Vol. 2, no. 2/3 – 2005

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

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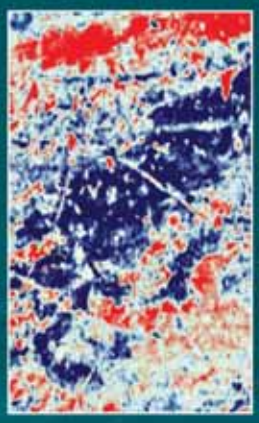

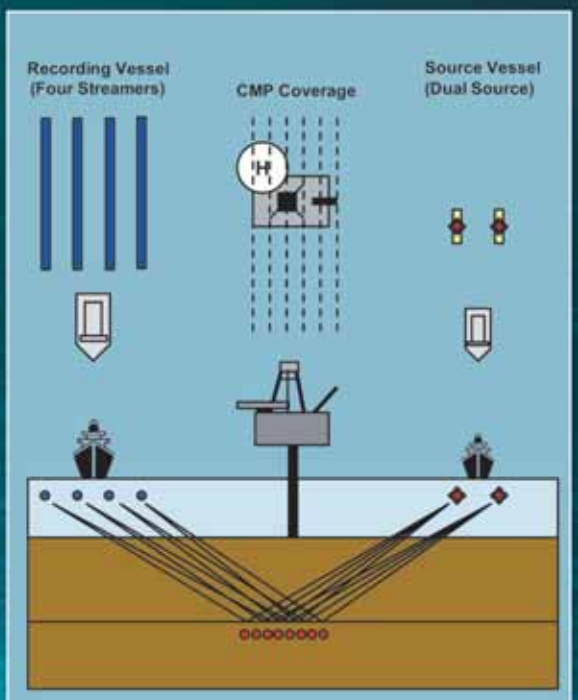

The illustration shows a typical two-vessel undershoot technique used by Fugro-Geoteam.

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May 2005, Vol. 2 No. 2/3

This years AAPG Annual Convention will be held in Calgary, Canada. GEO ExPro is using this opportunity to review the Canadian oil and gas potential. While most of the oil and gas production today occurs in the Western Canada Sedimentary Basin, the Athabasca Oil Sands and the Atlantic Margin, future activity will most certainly migrate towards the Arctic basins where huge volumes of gas have already been proven.

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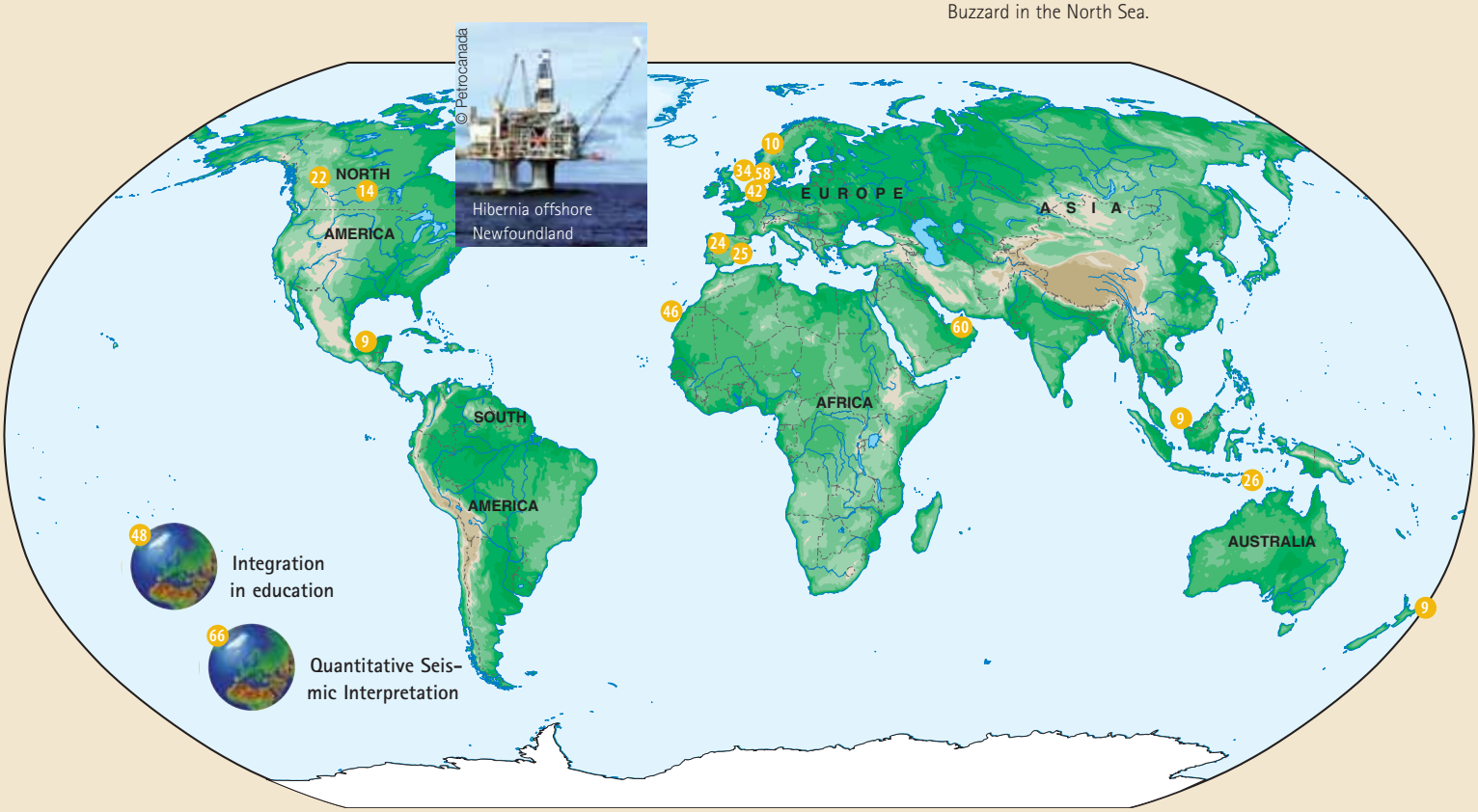
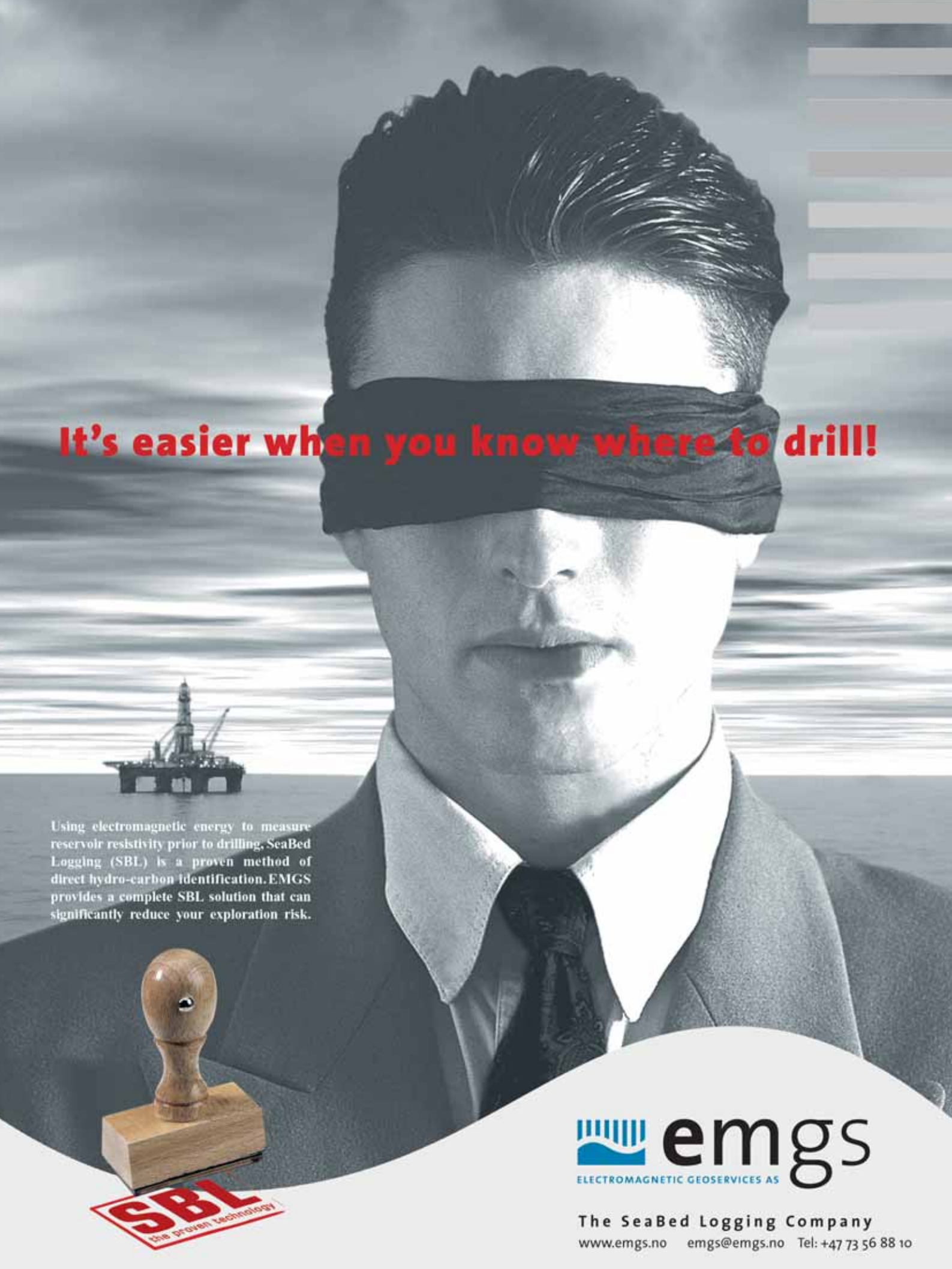
Coloumns

Features

"It's about time for the good geologist to come out of the closet." This statement by the legendary geologist and entrepreneur Michel T. Halbouty fits the oil finders Graham Doré and John Robbins who can claim they were instrumental in the discovery of the giant oil field Buzzard in the North Sea.

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The future of the oil and gas industry

Total oil production in the world averages approximately 82 million barrels of oil per day (bopd), the equivalent of 13 million m^3 per day. Also, 7 billion m^3 (0,25 Tcf) of natural gas is produced every day to meet our energy demands.

The total daily output of oil and gas for the entire world is therefore equivalent to 125 million barrels of oil (20 million m^3) equivalent per day. This number corresponds to the reserves of a "major" oil field (for nomenclature, see page 66).

Most of what is being produced is "conventional oil and gas", i.e. light to medium oil and gas that is tapped from high porosity and high permeability reservoirs. Reserve estimates quoted by various sources for the whole world also refer mostly to "conventional oil and gas." There are, however, a number of other geological occurrences of hydrocarbons that need to be included in our reserves and resources as the energy prices are steadily increasing and the technology to find and produce them is moving fast forward.

© Suncor Energy Inc.

Canada has vast amounts of "tar sand" that are in the process of being developed and produced.

Sources of unconventional oil include oil sands found in Canada (see story starting on page 14), Venezuela and Russia, heavy oil, as well as in oil shale deposits found all around the world, but particularly in the United States (GEO ExPro No. 3, 2004).

Sources of unconventional gas include coal bed methane, tight gas sands, shale gas and – for the more distant future – gas hydrates (GEO ExPro No. 1, 2004).

The total volume of hydrocarbons in these "unconventional reservoirs" is – in qualitative terms – enormous, and by far (!) exceeds the known reserves and estimated undiscovered resources of conventional oil and gas.

The recovery of the unconventional hydrocarbons, however, largely depends on the price of energy and improved technology.

With respect to future price, we know nothing.

With respect to technology, we know that there will be new innovations and significant improvements in the years to come.

With respect to the future of the oil industry, we know that it is going to be an extremely interesting place to work.

Halfdan Carstens
Editor in Chief

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The Canadian potential

Canada is the world's third largest gas producer, trailing only Russia and USA, and the world's ninth largest oil producer. Petroleum production has increased steadily through the last 20-25 years. The reason for the increases are the significant proven reserves in the Western Canada Sedimentary Basin, that have been tapped for more than 50 years, and recent developments along the Atlantic Margin (see story beginning on page 14).

In addition, the country's resources of hydrocarbons - in several onshore and offshore basins – are enormous, and far from clearly understood. A lot more data and research are necessary to reveal the secrets of the Canadian oil and gas richness.

Canada is thus destined to be one of the world's largest producer of both oil and gas in the future. While exploration and exploitation will certainly continue in mature basins, future efforts will take place in two different settings:

- Exploration in the remote areas in the Arctic north of 60 °N (compare map page 14-15)
- Technological developments to produce unconventional reservoirs

In the meantime, we can enjoy, among many other things, the Canadian scenery, including Moraine Lake, next to the more famous Lake Louise, in Jasper National Park, Alberta, only a few hours drive from Calgary that hosts this years AAPG Annual Convention.

Towards digital full-wave imaging

Photo: Tore Karlsson

Input/Output gave their 16th technical forum at the Marriott Sprowston Manor Hotel where it also started 19 years ago.

"About every 20 years, the seismic industry transforms itself to embrace a fundamentally new technology. In the 1980's, our industry transitioned from 2D to 3D. Today, we are on the brink of another era – towards digital full-wave imaging," says Mike Burrett, VP of I/O Sensor .

At the end of April 2005, I/O hosted the 16th Annual Sprowston technical forum (Norwich, UK) "to debate and develop ideas about our industry's current imaging challenges and pathways for innovation," says Bob Peebler, CEO of I/O. "We are confident that there is a strong need for a new era of seismic imaging technology to enable oil and gas companies worldwide to meet their exploration and production objectives," Peebler said.

"Digital full-wave imaging represents a fundamental rethink of everything we know about geophysics, from how surveys are designed to how the data is processed and the final image is rendered. The benefits of full-wave – increased image quality and improved field productivity – are beginning to be appreciated by more of our colleagues around the world," Burrett said at the seminar.

The workshop started in 1986 and has been held annually since then. The 1986 event was held in Voorschoten, in the Netherlands, when twelve leading thinkers from the European industry met to discuss emerging and innovative technologies. At that time, the main focus was on land sensor technology, but over the years the event has grown to cover all aspects of land and marine acquisition and processing, and the 2005 workshop attracted an impressive delegate list of 60 key industry representatives.

With participants from service and contractor companies, universities as well as oil and gas companies, the forum has become established as a valuable tradition in the geophysical community benefiting both industry experts and the company itself.

"I give priority to attending the I/O seminar," says one of the participants who finds great value in: "listening to a series of interesting presentations and the opportunity to meet and discuss geophysics with the E&P industry experts during both the formal and social programs." This year the forum included more than 15 technical presentations from I/O, leading oil and gas companies and contractors, and ample time was given to openly debate and develop thoughts on current technological challenges as well as future pathways for next generation innovations.

"These seminars have been a reservoir of ideas for us at I/O," says Mike Saur, Director of LISD, who prepared a presentation on how input in earlier seminars has resulted in new commercial products for I/O. Key I/O products like VectorSeis and DigiSHOT have all benefited from customers' input at Sprowston seminars. VectorSeis is I/O's land seismic acquisition sensor and DigiSHOT is the marine seismic source control solution.

"Current seismic challenges present opportunities, but only if we are willing to challenge conventional wisdom, to embrace a vision of innovation and next-generation technology solutions, and to partner across industry to successfully leverage resources as we embark upon the next era of seismic imaging," Burrett said at the seminar.

Photo: Tore Karlsson

Mike Burrett, Vice President for I/O Sensor, has been a key player since the first seminar in 1986.

"The world's first"

In the past few years, I/O was transformed from being an equipment manufacturer for the seismic contracting industry, to the world's first technology-focused seismic solutions company. The intention is to develop and deploy advanced technologies and services across the entire seismic workflow – from survey planning through field acquisition and into processing and final image rendering, thereby, fundamentally improving image quality while reducing costs and cycle times for customers. As the owners of advanced hardware, software, processing tools, and value-added geophysical services, I/O provides tailored seismic solutions that address the most difficult imaging and operational challenges.

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Roxar expanding across Asia

"We are facing a market that is big and expanding fast. The national oil companies in this region have a need to increase the recovery rate, which on the average is less than 20 percent. They all want to produce the last droplets in the reservoir, and they are all expressing ambitious targets," says Morten Tønnesen of Roxar in their Middle East office in Dubai.

Dubai, the largest city in the United Arab Emirates, is itself growing incredibly fast, chiefly due to its favourable economic climate, but also due to a booming oil industry where Dubai serves as the hub to the Middle Eastern and Asian markets. Key markets with strong purchasing power are advantageously close by.

Roxar offers their services in reservoir modelling and reservoir simulation based on the RMS-and Tempest software. Revenues are equally split between software sale, support and reservoir studies, and Tønnesen believes it is extremely important to be close to the customer:

"Our focus is on service which is particularly associated with the needs of the national oil companies for training of local staff, day to day support, knowledge transfer and project execution that uses advanced software technology. Most national oil companies aim to build competence to increase the number of local staff capable of performing software aided reservoir studies: This is what we offer to our clients. In addition, Roxar has donated software and is working closely with leading academic institutions in the region to support this effort."

Last year was exceptionally successful with contracts signed with ADNOC (UAE), Petrochina (China) and Petronas Carigali (Malaysia). Roxar technology is used on several of the largest oil and gas fields in the Middle East and Asia characterized by complex reservoirs in both clastic and carbonate environments where large numbers of wells need to be handled (up to 10,000). "RMS is the only software that is capable of correctly handling such large volumes," says Tønnesen who believes their Asian success "is a matter of being in the right place at the right time coupled with the right people and solutions."

Photo: Halfdan Carstens

Morten Tønnesen, regional manager for the Middle East and Asia Pacific, is running a successful operation from Dubai and has secured contracts all over Asia the last year on behalf of Roxar. Continuously expanding, the Roxar team has offices in nine major locations in the Middle East and Asia Pacific region. Having recruited 20 new employees from 14 nations over the past 18 month, here represented by Rebecca Clayton, it demonstrates its presence in a growing international, multicultural petroleum community. "We have a great need for competent people, and the Middle East and Asia is the place to find them," Tønnesen says.

New corporate branding

In February Roxar launched its new corporate branding. "The strapline Maximum Reservoir Performance reflects the company's goal to be the partner of choice for oil and gas companies throughout the world, both big and small, which helps them find technological solutions to achieve the best possible performance from their reservoir assets," says CEO, Sandy Esslemont. Roxar's new branding communicates the scope of solutions the company offers to help reservoir and production management issues, namely reservoir interpretation, reservoir modelling, reservoir simulation, well and completion optimization, production and process management and consultancy services.

50 wells reprocessed

Rock Solid Images has entered into an agreement with Endeavour International Corporation to provide regional rock-physics and seismic modelling data to support Endeavour's exploration activities within the Central Graben of the UK sector of the North Sea.

Approximately 50 wells will be pre-processed using Rock Solid Images GWLA petrophysical workflows and then analyzed within Rock Solid Images MOSS product-suite, which provides sophisticated tools for rock-physics and seismic modelling. The resulting data sets are essential pre-requisites to any AVO or impedance based seismic reservoir characterization study and allow for effective risk reduction within an exploration framework.

Said Ronald A. Bain, Ph.D. vice president, Geosciences at Endeavour: "This is an example of how our company is utilizing technology to enhance its exploratory efforts in the North Sea and reduce the risks associated with the search for new energy sources. This rock properties study with its interactive modelling capabilities will allow us to more accurately predict the potential fluid content in a reservoir before drilling."

© Rock Solid Images

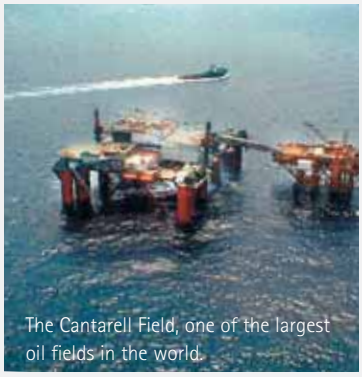
25 billion barrels in deep water

According to their own estimates, Mexico still has approximately 54 billion barrels of oil equivalent in and around the Gulf of Mexico. About half of that - 25 billion barrels - lie in what Pemex considers deep water, at depths of 500 meters or more. On the contrary, BP Statistical Review of World Energy 2004 estimates that Mexico has proven reserves of 16 billion barrels of oil and 14.7 Tcf (420 billion m^3) of gas.

The rest of the possible reserves in Mexico's portion of the Gulf lies closer to the surface or onshore, and are therefore easier to extract with the company's existing technology.

Pemex officials have been lobbying for greater foreign investment in an effort to tap deep-water reserves. Pemex invests about USD 10 billion a year in exploration and production, while the private sector estimate that for deep water reserves alone it is necessary to spend around USD 20 billion a year.

Pemex produced 3.4 million barrels a day of oil last year, making it the world's third-largest oil company.



The Cantarell Field, one of the largest oil fields in the world.

Multiwave break ground

Multiwave Geophysical Company has announced the signature of the first ever semi-permanent multi-component (4C) seabed seismic contract between BP Indonesia and Elnusa Geosains (Multiwave Geophysical's Indonesian partner company).

The 4C survey will utilise a revolutionary new method to reduce the effect of current induced noise on multi-component sea floor sensors and is expected to commence in the second quarter 2005.

The method comprises of burying 40km of 4C cable, acquiring data using a source vessel and retrieving the cable from the buried position for repositioning at the next location. Seabed conditions range from soft clays to consolidated sand.

"This is a milestone in field development not only in Indonesia but in the global arena," says Jan Sovik," Vice President Marketing and Commercial at Multiwave.

Government funded

Multiwave Geophysical Company's vessel "Pacific Titan" has arrived to acquire first ever government-funded seismic survey in New Zealand, off the North Island's East Coast.

The survey is the first of its kind under the $15 million fund established by the New Zealand government last year as part of a package of incentives to lift exploration in New Zealand.

"The Pacific Titan is probably the only vessel in the Asia Pacific Region that can currently tow the 12 km streamer and produce a large volume air source required and as such is the ideal vessel for the governmental objectives," says David Lamb, Marketing and Sales Manager for Multiwave Geophysical Company.

The survey will cover 100,000 km2 off the East Coast, from Wairarapa to Bay of Plenty, and is expected to take four to six weeks, with the data expected to be released in July 2005.

"The future looks bright"

Photo: Halfdan Carstens

Founder and Managing Director Odd Hjelmeland of ResLab was last year awarded the prestigious *Entrepreneur Of The Year*, which is nicknamed Oscar of Industry. The prize is a tribute to persons with special achievements when it comes to establishing and developing their own enterprises. The intention is to promote and provide motivation for growth and innovation, as well as highlighting the entrepreneurs themselves.

In Abu Dhabi, ResLab (Reservoir Laboratories) has an office with 25 employees from 8 different nations. Operations Manager Ian Green receives cores from the entire Middle East. Most of them come from Oman, Abu Dhabi, Qatar and Saudi Arabia, but the company has also secured a small workload based contracts with oil companies in Yemen, Kuwait and India. They are now tendering for additional work in Syria and Pakistan, and have plans for further growth in the area.

"We also keep an eye on Iraq. Something should be done with a number of cores there," says Ian Green who estimates that the market for laboratory services in this particular region is split 50/50 between CoreLab and ResLab.

"We expect lots of drilling in the years to come: The future looks bright," Green says of a region where the vast majority of the clients are the national oil companies.

From a slow start in 1986, when a barrel of oil was given away for 12 USD, ResLab has expanded to three continents and six countries. As a result of a steady growth the company now ranks second in their market segment, which includes core analysis, special core analysis and reservoir fluid sampling and analysis, data that is necessary to fully evaluate reservoir properties and producing capabilities.

Odd Hjelmeland, founder and managing director of ResLab, was last year awarded the prestigious prize *Entrepreneur Of The Year,* which is also called the Oscar of Industry. The audit company Ernst & Young supports the prize, which is arranged in 40 countries worldwide. It was the third time this prize was handed out in Norway, after its initiation in USA in 1986.

Odd Hjelmeland was appointed best entrepreneur in the service business. He achieved this title based on a continuous expansion through 20 years, first in Norway, then internationally, and a 30 per cent growth each year for the last three years. As a result, the company is now among the largest in the world within its market segment, second only to CoreLab, which has a dominating market share of close to 50 per cent.

Entrepreneur Of The Year is focusing on individuals who themselves have founded and continue to manage successful companies. To be nominated, the company must have had a substantial sales growth in the last two years, together with a positive result for the last year and a positive owners' equity. ResLab fulfilled these criteria with a good margin. The company has, however, no intention to rest on its laurels. Says Odd Hjelmeland: "Our strategy is to continue the expansion and growth. This we will do by both increasing our efforts in existing markets and by entering new markets."

The company is today established with laboratories in Norway (Stavanger and Trondheim), UK (London and Dorset), United Arab Emirates (Abu Dhabi), Oman (Muscat), Iran (Kish) and Brazil (Rio de Janeiro). "We are looking at several areas for expansion. South America, West Africa, North Africa and Russia are all on the priority list," says Hjelmeland.

Photo: Halfdan Carstens

Senior Core Analyst Ismail Azam is measuring rock permeability at ResLab's laboratory in Abu Dhabi.

Photo: Halfdan Carstens

ResLab's Operations Manager, Ian Green, manages the Abu Dhabi office and is busy handling cores from almost every Middle East country. ResLab also has a presence in Muscat, Oman, and last year a laboratory was established in Iran to take care of a huge work load from NIOC.

