VOL. 9, NO. 2 – 2012

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

Frontier Exploration: High Expectations in Morocco

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EXPLORATION
Unconventional No Longer?

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HISTORY OF OIL
The Many Lives of Belridge

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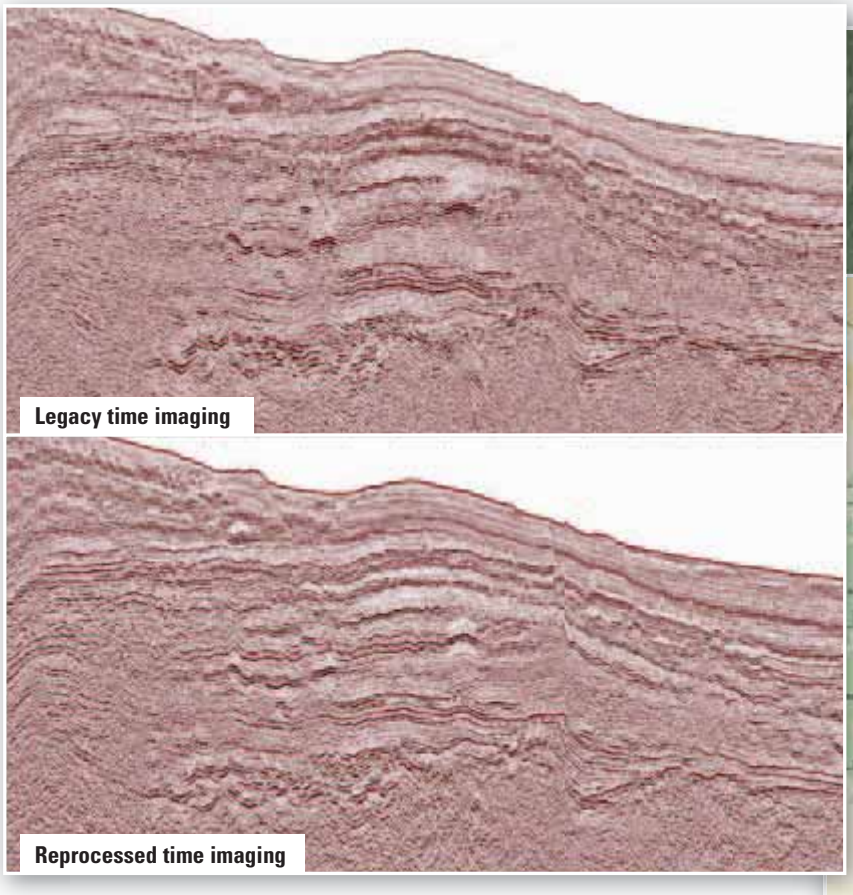

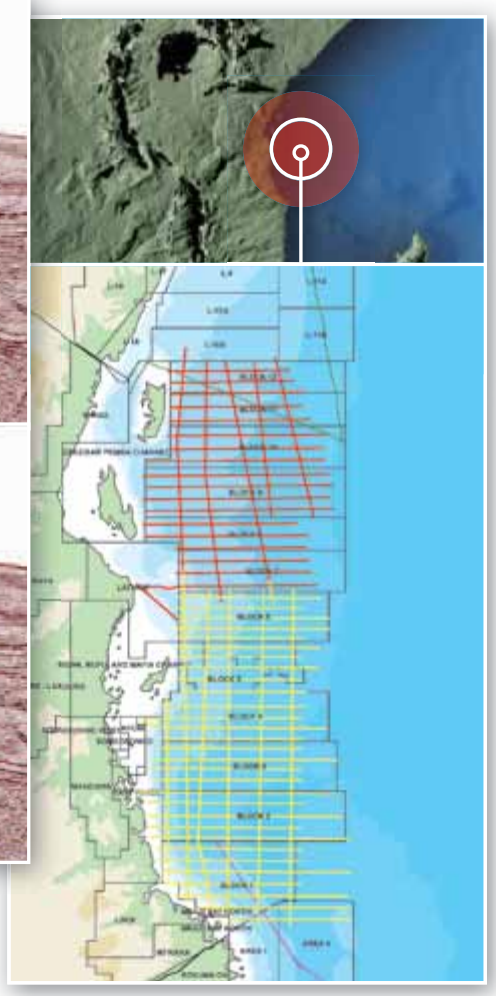

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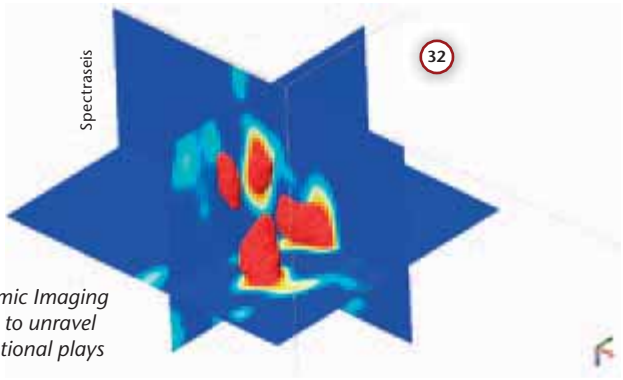

Microseismic Imaging is helping to unravel unconventional plays

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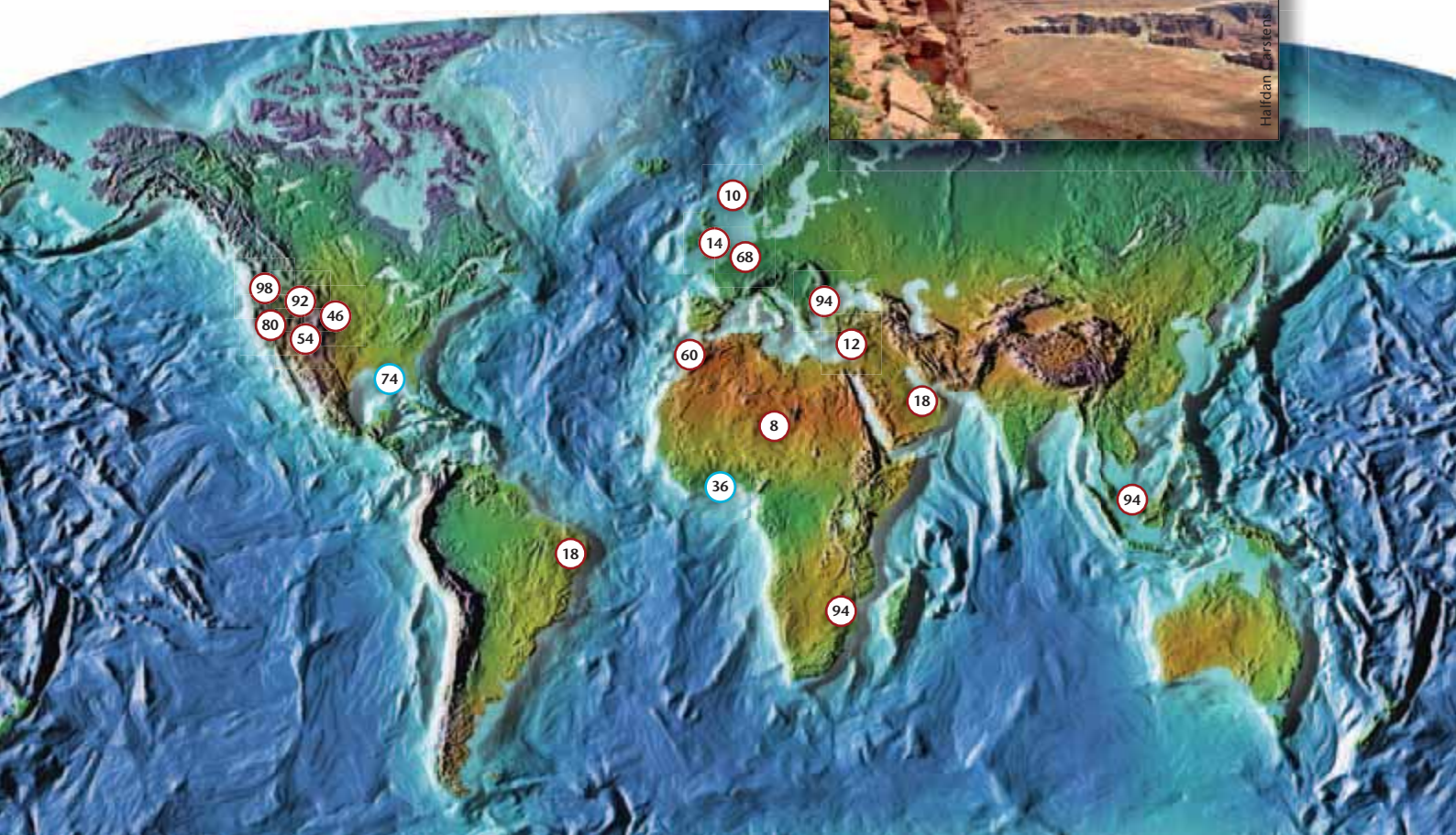

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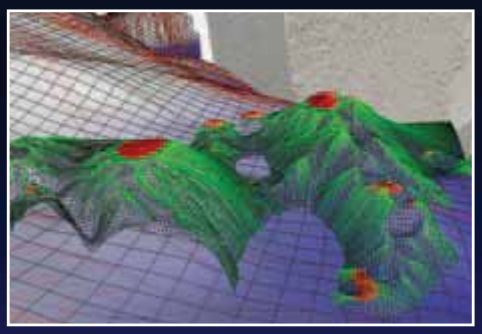

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Unconventional Thinking

Giant trucks at the Athabasca oil sands in Alberta, Canada

"Targeting unconventional resources requires unconventional thinking." So stated the Exploration Vice President of Saudi Aramco, Abdulla Naim, at the recent GEO 2012 conference. And this edition of GEO ExPro Magazine is focused on just that, starting with the unconventional notion that maybe we should no longer be using the term 'unconventional'. Just about every newspaper reader, even with no interest in the energy industry or in knowing what is powering their homes, has heard of shale gas – often through reading articles discussing the pros and cons of fraccing. Shale gas is the reason why the United States is now the world's largest gas producer – surely it no longer needs the unconventional tag. Oil sands; heavy oil; coalbed methane; oil shale; all rapidly moving from 'blue sky thinking' to tried and attainable resources.

Even gas hydrate, usually considered to be situated on the far end of the 'unconventional' spectrum, is now getting serious consideration in Japan. Drilling off the coast of central Japan, where there is an estimated 40 Tcf of methane hydrates in the Nankai Trough, was due to commence in February, and the energy-hungry country is hoping to start trial methane hydrate production early next year.

The successful exploitation of these reserves would not have been possible without the huge strides taken by companies and research organisations in developing cost-effective ways of discovering, imaging and safely extracting the resources. We take a look at some of these developments in this edition, from using microseismics for advanced fracture imaging, to methods of testing at the well head to reduce the number of fraccing cycles.

Communication between the service companies which often develop these ideas and the oil and gas companies which apply them is crucial. And communication means people. These technical applications will determine the future – and the future in turn will be determined by investing in the right young men and women now. People who will be able to innovate and learn, collaborate across disciplines and apply these new technologies, as well as tried and tested ones, to allow us to make the most of the Earth's bounty in a safe and sustainable manner. We should regard all the many reserves of energy available to us as resources, without hindering our thinking by describing them with phrases like 'unconventional'.

JANE WHALEY
Editor in Chief

UNCONVENTIONAL NO LONGER?

Aurelian Oil and Gas drilled Trzek-3 last year at Siekierki, an unconventional tight gas field in the Central Lowlands of Poland. The well encountered a 140m gas column and the field is thought to contain several Tcf gas in place. In 2010, Aurelian drilled Trzek-2, which was the first multi-frac well in Poland, a technology which has been used extensively for similar unconventional plays elsewhere in North West Europe and in North America.

Inset: The Kasbah at Imlil, near the base of Mount Toubkal, in the High Atlas Mountains, Morocco. In comparison to its North African neighbors, Morocco is relatively unexplored, but companies are now starting to look at the long Atlantic coast, comparing it to its conjugate margin in Nova Scotia.

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Goodbye to the Gas Guzzler!

THINA MARGARETHE SALTVELT, PH.D

The price of petrol at the pump in the US is – in fact, in some places has already exceeded – the psychologically important $4/gallon (EIA). Petrol prices have risen by around 14% this year, and this is clearly a headache for President Obama in an election year, as he strives to ensure that the US economy continues to expand.

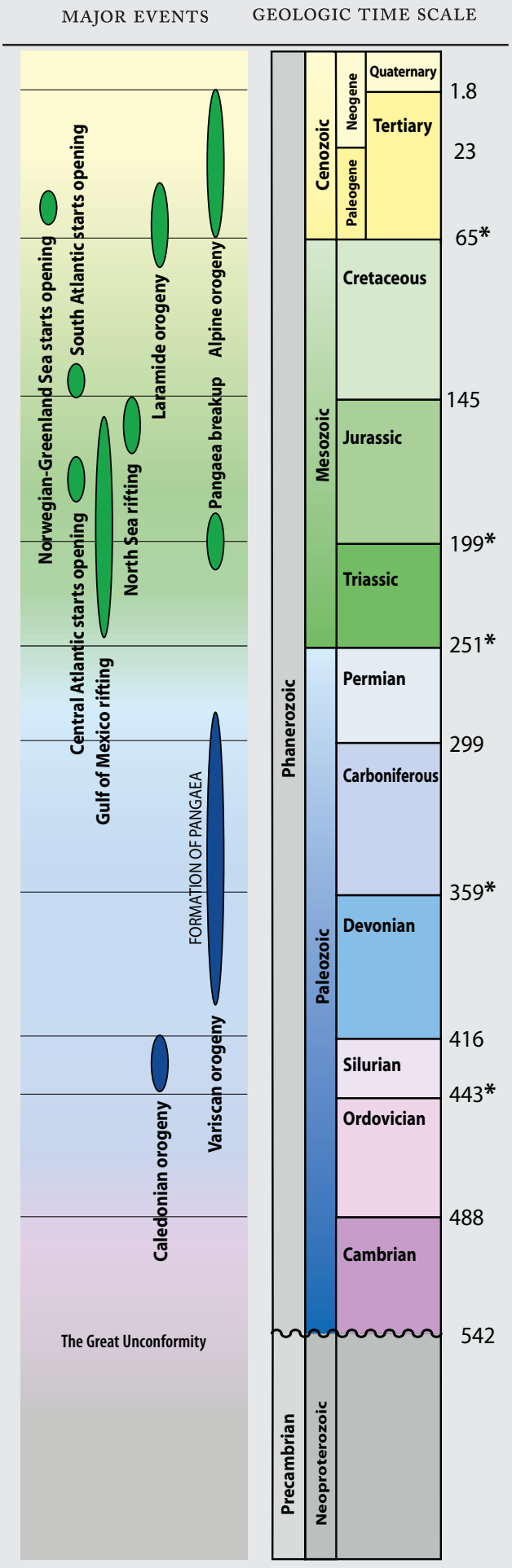
The impact has been most pronounced in the UK and the EU because of the weakening of the euro and sterling against the US dollar. Record oil prices in these currencies are aggravating the distress for many firms and households, already suffering as a result of the region's debt crisis and faltering growth.

Euro oil prices reached an all-time high last Friday at €93.26/barrel, just surpassing the previous record of €93.06/barrel in 2008, when Brent oil prices denominated in US dollars reached $146.08/barrel. Oil prices measured in dollars are still around 16% lower than the peak of 2008.

Although petrol prices have surged with the recent peak in crude prices, the rise started from a significantly higher base than during the previous highs in July 2008 and April/May 2001. When petrol prices peaked in 2008 at $4.165/gallon, petrol prices had increased by 46% from the 2007 average petrol price of $2.84/gallon. This year, by contrast, US pump prices have increased by 6% to average $3.78/gallon compared to the base (average 2011) a $3.58/gallon. For European consumers the story is very similar. European petrol prices (measured in euros) this year have increased by 12% from the base, compared to 59% in 2011 and 69% in 2008.

Rising crude prices have less impact on the total cost of fuel paid by retail customers and businesses in the EU than in the US because Europe's energy taxes are higher. Taxes accounted for 60-66% of the retail cost of a litre of fuel in the UK, France, Italy, Germany and the Scandinavian countries compared to 16% in the US in 2010 (OPEC). If we exclude the effect of exchange rate changes, rising crude prices thus have a much bigger proportional impact in the US than in the EU. But once the currency effect is taken into consideration, it is the European car owners who have been left facing record prices of petrol.

We do not expect the situation will improve very much for European car owners in the near future. The euro will continue to weaken against the US dollar and oil prices will remain high, at an average of $118/barrel in Q2, with a risk of much higher prices if the tension between Iran and the West escalates. In addition, we expect the petrol balances to tighten going forward as refinery closures in the Atlantic Basin will outweigh net additions. ■



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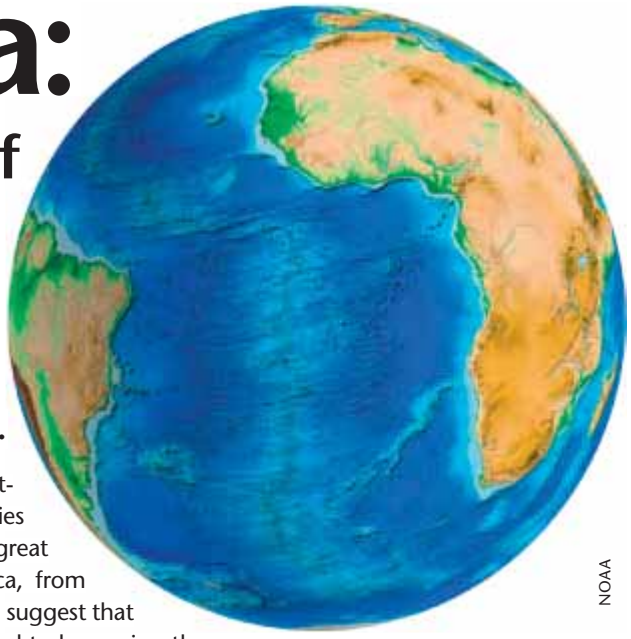
Africa:

Continent of Discoveries

Africa conference will examine exciting new plays and developments.



NOAA

Africa continues to deliver exciting new oil and gas discoveries in emerging plays. There is great excitement offshore East Africa, from the giant gas discoveries which suggest that Mozambique is well on the road to becoming the next new producing centre, to the string of encouraging wells along trend in Tanzania, with more drilling in the immediate future in Tanzania and Kenya's Transform Margin. Onshore East Africa, rift plays are being followed up by the industry after a number of successes in Uganda, continuing up into the South Sudan rift, which is shaking off its unsettled past to look at a promising future, with plays possibly extending to Eritrea, Ethiopia and Somalia – is Somalia's time yet on the horizon?

On the other side of Africa, along the entire west coast, analogs and conjugate margins are the hot topics, from Namibia possibly mirroring the discovered plays of the Brazilian Santos Basin, to Morocco looking right across the world to its conjugate Atlantic margin off Canada. Discoveries made below the salt in the Kwanza and Benguela Basins of Angola are thought to be analogs to the presalt Santos fields - but are they also giants? And will the trend continue to other parts of the Aptian Salt Basin in Congo and Gabon? Meanwhile, West Africa's Equatorial Margin continues to deliver discoveries from Ghana and Cote d'Ivorie west to Liberia, Sierra Leone and possibly Guinea.

Are there things to learn from South America that can be applied to Africa, and can the conjugate margin analogs work both ways? The players have already pushed the analogs to the conjugate margins of South America, with lots of new leasing and drilling in Guyane, Suriname and Guyana. And when will Brazil's Equatorial margin open up?

There are also continuing discoveries in the Nile delta area and some major new finds in the Eastern Mediterranean, but many wonder whether the recent political upheavals in North Africa and the Middle East will put a damper on Africa's historically most prolific oil and gas producing areas.

All these and many other issues are on the agenda for the annual Africa Conference, which this year will be held in Houston on September 11 – 12. This is the 11th in the series of yearly conferences on the continent, which are organized jointly by the Houston Geological Society (HGS) and the Petroleum Exploration Society of Great Britain (PESGB) and held alternately in London and Houston. The conference series covers all aspects of African E&P, with particular emphasis on new ideas for plays and prospects, the geology of the continent and its conjugate margins, and the application of emerging technologies. Because although it is the quality of the technical program which draws the participants each year, new and emerging technological refinements by service organizations make a significant contribution to the search for h ydrocarbons in Africa, and many of these will also be represented at the conference.

The most recent Africa conference, held in London, attracted nearly 500 delegates, speakers and exhibitors, the highest number ever to have attended the event. Further details can be found on the websites of the two organizing societies.

AL DANFORTH

ABBREVIATIONS

Numbers
(US and scientific community)

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

Liquids
barrel = bbl = 159 litre

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

Gas

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

Ma: Million years ago

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

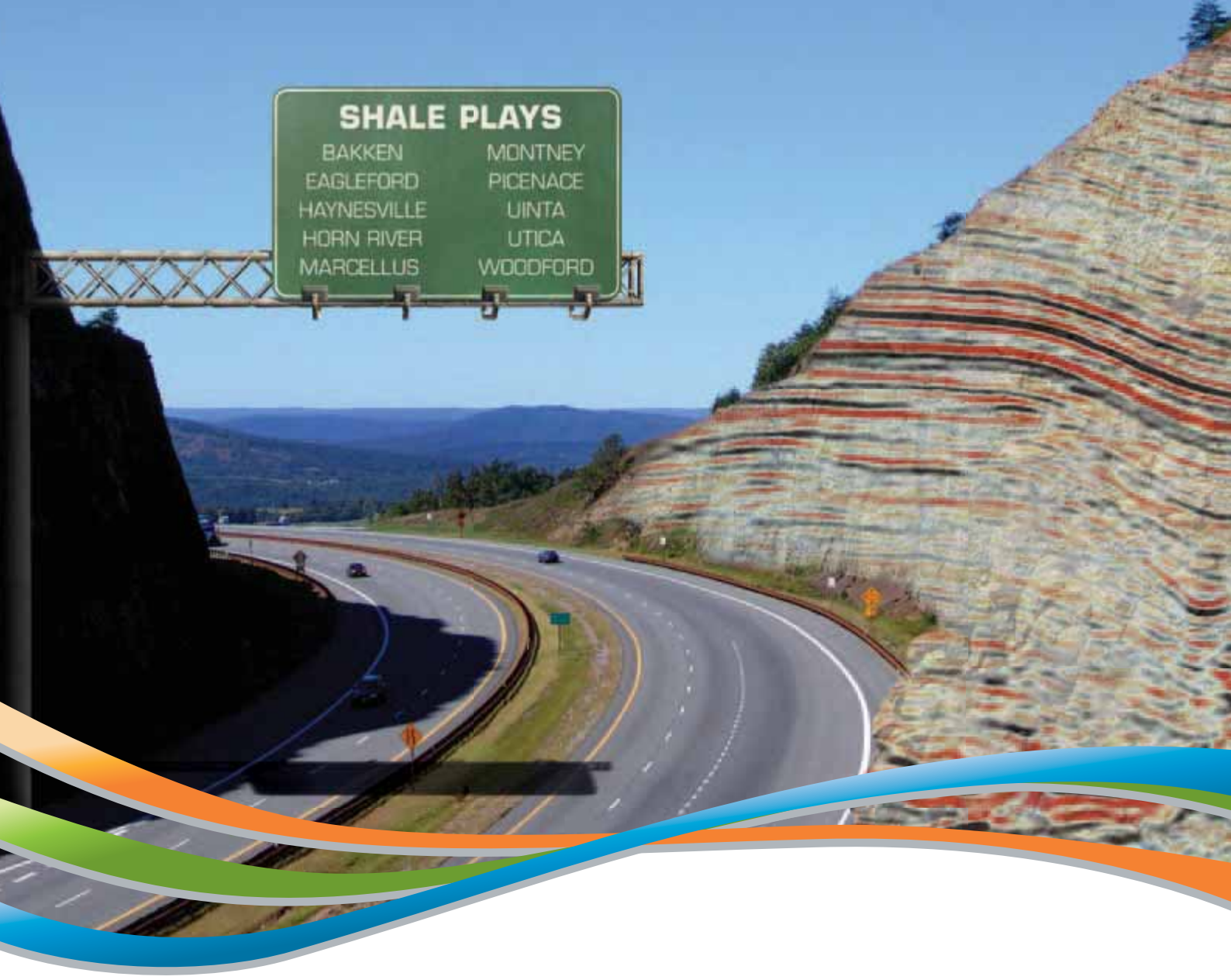
NGL
Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

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

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

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

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



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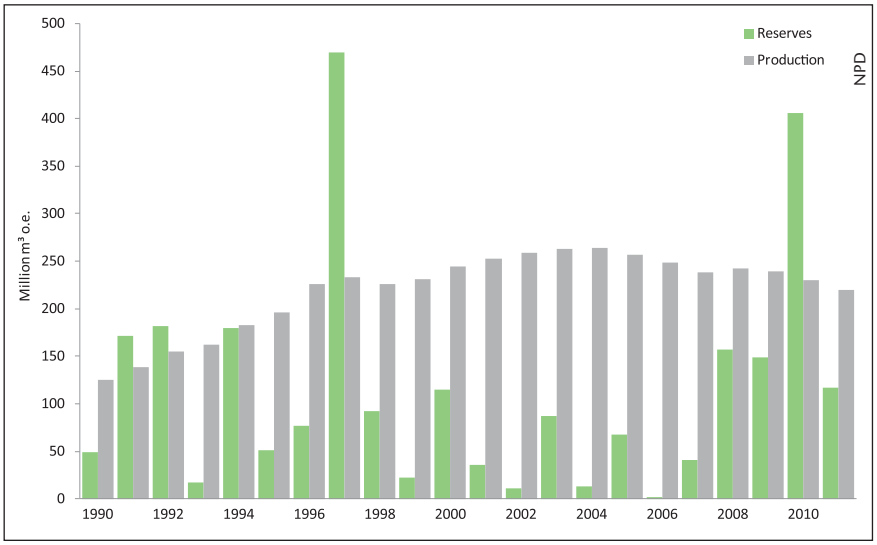
Three World-Class Discoveries

For the first time in 15 years, a giant discovery was made offshore Norway last year.

Three world-class discoveries made 2011 an exceptional year for the oil industry in Norway. And for the first time since 1997, when the gas field Ormen Lange was found, a giant discovery was made. Also, for the first time since 1997, Norway found more oil and gas than was produced.

That is why the Norwegian Petroleum Directorate called it 'the year of surprises'.

The foremost discovery last year – ranked as no. 1 in the world – is Avaldsnes/Aldous Major South, which may contain in excess of 3 billion barrels of recoverable oil, and it is among the five largest oil discoveries on the Norwegian shelf of all time. However, before the high estimate is confirmed, several appraisal wells have to be drilled.



The graph illustrates the annual growth in resources and production on the Norwegian Continental Shelf since 1990. The reason that 2010 stands out is that Johan Sverdrup was actually discovered by Lundin in 2010, although its true significance was only realized in 2011.

The accumulation has now got a new name: **Johan Sverdrup** field, honouring Johan Sverdrup who was the leader of the political movement which promoted the introduction of the parliamentary system in Norway in the 19th century, and who remains an important symbol of the growth of a democratic Norway.

As the graph shows, however, reserves are booked on 2010. Let us therefore recap what happened.

During fall 2010 Lundin announced a new discovery that was named Avaldsnes (16/2-6). The company was certainly proud of what they had achieved and published the story in the magazine GEO. The Norwegian Petroleum Directorate, known for its conservative estimates, said the discovery could hold between 100 and 400 MMb of recoverable oil.

Lundin presumably knew better, but kept their cards tight.

Several months went by, and it was late summer before Statoil announced that their *wildcat*, as it was then called, had found oil on another structural high (Aldous Major South; 16/2-8), but the well also proved that the Lundin and Statoil wells had drilled into the same accumulation, with a saddle between the two highs. Only a month later, Lundin had completed an appraisal well and presented the results on a press conference. The field had grown, again, and the best case estimate was 3.3 Bboe.

Barents Sea Discoveries Too

Johan Sverdrup lies on the Utsira High in the North Sea. The two other significant discoveries that were made last year were both in the Barents Sea.

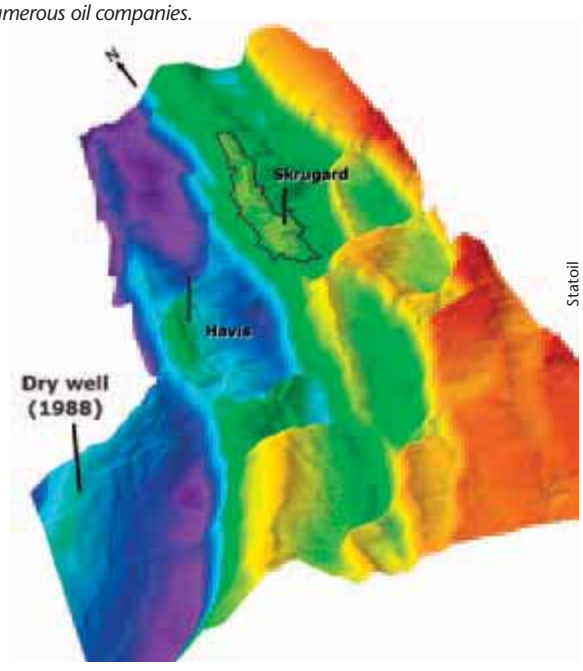
The oil discovery **Skrugard** may hold up to 300 MMb of recoverable oil equivalents, predominantly in Jurassic sandstones (*GEO ExPro* Vol. 8, No. 2). It was said to be the third largest discovery in the world last year.

The gas discovery **Norvarg** was made in Triassic sandstones. Gas is found in several strata and the reserve estimate is thus very uncertain. According to NPD, Norvarg has between 350 Bcf and 1.77 Tcf of gas. In oil equivalents, the high estimate equals the high estimate of Skrugard. This, together with the recently proven oil discovery **Havis**, of the same magnitude as Skrugard, has resulted in new optimism and interest in the largely unexplored Barents Sea.

Altogether 22 new oil and gas discoveries were made in 2011. 16 of these were made in the North Sea, 3 in the Norwegian Sea and 3 in the Barents Sea.

In total, 54 exploration wells were terminated in 2011. This is an increase from 2010, when 41 exploration wells were terminated. ■

3D view from south-west of top reservoir depth map showing the general setting of the Skrugard and Havis discoveries. Experts claim that this small geological province may hold up to two Bb of recoverable oil, which is partly why the 22nd Round, to be announced in early summer, has attracted interest from numerous oil companies.



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Second Cyprus Licensing Round Opens

Recent nearby giant discoveries will increase interest

The recent giant gas discovery in the area of offshore Cyprus (*GEO ExPro*, Vol. 9, No. 1) has made this a very attractive exploration area. As a result, interest in the second licensing round of the offshore area of the Republic of Cyprus is expected to be high. The round opened on February 11 this year and will close on May 11.

Cyprus is located in an exploration hotspot with borders to giant hydrocarbon producers Egypt and Israel. Huge natural gas discoveries have been found in the world class Levantine Basin, in particular **Tamar** (9 Tcf) and **Leviathan** (20 Tcf), both in Israeli waters. The **Aphrodite** well was spudded by Noble Energy in Cyprus, Block 12, in September 2011 and in December 2011 the results from the 5,860m deep well were presented: High quality multiple Miocene sand intervals, 94m net pay and a revised 'best estimate' natural gas volume of 5 Tcf.

It was understood that Cyprus wanted to commence their second bid round after the announcement of the first exploration well, and the government submitted the necessary documentation to Brussels for official translation and announcement by the European Commission. The round will be open for three months during which expressions of interest will be submitted by potential energy companies. The Council of Ministers will grant the licenses and the applications will be block specific. Model production sharing contracts (PSC) will be awarded from the Republic of Cyprus for the selected applicants.

The exploration area of 51,000 km^2 is part of the exclusive economic zone (EEZ) of Cyprus, and is divided into 13 exploration blocks. The exploration blocks are, on average, approximately 4,000 km^2 and span an area from the Herodotus Basin in the west to the Levantine Basin in the east. Block 1, and the northern parts of Blocks 2 and 3 are closest to the island and cover the Cyprus Arc and its deformation front. Blocks 4, 5, 6 and 10 are situated in the Herodotus Basin. Blocks 7 and 8 and the western part of Block 11 cover the Eratosthenes Continental Block and the west Eratosthenes Basin and finally the southern parts of Blocks 2, 3 and 11, together with Blocks 9, 12 and 13, cover the Levantine Basin.

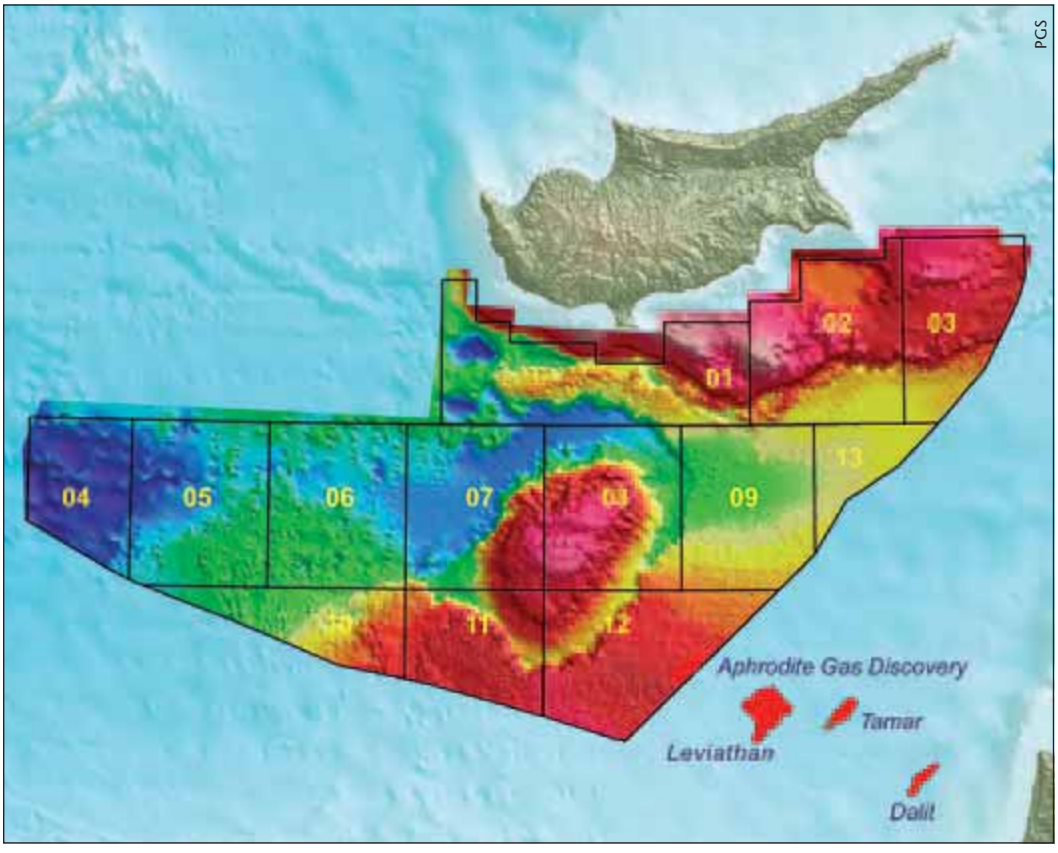
Noble Energy was awarded Block 12 in 2008 after the first licensing round, as part of a three year exploration license with defined exploration commitments. At the end of the time period, 25% of the block was relinquished, and the released acreage will not be available for the second licensing round.

Petroleum Geo-Services (PGS) is the official data provider and has provided Cyprus with a dense multiclient (MC) seismic data grid: The survey MC2D-CYP2006 was acquired for the first license round with a 10 km by 20 km coverage. MC2D-CYP2008 then infilled the previous survey to provide a seismic data coverage of 5 km by 5 km on average. This survey, undertaken in 2008 and 2009, utilized the GeoStreamer technology to obtain the best possible data quality and, following reprocessing in 2011, the original conventional data grid also has high data quality. Block 3 has the greatest multiclient seismic data coverage with 3D data coverage in part of the block. Geological interpretation reports based on the PGS datasets and including hydrocarbon assessments are available through the Cypriot Ministry of Commerce, Industry and Tourism.

More detailed information can be found on www.mcit.gov.cy.

ØYSTEIN LIE, Petroleum Geo-Services

A map of the exploration area offshore Cyprus, overlain by the structural map of the seabed. The Aphrodite gas discovery is marked in Block 12, close to the giant Leviathan and Tamar discoveries in Israeli waters.



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Vibrant International Petroleum Week

Celebrating historical roots back to 1913

More than 2,000 oil and gas professionals from around the world gathered in London late February for the International Petroleum (IP) Week to listen to senior energy industry figures and share knowledge and experience through the many networking opportunities on offer. The Energy Institute organizes this three-day annual conference with a focus on topics such as demand growth and the latest developments in technology to improve security of supply.

Although not an event traditionally attended by the typical GEO ExPro reader, upstream projects will obviously have downstream impact in the future and represent an important part of the supply equation. Several presenters represented the Exploration and Production community, including Patrice de Vives, Senior Vice President for Northern Europe with Total, who gave an optimistic view of E&P developments in the North Sea in light of recent discoveries in North West Europe.

In the Energy Africa session Angus McCoss, Director Exploration with Tullow Oil, provided an update on their fascinating project history in Ghana and how his company is 'exporting' their successful exploration ideas to other countries in Africa as well as to corresponding basins in South America. Kwabena Donkor, Chief Executive of the Petroleum Commission in Ghana, gave another enthusiastic presentation of his country. In addition to describing the opportunities for E&P companies to secure licenses, he explained how gas (more than oil) is expected to have a better 'multiplier effect' for the local society, as it can be used in power generation and to support Ghana's dominating agricultural industry. Being "at the center of the world" (as the country where the zero longitude and latitude cross!) Mr. Donkor was also advocating Ghana as an excellent basis for doing business in the region in general, with a much more stable regime than that of many of their neighbors.

New Recruits Sought

Over the course of the IP Week, two of the continuing themes of discussion were the acute shortage of talent and the need to educate the general public about the industry's safety records and how the risks attached to projects in frontier areas are mitigated. Louise Kingham, Chief Executive of the Energy Institute, said: "Much more needs to be done to promote science and engineering skills, to encourage young people to consider an energy career and become part of the generation to lead the industry into the future".

To support those new to the industry, the Energy Institute hosted a professional development program for recent graduates during the IP Week. This included sessions on developing networking skills and attending career surgeries to hear from industry executives on how to get ahead.

Even if the number of participants at the IP Week conference is limited to a few hundred, there were 1,300 guests at the traditional IP Week dinner, with oil company executives 'flying in from Houston' just for the dinner. London-based companies also used the opportunity to organize parallel events during the week. In addition, more than 100 registered journalists attended, which means that events can expect good publicity.

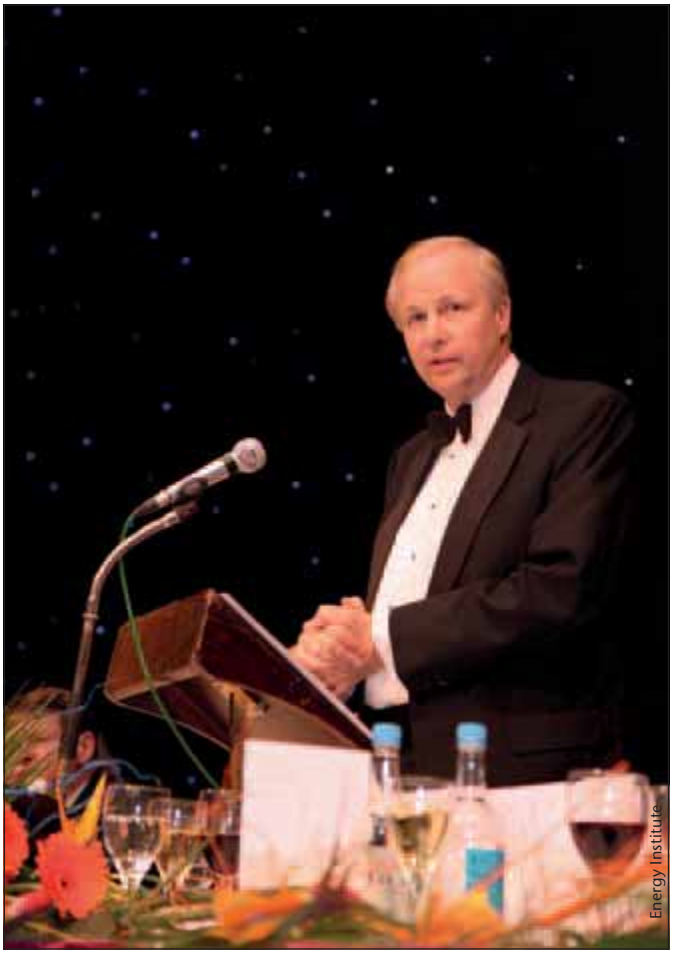
Two traditional highlights are the IP Week lunch and dinner. Charles Hendry, the UK Energy Minister, was guest speaker at the IP Week lunch and used the opportunity to express the need to work closer with the industry to improve predictability around future policy making.

