VOL. 12, NO. 2 – 2015

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

GEOTOURISM:
Canadian Rocky Mountains

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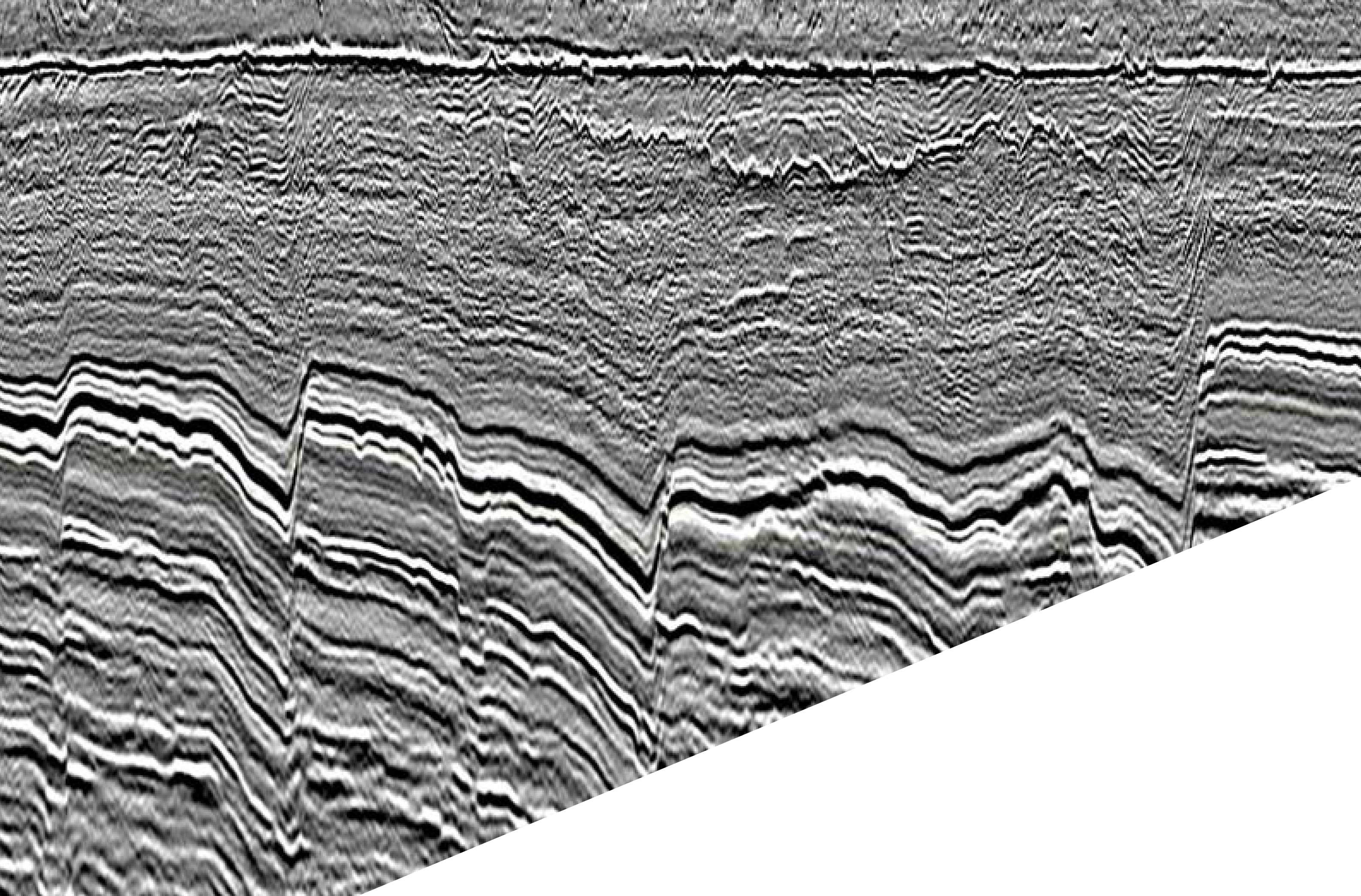
GEOSCIENCE EXPLAINED

Modeling Salt Tectonics

EXPLORATION
Mexico's Offshore Potential

THE DIGITAL OILFIELD
Managing the Transition

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT



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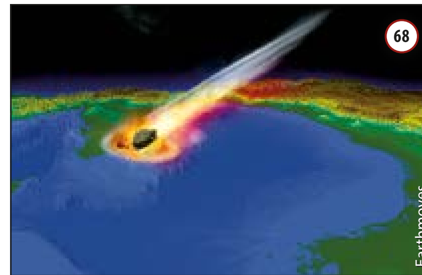

The Chicxulub meteorite was responsible for the reservoir rocks of Mexico's supergiant oil fields.

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This edition of *GEO ExPro* Magazine focuses on North America and the Digital Oilfield.

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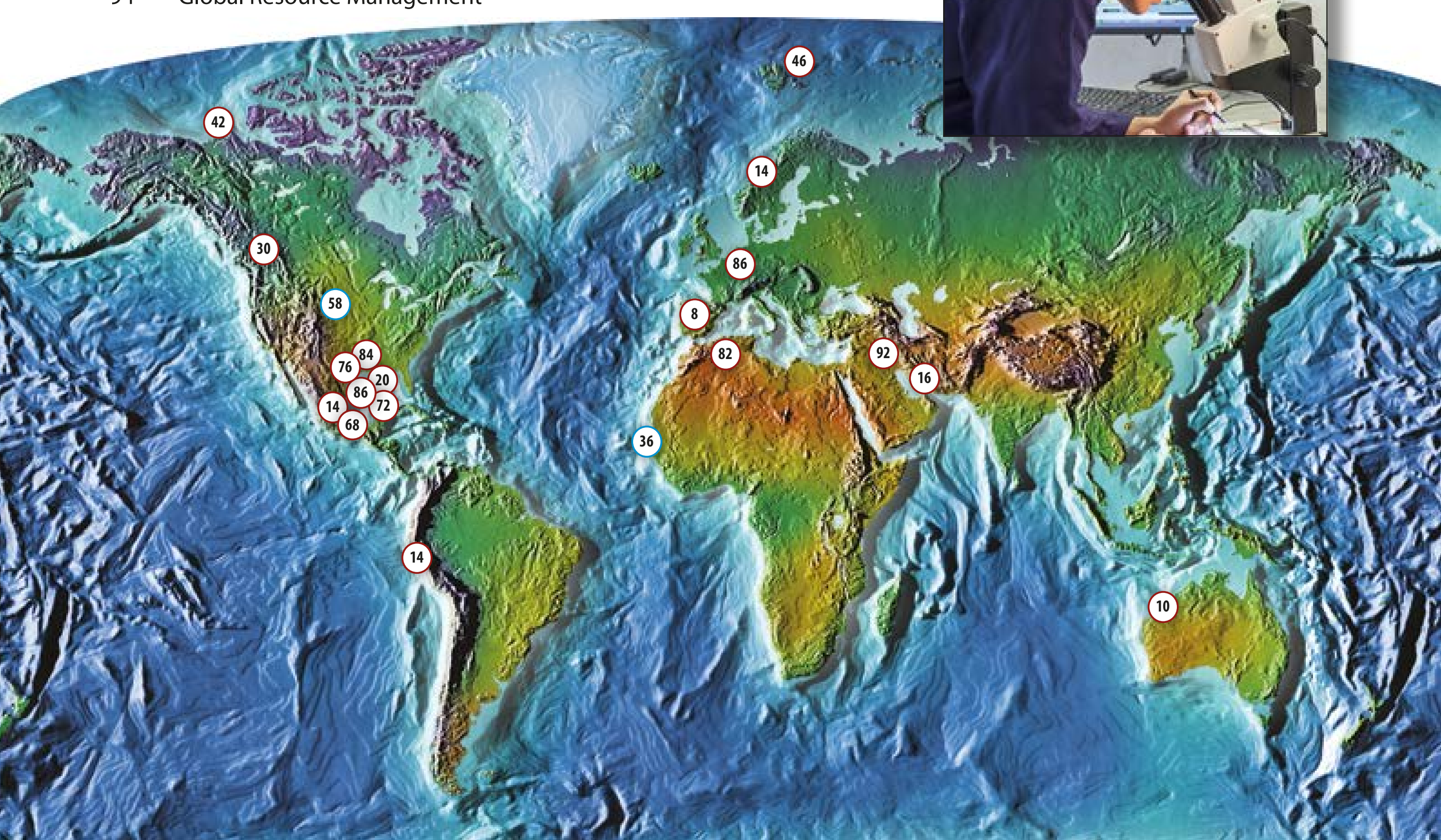
FEATURES

Mud loggers play a vital but poorly understood or appreciated role in exploration.



Riding the Waves


123rf.com/lightwise

Welcome back to the rollercoaster!

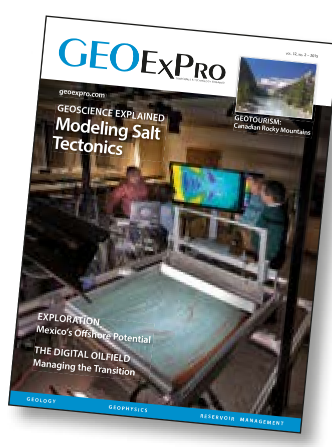
I have worked in this industry for nearly forty years and in that time, like so many of you, I have seen it ride the peaks and troughs of waves extreme enough to rival those facing me in the North Sea all those years ago. And here we are again, back in the doldrums, with a downturn fueled by a global oversupply coupled with weakening demand. The oil price, having rallied in February, is heading down again, the US rig count, which many consider an accurate harbinger of the state of the industry, has dropped more than a third since the end of 2014, and the inevitable closures and mergers of oil and service companies have begun.

Is this the same as all those other waves in the industry cycle? Some observers feel that it is different this time, and we might be in for a long haul back up. There have been thousands of job losses and companies appear to be cutting back faster and deeper than in previous downturns. Production is leveling out and is expected to decrease in the US, which was not the case in the 2008–09 recession. The world security situation does not inspire confidence, either.

In some ways, however, downturns can be beneficial; a pared-down industry is leaner and more productive. Many believe that those who manage to ride out the storm will be tougher and more efficient, making better use of the high-end technology, such as 'intelligent oilfields', available to them. Choices will have to be made, and it is to be hoped that somehow the industry will continue to invest, particularly in technology and also expertise. We need to learn from previous crises, and remember that knowledge – and the people with it – is our greatest asset. Lose that, or fail to pass it on, and this downturn will be much harder to climb out of.

The pundits are finding this particular cycle hard to predict. Enjoy the ride! ■

Jane Whaley
Editor in Chief



PUZZLING SALT STRUCTURES

Detailed salt modeling research at the University of Texas at Austin is proving to be a valuable exploration tool in unlocking the structural evolution of these complex petroleum systems. The imagery being viewed on the TV screen by (L-R) Tim Dooley, Naiara Fernandez, Martin Jackson, and Mike Hudec, is the surface evolution of the Florida Arch model from the processed DIC data. The top surface of this model can be seen in the deformation rig in the foreground.

Inset: The magnificent Canadian Rocky Mountains – a geologist's playground.

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From Cartel to Market Share

Oil prices dropped by 60% from June 2014 to mid-January. The two key explanations behind the unexpected sharp fall were a significant slowdown in oil demand growth and a complete change in OPEC's – and in particular Saudi Arabia's – market strategy, on the back of strong growth in US and Russian oil production. Defending market share and not price level is now the objective. The February rebound in oil prices was triggered by expectations that a falling number of rigs hired by the US shale industry and sharp cuts in oil companies' investment budgets will reduce the supply overhang of oil later in 2015 and in 2016. Yet supplies are still abundant and before we see clear signs that the physical supply/demand balance is tightening, we must assume that oil prices will remain volatile. In the medium term, oil prices can be expected to rebound as supply growth will be dampened and global demand continues to increase.

Oil demand is expected to grow at a slower pace as a consequence of both cyclical and structural factors. Overcapacity in the energy-intensive industry in China, coupled with weaker currencies and economic conditions in large oil-importing countries, such as Japan and the EU, are expected to weigh on demand short term, despite the positive effects of lower oil prices on stockbuilding and fuel consumption in the US. In the medium term, the ongoing structural changes and lower oil intensity are essential to the global oil market outlook. The most important factor is increasing competition in the transport sector, which accounts for 55% of total oil demand. Mounting attention given to climate/pollution and a decade of rising oil prices have triggered the technological development of new and more efficient batteries and engines and a sharp fall in the production cost of green energy such as wind and solar power. We have only seen early evidence of the growth potential offered by natural gas, electric, hydrogen and dual-fuel vehicles, airplanes and ships. Therefore we can expect that an accelerating rate of technological progress in the transport sector will curb the long-term growth momentum of oil demand markedly.

Until 27 November last year, the oil market was partly controlled by the OPEC cartel. With Saudi Arabia, the only country with a solid spare capacity buffer, acting as the swing producer, OPEC was able to support a price at around $ 110/barrel, above the estimated marginal cost (MC) of around $ 90/barrel. But the artificially high prices under the cartel regime had some undesirable side-effects: OPEC lost ground to the US and Russia. Saudi Arabia therefore unexpectedly introduced a new oil order: to defend market share. With a more competition-driven market, the new equilibrium price will move closer to the MC. We should also expect a downscaling of OPEC's spare capacity to squeeze more expensive producers out of the market. This should lead to a rightward shift in the MC curve and drive the new equilibrium price towards $ 80/barrel, depending on how faithful OPEC will be in defending its new market share strategy.

Thina Margrethe Saltvedt, Nordea

	Q1	Q2	Q3	Q4	Year
2012	118	109	109	110	**112**
2013	113	103	108	107	**108**
2014	108	110	103	77	**100**
2015E	55	60	65	69	**62**
2016E	70	72	77	79	**75**

ABBREVIATIONS

Numbers
(US and scientific community)

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

Earth Science for Energy and Environment

Europe's biggest annual multidisciplinary geoscience event is almost upon us. The 77th European Association of Geoscientists and Engineers (EAGE) Annual Conference and Exhibition, including SPE Europec, will be held on June 1–4, 2015, in Madrid, Spain.

This year's theme of 'Earth Science for Energy and Environment' will explore the vital role that geoscientists have to play in securing a sustainable future for the planet. The program for Madrid 2015 includes a conference, workshops, short courses, a technical exhibition and field trips.

What's on Offer?

The conference will bring together delegates from more than 70 countries to engage in over 1,100 presentations, making Madrid 2015 the perfect opportunity to learn about the latest worldwide technological research. The conference will comprise 14 parallel oral sessions and ten regular poster sessions, including two specifically for students, all carefully tailored to make the best of the various themes on offer.

To complement these presentations, a number of special sittings to which all delegates are invited will also be weaved into the program. These include the EAGE Forum, two Executive Sessions and three dedicated topical ones. We are also proud to include our sessions on 'Professional Women in Geoscience and Engineering' and 'Young Professionals'.

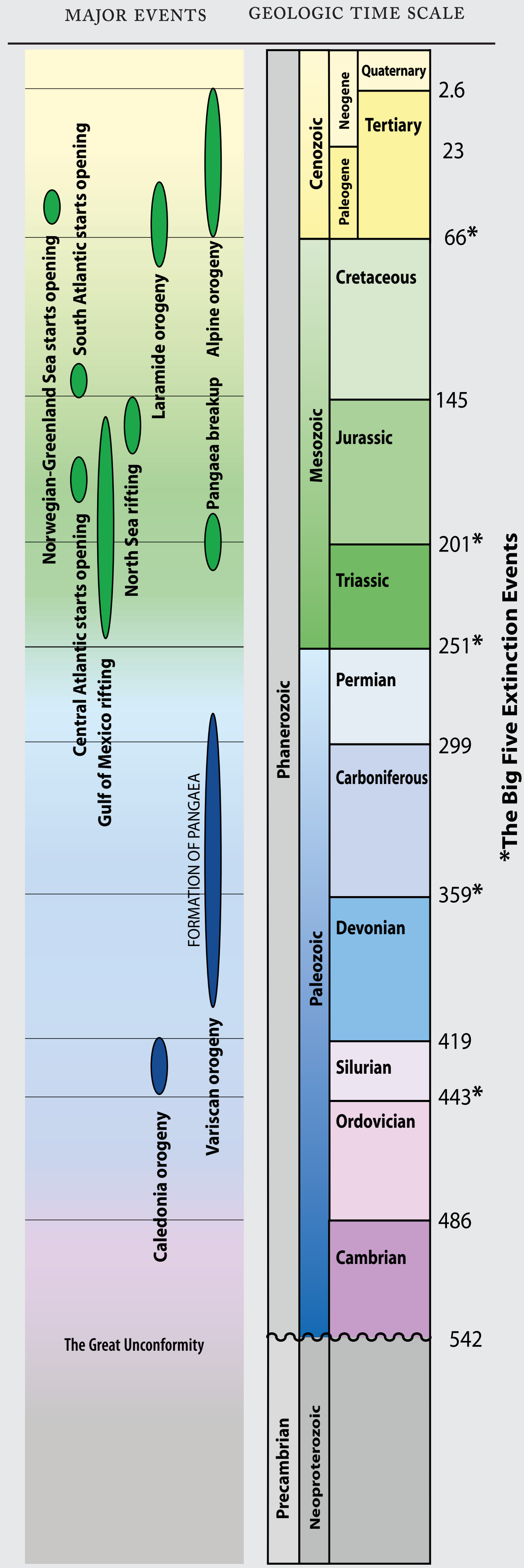
For students, a separate program has been developed. As a student delegate, you will have a chance to learn more about the industry, meet peers from other universities and find out how EAGE can support you with the development of your studies and future career.

You will find a warm welcome from EAGE to celebrate the start of the exhibition with the Icebreaker reception on Monday June 1, 2015. This is a perfect opportunity to meet exhibitors and peers from around the world in an informal setting, with Spanish drinks and delicious Spanish food served throughout. From Tuesday June 2 to Thursday June 4 the exhibition will be the meeting place for delegates, where breakfast, coffees and afternoon drinks will be served. A total of 350 companies from all around the world will present their products and services, including international oil companies, NOCs, energy industry consultants, software vendors, service companies, equipment suppliers, research institutes, licensing agencies and governmental bodies. EAGE and the exhibitors are looking forward to your visit!

Workshops and Short Courses

On Sunday May 31, Monday June 1, and Friday June 5, a total of 15 workshops and seven short courses have been organized. These intensive programs aim to cover a wide variety of topics and scientific disciplines, led by experts from industry and academia. Extended descriptions about all the workshops and short courses can be found on the EAGE website.

The 77th EAGE Conference and Exhibition 2015 is set to be the best yet. To learn more about the exhibition, conference program and sponsor opportunities, please visit the EAGE Madrid 2015 website, www.eage.org/event/madrid-2015.



Collaboration is the Future

Australian-based Searcher Seismic and Chinese BGP consolidate their relationship.

In the present rather straightened times, many people in the oil and gas industry believe that collaboration, even across continents, is the way forward for the future.