CALENDAR – SELECTED EVENTS

June			
13-16	EAGE 67th Annual Conference and Exhibition www.eage.org	Madrid, Spain	GEO ExPro No 3
19-22	AAPG 2005 Annual Convention www.aapg.org	Calgary, Canada	GEO ExPro No 3
September			
7-8	The 4th HGS/PESGB International Conference on African E&P, "Path to Discovery" www.pesgb.org.uk	Houston, USA	
5-8	2nd. International Conference on Submarine Mass Movements, Geological Society of Norway www.geologi.no	Oslo, Norway	
11-14	AAPG International Conference and Exhibition www.aapg.org/paris	Paris, France	
25-29	18th World Petroleum Conference www.18wpc.com	Johannesburg, SA	
October			
9 - 12	SPE Annual Technical Conference and Exhibition 2005 www.spe.org	Dallas, USA	GEO ExPro No 4
18-19	Recent Advances in Petroleum Assessment, Geological Society of Norway www.geologi.no	Trondheim, Norway	GEO ExPro No 4
November			
6-11	SEG International Exposition and 75th Annual Meeting www.seg.org	Houston, USA	GEO ExPro No 5
15-16	Production Geoscience 2005 - Understanding and Modelling Geological Heterogeneity www.geologi.no	Stavanger, Norway	
21-23	International Petroleum Technology Conference www.iptcnet.org	Doha, Qatar	

Preliminary programme now available: geologi.no

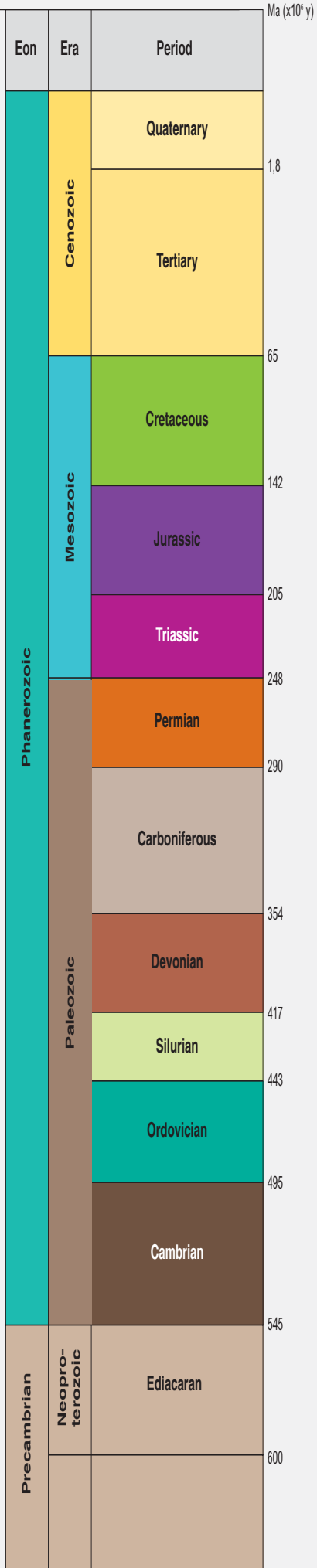
The technological breakthroughs from the early1990's have had enormous implications for the oil and gas exploration and production industry. New methods, changing work processes and an improved understanding of the subsurface have all contributed to new exploration arenas and increased oil recovery.

Increased understanding of the subsurface as a result of the technological revolution is the topic of an international conference to be arranged in Trondheim, Norway, 19-20 October 2005, entitled **Recent Advancements in Petroleum Assessment – Implications for Value Creation.** The Geological Society of Norway is the organiser.

Inexpensive seismic data covering large area in a short timespan has been used in both exploration and production. The conference will highlight how improved data has benefited our understanding of the subsurface.

The conference programme may be of interest to managers, geologists, geophysicists and engineers who see a need for taking part in a forum discussing how new technology is shaping the future of the E&P-sector.

A preliminary programme is shown here: www.geologi.no



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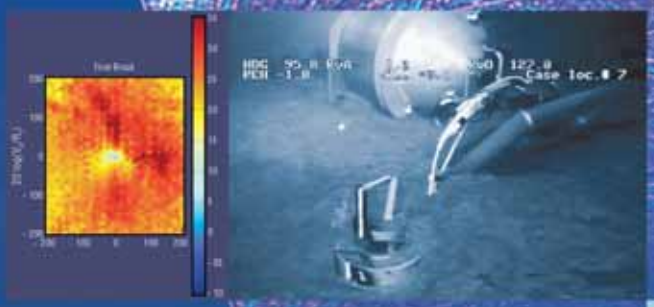

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Canada – significant production

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ALASKA
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FOXE BASIN
Nunavut
Yukon
Fort Norman
Northwest Teritories
Baker Lake
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Winona Basin
Nechako Basin
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Western Canada Sedimentary Basin
Arctic Cratonic
Pacific Margin
Atlantic Margin
Arctic Margin
Intermontane

and huge potential

Canada's hydrocarbon resources are both plentiful and varied. In addition to conventional resources of light to medium crude oil and gas that have been tapped for more than 150 years, unconventional resources like oil sand, coal bed methane, tight gas, shale gas and gas hydrates represent a vast potential for the future.

Canada's seven hydrocarbon regions comprise both onshore and offshore sedimentary basins. The main hydrocarbon province is the Western Canada Sedimentary Basin, which has been producing significant quantities of both oil and gas since the late 1940's. Also of great importance are the offshore basins on the Atlantic Margin including several giant and major oil and gas fields in the Grand Banks area. Canada's oil and gas history did, however, start in southwestern Ontario more than 150 years ago on the north side of Lake Erie, and petroleum production still continues here on a small scale. Also shown on this map are the enormous oil sand deposits in Alberta (in black) that represent a huge potential for unconventional oil resources that rival Saudi Arabia in reserves. The Mallik 2L-38 research well of the Mallik 2002 Gas Hydrate Research Programme in the Mackenzie Delta is also marked.
Source: Petroleum Communication Foundation

Halfdan Carstens

The Canadian oil and gas industry dates back to the 1850's when carriage maker James Miller Williams, often called the founding father of Canada's petroleum industry, dug a 15-metre-deep well in Ontario. Petrolia later developed into a boomtown in the 1860's and the 1870's when hundreds of wells were sunk around the small town. Significant quantities of crude oil were produced, which was then transported 200 km for refining and then sold as lamp oil.

Today oil is still pumping in the Petrolia fields driven by a central power plant, just as it was in the old days. At Petrolia, such a field has been set aside as a living museum, a major historic recreational exhibit.

Petroleum was, however, known long time before the 19th century by the Indians who made use of seepages along the Mackenzie River. This is the same area where the Norman Wells oil field still produces, and will do so for another 20 years.

A 100-year wait

In the late 19th century and early 20th century, the Canadians relied on imported oil to supplement the declining production from the Eastern Cratonic basins of the Lake District in Ontario. Exploration efforts in the Northwest Territories succeeded in finding oil at Norman Wells in 1920, but it was too far away from the market at that time. Smaller discoveries were made at Turner Valley in 1914, southwest of Calgary, and provided fuel for nearby areas. Heavy oil found in Alberta in 1923, was used to produce asphalt.

The Canadian oil industry did, however, change dramatically when Imperial Oil struck oil in the well that was named Leduc #1 on February 3 1947, 50 kilometres south of Edmonton. Until then, Canada depended on imports for 90 percent of its supplies.

The giant Leduc discovery led to a series of other major oil and gas discoveries in the area around Edmonton. Within a year, a major oil boom was underway in Western Canada with important discoveries made in Alberta, Saskatchewan, Manitoba and British Columbia, all in the Western Canada Sedimentary Basin, upon which Edmonton became the capital of the Canadian oil industry. As a consequence, crude oil replaced coal as Canada's largest source of energy some 50 years ago.

The subsequent discovery of huge gas fields in Alberta (e.g. Medicine Hat, now nick-named the "Gas City", close to the Dinosaur Provincial Park), combined with improvements in the technology of pipelining, made natural gas a clean and inexpensive energy source. Natural gas was also a raw material for making fertilizer and other chemical products.

Huge potential

Canadian oil and gas production comes mainly from three different sources: the

Shale gas: Huge volumes

Shale gas is conventional natural gas that is produced from reservoirs predominantly composed of shale with lesser amounts of other fine-grained rocks rather than from more conventional sandstone or limestone reservoirs. The gas shales are often both the source rocks and the reservoir for the natural gas.

The gas can be stored in three ways: adsorbed onto insoluble organic matter (kerogen), trapped in the pore spaces of the fine-grained sediments or confined in fractures interbedded within the shale itself.

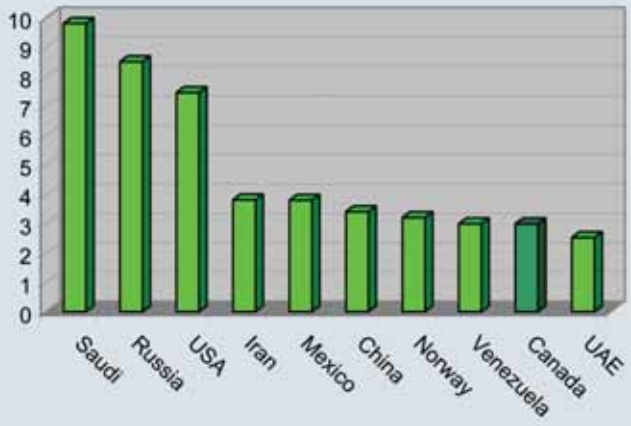
Natural gas has been produced from shale in minor quantities since the 1800's. Widespread development did not occur until the 1980s when a U.S. government tax incentive program stimulated exploration and development of unconventional reservoirs, including gas shales.

There has been no commercial shale gas production in Canada to date. The Gas Technology Institute conducted a study of Canadian gas shale potential that was released in 2003. This study estimated over 860 Tcf of natural gas (150 billion barrels of o.e.) in the gas shales *(in place)*. Thus, if only a fraction of Canada's gas shale resource could be recovered, it would represent a significant addition to Canada's natural gas reserves.

Enormous oil reserves

Canada's total oil production was 3.1 million barrels per day (bopd) in 2004. It has been increasing steadily since 1999, as both new oil sands and offshore projects have come on stream to replace aging fields in the Western Canada Sedimentary Basin. Also, it is expected that oil sands production will increase significantly in coming years and offset the decline in Canada's conventional crude oil production.

In the BP Statistical Review of World Energy 2004 Canada's proven oil reserves is estimated to 16.9 billion barrels of oil. It ranks as no. 11 in the world with respect to oil reserves. According to Oil and Gas Journal; however, Canada has 178.8 billion barrels of proven oil reserves in 2005 when taking into account the oil sand deposits in Alberta. The only country with higher reserves is Saudi Arabia. According to the Alberta Energy and Utility Board, the initial volume of crude bitumen in place is estimated to approximately 260 billion m^3 (1.6 trillion barrels), with 11 per cent or 28 billion m^3 (175 billion barrels) recoverable under current economic conditions.



Oil production in millions of barrels per day for the world's ten largest producers.
Source: BP Statistical Review of World Energy 2004

© Randulf Valle

Arctic Canada, where land and water blur in its barren, flat landscape, is a huge frontier petroleum province with a minimum of wells drilled. Vast amounts of gas found in the Mackenzie Delta may start flowing within five years.

Western Canada Sedimentary Basin, the oil sands deposits of northern Alberta and the offshore fields. However, the potential for significant future exploitation of conventional hydrocarbons includes British Columbia onshore and offshore basins that have hitherto seen virtually no exploration, the under-explored Arctic basins of Yukon, Northwest Territories and Nunavut, and the Atlantic Margin. Also, Canada has huge amounts of unconventional hydrocarbon resources such as oil sands, tight gas, coalbed methane and possibly also gas hydrates.

Western Canada Sedimentary Basin

The Western Canada Sedimentary Basin (WCSB), underlying most of Alberta and parts of British Columbia, Saskatchewan, Manitoba, Yukon and the Northwest Territories, and extending all the way to the Beaufort Sea, has been the main source of Canadian oil and gas production since the late 1940's. The Petroleum Communication Foundation (PCF) estimates that 57 percent of Canada's conventional hydrocarbon resources are found in this basin. However, more than 80 percent of the oil and gas produced to date come from Alberta alone.

Canadian oil companies

Several hundred companies are exploring for oil and gas in Canada. The Canadian Association for Petroleum Producers (CAPP) represents 150 member companies who produce more than 98 percent of Canada's natural gas, crude oil and oil sands, while The Small Explorers and Producers Association of Canada (SEPAC) represents the interests of 400 emerging and junior conventional oil and gas companies.

Canada has a privatized oil sector that has witnessed considerable consolidation in recent years, according to IEA. The largest integrated operator in the country is Imperial Oil, majority owned by ExxonMobil. In 2002, Alberta Energy Company and PanCanadian Energy merged to create EnCana, Canada's largest independent upstream operator. Other significant oil producers in Canada include Talisman Energy, Nexen, Suncor, EOG Resources, Husky Energy, and Apache Canada.

The Canadian government formed Petro-Canada in 1975 in an effort to reduce the dominance of U.S. companies in Canada's oil industry. The company received considerable initial resources from the Canadian government in its early years. In 1991, the Canadian government began to privatize Petro-Canada, and in late 2004, the government sold its remaining 20% stake in the company.

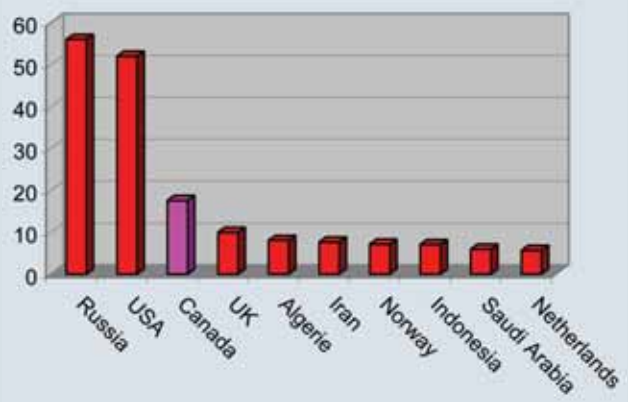
Unconventional reservoirs is for the future

In 2003, Canada produced almost 18 billion cubic feet (500 billion m^3) of natural gas per day, which is the third-highest level in the world behind Russia and the United States.

Canada's natural gas production is concentrated in the Western Canada Sedimentary Basin. Almost 80% of current natural gas production comes from this area, according to the International Energy Administration.

Canada's proven natural gas reserves are close to 60 Tcf (10.8 billion barrels of o.e.) at the end of 2003. Canada thus only ranks 19th in the world. Reserves have decreased steadily the last 10 years, and at current rates, production will completely deplete proven reserves in less than ten years. This may easily change, however, if the vast gas resources in Arctic Canada are explored at an intensified rate.

The National Energy Board has estimated that the ultimate gas resources of Canada to more than 10 times the current reserve estimate. Future gas production in Canada may rely on many resources; such as conventional reservoirs (including Arctic, Atlantic Margin and Pacific coast gas fields), tight gas sands, coal bed methane (see the following article on the huge potential for natural gas in British Columbia), shale gas, and – possibly – gas hydrates.



Gas production in billion cubic feet per day for the world's ten largest producers. Source: BP Statistical Review of World Energy 2004

Coal bed methane

Methane gas produced from coal seams is a relatively new source of natural gas. While substantial production started only in the early 1990's, Coal bed methane (CBM) now represents approximately nine percent of total United States natural gas production. Similar exploration for and development of CBM has only just started in Canada, Australia, Africa and Europe.

CBM is recovered from coal seams which are generally either too deep, of too poor a quality, or otherwise unsuitable for mining the coal itself as a resource.

Methane occurs in coal seams in varying quantities. The quantity of the gas per ton of coal, the gas quality, the permeability of the coal, the cost of completing and dewatering producing wells, and the cost of connecting these wells to suitable pipelines and distribution systems determine whether a CBM project is economically viable.

CBM production is still in its infancy in Canada, with the first wells drilled only in 1997, and according to IEA, there is a strong belief that CBM production will eventually replace the decline in conventional natural gas production.

Coal is Canada's most abundant fossil fuel and also contains the principal component of natural gas - methane. In place resource estimates for CBM in Canada, (concentrated in British Columbia and Alberta) vary greatly, from about 150 trillion to more than 3,000 trillion cubic feet (540 billion barrels of o.e.) of gas. The potential is thus enormous.

Henry Goodrich Mobile Offshore Drilling Unit drills wells for Terra Nova.

Icebergs are one of the challenges that faces the oil and gas operations on the Grand Banks offshore Newfoundland. Towing is necessary to redirect to another pass.

The undeformed portion of the WCSB beneath the Interior Plains can be viewed as a simple wedge of Phanerozoic (Cambrian-Quaternary) strata above Precambrian crystalline basement. The wedge tapers from a maximum thickness of about 6000 m in the axis of the Alberta Syncline (just east of the foothills front) to a zero-edge in the northeast along the Canadian Shield. The differentially eroded upper surface of the bedrock exposes basin strata as old as Ordovician and as young as Palaeocene (Geological Atlas of the Western Canada Sedimentary Basin.)

The Devonian contains more than 50 percent of Western Canada's initial recoverable oil reserves. Most of the marketable gas reserves, close to 50 percent, comes from Cretaceous reservoir rocks.

The age of many of the fields has led to a steady decline in conventional oil production, and it is expected that oil sands will completely supplant conventional sources as the focus of future oil production in this enormous basin, according to the International Energy Administration (IEA).

Atlantic Margin

Canada has considerable, proven offshore oil reserves, which have received more attention in recent years due to the decline in production of conventional crude oil from the WCSB. So far, nearly all offshore production of oil has occurred in the Jeanne d'Arc Basin off Newfoundland, while gas is being produced in the Scotian Basin further south.

Oil and gas exploration has a 40-year-old history on the Atlantic Margin. Mobil Oil Canada acquired the first offshore licences in 1959 in the Sable Island area and subsequently initiated the first seismic survey in 1960. Drilling began off Newfoundland and Labrador in 1966 and off Nova Scotia in 1967. The industry has drilled more than 350 offshore wells since then.

Natural gas was first found near Sable Island off the coast of Nova Scotia in 1968, while both gas and oil were discovered off Nova Scotia in the 1970's: the Panuke-Cohasset oil field, (began production in 1992) and the Venture natural gas field (began production in 1990). These were followed by the first big oil discoveries off Newfoundland and Labrador.

The Hibernia field, discovered in 1979, contains an estimated 615 million barrels of recoverable oil. Production in Hibernia began in 1997, and the field produced some 203,000 bopd in 2003. The Terra Nova field was discovered in 1984 and began operations in 2002 with an average production of 134,000 bopd in 2003.

Discovered in 1984, the White Rose offshore oil field is located in the Jeanne d'Arc Basin 350 km east of Newfoundland and Labrador. It is due to begin production in late 2005 or early 2006, with a potential peak capacity of 90,000 bopd. The field consists of both oil and gas pools and con-

tains an estimated 200-250 million barrels of recoverable oil.

The Scotian Basin, off the coast of Nova Scotia, is the centre of natural gas production on the Atlantic coast. The Sable Offshore Energy Project (SOEP) began production in 1999. SOEP encompasses numerous offshore fields, with the Alma and South Venture fields the latest brought on-line. SOEP produced 400 Mmcf/d of natural gas in 2003, and production should increase by 125 Mmcf/d in 2005, when the South Venture field comes completely on-stream.

There are plans to commence natural gas production in the near future also from both the Hibernia and White Rose fields that contain a combined 4 Tcf (720 million b.o.e.) in recoverable natural gas reserves. In addition, the huge and complex Hebron/Ben Nevis discovery (600 million barrels of heavy oil) is waiting in line to be developed.

There is also significant exploration activity in the Orphan Basin, located in the deep waters north of the Jeanne d'Arc Basin. Further north, in the Labrador Basin, several "stranded" gas discoveries, like Snorri, Bjarni and Gudrid, are waiting for better times and improved technology.

The Petroleum Communication Foundation (PCF) estimates that 18 percent of Canada's conventional hydrocarbon resources are found along the Atlantic Margin.

The Pacific Coast

Off the coast of British Columbia (B.C.), 14 wells were drilled in the late 1960s but failed to find commercial quantities of oil and gas. Environmental concerns, mainly about proposed oil tanker traffic from Alaska, led the federal and B.C. governments to impose moratoria on offshore oil and gas activities in 1972.

It is widely believed, based on various assessments of the area's potential, that the Pacific coast off British Columbia may contain 10 billion barrels of oil and 40 Tcf (7.2 billion b.o.e.) of gas *in place*. However, there has been no production to date on the Pacific coast because of a federal ban on offshore oil activities in the Pacific Ocean. The provincial government of British Columbia has continually lobbied to lift this ban, hoping to begin production by 2010.

The Arctic

Northern Canada comprises a mosaic of sedimentary provinces, each with differing

Oil sands

Oil sands, also known as "tar sands" because of their asphalt consistency, represent an enormous resource. According to Oil and Gas Journal, Canada is second only to Saudi Arabia in oil reserves because of these deposits. The problem is that removing the crude oil is technologically difficult, may be unfriendly to the environment and is expensive. Nevertheless, the oil sands have contributed to the recent boom in Canada's oil production.

Oil sands contain deposits of bitumen; a heavy, viscous oil. Lighter hydrocarbons must be added to the bitumen to allow it to flow. The bitumen is processed into "synthetic crude", and in general it takes about 1.16 barrels of bitumen to make 1 barrel of synthetic crude.

The oil sand deposits were originally giant oil reservoirs, but following the Laramide orogeny some 30-60 million years ago, the oil percolated to the surface upon which the lighter components evaporated and microbes eat the remaining hydrocarbons. The deposits are primarily located in sandstones of Early Cretaceous age

Shallow oil sands deposits can be mined in open-pit surface mines, while deeper in situ deposits require other recovery methods. The production of synthetic crude from oil sands is, however, with present day technology, only economically viable with synthetic crude prices in the USD 25-30 range. The oil sands industry is also heavily reliant upon water and natural gas, which is necessary in both the extraction of bitumen from oil sands and the upgrading of bitumen to synthetic oil.

Present output from the oil sands is approximately 1 million bopd. A significant increase is predicted in the coming years, 1.7 million barrels a day by 2010, increasing to 2.8 million barrels a day in 2015 and 3.6 million barrels a day in 2020. The last number is substantially higher than Canada's present output in total and in particular from conventional oil.

The Athabasca oil sands deposit in northern Alberta is the largest oil sands deposit in the world. There are also sizable oil sands deposits on Melville Island in the Canadian Arctic, and two smaller deposits in northern Alberta.

Tight reservoirs

Tight reservoirs with natural gas are those that have permeabilities less than 0.1 millidarcy. A generally accepted industry definition of "tight" are also those reservoirs that do not produce economic volumes of natural gas without assistance from massive stimulation treatments or special recovery processes and technologies. Poor permeability is primarily due to fine-grained sediments, compaction, or cementation of pore spaces by carbonate or silicate precipitated from water within the reservoir.

In some cases, production is drawn from marginal quality reservoirs within conventional producing regions, and in some cases from locally higher permeability strata within tight formations. The expansion of infill drilling in the shallow gas play of southeast Alberta and southwest Saskatchewan was due in part to recognition of the tight nature of many of the sandstone reservoirs in this area.

It is only recently, with the advent of higher commodity prices and development techniques such as horizontal and directional drilling, underbalanced drilling, directional fracturing and carbon dioxide and nitrogen fracturing fluids that tight sands have become exploration targets.

Recent activity in the Deep Basin area of Alberta and British Columbia is also driven in part by recognition of tight gas reservoirs. The largest sale of petroleum and natural gas rights (generally referred to as land sales) in Canadian history was in British Columbia in 2003, targeting tight carbonates in northeastern British Columbia using advanced drilling and completion technologies.

geological history and petroleum potential. Some – such as the Sverdrup Basin of the Arctic Islands - are unique in North America. Others, such as the Tertiary Mackenzie Delta, have similarities to the Mississippi Delta of the Gulf of Mexico. The basins contain substantial reserves and a long inventory of discovered resources of both oil and gas. Northern Canada should be considered one of the last under-explored hunting grounds for conventional gas and oil remaining in North America.

The pattern of exploration has been strongly influenced by geography and challenging logistics; thus, the density of drilling in the Western Canada Sedimentary Basin south of 60°N is much greater than further north despite comparable geology and a significant oil and gas potential.

Some frontier efforts in the Northwest Territories have met with success, such as the natural gas discoveries in the Mackenzie Delta, crude oil in the Beaufort Sea and huge natural gas reserves in the Arctic Islands. Because of high development and transportation costs, and the availability of supplies closer to densely populated southern regions, these discoveries have not yet been developed. Close co-operation with local communities and the province's aboriginal people is a necessity to achieve this.

The Mackenzie Delta, located in the Northwest Territories, holds an estimated 10 Tcf (1.8 billion b.o.e.) of recoverable natural gas reserves. There are three large, proven natural gas fields in the Mackenzie Delta: Taglua (3 Tcf), Parsons Lake (1.8 Tcf), and Niglintgak field (1 Tcf).

Arctic Canada is underexplored. Future efforts require improved technology.

Fantastic potential

Canada has vast reserves of conventional oil and gas that rank among the world's largest. If we also include unconventional oil and gas, Canada may – as illustrated in this article – have more hydrocarbon resources than any other country in the world, including Saudi Arabia and Russia.

The future of these resources depends on the future price of energy as well as developments in technology. However, the future is already here, as liquid oil is now being produced from the sticky "tar sands" and gas is tapped in small quantities from unconventional reservoirs.

Gas hydrates

Naturally occurring gas hydrates have been mapped worldwide since the 1970's. They appear in two different geological environments, in marine sediments on the outer continental margins, and below permafrost in arctic regions. In Canada gas hydrates may thus be found in both environments.

A significant part of the earth's fossil fuel seems to be stored as gas hydrates. Published estimates show that the total volume of methane in gas hydrates varies between 10^{15} to 10^{19} m^3 (the latter number equals 10 million trillion m^3) (GEO ExPro No.2, 2004). "If these estimates are anywhere close to being true, then the gas hydrates have twice the order of magnitude than the remaining conventional methane resources," says Timothy S. Collett in USGS.

Consequently, gas hydrate research has increased dramatically the last five to ten years. A research programme was carried out at the gas hydrate field Mallik in the Mackenzie Delta in 2002 (GEO ExPro No.2, 2004). The purpose was to carry out a full-scale production test by means of a 1200 m deep production well and two observation wells 40 m apart. Two zones were tested by two different methods, and for the very first time, gas from gas hydrates was produced. The flare from the tower confirmed that the gas hydrates could be a technical success when the gas saturation is great enough.

A gas hydrate field has also been discovered along the Cascadia Continental Margin outside Vancouver Island. Leg 146 of the Ocean Drilling Program in 1994 was designed to provide estimates of the volume of fluid associated with accretionary sedimentary wedges. A wealth of data pertaining to the in-situ nature of gas hydrates on the Cascadia margin was collected through the drilling of three wells.

