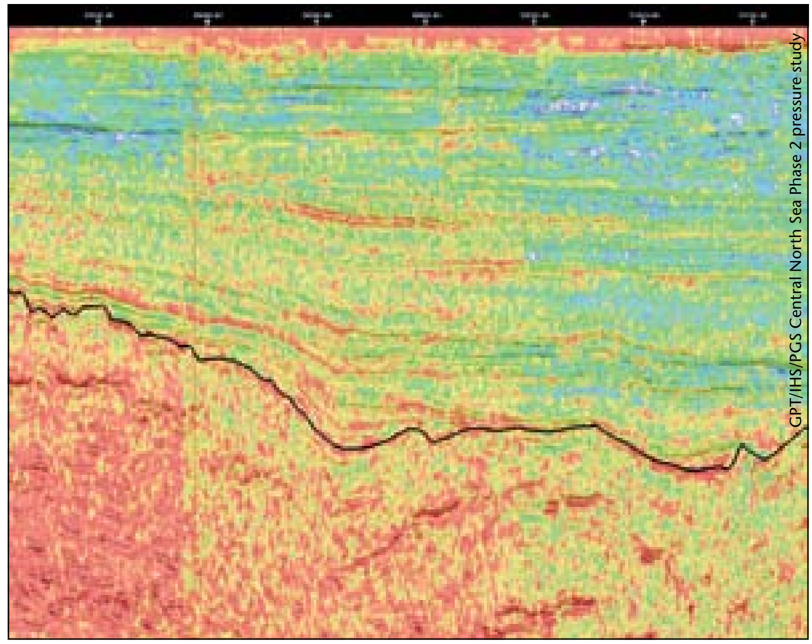
Working under pressure may not be everyone's ideal job, but Richard Swarbrick and his team at Ikon GeoPressure at Durham in the north-east of England are doing it all the time. Or, to be more accurate, working over pressure. Richard studied geology at Durham and Cambridge Universities, then joined Mobil and worked for ten years in the UK and Houston before returning to Durham to teach petroleum geology. During this time at Durham he had a lot of contact with the oil and gas business and realised that, especially in the North Sea, variable and high pressure and temperature conditions in some reservoirs were not only a hazard but a barrier to effective development of the reserves.

Richard reckoned the mix of the commercial oil business and technical discipline of academia he was immersed in at Durham would be a perfect environment in which to develop a more rigorous approach to subsurface pressure mapping. Between 1994 and 2001 he started up and ran GeoPOP, the Geosciences Project into OverPressure which was funded by 17 oil and gas companies. In 1997 he founded GeoPressure Technology, advising E&P companies on how to reduce the risks associated with drilling and assisting with important interpretation and well-planning decisions.

In 2006, GeoPressure Technology became a part of Ikon Science, the company that offers RokDoc, the well known rock physics modelling programme. Richard now leads the GeoPressure division of Ikon Science as Global Director, GeoPressure, but since 2008 has also been an Honorary Professor at Durham University involved in some research programmes. The GeoPressure team has grown from two people in 2004 to ten technical staff at the end of 2011, with a further four associate technical staff in Lagos working on Nigerian projects.

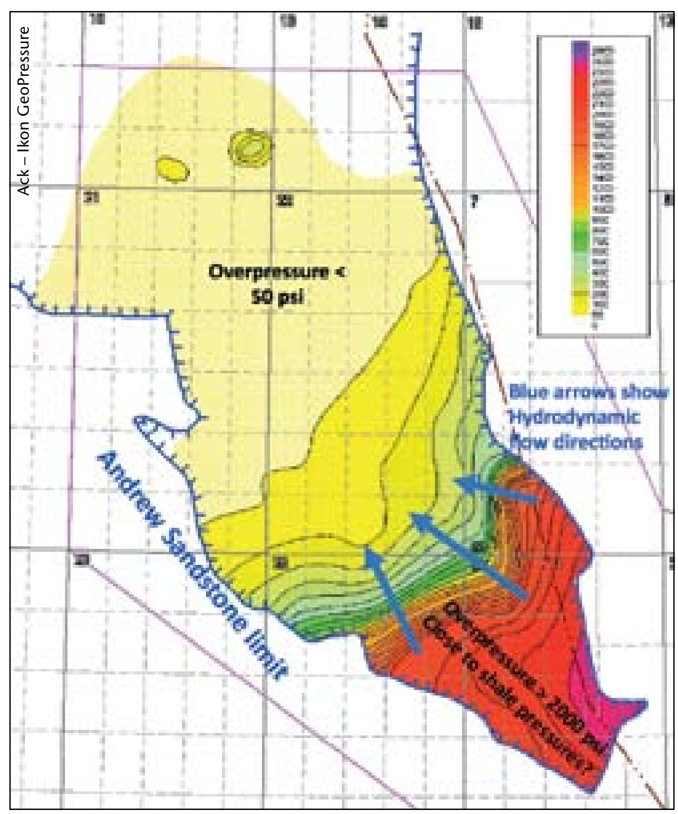
Pressure Prediction Workflow

In 2003, GeoPressure Technology established a robust pressure prediction workflow for the Central North Sea. In the Jurassic and Tertiary formations, fluid pressures are high, requiring high mud weights, but too much pressure in the mud column could fracture the rocks. The resultant narrow drilling window, combined with drilling difficulties in the chalk, meant that pressure prediction was vital and this work soon became the bread and butter of the company. Richard says, "I developed the catch-phrase 'the regional informs the local' to point out that it was necessary to study pressures on a regional scale in order to make specific local predictions." Working from the regional picture and then focusing on the detail, his team established the relationship between regional pressure trends and localised pressure cells.



Diagnostics such as this seismic line identify fluid flow pathways, indications of fluid escape due to seal breach at high pressure.

Regional studies are important because the North Sea, Mid Norway and the Barents Sea are not amenable to using seismic for pressure prediction, a standard method in areas of young, clastic rocks (like sand and shale mixes). Chemical processes destroy the relationship between porosity and velocity. But if there are many wells, perhaps thousands, it is possible to derive trends and then apply them locally once the regional geology is understood in terms of fluid flow.



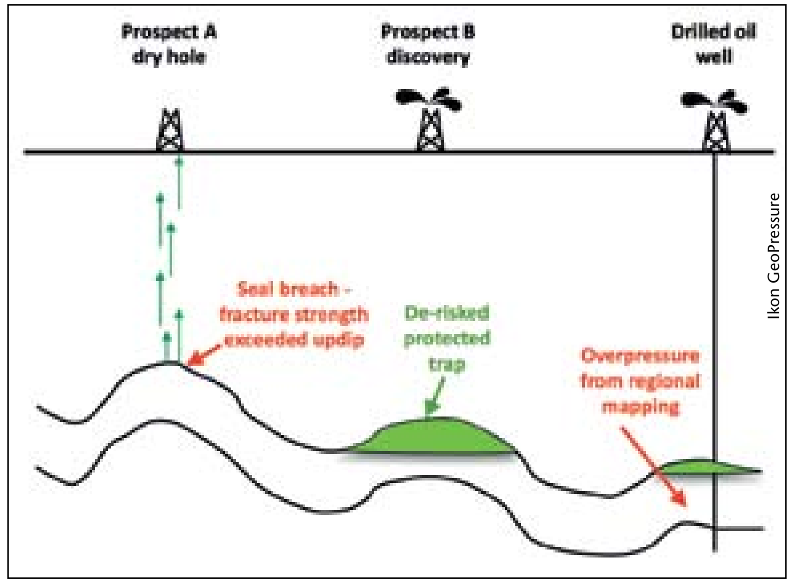
Map of overpressure for the North Sea Central Graben Paleocene Andrew Sandstone based on more than 200 values extracted from well data files. Regular spacing of the contours (psi) supports hydrodynamic flow in this reservoir, with fluid escaping to the north-west.

Hydrodynamic Flow

During this work in deep Central North Sea formations, it was revealed that many reservoirs experience hydrodynamic flow – slow water movement that created tilted hydrocarbon/water contacts. In hydrodynamic systems, oil and gas can be trapped in a different configuration than a 'conventional' hydrocarbon trap with a flat hydrocarbon/water contact. The team has discovered hydrodynamic traps in Paleocene, Cretaceous and Jurassic fields, some of them many years after the fields were originally discovered, where different hydrocarbon/water contacts were previously explained by complex (and most likely flawed) structural interpretations. Examples of hydrodynamic traps which have been inferred using structural models and interpreted by Ikon GeoPressure as hydrodynamic include Ormen Lange (Paleocene, Norway); north flank of Fulmar Field (discovered 1977, Jurassic, Central North Sea); Britannia Field (discovered mid-70s, Cretaceous, Outer Moray Firth, North Sea, published in O'Connor and Swarbrick, 2008).

In 2007, Ikon GeoPressure completed a second regional pressure study, this time of Mid Norway. Although it involved only 200 wells it was a very rich data set. It transpires that the 'normally pressured' sector of Mid Norway may only have been like that since the last glaciation. The majority of the main productive units in the Halten Terrace are normally pressured – the question posed previously was "how can these pressures occur within a regional high pressure system?" The study showed that the Jurassic and Tertiary reservoirs were originally part of the regional high pressure system and only lost pressure within the past 20,000 years. This could have occurred during isostatic rebound after withdrawal of the ice. This observation has led to the recognition of de-pressurisation as a geological phenomenon and not just as a result of depletion from production.

Characteristics linked to pressure such as hydrocarbon migration, sealing or reservoir quality can now be considered in the light of a system losing pressure. This is important for safety when drilling, as it is now possible to model a highly pressured shale overburden above laterally drained reservoirs. Commercially it leads to the possibility of longer hydrocarbon columns than with a normally pressured system. If the locations of the pressure systems are known then it is also possible to predict barriers to migration.



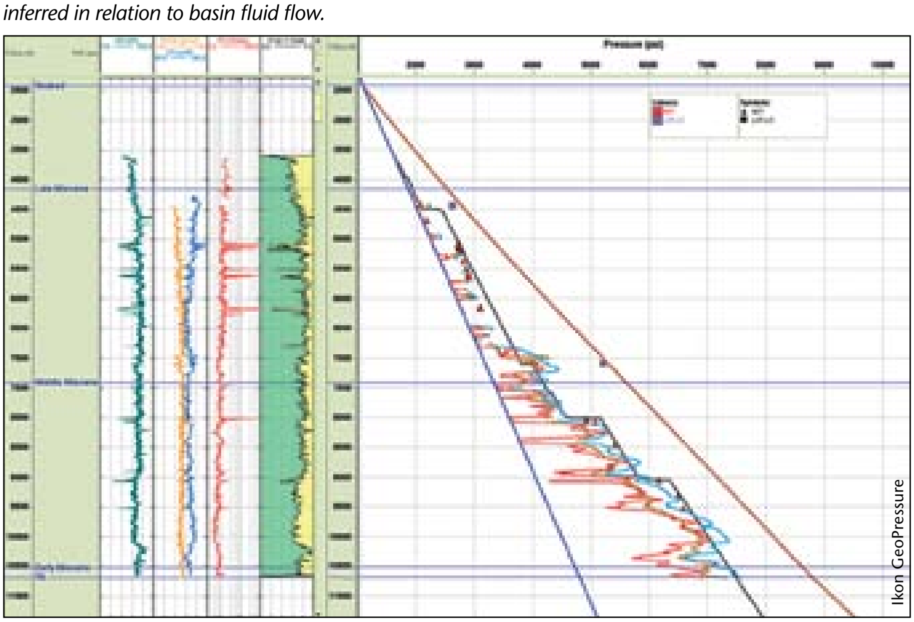
Seal breach analysis relies on regional mapping of overpressure and fracture strength. The shallowest structure in any pressure cell is the pressure valve (Prospect A) and Prospect B has a high chance of success being a 'protected trap'.

Niger Delta Study

In 2010 Ikon GeoPressure started on a pressure study of the deep water Niger Delta area. Richard Swarbrick had presented the North Sea work at a conference in Nigeria, where his overall message was that if you understand the context of pressures and the framework for their distribution then you can focus on safety and commercial aspects. Both of these are paramount in order to exploit deeper prospects in the Niger Delta and have been brought into even sharper focus by the Macondo incident in the Gulf of Mexico, with worldwide ramifications. Six companies pre-committed to the first phase (Deep Water) of the Niger Delta regional study, which allowed the study to be carried out on a regional basis from the start, as data across the Delta were made available by the consortium.

The Niger Delta Study Phase 1 was completed in a year and Richard is very pleased with the technical process and the collaboration with the Nigerian Government and local companies, as well as with the results. Almost all available data (94% of exploration and appraisal wells) were acquired and used and there were no big gaps resulting from the missing wells. The results have been very impressive, providing pressure prediction capability across the deep water region, and showing strong evidence for lateral drainage with implications for hydrodynamic trapping in some connected reservoirs. The pressure study has now started on the continental shelf (Phase 2) and subsequently will examine the swamp and land zones onshore (Phase 3). In both areas the industry is keen to know how to predict pressures in deeper exploration targets below current production levels.

Analysis of a well from the Niger Delta Deep Water area, comparing reservoir pressure data (red triangles) with shale-based pressure prediction using sonic (blue curve), resistivity (red curve) and density (brown curve) data. These relationships are used to determine where lateral transfer and lateral drainage can be inferred in relation to basin fluid flow.

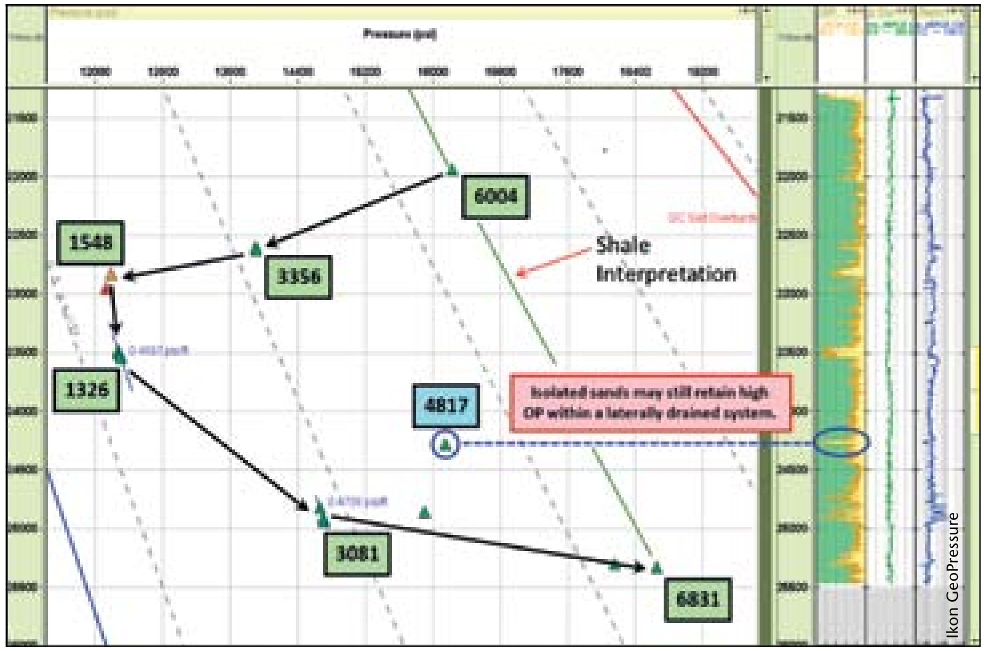


Data Access is Key

The formation of the Niger Delta consortium leads to a question – how much pressure work can be done at an individual company level rather than embarking on multi-company regional studies? As Richard says, "In Norway it may be possible for an individual company to do such work as the data are released after two years. The benefit of using a specialist like Ikon GeoPressure is that the regional work is done once and need not be repeated in-house by all the operators. Analogues are also of great benefit – if work is done in one location, then the results can be taken to another by the specialists."

But in areas like the Niger Delta or the Gulf of Mexico it is unlikely that a full regional study could be done in-house by a single company. Data access is the key and no one company would have access to all the data. A by-product of the Nigerian pressure study is the creation of a comprehensive data repository for almost all of the Deep Water wells in the Niger Delta, a high-value outcome for the Nigerian petroleum industry. In Europe, energy industry consultants IHS

supplied and quality controlled the data for the North Sea and Mid Norway studies, and also for the Barents Sea completed in 2010. Most recently a new West of Shetlands study was finished in late 2011. For the Central North Sea Phase 2, seismic company PGS supplied its mega-merge seismic to help update the model and allow the more detailed, structural mapping of pressure cells.



Pressure-depth plot for a well offshore Gulf of Mexico with overpressure values for each reservoir section indicated in the boxes. The data infer strong lateral drainage focused on reservoirs between 22,800 and 23,600 feet, with higher overpressures above and below.

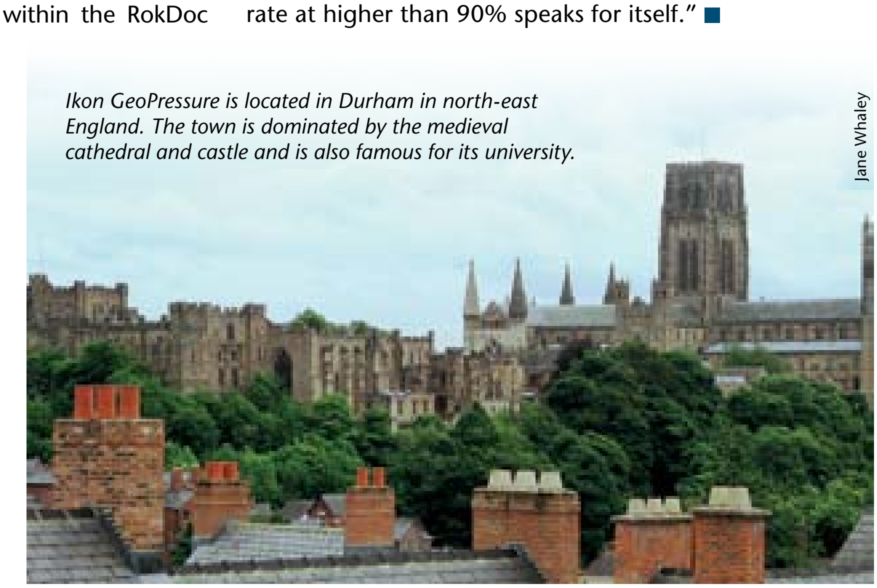
Solving Complex Pressure Problems

Ikon GeoPressure proprietary projects have ranged from the Arctic to the South Atlantic; from Mauritania to Namibia on the West African coast and from the north coast of America to the Far East and Europe. The company's speciality is in solving complex pressure problems where traditional methods do not work very well. The focus is on the geological challenges of carbonates, on high pressure – high temperature (HPHT) prospects, examining complex structures and investigating laterally draining reservoirs. Future regional projects are planned in North-West Shelf of Australia and the east coast of Canada. Are they going to get involved with the growing interest in shale gas? Richard says, "Because of the reservoir tightness, identifying pressure before drilling is almost impossible. But we do know there is high pressure down there too! We can only get drilling parameters and information, not suitable log data. The relationship between pressure and sweet spots is not yet known. 'Difficult conventionals' such as the sub-salt Wilcox play in the Gulf of Mexico look to be our bread and butter for the immediate future."

Richard considers that his original company GeoPressure Technology has derived considerable benefit from joining the Ikon Group as the specialism of pressure prediction can now be developed as part of an overall package within the RokDoc software suite. Seismic is now used routinely to derive 3D pore pressure models supported by interpretations in 1 and 2D models from well data. He says, "The relationship with Ikon allows more integration between rock physics and pressure prediction, which differentiates us as a company." Part of the company's strength is that it has recruited experienced staff from diverse backgrounds and also graduate staff from an international pool to 'grow its own' pore pressure specialists. For the Niger Delta project, Ikon GeoPressure also built a team of five in Lagos to enable technology transfer and build specialist local competence.

The result of building a team of specialists and applying their skills to regional data sets will be an important part of the future pursuit of difficult hydrocarbons. Safety aspects are of course paramount and commercially, implications could lead to improved prospectivity. Prospects could have been missed or drilled in the wrong place, or studies could identify non-structurally trapped hydrocarbons. The studies also look at top seal failure and seal breaches. Looking and exploring within mini-basins for protected traps could lower exploration risks if the pressure relationships are better known.

Richard Swarbrick is very happy with the capabilities he has built in his team and the results they have achieved so far. He sums up: "Our prediction methods are reasonably robust but they are not trivial so they do need specialists. We have analysed the success of our predictions where we know the results of drilling. Considering we focus on the most difficult projects worldwide, our correct prediction rate at higher than 90% speaks for itself." ■



Ikon GeoPressure is located in Durham in north-east England. The town is dominated by the medieval cathedral and castle and is also famous for its university.

Workstations Promise New Life for Geology

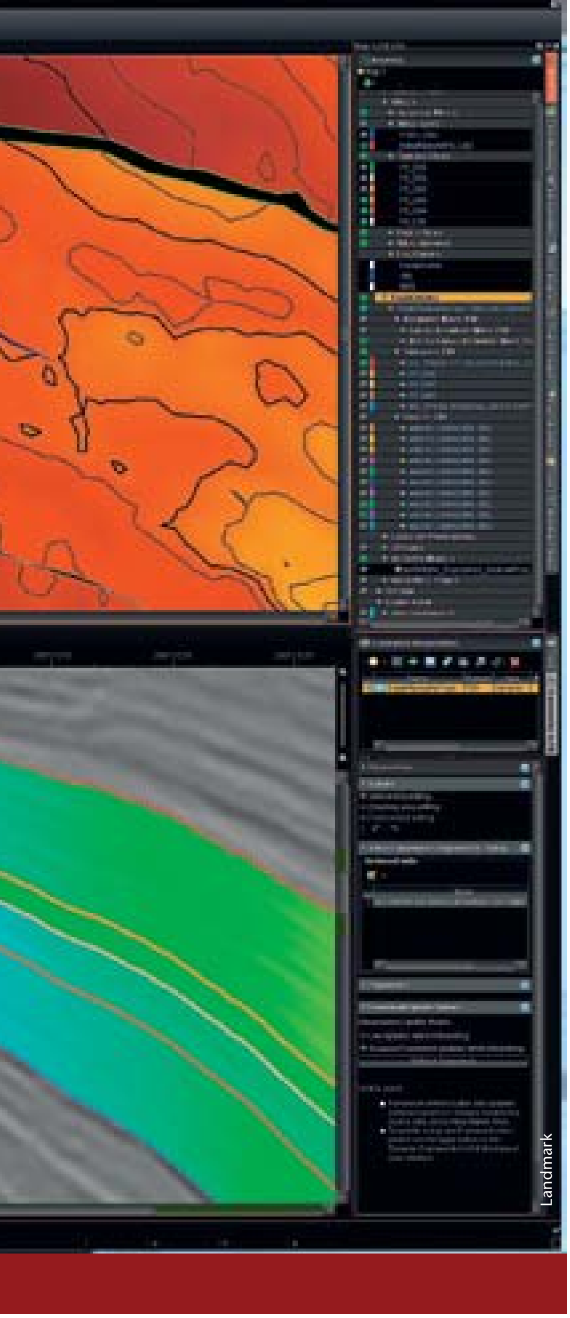
TED MOON

Is the workstation killing geology – or bringing it back to life and having a revolutionary effect on the field – and the future – of exploration and operational geology?

Computer-based geophysics interpretation has come a long way since its inception in the 1980s, giving geoscientists better access to the reservoir and improved accuracy in placing a wellbore. Still, there are some in the industry who feel these technologies have moved too far away from geological first principles, to the detriment of the overall well construction programme. In 2006, former AAPG Distinguished Lecturer Cindy Yeilding of BP gave a popular talk entitled "Is the Workstation 'Killing' Geology?" [1] This presentation, and a subsequent interview in an industry publication, prompted a great deal of discussion within the petroleum geologist community[2].

Yeilding's basic argument was that, given the allure and speed of modern digital workstations, geoscientists sometimes lose track of the geological basics. This may create a tendency to shortcut tenets they relied on 30 years ago, when structure maps were built with paper, coloured pencils and light tables in large workrooms, rather than with computers. In addition, the digital working environment offered by several software programmes did not support best practices based on the first principles of geology.

These limitations spurred the development of Landmark's DecisionSpace® Desktop workspace, an enterprise-scalable, collaborative software package for multi-domain asset teams. The software incorporates proprietary "Dynamic Frameworks to Fill" technology, which allows geologists and geophysicists to follow best practices based solidly on the first principles of both structural and stratigraphic interpretation that



New technologies allow geologists and geophysicists to recreate best practices in the digital environment based solidly on the first principles of both structural geology and stratigraphic interpretation.

were missing from most geological algorithms just a few years ago.

Addressing Workstation Limitations

"Yeilding made several valid points in her argument on the limitations of workstations, but the first principles we have embedded into the DecisionSpace Desktop help offer an equally valid counterargument," says Bill Ross, Manager of Geology for Landmark Software & Services.

The first argument cited was that while digital mapping packages can generate aesthetically pleasing maps, they might not always be geologically valid. "For example, the first computer mapping packages in the 1980s represented a huge step forward in terms of digitising geophysical workflows that had previously been built on paper," says Ross. "But if you more closely investigated the computer algorithms used, you found that the first principles to interpreting and building a structure map were missing." For example, the process by which surfaces were integrated with fault patterns and contours was often not executed in a robust fashion, which may have raised the possibility of essentially drilling in the dark.

The new workstation builds workflows that leverage classic geologic concepts and a topology engine that creates multi-surface 3D structural frameworks from well and seismic data. "During structure map building, it is important to accurately integrate the horizon data with the fault systems," Ross says. "This engine applies robust techniques with respect to the actual construction of those fault/structure relationships, to ensure that they are done properly." The workstation utilises an advanced topology engine, which was previously available only to reservoir modellers, as part of the mainstream interpretation and mapping system.

Conformance is another classic structure-map-building technique available through the workspace. "This concept, which assumes that formation thicknesses vary slowly, is one that structural geologists have been leveraging for decades to build cross sections," Ross says. "We have incorporated this principle into our structural mapping tools to ensure that when you build multiple structure maps simultaneously, a consistent thickness is enforced from surface to surface. This allows one to build very consistent and robust structure maps across fault systems and seamlessly incorporate various unconformities, or sequence boundaries, as well."

Another significant gap in conventional software offerings was the difficulty, or in some cases the impossibility, of making robust stratigraphic interpretations rather than simple structural interpretations. While a great deal of time and effort is spent mapping seismic horizons, the more technically challenging task of capturing observations and interpreting strata between horizons was often neglected by many initial workspace solutions.

The final argument traditionally cited for the negative impact of the workstation on geology centres on the insular work environment it creates. The theory goes that when geologists use a computer – particularly in the current cubicle-based work environment – they have little interaction with their colleagues and tend to stick with a single interpretation, rather than exploring multiple models that honour the data. "The ease and speed with which dynamic frameworks can be created through the DecisionSpace Desktop enables geoscientists to investigate multiple subsurface interpretations, if they wish, without feeling forced to settle for a single model based on time or trouble," Ross counters. "And, it allows them to quickly share these scenarios with their peers, such that real-time discussion and collaboration follows."

Need for Speed

The new workstation also helps address the critical need for speed in current drilling operations. Frameworks can be updated in a dynamic fashion – automatically and in a matter of seconds – as new interpretations are made, new wells are drilled and new reservoir information becomes available.

"Traditionally, geologists have spent up to 80% of their working time on collecting data, conducting the interpretation and finally, building structure maps," Ross says. "If you wanted to add a new fault interpretation to your model, then all surfaces encountered by the fault would have to be regridded in the context of that new fault relationship. This could take many hours or days by conventional methods that require hand digitising of fault polygons on a surface-by-surface basis."

DecisionSpace Desktop automates the creation of fault polygons as the by-product of fault-surface intersections. This permits the geologist to build and update many structural maps in a matter of seconds, not days. Operational geoscientists and asset teams can use these tools and techniques to quickly prepare cross sections and maps for exploration and development drilling. They can carry out reservoir characterisation with fracture mapping, perform rapid volumetric calculations and use dynamic frameworks to update their multi-surface 3D framework with real-time data to assist tricky geosteering workflows.

The real-time data updates from an actively drilling well translate automatically to the real-time updating of all structures. "For example, I can make a change to the shallow surface, which is typically the guiding surface in the conformance relationship, based on the real-time correlations I make while drilling through that surface," Ross says. "The software will then automatically update all the other surfaces beneath it in a cascading fashion. The deep target map, which is where the reservoir's sweet spot is located, will update as well, in real time."

Unconventional Focus

DecisionSpace Desktop is applicable to many types of plays. Deepwater fields, particularly the sub-salt-rich regions in the Gulf of Mexico and offshore Brazil, can capitalise on the software's 3D seismic visualisation and interpretation tools, which include velocity and depth conversion applications.