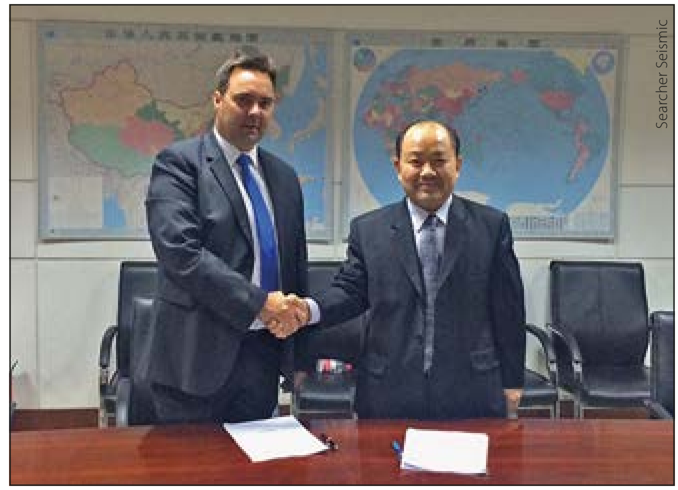
Two companies which are enthusiastically putting this theory into practice are Searcher Seismic, which is headquartered in Perth, Australia, and Chinese-based BGP, which have consolidated their ongoing association with two recent collaborations.

In February, they announced a commercial marketing agreement which provides BGP with an exclusive right to market the Searcher multi-client 2D and 3D seismic library within China and receive commission fees on the sales of this data. The agreement covers more than 900,000 km of 2D and 80,000km^2 of 3D seismic data from Searcher's global database. Searcher believe that this agreement with BGP is very exciting as it helps open the door to Chinese-based oil companies as they look to expand their presence around the globe. The company hopes that in addition to marketing its existing data, the agreement will help develop new projects for the Chinese market.

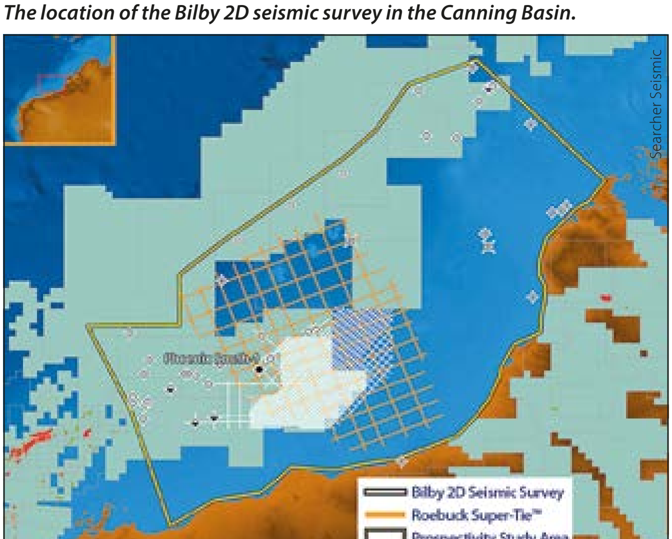
Canning Basin Survey

Further strengthening the relationship between the two companies, in March they embarked on Bilby, a new 2D non-exclusive survey of the Bedout Sub-basin and Broome Platform, in the Canning Basin offshore north-west Australia. This will be carried out close to Apache's Phoenix South-1 discovery, which in August last year confirmed a structure originally identified back in 1980, resulting in a wholesale change in thinking regarding the prospectivity of the area. Logging and pressure data from Phoenix South-1 confirmed at least four separate oil columns ranging from 26 to 46m in the Triassic Lower Keraudren Formation, with early estimates suggesting the possibility of 300 MMbo in place.

The Bilby 2D seismic is being acquired by the BGP Explorer using high-end Sercel Sentinel Solid Streamer technology, Sercel GII Gun Source equipment and continuous recording. The survey comprises approximately 12,300 km of 2D long-offset, high resolution broadband data over 2x4, 4x8 and 8x8 km grids and has been designed to provide modern, high quality data to help identify prospective structural and stratigraphic trends that can be used for regional evaluations and future detailed seismic survey design. Seismic data processing will be undertaken by Perth-based DownUnder GeoSolutions, with initial deliverables being DUG Broad PSTM data, while final results can be expected from June 2015.



Searcher Seismic's General Manager, Alan Hopping with BGP's President Marine and MC, Haibo Liu.



The location of the Bilby 2D seismic survey in the Canning Basin.

Tying nicely in with the Bilby survey will be Searcher's Roebuck Super-Tie™, a regional grid comprising over 5,000 km of reprocessed PSTM data, which will be available in May 2015.

In a further example of collaboration, Searcher Seismic, in conjunction with Insight Petroleum, have recently completed an Offshore Canning Area Prospectivity Study, which aims to provide timely and strategic information to assist companies in understanding the implications of the recent Phoenix South-1 discovery and the prospectivity of the Bedout, Rowley and Oobagooma Sub-basins and adjacent platform areas. Searcher believes that substantial potential appears to exist not only in and around the Phoenix South area, but up-dip on the flanks of the basin, where the results of Keraudren-1, a Roebuck Basin BHP well from 1973, demonstrate that significantly better quality reservoirs exist within the Triassic sediments. There is also the potential for oil to migrate up onto the adjacent Broome Platform into accumulations analogous to the Stag, Gwydion and Cornea fields elsewhere in the region.

Lower oil prices mean that efficiencies of scale, combined marketing and pooling of technological expertise are just three of the advantages to be gained from intercompany collaboration. ■

What is a Digital Oil Field?

Something of a 'buzz' phrase – but what do we mean by 'the Digital Oil Field'?

'Digital Oil Field'; 'Integrated Operations'; 'Smart Fields'; 'Intelligent Oil Field': all phrases that sum up a new approach to exploration which is becoming more and more necessary as costs are forced downwards and the labour force shrinks, whilst efficiency and production need to rise. An idea that a few years ago simply meant using a machine for a particular exploration undertaking has now widened to encompass automating and integrating a huge range of tasks across many aspects of the exploration and production cycle, all made possible by immense changes in our ability to rapidly process vast quantities of data in very short periods of time.

A Process, Not a Place

Many people think of the digital oil field as a fancy technological hub, with hundreds of flashing screens and a couple of experts earnestly comparing notes in a hushed environment. But it is better described not as a physical presence, but as a concept, encompassing not just data being streamed from far distant wells, but the processing, integration and analysis of that data in a number of physical environments. These could include not just a purpose-built technology room, but also an oil company's headquarters, a consultant's office and the wellsite itself. Digital communications such as videoconferencing between these diverse centers are an intrinsic part of the process. And the idea is not confined just to operational processes, as data fed through the intelligent oil field will inform decision-making prior to drilling an adjacent well, and will be fed into post-drill analysis.

Automation is a vital part of this process. By taking the human out of mundane tasks, productivity is increased, and the expert is freed to use his or her knowledge on more difficult, analytical work. Integrating a large number of the processes involved in drilling, such as remotely steerable down-hole and integrate-while-drilling tools, produces large quantities of real-time data across a range of disciplines. One of the features of the digital oil field is the requirement for collaboration across a wide range of expertise, meaning that decisions are arrived at with a full awareness of all the issues involved, hugely increasing efficiency.

Technological innovation has been a prime driver behind the move in the development of the digital oil field, but it can only work properly when automated operations are streamlined with new personnel work processes, and a vital component of their success is ensuring that people understand the concept and process, and are well trained and fully committed (see page 26).

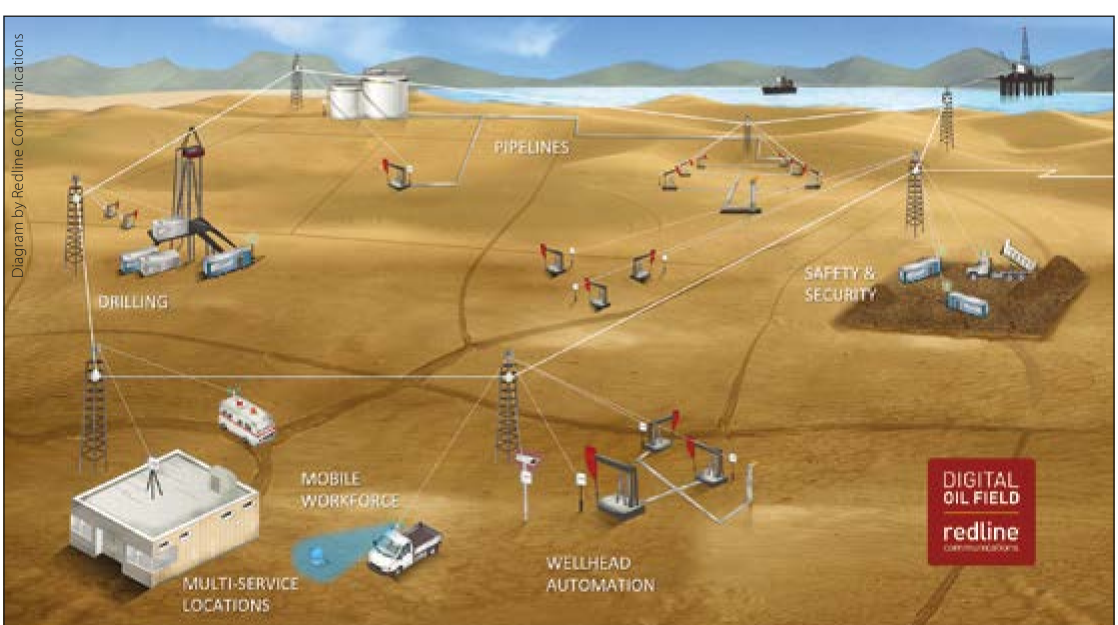
Many Benefits

And the point of all this? Timely information leads to better decisions and productivity gains, while an increase in the number of remotely operated fields decreases the risk of accidents, with fewer people traveling to, and working in, potentially dangerous environments.

Cost savings are tangible. Shell believes that the value of its 'Smart Fields' implementation over a five-year period was US$ 5 billion, while IHS Cera have calculated that by using digital oil field processes, companies could realize up to 25% savings in operating costs, up to 8% higher production rates, 2–4% lower project costs, and as much as 6% improved resource recovery, all within the first full year of deployment.

Lower costs, more efficient reservoir management and fewer mistakes during well drilling will in turn raise profits and make more oil fields economically viable. Quite some prize!

Jane Whaley



The digital oil field – connecting all aspects of a drilling operation to ensure productivity, efficiency and safety

New Areas for Exploration Offered

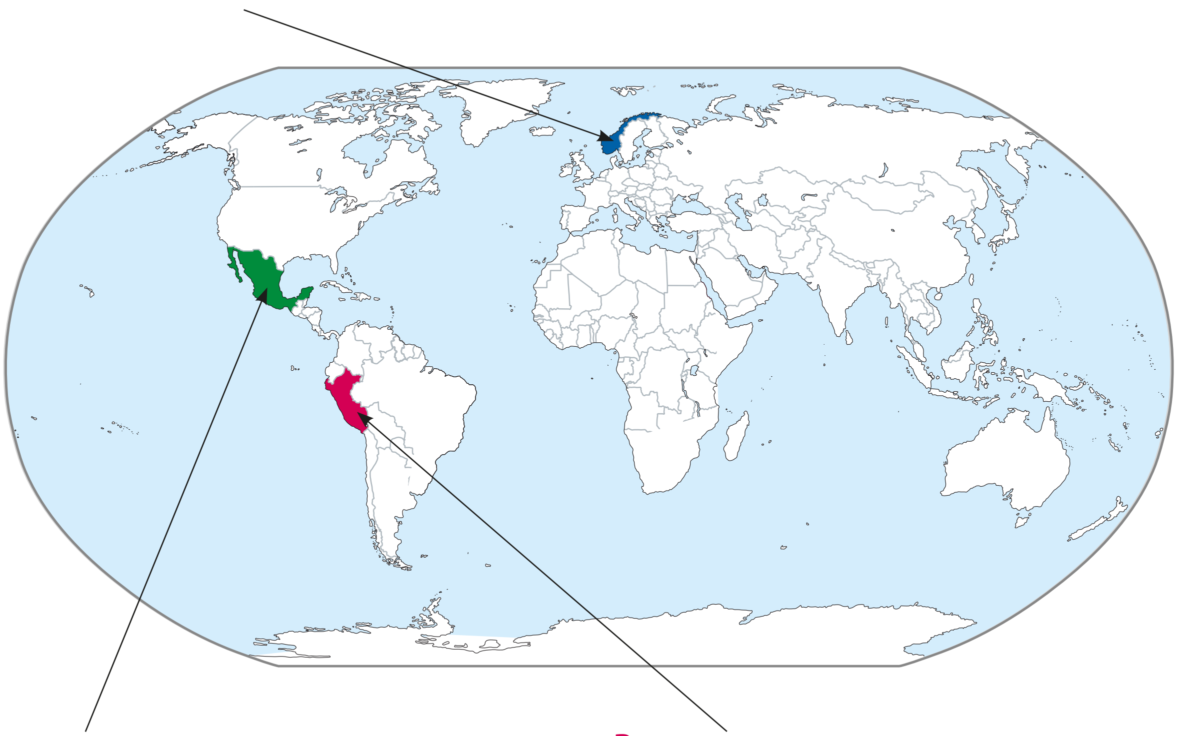
KEN WHITE

Norway

The Ministry of Petroleum and Energy (MPE) opened the 23rd Licensing Round on January 20, 2015. In total 57 blocks (or part blocks) are available – 34 in the south-east Barents Sea, 20 in the remainder of the Barents Sea and three in the Norwegian Sea. The deadline for applications is December 2, 2015 and awards are expected in the first half of 2016.

The interest in exploration in the Barents Sea has increased significantly following a number of good discoveries in recent years: Wisting, Gotha and Alta. The new areas in the south-east Barents Sea are particularly interesting. They are hitherto unexplored and could open up a new petroleum province in the Barents Sea. This is the first time since 1994 that Norway is offering exploration opportunities in an entirely new area of the Norwegian Shelf.

It should be noted that the cooperation agreement between the various political parties in Norway states that no petroleum activity shall be carried out near the ice edge during this parliamentary term, which ends in 2017. The official announcement states that for the announced blocks in the Barents Sea, drilling in oil-bearing layers will not be permitted in areas closer than 50 km from the actual/observed ice edge during the period December 15 – June 15. This year marks 50 years since petroleum activities began in Norway.



Mexico

Ending a 76-year state monopoly, Mexico's Comision Nacinal de Hidrocarburos (CNH) has opened Ronda Uno by issuing a call for bids on 14 shallow-water blocks located in the Bay of Compeche in 40 to 80m of water. The blocks range in size from 116 to 466 km^2, and have prospective resources between 30 and 151 MMboe. Each block has multiple drill opportunities in several play types identified by the Secrataria de Energia (SENER) including in the Pliocene, Miocene and fractured Cretaceous sections. Interested companies will have to prequalify to participate in the round by showing, among other things, proficiency as operator in three shallow-water E&P projects between 2010 and 2014 or as operator of a single E&P project having a capital investment of at least US $1 billion. This part of the round is scheduled to close on July 14, 2015.

Mexico is taking a staggered approach to the Ronda Uno tender, which will ultimately make available 169 blocks covering about 28,500 km^2 comprising 109 exploration blocks, 60 exploitation blocks, and 10 development projects entailing 14 separate fields previously granted to PEMEX. These blocks hold an estimated 3.8 Bboe (2P) and 14.6 Bb of prospective resources. A second call for bids will be associated with extra-heavy oil in new areas, and the selected farm-outs, while a third call for bids will include unconventional areas. The fourth will deal with onshore areas and new areas, and the final call for bids under Ronda Uno will offer deepwater areas, as well as some development farm-outs. Some time slippage is expected, especially for the unconventional element, given the low oil price environment.

Peru

State regulator Perupetro has opened a seven-block E&P bid round in the Amazon jungle with bid submission due August 26, 2015. Five of the seven blocks have executed prior consultation agreements under the Consulta Previa law, which guarantees that indigenous populations living within the limits of the permit areas will have the right to agree to the E&P activities that may take place. The other two blocks have no resident population. Reportedly the work program per block will require a minimum of US $450 million each and two exploration wells. For the commercial portion of the bid submission, companies must offer a 20% royalty in addition to the minimum bid values. Companies will have until May 2015 to submit a letter of interest. Four of the announced blocks are located in the Ucayali Basin, one is located in the relatively untested Madre de Dios Basin, one in the Solimoes Basin/Iquitos Arch area and one lies in the eastern Maranon Basin.

The new onshore licensing round is seen as an important test of investor confidence in Peru's hydrocarbon sector after recent disappointments. Factors that could increase the level of interest in the new round are improved contract terms – Perupetro will not be eligible to take up to a 25% stake if a commercial discovery is made – and the more favorable hydrocarbon prospectivity of the Amazon region compared to the country's largely unexplored offshore basins. It is understood that Perupetro has identified a further 19 blocks in the Amazon that it may include in two separate auctions that will possibly launch in 2015, subject to the successful conclusion of the prior consultation processes. An offshore round comprising six exploration blocks to be held in 2016 is believed to be in the planning stage.

New Ideas From Africa

The Petroleum Society of Great Britain and the Houston Geological Society are pleased to announce the launch of the **14th Conference** on African E&P, entitled '**Always Something New Coming Out of Africa**'. This annual conference, which alternates between London and Houston, has established itself as the primary technical E & P conference on **Africa**, with attendances in recent years reaching over 600, including operators, consultants, governments and academia. There will be a large poster program in addition to the oral program of about 25 high quality talks, complemented by a lively exhibition floor boasting over 50 exhibitors.

The conference themes include new exploration hotspots; new kitchens – geodynamics heat flow and source rock modeling; new insights on trap types and imaging; and new reservoirs – African carbonates in time and space. There will also be a new seismic workshop, during which seismic service companies will present on a geological topic of their choice and provide an in-depth investigation into the accompanying datasets.

If you would like to present, attend or exhibit at the conference head to www.pesgb.org.uk for more information.

Africa 2015 runs from **September 3rd to 4th** at the **Business Design Centre, London**. ■

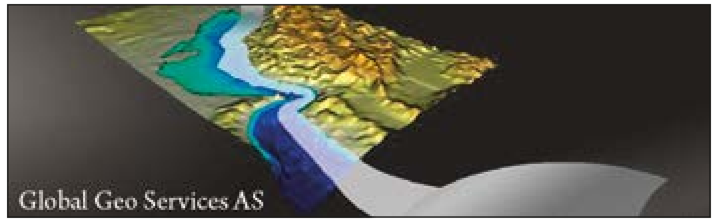
The PESGB/HGS Africa conference is always a busy one.

Where's That Seismic Boat?

Searcher Seismic have recently published '**The Vessel Searcher**', a slick, quick, map-based app which tracks the whereabouts of the world's seismic survey vessels. With it you can explore geographically or use the filter function to find a ship via vessel operator, or use the search field to enter the name of a vessel and select from the predictive text list presented as you type. Fleets tracked include those operated by BGP, CGG, COSL, DMNG, Dolphin, Fairfield, Gardline, MAGE, PGS, Polarcus, SeaBird, SMNG and Western Geco. A small disadvantage is that the position data provided lags real-time by up to 72 hours, so vessels in transit are not current.