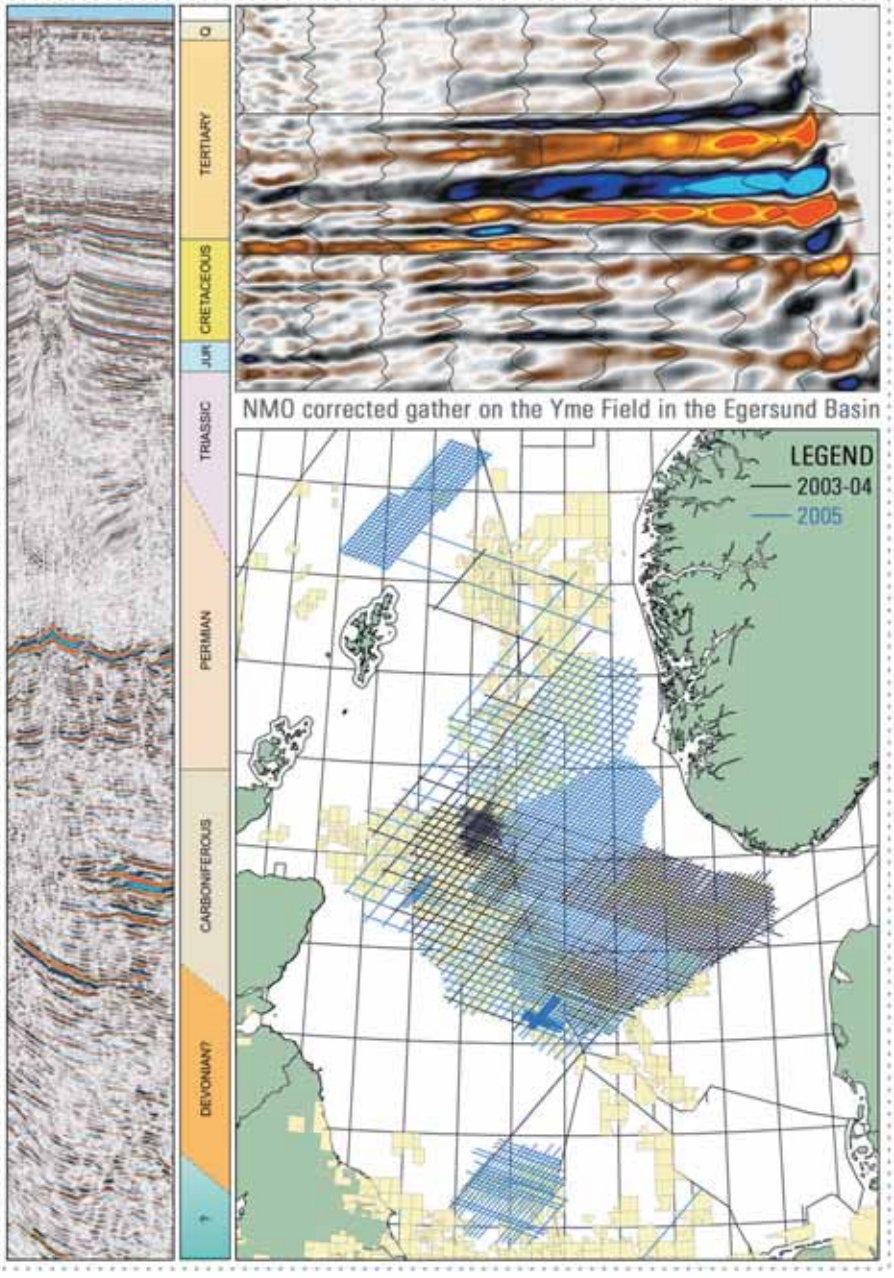
It is still unknown how much gas could be present and eventually recovered in the Canadian gas hydrates.

Photo: Tim Collett, USGS

The flares from the gas tower at Mallik 2L-38 confirmed that gas hydrates can be technically produced when the gas saturation is great enough.

NORTH SEA RENAISSANCE

NSR - Long Offset 2D Seismic Program



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Huge gas potential

Only a fraction of the estimated vast gas potential of British Columbia (B.C.), including unconventional resources awaiting technological breakthroughs, have been discovered. Companies looking to make large discoveries thus need look no further than B.C., Canada's most western province.

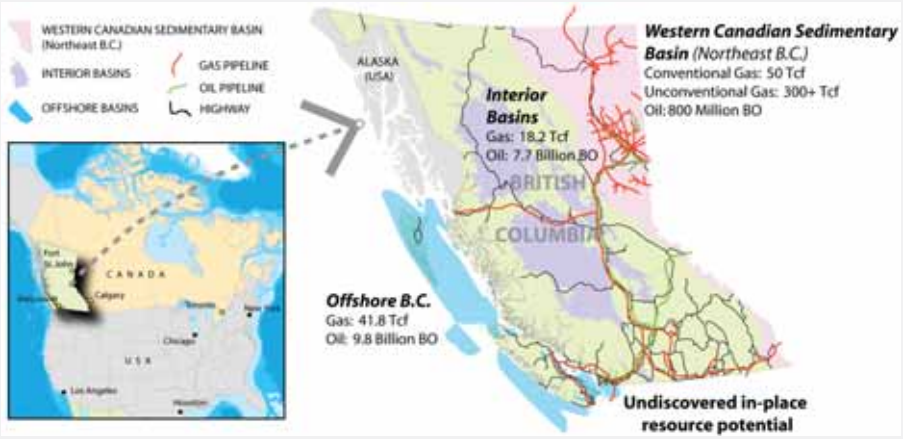
Photo: Tore Karlsson

David Molinski of the B.C. Energy and Mines believes that British Columbia has a significant untapped potential for natural gas, onshore as well as offshore, and in both conventional and unconventional reservoirs.

David Molinski, Assistant Deputy Minister, B.C. Energy and Mines

Long known for its rich mineral deposits, B.C. is now making a mark in North America as an under-explored natural gas resource. Home to a portion of the Western Canadian Sedimentary Basin (WCSB) that is 150,000 km^2 (roughly the size of Oklahoma), with only 17,000 wells drilled to date – B.C.'s well density is extremely low.

However, marketable gas reserves in the province's portion of the WCSB are 9.2 trillion cubic feet (Tcf) (260 billion m^3) and oil reserves are 141 million barrels of oil. Undiscovered *in-place* conventional natural gas resource potential is estimated to be 50 Tcf. (1400 billion m^3) In addition, undiscovered *in-place* oil resources are estimated to be 800 million barrels of oil.



© Ministry of Energy and Mines, Government of British Columbia

The sedimentary basins of B.C. are under explored – including the portion of the Western Canadian Sedimentary Basin located in the province. With only 17,000 wells drilled to date, well density is very low at one well per 9.32 square kilometres.

Accelerating activity

These resources are attracting attention as oil and gas activity in B.C. is growing at a higher rate than neighbouring, more mature jurisdictions. Even with increased production of more than 60 percent in the last 11 years, British Columbia was the only Canadian province to register a rig increase over the summer of 2004, as well as the only jurisdiction to increase natural gas reserves consistently for the past four years.

It is doing this by tapping into some of North America's recent large discoveries, including the *Ladyfern Devonian Slave Point* discovery of 2000 – a 765 billion cubic feet (Bcf) deposit (21 billion m^3). Rich resource-type gas accumulations such as the *Devonian Jean Marie* in the Greater Sierra area and the *Cretaceous Cadomin play* at Cutbank Ridge, are significant multi Tcf unconventional gas plays that point to the untapped potential still to be developed in the WCSB in B.C.

British Columbia's conventional oil and natural gas industry focuses on the northeast part of the province, producing 3 Bcf (80 million m^3) per day, up from 2 Bcf just 9 years ago. Targets range from shallow to deep and attract a wide range of exploration and development companies from small independents to large multinational firms. In fact, activity levels in B.C. are at an all time high, with industry investment expected to top $4 billion this year – well over double from four years ago.

© Ministry of Energy and Mines, Government of British Columbia

The Petitot River in northeast British Columbia stretches across the plains region of the Western Canadian Sedimentary basin.

The interior basins

Although most investment will go towards conventional resources in the WCSB, sustained natural gas prices have opened the eyes of explorers looking to the largely unexplored central B.C. The interior basins are estimated to potentially contain *in-place* resources of 18.2 Tcf (51

billion m^3) of natural gas and 7.7 billion barrels of oil.

In addition, government and industry are engaging communities and aboriginal groups in these areas, discussing the potential for petroleum development and learning about important environmental and historical features.

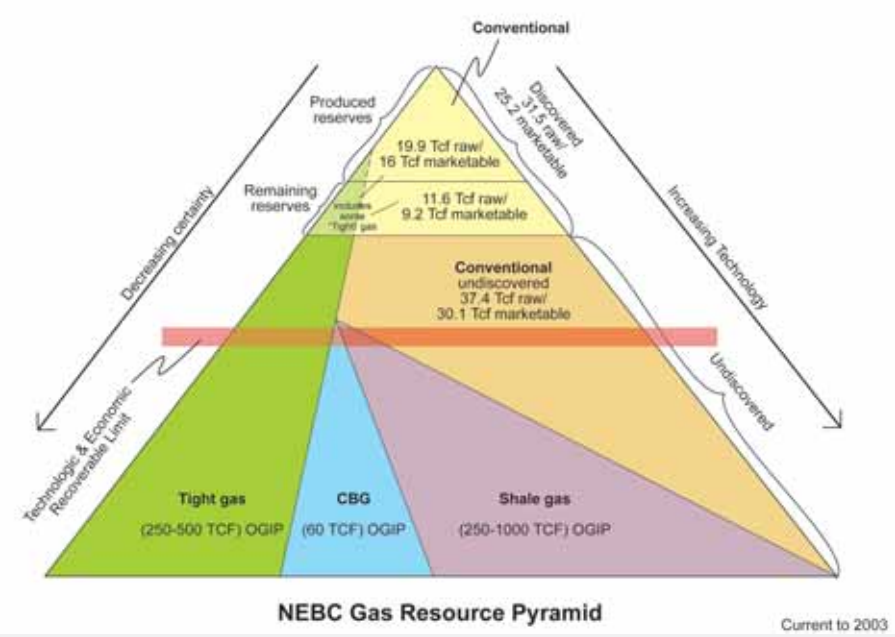
Unconventional Resources

With over 50 years experience developing conventional resources in northeast B.C., commodity prices and a competitive regulatory and royalty regime have also brought attention to previously non-economic, unconventional resources such as coalbed gas (methane), shale gas and tight gas.

Coalbed gas potential exists within coal seams in various areas around the province. Estimated *in-place* resources as high as 90 Tcf (2.5 trillion m^3) have piqued interest, and exploration is beginning in many regions. Although no commercial production has begun, industry is building on the knowledge gained in other jurisdictions and is working towards solving the technical challenges of economically extracting this resource.

With the commercial success of several *shale gas* plays in the United States (for example the Barnett Shale), British Columbia's shales are now being recognized as potential reservoirs estimated to have the capacity to hold between 250 – 1000 Tcf (7-28 trillion m^3) *in-place*. Though recoverable volumes will be considerably less, shale gas remains a significant untapped resource in northeast B.C. Details are available in a recent study of the shale gas potential within the Devonian strata of northeast B.C.

Tight gas is likely to hold the highest potential for remaining technically recoverable natural gas resources in B.C. Tight gas is now being specifically targeted in basin centred resource-type play developments such as those previously mentioned at Greater Sierra and Cutbank Ridge. In 2003 the Ministry of Energy and Mines released an Exploration Assessment of Tight Gas Plays in Northeast B.C. and determined that the *in-place* tight gas resource base could range from 250 to over 500 Tcf (7-14 trillion m^3).

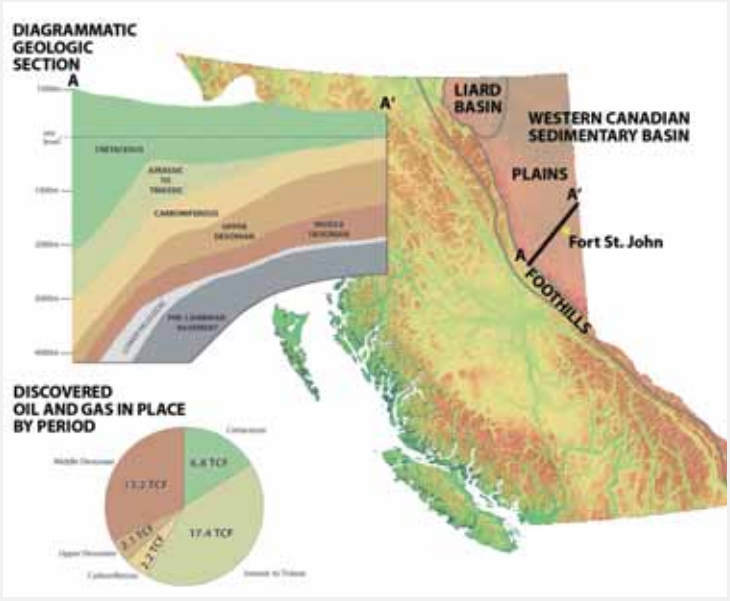


The resource pyramid illustrates the vast potential of unconventional resources in British Columbia, Canada.

The offshore potential

The province's offshore basins are estimated to contain a resource of 9.8 billion barrels of oil and 41.8 Tcf of natural gas *in-place*, with the most prospective Queen Charlotte Basin being the current focus of discussion.

For more information:
www.em.gov.bc.ca/oilandgas



Discovered resources (reserves) of the Western Canadian Sedimentary Basin (WCSB). The province's portion of the WCSB is divided into three regions: the homoclinal "Plains"; the structurally deformed "Foothills" (the Canadian Rocky Mountains); and the Liard basin.

Photo: Talisman Energy Inc.

Talisman Energy Inc. drilling for deep gas in the south foothills region of the Western Canadian Sedimentary Basin in B.C.

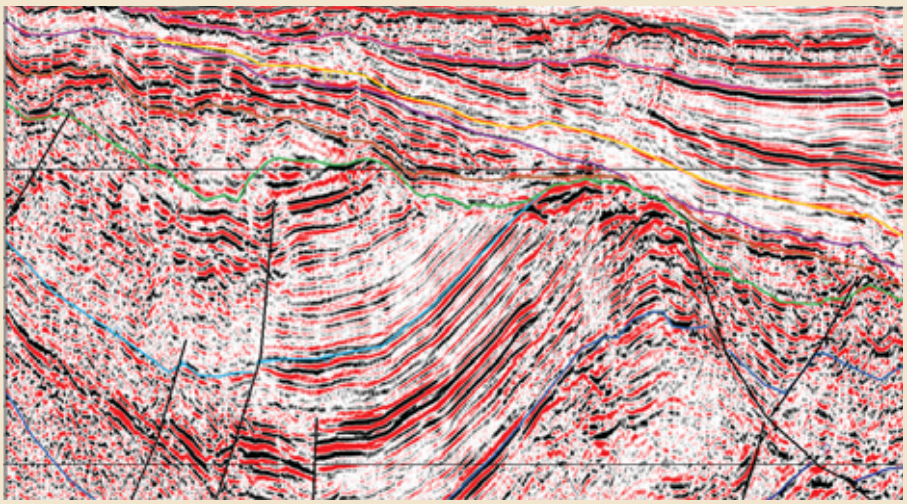
Spain – small reserves, small production

Spain has very limited oil and gas resources. Several basins do, however, need to be tested to learn more about the ultimate hydrocarbon potential.

The sedimentary basins in Spain are mostly composed of Mesozoic and Cenozoic sediments. These range from Triassic continental deposits and evaporites, through Jurassic and Cretaceous carbonate dominated rocks to Tertiary siliciclastics. The underlying Paleozoic series is in some areas slightly metamorphic and offers less exploration potential. Pyrenean and Alpine compressive tectonics have inverted several of the basins. Also shown in this map (purple) are important wine regions of Spain. Spain will host the 19th World Petroleum Congress in June 2008.

Spain is more famous for it's wine than it's oil and gas.

Spain's proven oil reserves are very small, only 158 million barrels (21 million m³) in 2005, according to the International Energy Administration (IEA), the equivalent of a single, medium-sized field in the North Sea. The Casablanca oil field just offshore the Ebro Delta, discovered in 1983, is by far the largest field. It has now reached its production tail and oil will soon cease to flow. Spain, which in 2004 produced only 6,000 bopd of crude oil from 7 oil fields, all operated by Repsol YPF, is therefore totally dependent on imports to meet its energy requirements.



The seismic event shown in green is a major unconformity representing a hiatus from Late Cretaceous to Miocene. The erosional relief is made of carbonates that are also reservoir rocks in the Gulf of Valencia. In the Ebro Delta on the northeastern coast of Spain (compare map) Tertiary shales constitute mature source rocks. Further south, play concepts have to rely on Upper Jurassic marls and late migration. Amplitude anomalies are evident, and the sequence that is subcropping the unconformity has not been tested.

Spain's natural gas reserves are also extremely limited with only 90 billion cubic feet (0.09 Tcf, corresponding to 2.5 billion m³ of gas or 16 million barrels of oil equivalent). The country's natural gas production is consequently also insignificant, a total of only 18 billion cubic feet (0.5 billion m³ of gas or 3.2 million barrels of oil equivalent) were produced in 2002. Almost all of Spain's natural gas production comes from one offshore field, Poseidon, in the Gulf of Cadiz, operated by Repsol YPF.

Exploration in Spain is concentrated in the Atlantic Ocean and in the Gulf of Cadiz. "TGS-Nopec and Fugro-Geoteam have lately acquired both seismic and aeromagnetic data in the Southern Gulf of Valencia and in the Bay of Biscay (Cantabrian Sea). New exciting play models have been identified, and existing play models have been better defined based on these surveys," says Chief Geologist Frode Sandnes of TGS Nopec.

Other areas offer additional frontier exploration potential. In the Canary Islands, east of Fuerteventura, Repsol YPF drilled two dry wells in 2003 following a 3,000 km² 3D survey.

Spain privatized its oil sector during the 1990's. The largest oil company is Repsol

A taste of Spain

It's time for another EAGE convention, this time in Madrid. I strongly recommend using this opportunity and tasting some of the "new" Spanish white, rosé and red wines – and what can be better than to combine them with local food?

Spain is – as you probably know – one of the world's largest producers of wine. It usually battles with France and Italy for first position; well ahead of countries like USA, Chile, Australia or South Africa. In spite of a several century long wine producing history it is only during the last few decades that some Spanish wines have been mentioned in awe. Since the country entered the European Community (1986) it has been a race for quality at the expense of quantity, but for most people Spain is still synonymous with cheap and robust reds. That is perhaps still the case in some areas, but if you care to scratch under the surface you will discover something special.

The Rioja and Ribera del Duero regions are particularly worth mentioning.

Rioja, which received its official status in 1926, is the homeland of the Tempranillo grape and the Gran Riserva (compare figure) elegant, spicy reds. The new buzzword in this part of the woods is "terroir". The local wine producers have gone a long way to investigate the impact of minor variations in climate, soil and terrain and how they can benefit from this knowledge in grape selection and winemaking. Another remark can be made about the battle between the modernists and the traditionalists: the young, fruit driven style (usually sold as Crianza) versus the old, vanilla and leather style (usually sold as Gran Riserva). To understand more, try a Crianza followed by a Gran Riserva – or vice versa –to discover your favourite. Some good wine producers to look for are Bodegas Marqués de Cáceres, Marqués de Murrieta, Muga, Roda or Ijalba. Here's a tip for you: "when in doubt, buy Rioja starting with an "M".

Personally, I hold Ribera del Duero as even more interesting for wine lovers. Its official status was first granted in 1982, but since then its reputation has climbed vertically. This is still homeland of the Tempranillo grape – here it is often called Tinto Fino or Tinto del Pais. If you really want to make a big dent in your wallet you should buy a bottle or two of Vega Sicilia Unico. This is definitely Spain's most prestigious wine.

The valley of Duero (yes, it is called Duoro across the border) averages about 750 meters above sea level and the river slowly runs through the sub-regions Cigales, Rueda and Toro on its way to Portugal. In Cigales, they have a history of making excellent, aromatic rosé and lately they have also turned their attention to serious red wine. The great thing is that the prices are still low. The region is extremely arid with less than 450mm/year of rain and average temperatures around 12°C (varying from +40°C to -10°C). Soils are generally very poor – a mix of sand, limestone and chalk over clay and marl. There is almost no organic matter, thick layers of pebbles (10-20cm) and a lot of minerals (especially iron) – in other words: ideal wine country!

In this large mountain plateau you will also find some really stellar reds and I want especially to draw your attention to the Museum series from the wine producer El Coto.

Museum Crianza is made 100 percent of the grape Tinto del Pais. Tasting notes: Dark cherry colour with purple rim. On the nose it is complex with toasted wood, vanilla, leather, tobacco and liquorice. The mouth is smooth blackberry and black currant with a spicy touch.

Museum Reserva is also made 100 percent of Tinto del Pais from old and selected vines (60 – 100 years old). Tasting notes: Deep, clean and lively colour with purple shades. In the nose it is forward with toasted wood, leather, tobacco and liquorice supporting a strong fruity appearance with raspberries and blackberries - followed by a hint of cigar box and dried apricot. In the mouth the Reserva has an elegant and complex appearance with spicy wood, superb round fruit (plums and blackberries) and great length. Firm finish. YES, this is "full pedal to the metal" and an acquaintance you simply cannot live without!

Have a happy time in Madrid!

Lars Haakon Nordby

Lars Haakon Nordby is a geophysicist with 20 years experience in the oil industry. His main hobby is "wine", and he has followed several classes at the Wine and Spirit Education Trust and the Institute of Gastronomy (London/Stavanger) to learn more about this fascinating topic.

Lacking domestic oil and gas in substantial quantities, Spain's dominating oil producers, Repsol YPF and Cepsa, are heavily involved in North Africa as well as in Latin America.

YPF, created through the merger of Repsol, the former, state-owned oil company of Spain, and Yacimientos Petroliferos Fiscales (YPF), formerly owned by the Argentine government. The combined group is one of the world's largest integrated oil operators.

Repsol YPF, operating in more than 28 countries, produces more than 1.1 million barrels of oil per day, and its oil and gas reserves total more than 5.4 billion barrels of oil equivalent. These reserves are located mostly in Latin America and North Africa.

Compañía Española de Petroleos (Cepsa), established in 1929, is Spain's oldest private and second-largest oil and gas company. Cepsa has significant exploration and production activities in Algeria and Colombia.

Surrounded by hydrocarbons

Only three years after Independence, East Timor is now ready to announce the first licensing round. With multiple oil and gas seeps onshore, several discoveries and four fields producing both oil and gas offshore, the Timorese have reason to expect significant interest from international oil companies.

Photo: Geir Ytreland

Masaoki Adachi

The Democratic Republic of East Timor, also known officially as Timor-Leste, is the world's youngest nation. The country consists predominantly of the eastern half of the island of Timor. Also included in the territory are the nearby islands of Atauro and Jaco, and the small enclave Oecussi situated on the northwestern coast of Timor. The total land area is 14,600 km^2, while the population is approximately 1,000,000, of which 250,000 live in the capital of Dili. The local climate is tropical and generally hot and humid, characterised by distinct rainy and dry seasons.

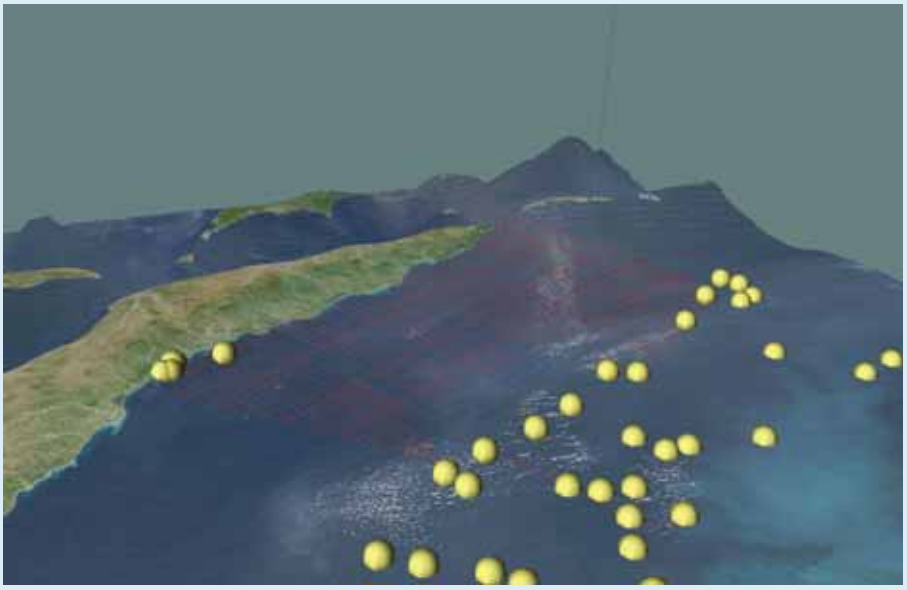
To the north and northwest of the island lie the Wetar Strait and Ombai Strait separating East Timor from some small Indonesian islands, to the south the Timor Sea separates the island from Australia, while to the west, on the same island, lies the Indonesian province of Nusa Tenggara Timur.

The Timor Trough, which runs through the area to be included in the first licensing round in East Timor, is a pronounced physiographic feature that was previously thought to represent the subduction zone where the Australian Plate collides with the Eurasian Plate. Today we know that this plate boundary is found to t he north of the island.

Also shown are the oil and gas discoveries made in the Joint Petreoluem Development Area (JPDA), including the small oil fields Elang/Kakatua and the gas/condensate field Bayu-Undan. The Timor Sea Treaty defines the JPDA, and the Timor Sea Designated Authority (TSDA), administrates petroleum authorities therein. Development of the Sunrise Gas Project, including the Sunrise and Troubadour fields discovered in the mid 1970's, has been postponed due to the unresolved boundary dispute between East Timor and Australia.

The eastern part of Timor is rugged, with the mountains rising to 2,963 metres at Mount Tatamailau in the centre of a high plateau. Hilly areas are covered with sandalwood, while scrub and grass grow in the lowlands together with coconut palms and eucalyptus trees. Hot springs and numerous mountain streams are found throughout the island.

East Timor, whose economy is largely agricultural, was one of the world's poorest nations at Independence, and the economy, primarily made up of subsistence farming and fishing, is in shambles. Rice, coconuts, and coffee (the main export) are grown, and stretches of grassland support cattle. The majority of the country's infrastructure, including homes, irrigation systems, water supply systems, and schools, and nearly 100% of the country's electrical grid were destroyed by the Indonesians before Independence. The republic is one of only two majority Roman Catholic countries in Asia, the other being the Philippines.



The only modern seismic survey available offshore East Timor was acquired by partnership of Global Geo Services and the Chinese Geophysical contactor BGP just a few months ago. The survey totals 6674 km and covers an area of 30,000 km^2, the equivalent of five UK offshore quadrants. The data is compulsory for companies that want to bid in the first offshore licensing round. The yellow balls show the location of wells.

Halfdan Carstens

East Timor is ready for its first offshore licensing round ever. The announcement is expected to take place in 3rd quarter this year, upon which the Timorese authorities will present the geological framework and the licensing terms to the international oil community in "petroleum capitals" around the world.