However, the software has been specifically targeted to the unconventional shale gas plays of North America over the past 12 months. Landmark is developing a new component to DecisionSpace Desktop that addresses the issue of dynamically updating shale gas wells, while drilling, to ensure that real-time adjustments are made to the well's drilling direction such that the reservoir's sweet spot stays in clear focus.

The newest DecisionSpace Desktop development is referred to as "Dynamic Frameworks to Fill", and is comprised of two components. The first is a framework building tool, that creates multiple-structural surfaces and integrates them with new faults and unconformities as they are encountered while drilling.

The second component 'fills' in the stratigraphy between the structural layers based on log- and seismic-derived reservoir properties. "This complimentary portion includes a unique tool for modelling facies distributions as a precursor to reservoir property mapping," Ross says. "We have created 'wizards' within the framework that allow geologists to select from up to 40 different depositional models, which can be plugged into the facies modelling algorithms. This allows geologists to essentially 'paint' onto their 3D cross sections, to show how the facies are varying throughout the distribution in the project area."

Technology Gap Filled

While Yeilding felt the workstation-based geophysics interpretation technology was not fully realised in 2006, she was nevertheless optimistic that one day geoscientists would be able to "create, iterate, collaborate, challenge and capture projects in a completely digital framework".

Ross believes that time has come, thanks in part to the DecisionSpace platform. "Without resorting to arcane, complex modelling software accessible only to a few specialists, operational geologists can now construct robust 3D stratigraphic frameworks, fully integrated with structural frameworks, and based on classic concepts such as sequence stratigraphy, conformance mapping and well established depositional models," he says. "It is no longer necessary to abandon first principles, shortcut the geology or let seismic data have the last word in reservoir development." ■

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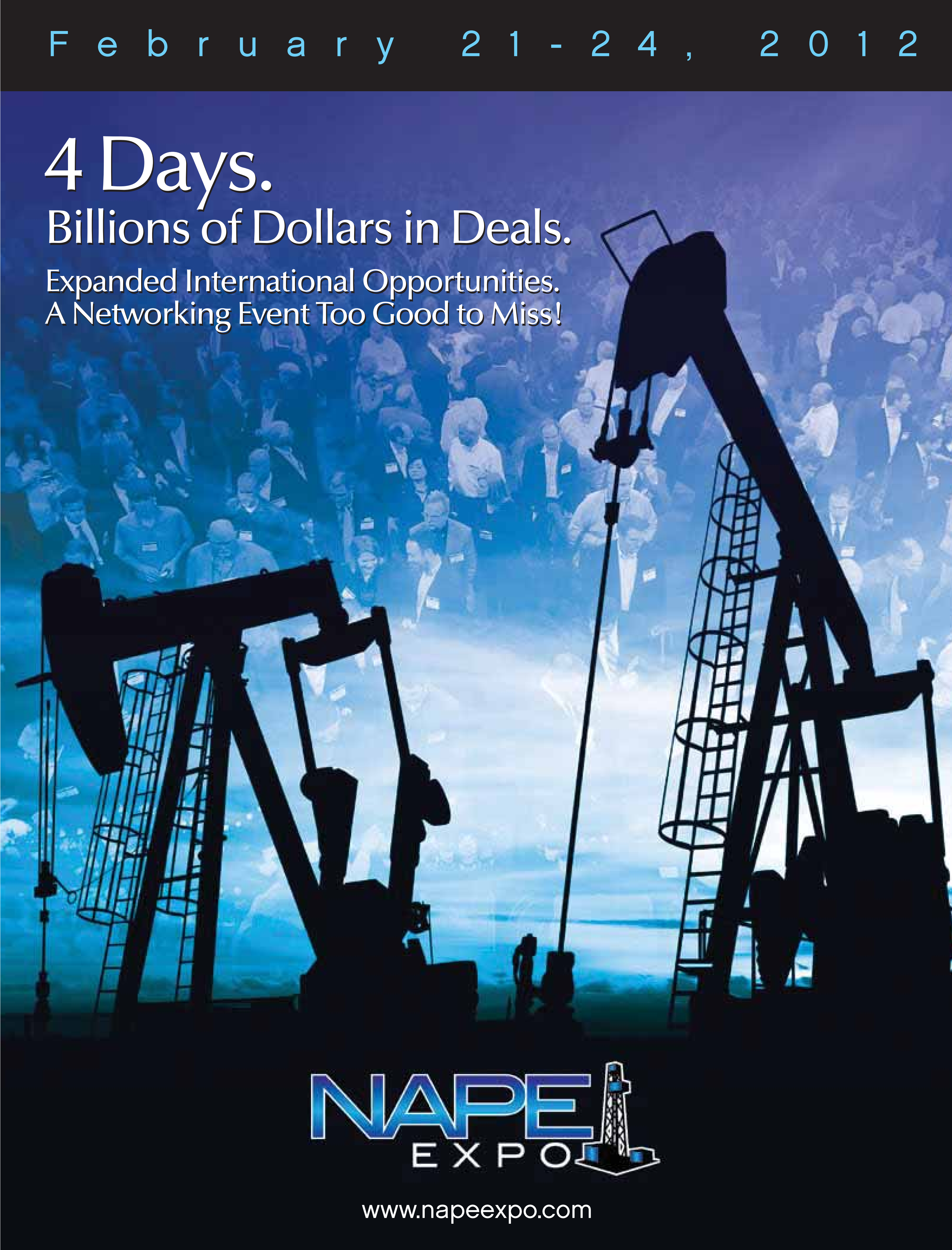
Bill Ross is Manager of Geology, Landmark Software & Services


Landmark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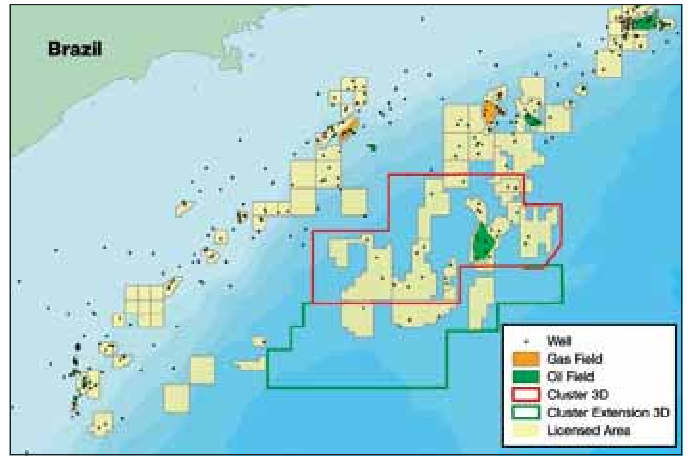
Santos Basin:

Complex salt structures and pre-salt potential revealed by new CGGVeritas 3D data

The CGGVeritas Santos Basin multi-client dataset now extends over 39,000 km² within the Santos Basin. This west–east trending seismic line, taken from the 3D Cluster Extension survey, is an example of the high-quality imaging that has been achieved beneath the salt in this structurally complex basin. The line extends over the Santos Outer High, which is an extensively faulted ridge crossing the basin from north-east to south-west.

RTM depth processing of the pre- and post-evaporite sequences displays clearly the following mega sequence packages:

- *A deeper sequence package, encountered in wells, includes interbedded sediments of volcanic and clastic origin.*
- *A syn-rift package, which can be differentiated into a lower and upper succession, each clearly displaying growth and thickening into extensional faults.*
- *A post-rift sag package which consists of potential pre-evaporite reservoirs, with main reservoir targets of lacustrine coquinas and restricted marine microbial stromatolites.*
- *These are overlain by a thick mobile and layered evaporite sequence. The influence of evaporites can be seen in the shallow section and acts as a detachment for localised compressional thrusts and extensional listric fault features.*



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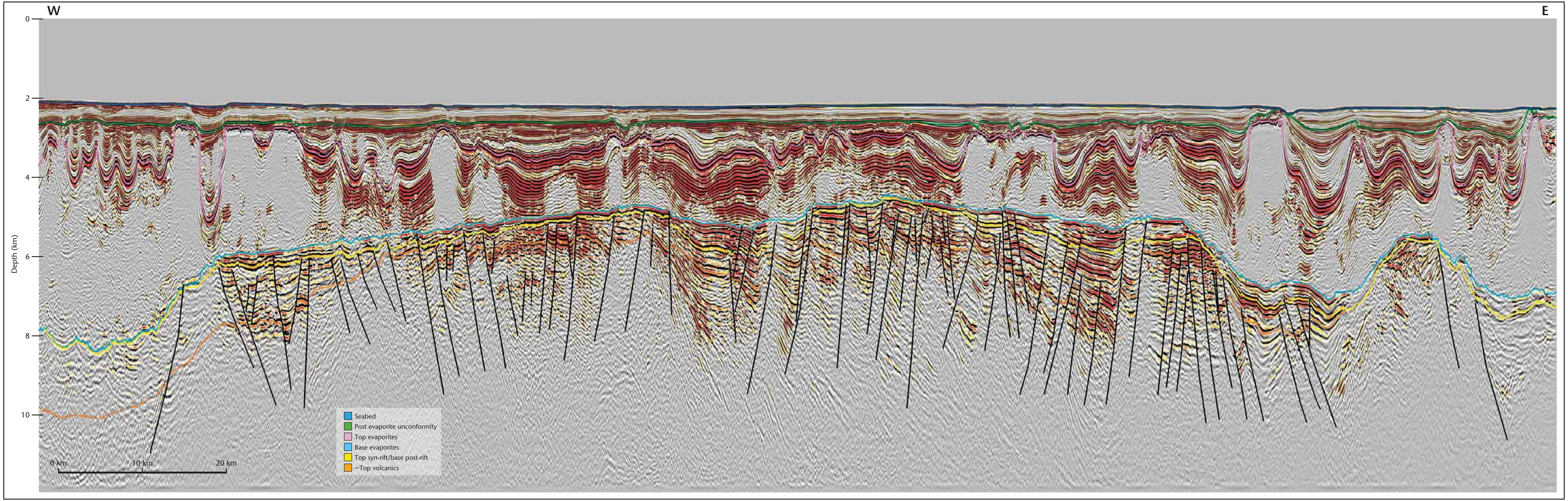


New Geological Insights Into the Santos Basin

New PSDM 3D seismic reflection data over the highly prolific Santos Basin provides comprehensive insight into, and enables a better understanding of, the evaporite architecture and potential pre-salt hydrocarbon reservoirs.

JASWINDER MANN and JAMES W. D. RIGG, CGGVeritas

The deepwater region of Brazil's pre-salt province covers an area of over 122,000 km². It has attracted growing interest for oil and gas exploration with many discoveries, some of them giants, being made in the Santos, Campos and Espirito Santos basins. Still largely underexplored, the Santos Basin has high potential for hydrocarbon exploration, due to its analogy with the neighbouring Campos Basin to the north, based on its similarities within petroleum systems, tectonics and stratigraphic evolution.

New 3D seismic data acquired by CGGVeritas is key in revealing the pre-salt potential in the Santos Basin. The 23,000 km² Cluster Survey covers the major Lula, Carioca and Jupiter discoveries, whilst the 16,000 km² Cluster Extension Survey covers an area with predominantly unlicensed acreage, where, to date, only three wells have been drilled, all of which have encountered oil shows.

Regional Geology

The South Atlantic salt province developed diachronously in the Aptian and consists of a number of basins, separated by deep rifts, and by basement and volcanic eastward-younging highs (Davison, 2007).

Initial rifting of the South Atlantic began with the break-up of Western Gondwana during the Late Jurassic/Early Cretaceous and advanced northwards. The syn-rift phase saw the formation of a number of synthetic and antithetic faults, creating several half-graben which were later infilled with volcaniclastics and fluvio-deltaic sediments. Early syn-rift sediments in the Santos Basin consist of lacustrine shales and sandstones with coarse-grained alluvial fans deposited along the faulted basin borders and rift lakes infilled with fluvio-deltaic sandstones.

A later rift cycle shows a shift to restricted marine conditions with the deposition of organic shales, coarse-grained siliciclastics and coquina shell limestones.

During a period of thermal subsidence, potential reservoirs of microbial and stromatolitic carbonates were deposited in a restricted marine environment. Continuing this period of transition from rift to drift phase the deposition of evaporites occurred in the Santos and Campos basins. The succession starts with Early Aptian siliciclastics to Late Aptian/Early Albian halites and anhydrites (Cainelli *et al.*, 1999). Restricted marine conditions commenced from Albian to Turonian, with the deposition of carbonates followed by turbiditic siliciclastics depicting a hemipelagic environment from Late Cretaceous to Quaternary.

Salt Architecture

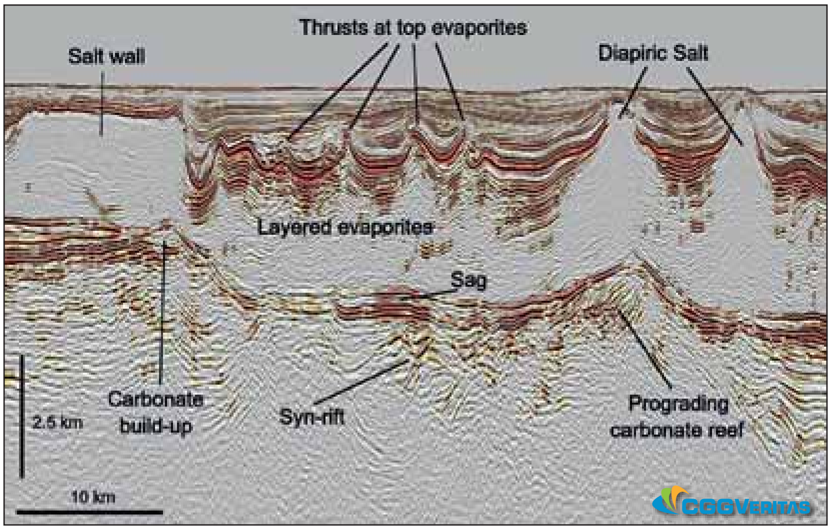
The evaporite package is a reflective sequence of deformed halite, interbedded autochthonous anhydrite and clastic sediments of Aptian age. The top evaporite pick is a strong high-amplitude unconformity known as the 'Enigmatic Reflector' (Davison, 2007) and the majority of the mobile halite appears to be capped by this horizon.

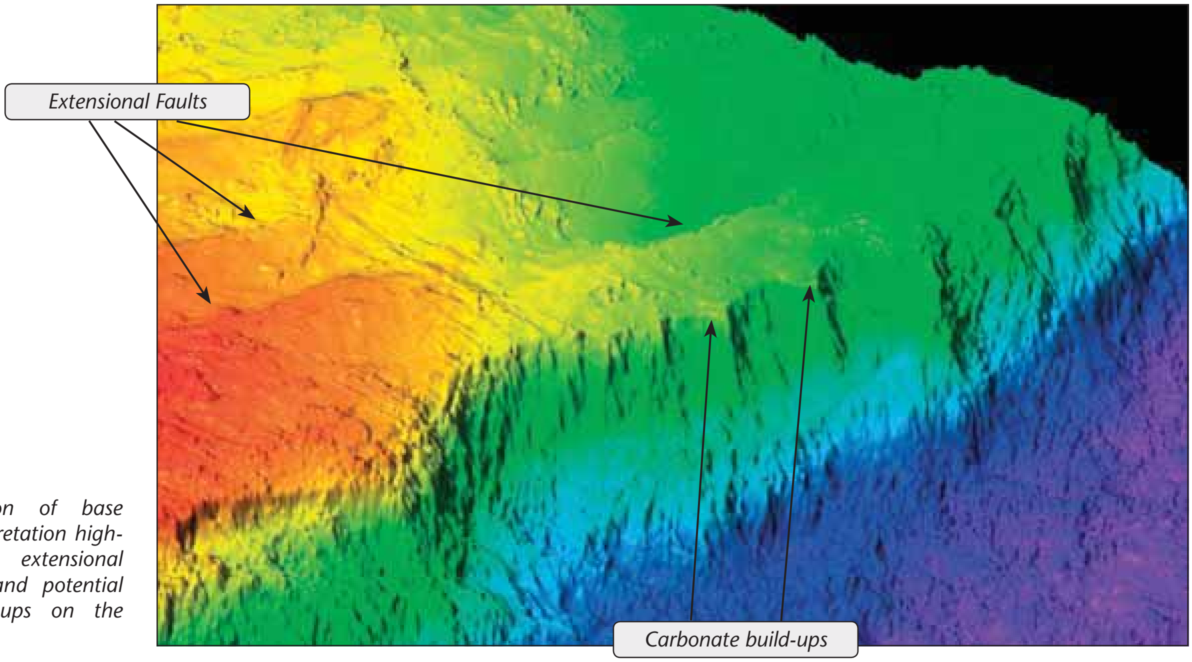
The halite sequence is found towards the base of the evaporite package and appears to pierce through into the layered evaporites and clastics. Regional tectonics and sediment loading by the layered anhydrites is the cause of displacement of the underlying halite, which creates a series of salt walls, folds and diapirs. In areas where halite has withdrawn, the layered anhydrites appear conformable and undeformed as a package, particularly over the Santos Outer High (Gomes *et al.*, 2002). Where the halite forms diapiric structures and salt walls, the anhydrite displays chaotic reflectivity and is highly distorted. Periodic phases of salt movement can be seen through a number of unconformities within the anhydrites and also seen reflected by the present day seafloor.

Sub-Salt

The Santos Outer High is a prominent feature throughout the survey. It has

RTM depth section highlighting pre-salt sequences, carbonate build-ups and post-salt features (CGGVeritas Cluster Extension Survey)





3D visualisation of base evaporite interpretation highlighting linear extensional fault systems and potential reservoir build-ups on the foot-wall uplifts.

a north-east to south-west orientation which is believed to represent the underlying, pre-existing fault trend. The high is comprised of syn-rift siliciclastic and volcanic deposits overlain by post-rift, sag phase carbonate facies. Its crest exhibits irregular topography due to faulting and erosion.

The syn-rift is underlain by volcanic rocks, which appear as high amplitude, parallel to sub-parallel reflectors on seismic. The rift series displays a volcaniclastic base, followed by a sand-dominated interval overlain by a shale-rich sequence and a carbonate-dominated upper section. This package is clearly imaged and faults can be picked into the deepest parts of the section (up to 10 km subsea). The syn-rift sediments are highly faulted and characterised by a series of graben and half graben. Faults have a dip of 24°–39° and sediment displays clear growth into the hanging walls, in places reaching over three kilometres in thickness. The seismic appears dimmer at depths where the stratigraphy is sand-dominated and heavily affected by faulting, in contrast to areas in which the sediment type alternates between sand, carbonate and clay, where the seismic is characterised by high-amplitude and continuous reflectors.

At the base of the sag phase is an unconformity which represents a major change in depositional environment. The sediment package is commonly between 400 and 700m in thickness, with high-amplitude, parallel reflectors. This sequence contains the majority of the discovered pre-salt carbonate reservoirs along with inter-bedded potential source rocks. Syn-rift faults generally terminate at the base of the sag sequence, and where faults pass through to the base evaporite layer no thickening into the hanging wall is seen.

Reservoir Distribution

Basement highs are a key control in the location of potential pre-salt reservoirs. Pre-dating the continental break-up of the South Atlantic, the Santos Outer High, trending across both 3D surveys, was located approximately 200 km from the African and Brazilian continental margins (Gomes *et al.*, 2009). This distal setting and the prominent palaeotopographic relief of the outer high resulted in an ocean-ward clastically-starved shallow water environment, which had a major influence on the distribution of potential pre-salt reservoirs. Prior to the deposition of evaporites within the basin, the likely environment for pre-salt reservoirs is thought to be a transition from a lacustrine to a restricted marine, carbonate platform.

Carbonate accumulations are best developed on faulted basement blocks. Increased subsidence during the sag phase aided the rapid growth of the carbonates and later uplift and exposure may have helped to enhance reservoir quality through the formation of secondary porosity (Gomes *et al.*, 2009). Characteristics of these structures display a clear base structure and pointed crest geometries, with internal layering indicating build-up and progradation. Post-rift stromatolites and microbial carbonates are the producing reservoir in the Lula Field and similar features can be seen across the entire basin and within the new 3D seismic coverage.

The quality of the CGGVeritas seismic data enables a more detailed interpretation of the sub-salt facies, and a greater understanding of basin evolution. There is considerable potential for further discoveries in the Santos Basin, as advanced seismic data, such as this new 3D PSDM multi-client survey, reveals the intricacies of the structure and stratigraphy of this highly prospective basin and furthers the success of pre-salt drilling. ■

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The Great Burgan Field, Kuwait

Second only to Saudi Arabia's Ghawar, the supergiant Burgan field in Kuwait was discovered by a series of wells drilled during 1938-1952. Sitting on a huge structural anticline and occupying an area of 780 km^2, the Cretaceous reservoirs of the Great Burgan field still account for most of Kuwait's oil.

A November 1996 satellite image of parts of Kuwait showing the Great Burgan Field in a desert landscape at elevations of 75-115m. The discovery well Burgan-1 was drilled in 1938. With the development of the oil industry in the Burgan field, Ahmadi City (named after the late Sheikh Ahmad Al-Jaber Al-Sabah who ruled Kuwait from 1921-50) rapidly grew into a large international city. Located about 40 km south of Kuwait City, Ahmadi is home to the headquarters of the Kuwait Oil Company.

Sources: NASA (satellite map); Kuwait Oil Company (photos)

RASOUL SORKHABI, Ph.D.

In 1991, the US-led Operation Desert Storm drew the occupying Iraqi forces out of Kuwait. The retreating Iraqis set fire to over 700 Kuwaiti oil wells, half of which were in the Burgan field. The images of black smoke plumes extending high and wide are well known to the public. But there is more to Burgan's story than that fiery year.

The Great Burgan field lies some 500 km north of Ghawar, the world's largest oil field (see *GEO ExPro*, Vol. 7, No. 4). Burgan ranks second, but since Ghawar is a carbonate field, Burgan is credited to be the world's largest sandstone reservoir both in terms of reserves and production.

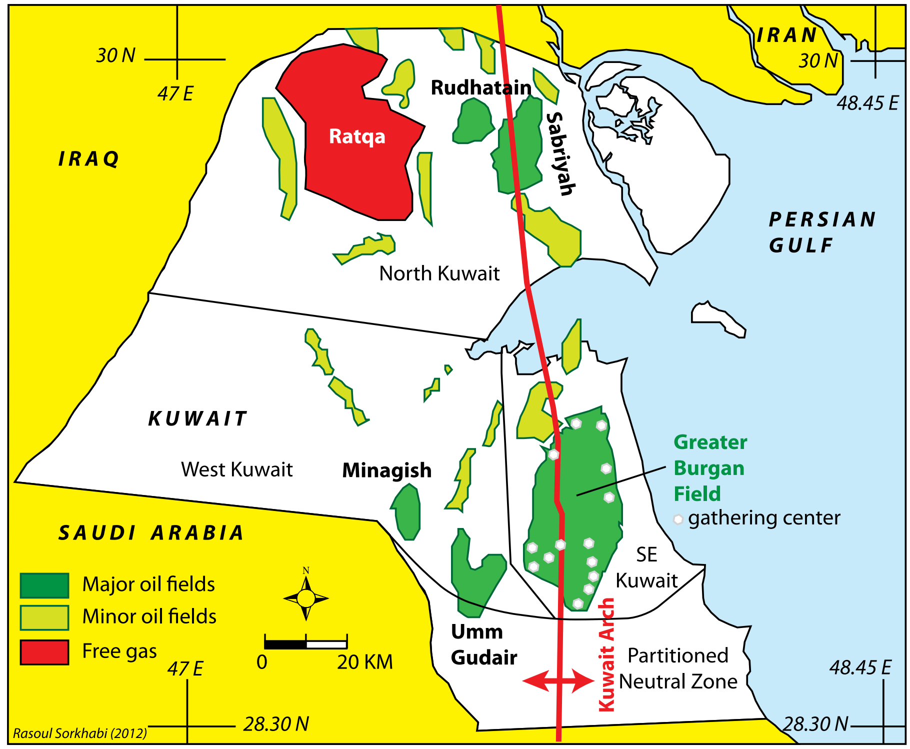
How Burgan Was Discovered

The discovery of the Burgan field dates back to the early twentieth century when Kuwait was in the domain of British influence. After the 1908 discovery of oil in Iran and subsequent formation of the Anglo-Persian Oil Company (APOC), British attention was drawn to the nearby land of Kuwait which was also rich in bitumen seeps. In 1912, a party of geologists commissioned by the British Admiralty visited the Burgan area, and one of the geologists from the Geological Survey of India, Edwin

Pascoe, reported the existence at Burgan of a gently-dipping structural dome with bitumen seeps on the surface. In 1913, the Emir of Kuwait, Sheikh Mubarak bin Sabah, also wrote to the British Political Resident in Kuwait about the famed abundant seepages in Kuwait and the possibility of an oil concession for a British entity. APOC dispatched the geologist S. Lister James in 1914 and again in 1917 to survey the seepages in the villages of Bahrah and Burgan, located respectively north and south of Kuwait Bay. James recommended drilling at the sites but it took two decades of on-and-off negotiations before any well could be drilled.

Major Frank Holmes, a New Zealander who had helped set up the Eastern and General Syndicate in London, was the moving spirit behind oil explorations on the Arabian Peninsula during the 1920s and 1930s; he even had an Arabic title, ‘Abu Naft’ (Father of Oil). In 1924-25, Holmes hired a Swiss geologist, Arnold Heim, to survey Kuwait and eastern Arabia, but Heim’s geological report was discouraging. Then, in 1925-26, APOC sent its geologists to Kuwait, and they also gave it a low ranking for oil prospects. In 1927, the American company Gulf Oil bought Holmes’ concessions (although Holmes still retained his job); this motivated APOC to enter the oil game in Kuwait afresh. For several years, both Gulf Oil and APOC held separate and competing negotiations with Sheikh Ahmad Al-Jaber al-Sabah of Kuwait, and the Emir was willing to play one side off against the other in order to get a better deal. Those were the days of the Great Depression: global demand for oil was low, and the rulers in the Persian Gulf region were in dire need of new revenues to offset the diminishing pearl industry. In 1933, APOC and Gulf Oil decided to put aside rivalry and act as a single entity. They registered a joint venture, the Kuwait Oil Company, in London, and offered a new deal to the Emir of Kuwait. In December 1934, Sheikh Ahmad al-Jaber signed an oil concession for the entire 16,000 km^2 of Kuwait for a period of 75 years in return for royalty.

A team of geologists started working in Kuwait in the hot summer of 1935. They recommended drilling at Bahrah; but a 2,423m well into the Cretaceous sediments drilled during 1936-37 yielded minor oil shows only. Meanwhile, gravity, magnetic and seismic surveys were conducted in



The Great Burgan field in the south-west part of Kuwait has 14 gathering centres for the oil produced from the giant field.

the Burgan area, and on 16 October 1936 Burgan No. 1 was spudded at a seepage. Sediments below 1,000m had oil shows, and finally, on 23 February 1938 the well hit a high-pressure sandstone unit at a depth of 1,120m. It was a gusher that at last put Kuwait on the world oil map. The reservoir was the Middle-Cretaceous Wara sandstone from which 32° API gravity oil flew at rates of over 4,000 bopd before the well was controlled with great difficulty and completed on May 14 at a depth of 1,126m (only 6m into the payzone because of logistic constraints). From 1938 to 1942, eight additional wells drilled in the Burgan field were all productive and yielded new payzones in the underlying Burgan Formation. However, World War II put an end to these operations.

In June 1946, a year after the War had ended, the Emir of Kuwait inaugurated the first shipment of Burgan’s crude from the Mena al-Ahmadi terminal, some 24 km east of Burgan. By the end of 1950, there were 99 productive wells in Burgan pumping 344,000 bopd. Also in 1950, oil was discovered at Magwa; two years later, a well hit oil at Ahmadi from the same Cretaceous sand units. In 1953, wells at Magwa and Ahmadi came on stream, and by 1955, production from the entire field stood at 1 million bopd. Both Magwa and Ahmadi are located on subsidiary domes of the mega-anticline on which the Burgan field is situated. These three structural culminations constitute the Great Burgan field with similar oil-water contacts at depth.

Structure and Stratigraphy

The Great Burgan field is located on the north-south trending Kuwait Arch, which according to George Carman (1996, *GeoArabia*, 1: 239-266) was a basement horst that was reactivated in the Late Jurassic during the break-up of Gondwana. The origin of the Burgan, Magwa and Ahmadi domes located on the Kuwait Arch have been ascribed to movements of the Infra-Cambrian Hormuz Salt at the base of the sedimentary succession (yet to be drilled); nevertheless, some geologists also consider the role of tectonic stresses that have affected this region in Mesozoic and Cenozoic times.