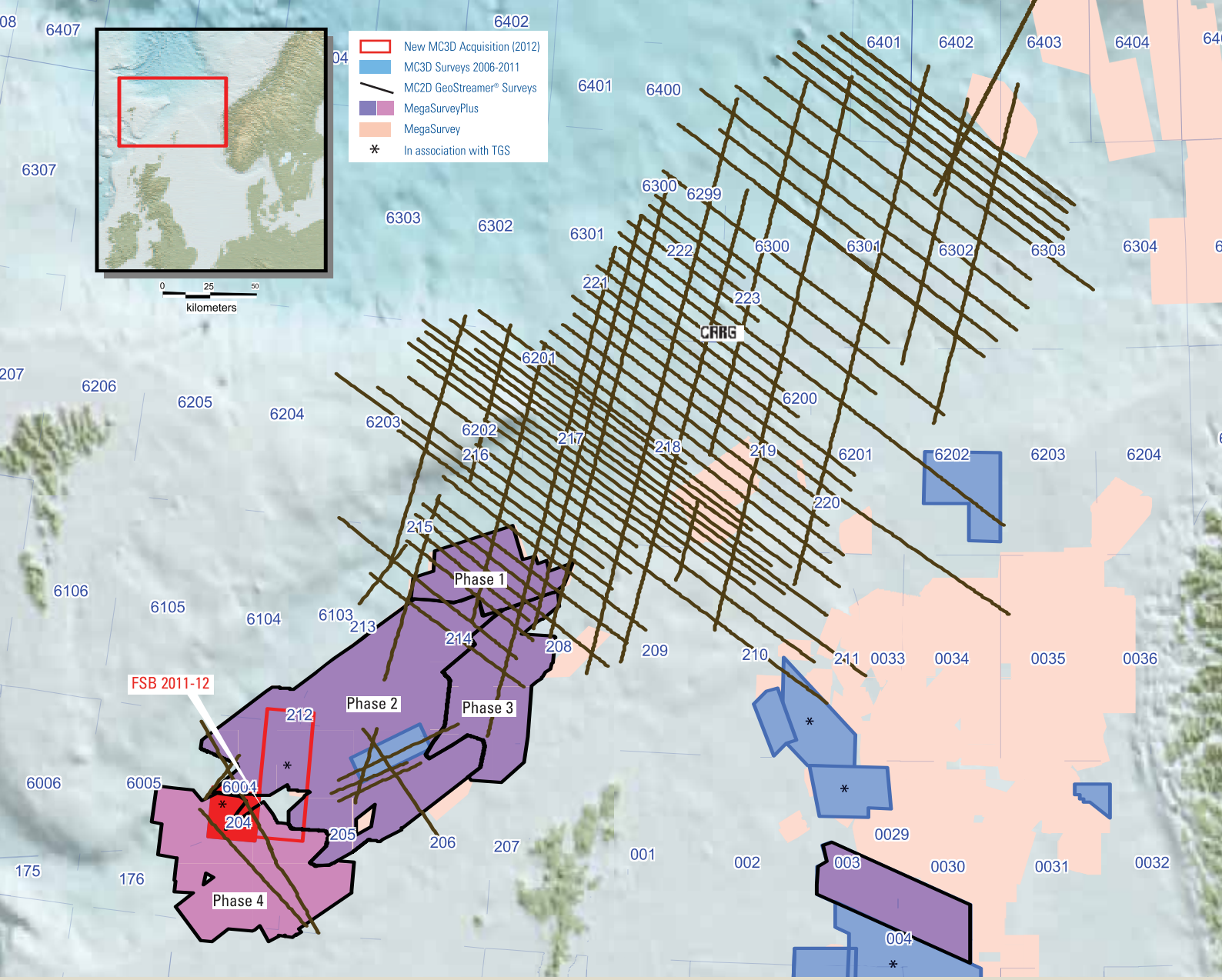
The dinner during the 2012 IP Week was number 98 of its kind! The Institute of Petroleum, which merged into the Energy Institute in 2003, started in 1913 and organized the first dinner. Bob Dudley, Group Chief Executive, BP, who was the guest speaker at this year's dinner, concluded the IP Week by reiterating the role the oil and gas industry has to play in future energy supply and the challenges of meeting increased demand with new technologies and exploration of new frontiers. He recognized that the industry needs to face up to scrutiny and also must engage with society more to gain their understanding.

The 2013 IP Week is held in London February 18 to 20 next year. ■

TORE KARLSSON

BP's chief Executive, Bob Dudley, was the guest speaker at the International Petroleum Week Dinner.





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A Marriage is Announced…

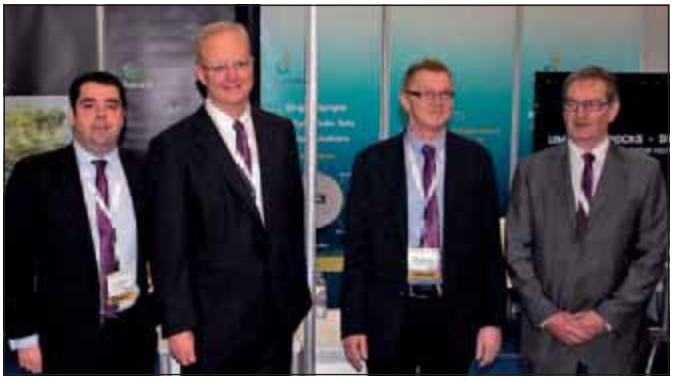
According to the prime movers, Dr Pål-Eric Øren and Dr Mark Knackstedt, it's been a long courtship – ever since they first did business together over twenty years ago – but the talking is over and it is now official. Two of the leading digital core imaging and analysis companies, **Digitalcore** Pty Ltd of Canberra, Australia and **Numerical Rocks** AS of Trondheim, Norway, have announced that they will merge. According to Dr. Victor Pantano, CEO of Digicore, who will become COO of the new company, "the combination of Digitalcore's unique core imaging and processing expertise with Numerical Rocks' multiphase flow modeling capabilities will place the merged company at the forefront of the digital rock analysis revolution."

Digital rock analysis allows oil and gas exploration teams and reservoir characterization experts to look inside core samples recovered from wells, enhancing the understanding of pore scale mechanisms that govern rock properties and hydrocarbon recovery.

Digitalcore was established in May 2009 as a spin-off from research at Australian universities, while Numerical Rocks AS was established in December 2004 as an innovation spin-off from Statoil. When Dr Øren, currently CTO of Numerical Rocks, was working with Statoil, he frequently did business with the research institute which was the forerunner of the Australian company, so it seemed a natural match for the two companies to come together. Dr Odd Hjelmeland will be CEO of the new company, which will continue to operate jointly out of Trondheim and Canberra. The two cities are about as far apart as possible in the globe, but the company anticipates serving a global market, with particular emphasis in the Middle East and North America.

The new name for the offspring of this alliance is a closely guarded secret, yet to be announced. ■

From left to right: Victor Pantano, CEO Digitalcore; Mark Knackstedt, CTO Digitalcore; Pål-Eric Øren, CTO Numerical Rocks; and Odd Hjelmeland, CEO Numerical Rocks after the announcement.



Do More With Less

A new, highly portable, rugged land recording system recently released by **INOVA Geophysical** has been designed to 'do more with less', as it has four analog channels in a single 1.2 kg remote acquisition module. With the **G3i**™ system there is less field equipment to transport, maintain and troubleshoot, optimizing field operations and crew productivity in the world's harshest environments.

G3i supports over 100,000 channels and can be used to capture 2D, high density 3D and time-lapse 4D data, using a powerful, cable-based recording system that offers advanced ground electronics, power down-the-line technology and high productivity vibroseis capabilities. It has a rugged aluminium enclosure and high-strength polycarbonate exterior for maximum durability, ideal for the harsh environments for which it was designed, and power requirements and battery dependence have been reduced to a minimum. ■

G3i™, a highly flexible and compact land recording system

New Joint Office

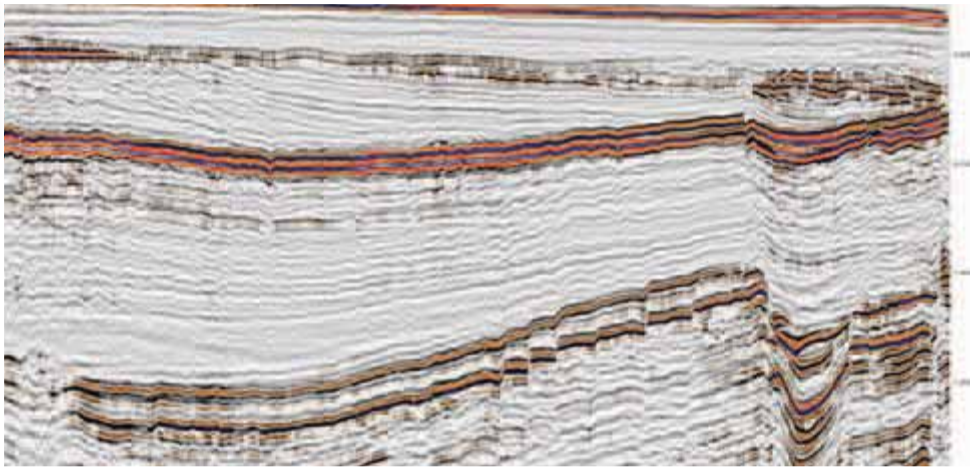
Realising the synergies between their two organizations, the American Association of Petroleum Geologists (**AAPG**) and the Society of Exploration Geophysicists (**SEG**) have decided to pool resources and open a joint office in the Middle East. At a reception in Manama, Bahrain, held during the recent GEO 2012 conference, the two largest geoscience organizations in the world announced that their new office will be located in **Dubai**. It will facilitate service provision to members in the Middle East, India and North Africa and will also offer a point of collaboration for conferences, workshops, lectures, and short-courses to advance the disciplines of geology and geophysics.

"The inauguration of the joint office in Dubai will create synergies to efficiently serve the professional needs of the upstream industry in the region," said Alan Wegener, AAPG Director of Global Development and Operations. "The impact of the efficiencies and energy created in this venture may well be felt globally as we provide new and additional projects, products and services to the professional E&P community." "Both AAPG and SEG see this as a long-term partnership that will benefit the entire industry," added Dr. Terrence Todd, SEG Director, Global Relations and Meetings.

It will be interesting to see whether this initiative is followed by other organizations elsewhere in the world. ■

Barents Sea Seismic Projects

APA 2012 Bid Round 22 - Norway



The Barents Sea 2D High-Resolution Seismic Projects

MAGE Project Partner

- The Barents Sea High Resolution 2D Seismic Projects were specifically designed to utilise a high frequency source signature in order to further enhance the high frequency signal recoverable in the data.
- Recent discoveries in the Barents Sea have proven the need for high spatial resolution to delineate faulting and structural trapping within the first 1-2 seconds of data acquired.
- The data processing is tailored to maintain the high frequency content with the latest demultiple algorithms being employed. A full suite of additional products will be generated during the PSTM processing sequence and will allow further work such as AVO studies.
- The High Resolution 2D Seismic Projects have been designed to follow the main structual elements of the Barents Sea.

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New Unconventionals Research Centre

In February **Baker Hughes**, in collaboration with **Saudi Aramco**, opened the Baker Hughes **Dhahran Research and Technology Center**, which will specialize in research and development of new technologies to unlock the potential of unconventional resources, with a particular emphasis on the Middle East. The new facility is the result of years of planning and cooperation between Baker Hughes and Saudi Aramco as part of their efforts to address the challenges facing the energy production operations around the world. It is situated in the Dhahran Techno-Valley, which was set up in 2006 to provide infrastructure for industrial R&D in Saudi Arabia

The centre will allow engineers and scientists from Baker Hughes to work closely with colleagues in the oil and gas industry in Saudi Arabia and with researchers at the King Fahd University of Petroleum and Minerals in Dharhran. It will also offer research opportunities for students and post-graduates in a range of disciplines, including petrophysics, drilling, geomechanics, fluids and production technology. In particular, there will be a strong emphasis on reservoir optimization and enhanced hydrocarbon recovery in Saudi tight gas accumulations. ■

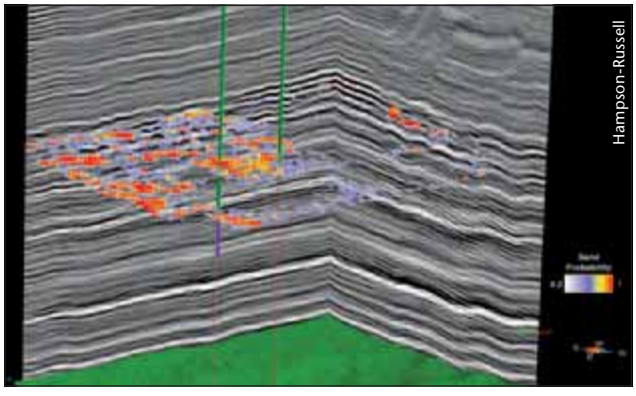
Reservoir Characterization Software

Hampson Russell, part of the **CGGVeritas Group**, provides intuitive software and services for seismic interpretation and reservoir characterization, in order to enhance knowledge of the prospects and reservoirs within an asset, thereby reducing exploration and development risk.

It has recently launched a complete redesign of its suite of reservoir characterization applications, enhancing it with additional functionality and a common intuitive interface and data management system, with customizable workflows, batch processing and the ability to chain processes together. The software, known as **HRS-9**, covers a range of seismic interpretation and reservoir characterization techniques, from AVO analysis and inversion to 4D and multicomponent interpretation.

It also incorporates a newly launched application, designed to predict facies type and fluid content from seismic inversion attributes, while quantifying the uncertainty in the prediction, which allows for much more refined risk analysis. This new product, **LithiSI**, is used to predict lithology or 'classified' well logs from prestack inversion attributes. ■

Example output of the LithoSI process, showing the distribution of sand within a geologic formation, color-coded with the probability of its presence.



IHS Connects Information

IHS, which has a wide range of information and analytical tools for geoscientists in the oil and gas industry, recently unveiled a new online platform that provides faster, smarter and more efficient access to its information. Available free to existing subscribers, the new platform, **IHS Connect**, allows them to access any of their products through a single interface directly to the desktop, or to a tablet or mobile device. With this easy-to-use navigation system, a subscriber can seamlessly weave through various information sources to look at recent E&P activity and review geological risks, recent discoveries and drilling activities in an area of interest while simultaneously assessing the regulatory and fiscal situation. Alternatively, the user may be interested in determining partnership opportunities by investigating operators and M&A activity in a region, all presented in an easy-to-use format.

A powerful keyword-based search engine allows access to oil and gas upstream-focused research from the range of IHS organizatons, including IHS CERA, IHS Energy Editorial, IHS Global Insight and IHS Herold, displaying results according to the users' preferences. ■

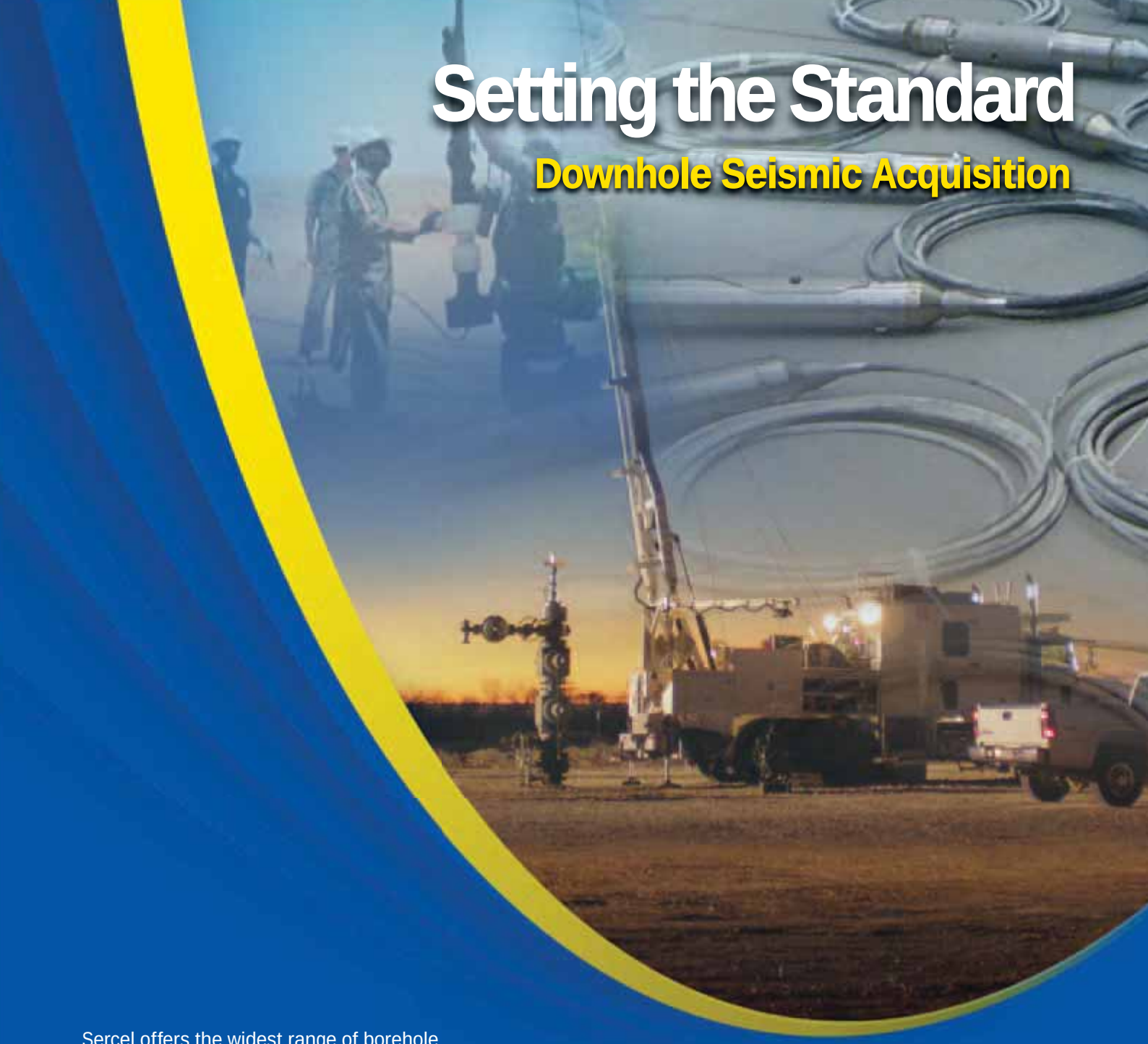
Brazil Record

With discoveries being announced on what seems like a weekly basis, it comes as no surprise to learn that oil and gas production in Brazil in 2011 broke all records for the country. According to the Brazilian National Petroleum Agency, ANP, a total of 768 MMb of oil and 848 Bcf of gas were produced in the year, an increase of 2.5% and 4.9% respectively. This amounted to a total output of 919 MMboe. Average daily output rose from 2.45 MMboe in 2010 to 2.52 MMboe in 2011. Records were also set for monthly production, with an average of 2.21 MMbopd in December 2011, an increase of 1.6% from the previous year, with gas output increasing 3.1% to 2.5 Bcfgpd between December 2010 and the same month in 2011. Production came from 306 concessions operated by 25 different companies.

Over the last ten years oil production in Brazil has grown by 45% and natural gas production by 55%. ■

Setting the Standard

Downhole Seismic Acquisition



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Unconventional No Longer

What exactly are unconventional resources – and is it time we stopped using the term?

The fundamental idea in this article is that oil and gas technology has progressed to the point where we can – or perhaps should – stop using the word unconventional and simply recognize that oil and gas can be found in many places and in various qualities, and that more or less all of them can in principle be developed and produced. The question is then simply "at what cost?"; or more precisely, "what is the margin per barrel or per million cubic feet, and how does it compare with alternative investment opportunities?"

DAVID BAMFORD

Statoil's Grane field has recoverable reserves of 700 MMbo and is the first field on the Norwegian continental shelf to produce heavy crude oil. It was discovered in 1991, and came on stream in September 2003.

Øyvind Hagen / Statoil

Reflecting first on technology: Barclays Capital publishes an annual review of the oil and gas industry, including a summary of its survey of the 'Most Important Technologies', based on the percentage responses received for each of 12 candidate technologies. As in 2009 and 2010, the top three for 2011 were Fracturing/Stimulation, Horizontal Drilling and 3D/4D Seismic, accumulating between them more than 70% of the responses. What is more, the same technologies have dominated this survey for all 12 years for which data has been published, invariably accumulating more than 60% of the responses between them. Over this period, the only other technology to win more than 10% of the responses has been Directional Drilling, garnering 11% four times.

One way to look at these results is to say that responses may be dominated by professionals working in North America and that the favoured technologies will therefore simply reflect what is happening there, in particular the pursuit of shale gas, shale oil, 'tight' gas, and coal bed methane, as domestic sources of conventional hydrocarbons begin to diminish.

But there is another way to look at it. The survey-leading technologies are those that offer the means to identify the presence of hydrocarbons in 'tougher' reservoirs and then extract them. Put another way, wherever there is a prolific source rock, our industry has developed the technical capacity to move away from conventional reservoirs with good porosity/permeability characteristics, and extract petroleum wherever it is reservoired – whether still in the source rock, in 'tight' sands, in fractured basement and so on. The North American industry is leading this charge.

Shale Gas and Shale Oil

Much has been made of the shale gas revolution in the USA, with production from such reservoirs rising from under 1 Bcfpd in 2003, when fracturing/stimulation, horizontal drilling and 3D/4D seismic were first used, to nearly 20 bcfpd by mid-2011.

However, despite this success, much shale gas production is not commercial at current gas prices. Specifically, nearly all shale gas plays require gas prices to be in excess of $4 per million BTU, mostly well in excess, towards $8/mBTU. The benchmark 'Henry Hub' US gas price dropped below $4/mBTU in mid-2011 and is projected to be below $3/mBTU this year.

A second difficulty is that shale gas resources do not respond to the same methodologies for conversion to reserves as conventional fields where it is acceptable to carry out reasonable appraisal to define the static reservoir and estimate OIIP, undertake a moderate amount of testing/flow assurance and then apply an often conservative recovery factor based on analogue fields. In the case of shale gas reservoirs, recoverable gas has to be estimated from the performance of existing producing wells, often over a relatively short production history, resulting in a wide range of possible ultimate production volumes and therefore asset reserves.

One could take the view that the best cash flow from shale gas has, in fact, come to oil field service companies that supply fracturing/stimulation, horizontal drilling and 3D/4D seismic, and to the US 'resource play' companies that have sold or farmed-down their shale gas assets. For more detailed reviews of the issues surrounding shale gas, I refer you to the work of the respected petroleum geologist Arthur Berman[1][2].

It is not surprising, therefore, that having learned how to apply the key technologies, these US 'resource play' companies are switching their attention to shale oil, in most cases in basins which have a long history of conventional oil exploration and are now in decline. The economics of shale oil are generally better than those for shale gas because of the linkage to global oil prices. The same challenge with the estimation of reserves remains.

Other countries and companies have not been slow to board the shale gas 'train'. For example, Repsol YPF has raised its estimate of shale oil and gas resources in Argentina's Vaca Muerta formation to 22.81 Bboe, quoting an external audit that shows that this formation holds gross prospective oil, condensate and gas resources of 21.17 Bboe in an area covering 8,071 km.

Turning briefly to western Europe rather than the US, pursuit of shale gas is encouraged by European gas prices but challenged by the limited availability of Fracturing/Stimulation equipment: where exploitation has been attempted, for example in Poland,

What is Unconventional?

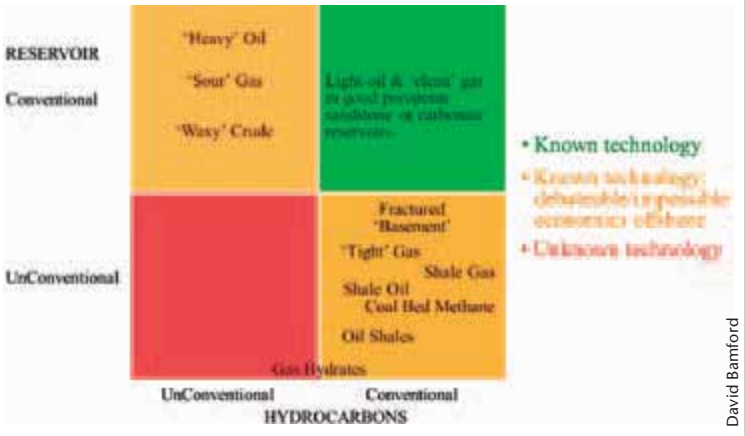
So if 'conventional resources' are defined as light oil or 'clean' gas in good poroperm sandstone or carbonate reservoirs, what do we refer to as 'unconventional resources' at the moment?

We can think about 'unconventional hydrocarbons': examples would include 'heavy' oil, 'sour' gas, 'waxy' crude. Or we can think about 'unconventional reservoirs': examples would include fractured 'basement', 'tight' sandstones, shales, coal beds, hydrates – in fact anything other than good poroperm sandstones or carbonates.

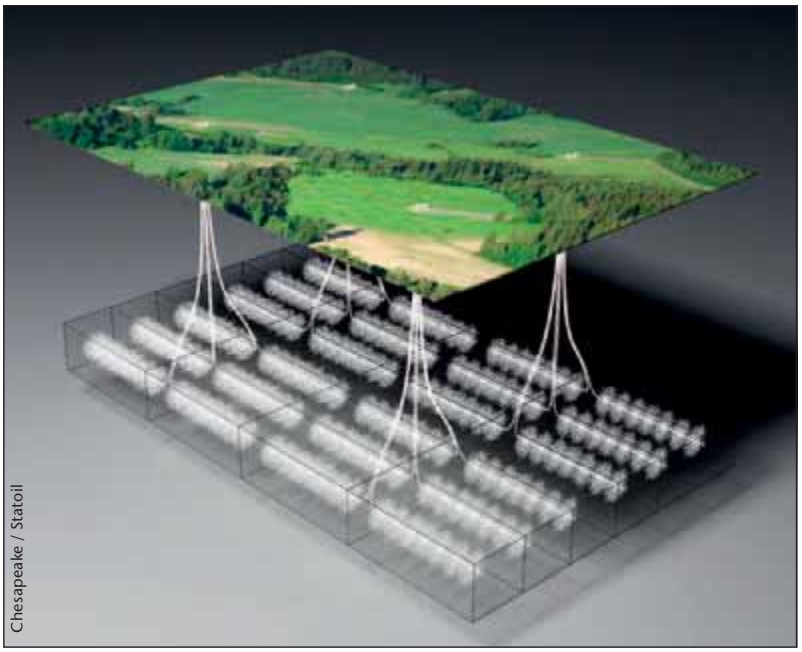
I have then made the small step of combining all of these in a simple 2 x 2 matrix where we can look at Reservoir up the vertical axis and Hydrocarbon Type along the horizontal. I have then made a call about the status of the technology required (for production) and the corresponding economics, especially when known technologies are contemplated offshore.

Of the items shown here, only Gas Hydrates truly sit in the 'unknown technology' category. The red quadrant to the lower left is where combinations to be avoided lie – for example, developing 'heavy' oil in fractured 'basement' may encounter technology and economic barriers. Of course this diagram is simplistic and the detail is key.

What do we mean by unconventional?
The colour code describes technology and economic status



the rocks have disappointed and success is still awaited. Perhaps shale oil, related to one of the region's major 'oily' source rocks, will be more fruitful.



Extraction of shale gas requires many wells, but since several can be drilled from the same location, little is visible above ground.

Waxy or Heavy Oil

'Waxy' crude, which is derived from lacustrine source rocks, is in production throughout South East Asia and in Rajasthan in India, and development planning is under way in the Albertine Rift in Uganda. Flow assurance is the critical issue, with the risk of the crude oil solidifying in flow equipment, for example when exposed to low temperatures in the oceans. The technology to solve these problems – special chemical additives, down-hole pumps, heated pipelines – is all tried and tested, and these projects are or will be economic.

However, recent discoveries in the pre-salt offshore Brazil and the North Falklands Basin are all sourced from lacustrine source rocks which are known to invariably yield a high wax content. Whilst Petrobras, the operator of the pre-salt discoveries, has plans to deal with this issue in what are reportedly huge discoveries, the Falklands discovery is much smaller and in a relatively hostile environment. The operator has mentioned that the crude oil is 'waxy' but has yet to publish any analytical data.

'Heavy' oil is the result of a poor seal, allowing the light components to evaporate or be consumed by bacteria, leaving a poorly-flowing viscous residue. In the North Sea it is in production at Grane in Norway and at Captain and Alba, both UK Continental Shelf, while also in the UKCS development planning is under way at Mariner, and appraisal at Kraken and Bentley, the last of which may be difficult due to the viscosity of the oil.

The new challenge on the UKCS is to develop a relatively modest number of remaining discoveries where the viscosity is greater than 5 centipoise (cP) and API below 22°. This has already begun, with for example the development of Captain (88 cP), Gannet E (20 cP) and Clair (up to 20 cP), and development planning is well underway for Mariner (up to 540 cP). Bressay (up to 1,000 cP) has been studied extensively but no development plan has been forthcoming. Excluding extensions and prospects, in 2006 there were 19 UK Sector North Sea heavy oil 'fields', ranging in size up to around a billion barrels of oil-in-place, although all but three of these are below 500 MMbo in-place. If the extensions and prospects are included, in total there are around 10 Bb of heavy oil in place on the UKCS.

The fields are located where the water depth is around 100m, with the reservoirs themselves at depths of 600 – 1,800m subsea. Although suitable infrastructure is expensive, the technology exists: assisted recovery is likely required to obtain realistic rates (1,000–10,000 bpd) and recovery factors, even with long horizontal wells. This is different to most UK sector experience so far and technology must be adapted to meet the challenge. In addition, the oil may have to be sold at a discount to Brent.

There are a variety of definitions of heavy oil and in a world context the UKCS viscosities are relatively modest but one can perceive a sensible 'queue', the lower viscosity fields being developed first. The maximum viscosity in the UK data base is

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around 2,000 cP, small compared to the Orinoco extra heavy reserves in Venezuela, with API of 7 – 10° and up to 5,000 cP, while Canadian extra-heavy crude has viscosity in the range 5,000–10,000 cP.

Basement Plays

Basement reservoirs owe their petroleum storage capability and productivity to the presence of naturally permeable fractures providing a lattice of void space within rocks which are typically igneous or metamorphic such as granite, basalt and gneiss. Such plays occur around the world, most notably in onshore China where they are referred to as 'buried hill' plays.

They present particular challenges to the explorer in that appeal may have to be made to sophisticated 'plumbing' for hydrocarbons to migrate from source to trap, while conventional seismic will not easily distinguish between a basement feature which is fractured and one that is not.

These plays provide development challenges too in that it is important to find 'sweet spots' where enhanced fracturing taps into granular porosity. It is then necessary to drill horizontal wells that access as many fractures as possible, for example by drilling normal to any preferred fracture orientation.

Overall, these plays provide some tricky problems for geoscientists and reservoir engineers, all of them soluble but with extra risk factors thereby introduced into economic calculations. A key technology will be multi-component 3D seismic which will allow fracture density and orientation to be mapped.

What Does This Imply?

It is a fact that our industry has developed the technology to escape from the 'conventional' – light oil or 'clean' gas in good poroperm sandstones or carbonates – resource limitations. Will this precipitate a dramatic change in the way many explorers think? The starting point needs to be plate tectonics, paleo-drainage systems and paleo-climatology so that we can arrive at a view of where prolific source rocks exist. Following this, we need to understand petroleum systems in an integrated fashion so that we can model a source rock's maturation history and predict where expelled hydrocarbons might have migrated to – if indeed they have left the source rock! And then we need to understand the dynamic properties of these 'unconventional' reservoirs.

Now at this moment, I can hear a large group of both ex- and current colleagues saying "That's what we always do!" And that of course is true – in some cases.

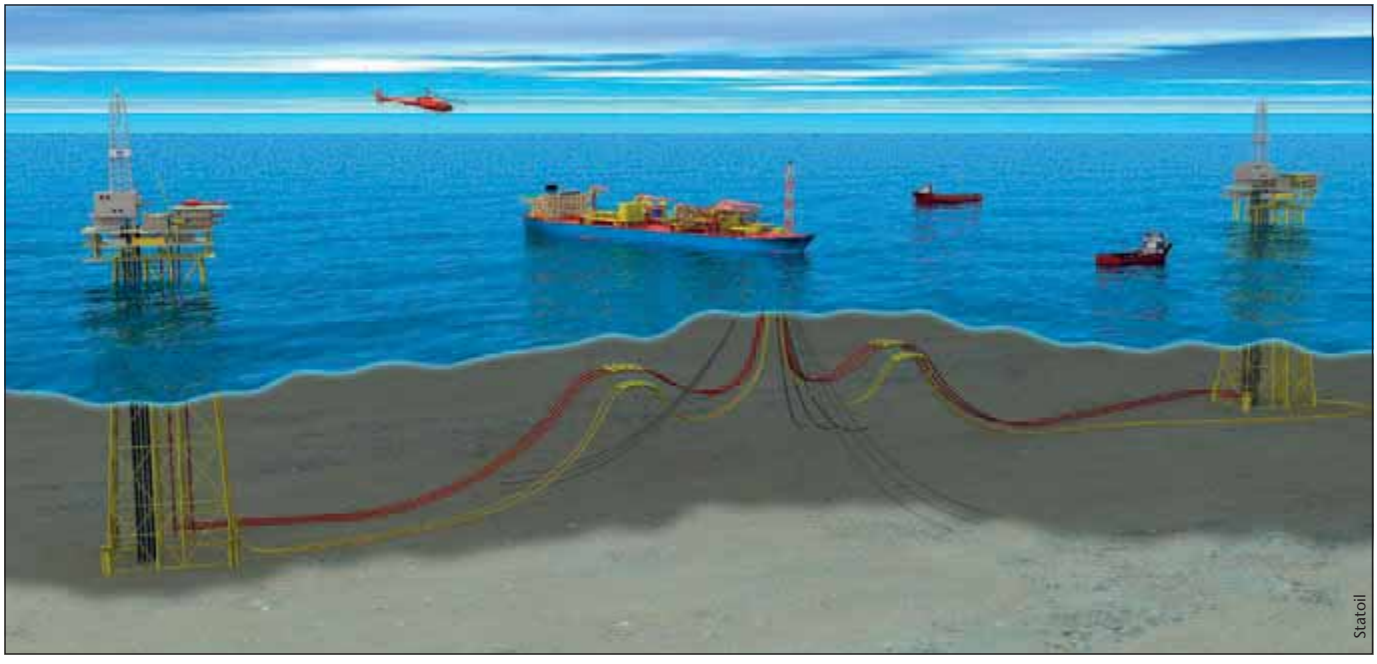
However, for the first step in understanding regional geology, what is obvious is that extraordinary amounts of very different types of data are now available in the public domain to supplement the proprietary data a company might itself hold, whether rock samples, geochemical analyses of seeps, well logs, seismic and so on. Integrating this mountain of data and making sure everybody is looking at the same thing is both difficult and time-consuming, and demands innovative technologies.

A team of subsurface specialists – whether working on a basin, a prospect, a discovery or a field – can in principle access very large amounts of different types of data, each requiring its own conditioning and analysis, before attempting to integrate these many strands into a coherent interpretation, certainly in three dimensions and possibly four. I say 'in principle' and 'attempting' because in reality the amount and diversity of data available to sub-surface specialists has outpaced the ability of their systems and workflow processes to manage, integrate and interpret it.

REFERENCES

1. *http://www.theoildrum.com/pdf/theoildrum_8212.pdf*
2. *http://www.smartplanet.com/blog/energy-futurist/everything-you-know-about-shale-gas-is-wrong* ■

The Peregrino field, 85 km off Rio de Janeiro, has estimated recoverable reserves of up to 600 MMb of heavy 13° API oil. It will be extracted using large volumes of heated water in the wellstream, which will then be pumped back to the reservoir to maintain pressure and help to draw oil with it back to the production wells, increasing oil recovery.



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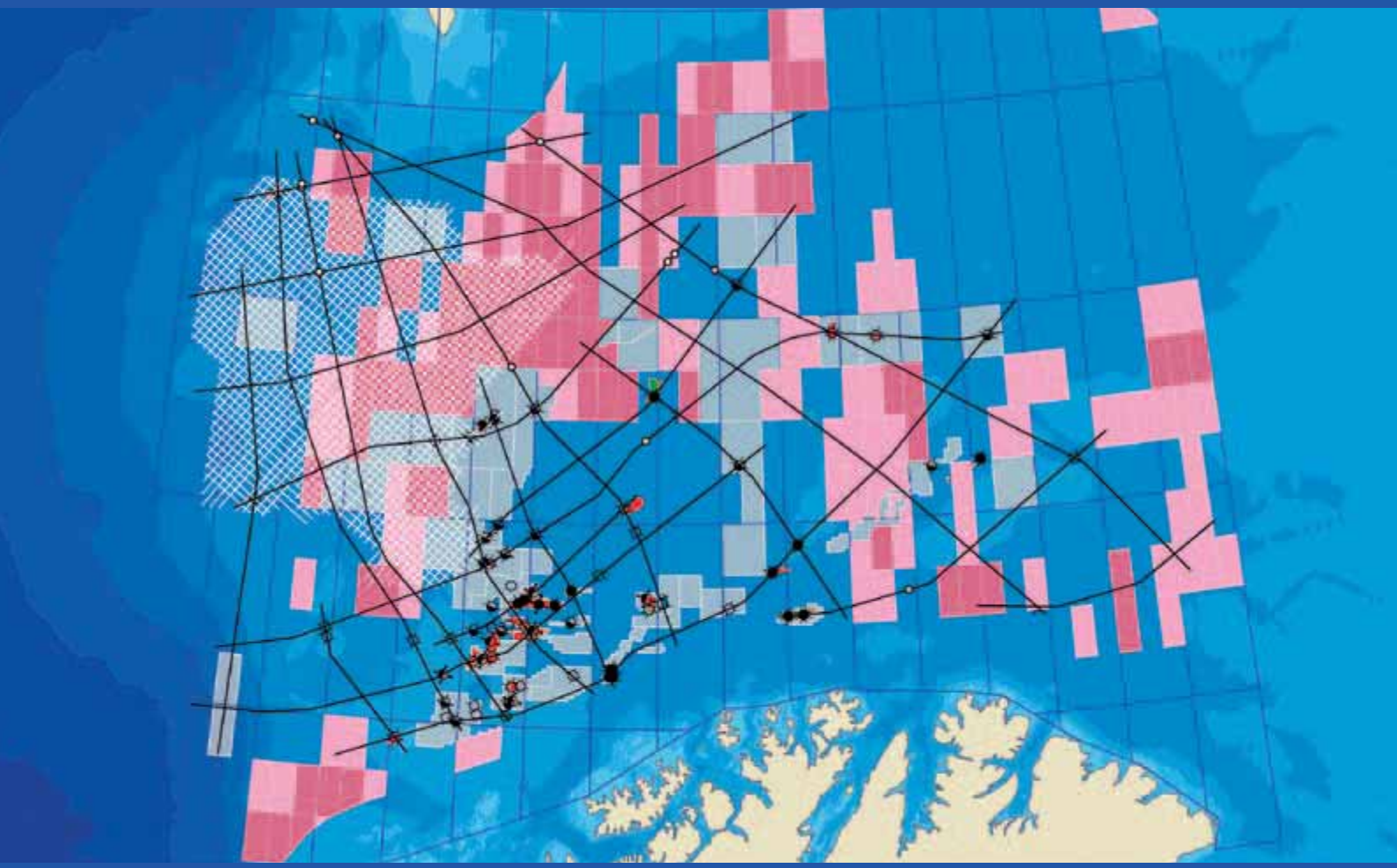

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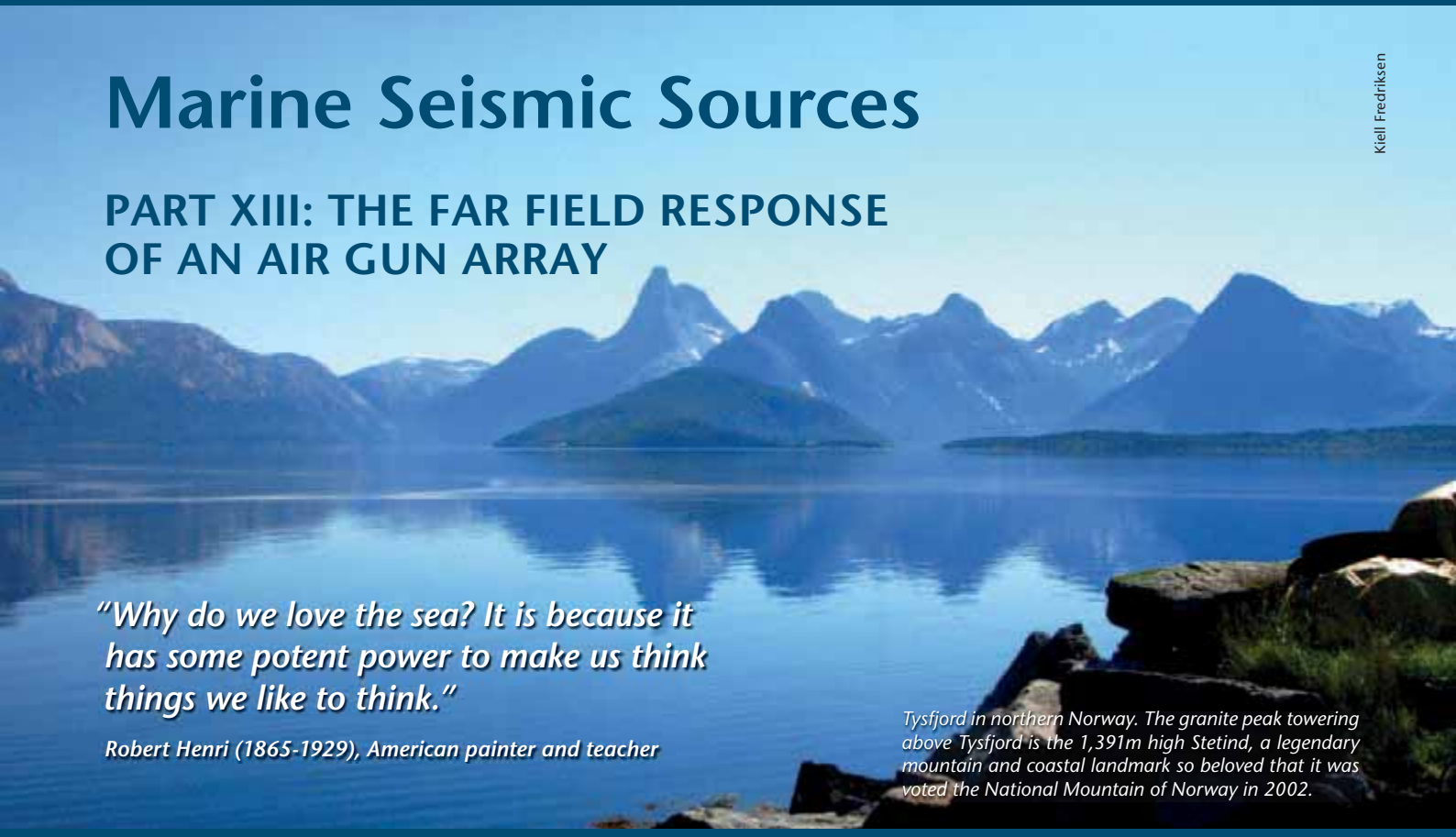
Marine Seismic Sources

PART XIII: THE FAR FIELD RESPONSE OF AN AIR GUN ARRAY



Kiell Fredriksen

"Why do we love the sea? It is because it has some potent power to make us think things we like to think."