This innovative app is free to download by searching 'Vessel Searcher' in the app store, and will be available on Android soon. It has proved very popular and is fun and easy to use – try it yourself! ■

A Persian Carpet



As the chance of a rapprochement between **Iran** and the west grows and the possibility of the lifting of sanctions increases, interest in opportunities for hydrocarbon exploration in the country will rise. With this in mind, Norwegian company **Global Geo Services (GGS)** are offering their **Persian Carpet** seismic survey data library, which covers the entire offshore Iran in both the Persian Gulf and the Oman Sea, making it one of the largest multiclient datasets ever put together.

Acquired under an exclusive agreement with the National Iranian Oil Company between 1999 and 2005, the dataset consists of a total of 90,700 line kilometers (Lkm) of standard offshore library and 11,700 Lkm of shallow water seismic, as well as 3,600 Lkm from the transition zone. In addition, there are 3,250 km^2 of pseudo 3D data which covers structures with a particularly high potential. The data is available in SEG-Y format and also includes interpreted horizons in Kingdom, plus data and interpretation of 120 wells, all in both hard copy and digital format. GGS is licensed to sell this data, with no money passing to Iran, avoiding sanctions issues.

As soon as sanctions are lifted, Iran will offer new rounds, so why not be prepared? ■

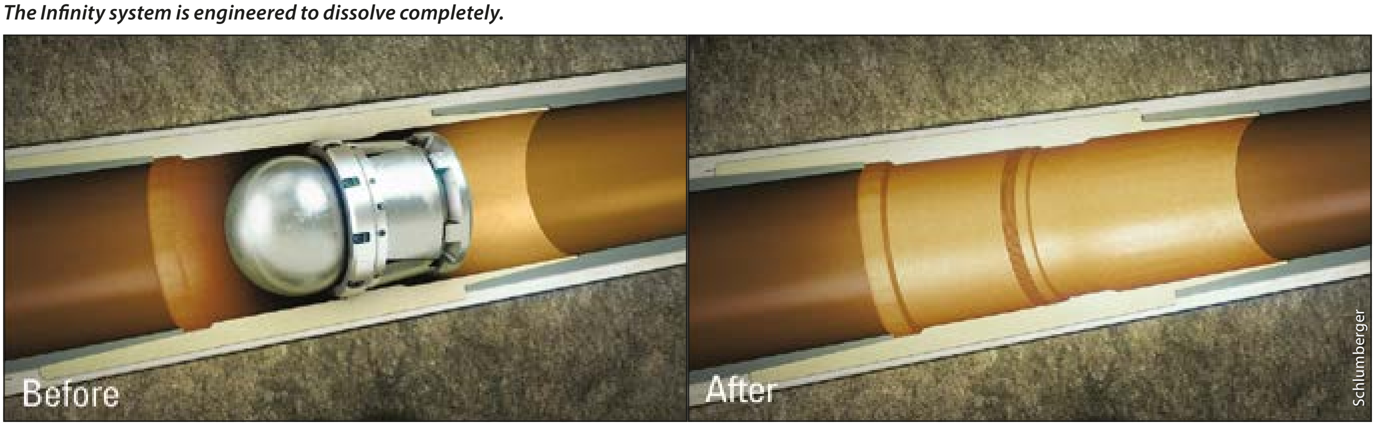
Dissolvable Plug-and-Perf System

Schlumberger has recently introduced a new '**plug-and-perf**' system which uses fully degradable fracture balls and fully degradable seats instead of plugs to isolate zones during well stimulation. This system, known as **Infinity*** dissolvable plug-and-perf system, eliminates the need for milling operations and leaves nothing behind in the wellbore. As a result, no plug debris is produced to surface where it can potentially interfere with surface equipment, since the ball and the seat assemblies both fully dissolve on contact with common completion fluids. As a result, the well is left with fullbore access and operators can bring production online faster, more efficiently and more cost effectively. The technique eliminates lateral length restrictions, thus maximizing reservoir contact and greatly reducing intervention-related risks and costs.

The Infinity system underwent extensive material science and laboratory validation and has been field tested in multiple unconventional reservoirs across the United States. Numerous wells were stimulated across five of the major plays in North America without any type of mechanical intervention required. ■

**Mark of Schlumberger*

The Infinity system is engineered to dissolve completely.



URTeC 2015: Record Number of Abstracts

The Technical Program Committee for the **2015 Unconventional Resources Technology Conference (URTeC)** has announced a record number of abstracts – 764 – submitted for the event, which is set for **July 20–22** in **San Antonio, Texas**. "This is more than a 10% increase in abstracts submitted over last year," said SEG Program Co-Chair Gene Sparkman, "and it also includes more geophysical focused papers which will continue to strengthen the true multidisciplinary context of the conference."

URTeC, the industry's leading multidisciplinary unconventional conference, is a joint venture between the Society of Petroleum Engineers (**SPE**), the American Association of Petroleum Geologists (**AAPG**) and the Society of Exploration Geophysicists (**SEG**). It attracts experts from every aspect of the unconventional sector and features a multi-themed technical program including oral sessions, ePapers, team presentations, topical breakfasts and luncheons and interactive panel sessions.

Last year the second annual URTeC event attracted more than 5,200 oil and gas professionals, a growth of some 20% over the inaugural event in 2013. More than 230 companies exhibited last year, showcasing the latest products, technologies and services for successful unconventional play development. ■

Discovery, Development and Recovery

Now in its 12th year, the annual **DEVEX Conference** will focus on the theme of **'Underpinning the Future: Discovery, Development and Recovery'**. This is always important but is particularly so now in this time of increased uncertainty. Despite the severe backdrop there continues to be a great deal of good and interesting work being carried out.

There have been several changes made to increase the quality of the conference for both delegates and exhibitors. With the introduction of Key Technical Papers and Masterclasses as well as the continuation of a strong technical program, plus the Young Professionals Event which asks 'how young professionals should cope in a reduced oil price', this year's conference is one not to be missed.

Delegate registration is now open with reduced rates available until April 10th, and the preliminary program is now available online at www.devex-conference.org. Exhibitor spaces and sponsorship packages can be discussed by calling +44 01224 330479 or emailing devex@aecc.co.uk.

DEVEX 2015 will take place on **May 20 and 21, 2015** at the **Aberdeen Exhibition and Conference Centre**. ■

Young Explorer

GEO ExPro believes that you are never too young to start learning about geoscience – and this young lady obviously agrees. According to her father, a geologist at a major oil company, two-year-old Erin loves to read 'Daddy's magazine' and particularly enjoys the colorful pictures – especially seismic lines and maps. She regularly colors in the fold-out seismic lines.

We look forward to welcoming Erin to the industry in twenty years time! ■

Puzzling Salt Structures

Detailed salt modeling has unraveled the development of a mystifying collection of structures that are a key element in the eastern Gulf of Mexico petroleum system.

THOMAS SMITH

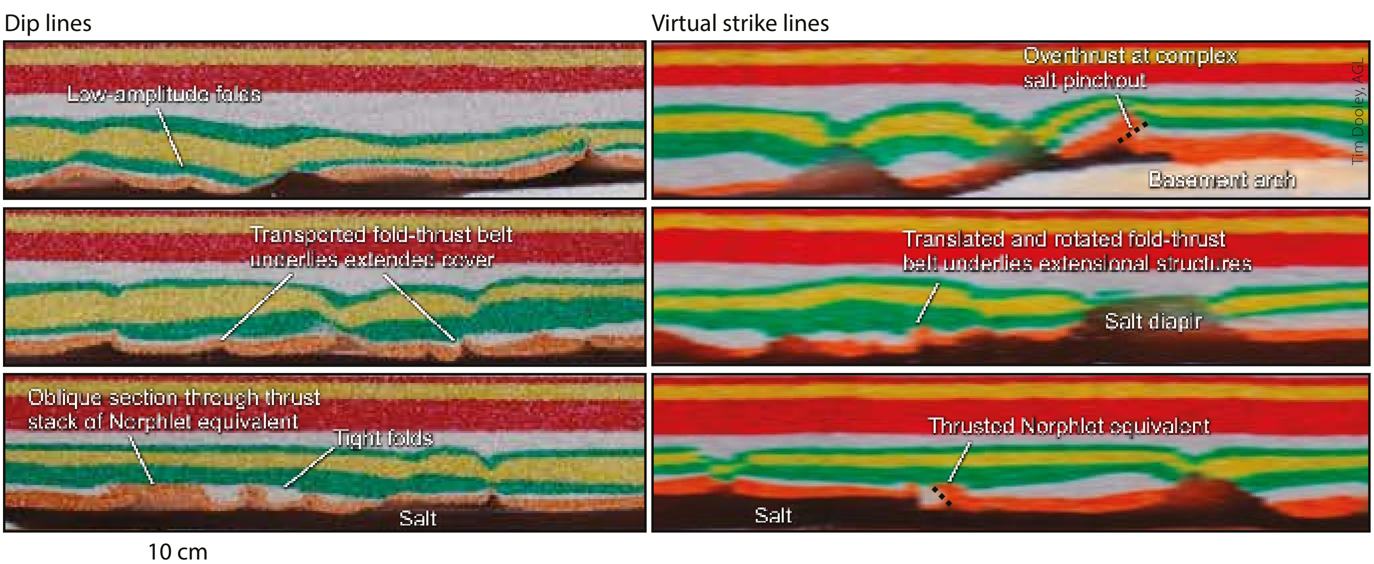
Seismic mapping near recent discoveries in the Jurassic Norphlet play, eastern Gulf of Mexico (GOM), has revealed extensional structures at expected orientations and shortening structures at odd angles to the prevailing salt flow. Geoscientists were at a loss to explain how, in a gravity-gliding salt system, this combination of structures could have formed. Funded by a consortium of oil companies, the Applied Geodynamics Laboratory (AGL), Bureau of Economic Geology (BEG) at the University of Texas at Austin, began to tackle this complex problem over three years ago.

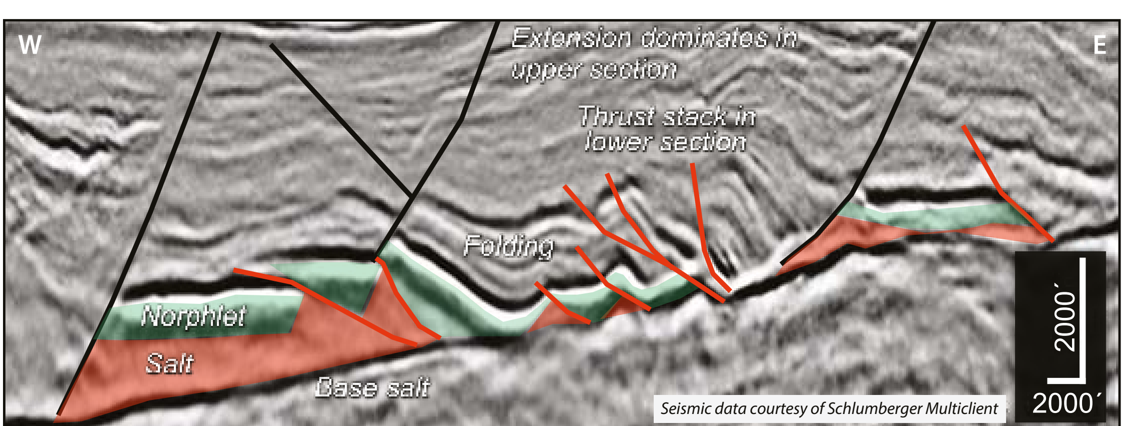
Dr. Tim Dooley, structural geologist, and Dr. Mike Hudec, senior research scientist and head of the AGL, were interested in exploring the origin of a series of thrust structures that form important elements of strike closure for numerous Norphlet traps. Many of these thrusts are further updip than expected, and are nearly parallel to regional dip, at right angles to their expected trend. Through new salt imaging and modeling technologies and a lot of persistence, they were able to mimic what was being seen in the subsurface and solve the secrets behind the origin of these structures.

Norphlet Play

The Upper Jurassic (Oxfordian) Norphlet Formation is a relative newcomer to the stack of GOM hydrocarbon plays. Oil was discovered onshore in the states of Mississippi and Alabama in 1967 and 1968 respectively, and in Florida in 1972. The first offshore discovery found significant quantities of gas in Mobile Bay just off Alabama's coast in 1979.

This prolific onshore play sparked interest around the eastern GOM as geoscientists postulated that it could extend into its deep waters. Sale 181, on December 5, 2001, was the first federal lease sale in the eastern GOM. The government awarded 95 leases and received high bids totaling over $340 million in that sale. Shell

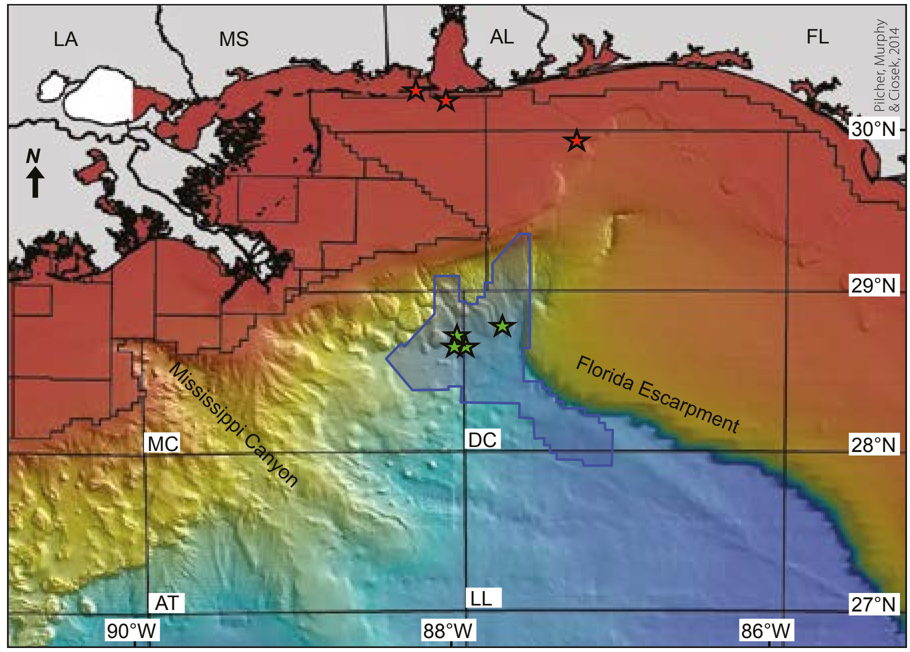




After many attempts to simulate the structures displayed on seismic data, salt modeling demonstrated how and when such structures formed and where they are likely to be found. Now, geoscientists have a better idea where to look for new traps in this and similar petroleum systems.

Offshore, Incorporated, won 28 tracts and Anadarko Petroleum Corporation received the second most tracts, winning 26. The federal government has held four additional lease sales in the area, including the last one in 2014, which received no bids. The next sale is slated for 2016.

Shell has been one of the most active companies exploring the Norphlet play. With its partners it has made six hydrocarbon discoveries in the area and three of those are considered large enough to be economic for development. Most of their prospects in the area are named after American Civil War encounters. The first discovery in the play was at Shiloh in 2003 followed by Vicksburg B (2007) and Antietam (2009). Then came the first major discovery at Appomattox in 2010 with an estimated resource of 500 MMboe. Shell and Nexen are currently in the design phase of development with the first production expected in 2017. Two more 100+ MMboe discoveries followed at Vicksburg A in 2013 and at Rydberg (named for the Swedish physicist) in 2014. Shell is currently following the Rydberg discovery with an exploratory well at their Gettysburg location.



Map showing offshore gas discoveries (red stars) and oil discoveries (green stars) in the Norphlet play located west of the Florida Escarpment, GOM.

Modeling Salt Flow

Drs. Dooley and Hudec have been working on salt-related structural complications in the eastern GOM since 2008 (see page 23). As Dr. Dooley relates: "The Florida Arch Modeling Program (Norphlet play) was an extension of this work. In total, 25 models have been run on this between 2008 and 2013 in an attempt to understand the origin of Norphlet thrust structures that are further updip and at orientations not expected by traditional models."

They initially worked on simple cases, varying the thickness of the basal salt layer across dip-parallel steps. As Tim points out: "This produced detached strike-slip faults in the overburden due to the differential translation between areas of thick salt (fast translation) and areas of thin salt (slow translation). Gradually, we began to monitor the effects of oblique sub-salt highs and lows on the deformation we saw in the overburdens overlying the salt." At the time, Tim was using standard monitoring techniques in the lab that consisted of overhead and oblique digital SLR cameras set on time lapse.

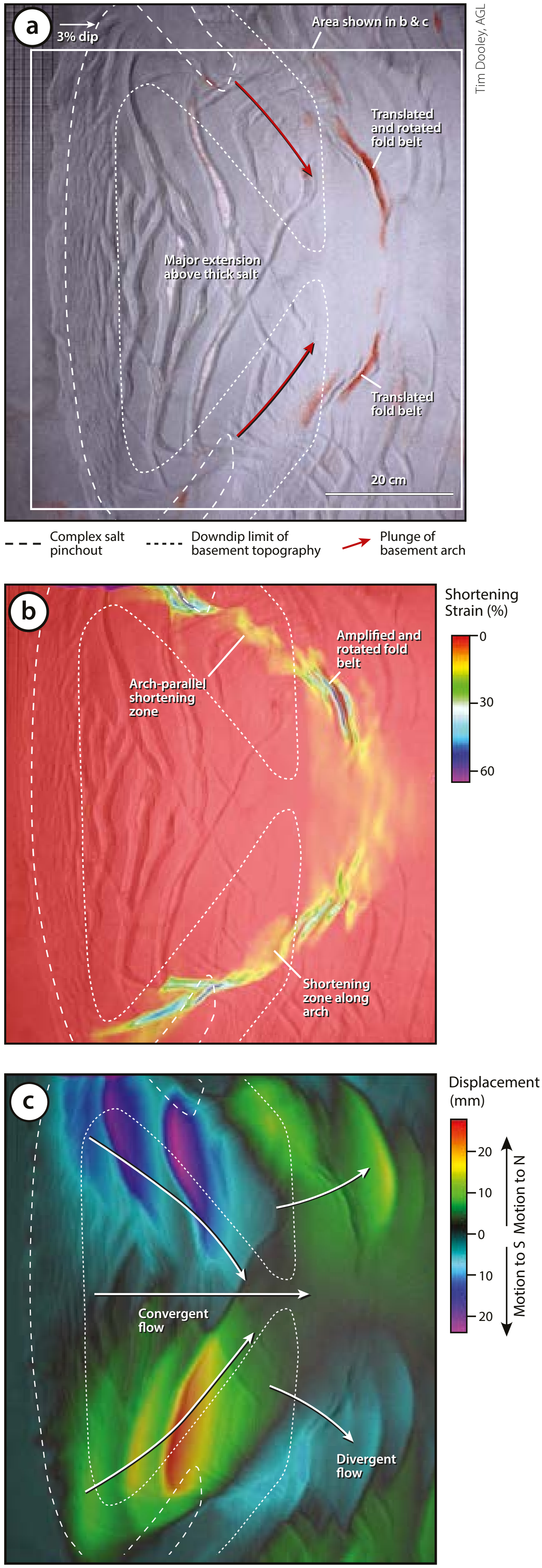
"On looking in more detail at some of the basement step models," Tim continues, "we began to see many more complexities than we had previously thought. Oblique photography hinted at shortening structures forming at both the updip and downdip margins of the basement highs, yet we knew we were missing key data."