Burgan’s oil producing zones are six Cretaceous-age reservoirs: (1) Wara (topmost) including First and Second Sand (as initially called); (2) the Mauddud limestone; (3-5) The upper, middle and lower units of Third Sand of which the middle unit is a quartz-rich, multi-Darcy porous sand unit and has produced over 75% of the field’s oil; and (6) Fourth Sand (lowermost), which is also quartz-rich and porous. The Third and Fourth Sands belong to the Burgan Formation. This Albian-Cenomonian succession of sediments, about 410m, was deposited in near-shore, shallow water (deltaic, littoral to lagoonal) environments on the gently subsiding continental shelf of the Tethys Sea that once covered the northern margin of Gondwana. A detailed study of sedimentary facies in the Burgan field by Christian Strohmenger and her colleagues (*AAPG Memoir 88*, 2006) show that the sediments have stacks of low-stand, transgressive, and highstand sequence sets controlled by sea-level changes. The Cretaceous play is capped by the Ahmadi Shale on the top of the Wara Formation and is sourced probably from the organic rich shale units of the Lower Cretaceous at the base of Fourth Sand. The generation and migration of oil occurred during Miocene-Pliocene times.

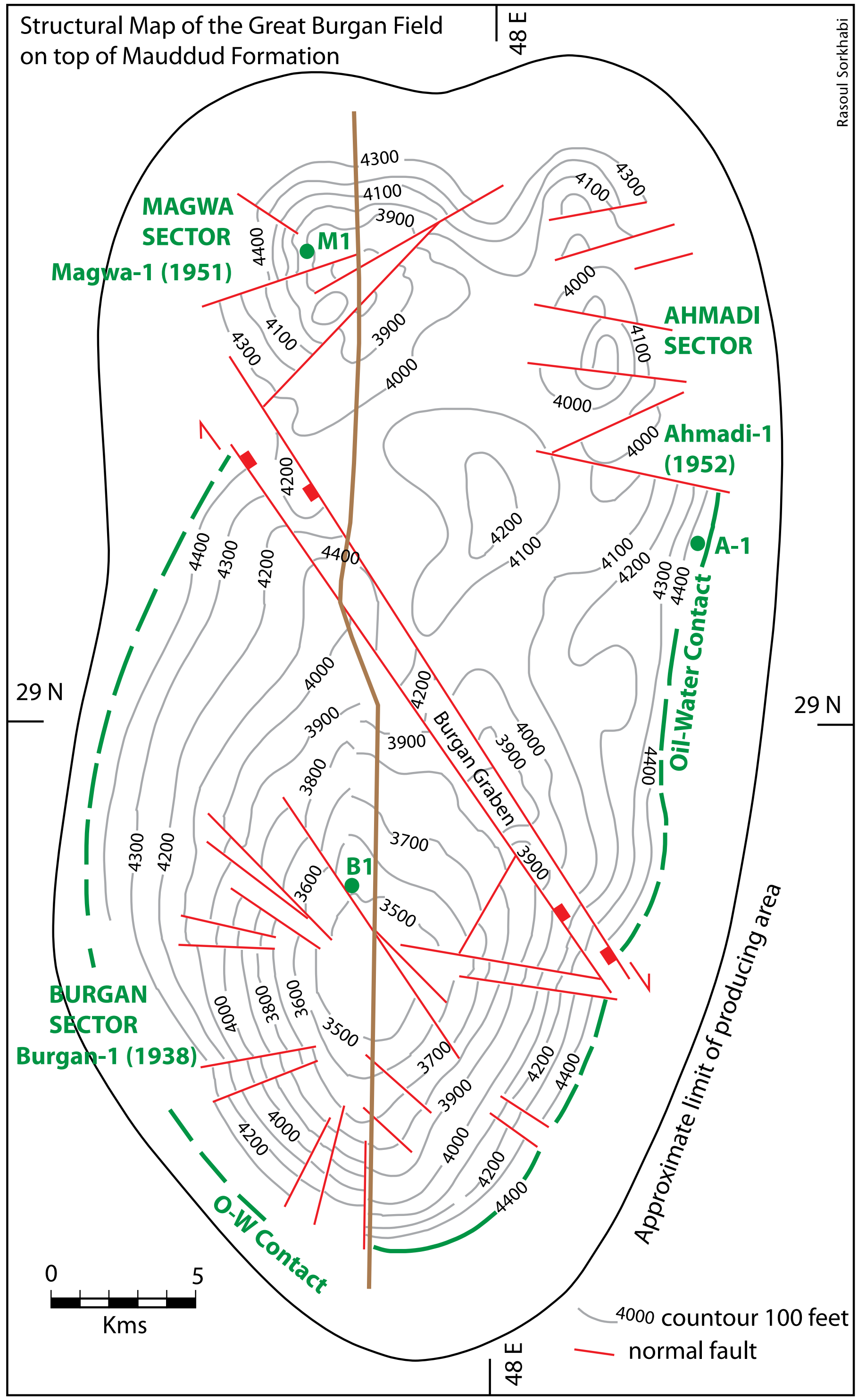
A few attempts have been made to assess deeper plays in Burgan. A 1951 well penetrating the Berriasian-age Minagish Oolite Limestone in Burgan and a 1984 well drilled into a Jurassic carbonate at Magwa both hit oil. Two wells drilled in Burgan toward the end of 1979 penetrated the Khuf (Permian) carbonates at depths of 5,930m and 6,780m but did not discover commercial gas as expected.

Reserves and Production

Like any other Middle Eastern oil field, the reserves and production data for Burgan are shrouded in a cloud of secrecy, uncertainty, and controversy.

In AAPG Memoir 14, Michel Halbouty *et al.* (1971) placed Burgan's ultimate recovery of oil at 66 Bbo with 9.9 Bbo already produced up to 1968. In AAPG Memoir 40, Carmalt and St. John (1986) gave the recoverable reserves as 87 Bboe, including 75 Bbo and 72.5 Tcfg. In AAPG Memoir 78, Paul Mann *et al.* (2003), using data supplied by Petroconsultants (IHS), cited 38.9 Bbo as the ultimate recovery equivalent, including 31.8 Bb of oil and 42.8 Tcf of gas. Brennan (1991) suggests the recoverable reserves to be at least 75 Bbo and cumulative production up to 1986 as 19 Bbo. A report in Bloomberg (10 November 2005) cites 55 MMbo reserves for Burgan; another report in Foreign Policy (14 August 2006) gives an estimate of 66.72 Bbo.

How much of Kuwait's proven oil is in Burgan? According to the annual data published in the BP Statistical Review of



A structural map of the Great Burgan field on top of the Mauddud Formation (modified after M. Adasani,1965, Fifth Arab Petroleum Congress*; P. Brennan, 1999,* AAPG, *Structural Traps I. A description of the structure has also been given by G. Carman, 1996,* GeoArabia, *1). The NNE-SSW trending anticline, measuring 35 by 20 km, is asymmetric with the western flank dipping less than 2° and the eastern flank dipping locally as high as 10°. The field has three structural culminations, known as the Burgan, Magwa and Ahmadi domes. The Burgan dome (the main structure) is to the south, with an area of about 500 km^2 and a high ellipticity of 0.7, delimited on the north by the Burgan Graben, a 1 km wide and 22 km long depression created by two bounding normal faults of 30–150m throw which also show right-lateral movement of about 4 km. The Magwa dome, to the north, is 186 km^2 in area with an ellipticiy of 0.75, while the Ahmadi dome is about 144 km^2 with an ellipticiy of 0.27. The entire field is crisscrossed by dozens of normal faults, some distributed radially around the domes (extensional features related to the growth of the domes) while others are younger tectonic faults. Most are 3–6 km long and have throws less than 15m. It is expected that the field has many other smaller faults below seismic resolution. A 2011 study (Society of Petroleum Geology Paper No. 141553) by Hamdah Al-Enezi and his colleagues at Kuwait Oil Company indicate some of these vertical faults have compartmentalised the reservoirs.*

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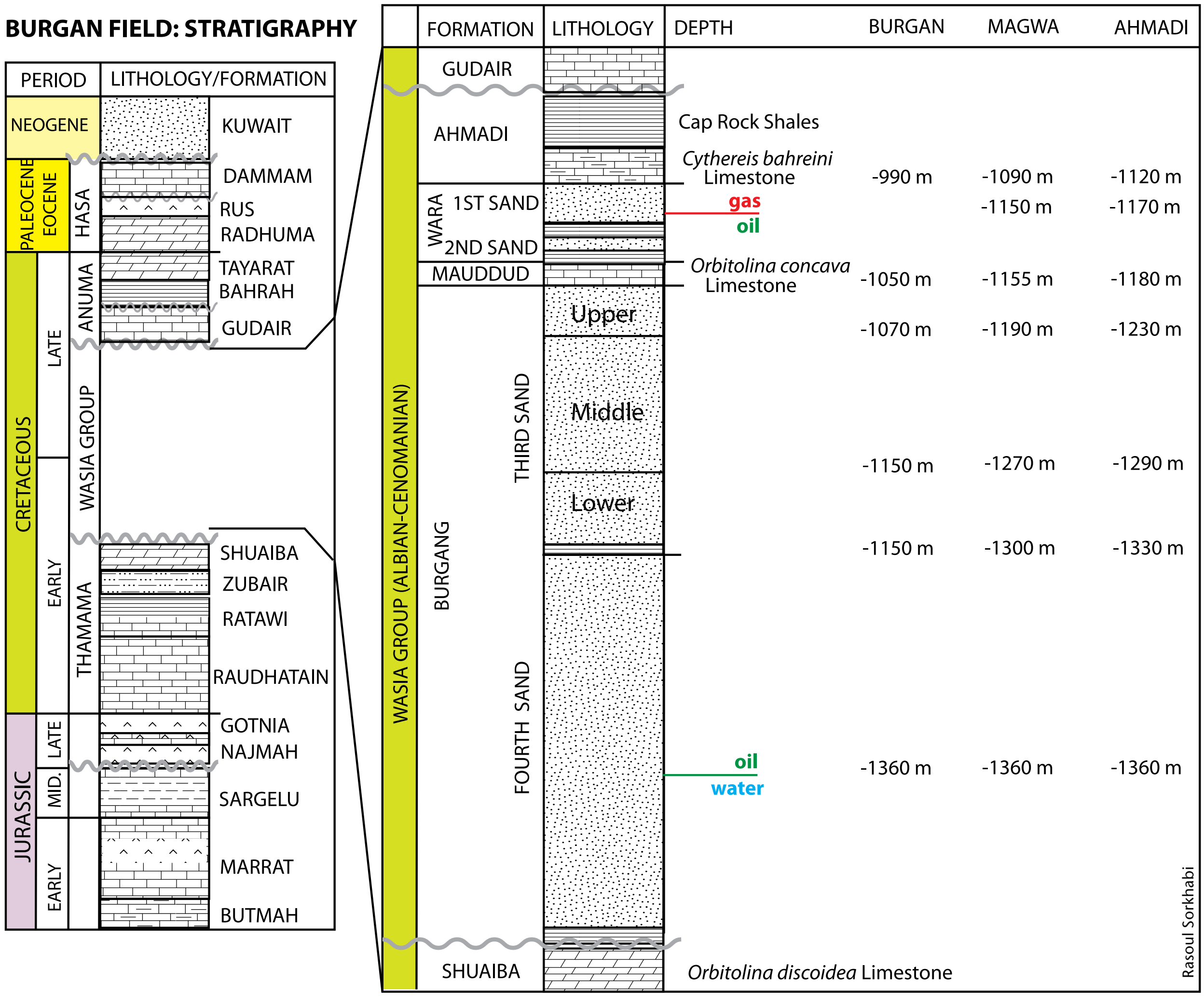
World Energy, OPEC's Annual Statistical Bulletin, and the Oil & Gas Journal, Kuwait's proven oil reserves stand at 101.5 Bb (excluding the Partitioned Neutral Zone with proven oil reserves of about 5 Bb which Kuwait shares with Saudi Arabia on a 50-50 basis); this figure accounts for seven to eight percent of the world's proven reserves. Assuming Burgan's recoverable oil to be 70 Bb, it seems that this supergiant field holds about 70% of Kuwait's proven oil.

Production data from Burgan, even when they are known, cannot be taken at face value to assess the life span of the Burgan field because the production is subjected to not only geological storage but also reservoir management and political-economic considerations. The maximum production from Burgan was 2.2 to 2.4 MMbopd during 1970-73 (with 1972 standing at 2,415,068 bopd). The field's production has declined since then, partly because of market considerations (for example, the production was between 0.5 to 1.0 MMbopd during 1980-86) and partly because of optimal reservoir management practices. In a 2005 interview, Faroul al-Zanki, chairman of state-owned Kuwait Oil Company, was reported as saying; "[To boost oil supply] Burgan itself won't be enough because we have exhausted that, with its production capacity now much lower than what it used to be. We tried 2 million barrels a day, we tried 1.9 million, but 1.7 million is the optimum rate for the facilities and for the economy." (*Bloomberg*, 10 November 2005). In 2010, Sami Rushaid, Chief Executive of Kuwait Oil Company, remarked that Burgan produced half of Kuwait's oil (*Upstream*, 28 June 2010). Kuwait's oil production from 2000 to 2010 varied between 2.0-2.8 MMbopd; in 2010, the production was 2.5 MMbopd, including about 200,000 barrels of non-crude liquids. According to the 2011 country briefing on Kuwait by the US Energy Information Administration, Burgan's recent production is between 1.1 and 1.3 MMbopd, about half of Kuwait's total production; but the field has a production capacity of 1.75 MMbopd.

Past and Future

Thanks to the rich oil endowments of Burgan and other fields, Kuwait, one of the smaller and less populous countries, is now one of the high-income economies in the world. Burgan has been pumping oil for 65 years or so, and like any other oil field, be it large or small, it will eventually be abandoned, but that day will probably be several decades hence. The Cretaceous play in Burgan is still a supergiant field. And with the application of improved recovery techniques, more of the oil in place can be produced. Moreover, the deeper Lower Cretaceous (Thamama Group) and Jurassic oil and Permian (Khuf) gas plays, which are proven and rich productive horizons in the Persian Gulf region, are yet to be rigorously explored in the Great Burgan field. ■

Stratigraphy and reservoir units of the Great Burgan Field (modified after Brennan, 1999, AAPG, *Structural Traps I)*



Denbury Resources Inc

CO_2 wellheads in the Rocky Mountain region

Enhanced Oil Recovery – Utilising Captured CO_2

Can the UK return to oil self-sufficiency?

DAVID BAMFORD

When governments get out of the way, remarkable things can happen.

For example, some industry pundits now say that it is perfectly possible that the USA could become substantially self-sufficient in energy, with huge resources of coal, abundant gas and a transformed oil sector, the latter two being driven by the adroit use of technology. Many aspects that are now common place – 'tight' gas, coal bed methane, shale gas, shale oil, deepwater oil, EOR using CO_2 – were once regarded as 'unconventional', new, full of risk. Indeed, in the next edition of *GEO ExPro*, I will argue that we should drop the term 'unconventional' and simply recognise that, with the appropriate technology, we can extract reservoired hydrocarbons from wherever they may be found.

But this applies to the USA (and Canada) where the efforts made by, and the technology available to, the oil and gas industry are truly staggering.

What about Europe and in particular the UK?

European Energy Policy

At the European level, what passes for energy policy seems to be focussed on mitigating the conjectured threats of climate change rather than establishing how exactly we Europeans are going to keep warm, cooking, moving around and running our industries for the next 50 years. There seems (to me) to be a lot of wishful thinking about the impact of renewables (praiseworthy but marginal) and in so far as a continuing dependence on fossil fuels is acknowledged, an acquiescence to an increasing dependence on imports of coal, gas and oil. The economic, political and security benefits of increasing self-sufficiency do not seem to resonate as they do in the USA.

Because the climate debate has gained so much traction in Europe, it is pretty clear that there will be an increasing focus on gas, the cleanest of our fossil fuels, and we can already see some of the Majors, for example Shell, having at least 50% of its production being gas from now on.

But what other levers are there? I want to link two here.

First of all, 'clean' coal (and gas), which requires the pre-combustion capture of CO_2 and its transport for either storage or utilisation. Speaking recently (19 January 2012), the UK's Energy and Climate Change (DECC) Secretary Chris Huhne said the Government will give every support to a proposed wave of 'clean coal' projects and biomass power plants. Mr Huhne insisted both technologies remain hugely important to Britain as it pushes ahead with efforts to slash carbon emissions by the end of the decade. "Clean coal and gas – taking the carbon out and storing it safely – is going to be a key part of our energy future," he said. "It will allow us to go on using coal, which is not just important here but also when you look at places like China. And it will allow us to go on using gas. There's a lot of shale gas under Lancashire which (drilling firm) Cuadrilla have just said they have found – now we are going to be able to use that in a sustainable way. So CCS is really key, and I am very excited by what's going on up here."

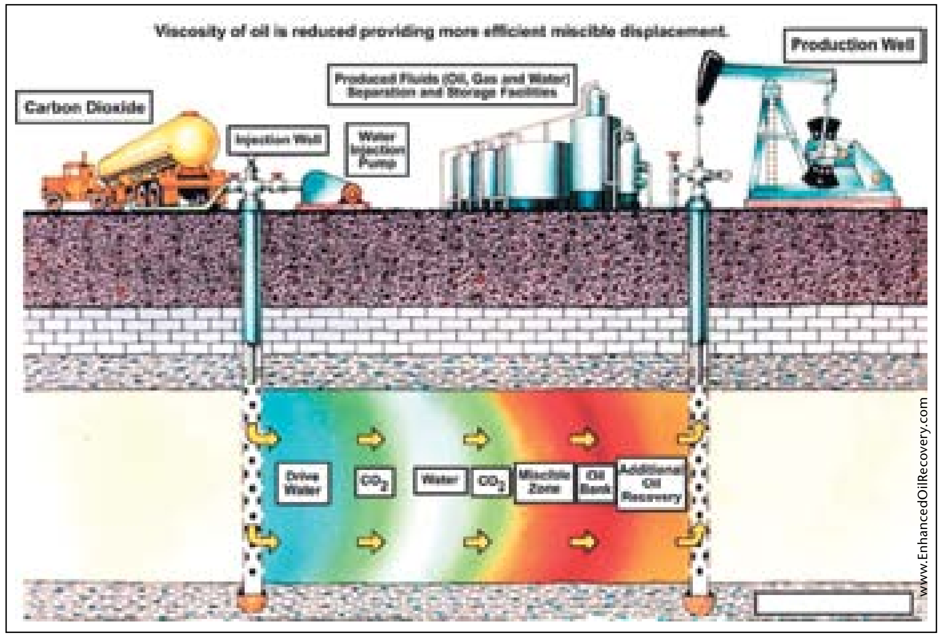
Secondly, enhanced oil recovery (EOR) utilising CO_2 is said to be the most efficient and effective of the improved recovery mechanisms available to us, in comparison to others like steam flood, the use of chemicals, water-alternating-gas and microbials.

Opportunities for CO_2-enabled EOR in the UK?

The UK has a unique position and opportunity – at the moment – because it has a vibrant offshore oil and gas industry adjacent to on-going and planned coal-fired electricity generation. This opportunity was the theme of a Finding Petroleum Forum in London recently, with presentations from 2CO Energy, CO_2 Deep Store, the University of Durham and Altona Energy.

What is the opportunity?

Consider the US analogue first. EOR based on CO_2 is very common, even commonplace. Technical 'know-how' exists in the oil and gas companies, not only in the Majors but in companies of all sizes. Subsurface assets are available. Some 50 million tonnes of CO_2 is injected annually, in miscible and immiscible floods, generating 350-400 Mbopd, or some 5% of US production, with some 1 billion 'extra' barrels recovered to date. Increases in STOIIP recovery factors are in the range 4-12%; some would estimate 'extra' reserves to be as much as 240 billion barrels. Much CO_2 is recycled but it is estimated that 1/3 tonne of 'new' CO_2 is needed per produced barrel of oil; thus a lot of CO_2 is needed. So far, CO_2-based EOR has been applied to relatively low quality, shallow and therefore cool, reservoirs, but significantly better reservoirs are available in the Gulf Coast and offshore.



How CO_2-enabled EOR works

The UKCS has these higher quality deep reservoirs. Again the technical knowledge is available, more concentrated perhaps in larger companies than in the U.S. Also, there is some experience of moving conventional gas around the North Sea, for example from the Schiehallion field to the Magnus field, in the Miller area, and in Morecambe Bay. Although EOR based on CO_2 is untested in the UK, with mainly miscible floods one could anticipate an average increase in STOIIP recovery factors of 5% or more, corresponding to at least 3 billion barrels of 'extra' reserves. As a first step, pilot carbon capture and storage (CCS) projects in the UK could supply between 5 and 11 million tonnes per annum of gas (probably via Humberside) to UKCS Central North Sea fields, by 2020. A field with circa 800-1,500 MMb STOIIP could consume around 80 million tonnes of CO_2 in 20 years and deliver 120-240 Mbo 'extra' reserves.

Costs and Economics

What is the cost base for a complete project, involving a new power station supplying CO_2 to an existing field? The numbers are quite large: about £1.5 billion for a power station plus another £0.5 billion for CO_2 capture, plus £1 billion for a pipeline, plus another £1 billion for modification of the existing field. The total of about £4 billion quickly puts such projects into the realm of needing a Major's balance sheet as well as its financial expertise, and requiring close cooperation between such a Major and a power company.

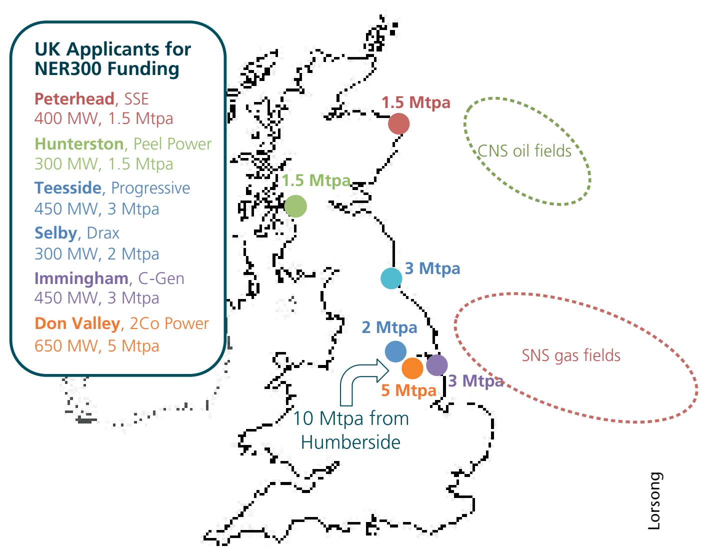
Is any of this likely to be economic?

A good place to start is to say that at current and foreseen gas prices, a 'clean' coal-fired power station, with CCS fitted, is significantly less attractive economically than a combined cycle gas-fired power station, and this seems likely to be so no matter what governments may do about carbon prices.

Thus using CO_2 for EOR delivers an extra, potentially highly lucrative, revenue stream that may outweigh the extra costs of implementation, in particular the costs of upgrading existing oil production facilities, improving pipeline protection against corrosion (CO_2 and water is an especially aggressive mixture) and so on. Also, and very importantly, the utilisation of CO_2 for EOR and then storage at the same site pushes out, perhaps for decades, the moment for decommissioning and its associated costs.

So the economic modelling for an onshore-to-offshore CO_2-enabled EOR investment is relatively sophisticated, and critically dependent on an assessment of the risks involved. As I have indicated, the technology, the technical knowledge, the favourable rocks and the finances all exist in the UK and for its offshore area. The main issue, the main stumbling block, is getting such a project moving when there are potentially

EOR candidates are accessible from proposed CCS projects



so many players – the Majors, big power companies, the UK Government (the Treasury on the one hand and DECC on the other), local government and local communities. The key may be for the UK Government to provide short term funding, perhaps a tax-based incentive, anticipating a future tax stream from increased UKCS oil production. A Durham University study found that CO_2 captured through CCS and used for EOR could lead to £150 billion of 'extra' oil revenue from existing oil fields in the UKCS North Sea, oil that would not otherwise have been produced. This would be of significant economic value to the UK, as it would add around £60 billion in revenue to the UK Treasury, as well as also having tangible political benefits, moving in the direction of energy self-sufficiency once more.

Stepping right back, the European response to these issues is incoherent and there is a risk that the Majors who know how to do these things will walk away and focus on projects that are more completely under their control. In this context we can understand Shell's decision to continue building global CCS capacities with a number of demonstration/research and industrial scale projects worldwide but to concentrate on those where it is in sufficient control to mitigate risks, can find supportive governments, and focus on driving unit CCS costs down. A good example is its >1 million tonne CO_2 per annum CCS project in Alberta, in connection with its oil shale mining, with regulatory and financial support from the governments of Alberta and Canada. Perhaps this is a model for how things might work in the UK?

There should be a sense of emergency. This opportunity exists at the moment but the other side of the decommissioning coin is that the age of abandonment in the UKCS is almost upon us – too much dilly-dallying and the existing infrastructure will have all but disappeared.

A Global View

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

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 and gas fields. For the UKCS's oil fields, CO_2-enabled EOR will be a key tool.

It should be emphasised that increasing recovery factors depends on a range of technologies – surveillance and 'smart' wells as well as EOR. Nevertheless, worldwide, just a 1% increase in the global average recovery factor represents almost 90 Bbo, equivalent to replacing roughly 3 years of production at current levels: expertise developed in the UK, for the UKCS, would be marketable worldwide. ■

Cuadrilla Resources

Cuadrilla Resources drilling for shale gas in north-west England

FINAL CALL FOR PAPERS

THE 11TH HGS-PESGB CONFERENCE ON AFRICAN E&P

Africa: Continent of Discoveries

September 11-12, 2012
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Short abstracts should be submitted as soon as possible and no later than March 16, 2012 to the technical committee, africa2012@hgs.org. The program will be finalized by end April.

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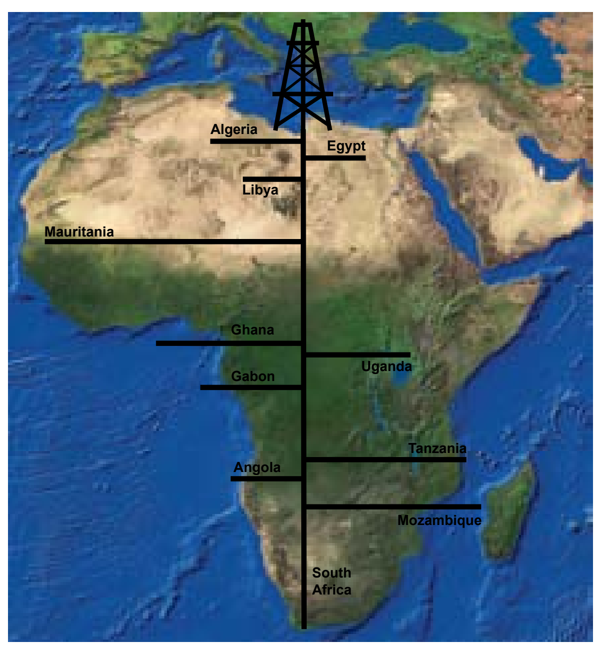
Early bird registration will be available from April 2012. Further details will appear in the HGS and PESGB bulletins and websites.



Conference Committee for 2012: Al Danforth, Ian Poyntz, Martin Cassidy, Justin Vandenbrink, Lucy Plant and Claudia Lopez (HGS), Ray Bate, Richard Dixon and Duncan Macgregor (PESGB).

From Trickle to Gusher: The Bakken Oil Story

Discovered in the 1950s, North Dakota's Bakken Formation oil production was just 1,500 bpd in 2004. Today, it exceeds 440,000 bpd and is expected to be 700,000 bpd within the next few years

THOMAS SMITH

The Bakken is one of a growing number of shale formation success stories, thanks to new, innovative technologies that make unconventional plays possible, as well as to the constant quest of the oil and gas companies to find new reserves. The increase of Bakken oil production in North Dakota has come within the past five years. In the beginning of 2007, North Dakota had 303 wells producing 12,000 bopd. By early 2009, that number had risen to 904 wells producing 106,000 bopd. Jump to November of 2011 (the most recent date published for North Dakota) where 3,118 wells were producing 443,425 bopd. The North Dakota Department of Mineral Resources predicts that oil production from the Bakken and Three Forks Formations will exceed 700,000 bpd in the next four to seven years.

North Dakota is not the only area currently with Bakken production. Neighbouring Montana, where the present oil boom originated (see *GEO ExPro* Vol. 7, No. 2), has been producing a steady 64,000 boepd. Further north in Canada, production is 75,000 boepd. In total, there are around 5,700 producing wells, with about 2,000 new wells to be drilled this year.

Huge Potential

A recent report prepared for the U.S. Department of Energy by the Energy and Environmental Research Center (EERC) at the University of North Dakota in Grand Forks, North Dakota, had this to say about the Bakken: "It is expected that the play will continue to expand to the south-west (into South Dakota), newly develop in the north-eastern and north-western corners of the basin in North Dakota, and fully develop in between… Currently, only about 15% of the play has been drilled, and recovery rates are less than 5%, providing a significant future of wells to be drilled and untouched hydrocarbons to be pursued through improved stimulation practices or enhanced oil recovery."