Robert Henri (1865-1929), American painter and teacher

Tysfjord in northern Norway. The granite peak towering above Tysfjord is the 1,391m high Stetind, a legendary mountain and coastal landmark so beloved that it was voted the National Mountain of Norway in 2002.

MARTIN LANDRØ AND LASSE AMUNDSEN

The Kraken is an ancient giant sea monster that originated in Norwegian folklore in the twelfth century. In 1752, the Bishop of Bergen, Erik Pontoppidan, described it as the largest sea monster in the world with a width of one and a half miles. When the Kraken attacked a ship, it wrapped its arms around the hull and capsized it. The crew would drown or be eaten by the monster. The Norwegians thought that fish were attracted by the Kraken and therefore, when a fisherman had a good catch it was said that he had successfully fished over the Kraken without waking it.

The seismic source is hopefully not as horrifying as the mythological sea-creature, although when asleep, we believe it, like the Kraken, attracts fish. When it shoots, it does not. Therefore, it is of interest to understand sound propagation in the sea.

During airgun shooting, the sound level in the sea measured far away from the seismic vessel depends not only on the seismic source parameters but also on the water layer propagation channel. Numerical modeling studies are valuable for providing rough estimates of plausible scenarios for the transmission of seismic energy in the water column. Luckily, there are several standard acoustic propagation models available to model sound propagation in range-dependent ocean waveguides. One of these is a computer program – nicknamed, appropriately enough, Kraken.

The Kraken program models so-called normal modes – complex solutions of wave propagation which at first sight may look as scary as the octopus-like Kraken. But, normal mode theory *(see box on page 28)* is an efficient tool to model the acoustic wavefield trapped within the sea layer, and can be used to understand the sound level that marine life is exposed to when it is several kilometres from a seismic vessel.

Normal Modes

There are only a few relatively simple oceanic waveguides which allow us to obtain a closed analytical form of the solution describing sound propagation at long distances from the source. Pekeris (1948) is regarded as one of the pioneers in this field. Consider a water layer with thickness ***D*** and water speed ***c*** with source at depth ***zs*** and receiver at depth ***z***. The pressure is effectively zero at the sea surface; the reflection coefficient is ***R=-1***. It is well known that for plane wave incidence on the sea floor beyond the critical angle, there is a perfect reflection with an accompanying phase shift. This reflection can be represented with an equivalent reflection having ***R=-1*** at a virtual pressure release interface displaced a distance below the sea floor. Therefore, when we study long-range sound propagation in a water layer over a real sediment, the simplest waveguide is the homogeneous water layer that has interfaces with vanishing pressure at the upper and lower boundaries.

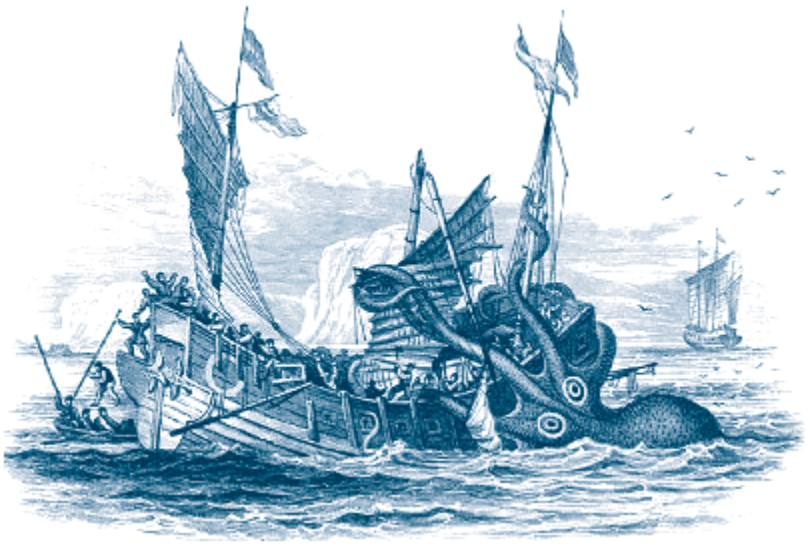
The sound pressure is the sum of the pressures in the modes. For source at depth ***zs*** and receiver at depth ***z***, the pressure is given as (Jensen *et al.*, 1994; Medwin, 2005):

$$p(r,z_s,z,t)=\frac{Ae^{i\omega t}}{D}\sqrt{\frac{\rho}{2\pi r}}\sum_{m=1}^{M}a_m(\kappa_m)\sin(\gamma_m z_s)\sin(\gamma_m z)\frac{e^{-i(\kappa_m r-\pi/4)-\delta_m r}}{\sqrt{\kappa_m}}$$

where ***A*** depends on the source power, ρ is the ambient density, and the summation is over all allowed modes ***m=1,…,M*** with real propagation wavenumbers; ***M*** increases with increasing

Below the thunders of the upper deep,
Far, far beneath in the abysmal sea,
His ancient, dreamless, uninvaded sleep
The Kraken sleepeth: faintest sunlights flee
About his shadowy sides; above him swell
Huge sponges of millennial growth and height;
And far away into the sickly light,
From many a wondrous grot and secret cell
Unnumber'd and enormous polypi
Winnow with giant arms the slumbering green.
There hath he lain for ages, and will lie
Battening upon huge sea-worms in his sleep,
Until the latter fire shall heat the deep;
Then once by man and angels to be seen,
In roaring he shall rise and on the surface die.

"The Kraken", Alfred Tennyson, 1809-1892



frequency; a_m is the modal excitation. The rest of the symbols are defined on page 28. This normal mode expansion of the field in the waveguide is referred to as the Pekeris model and is useful to understand the basic principles of normal modes. Each term in the series has simple trigonometric depth dependence of sinusoidal form.

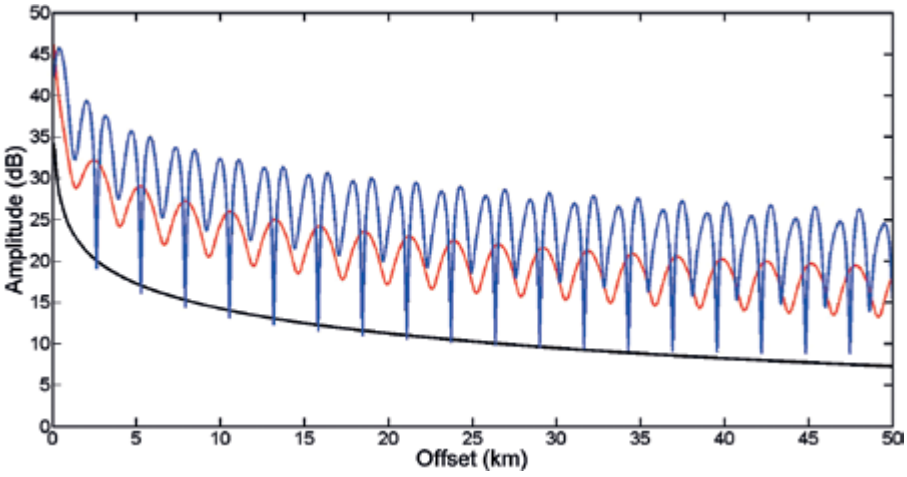
There are two major observations to be made: first, the amplitude decreases with square root of distance r, as one would expect for a cylindrical spreading wave trapped in the sea layer. Second, while the source has a single frequency, the dependence of pressure on distance and depth is very complicated because each of the mode components has different dependencies on distance on range and depth.

In real waveguides, absorption losses in the sea floor cause the sound pressure to decay faster than $1/\sqrt{r}$. These losses, as well as others, can be included in the empirical mode attenuation rate δ_m.

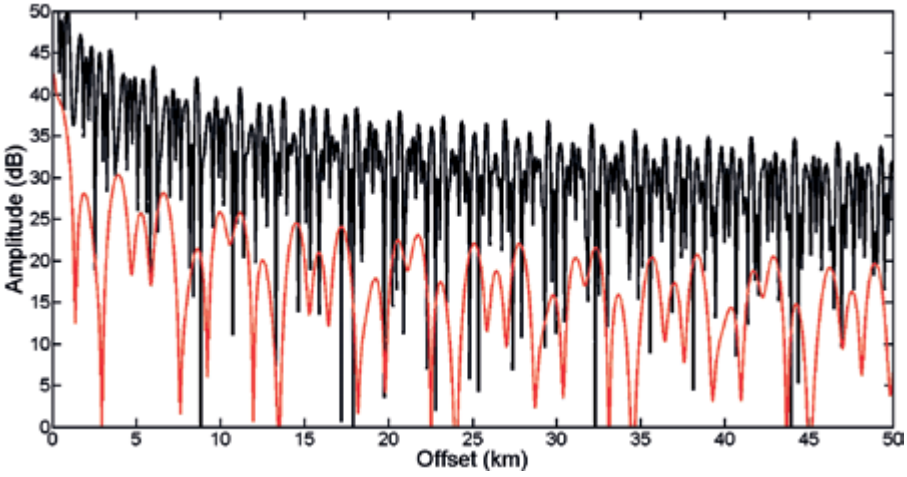
Often, however, we find that we lack sufficient information to perform realistic numerical modeling. Therefore, we frequently end up with a simple comparison using logarithmic plots to judge whether the signal decays as $-10\log(r)$ or $-20\log(r)$ or more. We will use a recent example from a seismic survey where the water depth is between 40 and 50m as an example.

Shallow Water Example

The Pekeris model has cylindrical



Normal mode solutions for first mode (m=1; solid black line), first and second (m=1 and m=2; solid red line) and the three first (m=1, m=2 and m=3; solid blue line) for the Pekeris model; water layer 100m, source depth 6m, receiver depth 50m, 100 Hz frequency.

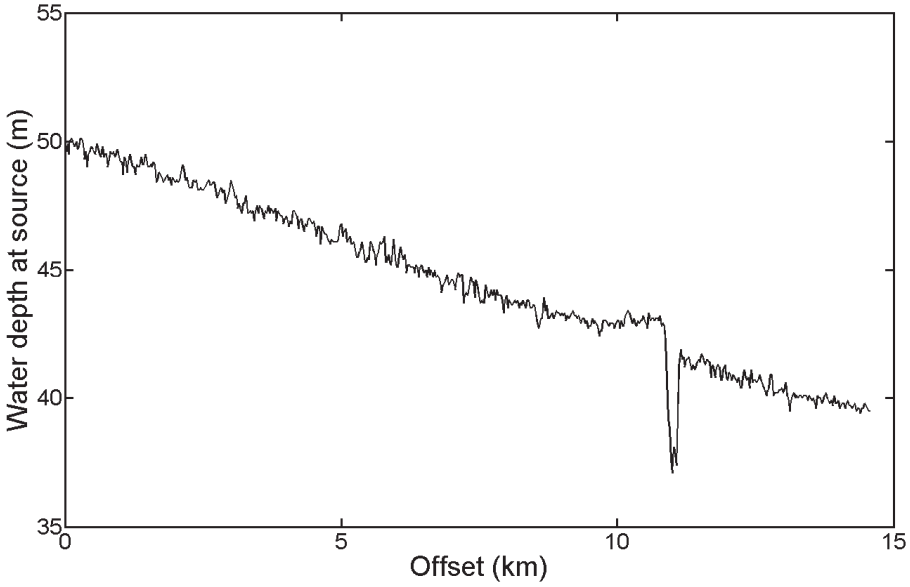


Normal mode solutions (including 5 modes) for two different sea layer thicknesses for a water layer of 100m (black solid line) and 200m (red solid line). The source depth, receiver depth and frequency as before. There is a significant reduction in acoustic amplitude level with depth, approximately 15-20 dB. Looking at the complexity of the solutions as more modes are included, it is easy to understand why normal mode solutions have Kraken-like behaviour.

attenuation with distance, which means that the signal attenuates as ***10log(r)***. In *GEO ExPro* Vol. 8 No. 5 we reported that transmission loss in a waveguide such as the sea, with constant speed of sound, follows a spherical spreading law (***20 log(r)***) at short distance and cylindrical spreading at longer distance. A combination of the two spreading laws gives for distances ***r*** greater than the ocean depth ***D*** (in meters), the asymptotic loss behavior ***20 log (D) + 10 log (r/D)*** .

To illustrate the possible huge difference between simplified models (where attenuation effects are neglected) and reality, we will use a field data set where we have measured 585 shots for 12 seconds each shot and where a geophone located at the seabed records the shots from a seismic vessel at distances from 30m up to nearly 15 km. The water depth at each source location is shown in the figure on page 30. A comparison between the root mean square (RMS) (measured for a window from 0-12 seconds) is shown together with the maximum amplitude as a function of offset. For comparison we have inserted attenuation proportional to -20, -40 and -60 times the logarithm of ***r***. For distances up to 3–4 km, we observe that the ***-20log(r)*** damping curve fits reasonably well with the observed data. Furthermore, there is practically no deviation between the maximum amplitude curve and the RMS-curve up to this point. However, for offsets larger than 3–4 km, we observe a distinct difference between the maximum amplitude curve and the RMS-curve. The latter has a slope corresponding to ***-40log(r)*** and the former is closer to ***-60log(r)***. This means that for this example the attenuation of the seismic data is significantly stronger than ***-20log(r)*** for offsets greater than 3-4 km.

We notice that the water depth changes gradually from 50 to 40m for offsets larger than 3 km. It is hard to judge how much a change in the water



Water depth at source versus offset for the field data.

Normal Modes

A normal mode is a free vibration of a physical system, represented by a characteristic frequency of each mode. This frequency is often referred to as the *eigenfrequency*. The most common example of such a system is a string that is fixed at the ends. This string (for instance on a guitar) might vibrate in a number of modes, each with a characteristic frequency, the eigenfrequency. The sum or superposition of all possible functions corresponding to these modes constitutes the general solution.

When a guitar string is plucked normally, the ear tends to hear the fundamental frequency most prominently, colored by the presence of integer multiples of that frequency. The lowest frequency of vibration along the entire length of the string is known as the fundamental, while higher frequencies are referred to as overtones. The fundamental and overtones, when sounded together, are perceived by the listener as a single tone. A harmonic overtone has evenly spaced nodes along the string, where the string does not move from its resting position.

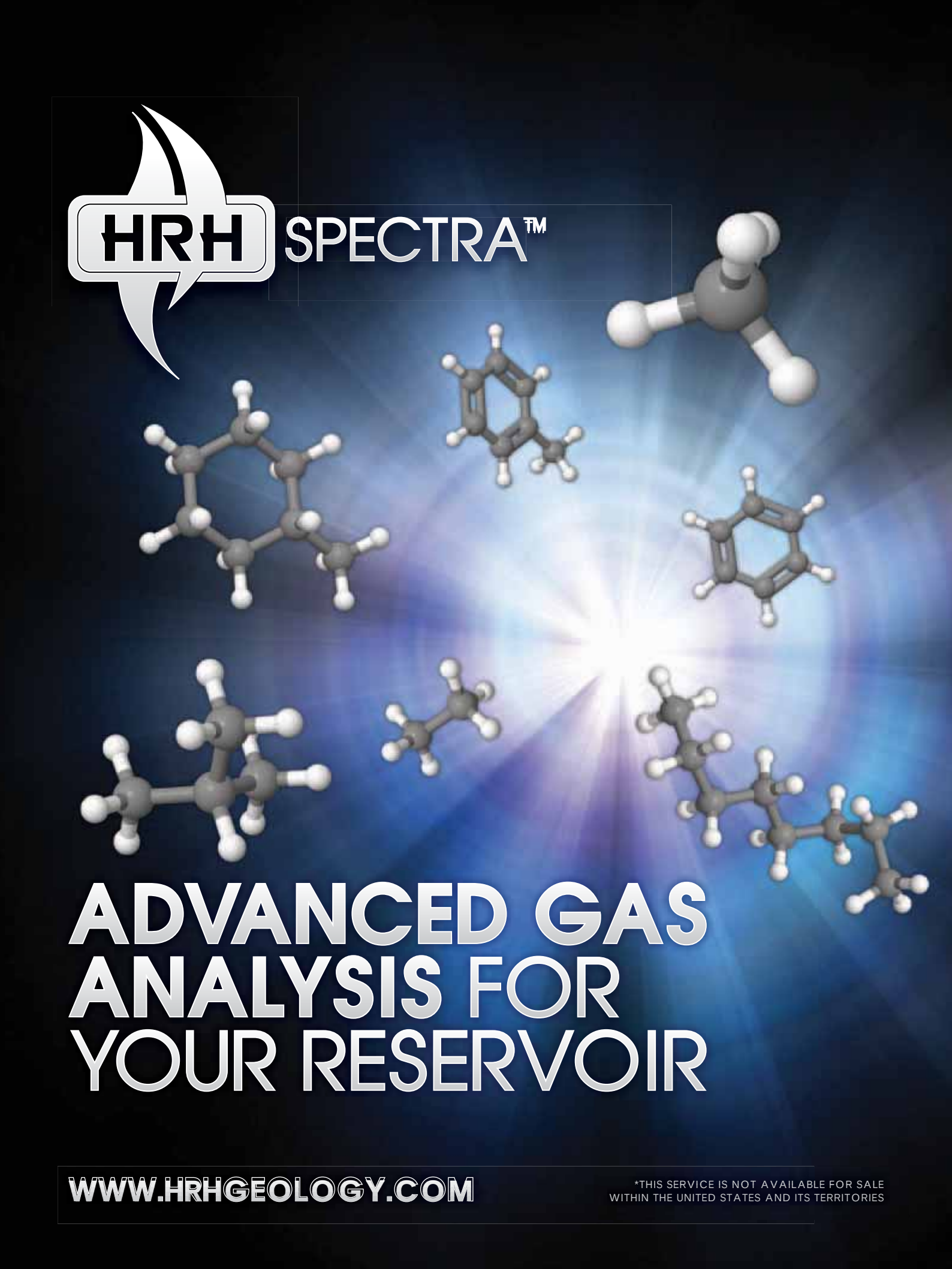
Other examples of normal modes are organ pipe and sound propagation in for instance a trumpet or the sea layer, as we discuss in this article. Mathematically, these normal modes can be represented as a sum of sinusoidal functions.

The actual solution of a normal mode system is dependent on the boundary conditions. For example, for a drum the normal mode solution depends on how the drum skin is suspended. A normal mode is independent of the other modes, in contrast to non-normal modes where this is not the case. The concept of normal modes is used in wave theory, optical applications, quantum mechanics and molecular dynamics.

Consider an ideal waveguide consisting of a homogeneous water layer of thickness D that has interfaces with vanishing pressure at the upper and lower boundaries at $z=0$ and $z=D$. Let $k=w/c$ where $w=2\pi f$, f being the frequency, denoting the wavenumber with horizontal component K and vertical component γ, obeying $K^2 + \gamma^2 = k^2$.

The 'eigenfunction solutions' of the wave equation, $Z(z) = \sin(\gamma z)$, must be zero at depths $z=0$ and $z=D$, since the pressure here is zero. The requirement $Z(D)=0$ gives the 'modal equation' for the idealized waveguide, $\gamma_m D = m\pi$, or $\gamma_m = m\pi/D$, where m is an integer which designates the 'mode number'. The γ_m are known as the eigenvalues. The values of the horizontal component of the wavenumber are $K_m = \sqrt{k^2 - \gamma_m^2}$ with $k^2 \geq \gamma_m^2$. In the idealized waveguide, the depth dependent eigenfuctions are simply $Z_m(z) = \sin(m\pi z/D)$, $m=1,2,3,\ldots$

The sound pressure is the sum of the pressures in the modes, as given in the main text.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depth will influence the field data. However, based on the equations given above, the maximum amplitude should increase rather than decrease if we assume the simple isovelocity model. Therefore, it is likely to assume that this change in slope for the measured data is not caused by this change in water depth, but rather that it is caused by attenuation effects. Unfortunately, this data set does not contain offsets above 15 km, so we are not able to check if the ***-60log(r)*** behaviour continues for larger offsets.

60log(r), which is observed between 4 and 15 km, corresponds to attenuation close to one over the cube of the offset. This indicates that the attenuation at far offsets (larger than 4 km) is severe. More experiments and larger offsets are needed to check if this behavior is common for shallow water depths. ■

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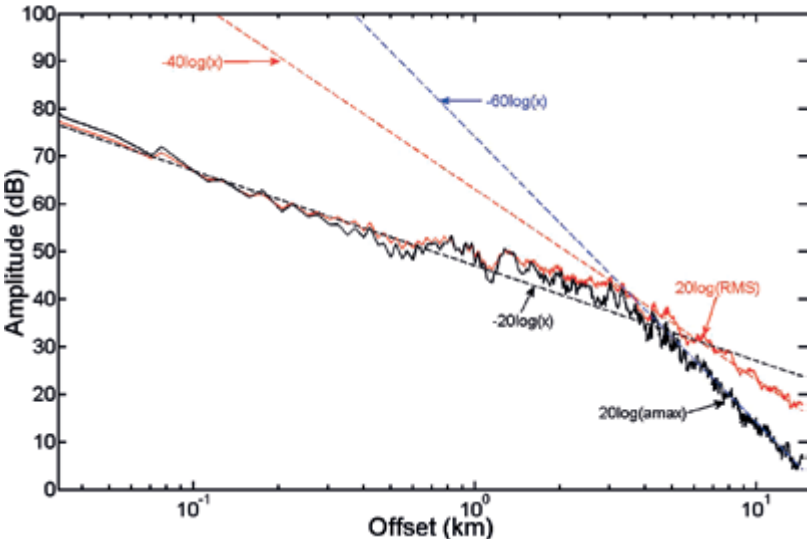

Measured RMS (root mean square) amplitude (solid red line) and maximum amplitude (solid black line) versus offset. For comparison -20, -40 and-60 log(x) straight dashed lines are fitted to the data.

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Deploying airguns

The Next Generation of Microseismic Imaging

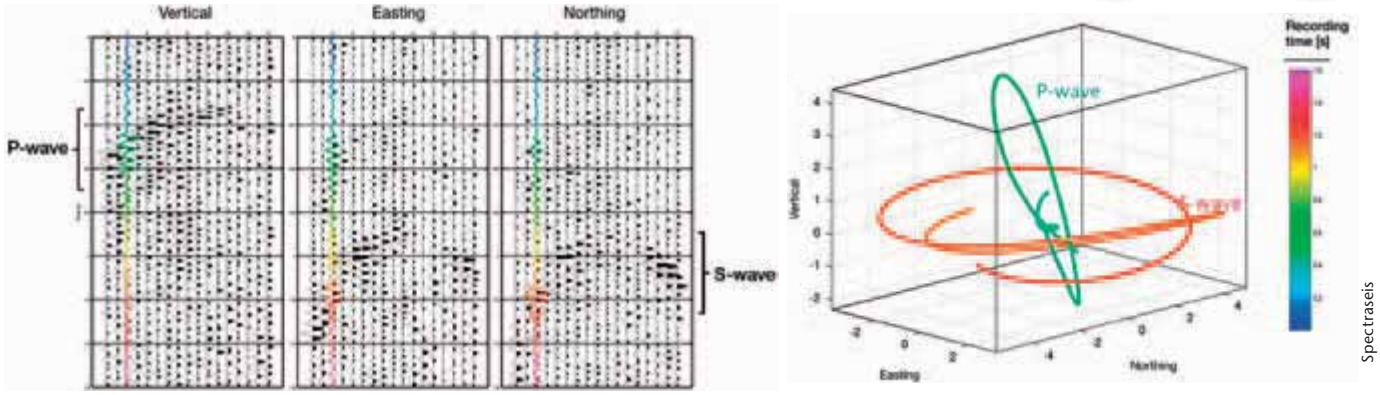


Figure 1: 3-C trace gather of a microseismic event triggered in U.S. shale (left) and particle motion (hodogram) for a single station (right). P- and S-waves can clearly be distinguished in the hodogram based upon their polarization properties. Note that the S-wave arrival is absent on the vertical component and would not be captured by single-component geophones.

Integrating advanced hydraulic fracture imaging with fluid system mapping helps unravel unconventional plays

DR. MARC-ANDRÉ LAMBERT and PAUL WEST, Spectraseis

In shale reservoirs, the reservoir and source rock are identical – our familiar concept of an oil/gas kitchen, migration path and hydrocarbon trap does not apply. The risk that an operator will not find hydrocarbons in a shale play is small compared to conventional traps, but the expected production rates are usually lower too.

The focus of geoscientists' and engineers' time and effort has therefore shifted from locating and delineating reservoirs towards increasing the productivity of known resource formations to make them economic.

New technologies have proven to be the key to success. The continued refinement of the technology suite for unconventional plays in the United States is fundamental to our expectations for the Marcellus and Haynesville shale (now considered the third and fifth largest gas fields worldwide), the economic success of the Barnett shale, and other future developments. One scenario of the International Energy Agency (IEA) is North American unconventional gas production almost doubling to 23.7 Tcf (670 bcm) by 2035. Can we really get there, from about 13.4 Tcf (360 bcm) today?

Despite truly remarkable achievements so far, our understanding of unconventional reservoirs is immature, especially when compared to over 100 years of experience in conventional oil and gas exploration and production. Hydraulic fracturing is still largely a blind process and too many wells fail to meet the operator's expectations. In this article, we introduce some new subsurface information technologies, which are helping to shine a brighter light on the intricacies of unconventional plays and improve their economics with richer, faster reservoir understandings.

Using the Complete Wavefield

The results of any geoscience data analysis are only as good as the quality and integrity of the recorded data set. Energy radiated from microseismic events is small by definition and recorded signals are often weak and masked by noise.

The critical signal-to-noise ratio (SNR) in microseismic data is a function of event size, distance from the event, local noise conditions, quality of the recording equipment, and the position of the recording station with respect to the event's radiation pattern. Capturing the most complete wavefield in time, space and frequency is a good strategy to minimize the risk of missing these faint – but precious – signals.

We see four requirements for an optimized microseismic acquisition system, incorporating several new technologies only recently available on the market.

Don't ignore shear waves: Single component data recordings, as delivered by conventional 2D/3D seismic recording systems, have ignored a large portion of the information radiated by microseismic events. S-waves are often the strongest signals recorded in microseismic data. The S-waves triggered by microseismic events are normally observed on the horizontal components of a 3-C receiver and are weak or completely absent on the vertical component.

A standard requirement for many years in borehole microseismic and VSP applications, three-component (3-C) recording is essential in both borehole and surface microseismic surveys because only 3-C data embodies the full three-dimensional wavefield. The maximum amplitude of an S-wave phase (SH or SV) radiated by a shear event can be 8 times

larger than the maximum amplitude of the associated P-wave[1], but a single component system probably won't record it. We simply cannot afford to keep ignoring this data.

Figure 1 shows how 3-C instruments not only capture all wave modes, but also facilitate polarization analysis to distinguish easily between the different modes. Classification of the recorded signals into vertically polarized P-waves and horizontally polarized S-waves is crucial to avoid imaging false positives from misinterpreted wave modes.

Use high-sensitivity instruments: Like a raindrop in the forest, a microseismic signal is small and weak. Many of them occur far from the recording array, at the remote end of a multi-stage frac and well below the surface in a deep formation. High-sensitivity instruments are essential to capture weak microseismic signals and an instrument with low self-noise is needed to ensure that any event stronger than background noise is detected.

Capture the low frequencies: An ordinary 15 Hz geophone doesn't measure the optimal frequency band for microseismic data. True broadband instruments with a good frequency response down to 0.1Hz (and up to 1000 Hz) are a vastly superior choice, particularly for surface acquisition. Recording the low frequency segment of the wavefield is especially important for large measurement offsets, where high frequency signals tend to be heavily attenuated. The maximum S-wave amplitudes of microseismic signals recorded at the surface often occur at frequencies well below 20 Hz.

Figure 2: An UltraSense™ microseismic recording node monitors a fracture treatment in Canada.

However, the major benefit of recording at low frequencies is the shallow and deep subsurface information added by characterizing the continuous ambient wavefield – more about that in a moment.

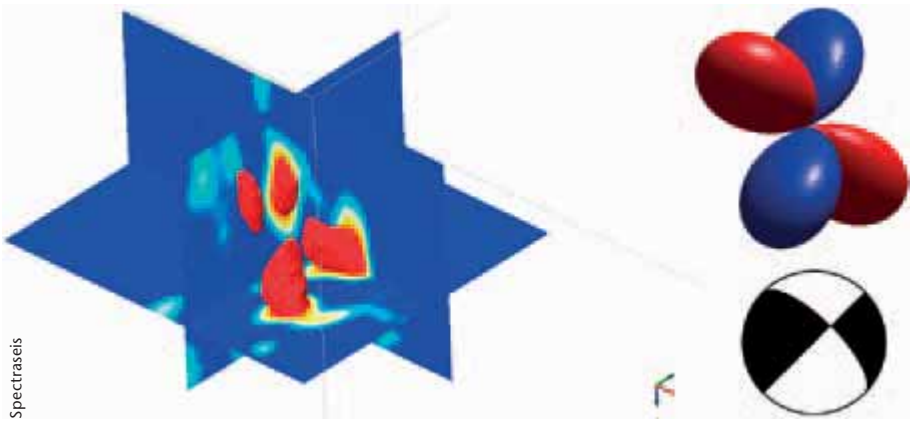
Get rid of cables: use nodes to optimize your survey design: Optimizing array geometries has been poorly neglected in many microseismic designs, although it is one of the most powerful ways to improve data quality and increase the value of microseismic data to the interpreter. Whether they are deployed at the surface or multiple downhole configurations, nodal systems have the advantage over cabled arrays for data acquisition.

Nodal systems offer vastly more flexibility in acquisition geometry design, a low-impact environmental footprint, easier permitting and operational safety benefits. The Spectraseis UltraSense™ nodal surface recording station in Figure 2 is a three-component instrument with a sensitivity of 4800 V/m/s and self-noise level below the seismic background noise of the Earth. The sensitivity of a standard geophone is generally less than 100 V/m/s. Arrays of several hundred stations are quickly deployed for a typical fracture stimulation survey.

The associated UltraSense multi-level borehole tool, which has the same sensor specifications as the surface nodes, can be integrated with the surface gear and other borehole acquisition modes to optimize the acquisition geometry for any stimulation program.

Pre- and post-frac recordings with UltraSense arrays provide a rich new data set for monitoring fluid system changes caused by the frac operations.

Figure 3: From TRI event image to focal mechanism: the 3D pattern in the TRI image domain is compared with theoretical radiation patterns to determine the event's source mechanism and orientation. (a) 3D TRI image of the microseismic event shown in Figure 1; (b) P-wave radiation pattern of double-couple source; (c) Focal mechanism of the shear event



The Most Complete Physics

Until now, the standard approach to microseismic event location has been automated arrival time picking followed by a ray tracing-based travel time inversion. Many microseismic data processing workflows still apply this method. It is overdue for an update.

Elastic wave-equation migration of multi-component data is the more natural and most physically complete approach.

How does this work? Spectraseis' time-reverse imaging (TRI) algorithm propagates time-reversed microseismic signals from the receiver locations through a velocity model back to its source location. TRI solves the 3D elastic wave-equation in the velocity-stress formulation on a rectangular, staggered grid using a finite difference technique. TRI reduces analyst interactions to a minimum and does not require arrival time picking – eliminating a common source of error in microseismic data processing.

If our velocity model is good, the resulting TRI image will focus at the location where the event has occurred. The result not only pinpoints the event location, but actually images a proxy of the event's three-dimensional radiation pattern.

As shown in Figure 3, the imaged 3D pattern can be matched with theoretical radiation patterns of common event types. This event characterization capability is a powerful benefit of elastic wave equation imaging. It facilitates a simple and direct measure to understand the local stress field in the target zone.

Understanding Fluid System Changes

Microseismic signals make up only a tiny fraction of a passive seismic survey recording. The vast majority of the recording captures the stationary seismic background noise of the Earth's crust.

In recent surveys, Spectraseis has been analyzing this ambient wavefield to identify fluid system changes occurring in the target zone as a result of fracturing operations, which create dramatic new physical contrasts and reservoir dynamics. Fluid effects on seismic amplitudes have been around for a long time in active 2D/3D seismic and have been exploited successfully as direct hydrocarbon indicators[2]. Spectraseis calls upon the same physical principles in analyzing continuous passive data recordings in the frequency domain.

This ambient wavefield characterization (AWC) method employs spectral attributes that are sensitive to the subsurface rock-fluid system[3]. After removing non-stationary signal elements, a comparison between attributes from pre- and post-frac recordings has then the potential to highlight fluid system changes related to the fracture stimulation treatment.

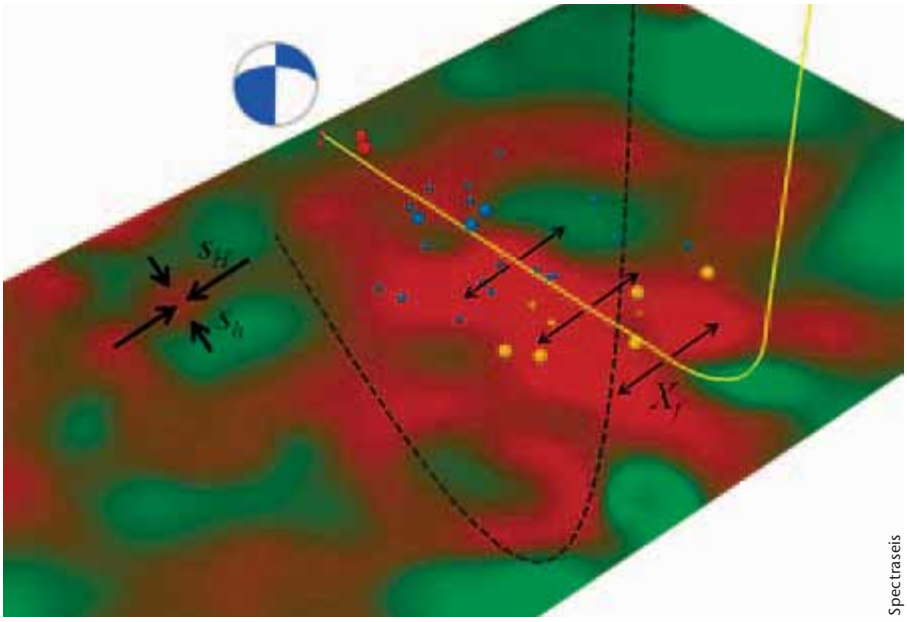


Figure 4: Improved reservoir development through integration of hydraulic fracture imaging with AWC fluid system mapping. A future well (dashed) is planned based on local stress field information and ESRV estimates derived from 3-C broadband microseismic analysis.

Figure 4 includes an example from a recent survey over a shale play in North America. The map displays the ratio between post- and pre-frac attribute values. The division eliminates stationary attribute patterns caused, for instance, by near-surface geology. High values (in red) indicate changes in the stationary characteristics of the ambient wavefield recorded after the treatment. The map is projected to the target depth for interpretation purposes. High values are observed in the zone near the treatment well. These patterns can be interpreted with respect to fluid-system changes caused by the fracture stimulation and add an exciting slice of new information for estimation of the effective stimulated reservoir volume (ESRV).

Integrating All Data

Microseismic event locations only provide a structural estimation of the induced fracture network. Information on effective permeability or even fluid mobility inside the ESRV is limited.

Pre- and post-frac AWC can close this information gap by adding fluid system information to the imaged fracture network. It provides an additional, independent input for reservoir simulation models and contributes to the estimation of important parameters, such as the ESRV, the fracture half-length and the ultimate productivity of the well.

Moreover, with elastic wave-equation imaging, the character and location of microseismic events can be used to directly map the local stress field in the target formation, helping the operator to determine the optimal orientation for future treatment wells.

Figure 4 again illustrates a combined analysis of event locations, focal mechanisms and AWC attributes. The sketch shows how a future well can be planned with more confidence regarding its optimal orientation and distance to the adjacent well. Integrated analysis of the many aspects of broadband microseismic data facilitates improved reservoir management, eventually resulting in more economic wells and higher production.

Doubling US unconventional gas production, here we come!

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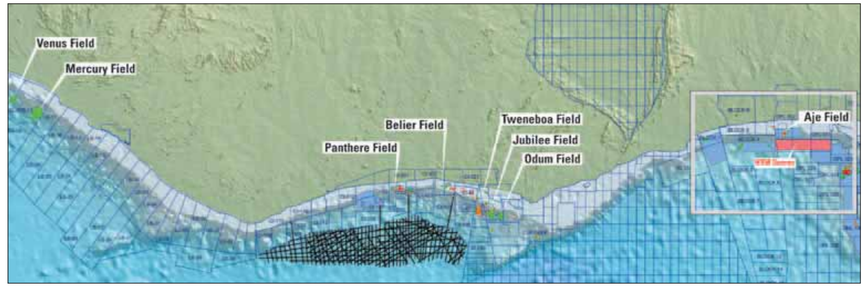
Exploration Potential of the Nigerian Transform Margin

Recent industry success on the African Equatorial transform margin, including offshore Ghana, Côte d'Ivoire and Sierra Leone, has focused much attention on the region, of which the Nigeria Transform Margin area is the easternmost extension

The Nigeria Transform Margin GeoStreamer® MC3D seismic survey, which was acquired in 2010 using innovative dual sensor technology, has resulted in a significantly improved data set, with coverage which extends over prospective areas that are unlicensed.

The seismic section illustrated is a PSTM west to east strike line across the width of the entire survey. The section shows the clarity of dual-sensor acquisition in its characteristic high resolution, good penetration and imaging at depth.



PGS

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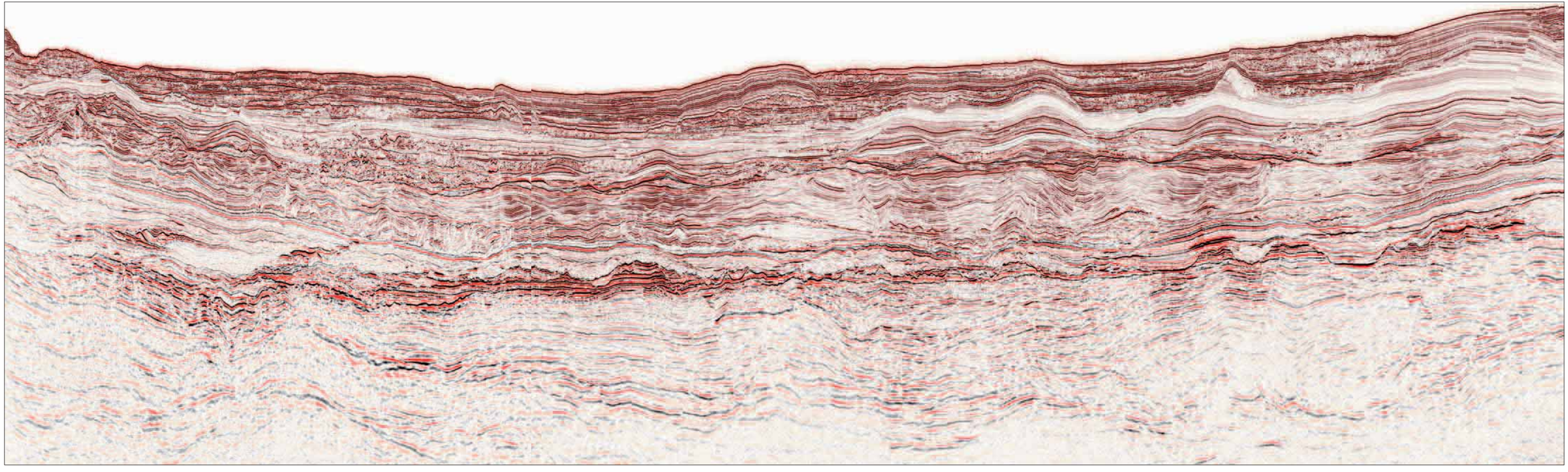


High Potential in the Offshore Nigeria Transform Margin

The African Transform Margin is a new major petroleum province, with offshore basins still relatively poorly explored, but the new Nigeria Transform Margin survey is revealing major clues to exploration success

JENNIFER GREENHALGH and MATT WHALEY, PGS Reservoir, UK;
A.O. LUFADEJU, Department of Petroleum Resources, Nigeria

The Nigeria Transform Margin (NTM) GeoStreamer® MC3D survey, shot in association with the Department of Petroleum Resources, is situated in the west of Nigeria and positioned to cover the eastern extension of the post-transform turbidite fan play in open blocks OPL 312, 313 and 314. Petroleum systems are proved to be working through the presence of the Aje Field to the north, and the Hihon and Fifa discoveries to the west, in Benin.

