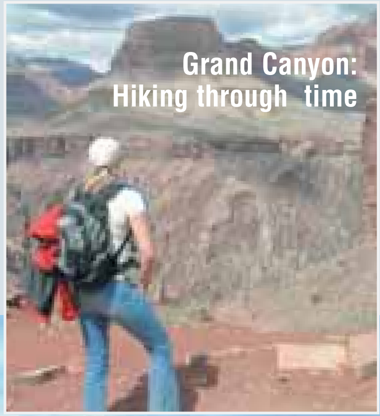
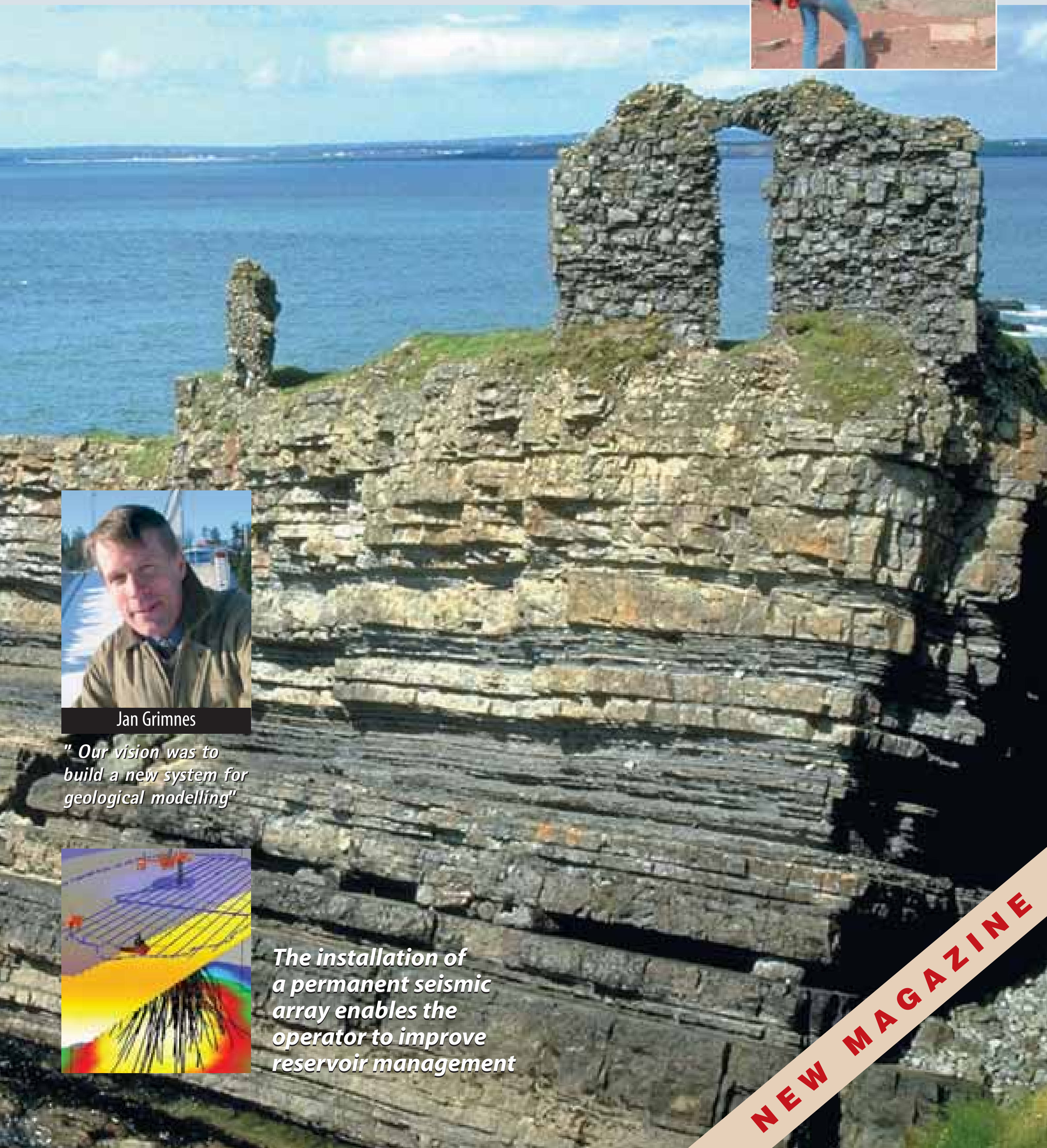
Vol. 1, no. 2 – 2004

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



Grand Canyon:
Hiking through time

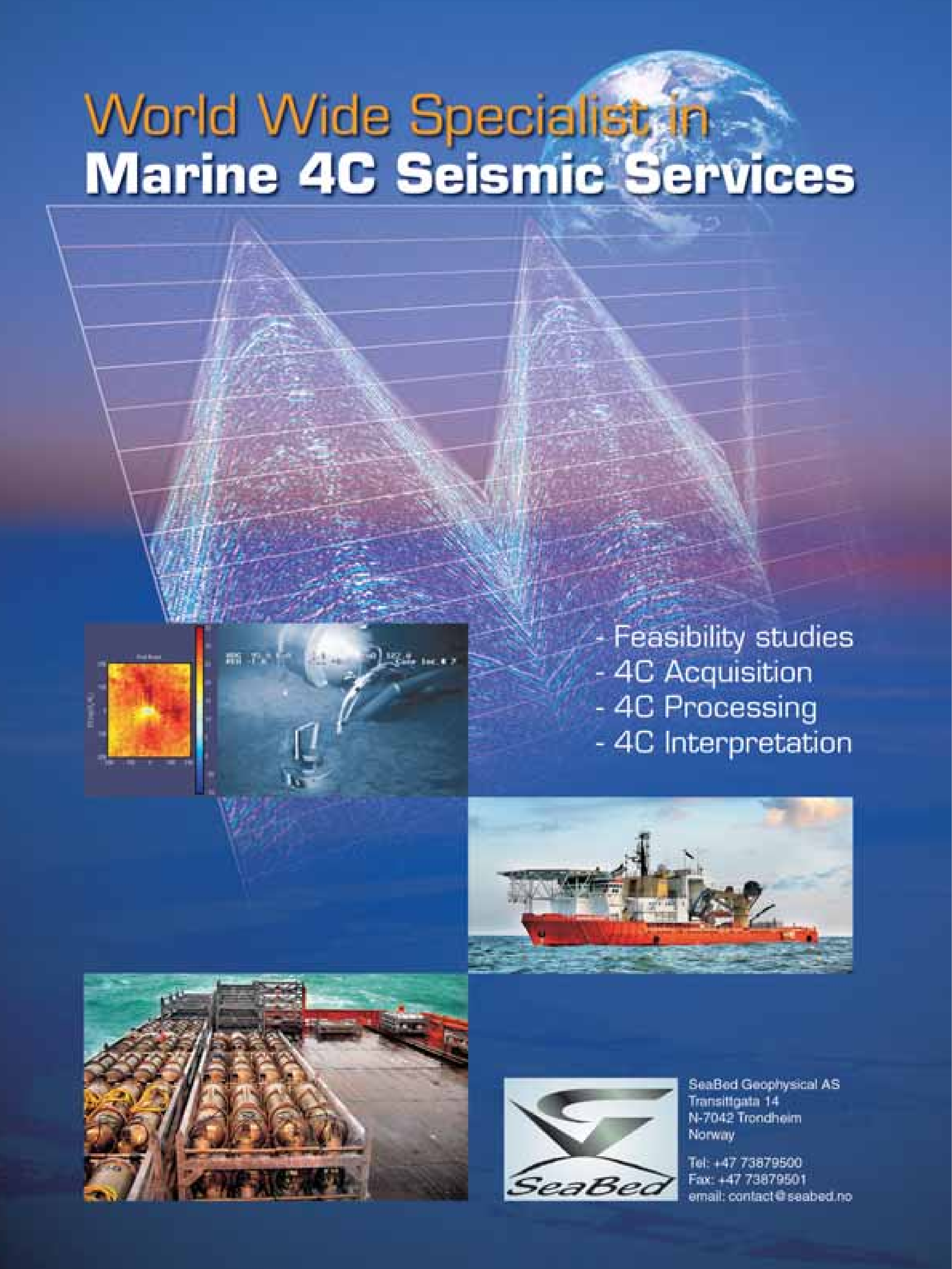


Jan Grimnes

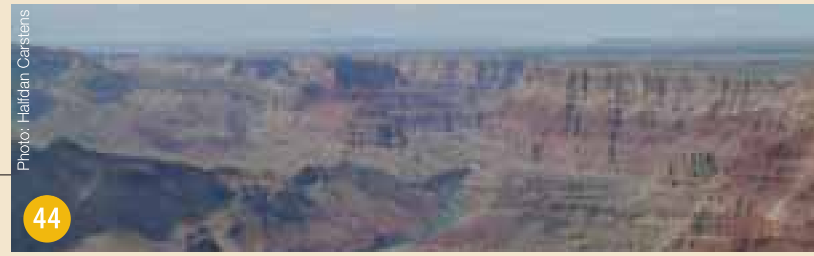
" Our vision was to build a new system for geological modelling"

The installation of a permanent seismic array enables the operator to improve reservoir management

NEW MAGAZINE


World Wide Specialist in
Marine 4C Seismic Services
- Feasibility studies
- 4C Acquisition
- 4C Processing
- 4C Interpretation
SeaBed
SeaBed Geophysical AS
Transittgata 14
N-7042 Trondheim
Norway
Tel: +47 73879500
Fax: +47 73879501
email: contact@seabed.no

GEO ExPro
GEOSCIENCE & TECHNOLOGY EXPLAINED



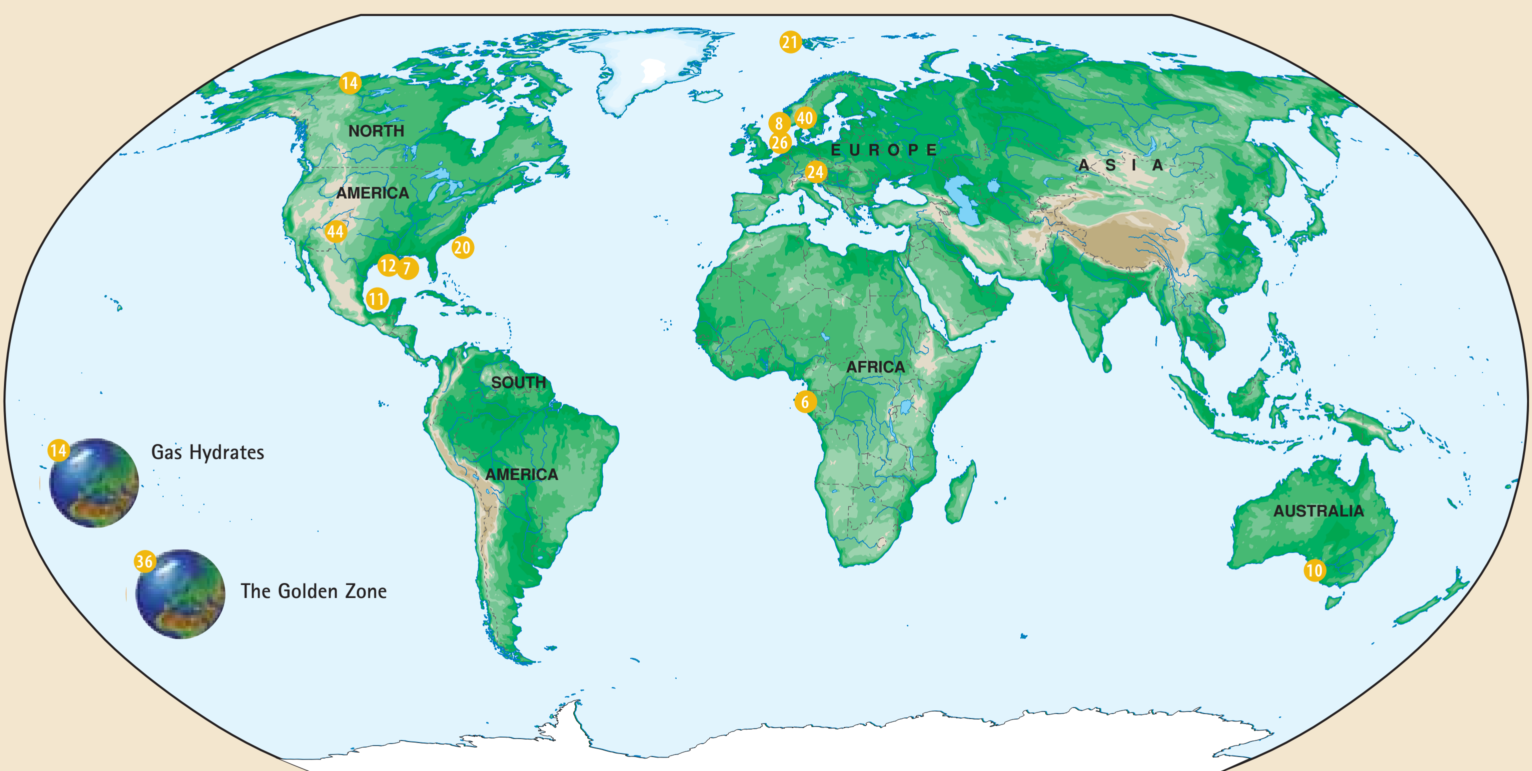
The Grand Canyon, the most famous of all canyons, was formed through some five million years by swiftly flowing waters of the Colorado River cutting into Precambrian and Palaeozoic rocks of the south-western Colorado Plateau in the American West. The colourful, exposed rocks give geoscientists a rare look into the development of geologic time.

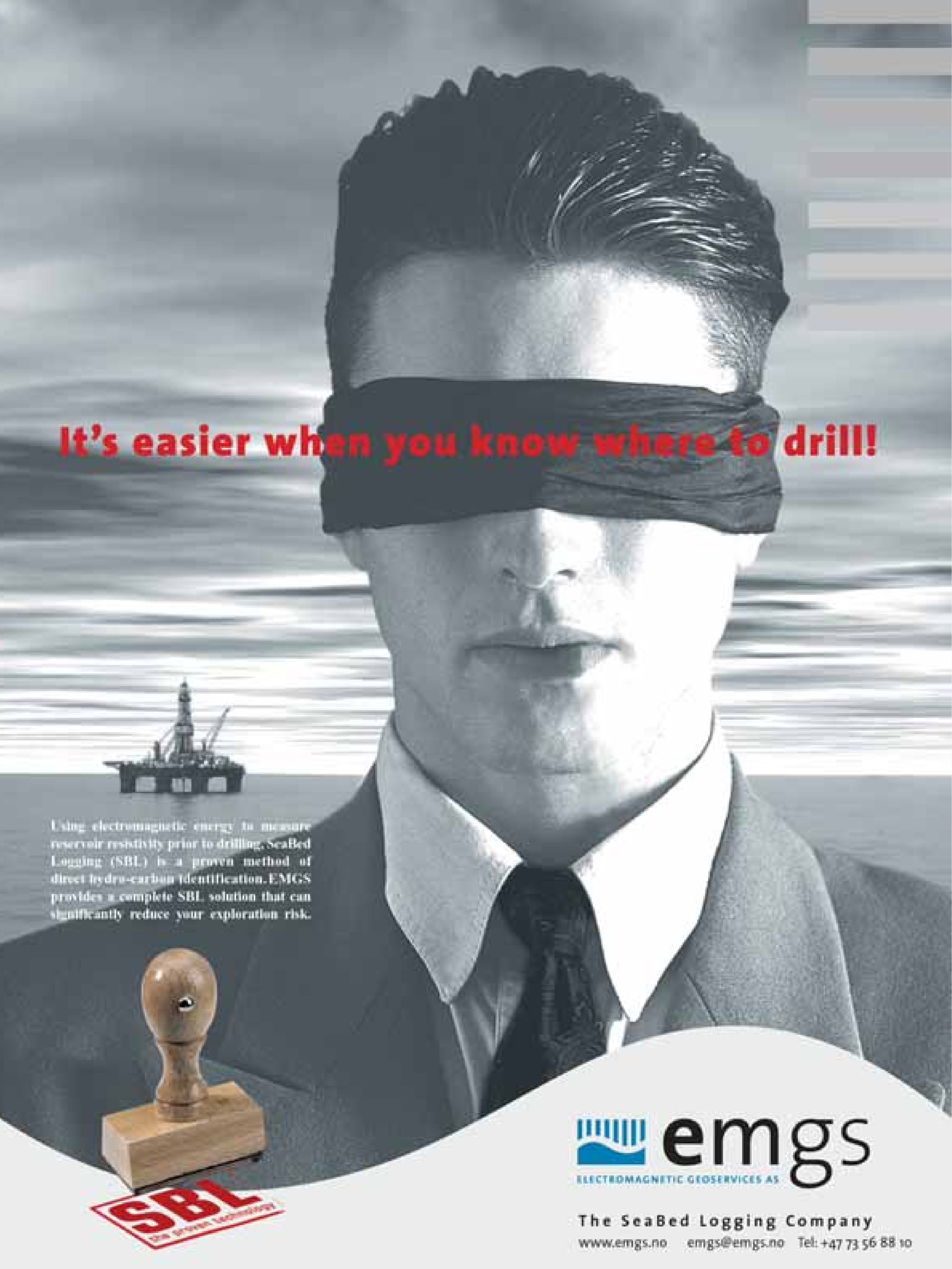
Table of contents

Coloumns

Features

The amount of methane sequestered in gas hydrates, buried under the outer continental margins in deep water and below permafrost in the Polar Regions, is in all probability enormous. The gas flare that lit up in the darkness of winter far up in northern Canada the winter of 2002, signalled a hope of a new energy source that could last for generations to come.





It's easier when you know where to drill!
Using electromagnetic energy to measure reservoir resistivity prior to drilling, SeaBed Logging (SBL) is a proven method of direct hydro-carbon identification. EMGS provides a complete SBL solution that can significantly reduce your exploration risk.
SBL
emgs
ELECTROMAGNETIC GEOSERVICES AS
The SeaBed Logging Company
www.emgs.no emgs@emgs.no Tel: +47 73 56 88 10

Recent advances explained

Progress in petroleum geoscience and technology is made through elaborate research carried out by the either oil companies, contractors (the service industry) or research institutions. We have, for example, seen numerous examples of how the seismic companies, like WesternGeco, PGS and Fugro Geoteam, have spent millions of dollars in moving first from 2D to 3D seismic in the 1980's, and then from 3D to 4D in the 1990's.

In developing 4C seismic the service companies have to a large extent been in the driving seat. In this case, it is, however, not the large contractors that have been in the forefront. Instead, small and hitherto little known companies are introducing new 4C seismic technology that appears to be highly competitive. Three such schemes, all being tested in the Gulf of Mexico, is briefly mentioned in this issue of GEO ExPro. These examples also serve to demonstrate that the technological development in the seismic industry is still making fast progress.

One important exception of where oil companies have played a significant role is with the concept of *Life of Field Seismic*, which is also described in the current issue of GEO ExPro. This new innovative technology, after only one year in operation, has proven to be of immense value in reservoir management for BP on their giant Valhall field. For this reason, the company received an award for their contribution.

Likewise, a new theory on the accumulation of oil and gas in "*The Golden Zone*", also explained in this edition of GEO ExPro, has been developed by geoscientists working for an oil company that has access to data from all over the world. The theory, which specifies at what depths we may find discover new oil and gas fields, may have important implications for how explorationists analyse the subsurface.

Gas hydrates is another field of rapid development, which is being discussed at length in this edition of GEO ExPro. The geoscientific knowledge of this possible energy source – how and where it occurs – is largely developed at universities and research institutions, even if the funding partly comes from the oil companies. The development in exploration and production technology is, however, for the most part done by the service companies and the oil companies.

As demonstrated in the present issue, GEO ExPro aims to present recent geoscientific and technological advances in the petroleum business. Moreover, it will give simple explanations that will be easily understood by a broad range of professional geoscientists and engineers who study the subsurface by means of geological and geophysical methods.

In short, the idea behind GEO ExPro is to assist those concerned with the subsurface to take part in the overwhelming flow of information on developments in both geoscience and technology.