This potential has not been missed by companies operating in the area. At the last count there were at least 82 operators, and new ones are continually added, including Norwegian giant, Statoil, which entered the region in 2011. One of the most aggressive is the play's largest lease holder and Bakken oil producer, Continental Resources. Their spokesman, Brian Engel, states, "The field could have up to **24 billion barrels** of technically recoverable oil… the [2008] USGS estimate was

David McNeese

Across a broad area of North Dakota, drilling for Bakken Formation oil has reached a blistering pace, with an average active rig count of 200.

Oil companies have just 'started to scratch' the surface of the gigantic play covering the eastern portion of Montana (MT), North Dakota (ND), and possibly South Dakota (SD) in the U.S. and north into the Canadian provinces of Saskatchewan (SK) and Manitoba (MB).

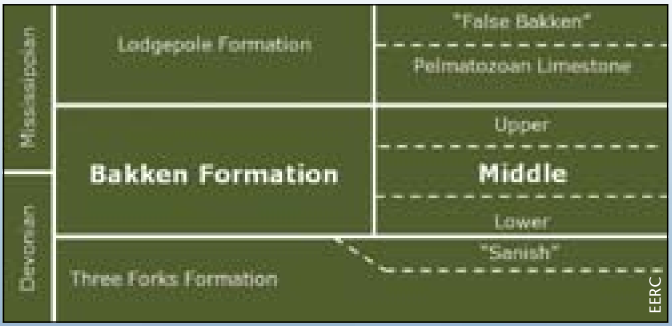
fair and reasonable given the data available at the time of its report. Like Continental, the USGS utilised existing producing Bakken wells to estimate ultimate oil recoveries per well and the effective drainage area. The difference between the estimates is that recoveries on a per-well basis have increased substantially since June 2007. Since that time, approximately 1,680 new horizontal producing Bakken wells have been drilled, and these wells have been completed using almost exclusively single leg horizontal and multi-staged fracture stimulation technology."

The USGS has certainly recognised this fact, saying that, "the new scientific information presented to us from technical experts clearly warrants a new resource assessment of the Bakken". To this end, a new assessment got underway in October 2011 and should be out in September 2013.

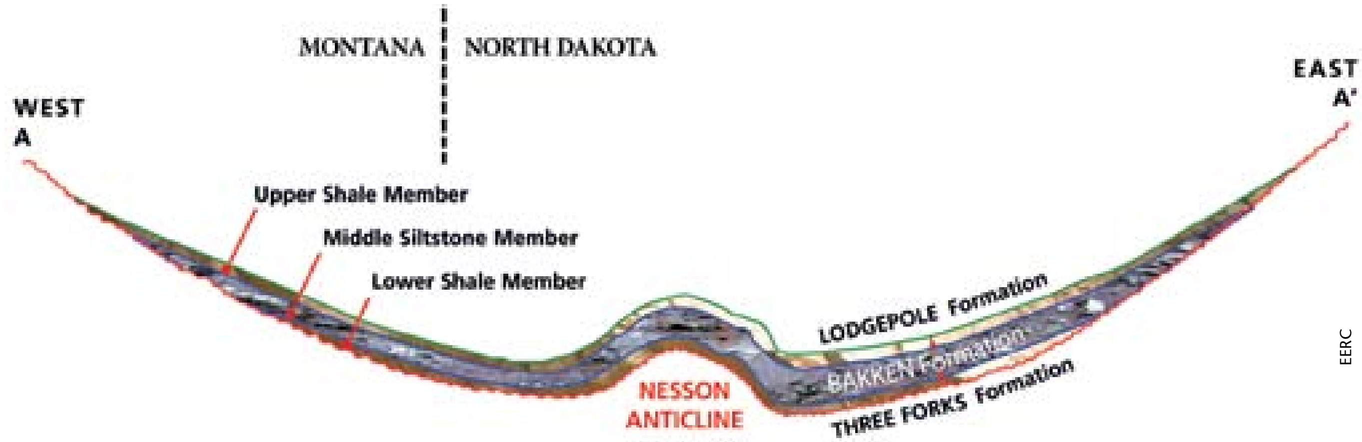
Source and Reservoir

The age of the Bakken Formation straddles the Devonian/Mississippian boundary and it was deposited approximately 360 million years ago. It is contained in the Williston Basin where stratigrapher Lawrence Sloss first proposed his cratonic sequence concept (*GEO ExPro* Vol. 7, No. 2).

The thickest portion of the Bakken (46m) is in north-western North Dakota and it thins evenly south-eastwards toward the margins of the Williston Basin. The upper and lower members consist of hard, siliceous, black organic-rich shales. These form



The Bakken Formation is divided into three informal members and lies between the Three Forks and Lodgepole formations. The upper and lower shale members are world class source rocks. While the middle member is the primary reservoir target, all the units shown are potential reservoir targets, with oil production from the Three Forks Formation growing rapidly.



The Three Forks, Bakken, and Lodgepole formations all pinch out on the flanks of the Williston Basin.

effective seals for the middle member, which consists of five highly variable lithologies, from several argillaceous siltstones to fine-grained sandstone and limestone, all with low primary permeability (0.04 mD average) and porosity (5% average). The other important reservoir target, the Three Forks Formation, consists of shales, dolostones, siltstones, and sandstones with a maximum thickness of 76m.

Depositionally, the Three Forks Formation consists of shallow marine to terrestrial sediments that transition from highly oxidising conditions to the anoxic conditions of the lower Bakken. The middle Bakken sedimentation is associated with the drop in sea level and influx of sedimentary material into near-shore tidal basins and lower shoreface environments. Anoxic conditions resumed during the deposition of the upper shale member, followed by oxidising water conditions during the deposition of the overlying Lodgepole Formation.

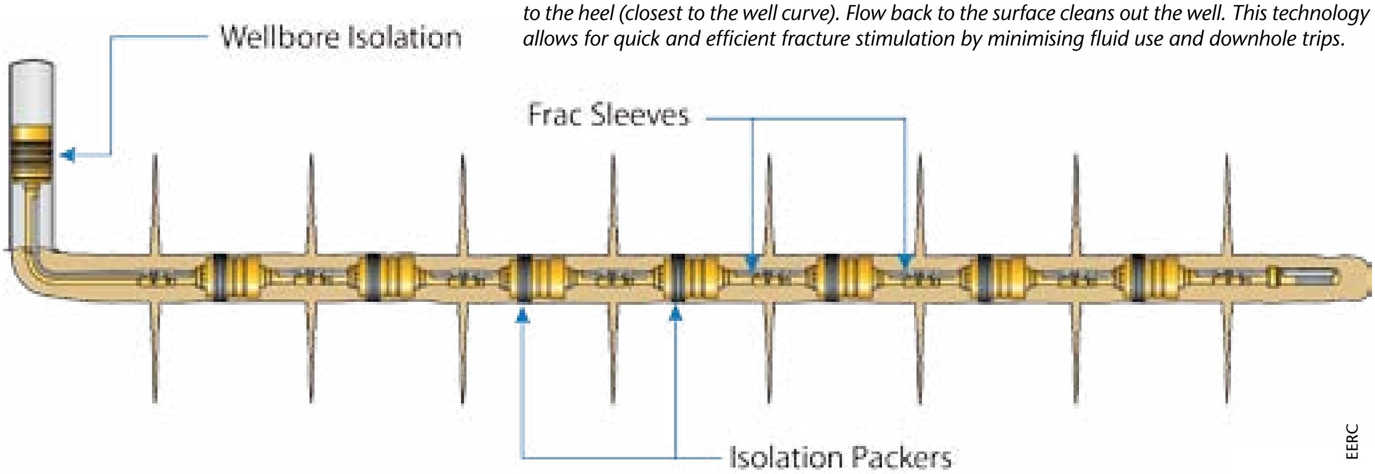
According to federal 2009 testimony from the Director of the North Dakota Department of Mineral Resources Lynn Helms, "Hydraulic fracturing is a critical component of developing the Bakken Formation, indeed every shale play throughout the U.S. and Canada. Without hydraulic fracturing, under regulation of the states, this resource could not be produced."

Completion and Stimulation

Bakken Formation completion and stimulation has come a long way since its first oil production in 1955. The upper Bakken shale member was first targeted for production at the Elkhorn Ranch Field in 1976. Vertical wells were fracture-stimulated with sand and oil. The first horizontal wells were completed in 1987, however the play ended in the 1990s because of low oil prices. The real breakthrough came in 2000 when Richard Findley approached Lyco Energy Corporation to drill horizontal wells in Montana's Elm Coulee Field (see the complete story in *GEO ExPro* Vol. 7, No. 2), targeting the middle Bakken member. The drilled program was a huge success with ultimate recoveries approaching 750,000 barrels of oil.

In 2005, EOG Resources utilised horizontal drilling combined with hydraulic fracturing to recover significant oil from the middle Bakken interval at the Ross Field in North Dakota. At that time the average rig count was 25 and production under

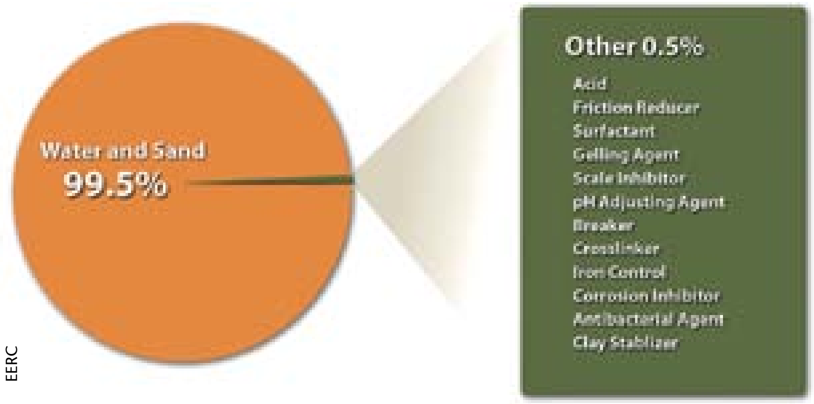
Diagram of the sleeve/packer completion system commonly used for multi-stage stimulations in the Bakken. Ball-actuated sliding sleeves are run inside a liner or in openhole. Ported sleeves are installed between isolation packers on the liner string. A ball pumped down the sleeve will seat in the mechanical sleeve exposing the ports and diverting frac fluids into the formation. Progressively larger balls are pumped down to activate the sleeves from the toe of the well back to the heel (closest to the well curve). Flow back to the surface cleans out the well. This technology allows for quick and efficient fracture stimulation by minimising fluid use and downhole trips.



100,000 bpd. EOG quickly expanded into adjacent areas utilising multistage fracturing of horizontal wells and obtained rates exceeding 500 bpd per well. Completion technology has kept improving and in 2011, Baker Hughes completed a successful 40-stage stimulation (the largest to date) using a fracturing sleeve/packer completion system. Now the average rig count is 200 and production is approaching 500,000 bpd.

The North Dakota wells are completed on 640 acre (2.6 km^2) spacing for 5,000 ft (1,524m) horizontal wellbores to 1,280 acre (5.2 km^2) spacing for 10,000 ft (3,048m) horizontal wellbores. Most wells are oriented in a north-south or a north-west to south-east direction to take advantage of the induced fracture propagation. A cemented liner is required from the surface to the base of the curve to horizontal, to ensure the Bakken Formation is isolated from the overlying formations. From this point a number of different completion methods have been employed. These methods range from a cemented liner throughout the horizontal well bore to openhole completions and combinations of both. The cemented liner completions utilise a 'plug and perf' stimulation that require time to trip perforation guns, but allow specific frac placement in the horizontal wellbore. The openhole completions only allow for single-stage fracturing which provide little control over fracture initiation and propagation. To gain more control in the fraccing process, uncemented, preperforated liners can be used with or without positive annular isolation. The use of swell packers set at various intervals along uncemented, preperforated liners allows for multi-stage fraccing. It is the most commonly used completion method allowing a high degree of fracture control and success in stimulation long-term production.

Fracturing fluids and the size of treatments have varied widely over time. The amount of fluids used in one treatment can be staggering as seen from a 2010 example, where 10,000 horizontal feet (3,048m) were treated with 3.5 million gallons (13.3 million cubic litres) of fluid to place 4.5 million pounds (2 million kilograms) of proppant. ▶



EERC

Water and sand make up most of the frac treatments with additives to give the fluids special properties, like cross-linked gels to better transport proppants into the formation. Proppants, typically sand or ceramics, are used to hold the fractures open and allow reservoir fluids to flow to the wellbore.

Future Growth

Lynn Helms reflects on the oil boom affecting North Dakota, “We’re estimating now about 18,000 mi² (46,600 m²) in western North Dakota, another 6,000 mi² (15,500 m²) in Montana, Saskatchewan and Manitoba that is mature oil-source rock (in the Bakken Formation). It can be drilled up almost (like) an oil-producing factory. We did not drill a single dry hole in the last year-and-a-half.” Later, he went on to say, “We’re very confident that we’ve got a 20-year oil boom ahead of us.”

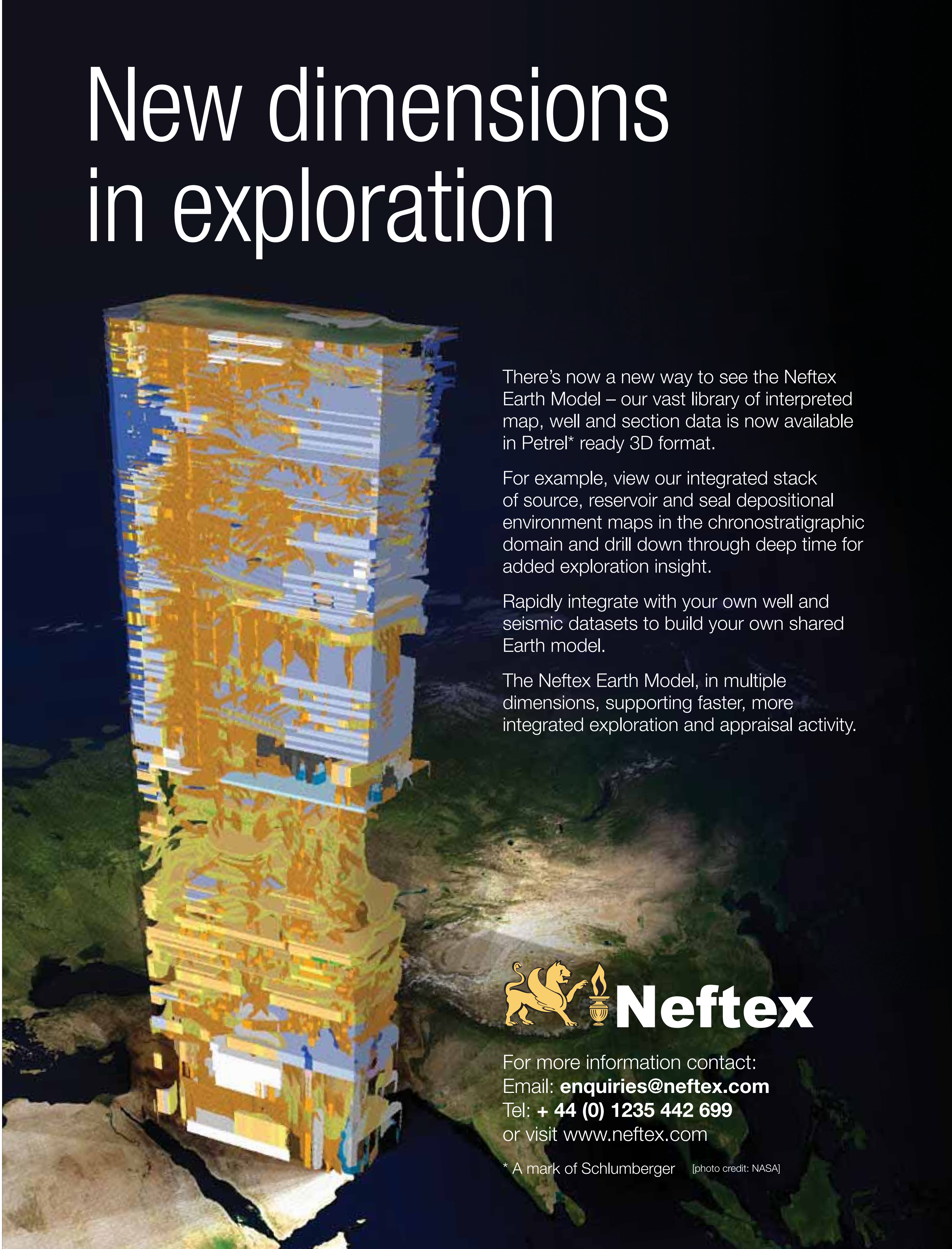
It has been the hard work of a few visionary people and oil companies with new technologies that have made this all possible. Research by organisations like the EERC hopes to help refine exploration and make production of this resource increasingly efficient in the future. New areas of shale oil exploration in source rocks like the Eagle Ford in Texas and at Repsol’s Vaca Muerta Basin shale oil discovery in Argentina are being opened up thanks to the pioneering work on the Bakken. This is exactly what Richard Findley had in mind after the success at Elm Coulee and ultimate expansion of this type of play “beyond Elm Coulee and the Williston Basin”. ■

EERC The Energy and Environmental Research Center (EERC) employs over 345 people and is located at the University of North Dakota in Grand Forks, North Dakota. Their research provides practical, cost-effective solutions for a wide array of energy and environmental issues, including clean coal technologies, oil and gas activities, CO^2 sequestration, sustainability, biomass, climate change, and many others.

The Center for Oil and Gas at the EERC focuses on design and implementation of new approaches of exploration, development and production of oil and gas. Apart from their cutting edge research into the Williston Basin and Bakken production, they are conducting research for coalbed methane, deep-basin-centred gas, enhanced oil recovery, utilisation of flared gas, and produced water handling. They maintain a website that contains extensive information about their research and provides links to numerous geologic maps and studies (www.undeerc.org).

Along with more effective completion technology, companies like Continental Resources are increasing production efficiency by drilling and completing four wells on one pad. With their ECO-Pad© concept, they can develop two separate formations on two separate spacing units simultaneously while reducing environmental impact on the surface of the land.

David McNeese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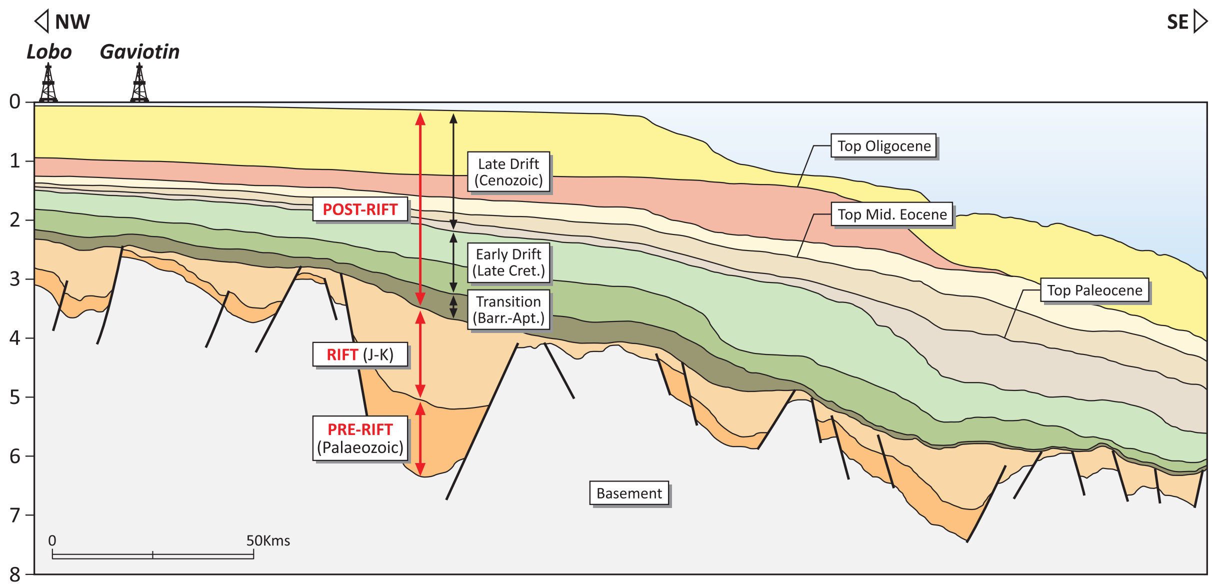
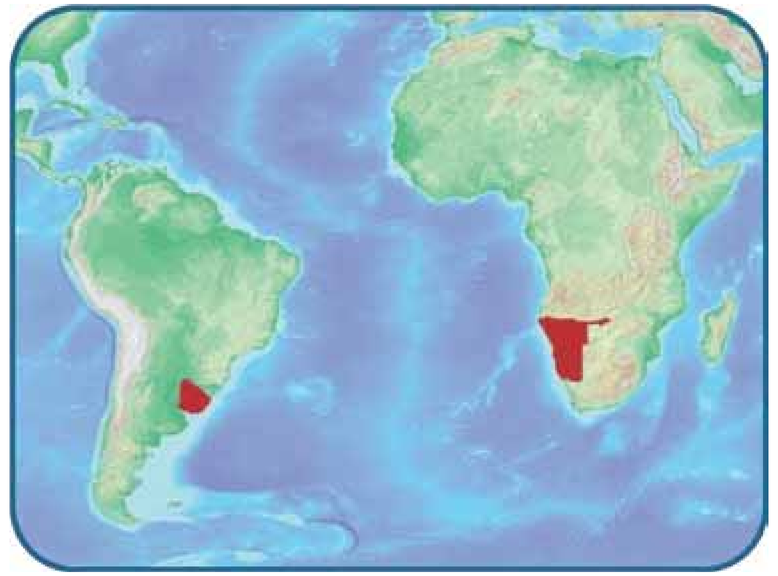
Offshore Uruguay:

Uruguay is a frontier area in terms of hydrocarbon exploration, but now the exploration spotlight has focussed on this region with the announcement of Uruguay's second offshore licensing round

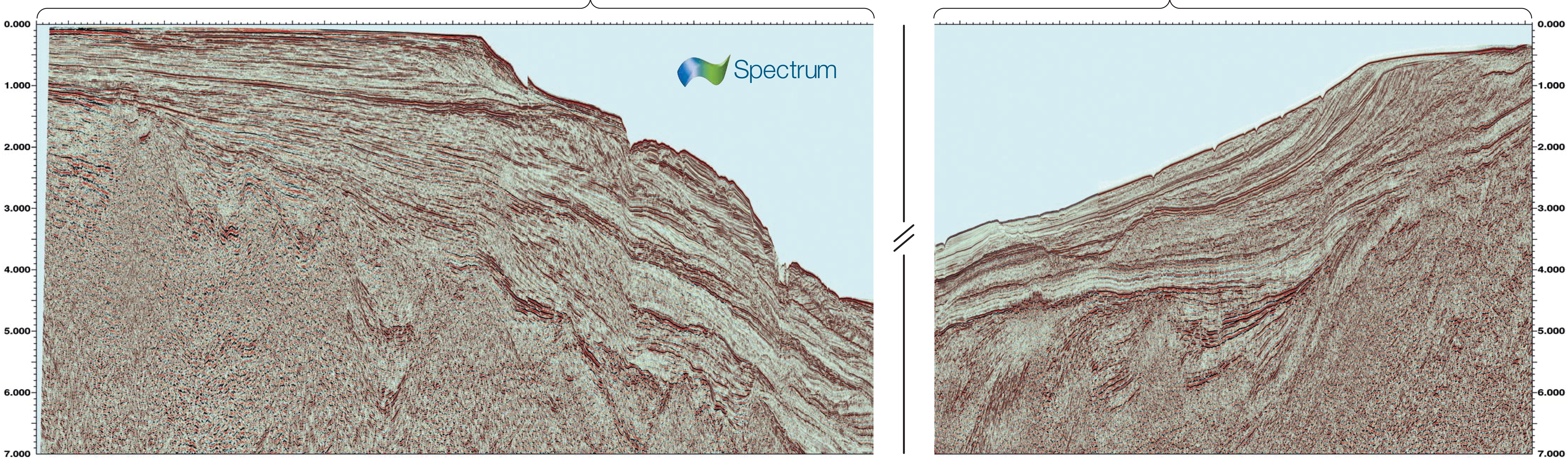
Cross-section through the Punta del Este and Oriental del Plata Basins (taken from Morales et al. 2010)



Offshore Uruguay has gained significant interest due to its unique positioning on the conjugate margin with West Africa, in particular offshore Namibia where significant hydrocarbon discoveries have occurred. Also, key analogues may be extrapolated from the prolific offshore hydrocarbon basins of Brazil to the north and Argentina in the south.



Seismic lines demonstrating similarities between the conjugate margin of Uruguay and Namibia across the South Atlantic Ocean. Uruguay seismic line to the left (290 km) and Namibia seismic line to the right (180 km).



Perfect Atlantic Analogues

Offshore Uruguay is still regarded as an exploration frontier region, but is considered to have a wealth of hydrocarbon potential.

LAUREN PENN, GARY SCAIFE and RICHARD SPOORS, Spectrum

Limited offshore exploration occurred in Uruguay during the mid-1970s, resulting in two exploration wells, Lobo and Gaviotin. These were drilled on structural highs within the Punta del Este Basin in very close proximity to each other and in relatively shallow waters. The results were disappointing as both wells were declared dry. Critically, however, there were inclusions of oil and gas shows, indicating the possibility of a working hydrocarbon system. Drilling exploration ceased during the 1980s and since then exploration has been limited to the acquisition of a number of seismic surveys, including Spectrum's 2002, 2007 and 2008 surveys. However, the presence of hydrocarbon shows maintain the belief that there is a regional working hydrocarbon system and that the offshore area may deliver the next world class high impact hydrocarbons.

Three Offshore Basins

During the Permian and Triassic, Western Gondwana divided as a result of crustal extension, then during the Jurassic and Early Cretaceous the South Atlantic Ocean opened, due to dextral strike slip movement, initiating a triple junction. Prior to the break up, South America and Africa were joined and therefore the West African and Latin American east coast margins consist of a transform margin, characterised by a series of discrete on and offshore Mesozoic-Cenozoic basins.

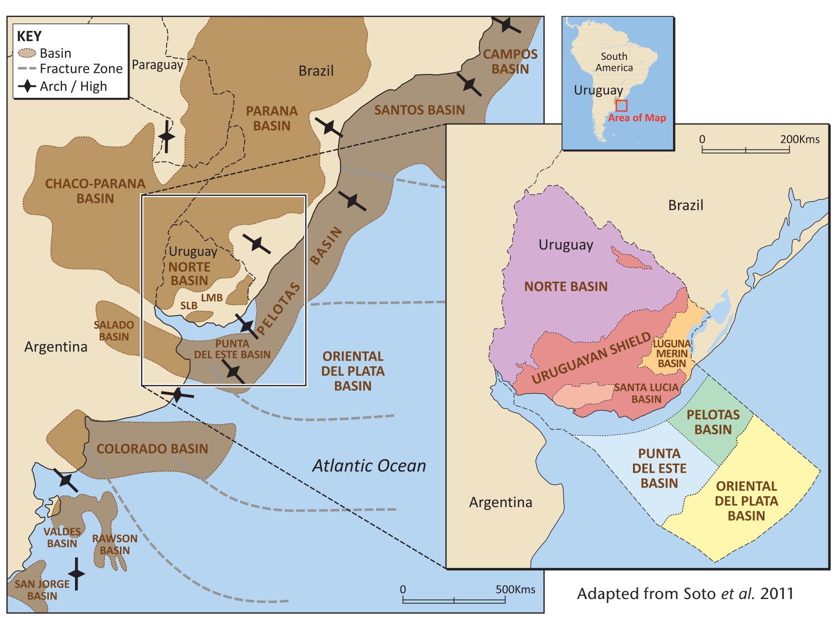
Uruguay has six main sedimentary basins, three of which are offshore: Punta del Este, Pelotas and Oriental del Plata. The offshore basins lie on trend with the prolific hydrocarbon-producing Argentinean San Jorge and the Brazilian Santos Campos Basins and on a conjugate margin with Namibia, where the Kudo gas field is located. Offshore basins cover a total area of 80,000 km² extending up to 370 km offshore, with water depth varying from 20m to over 4,000m.

The Punta del Este Basin has four main tectonic stratigraphic stages: the pre-rift during the Permian, syn-rift in the Jurassic and Early Cretaceous, a transition period through the Hauterivian Aptian and drift through the Aptian to present day. The Pelotas Basin extends from the Polonio High to the Florianopolis Fracture Zone in Brazil, where the Santos Basin commences. The pre-rift sequence can be interpreted as an analogue to the Brazilian area, where it is shown to correspond to the Paleozoic and Mesozoic units of the Parana Basin. The third offshore basin in Uruguay is the ultra deep water Oriental del Plata Basin. It consists of Cretaceous and Cenozoic marine sequences, comparable to the Argentine Ameghino Basin.