Proven hydrocarbon province

Acreage to be announced encompasses an area off the southern coast in the Timor Sea that hitherto has seen virtually no exploration, the only exception being a 1500 km seismic survey in near coastal waters in 1974 and the drilling of one well in the 1975, Mola 1, operated by the Australian company Bocal. The well had oil and gas shows in the Pliocene section even if reservoir rocks were not encountered. The presumed structural closure was probably an artefact according to experts on the offshore geology.

Extensive exploration has been carried out since the 1970's further south, within what is now known as the Joint Petroleum Development Area (JPDA), and four fields, one giant and three small, have been put on production.

"Large gas and condensate fields have been discovered in the JPDA, and the ConocoPhillips-operated gas/condensate field Bayu-Undan as well as the Kakatua/Kakatua North/Elang oil fields give revenues to this poor country. In addition, gas will start flowing from Bayu-Undan in 2006. Several more discoveries have been made in the undisputed Australian sector further south and west thereby proving that we are within an oil-rich province," says Geir Ytreland who is Project Manager for the Norwegian Petroleum Directorate's collaboration project with the petroleum administration on East Timor.

International assistance

A collaboration agreement was signed by the Norwegian Petroleum Directorate (NPD) with the Ministry of Development and the Environment in the East Timor capital of Dili in October 2003. This deal kicked off the latest in a series of projects involving the agency that have been funded by the Norwegian Directorate for Development Cooperation (Norad).

Over a six-year period, backed by USD 5 million, the NPD will help the East Timor authorities to develop a regulatory structure for managing their petroleum resources.

"The goal of the project is to provide assistance in building up and developing the petroleum administration in East Timor in such a way that the country will in the future be able to manage its petroleum resources on its own, with minimum assistance from foreign consultants and advi-

Unresolved boundary

Timor's offshore gas and oil reserves promised the only real hope for lifting it out of poverty, but a dispute with Australia over the rights to the oil reserves in the offshore region has currently thwarted those efforts.

The oil and gas fields lie much closer to East Timor than to Australia, but a 1989 deal between Indonesia and Australia set the maritime boundary along Australia's continental shelf, which gives it control of most of the oil. East Timor now wants the border redrawn in the middle of the 600 km of sea separating the two countries. They estimate that this would allow it to earn several billion dollars more over the next 30 years as opposed to previous borders. However, Australia wants the same boundary it set with Indonesia.

East Timor has so far refused to ratify a second revenue-sharing deal known as the International Unitization Agreement. Under this deal, 80% of Woodside's Sunrise gas field would fall within Australian waters and the remaining 20% in the JPDA.

In terms of a permanent boundary, East Timor wants a border in the middle of the 600 kilometres of ocean separating the two nations.

Within the Joint Petroleum Development Area (JPDA) revenues will be split 90/10 between East Timor and Australia. According toan announcement made in early May following the ongoing negotiations between the two countries, East Timor will also receive USD 3.9 billion on top of the 90 per cent share of revenue. In return, East Timor has agreed to postpone for some time final resolution of the sea boundary. The areas coloured red, Red Zone West and Red Zone East, are still under negotiation.

sors," says NPD's Project Coordinator Principal Engineer Erling Kvadsheim to the quarterly magazine *Norwegian Petroleum Diary* published by NPD (www.npd.no).

The Norwegian Petroleum Directorate's main collaborating partner on East Timor is the Ministry of Development & Environment (MDE). Daily cooperation takes place with the Energy and Mineral Resources Directorate (EMRD), which is one of the units in the Ministry. The EMRD is divided into two divisions, one for mineral resources and one for petroleum.

"The level of knowledge within the petroleum administration has increased, and key parts of the framework are now in place, or are being completed. The cooperation between the various parts of the petroleum administration has also been strengthened," says Kvadsheim.

"High unemployment and widespread poverty characterise the East Timor today. A number of challenges have to be overcome, such as filling the continued need for increased technical and academic expertise in key petroleum disciplines. In addition, fundamental social and economic structures must be set into place. The lack of health care services, general poverty, high prices, and limited access to electricity (the power supply is extremely unreliable for the 20% who have it), are key challenges for East Timor, and for the Norwegian collaboration project."

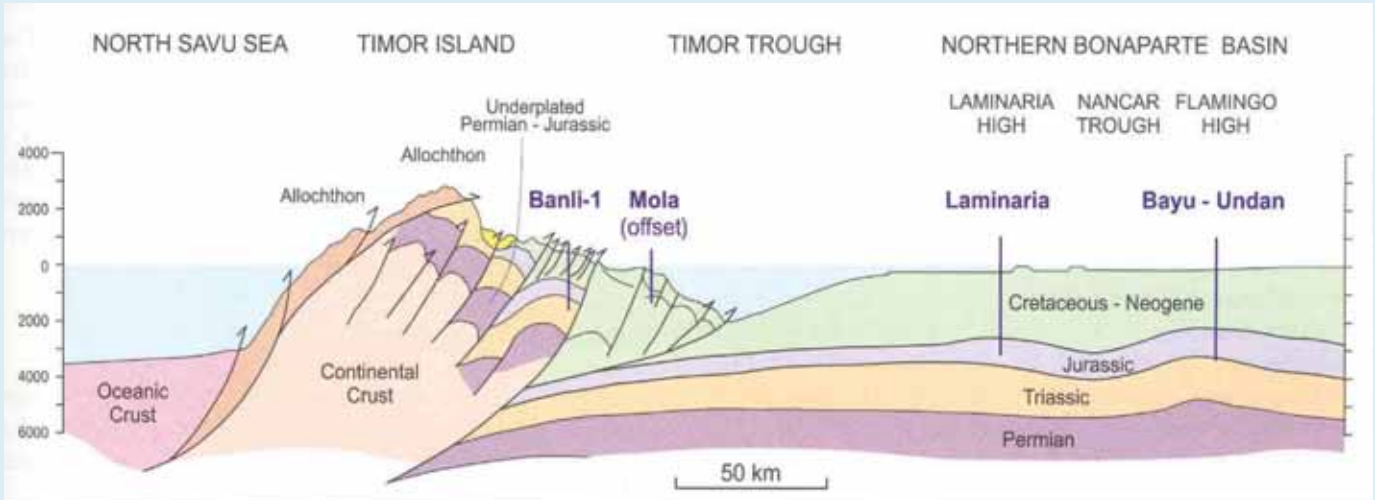
"Good governance"

The need for direct technical assistance to the Timorese people has been considerable. Moreover, there has proven to be a great need for increased administrative support and development of the education programme for the petroleum sector in the country.

"There is little administrative experience among government employees. Their experience largely stems from the period of Indonesian government, which gave precisely the practices that the country wants to get rid of. Petroleum is the country's most important industrial sector. If we can succeed in building up a good governance culture here, this will create spillover

Geir Ytreland is project manager for NPD's collaborative project with the petroleum administration on East Timor. Geir, who currently lives in the capital of Dili, is a geologist by profession with more than 30 years experience in international petroleum exploration and production. Postings include Norway, Saudi Arabia, USA, Venezuela, Indonesia, UK, Egypt and Togo.

Photo: Halfdan Carstens



A schematic cross-section through Timor Island to the northern Bonaparte Basin illustrates oceanic crust to the north, how continental crust underlies both the island and the deep Timor Trough and the general belief that Mesozoic rocks continue with the same facies as the Australian equivalents below the young sedimentary wedge. Modified from Norvick (1997), jeg trenger referansen

Struggle for independence

The Timorese people have been under foreign rule for almost 500 years following the first Portuguese settlements in 1520. Only in 2002 did East Timor become a sovereign state with international recognition.

Formerly Portuguese Timor, East Timor became a province of Indonesia on July 1976. After the UN-sponsored second referendum on 30 August 1999, Indonesia relinquished control of the territory, which achieved full independence on May 20, 2002. The planned licensing of offshore and onshore acreage thus comes after only 3 years of independence.

The Portuguese were the first Europeans to arrive in the area in 1520. They established an isolated presence on the island of Timor, while the surrounding islands came under Dutch control.

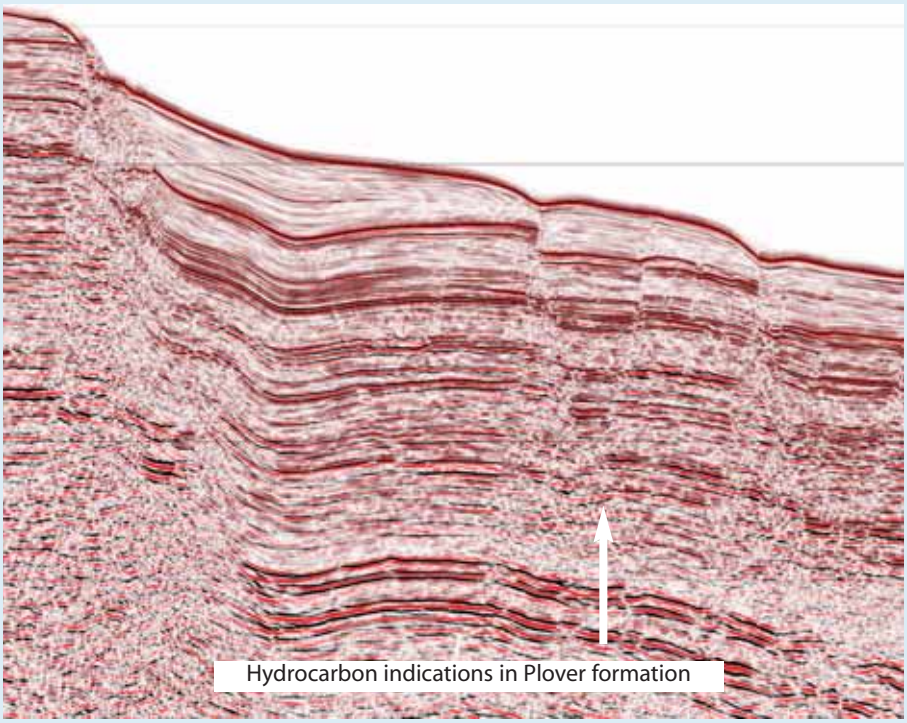
The process of decolonisation began in 1974 when, owing to political instability and more pressing concerns with decolonisation in Angola and Mozambique, Lisbon effectively abandoned East Timor. One of the political parties – Fretilin - had gained control of much of the territory, and on November 28, 1975 the movement unilaterally declared itself independent as the Democratic republic of East Timor. Nine days later, however, the country was invaded and occupied by Indonesian forces. Indonesian rule in East Timor was marked by extreme violence and brutality. During the invasion and 27-year occupation, an estimated 100,000 to 250,000 people were killed, either because they resisted occupation or because of famine and disease, compared with a population of about 600,000 at the time of the invasion.

effects for other sectors in state administration," says Kvadsheim.

The project involves many aspects of petroleum administration. Says Kvadsheim: "In addition to developing a division of the ministry that is responsible for administration of the petroleum sector, the project has supported the authorities in their work on ocean border negotiations with Australia, it has provided advice regarding how to handle the petroleum revenues, it has participated in shaping the country's new petroleum legislation, it has participated in discussions regarding the East Timor Petroleum Fund, and it has participated in discussions concerning State involvement in the petroleum activities."

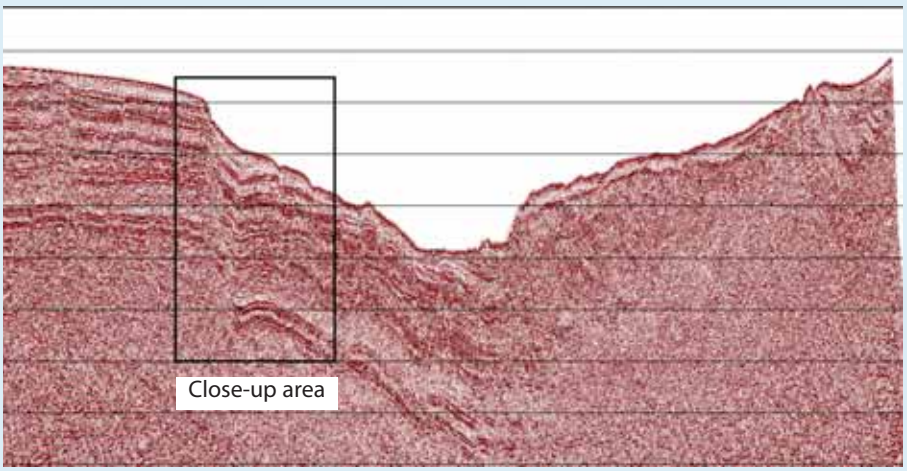
Geology

"Onshore data, drilling in the JPDA and on the Australian continental shelf, combined with interpretation of regional seismic data, prove that there is a full stratigraphic sequence from the Permian through to the Tertiary within the offshore acreage that is to be offered this year," says Geir Ytreland.



© GGS/BGP

A segment of the seismic line below that shows a large roll-over structure with hydrocarbon indications assumed to be in the Jurassic Plover formation. The Plover formation is a producing reservoir in the JPDA to the south of this structure.



© GGS/BGP

Seismic line across the Timor Trough shows fault blocks and rollover structures in the thick Mesozoic sequence on the southern margin. North of the trough, a thick Tertiary wedge is overlying the Mesozoic succession that steps up towards the Timor island

Proven oil and gas

Petroleum is already the cornerstone of the East Timor's economy, and it will most certainly also remain so in the future.

In the Joint Petroleum Development Area (JPDA), three small oil discoveries were made in the 1990's – Kakatua, Kakatua North and Elang – that together have produced approximately 28 million barrels of light, low sulphur crude oil since 1998. Initial combined production rate exceeded 30,000 bopd, but they are currently producing less than 5,000 bopd and may be shut down next year.

The Bayu-Undan gas/condensate field, operated by ConocoPhillips, was discovered in 1995, when the Bayu-1 well intersected a 155m column of gas/condensate at a depth of 897m. In July 1995, Undan was discovered 10km northwest of Bayu.

Bayu-Undan is being developed in two phases. The first is a gas recycle project, where gas liquids are extracted and the dry gas is reinjected into the reservoir. The second phase, an LNG project, is expected to be completed in 2006. A gas pipeline is being built from the field to an LNG facility near Darwin, Australia. Production from the first phase began in 2004. Daily exports from the floating production facility currently exceed 75,000 barrels per day.

The total recoverable reserves of Bayu-Undan are estimated to 350-400 million barrels of hydrocarbon liquids and 3.4 TCF of gas, according to the operator. The field is expected to yield USD 5 billion in taxes to East Timor over the next 20 years.

The Greater Sunrise field, operated by Woodside, is the largest known petroleum resource in the Timor Sea. The field may contain as much as 300 million barrels of condensate (light oil) and LPG, and about 8 TCF gas. The Greater Sunrise field straddles the eastern perimeter of the Joint Petroleum Development Area (JPDA) established under the Timor Sea Treaty. The field lies fully within an area that would likely belong to Timor-Leste under a maritime boundary agreement consistent with international law.

Gas seep in Aliambata on the southeastern part of the island put on fire. Instead of being wasted, it will soon be used to produce electricity for the local communities.

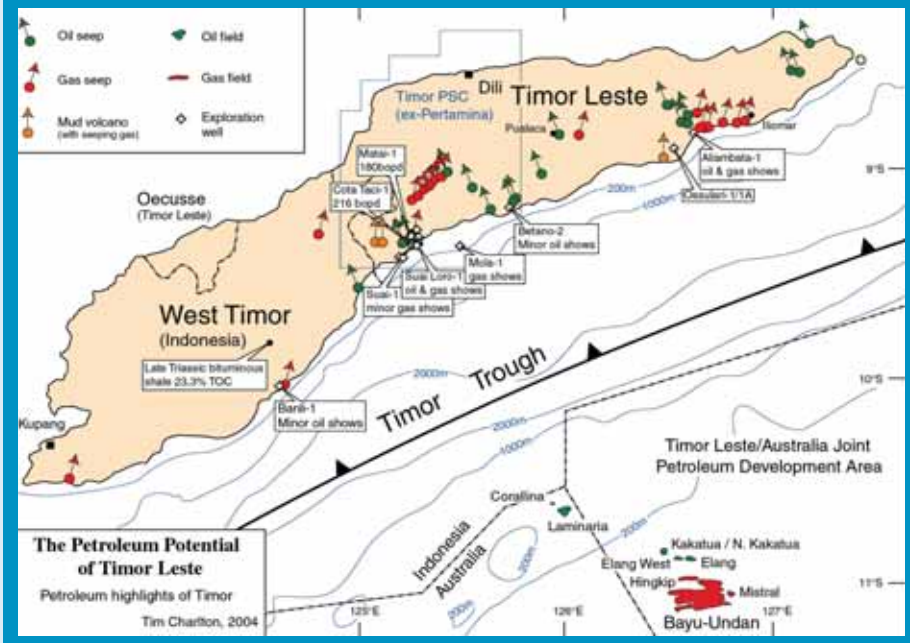
Because this was just before the Indonesian invasion it was never put into production.

Petroleum is not just found offshore. There is a long history in East Timor of using seeping oil in local communities, and the oil industry already started to show their interest in the 1890's.

"Oil-seeps, i.e. oil that has seeped up to the surface from mature source rocks, are found in many locations in East Timor. During World War I a well was drilled to 800m producing oil for a steam boiler. During World War II, the Japanese mined approximately 100 barrels of light oil per day from open pits on the southern coast of East Timor", says Geir Ytreland.

In the early 1970's a 1500 km seismic survey was acquired onshore and in the near coastal waters. One offshore well was subsequently drilled; Mola 1, and gas shows were encountered in the Pliocene section. In the 1960's and the early 1970's, Timor Oil drilled a number of onshore wells on the southern coast. Oil shows were reported from several of the wells, but commercial production was not established. All onshore operations were halted after the Indonesian invasion in 1975.

There is no question that the onshore acreage is also underexplored leaving a potential for small to medium fields. Says Ytreland: "This is why there is also interest in exploring for oil and gas on the island itself, and several oil companies have already approached the authorities on this possibility. We will therefore look at offering acreage also onshore this year."



It is not a question of if there is oil in East Timor. It is a question of how much. Onshore, numerous oil and gas seeps have been discovered, and oil has been produced from several wells in the past. Offshore, both oil and gas is so far proven in the Joint Petroleum Development Area (JPDA), while the acreage to the north towards the coast remains to be explored.

"Middle Jurassic sandstones and Permian carbonates may constitute reservoir rocks, while good source rocks are expected to be found within the Triassic shales."

Geir Ytreland is fully aware that some of the fields in the JPDA are not filled to spill-point, thereby suggesting that oil is leaking from the reservoirs. "Further north, however, there is a thick Pliocene wedge of largely clays and mudstones that may have protected the reservoirs from leaking. This wedge may also contain reservoir rocks," he says.

Ytreland adds that fault blocks and roll-over anticlines are the primary structural targets. Stratigraphic traps are nevertheless not dismissed.

Favourable terms

"The licensing round will be announced 3rd quarter this year when the Petroleum Law, the Petroleum Tax Law and a model Production Sharing Contract have been approved by the government," says Geir Ytreland.

The seismic data acquired is now being processed and will be available in June 2005. The Energy and Mineral Resources Directorate (EMRD) in cooperation with the Norwegian Petroleum Directorate and Global Geo Services, will subsequently run a "road show". Cities to be visited include Houston, Singapore and London. EMRD will arrange a technical conference for prospective bidders in the 4th quarter, while deadline for bidders is expected to be in the 1st quarter of next year with bid awards 2nd quarter 2006.

"The acreage to be offered offshore East Timor is likely to be both oil and gas prone. Major discoveries can be expected. We base our conclusions on geological correlations that include both onshore and offshore findings," says Geir Ytreland. With worldwide experience, including many years in Indonesia, he is definitely in a position to judge.

"The terms offered by the Timorese government also appear to be favourable. There will be no signature bonuses; rather, the government will put emphasis on work programmes, local content and geological knowledge," Geir Ytreland says.

The vessel had a crew of 36 and 3 Timorese trainees.

New data available

A major step towards the forthcoming licensing round was taken upon completion of a non-exclusive seismic survey, named ET-05, offshore East Timor in February. Almost 6700km was acquired in an area of 30,000 km^2 with the seismic vessel Zephyr 1 following a multi-client seismic contract awarded to a partnership of GGS and the Chinese Geophysical contactor BGP. The partnership was selected after a competitive bidding round.

The data will be available during May and June in due time before the round will be announced. The seismic, gravity and bathymetric data to be collected will be mandatory data for the first licensing round in East Timor, planned for 2005

The grid is very open with 6 km between every dip line and 12 or 30 km between strike lines. Ties are made to discoveries in the Joint Petroleum Development Area and the Australian sector, including the discoveries The Greater Sunrise, Laminaria, Barnacle, Thornton, Squilla and Thornton.

Preliminary processing was carried out onboard using a Promax. The Timor Trough stands out as a prominent physiographic feature of the sea bottom. The trough was previously thought to represent a subduction zone, as demonstrated in several scientific publications, but this has now been disproved. Instead, it represents a prominent geological boundary where the Mesozoic of the Australian shelf dips below a Tertiary wedge shed from Timor Island.

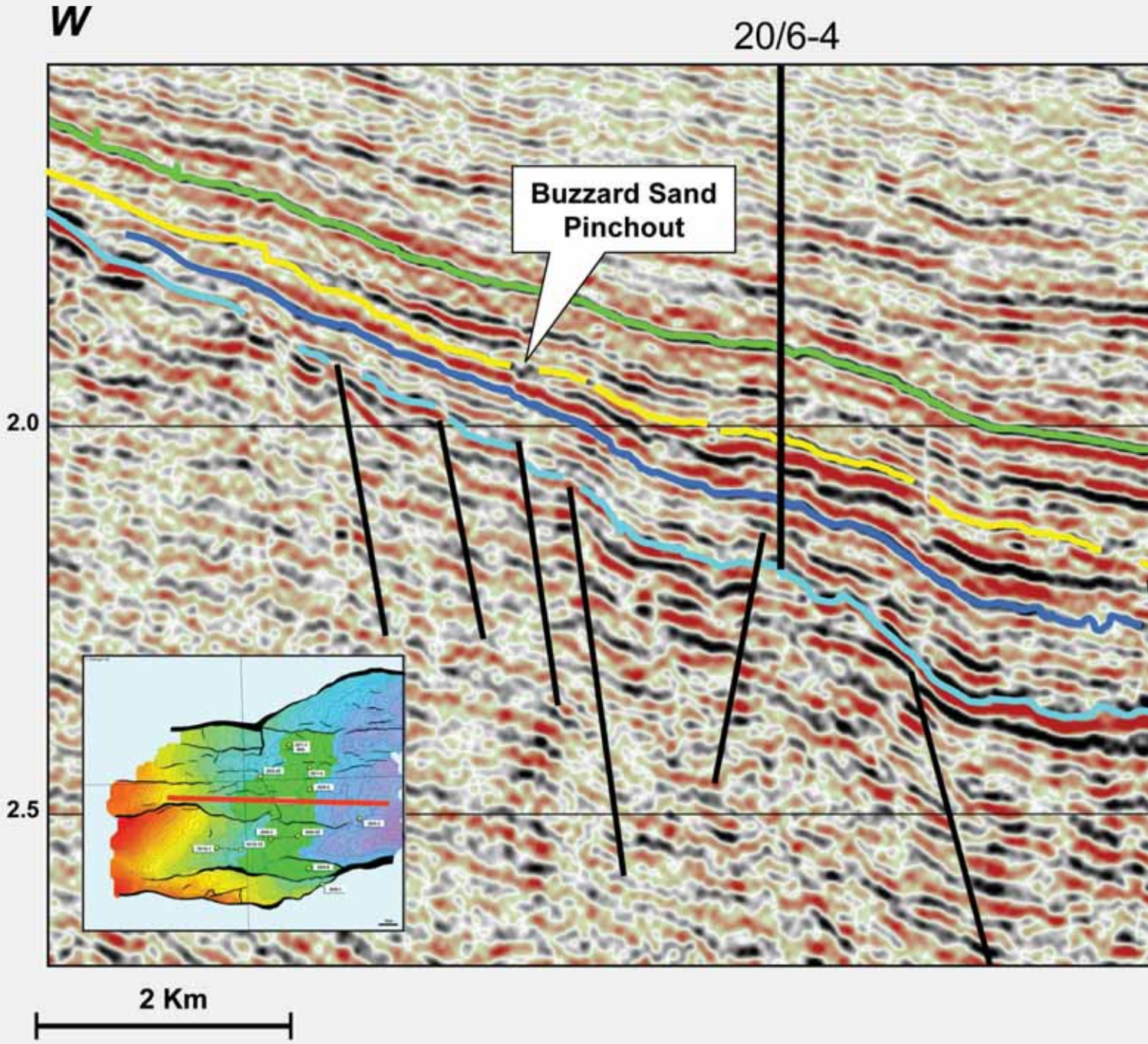
The seismic survey ET-05 was carried out with the Russian vessel Zephyr 1 operated by the Chinese seismic contractor BGP and the Norwegian company Global Geo Services (GGS) through December of last year and January and February of this year. It used an 8000 m streamer thereby facilitating good quality deep data down to 10 seconds 2-way-time.

Before survey start-up Prime Minister Mari Alkatiri was given a tour of the ship.

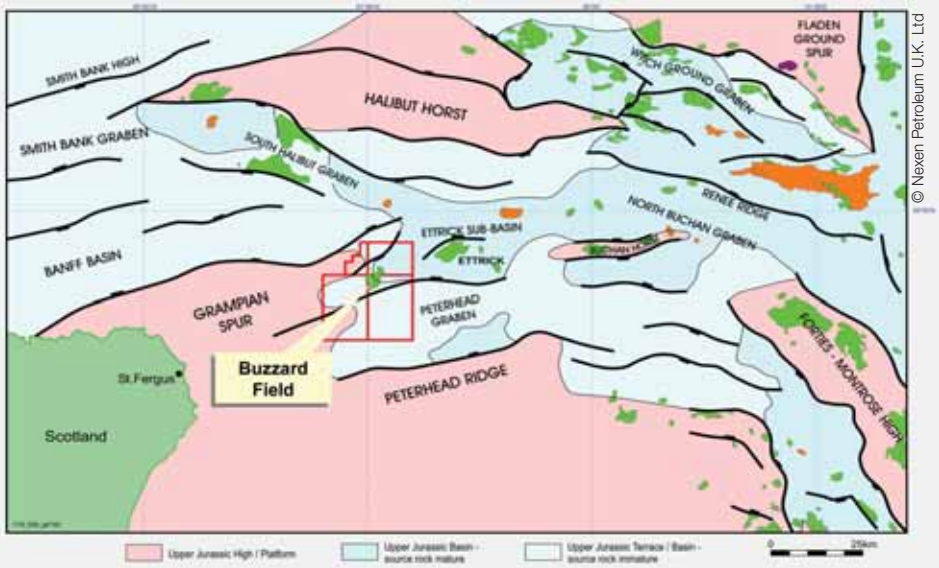
Buzzard

– a discovery based on sound geological thinking

With no apparent closure to the west, the giant Buzzard field was targeted as a stratigraphic trap within Upper Jurassic deep-water sandstones. The discovery should be recognised as a result of high risk/high reward exploration based on a robust geological model and fit for purpose geophysics.