Halfdan Carstens
Editor in Chief

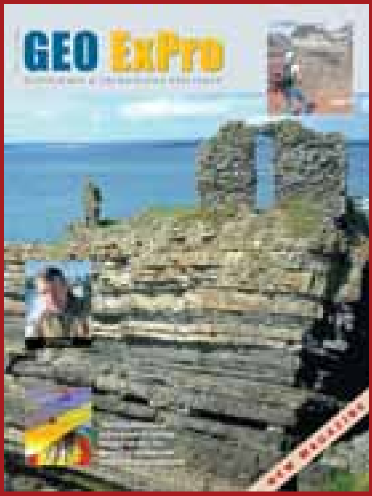
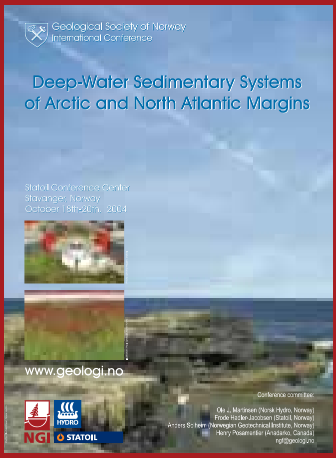


Photo: Ole Martinsen, Norsk Hydro

'The Namurian (Upper Carboniferous) Ross Formation is exposed around the Shannon Estuary in Western Ireland. The sandstones represent turbidite deposition in a deep-water basin and form a 460 m thick submarine fan complex. The formation is widely used by oil companies for training and for illustrating probable depositional analogues to petroleum-bearing sandstones in many deep-water basins around the world such as in the North Sea and offshore Africa.

Turbidite reservoirs will be in the focus in the forthcoming three-day conference on "Deep Water Sedimentary Systems of Arctic and North Atlantic Margins" to be held in Stavanger, Norway.

For additional information and registration: www.geologi.no.



GEO ExPro
www.geoexpro.com

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

Managing Director
Tore Karlsson

Editor in Chief
Halfdan Carstens

Editorial enquiries
GeoPublishing
c/o NGU
7491 Trondheim, Norway
+ 47 73 90 40 90
halfdan.carstens@geoexpro.com

Advertising enquiries
Media-Team
Ellinor Kittilsen
+ 47 22 09 69 10
ellinor@media-team.no

Marketing Coordinator
Kirsti Karlsson
+ 44 20 7937 2224
kirsti.karlsson@geoexpro.com

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

GEO ExPro is published bimonthly for a base subscription rate of €40.00 a year (6 issues).

We encourage readers to alert us to news for possible publication and to submit articles for publication.

Layout: Skipnes AS

ISSN 1744-8743

Improved well treatments

"There are significant advantages in producing acid downhole instead of using "live" acid. Therefore, we have developed a family of acidizing and polymer breaker solutions using catalysts", says Ralph Harris.

There is no use in finding oil and completing wells if the oil does not flow easily into the well bore. Reduced flow can result when drilling fluid and cuttings solids deposit as a 'filter cake' on the borehole wall or penetrate far into the formation. Also, in low permeability reservoirs, production may depend on flow through natural fractures that become blocked by infiltrating mud during drilling and production.

Acidizing with hydrochloric acid is often used to improve communication by dissolving the mud cake or the mud that is blocking pores in the formation. A major drawback, however, with the use of conventional acids, in particular in carbonate formations, is that they start to react as soon as they reach their target. The fast reaction rate results in poor zonal coverage (i.e. an inefficient treatment).

To overcome this problem, Cleansorb has developed a new product in which catalysts, including enzymes, can generate chemicals downhole. A precursor compound, which is itself neutral but can make an acid, is mixed on the surface with the catalyst in an aqueous fluid. The catalyst then converts the acid precursor to acid over a period of time after the fluid is placed in the wellbore or in the formation.

Stimulation of production through natural fracture networks is difficult to achieve using conventional acids, which react immediately at the wellbore face and do not penetrate far into the fractures. With downhole chemical production the fluid can be placed deep in the fractures while the reaction is starting, ensuring effective delivery of acid to increase fracture conductivity and possibly connectivity.

The low reactivity of the fluid during pumping also allows it to be placed around a wellbore to a radius of a few metres increasing the matrix permeability and thereby improving production or injection rates.

"For wells that have been produced for some time, the most effective use of downhole production of chemicals is critically dependent on quality input on lithology, chemistry and pore fluid properties from geoscientists, petroleum and reservoir engineers as well as knowledge of the original drilling/completion activities and subsequent production history," says Ralph Harris, director and partner at Cleansorb in Surrey, UK.

"Acrasolve has been used successfully for mud damage removal in Venezuela, West Africa, Canada, Algeria and India. Laboratory results and field tests have also confirmed the effectiveness of the process for deep matrix acidizing and stimulation of natural fracture networks," says Ian McKay

The Libwa field

Downhole acid production was successfully used in the Libwa field, a low permeability (2 millidarcy) limestone reservoir off the coast of the Democratic Republic of Congo in West Africa where all wells require stimulation to establish economic production rates.

The Libwa 4 well was initially acidized with 15% hydrochloric acid immediately after completion. Well logging shortly after stimulation showed fluid production from only 40 meter of the more than 650 meter long open hole wellbore. Since then oil production from Libwa 4 declined at an annual rate of 15% to under 100 BOPD.

The well was stimulated using downhole chemical production. Acid was produced evenly throughout the fluid, typically more than 95% after placement, resulting in high efficiency treatment along the whole of the wellbore. Peak production of 759 BOPD subsequently stabilised at around 500 BOPD. This "acidising only" treatment was to dissolve carbonate weighting material and cuttings fines in suspected residual oil based mud damage. Treatment details are given in an SPE paper (SPE 68911).

Shell contract to Multiwave

"We are naturally delighted to have won the contract," he added, "and the fact that we are seen by Shell as the most appropriate solution for such a project further underlines our capability and track-record," says Karstein Roed, president of Multiwave Geophysical (MGC).

Multiwave has become the only seismic contractor currently installing permanent seismic monitoring systems.

Shell recently awarded Multiwave Geophysical a 4C seismic contract in the Gulf of Mexico. The contract, which involves installation of 4-component seismic cable over Shell's deepwater Mars field, also requires Multiwave to acquire repeat seismic surveys for 4D analysis over the next one to two years.

Multiwave Geophysical is an upstream services company specializing in 2D and 3D marine seismic acquisition using towed streamer systems plus four component seabed systems, which are designed not only for conventional bottom cable acquisition but also for permanent installation over fields for continuous seismic monitoring.

"Now the only seismic contractor currently installing permanent seismic monitoring systems, Multiwave will be utilising advanced cabling from Geospace Engineering Resources International. Operating at a depth of 1000 metres, the cable will be placed on the seabed and tied back to a recording system located on the platform, designed to give Shell the most accurate and reliable survey possible," said Karstein Roed, President of Multiwave.

Successful test-survey

Data from recent electromagnetic surveys provide evidence for direct detection of deeply buried hydrocarbon accumulations by remote sensing in both shallow and deep waters.

Direct remote sensing of deeply buried oil and gas reservoirs, Sea Bed Logging (SBL), has recently shown very promising results (GEO ExPro 2004, Vol. 1, No.1, pp. 22-30). The validity of the method has been demonstrated in deep water both offshore Angola and across the Ormen Lange gas field offshore Norway. However, the SBL technique has not yet been fully demonstrated in shallow water, and for this reason it has not yet been widely accepted in the oil industry as a valid tool in exploration for oil and gas.

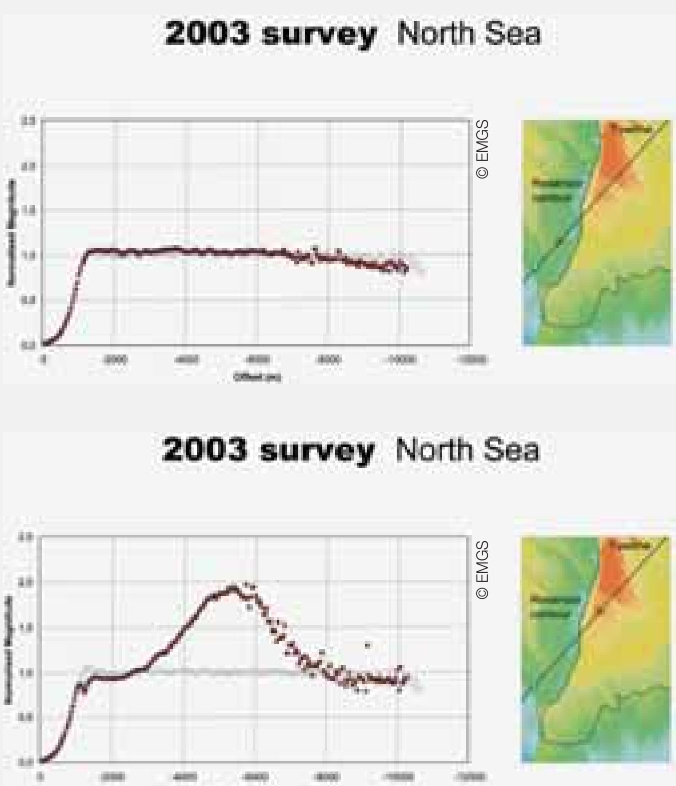
This is now to be changed, as new data across the giant Troll field offshore Norway provide the first evidence for the usefulness of this method also in shallow water. "The survey across the Troll West Gas Province opens a new frontier in hydrocarbon exploration," said a representative of Electromagnetic Geoservices (EMGS) in a talk at the EAGE 66th Conference & Exhibition in Paris this year. EMGS, a spin-off from Statoil, was founded only two years ago on the business idea of commercialising the new technology.

A full-scale electromagnetic sounding test in deep waters offshore Angola in 2000, while the technology was being developed in Statoil, indicated that SBL had a promising potential for direct detection of hydrocarbons in the subsurface. Four years later, it has been shown that increased electromagnetic return signals over the giant Troll gas field are caused by reflection and refraction of electromagnetic energy from a high resistivity hydrocarbon accumulation situated approximately 1100 m below the seabed. Says Terje Eidesmo, president of EMGS, who also attended the EAGE meeting where the data were presented: "These data are in accordance with modelling results and provide the first irrefutable evidence for direct detection of hydrocarbons by offshore electromagnetic sounding."

The SBL verification test was over the Troll West Gas Province (TWGP) with a 160 m gas column in a Jurassic sandstone reservoir. Hydrocarbon filled sands show high average resistivities and occur at a depth of about 1000 m below the sea floor. The water bearing reservoir sandstones and overburden sediments show considerably lower resistivities.

"The goal of this full scale Sea Bed Logging (SBL) experiment, run in addition to a multitude of surveys on untested prospects both in the Norwegian Sea and elsewhere, was to prove that a reservoir with high resistivity hydrocarbons in shallow waters could be detected by use of electromagnetic energy," EMGS said in their EAGE talk in Paris.

There should be no doubt that the electromagnetic survey conducted by EMGS over the Troll field last year was successful. The results presented at the EAGE 66th Conference & Exhibition in June were very convincing as to the applicability of the method for detecting hydrocarbons, also in shallow water (< 500 m).



Measurements outside and inside the Troll field clearly demonstrate the anomaly caused by high resistivity hydrocarbons compared to low resistivity saline formation water.

3D without glasses

The Autostereo 3D Display Wall provides interactive, accurate high-fidelity 3D images for all viewers - without glasses - in a normally lighted room.

The high-resolution Autostereo 3D Display Wall, developed in close collaboration with automotive engineers, designers and other collaborators, displays 25 times the information content and is 10 times brighter than conventional stereo visualization images, QinetiQ claims.

Based in the U.K., QinetiQ recently unveiled the prototype of its Autostereo 3D Display Wall, a new product that offers a combination of large image size and excellent 3D image qualities. At its heart is an advanced projection system that delivers unprecedented amounts of information to viewers via a diffractive optical screen.

Unlike traditional stereo visualization techniques, QinetiQ's 3D autostereo technology allows multiple viewers to see geometrically accurate, stable 3D perspectives simultaneously. The display projects large, 3D images that can be viewed without the use of special glasses in any normally lighted office environment.

Workshop on gas hydrates

A national workshop on gas hydrates and natural seeps is aimed to strengthen and exchange knowledge about the interrelation of geological and biological processes in the Nordic Sea deep water systems. It will be held in Trondheim, Norway, November 8-9.

©Ifremo 2003

"We intend to bring together a wider range of expertise and information to stimulate a program of research that elucidates the Nordic Sea regions as a potential source of natural marine resources as well as for monitoring global change. Our goal is to initiate a general discussion on a national level and to find synergies to establish a common portal for integrated research on gas hydrates and natural seeps in Norway," says Jochen Knies at the Geoogical Survey of Norway who is organising the workshop.

The workshop addresses geoscientists, including both academia and the industry, who are strongly involved in basic and applied research on gas hydrates and natural seeps.

For additonal information: www.ngu.no.

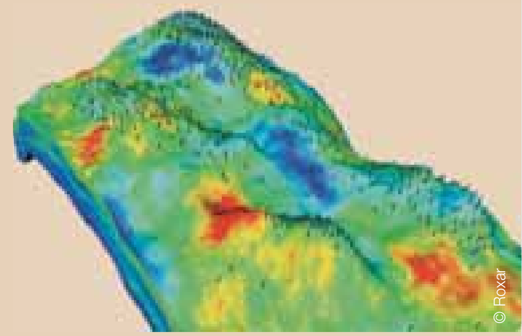
Roxar Donates Software

Roxar Software Solutions has donated over US$1 million of its Irap RMS reservoir modelling software for academic use at the Australian School of Petroleum at The University of Adelaide, Australia.

The Australian School of Petroleum, formed out of a merger in 2003 of the University's School of Petroleum Engineering & Management and the National Centre for Petroleum Geology & Geophysics, is one of the world's leading teaching and research schools into petroleum engineering and geoscience. Reservoir modelling techniques are a key component of the teaching, particularly for PhD and Masters students, and the new partnership with Roxar will enable students to build detailed reservoir models in a real-time environment.

The Irap RMS software consists of a full suite of integrated software modules including mapping, modelling, flow simulation, well planning and workflow management tools designed to help geophysicists, geologists, reservoir and drilling engineers to work together faster and more easily, to increase productivity from existing fields and to shorten the discovery-to-production lifecycle.

Said professor John Kaldi, head of the Australian School of Petroleum: "Pooling resources and expertise from the private sector is a vital means of ensuring our graduates of tomorrow have the right skills and knowledge to move the E&P industry forward. Roxar's industry-leading software will provide a hands-on tool that will allow our students to learn the basics of reservoir modelling with the same state-of-the-art techniques used in the industry. We look forward to a long and mutually beneficial partnership."



© Roxar

Innovation Award to BP

The 12th ONS Innovation Award has been won by BP Norway for the world´s first permanent seabed seismic array, which has been installed on the Valhall field in the Norwegian North Sea. Kjell Magne Bondevik, prime minister of Norway, presented the award during the opening ceremony for the 16th ONS exhibition and conference.

A BP team supervised 10 specialist contractors which delivered products and services to this life of field seismic (LoFS) facility. These include installing 120 kilometres of seismic cables, operating seismic source, logistics to handle huge data volumes and the ability to produce high-end four-dimensional images.

According to BP, the aspiration of being able to acquire seismic on demand has been demonstrated, with improved recovery as a realistic expectation. Four-D images revealing changes in the reservoir over periods of months are already in use by the well delivery teams at BP.

In its evaluation, the innovation awards jury noted that this solution represents an essential piece of reservoir monitoring for the future. "Justifying such investment can be difficult, but the industry knows we have to go for it," the jury observed. "It´s very applicable to more mature offshore areas."

This technology is explained on p. 26 - 29.

© BP

220 km² in Mexico

SeaBed Geophysical, founded in 1997, based on a novel idea of how to acquire seabed seismic in a more efficient way than state of the art at that time, finished a major 4C seismic program offshore Mexico in March this year. SeaBed Geophysical won the contract for the state owned company Pemex in tough competition with better-known seismic contractors with a longer track record. The contract was worth 15.5 million dollars and lots of prestige.

Eivind Berg, president of SeaBed Geophysical, is pleased with the company's performance in their first large survey done on the giant Cantarell oilfield.

The survey has been extremely important to the company, as it is their first large-scale survey ever and their first possibility to demonstrate the CASE technology to the oil community.

" What we did in Mexico clearly shows that we passed the test," says Eivind Berg, president of SeaBed Geophysical.

CASE means "CAble-less SEismic System". Nodes that are laid down on the sea bottom and picked up again after the survey is finished replace traditional cables, which are dragged behind a vessel. "The system is especially applicable for time-lapse surveys (4D), due both to the quality of the data and the accuracy of the positioning. Avoiding using cables we are able to reduce the noise from platform and vessels and get a very accurate positioning," says Berg.

All communication with the CASE units at the sea floor is done hydro-acoustically. The CASE unit is equipped with a programmable communication transducer and modem, with equivalent transducer and modem placed on the vessel. A specific request will be sent from the operator onboard the vessel to the CASE unit. The computer inside the CASE unit will respond the requested information and send it up to the vessel again. The information includes status of the CASE unit as well as seismic data.

The development of this system has required brains, time and more than 15 million dollars. The next step, to persuade the oil companies to use the new system, has also required time and money, this time on marketing. The Pemex job was a breakthrough in this respect.

The survey was done above Cantarell, which is the world's largest offshore oil field. Altogether 220 km² of data were acquired in a little more than four months. Rough weather during the first weeks caused delays, but acquisition sped up reaching an "all time high" with 36 km2 in two weeks. – This is probably far better than any other company has done before, says Berg.

Cantarell is a very complex oil field to acquire seismic data, as there are a number of installations that has to be avoided. This is also why the technology that SeaBed Geophysical is using is well suited.

"Our conclusion based on this experience is that this kind of technology is very useful when doing a survey on a producing field with several platforms, other installations and heavy traffic," says Berg.

The processing started early this year and is now well under way. The data will be completed this autumn, but it is a long and tedious process with highly sophisticated software and methods being used."The subsurface is very complex because of overthrusting and gas leakages. Both P- and S-waves are thus being processed, and S-waves are equally important as P-waves in imaging the reservoir. The S-waves are important to detect the fracturing and the direction of the fractures in the carbonate reservoir," explains Berg.

"We are pleased with the progress and will deliver what we have promised," Berg says.

Cantarell Field

The Cantarell Field is a giant oilfield located in the Gulf of Mexico operated by Pemex Exploración y Producción (PEP). The complex lies in the Bay of Campeche off the coast of the Yucatan Peninsula, 75 to 80 km northwest of Ciudad del Carmen. Water depths range from 35 m in the south to 40 m in the north.

Cantarell produces about one-third of Mexico's total output of oil, which is approximately 1.2 million barrels per day, and it is the most important oilfield complex in Mexico. It is also one of the largest oil fields in the world, with initial oil in place of 35 billion bbl oil (Bbo) and proven hydrocarbon reserves of about 13.5 Bbo equivalent. This represents about one quarter of Mexico's total oil reserves.

The technology developed by SeaBed Geophysical - "CAble-less SEismic System" – is particularly well suited for fields with numerous installations where it is difficult to move vessels around.

Field production started in June 1979, reaching a peak in excess of 1.1 MM BOPD in 1981. This production level was sustained until early 1996 through the drilling of 139 development wells.

The 1999 Sihil discovery lies within the Cantarell-complex area, but is much deeper. Estimated reserves exceed 1.4 billion bo equivalent.

New Technology Promises Increased Efficiency

rxt is using I/O's Vectorseis Ocean system, which utilises solid-state accelerometer sensors whose performance has been extensively proven onshore. New recording, battery and telemetry technologies are incorporated into the radio controlled buoy-based acquisition configuration. The flexibility of this solution allows a reduction in the number of vessels required without compromising operational efficiency, claims rxt.

The newly established company rxt, formerly known as Terra Seismic Services, specializing in marine OBC 2C/4C seismic surveys, is presently acquiring its very first survey in the Gulf of Mexico for Chevron Texaco. Based on innovative technology, its aim is to acquire marine OBC 2C/4C-data in a much more efficient way than their competitors.

"Over the last few years a number of cases reported from the offshore arena have proven that multi component seismic, both two component (2C) and four component (4C), bring critical new input to the E&P process, in particular in terms of reservoir imaging and fault definition. The cost of seabed seismic is still, however, several times higher than the cost of towed streamer data and therefore the market has not grown as expected," says Mike Scott, president of rxt.

"We believe we can change this through improved operational efficiency," he adds.