Promising Petroleum Systems

It is important to review the regional context of the petroleum systems to enable a better understanding of Uruguay's offshore geology. Both the Orange Basin in Namibia and the Santos Basin in Brazil are examples of almost perfect analogues in petroleum system terms, and these systems can be extrapolated into offshore Uruguay. Both regions demonstrate lacustrine and marine source rocks with similar oil type and comparable reservoir depositional environments. The traps in the basins are associated with basement highs and the areas have vertical migration pathways with normal fault pathways to provide carriers.

Hydrocarbon-prone Aptian rocks are thought to be the primary source rock and have been identified and mapped throughout the offshore Uruguay continental margin. The Aptian source rocks play a vital role in the working petroleum system of the conjugate margin, offshore Namibia, particularly in the Orange Basin,



Adapted from Soto *et al.* 2011

Topographic-bathymetric map of South America including location of the six Uruguayan basins. The Punta del Este syn-rift sequence includes alluvial, fluvial and lacustrine deposits interbedded with volcanics. During the drift sequence, sea level regressions took place depositing the deltaic sandstones of the Mercedes Formation, followed by eustatic oscillations and transgressions. The Pelotas Basin corresponds to the flexural border of the precursor to the syn-rift structure.

where, as well as the main source rock, the Aptian sequence also provides the high quality reservoir sands found in the Oribi gas field. The Aptian source is responsible for the 1.4 TCF Kudo gas field where over 100m of high quality (TOC 2%) mature source rocks are present. As Namibia and Uruguay are a conjugate margin this source rock evidence is significant in evaluating Uruguay's hydrocarbon potential.

Onshore exploration in Uruguay is far more developed than its offshore counterpart and it is thought that this data can also be extrapolated to the offshore basins. The main onshore source rock potential is associated with the pre-rift, rift and transition sequence. The onshore Norte Basin contains excellent source rocks in the Devonian marine shales of the Cordobles Formation (TOC 4%) and in the Artinskian marine oil shales of the Mangrullo Formation (TOC 13.5%). Secondary source rocks include Early Permian marine shales of the Cerro Pelado and Frayle Muerto formations (TOC 2%).

Uruguay has high quality reservoir rocks within the sedimentary record, as encountered in the Lobo and Gaviotin exploration wells, where porosity is up to 25%. The most important reservoir rocks are related to the alluvial fluvial sediments in the syn-rift sequence. Other reservoirs include the fluvial deltaic sandstones in the early drift sequence and the lowstand deposits in the early and late drift sequence.

Namibia has comparable good quality sandstone reservoirs with numerous prospective structural and stratigraphic traps. The reservoir rocks are composed of syn-rift sandstones, shallow marine sandstones with 12% porosity and widespread Upper Cretaceous and Tertiary turbidite systems. Seismic amplitude anomalies have also been identified in the Aptian succession in the deep water areas. Although these reservoir targets are untested, they can be correlated to similar rocks in the Santos Basin in Brazil and Uruguay.

Structural and stratigraphic plays have been identified in the basins offshore Uruguay, in both shallow and deep waters. They can been seen in the pre-rift and syn-rift sequences including anticlinal structures related to basement highs, rotated blocks, compaction synclines, truncation of syn-rift deposits and pinch-outs against basement highs and grabens. Within the Cretaceous post-rift sequence, floor fans, channel fan complexes and lowstand fans are present, while Cenozoic pinch-outs are seen in both the post- and syn-rift sequences. Numerous prospects and leads have also been identified. Similar play types found offshore Namibia could be translated in to the Uruguayan region.

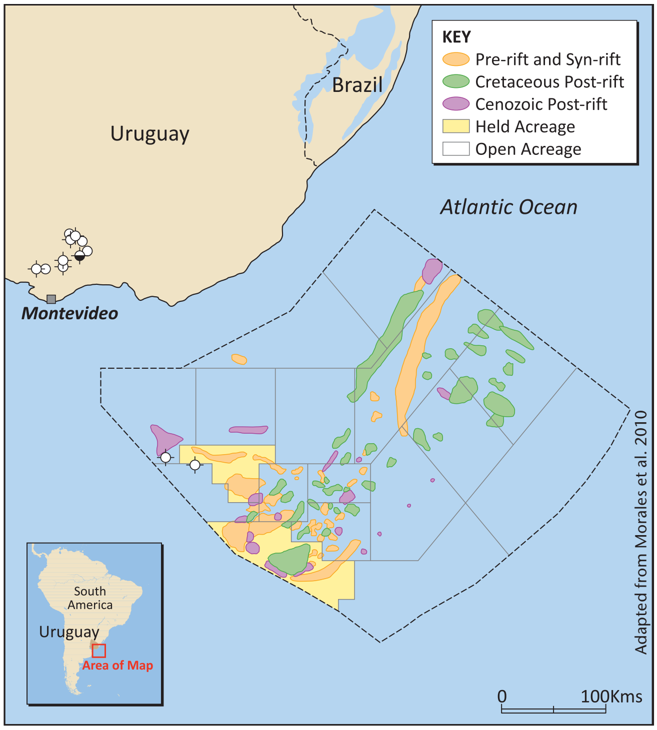
There is direct and indirect evidence of the presence of hydrocarbons including fluid inclusions of oil and gas, gas chimneys, oil seeps, velocity, frequency and AVO anomalies, and bottom simulating reflectors, suggesting the area has hydrocarbon generation and expulsion and therefore a working hydrocarbon system.

New Round Closing

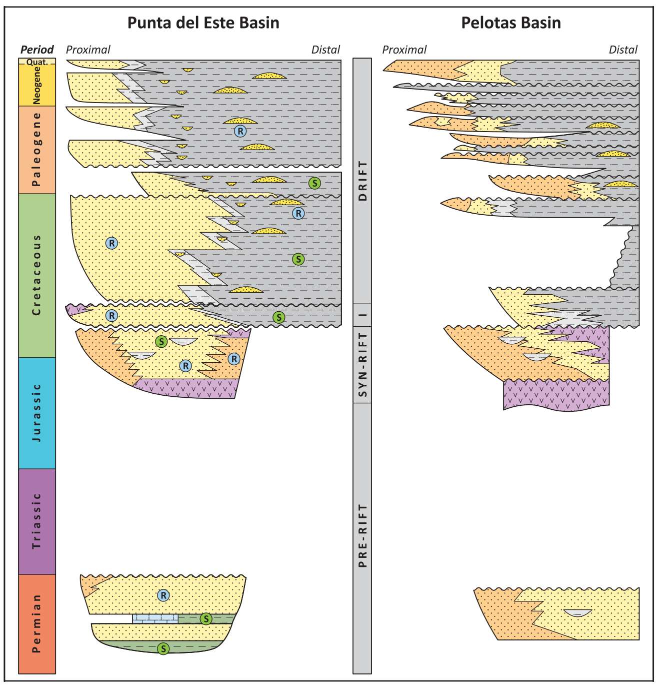
Uruguay has announced its second licensing round, closing 29 March 2012, offering 15 areas ranging from 3000 km² to 12,000 km² located in both deep and shallow water within all three offshore basins. Spectrum has approximately 12,000 km of 2D seismic data covering offshore Uruguay and holds significant datasets offshore Namibia and Brazil.

Although still underexplored, offshore Uruguay is considered to have a wealth of hydrocarbon potential. Evidence of a mature regional source, potential reservoir sequences, numerous potential trapping geometries and abundant hydrocarbon indicators imply that the offshore region could deliver future hydrocarbons. Analogue data from offshore Namibia and onshore Uruguay can be extrapolated into the offshore regions and provide further evidence of a working hydrocarbon system. ■

Leads and prospects offshore Uruguay with location of Lobo and Gaviotin wells. The licensing areas are located in both shallow and ultra deep waters, in all three offshore basins.



Stratigraphic column of the Punta del Este and Pelotas Basins offshore Uruguay.



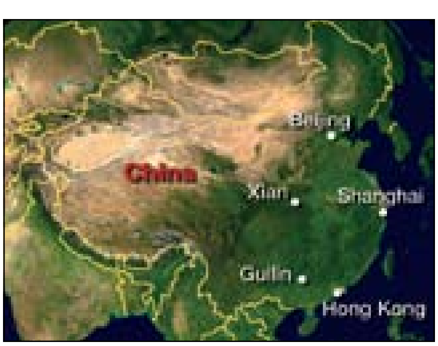
Morten Smelror

The Dragon Pagoda, or the Palace of the Dragon King, houses a small lake which mirrors the karst formations in the colourful light

Crowns of Nature:
The Majestic Landscape of Guilin

MORTEN SMELROR, Geological Survey of Norway

A landscape of harmony and peace, with scenery made for poetry and romance: the majestic karst landscape of the north-east Guangxi Zhuang Region in south-west China is one of nature's true masterpieces.



Large areas in south-west China comprise spectacular landscapes as a result of karst limestone. In the centre of this scenic tropical world is Guilin, one of China's leading tourist cities. In the yellow light of the setting sun, the peaks rising sharply from the green plains of the Guilin district appear to be competing for the beauty crown. No wonder the region attracts millions of tourists every year.

Capital of Karst

In Chinese, the name Guilin literally means "the forest of sweet osmanthus trees". If you visit Guilin in early October, you will experience a city covered in flowering trees. There are many historical sites in Guilin, but the most renowned feature is its dramatic karst terrain, and the city is often referred to as the 'capital of karst'. Guilin City was first established during the Qin Dynasty (221 to 206 B.C.) by Emperor Qin Shi Huang and thus has a 2,000-year history. Emperor Qin Shi Huang is well known for creating the army of terracotta warriors, which was found in Xian (over 1,000 km to the north of Guilin) during the 1970s. He also started the building of the Ling Canal, linking the Yangtze and Pearl River systems, which is a significant factor in cultural and economic exchange between central and southern China.

The bedrock around Guilin consists of Devonian limestone. As a consequence of the collision of India with Asia which formed the Himalayas, the limestone was uplifted and exposed. Over the past 40 million years these rocks have been weathered, dissolved and eroded by rain and flowing water. The product is a landscape with thousands of majestic peaks, with numerous sharp, narrow valleys, and with many caverns and sinkholes beneath. Some of the underground caves stretch for many kilometres.

Generally, two types of karst landscapes predominate in Guilin: fenglin or peak forest (isolated towers) and fengcong or peak cluster (linked-base towers). The monsoon climate with high moisture during the warmest season has been a driving force for the sculpturing of the landscape, which comprises some of the most spectacular karst topography in the world.

The Reed Flute Cave

The Reed Flute Cave is located on the southern shoulder of the Guangming Hill, five kilometres north-west of Guilin City centre, and is one of the most extraordinary sights in Guilin. Reeds for making flutes and pipes have been grown in this region since ancient times, and according to legend, Reed Flute Cave got its name because people believed that the reed by the cave's mouth could be made into flutes.

The cave, which also is known as "the Palace of Natural Arts", is 240m deep and 500m long and offers a majestic display of underground karst features such as stalactites, stalagmites, stone pillars, stone curtains and more. In the glittering colourful light, the formations take the form of birds, plants and animals in fantastic shapes and hues. Some of them are given imaginative names like Pines in the Snow, Mushroom Hill, Dragon Pagoda, Sky-Scraping Twin, Virgin Forests and Red Curtain.

Tourists had already begun visiting this cave in the Tang Dynasty, which existed between the years 618 and 907, and the more than 70 wall inscriptions from the Tang Period inside the cave bear eloquent witness to its long history. In modern times the cave was opened for tourists in 1959. The walk through the cave normally takes about an hour. Among the many visitors that have been captivated and inspired by the fascinating underground theatre in the Reed Flute Cave are the script writers and set designers for the Star Trek movie, and the former Prime Minister of Norway, Gro Harlem Brundtland.

The taste of snake-wine is definitely something special!

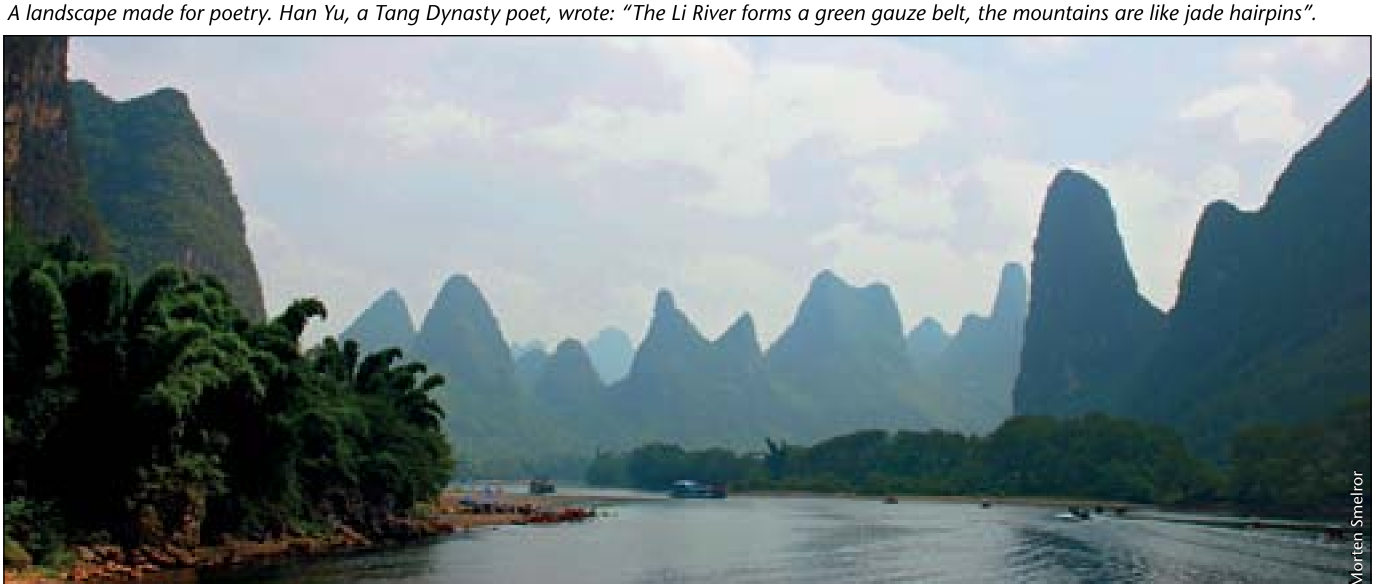
Floating on the River Li

No trip to Guilin would be considered complete without a boat ride on the Lijiang River to Yangshuo, regarded by many visitors as the centrepiece of a trip to the north-eastern Guangxi Province. The Li River cruise offers one of the best opportunities to experience the varieties of the scenic karst landscape.

As you float downstream, gorgeous peaks offer you surprises at each bend of the limpid river. Along the way you will see water buffalo eating plants in the shallow water, peasants working on the rice paddies, school kids waving from the villages and fishermen floating by on bamboo rafts. Many Chinese paintings and poems present this charming scene and tourists never tire of photographing it.

Following Chinese tradition the peaks along the river are given imaginative names, such as Snail Hill, Green Lotus Peak (Bilian Peak), and Schoolboy Hill (Shutong Hill). Although many take

A landscape made for poetry. Han Yu, a Tang Dynasty poet, wrote: "The Li River forms a green gauze belt, the mountains are like jade hairpins".



some imagination to visualise, listening to your tour guide's legendary stories behind them is a delightful experience as you appreciate the landscapes. Most are mystical fairy and love stories – and the scenery is equally beautiful.

On the way you may be treated to many local delicacies, including a taste of the local Sanhua wine, which is very famous in China. Sanhuajiu is a typical Chinese savoury rice wine, known as "the King of Wine", and can be traced back to the Song Dynasty (960–1127). It is made using the pure water from the Li River, and is of very high quality. The taste of local snake-wine is, however, a matter for discussion!

On the Li River you can see fishermen in traditional costume with a very special and time-honoured way of fishing; they use cormorants to catch fish. After sunset the fishermen on bamboo rafts suspend strong lights over the water to attract the fish. The cormorants, which are tethered with rings round the base of their necks, jump off the rafts and dive on the fishermen's command. They catch the fish and then disgorge them for the fishermen. The catch provides food and income for an entire family, and good cormorants are highly valued.

A Day in Shangri-La

Ever since the English writer, James Hilton, published his legendary novel "Lost Horizon" in 1931, the paradise of Shangri-La, characterised by snow-capped mountains, vast grasslands, lush vegetation, gorgeous gorges and idyllic lakes, has been a distant dream for many. However, not far from Guilin you can visit what some claim is the real Shangri-La.

You can make your own reflections about lost paradises and the art of modern day tourism, but at the present day Shangri-La you get a good sense of Hilton's original ideas of a paradise on earth. More importantly, at the visitor centre at Shangri-La you gain an excellent insight into the rich and colourful cultural heritage of the various Chinese Minority folk groups in the area. Here you will find traditional building complexes showing the symbolic architecture of the Dong Minority people placed around the idyllic Swallow Lake and surrounded by impressive natural scenery. It is best to board a boat and sail on the gentle water and enjoy the breathtaking natural beauty.

Folk art lovers should not miss the Folk Customs in the Grand-view Garden. Here you will find a variety of art, crafts and local souvenirs displayed. During your visit you can also enjoy various performances featuring ethnic dances and songs. ▶

The unique performance "Impressions Liu Sanjie" involves up to 1,000 singers and dancers and is the largest of its kind in the world. The performance builds on a local love story, and includes elements of the Minority people folklore as well as fishermen on rafts, and cormorants.

The Dong people's costumes have a long history, being colorful and varied. They generally value simple and unsophisticated designs, but extra fine costumes used at the most important occasions include beautiful silver jewelry.

Spectacular Outdoor Theatre

After a day filled with scenic delights on the River Lijiang, you might be ready for even more. Spend at least one night in Yangshou so you can be highly impressed by the unique performance "Impressions Liu Sanjie". This utilises the landscape for its actual setting, creating a spectacular outdoor theatre, where the Li River itself is the stage and twelve mountains serve as the backdrop. The water stage is two kilometres long and 600m in width. The show involves as many as 1,000 singers and dancers and is the largest of its kind in the world.

The performance builds on a local love story, and involves elements of the Minority people folklore. Fishermen on rafts, and cormorants, are of course included. It took more than three years to develop the show, and it was directed by Zhang Yimou, who also directed the famous 2002 movie 'Hero' and the opening ceremony of the recent Beijing Olympics. The audience sits on specially designed terraces with capacity for up to 3,000 visitors. The theatre is designed to blend, merge and work with the natural environment. The changing weather and seasons bring something different to each performance and the fantastic lighting effects highlight the beauty of the setting. The performance is a landmark of Lu Sanjie culture, and is a unique experience indeed, not to be missed. ■

The Li River cruise from Guilin to Yuangshou offers fantastic opportunities to experience scenic karst landscape.

Green fields surrounded by majestic karst peaks at Shangri-La

The Search for Oil in Oman

MICHAEL QUENTIN MORTON

A discovery at Yibal in April 1962 marked the end of a long and frustrating search for commerical oil in the Sultanate of Oman. The country is now 24th in the global oil production table with reserves of about 5.5 Bbo.

The Beginning

In the Omani desert, a few miles inland from Nafun, lies a groundwater seepage in the Wadi Jurf. On approaching this spring, you can see streams of glistening salty water on the surface of dolomitic rocks that are fringed by ribbons of black algae. To the untrained eye, from the distance, it looks black like crude and could easily be mistaken for an oil seepage. This was the likely source of a rumour in the early 1920s that travelled all the way up the Omani coast, crossed the Arabian Gulf and reached the offices of the Anglo-Persian Oil Company in Abadan.

Until then, the history of geological exploration in Oman had been slender. There had been visits in 1901/2 by members of the Geological Survey of India to look for coal to keep it from falling into French or Russian hands. Then in 1904, the Government of India dispatched Guy Pilgrim to examine the countries surrounding the Arabian Gulf and Oman in search of oil. He reported that the oil prospects of Persia were more encouraging than on the other side of the Gulf. There matters rested until the 1920s when stories of Frank Holmes' activities spurred Anglo-Persian into pre-emptive action (see 'The Emergence of the Arabian Oil Industry,' *GEO ExPro,* Vol. 7, No. 6). Through its exploration arm, D'Arcy Exploration, the company obtained a two-year licence to prospect in Oman in 1925. The agreement ominously stated that certain parts of the territory were "not at present safe for its operations", a reference to the volatile situation in the interior.

A survey party assembled in Muscat in November 1925. It included geologists George Lees and K. Washington Gray, with "Haji" Williamson (see *GEO ExPro,* Vol. 8, No. 3) as their guide. The party was able to penetrate the mountain country on camels, reaching Yanqul on the western side of the Hajar range. Because of tribal unrest, they were unable to visit one of the most interesting geological areas, the Dhahira plain, although Lees had noted that the plain was broken by several 'hog-back anticlines', which were possible indicators of oil traps. They moved down the coast, landing near Nafun to investigate the reported oil seepage, but they were unable to locate it. Bertram Thomas recalled that the geologists had

Nick Lee

An oil company Land Rover on the edge of the Empty Quarter at Sahmah, Oman, in 1960

Members of the 1925/6 geological survey: second from left, K. Washington Gray, fourth from left George Lees, right Haji Williamson

Geologists René Wetzel (left) and Mike Morton who surveyed Dhofar in March 1948

been "greeted by a hail of stones".

Lees aptly summarised the difficulties that lay ahead: "Systematic exploration of the Arabian peninsula, or indeed its fringes, is greatly hampered by formidable natural barriers and by the still more serious obstacles caused by the independent spirit of its inhabitants."

In 1937, Iraq Petroleum Company (IPC), an international consortium of oil companies (see *GEO ExPro,* Vol. 6, No. 2), obtained concessions for Oman and Dhofar through its associate company, Petroleum Development (Oman and Dhofar) Ltd. The following year, company geologists travelled to Buraimi with the blessing of the ruler, Sultan Said bin Taimur. The leading sheikh appeared to welcome them with open arms, but he was plotting to ambush them, seeing their arrival as a God-given opportunity for a "first class hold-up". Although the geologists emerged unscathed from the ambush their report was, of necessity, brief.

Disappointment in Dhofar

In 1939, the company organised an aerial reconnaissance and a brief land survey around Murbat. This revealed nothing of interest, apart from an odour of petroleum between two shale beds (which later turned out to be petrol that had leaked from oil drums which had floated to the shore). The rugged interior blocked any further investigation, and operations were suspended during World War II.

The success of Aramco's exploration of eastern Arabia renewed interest in the regional geology of southern Arabia in the post-war years. However, IPC was committed elsewhere and reluctant to proceed in Dhofar. At the request of the Sultan, Sir Cyril Fox (formerly of the Geological Survey of India) carried out a brief survey and reported "potentialities of oil in Dhofar". IPC relented and, in February 1948, two IPC geologists, René Wetzel and the author's father, Mike Morton, arrived in the main town, Salalah. Over the next six weeks, they carried out a camel-borne survey of the province, a gruelling, cumbersome journey of 600 km in a caravan of 76 camels. Their report recommended that Dhofar be rejected as an oilfield and, in December 1950, the company duly relinquished its concession.

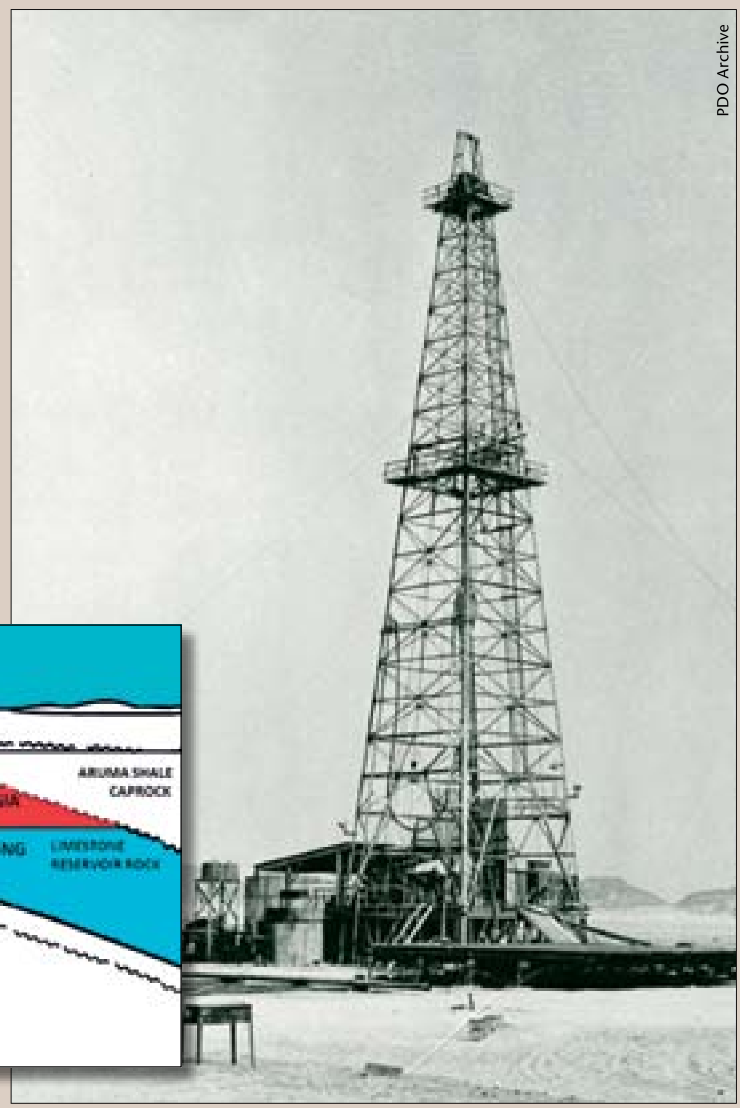
In 1952, the Sultan granted a concession in the Dhofar region to Wendell Phillips, an American archaeologist with little knowledge of the oil business. Phillips assigned it to an American oil company, Dhofar-Cities Service Petroleum Corporation. The company spudded-in its first test-well at Dauka in April 1955, followed by three wells at Marmul between 1956–58. The early signs were encouraging, but they did not last. The oil flow from Marmul declined on testing and the oil was too heavy to exploit commercially. Further disappointments followed, with low oil prices and the problem of loading crude on the coast during the monsoon season only adding to the difficulties. In 1967, after an expenditure of $40 to $50 million, and 29 wells sunk, the American companies relinquished the concession.

Central Oman Exploration

As World War II was drawing to a close, IPC re-confirmed its agreements with the Sultan in respect of Oman and Dhofar. In 1948 Dick Bird, the company's representative in the Buraimi Oasis, negotiated separate agreements with individual sheikhs, but when he returned from leave he discovered that the Sultan had made his own arrangements with them. Buraimi was considered

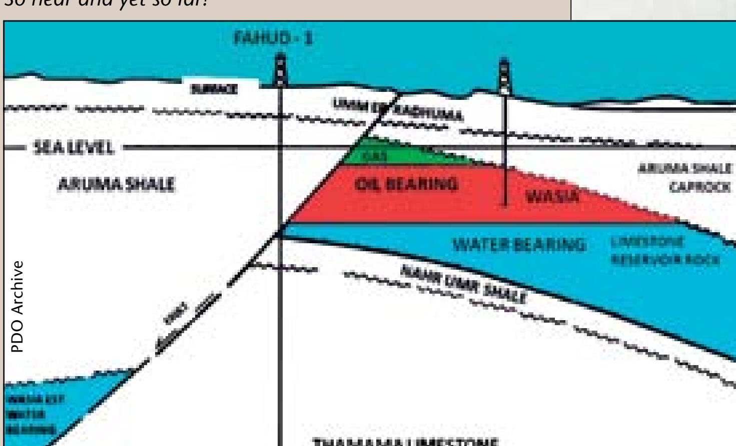
Fahud No. 1:
The Unluckiest Well

After the initial disappointment, a subsequent drilling programme at Fahud revealed new oil sources and indicated that oil might be present after all, in the Wasia Limestone. Only a few hundred metres from the original test well site a second well was sunk and, in 1964, oil was found in commercial quantities. It was discovered that a fault identified by the original geologists had cut out the productive part of the Wasia reservoir in the original Fahud dry hole, and the reservoir rocks had dropped a thousand metres. Those early geologists had missed striking oil by less than a hundred metres – hence its description as the "unluckiest" wildcat well in the history of Middle East oil.



PDO Archive

So near and yet so far!



PDO Archive

the gateway to the real area of petroleum interest, Jebel Fahud, which had been sighted on a reconnaissance flight. But further tribal unrest persuaded IPC to put its plans for exploring central Oman on hold, a decision that was vindicated when a Saudi force occupied one of the Buraimi villages in September 1952.

By now IPC's operating company had dropped Dhofar from its title to become Petroleum Development Oman (PDO). In a change of tactics, the company decided to approach Fahud from the south via Duqm Bay, which was suitable for a seaborne landing. This was known as operation DEF, possibly signifying "Duqm Expeditionary Force". The company had acquired a number of tank and infantry landing craft, ex-World War II stock, and financed a small force of native troops to provide protection (the Muscat and Oman Field Force).