The Buzzard field is located just downdip from the Grampian Spur, an Upper Jurassic platform, and immediately adjacent to Upper Jurassic mature source rock (Kimmeridge Clay Formation) that measures up to 600 m in thickness. Hydrocarbon expulsion was simply updip to the west and directly into the trap. Maturation modelling indicates hydrocarbon generation and migration commenced in the Eocene (some 55 million years ago) and has continued until the present day.



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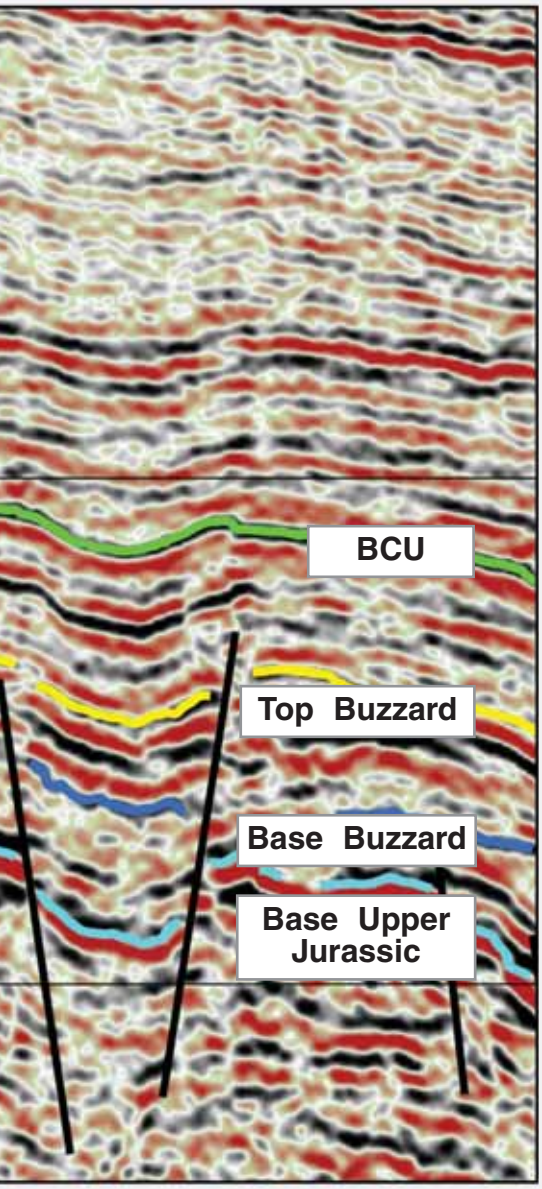


The giant Buzzard oil field is located in the prolific Moray Firth Basin of the North Sea, some 100 kilometres northeast of Aberdeen and in water depth of 100 m. Co-ventures in the project are Nexen Petroleum U.K. Ltd (operator), Petro-Canada Ltd, BG Group and Edinburgh Oil and Gas Plc.

Seismic dip line running from the deep Ettrick Graben (east) towards the Grampian Spur (west) illustrates the Buzzard stratigraphic trap component with Upper Jurassic reservoir sandstones thinning towards west. Well 20/6-4 was the first appraisal well to be drilled following the discovery well 20/6-3 in May 2001. An aggressive appraisal campaign included six appraisal wells and two sidetracks in one year to delineate the extent of the discovery. In addition, two production tests and an injection test were done. A 305 km^2 3D seismic survey was also acquired. A giant oilfield was thus defined with an estimated 1,2 billion barrels (190 million m^3) of oil in place. Current estimates of recoverable reserves exceed 400 million barrels (65 million m^3). *The index map is a depth map on the reservoir level.*

Halfdan Carstens

It must have been quite an exciting moment: We can suspect that the adrenalin was flowing fast. Following years of meticulously developing and soliciting a prospect few explorationists would believe in - and even fewer companies wanted to put their money into - the first well was about to enter the reservoir in the spring of 2001.

"The tension and anticipation was palpable," says Graham Doré, who was at the time chief geologist with the large independent Canadian oil company PanCanadian. "On Friday 11th May the well encountered a significant drilling break. We had oil and gas shows about 200 m through the Upper Jurassic, and there was almost a sense of disbelief in the office as we considered the possibility of having a major discovery on our hands. There followed a few nerve-jangling days as the reservoir was cored and the scale of the find slowly became apparent, but any doubts were finally replaced by elation and excitement when logging confirmed that the reservoir was fully oil bearing. Buzzard had come in big time!"

The discovery well was found to be fully oil-bearing. It was therefore sidetracked 1300 m to the east and successfully established an oil-water contact and proving an oil column of 425 m. The upper part of the reservoir was subsequently tested, flowing a surface-constrained rate of 6547 BOPD of 32° API oil on a 36/64" choke.

Significant potential identified

Four years later we have learned that the Buzzard Field is one of the largest fields to be discovered in the UK continental shelf in the last 25 years. Current reserve estimates are conservatively put in excess of 400 million barrels, but it may well turn out that the field is significantly larger. If that is the case, it will eventually be classified as a *giant* oil field, meaning that the reserves exceed 500 million barrels of oil (80 million m^3).

We may, however, also have learned something about the value of sound geological thinking when exploring mature basins. Geological knowledge may be worth millions of dollars if used correctly and if managers are ready to listen.

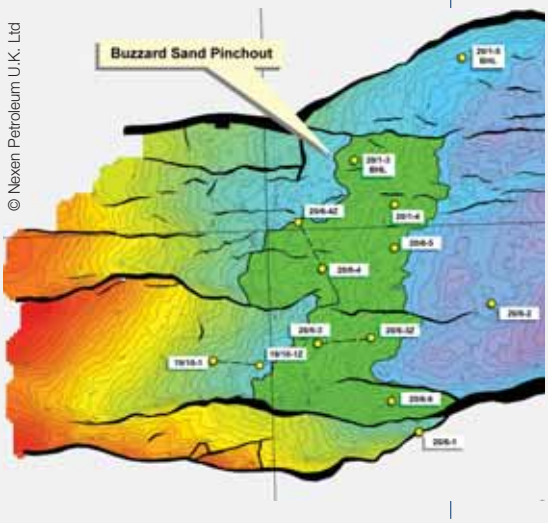
A decade prior to the discovery, the successful prospect existed only in the minds of a few geologists. Their asset was an intimate knowledge, acquired through years of experience, of the geological evolution in this part of the North Sea. Says Doré: "Without good quality seismic data, the prospect was very much based on an idea. But we thought the geological concept looked really good."

Doré first came up with the idea in 1992 when working as a geologist with Amerada Hess. "The prospect was considered too risky. The oil companies were at that time prone to test well defined structural traps rather than subtle stratigraphic tests," he says.

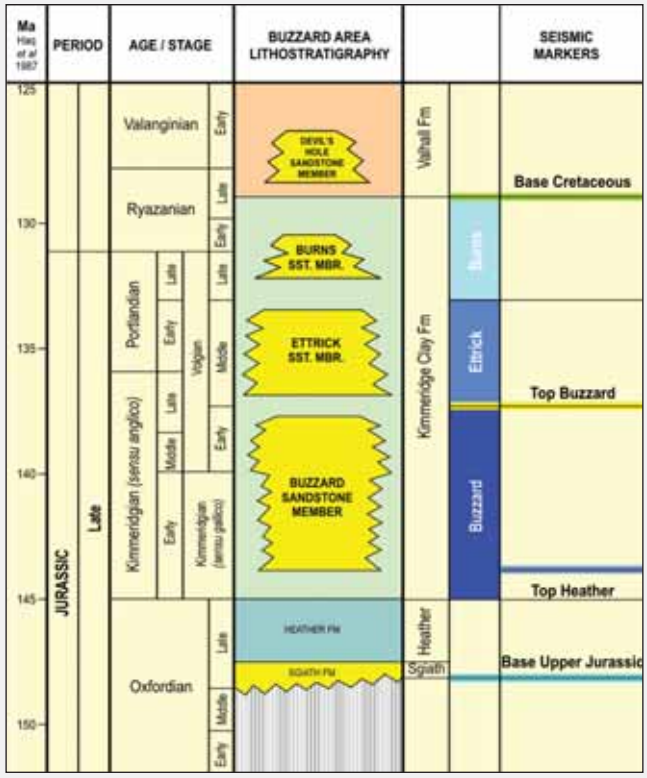
By moving from Amerada to PanCanadian, a new entrant to the North Sea arena, Doré got a new chance to work on his innovative ideas.

"Based on data from well 20/6-2 drilled in 1986, a well that encountered 200 m of submarine gravity flow sands of Upper Jurassic age in the centre of the sub-basin, we knew that fantastic quality reservoir sands existed. A limited number of 2D seismic lines enabled us to sketch a simple map identifying a stratigraphic trap with updip pinchout of the sandstones. The potential size of Buzzard prospect made it a very exciting project to work on."

PanCanadian thus acquired the rights to the licence in 1998. It would take another three years before the prospect had matured and was ready to be tested. "A key fac-



This depth map of the Top Early Volgian (i.e. top reservoir level, compare stratigraphic column below) illustrates the predominance of the east-west oriented faulting separating the field into five separate compartments. Also shown are the updip pinchout and the oil-water contact. The Buzzard Field is considered to be a fault-bounded stratigraphic trap. The field is dip closed to the east. To the north and south the closure is determined by downthrow against the east-west-trending graben-bounding faults. To the west the trap is clearly stratigraphic in nature. This stratigraphic trap is thought to be a simple depositional pinchout at the base of a depositional slope, with the slope to the west acting as an area of sand bypass.



The stratigraphic column shows the Upper Jurassic reservoir sandstones of the southern Moray Firth Basin being encased in Kimmeridge Clay Formation source rocks. The Buzzard reservoir, being older than the Ettrick reservoir further east, has been subdivided into four stratigraphic units. The upper unit, which contains 80 % of the reserves, has a fairly uniform thickness across the field and is characterised by a high net to gross ratio and excellent porosities and permeabilities. Triassic sedimentary rocks or granitic basement generally underlies the Upper Jurassic sequence.

tor in helping to determine the 20/6-3 well location was the successful reprocessing of the original 1995 3D," says John Robbins, senior geophysicist with PanCanadian at the time. "A significant improvement in multiple attenuation and resolution in the Upper Jurassic highlighted key stratigraphic detail and gave us more confidence in the pinchout."

Excellent reservoir properties

The Buzzard Field is situated at the western margin of the Ettrick Sub-basin in the southern part of the Moray Firth Basin (compare page 35). Prior to the discovery of the Buzzard Field, 15 exploratory wells had been drilled within this northeast-southwest trending sub-basin with Jurassic strata plunging below 4000 m. The most significant was the Ettrick Field discovery well (20/2-1) in 1981 that proved the presence of gravity flow sands of Upper Jurassic age.

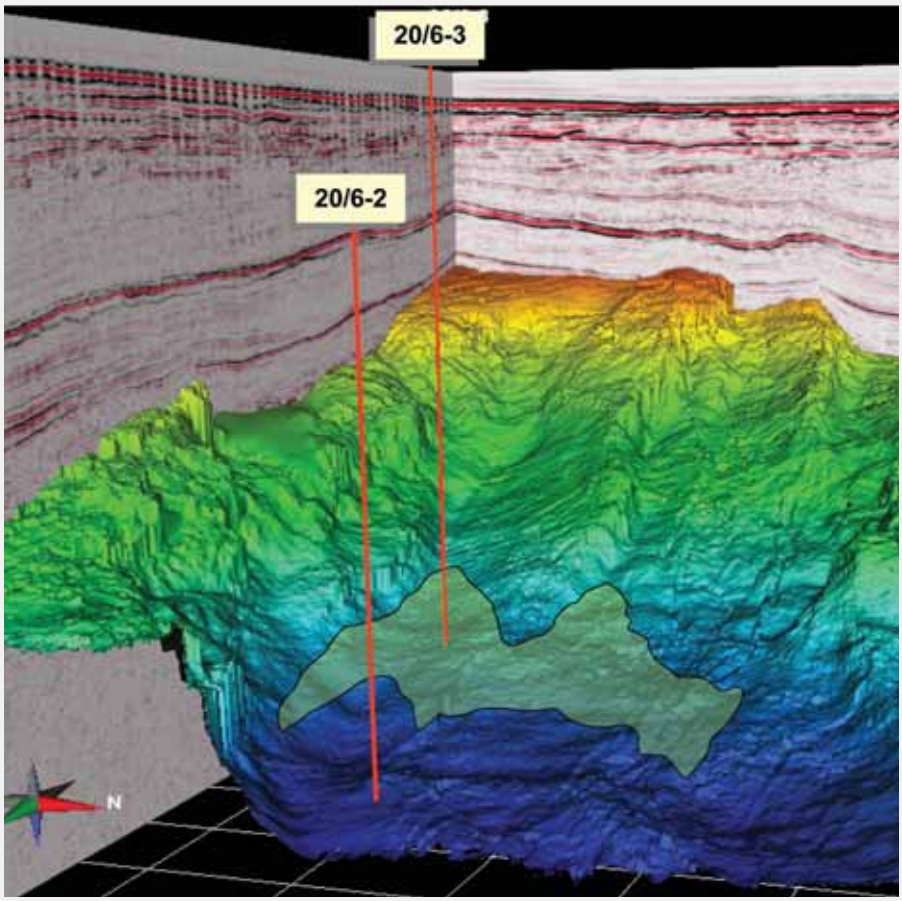
At the end of the Oxfordian in Late Jurassic time (compare stratigraphic column) rift-related tectonics drastically altered the basin geometry, bathymetry and sedimentation style. "Thick organic rich mudstones of the Kimmeridge Clay Formation were subsequently deposited within the Ettrick Sub-basin. Additionally, submarine gravity flows introduced significant amounts of sands from the Halibut Horst to the north and the Grampian Spur to the west," explains Doré.

"We interpreted the sands to have been deposited in a base of slope setting. The sand provenance is thought to be Permian and Triassic age continental clastics eroded from the Grampian Spur hinterland to the west. A river or braided delta system is thought to have fed sediments in an eastwards direction into the Buzzard Graben. These sediments bypass the easterly dipping slope between the shelf and deep water and were deposited at the base of the slope," says Doré.

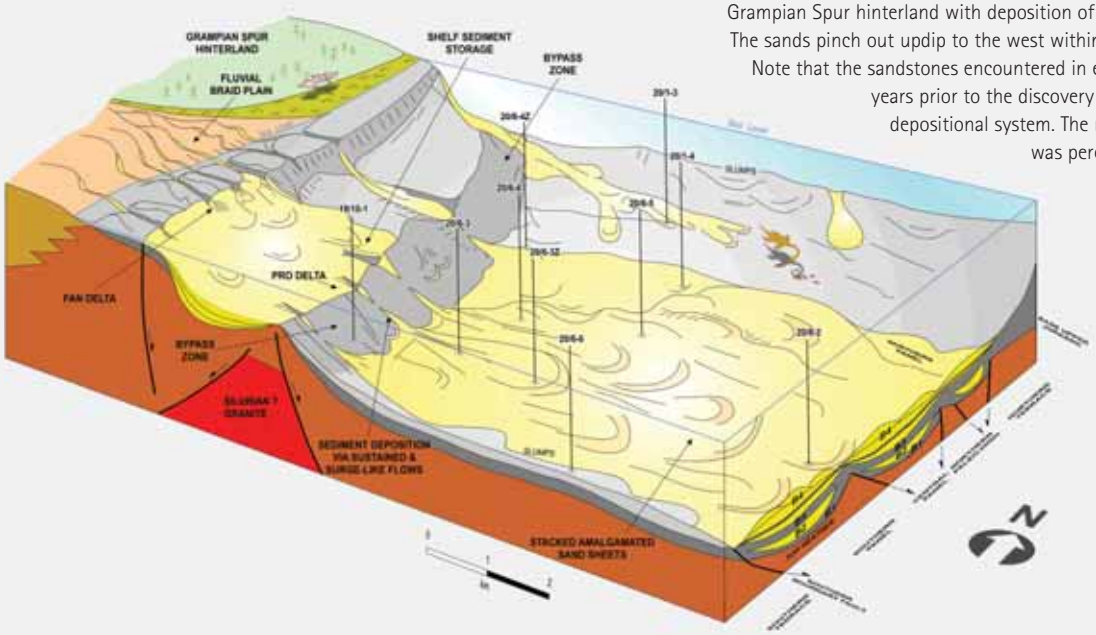
"The Buzzard Field reservoir units are up to 100 m thick and generally have high net/gross ratios. Porosities vary between 15% and 34% and permeabilities between 200 mD and 18 Darcys," adds Doré, thereby substantiating why he claims this to be an excellent reservoir. "We believe the combination of a high quartz and low clay content is the key to the development of the exceptional reservoir properties. An emplacement of silica cement aids this during the diagenetic history, as the silica added an early rigidity to the reservoir and

Photo: Halfdan Carstens

Graham Doré (right) and senior geophysicist John Robbins can claim that they have been instrumental in the discovery of the Buzzard Field. By combining in depth geological knowledge with appropriate geophysical methods they were able to define an exploration target missed by several others. They recently presented their story in the 1st Biannual Petroleum Geology Conference convened by the Norwegian Petroleum Society in Bergen this year. It has also been published in the *Proceedings of the 6th Petroleum Geology Conference*.



The 3D perspective of the Base Cretaceous seismic reflector - with the field outline superimposed - clearly demonstrates the lack of structural closure in the east-west direction as the structure rises onto the Grampian Spur. Note also the location of the exploration well 20/6-2 drilled in 1986, 15 years before the discovery well 20/6-3, which proved excellent reservoir properties and a 3-4 m hydrocarbon column in a small structural trap.



The Buzzard sandstone depositional model implies a provenance area in the Grampian Spur hinterland with deposition of gravity flow sands in deep water. The sands pinch out updip to the west within the Kimmeridge Clay Formation. Note that the sandstones encountered in exploration well 20/6-2, drilled 15 years prior to the discovery well 20/6-3, are part of the same depositional system. The major risk factor for this prospect was perceived to be the stratigraphic seal to the west.

significantly reduced the compactional effects of the overburden."

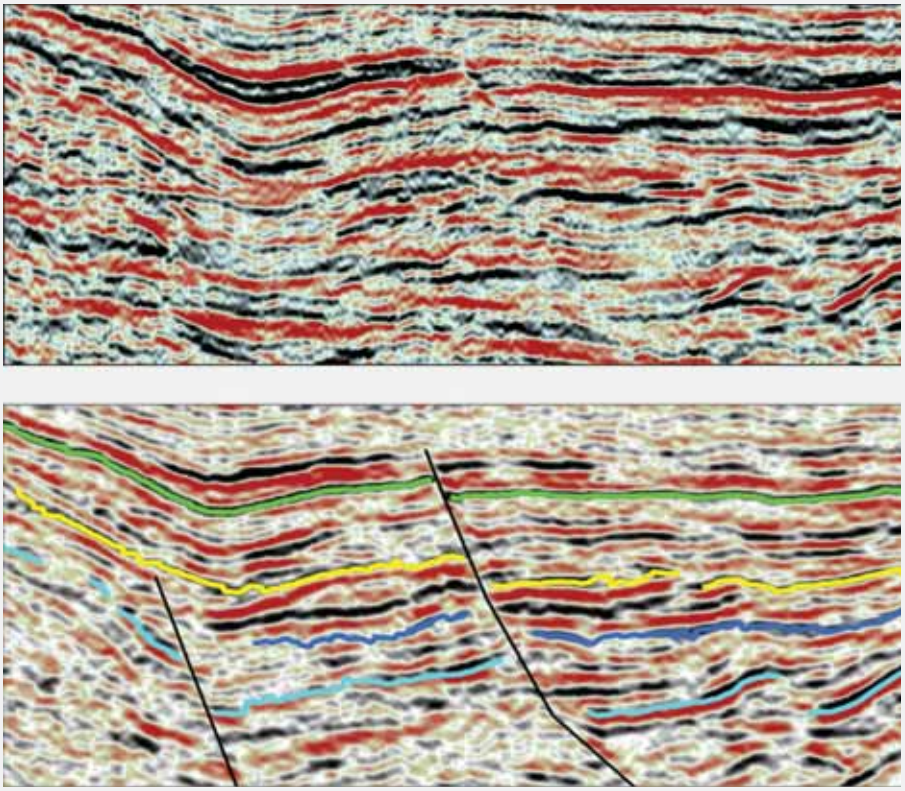
A success story

The Buzzard Field, with more than 1 billion barrels of oil in place discovered at a late stage in the exploration of a mature basin, is nothing less than a success story. "The updip potential was apparently recognized by a significant number of independent oil companies, but the per ceived risks deterred them from drilling the prospect," says Doré.

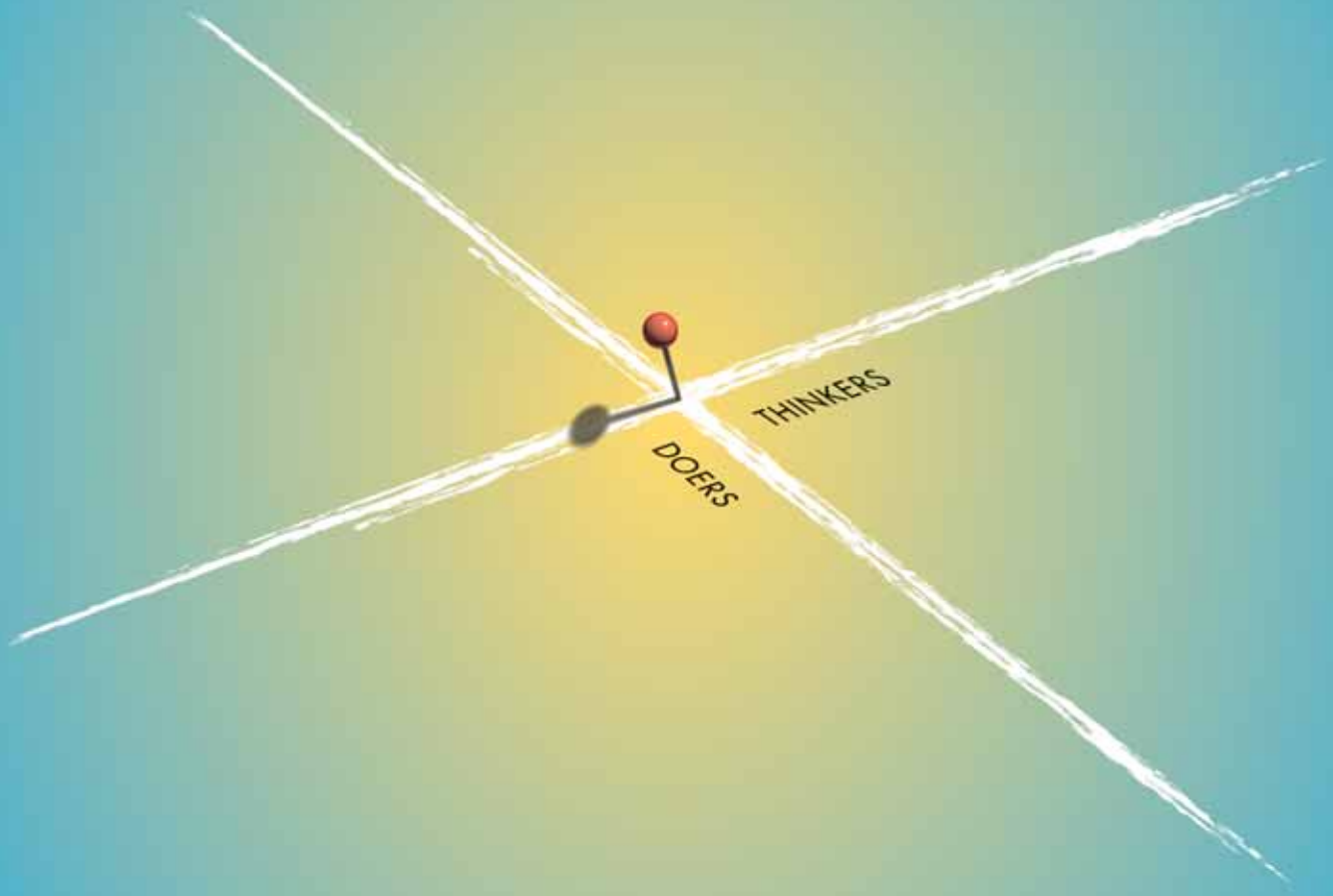
"The play was originally targeted by well 20/6-2 in 1986. At that time the updip potential was missed or deemed to be too high risk by many oil companies. The Buzzard partnership, however, had a willingness to explore on the basis of a strong geological model and good seismic interpretation, without the requirement of AVO or other seismic attribute indicators. This, combined with a belief in high risk–high reward exploration, led to the drilling of the Buzzard discovery well 20/6-3 in 2001."

Graham Doré and John Robbins claim that a number of geological factors were in favour of the prospect which was given a chance of success of 12% prior to drilling: "The proximity to a significant sand provenance area in combination with a location within an embayment that was focus for sand deposition, played a key role in establishing the depositional model. If the depositional slope was sufficient for sediment bypass - thereby producing an updip pinchout - was a key risk factor. Source and migration were a minor risk factor with oil being generated in a mature basin immediately to the east. Low risk was also envisaged for sealing, also because there was no evidence for late fault reactivation."

Michel T. Halbouty, the celebrated American petroleum geologist, once remarked, "it's about time the good geologist came out of the closet." As evidenced by their discovery of the giant Buzzard Field, Graham Doré and John Robbins have responded punctually to Halbouty's call.



Significant improvements in data quality were achieved when reprocessing the original 3D-data. The yellow colour denotes top reservoir level, while green colour is base cretaceous level.