The current crew employs 6 cables, each 6000 m long, with 4C sensor nodes spaced every 25m, uses a shooting vessel and a dynamically positioned cable handling vessel and can acquire up to 5 - 7 km^2 of 3D data per day depending on survey parameters. Recording system command and control signals together with data for QC are telemetered from a digital recording buoy attached to each cable back to the vessels with ranges up to 15 km.

Each sensor node contains a 3-component MEMS (micro electromechanical systems) accelerometer (VectorSeis) and a hydrophone in addition to the cable telemetry electronics. Between the sensor modules there is a steel armoured cable with sufficient strength to carry the tension during deployment and recovery in water depths up to 2000m. This cable design permits the cable to be dragged into position where water bottom conditions allow. Dragging the cable in this way can improve sensor coupling to the seafloor. An I/O patented in-line stress decoupling system avoids the compromise in 3C vector fidelity which usually results from such tensioned deployment

Cable handling is accomplished using specially designed linear cable recovery "engines" which, by ensuring that the cable is spooled onto the storage reel under constant tension, prevent crush damage which might otherwise occur during recovery.

"Operational efficiency in the movement of the recording cables is key to the overall crew performance. Deployment and recovery are accomplished using specially designed cable recovery "engines" which, by ensuring that the cable is spooled onto the storage reel under constant tension, prevent crush damage which might otherwise occur during recovery," says Chris Walker, Vice President, Geophysics.

The rxt management team brings with them more than 150 years of experience in marine seismic operations from several contracting companies under the leadership of Mike who held both field and operations management positions in both Seismograph Services Limited and GECO AS. As one of the founding members of PGS he was responsible for the rapid development of their seismic fleet in the 1990's.

"In particular, the team's experience of development and operation of complex 3D streamer acquisition systems is vital for new innovative solutions for rxt," Mike Scott said.

rxt's brand new cable vessel, the m/v Bourbon, whose dynamic positioning capability is of critical importance for precise, rapid deployment and recovery of the Vectorseis Ocean 4C cables.

AAPG
European Region Council

is proud to welcome you to Prague to the first
European Region conference, 10 - 13 of October 2004.

Theme: Regional Geology and Hydrocarbon Systems of European & Russian Basins: Looking for Sweet Spots.

The European Region is seeking to establish and maintain a high level of student participation in education and research relevant to the interests of the petroleum industry. Students, make use of the opportunities available to you through the AAPG.

National and regional groups within the European Region need active members to volunteer small amounts of their time and so contribute to the global activities of the AAPG.

On behalf of the
European Region Council

Sigrunn Johnsen
President

Gas Hydrates: A Giant Resource – and Possible Environmental

Photo: Timothy S. Collett, U.S. Geological Survey

Gas hydrates are buried under the outer continental margins in deep water and below permafrost in the Polar Regions. Gas hydrates may constitute a sizable resource for future generations, but they may – through natural processes – also generate huge emissions of hazardous, environmental gases and cause large submarine slides.

The amount of methane sequestered in gas hydrates is in all probability enormous.

Threat

Mallik 2002 Gas Hydrate Research Program

The gas flare that lit up in the darkness of winter far up in northern Canada the winter of 2002, signalled a hope of a new energy source that could last for generations to come.

The gas hydrate field Mallik, on Richards Island in Mackenzie River Delta in northern part of Canada, 180 km north of the research centre in Inuvik, was already proven back in 1972 when Imperial Oil drilled through it while looking for conventional oil- and gas fields deep below the surface. In 1998, 26 years later, a research well was drilled to a depth of 1150 m (Mallik 2L-38) through the tundra (max depth of 650 m), which confirmed that a layer of gas hydrates was present underneath the permafrost. Ten different layers of gas hydrates were identified from the logs, with a total vertical thickness of 113 m, and for the very first time cores containing gas hydrates were brought up to the surface. With high gas hydrate saturation, some places up to 80% of the pore volume, Mallik is one of the greatest gas hydrate fields known today.

A new research program was carried out in 2002. The participants were a syndicate of national research institutions from Canada, India, Japan, Germany and the USA, together with the US Department of Energy, the International Continental Drilling Program (ICDP) and several oil companies. 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. The two latter registered the reservoir response to the adjustments of pressure and increase in temperature needed to produce the gas. Two zones were tested by two different methods. The methods utilized the destabilization of the gas hydrates caused by lower pressure and an increase in temperature. The gas hydrates were then released from the rock and became available for production. The lower layers experienced pressure reduction, and in the upper layers the temperature was increased by circulation of hot water through the formations. The latter method in particular proved successful.

For the very first time, gas from gas hydrates was produced. The flare from the gas tower confirmed that gas hydrates could be a technical success when the gas saturation is great enough.

Cartography: Masaoki Adachi

Halfdan Carstens

Gas hydrate is ice that burns. Methane – stored as gas hydrates in sedimentary deposits – highly deserves our attention. Researchers believe that they occur in large volumes, and it is a common assumption that more carbon is bound to gas hydrates, worldwide, than in all other fossil fuels like gas, oil and coal combined. Hence, they can represent a future energy source by replacing or supplementing fossil fuels. In this way, the gas hydrates can come to rescue for future generations when the conventional energy resources are depleted.

As we are about to see, great uncertainties are bound to the volume calculations. And, given that the technical challenges regarding producing gas hydrates is overcome, the future extraction of this resource may also represent a safety risk. Natural changes in pressure and temperature on the outer continental margins can also cause the gas hydrates to transform into water and gas. The consequence is that submarine slides can be triggered, something that has happened several times since the last glacial period.

Unfortunately, it seems like the gas hydrates represent a great danger for generations to come, if they dissociate (melt) and their gases are released into the atmosphere. Methane (CH_4) is about 20 times more effective as a greenhouse gas than carbon dioxide (CO_2). If some of this gas is released, it will represent significant emission that will worsen the existing climatic crisis, according to the IPPC/Kyoto protocol.

Researchers in the industrial countries throughout the world have started to focus on this geological phenomenon. A huge increase in number of publications and seminars dealing with this issue has resulted. Nevertheless, we still lack the answers on several key questions.

All over the world

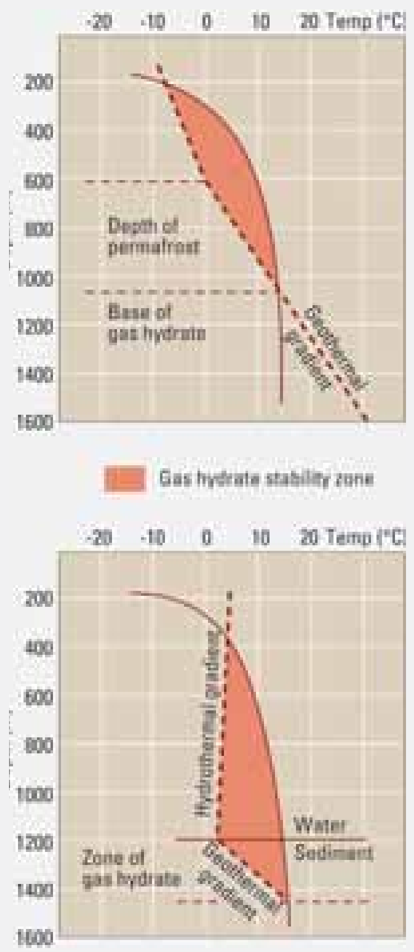
Naturally occurring gas hydrates have been mapped worldwide since the 1970's. They appear in two different geological environments, in marine sediments on the outer continental margins, and below permafrost in arctic regions. The pattern seen from the global occurrence is connected to the fact that gas hydrates only exist where the pressure and temperature conditions can provide a stable hydrate structure like the diagram shows.

Gas hydrates in marine sediments along the outer continental margins have been mapped using geophysical, geochemical and geological data on all the continents. They are found at a depth from 100 to 1100 m below the sea floor. Close to 80 occurrences have been discovered, and 19 of those have been sampled.

Gas hydrates below permafrost occur both onshore and offshore in Alaska, Canada and Russia. The upper limit for stable gas hydrates is 150 m below the surface, and they have been discovered as deep as

Photo: Jürgen Mienert, University of Tromsø, Norway

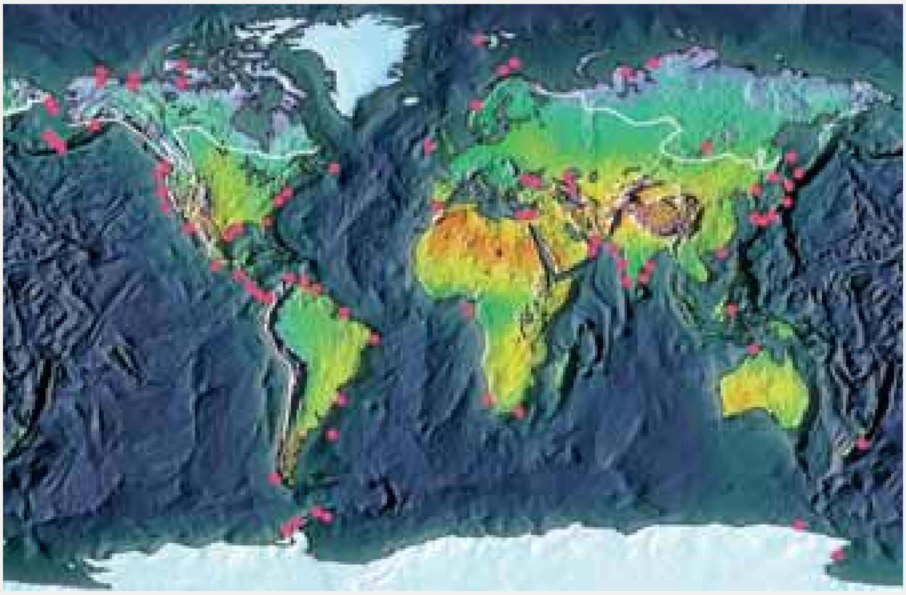
Gas hydrates resembles ordinary ice but dissociate quickly when reaching the surface, since the structure of water and methane is unstable at 1 atmospheric pressure. Dissociation means that huge amounts of methane are released. The phase diagram on this page shows that even in high Polar Regions, where the average surface temperature is below –10 °C, gas hydrates will only be preserved at a depth of 100 meter or deeper.



Graphs showing the depth-temperature zone in which methane hydrates are stable in (A) a permafrost region and (B) an outer continental margin marine setting. Water freezes to ice when the temperature falls below 0 °C and the phase transition is mainly independent of pressure. The stability of the gas hydrates, however, is highly dependent on both temperature and pressure. The graph shows that methane and water are stable as gas hydrates at low temperatures and high pressure (Gas Hydrate Stability Zone – GHSZ.

Modified from a drawing by Dr. Tim Collett.

Cartography: Masaoki Adachi



Gas hydrates can be identified in seismic data, well logs and from well bore samples. The map shows that gas hydrates are proven (red dots) in deep water along most of the continental margins. In addition, gas hydrates are proven in areas with permafrost (north of the white line on the map), both onshore and offshore. The gas hydrate discoveries on the Blake Ridge (east coast of the USA), Hydrate Ridge (west coast of the USA) and in the Nankai trough (offshore from Japan) are marked with a larger red dot since these areas are all well explored. The location of seismic line from Svalbard (page 20) and the location of the Mallik well are also marked on the map.

2000 m. The thickness of the gas hydrates can be several hundred meters.

In the upper part of the sedimentary sequence, microorganisms transform organic material to methane (the same process that form methane in swamps and waste disposal sites). Further down in the sedimentary sequence, at a depth of several thousand meters, it is the heat that transforms the organic material to hydrocarbons. A method called isotope analysis makes it possible to distinguish between shallow (biogenic) and deep (thermogenic) originated gas.

The majority of gas hydrates seems to have its origin from biogenic gas. However, the source for some of the gas hydrates in the Gulf of Mexico and the Caspian Sea are believed to be thermogenic gas. Thermogenic gas may also be the source for gas hydrates below the tundra in Russia, Canada and Alaska.

A key characteristic of gas hydrates is that they contain up to 180 times more gas than an equivalent volume without the hydrate. That means that a very large seepage of gas is required, whether it is of biogenic or thermogenic origin, to form an occurrence of gas hydrates.

Gas hydrate habitat

Gas hydrates behave differently than conventional oil and gas. Usually they are present as fine crystals, but they also occur as pore-filling material in massive beds (up to several hundred meters thick). Other areas to find gas are in tiny cracks, as thin layers along the bedding plane, layers across the bedding and as cement between sand grains.

> "Gas hydrate is the unknown and enigmatic matter that petroleum geologists, climate researchers and geohazard experts increasingly focus more on."

Along the passive continental margins, the younger sediments on the continental slope will mainly be fine-grained, due to long transportation from the source area. The degree of consolidation is low, and the deposits have high porosity. On the other hand, the permeability will be low, hindering seepage of large amounts of gas, and subsequently the formation of hydrates. This points to the fact that gas hydrates are only present on a limited area on the passive margins. The most well known occurrence is Blake Ridge offshore the east coast of the USA.

Gas hydrates

Gas hydrates are naturally occurring ice-lie solids in which water molecules trap gas molecules in a cage-like structure.

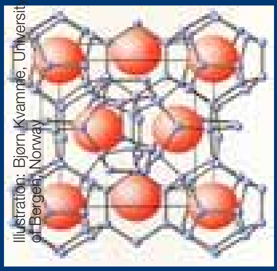
Gas hydrates are a naturally occurring hard, crystalline matter consisting of water and gas, which require very particular environment to form and stay stable. An open network of host molecules that cap in other guest molecules characterizes gas hydrates. The description hydrate is used when the host molecule is water, and gas hydrate is used when the guest molecule is a gas.

The gas is incorporated in a crystal structure without being chemically bound, and the molecules are packed a lot denser than in a conventional gas reservoir. This means that 1 m^3 gas hydrate gives 164 m^3 of gas and 0,8 m^3 of water at standard conditions (1 atmospheric pressure).

Methane is the most common gas that is incorporated in hydrates, and methane hydrates constitutes for more than 90 % of all gas hydrates. Other gasses incorporated in the structure are nitrogen, hydrogen sulphide, carbon dioxide and hydrocarbons.

Although many gases form hydrates in nature, methane hydrate is by far the most common and makes up more than 90 % of all hydrates. Other gases include nitrogen, hydrogen sulphide, carbon dioxide and hydrocarbons.

As a function of the conditions for stability, gas hydrates appear either below the permafrost in Polar Regions at a depth of a few hundred meters, or far out on the outer continental margin and below the continental slope where water depth exceeds 3-500 m. There are minor chances for finding gas hydrates on the abyssal planed. Even though the sediments in the greater ocean areas lies within the stability area for gas hydrates, the biological productivity necessary to produce the organic material. Low rates of sedimentation also make the organic material to be oxidised.



Gas hydrates consist of methane molecules (red) in a cage with water molecules (blue).

Photo: Sadao Nagakubo, Technology and Research Centre, Japan National Oil Corporation

Core from Mallik 1 with bubbling gas hydrates that dissolve as the pressure is relived.

Along active continental margins, where the lithosphere plates collide, the situation is totally different. The high relief on the land area supplies coarse clastic sediments, and the source area is close the deep-water sedimentary basins. The sediments will be unsorted and coarse grained with high porosity and permeability, while tectonic activity results in sediment deformation and faulting, allowing the gas to migrate from the deep and into the reservoirs. Possible reservoirs are proven by drilling outside Japan (Nankai Trough) and outside the west coast of the USA (Hydrate Ridge).

The volumes are questionable

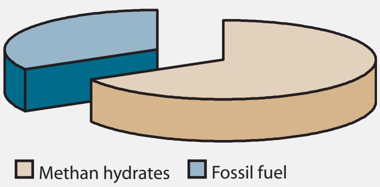
A significant part of the earth's fossil fuel seems to be stored as gas hydrates. The experts, however, cannot agree on how big the volumes are. The question has been debated for more than 20 years, and many think that 20 more years will be needed before we have reached a good enough understanding that allow us to estimate the actual size of this vast resource.

According to an article in the acknowledged magazine Nature (Nov. 20th 2003), researchers at the Colorado School of Mines, Centre for Hydrate Research, believe that the energy in the gas hydrates amount to twice as much as all fossil fuels combined. They also went one step further to postulate that we will start using gas hydrates as a supplement to conventional energy in the near future. *"Most probably we will produce from this source of energy in 10-20 years time in order to cover the increasing energy demand,"* writes E. Dendy Sloan Jr.

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). In all publications it is stressed that these numbers are very uncertain, but even the lowest number equals the amount of fossil fuel on earth, or one million times the volume of gas present in the giant Troll field on the Norwegian continental shelf.

"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, who has worked with gas hydrates in his entire 20+ year career. He is fully aware of the great uncertainties connected to the calculations, but believes they are still of interest as even the lower most numbers are huge. Collett does not believe that gas hydrates will be produced in significant quantities before 30-50 years from now.

Volume calculations of marine gas hydrates are mostly based on seismic data



The total volume of methane in gas hydrates is considered to be greater than the total volume of fossil fuel on earth (coal, oil and gas combined). Great uncertainties are, however, connected to the calculations leading to this assumption.

The research

Gas hydrate research has increased dramatically the last five to ten years. We find the most active research groups in the USA (Woods Hole Oceanographic Institute, Palo Alto, Colorado School of Mines, Scripps Oceanographic Institutes, Santa Barbara, USGS), Canada, Japan, and China.

Japan has been a driving force, and somehow their enthusiasm and investments have resulted in increased research activity also in the US. Active research is also going on in Russia following their discovery of hydrates in Siberia.

Gas hydrate research is a multidisciplinary task and includes geology, chemistry, biology, climatic and several forms of technology related to proving, drilling and production.

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.

"Gas hydrate is a highly expandable field of research for a multi-disciplinary group consisting of geologists, geophysicists, geochemists, geotechnicians, oceanographers, ecologists, biologists and engineers."

and occurrence of Bottom Simulating Reflectors (BSR). As the name implies, BSR's are situated parallel to the sea floor, and are caused by changes in sedimentary acoustic properties due to a phase transition between gas hydrates (with high acoustic velocity) situated above the gas or water saturated sediments (with low acoustic velocity). The reflector is strong, crossing the bedding planes and is usually quite easy to identify.

"Mapping of Bottom Simulating Reflectors can to some degree tell us where to find gas hydrates, but it has been proven that there are areas with such reflectors where no gas hydrates can be found," explains marine geologist Martin Hovland in Statoil, who for several years has studied gas hydrates and associated phenomena in marine sediments. For this example he refers to a geotechnical drilling through a BSR in the Norwegian Sea that neither showed gas hydrates above the reflector nor much free gas below the reflector. "The opposite can also be the case, gas hydrates have been found without any evidence for BSR," Hovland says.

"The volume in a specific deposit can be estimated if we know the size of the area, bed thickness, porosity and gas saturation in the pore volumes," says Professor Jürgen Mienert at the University of Tromsø, Norway. He has a long international experience working with gas hydrates, and is particularly interested in how they affect the stability of the sediments. "After all, the change in volume as gas hydrates transfer to water and gas needs to be taken into consideration. This can be a factor up to 180, which is equivalent to compressed gas, but a lot less than LNG (Liquefied Natural Gas)", explains Mienert.

"It will be possible to give an indication of how much gas is present for small areas. On a global scale, however, it is only possible to do qualitative and most uncertain quantitative volume estimations", claims Mienert, who would rather not estimate how large the total gas hydrates volumes are worldwide.

Associate Professor Karin Andreassen at the University of Tromsø, holding a PhD on gas hydrates along the Norwegian continental margin, also questions many of the resource estimates. "They are very uncertain and show great inconsistency. Even

Photo: Halfdan Carstens

Dr. Tim Collett of the U.S. Geological Survey has worked with gas hydrates in his entire career as a geologist. Collett also played a lead role in planning and conducting the Mallik 2002 fieldwork, and he was on site around the clock during drilling and coring operations.

The history

Gas hydrates were initially, when discovered in the early eighteenth century, known as laboratory curiosities as naturally occurring gas hydrates were not known at that time.

In the 1930's and 1940's, as natural gas pipelines were extended into colder climates, the hydrocarbon industry became interested in these substances when it was discovered that gas hydrate formation inside pipelines might block the flow of natural gas.

In the middle of the 1960's the interest for gas hydrates changed dramatically. For the first time gas hydrates below the permafrost and above the huge gas reserves in Siberia were discovered. Soon after, in 1972, gas hydrates were also discovered below permafrost in the Prudhoe Bay oil field on the North Slope of Alaska and in Canada's MacKenzie Delta.