Seeps and Giants

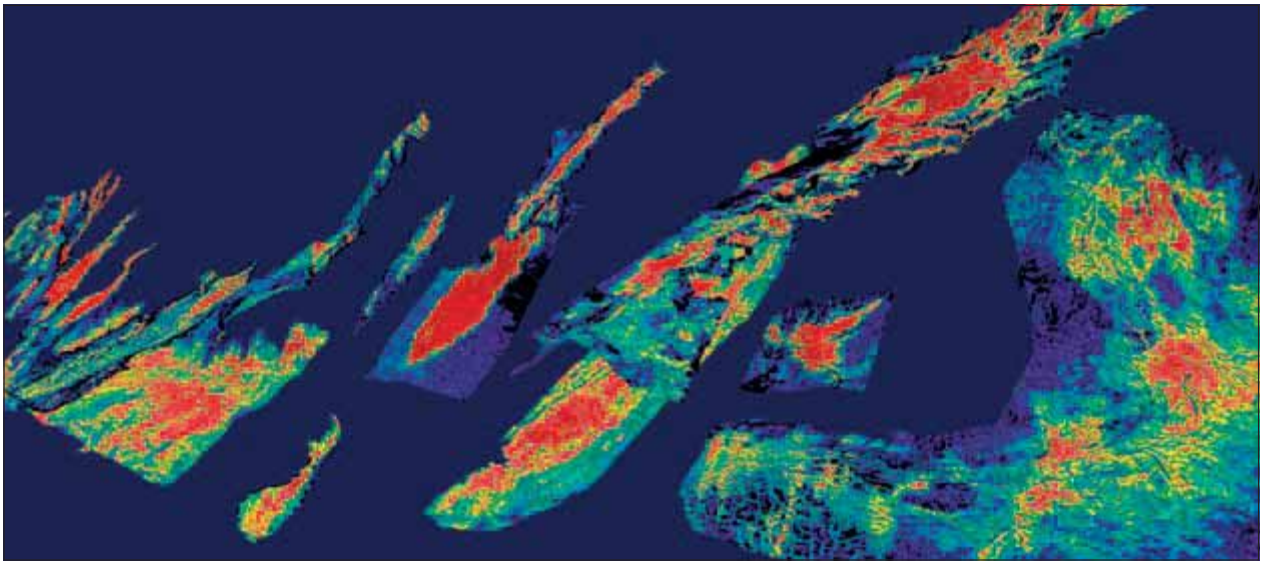
Evidence of oil seeps and tar sands have long been recognized along the outcrop of Late Cretaceous sediments of the African Equatorial transform margin. The thickness of the sedimentary cover in the onshore and shelfal areas is insufficient for hydrocarbon maturity so these strata were followed offshore onto the shelf. The earliest fields were discovered in the late Sixties and early Seventies, such as the Seme Field (1968), the Lome Field (1970) and the Saltpond Field (1970). These fields were small, had limited upside potential, and did not produce the volumes that had been hoped for. Smaller independent operators continued to invest in the region, and further discoveries were made, with a number of fields being productive.

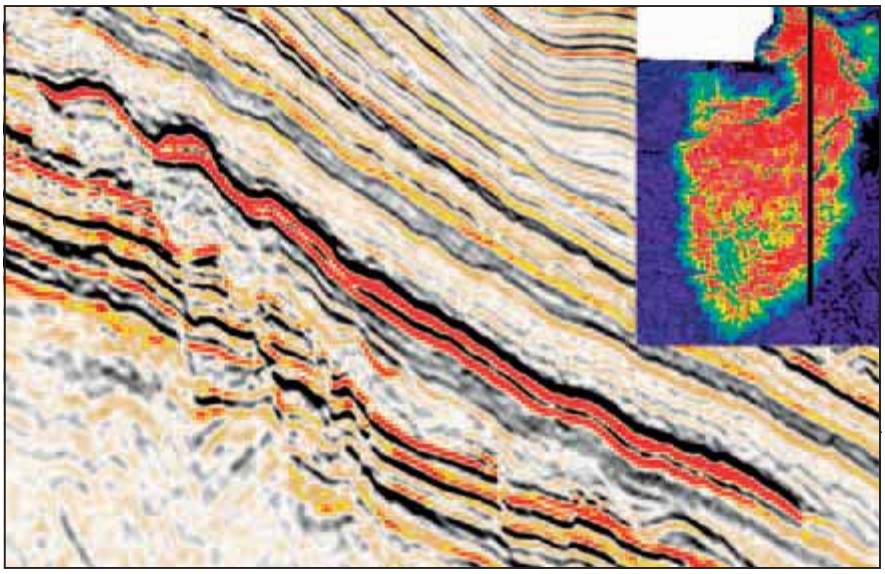
Things changed dramatically when the Jubilee Field, Ghana, was discovered in June 2007 by Tullow and partners, in a post-transform Turonian-age turbidite fan. The quality of both the oil and the reservoir was apparent very early, and the Jubilee Field was soon termed a world class field with exceptional upside potential. Further discoveries were made in the immediate vicinity in a series of turbidite fans and channels, such as Odum, which extended in the play stratigraphically up into the Campanian, then Tweneboa, which continued the Turonian play fairway to the west. The more recent discovery of the Venus Field, Sierra Leone, in 2009 by Anadarko confirmed the extension of the post-transform turbidite fan play fairway 1,100 km to the west.

Innovative Acquisition and Processing

The dual-sensor streamer acquisition used to acquire the survey offers

A 3D view of some of the interpreted anomalies on the NTM survey. Several fans and channel features are clearly visible.





A strong amplitude fan anomaly – similarities to Jubilee in response, hydrocarbon system and size.

improved opportunities, demonstrated fully in this area. The combination of pressure sensor and vertical particle velocity sensor allows wavefield separation, which is not possible in conventional data. By separating up-going pressure, down-going pressure and the velocity wavefield, it is possible to completely remove the receiver ghost whilst towing the streamers deeply enough to reduce noise and increase signal penetration. This acquisition method directly produces a significantly broader, uncompromised seismic bandwidth and better signal to noise ratio over the entire time window. These advantages mean that interpretation of dual-sensor seismic data is easier, more reliable and seismic inversion techniques produce better results (Ozdemir, 2009 *First Break*; Reiser *et al.*, 2010 EAGE, Dhelie and Reiser, 2011 AAPG). For this survey, relative inversion volumes of acoustic impedance, shear impedance and Vp/Vs ratio were produced using PGS' Prospect Scanner AVO/AVA workflow.

The data was processed with a state of the art anisotropic pre-stack time processing workflow comprising wavefield separation, pre-stack time migration, automatic dense velocity picking, wavelet destretch, spectral offset balancing and trim-statics. Close collaboration between the geophysicists and geoscientists ensured preservation of the signal and frequency bandwidth at maximum offset and the flatness of the gathers. The resulting data is therefore optimized for reliable interpretation, AVO analysis and seismic inversion workflows.

Geological Features Clearly Imaged

The seismic stack clearly images the geological features which are characteristic of a transform margin. The high frequency content allows accurate imaging with high resolution, and the low frequency content ensures good penetration down to the Cretaceous targets and better reflection continuity.

Within the intervals of reservoir interest, the Turonian and Albian sandstones, there are many interesting fan and channel anomalies. Interpretation and auto-tracking of these anomalies is reliable, as reflectors are continuous and well resolved throughout the section.

One of the interpreted features is a large fan with a very strong amplitude response which dominates the 2,845 km^2 survey. The most appropriate analogue to this is the Jubilee Field further west on the transform margin. The feature is also in the same Turonian hydrocarbon system as Jubilee, functioning locally up-dip at the Aje Field.

Another lead shows the combined use of full stack, relative inversion and angle stack information in order to better understand an anomaly. This was identified as a channel feature which includes a four way dip closure. The closure occurs on two levels, but when viewed with inversion attributes or an AVO screening attribute it is clear that the lower structure is higher risk, which is not so evident on the full stack image. Even working in an exploration context, using pre-stack information and attributes can provide a useful perspective and improve interpretation of the area. This area has many interesting anomalies, so use of pre-stack attributes can significantly help characterization and understanding.

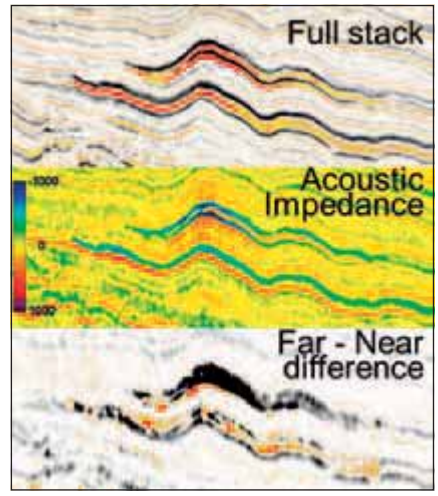
Expectation of Success

The African Transform Margin is a new major petroleum province, with offshore basins still relatively poorly explored. The majority of wells have historically been drilled on the shallow platform areas with the deeper slope and basin areas still frontier areas.

There is great expectation of exploration success in this extension to the prolific post-transform turbidite play fairway. The interpretation of this dual sensor seismic survey has reinforced this view. The proven reservoir interval has high potential with many anomalies, and the combination of high quality seismic data and attributes (AVO and pre-stack inversion) allows reliable interpretation and better understanding of these features.

ACKNOWLEDGMENTS: The authors would like to thank PGS and DPR for permission to show the data examples and the many colleagues at PGS Reservoir and PGS Data Processing who have contributed to this project. ■

A four way dip structure anomaly. Top: full stack seismic data; middle: acoustic impedance (blue indicates reduced impedance); and, bottom: ERG – an envelope calculation of difference between near and far stack (far(far – near)).*



Bringing the Lab…

Weatherford

…to the Field

HENDERSON WATKINS and REBECCA TECHEIRA, Weatherford International Ltd.

Bringing advanced laboratory analysis to the field: Weatherford International's new formation evaluation service brings advanced, laboratory-based testing techniques to the field, enabling faster, more informed reservoir management decisions for unconventional plays.

Weatherford's XRD-based RockWise service measures the compositional analysis of 30 elements (12 major and 18 trace). Applications of the data include assessing reservoir potential, identifying brittle zones and supporting geosteering operations.

Prior to developing any unconventional reservoir, an operator must confidently answer two fundamental questions. Firstly, are there sufficient quantities of hydrocarbon present in the formation, and secondly, can these hydrocarbons be extracted economically?

Weatherford Laboratories provides answers to these questions with its wellsite geosciences service, a recent addition to a robust portfolio of formation evaluation techniques. The service combines portable technologies with interpretative expertise to deliver reservoir measurements at the wellsite. These measurements help operators optimize production and reduce development costs in shale plays to ensuring timely delivery of reservoir data in high-pressure/high-temperature (HP/HT) environments.

Sharpening the View in Shales

Over the past decade, unconventional oil and gas plays in North America have flourished, as shale has shifted from being a cap rock for a hydrocarbon-bearing reservoir to a commodity rock in its own right – a viable production target holding vast quantities of oil and gas.

But until recently, operators working in shale plays have resigned themselves

to a 'perf and pray' mindset, in which they set their packers a certain distance apart, perforated every zone in exactly the same way, and then hoped that the resulting production profile from each zone matches their plan.

Increasingly, geologists understand that the data gleaned from rock cuttings and gas analysis can be used to optimize a well's completion so that production from each fractured zone is maximized. The ability of the wellsite geosciences service to accurately report on the geochemistry, mineralogy and elemental composition of each zone provides in-depth and near real-time reservoir information that conventional techniques such as core analysis cannot offer.

Conventional core analysis is typically not a cost-effective method in the long horizontal wells that characterize shale plays. For new shale plays, it is not uncommon to core three or four pilot holes, which requires sending these core samples to an offsite laboratory for analysis. Getting all the pertinent reservoir data back from these samples – the data that is important for ensuring that the laterals land to their optimal target depth and location – might take three to four months.

In this case, the operator has two choices: to either immediately drill the lateral without the benefit of this core data and make educated guesses as to where to frac, or to move the rig off location to drill another well, and come back to complete the lateral once the core analysis is available.

By contrast, Weatherford's new wellsite geosciences service provides a complete report of this reservoir information in 24 hours. Completion engineers can then take this information and identify the ideal spot to land their interval, almost immediately, and formulate the proper fracturing fluid for the formation.

Four Primary Technologies

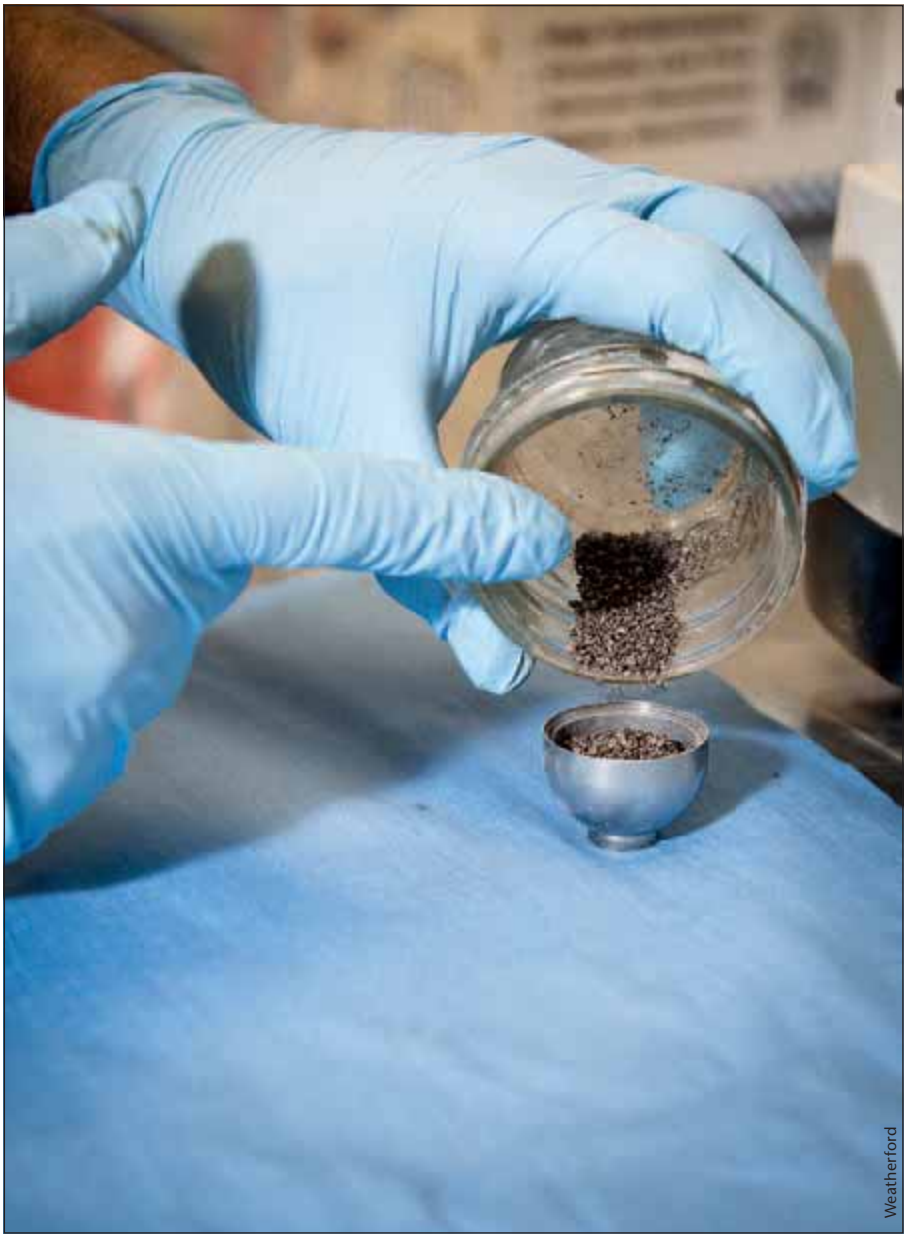
The wellsite geosciences service incorporates four primary technologies – the proprietary GC-TRACER® surface gas detector, the Source Rock Analyzer (SRA), an X-ray diffraction (XRD) tool and RockWise℠ X-ray fluorescence (XRF) – to enable field analysis of formation gas and rock samples. Unlike core samples, which have to be cut from the formation and analyzed in the laboratory, these gas and rock cuttings samples are a natural by-product of the drilling process and are therefore essentially free.

The surface gas detector system incorporates extraction technology to obtain and characterize formation gas samples from drilling mud. Taking only approximately 55 seconds, it provides precise compositional analysis of formation gases, including light-end alkanes, benzene, toluene, nitrogen and carbon dioxide. This data is used to elucidate the presence and quantity of hydrocarbons in a reservoir. The system's capabilities exceed those of traditional gas-agitator-trap systems, which prolong exposure of samples to air and leave substantial amounts of gas in mud, thereby skewing the analysis and providing a less accurate representation of the reservoir.

Also proprietary, the SRA pyrolyzes rock samples to offer insight into a reservoir's expected hydrocarbon production. Specific measurements include total organic content (TOC); hydrogen and oxygen indices, used to estimate kerogen type and quality; and thermal maturity, used to assess production potential.

Two rock characterization technologies – the portable XRD tool for

Rock chips are a primary source of input for Weatherford's wellsite geoscience service.



direct quantification of mineralogy and the XRF tool for direct measurement of elemental composition – help keep the wellbore in zone and locate brittle zones in formations, which is particularly important for shales. As a general rule, the more brittle a zone, the more receptive it is to hydraulic fracturing.

Instruments Designed for Mars

Mineralogical information provided by the XRD helps identify formation tops and variations within the formation, as well as determine the most attractive intervals for lateral drilling and where to fracture for optimal production. The instrument was initially designed by NASA to characterize the mineralogy of rocks on Mars. The space agency launched the XRD technology in November 2011 as part of a Mars Rover mission, and it will start analyzing the Martian landscape in August 2012.

Similarly, the XRF analysis directly measures the elemental composition of cuttings, providing data for up to 30 elements – 12 major and 18 trace elements – with a high degree of precision and within 30 minutes of sample collection. The primary use of this data is for chemostratigraphic correlation to increase confidence of borehole position. XRF-enhanced mineralogical determinations, including estimation of certain clay types and refined brittleness assessment, document subtle changes in rock composition that cannot be detected by other technologies. With this knowledge, drillers can make on-the-fly changes in trajectory to land and keep the wellbore in the target zone.

Frac Stages Reduced

An operator in the Eagle Ford shale gas play in Texas deployed the wellsite geosciences service to optimize their hydraulic fracturing program. The real-time formation data afforded by the service allowed the operator to reduce the number of logs run on well by four, which lowered the risk of getting a logging tool stuck in the hole and requiring additional rig and tool time to remedy the problem. And because the service provided the operator with a more accurate picture of which formation zones had the right combination of brittleness and TOC, they were able to eliminate two frac stages per well.

The significance of eliminating stages comes into focus when one considers a sobering statistic. According to a recent industry study, the act of blindly fracturing an entire interval can result in as many as 30 to 40 percent of the perforation clusters contributing only 1 percent of total production. This is all the more important when one considers that it is not uncommon to spend up to US$250,000 on one frac stage, and many shale gas wells may require up to 20 stages.

A 40 percent failure rate may translate to an operator overspending US$2 million on a single well. But by eliminating just one frac stage, the wellsite geosciences service pays for itself.

Data Acquisition with HP/HT

The wellsite geosciences service also offers benefits in high-pressure/high-temperature (HP/HT) reservoirs, in which ambient temperatures exceed 325°F (163°C). These conditions are typically too severe for conventional logging tools that have to be deployed downhole. By contrast, an XRF unit deployed at the surface can ensure acquisition of an elemental spectral gamma ray from potassium (K), thorium (Th) and uranium (U), measured from the cuttings. The data can then be used to update seismic models and verify the driller's location in the stratigraphic sequence.

Since its debut in early 2010, the service has enabled operators in North America, and increasingly in several South American shale plays, to streamline exploration projects, optimize wellbore placement, and gain a new measure of geological confidence as drilling programs proceed. ■

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Weatherford's mobile laboratories make advanced geochemical analysis at wellsite possible.

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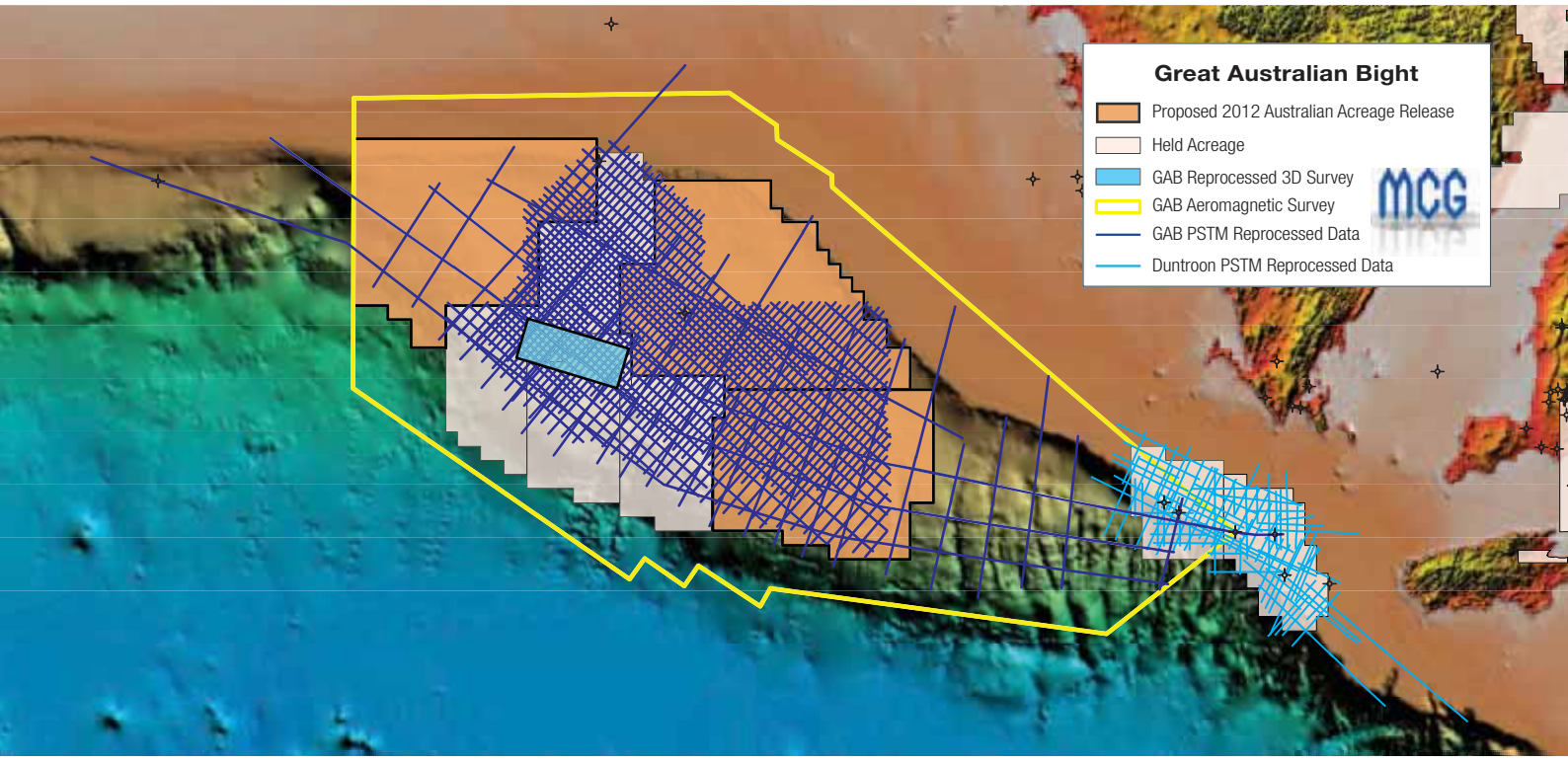

...COUNT ON **FUGRO**

The **Great Australian Bight** data package is a joint project with MCG. The data covers three permits proposed to be announced in the 2012 acreage release and provides a superior starting point for evaluation of this exciting frontier region.

- PSTM reprocessed 2D seismic data
- Post-stack reprocessed 3D seismic
- New high resolution aeromagnetic data
- Existing satellite gravity and marine gravity data
- Satellite seep data
- Integrated interpretation report

The Duntroon project consists of approximately 4,000 km of PSTM reprocessed 2D seismic data that straddles the Duntroon and Ceduna sub-basins.

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Is Shale Gas Bringing Independence?

Shale gas has helped the US to become the world's largest gas producer. Will shale gas and shale oil production lead America to energy independence?

THOMAS SMITH

The headline from the Forbes-INSIGHTS report, 2012 US Energy Sector Outlook reads "Majority of Executives See Energy Independence Achievable Within 15 Years, With Nearly Half Citing Natural Gas as the Most Crucial Fuel".

The Potential Gas Committee, a nonprofit organization consisting of knowledgeable and highly experienced volunteer members who work in the natural gas industry, reported from the Colorado School of Mines in Golden, Colorado that "…the United States possesses a total resource base of 1,898 Tcf as of year-end 2010. This is the highest resource evaluation in the Committee's 46-year history, exceeding the previous record-high assessment by 61 Tcf. **Most of the increase arose from reevaluation of shale-gas play in the Gulf Coast, Mid-Continent and Rocky Mountain areas**" *(author's emphasis)*.

A recent Wall Street Journal headline reads "It's Official: 'Age of Shale' has Arrived" and they say, "Shale is rocking the US energy industry to its core."

Headlines like these paint a very rosy future for US energy supplies. Two technologies have been key components in new shale oil and gas discoveries and a surge in production of both. Without long-reach horizontal drilling and multi-stage hydraulic fracturing these resources would remain largely untapped and uneconomic.

Birth of America's Gas Industry

Early Indian settlers in an area that is now western New York State near Lake Erie referred to flammable bubbles in the area's streams as 'burning the creek' and the village residents noted the smelly rocks beneath the water, whose bubbles ignited when lit. That village was Fredonia and would be the site where America's first commercial gas would be delivered, derived from the fractured shale rocks in the Marcellus Formation.

The first attempt to drill a gas well is attributed to William Hart, who moved to Fredonia in 1819. An eight meter deep well was drilled on the north-east side of the Main Street Bridge in the late spring of 1825. Gas was initially brought to two shops and a mill through small wooden pump-logs covered with tar laden cloth, which were soon replaced by lead and tin piping. The people were impressed that the gas lights did not emit an odor. Thirty-six gas lights were being lit in the village by November 1825, with usage measured by the world's first commercial gasometer, prompting Mr. Hart to form a private gas company to market the gas, thus becoming "the father of the natural gas industry".

Local use of gas from shallow, low pressure wells in fractured shale rocks like the Marcellus continued through the

Gary Lash

1920s until pipeline technology made it possible to bring in large volumes of gas from the mid-continent and south-eastern oil fields.

Second Era of Shale Gas

Starting in the 1930s, pipelines supplied large volumes of gas to the east coast markets; shale gas was all but forgotten. Numerous technical developments and 50 years later, shale gas became a target once more by the US Department of Energy (DOE), the Gas Research Institute (GRI), and a partnership of private operators. In the mid-1970s, this consortium conducted a study on the shallow Devonian Huron shale in the eastern US to develop technologies for the commercial production of natural gas. The partnership's research helped promote technologies that are critical today in the production of natural

Photo from 1850 of the cistern hole where gas accumulated above the first commercial gas well.

The Devonian Dunkirk Shale exposed here along the shores of Lake Erie was the source for America's first economic gas production in 1825. Now, similar fractured shale rocks across the US are once again attracting the attention of oil and gas producers.

Sedimentary basins across the US showing current and prospective shale plays.

gas from very tight shale rock. These technologies include the use of horizontal wells, multi-stage fracturing, and slick-water fracturing, but large scale shale gas production would still be years off.

Texas's Barnett Shale would become the first world's first large scale shale gas producer thanks to the pioneering efforts and perseverance of one company – Mitchell Energy Corporation, which first tested the Barnett Shale in 1981 (see *GEO ExPro* Vol. 4, No. 2).

Jointing and natural fractures make shale rocks like the Marcellus pictured here attractive units for the production of oil and gas.

This real success of the Barnett play would take many more years of applying different methods to a lot of wells. Mitchell Energy tried the first slick-water frac in 1997. Horizontal drilling started in earnest in 2002 with about 1,500 wells completed that year. Slowly, production increased from 380 Bcf in 2004 to 1,847 Bcf in 2010. In the first six months of 2011, production was up again to 1,092 Bcf or 31% of Texas's total gas production. There are currently 231 operators that have leased 10,550 km² across this field (Devon purchased Mitchell Energy and is the largest Barnett gas producer). As of September 2011, 15,316 wells have been drilled in the Barnett play.

Astronomical Growth of Shale Gas

The successful production of Barnett shale gas has now spread to other shale reservoirs across the US The Energy Information Administration's (EIA) Annual Energy Outlook 2012 (AEO2012) Early Release estimates 482 Tcf of unproved gas resources and 60 Tcf of proved reserves that are recoverable using current technology. The US

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Geological Survey's (USGS) most recent estimates are slightly lower with a mean of 336 Tcf unproved gas. Both estimates exclude Alaska.

While the Barnett Shale is currently the largest gas producer in the lower 48 states, the Marcellus may have the largest potential covering an area over 246,000 km². The most recent USGS assessment using data for the Marcellus through 2010 put the mean undiscovered gas at 84 Tcf and 3.4 Bb gas liquids. This estimate is huge by any standards and was considerably higher than the 2002 estimated mean of 2 Tcf. The EIA currently estimates 141 Tcf, down from last year's 410 Tcf of unproved gas resources in the Marcellus Basin but now within the USGS's 90% confidence range from 43 to 144 Tcf.

Philip Budzik, Operations Research Analyst for the EIA, points out, "What is evident about any of the published resource estimates is that less data translates to more uncertainty. This resource is relatively new and the long-term productivity is yet to be determined. Companies have concentrated on the 'sweet spots' with known high production rates in a given play and are gradually moving into new areas. New technical advancements, development of untested shale plays, and more production data will lead to refined resource estimates."

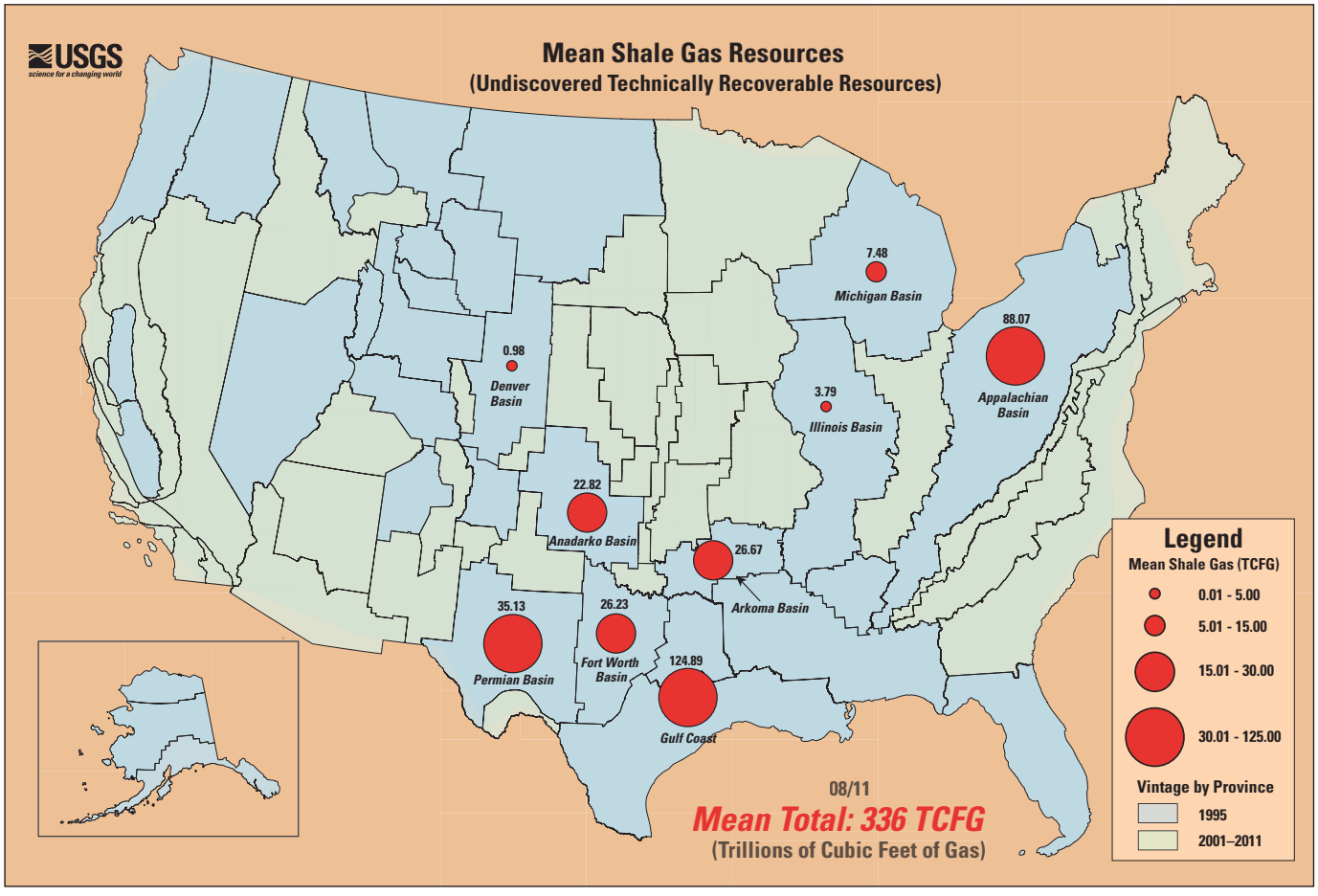
The Marcellus play provides clear

Assessment Methodology

According to Philip Budzik, "Both USGS and EIA use much the same data to assess continuous petroleum resources. The resource estimates are based on the play area, well spacing, and average expected ultimate recovery (EUR) per well for each shale play. One difference is that the EIA uses both proved reserves, those reported by companies to the Security and Exchange Commission as financial assets, and unproved resources in their computer model databases for projections. The USGS only estimates unproved resources. Another difference is that the EIA use averages, while the USGS used a probabilistic approach."

Published in 2010, the Improved USGS Methodology for Assessing Continuous Petroleum Resources states, "Rather than the traditional in-place calculation of resources with a poorly understood recovery factor, the USGS methodology was built to use well production information to better constrain estimates of recoverable volumes. This was a significant improvement, at least for those resource accumulations that already had significant production history available." This last statement is a key item when looking at resource estimates, and that amount of production data across a given play is one reason the assessments can change drastically over time. A second reason is that their technically recoverable resources are based on contemporary production practices. As new technologies become available, expect different resource estimates.

Distribution of undeveloped shale gas resources across the US



examples of how new data and technology can change resource estimates. The first USGS estimate of 2 Tcf was much lower than their current because it was completed before horizontal drilling and multi-stage fraccing had become commonplace. As in the EIA case, the new estimate was lowered considerably because between 2010 and 2011 drilling in the Marcellus accelerated rapidly and much more data became available. In fact, production doubled in 2011 alone, enabling them to refine their resource estimates.

The Barnett provides an example of a more mature play. Data from over 15,000 wells which average 1.6 Bcf in expected ultimate recovery (EUR) is available to these agencies for resource assessment. When this figure is combined with the well spacing and total area, fairly accurate resource estimates can be made. For example, the EIA uses these averages to calculate the current Barnett actively developed area of 23.81 Tcf gas reserves and 19.56 Tcf gas in the undeveloped portion of this play. The USGS has the mean undiscovered technically recoverable resources for the undeveloped Barnett at 26.23 Tcf. The EIA's resource estimates are well within the USGS's probable resources.

Shale and Tight Oil Plays

The success in the Bakken play (see GEO ExPro Vol. 9, No. 1, and Vol. 7, No. 2) and lower gas prices have promoted rapid growth in other tight oil and gas liquids plays. The Texas Eagle Ford play would be the next source rock tapped for its liquid hydrocarbons. Starting out with a shale gas play, operators began drilling into the wet gas window and finally into the oil window to capture the more valuable liquids. Production has increased from an annual oil and condensate production of just over 1 MMb in 2009 to 40 MMb for the first 11 months of 2011. Most of the other shale gas plays have potential oil and wet gas windows that are just beginning to be explored.

It should be noted that this is a very new resource and the USGS is already updating the Bakken resource assessment to be published in 2013 and that the estimates presented on the USGS map will be in a state of flux as more data becomes available and new areas are developed. The current government assessments do not include other major potential shale plays that are just starting to be tested such as the Utica, the Tuscaloosa in Louisiana and Mississippi, and some of the many source rocks along the Rocky Mountains to name a few (See Hotspot, page 98, for more information on these plays).

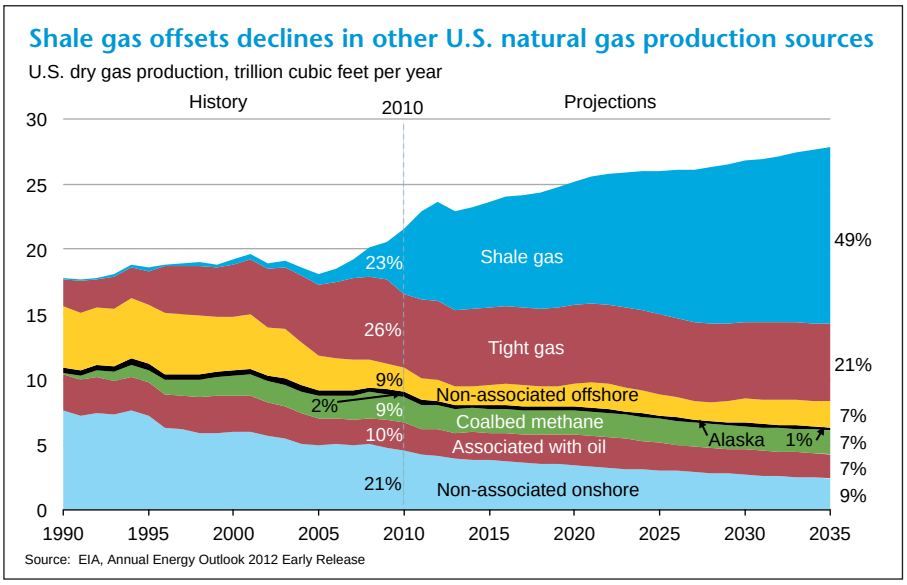
> The success of the Barnett Shale, as Dan Steward, who was there for that first test well in 1981, puts it "redefines our exploration model for shales. We are still learning and just about any area may be productive."

The Reality

This article started asking "Will shale gas and shale oil production lead to (US) energy independence?" There is little question that the potential of shale gas and oil is huge and new resources are being discovered across the country and the world. However energy independence may be difficult to achieve relying on just shale resources. ▶

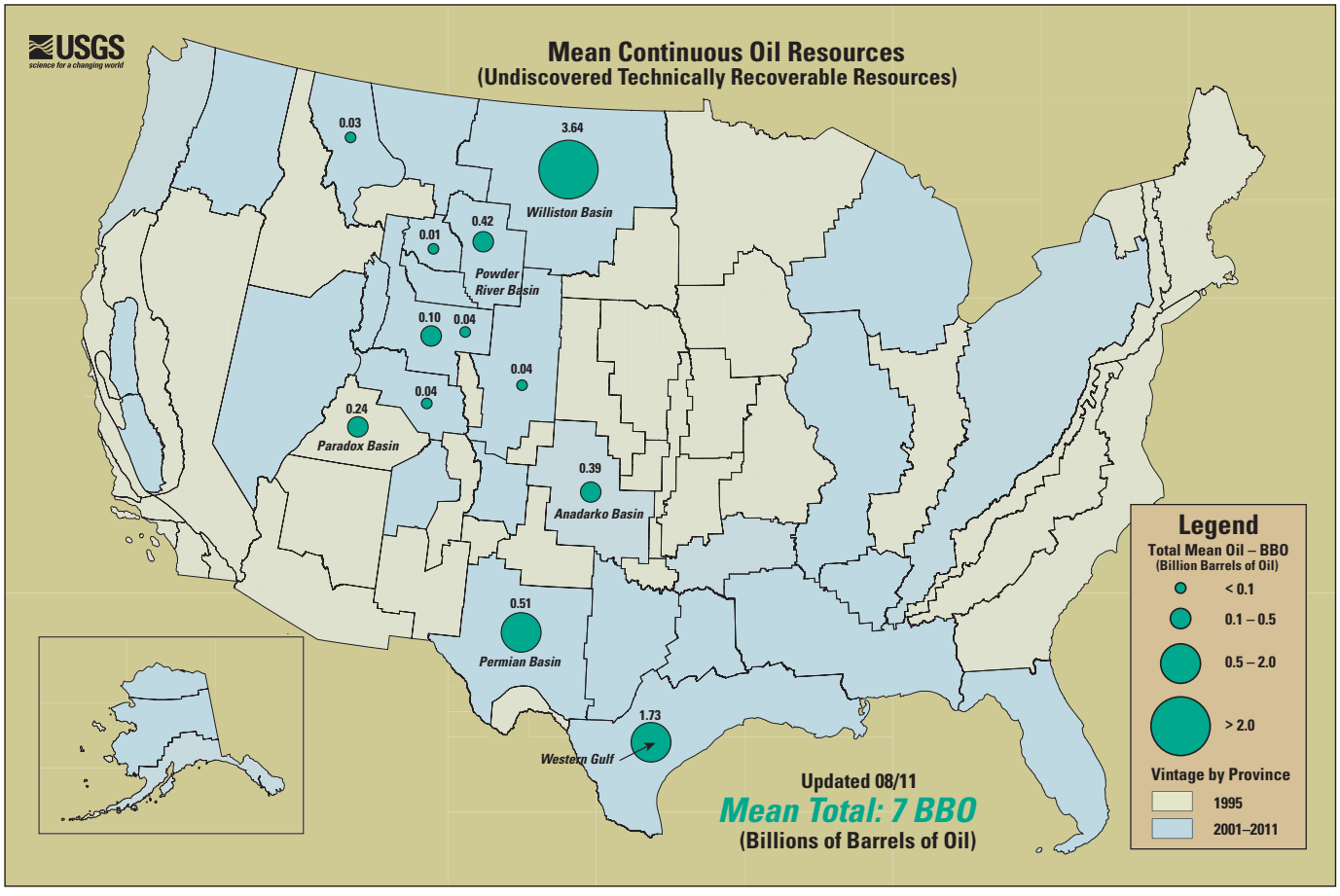
A recent National Petroleum Council (NPC) report titled "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources" puts some realistic terms to our energy future. The report highlights that: "Significant technology advances have unlocked abundant natural gas and oil resources." They conclude that: "The United States needs these resources to reduce oil imports (Author's note: The most recent EIA projections confirm this.) even after continued efforts to improve energy efficiency, and even as the nation transitions to a lower carbon energy system." They add that, "Realizing the benefits of these natural gas and oil resources requires environmentally responsible development of them in all circumstances, continually taking advantage of new technologies and evolving effective practices."