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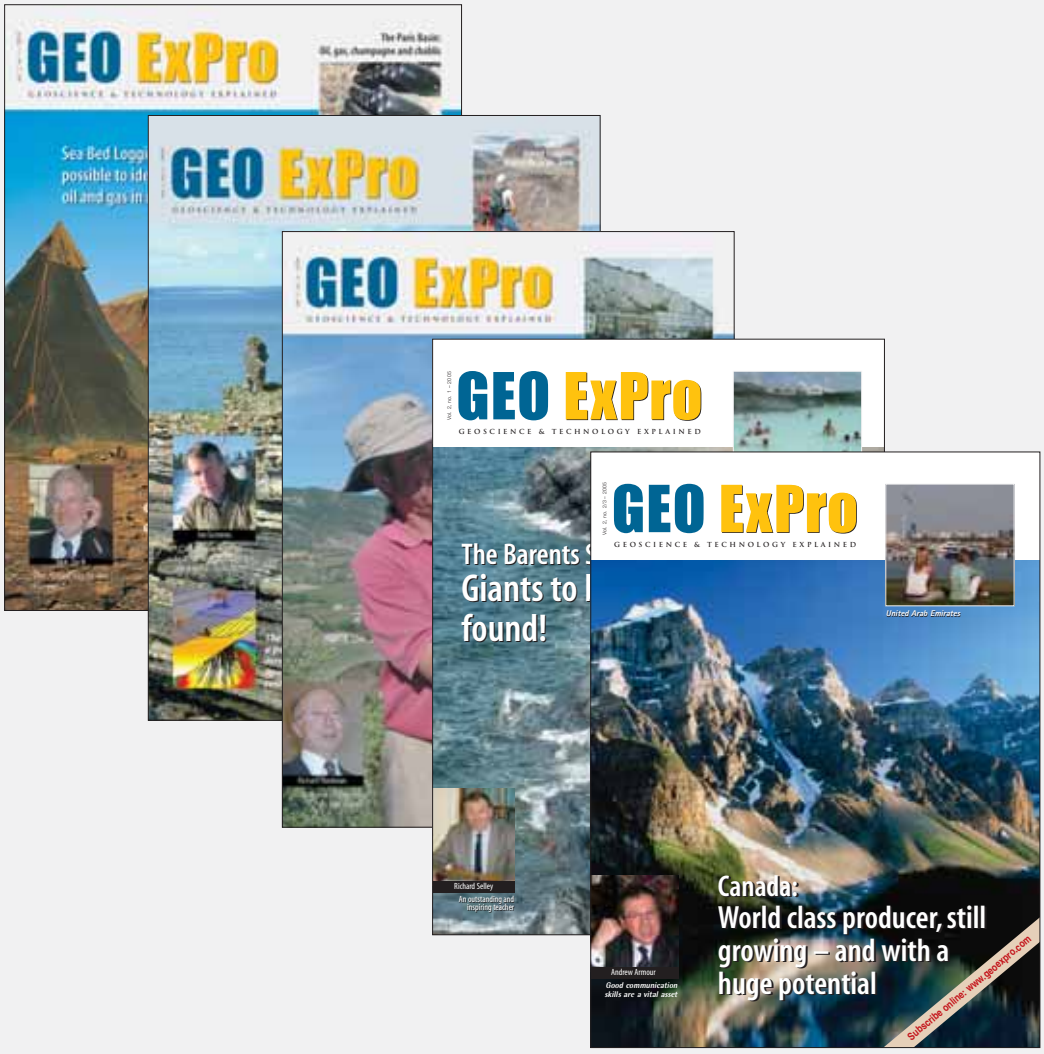

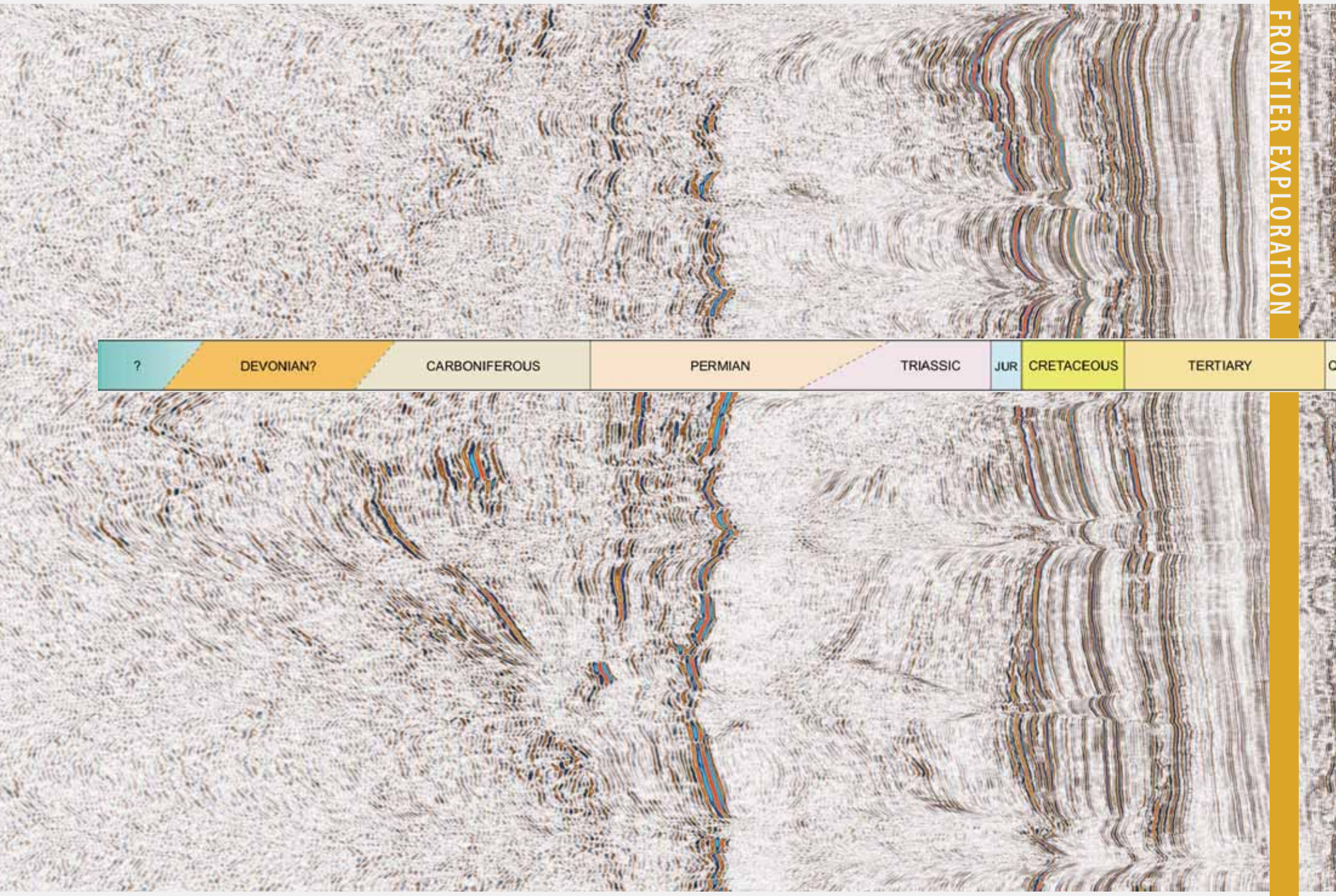
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DEVONIAN?
CARBONIFEROUS
PERMIAN
TRIASSIC
JUR
CRETACEOUS
TERTIARY

Courageous risk takers needed

Experienced oil-man John Brooks thinks that there is still a great deal of potential in the deep reservoirs of the southern North Sea. "To test the deep potential, we need political initiatives and the harnessing of technological innovations, coupled with a willingness by big companies to take a risk," he says.

Jane Whaley

"It is remarkable to note that no well in any basin in the North Sea has evaluated the full succession through to basement. The deepest well in the Southern Gas Basin was drilled to a depth of about 6,500m, while the basin itself is thought to have a total thickness of about 12,000m."

"Why are we ignoring these lower potential reservoirs?" says John Brooks, CBE[1], for many years Director of Exploration and Licensing at the UK Department of Trade and Industry (DTI).

"My colleagues at the DTI often teased me about my obsession with the possibility of finding Cambrian oolite reservoirs in the North Sea, just as they have been found in Oman and elsewhere. We don't have to look as far as Oman for interesting pre-Carboniferous reservoirs, but if we don't look for them at all, they certainly won't be found!"

Exploration is also about new play concepts

Current exploration efforts in the North Sea concentrate on plays in the known drilled succession, and do so very successfully. However, the present perception in the industry is that the UK Continental Shelf (UKCS) is mature and that anything left will be relatively small. As a result, many of the majors have moved out of the area, finding it easier to buy or explore elsewhere in the world.

John Brooks points out that the 'Promote' initiative is doing an excellent job of mopping up the remaining relatively small reserves in the known areas and plays, at affordable costs. "This is what I call 'snuggle' exploration, dealing exclusively with what is known. Exploration, however, is also about the unknown - new play concepts which may prove to contain hydrocarbons and which will need imaging, evaluation and drilling."

To begin to gain some idea of the potential of the deepest parts of the North Sea, a number of challenges need to be overcome. John Brooks summarises these as technical problems, associated with the successful acquisition and processing of seismic imaging to a depth of about 12 seconds, as well as those related to the drilling of very deep wells; and licensing and bureaucratic issues such as ensuring acreage is obtainable and making funding available for such innovative exploration.

The deep potential

Our current knowledge about the prospectivity of the Pre-Carboniferous in the Southern Gas Basin and the Central North Sea is very limited at present. This is because few wells are being drilled into this succes-

Photo: Tore Karlsson

John Brooks, geologist by profession, and with a long career in the DTI, is of the opinion that the government should support exploration in the deep Paleozoic section in order to maximise the full potential of the North Sea.

The TGS Nopec North Sea Renaissance survey has been recorded to 9 seconds 2-way time with an 8000 m long cable, making it possible to interpret geological horizons within the Palaeozoic. Note that the Top Rotliegendes (base salt) is found shallower than 4 seconds. The survey has to date been acquired in the central and northern North Sea. The programme will be extended to the Southern Gas Basin this year.

[1] Commander of the British Empire, a high honour given by the Queen.

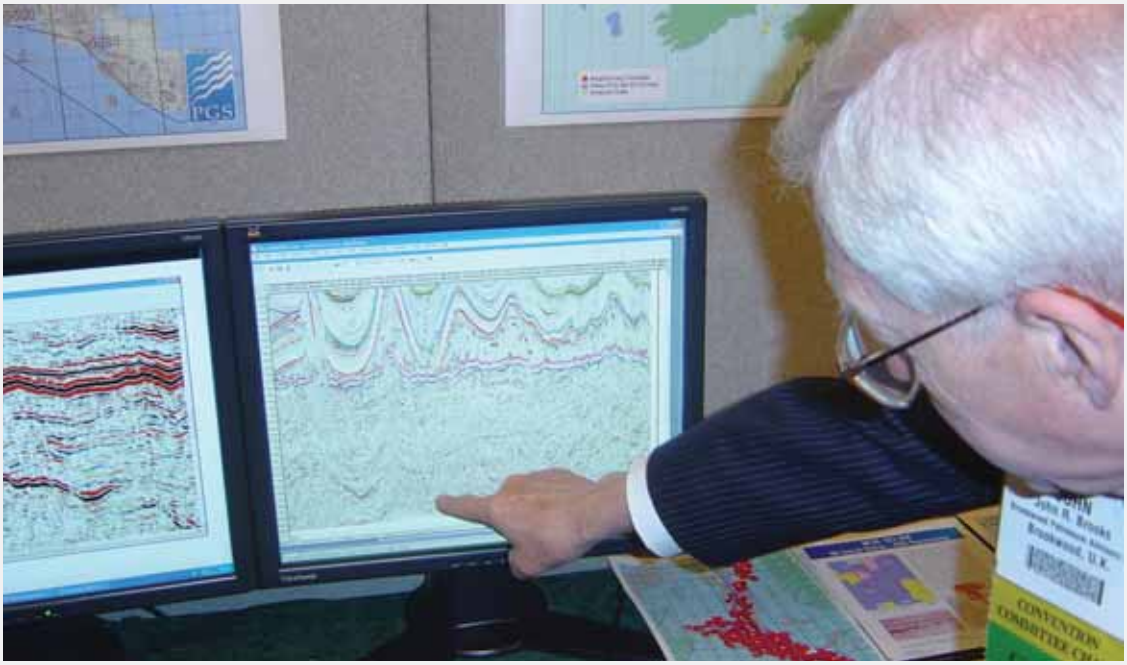


Photo: Tore Karlsson

Says John Brooks: "I know discussing the hypothetical idea of pre-Carboniferous reserves in the Southern Gas Basin is what some people call Blue Sky thinking – but why not? Prove me wrong!"

sion and seismic data is focussed on shallower stratigraphic levels.

John Brooks says, "We know, first of all, that the basin extends a further 6,000m or more below the currently drilled horizons. Furthermore, we know that Palaeozoic source rocks and reservoirs may exist. The problem is we appear to have stopped drilling further a few years ago because at the time we could not see any deeper, not because we knew what was there. In the Southern Gas Basin we know we have Cambrian on the edges of the basin on both the UK and the Dutch sides, so there is certainly evidence of continuity."

He also notes that exploration in Palaeozoic rocks is proving very fruitful at the moment. He sites North Africa as being an example of successful exploration in older rocks, albeit with different geological concepts from those in the North Sea. In Europe, the Latvians have production from the Lower Palaeozoic succession sub-cropping beneath the Lower Devonian, at a depth of about 1,600m. They have structural traps in the Cambrian, and stratigraphic traps in Ordovician and Silurian reefs as well as in Cambrian pinch-outs. Similarly, in Poland, Lower and Middle Cambrian sandstones form reservoirs overlain by a regional seal of Ordovician and Silurian shales.

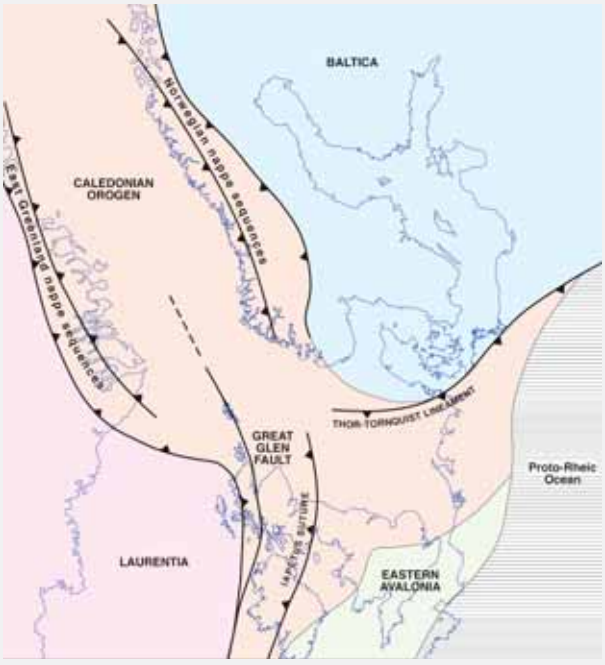
"We don't know whether, if there are any hydrocarbons in the Pre-Carboniferous of the North Sea, they will be oil, gas, or completely over-mature. Rocks usually become more indurated with depth, but as we all know, there are many exceptions to this. I can think of a number of examples from the North Sea where porosities have not decreased with depth, much to everyone's surprise."

Government funding may be necessary

"Imaging is key," says John Brooks. "Modern seismic has improved to an amazing level over the last decade, and we now have the ability to image below the salt and to great depths."

"There are still technological issues to be considered, such as filter termination and improvement of 3D imaging, but we are on the way to overcoming these. Long offsets, together with new processing methods, have produced very interesting results, but perhaps the decision makers in the industry are not really aware of just how deep we can image? A number of long offset lines run in the Central North Sea clearly demonstrate the pre-salt horizons. The results are fascinating."

"Of course, we are now all accustomed to such excellent seismic, particularly since the advent of 3D, that we tend to drill on



The North Sea rift system is located in the area of a triple-plate collision zone. The collision occurred during the Late Ordovician to Silurian Caledonian Orogeny. According to John Brooks, the Paleozoic of Eastern Avalonia should be tested by deep wells targeting stratigraphic horizons down to and including the Cambrian.

clearly imaged prospects and, at least in the North Sea, within a known stratigraphic column. Finding has become easier. We may need to go back to basics and revert to the mindset of the 60's, when we didn't drill with such certainty," John Brooks claims.

To start looking seriously at these deep potential reservoirs, an extensive seismic programme is required. As John Brooks is only too aware, seismic is expensive, and it is highly unlikely that seismic companies will be able to cover the whole of the North Sea with long offset data on a speculative basis. How, therefore, do we fund this initial acquisition of data? It would appear that assistance from government would probably be needed.

A "deep reservoir" licensing round

John Brooks feels that in order to encourage oil companies to start to look at the pre-Carboniferous in the Southern North Sea, we need to convince government that there is a chance of finding reserves there. "Maybe shoot just a couple of speculative lines and show them what can be seen."

Once interested, there are a number of actions that the government could take. "They could, for example, commission seismic surveys and possibly give tax breaks to companies buying the newly acquired data. And it would be wonderful if we could get the Norwegian, Danish and Dutch governments to work with the UK on an intergovernmental initiative in this, so we could draw up the whole picture of the basins in the North Sea, to the benefit of everyone."

"Some creative thought also needs to be given to ways in which we can make acreage available to oil companies interested in these potential reservoirs. A 'deep reservoir' licensing round might help concentrate minds. At the moment, all licences commence at the surface and subtend to the centre of the earth, but no one is actually drilling below 6,000m. We could suggest that companies relinquish their entitlement to the subsurface below 6,000m and that this lower part is then re-licensed on frontier terms."

Once seismic has been obtained and potentially drillable prospects identified, there is the problem of how to finance this deep prospect investigation. Exploration is usually funded from production, but oil companies will be unwilling to divert funds from more certain areas.

Suggests John Brooks: "This is not really for the Promote licensee, who is working within the known at affordable depths. It is much more expensive and will need investment from government and the major oil companies. We need to encourage the majors to remain in and return to the North Sea. Perhaps government could take the initiative and help fund a number of wells to test the viability of Palaeozoic reservoirs. Once governments were convinced that there was a chance of finding further resources, then maybe instead of taxing oil companies on windfall profits, they could persuade companies to put the money into this type of frontier exploration."

Alternatively, it is possible that existing licensees or financiers and venture capitalists will need to be involved. As John Brooks says: "There must be people in the major companies who are also thinking that if you look below the Carboniferous in the North Sea, you'll come up with a few surprises - I can't be alone in the world! What we really need is discussion on the various funding options."

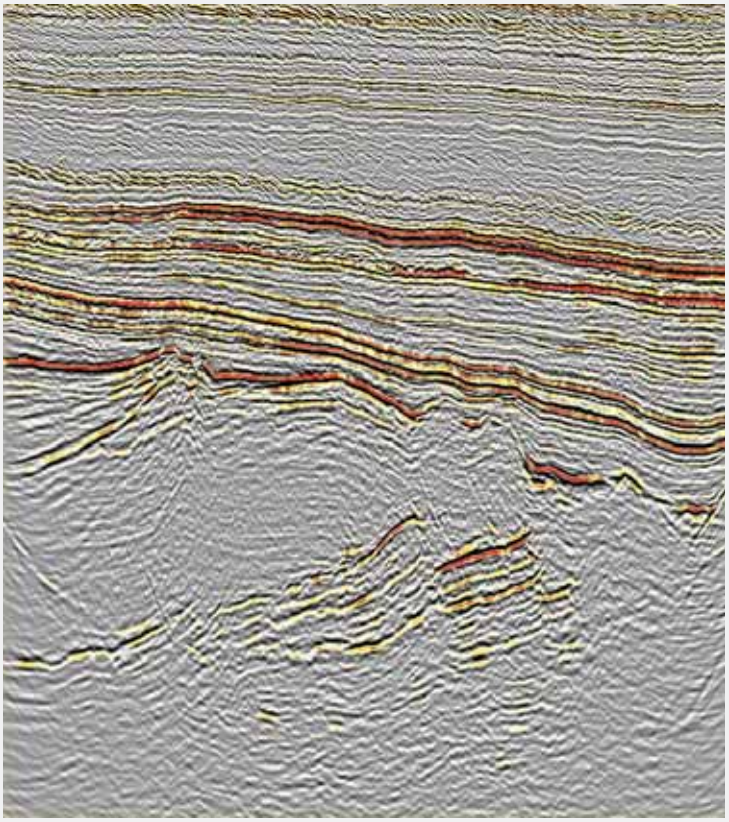
Blue Sky Thinking

John Brooks agrees that it is possible that market forces will dictate, and that only when we run out of known hydrocarbons will explorationists start to look for these deep reservoirs.

"I'm a great believer in market forces, but I do think that you have to be a bit prudent too. If we leave it too late, companies will have moved out of the North Sea and we will have lost our infrastructure. If market forces are going to tell you something in a number of years time, by which time you will be unable to do anything about it, then it is necessary to have the idea earlier, and plan ahead."

be, with new play concepts often left untested. "This is partly because business finds it hard to understand failure. No percentage is given to thinking outside the box." He feels that the excellent quality of much modern 3D and 4D seismic means that geologists are used to drilling on such well-imaged prospects, that any area not clearly imaged is instantly less attractive. He also questions whether geologists have sufficient decision-making authority in many companies.

"Considerable investment in technology is being made in order to harness alternative energy sources," he says. "Compare that to the idea of looking at deep reservoirs in the North Sea. The infrastructure is in place



3D seismic data image illustrates Palaeozoic stratigraphy beneath the Permian salt.

'If the perception is that we are constrained on the amount we have to extract, and we are starting to look elsewhere, then it follows that we should be putting some amount of effort into establishing whether or not there is potential in these deep reservoirs. If you want your own country to be as self sufficient as possible, you would be expected to look at all possibilities. We can't just walk away and say no to such exploration when we have the ability to actually see to these depths.'

John Brooks considers that there is less willingness to take risks than there used to and we have the technology to look a lot deeper than we currently image, so why don't we do it? Is it simply because it takes us into unknown territory, where the play concepts and geology are undefined?"

John Brooks does not see the value in being pessimistic, which he considers is the easy way out. "I know discussing the hypothetical idea of pre-Carboniferous reserves in the Southern Gas Basin is what some people call Blue Sky thinking – but why not? Prove me wrong!"

Moving forward

emgs recently announced that it is launching a second ship, the MV Atlantic Guardian, to perform electromagnetic SeaBed Logging (SBL) surveys to detect hydrocarbons in the subsurface. emgs' first ship, the MV GeoAngler, for which it has extended an exclusive charter through April of 2008, has helped the company complete nearly 100 surveys for more than 10 oil companies, including Shell, Apache, and Statoil in regions as varied as the Mediterranean, South China Sea and North Sea.

The latest customer is Woodside Energy, Australia's largest publicly traded oil and gas exploration and production company, which has awarded emgs a survey offshore Mauritania, West Africa. The scope of emgs' work will enable Woodside to calibrate the SBL technology while more accurately predicting exploration targets. The work that emgs has been performing for Woodside in relation to the contract includes SBL surveys in both well-known and exploratory fields offshore Mauritania.

The Sea Bed Logging company has now opened an office in Houston to expand their business in the Gulf of Mexico and North and South America. emgs is backed by the global private equity firm Warburg Pincus, which announced in July of 2004 that it had acquired a majority shareholding position of the company.

Photo: Halfdan Carstens

Managing Director Terje Eidesmo in emgs.

Photo: Tore Karlsson

Integration

– the Foundation for the Asset Team

For many years, Dr. Alain Gringarten considered that "Integration of geological and engineering disciplines is the key to successful exploration and production." Now Professor of Petroleum Engineering at Imperial College, he is putting this into practice.

Alain Gringarten is Professor of Petroleum Engineering and Director of the Centre for Petroleum Studies at Imperial College, co-ordinating all research and postgraduate teaching and activities in petroleum related studies at the College.

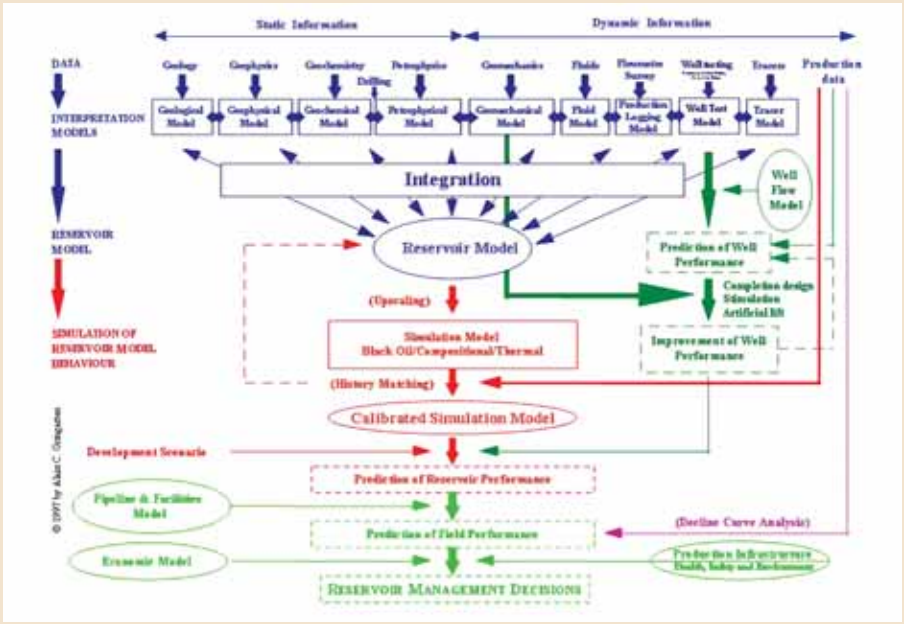
Jane Whaley

Walking through the imposing entrance to the Royal School of Mines at Imperial College in Kensington in London, one is aware of a great sense of history and scientific advancement. The many years of innovative and groundbreaking science and research, which has been conducted in this famous institution, seem almost palpable. It is gratifying to realise that this pioneering approach to the teaching of earth sciences is still cherished and practiced.

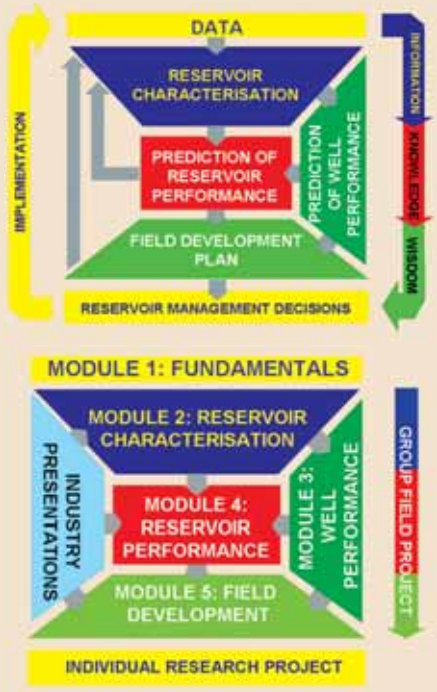
Educating future geoscientists

Dr. Alain Gringarten, Professor of Petroleum Engineering at Imperial College, believes that "Integration of geological and engineering disciplines is the key to the optimisation of the exploration and production of hydrocarbons." Oil companies agree with this and have eliminated their separate departments for geology, geophysics, drilling, geochemistry and various other subdivisions, consolidating their experts into multi-disciplinary teams.