At the same time as the discovery in Siberia, Russian researchers postulated that gas hydrates could also be found in deep water where the temperature were low and the pressure were high. And sure enough, in 1970 gas hydrates were discovered in the first well drilled on Blake Ridge outside the eastern coast of the USA, completed by Deep Sea Drilling Project (DSDP). Since then, gas hydrates have been proven on the outer continental margins all over the world, and the scientists got the understanding that they did occur more or less everywhere.

Strange as it may seem, however, it was only at the beginning of the 1980's that scientists for the first time could see and touch marine gas hydrates. That happened on one of the DSDP-project cruises.

India and Japan got involved in gas hydrates in the middle of the 1990's. The lack of conventional energy sources is the reason for their interest. The first well offshore Japan was drilled in 950 m water depth in the Nankai through. Considerable volumes of gas hydrates were proved by this well.

though we talk about enormous volumes, it doesn't automatically make it an exploitable resource," she says.

Andreassen also points out the problems that could arise if the gas is to be produced: "Marine gas hydrates are to be found in unconsolidated sediments that easily turn into a soup of water and gas when drilled and the pressure conditions are changed. Production is further complicated by the low permeability in the sediments, which consists of clay and silt."

Marin geologist Martin Hovland, who is interested in gas hydrates as agents for driving various natural seabed processes, also warns against hasty quantitative calculations: "Imagine 15% porosity in the sediments, and you would like to produce 5-15% (common concentration of gas hydrates) of 15%,which is almost like extracting gold from an ordinary gold ore." This is his way to illustrate that a little scepticism must be called upon regarding the optimistic future plans for the utility of gas hydrates as a energy source.

Professor Dr. phil. Karl Berteussen at The Petroleum Institute, Abu Dhabi, also points out that volume calculations involve a lot of guesswork. "The reasonable plan of action to reduce this uncertainty is to carry out more measuring. We now have new methods in seismic that enable us to reduce the insecurity dramatically, if only we were willing to make use of it," he claims.

On a global scale, the gas hydrates on land, below the permafrost in the Arctic, have a considerable smaller volume than marine gas hydrates, but it is assumed that a greater portion can be produced. Many experts also predict that the first gas hydrates to be produced will be from the hydrates below the permafrost. Production of marine gas hydrates, on the other hand, seems to be dependent on a technological breakthrough.

Climate change

Much of the gas hydrates occurrences around the world have a pressure and a temperature that cause them to be at the borderline between stable and unstable. Hence, small changes in temperature and pressure can cause dissociation (melting).

The amount of methane adsorbed in gas hydrates is several thousand times larger than the volume of methane in the atmosphere. Even the amount of methane hydrates in arctic areas – below the permafrost – is estimated to be twice as high as the total amount that's present in the atmosphere. A proportional "small" emission of methane from this source is consequently powerful enough to change the chemical composition in the air considera-

Jürgen Mienert is a professor in arctic geology and applied geophysics at the Department of Geology, University of Tromsø. He is particularly interested in submarine slides in conjunction with hydrates, climatic changes and the development of ocean bottom seismic for detection of gas hydrates. Mienert has lead several major projects with European funding, built GEOMAR in Germany (now IFM Geomar), had research positions at the Woods Hole, Oceanographic Institute (MIT, Boston) and at Lamont Doherty, Columbia University (New York).

Blake Ridge

Blake Ridge is a type locality for gas hydrates. As a part of the DSDP-program (Deep Sea Drilling Project) the first well was drilled on Blake Ridge in 1970. The purpose of the drilling was to improve the knowledge of the oceans of the world, but in this particular case one of the objectives was to explore the significance of a Bottom Simulating Reflectors (BSR) that prohibited sound waves to penetrate through to the deeper layers.

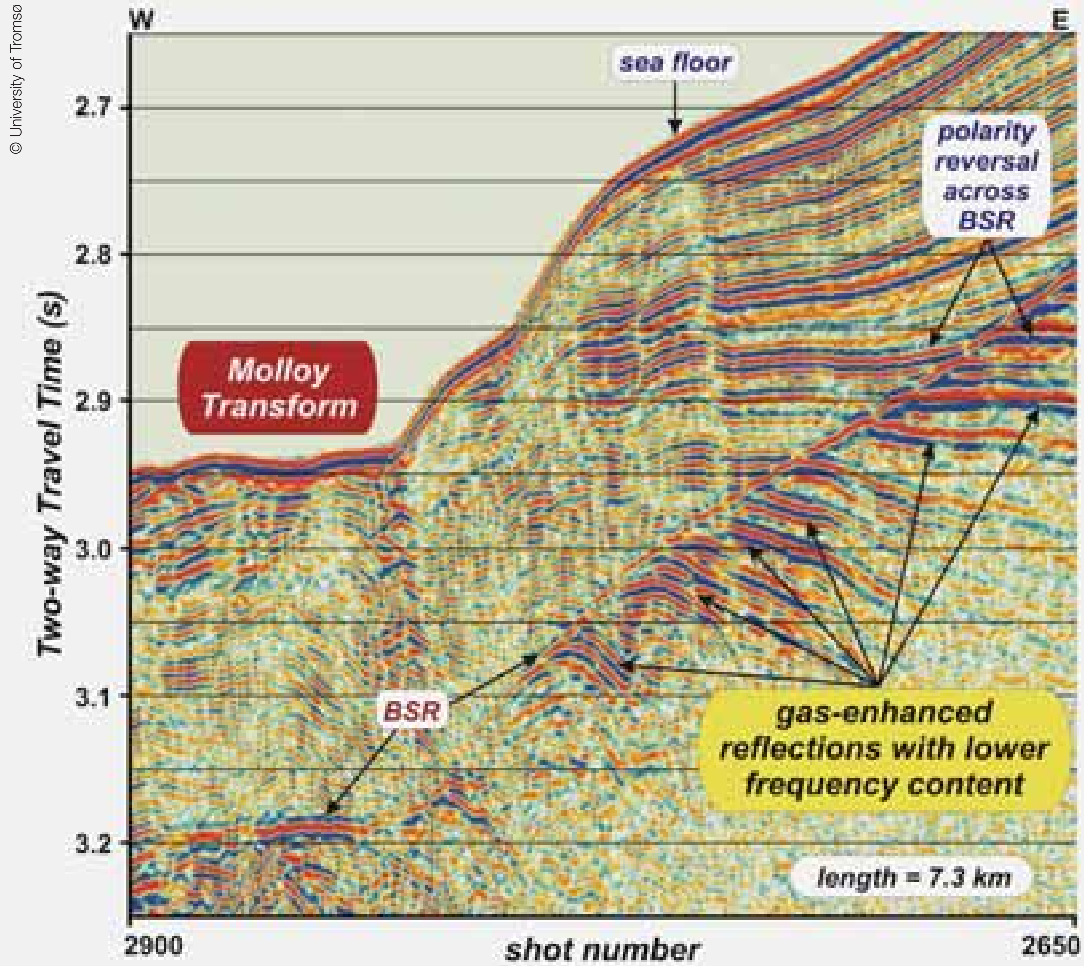
High concentration of methane was found in the core, and the correlation between methane in the sediments and high acoustic velocity led to the conclusion that the Blake Ridge contained gas hydrates. Ten years later, a sample was collected to prove this.

The drilling also showed that the BSR represents the base of the hydrate zone. We now know that the strong reflector usually is caused by free methane gas below the gas hydrate zone.

Even though the volume estimation of the amount of gas in Blake Ridge varies greatly, there is a general agreement that the volumes in question are enormous. Calculations done by Tim Collett in U.S. Geological Survey show that 38 trillion m^3 methane in addition to 20 trillion m^3 free gas below the hydrates are present. In comparison, the original gas reserves in giang gas field Troll on the Norwegian continental shelf were estimated to 1,4 trillion m^3.

For the time being there is no technology available to produce the gas on Blake Ridge, and it is important to emphasize that the volumes in question are total gas volumes present in the reservoir and not the reserves.

In 1999, a well was drilled in the Nankai Trough, southeast of Japan, where huge sedimentary deposits have been laid down. The well drilled through a well defined BSR, which corresponded to the border between gas hydrates and the underlying free gas. The free gas was kept in place due to the impermeable hydrates. The volume of free gas was estimated to 16-27 trillion m^3, and the gas volume from the hydrates could be as high as 50 trillion m^3.



Bottom Simulating Reflectors (BSR for short) represent the transition between gas hydrates and free gas in the sediments below. This line is from the westward dipping sedimentary sequence west of Svalbard in the Arctic Ocean.

bly. Because methane is 20 times more powerful as a greenhouse gas than carbon dioxide, its emission will harm the environment far more than human activity.

"Emission of methane from gas hydrates can have had an effect on the climatic changes, but the relationship between temperature and methane is still not fully understood. We still lack knowledge about the amount of methane released from the ocean or the swamps on the tundra, and how much of the gas generated that reaches the atmosphere," explains Jürgen Mienert.

In a recent publication, US scientists claim to have proven that methane from gas hydrates was a direct cause for the global warming that ended the last glaciation about 15,000 years ago. Global warming at the end of Paleocene, about 55 million years ago, with a magnitude of 4-6 °C ("Late Paleocene Thermal Maximum"), is also seen in relation to thawing of gas hydrates. "Both theories have been widely discussed in the scientific arena. Although they are theoretically well founded, and can be supported by several observations, there is still a question of what came first, the gas release or a warming; that is, the well-known chicken and egg problem," claims Martin Hovland.

Danger of submarine slides

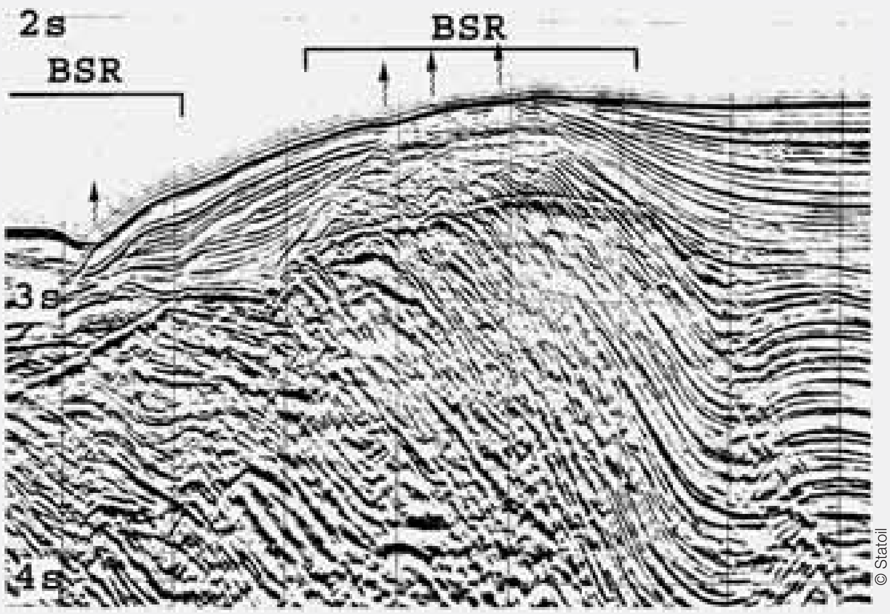
Destabilisation of gas hydrates on the outer continental margins by an increase in water temperature or by a decrease in pressure due to lowering of the sea level, can cause submarine slides. Both historic and modern events show that such slides can cause catastrophic flood waves (tsunamis) that reach land with a great speed.

"We suspect that gas hydrates are very close to the limit of their existence several places on the outer continental margin. They can easily dissolve if there is an increase in temperature while the pressure is maintained. This happened on the Norwegian continental margin as the temperature rose after the last glaciation," says Jürgen Mienert who refers to the Storegga slide, the greatest-ever submarine slide which was triggered 8,200 years ago.

There are similar examples of the relationship between the gas hydrates and submarine slides on the continental slope outside West Africa, the east coast of North America, the northern coast of Alaska, as well as other locations along the Norwegian coastline. The slide scars left often coincide with the top of gas hydrate zones suggesting a connection.

Presently there is great interest associated with the drilling of research wells in connection with the huge scar left by the slide known as "Storeggaraset." The gas hydrate community in Tromsø is in the process of implementing a detailed program through IODP (Integrated Ocean Drilling Program), including seven wells, three outside the scar, and four inside.

"The purpose of these drillings, which we hope to commence within a couple of years, is to understand how gas hydrates behave in and around slide areas. So far we have obtained some knowledge about



BSR's offshore Nigeria.

> "Gas hydrates can be the geological resource that can replace the conventional hydrocarbons (oil and gas)."

marine hydrates on lower latitudes with contourites and turbidites, but we know very little about the gas hydrates in glaciomarine deposits on higher latitudes," Mienert says.

Mienert goes on toexplain that there are several good reasons for why such drilling should take place on the Norwegian continental margin. For a passive margin, it is strikingly active with greater slides, mud volcanoes and pockmarks, and several BSR's close to the Storegga slide indicate both gas hydrates and underlying free gas.

According to Mienert, the oil industry's interest in deep-water oil and gas exploration, in combination with slide risks, creates a unique incentive for cooperation between the oil companies and academic community.

Facilities for oil and gas production are also at risk for being damaged. Blowouts, casing collapse (already happened) and gas leakage on the outside of the casing are real hazards that needs to be considered. Gas hydrates are also said to represent a danger during drilling. Supposedly, the reservoir can be punctured and release large amounts of gas that will surface. Tim Collett, on the other hand, is in disagreement with this. Says Tim: "This has been shown not to be true for deep water gas blowouts. Numerous technical studies have shown that a gas release from below a gas hydrate, with a minimum water depth of 300 m, would have no affect on the buoyancy of a ship. The gas plume from a deep water release will be dissipated before it reaches the surface."

More research is expected

Sufficient amounts of gas have been found, both on land and in marine deposits, in order for us to hope that, at some time in the future, hydrates will be considered economically feasible to exploit as a possible source of energy.

Industrial exploitation is expected during the first half of this century. Presently the technology needed for an efficient production has not been developed, but research will be prioritised with regards to both exploration and production due to the huge volumes available worldwide.

As of today, our geological, physical, chemical and geotechnical knowledge is too limited to predict anything about any possible unwanted environmental consequences of gas hydrate production. Thus, "ice that burns" will most certainly be subject to increased research in the years to come.

The Hydrate Gun Hypothesis

The striking resemblance between two curves showing the methane content in the atmosphere and the temperature development the last 800,000 years (late Quaternary time), makes it easy to assume a connection between natural emission of methane and the global climatic evolution. The explanation could be that marine gas hydrates on several occasions were dissolved, as they got unstable due to changes in temperature or pressure, then leaked to the atmosphere and contributed significantly to the greenhouse effect.

At the University of California, Santa Barbara, four scientists have proposed this hypothesis in a newly published book *(Methan Hydrates in Quaternary Climate Change, The Clathrate Gun Hypothesis).* Professor James Kennett is the ringleader behind the idea. Environmental studies, based on ODP-drillings (Ocean Drilling Program) in Santa Barbara Basin on the west coast of the USA, has encouraged his interest for the gas hydrate and climatic relation.

According to Kennett and his colleagues, gas hydrates have repeatedly been very unstable due to changes in sea level over the last hundred thousand years, which have caused both pressure and temperature changes in the reservoirs.

Gas hydrates were stable and increased in volume during the cold climatic intervals, due to cold water invading the land area in the Arctic region. As changes in the ocean circulation increased the water temperature, the gas hydrates became unstable and disintegrated. Following Kennett's hypothesis, this resulted in catastrophic releases of methane. Subsequently, as the gas reached the atmosphere, the climate was changed because of this strong *klimagass*.

Mineral fuels in the Czech Republic:

Lack of oil and gas, an abundance of coal

The Czech Republic, host this year to the AAPG European Region Conference, has no significant production of oil and gas. The coal reserves are, however, sufficient to cover the country's own needs.

Halfdan Carstens

The Czech Republic produces only negligible quantities of oil. Last year the output totalled approximately 300,000 tons (equivalent to ca. 1,9 million bbls, or slightly more than 5,000 BOPD), while total resources (undiscovered and proven) may not exceed more than 35 million tons (ca. 250 million bbls) from approximately 20 small fields.

"Although the domestic output has been gradually increasing in the last 15 years, almost the entire consumption has been met through by import," says Jaromir Starý, Head of the Department of Mineral Resources Information, at the Czech Geological Survey (Geofond) in Praha. He adds that today, domestic production represents less than 5 % of the consumption.

The gas production in the Czech Republic is also very low. "The average annual production has been about 120-140 million (10^6) m^3, which means that production only covers 2 % of the annual consumption," says Starý. In comparison, Poland has a modest gas production of 4 million m3 per year, while the gas production of UK, Norway and the Netherlands are of a different order with 103, 65 and 60 billion (10^9) m^3 last year, respectively.

Cartography: Masaoki Adachi

The oil and gas fields are all located in the Carpathian Foredeep and the Vienna Basin. The coal deposits are located west and northwest of Praha (brown coal/lignite) and in the Upper Silesian Basin (hard/bituminous coal) in the easternmost part of the country.

A surplus of coal

The situation is, however, very different for coal. There is a long mining history of coal production starting at the beginning of the industrial revolution. Although the total resources are quite large, compared to their own consumption, the exploitable resources are limited. The Czech Republic has been a long time exporter to the neighbouring countries of Slovakia, Austria, Germany, Poland and Hungary. Coal does also cover more than 50 % of the country's primary energy supply.

"Coal production reached its maximum in the period from the 1970's to the end of the 1980's. At that time the combined output of hard coal, brown coal and lignite exceeded 130 million tons," explains Starý. Today, this number is almost halved as the production of coal has been reduced to some 65 million tons. Nearly the entire production of brown coal comes from 9 open-pit mines in north-western (North Bohemian Basin) and western (Sokolov Basin) part of the country. Hard coal is produced in 5 underground mines, all located in the eastern Silesia region (Upper Silesian Basin).

The Czech Republic now ranks as the 5th largest coal producer in Europe (behind Russia, Poland, Germany and Ukraine).


© Moravian Oil Comp.

Converted to oil equivalents, the annual coal production equals 500,000 BOPD.

For comparison, Norway's coal production from the Arctic mine in Svalbard (Svea Nord) is now more than 3 million tons per year. The world largest producers of coal are by far China and the United States.

"While the Czech Republic has moderate coal reserves, most are not suited for mining due to environmental and economic reasons. The total recoverable reserves are approximately 1,7 billion tons. At current production rates, producible hard coal reserves should last about 30 - 50 years, while mineable brown coal and lignite will last only 30 years," explains Starý.

Geology

The major part of the Czech Republic belongs to the European Variscan fold belt that stretches from Spain to the Czech Republic. Locally it is called the Bohemian Massif. The fold belt results from the Variscan orogeny that lasted from the Late Devonian until the end of the Permian and owes its existence to the collision between Gondwanaland and Laurasia creating the supercontinent Pangaea.

In the Bohemian Massif, limnic and paralic-limnic basinal sediments, ranging in age from the Carboniferous through Permian, and platform Cretaceous and Tertiary sediments overlie crystalline basement. Hard coal deposits, locally with natural gas, are concentrated in the Carboniferous to Permian sediments, whereas brown coal and lignite occur in the Tertiary ones.

The eastern part of the Czech Republic belongs to the Western Carpathians of Alpine (Tertiary) age, involving the Carpathian Foredeep, Outer Flysh Carpathians and Carpathian basins (Vienna Basin). Crude oil and natural gas deposits are associated with these Carpathian units. In addition, lignite deposits occur in the Vienna Basin.

The occurrence of oil and gas

Oil in the Czech Republic is confined to the Vienna Basin. "The deposits are distributed over a large number of structures and producing horizons down to almost 3000 m with Miocene sandstones being the most productive oil-bearing rocks. The largest field, Hrusky of the Vienna Basin, has already been depleted and now serves as underground gas storage," says Starý.

Connecting the Alps and the Carpathian mountains, the Vienna Basin is an intramontane Tertiary basin that lies primarily in Austria and Slovakia. Only a small portion of the basin straddles the Czech Republic. The Vienna Basin is one of the most explored sedimentary basins in Europe, with lots of borehole and seismic data. It is also central Europe's most prolific oil and gas basin, and the Vienna Basin contains Austria's biggest oil and gas-fields.

"The most significant region with 95 % of the Czech oil production lies in the Carpathian Foredeep. The most important accumulations occur particularly in the Miocene, Jurassic, Palaeozoic and weathered portions of the crystalline rocks," says Starý.