As the shale story began, without the drilling of many horizontal wells and multi-stage fracturing, the benefits from the resources these rocks contain will not be realized. To date, the Obama administration has given some mixed signals regarding shale development. However, in the recent State of the Union address he called for the government to develop a roadmap for responsible shale gas production and said "America will develop this resource without putting the health and safety of our citizens at risk." ■



Shale gas production has jumped dramatically in the last decade, accounting for less than four percent of the total annual production in 2005, which increased to 5 Tcf or 23% of total production in 2010. It is projected to be at 13.6 Tcf, making up 49% of total gas production in 2035.

The USGS latest (August 2011) estimates of mean continuous oil resources of 7 Bbo for the area shown with the largest resources in the Williston Basin (Bakken) and the Western Gulf (Eagle Ford). The EIA has a much higher resource estimate of 23.94 Bbo which includes 15.42 Bbo in the Monterey/Santos formations in southern California that the USGS is not considering at this time. A new EIA assessment will be released in May 2012.



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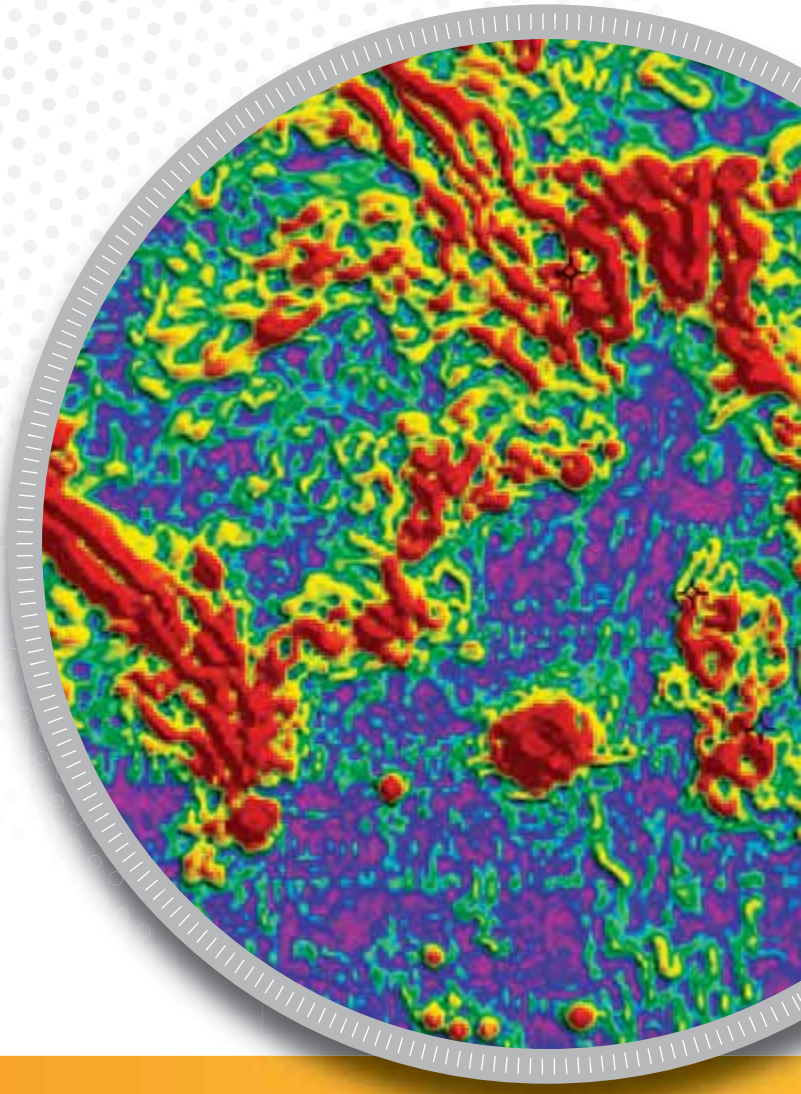

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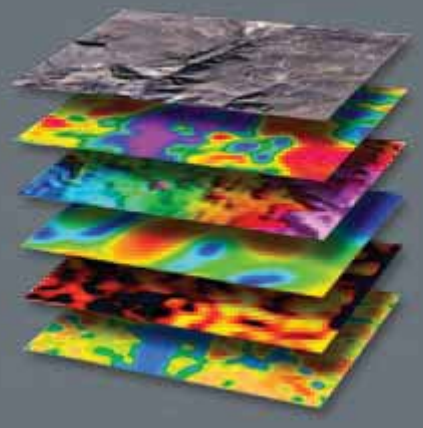

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Above, Below and Beyond

The Colorado Plateau: A Geologist's Paradise

Even if you have not been there, the Colorado Plateau is familiar to almost everyone through movies, commercials or – for students of geology – textbook examples

HALFDAN CARSTENS

The Colorado Plateau is said to make up America's most colorful and beautiful landscape. This is why the entire region is an extremely popular tourist attraction.

For the curious geologist, however, the Colorado Plateau is also a massive, outstanding outcrop of sedimentary rocks ranging in age from the Cambrian to the Tertiary.

Don't Forget Sunglasses!

The unlikely combination of stunning landscape, superb outcrops and favourable climate make the Colorado Plateau a desired destination for geology students from around the world.

Personally, I joined a group of master graduate students from the University of Bergen, Norway. This turned out to be the perfect way to get familiar with the plateau itself and at the same time absorb modern geology from up-to-date university professors – giving their excellent lectures standing on white, yellow, orange and red rocks of all ages.

The Colorado Plateau, with elevations ranging from about 1,000 to more than 4,000m, is made up of largely flat-lying sedimentary rocks that are offset vertically by faults and folds. The rocks are exceptionally well exposed thanks to an arid climate and deep down-cutting by – first and foremost – the Colorado River itself, but also by its many tributaries.

Standing on the rim of the many deep and colorful canyons is a real treat. In some places, you can watch hikers trotting slowly in the bottom; in other places bikers enjoy off-road cycling. Regrettably, in some places you will also spot motorbikes or cars, easily seen because of the small dust storms they create.

Getting around is easy. Walking or biking is just for local excursions; to get to the right places you definitely need a car.

But using your legs is a must. There is no way you can experience the best parts of this geological province just by stopping at parking lots for a few minutes and taking your photos.

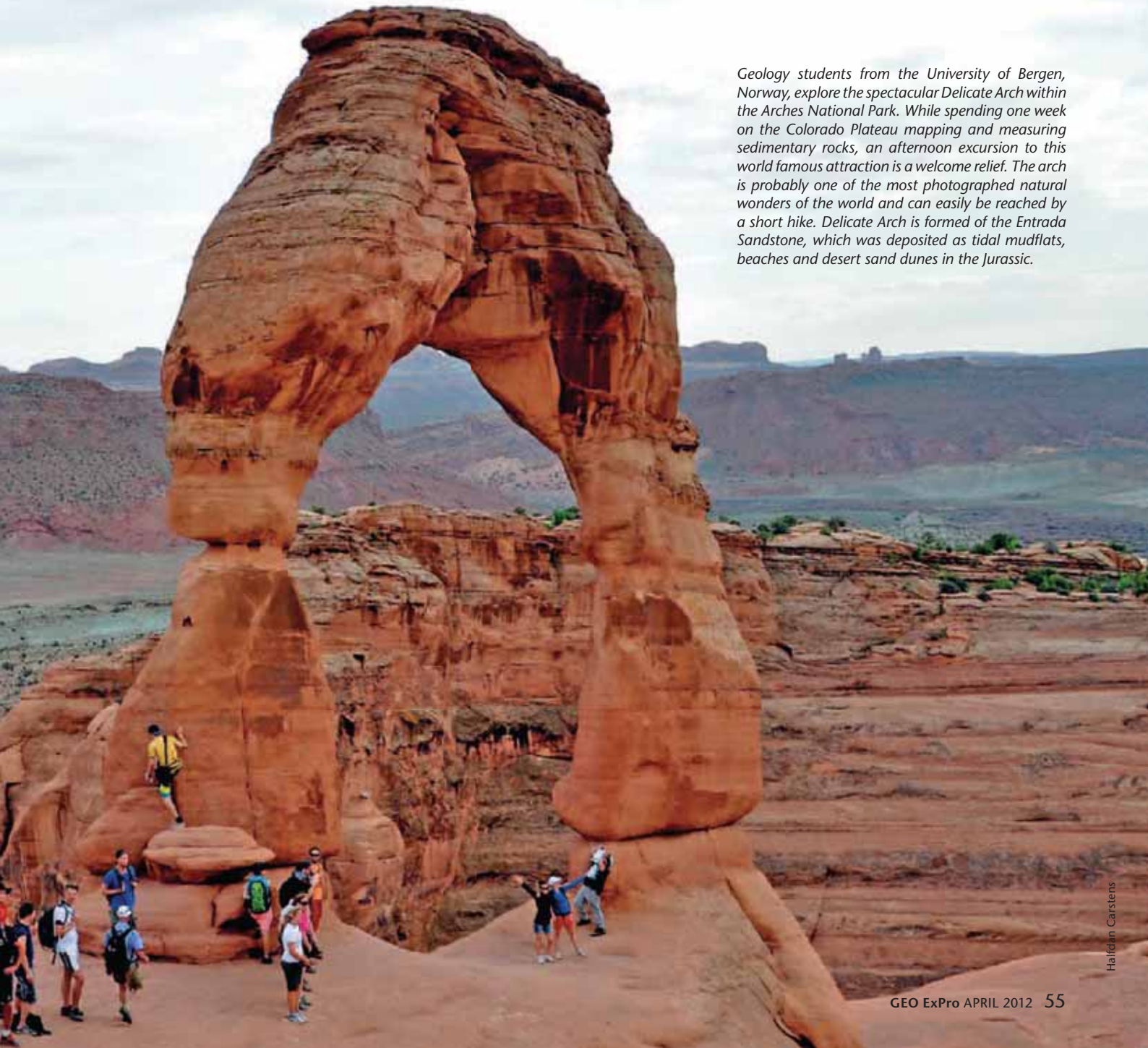
In my view, the ultimate experience is to either walk down the Grand Canyon (one full day, down and up, if you are fit), from the Permian all the way to the Precambrian, or – and maybe even better, but also a lot more expensive – to float down the Colorado River within the Grand Canyon (one week, no internet connection!).

However, a late afternoon short stroll through some of the short, designated walks in the Arches National Park can also be recommended – or in any of the other parks, if you like. If you choose to take advantage of the National Parks, you will also have the good fortune to see a series of instructive signs explaining the local and regional geology of the region. In that respect, the national parks of the US are second to none.

My first stop is always the Visitor Centres. For two reasons: firstly, you get the information you need to travel within the park, and secondly, they usually have a good bookstore.

A Layer Cake Pattern

The Colorado Plateau is a stable block of North America that is set off by linear trends in the Earth's crust. Its simple structural geology is contrasted by surrounding complex mountain chains that are heavily faulted and folded. Geologists appreciate the characteristic layer-cake patterns that have not been tilted or distorted by mountain building. In fact, the entire region seems to have been bypassed by the kind of mountain building that characterizes the nearby, but much younger, Rocky Mountains.



Geology students from the University of Bergen, Norway, explore the spectacular Delicate Arch within the Arches National Park. While spending one week on the Colorado Plateau mapping and measuring sedimentary rocks, an afternoon excursion to this world famous attraction is a welcome relief. The arch is probably one of the most photographed natural wonders of the world and can easily be reached by a short hike. Delicate Arch is formed of the Entrada Sandstone, which was deposited as tidal mudflats, beaches and desert sand dunes in the Jurassic.

Halfdan Carstens

The Colorado Plateau is a physiographic region of the south-western United States that takes its name from the Colorado River. The province covers an area of close to 350,000 km², equivalent to the size of Norway, within western Colorado, north-western New Mexico, southern and eastern Utah, and northern Arizona. The nickname 'Red Rock Country' suggests the brightly coloured rock left bare by dryness and erosion.

Precambrian rocks, consisting of highly metamorphosed gneiss and schist, are exposed in the uplifts surrounding the Colorado Plateau. As a visitor to the Plateau it is best to see them in the deeply entrenched Grand Canyon, where these grey-colored rocks are in contrast to the rainbow colors of the sedimentary rocks above.

The Great Unconformity

Resting on crystalline basement, the oldest sedimentary rocks of the Colorado Plateau are Paleozoic; thereafter Mesozoic and Cainozoic rocks follow, making up an almost complete Phanerozoic record. Therefore, if you have enough time, you can walk, step by step, through every geological period from the Precambrian to the Quaternary. When the time is right, I may volunteer to do exactly that. Imagine, one month (or more?) just hiking through well-exposed rocks of all ages and every kind of sedimentary environment. Lots of sunny days lie ahead of me.

The layered rocks of the Colorado Plateau form what is termed the Grand Staircase, which refers to a succession of cliffs rising northward from the bottom of the Grand Canyon of northern Arizona to the very top at Bryce Canyon in Utah. It is composed of resistant Paleozoic, Triassic, Jurassic, Cretaceous and Tertiary

'The Great Unconformity' of the Grand Canyon refers to a 1.2 billion year gap separating Precambrian basement rocks (bottom right of picture) from the overlying Cambrian Tapetes Sandstone. 'The Great Unconformity' (in red) is exposed in the Blacktail Canyon at the bottom of the Grand Canyon. It is easily accessible on a short hike for kayakers and rafters on the river.


Halfdan Carstens

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NEW THIS YEAR: The Vision: 2012 committee is pleased to introduce an initiative geared to attract greater numbers of students to the convention. For the first time, students may apply to the convention committee for a travel and accommodation grant that will make it easier to attend this important convention on a limited budget. Proudly sponsored by Husky Energy and Imperial Oil, this initiative will allow more students to network with industry professionals both on the exhibit floor and in the technical sessions as well as in such student-focused events as the Challenge Bowl and the new Industry/Student Luncheon.

Full technical program and information on how to register can be found at www.geoconvention.com

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Students undertaking field work in the mountain range named Book Cliffs. The name of the range reflects the fact that the geology can be read like an open book. Taking advantage of warm, dry days, the students learn how to interpret sedimentary environments and practice sequence stratigraphy. In fact, during the 1980s, Exxon geoscientists used the Cretaceous strata of the Book Cliffs to develop the science of sequence stratigraphy.

layers. In some places the uppermost step is a final, resistant lava cap. The layered steps are found, respectively, in the Grand Canyon multi-coloured cliffs (Paleozoic), the Chocolate and the Vermillion Cliffs (Triassic), the White Cliffs (Jurassic), the Grey Cliffs (Cretaceous) and the Pink Cliffs (Tertiary).

Characterizing the Plateau region are the many colors of the rocks. We find red, pink, yellow, green, purple and white caused by minor constituents of iron oxides (reds, pinks and

The Colorado Plateau is certainly not famous for its oil fields. The reason why geologists spend time around here is to learn more about reservoir rocks and structural geology. Nevertheless, oil fields do occur, and in some places nodding donkeys like this one can be spotted. Note the scenery in the background with typical Plateau cliffs.

Popular Tourist Spot

The Colorado Plateau has the greatest concentration of national parks and national monuments in the United States. Altogether 8 parks and 10 national monuments are found within four states centered on the Four Corners region. Indisputably, best known is the Grand Canyon, attracting about five million visitors per year, including quite a few curious geologists.

yellows) and unoxidized iron minerals (greens and purples). Manganese also plays a role (lavender). In addition we find contrasts of grey and black caused by granite and basalt. On top of that, the yellow and brown desert colors characterize certain regions, while vegetation, although sparse due to little precipitation, gives a striking green flavor, in particular in spring.

In order to fully appreciate the colors, the best thing to do is to use the whole day, from the very early morning before the sun rises until late evening when the sun sets. Then you will have the chance of experiencing unbelievable colors, in particular if thin clouds show up on the horizon.

Sculpting the Land

Approximately 5 million years ago the Colorado Plateau was uplifted some 1,000 to 1,500m. The uplift was facilitated by reactivation of pre-existing faults and accompanied by tilting of the plateau toward the north. This type of uplift which does not involve deformation is termed epeirogenic uplift.

Present-day streams established their courses at this time and because they were lifted high above base level (sea level) they began to rigorously cut into the sedimentary layer cake. This is exactly why the Book Cliffs – as well as all other cliffs and the walls of numerous canyons – can be read like a book by experienced geologists.

This is also why so many people come a long way to admire the work of nature. The canyons are textbooks when it comes to erosional and sedimentary processes of rivers.

Wayne Ranney, geologist, traveller, guide, author and dedicated expert on the geology of the South West, elegantly summarizes five rather independent conditions that have produced the unique landscape of the Colorado Plateau.

"The presence of a thick stack of sedimentary rocks, vivid and varied colors within these strata, the massive and widespread uplift, an arid climate and the presence of large rivers flowing through the region have acted in concert," says Ranney, who is also an experienced rafter with numerous trips down the Colorado River.

"If only one of these were to be removed from the landscape history, the plateau as we know it today would not exist," he says.

I got to know Wayne when leisurely floating through the Grand Canyon – with the Colorado Plateau above – looking at rocks for a full week. The combination of excellent outcrops, a stunning landscape, perfect weather and – last but not least – a knowledgeable and talkative guide should be the ultimate experience for the curious geologist.

Don't miss the Colorado Plateau. ■

High Expectations Morocco

With landscape varying from the wonderful, snowy High Atlas mountains to the sand dunes of the Sahara, vibrant Morocco is one of Africa's largest energy consumers, yet it remains remarkably underexplored, particularly along its long Atlantic Margin

JANE WHALEY

Although hydrocarbons were first investigated in Morocco over a hundred years ago, the country is still surprisingly underexplored, especially when compared to its North African neighbors like Algeria and Libya. The Atlantic Margin offshore, in particular, is undeveloped, with only 34 wells along the whole Moroccan Atlantic coast. Recently, however, companies have begun to look at this area, spurred by interest in Atlantic conjugate margins. Meanwhile, several recent successes suggest that the onshore area could also be revisited. The number of exploratory wells drilled in most of the fourteen sedimentary basins in Morocco is extremely low, with many not reaching their objectives or spudded off structure, and the number of exploration models tested so far is limited.

As one of the continent's largest energy consumers, Morocco is now the second largest importer of energy in Africa, importing 91% of its gas and a massive 99% of its oil requirements. Total annual production is about 2 Bcfg and comes from only two onshore basins, Rharb, north of Rabat (0.8 Bcfg) and Essaouira, south-west of Marrakech (1.8 Bcfg). With a rapidly growing economy, Morocco is under pressure to find new reserves at home.

Complex Triple Junction Setting

Morocco is intriguingly situated at the triple junction where the African continent, the expanding Atlantic Ocean and the Alpine Collision Zone all meet, resulting in a highly complex and fascinating geology, with rocks spanning all geological ages. It is dominated in the south by the Precambrian-Paleozoic Anti-Atlas mountain ranges, which were deformed and faulted during the Upper Devonian-Carboniferous Hercynian orogeny.

An event which had a significant effect on the petroleum geology of Morocco was the prolonged extensional period, resulting in the opening of the Atlantic. This commenced with

San Leon Energy are shooting seismic in the underexplored Zag Bas Draa Basin in south-east Morocco

Novoseis

Triassic-Lower Jurassic rifting, followed by massive regional subsidence in the Atlantic passive margin during the Jurassic and Lower Cretaceous. The extension was responsible for the deposition of up to 7 km of clastics, evaporites and carbonates in Mesozoic troughs, which were inverted to form the Mid and High Atlas Mountains in the Middle to Late Tertiary as Africa and Europe collided, an event which also resulted in the formation of the Rif Mountains in the north of Morocco.

Equally important was the widespread deposition of syn-rift salt in the Triassic, sometimes over a kilometre thick, in both onshore and offshore basins. These evaporites are found on both sides of the Central Atlantic rift, but in Morocco their overall depositional and stratigraphic setting are relatively poorly understood and their occurrence is complex and unpredictable, especially when compared to the 'post-rift' salt deposits further south in Angola and Gabon.

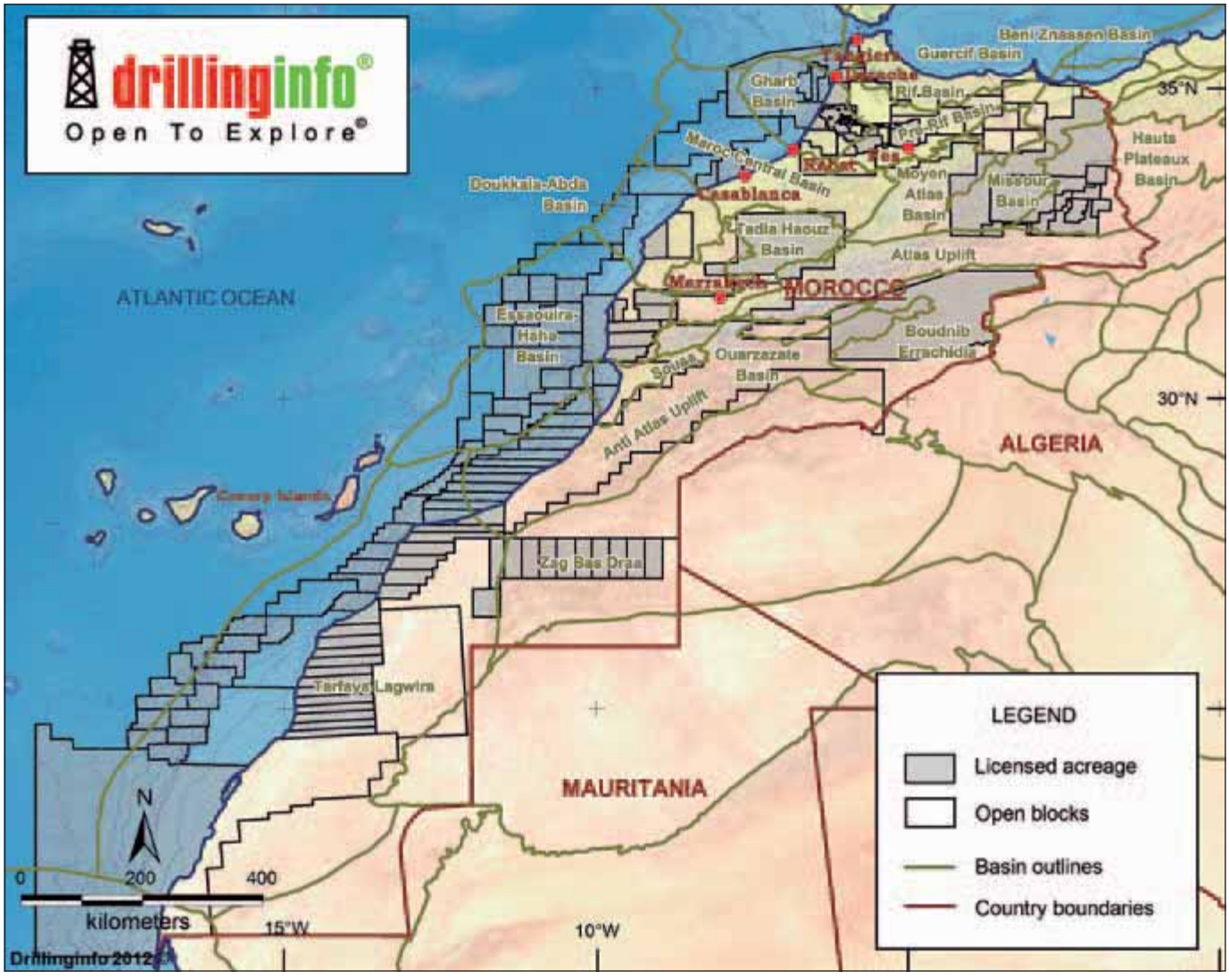
Sources, Seals and Reservoirs

Source rocks of varying ages have been identified in Morocco. As with much of North Africa, Silurian shales, which can exhibit TOC values as high as 12%, are an important source and are probably responsible for the highly mature gas in the eastern Essaouira Basin. Other Paleozoic organic facies are widespread throughout Morocco and oil sampled from both on and offshore wells have been found to be generated from Paleozoic source rocks.

Potential Mesozoic sources include Triassic lacustrine syn-rift infilling graben in the Atlantic coastal basins, while the Rif, Mid and High Atlas basins contain rich Lower Jurassic source rocks, up to 10% TOC and usually within the oil window. These are probably the source for the many seeps in these areas and may be quite widespread, possibly sourcing the light oil in the offshore Cap Juby structure in the Tarfaya Basin, while the heavy oils in the same structure are biodegraded Late Jurassic hydrocarbons. Marine Cretaceous rocks containing up to 20% organic matter are found throughout Morocco and if the overburden is sufficient, as in the offshore Atlantic Basins, these should provide a very effective source rock. Similarly, Neogene marls and shales, which are known to produce biogenic gas, can also produce oil if buried deeply enough.

Paleozoic Carboniferous deltaic to turbiditic reservoirs are found in the north-east and also possibly in the southern Tindouf Basin. Devonian carbonate reefs also form reservoirs, while Cambro-Ordovician sandstone and conglomerate reservoir intervals are

Basins and license areas of Morocco. The southern Tarfaya Lagwira Basin lies in the disputed territory of Western Sahara, which seeks independence from Morocco.



Sporadic Exploration History

Oil seeps have been known in Morocco for centuries. In 1923 the first discovery, Ain Hamra, was made near seeps in the Rharb Basin in the north-west, coming on stream in the 1930s. A few seismic surveys were undertaken in the 30s, before WWII stopped exploration.

In the 1950s seismic was first shot in the Souss, Guercif and Essaouira basins, resulting in small gas discoveries, and oil was found in the Prerif area. By 1958 cumulative production was still low, but a new Hydrocarbon Law successfully attracted foreign interest, and by the 1970s over forty companies held exploration licenses and 176 wells had been drilled, covering most basins. Fifteen commercial oil and gas accumulations fields were found, including Morocco's largest oilfield, Sidi Rhalem (1961) in the Essaouira Basin, and the only offshore discovery, Ras Juby (1969), which remains undeveloped.

However, by 1981 many of the new entrants had moved elsewhere. In 1980 Morocco's largest wet gas field, Meskala, with 52.5 Bcfg recoverable reserves, was discovered. To develop this and to encourage further exploration, the government set up ONAREP to explore for hydrocarbons both alone and with foreign companies. Between 1981 and 1990, 85 wells were drilled, and several discoveries were made, but by 1990 all exploration licenses had been relinquished. With a new hydrocarbon law in 1992 interest again increased, and between 1990 and 2000 fifteen onshore wells had led to the discovery of three gas fields. Only one well was drilled offshore, and that proved dry.

More attractive fiscal terms were introduced in 2000, and in 2003 ONHYM merged previous state entities ONAREP and BRPM. A new dynamic was implemented and a total of 40 onshore and six offshore wells have been drilled since 2000, leading to 11 gas discoveries. By the end of 2011 nearly 30 companies, mostly independents, had interests in Moroccan acreage, but large areas of acreage remain open both on and offshore.

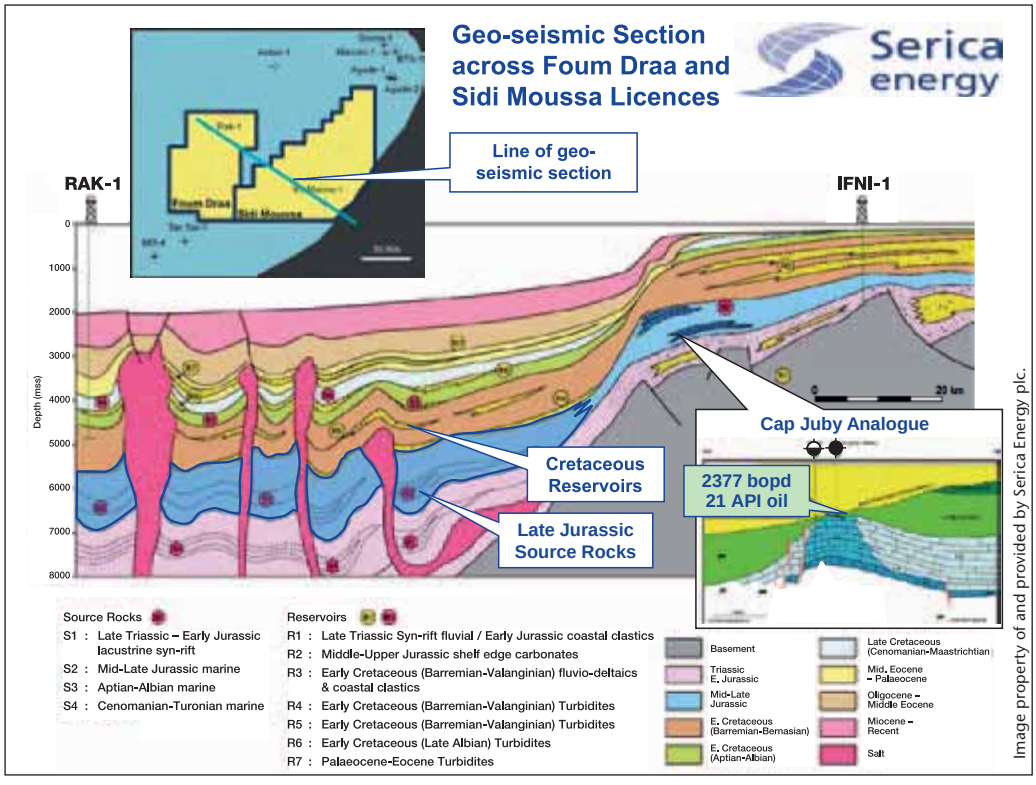
found in central Morocco. The majority of reservoirs, however, are Mesozoic. There are widespread Triassic fluvio-deltaic sediments, and many Jurassic reservoirs, varying from reef carbonates in northern basins to sandy dolomite and carbonate in the Essaouira Basin. Cretaceous sands with porosity as high as 30% are found in the central Tadla Basin and in the south. Tertiary reservoir intervals include sands in the Rif, the Rharb Basin and sands and conglomerates in and underlying the melange of the Prérif nappe.

Offshore, deep water gravity deposits such as turbidites provide the main reservoirs, although less well explored plays may include carbonate reefs and deltaic topsets further up-dip. Lack of offshore exploration means that a detailed knowledge of offshore basins is poor.

The main seal for the subsalt is provided by thick Triassic shale and evaporite layers, while Tertiary, Cretaceous and Jurassic marls and shales and in places salt seals the younger reservoirs.

The primary trapping mechanism is expected to be halokinesis, providing a variety of traps below and above the salt, particularly in the offshore. Other trapping mechanisms include tilted fault blocks, flower structures, extensional rollovers, compressional folding and stratigraphic pinch-out.

Schematic cross section through Serica Energy's blocks off southern Morocco, illustrating the variety of prospective offshore plays.



Conjugate Margin and Offshore Potential

Much of Morocco remains hardly touched by the drill bit, particularly the offshore Atlantic Margin, where only a few wells have been drilled in an area that extends along 3,000 km of coast and is up to 150km wide. The majority of these wells date from before 2003 and tested Jurassic carbonate objectives in shallow water areas. Many had shows, proving working petroleum systems, but Cap Juby was the only discovery. Further indications of the potential of the offshore Moroccan Atlantic margin come through comparisons with its conjugate margin in Nova Scotia. Corresponding

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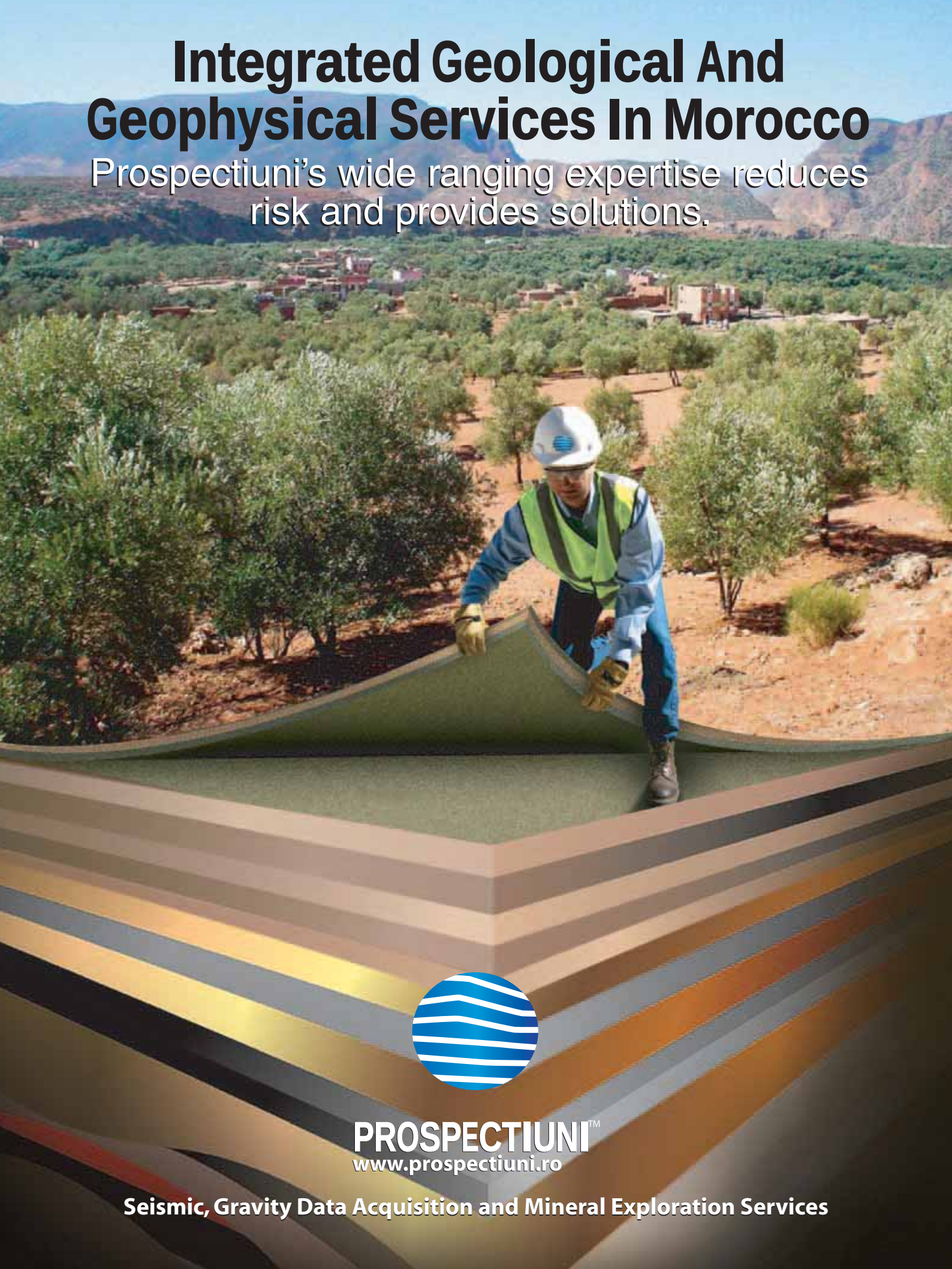

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seismic sections show a convincing symmetry in structure and stratigraphy. In the Scotian Margin off Canada over 200 wells have resulted in 23 fields and proven resources of 6 Tcfg and 200 MMbo, suggesting that Atlantic Morocco, with only 34 wells, could hold significant undiscovered reserves.

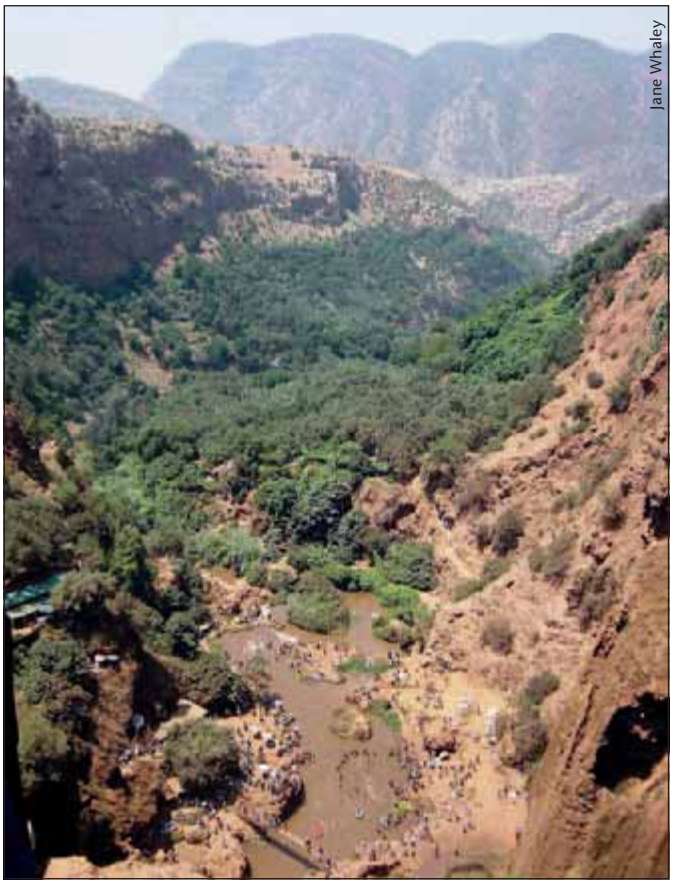
A number of almost untouched offshore play concepts have been identified, including Tertiary and Upper Cretaceous sediments trapped by salt walls, charged by Cenomanian-Turonian source rocks. This play was unsuccessfully tested by three deepwater wells in 2004. A 2009 well about 70 km south-west of Tangier also tested the Tertiary and found a 90m gas column. Lower Cretaceous deepwater sandstone turbidites, charged by Lower Cretaceous and Jurassic shale intervals, were unsuccessfully tested in 2008. Along the Jurassic shelf edge and the present upper slope domain, Lower and Middle Jurassic further deepwater sandstone turbidites, sourced by Jurassic or older shale intervals and trapped in structural fault rotated blocks and stratigraphic reef build-ups, are expected. Similar turbidite reservoirs sourced by Cretaceous and Jurassic shales form the main sub-salt plays, with hydrocarbons trapped in salt-induced structures. There is also potential for discoveries in Triassic red beds and fractured Paleozoic sandstones and carbonates.

Serica Energy has identified 33 prospects and leads and over 2.9 Bboe unrisked reserve potential (Serica's best technical estimate) in its two large blocks off Agadir, in a range of halokinetic, stratigraphic and structural plays. About 100km to the north, off Essaouira, Kosmos has a multi-well program targeting Cretaceous and sub-salt prospects on channel reservoirs. Further offshore PuraVida Energy have identified several leads, including a 790 MMbo (mean) prospect it believes to be a lookalike to Jubilee in Ghana. Kosmos have also identified a very large, unexplored Cretaceous river delta system with potentially billions of barrels further south off the Western Sahara area, while Maghreb Petroleum is looking offshore Casablanca, with objectives in pre-nappe Paleozoic, Mesozoic and Tertiary rocks and in post-nappe Miocene sands. And these are just a few examples of the potential many companies believe could lie offshore Morocco.

East of Tangier and into the Mediterranean lies the Alboran Basin. The geology here, the result of the collision of Africa and Europe, is complex, but there are potential turbiditic reservoirs, Tertiary organic-rich shales and a variety of possible stratigraphic and structural traps. With only two exploration wells and very little seismic, this area is seriously underexplored.

The ancient port of Essaouira looks out over the rough and windy seas of Morocco's Atlantic coast. It has attracted visitors for millennia, from the Phoenicians in the 7th century BC, to Orson Welles, who shot his 1952 Othello here. It is now interesting explorationists, who believe billions of barrels of oil may lie offshore.


Jane Whaley


Jane Whaley

Looking over the edge of the Cascade d'Ouzoud in the High Atlas mountains to the valley 110m below. Faulted Jurassic rocks are overlain by Quaternary lacustrine limestones.

Untapped Potential and Oil Shale

Onshore, there remains considerable hydrocarbon potential throughout Morocco, in almost untouched areas as well as heavily explored ones. The Rharb Basin, for example, the setting for the first commercial discoveries, is still attracting interest, being one of only two actively productive basins at the moment. Circle Oil has made ten commercial gas discoveries from 11 wells drilled in the northern part of the basin since 2008. As the basin lies close to large population centres, the small, shallow fields found to date have proved profitable. With over 3,000m of Upper Miocene clastic sediments above the nappe complex and a thick series of infranappe Eocene and Oligocene turbidites, there remains considerable potential, particularly in the practically unexplored deeper parts of the basin, where there may be sufficient depth of burial for oil generation.

Similarly, the Rif mountains folded belt in northern Morocco was a hydrocarbon-producing province until the 1950s, mostly from Tertiary turbidites or thrust-related plays with Jurassic reservoirs. Exploration in the area is now concentrating on the deeper reservoirs and also moving to the almost completely unexplored area near the city of Fez, where Cabre Maroc has

Clearly see thin layers

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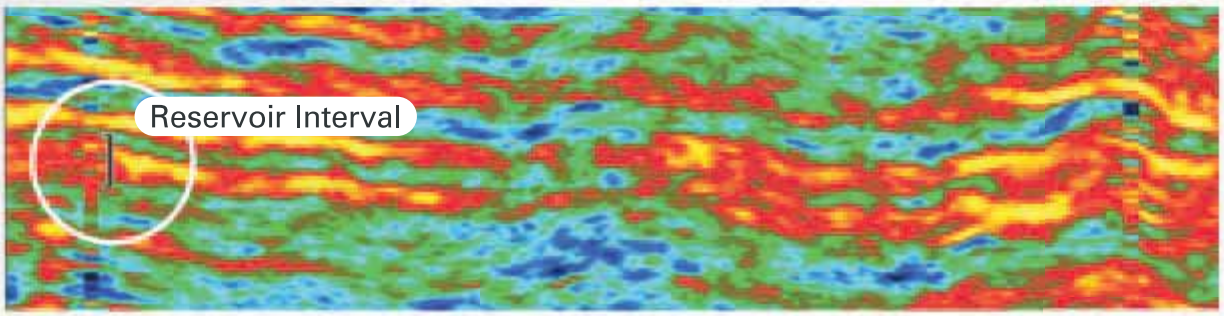
Ambiguous detail from seismic



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identified a number of large prospects.