When he became Director of the Centre for Petroleum Studies in Imperial College in 1997, Prof. Gringarten rapidly reorganised the MSc. courses in the department to reflect these ideas. Students are educated to understand the workflow concepts prevalent in the modern oil industry. As Prof. Gringarten says, they become "petroleum professionals who are specialists in their own fields but trained to work efficiently in multi-disciplinary teams." The MSc. course in Petroleum Engineering enables students to understand the fundamental concepts of field management, reservoir characterisation, modelling and simulation as well as the processes of integrating available data. On completing the course, students are well equipped to step into an oil company's multi-disciplinary "asset" team, immediately able to make a useful contribution.



The Reservoir Management Process.



MSc. in Petroleum Engineering at Imperial College.

The key to this new approach is understanding and using the reservoir management process. Prof. Gringarten's defines reservoir management as *"the application of available technology and knowledge to a reservoir system in order to maximise the economic value of the reservoir and make the best possible decisions."* There are 3 main phases to this approach: reservoir characterisation and modelling, followed by well and reservoir performance and finally field development.

Reservoir characterisation and performance

The importance of the integrated approach becomes apparent in the **first stage** of this process, reservoir characterisation. To fully understand a reservoir, data from many disciplines is needed, including geology, geophysics, petrophysics, geomechanics, flowmetrics, well testing and tracing. Each discipline creates its own model, but the next step is to amalgamate these into a single, integrated, consistent reservoir model, which can be verified and matched against real data.

All MSc. students of petroleum studies at Imperial College are taught fundamental courses together, to enhance their full understanding of every aspect of petroleum geoscience. The petroleum geoscience student will spend some time studying well testing, although not to the level of the petroleum engineer, who will in turn have had a number of hours tuition in geological and geophysical modelling. This enables students to understand both the power and the shortcomings of the various techniques involved in building the full reservoir model. Well test data, for example, can elucidate faults and compartmentalisation, which may not fully accord with the seismic interpretation, allowing the geophysicist to refine the interpretation.

To teach the technical and interpersonal skills required to create a reservoir model in an oil company environment, students form multidisciplinary 'asset teams'. They are presented with real oil company data and expected to come up with a working reservoir model. This project is introduced 2 months after the start of the course and is a very important aspect of both the engineering and geoscience courses, each team being made up of both geoscientists and petroleum engineers. At the end of the 15-day project they present their results,

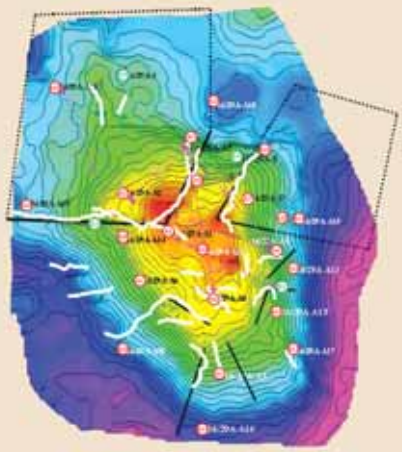
complete with STOIIP, a 3D reservoir model and preliminary reserve estimates. They are guided by staff and external industry consultants, but are expected to act as a team and to resolve any technical differences. They are marked as this team rather than individually.

Once a consistent reservoir model has been obtained through this project, Petroleum Engineering students move on to consider the behaviour of the reservoir through a range of development scenarios. In the **second stage** the *production behaviour* of the reservoir is viewed with well test data, in order to come up with a calibrated simulation model, an optimised well placement plan and a prediction of reservoir performance. For this phase the team does not include geoscientists, so students must work in new teams. With only six days allowed for the project, they are also under time pressure.

The **third stage** of the Petroleum Engineering course covers *field development*, including process engineering, pipelines, surface facilities, field life, HSE and petroleum economics. By this stage students are fully aware that to predict the final behaviour of a field, it is necessary to have an understanding of the total system, from reservoir characterisation, through well performance to surface facilities. As with stages 1 and 2, a group project is the final product of this phase, the ultimate deliverable being a development plan for the Maureen Field.

Using external expertise

The two best Group Projects, incorporating all the work from Phases 1, 2 and 3, are presented to an industry audience at the end of the third phase of the project work. The winning project performance, as judged by the audience, is awarded the Colin Wall prize, an award that is much sought after, more for the accolade and recognition from peers than the value of the actual



© Alain C. Gringarten, et al 2000

Example from Maureen Group Field project: Top Structure Map With Boundaries from Well Tests (seismic faults in white; well test faults in black).

World renowned expert

Professor Alain Gringarten came to the post of Director of the Centre for Petroleum Studies in 1997, after 25 years in the oil industry, having begun his post-doctorate career in the Bureau de Recherches Geologiques et Minieres in France.

He moved from there to Schlumberger, where amongst other things he was responsible for the development and worldwide implementation of well test interpretation services, working in both France and Houston. From 1983 to 1997 he worked for Scientific Software-Intercorp in senior technical, marketing and managerial roles. He is a world-renowned expert in well test analysis and has taught many industry and academic courses on the subject throughout the world.

On joining Imperial College in 1997 he was determined to revolutionise the teaching of geoscience courses in order to make them more useful to the industry. He reorganised the MSc. Petroleum Engineering course onto reservoir management lines, initiating the concept in June 1997 and welcoming the first new students in October the same year. To achieve the integrated approach to educating petroleum professionals he says: "It was important that the faculties worked together to formulate the new courses, with no contradiction and no repetition. Each step of the course has to build on the previous steps and prepare for the next ones." He knew that students needed to use real data and he also involved speakers from all aspects of the oil business. After his many years in the industry, his numerous contacts and friends in oil producing, service and consultancy companies were happy to support him with data and specialist lecturers.

Prof. Gringarten speaks with great enthusiasm about both the course and his students and he is justifiably proud of both. As he summarises "a student can start this course knowing nothing, and can leave one year later as a bone fide petroleum engineer. It works!"

A long-term investment

Photo: Tore Karlsson

Ian Morgan, a graduate of Exploration Geophysics from University College, London, worked as a geophysicist with PGS before deciding to take the Imperial College MSc. in Petroleum Engineering. "I enjoy working offshore and want to stay in the technical rather than administrative fields, but I felt I could progress further and keep interested by moving into well operations and production. I looked at a number of options and this course appeared to offer the most powerful combination of teaching, expertise and hands-on experience." He is funding the course himself, but considers it is a good long-term investment.

He finds the course intense but fascinating, although he admits that returning to studying was quite difficult. With his background in geophysics, he considered the integrated project in Phase 1 very interesting, and he now feels that he has a much greater awareness of the many facets of reservoir management. "The team-work aspect of the projects was a good, although challenging experience. It is very important to realise what the other team members contribute and to understand the strengths and weaknesses of their disciplines. Using raw industry data for this is important."

Ian is looking forward to returning to the oil industry after he graduates in September, hoping for a position as an offshore drilling engineer. He feels happy that this course will help towards his eventual ambition to be an exploration manager in a major oil company.

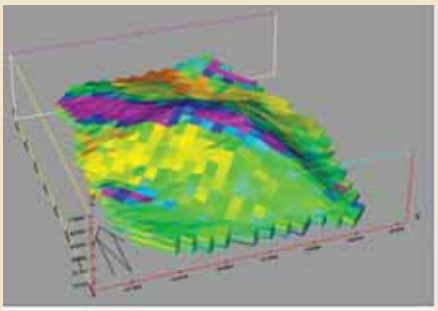
prize - £300 in pound coins!

Following exams and a two week field trip, the students spend several months on individual dissertations, building on their integrated knowledge of all aspects of Petroleum Engineering and where possible using industry data to build realistic models and scenarios.

An important feature of the Imperial College Petroleum Engineering MSc. is the use of external industry experts in a variety of roles. Some guest speakers represent software vendors in the industry, who are happy to train the petroleum engineers of the future in their products. For example, students know how to use Interpret, PIE and Saphir for well testing or Eclipse for reservoir simulations. Computing facilities include top of the range PCs, a server and fibre optic network and a fully immersive 3-D visualisation system.

Lecturers also come from oil companies, such as Dr Satinder Purewal from BG, who helps students with practical aspects of petroleum engineering and feels that he is able to offer them a worldwide professional perspective. This year, reserves assessment is being taught by Shell – Prof Gringarten feels that they are well-suited to explain the potential rewards and pitfalls in this area!

Oil companies are very happy to lend their staff and expertise in this way and they feel it is an important contribution to the future of the industry. Additional presentations by industry experts are provided every Friday afternoon and industry specialists act as mentors to the students, offering valuable advice and guidance.



Example from Maureen Group Field project: 3D reservoir model.

Multi-disciplinary specialists

Dr. Matthew Jackson, lecturer in Petroleum Engineering at Imperial College, points out: "This course is very hard work. It is intense, with students working long hours and there is no chance to slack or relax. But it works! Every year I see a group of unsure and confused students arrive in September, and just a few months later when they make their Phase 2 presentations, they are already professional petroleum engineers."

Feedback from past graduates of the integrated Petroleum Engineering MSc. in Imperial College suggests that the diversity of experience and quality of teaching on this course has been a major asset to them

Positive students

MSc. Petroleum Engineering students at Imperial College come from a very wide range of background and experience, their only common feature being that they are all of a very high calibre. Only graduates with First Class Honours degrees are accepted on the course, although this can be waived if a candidate has relevant industry experience. On average, of the 40 students who graduate from this course each year, about 40% will have up to 5 years previous industry experience. Some 60% of the students come from overseas, and this year 15 different nationalities are represented, with the largest foreign contingent coming from Nigeria. A third of students are women and for many students English is not their first language, all of which makes for an eclectic and dynamic mix.

The students interviewed for this article had only positive comment and praise for the course and the way in which it is structured and taught. The teaching of subjects in blocks is very effective, as they logically follow one another according to the reservoir management process, rather than being taught concurrently to suit timetabling issues.

Students build up knowledge in a coherent fashion, finding they have the information they need and the means to apply it at the appropriate time. They found the use of projects with genuine data very helpful, and particularly relished the teamwork element, when people with diverse backgrounds and skills had to work effectively and efficiently together, as will be required in a working situation. They even thought that the considerable pressure of the course was a positive feature – having prepared a reservoir characterisation model with a team of novices in only 15 days, anything an oil company could throw at them in the future would be easy!

Teamwork

Nolwenn Perzo comes from Brittany and is taking a degree in Fluid Mechanics in Toulouse. She is spending the final year of her graduate studies on the Petroleum Engineering MSc. in Imperial College and will therefore graduate in September with both the MSc. and her B.Eng. She came to Imperial College with no knowledge of geology or the oil industry, but thought "It sounded interesting – and I would be able to improve my English!" Nolwenn was sponsored by Wintershall for the MSc. course, and will do her individual project with Total in Paris.

She likes the Reservoir Engineering course and the way it is constructed. She particularly likes the integrated approach and teamwork on the Maureen Field projects. "I learnt a lot from the other team members and relied on them for their experience of working in the industry." She found that the teams worked well together, with the different backgrounds and skills enhancing and supporting each other – for example, she was able to contribute her strong mathematical and engineering knowledge despite of her lack of industry experience.

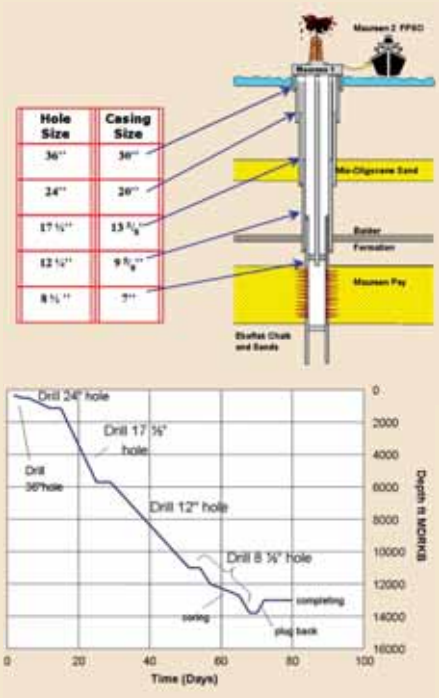
Nolwenn is keen to continue in the oil industry, which she finds challenging and exciting. She thinks there will be interesting job opportunities for reservoir engineers as they meet the challenge of optimising production from the world's declining resources.

Photo: Tore Karlsson

in their professional life. All graduates wishing to find employment in the hydrocarbon industry have done so and most consider that the course has substantially improved their job prospects and accelerated their career progression. A major endorsement is found in Thabo Kgogo, a student from South Africa who is on the course this year. He was sent to Imperial College by his employers, PetroSA, on the recommendation of his manager, who himself took this course four years ago.

Now well established, it would appear that this programme, with its integrated subject approach, block teaching by objective and use of industry specialist lecturers, is a great success. By teaching students to follow the reservoir management process and to work with real data, Imperial College are producing specialists with in-depth knowledge of their chosen field. They understand all facets of reservoir management and are trained to work in multi-disciplinary teams.

Professor Gringarten and his colleagues are to be congratulated for their success in formulating this innovative and effective approach to the teaching of petroleum geoscience and Petroleum Engineering.



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Example from Maureen Group Field project: Casing design and Drilling Program.

250 million barrels left out

It is considered crucial for the success of the course that students use actual oil company data to build up their reservoir model. The course uses data from the Maureen Field in the North Sea made available to the College by the operator, Philips Petroleum, and their partners. Data includes seismic traces, geological maps, core photographs, routine and special core analysis reports, PVT analysis, RFT, DST and production information.

The data has now been reanalysed by more than 40 teams of students over 7 years, and Prof. Gringarten finds it is interesting to see the progress that has been made. While all groups come up with essentially the same results, he feels that the standard of students has improved over the years and that they are now capable of reaching deeper into the data to refine their conclusions. He also considers that history matching has produced some interesting results: "for example, the Maureen Field was abandoned after the production of 250 million barrels of oil, but recent analysis by the students suggests that it may have contained as much as 500 million barrels of oil recoverable"

However, the Maureen Field data set is aging, and the 2005 intake of students will be presented with new data from the BP Wytch Farm Field.

Using real data for the project work gives students an experience close to the true working environment. Carmen Morataya, one of the industry external lecturers on the course, says: "It is important that students learn where to find the information they require and how the different data types interact. They learn that there are no perfect datasets, and it is necessary to get the best out of the existing data. This is a 'real world situation' and I think it is a very important lesson."

Through using authentic data the students also learn about risk management, becoming fully aware of the importance of risk assessment in the hydrocarbon exploration and production process.

Best available anywhere

Photo: Tore Karlsson

Carmen Morataya has been a consultant lecturer for the Petroleum Engineering MSc. for 2 years. She comes from Venezuela, gained a Masters degree from London University and has over 25 years experience in managing facilities projects all over the world. She tutors the students in surface facilities and economics in the third phase of the course and advises on these aspects of the field development project.

"The use of industry lecturers in this course is crucial to its success," she says. "They can offer students invaluable advice on how to look for and at data and how to extract the best from data sets which are not perfect. We give the course worldwide expertise." She considers the external lecturer should be interactive with the students, more mentor and guide than teacher, particularly during the team project phases. "Our main aim is to expose them to practical ideas and stimulate their thought processes."

Carmen considers that the course offered in Imperial College is the best available anywhere in the world. She has reviewed a number of similar courses and feels that none of them offer the same breadth of teaching combined with experience and practical skills.

Exploration is in the mind

What are the keys to a successful career as an exploration manager? Andrew Armour, formerly Board Director of Exploration for Enterprise Oil and now Chairman of private Norwegian start-up Revus Energy, explains how he considers that effective and continuing training, lateral thinking and an ability to communicate at all levels are major factors – together with a little element of luck.

Jane Whaley

Andrew Armour considers that good communication skills are a vital asset for any Exploration Manager. 'It is important to be able to talk to people competently at all levels. You must have the ability to impress the geologists and technical staff, so that they will respect your decisions. Simultaneously, an Exploration Manager needs to be happy talking to financial and business people and shareholders, in language they understand. It is quite difficult to successfully convince shareholders why you drilled a dry hole but it needs to be done occasionally! Many people find that transition from the technical to the business world difficult.'

Having spent a number of years working in Norway, Andrew speaks Norwegian poorly and believes that attempting to talk to colleagues and business associates in their own language aids relationships enormously. 'I particularly enjoy giving the speech at the annual Christmas party' he adds. 'I talk about who in the team has got married or had babies, the company's successes and failures for the year, make a joke about the Danes, or the Swedes, or the Brits and most importantly, one against myself – simple really and it goes down very well.'

Listening to each other is another key skill, he believes. 'It is amazing how few people really listen. You can learn a great deal more from your colleagues when you start to listen to them and that requires you to stop talking!' Something he readily admits he has had to work at.

Andrew is also very skilled at communicating his ideas through public speaking and presentations at conferences. This, he believes, is helped if you have faith and confidence in your own abilities and a real understanding of your strategy. In his case his presentation abilities have also been enhanced by training targeted at these skills.

'The industry is stupid'

Training is an issue that Andrew Armour feels is key to a successful career in the oil industry, and is something that he is quite passionate about. He joined Enterprise Oil as Team Leader Central North Sea in 1984, just as the company was being formed, and rose rapidly through the ranks, so that by 1996 he was a Main Board Director. Despite this rapid progression, Andrew is modest about his success.

'Enterprise were a wonderful company to work for, because the training was exceptional, and they were prepared to invest in staff to get the results. As we grew we developed an excellent graduate recruitment programme – all geoscience graduates were handpicked and then trained for 2 years. They moved around different departments, spending a few months in each, gaining a thorough knowledge of how the business worked. Only then did they join a department or overseas office full time. Few graduates left the Company and ex-Enterprise geoscientists are still in high demand in the industry'.

Andrew has a poor opinion of the present industry approach to recruitment and training. 'Frankly, the industry is stupid! It is not actively recruiting and training talented people and, as we all know, the average age of geoscientists in the oil industry is rapidly increasing. This is a major problem just waiting to explode!'

Not only did Enterprise Oil train Andrew in technical matters, they also recognised his business abilities and ensured that he was exposed to the commercial world. In 1987 he was assigned to the select Business Development Analysis Team, involved in deal evaluation, asset trading and shareholder briefing. 'I saw the financial directors in action in the city, which was a terrific introduction to the world of finance, and I learned a huge amount.' In 1992 Enterprise also sent him to Harvard Business School on an intense 3 month Professional Management Development course, which prepared him well for his next position, as General Manager of Enterprise Norge.

Geology explains everything!

Andrew explains that he had not intended being a geologist. He planned to study Physics when he went to Reading University in 1971 and only did a subsidiary course in Geology because it appealed to his outdoor nature. Then, as he puts it, "the world suddenly expanded for me – I couldn't believe it! Geology explained everything and described physical features of the whole world. You mean the Lake District is shaped like that because there were huge volcanoes there? It was amazing! Plate Tectonics and sea floor spreading had just been proven and it was so exciting. By the second term I had changed courses and eventually graduated in Geological Geophysics."

Andrew then went to Durham University to do a PhD, using geophysics to determine the thickness of the ocean crust in the Rockall Trough area. After completing his post-graduate studies, he worked for Shell in Norway and Tunisia and Superior Oil in the UK before moving to the newly formed Enterprise Oil. He remained with them until Enterprise was bought by Shell in 2002, by which time the market capitalisation of the company had grown from an initial £400 million to around £4,500 million.

Andrew can look back on a number of major successes achieved during his time as Exploration Director in Enterprise. He saw total reserves grow from 870 million boe in 1996 to 1,487 million boe in 2001, despite 505 million boe having been produced during this time. Reserve replacement from drilling was an average of 183% of production, with finding costs of $1.3 per boe. In 1984 Enterprise had only 5 fields in one country; by 2002 they had over 40 in five countries. In his 3 years as General Manager in Norway, Andrew oversaw the drilling of 18 exploration wells, leading to a growth in reserves of 88% and the important discoveries of Jotun, Skarv, Siri and Tune.

Revitalising the Norwegian North Sea

Dr. Armour is fascinated by the recent revitalisation of the North Sea in the UK and Norwegian sectors and considers that both governments are doing an excellent job of encouraging new companies and continued exploration as they reinvigorate their areas. He believes that it is important for the Norwegian Continental Shelf 'to attract more companies in and to get acreage into the hands of those who really want to drill, possibly with policies similar to the UK fallow acreage initiative. It is also important to get more rigs qualified and contracted for Norway and if possible to reduce average well costs to below $20m.'

Proving his faith in these developments, Andrew is Executive Chairman of Revus Energy AS, a new independent Norwegian E & P company, set up in 2003 to fill the vacant niches left as the major multinationals merged or gobbled up the smaller players on the Norwegian Continental Shelf. The company understands that this well established area, with its mature producing fields and smaller marginal fields awaiting development, requires 'a change in mind set and a willingness to accept a different magnitude of economic returns.' "It is now a question of whether the finds to be made and the discoveries to be developed can really be material to the larger companies who have dominated the Norwegian Shelf for so many years." he says. Since set-up nearly 3 years ago, Revus has gained 13 licences, has interest in 3 producing fields and 3 possible development projects and is actively drilling exploration wells. 'A small but perfectly formed oil company', as Andrew describes it. Revus Energy is presently privately funded but expects to float on the Norwegian stock market later this year if conditions permit.

The Millennium Atlas

Dr. Armour is well known in the North Sea Petroleum industry in yet another capacity; that of Chairman of the Millennium Atlas Company (see page 58). The project needed someone with strong organisational and managerial skills as well as contacts in the industry at the highest level. Andrew says 'When I was asked to participate, I was still working for Enterprise and was assured that it would just mean chairing a few meetings a year. Instead, I found myself running monthly progress meetings, trying to cajole and encourage participants, sponsors and data providers. I learnt a lot about collaboration and letting all the specialists do their own thing, from editors and reviewers, to auditors, map makers, and printers.' The Atlas had a budget of $1 million, but probably cost 3 times that much, if one includes the cost of the time many participants, including Andrew, gave for free.

The initial plan was to publish in 2000, but the final project proved much larger than originally intended. The Atlas was finally published in 2003 and Andrew is rightly very proud of his association with such an important work. 'It was a tremendous privilege to be involved in this. It's a terrific achievement. We've given a copy to every university in the UK, Norway and Denmark and with the PESGB have distributed over 5,000 copies of the Atlas GIS to PESGB members. We also were able to sell the full capability GIS (Geographical Information System) to oil companies, which means that we finally made a small profit, which had not been planned. We contacted all the authors, most of whom gave their time for free and asked what they wanted us to do with the money and a number of them suggested it was given to charity, so we've given about £15,000 to WaterAid, Intermediate Technologies, Shelter and a number of University departments.'

Andrew Armour points out that 'The MIllennium Atlas is a very important project, primarily because it crosses the international boundaries and gives the full picture of the Petroleum Geology of the North Sea for the first time.'

Get Lucky

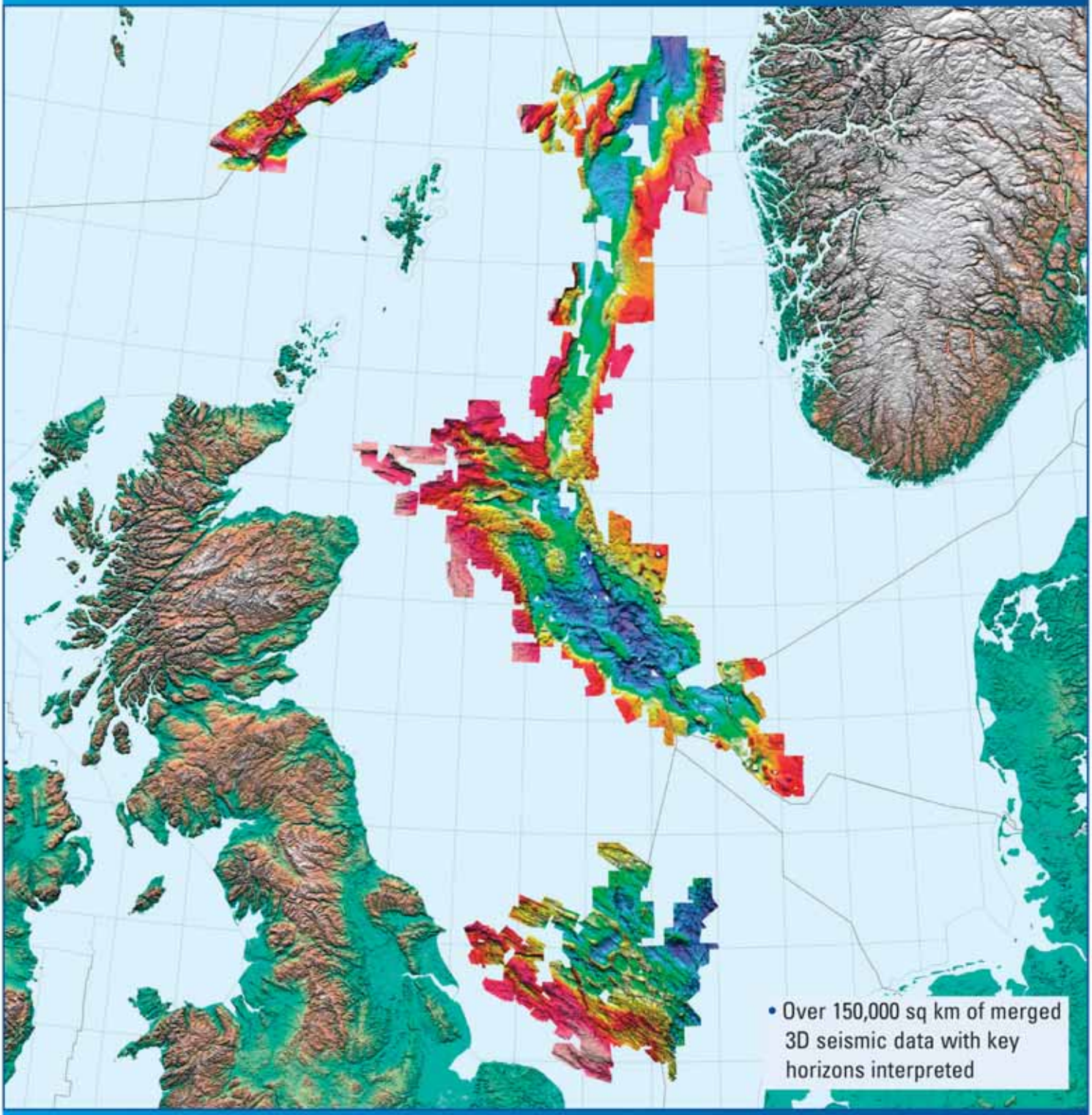
How does Andrew see the future of the oil industry? 'Well, there is an essential conundrum at the heart of the industry. We are rich, successful, well fed and healthy in the west because of our access to cheap energy, and as Colin Campbell points out, it won't go on for ever. I differ from Colin in that I think we aren't as near Armageddon as he makes out. I also think it is important not to be so extreme to the media, as they tend to write off your ideas completely if you are too sensational. Obviously, I don't know how it is going to work out, but I have a feeling the rich part of the world will be able to make the necessary adjustments, when it has to, and it will be the poorer nations who will struggle to adapt.'