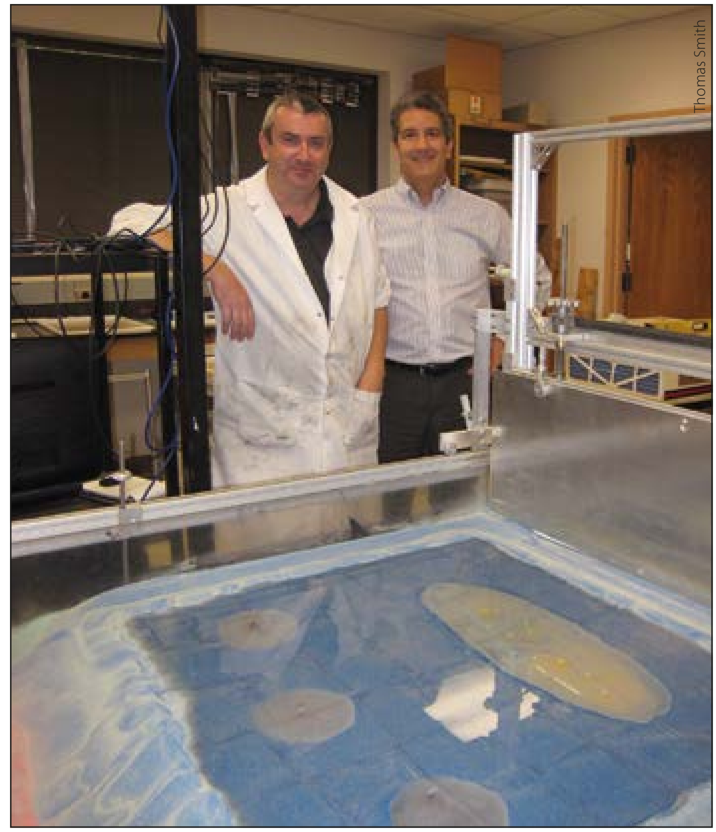
Their early modeling through 2011 created interest in their work looking at the influence of what more complex subsalt topography had on the deformation in the overburden. To do this, Tim knew that their monitoring techniques were not accurate enough to detect small strains and variation in flow direction over time, and over a changing topography in the basement. "To understand the formation of the puzzling array of structures seen on seismic lines from the eastern GOM," says Tim, "we knew we had to come up with better monitoring of our experiments, preferably in 4D."

He visited colleagues from his former laboratory at the Royal Holloway University of London to look into Digital Image Correlation (DIC) systems. The system he now uses consists of two large CCD sensors mounted above the deformation rig (see front cover image). The use of two sensors can capture sequential stereo pairs that will yield 3D images. Tim is now able to monitor the entire experiment, which can last up to two weeks, and produce a variety of maps such as velocity, displacement,

Early Gulf Development

The Earth's continents were once joined as the supercontinent Pangea. Rifting in Late Triassic caused the North American plate to pull away from the South American and African plates. Crustal stretching produced graben structures and eventually seafloor spreading in an area of the North American plate that would later become the GOM. During the Middle Jurassic, cycle after cycle of replenishment and evaporation in the shallow proto-Gulf left thick and extensive salt deposits now referred to as the Louann Salt. Sedimentary deposits began filling the GOM. Jurassic uplift of the Appalachian Mountains and subsequent erosion led to the deposition of feldspathic sandstone. Locally, winds transported and deposited the quartzose fraction into the eolian deposits that would become the Norphlet Formation. Pre-Norphlet geology and paleotopography, particularly paleohighs and salt distribution, controlled its depositional patterns and structural development.





Dr. Tim Dooley and Dr. Mike Hudec at the AGL in Austin, Texas.

changes in topography, and strain.

To image beneath the surface, transparent baseboards are placed in the deformation rig and a camera is mounted on the floor beneath it. "This setup allows us to continuously monitor the deformation within the salt and buried prekinematic layer," says Tim. "Passive markers can also be inserted within the model salt to mark where the salt flow directions change over time and across topography."

Solving the Puzzle

Armed with this new monitoring setup, Tim and Mike set out to see what effect basement arches have on deformation above a salt layer. "We started out simple, with arches that ran subparallel to the dip direction in the first year," says Tim. "This produced some highly complex deformation patterns; however, the strains were never high enough to produce shortening structures. Preliminary modeling of oblique highs showed promising signs with the development of shortening structures. We decided to focus on this for the second year of modeling." (Note: Tim works on four to five modeling series during any given year, thus most projects require multi-year efforts.)

It was in that second year, where they focused on plunging arches that were highly oblique to the direction of salt flow and

These map views (left) of the final modeling run show what happens to early formed structures in a gravity-gliding salt system. (a) A double plunging arch (downdip limit outlined with white dots) and rotated, displaced fold belts downdip from the arch; (b) shortening zones parallel the arch but become rotated as they are transported downdip; (c) salt flow (white arrows). Salt flowing off the flanks of the arches creates convergent flow on the updip side of the arches and divergent flow on the downdip side of the arches. The convergent flow creates compression and shortening structures which can be carried and rotated great distances from the arches, thus creating a puzzling array of structures where they were not expected.

Laboratory Salt Modeling

The Applied Geodynamics Laboratory (AGL) at the University of Texas at Austin was established in 1988 by Dr. Martin Jackson as the only full-scale tectonic modeling laboratory in US academia focused on salt tectonics. The first researcher he hired was Dr. Bruno Vendeville, who was highly experienced in extensional tectonics and the technique of sand-and-silicone modeling. Dr. Tim Dooley left his position at Royal Holloway, University of London, in 2003 to manage the laboratory when Bruno Vendeville departed and continues to run their modeling program. For salt tectonics, sand-and-silicone was found to be a superior technique to the more sophisticated centrifuge approach initially used at the laboratory. Researchers have continued to refine this method, establishing AGL as the world's premier institute for research on salt tectonics.

Sand-and-Silicone Modeling

Dr. Tim Dooley explains how the sand-and-silicone modeling is accomplished: "First, we simulate rock salt using ductile silicone (a long-chained polymer) and the brittle overburdens using a mixture of silica sand and hollow ceramic microspheres. So that our models can be directly compared with natural systems, the density contrasts between roof sediments and the underlying salt need to be realistically scaled. For example, a thickness of 1,500m of siliciclastic sediments is typically necessary to compact the deepest sediments to densities equal to rock salt. It typically takes 3,700m before the average density exceeds that of rock salt. The silica sand and ceramic beads are therefore mixed to form different colored layers reflecting different bulk densities. The prekinematic strata densities are usually equal to that of salt in order to inhibit foundering. Synkinematic strata with distinctive colors are added during the experiment with bulk density ratios of 1.1:1 or greater. With a model length ratio of 10^{-5}, final model overburdens in this series of experiments scale to approximately 8 km thickness and source-layer thicknesses of 0 to 1.5 km in nature.

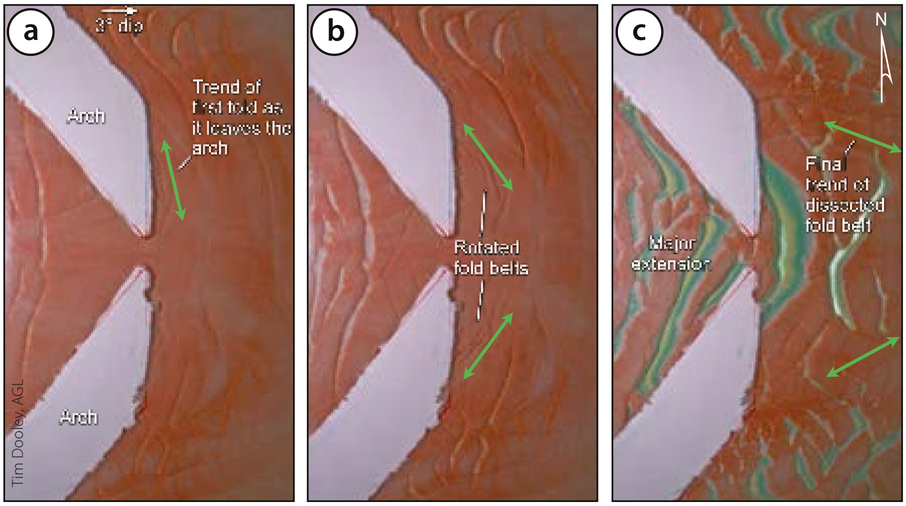
"In the Florida Arch models the basement arches were constructed of sand that was wetted and molded to form subsalt highs which plunged oblique to the dip direction. Our model salt was deposited above this and allowed to settle and pinch out against the basement topography in an irregular fashion. Once the polymer had settled out and de-bubbled, a thin prekinematic layer with a distinctive color was deposited above the salt. Then the model was tilted by 3° to initiate gravity-driven deformation. At time intervals varying from 18 to 24 hours, synkinematic layers were added to the model. These layers of sediment pinched out in the downdip direction.

"Once the models are completed, typically after 4 to 14 days, they are buried by postkinematic sediments, soaked with a gelatin mixture and left to partially dry for up to 14 hours. After that the semi-solid model is moved to a table and sliced into 3 to 4mm-thick slabs using a thin wire mounted on a movable arm. This results in 150+ closely spaced slabs that are used to generate a 3D reconstruction of the deformed model. Digital reconstruction of the virtual model allows it to be sectioned in any orientation, although the highest resolution slabs are those in the dip direction (original orientation of the slices)."

Dr. Dooley has recently deployed a new stereo-CCD system and associated software that continuously monitors the entire experiment, which can last up to two weeks.

Years of experimentation and innovation have produced scaled models that closely mirror actual subsurface structures in salt-driven petroleum systems. Armed with the knowledge of how the structures formed and where they occur, geoscientists can look for hydrocarbon traps in places not previously expected in gravity-driven systems.

This photo was taken during the Florida Arch Modeling Program (Norphlet play). Oblique view of a sandbox model simulating the early breakup and rafting of a prekinematic overburden above a salt layer. The model was tilted from left to right to initiate gravity-driven deformation. Visible beneath the transparent silicone (salt) is the white sand that was wetted and sculpted to form a series of subsalt arches across which the salt flowed. Note that the separation between the rafts increases downslope (left to right) where the salt was initially thicker.



The view from the underside of the rig clearly shows the progressive rotation of folds due to divergent salt flow downdip of the arch. The displaced fold belts end up nearly perpendicular to the original fold.

basin tilt, that the modeling began to mimic the structure seen on seismic data. "We started out with a simple model of a plunging ridge that extended across the entire rig," says Tim. "This produced a field of shortening structures that gradually rotated as they traversed across and off the high block. After that experiment, we were ready to build a more complex arch array that could be compared to the situation in offshore Florida, which consists of an embayment of thick salt bounded by plunging arches with thin salt."

It took them several runs to produce a model that clearly reflected what was being seen on the seismic data. "Once we had the correct formula, the models formed shortening structures due to the variation of salt flux from thick to thin and back to thick salt as you go from the embayment onto the arch and then off the arch," says Tim. "The DIC data was key in that it clearly showed the zones of shortening. Initially, shortening structures formed parallel to the arches and were gradually rotated into an orientation that was dip subparallel with increasing displacement, which is similar to the situation seen on the seismic data from offshore Florida. The underside camera clearly captured the rotation process once the early-formed folds were buried under younger synkinematic sediments."

Norphlet Petroleum System and Beyond

"The modeling illustrates that the shortening structures, and thus potential petroleum traps, can form in areas where traditional models would not have predicted," says Tim. "A traditional view of a gravity-driven system typically predicts updip extension, a zone of translation, and downdip contraction where the salt pinches out or is buttressed and inflates by salt drainage. Our models show that basement topography and resultant changes in salt flux and flow velocities can produce shortening structures surrounded by extensional structures far updip from where previous models would have predicted. Once these structures have formed, they can be translated great distances, thus making it difficult to understand why they formed in the first place."

In the case of the Norphlet play in the north-eastern GOM, recent studies certainly back the modeling work. In a recently published paper in Interpretation, entitled 'Jurassic raft tectonics in the northeastern Gulf of Mexico,' Pilcher et al. concluded: "The Upper Jurassic source rock (lime mudstones) of the Smackover Formation and the eolian sandstone reservoir intervals of the Norphlet Formation are structurally segmented and entirely contained within the raft blocks. The main episode of rafting occurred after deposition of the Smackover and Haynesville Formations and broke the Jurassic carbonate platform into raft blocks 2 to 40 km in length, which were then translated 25–40 km basinward from their original position." Their mapping also shows a divergent rotation of individual raft blocks similar to that shown in the physical models.

The observed structures in the north-eastern GOM are similar to those found along the West African and Brazilian margins. Tim's modeling shows that shortening structures and possible hydrocarbon traps can be formed in many different parts of a gravity-driven system and not just at the downdip buttress.

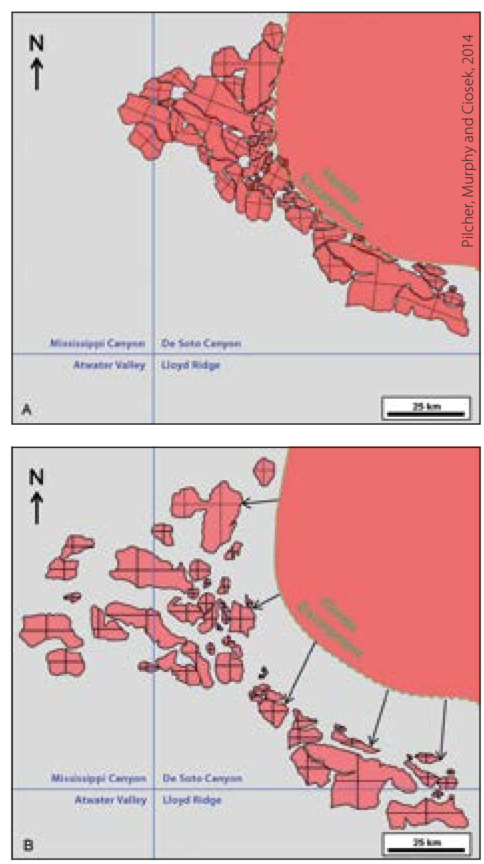
In conclusion, the modeling demonstrates two highly prospective areas of interest in these salt-driven petroleum systems: firstly, in and around complex salt pinchouts in the updip parts of the basin; and, secondly, fold belts formed due to the presence of subsalt topography that are subsequently rotated and translated far downdip of where they formed.

Reference:

Pilcher, R. S., Murphy, R. T., and Ciosek, J., 2014, Jurassic raft tectonics in the northeastern Gulf of Mexico: Interpretation, Nov. 2014, pp. SM39-SM55.

Acknowledgement:

A special thank you to Dr. Tim Dooley and Dr. Mike Hudec for their assistance with this article. ■



The upper map shows the pre-glide and the lower map present-day locations of blocks in the eastern GOM. Individual blocks have been rotated and translated up to 40 km from their original positions.

The Digital Oilfield: Managing People Transition

Why has people transition proved so difficult in oil and gas projects?

Dr JULIAN PICKERING, SAMIT SENGUPTA and BARNABY ANNAN, Geologix Systems Integration Ltd.

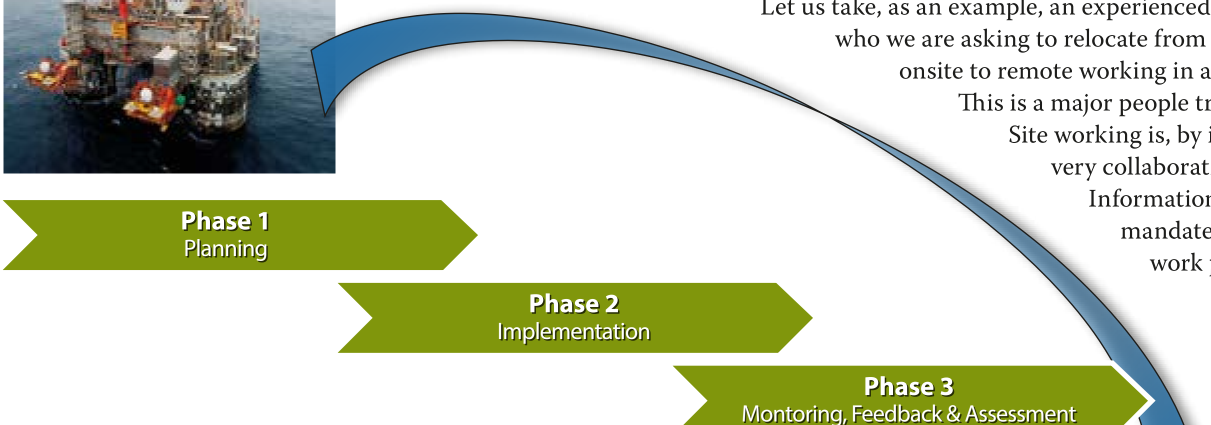
It is well established that successful digital oilfield deployment projects require careful attention to '**People**', '**Process**' and '**Technology**'. We are very good at recommending technology solutions and after many years of operational experience in the oil and gas industry we can extend our expertise to recommend optimum workflows. But just how good are we all at managing the people transition? Maybe a few interviews with the stakeholders backed up with a couple of workshops will address the concerns?

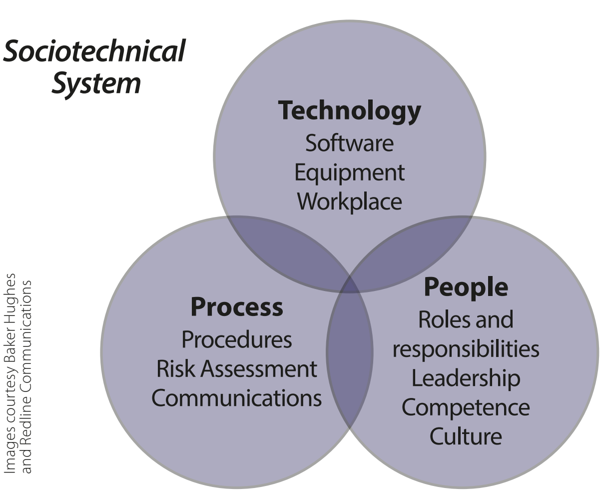
If we are honest with ourselves, we know very well that this approach is woefully inadequate. If the operations staff, be it in drilling or production, do not buy into the digital oilfield workflows, then a very well designed Real-time Operating Center (RTOC) may become little more than a glorified meeting room. As for business value, this falls well below predictions and the overall digital oilfield project can unfortunately take on the personality of a very expensive failure.