The Carphatian Foredeep is a hydrocarbon province that extends from Romania westwards through Ukraine, Poland, Slovakia, the Czech Republic and Austria. Oil and gas have been produced from this province for more than a century. Activity peaked in the 1920's and 1930's when literally hundreds of new discoveries were brought into production. After World War II, Czechoslovakia came under control of the USSR, which precluded private initiatives, and between 1945 and 1989 there was virtually no exploration within the area. This has now changed following the disintegration of the Soviet Bloc in 1989.

Natural gas of obviously Carboniferous origin and age is extracted during so-called degasification of coal seams of the Czech part of the Upper Silesian coal basin.

Strategy

The Czech Republic has adopted an energy strategy in which energy prices should be fully decontrolled, state owned energy enterprises should be privatised, energy conservation should be strongly encouraged and domestic oil and gas production should be made more efficient.

According to the Energy Policy, approved by the Government of the Czech Republic in March 2004, the share of solid and liquid fuels in primary energy consumption should gradually decrease in future. At the same time, the share of fluid fuels, nuclear and especially renewable sources should increase.

A paper entitled "Mineral Fuels in the Czech Republic" by Jaromír Starý can be found on www.geoexpro.com.

AAPG in Praha

This year's AAPG European Region Conference is being held in Praha, the Czech Republic, from October 10 to October 13. It is the first AAPG European Conference with the Geological Society of America (GSA) ever held. "Regional Geology and Hydrocarbon Systems of European & Russian Basins: Looking for Sweet Spots" is the conference theme.

© BP

Breakthrough for repeated seismic

The installation of a permanent seismic array in the Norwegian Valhall field enables the operator to run frequent 4D re-shoots, and the amount of oil to be recovered may increase substantially by managing the reservoir better.

Valhall is located in the Central North Sea next to the giant Ekofisk complex with oil and gas in chalk reservoirs. Ekofisk was discovered in 1969 by Phillips Petroleum, Valhall a few years later by Amoco. Valhall is today operated by BP.

Halfdan Carstens

A new way of monitoring an oil field has now been in operation for almost one year at the Norwegian Valhall field, operated by BP on behalf of its partners Shell, Total and Amerada-Hess. The results are indeed promising, as the seismic images show their capability to capture changes in the reservoir as oil production and water injection proceed.

"If this promise of increased effectiveness of reservoir management is realized, I expect this new model of how to manage an oil field will become an industry standard", says Olav Barkved, BP's project manager.

Now, the future potential of this tool is also recognised by others. At the Offshore Northern Seas Exhibition & Conference this year, the 12th ONS Innovation Award was awarded to BP Norway for the world´s first permanent seabed seismic array – "Seismic on demand".

Proving its value

Using a permanent array of seismic receivers, 4D seismic re-shoots can be done several times a year instead of only in intervals of several years. Following a long period with development and trials, the initial survey using the permanent seismic array was acquired in November of last year, the second survey was completed in April of this year and the third survey was wrapped up only two months later in June. A fourth survey is currently under way and will be completed in September. Approximately every three months, a new survey will take place, and the seismic array is expected to be on location though the entire life of the field.

"This is why the new scheme has been named *Life of Field Seismic* (LoFS) by BP," explains Barkved.

Downhole measurements in the production wells, such as pressure, temperature and the flow of fluids, only tell us about what is happening in the boreholes. For assessing the entire reservoir, application of 4D seismic is the preferred tool. "Although the seismic only provides seismic signatures (e.g. amplitudes), and not direct information about the reservoir (e.g. saturations), it is the only measurement we can make which covers the entire reservoir," says Barkved.

"However, the high cost of conventional 4D seismic means that it can only be performed at intervals measured in years. If 4D seismic can be done cheaply and frequent-

The Valhall is a low permeability chalk reservoir of late Cretaceous to early Tertiary age at a depth of 2500 m. Discovered in 1975, oil originally in place has been estimated to 2.7 billion barrels and it has so far been producing for 23 years. Total production to date has reached 500 million barrels of oil equivalents, and the current estimate of remaining reserves is 550 million barrels. The field continues to produce at near-peak rates, and it is expected to be economic for another 25 years. Aggressive reservoir management, including the application of advanced seismic technology, is the recipe. Latest in seismic technology is the permanent seismic array that was installed last year. It is the world's first monitoring system of this kind and has the potential of increasing the output from the field by as much as 60 million barrelsby placing the wells in a more optimal position.

ly, it will have an enormous impact on the way that oil reservoirs are managed." And this is why BP has spent years to develop the new concept, which has the potential of making 4D seismic on producing fields much more efficient than with traditional cables in the sea water. The data, after less than one year in operation, are likely to do well.

"We have already been able to show that the details shown in the seismic images allow for optimisation of production from individual wells, and even individual perforations. We have also been able to capture the benefit of combining 4D visualisation with novel stimulation technology as the seismic images have revealed an uneven drainage pattern around some of the wells."

"The seismic array is therefore already showing its worth in reservoir management," Barkved adds.

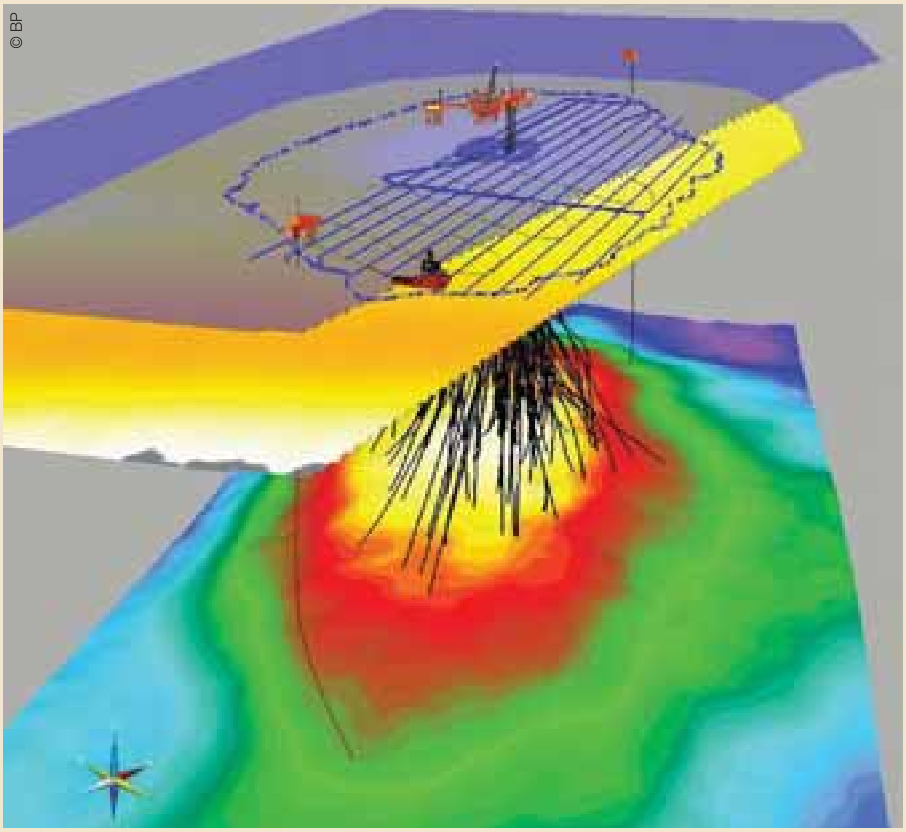
The worlds first

In the early 1990's, BP conceived the idea of a permanent installation of Ocean Bottom Seismometers (OBS) on the sea floor. With a permanent seismic array, 4D re-shoots could be done relatively inexpensively on a regular basis with only a source-boat working. The implication would be that the 4D re-shoots could become an integral part of active reservoir management.

With seismic receivers permanently emplaced, a major source of artefacts (receiver-position variation) in the 4D seismic difference is eliminated. The result is that the reservoir engineer can reliably detect small changes in the reservoir, occurring within short time-spans. "A reservoir engineer should be able to commission a re-shoot only a few weeks after starting an injection program. This will enable him to see exactly where the injected fluids are going," says Barkved.

The first version of a permanent seafloor seismic array was on the Foinaven field in the UK sector in 1995. "The OBS technology was less mature then, and all the objectives of the programme were not fulfilled. The project, however, showed that the concept could work. We established that good repeatable seismic data could be acquired and processed with receivers trenched into the seabed," says Barkved.

Since then, 4-component Ocean Bottom Seismic (4C-OBS) has become feasible,



A schematic idea of how a Life of Field Seismic installation over an active field might look. The details resemble those of the Valhall field.

Valhall

Near the crest of the Valhall structure, the conventional seismic image is severely distorted by the presence, in the overburden, of gas in low concentrations. Such gas-obscured-zones can be imaged regardless, using converted shear waves recorded on the horizontal components of 4C-OBS receivers.

During twenty years of production, the extraction of hydrocarbon fluids from the reservoir has lowered the pore pressure substantially. At the crest of the Valhall structure, the chalk framework cannot support the overburden because the pore pressure has been reduced during production. Hence, the framework compresses, leading to a sagging of the entire overburden. Also, the seafloor surrounding the original production platform complex has subsided. An elaborate plan has been created to deal with these effects. It includes the waterflood and two additional platforms, at the north and south ends of the field. The LoFS images will be crucial for monitoring the progress of this subsidence mitigation plan.

According to classical analyses, time-lapse effects in seismic data are supposed to be minimal in carbonate reservoirs, because the stiffness of the framework of grains minimizes the seismic effect of fluid substitution, and of changing pore pressure. However, at Valhall, the porosity is so high that these arguments do not apply, and in fact recent time-lapse processing of conventional data has empirically revealed the existence of substantial time-lapse seismic changes due to production over 10 years. This analysis also provides a basis for estimating the size of changes to be expected after much shorter intervals.

© BP

Olav Barkved, "geophysicist by heart" and project leader, is largely responsible for developing the seismic array on Valhall. He has worked with this field since 1992 and followed the development since the first 3D survey. "We have had strong technical support from experts and resource groups in Houston, London and Aberdeen, and we have also had assistance from ten different technology providers outside the company," Barkved says.

enabling the recording of converted shear waves, as well as conventional P-waves. The world's first full-field permanent 4C-OBS-seabed array was thus installed in late 2003 on the Valhall field in the southern sector of the Norwegian North Sea.

Our vision that Life of Field Seismic could be an integral part of reservoir management was about to come true," says Barkved.

A continuous operation

The permanent seismic array at Valhall consists of 120 km of OBS cable trenched into the seafloor to a depth of one metre. Areal coverage of the receivers is 35 km^2 while the areal coverage of shots is 125 km^2. The cable spacing is 300 m and the receiver spacing along the cable is 50 m. More than 10,000 geophones and hydrophones are thus covering the whole field.

The baseline LoFS survey was acquired in October 2003. The shooting was done with a standby vessel, and the airgun array was designed to radiate energy equally in all compass directions, because receivers are live in all directions (not just aft, as with conventional surveys).

Current plans call for re-shooting 6 times in 18 months, with further shooting "on-demand". This requires that the data processing be done with extraordinary speed, with much faster turnaround than is conventionally expected in a time-lapse survey. The data is brought ashore via a fibre-optic link, first to the BP operations centre, and next to the processing contractor, who has a dedicated team located in BP's Stavanger office.

"The processing requires 3 months for the P-wave image volume, and an additional month for the converted-wave image volume. Although these are rapid schedules for a field of this size, by the time the first volumes have been delivered, it is probable that the first re-shoot will already have been acquired," says Barkved. "In the future this turnaround time may be reduced to only a few weeks," he adds.

The current plan calls for 30 wells to be drilled into the area of Valhall covered by the LoFS array, and a water-flood program was started late 2003. The expectations are that these activities will all be managed more effectively because of the LoFS seismic imaging.

A reservoir management project

Life of Field Seismic is not a seismic project. It is a reservoir management project, which means that management decisions have to be taken on the same time-scale as the repeated surveys," says Barkved.

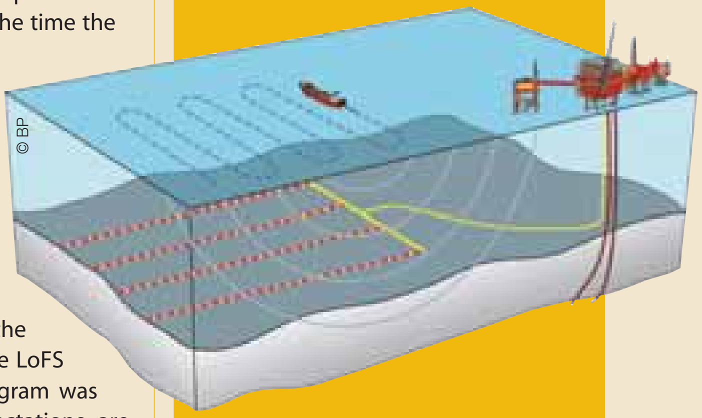
"Fundamentally new ways of managing reservoirs may also emerge. After all, a reservoir manager is most concerned with future prediction of reservoir performance. "History-matching" is only a means to estimate parameters that are needed to predict the future. Consequently, frequent, full-volume 4D seismic snapshots of the reservoir will become an invaluable aid for estimating these parameters," concludes Olav Barkved, winner of the ONS Innovation Award for 2004.

Improving quality

The essential idea is for the reservoir manager to look into the future and to design a 4D seismic program for the entire life of the field.

A permanent seismic array offers several technical advantages in this respect. Most important, reservoir engineers can obtain cost-effective surveys when they are needed. The engineer should also expect the time-lapse seismic differences to be of higher quality than is achieved with conventional techniques, and later re-shoots would not be hampered by the growing obstructions of platforms over the field. The quality of the data also has the potential of being much better as the reservoir would be illuminated from all sides, and surveys would acquire converted shear-waves in addition to conventional P-waves.

© BP



These features will certainly add value, but it is, nevertheless, questionable if they will justify the cost.

Even with large upfront costs, the economic argument may be successfully made for a field that is characterized by large reserves, an extensive drilling program planned that may be subject to influence by the 4D seismic, and production platforms on the sea floor that renders conventional 4D seismic difficult. All of these characteristics are present in the Valhall field.

Fault modelling:

New techniques improve reservoir description while reducing risk

Errors in fault interpretation can have significant negative impact on reservoir models, facility plans, and field economics. By using integrated software applications and workflows that cross disciplines, asset teams can understand complex reservoirs better and faster.

Drew Wharton, Schlumberger Information Solutions, Houston, Texas, USA

Using the latest software tools from Schlumberger Information Solutions (SIS), geologists, geophysicists and reservoir engineers are able to collaborate like never before using integrated workstations with shared applications and data. New workflows created for viewing and interpreting data have resulted in improved reservoir characterization and better decision-making. These workflows include using multi-trace seismic attributes to detect fault edges, using swarm intelligence for automated fault interpretation, and using seismic attributes, formation pressure data and reservoir simulation to improve fault seal analysis

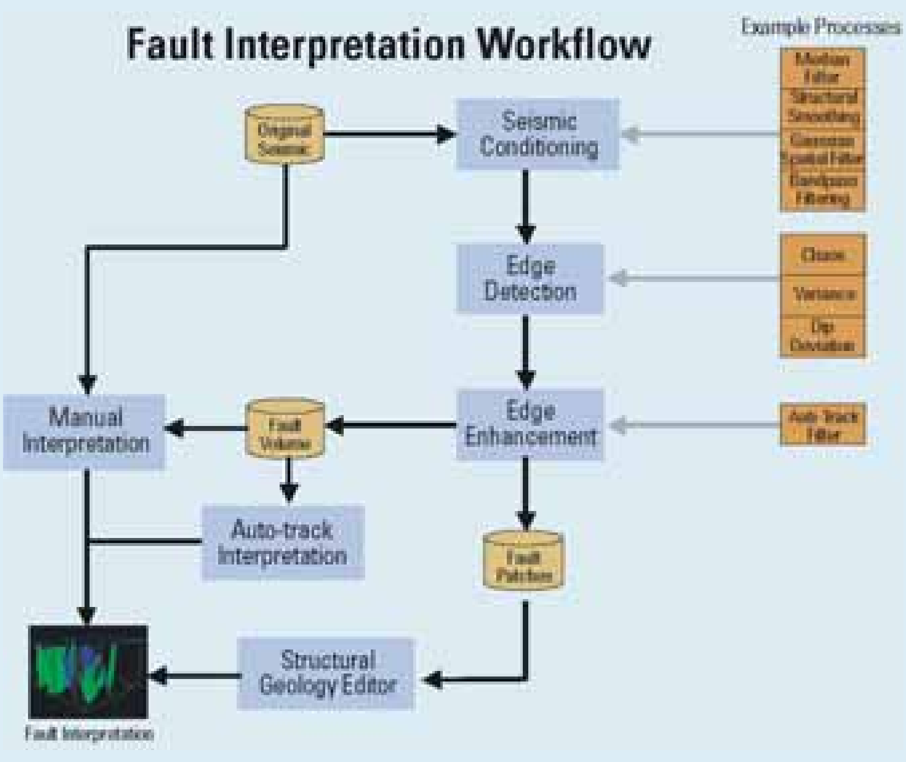
Edge detection

Multiple edge-detection attributes can highlight fault features much more clearly than using single attributes. Three commonly used attributes are variance, dip deviation and chaos. While there are significant differences among these attributes, all are derived from the same input data. Different attributes can detect different expressions of a geological feature, and when combined, they offer a more complete fault expression and better fault interpretation.

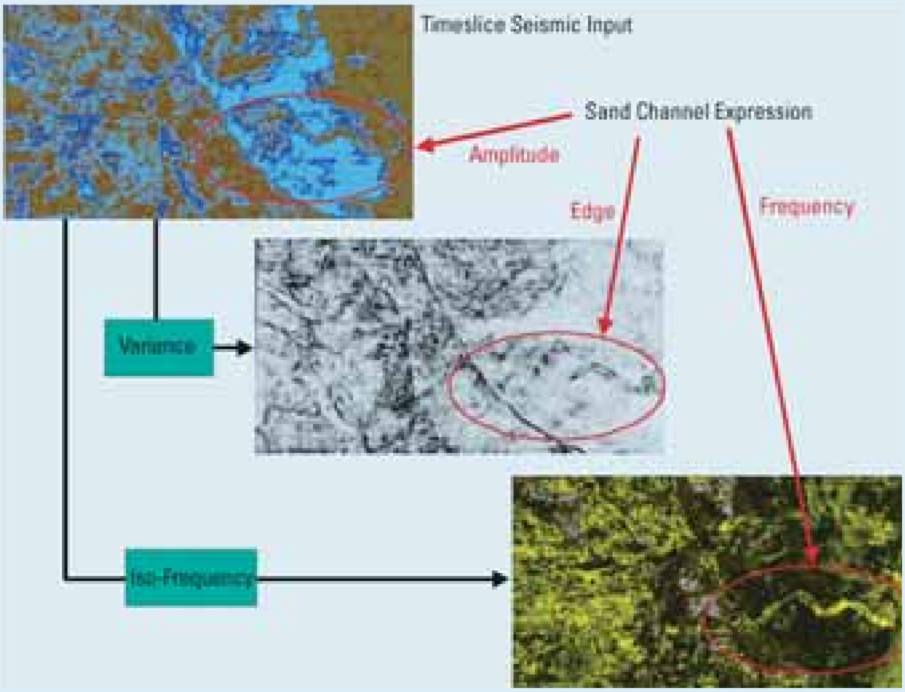
Automated fault Interpretation

Even with the aid of edge-detection algorithms, manual interpretation of fault surfaces remains a painstaking exercise, and traditional 2D interpretation techniques of picking fault and horizon intersections or fault polygons can produce significant errors in 3D space. A novel approach for automatically extracting fault surfaces from attribute data is now available. This methodology, called Ant Tracking, which has been implemented in Petrel™, enables: shorter fault interpretation cycles, geologically consistent sets of faults based upon unvarying rules, and repeatable fault interpretation solutions.

The automatic extraction of fault surfaces is nontrivial due to the noisy and repe-



This workflow shows how Ant Tracking, Edge Detection, Automatic and Manual Fault Interpretation all fit together to generate the best possible fault interpretation.