Revus Energy keeps Andrew busy about 3 days a week, leaving him free to pursue other interests such as the Millennium Atlas for the rest of the week. He is a non-executive director of IKON Science Ltd., a specialist geoscientific software company, as well as being Chairman of the Durham Earth Sciences Advisory Board, which advises the university Geology Department on up-to-date industry and research developments. All these interests Andrew seems to follow with great excitement and enthusiasm.

Reverting to the question of what it takes to succeed in hydrocarbon exploration, Dr. Armour points out 'You need to allow lateral and maverick thinking – what about a Devonian source rock, or maybe a Lower Cretaceous Play in the Norwegian part of the Central North Sea? Let these ideas develop, and remember that exploration is in the mind, not just in computers. You should reward and not penalise risk taking.' He also considers that an element of luck is definitely involved, but in his opinion 'good luck comes when good preparation meets good opportunity.'

'If you want to be successful, you must communicate effectively with everyone, invest in training and then put yourself in a position to get lucky!'

LOOKING FOR DATA IN NW EUROPE ?



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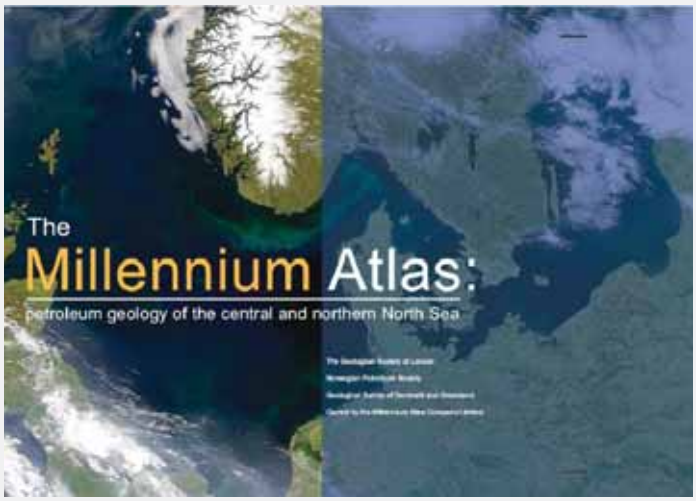
The Millennium Atlas



To produce the Millennium Atlas was no easy task. It took some 7 years from inception before the product was available to geoscientists exploring for new oil and gas discoveries in the North Sea.

Paul Bathurst was instrumental in getting the Millennium Atlas produced.

In 1997 Paul Bathurst and Mark Groves Gidney, of the consultancy Exploration Geosciences Limited, were working in western Canada, using an atlas of hydrocarbon geology which they found invaluable in their consulting work. Returning to Britain, they suggested to a number of people that the production of a similar atlas was just what the North Sea needed and also a fitting way to mark the new Millennium.

They sought out initial sponsorship, and by 1998 had sufficient interest and commitment from industry for the Millennium Atlas Company Ltd. to be set up. This is a single purpose company owned jointly by the Geological Society of London, the Norwegian Petroleum Society and the Geological Survey of Denmark and Greenland and was set up to complete the Millennium Atlas and close down without a profit or a loss. Dr. Andrew Armour was invited to be Chairman of the company.

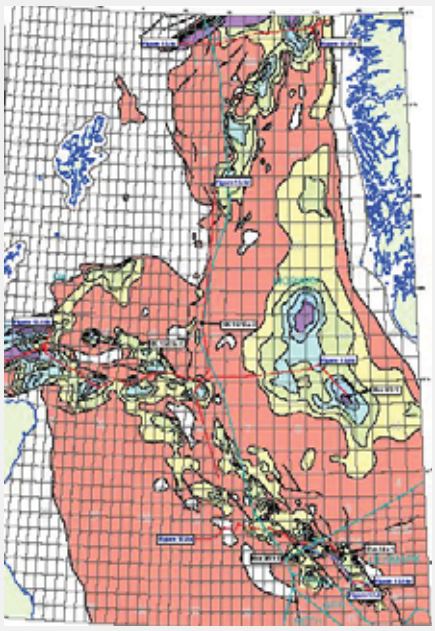
35 oil companies eventually became full sponsors and data were provided by many sources, including oil companies, seismic companies, consultancies and academic institutions. Governments did not provide data, but gave the project full backing and encouraged all the organisations to be involved. EGL undertook project management with Paul Bathurst as Project Manager and the British Geological Survey agreed to edit the Atlas. Book production was undertaken by Lovell Johns Ltd. A steering committee representing the three nations was set up and effectively managed the project through to completion.

The Atlas describes the petroleum geology of the central and northern North Sea from 55°20'N to 62°N and, since all relevant countries were involved, it successfully crosses the national boundaries, emphasising the geological "oneness" of the North Sea basin. It was written by regional experts, with small groups of companies or individuals responsible for writing selected chapters and producing the very high quality illustrations. They were provided with a broad outline framework and each chapter then underwent external refereeing and intensive editing.

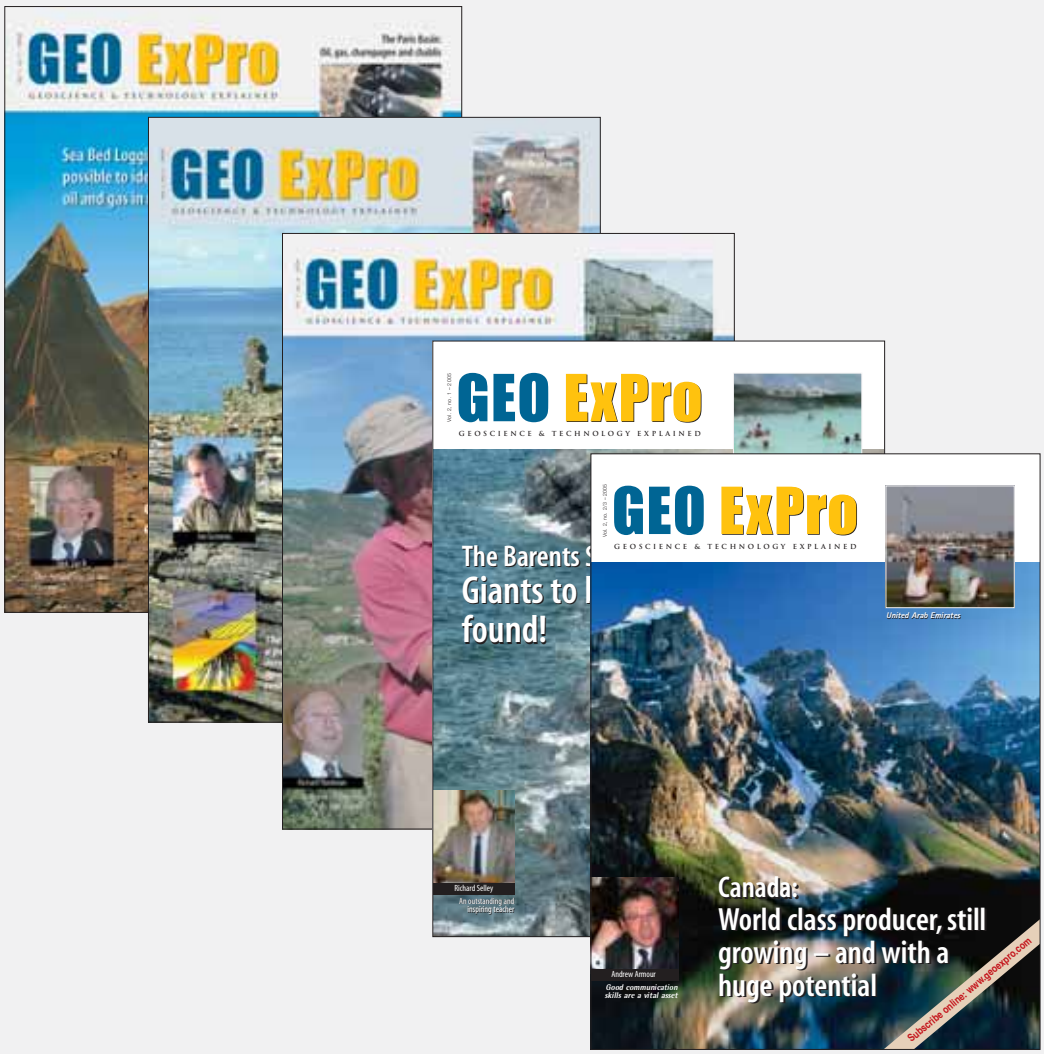
Organised in twenty chapters, the tectonic evolution, basin history and structural framework of each region are covered, as are the main stratigraphic intervals, from the Sub-Devonian to the Holocene times. The fluid contents of the rocks are dealt with in two chapters covering petroleum generation/migration and formation waters and hydrodynamics. In addition, the history of exploration and licensing in the basin is discussed, together with a summary of resource assessments. In all more than 100 authors and contributors, together with over 60 referees from industry, academia and government departments were involved, the large majority offering their services free of charge. To help maintain consistency a number of workshops were held with all the authors attended.

The Millennium Atlas was finally published to great acclaim in 2003. It is in A2 format in full colour and contains over 400 pages, nearly 500 illustrations and 1,600 references, and is also available on CD-Rom. It costs £149 in book format and £199 if the digital version is included, with discounts for members of PESGB, EAGE, the Norwegian Petroleum Society, the Danish Geological Society and the Geological Survey of Denmark and Greenland. It can be obtained from the geological Society Publishing House website online bookshop at http://www.geolsoc.org.uk.

Jane Whaley



The isopach of the Lower Cretaceous, corresponding to the Cromer Knoll Group, exemplifies the numerous excellent illustrations in this masterpiece.



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Oil, peace, fertility and security

The flag of United Arab Emirates feature the Pan-Arab colours of red, green, white and black, colours symbolic of Arab unity. In addition, other colour references include green representing fertility; white representing neutrality, and black the incredible oil wealth.

The oil riches of the United Arab Emirates have created a tourist heaven for wealthy foreigners who enjoy shopping and urban entertainment.

Photo: Halfdan Carstens

The skyline of Abu Dhabi – an Arabian Manhatttan – shows how much this former oasis has grown. When oil was found in the emirates in 1958, less than 50 years ago, the capital was a tiny settlement of less than 5000 inhabitants, mainly fishermen. Only about a dozen buildings from the days before the oil boom in the early 1960's still stand. Today, Abu Dhabi is a sprawling city with a population of more than 1 million, of which 80% are expatriates, predominantly from South Asia.

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The United Arab Emirates (UAE), situated in the south-east of the Arabian Peninsula, is a young nation. It was formally established on 2 December 1971 from a group of tribally organized sheikhdoms along the southern coast of the Arabian Gulf and the northwestern coast of the Gulf of Oman. The country thus comprises seven emirates: Abu Dhabi, Ajman, Dubai, Fujairah, Ras al-Khaimah, Sharjah and Umm al-Quwain. Before 1971, they were known as the Trucial States, in reference of a nineteenth-century truce between the British and some Arab sheikhs.

The landscape of UAE is best described as a flat, barren coastal plain merging into rolling sand dunes of vast desert wasteland. Mountains dominate in the east. The highest mountain is Jabal Yibir with 1527 m. The United Arab Emirates covers an area of 82.880 km^2. The capital, Abu Dhabi, is located in the emirate of the same name.

Only about 20% of the UAE's population are native citizens. The nonindigenous population is mostly from east and southeast Asia and was first attracted by the employment provided by the UAE's petroleum boom.

Muslims comprise 96% of the population (80% of these are Sunni, the balance Shiite) and the remaining 4% are largely Christian and Hindu. The official language is Arabic, but Farsi and English are widely used, and Hindi and Urdu are spoken by many of the Asians.

Halfdan Carstens

The founding of the oil industry within and around the Arabian Gulf dates back almost 100 years. Oil was first discovered onshore Iran in 1908. Further development of this oil rich region was nevertheless slow, in spite of the vast resources that should later be proved. By the end of World War II, only seven fields had been put on stream. The fields were located in Iran, Iraq, Qatar, Kuwait and Saudi Arabia. However, at that time it was eventually evident that the Middle East would become a major petroleum-producing region.

Photo: Halfdan Carstens

While the coastal plain is characterised by sabkha, a flat, barren coastal plain many miles wide, covered by a salt slick, where no plants grow, four-fifths of the UAE is vast desert wasteland dominated by an endless sea of rolling sand dunes up to 200 meters high and with rounded curves. A fortune has been spent trying to make the desert bloom.

Towards 50-year anniversary

This truth was substantiated by the discovery of the world's largest oil field, Ghawar, in 1948. Reserves in the Upper Jurassic limestones are said to exceed 80 billion barrels (13 billion m^3), of which 55 billions already have been produced with a current daily rate of 5 million barrels of oil per day.

The United Arab Emirates (UAE) was fairly slow to enter the emerging industry. The first oil was discovered in Abu Dhabi in 1958. Since then, a significant number of major oil and gas fields have been found and developed onshore as well as offshore, resulting in oil reserves of 100 billion barrels or more (BP Statistical Review of World Energy 2004 says reserves are 97,8 billion barrels of oil and 214 trillion ft3 (6.06 trillion m^3) of gas).

The efforts in exploration and production are now concentrating on assessing and exploiting undiscovered reserves and optimizing hydrocarbon recovery. Gas production capabilities of existing reservoirs are thus being expanded to meet increasing demand from industry and gas injection users.

Photo: Halfdan Carstens

Only a few hours drive from Dubai, including a small stretch of Oman, lies the city of Hatta, pleasantly located within the mountains and with a luxurious resort giving tourists a nice break from the hectic life in the big cities.

Dubai - a thriving city

Long before the oil boom in the Middle East Dubai was the trading centre of the southern Gulf. Generations of merchants made their living by importing goods free of duties and taxes and then re-export them to neighbouring countries. The city has since developed into a centre for modern commercial activity with a market far in excess of 1 billion people, including India, Pakistan, Russia, Africa and its neighbouring states in the Gulf. Many large corporations have therefore decided to centre their operations here.

Southwest of Dubai, in the Jebel Ali Free Zone, oil service companies serving a market far beyond the Gulf have settled in a huge industrial area largely due to a favourable economic climate topped by guaranteed freedom from taxes. The zone was originally set up in 1977, but was not a success before 1985 following the creation

"As good as gold"

Dubai is the primary City of Gold, and it has the highest concentration of gold in the world. At any given time there are almost 10 tonnes of gold available at the gold souks. This is why at least eight out of every ten visitors in Dubai invest in gold, and for most tourists a trip to Dubai is incomplete without a visit to the Gold souk. This is not only because of its reputation as a gold centre but because it comes guaranteed against fraud. Dubais image is literally "as good as gold."

The UAE is now one of the top ten consumers of gold in the world, importing three hundred tons every year.

The world famous gold souq in Dubai may at first sight look like any other ordinary shopping street, but it houses more than 200 shops selling 18 karat gold jewellery with European, Arabic, Indian and many other designs. Most of the goods are sold by weight, and it is wise to have a rough idea of the current price of gold before shopping. Bargaining is a must.

Photo: Halfdan Carstens

Desert safari in a 4WD

The United Arab Emirates (UAE) boasts mountains, beaches, deserts, oases, camel racing, Bedouin markets and, above all, duty-free shopping. It also has the most relaxed entry regulations in the region, the best tourist infrastructure and is accessible also to independent budget travelers.

The best time of the year to visit the UAE is between November and April, when the weather is at its best. The rest of the year it is too hot without air-conditioned environment. Ramadan, the muslim month of fasting, is strictly adhered to in the UAE; that means no eating, drinking or smoking in public from sunrise to sunset. Places that normally serve alcohol stop serving it during this month. Ramadan is in October this year and half a month earlier next year.

A favourite pastime for expatriates, as well as for tourists, is desert safaris, or "wadi bashing", which involves zooming around the desert with four-wheel drive vehicles. You can either enjoy a ride with an experienced chauffeur or try out your own skills by hiring a car in designated areas.

Photo: Halfdan Carstens

of an infrastructure that included steelworks, a gas liquefaction plant, an aluminium smelter (one of the world's largest, of course) and a huge desalination plant utilizing waste heat from the smelter.

Tourists to Dubai can't avoid the main attraction located at the beachfront: The Burj al-Arab (the Arabic Tower), opened in 1999, is a "7-star" luxury hotel with the shape of a giant sail, and with 321 meters it is the tallest building in the world used exclusively as a hotel. It stands in the sea on an artificial island away from the beach, and it has been placed in such a way that its shadow does not cover the beach. On top of the hotel is a large helipad extending from the side of the hotel that has been used for friendly tennis matches. The hotel is also famous for having the tallest atrium lobby in the world with 180 meters.

In short time, the Burj al-Arab will, however, be surpassed by the tallest building in the world that is now under construction within an area that is termed "The Most Prestigious Square Kilometre on the Planet". The marketing skills of the Arabs are phenomenal.

UAE: Profound transformation

Today, the UAE has an open economy with a high per capita income and a sizable annual trade surplus. Its wealth is based on oil and gas output (about 33% of GDP). Since the early 1970's, the UAE has undergone a profound transformation from an impoverished region of small desert principalities to a modern state with a high standard of living. The government has increased spending on job creation and infrastructure expansion and is opening up its utilities to greater private sector involvement.

Expatriates from India and Pakistan perform a significant role in the local economy. However, to control illegal immigration into the country, on November 9, 2002, the UAE immigration ministry announced that all Indians visiting the country must have a return ticket. Foreign workers now make up three-quarters of the UAE population, making it one of the most liberal and pluralistic countries in the Gulf region.

Future prosperity may be threatened by a more basic problem: water. The UAE is the highest consumer of water per capita in the world, and the groundwater levels have fallen 30m (100ft) in 30 years.

The oil and gas industry

The geology of the United Arab Emirates (UAE) is dominated by one sedimentary basin: the Rub Al Khali Basin with largely carbonate rocks throughout the stratigraphic column. The basin continues to the south into Saudi Arabia.

UAE's crude oil production is roughly 2.25 million barrels of oil per day (bopd) compared to its total production capacity of 2.50 million bopd. By substantially upgrading the infrastructure at existing oil fields the authorities have established an overall goal of raising the UAE's production capacity to 3 million bopd.

The UAE contains proven crude oil reserves of close to 100 billion barrels, according to the BP Statistical Review of World Energy 2004. This is slightly less than 10% of the world total but only ranks the desert country as number 4 in the Middle East. At present production rates, these supplies would last well more than 50 years. Under the UAE's constitution, each emirate controls its own oil production and resource development.

Abu Dhabi has with 94% by far the largest reserves of the seven emirates. Dubai contains an estimated 4 billion barrels, followed by Sharjah and Ras al-Khaimah, with 1.5 billion and 400 million barrels of oil, respectively. Most of the UAE's oil fields have been producing since the 1960s or early 1970s.

Proven oil reserves in Abu Dhabi have doubled in the last decade, mainly due to significant increases in rates of recovery. Abu Dhabi has continued to identify new finds, especially offshore, and to discover new oil-rich structures in existing fields, according to the International Energy Association.

The Abu Dhabi National Oil Company (ADNOC) is currently planning a limited opening of UAE upstream oil production to foreign firms. The initial asset sale will involve 28% of the offshore Upper Zakhum field.

The UAE's natural gas reserves in excess of 200 trillion cubic feet (tcf) (6 trillion m^3, 38 billion barrels o.e.) are the world's fifth largest after Russia, Iran, Qatar, and Saudi Arabia. The largest reserves, 95% of the total, are located in Abu Dhabi.

Photo: Halfdan Carstens

An oil-drilling platform brought into port in the city of Sharjah, due east of Dubai, for repairs.

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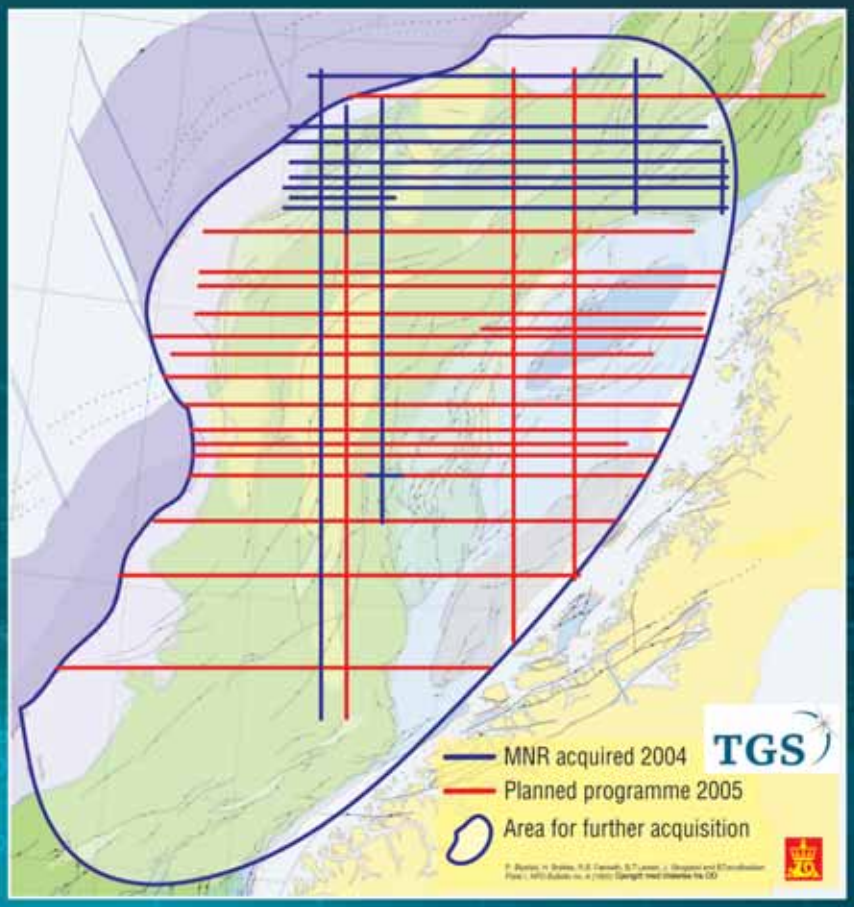

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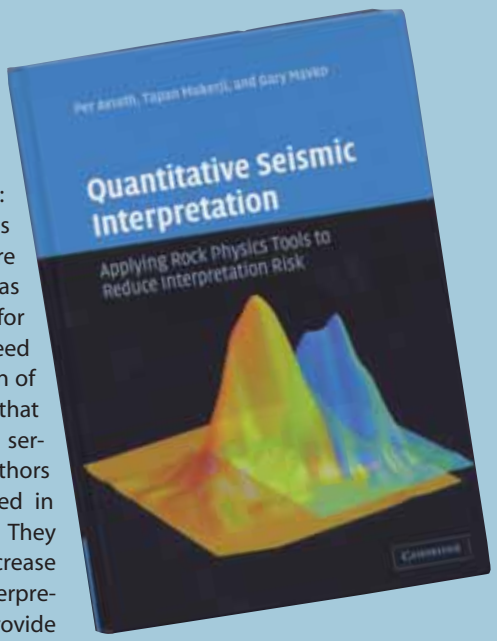
Quantitative Seismic Interpretation: Authors: Per Avseth, Tapan Mukerji and Gary Mavko, 340 pages.



Seismic interpretation has gradually moved in a more quantitative direction during the last two decades. There are several reasons for this: First, more demanding play concepts and marginal prospects require more precise numerical estimates as well as associated uncertainties. Secondly, for reservoir management there is a need for accurate estimates of and location of remaining hydrocarbons. This means that a book focusing on this topic should serve to fill a gap, and I find that the authors of this book have indeed succeeded in meeting this demanding objective. They manage to motivate the reader to increase their skills in quantitative seismic interpretation. In addition, they are able to provide some guidelines on how to achieve this challenging goal.

The book is well organized into six chapters. Its short introduction to rock physics is necessary, as this topic is the basis for quantitative seismic interpretation. I find the next chapter very interesting, since this is an attempt to couple sedimentology (and diagensis) to rock physics – a topic that I have missed in the present literature. The chapter is innovative and I am sure the readers will appreciate this. The examples are mainly from turbiditic deposits, so some readers might miss a more thorough treatment of various depositional systems. Despite this shortcoming, I conclude that this chapter is the most innovative – and perhaps the most useful.

Statistical analysis methods and conventional seismic methods are well described and nicely presented, prior to the presentation of five case studies. All their case studies clearly demonstrate how the theory pre sented in preceding chapters can be utilized. These examples show the variability between cases, and that one has to adapt methods to each case.

The authors conclude with guidelines and advice, which I think most seismic interpreters will appreciate. The book is useful both for graduate students as well as established interpreters. At my university (Norwegian University of Science and Technology), this book will be used in our reservoir seismic course. The combination of clear pedagogic exposition and useful field cases are the main reasons for this choice.

My main conclusion is that this book fills a gap, and I sincerely hope that it will contribute to a step forward for seismic interpretation.

Martin Landrø
Professor, Norwegian University of Science and Technology

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.

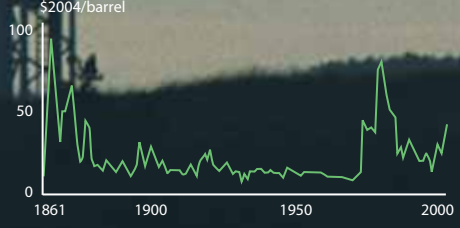
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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 Sm^3) of oil equivalents

Historic oil price



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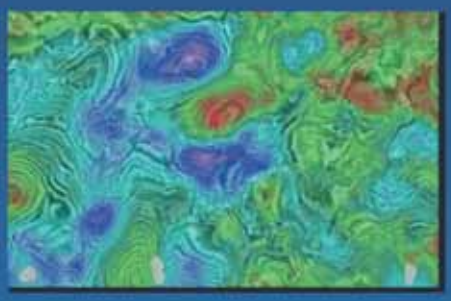

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