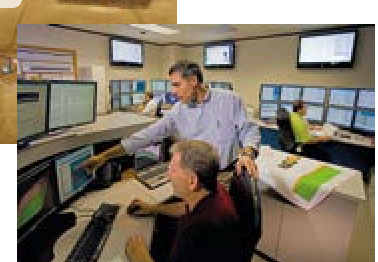
So why have we been less successful at transitioning our subject experts in oil and gas when many other industries have accomplished this very effectively? Take the automotive industry, for example. The days of the hand-made car have disappeared in all but the most expensive models. Robotics, just-in-time manufacturing and integrated operations have become the normal way of doing business. The difference is that economic pressures have forced the automotive industry to make the transition – the manufacturer can only make a profit on a standard production car using highly automated assembly processes. The margins in oil and gas have historically been far more comfortable and many operators have not seen an urgency to transform their operations into digital oilfield operations. However, with the current situation of very low oil prices, the economic drivers are suddenly very different.

The People Transition Process

Let us take, as an example, an experienced field operator who we are asking to relocate from operating onsite to remote working in an RTOC. This is a major people transition. Site working is, by its nature, a very collaborative process. Information exchange is mandated by the site work procedures







Images courtesy Baker Hughes and Redline Communications but is supplemented by informal exchanges during relaxation breaks, meals and ad hoc meetings. The remote worker cannot participate easily in these less formal interactions and can, as a result, feel much less engaged with the drilling or production operations.

A standard people transition curve is shown in the diagram on the following page. It is characterized by three main stages:

Stage 1. Shock and denial – due to concerns about the personal future and doubt that change is really necessary.

Stage 2. Anger and depression – this is an emotional response to the change by holding individuals accountable and starting to accept the inevitability.

Stage 3. Acceptance and integration – the individual is now going through full acceptance of the change and looking to make the best of it for what will hopefully be a positive future.

The goal of an effective people transition process should be to minimize rather than eliminate the time duration of Stages 1 and 2 and to encourage the positive behaviors in Stage 3.

Key Considerations

When there is a change in an organization there is always an impact on people which requires them to make a transition. There are many scenarios which have such an impact: for example, movement of roles from offshore to onshore, a change in equipment used to perform a process, or the introduction of new capabilities. Our experience of supporting oil and gas organizations has identified a number of key considerations to support successful transition of staff.

Whilst there are many recorded people-transition approaches documented in literature, each variation is typically built around a framework of similar topics. The framework approach works well in practice as it allows a degree of tailoring and personalization to meet the nuances and cultures of different organizations. There are six key elements that need to be addressed for a successful transition.

- **Baseline Capture:** Assessing, recording and capturing the way tasks are currently carried out. Often the way tasks are achieved in reality can vary from documented procedures and processes. It is essential to understand the 'true' baseline in order to properly assess the impact of the changes on people.
- **Organization Design:** Developing, understanding and capturing what the organization looks like in the future. The change may require additional staff positions to be created, a modified organizational structure or may need to combine additional functions into existing roles. Outlining details early on in the transition process is essential to ensure transparency.
- **Leader Engagement:** Most organizational changes fail as a consequence of leadership not buying in and leading the change. Engaging leadership early and involving them in defining future design helps to support buy-in and uptake of the changes. This activity creates a sense of ownership for the change and is key to ensuring staff embrace the change rather than push back against it.
- **Organizational Transition Assessment:** Assessment

of the 'new' world versus the 'old' world to address gaps that need to be bridged in staff knowledge and skills. This activity is used to identify where modifications to competence management, training and recruitment systems are necessary, to assess the level of manpower change and analyze any new risks where poor human performance can have a significant impact on the business.

- **Staff Engagement:** Communication with all staff at regular intervals throughout the transition. The key focus should not only be the high level vision and goals of the change but also on the personal impact for each individual.
- **Competence Assurance:** Delivery of necessary modifications to the competence management and training systems to move staff from their existing roles to their future roles. Addressing this aspect at the right time will ensure people are ready for the changes from day one of the new operation.

People transition is very complex as the management of these key aspects involves a much wider group than the immediate project team. It is usually necessary to involve senior management, operations, human resources and possibly even legal teams. The transition team needs to be an integrated function involving people from these business departments throughout the process.

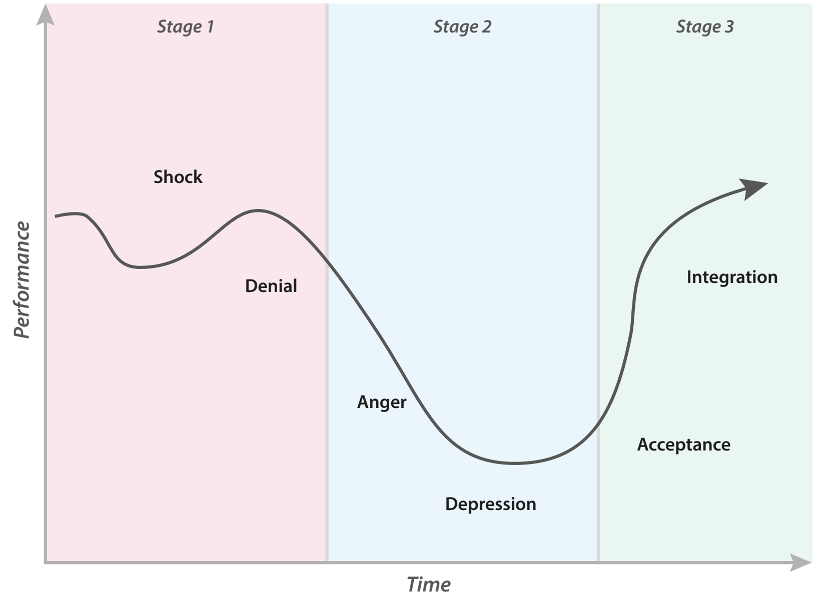
Managing the Transition

The transition, in digital oilfield terms, is about managing the people factors as an organization moves from its current operational model to an optimized digital oilfield model. From our experience, this requires three distinct project phases, as shown in the diagram on page 26.

The first stage is **planning**. This must address fundamental concerns in an organization about the transition. Typically, these will include: finding out what critical areas of its business will be impacted by the transition; what the risks are and how to manage them; how many people and what range of skills will be needed in the new organization; how well existing staff will be able to cope with the transition, and if not, how to help them; and how to inform staff of the changes, motivate them and take them along for the journey.

The second stage is **implementation**. This is the execution of the transition, during which time the company should undertake training and competence management to ensure that staff can fulfill their roles in the new organization. A consultation process should be actioned to manage staff mobility to new roles or work processes (including those leaving the organization, if appropriate), and there must be regular communications to inform staff about what is happening.

The third stage is **monitoring**, feedback and improvement. This assumes that the transition is complete and provides an on-going health check to address concerns, make any adjustments and ensure that the new operating model is delivering the expected business value.



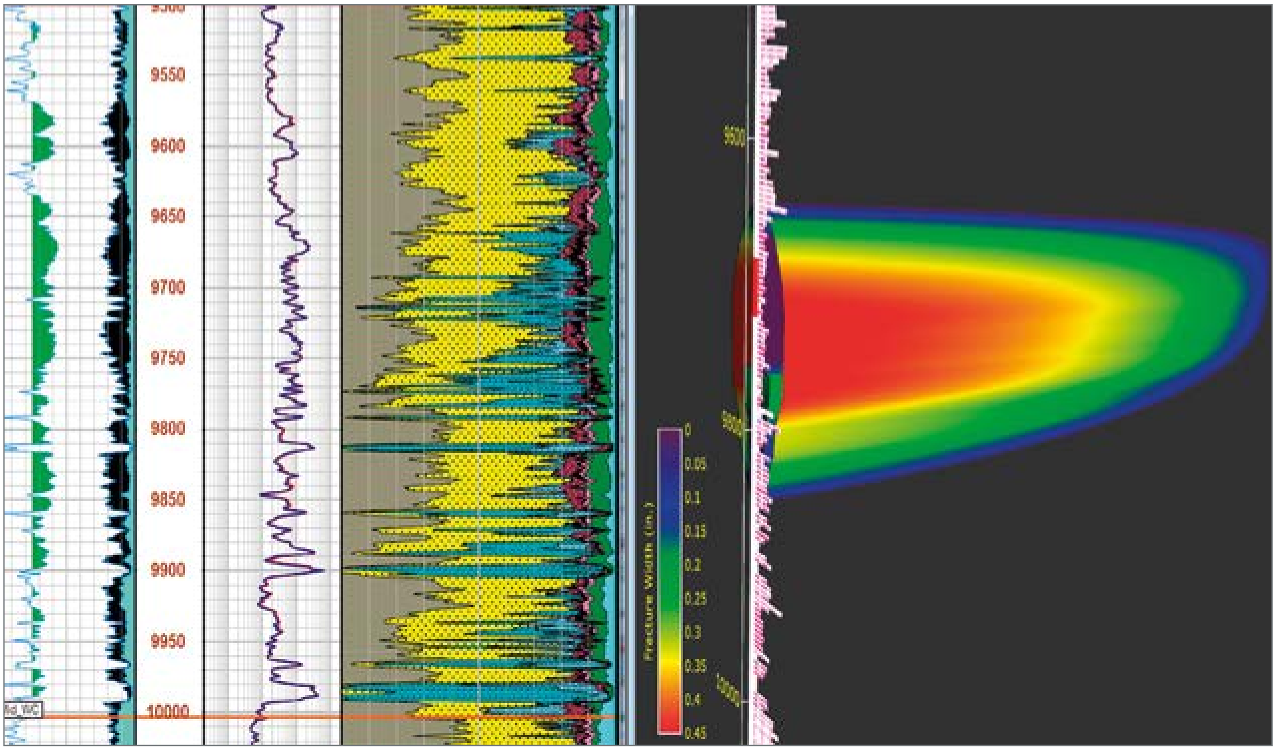
People transitioning from field to remote operations tend to go through three distinct phases.

Digital Oilfield Success

An organization that has made a successful digital oilfield people transition feels like a great place to work. Staff are motivated, much of the bureaucracy is eliminated and the efficiency of the organization has improved significantly. There is much greater awareness of drilling and production operations and individuals feel much more empowered to contribute to the success of the organization. There is also a much closer dialog between the oil company personnel and third party contractors who are supporting the operations. In an ideal situation they may be completely indistinguishable. The old methods of blame and financial claims should be replaced by a spirit of collaboration and the promotion of a win-win culture.

The real test of this comes at a time of lower revenues, as we are seeing currently. Is the immediate response to shed all the personnel to protect the short term balance sheet or to take a longer term view, retain the workforce and strive to improve efficiency and build opportunities for when the inevitable price recovery occurs? History has shown that it is those companies who ride out the storm and demonstrate loyalty to their staff and contractors who are best positioned to capitalize once recovery occurs. If key personnel have been lost from an organization it can take a significant amount of time to rebuild capability.

Geologix Systems Integration delivers an independent advisory service covering all aspects of the digital oilfield. We see people transition as a very critical component of a successful digital oilfield implementation. For each of the three transition management phases we have detailed work processes that have been developed based on significant experience with oil and gas clients. Unfortunately there are case examples of operators that have spent tens of millions of dollars implementing digital oilfield technology solutions who have failed to realize expected investment returns because the people transition was not addressed in a professional manner. ■



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The Magnificent Southern Canadian Rockies

ANNE HARGREAVES

The Canadian Rocky Mountains rise majestically from the interior plains of Alberta, and the mechanisms which formed them are well illustrated on the scenic drive from Calgary to Banff and Lake Louise.

The drive from Calgary through Banff to Lake Louise westbound on the Trans-Canada Highway is a scenic tour that attracts people from all over the world. The drive only takes two hours, but is best spread over at least a full day, allowing time to stop often for photos, hikes and wildlife viewing. Traveling south from the Icefields Parkway area described in *GEO ExPro*, Vol. 10, No.2, this article will focus on the area from Calgary west through Banff along the Trans-Canada Highway, and then north to Lake Louise.

Thrust Fault Geology

The long narrow ranges of the Canadian Rocky Mountains extend from the US border in the south and trend north-west for almost 1,500 km following the Alberta-British Colombia (BC) border before crossing it and terminating just shy of the BC-Yukon Territory border. It is a narrow range up to 180 km wide at most, and was created by thrust faulting from west to east, where older Cambrian rocks were thrust up and over younger Mississippian and even Cretaceous rocks.

Thrust faults occur in fold and thrust belts, which are associated with periods of mountain building due to colliding plates, and foreland basins form at the edge of the plates, where they collect sediments shed off the newly accreted mountains. Thrust faults respond to pressure and propagate laterally and upward through previously deposited sediments in the area. Thrusting upward through time, they always result in older over younger rocks. The areas of movement are usually along weaker shales and the uplifted

Emerald Lake, an aptly named emerald-hued glacial lake near the location of the famous Burgess Shale and its Cambrian fossils.

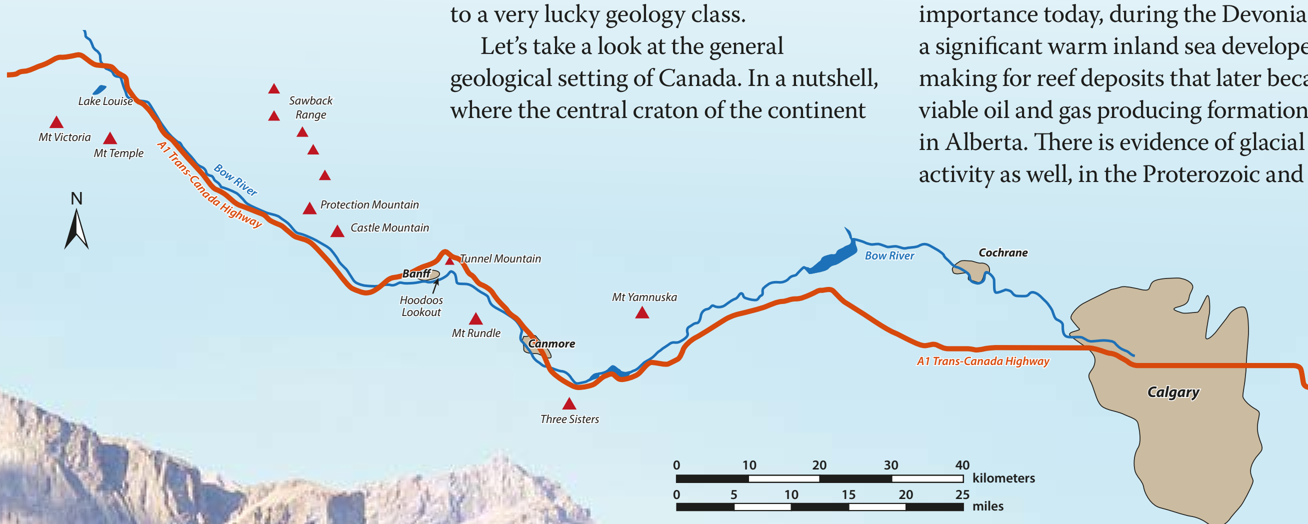
rocks often form resistant cliffs, while the shale-filled valleys deepen as a result of glaciation and water erosion.

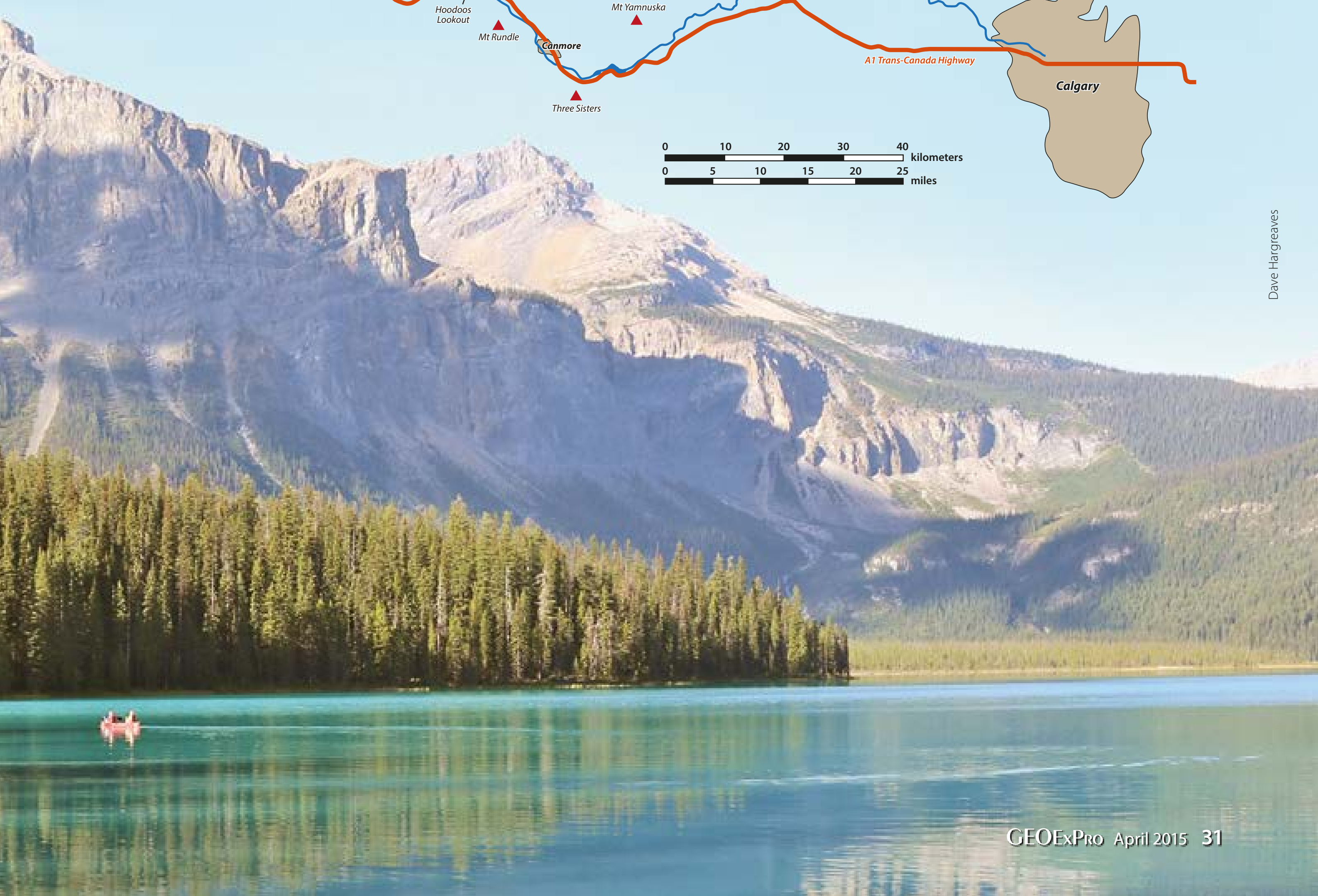
In the Rocky Mountain belt the thrust faults run north-east to south-west and are generally hard cliff-forming carbonates from the Cambrian, thrust up and over soft clastics from the Mesozoic. While the valley with the clastics erodes ever deeper, the resistant carbonates remain high, so the difference in elevation between cliff peak and valley bottom is greater now than when they were formed.