The landing took place on 15 February 1954 but, because of political difficulties, the party did not receive permission to proceed northwards until the autumn. On 21 October, two geologists and a guide arrived at Jebel Fahud, a low, hog-back structure rising 120m above the surrounding plain. The western half of the fold was covered by Tertiary limestones which by virtue of its preserved surface showed the true anticlinal shape. At the eastern end, erosion had removed this limestone from the crestal area, and a cirque with opposing scarps and dip slopes revealed older beds of rock.

The well was spudded in January 1956 but abandoned 14 months later at a depth of 3,729m in Ara salt. Between 1956 and 1960, three further exploration wells were drilled, at Ghaba, Haima and Afar, and two seismic parties and a gravity party were at work, but there was still no indication of oil in commercial quantities. The global supply of crude oil exceeded demand, prices were low and political instability continued – these factors led to a major re-think of the Omani concession. Three of the IPC partners decided to withdraw, leaving Shell (85%) and Partex (15%) as partners in PDO.

Shell Leads the Way

Royal Dutch Shell took over the management of PDO and undertook a comprehensive review of all the geological and seismic data. Hugh Wilson, Shell's regional exploration manager, carried out a careful study of cores, cuttings and logs from the dry IPC wells. By then too, discoveries had been made in the Cretaceous Thamama in Abu Dhabi (*GEO ExPro,* Vol. 8, No. 3). A new drilling programme was started in 1962, leading to the discovery of oil and gas in the Cretaceous Shuaiba and Wasia limestones in the Yibal oilfield 48 km south-west of Fahud. The Natih anticline, 20 miles north-east of Fahud, proved productive in 1963 from the Wasia limestone, followed by Fahud itself in 1964. A pipeline of 276 km was laid from Fahud and Natih to the coast at Mina al Fahal, where a tank farm, moorings for sea-going tankers and a 20-megawatt power plant were built. The first export of Omani oil took place on 27 July 1967. The Government of Oman acquired a 60% stake in PDO in 1974. ▶

A PDO landing craft approaching the Duqm shore on 15 February 1954.


Mike Morton

Map of Oman showing the places mentioned in the article

Oman Today

The country now has more than 150 oil fields, many of them rather small, complex and not as productive as those typical of the Middle East, with the result that production costs are proportionately higher. The largest fields in the north are Fahud, Yibal, Natih, Lekhwair, Al-Huwaisah, and Safah, which produce a light or medium crude in the 30–42° API range, as well as gas. The southern fields such as Marmul, Nimr, Mukhaizna, Amin and Amal produce heavier, more viscous crude in the 14–22° API range. As oil fields have matured – the "easy" oil having been extracted, the challenge facing PDO and the other oil companies which now operate in Oman is how to improve the amount of oil recovered. A number of enhanced oil recovery projects are in progress or about to come on-stream, including steam injection in Mukhaizna, Amal and Qarn Alam, polymer injection in Marmul, and miscible gas injection in Harweel. Overall, these methods appear to have had some success: from a peak of 970,000 bopd in 2000, oil production fell to 710,000 bopd in 2007 but is back to around 900,000 bopd today. An awareness of modest remaining resources has led the government to recently introduce programmes to diversify the economy. ■

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

Quentin Morton's book Buraimi: The Struggle for Power, Influence and Oil in Arabia *(ISBN: 9781848858183) is to be published later this year by I.B. Tauris Ltd*

The trials and tribulations of oil exploration: digging out a Land Rover at Sahmah, Oman, 1960

The Arctic: The Real

JANE WHALEY

John Simmons, ON Communication

Where will we find Arctic Oil and Gas resources and what challenges lie ahead?

"Everyone says that their part of the world is the final frontier – but believe me, the Arctic really is," says Al Fraser, EGI Professor of Petroleum Geology at Imperial College in London, and former Exploration Manager involved in BP's circum-Arctic project since 2002. "It's the last place we can expect to find significant oil and gas reserves, with approximately 200 Bboe already discovered, and USGS estimates of 114 Bbo, 2,000 Tcfg and 44 Bb of natural gas liquids yet to be found (Gautier *et al.*, 2009). Looking at the way in which the Earth's rapidly increasing population is eating into our discovered reserves, we need new sustainable oil and gas developments, and the Arctic is one of the few places we will find them."

Five countries hold major interests in the Arctic – Russia, USA, Canada, Norway and Greenland – and as interest in the region increases, access opportunities have become increasingly available. A few areas, like Alaska, have been explored for decades, while others, such as East Greenland, are only just seeing the results of their first deep seismic surveys. Discoveries are focussed geographically, reflecting

Driftwood on the Arctic Beaufort Sea shore

Final Frontier

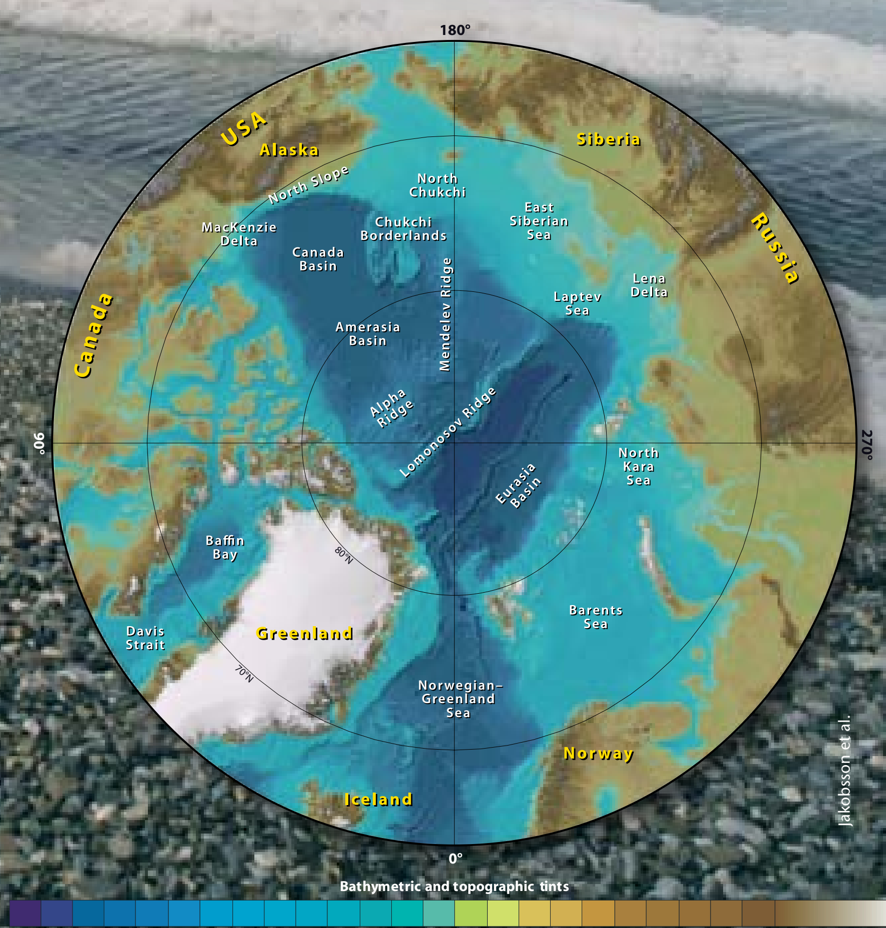
access rather than resources, with most so far having been made off West Siberia and the South Kara Sea (90 Bboe) and Alaska (40 Bboe). Vast areas remain unexplored, including a 5,000 km long swathe of shallow continental shelf from the North Chukchi Basin to the North Kara Sea.

In fact, the vast Arctic Ocean region, which covers over 14 million square kilometres, has the most extensive continental shelf area of any ocean basin. "Remove the ice and the Arctic is 50% continental shelves, much of it in less than 50m water depth," Al says. "The shelf of the Alaskan margin is relatively narrow when compared to the broad expanses of unexplored shelf off Russia, which includes the Lena Delta, arguably the largest unexplored delta in the world, and known to contain up to 15 km of Tertiary sediments."

Plenty of Potential

The geological map of the Arctic is dominated by two major spreading centres: the Eurasia Basin – the northwards continuation of the North Atlantic Ridge ▶

About 50% of the Arctic Ocean is continental shelf, much of it in less than 50m water depth. There are two deepwater basins floored to some extent by oceanic crust, the Eurasia Basin and the Amerasia Basin, separated by a thin sliver of continental crust comprising the Lomonosov Ridge.



Planting 4C geophones in West Siberia. Working in the Arctic presents many challenges.

– and the Amerasia Basin, which are separated by the thin continental sliver of the Lomonosov Ridge. Cretaceous ocean crust is likely to floor most of the Canadian portion of the Amerasia Basin, but the region around the Alpha and Mendeleev Ridges, thought to be a mixture of extended continental crust and igneous province, is still unclear. Regional knowledge suggests that the Eurasia Basins started to experience spreading in the Early Eocene, with Greenland moving away from Norway, as the Lomonosov Ridge moved away from the Barents-Kara margin. At a later date the two oceans rejoined, allowing anoxic conditions to prevail in the Arctic Ocean throughout most of the Palaeogene. Baffin Bay is thought to have also experienced Paleogene spreading, but the timing is not proven. "Understanding the distribution of oceanic versus extended continental crust is vital," Al explains. "It is key to tectonic model assessment and thus to understanding the true potential of the region."

"For a good working petroleum system, four main factors are always required. World class source rocks; sufficient heat flow for oil generation and migration; excellent reservoirs such as thick, permeable sandstones and major deltas and carbonate platforms; and giant structures sealed by mudstones or salt. I believe that these are all present in many different formats throughout the Arctic."

West Siberian wellheads in the snow

John Simmons, ON Communication

Vibrator trucks at work in West Siberia.

"The key source rocks are the Triassic Shublik Formation, the Jurassic Bazhenov and the Cretaceous HRZ, as well as the Devonian Domanik in the South Barents Sea and Timan-Pichora, all of which were deposited in large anoxic epicontinental seas. The Tertiary has major regional source rock implications, as the period after the Palaeocene-Eocene thermal maximum was the last time the Arctic Basin was enclosed. It experienced high temperatures, rainfall and runoff, an atmosphere rich in carbon and nitrogen, and major growth of azolla, a free floating freshwater fern and the fastest growing organism on the planet (see *GEO ExPro*, Vol . 4, No. 4). Key to success in the Arctic will be prediction of world class regional source rocks."

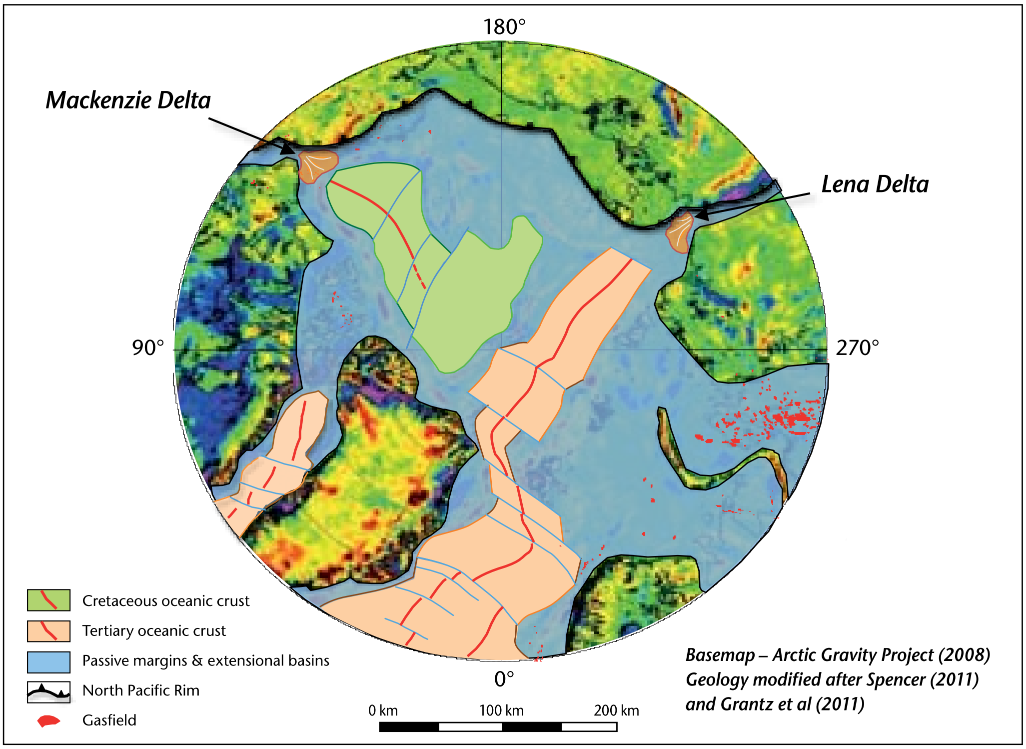
"During the Permian, there was widespread development of a broad carbonate platform throughout the extensive continental shelf area running from the Barents Sea anti-clockwise to the Offshore Alaska with additional excellent reservoirs in the Triassic of Prudhoe Bay and Triassic and Jurassic in the Barents Sea. There are also the huge Tertiary Mackenzie and Lena Deltas which offer vast unexplored potential."

"The resources are there – it's extracting them that presents the challenges."

Exploring Under the Ice

So what are the important issues ahead of us in the search for Arctic hydrocarbons?

"Well, obviously, there's a lot of ice in the Arctic – but its distribution varies from year to year," Al says. "We need to fully understand the constraints. The ice is reported to rotate clockwise at a rate of up to 3 m/hr and exits the Arctic into the North Atlantic through Baffin Bay and between Greenland and Iceland, producing hazardous icebergs (as the Titanic found out to its cost) which will hinder data acquisition and any future drilling. Also, the Arctic shelf is very broad and very shallow; water depths over most of the Chukchi Sea, for example, are less than 200m, much of it less than 20m. The mobile ice presents a set of challenges to economic exploration, drilling and development that we currently have ▶



The areas of Tertiary (pink) and Cretaceous (green) ocean crust around the spreading ridges are flanked by the highly extended continental crust of the predominantly unexplored passive margins (blue). Much of the intracratonic basin area extending landwards from the passive margins has experienced basement-involved compression, forming gentle anticlinal folds, which create the traps for some significant Arctic gas fields. Two major deltas are located at the tip lines of the two spreading centres and flanked by the Pacific Rim foldbelt – the Mackenzie Delta and the Lena Delta.

no idea how to overcome. Of course, such things were said about exploring in deepwater just over 20 years ago, and look at the progress we have made there."

"A seasonal approach to exploration is obviously essential, but we also need to understand the climatic changes the region is experiencing," he continues. "In Alaska and Western Canada the average winter temperatures have increased by as much as 4°C over the past 60 years. No one had tackled and survived the famed North West Passage (the Arctic sea route linking the Atlantic and Pacific Oceans) until Amundsen's three year expedition at the beginning of the last century. Now it can be done in a few days, through waters that were previously permanently icebound. This has major implications for seismic acquisition, exploration drilling and ultimately for the development of production facilities."

A further challenge is the sparseness of the existing database, particularly for regional seismic and wells in the high Arctic, with drilling clustered in a few regions, and large areas or the ▶

Uvat helicopter over seismic camp

Arctic relatively poorly understood. The seismic database is gradually increasing, however, spearheaded by improvements in the technologies being used by the seismic companies, such as methods of shooting marine seismic under the ice, as well as improving methods of land seismic acquisition.

Sustainable Development?

Looking ahead, however, Al thinks that dramatic innovations in technology will also be required in order to drill and produce in the Arctic. "In the South Kara Sea only two structures have been drilled, and both are large gas discoveries – Russanovskoye and Ldeningradskoye. They are sitting there under the ice, waiting for us to work out how to produce from them. We need to find techniques for both drilling and producing below the ice flow. I expect these will involve using downhole methods, with subsurface hydrocarbon separation and conversion all occurring in the well, producing hydrogen and syngas to the surface as the energy source. These are the technologies we are going to have to think about – and they are actually already working on the test bench at Imperial College."

"The Russian program for oil production in the Arctic includes one scheme to use a manned nuclear-powered drilling submarine that can move between wells, attached to a fixed frame on the sea bottom."

The prospect of nuclear-powered drilling submarines, of course, brings us to another major issue: the environment. The Arctic is a pristine wilderness, probably the last one left on earth. Many are completely opposed to hydrocarbon exploration and production in the area. All exploration and development plans have to take into account this opposition, and undertake all possible measures to prevent risk to the environment.

"There are many conflicting interests involved in Arctic exploration," Al says. "The environmentalists represent one facet, while governments can denote a number of different viewpoints. For one country, exploration for oil in their waters presents important development opportunities, and for somewhere like Greenland, possibly independence. Other decision makers will have their eye on energy security - or the next election. And we must not forget that about four million people live in the Arctic, 15% of whom are indigenous peoples who see nature as a long term resource which must be protected. Finally, of course there are the oil companies, often driven by short term shareholder value and demands."

"Sustainable development will require real partnerships between governments, industry and indigenous peoples, requiring a consistent approach across political boundaries."

A Striking Paradox

In summary, Al reiterates that the Arctic is a major hydrocarbon province, with many potential oil and gas reservoirs throughout the region just waiting to be exploited, particularly in the extensive passive margins and associated deltas. Despite avid discussion between many nations about the environmental and sustainability issues involved in Arctic exploration, he points out that it is Russia, already holding three-quarters of the discovered reserves in the Arctic, who will control future Arctic energy resources.

"And this is not going to happen quickly," he adds. "Despite technological advances, estimates of timing to production have not changed in ten years – it will take a long time and there are many, many challenges ahead.

"There's a striking paradox here," he points out. "We are facing new industrial challenges as the Arctic is warming due to the products of the very same industries that are now entering the Arctic regions. This has not only global implications, but also very concrete local and regional effects." ■

Imperial College/Layton Thompson

Professor Alastair J. Fraser holds the EGI Chair in Petroleum Geoscience at Imperial College, London. He worked for BP as a Petroleum Geologist/Exploration Manager for over 30 years in a career that took him to most corners of the world. Following the BP Amoco merger, he led the team which made the significant Plutonio discovery in Block 18, deepwater Angola. He is the author of many papers on the petroleum geology of extensional basins, most notably on the North Sea Jurassic and northern England Carboniferous.

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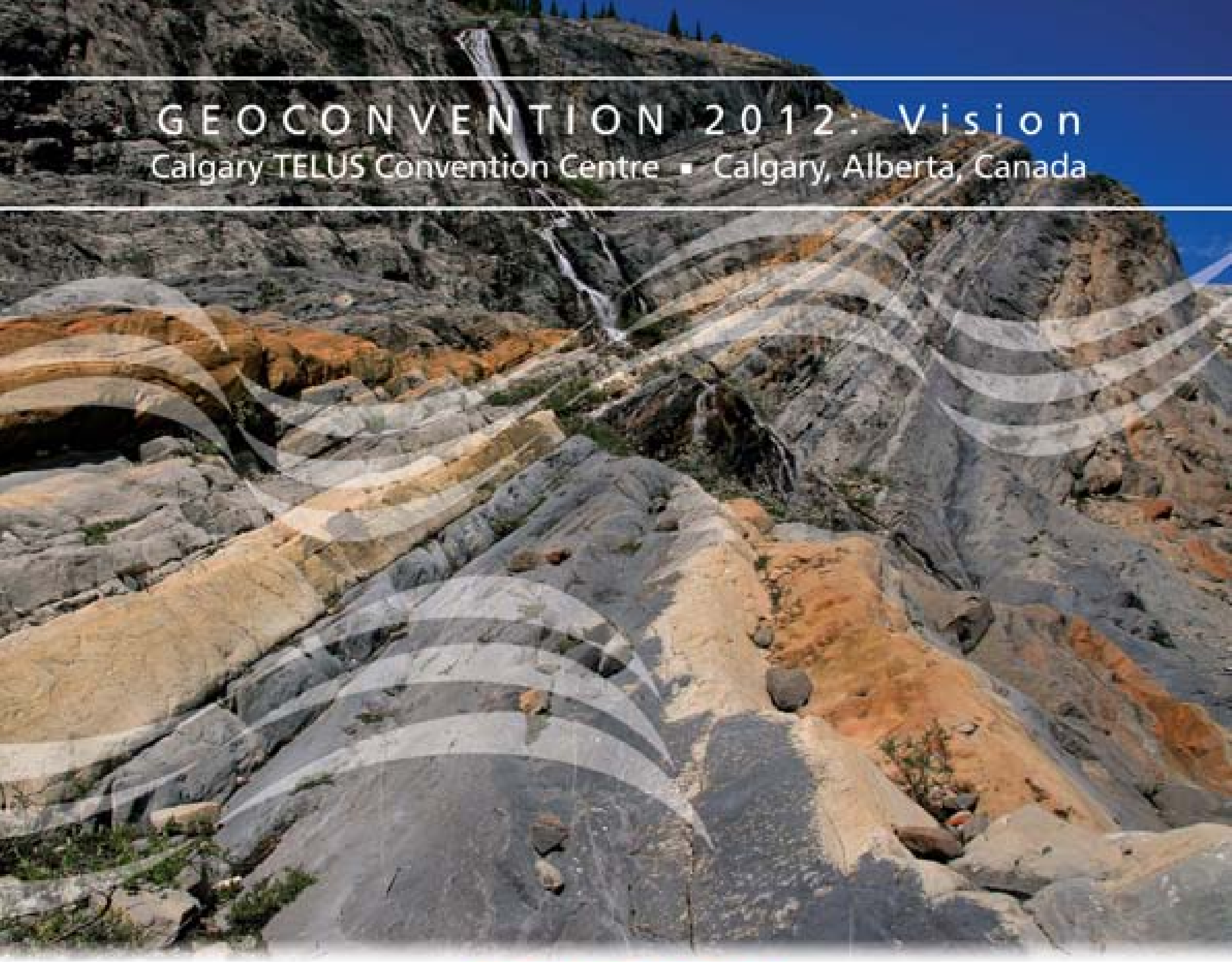
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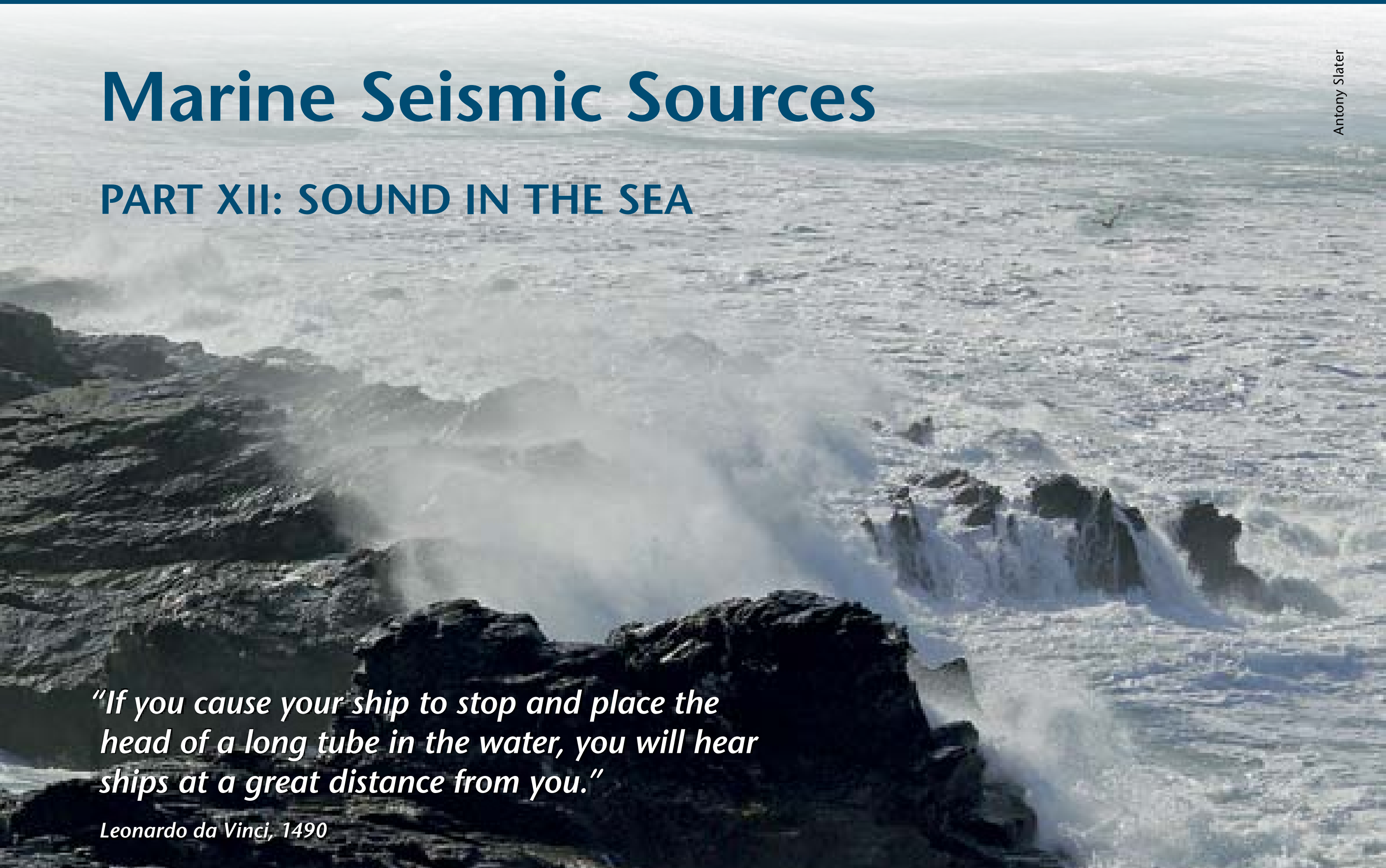

Antony Slater

Marine Seismic Sources

PART XII: SOUND IN THE SEA

"If you cause your ship to stop and place the head of a long tube in the water, you will hear ships at a great distance from you."

Leonardo da Vinci, 1490

MARTIN LANDRØ AND LASSE AMUNDSEN

Aristotle (384–322 BC) was among the first to note that sound could be heard in water. Nearly 2,000 years later, Leonardo da Vinci (1452-1519) made the observation quoted above that ships at great distances away could be heard underwater. In 1743, Abbé Nollet conducted a series of experiments to settle a dispute about whether sounds could travel through water. With his head underwater, he reported hearing a pistol shot, bell, and shouts. He also noted that an alarm clock clanging in water could be heard easily underwater, but not in air, clearly demonstrating that sound travels through water.

The name of Willebrord Snellius (1580-1626), a Dutch astronomer and mathematician, has for several centuries been attached in English-speaking countries to the law of refraction of light. But it is now known that this law was first described by the Arabian optics engineer Ibn Sahl (940-1000) working in Baghdad, when in 984 he used the law to derive lens shapes that focus light with no geometric aberrations.

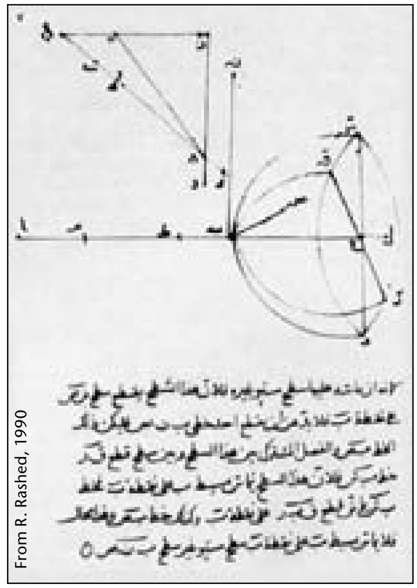
Development of Acoustics

In 1878 Lord Rayleigh published *The Theory of Sound*, a work marking the beginning of the modern study of acoustics. Lord Rayleigh was the first to formulate the wave equation, a mathematical means of describing sound waves that is the basis for all work on acoustics. His work set the stage for the development of the science and application of underwater acoustics in the twentieth century.

The sinking of Titanic in 1912 and the start of World War I provided the impetus for the next wave of progress in underwater acoustics. Anti-submarine listening systems were developed and in 1914, Reginald A. Fessenden developed the echo-ranger. The development of both active ASDIC and passive sonar (SOund Navigation And Ranging) proceeded apace during the war, driven by the first large scale deployments

Willebrord Snellius is famous for the 1621 discovery of Snell's law (also called Snell and Descartes' law) which describes the relationship between the angles of incidence and refraction, when referring to light or other waves passing through a boundary between two different isotropic media.

Reproduction of a page of Ibn Sahl's treatise on Burning Instruments from 984 showing his discovery of the law of refraction. In the treatise, he set out his understanding of how curved mirrors and lenses bend and focus light.



From R. Rashed, 1990

of submarines. Other advances in underwater acoustics included the development of acoustic mines.