At the opposite end of the country is the large, almost unexplored, Zag Bas Draa Basin, the westernmost extension of the prolific Paleozoic basins which extend right across North Africa. The basin extends over 96,000 km^2 and has almost no seismic coverage and only 27 wells, all drilled between 1959 and 1964. With over 6 km of Paleozoic, including thick Silurian shales, this basin could well hold untapped potential. San Leon Energy, for example, considers that its large Zag permit in this basin has estimated resources over 500 MMboe.

Evening shadows and the last rays of sunset playing against the courtyard of La Grande Mosquée Hassan II in Casablanca, a seaside mosque of spectacular size and grandeur.

Increased Production Needed

Ever-increasing energy demands and a decreasing number of large discoveries turned the attention of Moroccan geoscientists to unconventional resources. A first assessment of possible unconventional gas reservoirs, based on rock descriptions and geochemical data such as vitrinite reflectance, TOC and Rock-Eval analyses, showed that the subsurface contains a significant number of interesting shale layers, particularly in the Paleozoic. The main shale gas reservoirs are the Silurian sequence, with black 'hot' shale at the base, characterized by a high TOC content ranging from 1 to 12%.

Part of the famous Djemaa el Fnaa square in Marrakech – the vibrant beating heart of Morocco

Oil shale is also under development – in fact an oil shale pilot plant produced from the Upper Cretaceous Tangier oil shales in Northern Morocco between 1939 and 1945. San Leon Energy is involved in the Tarfaya oil shale project in the south, and has drilled a number of appraisal wells, estimating that there are in place reserves of about 22 Bbo in an Upper Cretaceous eroded anticline. This resource is also found at Timahdit in the Mid Atlas, where the Upper Cretaceous oil shales are up to 250m thick and estimated reserves are 15 Bbo in place.

Morocco is considered to be one of the most politically stable countries in Africa, virtually untouched by the recent troubles in neighboring countries, with a democratically elected government. The fiscal terms for hydrocarbon exploration are considered to be very favorable, with long duration permits, total exemption from income tax for ten years after first production and the state paying its share of participation.

With a growing population and economy – GDP grew by 4.6% in 2011 – as well as a major phosphate industry, which needs natural gas for processing, Morocco is looking to international companies to help fill its energy gap. It would appear that there are plenty of resources out there, both on and offshore, just waiting for companies to explore and exploit.

Acknowledgement: Many thanks to Haddou Jabour of ONHYM and Dimitri Massaras of DrillingInfo International for assistance with this article. ■

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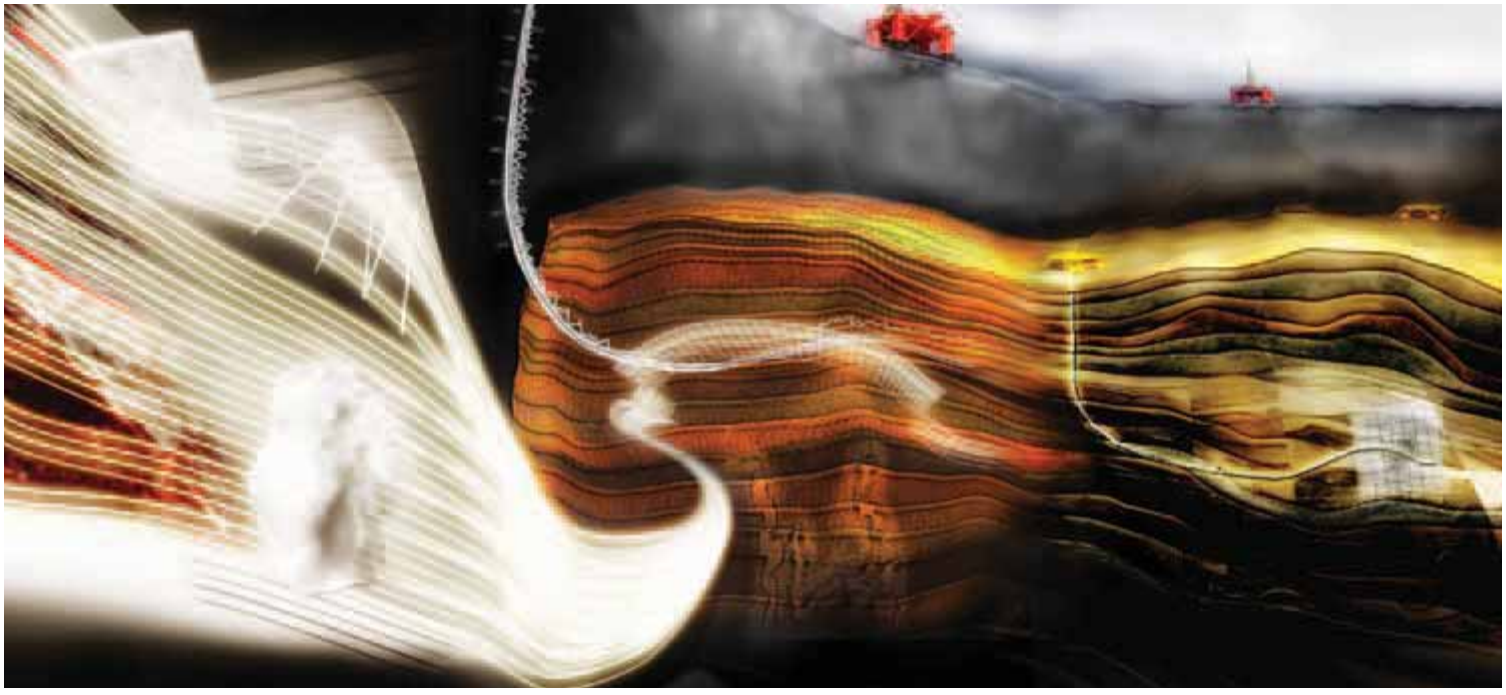

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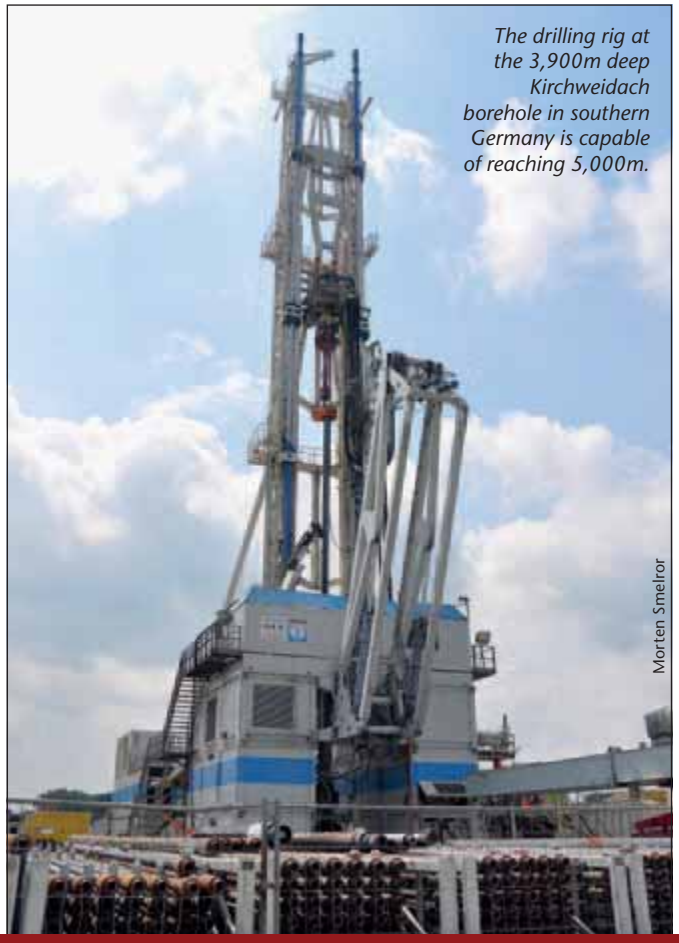
Going Deep for the Heat

Geothermal energy is becoming an increasingly hot topic. Recent research suggests that even areas outside 'high-temperature fields' may be sufficiently warm to generate electricity.



The drilling rig at the 3,900m deep Kirchweidach borehole in southern Germany is capable of reaching 5,000m.

Morten Smelror

MORTEN SMELROR, Geological Survey of Norway

Beneath our feet there are rich reserves of heat and energy stored in rocks and groundwater. On average, with increasing depth, the temperature increases by around 3°C per 100m. In the upper surface layers the heat in the ground comes from the sun. A number of quantitative models from geothermal low activity areas (i.e. on stable platforms outside tectonic and volcanically active areas) show that at shallow depths down to a few hundred meters, mean annual surface temperature is the main factor controlling subsurface temperature. Geological variation in the underground, such as heat flow, heat production and thermal conductivity, first become significant around 1,000m and deeper below the surface.

At depth, some of the heat comes from the cooling of the Earth's core, but most is from decay of radioactive elements, mainly uranium, thorium and potassium, in rocks of the crust. This means that the geothermal gradient (the increase in temperature with depth) varies with the chemical composition and age of the rocks. As one example we could mention the radioactive Løvstakken Granite, near the city of Bergen in western Norway, which shows an average heat generation value of 8.03μW/m³, which is more than twice as much as normal levels for Norwegian granitic basement rocks. On a global scale the Earth's surface heat flow averages 82 mW/m², and the estimated total thermal energy above mean surface temperature to a depth of 10 km is 1.3x1027J, equivalent to burning 3.0x1017 barrels of oil.

The potential for utilizing geothermal energy from deep underground is generating increasing interest, as previously discussed in GEO ExPro Vol. 4, No. 5. Exploration drilling and geothermal heating plants already on steam in Europe have documented that many areas have good potential for using geothermal for heating, but also that some areas outside the well-documented `high-temperature fields` may have temperatures at depths sufficient for generating electricity.

Heating from Shallow Sources

Geothermal energy is extracted from within the earth via water, occurring either in liquid or steam phase. By using geothermal heat-pumps, geothermal energy can be obtained from low-temperature sources, and used to heat workplaces, hospitals, schools and our homes. More than 80 countries around the world today use geothermal energy for heating. Since ground-source heat for household warming is commonly extracted from shallow boreholes between 100 and 200m deep, the key factors controlling the effect and economy of installations for extracting geothermal energy at shallow depths are mainly linked to the overburden, hydro-geological activity underground, and the capability of the rocks to act as reservoirs and water carriers. We therefore need information on the spatial distribution, the porosity and the permeability of the geothermal reservoirs to evaluate the geothermal potential of a certain area.

With a few exceptions, geothermal energy for heating has been used only rarely in Europe. In the Paris region, a limestone reservoir with an area of 15,000 km² provides temperatures ranging between 56 and 85°C and has been exploited to heat

the equivalent of 150,000 homes for the past 20 years. For a geothermal heating plant, water at less than 100°C would be sufficient, and 60-70% of the energy used in Europe is for low temperature applications. Recent studies carried out by GeoForschungsZentrum Potsdam (GFZ) have shown that large areas of the North German basins, the foothills of the Alps and the Rhine Graben are suitable for extracting heat from the ground. A geothermal heating plant established in Neustadt Glewe in Mecklenburg has been using water at a temperature of 98°C from a depth of 2,300m since 1995. GFZ has estimated that, looking at the geological and the geotechnical requirements, it would be possible for 17,000 plants to generate heat from the North German basin alone. However, one limitation is that geothermal energy must be used close to where it is generated, as it is not economically viable to transport such energy over long distances.

Drilling Deeper

In areas with high thermal gradients, like the volcanic active zone in Iceland, geothermal steam and hot water can be used to generate electric power. But even in low-temperature areas water with high temperatures can be found at depth. Water pumped from the depths at temperatures of 100-150°C can transfer heat via a heat exchanger to a heating circuit containing a liquid with a low boiling point. The gas pressure generated in this way drives a turbine to produce electricity. Going for the deep heat seems to become more and more technological feasible and economic attractive.

In Kirchweidach, in southern Germany, a 3,900m deep borehole was completed in summer 2011. The target was a karstic carbonate Upper Jurassic reservoir with good permeability and with water temperature reaching 130°C. This is used to produce electricity, in addition to the heating power plant capacity. The plan is to produce up to 13,000 MWh per year. The drilling was carried out with GFZ's InnovaRig, which proved very efficient. The drilling started in November 2010, and after one month the drill-bit had reached 2.5 km. The well is deviated, so that by 3,800m the horizontal deviation is almost 600m. The total concession area for the geothermal drilling is 76 km², with two deep boreholes planned. After completion of the two Kirchweidach boreholes, new drilling for geothermal energy will be started in the nearby district.

The use of geothermal heating and energy produces no nitrogen oxides, sulphur dioxide or carbon dioxide. One megawatt of power will provide enough electricity for about 1,000 households. This would prevent about 3,000 ton of carbon dioxide from entering the atmosphere every year. There is a green light for further developments of the use of the heat beneath our feet. ■

InnovaRig has a high degree of automation (pipe-handling system, automatic round trip equipment) and applies new technologies like casing while drilling, directional drilling, wire-line coring and air lift drilling. However, joining the pipes still require hands-on skills and experience. By using silent operations and high safety and environmental standards, this rig was used to drill for deep geothermal energy within the very city center of Hanover, with no complaints from the residents living close to the drill-site.


Morten Smelror

Defining Reserves & Resources

Effective resource management in a globalizing economy requires accurate assessments of fossil energy and minerals resources.

JANE WHALEY

How can we ensure that countries, companies and organizations are all assessing and estimating their reserves in the same manner?

This is an issue which has been under consideration for many years, and although a United Nations Framework Classification (UNFC) for Solid Fuels and Mineral Commodities has been in place since 1997, and UN members encouraged to use it, it did not cover oil and gas. So in 2001 the UNECE (United Nations Economic Commission for Europe) Committee for Sustainable Energy created an Ad Hoc Group of Experts to extend the principles of this Classification to other energy resources, like oil, natural gas and uranium.

As David MacDonald, Vice Chairman of the Bureau of the Expert Group on Resource Classification (EGRC), explains; "We work in a global industry, and need global standards that are clear and consistently communicated. By harmonizing energy reserves and resources terminology, we can obtain a more reliable and consistent estimate of global quantities of fossil energy, both in place in the subsoil and recoverable. In addition, increasing overlap between minerals and petroleum extraction methods, such as the mining of bitumen and other nonconventional petroleum operations, makes a common generic system essential. Developing the UN Framework, the universally applicable instrument for classification based on market criteria, was the obvious way forward. By talking to a wide range of the stakeholders involved, we have been able to develop an international scheme that can act as an umbrella for national systems for reserves and resources evaluations, making them comparable and compatible."

In 2004 the initial classification, UNFC-2004, was published. Since then, the EGRC has partnered with the SPE and CRIRSCO to ensure that the Classification is in harmony with and meets the specifications of the Petroleum Resources Management System of the SPE and its co-sponsors (WPC, AAPG and SPEE) and the CRIRSCO Template (which is widely used as the basis for solid minerals classification). As a result, a revised version, UNFC-2009, was approved for use in November 2009.

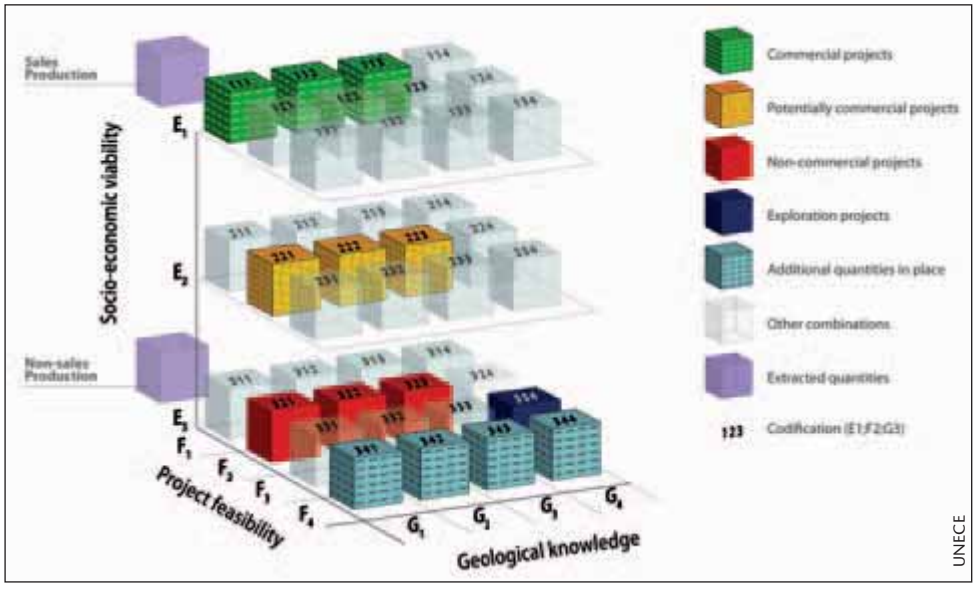
Three Dimensional Representation

How does such an all-encompassing classification system work?

"UNFC-2009 is a generic principle-based system in which quantities are classified on the basis of the three fundamental criteria," David explains. "These are economic and social viability (E), field project status and feasibility (F), and geological knowledge (G), using a numerical coding system, and each of these are sub-divided into three or four categories (e.g. E1, E2, E3), which are each defined using plain, generic language. Combinations of these criteria can be used to create a three-dimensional classification system with three axes; E, F and G."

"The E axis designates the degree of favorability of social and economic conditions in establishing the commercial viability of the project, including consideration of market prices and relevant legal, regulatory, environmental and contractual conditions," he continues. "The second set, the F axis, designates the maturity of studies and commitments necessary to implement development projects, ranging from early exploration efforts before a deposit or accumulation has been confirmed, through to

UNFC-2009 can be visualized in three dimensions, with the categories and optional sub-categories being the building blocks of the system. It can also be represented in a two-dimensional tabular version



Total Commodity Initially in Place	Extracted	Sales Production			
		Non-Sales Production			
		Class	Categories		
			E	F	G
	Future recovery by commercial development projects or mining operations	Commercial Projects	1	1	1, 2, 3
	Potential future recovery by contingent development projects or mining operations	Potentially Commercial Projects	2	2	1, 2, 3
		Non-Commercial Projects	3	2	1, 2, 3
	Additional quantities in place associated with known deposits		3	4	1, 2, 3
	Potential future recovery by successful exploration activities	Exploration Projects	3	3	4
	Additional quantities in place associated with potential deposits		3	4	4

UNFC-2009 displayed in 2D tabular format

a project actively extracting and selling a commodity, reflecting standard value chain management principles. The third set of categories (the G axis) designates the level of confidence in the geological knowledge and potential recoverability of the quantities."

The categories and optional sub-categories are combined in the form of 'classes', which are uniquely defined by a particular combination from each of the three criteria, E, F and G. For example, if the estimated quantities in a resource can be classified as E1, F1 and G1, the project is designated as 111, which would be considered as 'proved reserves' under the SPE-PRMS system. The numbers are always quoted in the same sequence (E, F, G) and the numerical code is used so that the Classification can be independent of language or alphabet.

Obviously, except for past production, quantities are always estimated, and this uncertainty is communicated either by quoting discrete quantities of decreasing levels of confidence (high, moderate, low) or by generating three specific scenarios or outcomes (low, best and high estimates). The former approach is typically applied for solid minerals, while the latter method is commonly used in petroleum.

"There are also efforts underway to extend the UNFC to address renewable energy resources, which would allow a meaningful comparison of renewable and non-renewable energy projects, David adds. "Currently, there are no classification systems that are applicable to all renewable energy resources."

Benefits of Standardized Classification

What are the benefits to the industry in ensuring comparable reserves and resources information?

"I think they are very significant," David replies. "Harmonized energy reserves and resources terminology offers a key to obtaining a more reliable and consistent estimate of global quantities of fossil energy, both in place in the subsoil and recoverable. It aids transparency and improved comparability of assessments of asset or company values, and, as we all know, better data leads to more informed and efficient investment decisions. However, ensuring that there is a method of classification that meets the needs of all users requires understanding and consistency in both application and standard setting."

The UN Framework Classification is a long-term activity, aiming to provide a system which is internationally applicable and has international acceptance; a flexible system for application at global, national, industrial or institutional level. By developing a system that is based on a numerical classification code which is simple and intuitive to use, UNFC-2009 provides a global communications tool that transcends language, commodity type and extraction methodology. ■

David MacDonald is the Vice President, Segment Reserves for BP, where he is responsible for managing the group policy on estimation, categorization, approval and disclosure of reserves and resources. He is Vice Chairman of the United Nations Economic Commission for Europe Expert Group on Resource Classification` and a member of the AAPG Committee on Resource Evaluation and a past member of the SPE Oil and Gas Reserves Committee.

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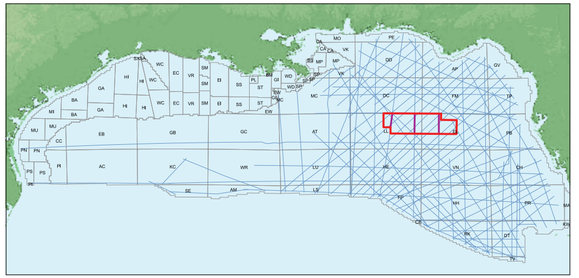
Florida – The Next US Frontier:

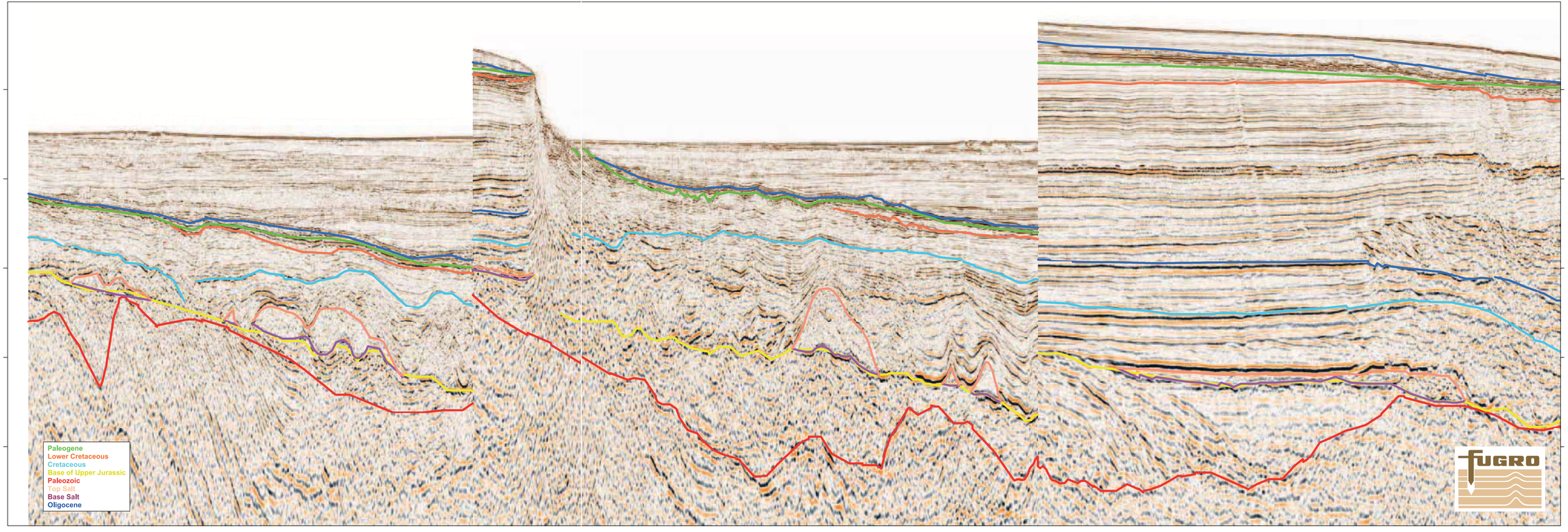
Revisiting an Old Exploration Region of the Gulf of Mexico with Modern 3D Data…

Fugro Multi Client Services (FMCS) Inc has just completed the first phase of its campaign offshore Florida. The 3D survey was designed based on Fugro's regional 2D data in the area and covers more than 28,500 km² (11,000 square miles). It covers a large area of the Elbow and Lloyd OCS areas in anticipation of future Lease Sale activity as planned before the Macondo incident. Results from previous exploration phases and preliminary data suggest that the area is highly prospective and it also covers the northern salt basin of the region.

This survey compliments the regional grid of 2D seismic, gravity and magnetic data that make up the Deep East Survey acquired from 2008 to 2010 in anticipation of the planned Lease Sales. These plans were changed by the Government's reaction to the Macondo incident. Fugro continues to look east and is currently acquiring a long offset 3D survey that ties the planned Lease Sale area to open future areas. Companies continue to look at this region as a new area for exploration.



Map of the Gulf of Mexico showing the lines used to make the composite seismic lines shown on this page in purple.



Three 2D line segments across the 3D survey exhibiting three major geologic features. The segment on the left shows the steeply dipping reflectors of the Paleozoic strata below the red horizon; the middle segment exhibits two salt structures above an early Mesozoic basin; and the segment on the right shows a prograding sequence in the early Mesozoic basin which is capped by a thin layer of salt followed by the thick Mesozoic strata.

Offshore Florida

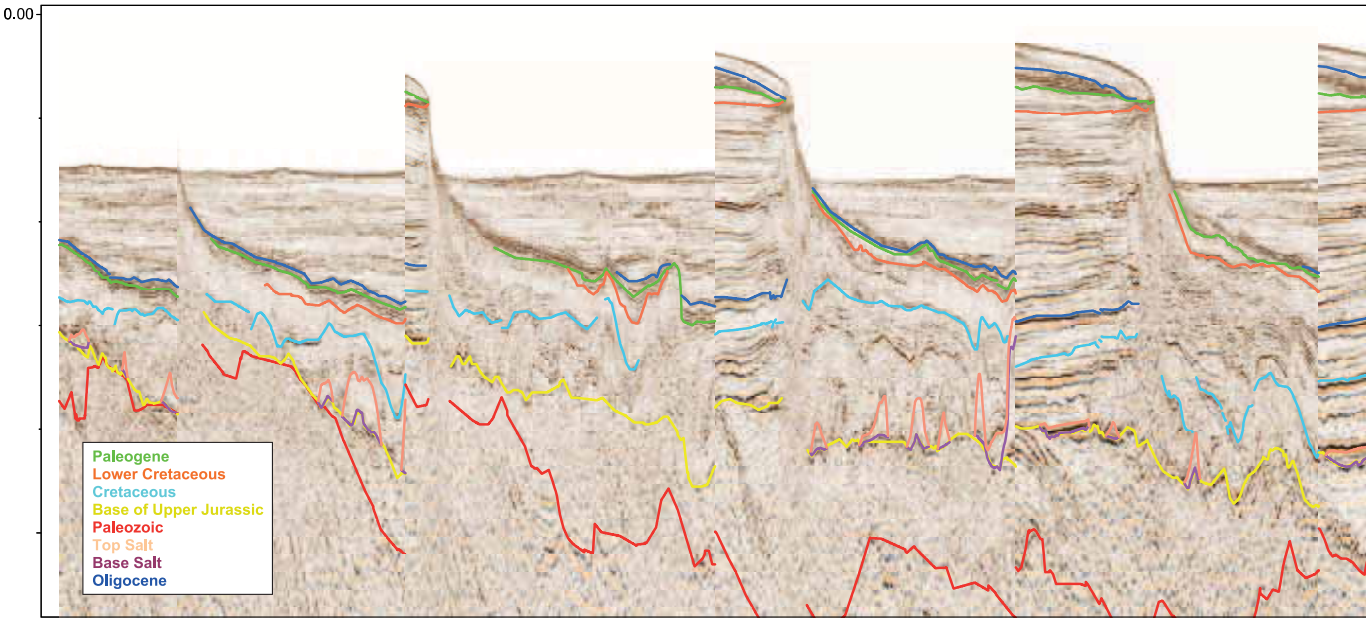
Offshore Florida has a long, interrupted history of exploration – and plenty of potential.

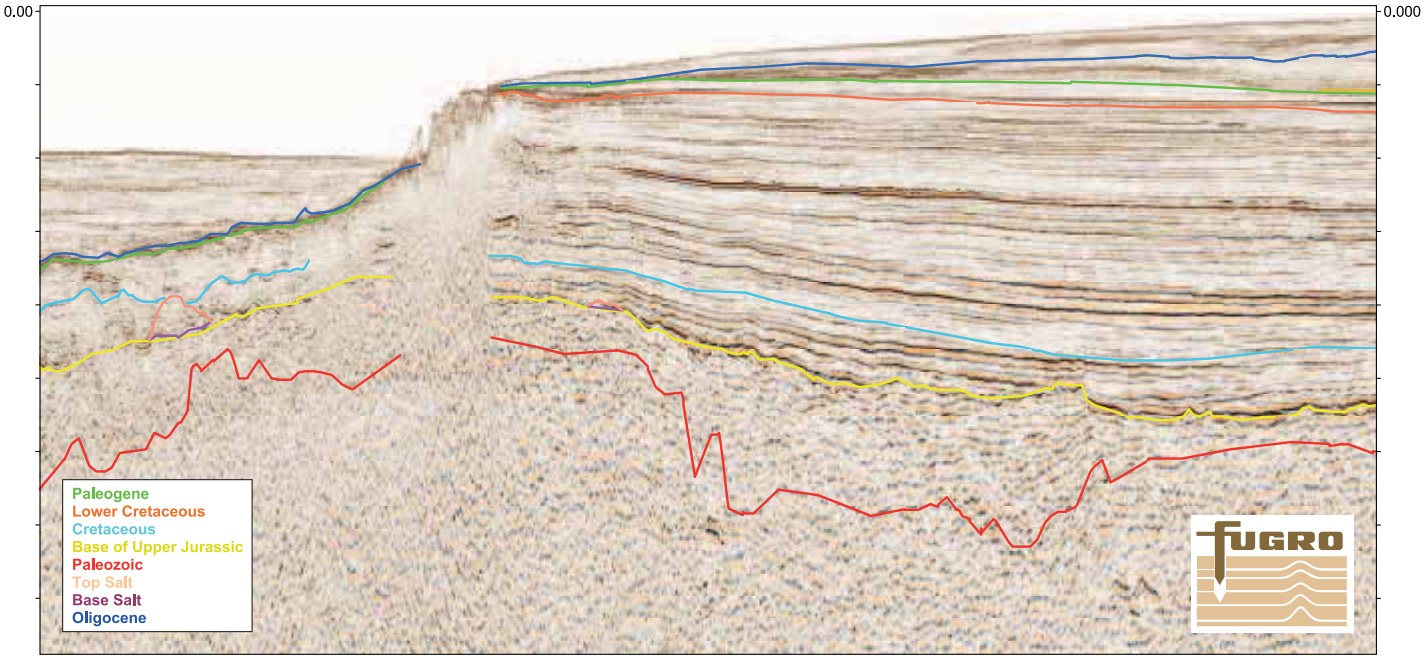
KENNETH MOHN and BRUCE BOWEN, FMCS

Many writers call Florida a 'frontier', but the region has a long, interrupted and challenging history of oil and gas exploration. These are a few of the major events:

- Sunniland Field (discovered in 1943) and a few other oil fields in the Sunniland trend that have been producing since the 1940s.
- The first Federal Lease Sale was held in 1959. From this sale, 23 blocks were leased and three wells were drilled offshore Florida. Gulf Oil Corp drilled oil off the Marquesas Key in 1959.
- Drilling in the offshore regions of the Eastern Gulf started in the mid 1970s with the drilling of Destin Dome Block 162. During this time, two years of drilling resulted in 15 dry holes and the discovery of gas around Destin Dome, but no significant discoveries in other regions of the offshore Eastern Gulf.
- Three Eastern Gulf lease sales in the 1980s were a result of higher oil prices and Area Wide Lease Sales, which created new interest in this region. During development of the 1987 to 1992 Oil and Gas Leasing Program, the Eastern Gulf was proposed to extend into Florida Bay and to the Florida Keys.
- Exploration evolved into a campaign issue with Florida and a call for a 100-mile (160 km) coastline buffer. Congress has included yearly moratoria language prohibiting new leasing offshore Florida and the Eastern Planning Area since 1989. The last moratorium was allowed to expire on September 30, 2008.
- Between 1997 and 2002 there was one Lease Sale covering a small part of the Eastern Gulf. This Lease Sale 181 area was modified to maintain the 100-mile (160 km) buffer offshore Alabama and Florida. The area was further modified from 5.9 million acres (24,000 km^2) to 1.47 million acres 6,000 km^2) by the state of Florida to include just a small portion of the area offshore Alabama that was located 100 miles (160 km) off the coast of Florida. Further sales within this area were held subsequently.
- In 1998 President Clinton withdrew the majority of the Eastern Gulf from new leasing through June 30, 2012.
- On July 14, 2008, President Bush suspended the withdrawal.
- First production in the Eastern Gulf was in February 1999 on Pensacola Block 881 by Unocal (Spirit Energy). Many of the other leaseholders became embroiled in a dispute with the government that was eventually settled by most operators in 2002.
- In 2006 the Gulf of Mexico Energy Security Act (GOMESA) was implemented. This established a moratorium on new oil and gas leasing offshore Florida until June 2022. This included areas 125 miles (200 km) offshore Florida and 100 miles (160 km) from the Florida coast offshore adjacent states.
- In 2009 legislation to open state waters offshore Florida was introduced and positive discussion with regards to the Federal OCS was circulating through the industry.
- In early 2010 the Obama administration moved to open up large portions of the East Coast and Eastern Gulf of Mexico to exploration and drilling.

Eight line segments trending north-east to south-west across the 3D survey. The segments exhibit the shelf to slope transition along the Florida Escarpment.





A west-east seismic line on the north side of the 3D survey shows the thinning of the Mesozoic (green to yellow) strata across the shelf and slope. A series of pre-Louann salt basins below the yellow horizon have been interpreted on the line.

- On April 20, 2010, the Macondo disaster resulted in a seven-year ban placed on exploration in the Eastern Gulf of Mexico by the Federal Government.

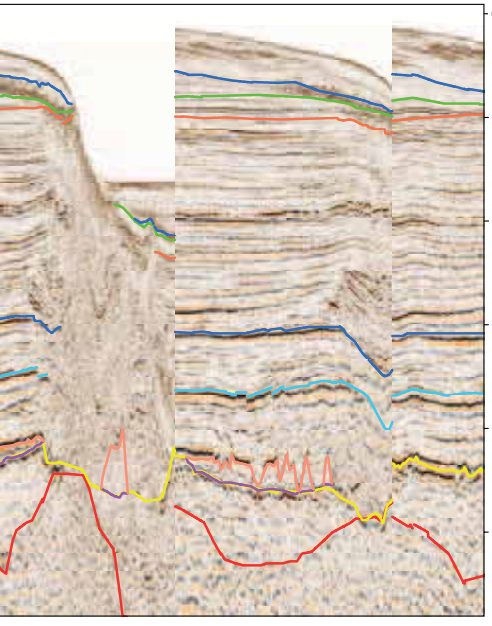
Plenty of Potential

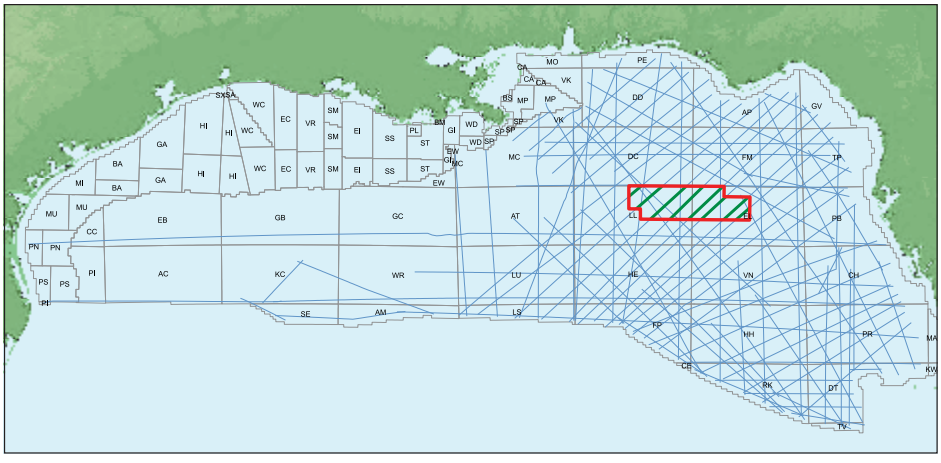
The information from the wells drilled offshore Florida provides geoscientists with good basic geological knowledge that can be used to develop new ideas and concepts for future exploration. New trends in the Deep Water regions such as discovered through the Shiloh and Appomattox wells and others have encouraged companies to look at the potential of the Eastern Planning area for extending these trends. Explorationists are always using both old and new ideas and technologies to find hydrocarbons. Fugro is supporting these efforts with new regional 2D data as well as with a new long offset 3D survey covering 500 blocks.

There are many good reasons to explore this region. With oil prices high, there will be a time when America will need to search for additional natural resources. Offshore Florida is probably the easiest and fastest to market, both from a geological and engineering standpoint. Geologically it is similar to the areas explored onshore Alabama and parts of the Central planning area.

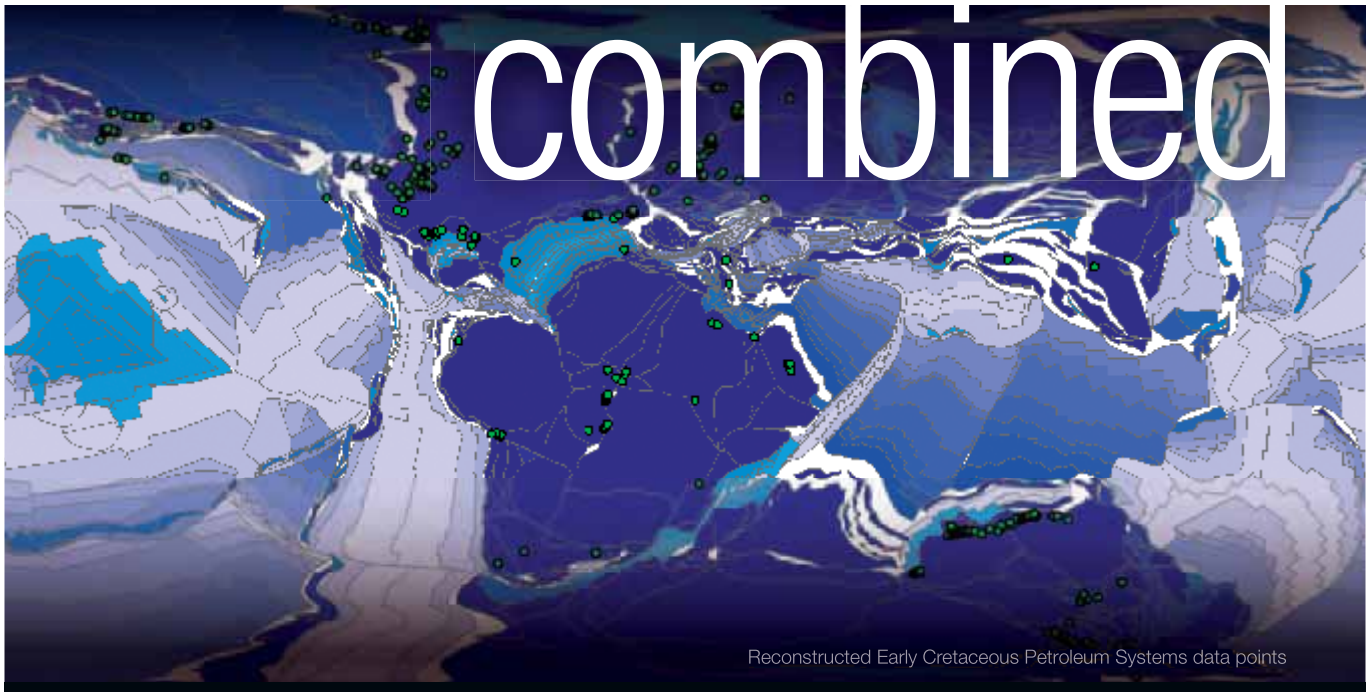
From an engineering standpoint, companies have been operating in the Gulf and they understand the climate and environment with respect to drilling and development. Coupled with this, the existing support and infrastructure is not far away, making Florida one of the easier future exploration areas. Concerns regarding the environment and beaches are reduced because of new mitigation methods and new government regulations. Better knowledge of the OCS through detailed information should result in better decisions across the board. Oil is over $100 per barrel and the industry will need to find new resources in our own territorial waters. For once, a 3D survey will be ready before the Lease Sale and should provide clients with plenty of time to evaluate the data as well as giving the BOEM a base from which to evaluate future bids. ■

Position of lines shown in green on map on right.





Creativity combined



A global database of 2 million pieces of geochemistry data has huge value – but what if you could visualise this in its true geological context? Imagine the new spatial and temporal relationships you would find.