Complex folding and faulting is associated with the thrust faults, including drag folds and break thrust faults where the anticline/syncline pair rupture, leaving steeply dipping formations falling off in either direction.

As a student, the idea of thrust faults and plate tectonics was a concept introduced by the professors, but perhaps interpreted somewhat skeptically by the student. One memorable spring day, our third year class was at Lake Minnewanka, near Banff, on a day trip to see local rocks in the area. The lake was still covered by a thick layer of softening ice when suddenly a strong wind blew up the valley. The force of the wind blew on the ice floes (the 'continents') overlying the lake water (the 'molten core') which hit and rode over each other, creating 'subduction zones' as well as simulating thrust faults as the moving ice 'continents' met with the resistant 'land' masses; both plate tectonics and thrust-faulting were demonstrated convincingly to a very lucky geology class.

Let's take a look at the general geological setting of Canada. In a nutshell, where the central craton of the continent is exposed in northern Saskatchewan, Manitoba, Ontario, Quebec, Nunavut and the Northwest Territories, it is called the Canadian Shield. The gneisses underlying the Rockies as basement are of this same Archean age and are part of the craton. The shield area in the Archean was located in the southern hemisphere, and was a mountainous uplifted area, which shed sediments towards the future interior plains and Rocky Mountain area site. At times underwater, most notably during the Cambrian when the famous Burgess Shale was deposited, and at other times exposed, for example during the Silurian, the sediment layers built up, consisting mostly of shales and carbonates interlayered with some quartz sandstones and silt layers. Of economic importance today, during the Devonian a significant warm inland sea developed, making for reef deposits that later became viable oil and gas producing formations in Alberta. There is evidence of glacial activity as well, in the Proterozoic and





Dave Hargreaves

Carboniferous as well as the most recent cyclic Neogene and Quaternary glacial episodes.

Crossing Faults

The last glaciation in the area was the Wisconsinan, which brought the Cordilleran ice sheet, probably 1 km thick, over what is now the city of Calgary between approximately 31,000 and 14,000 years ago. In fact, Nose Creek in Calgary is believed to mark the place where the Cordilleran ice sheet from the mountains met the Laurentide ice sheet from the Canadian Shield. In north-west Calgary's Confluence Park there is an erratic, which was carried more than 400 km from Mt. Edith Cavell in Jasper.

Calgary is built on glacial till from the aforementioned ice sheets. The Paskapoo Sandstone lies beneath the till, and rocks from this formation are visible in the old downtown sandstone buildings and also the huge boulders used extensively as retaining walls in the newer residential areas of the city. As the great ice sheet receded, Calgary's Glacial Lake came into existence, and up to seven lake terrace levels are visible in the Bow Valley today. As you drive west of Calgary, on the 1A highway, near Cochrane you will have a nice view of the lake terraces. After the ice sheets withdrew, the Bow River set its present-day course and ultimately empties into the Hudson Bay, over 1,000 km to the north-east.

Continuing west along the Trans-Canada Highway, we know we have entered the foothills belt of the foreland basin when we begin to see south-west tilting rocky outcrops on the side of the road. The first thrust fault is approximately 30 km west of Calgary and we will cross 31 faults on our journey. Mt. Yamnuska, seen on the right-hand side of the highway, is the first mountain that you meet, and it shows the McConnell Thrust fault clearly near the top of the talus slope, where the middle Cambrian Eldon Formation lies on Cretaceous Brazeau deposits.

Driving up the valley towards Canmore, on the left-hand side of the highway roughly at the tree line, the Rundle Thrust fault has pushed up cliffs which comprised the typical front ranges 'sandwich' of uppermost Rundle, Banff and Palliser Formations, over-riding the Fernie shale.

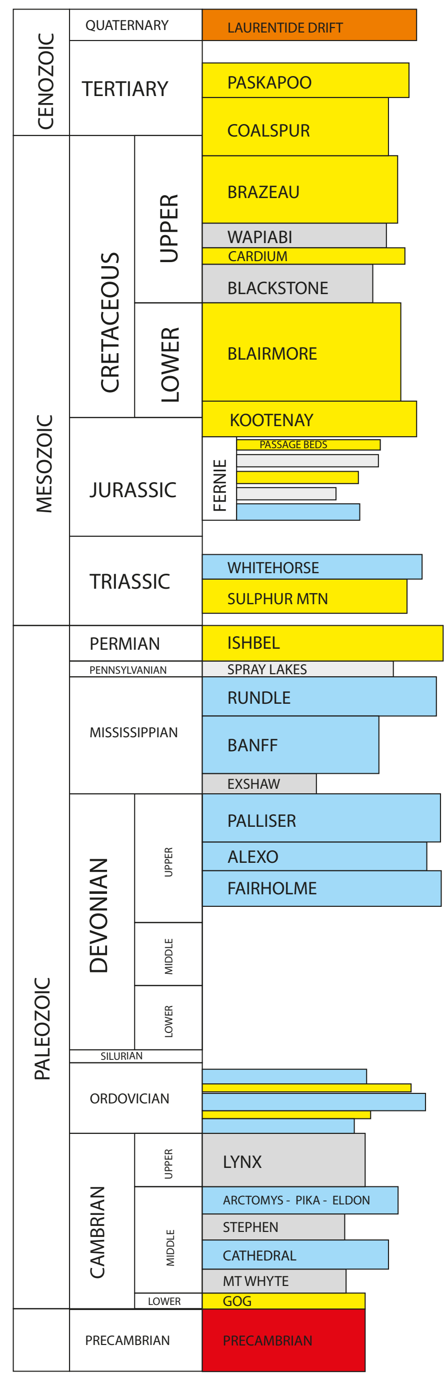
The Banff Area

Continuing along the Bow River to the lookout point at the Banff Hoodoos, approximately a kilometer outside the town of Banff, one can see a thick section of glacial deposits in the valley. The current analysis suggests these formed from a debris flow created by a glacial ice dam from a valley in the area, which, as the ice receded, allowed for a Jokulhlaup-type debris flow. This flow is homogeneous in nature and similar to glacial till, but will also include some layering of lakebed alluvium: the layering indicates a debris flow rather than till, which would be completely homogeneous. As the river etched its way through the loose deposits the soft sediment eroded, but areas capped with harder rocks resisted erosion, resulting in distinctive pillar-shaped structures, known as hoodoos.

Cascade Mountain, overlooking Banff, is also made up of the typical Rundle-Banff-Palliser package, and shows a gentle curve between the layers, showing the powerful folding forces that

Split Rock at Confluence Park in Calgary, which was carried by the Cordilleran ice sheet approximately 400 km from Mt. Edith Cavell in Jasper.

Stratigraphy of the Canadian Rocky Mountains in the Banff area



Bow Valley near Canmore, Alberta. The Rundle Thrust Fault has uplifted this range with the cliff-forming carbonate Palliser Formation cropping out above tree line, topped with the recessive Banff Formation and capped with the resistant Rundle Formation.

occurred during the thrusting.

Mt. Rundle, about seven kilometers south-east of Banff, is named after the cliff-forming Rundle Formation found on its peak and is often shown in tourist brochures of the region. Adjacent to the Banff town site, the stubby nature of the equally famous hill called Tunnel Mountain owes its shape to glacier ice, which rode right over the top of it, leaving it rounded on the side the glacier approached and cliffy on the other side.

Of interest as we continue the drive up the Bow Valley are the Jurassic and Cretaceous Kootenay Formation's Passage Beds. They mark the transition from sediments being derived solely from the eastern Canadian Shield to those resulting from off the new mountainous area to the west, created as the North American continent collided with western terranes as Atlantic seafloor spreading propelled the plate west. The Passage Beds themselves are composed of siltstones with thin planar rust-weathering sandstones deposited onto the largely deep-sea shales.

Beyond Banff

Passing Banff, the Sawback Range becomes visible on the right side of the highway. Its sharp peaks are rugged, but its lower slopes are smooth, as a result of glacier movement down the valley during the Wisconsinan glaciation. The maximum height of the glacial ice is seen where the peaks become rugged at an elevation of about 2,000m. These Cambro-Ordovician carbonate rocks are tilted almost vertically on the north-east side of the valley due to back rotation during the thrust faulting.

The next major sight on the highway is the majestic Castle Mountain, where the Castle Mountain thrust fault is nearly flat below the tree line, putting Cambrian Eldon, Stephen Cathedral and Gog Formations, as well as Precambrian Miette, on top of younger Paleozoic carbonates of the front ranges. As we cross this fault we transition to the Main Ranges of the Rocky Mountains.

The bulky Cambro-Ordovician carbonates of Protection Mountain on the right side of the highway are seen about 50 km from Banff as we approach the Lake Louise area, and exhibit some slumps that occurred after the glacier scoured the valley.

Nearing Lake Louise, Mt. Temple is visible on the left-hand side of the valley. It is the tallest mountain in the area, and is topped with rocks from the Eldon, Stephen, Cathedral and Mt. Whyte Formations, which overly a significant thickness of Gog Formation.

Beautiful Lake Louise is the final destination, and it is advised to arrive as early as possible as the parking lots fill very quickly. A short walk gives you a view of the lake with Mt. Victoria and its glacier as the backdrop. As with Mt. Temple, the Eldon, Stephen, Cathedral, Mt. Whyte and Gog Formations dominate the area. Two nearby hikes are highly recommended and both destinations have a historic and rustic Teahut where food and beverages are served. The hike to Lake Agnes and the Little Beehive offer great views of the Bow Valley, and the Plain of Six Glaciers allows up-close access to the length of lateral moraines of the receding Victoria Glacier.

References and further reading available online. ■

Castle Mountain, Bow Valley Parkway: the castellated Eldon, Stephen and Catherdral formations overlie the treed slopes of the mountain composed of Cambrian Gog and PreCambrian Miette formations, below which lies the Castle Mountain Fault marking the transition to the main ranges of the Rockies.

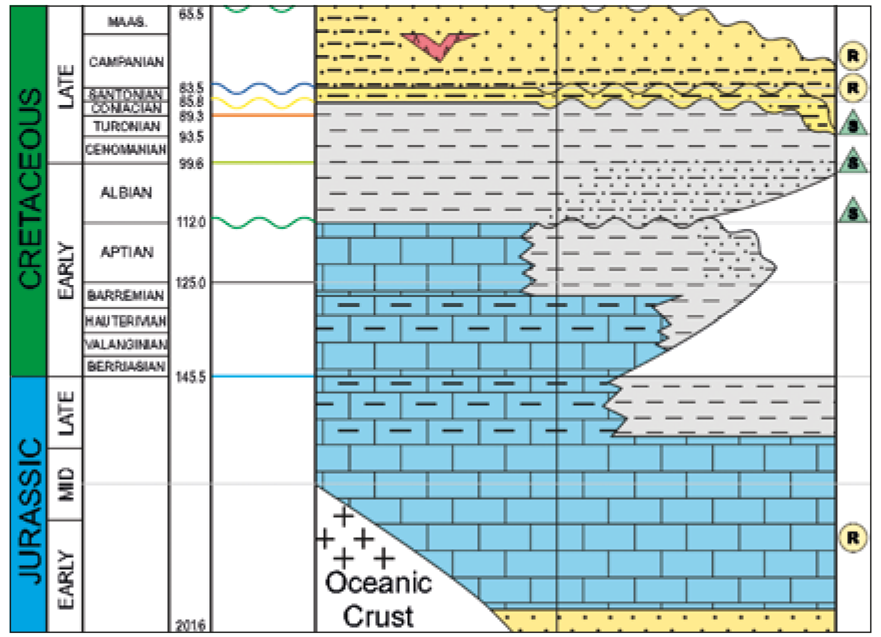

While oil prices have gone down,
we've gone the other way.

Offshore Senegal:

Sud Profond 3D Illustrates Potential

Dolphin Multi-Client's long offset 3D seismic survey was acquired in early 2012, and covers 3,611 km² of the offshore Senegal Sud Profond (Senegal Deep) exploration block, operated by African Petroleum. This is an area which has key recent discoveries, and where farm-in opportunities are available.

Below are examples of the 3D long-offset data from this survey. The bright blue highlighted section is the Jurassic-Early Cretaceous Carbonate Platform. The lighter shaded blue section represents mixed carbonate muds and other carbonate-prone sediments, while the yellow area indicates Late Cretaceous sand-prone submarine slope and channel fans.



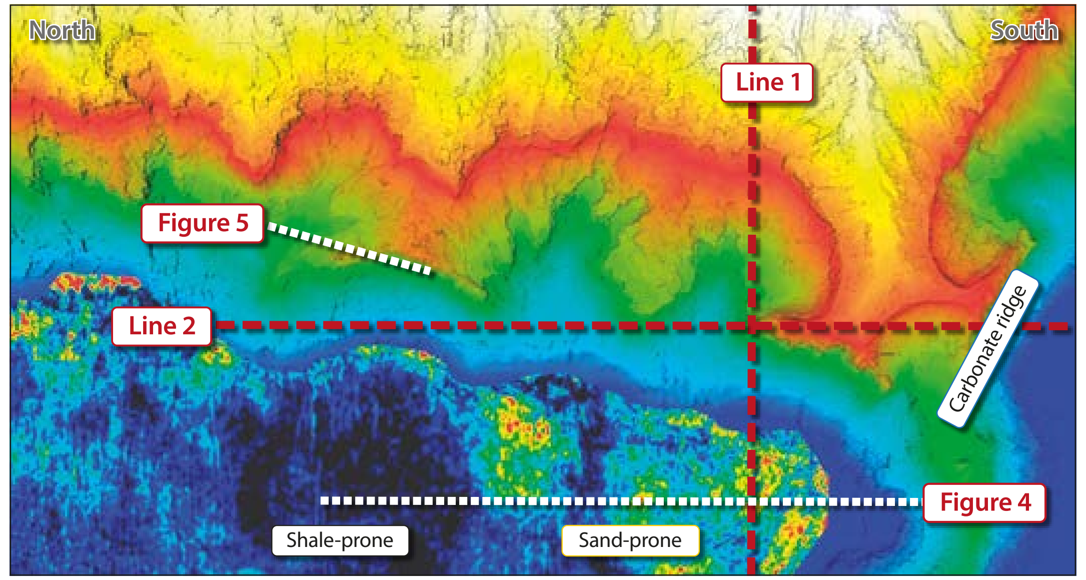
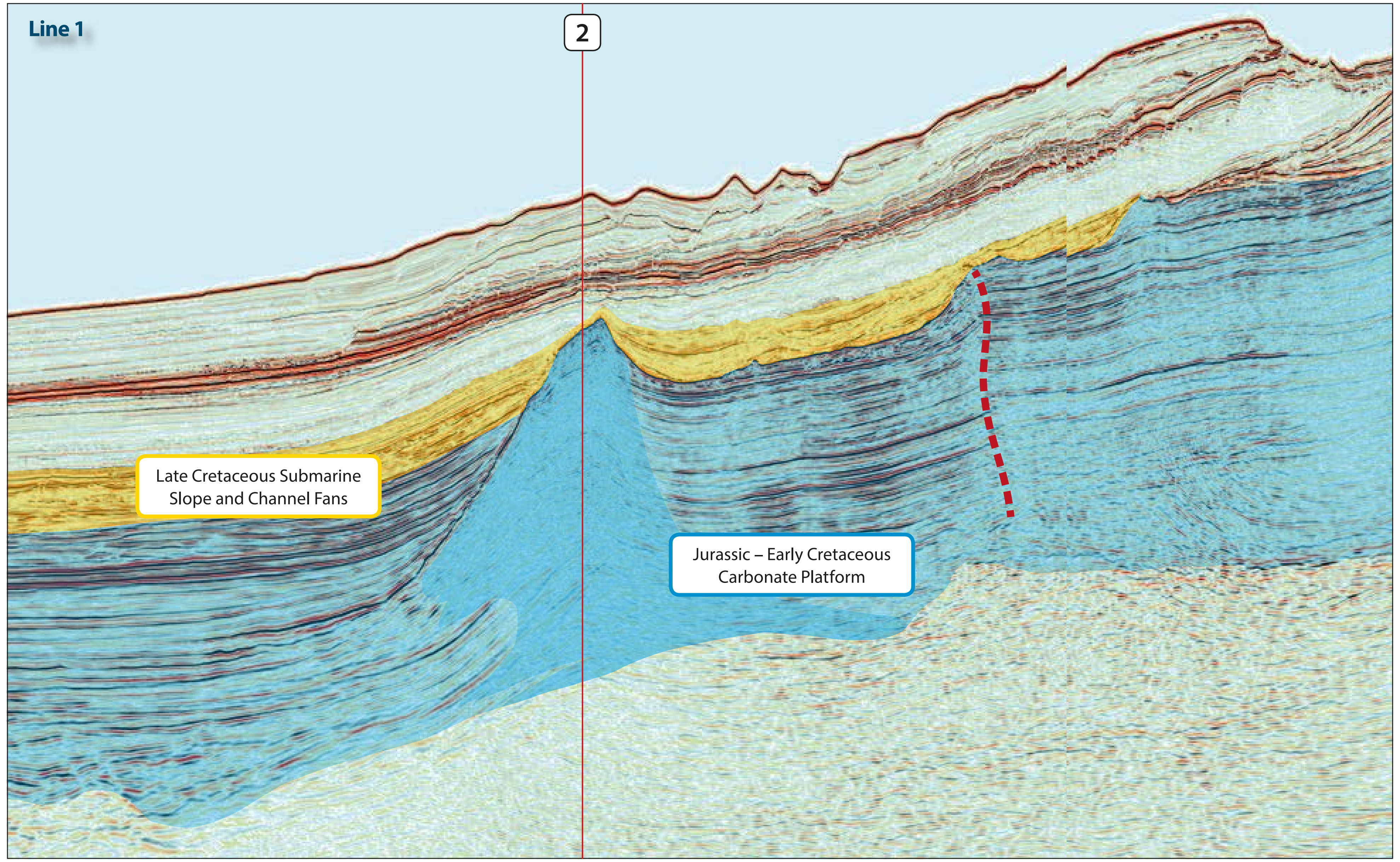
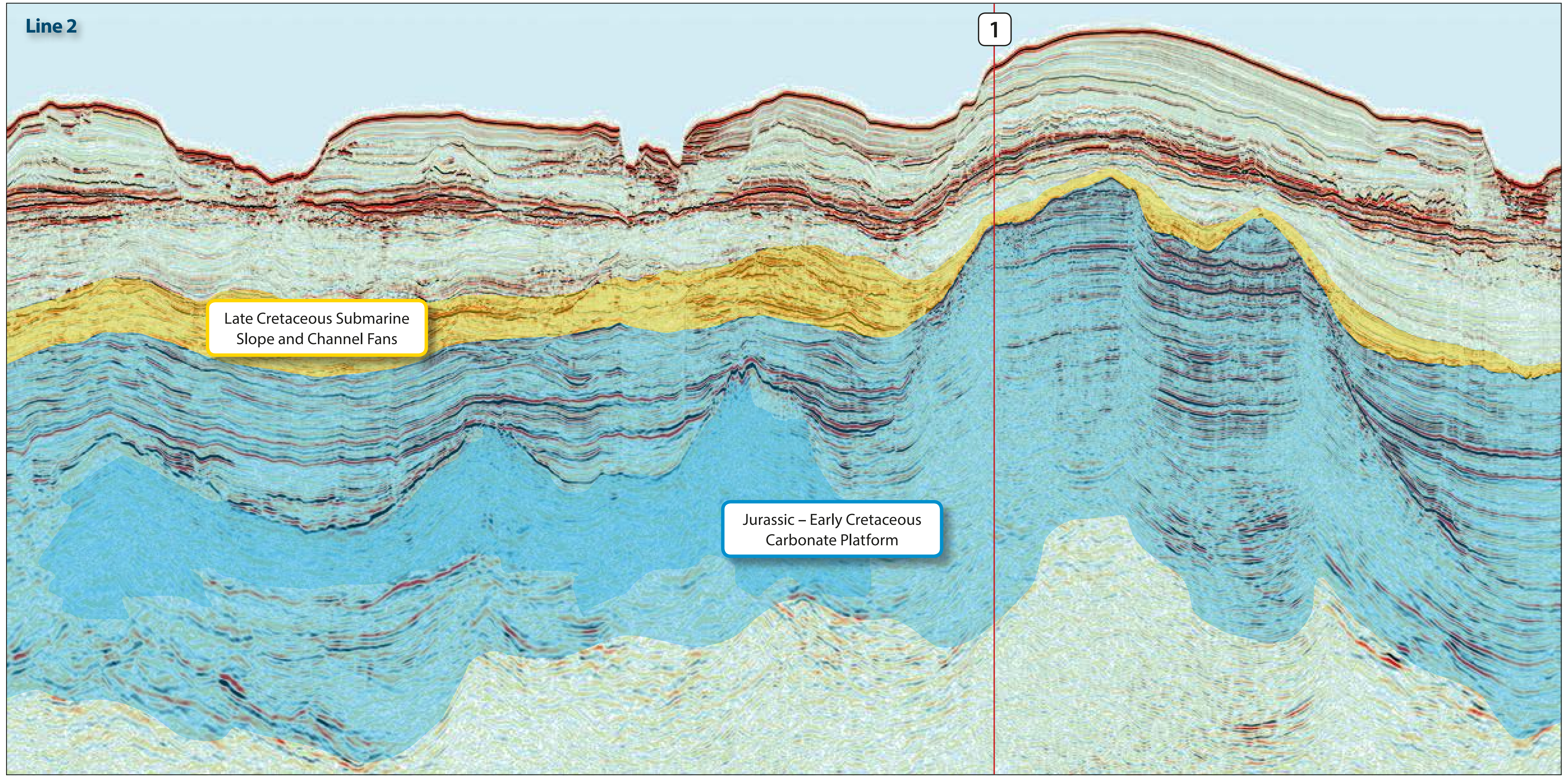