Different seismic attributes emphasize different aspects of the original input signal. The change in attribute response spatially allows us to correlate these attributes to geologic features.

titive nature of seismic attributes. The surfaces usually appear more like trends than well-defined, continuous surfaces. Further data processing is needed, and this is achieved using the principle of swarm intelligence, a term for the collective behaviour that emerges from a group of social insects. For example, ants are able to find the shortest path between the nest and a food source by communicating via pheromone, a chemical substance that attracts other ants.

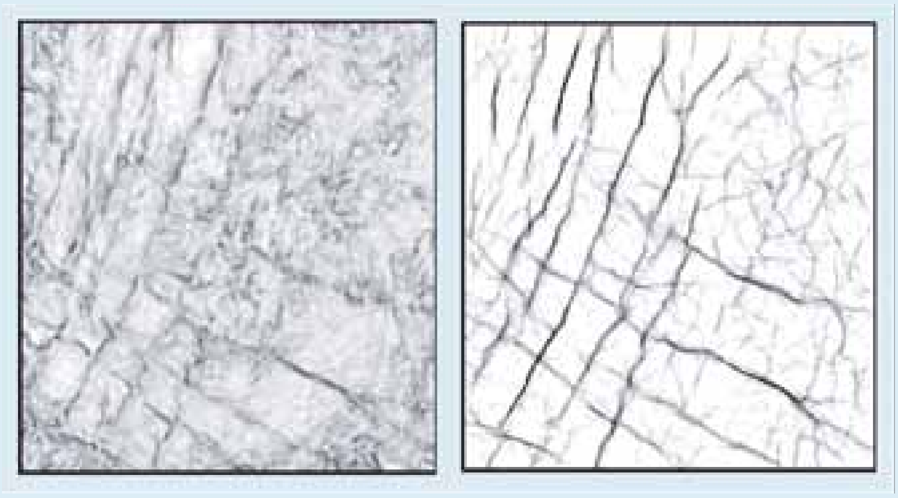
By encoding fault property expectations (rules) as a behaviour of intelligent software, it is possible to enhance and extract fault-like responses from the attribute. The idea is to distribute a large number of these electronic "ants" in the volume; and let each ant move along what appears to be a fault surface while emitting "pheromone." Ants deployed along a fault should be able to trace the fault surface for a while before being terminated. Surfaces meeting expectations will trace faults deployed at different positions in the volume, and will be strongly marked by "pheromone." Surfaces unlikely to be faults will be unmarked or weakly marked. The interpreter uses geological insight to validate and edit the results, rather than spending time extracting fault surfaces manually.

Fault seal

With faults identified, the asset team still needs to know whether or not they are sealing or conduits to flow in order to develop a proper field plan. Existing 3D reservoir modelling techniques cannot incorporate the full complexity of fault systems. Typically, faults and their properties are calculated and collapsed onto 2D fault planes, with transmissibility multipliers used to regulate the flow of hydrocarbons across the fault in the reservoir simulator.

Combining seismic attributes designed to highlight stratigraphic events and geostatistical algorithms for estimating rock properties from wireline logs, it is possible to improve the interwell distribution of reservoir properties resulting in enhanced fault characterization.

Fault seal analysis is essential to explain how flow paths have been modified through faulting.



The timeslice of the Variance cube (left) contains a lot of responses in the top right corner because the slice is cutting through some chaotic texture in the seismic data. In the corresponding Ant Tracking results (right), the chaotic responses have not been extracted because they do not fulfill expected fault properties. Detailed fault data have been derived from the surrounding voxels.

Calculating transmissibility based on the fault throw, shale gouge ratio, and fault permeability values, the higher the transmissibility multiplier, the easier oil can flow across the fault plane.

Well pressure data

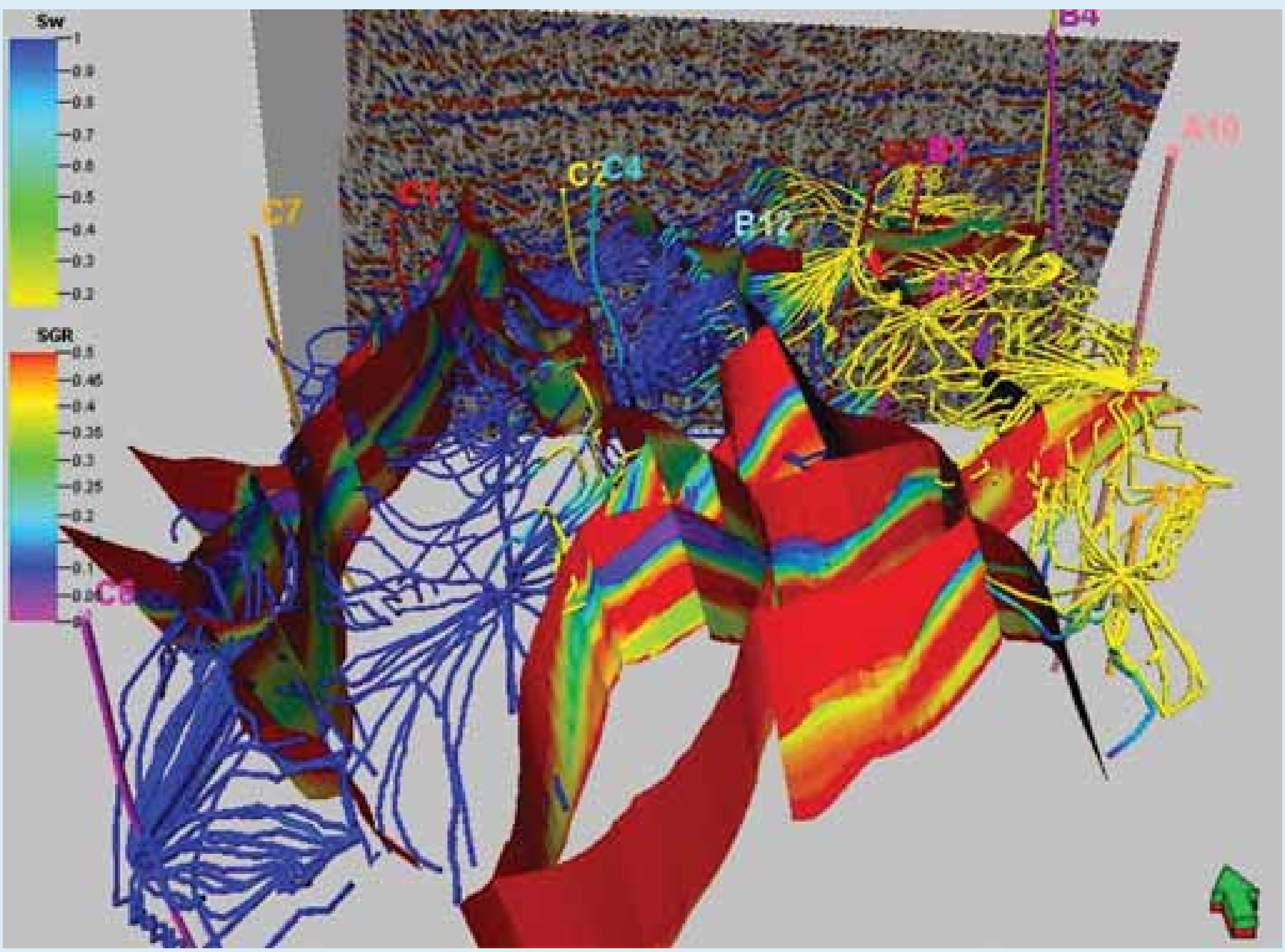
Accurate fault interpretation is encumbered by the fact that the data necessary to understand communication across faults isn't available until the well is drilled. Today, repeat formation test (RFT) analysis provides accurate pressure correlation between wells to confirm reservoir continuity. Fluid densities can be measured and fluid contacts can be located by analysing pressure gradients. Pressure measurements in development or infill wells can be compared with original formation pressures to positively identify drainage discontinuities due to faulting or stratigraphy. In addition, formation pressures from well tests are often used to evaluate reservoirs by creating a pressure transient by withdrawing fluid from the reservoir, shutting in the well, and monitoring the pressure build-up over time. Pressure build-up curves are analysed to determine formation permeability and interwell continuity.

Reservoir simulation

The static reservoir model with the initial fault interpretation should be considered a starting point, not a finished product. Projections based on the static model may provide expected production rates and pressures during various operations, but these must be updated as the reservoir characteristics change during production. Reservoir pressure measurements from well tests, coupled with production history, help improve the reservoir description over time.

The initial static reservoir description is seldom accurate since reservoirs are rarely homogeneous and significant changes can occur as fluids are injected or produced. Therefore, construction of a dynamic model using a reservoir simulator should combine the static reservoir model with production data and pressure data obtained from well tests. The reservoir model can be adjusted and fault interpretations updated until the simulation matches the actual well behaviour, with continual updating throughout the life of the field.

Streamline simulation of the tortuous fluid flow paths through the reservoir validates the fault seal interpretation and indicates where improvements to the reservoir model should be made. The streamline colour indicates water saturation, while the fault plane color represents the shale gouge ratio of the damaged zone



Measuring formation pressure while drilling

The TesTrak tool, here being operated on Norsk Hydro's Grane platform in May 2004, is an integral part of the drilling assembly. What appear to be just shiny pieces of pipe is in fact packed with highly advanced sensor and computer technology.

Photo: Baker Hughes INTEQ

New technology developed by the oil service industry now makes it possible to measure formation pressure during brief pauses in the drilling operation. This information is very valuable to drilling engineers as it can directly improve the drilling process in terms of wellbore pressure management; but also to reservoir engineers as it provides information on reservoir depletion and connectivity.

Trond Gravem, Baker Hughes

Measurements of rate of penetration, torque, RPM and weight on bit have traditionally been made on the drill floor. These are all parameters essential for drilling oil wells in a safe and cost efficient manner.

Over the last 15-20 years, however, there has been an accelerating development of new drilling technology, including both measurement of directional (x, y, z) and mud pressure data (Measurements While Drilling, MWD) and measurements of formation and reservoir fluid properties while drilling (Logging While Drilling, LWD). Parameters that can be measured include natural gamma ray, resistivity, formation bulk density, neutron porosity and acoustic travel time.

The latest in this string of technology developments is a device that enables us to measure formation pressure during the drilling operations (TesTrak), only incurring short pauses in the drilling operation.

The need for pressure data

Both the drilling and reservoir engineer are interested in knowing the formation pressure (pore pressure) while drilling. The drilling engineer needs the information to ensure that the drilling operations are conducted in a safe manner, while the reservoir engineer values the data for improved reservoir characterisation, planning the completion of the well and modelling the production.

Direct measurements are the only way to find the exact magnitude of the formation pressure. Traditionally this has been performed by running a pressure measurement tool downhole on wireline, after the drilling assembly has been pulled out. However, depending on the well trajectory, this operation can take up to several days, which is very costly on off-shore rigs where day rates can be as high as USD 450,000 or more.

The importance of this information has prompted development of indirect methods to provide an estimate of the formation pressure. Unfortunately, these are inaccurate and there are many examples where the formation pressure has been wrongly estimated, in some cases with grave consequences, such as borehole stability problems or loosing well control.

The drilling engineer has therefore always been interested in getting accurate formation pressure information while drilling, without interfering too much with the drilling process.

New method

A new method that determines formation pressure while stopping the drilling process only briefly has been developed. The pressure measurements are performed in brief pauses of the drilling process, as for example when the drill bit is pulled back for the connection of an extra drillpipe, or when a directional survey is taken. The TesTrak formation pressure tester while drilling is an integrated part of the bottom hole assembly and is placed just behind the drill bit. Circulation can be maintained at all times, further improving well control.

The measurement is performed by extending a piston out from the tool. At the end of this piston is a pad, which makes contact with the borehole wall. Once a seal has been established with the rock formation, a drawdown is applied, which results in fluid from the (higher pressure) formation flowing into the (lower pressure) tool, until pressures have equalized. The tool then utilizes a built-in logic to analyse the measured data to approximate formation permeability and pressure, and, based on the results, performs two additional pressure tests to validate the first measurement. The measurement results, including quality indicators, are then transmitted to the surface through mud pulse telemetry.

Measurements While Drilling may remove the need to run wireline logging tools after the drilling operations are finished. Running wireline can take time, especially on long, horizontal wells, and there is also an inherent risk for further delay. On a recent job on the Heidrun platform in the Norwegian Sea, the direct rig timesavings resultant from not having to run wireline was estimated to be almost USD 400,000.

The development of such technology is a time consuming process. Five years ago a feasibility study was performed to investigate what the industry requirements were for such technology. Functionality, reliability and accuracy were the key elements identified. The Norwegian companies Norsk Hydro and Saga Petroleum partly financed this study and took active part in the development. The work was primarily performed at Baker Hughes' Technology Centre in Celle, Germany.

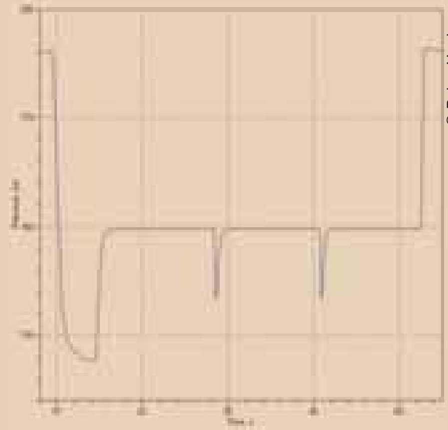
Satisfied customers

Several oil companies on the Norwegian, Danish and UK sector have used TesTrak during the last 12 Months.

"Our main use of formation pressure data is for calibrating and adjusting the reservoir model which forms the basis for how we plan the drainage strategy. In addition, we determine reservoir fluid type through gradient analysis. The data are also used actively when drilling, as they will provide important information in placing a production well an optimal distance from neighbouring injection wells", says Jarl Valdal, senior reservoir engineer in ConocoPhillips of Stavanger, Norway.

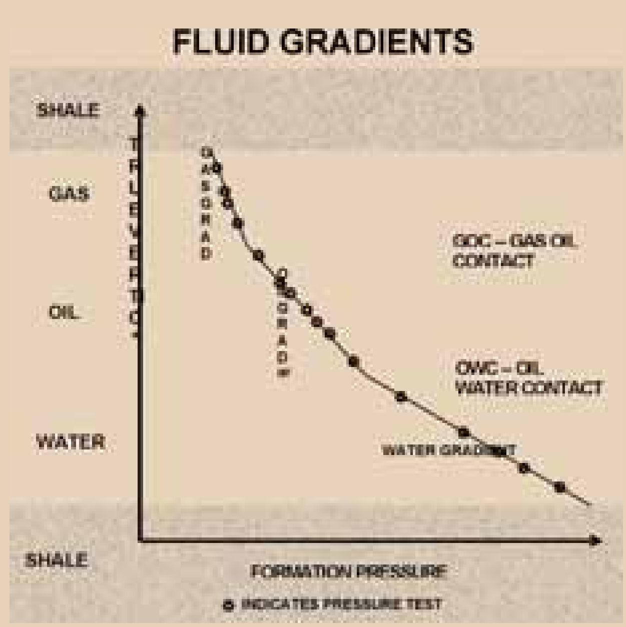
In January Statoil officially approved and qualified TesTrak as a wireline replacement, the first LWD formation pressure tester technology officially qualified by the company. This followed an evaluation of data quality compared to traditional wireline formation pressure tester on multiple wells on the Norwegian continental shelf. The results from TesTrak compared very well, even if small differences due to supercharging effects were seen in low permeable zones.

"We have closely monitored the LWD Formation Pressure technology for many years and we are pleased with the achievements that Baker Hughes INTEQ has shown us. "Formation pressure while drilling" technology is of great importance and value to Statoil, especially in the production drilling environment", says Harald Laastad, discipline leader of the LWD technology group in Statoil.



© Baker Hughes

Schematic overview of an optimised test sequence with the pressure development. Here a measurement is performed at a certain depth in the well and the total sequence is 3-5 minutes. As soon as the formation fluid is sucked in, a pressure drawdown is seen. By stopping this, a pressure build up can be seen. This is repeated twice before the snorkel is pulled back into the tool and drilling commences.



By measuring formation pressure at different depths, the reservoir fluid gradient can be determined. From this it can be established what type of fluid (water, oil, gas) the reservoir contains, and the position of the gas-oil-contact and oil-water-contact. By having this information early during the drilling operations, the completion strategy can be planned better and resources used more intelligently.

It's the temperature that counts

The Golden Zone

Most of the world's oil and gas occur in reservoirs with a temperature between 60 and 120 °C

A new and empirically verified theory shows that hydrocarbons occur in a universally similar manner that is controlled by the temperature. Petroleum geologists have therefore got a new tool to make it easier to explore for oil and gas in both immature and mature basins.

Halfdan Carstens

The idea behind "The Golden Zone", which includes 90% of the oil and gas resources of the world, is easy to understand and is in the process of being accepted among petroleum geologists.

The principal message in the theory is so simple that everyone can understand it: most of the hydrocarbons in a sedimentary basin – both oil and gas – are located at a depth where the temperature is between 60 and 120 °C. This new understanding represents perhaps one of the main advances in petroleum geological thinking in recent years. All petroleum geoscientists should therefore take note of the expression "The Golden Zone".

"The theory is, in principle, applicable everywhere, that is to say in all types of sedimentary basins," says Per Arne Bjørkum in Statoil. Together with Paul Nadeau he has, over a ten-year period, developed rather hazy ideas into a well thought out theory, which is now in the process of becoming firmly rooted in petroleum circles. But it was necessary for an American, Bill Maloney, to give it a name, attractive both for colleagues and for Statoil´s management.

"The Golden Zone"

"We have developed a synthesis involving several different fields of scientific study. The premise is that oil and gas occur in a definite pattern despite many geological differences from basin to basin," says Per Arne Bjørkum.

All sedimentary basins give the appearance of being unique. They all have their own history of development that gives them special features. Nevertheless, it is possible to discern a pattern, which is common to all of them, and it is also apparent that they show great similarities as regards the location of hydrocarbons. The traditional sub-division into types of sedimentary basin becomes thereby less relevant seen in the light of the new theory.

Petroleum geologists without long and habit-forming work experience will have no difficulty in accepting the existence and significance of "The Golden Zone". When, however, the two geologists first introduced the theory many refused to be convinced. This was largely due to traditional thinking regarding generation and migration of oil and gas suggesting a basin-specific distribution of hydrocarbons rather than the universal pattern as suggested by Bjørkum and Nadeau.

"But the opposition was also due to a certain doubt regarding a petroleum geological world, which was easy to understand but required a radically different way of thinking. It was necessary, first of all, to eliminate "all" preconceived lines of thought," say the two scientists.

"We have searched for a simple explanation and for a robust theory independent of details or information that is difficult to access," says Bjørkum.

Now the two research scientists go even further in their theoretical studies. Mechanisms that come into force at 120 °C can possibly also explain other phenomena. "We believe that overthrusting, for example, in which thrust sheets or nappes were pushed across Norway during the Caledonian episode of mountain folding, can be more easily understood if we take into consideration the effect of temperature on the geological processes involved. The same temperature and the processes we have described can also largely control the late phase of subsidence of sedimentary basins," says Bjørkum.

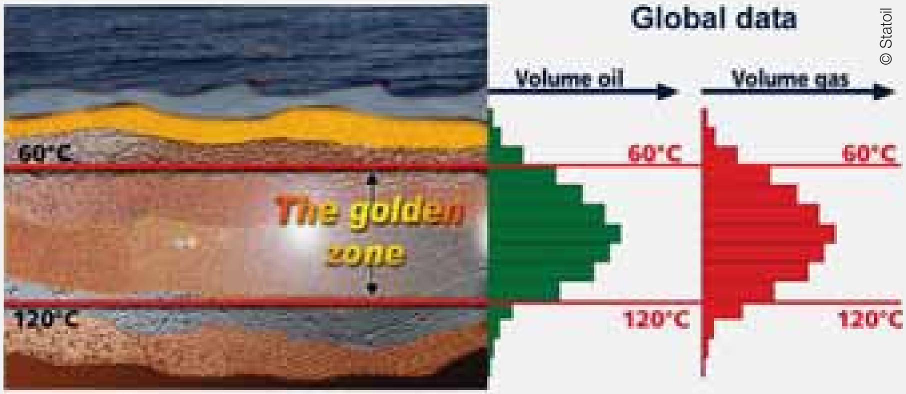
"Our theory is a contribution to our understanding of the earth's dynamic behaviour," he maintains.

It is tempting to believe him. He has the capacity to be convincing without overwhelming us with technical arguments. Instead he offers observations from many basins around the world, which document the pattern, together with philosophical considerations based on his study of scientific thought over many years.