The period between the two world wars was a time of increased discovery about underwater acoustics. Scientists were beginning to understand fundamental concepts about sound propagation, and underwater sound was being used to explore the ocean and its inhabitants. For example, shortly after WWI, the German scientist H. Lichte developed a theory on the bending, or refraction, of sound waves in sea water. Building on work by Lord Rayleigh and Snell, Lichte predicted in 1919 that, just as light is refracted when it passes from one medium to another, sound waves are refracted when they encounter slight changes in temperature, salinity, and/or pressure. He also suggested that ocean currents and seasonal changes affect how sound moves in water.

Scientists also discovered that low frequency sound could penetrate the seafloor, and that sound is reflected differently from individual layers in the subsurface sediment. For the first time, using sound, scientists could create a picture of what was beneath the seafloor. This provided clues to the history of the earth and a means for prospecting for oil and gas beneath the seafloor. Pioneering work was done by Maurice Ewing, A. Vine, B. Hersey, and S. ("Bud") Knott. In 1936-37, Ewing, Vine, and Worzel produced one of the earliest seismic recorders designed to receive sound signals on the seafloor. The need to generate high-energy, low-frequency sound that could penetrate deep into the seafloor led to the use of explosives and eventually to the development of air-guns and high-voltage discharges (sparkers).

The development of ocean bottom seismic stations continued sporadically until the early 1960s when nuclear monitoring became important. Then, new generations of seafloor seismometers resulted from Vela Uniform, a U.S. project that was set up to develop seismic methods for detecting underground nuclear testing. In the seismic industry, Eivind Berg and coworkers were the first to develop 4-component ocean bottom sensors, more than 60 years after Ewing's first trials.

Rapid Advancement

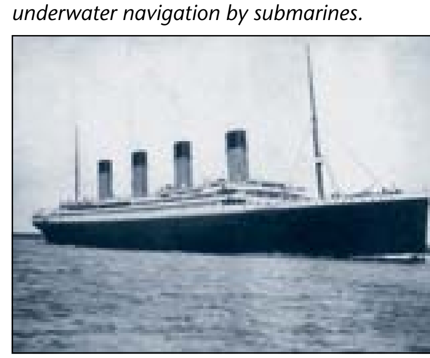
The beginning of WWII marked the start of extensive research in underwater acoustics. Nearly all the established methods of studying submarine geology were found to have military application, so progress in underwater acoustics, as in areas like radar and weapons, was shrouded in secrecy. At the end of the war, the U.S. National Defense Research Committee published a Summary Technical Report that included four volumes on research discoveries, but much of the work done during the war was not published until many years later, if at all.

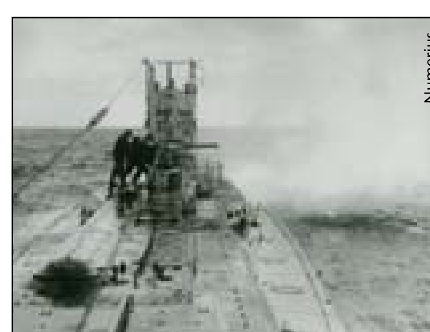
The WWII effort focused on making careful measurements of factors that affected the performance of echo ranging systems. Things that affect the performance of sonar systems are described by what is now called the "sonar equation" which includes the source level, sound spreading, sound absorption, reflection losses, ambient noise, and receiver characteristics.

The rapid advancement of underwater acoustics continued after WWII, with wartime developments leading to large-scale investigations of the ocean's basins. Coupled with advancements in technology (e.g. computers), underwater acoustics became an important tool for uses such as weather and climate research, underwater communication, and not the least, seismic exploration.

Lord Rayleigh's first researches were mainly mathematical, concerning optics and vibrating systems, but his later work ranged over almost the whole field of physics, sound and wave theory, electrodynamics, hydrodynamics and photography. He was awarded the Nobel prize in Physics in 1904 for his work on gases

The passenger ship Titanic's tragic sinking on April 14, 1912, encouraged developments of underwater detection systems. The French physicist Paul Langevin developed what he termed a "hydrophone" as a mechanism for ships to more readily detect icebergs. Similar systems were put to immediate use as an aid to underwater navigation by submarines.





Numerius

A German U boat: the study of acoustics was spurred by the use of submarines during World War I

Propagation Modelling

The propagation of sound through water is described by the wave equation, with appropriate boundary conditions. A number of models have been developed to simplify propagation calculations, including ray theory, normal mode solutions, and parabolic equation simplifications of the wave equation. Each set of solutions is generally valid and computationally efficient in a limited frequency and range regime. Ray theory is more appropriate at short range and high frequency, while the other solutions work better at long range and low frequency. Various empirical and analytical formulae have also been derived from measurements that are useful approximations. Here, we discuss the two most elementary and simple ways in which sound spreads out in the ocean.

But first, think of a wave spreading out from a raindrop hitting the water surface; the further from the raindrop source, the bigger the circle formed by the wave. As the circle gets bigger, its total length (circumference) also gets bigger. Spreading loss occurs because the total amount of energy in a wave remains the same as it spreads out from the source. (We are neglecting sound absorption.) When the circle of a surface wave gets bigger the energy spreads to fill it. Therefore, the energy per unit length of the wave must get smaller.

The total amount of energy in a wave remains the same as it spreads out from the source.

Spherical and cylindrical spreading are two simple approximations used to describe how sound level decreases in the ocean as a sound wave propagates away from a source. Let us look into these spreading laws in more detail.

The amount of energy from a sound source that is transported past a given area of an acoustic medium per unit of time is known as the intensity *(I)* of the sound wave. Intensity is energy/time/area. Since the energy/time ratio is equivalent to the power *(P)*, intensity is simply the power/area, $I=P/A$.

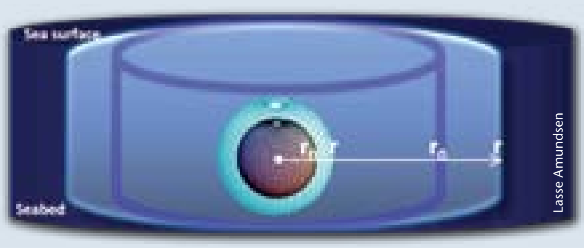
When sound propagates equally in all directions, the surface area is that of a sphere, $A=4\pi r^2$, where r is the radius. The power crossing all such spheres is the same:

$$P = 4\pi r_0^2 \, I_0 = 4\pi r^2 \, I$$

Then $I/I_0=(r_0/r)^2$. The amount by which the intensity I has decreased relative to its level at the source, I_0, at $r_0 = 1\ m$ is called the transmission loss. It is usually expressed in dB, leading to the spherical transmission loss equation:

$$TL = -10 \log_{10} (I/I_0) = 20 \log_{10} (r)$$

But sound cannot propagate uniformly in all directions from a source in the ocean forever. Beyond some range the sound will hit the sea surface and the sea floor. A simple approximation for spreading loss in a medium with upper and lower boundaries can be obtained by assuming that the sound is distributed uniformly over the surface of a cylinder having a radius equal to the range r and a height H equal to the depth of the ocean.



Sound generated by a sound source (shown as a white dot) at mid-depth in the ocean. At first the sound is radiated equally in all directions; sound levels then decrease rapidly with spherical spreading as sound spreads out from a sphere with a radius of r_0 to a larger sphere with a radius r. But once the sound is trapped between the top and bottom of the ocean it gradually begins to spread cylindrically, with sound radiating horizontally away from the source.

The surface area of the cylinder is $A=2\pi rH$. The total power crossing all such cylinders is the same: $P = 2\pi r_0 H I_0 = 2\pi r H I$. Then $I/I_0=r_0/r$, so that the cylindrical transmission loss in dB is:

$$TL = -10 \log_{10} (I/I_0) = 10 \log_{10} (r)$$

We can now construct a table showing the relative intensity levels and transmission losses for spherical and cylindrical spreading at various ranges, assuming that r_0 is 1 meter.

Range r (m)	Spherical spreading		Cylindrical spreading	
	Relative intensity I/I_0	Transmission loss (dB)	Relative intensity I/I_0	Transmission loss (dB)
1	1	0	1	0
10	1/100	20	1/10	10
100	1/10,000	40	1/100	20
1000	1/1,000,000	60	1/1000	30

The relative intensity level decreases less rapidly for cylindrical than for spherical spreading. Equivalently, the transmission loss decreases less rapidly.

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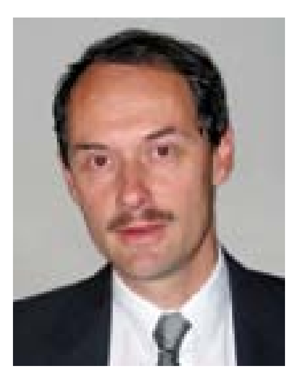
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Airgun History

The airgun produces an air bubble as we described in GEO ExPro Vol. 8, No. 1

In 1917 Rayleigh gave one of the first theoretical descriptions of an underwater air bubble. He was interested in the sounds emitted by water in a kettle as it comes to the boil, and explained these noises as resulting from the partial or complete collapse of bubbles as they rise through cooler water. The water in Rayleigh's theory was treated as an incompressible liquid.

During WWII much classified research was done on producing and detecting underwater sound in the ocean, includiing creating and studying bubble pulses, and many advances in theory and instrumentation were made. Some of this work was subsequently declassified and parts that are of interest to marine seismic surveying were published by Ewing (1948).

Following WWII seismic exploration in the Gulf of Mexico and offshore California expanded, but the source used for these surveys was explosive charges that caused environmental concerns and safety problems. In the mid 1960s Steve Chelminski began manufacturing and testing airguns for use in seismic surveys, and in 1970 he founded Bolt Technology Inc. Since that time Bolt has continued to improve and develop airguns. The need for a replacement for explosive charges was so great that many other marine sources were developed at that time, but none have been found that were as versatile as the airgun.

On the theoretical side advances were also made. In 1942 Kirkwood and Bethe derived an equation of motion for an exploding bubble in a compressible liquid. Later on, Keller and Kolodner (1956) derived a similar equation assuming adiabatic conditions that lead to a damping of the bubble oscillations.

Airgun firing in the sea

While the airgun won the competition for most popular marine source it was not without its problems. It was not yet the ideal marine source that the seismic industry wanted. Three specific improvements in airguns were sought after; more reliability, more power and a wider signal bandwidth. Geophysical Services Inc (GSI) began a development program to address these needs. A radical new design of airgun based on an external sleeve was produced to replace the conventional internal shuttle valve airguns. The first production unit was mobilised in 1984. Airgun development continued and improved models of the internal shuttle guns have been introduced so that both sleeve guns and internal shuttle guns are popular today.

One other innovation in marine sources needs to be mentioned. In 1989 Adrien Pascouet and his company Sodera presented the GI airgun which first generates a bubble and then (delayed by 10-20 ms depending on gun size) injects air into the bubble to prevent unwanted bubble oscillations.

Recently, Bolt Technology Corp. and WesternGeco have begun a joint effort to develop the E-Source air gun as an environmentally sensitive energy source for marine seismic surveys. The E-Source air gun is said to be a bandwidth-controlled source designed to reduce the potential impact of seismic signals on marine life. According to Bolt it optimises output in the seismic band, suppresses the high-frequency components with acoustic impact, and retains the low-frequency components critical to seismic exploration. ■

MARTIN LANDRØ

Kuala Lumpur – A Piece of Asia

Although sited a long way from Malaysia's oil and gas producing regions, the vibrant, exciting city of Kuala Lumpur is the centre of the country's hydrocarbon industry, as it is home to Petronas, the National Oil Company

INGVILD CARSTENS

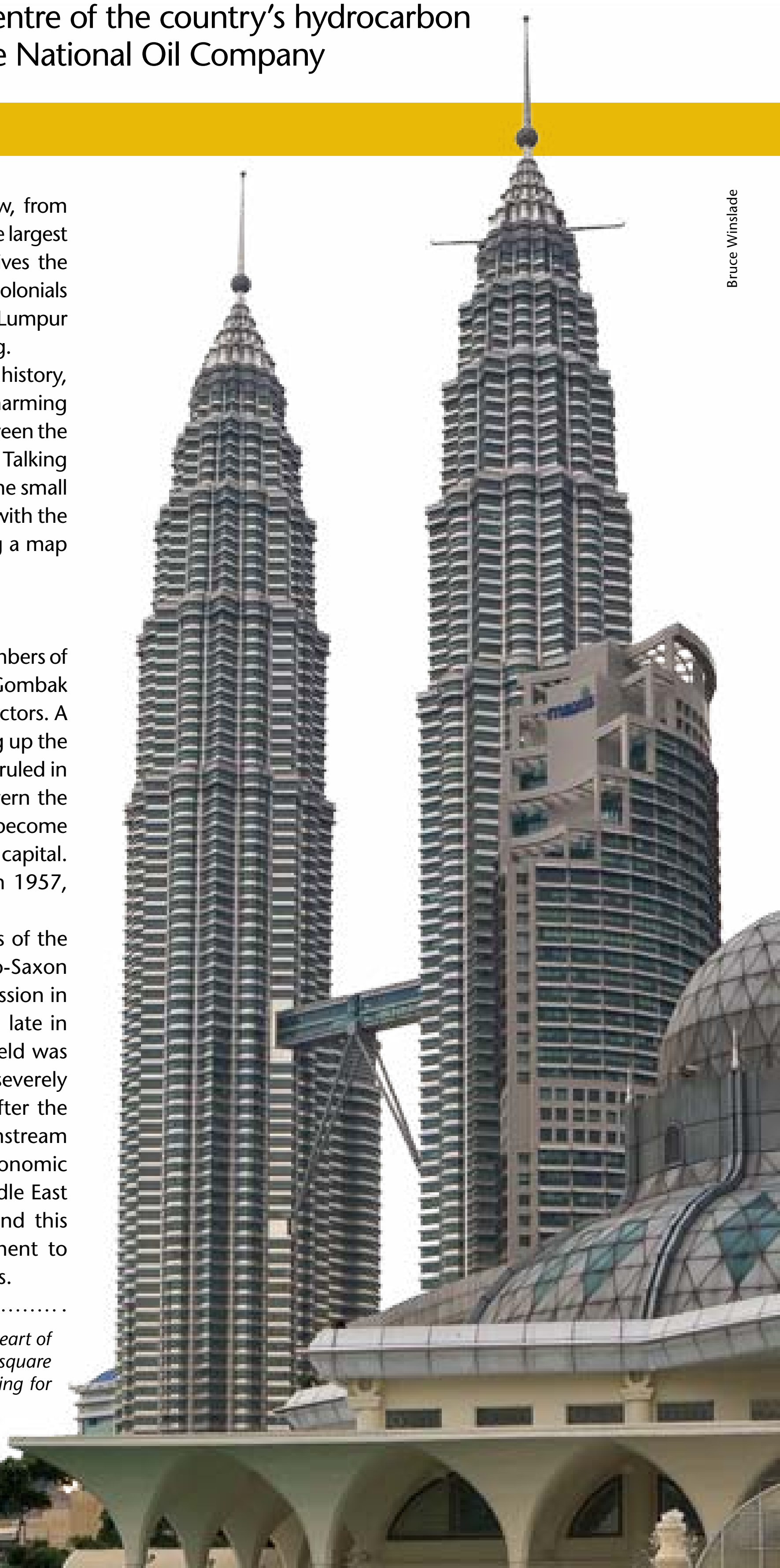
Kuala Lumpur is a fascinating mix between old and new, from historical sites to cutting edge architecture, with some of the largest skyscrapers in Asia. But it is the cultural diversity that gives the city its soul. Malays, Chinese, Indian migrants and British colonials have all put their mark on the city, making a visit to Kuala Lumpur – or KL, as it is commonly known – all the more interesting.

KL is a city that has something to offer everyone, from history, cuisine, shopping and culture to exotic nightlife. In the charming older parts of the city, the streets are narrow, winding between the old unique colonial style and Chinese inspired buildings. Talking a walk through the streets of this part of town is a must. The small shops and cafes, the sounds and exotic smells combined with the hectic life of the locals are thrilling – just be sure to bring a map with you. It is easy to get lost…

Tin Excavation to Modern Capital

The city of Kuala Lumpur was founded in 1857, when members of the Selangor Royal Family settled between the rivers of Gombak and Klang, and opened up the Klang Valley for tin prospectors. A mine was opened, and with it came other settlers building up the trade around the small settlement. At the time the British ruled in Malaysia, and they appointed a Chinese Captain to govern the town. Under Captain Hiu Siew, Kuala Lumpur grew to become the leading city of Selangor, and in 1880 it was made the capital. After Malaysia became independent from British rule in 1957, Kuala Lumpur remained its capital.

In the late 1870s oil was discovered in the territories of the island of Borneo, in what is now Malaysia. The Anglo-Saxon Petroleum Company received the first petroleum concession in 1909, and commercial amounts of oil were discovered late in 1910, in Miri, Sarawak. Oil production from the Miri field was limited until after World War II, as the installations were severely damaged by bombings during the war. In the years after the war, Shell and Esso dominated upstream and downstream production, but by the beginning of the 1970s, the economic and political tides were changing. With war in the Middle East and the OPEC embargo, oil prices were increasing, and this became a major incentive for the Malaysian government to increase their control over the oil business and its profits.



Bruce Winslade

The 88-storey glass and steel Petronas Towers are located in the heart of the city of Kuala Lumpur. They contain more than eight million square feet of shopping and entertainment facilities, underground parking for 4,500 cars, a petroleum museum, a symphony hall, a mosque, a multimedia conference centre – and the headquarters of the National Oil Company, Petronas.

The Foundation of Petronas

As a result, the National Oil Company of Malaysia, Petronas, was founded in 1974. The head office was located in the capital city, Kuala Lumpur, on the west coast of the Malay Peninsula, even though the bulk of the country's hydrocarbon reserves are to be found either in the Malay Basin off the east coast or the waters off Sabah and Sarawak on Borneo.

Petramina, the National Oil Company in Indonesia, became a close supporter in Petronas' first years. It contributed with technical assistance and other support that has shaped the governance and development of the oil industry in Malaysia. Petronas was run by Malays from the beginning, and has become a symbol of pride, an example of a successful Bumiputra-run company (Bumiputra is a Malay term for the indigenous people of the Malay Archipelago.) From the beginning Petronas wanted to be seen as a real, commercial player, making a profit and contributing to the growth of the Malaysian economy.

One of the major challenges for Petronas in the 1970s was access to qualified engineers from Malaysia, so the company launched scholarship programs to encourage Malaysians to get degrees within engineering disciplines. The strategy has paid off, and in the 70s and 80s the company expanded its operations into upstream and downstream industry. With the founding of the exploration and production arm Carigali Corporation in 1978, it become a major player in oil and gas exploration; in 1981 it expanded into the retail gasoline business, and in 1983 the first oil refinery was opened in Kertih, Terengganu. By this time, the oil and gas industry had become the most important revenue source for the Malaysian government, contributing significantly to the modernisation of Kuala Lumpur and the whole of Malaysia. The country's oil reserves are the third highest in the Asia-Pacific region after China and India.

Modernising KL

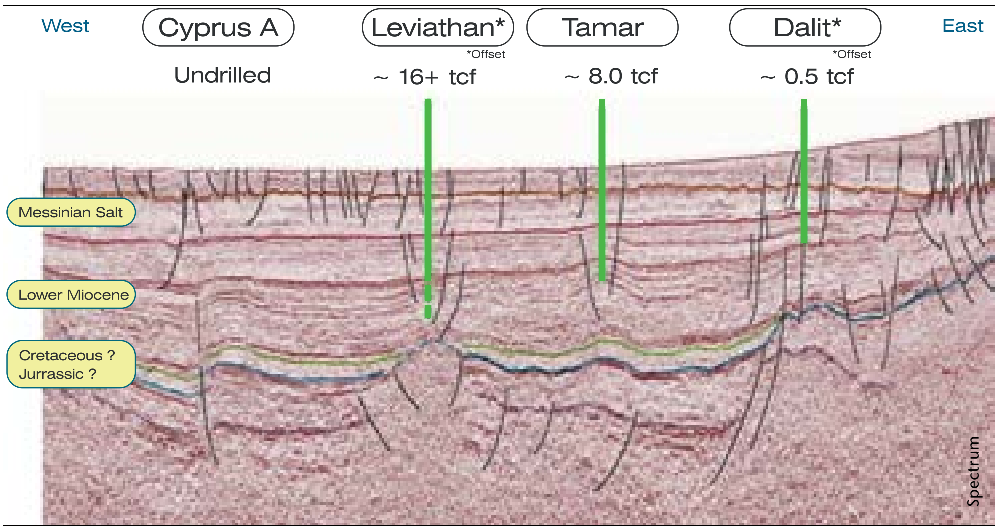
The real modernisation of KL started in the 1990s with the economic boom. Some of today's most important landmarks have been built since then, and a lot of the historical buildings of the city have had to give way to new residential buildings, shopping centres and office buildings.

And dominating the skyline are the Petronas Towers, which at the time they were built were the tallest buildings in the world, standing 452m high. The design of these dramatic towers, by American architect Cesar Pelli, was an attempt to express the culture and heritage of Malaysia through references to Islamic symbols and Muslim architecture, and these iconic buildings have now come to represent modern Malaysia. ■

Batu Caves are located about 13 kms north of Kuala Lumpur. It is a Hindu shrine, and it hosts the Hindu festival Thaipusam, a Tamil celebration held in January/February. It has become a pilgrimage site for Hindus from countries such as India, Australia and Singapore.

Cyprus: Historic Gas Discovery

The inhabitants of the island of Cyprus had a very exciting late Christmas present, when Noble Energy announced that they had made a significant gas discovery offshore on December 28 last year. The Cyprus A-1 well is reported to have found 95m of pay in multiple high-quality Miocene sand intervals, and initial estimates suggest that the field could hold gross reserves of between 5 and 8 Tcfg . The well, which is in Block 12, has an area of about 100 km^2, is in waters about 1,690 m deep, and was drilled to a depth of 5,860m.



Regional West-East seismic line illustrating the recent gas discoveries in Israel and the site of the recent Aphrodite discovery off Cyprus

Further appraisal drilling will be carried out on the field, known as **Aphrodite**, and on the rest of Block 12, one of 13 offshore Cypriot blocks available. It is considered possible that these reserve estimates will increase. Noble Energy operates the well with a 70% working interest. Delek Drilling and Avner Oil Exploration will each have 15%, subject to final approval by the Government of Cyprus.

On hearing of the discovery, the Commerce Minister Praxoulla Antoniadou stated that the find could be worth approximately US$129 billion (€100 billion), enough to satisfy he country's electricity production needs for 210 years. At the moment Cyprus imports has to import all its fuel, so the discovery has very significant implications. There are also serious political implications, as Turkey still lays claim to the northern part of the island, which it invaded in 1974, and it does not acknowledge the internationally recognised Greek Cypriot government. The Greek and Turkish Cypriots have been engaged in peace talks under United Nations auspices for decades, and this discovery is likely to increase tensions in the country.

Exploitation of the reserves could present financial challenges, as it is suggested that building a gas pipeline to reach the Cyprus coast would cost at least US$1.3 billion (EUR 1 billion. The size of the Cypriot market does not justify such a large cost and a liquefaction plant will also be needed to enable gas exportation and render the project profitable.

Israel: Increased Reserves at Leviathan

The Cyprus discovery is the fifth consecutive natural gas field discovery for Noble Energy and its partners in the greater Levant Basin. Earlier in December it had announced that results from its **Leviathan** appraisal well on the Amit license offshore Israel suggest that the reserves are likely to be larger than the initial estimate and the field is now thought to hold up to 20 Tcf reserves of gas.

The upgrading of reserves estimates comes from the discovery of approximately 88m net pay in multiple intervals at the appraisal well, Leviathan 3, which is located more than three miles east of the original Leviathan discovery and was drilled to a total depth of 5,225m (17,146 ft) in about 1,670m (5,480 ft) of water. Reservoir thickness and quality were found to be greater than anticipated and the appraisal well confirmed the gas/water contact.

The Leviathan field, which was initially discovered in December 2010, is estimated to cover about 325 km^2. Drilling has now recommenced at Leviathan 1 using the Homer Ferrington deepwater semisub, to investigate deeper targets at the site. The gas found at Leviathan is biogenic in origin, but Noble Energy believe there is good evidence for a thermogenic petroleum in deeper, pre-salt sediments.

Leviathan is operated by Noble Energy Inc. with a 39.66% interest, with Delek Drilling and Avner Oil Exploration having 22.67% each and Ratio Oil Exploration 15%. The field is expected to begin producing by 2016, while the Noble's other large Israeli accumulation, Tamar, is expected to begin production later this year.

Approximate location of the recent Noble Energy gas discoveries in Israel and Cyprus, which together amount to over 33 Tcfg

JANE WHALEY

Australia: Thirteenth WA Discovery

Chevron has been making steady progress in the Carnarvon Basin off North West Australia. On January 19 this year it announced that its **Satyr3** well in Block WA-374-P had discovered 74m (243 ft) net gas pay. The block is in the Exmouth Plateau, about 182 km north of the town of Exmouth in deep waters of over 1,120m. It is operated by Chevron with a 50% stake, partnered by ExxonMobil and Shell, each with 35%. It lies just to the south of the large Io-Jansz gas condensate field, which was discovered in 2000 and contains about 20 Tcf of recoverable reserves and covers an area in excess of 2,000 km^2. The primary reservoirs of the Exmouth Plateau are the Middle – Late Triassic Mungaroo Formation, the Late Jurassic (Oxfordian–Tithonian) sands of the Dingo Claystone, which forms the reservoir at Io-Jansz, and the Early Cretaceous Barrow Group.

Satyr 3 is the thirteenth discovery Chevron has made off Australia since 2009. Its most recent success before this was **Vos 1**, discovered in mid-December 2011. This well was also drilled on the Exmouth Plateau, in the WA-439-P permit area, approximately 300 km from Exmouth and the same distance due west of Satyr. Chevron is again operator on this permit and holds a 50% interest, with Shell holding the remaining 50%.

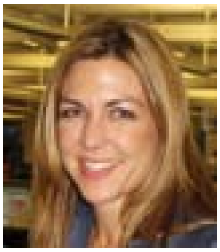
Chevron has been working in Australia for nearly 60 years and is closely involved with the development of the Wheatstone natural gas projects and the Browse liquefied natural gas development scheme. It is also operator of the Gorgon natural gas project, one of the world's major natural gas projects and the largest single resource natural gas project in Australia's history. It is designed to develop the Gorgon and Jansz/Io gas fields, which have a combined resource of about 40Tcfg. The project includes the construction of subsea gas-gathering infrastructure, and it is to be expected that the hydrocarbons found in the Satyr discovery will be exploited as part of the scheme. The project also involves the construction of a 15 million tonne per annum LNG plan on Barrow Island and a plant with the capacity to provide 300 TJ per day of domestic gas for Western Australia. Gorgon LNG will be off loaded via a four kilometre long loading jetty for transport to international markets. The project is on schedule for first gas in 2014. ■

One of the new discoveries, Satyr, lies close to the giant Io-Jansz gas condensate field, which will be developed as part of the massive Gorgon Project

Aerial view of the Gorgon LNG plant site being built on Barrow Island, 56km off the north-west coast of Western Australia

Oil: A Political Tool

Oil is the world's most powerful political tool at the moment



THINA MARGARETHE SALTVELT, PH.D

While softer supply/demand balances point to weaker oil prices in the first half of 2012, global geopolitical risk outweighs the bearish fundamental signal. OPEC's new 30 MMbopd production target will do little to cut down on oversupply in the market as we expect the call on OPEC will be below this target, at 29.35 MMbop for the first six months. Nevertheless, the recent sabre-rattling between the West and Iran has pushed up the political risk premium by US$6–8/barrel since mid-December. We expect oil prices to average US$107/barrel in Q1 2012, but the risk is on the upside as the political risk premium may push prices higher.

With President Obama signing a sanction bill on the last day of 2011, making it more difficult to sell Iranian oil, and most EU countries now supporting an embargo on Iranian oil, the pressure on Iran has clearly been building lately. In response to this, Iran has threatened to close the Strait of Hormuz, which would have an immense effect on the global oil market. The elevated rhetoric together with Iranian threats and naval activity in the Persian Gulf have increased the risk of confrontation.