Figure 1: An intra-Jurassic TWT surface over the 3D survey area with incised feeder valleys and karstified carbonate terrain. Downdip, there is an amplitude extraction highlighting the Late Cretaceous slope and channel fans.





New Play Concepts Revealed

Recent discoveries indicate the potential of the Sud Profond Offshore Senegal Region.

NICOLAS HAND and DAVID JACKSON, Dolphin Geophysical Multi-Client New Ventures

The North West Africa region was under-explored for many years, but since the discovery in 2007 of the Jubilee Field in Ghana, industry has refocused efforts to explore similar plays around the entire West and North West African coast.

On October 7, 2014, Cairn Energy announced an important and potentially commercial oil discovery in the Sangomar Deep block offshore Senegal. The FAN-1 exploration well recovered light oil from a series of stacked Cretaceous sandstones, with APIs ranging from 28° up to 41°. Cairn Energy drilled a second well, SNE-1, in 1,100m of water and announced on November 10, 2014 that they had made an additional discovery. Initial analysis of the well, as reported by Cairn Energy, showed a 95m gross oil-bearing column with a gas cap. It found excellent reservoir sands with net pay of 36m of 32° API oil and a P50 contingent resource of 330 MMbo. Following Cairn Energy's two discoveries in these Senegalese blocks immediately to the north, the Gambian government restored African Petroleum Corporation's licenses for blocks A1 and A4. The licenses had been canceled in January for non-performance. African Petroleum had disputed the government's move and sought arbitration at the International Center for the Settlement of Investment Disputes, but proceedings will now be dropped. African Petroleum has negotiated an extension to the first exploration period, which will now expire on September 1, 2016. Figure 2 shows the location of the FAN-1 and SNE-1 discoveries in relation to the Dolphin Geophysical Sud Profond Offshore Senegal long-offset 3D seismic survey, and the block and operator details for the region.

Geological Overview

The offshore geology of Senegal has been shaped by the evolution of the rift system that started with the Late Permian breakup of the African, North American and South American Plates. The Senegal sub-basins include the Southern Mauritania sub-basin, the Northern-Rufisque sub-basin, and part of the Casamance sub-basin.

The area underwent three main tectonic phases consisting of a pre-rift, syn-rift, and post-rift stage. The rift phase occurred in the Proterozoic-Paleozoic, the syn-rift phase occurred in the Permo-Triassic, and a post-rift/drift phase occurred up to the present day. (Brownfield and Charpentier, 2003).

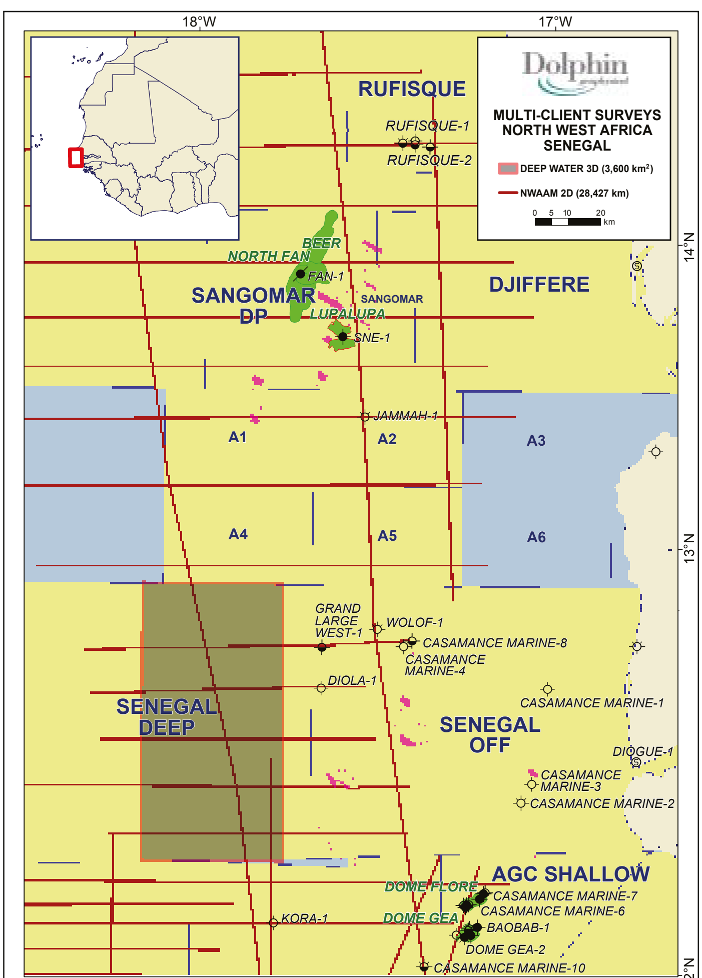
The geology of offshore Senegal is dominated first of all by carbonate deposition, which occurred during the Early Jurassic to Late Early Cretaceous (syn-rift and post-rift phases). There was a period of uplift, erosion/reworking, and karstification of the carbonate platform, which in turn was followed by downslope deposition of a mixed sand-mud system during the Late Cretaceous. This downslope transfer of sediment continues to the present day.

Exploration Since 1950s

Exploration of the Senegal basins started during the 1950s with discoveries of some onshore gas reservoirs, these fields proving the existence of mature source rocks and effective traps within the basin. Commercial gas is present onshore east of Dakar in the Gadiaga Field (the only productive field in Senegal up to present) and Diam Niade fields (productive from 1961 to 2000), where over 20 Bcf of Upper Cretaceous gas has been produced, along with a significant amount of oil.

The first offshore well in Senegal was DK-1, drilled in 1955 on the beach of the Dakar

Figure 2: Map showing Dolphin's Senegal Multi-Client 3D in relation to the FAN-1 and SNE-1 discoveries.



Peninsula, which encountered oil shows. Offshore Senegal, in the Sangomar-Rufisque Block, there were hydrocarbon shows within the Cretaceous to Tertiary section in the wells RF-1, RF-2, RF-3 and DKM-2. All these wells are located on the positive structure produced by the igneous intrusion of the Rufisque Dome (Conn et al., 2012). As mentioned previously, offshore Senegal has recently seen very significant discoveries by Cairn with the FAN-1 and the SNE-1 wells.

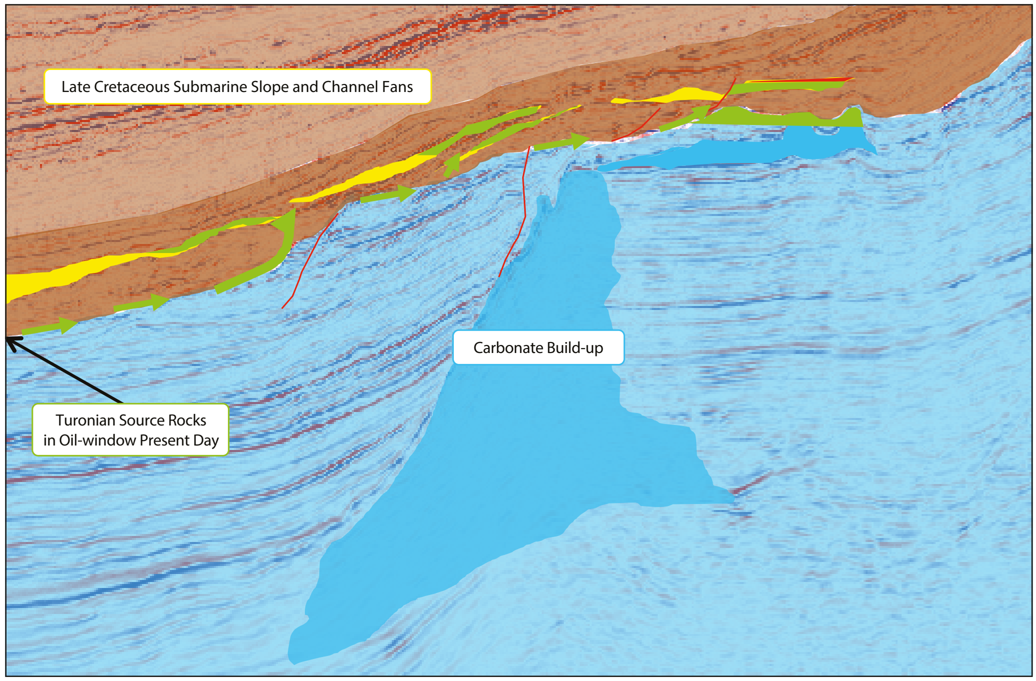


Figure 3: Schematic play concepts.

Exciting Play Types

Several examples of play types can be illustrated using the Sud Profond 3D seismic. These include basin floor fan turbidites, channelized turbidites, carbonate build-ups, karstified carbonates, and toe-slope carbonate debris. These concepts are outlined schematically in Figures 3, 4 and 5.

The sand-prone basin floor fans appear to be well-developed in the south of the block, as shown on Figure 1. The Turonian source rocks are believed to be mature for oil downdip from these Late Cretaceous fan deposits. Locations of two example seismic sections (Figures 4 and 5) are shown in Figure 1.

The Late Cretaceous submarine fan lobes highlighted by amplitude extraction in Figure 1 are highlighted on Figure 4. They are represented by differentially compacted seismic character, believed to be a mixed sand-mud fan system.

The Jurassic-Early Cretaceous carbonate deposition is exemplified by a seismic section on the outer edge of the main carbonate platform (Figure 5).

References available online. ■

Figure 5: Seismic section traversing carbonate build-ups – play requires a shaley top-seal.

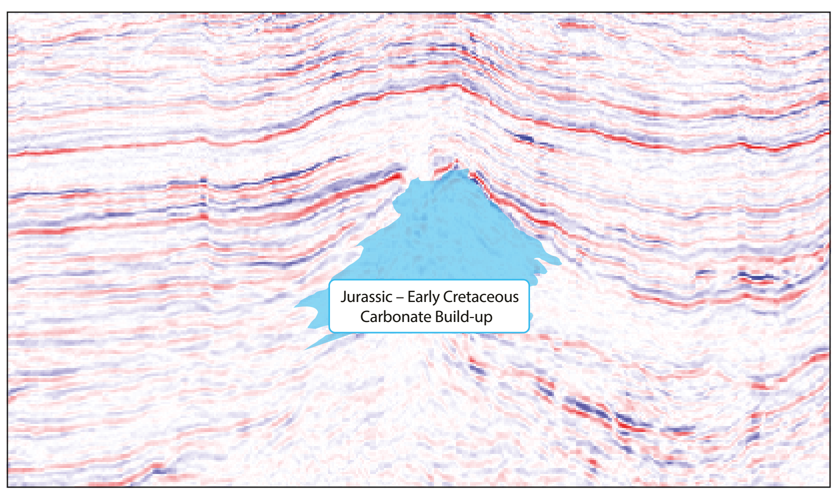
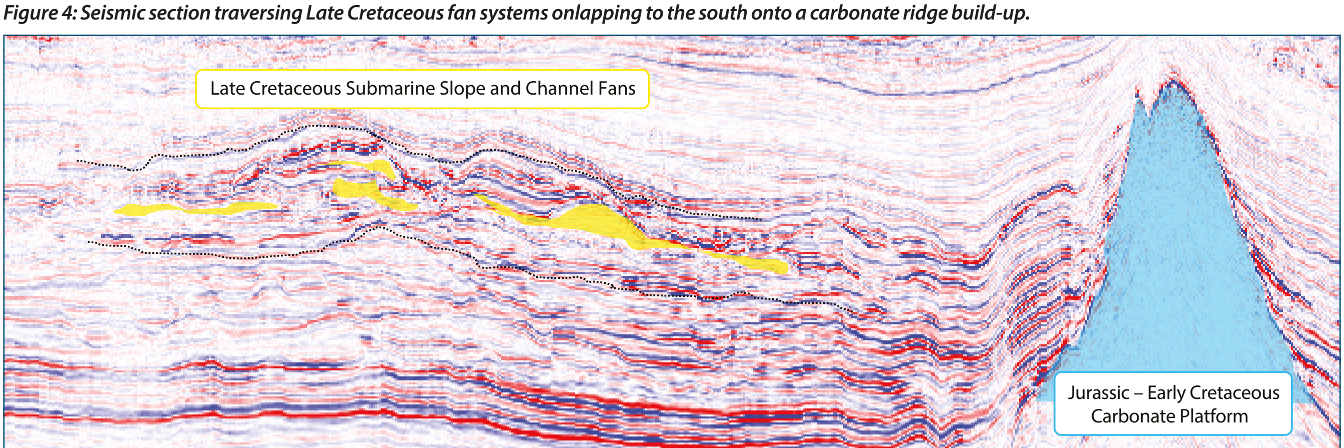


Figure 4: Seismic section traversing Late Cretaceous fan systems onlapping to the south onto a carbonate ridge build-up.



Oil Exploration in the Canadian Beaufort

PAUL BARRETT,
Franklin Petroleum

A frontier environment with conventional resources, where exploration risk is low, execution risk is manageable and the plays are world-class.

The Arctic represents both a challenge and an opportunity for significant reserves replacement. There are fantastic exploration prospects in the region and the allure of adding billions of barrels of contingent resource with just a few wells is driving the majors' longer term approach to the region.

Road to the North

The strategic Mackenzie Delta town of Inuvik lies at the northern end of the Dempster Highway, currently being extended to the port at Tuktoyaktuk to form Canada's only road link to the Arctic Ocean. Lying north of the Arctic Circle, the Mackenzie Delta is a true Arctic environment, with seasonal (but not multi-year) ice cover and highly sensitive ecosystems, primarily in the extensive shallow shelfal and delta distributary environments. Hunting and harvesting of species such as Beluga whales are key activities that any oil and gas operation must take into account.

Conventional marine seismic can be conducted generally between late July and early October, with the most recent 3D survey in 2012 being able to exit the area via the famous Northwest Passage, resulting in a significant saving in demobilization costs. Drilling has been achieved year-round using a range of novel drilling units. One of these, the SDC, remains in the region off Herschel Island and is an ideal candidate to drill wells in up to 50m of water.

Exploration Promise

Exploration for oil and gas in the Canadian Beaufort reached a high point in the late 1970s, when a large number of wells were drilled, primarily in the shallow shelfal waters of the Mackenzie Delta. Generous tax incentives drove companies to explore in this harsh environment on the most rudimentary of seismic data and, despite these issues, exploration success rates were over 50% and a number of plays were opened up. Over a billion barrels of oil were discovered along with many trillions of cubic feet of gas, but there is considerable remaining undiscovered potential according to several authors, including the US and Canadian Geological Surveys.

For decades the dream for Canada was to evacuate this gas southwards through the Northwest Territories to Alberta, but no viable export route ever materialized, nor is one envisaged in the foreseeable future. This led to a slowdown in exploration activity.

However, with an export option now available through the Alaskan TAPS line to Valdez, oil plays are again a focus for exploration. The most recent well to be drilled offshore was the 2005 Paktoa oil discovery (240 MMbo). Meanwhile, ConocoPhillips are assessing the development of the 300–500 MMbo Amauligak discovery, situated in

The modern-day Mackenzie Delta.

Paul Barrett

the shallow waters of the delta, and ExxonMobil are in the early stages of planning an exploration well in the deepwater area to the north. All eyes have been focused recently on Shell's drilling campaign across the border in Alaska and further progress here will create more momentum for exploration on the Canadian side.