"We must find the patterns in Nature – the fact that the sun rises once every 24 hours is one of them. We must look for organized patterns since these reflect Nature's inherent orderliness. We foresaw the universal pattern in the "Golden Zone" from theoretical considerations *before* we had the data to support it. This is the fundamental scientific philosophical appro-

Dr Per Arne Bjørkum, chief exploration scientist for Statoil, with a Master degree and a doctorate in sandstone diagenesis.

Paul Nadeau has a PhD in geology and works for Statoil in the field of international exploration.



"The Golden Zone" contains 90% of the world's oil and gas resources. The idea behind the theory is easy to grasp, and more and more geoscientists believe it is worth while to pursue this concept when exploring for additional hydrocarbons.

ach. Geologists have a habit of being fascinated and engaged in the unusual, that is to say, in cases which are exceptions to the rule and which cannot therefore form the basis for a pattern.

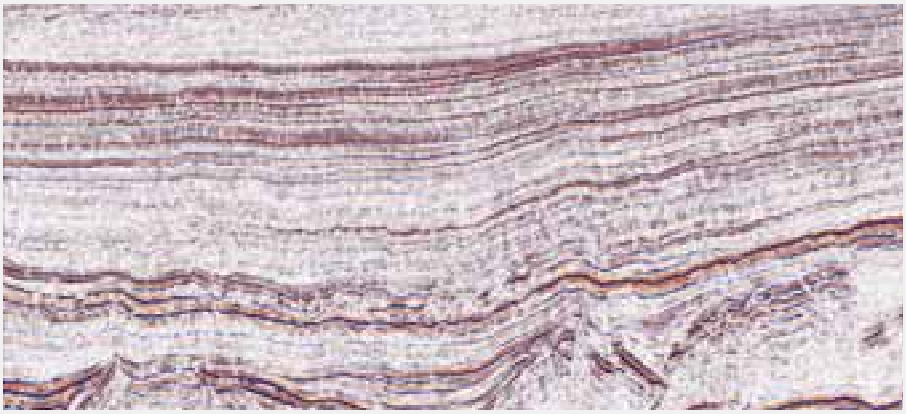
Oil first, gas later

"Geologists have been negligent regarding temperature. Only geochemists have really bothered to understand what happens when the temperature in a basin increases. It is therefore geochemists that have developed the theory that the formation of oil and gas is controlled by temperature," says Per Arne Bjørkum.

With increasing temperature oil is formed first (real speed in the process does not occur before 120-130 ºC) and then gas (with a maximum around 150 °C) from decayed organic material (kerogen) incorporated in shales or carbonates (source rocks). This understanding as to how oil and gas form has also determined how geologists have perceived the distribution of hydrocarbons with increasing depth, oil "uppermost", gas "lowermost". And it was just this argumentation which Per Arne Bjørkum and Paul Nadeau ultimately became involved in, though they did not start with it.

"When working on my main subject in geology I studied the diagenesis of sandstones and the reduction of the porosity of rocks with increasing depth. Later, when working in Statoil and cooperating with Paul Nadeau we began to think about the consequences of our combined knowledge. Paul was an expert on shales and I knew something about sandstones, which I had acquired together with Olav Walderhaug, now technical adviser in Statoil. Slowly a pattern emerged which we were not looking for at the outset."

"This is a classic approach for research scientists. We attack one problem, solve it and thereby gain insight into another area, which we had not thought about to begin with. This is often the way new interdisciplinary insight emerges," explains philosopher Per Arne Bjørkum.



"The Golden Zone"

The theory is based on two main patterns that can be observed in sedimentary basins worldwide: the pore pressure in the water phase, and the spatial distribution of hydrocarbons in sedimentary basins. Experience has shown that there is a connection between the two patterns, i.e. they are related because they have a common cause.

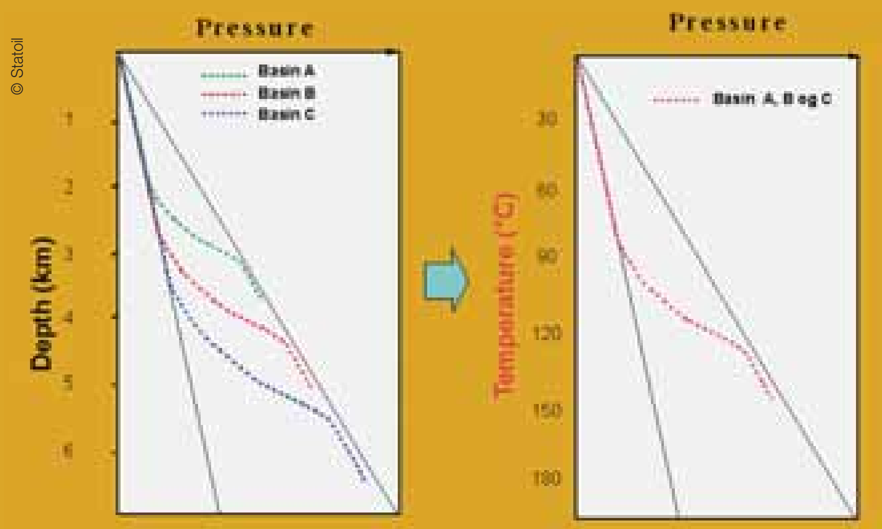
In nearly all sedimentary basins the pore pressure exceeds the hydrostatic pressure (pressure of the water column) beneath a certain depth. The depth at which overpressure first appears varies from basin to basin and it is impossible to say in advance where this pressure increase above the "normal" will be found. By comparing pore pressure with temperature – instead of depth – a distinct pattern becomes apparent. Increase in pressure above hydrostatic starts typically at 80-90 ºC and increases rapidly until the temperature reaches 120 ºC.

"We have replaced basin specific pore pressure profiles with a universal profile, and with the help of this it is possible to say something about the increase in pressure in a basin before drilling starts," explains Per Arne Bjørkum in Statoil.

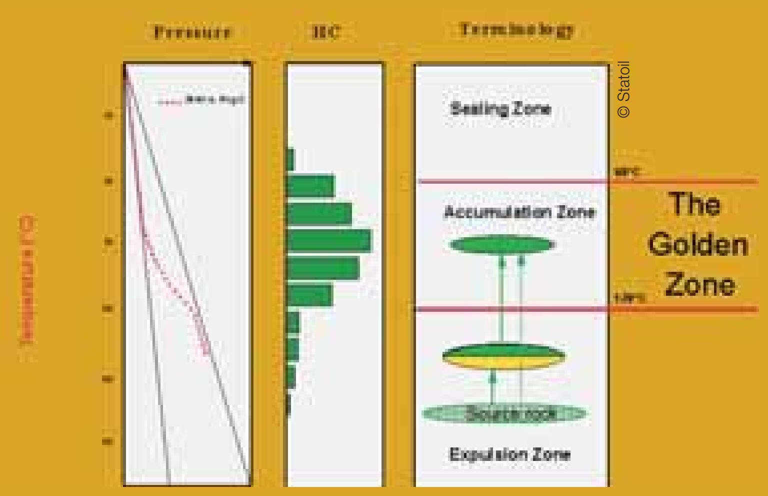
Likewise, the distribution of oil and gas resources can be plotted against temperature instead of depth. In this way a universal pattern emerges, that is to say we find the pattern in all sedimentary basins independent of the way they formed, their history of development, and age. We obtain a distribution that shows an accumulation of oil and gas between 60 and 120 ºC ("accumulation zone") commonly referred to as "The Golden Zone". Surprisingly, gas also occurs in precisely the same temperature interval as oil, despite the fact that it forms much deeper and at different temperatures compared to oil.

"The volume of hydrocarbons in reservoirs falls exponentially with temperature when it rises above 110-120 ºC, and the total volume of oil and gas that geologists can find at temperatures above 120 ºC is only about ten percent of the total amount in a given basin. This we have proved by data from the whole world," says Bjørkum.

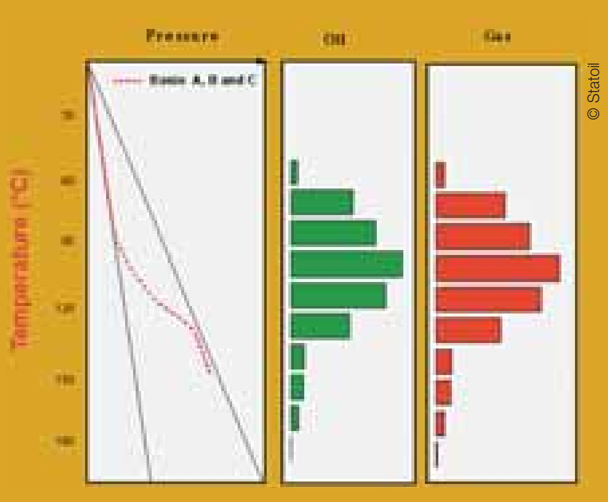
"Most of the hydrocarbons form in source rocks where temperatures exceed 120 ºC. Since oil and gas do not collect in reservoirs at such high temperatures, we conclude that oil and gas are driven outwards and upwards to lower temperatures than those prevailing in the source and reservoir rocks. The zone where tempera-



Normally, the pore pressure is plotted against depth. Each basin will then have its own curve. By plotting the increase in pore pressure against temperature the profiles combine to a universal curve that is common to all sedimentary basins. The increase in pore pressure (the pressure ramp) starts at around 80-90 °C and reaches hydrofracture pressure at around 120 °C.



The zonation of a sedimentary basins based on temperature boundaries. The expulsion zone applies to both source and reservoir rocks.



By plotting the volume of hydrocarbons against temperature a pattern emerges which is similar to sedimentary basins all over the world. There are upper and lower limits at 60 and 120 °C, respectively, with an approximate norm around 90 °C. Note the exponential reduction in volume of both oil and gas at around 120 °C where the pore pressure is around hydrofracturing pressure.

ture exceeds 120 ºC we call the "expulsion zone", which is characterized by a pore pressure that lies around the pressure needed to fracture the host rock. Hydrocarbons will then stream upward through hydraulically formed cracks, that is to say from the expulsion zone and into the "The Golden Zone"."

"When the temperature is lower than 60 ºC, there are few hydrocarbons left. We call this the "Sealing Zone" which is also the zone where microorganisms devour most of the hydrocarbons which have migrated into it."

The pattern established here is independent of the type of basin, its age, rate of subsidence, temperature gradient, the total amount of oil and gas and the size of individual fields. Therefore only temperature can say something about the distribution of hydrocarbons at depth. "Isn't it fantastic to see how well organized Nature is?" asks Per Arne Bjørkum.

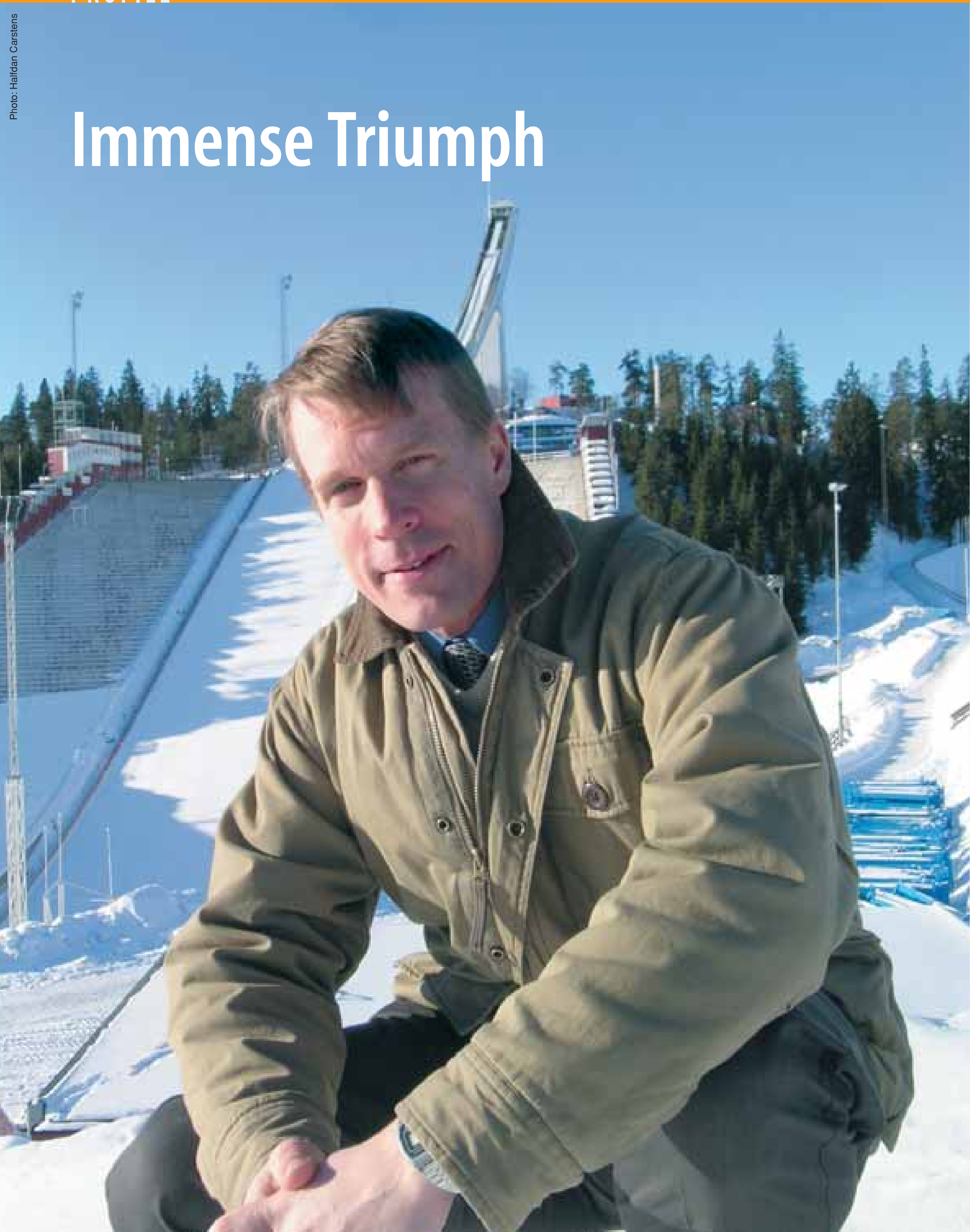
"The reason why the pattern exists and is so robust and stable is because the basic processes that operate in the expulsion zone are controlled by one parameter only – the temperature. Water, oil and gas, are driven out by thermally controlled processes and we can regard the expulsion zone as a thermally powered chemical pump in which the fluids are forced upwards into the overlying accumulation zone at the same time as the pore volume progressively disappears due to `cementation´ in the expulsion zone," explains Per Arne Bjørkum.

"The temperature is also responsible for much more than has so far been realized. The more mechanical understanding of a basin controlled by stress factors is replaced by one in which dynamical forces are related to fluid flow and the subsidence of a basin due to thermally controlled chemical processes. Therefore, it is logical for the universally accepted pattern to become apparent only if one relates these factors to the parameter that controls the processes, namely, the temperature."

"We have managed to create a new and logical order in the spatial distribution of hydrocarbons in sedimentary basins. We have done this by identifying - and describing - a few controlling processes related to reduction in porosity in sandstones and permeability in shales thus providing a basis for the stable dynamic patterns now documented. We believe that in this way we have simplified understanding as to how oil and gas behave – and thereby also simplified the exploration process for hydrocarbons," says Per Arne Bjørkum.

Photo: Halfdan Carstens

Immense Triumph



Together with some former colleagues, Jan Grimnes built a software company that distributed products throughout the petroleum industry. Hugely successful sales along with its thoroughly developed technology made the company Technoguide a great catch for Schlumberger.

Halfdan Carstens

Jan Grimnes built Technoguide into one of the most successful software companies in the petroleum industry. Today, the company is known as Petrel, a member of the Schlumberger group.

With the goal of providing the petroleum industry software that models geological data – from exploration to tail end production – the four founders in a short time had constructed a company that sold products to asset teams around the world.

Before long, Schlumberger took notice of Technoguide. Not only had this company created a product that suited Schlumberger's customers, Technoguide's software would fit perfectly into their strategy. Schlumberger wanted to offer a complete software package, a package that could be used by geologists, geophysicists, reservoir engineers and drilling engineers for interpreting and visualizing statistical and dynamic data in what is known as a *continuous workflow*. With that, the company was acquired and the founders were left with thick wallets.

A Deliberate Choice

The story of Technoguide is something like a fairytale, a tale where the company gets eaten up by a big wolf. In reality, the story started more than 20 years ago – in 1984.

It was then that Jan graduated from *The Norwegian Technological Institute* after studying petroleum technology and specializing in reservoir engineering for four and a half years. After completing compulsory military service, he accepted a position with the Norwegian oil company, Norsk Hydro, where he spent five instruc tive years. While still working for Norsk Hydro, Grimnes completed a master's degree in economy at *The Norwegian School of Economics and Business Administration*, in Bergen. Based in Oslo, it would have been easier for him to attend *The Norwegian School of Management*, but he preferred the school in Bergen because it had a more theoretical approach to his field of study. Hence, this was all very well thought-out.

Jan Grimnes has always been a competitor. For a long time he had dreamt about participating in the world famous Holmenkollen Ski Festival on cross county skis. After an autumn of rigorous training and little studying, illness put him out of action just as the season was about to begin. So instead, he decided to compete in the business world.

"I had a job that was partially offshore and my wife was incredibly busy with her studies," is his explanation for how it was possible to do two demanding activities at the same time.

In 1990, a new offer brought Jan to the other Norwegian independent oil company, Saga Petroleum. Here, he was working with a variety of tasks including well testing, reservoir technology, quality management and project management. Many people may be pleased to hear that Jan looks back on his engagements with Norsk Hydro and Saga with satisfaction: "I enjoyed having excellent managers."

"I began my studies with the ambition of one day running a little company, but I was determined to start by learning how the larger companies operate. So, I spent the first years combining professional activities with other activities that gave me skills I thought would be useful later."

"I have always made deliberate choices, and friends have accused me for being dull as I planned my life and career in detail," Jan smiles. "At the same time, I am certainly willing to admit I have been lucky," he adds modestly.

In 1993, his career took an abrupt new turn. "Geomatic, a software company, offered me a position to commercialize the results from a research project. As chance would have it, I was soon made manager. Geomatic was subsequently sold, and shortly after I left the company due to differences in opinion with its leaders about the future direction of the company," Jan explains.

It was time to establish his own business, and Technoguide was conceived. Several of his colleagues from Geomatic were eager to start something new and joined with Grimnes to found the company. The business plan was to make advanced modelling available to all users, by developing a tool that ran on Windows to make it compatible with a PC. "Our vision was to alter the industry standard from Unix to Windows," declares Grimnes.

Risking the future

Starting out early in 1997 with ten employees they offered consulting services to the petroleum industry. The earnings of company were re-invested to develop new technology.

"Our vision was to build a new system for geological modelling. This would give an integrated flow in the interpretation of relevant data from early stages in exploration, throughout the life of the field and to the end of production. In addition, it was important to make the software user-friendly, gambling that the computer game industry would develop graphic cards powerful enough for our requirements."

The four innovators received little financial and moral support as they started developing the new PC-based software. "The industry claimed the existing software fulfilled their needs. However, to us, it was simple: The current products had obvious weaknesses and shortcomings that we felt we could avoid. Furthermore, we decided to utilise cheap PC's."

"We had no investors: we financed the project with earnings from our consulting business. However, in the early phase we received invaluable aid from the investment firm *Innovation Norway*, support we have repaid countless times in taxes and work places," says Jan.

"Strict budgeting, tough liquidation management, and only using the reserves saved up from consulting, spared us from taking up loans. Making the software as cheap as possible, without this being noticed, became a mission. It was important for us to squeeze as much as possible out of our investment. We followed the old economic principle of living within our means."

Driven by competitors

The young entrepreneurs were all driven by a strong desire to succeed. "We were a highly competitive group, many of us are former athletes. This is one reason for our success. Also, we did not follow textbook examples."

Competition in this market is extremely tough so hiding from the customers is not an alternative. Knowing that successful companies invested heavily in marketing, Technoguide also conducted an aggressive marketing campaign; in fact, they invested more money in marketing than software development.

"The strategy was to meet with potential customers to inform them about our project and actively participate at exhibitions long before we had a product to demonstrate. This strategy resulted in great curiosity from the industry, and firms contributed with data and participated in the testing of the software."