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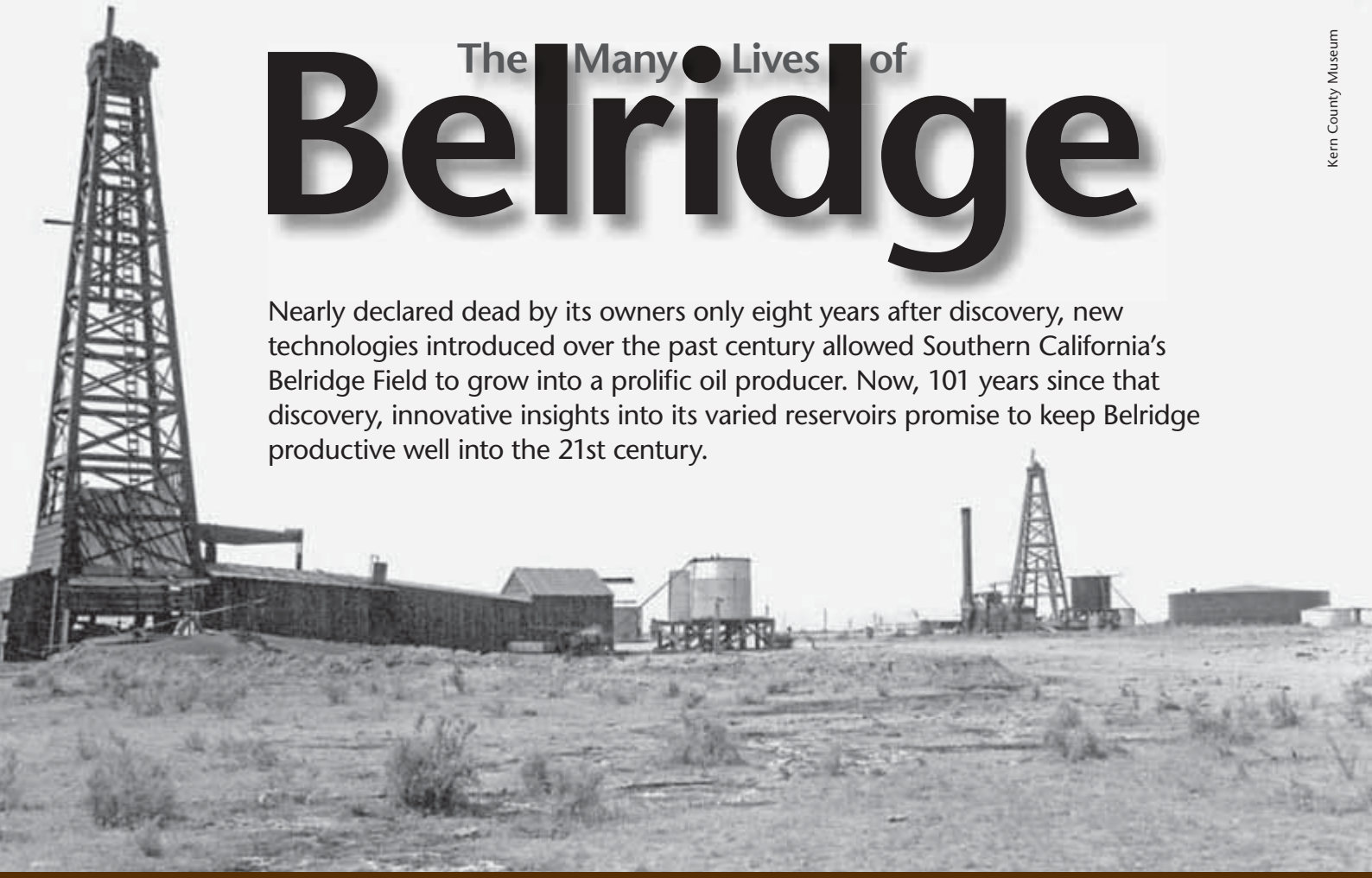
The Many Lives of Belridge

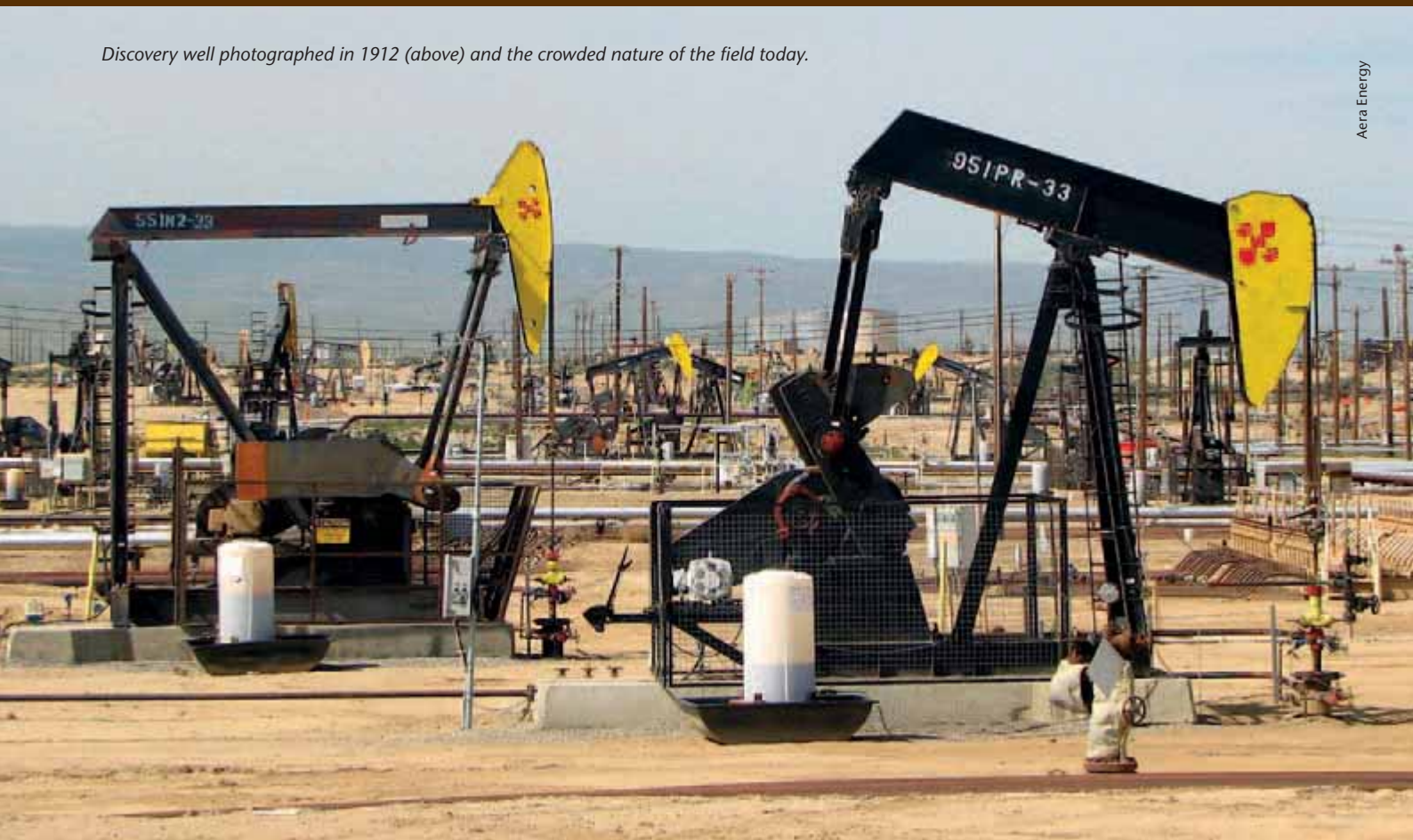
Nearly declared dead by its owners only eight years after discovery, new technologies introduced over the past century allowed Southern California's Belridge Field to grow into a prolific oil producer. Now, 101 years since that discovery, innovative insights into its varied reservoirs promise to keep Belridge productive well into the 21st century.



Kern County Museum

THOMAS SMITH

Discovery well photographed in 1912 (above) and the crowded nature of the field today.



Aera Energy

Located on an outcrop of oil-stained sand near a small stream bank in Southern California, the Belridge Oil Company Well No. 101 was started on March 11, 1911 and finished on April 21, 1911. The driller's log shows the well penetrated 238m of clay, tar sand, oil sand, and shale. They perforated an oil sand interval from 198m to 231m in the Pleistocene Tulare Formation and the underlying Upper Miocene Monterey Formation diatomite. The well's initial production was 100 bpd of 23.4° API gravity oil. This new field would be called South Belridge and the discovery of the North Belridge Field would follow one year later.

These were indeed humble beginnings for the field. The Belridge Oil Company's own Valuation Report in 1919 stated, "...within ten years both pools will be commercially exhausted." However, new steel derricks and diesel engines introduced in the late 1920s enabled safer and deeper wells to be drilled in the field. By 1934, the field held the deepest well drilled in the world at 3,468m. Consequently, new oil pools were discovered in the North Belridge Field and it remained an important petroleum resource throughout World War II.

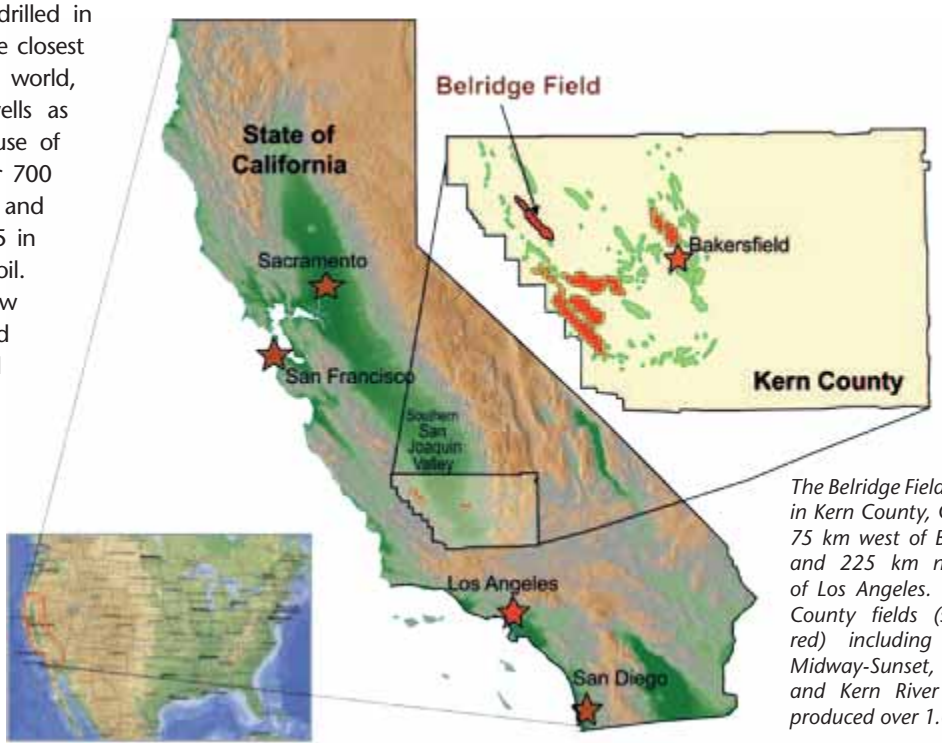
Peak daily production for the 24 km long by 5 km wide field was 186,000 boe in 1986. Today, daily production is at 80,500 boe and the field has produced over 1.6 Bbo of the 6 Bbo in place. More than 25,000 wells have been drilled in the structure, giving Belridge the closest well spacing of any field in the world, with vertical and horizontal wells as close as 11.5m. Through the use of new technology and ideas, over 700 new wells have been drilled and completed each year since 2005 in an effort to recover much more oil. Also, after a gap of many years, new exploration wells are being drilled to look for deeper structural and stratigraphic traps.

Kern County's Colorful Oil History

In the 1500s the Spanish explorers found Native American Indians gathering the very thick oil from natural seeps. Early settlers used the seeps along the well-traveled route on the west side of the San Joaquin Valley to lubricate their wagon wheels. The first commercial production started in 1864 when small amounts of oil were refined into kerosene in the nearby farming town of Bakersfield, California. By 1877, the first oil wells were drilled in Kern County. Numerous fields were discovered in the following years including several giant oil fields that still rank near the top 10 ever discovered in the US. These include the Midway-Sunset Field in 1894, Kern River in 1899, Elk Hills and the Belridge South fields, both in 1911. The 1899 discovery from a shallow, hand-dug well near the bank of the Kern River really started the oil boom for the area. After that, wooden derricks sprang up north of Bakersfield and soon the Kern River production accounted for 70% of California's oil production. By 1903, California was the country's top oil-producing state.

The occurrence of oil and tar sands in the southern San Joaquin Valley has been known for centuries.

During these early times, drilling was occurring at a frantic and somewhat reckless pace across the area marked by numerous blowouts. Some of the notable blowouts included the Wild Goose Gusher, 1887, Shamrock Gusher, 1896, Blue Goose Gusher, 1898, and the Silvertip Gusher in 1909. The Lakeview Gusher in the Midway-Sunset Field blew on March 15, 1910. Drilled to a depth of 678m, this well came in with a roar that blew off the crown block with an estimated flow of 125,000 bpd. Soon the column of sand and oil six meters in diameter and 60m high completely enveloped all the well equipment. Crews built sandbag dams to contain the crude and in just four hours a four inch pipeline was built to convey oil to large holding tanks four km away. This well flowed for over 18 months and finally died when the bottom of the well caved in. An estimated 395 million gallons (1.1 MMm³) of crude were discharged on the surface to become the largest spill in US history, at least twice as much as the Deepwater



Allan and Lalicata, 2011 AAPG Pacific Section

The Belridge Field is located in Kern County, California, 75 km west of Bakersfield and 225 km north-west of Los Angeles. Four Kern County fields (shown in red) including Belridge, Midway-Sunset, Elk Hills, and Kern River have all produced over 1.0 Bbo.

Horizon disaster spilled into the Gulf of Mexico in 2010. Today, there is little evidence left from the Lakeview Gusher.

Many more fields were discovered in the Southern San Joaquin Valley over the decades following these first important discoveries. Thanks primarily to steam flooding, the San Joaquin Valley oil production peaked in 1985 at almost 300 MMbo/year, 256 MMbo/year for Kern County alone. By 1993, 16 Kern County fields had produced over 100 MMbo. Twelve refineries were built in Kern County to handle all this oil, with only two remaining today. The last major find in the area was made by Occidental in 2009. Located between the Elk Hills and Railroad Gap fields, the 150 MMboe Gunslinger discovery is the largest in over 30 years.

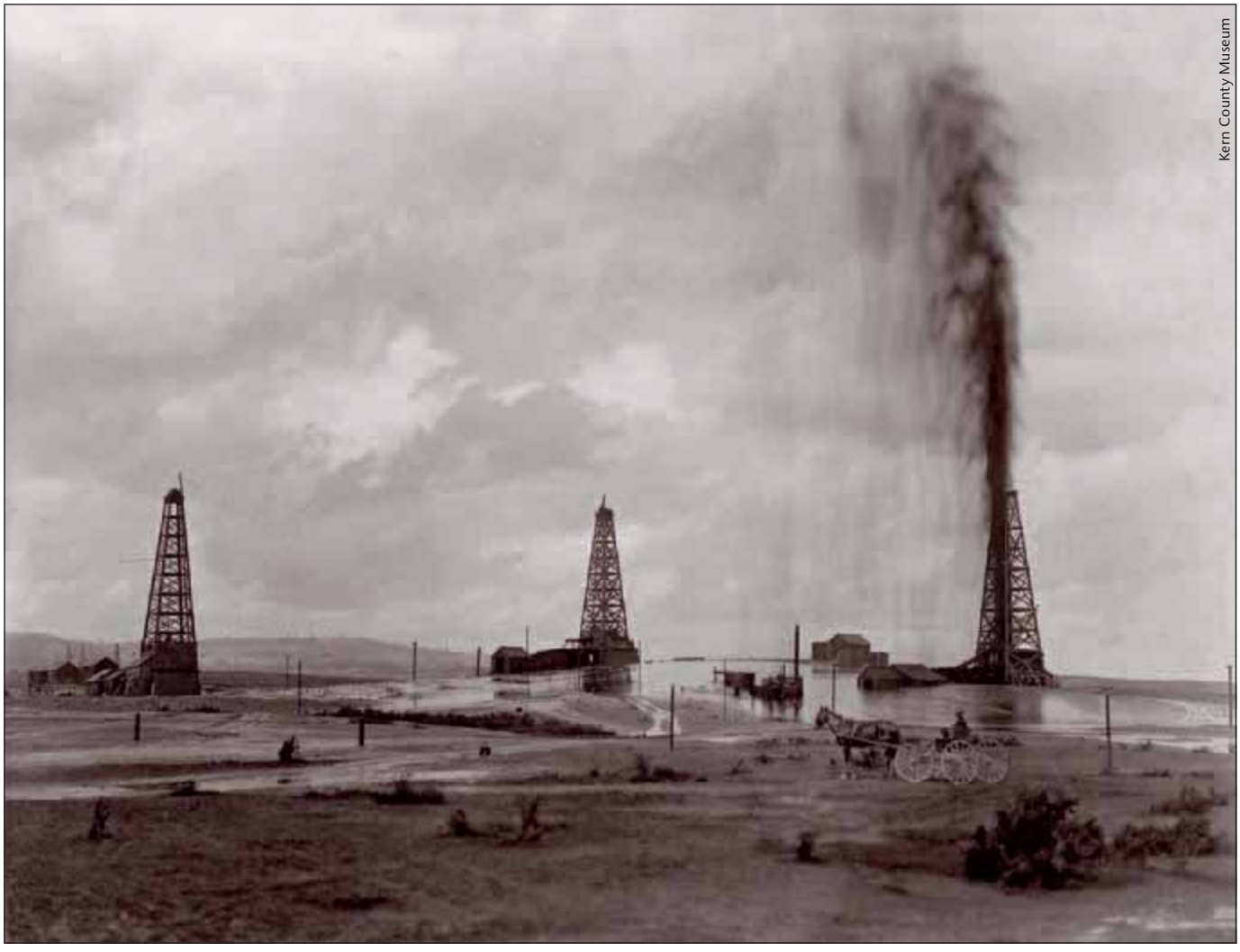
Belridge's Early Lives

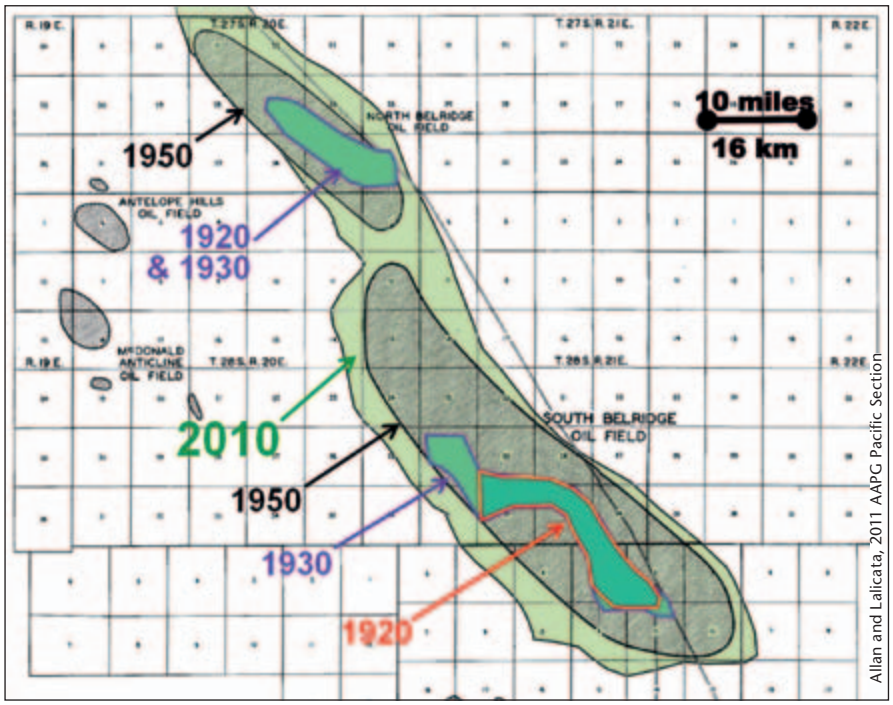
Using wooden derricks and steam powered workings, drilling focused on the area around the original 1911 and 1912 discovery wells. After only eight years of development, Belridge Oil Company stated that the "Southern Belridge Field is entirely drilled up" and the "future production is estimated to be about 1,800,000 barrels". Thus, the two Belridge fields remained very small in area. Only about 100 wells had been drilled in the south field by 1920 and only about 30 wells through 1930 for the northern field. The original discovery pools, the Tulare Formation that contained heavy 11–15° API oil and the Monterey diatomite pool with its much lighter 25–39° crude were often completed together. This completion method would allow the light oil from the diatomite zone to dilute the heavy oil in the Tulare and allow economic production of the heavy oil. This practice continued into the 1970s.

The Belridge Field's second life was marked with the advent of more powerful steel drilling rigs that were able to reach objectives below the Tulare and Monterey diatomite reservoirs. The 1932 discovery of the sub-Monterey reservoirs (Miocene to Eocene) in the North Belridge Field was an important find, increasing both oil production and the productive area. The 650 km^2 pool reached a peak daily production in 1938 at 38,600 boe. More producing intervals were discovered in the sub-Monterey in the 1940s and 1960s and today remain the deepest reservoirs in either field at 1,830 to 2,865m.

Cyclic steaming in the Tulare pool began in 1963 and marks yet another new life in the field's production process. The cyclic steam stimulation involves initial steam injection into the heavy oil zone. After a soak period to heat the reservoir fluids, oil and some water flow back though the same well. The oil flows back at a dramatically reduced

The Lakeview Gusher photographed shortly after blowing out.





The developed area of the North and South Belridge fields gradually expanded over time until the two fields were joined.

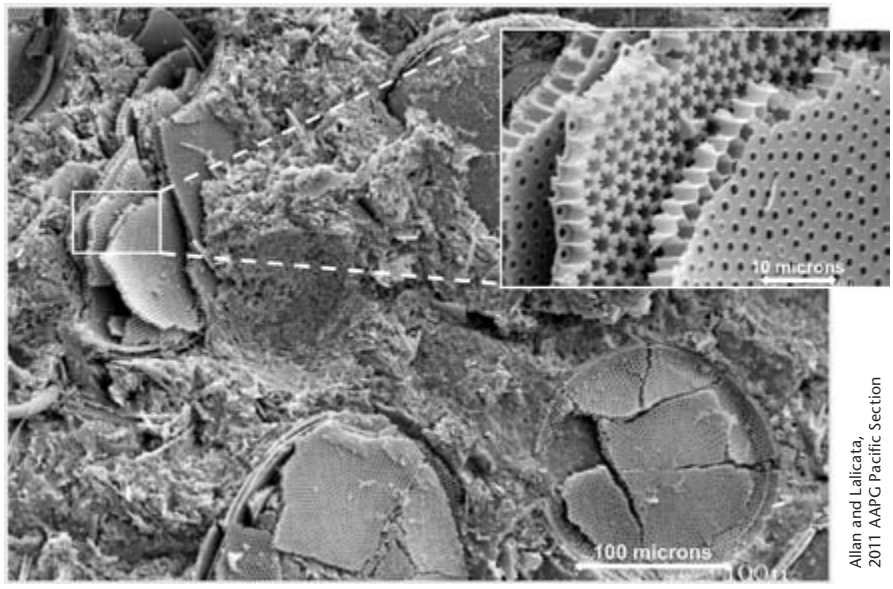
viscosity because of the added heat to the reservoir. Gradually larger areas are heated and the pattern can be converted to continuous steam injection with dedicated producers and injectors. A peak daily production rate of 186,000 boe was achieved in 1986; nearly 70% of it was from steaming the heavy oil.

More life from the oil field ensued with the first successful hydraulic fracture in the diatomite reservoir in 1977, followed by the use of water injection in the 1980s. The first horizontal wells were drilled in the early 1990s, keeping the field viable but producing only about half of what it did at its peak. Much oil remains locked in the ground, only about 25% of the oil-in-place has been produced, leaving more than 4 Bbo yet to be recovered.

Belridge – The Final Chapter?

Shell purchased the assets of Belridge

The diatomite reservoirs are composed of about 40% diatoms, 40% detrital quartz and feldspar, and 20% mixed layer clays. While having high, fluid-supported porosities greater than 50%, the formation is extremely tight with very small pore throats and permeabilities ranging from 0.1 to 1.0 mD.



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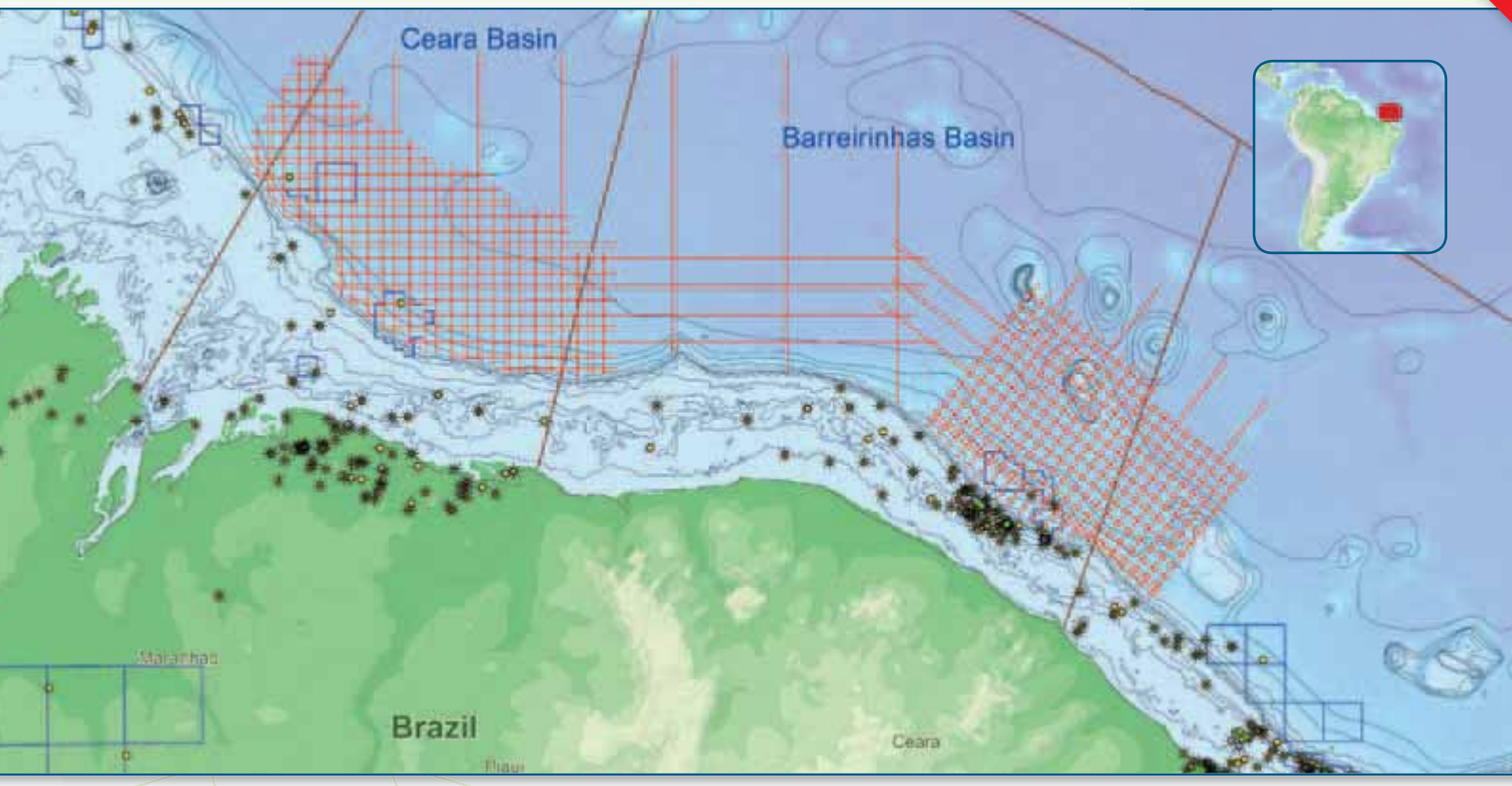
Offshore Brazil

New Multi-Client Acquisition, Santos Campos, Northern Equatorial Margins



Northern Margins - Spectrum Multi-Client coverage

Santos Campos- planned survey coverage

Spectrum has recently completed acquisition of a new 2D Multi-Client seismic survey in the Northern Equatorial Margins Offshore Brazil. Phase 1 of the program is 12,000 kilometers of high-quality seismic data from the Barreirinhas and Ceara basins with additional regional tie lines. The program provides oil companies with a competitive advantage in the upcoming Licensing Round 11. First data will be available in April.

In addition, Spectrum and Dolphin Geophysical are set to commence an extensive, long-offset 2D Multi-Client survey over the Santos/Campos basins. These Multi-Client surveys will be acquired by Dolphin Geophysical and processed by Spectrum with the aim to better define the exploration prospectivity. The data will be available ahead of the expected pre-salt bid round anticipated in the 2012-2013 timeframe.

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Pictured at his Belridge workstation, Malcolm Allan, geologist and reservoir manager for Aera Energy claims, "Belridge's next life requires applying conventional technologies and techniques in new and unconventional ways."

Oil Co. in 1979 and Aera Energy LLC was formed in 1997 from the Shell and Mobil assets in the area. **Malcolm Allan** has been working with the complex reservoirs at Belridge for 10 years. One of his first priorities was to organize all the geologic, petrophysical, and completion data into a single unified database. "We are using Landmark's OpenWorks© database and Stratworks© plus Schlumberger's Petrel programs," says Malcolm. "The database contains over 15,000 wells and we are adding about 700 more each year. About 80% of the wells have digital logs that can be used to pick markers. The markers, porosity, oil saturation calculations and pressure surveys are in a single database that can be used by all our geoscientists. From this data, we can generate reservoir models and pseudo-logs (synthetic logs) necessary to pre-plan the wells and schedule completion intervals. On wells we have logged, the predictions have proven to be very accurate."

At just under 50,000 bopd, the Monterey Formation diatomite reservoir is currently producing the most oil at Belridge. It is also a very unique reservoir and may be one of the first unconventional shale reservoirs to be produced commercially. "Fluids move very slowly through this reservoir at only 0.3 to 1.0m per year," says Malcolm. "It has extremely high porosity, a large surface area per unit volume, and is highly compressible; all very challenging characteristics for a reservoir that can be 300 to 400m thick."

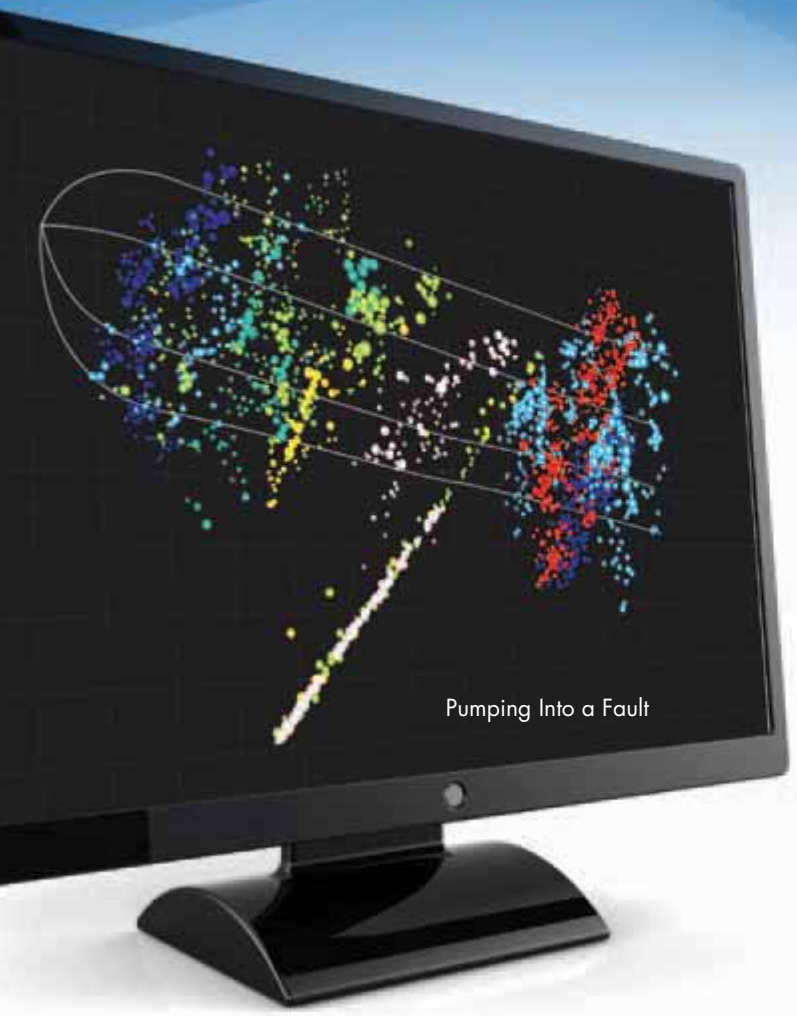
"The first horizontal wells were aligned parallel to the anticline axis and completed with multiple transverse fracs," explains Malcolm. "This area had limited productivity and since then nearly all our horizontal wells have been drilled along the flanks of the anticline and completed with longitudinal fracs along the wellbore. After multi-stage fraccing, these wells have proven to be very successful."

"Water injection is essential to improve oil recovery and to maintain reservoir pressure to avoid compaction in the diatomite. With this massive, thick reservoir, accurate placement of injectors is warranted," states Malcolm. "To solve this problem, we are using a multi-faceted approach. Open-hole Repeat Formation Tester (RFT) data allows us to easily locate where additional injection support is needed to maintain hydrostatic formation pressure. In that same content, we are using satellite data every 24 days to compare surface subsidence caused by reservoir compaction. This allows us to monitor conformance of injection and production across the field. Additionally, we have 50 well pilot programs to monitor water injection profiles using distributed temperature sensing (DTS) with the optical fiber between the casing and cement. Full DTS deployment may involve over 1,000 wells. For active reservoir monitoring, microseismic arrays have been deployed to monitor fracture growth and cross-well tomography may be used in the future to detect changes in reservoir fluid content. These are clear examples how new technologies can solve surveillance issues in oil fields."

"Going forward, and along with trying to recover more oil from existing reservoirs, Aera is drilling new exploration wells into deeper zones throughout the field," says Malcolm. "To lower our environmental impact, the old gas-fired steam generators may soon be replaced with solar or biomass steam generation. We are also trying to minimize the surface impact with possible redevelopment by multilateral horizontal wells."

A final life could occur at Belridge towards the end of this century with the recovery of heat from the steamed reservoirs using low temperature geothermal technology. Until then, Aera will continue to apply modern technologies to this giant field to keep producing oil from its huge remaining reserves.

Acknowledgement:
Special thanks to Malcolm Allan for his valuable contributions to this article. ■



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Committed to the Industry

GABRIELLE SAMPLES

Drawn to challenge, committed to an industry – that's **Ralph W. Baird,** 2011 recipient of the Colonel Edwin L. Drake Legendary Oilman Award from the Petroleum History Institute

Ralph W. Baird on the riverboat in Marietta, Ohio, to receive the Petroleum History Institute's 2011 Edwin L. Drake Legendary Oilman Award for lifelong dedication to exploration geophysics work and international education work with IYPE 2007-2009; with Daniel Leech on left, founder of Leech Carbide

Ralph W. Baird has been attracted to challenge since he began his education at the Colorado School of Mines in the spring of 1967. In a 2008 article in the *Colorado School of Mines Magazine* Baird stated:

"At every other school where I interviewed, people chauffeured me around. But at Mines they just said: 'We're at the top of the hill. Look for the gold dome. We'll be waiting for you.'" Baird had to hoof it up to Guggenheim with his heavy bags in tow. And he decided right then that Mines was the college for him. "That impressed me," he says. "I knew I'd have to work for whatever I got. I knew I'd have to earn it. And I found that attractive." *(Colorado School of Mines Magazine)*

In his daily work, Baird tends to take a different view of geologic and seismic data and offset well daily drilling reports. At a high level meeting a few years back, the exploration manager of this offshore operator asked why Mr. Baird was reviewing the work of his geoscientists. The drilling manager hesitated, and then replied, Mr. Baird is *"***The Driller's Geophysicist***"*. Since that day, that moment, Baird has proudly carried the label 'The Driller's Geophysicist'. If Ralph could, he says he would look at and review every well's drilling plan before they are drilled; his methodology and procedures would reduce the costs and the risks.

In an industry overshadowed by misunderstandings and a bad rap, Ralph Baird acts as a voice that counters the negative public opinions and sentiment of the business by extending his knowledge and expertise to educate the public as well as industry professionals.

"People do not see the good that oil companies do for society. Most people see only the price at the pump

and depend on what they hear from the media, particularly the TV. Yet the attitude should be that oil and gas companies are heroes."

"We need smart, working people to explain the real jobs that deal with exploration." Baird explained. "It's not going to be Exxon, Shell, Chevron or BP, it's going to be working people who will communicate this message."

Building Blocks

Baird earned a B.S. in geophysical engineering from the Colorado School of Mines in 1971 and continued his graduate studies in petroleum engineering, economics and business administration at the University of Tulsa, Oklahoma State University and the University of Houston respectively.

"In college I didn't see a future in oil and gas," Baird explained. "I studied exploration geophysics and went into exploring for uranium using aero-radiation and aeromagnetics and then ground-truthing the data we collected from the aircraft."

Baird came to understand the integral role of exploration for resources to meet society's needs for energy and materials. "It was a real commitment to be in this industry," Baird said. "Society is built on mobility – it makes us independent."

In 1971, Baird joined ConocoPhillips as an exploration geophysicist. He later served in positions at Fairfield Industries and Timko, Lindahl and Schweikhardt, Inc. before he founded Baird Petrophysical International in 1978, a Houston-based international geological and geophysical services company that specializes in applying exploration technologies to solve petroleum engineering problems.

In 2008, Mr. Baird co-founded PetroDevelopment Partners, a Texas and Louisiana based private equity fund. The fund manages and invests in producing properties and is organized as an opportunity fund to invest in private companies and technology.

Another company, Baird Petrophysical, maintains a database of seismic attributes, pore pressure data, drilling data and drilling results for over 4,600 wells, at last count.

Standing for Education

Baird is especially passionate about the education system and actively advocates that young men and women study engineering and sciences and avoid undergraduate business degrees.

"When I think about the next generation, I see how we're going oversees to hire people because the people now in this country are not prepared to work in engineering or science," Baird said. He believes in fostering the principles on which industrialized nations were built, such as innovation and engineering.

President George W. Bush's 2007 American Competitiveness Initiative (ACI) gave Baird a bit of hope for his own country's future workforce. "When I read the National Academies report entitled *Rising Above the Gathering Storm*, it inspired me to speak out," Baird said. The ACI was purposed to reinvigorate investment and research in the physical sciences and engineering and to encourage youth to study math, science and engineering.

Baird followed the American Competitiveness Initiative to Congress and continued to advocate its implementation.

Still, Baird attempts to share his vision. He asks, "What do you want for your children and grandchildren in the next 10 years?"

In 2011 Ralph W. Baird received the Colonel Edwin L. Drake Legendary Oilman Award from the Petroleum History Institute for his outstanding contributions to the business of oil and natural gas.

The Petroleum History Institute is a non-profit corporation that is dedicated to pursing and promoting the history, heritage and development of the modern oil industry.

Baird is an active member in 32 professional organizations, including the American Association of Petroleum Geologists, the Society of Exploration Geophysicists, and the American Petroleum Institute among others.

Wide Ranging Interests

Baird was a board member and manager of the International Year of Planet Earth (IYPE 2007–2009), a group formed to celebrate the 50th anniversary of

Ralph (right) with brother Glenn Baird and Ralph's Bellanca Super Viking, the Corvette of small planes

the highly successful International Geophysical Year (IGY 1957–58) in which Russia's Sputnik was launched. The IYPE advocates the accumulation and expression of the knowledge of the world's 400,000 earth scientists that makes the Earth a safer, healthier and wealthier place for future generations. This group developed a global umbrella of now 80 countries with active committees with a unified purpose of educating the next generation about Earth Science. Baird is now a senior advisor to the follow-on organization, the Earth Science Matters Foundation, based in The Netherlands.

Baird also applies his experience in GIS mapping, underwater sonar searching, field planning and supervision, data collection and analysis, data interpretation and reports in his work with Texas EquuSearch, a technology search and recovery team that started in August 2000 to provide volunteer horse-mounted search and recovery for lost and missing persons. With Baird's help and guidance, the organization now utilizes oilfield methods and technology to find missing loved ones. He believes in the EquuSearch motto, *'Lost Is Not Alone'*. Families who contact Texas EquuSearch know what this means.

Baird has conducted numerous searches with Texas EquuSearch, including the well-known search for Alabama teen Natalie Holloway in Aruba, using geophysical instruments and methods such as a side scan sonar, ground penetration radar, model aircraft/drone photography and exigent requests to access and interpret cell tower data and FAA radar data in hot-shot emergency surveys and research/training surveys.

Baird is a licensed professional engineer in the state of Colorado and a licensed professional geoscientist in the state of Texas. He also enjoys flying as a licensed pilot.

Challenging the Industry

As the industry struggles to attract new talent and exploit more challenging resources, Ralph Baird provides a proactive and positive voice. He has risen to the occasion and challenges the rest of the industry to join him.

"I am a geophysicist and I don't think I've ever had a boring day working." Baird said. "I'm committed to finding more resources for society." ■

At the Houston Club, Ralph (right) with Richard Baile, SEG Foundation Board Chair Emeritus. Ralph is a Trustee Associate of the SEG Foundation.

Salt Lake City
An Attractive Destination

A beautiful location overlooked by the Rocky Mountains; history, culture, four seasons and the "greatest snow on earth" – Salt Lake City in Utah has plenty to offer the visitor

RASOUL SORKHABI

A flight over Utah in south-western USA depicts a picturesque landscape of red sandstone country to the south, the deserts of the Great Basin to the west, and lofty mountains fringing the Colorado Plateau (see *GEO Tourism, Page 54*) to the east and north-east. One spot will particularly draw the observer's attention: A relatively large settlement on the bank of a great lake and surrounded by mountain ranges on almost all sides. That spot is the Salt Lake Valley, where the capital of the state of Utah is located. The Valley is part of the Basin-and-Range in south-west USA, formed by tectonic extension in Neogene times.

Snow and Sun

Salt Lake City (known as SLC) itself has a population of about 186,000 people but over 1.1 million people (or almost 40 percent of Utah's entire population) live in the larger Salt Lake metropolitan area. Although Native American tribes had resided in the Valley for millennia, the modern city of SLC is of recent origin: In 1847, Brigham Young, leading a community of Mormons, moved into the Valley and diligently started constructing houses and irrigating the land. The Emigration Canyon through which the pioneers entered the Valley is now a national historic landmark. The City is home to the headquarters of the (Mormon) Church of Jesus Christ of Latter-day Saints (LDS), although huge fluxes of people from other states and countries in recent decades have diversified the ethnic and religious composition of the population; today more than half of the city's population is non-Mormons. Nevertheless, the Temple Square close to downtown is still the historical heart of SLC, visited by several millions each year.

SLC is generally characterized by a semi-arid climate. Situated at latitude 40° North and at an altitude of nearly 1,300m, the city, however, enjoys snowy winters from mid-November to the end of April. The Valley is surrounded by the Wasatch Range on the east where a dozen ski resorts attract thousands of tourists and skiers every year. In February 2002, the XIX Winter Olympic Games were held in SLC which boosted the city's development and fame. What particularly makes SLC the "greatest snow on earth" (as the local advertisement goes) is the precipitation from the cold Pacific storms aided by the Great Salt Lake (lake-effect snow or picking up and freezing water vapor) on the west and the mountain barrier on the east of the city.