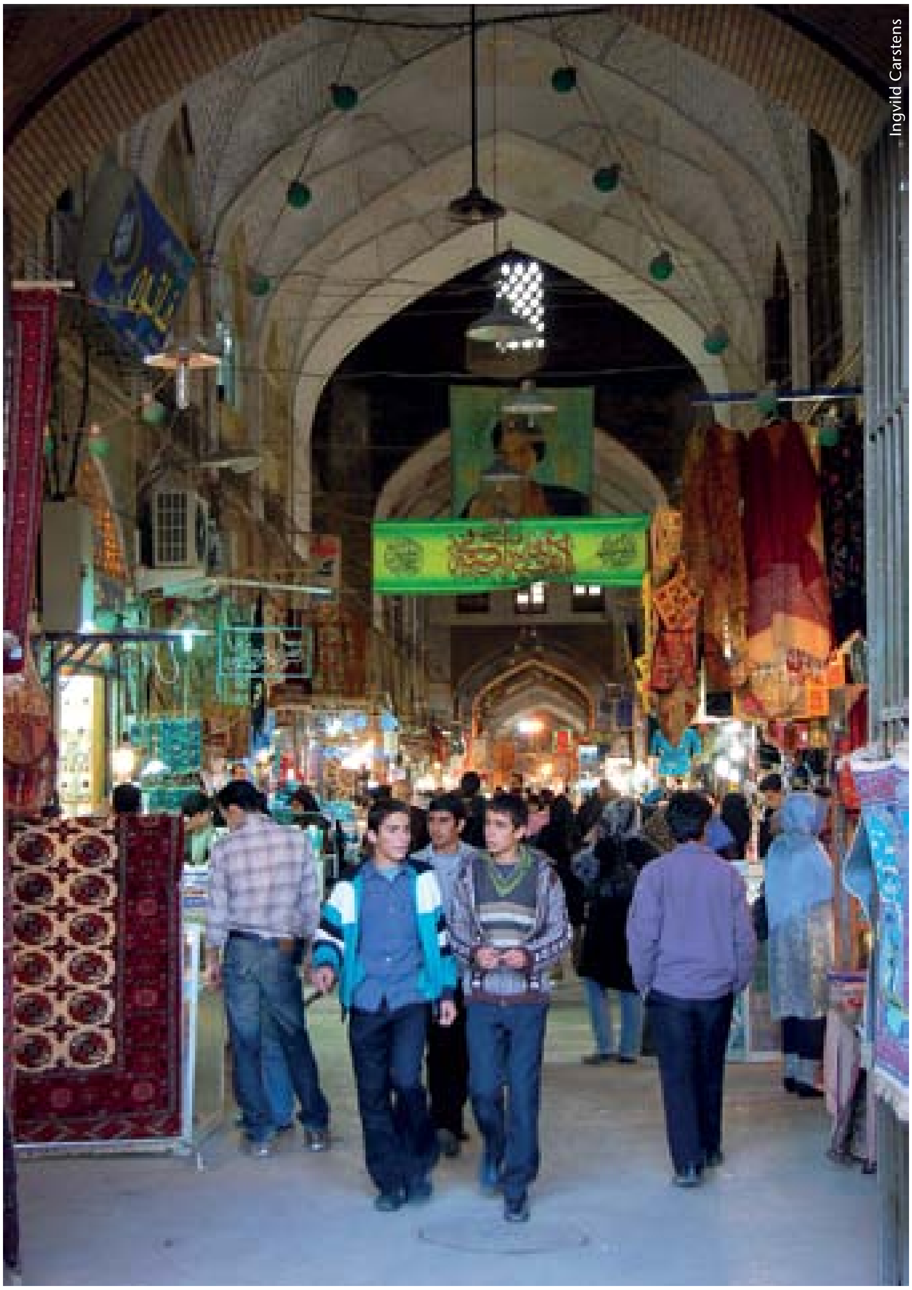
We expect the political climate between the West and Iran to deteriorate in the weeks to come as the verbal war will continue and pressure will be building up to the next milestone – the EU meeting on 30 January. With the Arab Spring and production stoppages in Libya fresh in mind, the risk premium – and thus oil prices – may continue to rise before the EU meeting, as the oil market is increasingly worried that the political tensions between the West and Iran will escalate to a military conflict that may harm oil production and transportation in the area.

Neither Iran nor the US wants a military conflict in the region or to push the ongoing conflict too far. But the pressure is high on both sides. It is election year in the US and Obama has been criticised for being too soft on Iran. Tehran's main goal is to scare the US and its allies away from implementing new and tougher sanctions which could break the country financially.

Closing the Strait?

However, we do not expect that Iran will push forward the closure of the Strait of Hormuz or a military conflict as this would block the country's ability to export oil and hurt the economy

The busy souk in Esfahan, Iran



Ingvild Carstens

badly. Oil exports provide half of the Iranian government revenues and account for around 80% of total exports (EIA).

In addition, an Iranian closure of the Strait of Hormuz for an indefinite period of time will have severe repercussions on the country's most important trading partners, China and Russia. Thus it is not likely that Iran wants to use this tactic as it will isolate the country further both militarily and economically. China is the largest importer of Iranian oil with 543 Mbopd, followed by Japan (341 Mbopd), India (328 Mbopd) and South Korea (244 Mbopd) (EIA). The increasing political tension in the area and the US sanctions have clearly started to hurt Iran's trade relations, as reported by the Financial Times recently, with Japan and South Korea trying to reduce their dependence on Iranian oil by seeking new suppliers. China and India have not signalled that they will follow these examples and bow to the pressure from the US to stop trading with Iran. These countries can actually benefit from the situation as they are now in a position to push for lower prices for Iranian oil.

Disruptions to the flow of oil through the Strait of Hormuz would threaten regional and global economic growth. Higher oil prices can push large economies over the edge and into a double-dip recession. A sharp fall in the world economy will have a severe impact on global demand for oil and may trigger a rapid fall in oil prices.

Saudi Arabia is the only oil exporter able to increase production substantially if global oil supplies are disrupted. OPEC's total effective spare capacity buffer is 3.95 MMbopd today, with Saudi Arabia accounting for almost 60%, which is not enough to cover the loss of Iranian exports, totalling 2.5 MMbopd. The growing appetite for the Kingdom's oil from EU countries, in case they go ahead with an embargo, and from Asian countries to reduce their dependence on Iran, is clearly cutting sharply into Saudi Arabia's spare capacity buffer. The country's ability to work as the producer of last resort will be weakened, making the global oil market more exposed to supply-side disruptions outside Iran. The political risk is also high in countries like Iraq, Nigeria, Kazakhstan, Sudan, Syria and Yemen.

Military Confrontation?

What may happen if the West attacks Iran? The response is expected to be severe and may lead to serious disruptions of oil supplies coming from the region. A military confrontation will increase the risk of damage to oil installations and tankers in the area, which could halt oil production and transportation for an extended period of time. The entire area will be affected by a military attack on Iran and, according to a Saudi journalist talking to the newspaper Al Jazeera, that "will make damages beyond calculations". Iran's own predictions of an oil price around US$200/barrel may then become a reality.

In addition, frustration with the current leadership in Iran is increasing, not only from the Arab countries but also internally. Isolating the country further economically and politically by souring the relationship to vital trading partners such as China and Russia and its Arab neighbours may put the current leadership under further strain. The Iranian leadership is trying to prevent a political uprising similar to those seen in Libya, Egypt and Tunisia last year. ■

Daniel Yergin's Quest for Energy in the 21st Century

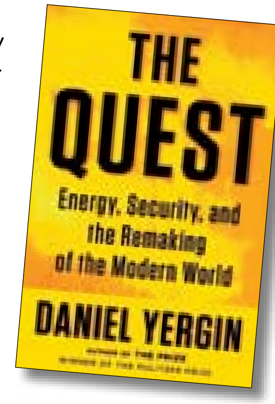
The Quest: Energy, Security, and the Remaking of the Modern World

Penguin Press, New York, 2011
$37.95 (Hardcover), 814pp

Daniel Yergin's 1991 publication *The Prize: The Epic Quest for Oil, Money, and Power* became one of the most widely read books on petroleum; it was made into a PBS documentary serial and won the Pulitzer Prize. Twenty years later, Yergin has produced another major work, *The Quest: Energy, Security, and the Remaking of the Modern World*. If *The Prize* was a historical narrative of petroleum, *The Quest* paints a near-future scenario for global energy based on the events of recent decades. Indeed, the collapse of the Soviet Union and the new Russia's appetite for power, the emergence of the European Union, the rise of the giant economies of China and India, the rapidly changing geopolitics in the Middle East and North Africa, the strengthening of OPEC's national oil companies, and the spread of the internet and digital technologies around the world have created a new world situation in which the globalised economy, geopolitics, technology, transportation, food, the environment, and so on are tied to energy more closely than ever. It is in this context that the analyses and opinions of energy watchers such as Daniel Yergin draw the attention of policy makers, entrepreneurs, energy companies, environmentalists, journalists and the public. As a co-founder and chairman of IHS Cambridge Energy Research Associates, a US-based consulting firm, Yergin has a bird's-eye view of global energy history, geopolitics, markets, technological trends, and strategic thinking.

Three questions lie at the heart of this book: How can we find sufficient resources for the world's increasing thirst for energy? How can we ensure access to and security of energy production and flow to the international market? How will we be able to resolve or cope with the environmental impacts of our energy consumption and technologies?

To address these issues, Yergin has organised his book into six parts. Part I looks at the current geopolitical situation of the world, focusing on energy hotspots such as Russia, China, Iraq, and Venezuela, while Part II reviews the state of conventional and unconventional hydrocarbon resources. Yergin shows excitement for the rapid growth of shale gas and envisions an important role for these technologies in the near future. Part III highlights electricity as the foundation of modern civilisation, and reviews the pros and cons of various technologies needed for electricity generation including nuclear power and coal. Part IV focuses on the thorny issue of global warming and gives a historical account of how studies of glaciers and ice ages in nineteenth-century Europe led to the measurement of the greenhouse effect of atmospheric carbon dioxide from the mid-twentieth century onwards. Yergin then extends this curiosity-based climate research to the international discourse undertaken at climate treaty gatherings in Kyoto (1997), Copenhagen (2009), and Cancun (2010). Part V concentrates on renewables, most notably solar and wind power. Yergin welcomes the contribution of these resources to the global energy budget but cautions that their future growth depends on large-scale commerciality. He also suggests that energy conservation or efficiency is a significant resource in its own right. Part VI discusses energy for transportation and vehicles, with Yergin supporting the emergence of the electric car mainly because it would drastically lower our dependency on oil. As more and more people buy and drive cars, the electric or hybrid car will probably be viewed as an urgent development for world energy.



Central to any discussion on future energy planning is the "peak oil" theory, according to which the era of cheap oil has passed because the world is already at or imminent to a peak point in oil production. Instead of a break-point peak oil, Yergin envisions an undulating plateau in oil production for decades to come. By 2030, world energy consumption will have increased by 35–40%, and hydrocarbons will still dominate, accounting for up to 80%, but from 2050 onward, Yergin suggests, the oil plateau may begin to decline.

The Quest ends with three wise comments on the future of world energy. Firstly, we need a 'new energy revolution' to satisfy and secure the world's increasing demand for energy. An energy-mix, including non-carbon resources, and energy efficiency are the critical components of this new energy scenario. Secondly, energy transitions have long lead-times; therefore, those groups and countries who invest now in the energy sector with intelligence and resilience will come out as the winners. Thirdly, the quest for progress and power is possible only because of human resources and how they are used. If the maxim 'oil is first found in the minds of men' proved true for the hydrocarbon age, mankind's ingenious thinking and innovate technologies will also find the solutions to our energy problems.

RASOUL SORKHABI

Daniel Yergin at the annual meeting of the World Economic Forum in Davos, Switzerland, January 29, 2011.

Michael Wuertenberg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Sequence Stratigraphy in the Middle East

Roger Davies of Neftex explains how sequence stratigraphy is a particularly useful tool for understanding the petroleum systems of the Middle East

What is Sequence Stratigraphy?
Sequence Stratigraphy examines the stratigraphic geometries and associated patterns of sedimentary facies that are generated by rises and falls in relative sea level, as my colleague Mike Simmons explained recently in *GEO Expro* (Vol. 8, No. 5). It is a valuable tool for predicting reservoir, source and seal facies and understanding reservoir architecture. While the concept was first applied using seismic data, it can equally be applied to well and outcrop data, and hence is widely used in the petroleum industry.

When was it first applied to the Middle East?
Much earlier than people realise! Even though sequence stratigraphy is considered to have been invented in the 1970s, employees of the Iraq Oil Company identified transgressions and regressions during the 1950s, described stratigraphic geometries and even drew somewhat primitive chronostratigraphic charts. Workers such as Dunnington and van Bellen deserve great credit for works that maintain their value today 50 years after they were written. Similarly, James and Wynd (1965) working in Iran appreciated that geological time was just as important as thickness or lithology. Lee Entsminger published a paper on sea level changes in the Wasia Group of Saudi Arabia in 1981. I would also highlight studies of the Hanifa and Hadriya reservoirs in the Berri Field of Saudi Arabia where a transition from carbonate platform to the adjacent source rock basin can be seen (McGuire *et al.* 1993; Kompanik *et al.* 1993, 1995; Koepnick *et al.* 1995). I am proud to have worked on the volume *Arabian Plate Sequence Stratigraphy* (Sharland *et al.* 2001) which certainly advanced the regional understanding of the entire Middle East, but we were building on the work of these earlier pioneers.

What is its significance to the Middle East?
It has the same implications as in basins worldwide; improved understanding and greater ability to predict into areas of limited data leads to risk reduction and better investment decisions. Moreover, the Middle East is an excellent place to study sequence stratigraphy, being dominated by stable platforms and interplays between carbonates and siliciclastics, or carbonates and evaporites. These interplays highlight cyclicity associated with rises and falls in relative sea level, and can then be applied to predict underexplored lowstands and stratigraphic trap plays.

Can sequence stratigraphy be applied throughout the Middle East?
Absolutely. In some parts of the Middle East, exploration is fairly mature and most conventional structures have been tested. Attention is switching to searching for stratigraphic traps. Sound sequence stratigraphic understanding is intrinsic to this. Many of the large fields have yielded much of their "easy" oil, with remaining oil in more complex, heterogeneous reservoirs. High resolution sequence stratigraphy is fundamental for improved reservoir description and prediction, leading to optimalisation of development schemes and improved ultimate recovery. Also, while Kurdistan may appear to be a simple structural play, an ability to understand and predict mechanical stratigraphy through regional sequence stratigraphic understanding can lead to better investment decisions in this exciting area. Finally, the time will come when the Middle East focuses on unconventional resources, including shale gas and shale oil. Regional sequence stratigraphy can help improve predictions of both source rock distribution and that of the all important brittle beds hosting the fractures that contain and deliver the hydrocarbon resources.

What are the most recent developments?
The science behind sequence stratigraphy has got bogged down in jargon but this is being cleared up. Sequence stratigraphy and eustasy are not interdependent, but eustatic models and understanding the causes of eustasy are coming back into vogue. I think the most exciting developments are arising from integration of detailed sequence stratigraphic understanding, high resolution biostratigraphy and isotope records (acting as proxies for global temperature changes or absolute dating) with an understanding of the timing of major plate tectonic events and of the creation of Large Igneous Provinces (LIPS) which comprise enormous volumes of mafic rocks preserved, for example, as continental flood basalts, volcanic rifted margins, oceanic plateaus and ocean basin flood basalts. Geodynamic models in the form of global palinspastic reconstructions reaching back into the Palaeozoic have a critical role in generating this understanding. Together they firmly demonstrate that glacio-eustasy has been happening throughout the Phanerozoic and that the concept of long periods of either ice-house or greenhouse conditions is simplistic and misleading. We are building towards a much better understanding of the timing and magnitudes of global changes in sea level. We shouldn't forget that high resolution 3D seismic is being used to recognise stratigraphic geometries that are intrinsic to a regional understanding of sequence stratigraphy.

How did you first become interested in the topic?
My interest evolved over a long period. I worked as a sedimentologist for BP during the 80s and early 90s, where I examined core from many different settings and worked with some very talented people. Sediments clearly show the effects of rising and falling sea level and sequence stratigraphy increasingly became an essential tool in detailed reservoir description over that period. I started applying it regionally in the early 1990s while I worked the Arctic from the Chukchi Sea to the Mackenzie Delta. My first applications to Middle East geology were in the late 1990s, when I started applying it to detailed reservoir descriptions in Kuwait and Iran, and to the regional geology of the Middle East, leading to my involvement with the team that wrote *Arabian Plate Sequence Stratigraphy*. ■

Discovering a New Province

Three discoveries in less than a year, proving up to one billion barrels of oil equivalents, mean that oil companies are once more flocking to the Barents Sea.

HALFDAN CARSTENS

Another oil and gas discovery was announced in the south-west Barents Sea, north of the Arctic Circle, early in January this year. **Havis** (meaning 'sea ice') lies just a few kilometres away from **Skrugard** (meaning 'pressure ridges') which, with up to 300 MMboe recoverable, was said to be the third largest discovery in the world last year. (*GEO ExPro* Vol. 8, No. 3; Vol. 8, No. 5). Havis may also contain more than 300 MMboe, the majority of which is oil.

This latest well (7120/7-1) encountered a 48m gas column in the Middle Jurassic Stø formation and a 128m oil column in the Stø and Lower Jurassic Nordmela formations.

Actually, hitting oil in the Havis prospect was no surprise at all. The rotated fault block is a look-alike to Skrugard. Both structures have well-defined flat spots at two levels and excellent EM-anomalies, both indicating the presence of hydrocarbons. The occurrence of flatspots at two levels is, however, unusual and very few examples are known. The upper one corresponds to the gas-oil contact, while the lower one demonstrates the oil-water contact.

The question was thus not *if* oil and gas would be found, but *how much*. Now we know, and it is a substantial amount.

More good news can be expected. Statoil, the operator, has published maps showing additional prospects in the same licence. This was substantiated in January, when Statoil geologists spoke about the discovery on prime time Norwegian television, when they also showed flat spots on a neighbouring prospect and demonstrated how EM-anomalies indicated the presence of hydrocarbons.

In other words, while up to 600 MMboe have been discovered in two prospects so far, more is to be found. Moreover, reliable sources say that there are additional look-alikes in open blocks next to the Statoil licence. Geologists with inside knowledge claim that this basin on the western side of the Loppa High may eventually prove one billion barrels of oil equivalents - others are even more optimistic.

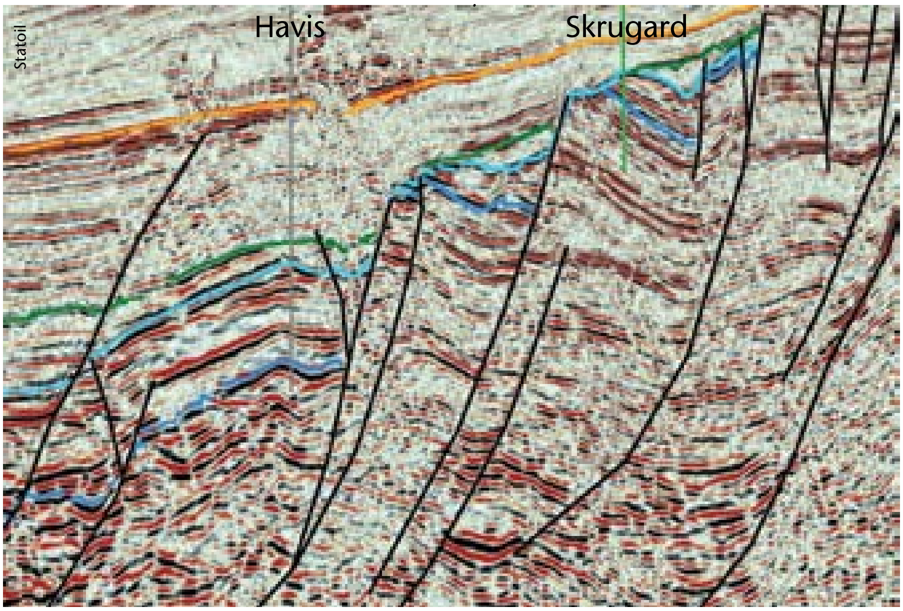
"This is a new petroleum province where exploration has just started. I believe there is a good possibility of finding find some two billion barrels around the Statoil discoveries," says Snorre Olaussen, professor in Arctic geology at the University in Longyearbyen, Svalbard, who had nine years experience as an explorationist in Eni (a partner in both discoveries), before becoming an academic. This confirms that the Barents Sea will be a Hot Spot for many years to come."

In total, 92 wells have been drilled in the Barents Sea so far. One gas field, Snøhvit, is on stream, one oil field, Goliat, will start producing next year, while three major discoveries have been announced in less than 12 months. Because of these, the interest in the Barents Sea has increased tremendously, confirmed when some 181 blocks in the region were nominated, the highest number ever, when the Ministry of Petroleum and Energy asked the oil companies which blocks they wished to see included in the 22nd licensing round, which will be announced in June. Nobody will be surprised if acreage is made available in the petroleum province that hosts Skrugard and Havis.

The race is definitely on - again. While several of the supermajors left the Barents Sea a long time ago, some of them, like ExxonMobil and Shell, may be on their way back, joining the group that at present consists predominantly of minor sized companies hoping to make a fortune in what must still be considered a frontier province.

The Barents Sea finally seems to have come of age.

The new find, Havis, looks very similar to the 300 MMboe Skrugard discovery



Gas Hydrates in the Arctic

Halfdan Carstens

The Arctic contains huge volumes of conventional oil and gas, but if we also include non-conventional hydrocarbons – such as gas hydrate – the Arctic may be a source of energy for centuries to come.

Arctic Alaska and Arctic Russia are two established petroleum provinces that have already produced vast volumes of oil and gas.

In addition, as we discuss on page 78, the USGS has concluded that some 400 Bboe, including 90 Bb of oil, have yet to be discovered in the Arctic. That amounts to 25% of the undiscovered resources worldwide as judged by the same experts. The Russians, on the other hand, claim that as much as 58% of the world's undiscovered oil and gas belong to the Arctic. As a comparison, the annual world oil production is about 30Bbo.

For oil, five basins stand out in the USGS assessment: Arctic Alaska, the Amerasia Basin, East Greenland Rift Basins, the East Barents Basins and West Greenland-East Canada, while three basins account for most of the undiscovered gas: the West Siberian Basin, the East Barents Basins and Arctic Alaska. If we combine oil and gas and convert to oil equivalents, it turns out that the West Siberian Basin alone may contain 30% of the Arctic oil and gas to be found.

It is worthwhile to keep in mind that almost all of the Arctic resources (84%) are expected to found offshore and in water depth less than 500m.

These numbers, however, dwarf when we include gas hydrates. While the figures for unconventional resources definitely are more speculative than for conventional oil and gas, there is reason to believe that there may be enough gas around the Arctic to keep the hydrocarbon economy going for several centuries. 'Peak oil' takes a different meaning when we look at resources from that perspective.

"The energy content of methane occurring in hydrate form is immense, possibly exceeding the combined energy content of all other known fossil fuels," said Espen Andersen of Statoil at the Arctic Frontiers conference in Tromsø, Norway, in January.

Gas hydrate is a solid, crystalline material formed from natural gas (mainly methane) and water. 1 m^3 of hydrate contains about 164 m^3 gas (at STP). Gas hydrate occurs on land in permafrost regions and in oceanic sediments in Gas Hydrate Stability Zones (GHSZ), ocean continental slopes and deep continental shelves. Gas hydrate will be stable in the very cold Arctic Ocean sediments from depths as shallow about 350m.

"Gas hydrate is an environmentally secure resource in an environmentally fragile area like the Arctic region. It is a thermodynamically stable solid in its natural environment and is unlikely to be spatially associated with petroleum," according to Michael Max of Hydrate Energy International speaking at the Arctic Frontiers conference.

"What matters is the volume of gas hydrates accumulated in sand sediments. Even if a small fraction of the energy contained in natural gas hydrates can be commercially produced, it could substantially increase the volume of clean-burning natural gas and improve global energy security by reducing imports," said Andersen.

While the US consumes about 125 Tcfg a year, the Arctic may on its own contain some 6,000 Tcf, according Michael Max. But, beware, that is not to be looked upon as 'reserves'. We are talking about highly speculative, undiscovered resources. ■

CONVERSION FACTORS

Crude oil
1 m^3 = 6.29 barrels
1 barrel = 0.159 m^3
1 tonne = 7.49 barrels

Natural gas
1 m^3 = 35.3 ft^3
1 ft^3 = 0.028 m^3

Energy
1000 m^3 gas = 1 m^3 o.e
1 tonne NGL = 1.9 m^3 o.e.

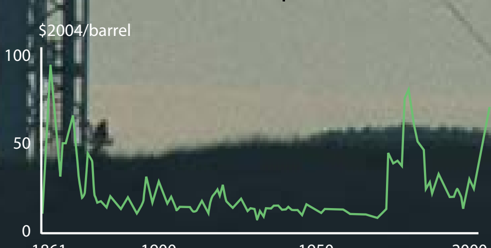
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

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

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

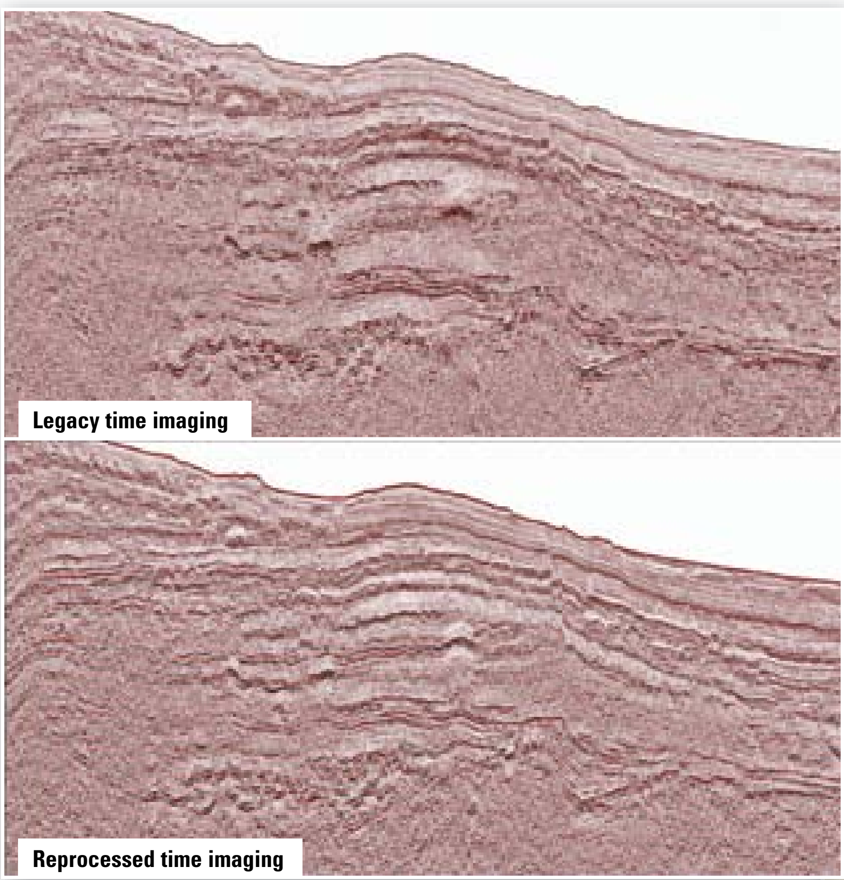
Historic oil price

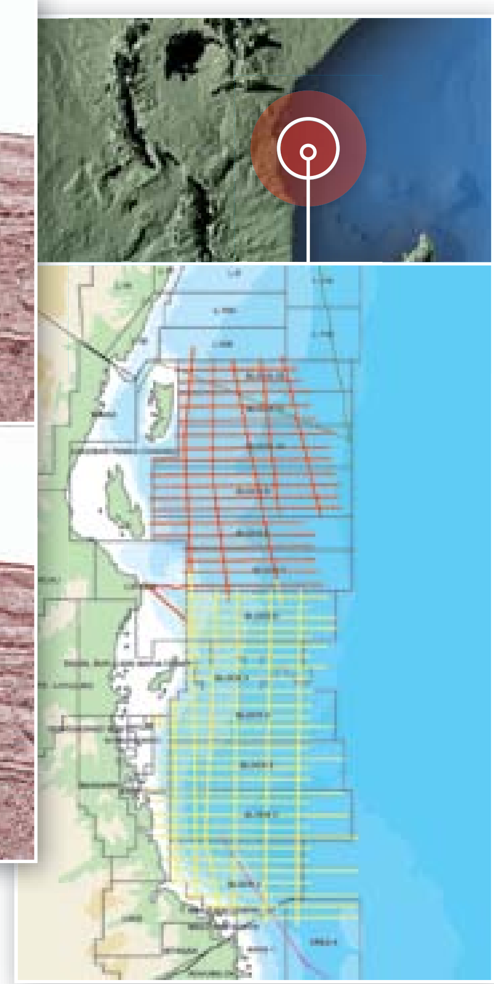


Multiclient Services

Tanzania Reprocessed Seismic Surveys Available

Full Kirchhoff Depth Migration Now Underway





- 4,340 km PSTM completed, PSDM underway
- 7,035 km PSTM and PSDM underway

Increased Resolution and Prestack Data Deliverables

- 2D anisotropic VTI Kirchhoff prestack time migration
- 2D anisotropic VTI Kirchhoff prestack depth migration
- AVO and inversion-ready seismic gathers
- Petrel* seismic-to-simulation software and SEG-Y deliverables available now
- Reprocessed in association with the Tanzania Petroleum Development Corporation

For more information, please contact us on
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