In December 1998, Technoguide launched the beta-version of the software Petrel. From this moment the focus was on meeting with customers and selling as much as possible. Sales offices were established around the world, and in 1999 included the strategic locations of Houston and London. It was important to open sales offices near the largest markets.

"The accounting books have always shown positive numbers, but it was not until 1999 that we were able to discontinue the consulting business. From then onwards, the profits took steep upward climb, 2000 was good and 2001 was better. We had our final breakthrough in 2002: it was a fantastic year."

As the software infiltrated the market, focus remained on profitability. The philosophy was to spend minimal resources on support. This could only be achieved by ensuring that an increase in the customer base would not automatically result in an increase in the resources spent on the support teams.

Outstanding customer service

After Schlumberger acquired Technoguide, Grimnes received countless questions as to why they chose to not develop the company further on their own.

"There were two reasons for selling. First of all, it was interesting to gain access to a global sales organization with the possibility of conquering markets unavailable to us as a small organization. Secondly, it provided us with an opportunity to cultivate the software in collaboration with Schlumberger who lately have allocated a lot of resources toward this field," he explains.

"The Living Model" was introduced as a concept when Schlumberger acquired Technoguide. "Petrel is the key application, the heart of the product. The other applications complete this application. Our goal of offering a complete solution, furnishing continuous workflow, would have been tough to accomplish on our own. We possessed neither time nor aptitude."

The founders of Technoguide achieved what they had set out to do. This was the conclusion after a year of follow up and evaluations. Jan Grimnes explains: "Sales are up. Undeniably, our own sales force did the job, but they were backed by a professional sales organization. We have attained customers we otherwise would have never even dreamed about capturing. It is also interesting to see that we have had influence on this organization. Technologically, we have obtained acceptance for our products and they are incorporated into the Schlumberger organization. In addition, technology to improve Petrel is now available to us."

Grimnes continues: "The focal point for the development of the software *"The Living Model"* is now moved from the United States to Norway. This trend was confirmed when Schlumberger acquired Voxel Vision last year. Oslo is now the geological centre for technology."

About a year after Schlumberger purchased Technoguide, all concerns that this small Norwegian firm would be completely swallowed up were laid to rest. Both the product and the staff of fifty in the offices at Røa in Oslo are healthy. Now, they are getting ready to expand: twenty new programmers from around the world are about to move in to ensure further development of the software.

Grimnes is thus content with the sale of Technoguide. It fulfilled his expectations. Fortunately, his customers are also satisfied: "None of our customers claim we do a worse job now. The level of service we established has been maintained."

The Public Sector must contribute

Schlumberger has invested time and money into Petrel, and today it accompanies one of the three software packages Schlumberger offers its customers. The other two are GeoFrame and ECLIPSE. Petrel is an unbridled success. Grimnes is very satisfied with the attention Petrel receives in Schlumberger.

Further development of Technoguide would have been impossible, according to Jan Grimnes. "The milieu in Norway is too small and we cannot sell. Selling is looked upon as a shady profession in Norway. In the United States, many sales people proudly proclaim their occupation. This is sad for Norway, because we have many excellent entrepreneurs."

Asides from the crucial support from Innovation Norway, Grimnes is not impressed with the municipal support they received. Technoguide succeeded in spite of, rather than because of, support from the Norwegian authorities. The reason may be that Norway provides no infrastructure for IT firms striving to succeed on the international market, and the banks are of little help due to lack of experience in finance management. Additionally, advertising agencies with expertise in brand awareness are almost non-existent in Norway. "As a business leader, you are lonely. A forum where you can meet and discuss common challenges is missing."

Paving the road

Jan Grimnes is an entrepreneur. He has achieved tremendous success. It is rare that a Norwegian develops software that attains status of an industry standard. For geologists, geophysicists, petrophysicists and engineers globally, however, Petrel is a part of every day life when large amounts of data are to be interpreted and evaluated in the chase for more oil and gas.

Hiking through the Palaeozoic

Photo: Halfdan Carstens

For a geoscientist, hiking the Grand Canyon is a trip through two billion years of the past, making on average an impressive 60,000 years back in time for every step. This geologic showpiece, the greatest gorge on Earth, has been carved out by the Colorado River in a mere five million years.

Cartography: Masaoki Adachi

Carved by the Colorado River, the Grand Canyon slices deep into the geologic province known as the Colorado Plateau, a vast upland of colourful and rugged topography that is home to some of the most spectacular scenery in the world. The plateau is characterized by thick sequences of flat-lying sedimentary rocks sitting more than 1 km above sea level. The width of the canyon ranges from less than 1.5 km to more than 25 km, and in places it is more than 1500 m deep. Along both rims, the topography is level. In contrast, relief within the canyon is characterized by steep slopes and massive cliffs.

The Grand Canyon runs 440 km through northern Arizona and is easily accessible by car from Flagstaff, Phoenix and Las Vegas. There are two main points of entry, the Grand Canyon Village on the South Rim and the North Rim. Only the South Rim is open all year round. From these excellent vantage points one can either stroll along the rim and have a gorgeous view over the Canyon vistas, or, if one is in good physical condition, start early in the morning to hike all the way down to the base of the canyon and up again before the sun sets and makes the canyon dark and cold. Hiking all the way down is strongly recommended to all geoscientists wanting to experience the canyon's beauty and at the same time catch a glimpse of the sedimentary and metamorphic rocks of the Grand Canyon. Planning ahead, an overnight stay at the bottom ranch or at the campground is possible.

The view from the rim is nothing less than outstanding, for geoscientists and everyday tourists alike. Here, from the South Rim, close to the Grand Canyon Village, we look towards the Bright Angel Trail that descends all the way down to the greenish Tonto Platform and the Colorado River (not visible in this photo). In the middle of the picture, we see the uppermost section of the inner gorge with Precambrian igneous and metamorphic rocks below Palaeozoic flat-lying, sedimentary rocks. The North Kaibab Trail follows the north-south running canyon towards the North Rim. Note the extent of red colours caused by iron oxides in the Hermit Shale and Supai Group that also stain the underlying Redwall Limestone (for nomenclature, compare the stratigraphic column on the next page).

Halfdan Carstens

The Grand Canyon presents and unrivalled view into the Earth's history. From the Permian limestone on the rim to the Precambrian schists at the bottom of the inner gorge, millions of years are represented by exposed rocks and unconformities (an unconformity is a gap in the geologic record caused by erosion or nondeposition).

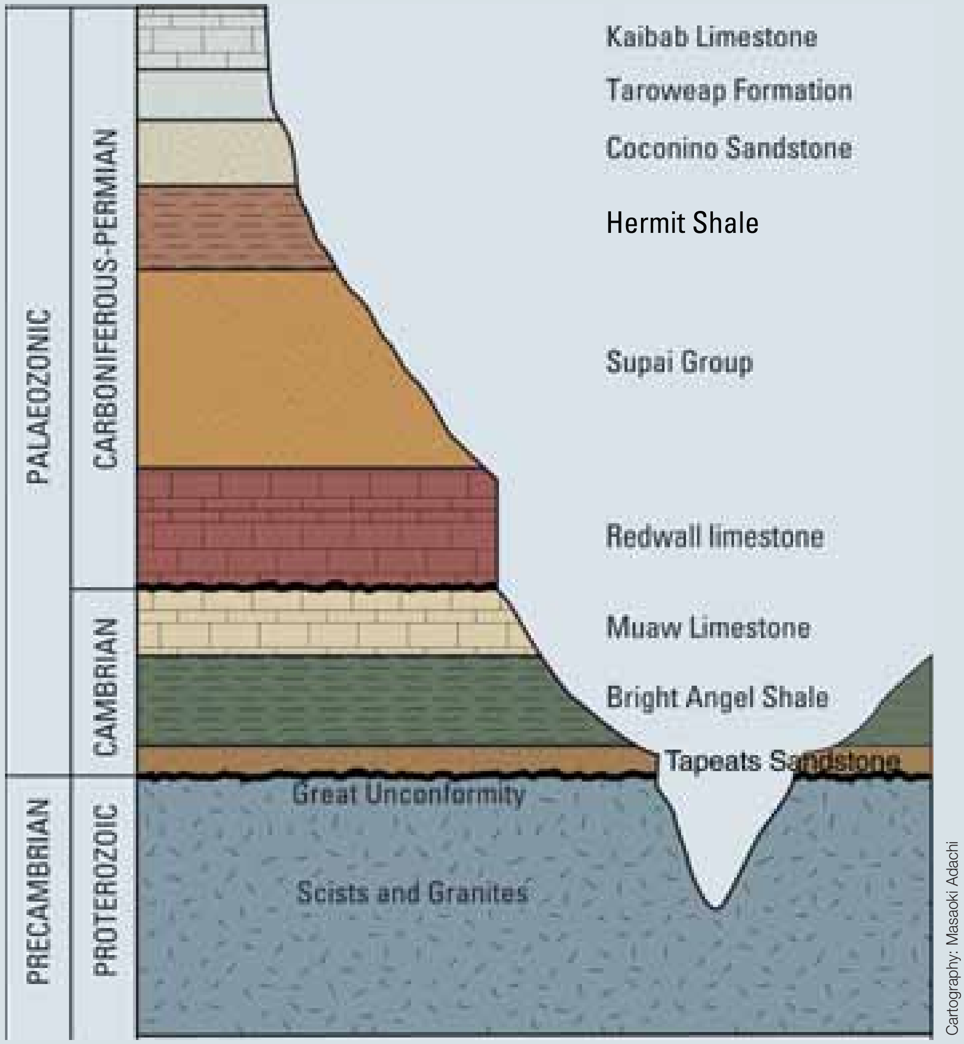
Listed as one of the Seven Wonders of the World, the Grand Canyon became a United States National Park in 1919 and was named a World Heritage Site by UNESCO in 1979. The latter meant that the canyon's superb natural and cultural features are considered to have universal value for all humans. The same can probably be said of the Grand Canyon by geoscientists with regard to naming geological sites that contribute universally to the understanding of geologic processes.

A "pilgrimage" for geoscientists

In 1540, the Grand Canyon was first seen by Europeans when the Spaniards ventured north from Mexico in search of the fabled riches of the Seven Cities of Cibola. Nevertheless, by the middle of the nineteenth century, only some 150 years ago, the Grand Canyon had only been visited by a handful of non-Native Americans. Until this time, the canyon was best known to the various Native American Indian groups who had inhabited the region for thousands of years.

In 1869, John Wesley Powell, in charge of the U.S. Geographical and Geological Survey of the Rocky Mountain Region, set out with a team of nine geologists and scouts to explore the previously unmapped Grand Canyon. They started out in Green River of the Wind River Mountains, Wyoming, and emerged three months later at the north end of what has later been turned into the manmade Lake Powell. Powell is said to be responsible for popularising the name Grand Canyon. He is also believed to be the first man to complete such a trip.

The first geological descriptions were, however, made 11 years earlier when one of the pioneers of North American geology drew the first geologic column as he reached the western segment of the canyon on an expedition along the Colorado River from California. He recognized and named many of the individual rock layers, and he also understood the importance of erosion



Sequence of rock formations exposed in the Grand Canyon, along the Bright Angel Trail from the South Rim.

in the creation of the landscape.

By the turn of the century, a fundamental understanding of the origin and significance of the Grand Canyon had been reached. At the same time, tourism had already begun and caught on very quickly. By 1901 it was possible to travel directly to the South Rim by train.

Today's tourists will arrive by car, and the Grand Canyon has become a tourist trap for visitors to the American West. But the Grand Canyon is also the world- famous gorge that all geoscientists should endeavour to visit.

A scenery coloured by rocks

An overriding impression of the geological formations of the Grand Canyon is that of almost vertical, dark, chaotic, crystalline rocks in the deep bottom, with flat-lying sedimentary rocks above. The sedimentary rocks reach all the way up to the South and North Rim along a steep, colourful slope mixed with steep cliffs.

The crystalline schists and granites are all Precambrian in age. Sedimentary and volcanic rocks accumulated approximately two billion years ago and were later uplifted and subsequently metamorphosed and deformed into the Vishnu Schist during a mountain-building tectonic phase. This schist forms the walls of the inner gorge far below Grand Canyon Village and is easily differentiated from the younger, overlying sedimentary rocks.

About 1.5 billion years ago, the mountains eroded to a nearly level plain and 300 million years later a long period of sedimentation began that led to the formation of the Precambrian Grand Canyon Supergroup. These rocks were later block-faulted and subsequently eroded to a hilly topography. Remnants of the Grand Canyon Supergroup are not easily spotted by geotourists hurrying down and up in one day.

The rocks that are most visible from the rim began to form 600 million years ago when the area once again subsided. This is also the beginning of a 600 million-year timespan of sedimentation in the sea, on floodplains, in rivers and in deserts, interspersed with several intervals of nondeposition and numerous episodes of erosion. The rocks tell a story of constantly changing sedimentary environments brought forward by changes in climate and sea level and tectonic events that affected subsidence and uplift.

In the Grand Canyon, the youngest rocks preserved are those from the Palaeozoic era, which lasted some 300 million years. Mesozoic strata, now found farther east on the Colorado Plateau, once covered this sedimentary basin but they have been eroded away during uplift of the plateau in the Cenozoic.

This sequence of Palaeozoic rock formations (compare adjoining page) is responsible for the magnificent scenery in the Grand Canyon for two reasons:

First, the canyon walls consist of hard rocks like sandstone and limestone shaping steep cliffs (note for example the almost vertical edge of the Kaibab Limestone lying at our feet on the South Rim), and soft rocks like claystone and siltstone that form slopes. These effects are elegantly illustrated just above the crystalline rocks (which in themselves are hard rocks that compose the steep walls of the inner gorge) where the soft Bright Angel Shale rests upon the hard Tapeats Sandstone; the juxtaposition of these two rock types formed the basis for the broad and characteristic Tonto Platform which is so easily seen from the rim.

Second, the sedimentary rocks display a multitude of colours in white, grey, yellow, green, red, brown and black, giving the canyon en ever changing appearance as the sun crosses the sky from the early morning to the late evening, with torrential rain, rainbows and lightning emphasising the colours. The impressive Redwall Limestone in the middle of the canyon, which stands out as a 150 m cliff because of its hardness, is grey by origin. However, the surface of the cliff is stained red by iron oxide washed down from the Supai Formation above. Iron compounds also account for the deep red colour of the overlying Hermit Shale deposited as mud and clay by freshwater streams.

Five million years old

The Colorado River runs more than 2200 km from where it begins on the Continental Divide in the Rocky Mountain National Park, northwest of Denver, to its mouth in Mexico, in the Gulf of California. From its headwaters to its mouth, its descent is nearly 4 km, averaging almost 2 m/km.

Uplift of the Colorado Plateau in the Tertiary set the stage for the Colorado River to cut downward. The river is thus the primary agent of erosion responsible for the canyon, but there are also other forces of erosion continually shaping its spectacular visage. Erosion is the all-encompassing term for the processes that constantly sculpt and wear down the landscape, and erosion involves the transport of all kinds of weathered debris.

The geologic history of the Colorado River is long and complicated. Interestingly, the full excavation of the Grand Canyon began only about five million years ago, long after the sedimentary rocks, through which the river now cuts, were formed. A final stage of major erosion took place during the last ice age. Glacial meltwaters sent raging torrents down the Colorado, carving more deeply into the canyon. The canyon may have deepened as much as 300 m during the last million years. However, the exact time at which the canyon was formed, and its true history, still remain unclear because crucial rock evidence has

"Do not attempt to hike from the canyon rim to the river and back again in one day. Each year hikers suffers serious illness or death from exhaustion," the sign says. If used to fieldwork, one will have no difficulty in hiking down and back up in one full day. The same applies if one is otherwise physically fit. When making the trip, be certain to have the time and courage to venture down; it will be the experience of lifetime for the curious geoscientist.

Intervals of time not represented in the sedimentary record are known as unconformities. The Great Unconformity of the Grand Canyon, named by John Wesley Powell, separating Precambrian metamorphic and igneous rocks of the inner gorge from overlying horizontal Palaeozoic sedimentary rocks, becomes visible as we approach the bottom. The latter part of the descent to the Colorado River is thus through a time gap spanning more than one billion years. Note the green colour of the river, which is caused by the lack of clay, silt and sand being transported downstream. The large dam creating Lake Powell, now a popular resort area, upstream from Grand Canyon, traps sediments carried by the river all the way from Wyoming and causes the lack of sediments in this part of the Colorado River. At times, however, it regains a measure of its former muddy appearance when small tributary streams flood.

U.S. National Parks are generous in relating geological information to the public. In the visitor centre one can study the stratigraphy of the Grand Canyon prior to hiking through the colourful rocks of the Palaeozoic and further into the Precambrian of the inner gorge. The sedimentary rocks of the Grand Canyon belong entirely to the Palaeozoic as the Mesozoic has been eroded in Cenozoic time. The Grand Canyon Supergroup below the Great Unconformity is shown as tilted beds within the Precambrian schists.

been eroded.

By the time the Spaniards arrived some 500 years ago, the canyon had assumed its present form. But the Grand Canyon remains a very active geological setting with minor changes happening on an everyday basis as cracks open by frost weathering, rock falls from cliffs and debris is washed into the river. These small changes do not alter the canyon in a notable way in Man's concept of time, but the landscape is slowly changing, and the cumulative effect through Geologic Time will eventually make the Grand Canyon disappear.

Hard layers of rock in the canyon walls – granites, schists, limestones and sandstones – form cliffs, while softer rocks – shales and siltstones – form slopes. Cliffs retreat by the falling of large blocks as softer rocks at the base are worn away and undermine the cliffs. The large plateau in the centre of the picture – the Tonto Platform – owes its origin to the soft Bright Angel Shale that rests upon the hard Tapeats Sandstone, both of Cambrian age.

Endless time

Geologic time is a relatively new concept. In 1654, Irish archbishop James Ussher studied the Old Testament and arrived at the conclusion that the Earth came into being on October 23, 4004 B.C. The idea that the world is only 6000 years old prevailed well into the 19th century, and even today, in spite of overwhelming evidence to the contrary, there are religious groups claiming this to be the truth.

It was not until 1785 that this persistent dogma was questioned. James Hutton, the Scottish doctor turned natural philosopher and geologist, argued that the Earth must be much older based on his world-famous, detailed geological studies in England and Scotland. His reasoning was that long time periods must be involved to account for the physical processes that shape the Earth and the process of diversification of species by natural selection, pioneered by Charles Darwin. Hutton completely ignored the Bible and its Deluge, and proposed the often cited 'no vestige of a beginning, no prospect of an end' to describe geologic time.

Ussher was wrong and Hutton was right. Today we know the Earth is 4.6 billion years old. Most of the story since the beginning is recorded by the rock record, and almost half of that time – approximately 2 billion years – has been recorded in geological formations in the Grand Canyon.

Through elaborate studies in the 19th and the 20th centuries, involving many scientific disciplines and a long series of researchers, geoscientists have been able to generate a Geologic Time Scale – the geologic column – that in absolute terms assigns numerical ages to individual rock formations (compare Geologic Time Scale, page 50).

STATOIL 2003 research prize

Photo: Åge Hojem

Bjørn Ursin was awarded Statoil's 2003 research prize that comprises an artwork and a cheque for NOK 200,000 (ca. USD 30,000).

Bjørn Ursin was in June awarded the prestigious Statoil's 2003 research prize for 30 years of research and development work in the field of petroleum geophysics. Ursin is professor in applied geophysics at the Department of Petroleum Engineering and Applied Geophysics at the Norwegian University of Science and Technology (NTNU) in Trondheim, Norway.

The research prize is awarded annually to an external scientist in Norway whose work has been significant for the group. It recognises research results of a high international calibre, and is intended to serve as an inspiration to and support for further efforts. This year's research prize is the 13th to be presented, and was given to a scientist who works in a discipline that plays a key role in exploration and reservoir management activities of the petroleum industry.

- Bjørn Ursin has made one of the most important contributions to geophysical science by a single individual, and his work has helped Statoil to improve recovery on the Norwegian continental shelf, said Statoil research vice president Ingve R. Theodorsen.

With more than 160 published scientific papers to his credit, Professor Ursin has tutored 23 doctoral students. Previous honours include the Norwegian geophysical prize (1985) and the EAGE's Conrad Schlumberger Award (1993).

Ursin has always cooperated closely with the industry, and he has worked with several companies, including Geco, SINTEF, Merlin and SERES, before he came a full time professor in 1989.