A pleasant summer climate and the city's key location to travel to Utah's world-famous national parks or to the other

Rasoul Sorkhabi

The snowy Wasatch Range overlooking Salt lake City is part of the Rocky Mountains, formed during Late Cretaceous-Eocene Sevier-Laramide orogeny in western continental USA and Canada.

states in south-west USA also makes Salt Lake City an attractive destination for tourists from the around the world.

Remnant of Ancient Lake

The Great Salt Lake, on the western side of the city, is a remnant of the much larger Pleistocene-age Lake Bonneville. The ancient shorelines of this lake are hiking trails along the Wasatch Front, and SLC itself sits on the lake deposits. Three rivers carrying high concentrations of minerals flow into the lake, but it has no outlet, so evaporation results in high salinity in which few organisms can thrive, although the lake provides habitat for a variety of birds. Sunsets on the Great Salt Lake and the night view of the city from high ground on the Wasatch Front offer very scenic displays of the city.

In the Oquirrh Mountains bordering Salt Lake City on the west is found the Kennecott (or Bingham Canyon) Copper Mine, the world's deepest open-pit mine, which began its operation in 1906 and has greatly contributed to the commercial development of Utah over the century.

SLC has an international airport; it is also accessible by three cross-country freeways (the Interstates 15, 80 and 215) and by the national railway Amtrak. It is convenient to drive and find your way around in SLC as the city has been developed on a grid plan. The streets are numbered north or south (with respect to Main Street), and east or west (with respect to South Temple Street). Capitol Hill, high ground to the north of the city, overlooks downtown and houses the building of the Utah state government constructed in the 1910s.

SLC is home to University of Utah, which has one of the largest medical schools in the USA, the state's largest theaters and mass media (newspapers, television channels and radio stations), sports teams, a large convention hall and public library, green parks, a variety of restaurants, attractive shopping complexes including the Gateway, Trolley Square and City Creek Center (inaugurated this year), and a host of commercial enterprises and banks. A very recent addition to the city's sightseeing spots is the Natural History Museum of Utah located close to the Red Butte Garden; both these places belong to the University of Utah and lie in the shadow of red Jurassic sandstone hills. Indeed, this part of the Wasatch Mountains expose rocks which are major oil reservoirs in the subsurface of Utah and Wyoming.

Although a mid-sized city, Salt Lake City has a lot to offer in terms of landscape and outdoor recreations as well as cultural history and urban development. ■

Salt Lake Temple of the Church of Jesus Christ of Latter-day Saints located in the Temple Square was built in the second half of the 19th century from the granites outcropping in the Little Cottonwood Canyon on the Wasatch Mountains.

Rasoul Sorkhabi

Malaysia: Two Gas Discoveries

At the tail end of 2011 Petronas, the state oil company of Malaysia, announced the success of an offshore well in moderately deep waters in Block SK316, about 100 km north-west of Miri in the state of Sarawak, which is in the Malaysian part of the island of Borneo. Kasawari 1 was spudded in November last year and found a 1,000m high gas column in carbonate reservoirs – the longest gas column found to date in the country. At the time it considered the find promising, and after testing and preliminary assessments this has been confirmed by the announcement that the in-place reserves are considered to be in the region of 5 Tcfg, with about 3 Tcfg recoverable (2P). This makes the Kasawari field one of the largest non-associated gas fields in Malaysia. The well test conducted produced a flow of nearly 30 MMcfpd of gas.

A few months earlier Petronas had also struck lucky with NC8SW-1, 17 km south of Kasawari in the same block, which found a 440m gas column in similar carbonate reservoirs. The recoverable reserves in this field are thought to be about 450 Bcfg, and the well also uncovered a potential oil play which is under investigation to assess its commerciality. The potential of these two wells alone amounts to almost 4% of Malaysia's current natural gas reserves of 14.8 MMboe.

These successful wells follow a string of previous discoveries off Sarawak, including NC3 and its appraisal well in the same block, which have an estimated 2.6 Tcfg of in place reserves. Sarawak is the major state gas producer and exporter for Malaysia, with the country's only liquefied natural gas plant located in Bintulu, 150 km south-west of Miri.

Block SK316 is in the Central Luconia Province, part of the Sarawak Basin. The reservoirs are Middle to Late Miocene pinnacle reefs and are predominantly gas-bearing, sourced by terrigenous organic matter. ■

A fishing boat off the beautiful Sarawak coast

Romania: Black Sea Gas Discovery

While it is far too early to give accurate figures, the first deep water well in the Romanian part of the Black Sea looks to be a major success for operator and 50% shareholder ExxonMobil and its partner, Petrom, a member of the OMV Group.

In February it was re ported that the Domino-1 well had encountered 72m of net gas pay, suggesting as a preliminary estimate that the field could hold between 1.5 and 3 Tcf of gas. The discovery lies in the Neptun Block, about 170 km offshore, in the western Black Sea. The block covers an area of 9,900 km^2 and has water depths varying from 50 to 1,700m, being about 930m at the well location. Between 2009 and 2010 the partners obtained more than 3,000 km^2 of 3D seismic over the Neptun block, the largest seismic program ever undertaken in Romania.

Domino 1 in the Neptun Block is Romania's first deepwater well in the Black Sea

Although the commerciality of the find is still under discussion, Exxon Mobil and OMV Petrom plan new 3D seismic over the block in the near future. The water depth and the relative remoteness of the region from other deepwater exploration areas will make getting the equipment needed to exploit the find an expensive business. The discovery well, however, was drilled using the Transocean Deepwater Champion, which was specially designed to facilitate entry into and out of the Black Sea. The double-hulled, self-propelled vessel is capable of holding its position in open water with nine-metre waves and 60-knot winds.

This discovery is potentially the biggest gas find ever for OMV, although Petrom is already the largest oil and gas producer in South East Europe. It is the sole crude oil producer in Romania, and accounts for approximately half of Romanian gas production. It holds exploration licenses for 15 onshore and two offshore blocks, and operates 255 commercial oil and gas fields in the country.

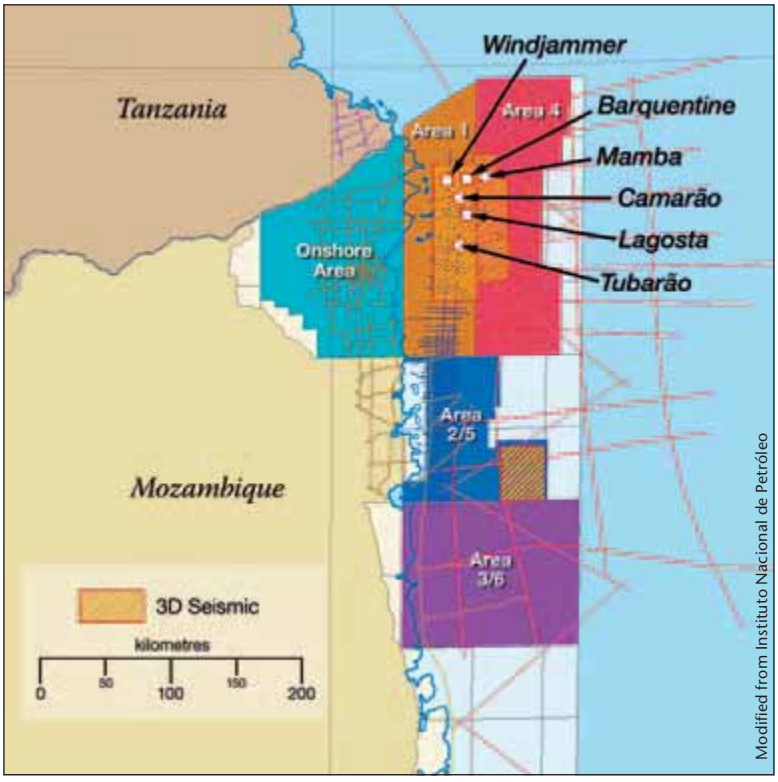
Romania is one of the oldest hydrocarbon producing countries in the world with initial production recorded in 1858. At one time it was the largest petroleum producer in Eastern Europe. ■

The Deepwater Champion was especially designed for the Black Sea

Mozambique: 2nd Giant Discovery in Block

As reported in *GEO ExPro* Vol.8, No. 6, exploration in the Mozambique's deepwater Offshore Area 4 looks to be following the trend set by drilling in Area 1 to its west. After Mamba South was revealed at the end of 2012 to hold up to 22.5 Tcfg, it was announced in mid February that Mamba North 1 was found to have potentially of 7.5 Tcfg in place, bringing the total reserve in the block to a massive 30 Tcfg. During production testing - the first time this has been undertaken in the offshore Rovuma Basin – the well produced high quality gas with flow rates, constrained by surface facilities, of about 35 MMcfgpd. It is estimated that the gas production per well will reach over 140 MMcfgpd.

The new discovery well, which lies 23 km to the north of Mamba South and 45 km from the coast, in water depths of 1,690m, reached a final depth of 5,330m and found a total of 186m gas pay in multiple high-quality Oligocene and Paleocene sands. The operator, ENI, now plans to drill at least five more wells this year on nearby prospects and structures to assess the total potential of the Mamba area.



At the same time, the 10,500 km^2 Block 1 has been the site of yet further success, with appraisal well Lagosta 3, which was spudded in January, encountering high-quality sands, with 176m of gas pay. The reservoir is in communication with the Lagosta 1 discovery well, which lies 3 km further west, and up to 30 Tcfg have been discovered in the block so far. Lagosta 3 was drilled to a total depth of 4,180m in water depths of over 1,400m. The well was suspended for the rig to undertake flow testing at the Barquentine discovery, a few kilometres to the north. This was the first such testing undertaken in Mozambique by the operators, Anadarko, and the well successfully flowed at an equipment-constrained rate of 90 to 100 MMcfgpd with minimal pressure drawdown, suggesting that production could be as high as 200 MMcfgpd.

Anadarko and its partners are now in the process of designing a scheme to exploit the gas, with a flexible offshore production system at the fields, which are about 55 km from the coast. This will send the gas to an onshore LNG processing plant with initially two trains, but with the flexibility to expand to six if necessary. According to Anadarko, the project is well under way to becoming the second largest LNG project in the world. ■

Switch – Starting an Energy Conversation

After first watching 'Switch', I thought I may be missing something. It bothered me through the night. Sure, there were impressive scenes of some of the world's most important energy sites, experts chiming in at just the right times, and an important message for us all at the end. So what did I miss?

The next morning when I turned on our television connected to the outside world via satellite, it started to dawn on me. There are hundreds, if not thousands, of shows, and even full networks, devoted to your health. What to eat, what not to eat, how to exercise, what this or that does to your overall health – well, you get the idea. The same thing goes for the financial side of our lives: How to buy a house, keeping out of debt, ten ways of paying less in taxes, and so on. While some still eat the wrong foods, don't exercise, or continue to go into debt, many have benefited from the information available to them and are able to make much more informed decisions about their life styles.

So what messages do we see on the 500 or more channels available to us in the US about our energy situation? High gas prices predicted for this summer's driving season; scenes of the Deepwater Horizon disaster in the Gulf of Mexico; Home Depot occasionally putting a clip about insulation or weather stripping on the Weather Channel; conflicts along the Strait of Hormuz that could spike energy prices; the controversies regarding hydraulic fracturing and global warming. Little wonder that the average person really does not know where our energy actually comes from or what our energy future may bring.

With energy playing such a big role in everything we do, how can we all become informed? That is exactly the central theme of 'Switch'.

Revolutionary Conclusions

In this documentary, Dr. Scott Tinker starts out packing a very tidy suitcase at home and heading out into the world. He adds up all the energy it takes to run his house, the gadgets he uses, his car and so on. It turns out to be a huge amount, about 20,000,000 watt hours every year. He simply calls this unit 'me or you' or 'one person's total energy footprint for a year'. Scott uses this unit of energy throughout the movie to indicate the size of different energy producing methods and how many people can be supplied with that energy for a year. For instance, he visits the Parish Generating Station in Texas, a coal plant that can supply energy to 900,000 people per year. After explaining where coal comes from, how it is used, and why it is used, an expert puts the scene into perspective by discussing the economics, problems the use imposes such as the cost to clean it up, and the reality of actually doing so. The documentary explores nearly every energy option currently available and being used today. For each, the experts give the listener the pros and cons that lead to some thought-provoking and quite revolutionary conclusions.

> "(We) will make the right choices if we have the right information."

In my opinion, the documentary saves the best for last as Dr. Tinker discusses, with the aid of some excellent graphics, our energy future. He outlines which fuels and methods to generate power will become more important and what the 'Switch' will look like in the near future, along with the challenges to meet our energy needs. I will not tell you the ending as that is the most important point Scott Tinker is trying to make. I will give a hint, however: it has a lot to do with you and me and how we relate to the overall energy equation.

So what really bothered me through the night after watching 'Switch' is not that I missed something the movie was trying to get across, but why have we waited so long to hear its clear and distinct message. The vision that Scott and co-producer and director Harry Lynch have is simple: to change the global energy conversation. This film is a monumental first step towards achieving that vision and I applaud Scott Tinker, Harry Lynch and Arcos Films in creating a balanced, informative, and entertaining presentation. ■

THOMAS SMITH

(Scott Tinker was profiled in GEO Expro Vol. 8, No 4)

Dr. Scott Tinker, Director of the Bureau of Economic Geology at the University of Texas at Austin, co-producer and on-screen guide in the film 'Switch', and Harry Lynch (pictured at right), producer and director at Arcos Films, shown on location in Iceland. They have traveled the world to make a spectacular feature length film that offers an insightful look into our energy future.

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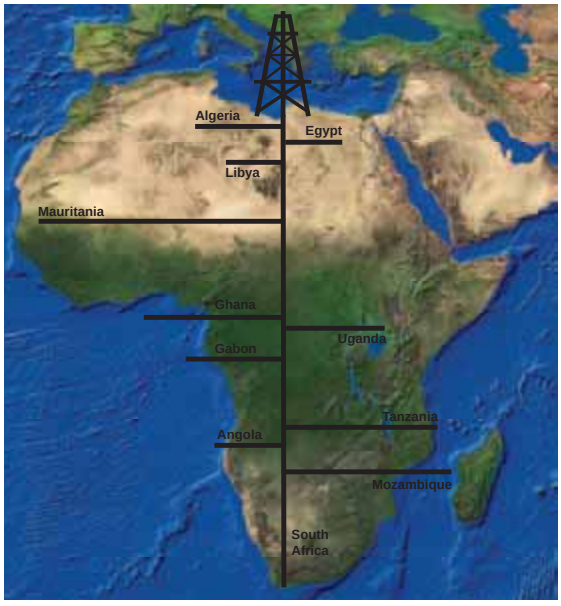
The technical program will be assembled by end of April, however, there **may be space for a few more good talks**. Contact the technical committee or submit a short abstract or topic as soon as possible to: africa2012@hgs.org. Extended abstracts are to be submitted after the talks are accepted and will be included in the CD of conference proceedings.

To become a sponsor or enquire about exhibit space, contact lucyplant@hgs.org or office@hgs.org

Early bird registration, at significant savings, is available until end of June 2012. Further details and a preliminary program will appear in the HGS and PESGB bulletins and websites.



Thank you to Fugro for providing CDs of the conference proceedings and to GeoExpro for their continued support.

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

Tight Oil Plays

Horizontal drilling and multi-stage fracturing technologies that have enabled companies to unlock large amounts of gas from shaley source rocks are now targeting similar rocks for oil and gas liquids.

Organic-rich, shale rocks like the Pebble Shale on Alaska's North Slope are fast becoming hot exploration targets in many of the world's sedimentary basins.

THOMAS SMITH

Usually, the 'Hotspot' page in *GEO ExPro* is devoted to a localized area like the Keathley Canyon, Gulf of Mexico, or the Santos Basin, Brazil, highlighting huge discoveries in extremely challenging conditions and the opening up of new frontier areas. This new frontier resource could also soon echo around the globe – and is being found primarily in fully explored and exploited onshore sedimentary basins, many of which have long passed their peak oil production.

Oil production from shale and tight source rocks is already making an impact in the US with the Bakken Formation leading the way. With substantial increases in shale oil development, there are even predictions that the US could become the world's top oil producer within the next five years.

The shale oil boom got its start in the Williston Basin (see *GEO ExPro* Vol. 9, No. 1). North Dakota's Bakken Formation production has increased from 1,500 bopd in 2004 to an impressive 440,000 bopd in 2011 and is expected to be over 700,000 in a few years. While the Bakken is primarily an oil play, many of the growing number of shale gas plays also have oil and gas liquid windows now being tested for the first time.

The Eagle Ford play in south Texas started out as a very hot gas play. Operators in the area soon discovered they could tap the formation's more valuable oil and gas liquids. Liquid hydrocarbon production has since shot up 40-fold in just two years. Other gas producing shale rocks across the US are seeing encouraging results from early production testing. Exploration activity for the Utica Shale, a formation that underlies the Marcellus, is centered in eastern Ohio and western Pennsylvania. Chesapeake Energy holds 5,058.6 km^2 in the area and has tested wet gas and oil at rates from 980 bpd to over 1,400 bpd. Further south, the 60-120m thick Tuscaloosa Shale play extends from east Texas to Mississippi. The area's first horizontal well test flowed 45° API oil from this Eagle Ford-like play.

South of the Bakken Field, the widespread Niobrara Shale, located in the Central Rocky Mountains, is being referred to as a Bakken look alike. Leasing has been active and EOG Resource's first well in northern Colorado produced 50,000 bo within 90 days. They are saying assessment of long-term production performance and completion optimization will be necessary before the resource can actually be developed. Other operators in the area have started horizontal drilling programs testing the Niobrara. If the Niobrara play pans out, there are a host of other Rocky Mountain region shales that will soon be exploration targets.

California and Alaska Too

The oil basins of southern California are also getting a second look. The organic-rich Monterey Formation has sourced much of the area's very productive oil fields and has been a prolific reservoir rock in the conventional fields. Now, Oxy Petroleum and Venoco Inc. are both looking at the Monterey as an emerging shale oil play that is estimated to contain more than 400 Bb of original oil in place.

Finally, what could turn out to be one of the largest of America's oil shale plays will be tested on Alaska's North Slope this spring by Great Bear Petroleum. Drilling the first wells was delayed due to rig availability but they have secured all the necessary permits for their year-round operation, proof of concept, and testing program. Great Bear has recently teamed up with Halliburton and each company will test two separate areas of the play. With excess capacity in the Trans Alaska pipeline, successful tests could prove vital in keeping the oil flowing.

As in the US, shale resources in Canada are seeing a great deal of activity. Along the Rocky Mountains in British Columbia and Alberta, Montney, Duvernay, and the Horn River shales have a proven huge gas potential, with Devon and other companies beginning to look at the oil potential. Virtually every source rock across the US and Canada within drillable depths is being studied.

Outside the US and Canada, shale and tight oil plays are just starting to be evaluated. Repsol has discovered a large shale oil deposit in the Neuquén province of western Argentina. The European Union is looking hard at shale gas to meet their energy needs and already, the Paris Basin is one very promising area for shale oil exploration. China has big plans for shale resource exploration and the list continues.

US crude production is expected to jump 1.5 MMbpd by 2015, driven largely by shale oil production. With much of the world's source rocks retaining great quantities of hydrocarbons and extending over very large areas, expect the technologies that have unlocked the huge shale reserves in the US to soon spread into many other sedimentary basins around the globe. ■

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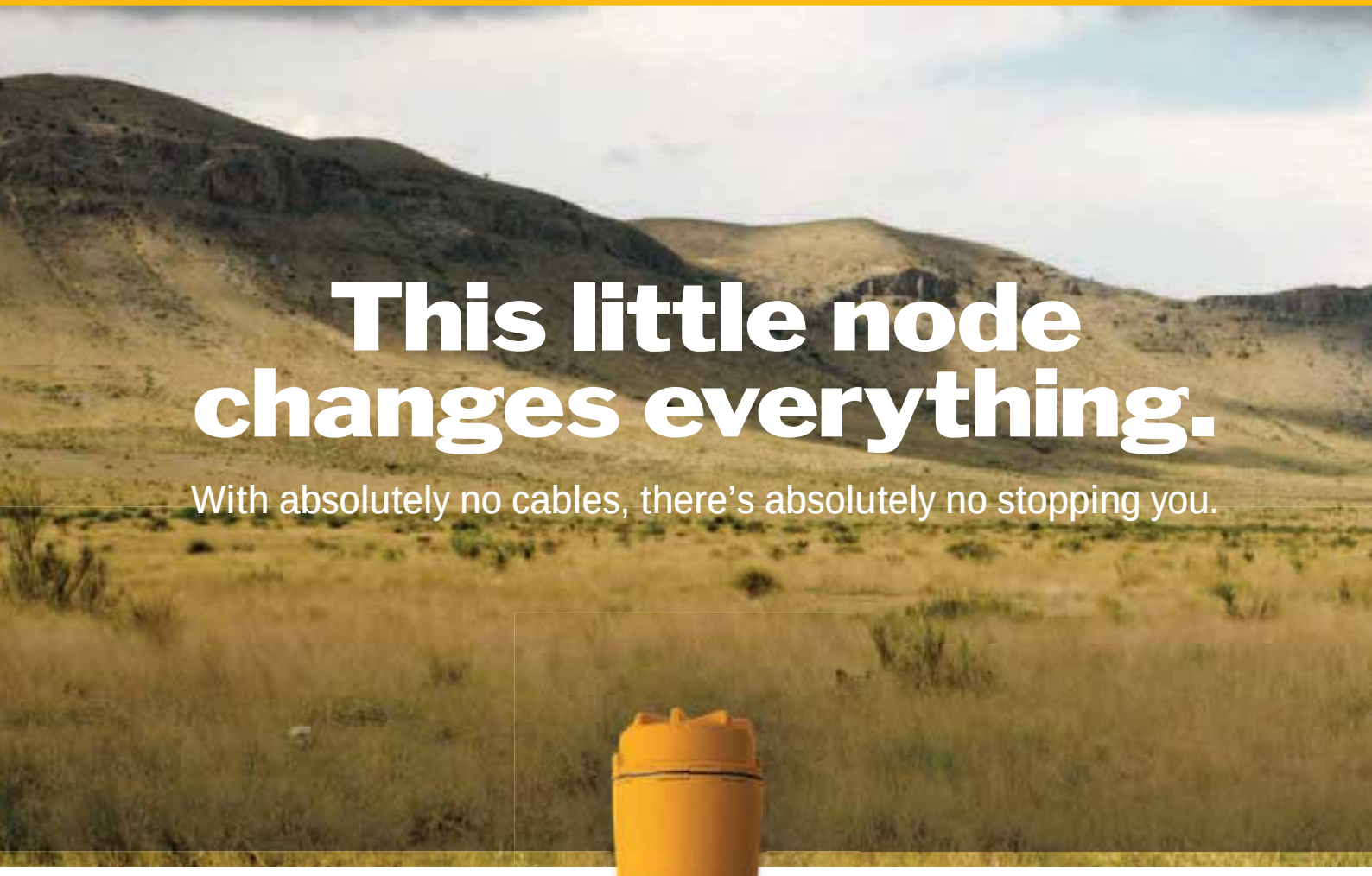

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A Good Career Choice

Dr. Lucy Ramsey is one of the new generation of geoscientists in the oil and gas industry. We ask her about her impressions of the industry so far.

What attracted you to the industry?
I had not thought about joining the oil and gas industry until quite late on at university, but from friends in it I knew a little about the work and lifestyle. The practical application of subsurface knowledge to business problems appealed, alongside the opportunity to travel and live abroad.

What is your academic background?
I studied Natural Sciences at Cambridge, intending to specialise in chemistry – but, having heard that it was a lot of fun, I took geology in my first year. The connection between geological theory, followed by observations and application in the field, appealed, and I was hooked. I was particularly interested in the link between continental deformation and geomorphology, so I did a PhD looking at deformation styles in Taiwan and Iran. I did not want to pursue academia long-term, and the oil and gas industry was the obvious place to apply my skills.

Was this your first job after university?
I joined BG Group straight after my PhD five years ago. I took part in the graduate training programme for the first two years, before joining UK Exploration. I found the North Sea a fascinating place to work. Despite a lengthy history of exploration, we are still testing new play concepts, aided by the latest innovative technologies. I am currently an Exploration Geologist in the Barents Sea, Norway. Significant discoveries in the Barents last year, combined with the resolution of the maritime border dispute, make it an interesting time to be working in an otherwise underexplored basin.

What industry training have you done?
The first two years at BG Group are all about working in a variety of teams and assets – from exploration to development and new ventures to operations. I was concerned that I would have missed out by not having a petroleum masters, but there is a range of technical and soft skills courses available to provide the support required.

Obviously, shooting seismic and drilling wells are a key component of the learning curve. Every graduate recruit takes part in geological and geophysical operations - before you know it, you are on a rig in the North Sea (or Mediterranean, if you are lucky!). It is a truly unique experience that should be a core part of any geologist's training. Recently, I have started to build on greater cross-functional training (economics and commercial) and to develop my leadership skills, but I also want to see more rocks! It is difficult to gauge the scale of features when looking at structures and maps on the workstation. Taking the opportunity to see actual rocks, whether through fieldtrip analogues or core workshops, brings the play to life, and you get a real sense of what could be down there. I take every opportunity to get out in the field and see a variety of reservoir types and structural styles.

What do you enjoy about the industry?
I greatly enjoy the variety of challenges on offer. Delivering a high-standard of technical work is still my primary focus. However, I am also taking on greater responsibility; presenting key concepts to senior management and anticipating the challenges and opportunities ahead are all part of the bigger picture. It might sound clichéd, but there is always something new to learn. It is an exciting time: BG Group is building on its LNG expertise and unconventional plays are increasingly important. The development of previously unconventional resources, alongside recent success in underexplored basins, ensures that there is always something new to learn about. The opportunity to travel is attractive. I am lucky enough to live in Norway at the moment, and I also spent six months in India as part of my training. Not many people get the chance to work overseas in such a supportive environment. Every asset has its own distinct atmosphere, culture, opportunities and challenges.

And what should change?
There is not much that I would change about the industry as I have experienced it. The subsurface community is a relatively tight-knit and supportive environment to develop in. As we all know, there is a distinct bimodal age distribution in industry demographics, and this needs to be addressed through longer-term strategy and resourcing. There are a limited number of role models 10 years ahead of me, but at the same time, there is a wealth of people with 30 years of experience to learn from.

How can we encourage more young people to join you?
I took geology by chance, and I ended up wanting to make a career out of it; how many people never had that opportunity? Early exposure to the subject is key, and the oil and gas industry has to play its part in promoting geology as a subject with significant career potential.

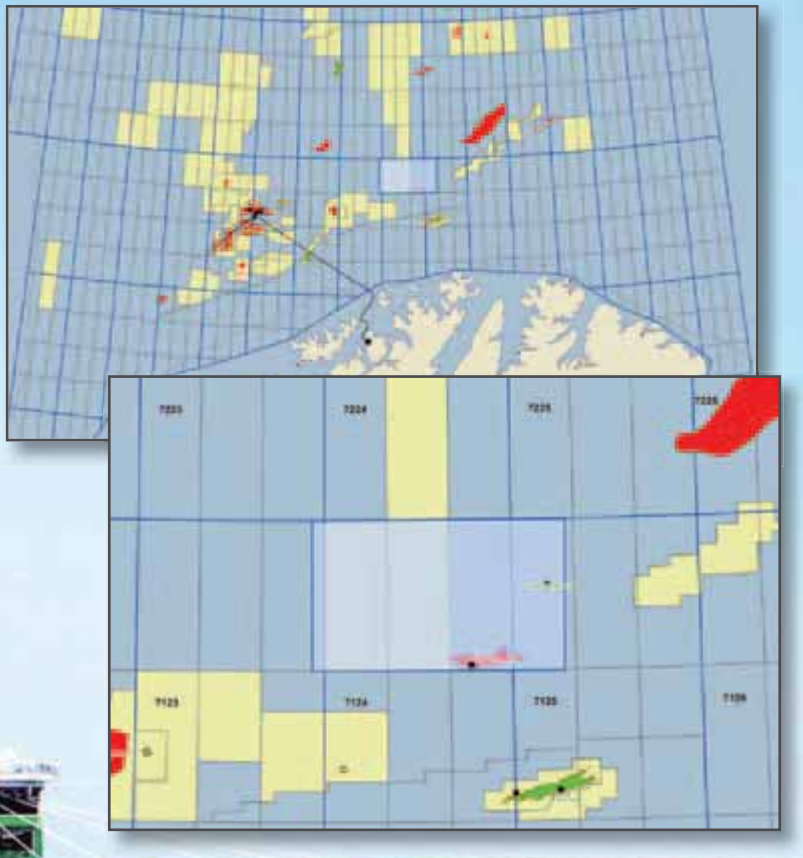
Where do you see your future?
I want to continue in exploration, whether at a technical level or in a management role. The excitement of drilling a well and not knowing what is down there is addictive. There are always going to be disappointments – but perhaps we learn more from our failures than our successes. You lament for a short time, dust yourself off, and look to where the interpretation takes you next. ■

Norway Bjarmeland Platform

Multi-Client 3D Data

Polarcus has acquired 1,300 sq. km of high-density multi-client 3D data over the Bjarmeland Platform in the Barents Sea, offshore Norway.

Final Pre-STM data available for 2012 APA round evaluations.



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Scan to read more about Bjarmeland Platform survey.

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CONVERSION FACTORS

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

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

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

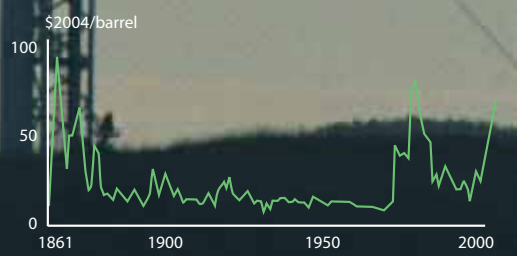
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

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

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

Historic oil price



More Oil and Gas to be Found

There is no doubt: oil and gas will remain the preferred energy source for years to come, according to Exxon Mobil's comprehensive review of energy demands in the next 30 years.

Global energy demand will be about 30% higher 30 years from now. This is one of the main conclusions in ExxonMobil's The Outlook for Energy: A View to 2040.

The reason is that economic output is expected to more than double and prosperity to expand across a world whose population will grow to nearly 9 billion people. However, it is also important to keep in mind the probability that the increase in energy demand will slow down in the years to come.

Another important observation is that while energy demand remains essentially flat in OECD countries, non-OECD energy demand will grow by close to 60%. "China's surge in energy demand will extend over the next two decades then gradually flatten as its economy and population mature. Elsewhere, billions of people will be working to advance their living standards – requiring more energy," the report says.

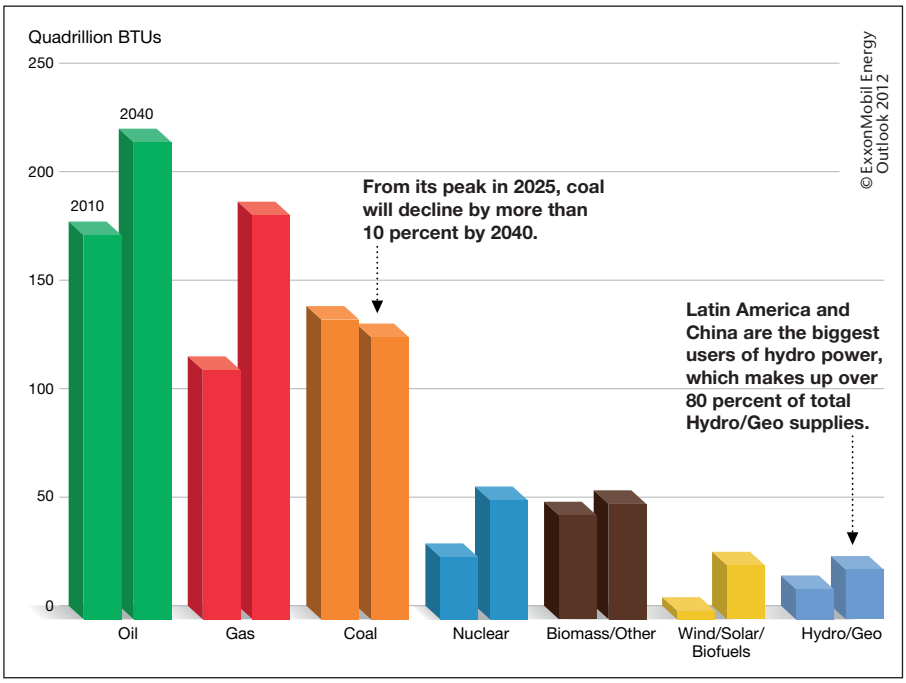
Fossil fuels will remain the premier energy source. In 2040, oil, gas and coal will together make up about 80% of the global energy consumption.

With respect to coal, demand will peak and begin a gradual decline within the next 30 years, the Energy Outlook says. This is because new policies seeking to curb emissions by imposing a cost on higher-carbon fuels. Natural gas, on the other hand, is expected to overtake coal for the number-two position behind oil as demand rises about 60%.

For both oil and natural gas, an increasing share of global supply will come from unconventional sources, such as oils sands, shale oil and shale gas.

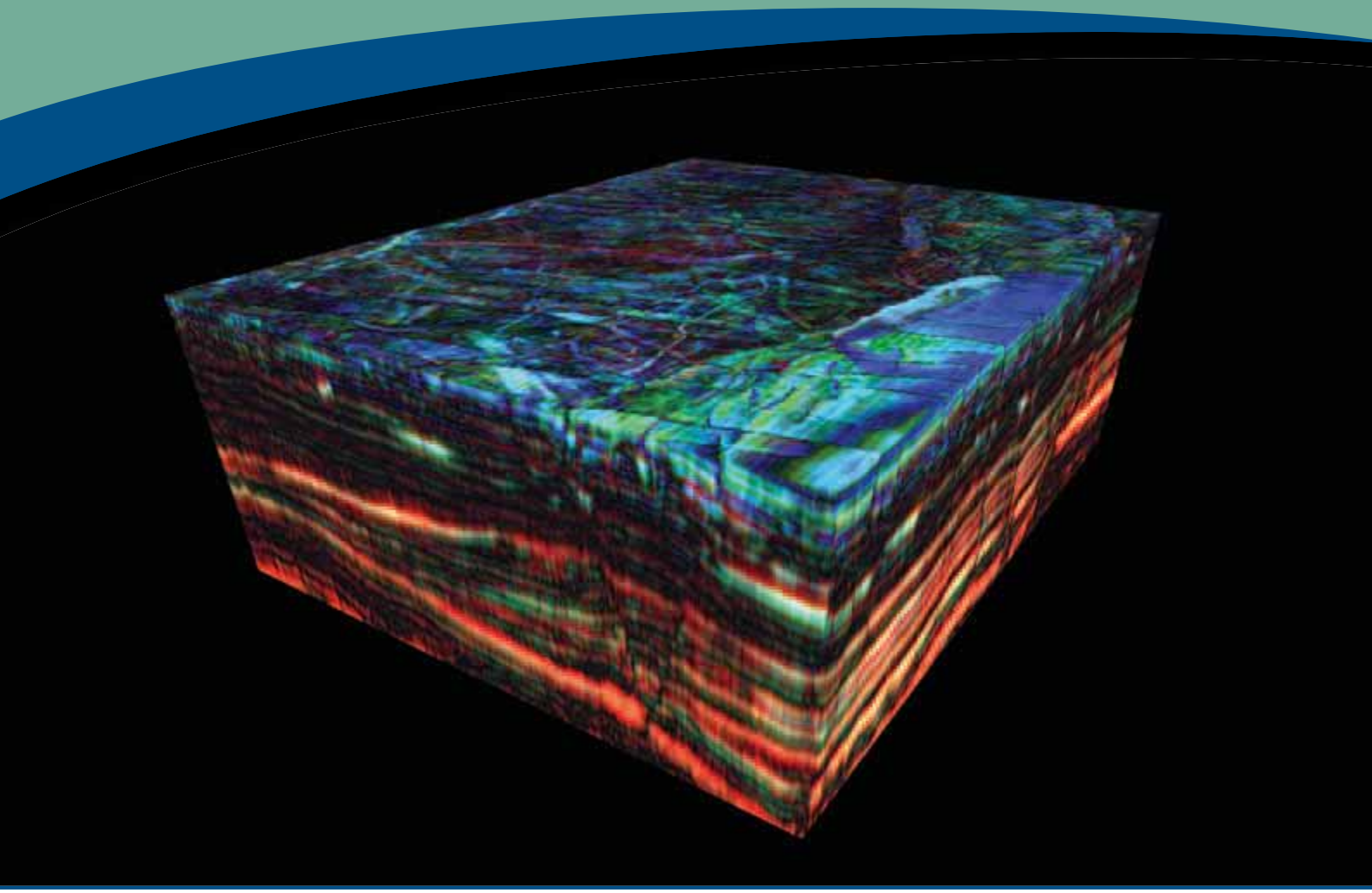
The good news is that ExxonMobil expects global energy-related CO_2 emissions to level off around the year 2030. This global emissions trend is the result of significant improvements in energy efficiency, plus shifts toward natural gas and other less carbon-intensive fuels, as efforts continue to manage the risks posed by rising greenhouse gas emissions. ■

HALFDAN CARSTENS



Global energy demand by fuel type. By 2040, oil and natural gas will be the world's top two energy sources, accounting for about 60% of global demand, compared to about 55% today, according to ExxonMobil. Gas is the fastest growing major fuel source over this period. Coal is the only energy source to be reduced in the years to come.

High Hopes for Hoop



New 3D data available in the Norwegian Barents Sea

TGS offers an industry leading 3D database in the Hoop Fault Complex of the Barents Sea:

- Extensive multi-client 3D survey (7,300 km^2) covering the entire Hoop Basin and surrounding highs
- Plays in many levels from Carboniferous, Triassic, Jurassic to Cretaceous
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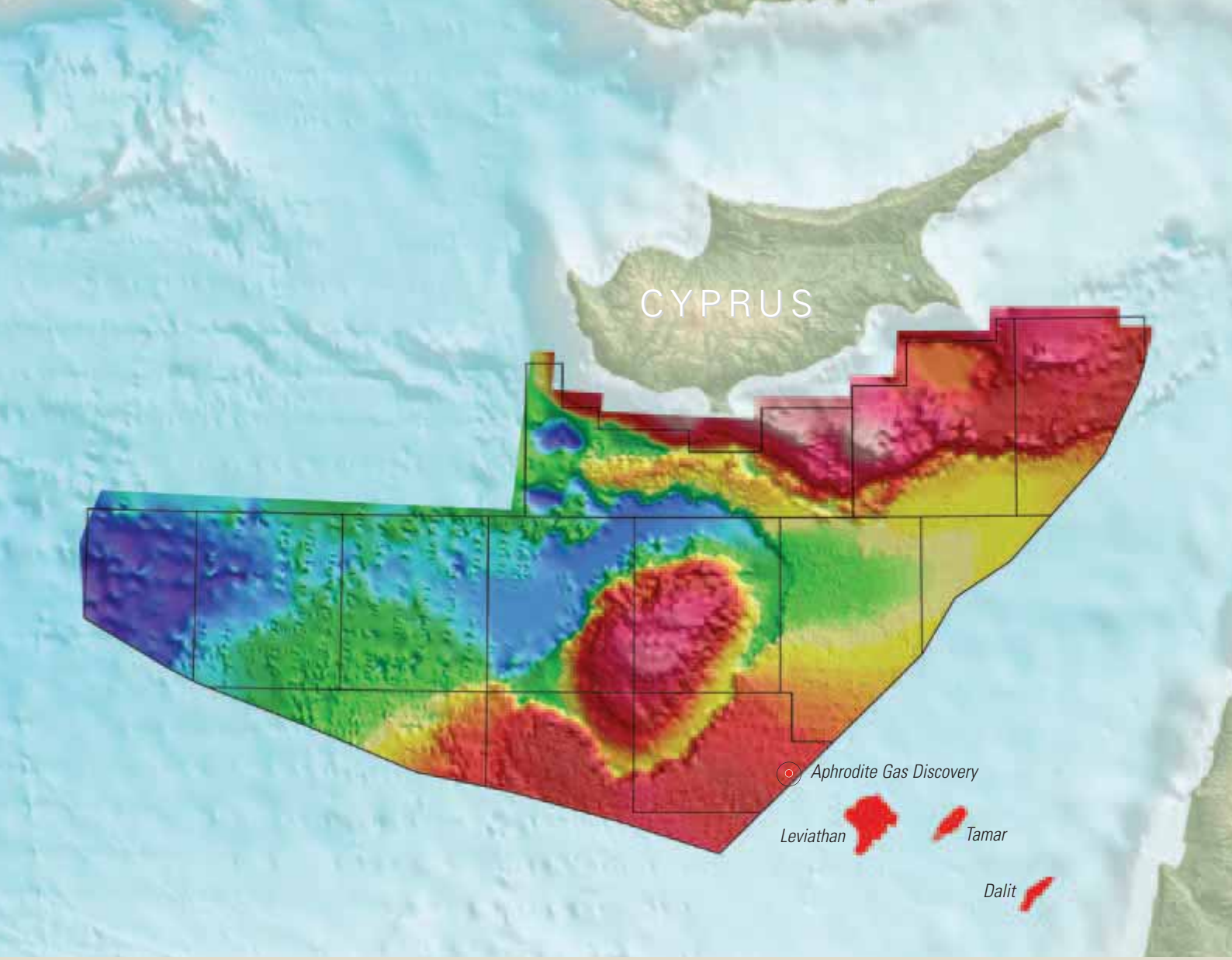

MultiClient

Cyprus - 2nd Licensing Round

PGS is the official data provider for the 2nd licensing round Offshore Cyprus, open 11th February - 11th May 2012. Approximately 19,000 km of MC2D data and 659 sq.km of MC3D data is available, covering prospective plays and the recent giant gas discovery in Cyprus.

Contact us to book a data review meeting in Nicosia, Oslo, London or Houston today.

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