Petroleum Plays

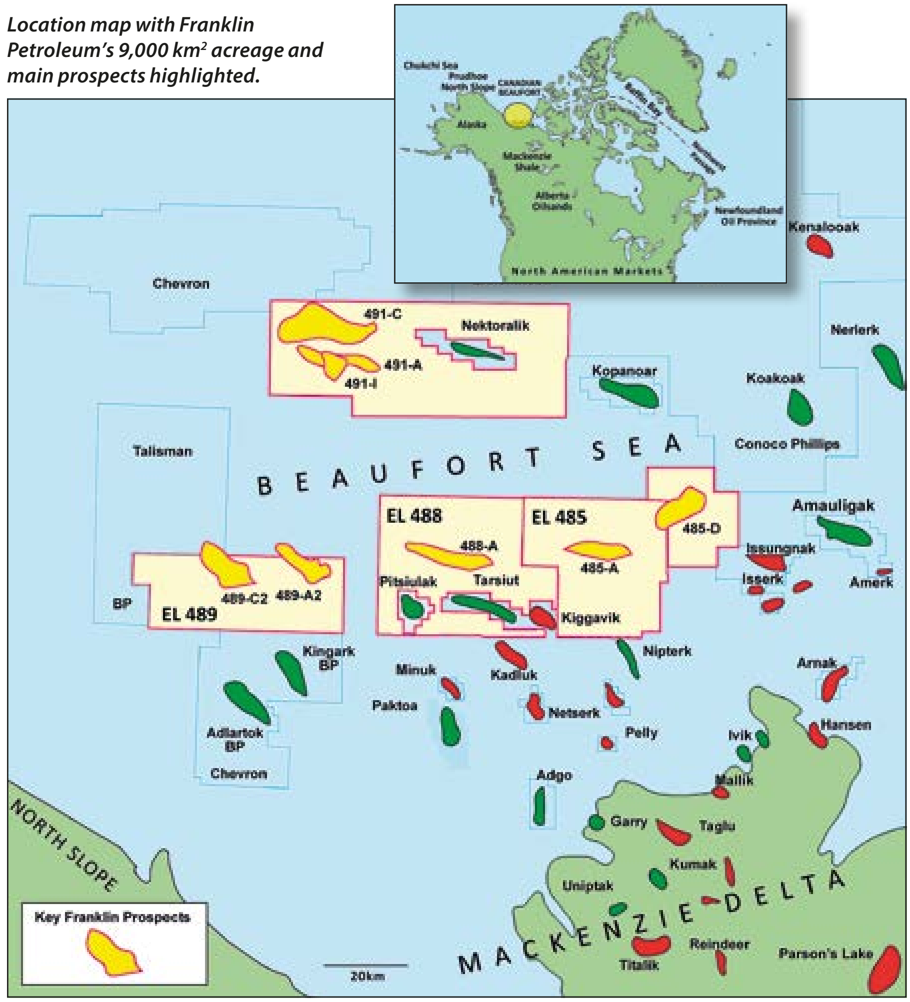
The Canadian Beaufort Sea is dominated by the Mackenzie Delta system, the second largest in North America. The Mackenzie River has been supplying sediment to the delta from the Canadian interior since the Late Cretaceous, and has deposited in excess of 14 km of sediment fill in the accommodation space created by the opening of the Canada Basin between the Alaskan North Slope and the Canadian Arctic Islands. The delta overprints the rifting episode associated with the Canada Basin. This in turn is overprinted in the south-western part by Brookian orogenic compression that created the major structures of the Alaskan North Slope, such as Prudhoe Bay.

The northward-prograding delta system deposited sediments with a generally more marine nature northwards into the basin, resulting in a gradual increase in oil-prone source rocks to the north. Most of the discoveries onshore are gas prone, such as the giant Taglu gas field, with some minor oil present. In the shallow waters of the present day delta-top, hydrocarbon type is a mixture of oil and gas (eg. Amauligak), while moving into the deeper water, the main hydrocarbon phase is oil (eg. Kopanoar). There are exceptions to this general rule, for example the West Atkinson oil discovery, which is situated onshore on the eastern part of the delta, where the oil is thought to be sourced from deeper, Devonian source rocks. In general, though, if you are looking for oil, you have to be offshore.

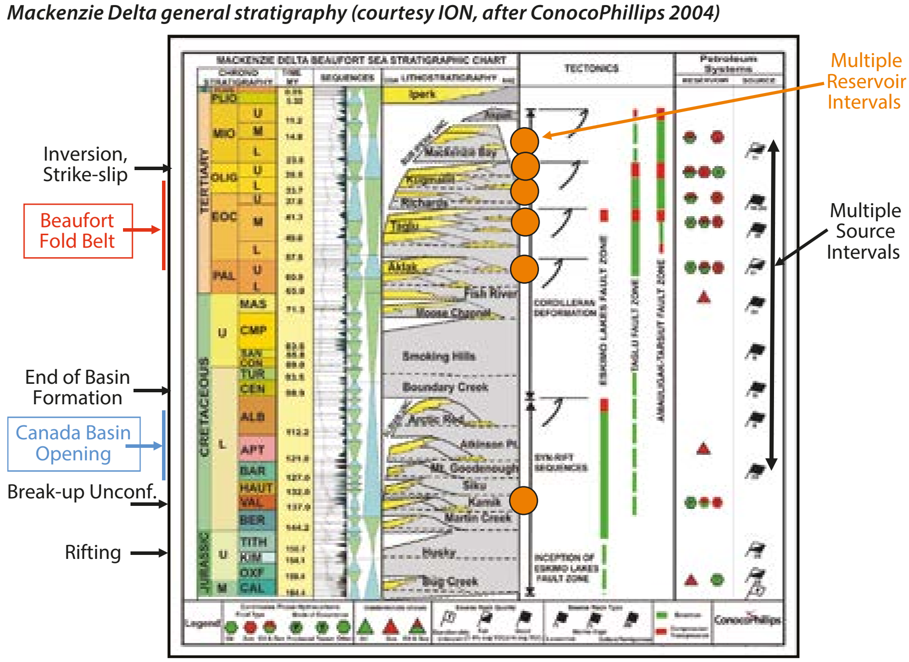
The Mackenzie Delta developed in several discrete pulses of delta-building. These pulses led to the identification of a number of source-reservoir pairs where the delta-top and pro-delta areas young northwards. The delta-top and pro-delta submarine fan facies represent the best reservoir targets; the vast majority of the delta system is mud-prone with sporadic sand pulses.

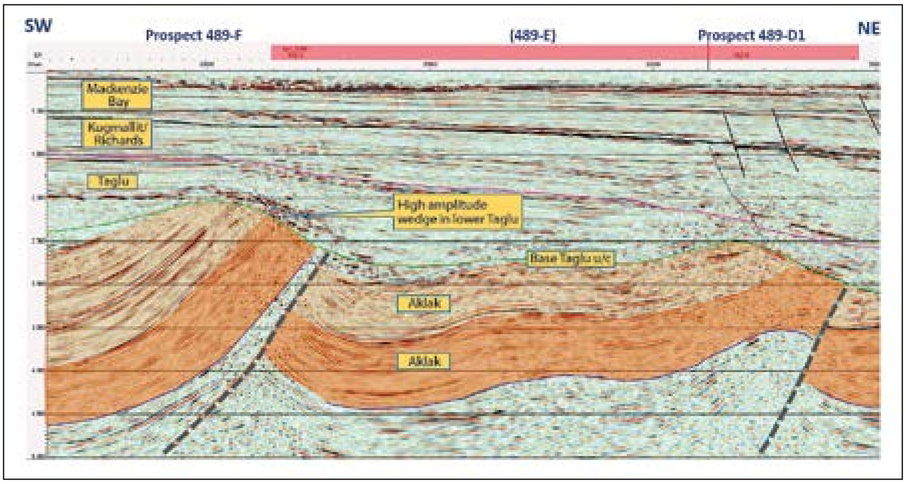
Structural traps are developed in three main settings. Firstly, in the south-west of the area, the Brookian compression has created spectacular compressional structures, originally thought to be diapiric in nature, but modern seismic has illuminated the

Location map with Franklin Petroleum's 9,000 km² acreage and main prospects highlighted.

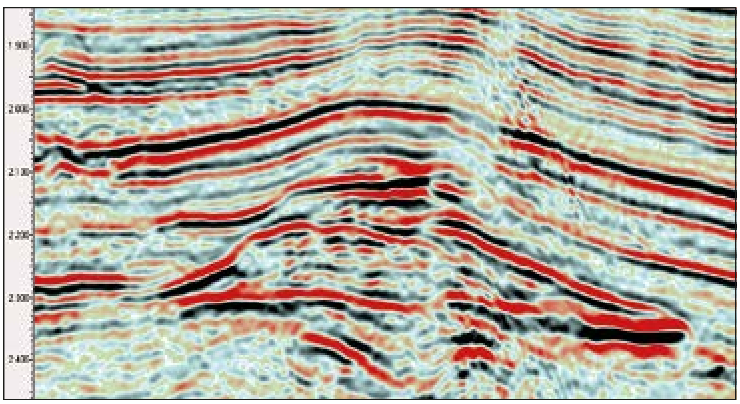


Mackenzie Delta general stratigraphy (courtesy ION, after ConocoPhillips 2004)





Brookian compression features in the south-west of the Canadian Beaufort.



Mounded basin floor fan feature in the Pliocene Iperk delta sequence, with possible DHI's (from ION's BeaufortSPAN survey)

BasinSPAN
Imaged by GXT

bedded nature of these 'diapirs' and they are better explained as tight compressional folds detached on the base of a mobile shale.

Further north, a series of normal fault blocks is developed, with faults predominantly throwing down to the basin and with a listric, growth fault character. The Amauligak discovery is developed as a classic fault and dip-bounded closure with multiple stacked delta-top sands filled to different oil-water contacts. It can be inferred that the bounding fault is a highly effective seal and that clay smearing along the fault may be responsible for this.

The third main structural type is a northern trend of dramatic structures, probably related to gravity collapse of the delta system and the creation of a kind of toe-thrust regime. Like the Brookian structure to the south, these are very tight structures. Some of them have been drilled, yielding primarily oil discoveries such as Kopanoar and Koakoak.

Franklin's acreage contains several of the structural play types described above. In addition, however, undrilled stratigraphic plays represent significant upside that was unrecognizable on the early vintage seismic data. Most spectacular is the development of mounded base-of-slope submarine deposits of the Pliocene-age Iperk Formation (one of the youngest delta pulses).

The Canadian Beaufort in 2015

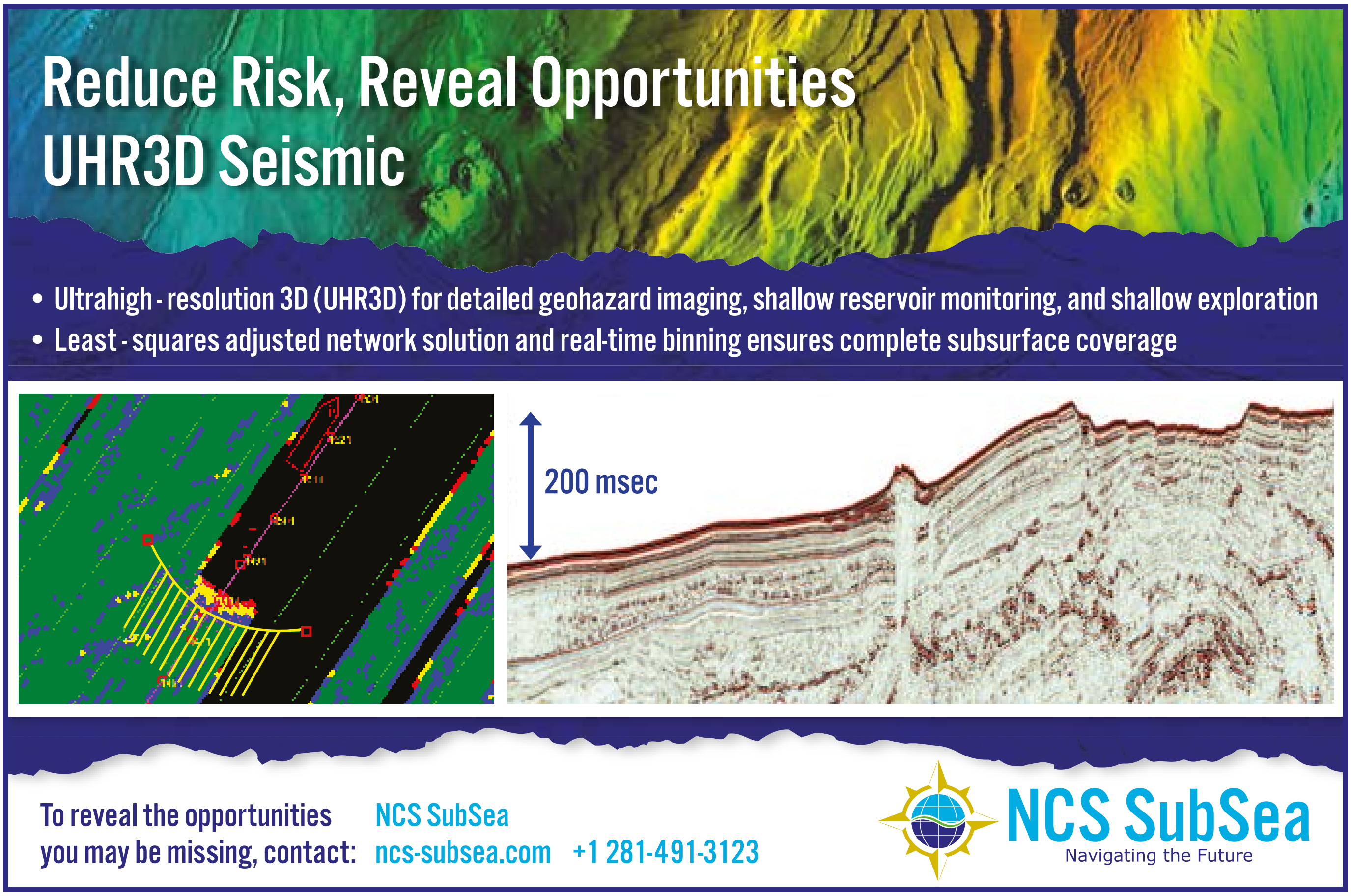
Activity in the Canadian Beaufort has been very low even during the heady years of $100+ oil price in the recent past. Chevron-Statoil undertook a 3D in 2012. Prior to this survey, ION acquired several vintages of BeaufortSPAN data – the deep regional lines that are their trademark – which illuminated the vast array of both proven and undrilled petroleum plays in the basin.

Short term fluctuations in oil prices do not materially affect the long term viability of Arctic oil plays and Shell's recent announcement that it will be restarting its Alaskan Arctic exploration program underlines the fact that exploration drilling in the non-Russian Arctic can be achieved in a post-Macondo world. Franklin Petroleum is taking advantage of the worldwide softening of seismic acquisition costs to undertake a 3D seismic survey over its key prospects in summer 2015. Using ION's pioneering BeaufortSPAN survey to evaluate the area has led to a prospect inventory of around 8 Bbo potential resource that the 3D survey is designed to firm up to drillable status.

Going forward, levels of Arctic activity can be expected to pick up. Not just Shell, but other majors are coming to the realization that large resource numbers can be achieved through a handful of Arctic wells, compared to thousands of shale play wells, while many other high impact exploration areas around the world, such as Namibia and Angola, are not producing the results anticipated.

In essence, the Arctic, especially basins like the Mackenzie-Beaufort, are areas where exploration risk is low, execution risk is manageable and the resources are world-class. ■

SDC drilling unit – Arctic-capable and ready to drill wells in up to 50m of water.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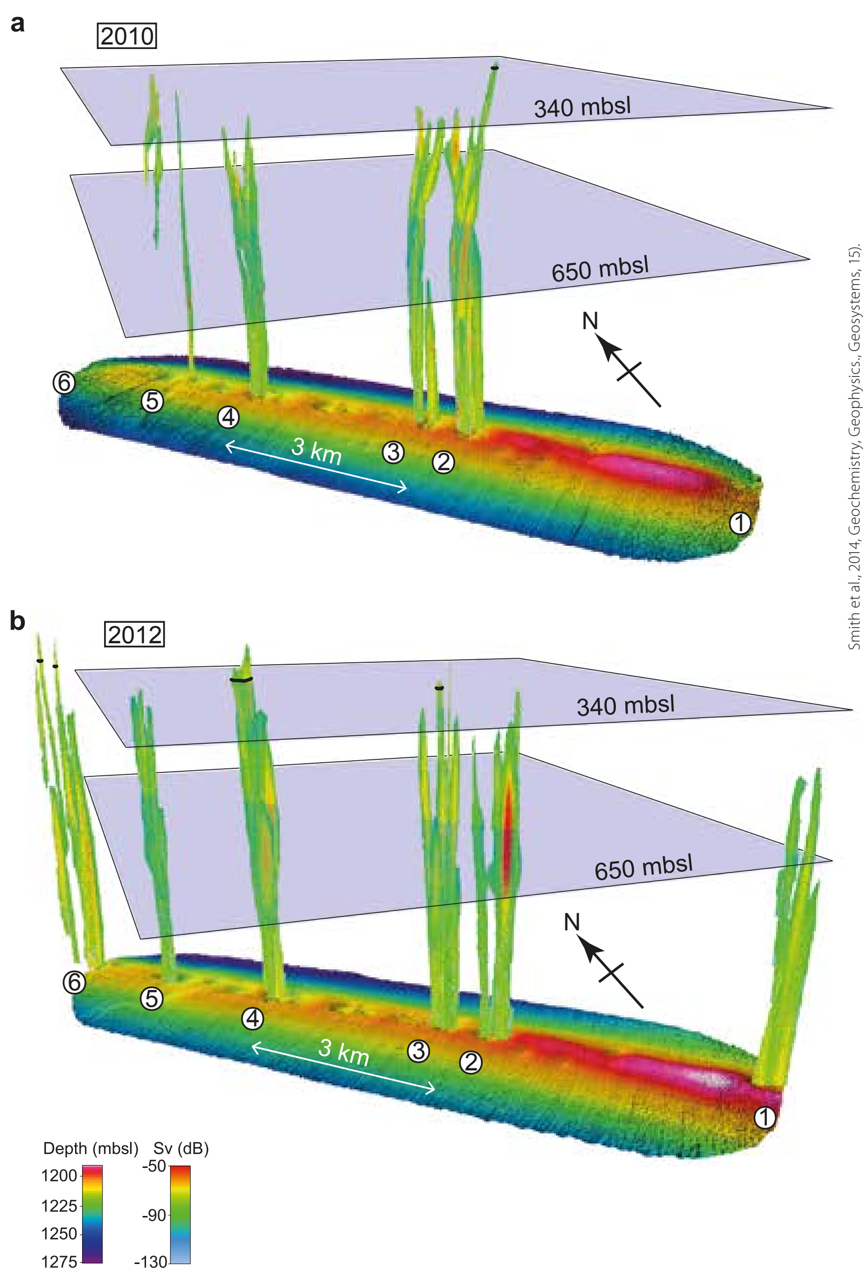
Gas Hydrates

JÜRGEN MIENERT, UIT,
MARTIN LANDRØ, NTNU Trondheim,
LASSE AMUNDSEN, Statoil

PART VII: Hydrates in the Arctic (II)

In a fascinating study focusing on the interplay between gas hydrates and free gas at the Vestnesa Ridge, west of Svalbard, researchers have mapped methane gas flares, up to 800m high, rising from the ocean floor – almost as high as the tallest man-made structure in the world, the Burj Khalifa in Dubai.



This time-lapse effect, where there are more gas chimneys in the water layer in 2012 compared to 2010, is due to an increase in the water temperature which pushes the gas hydrate stability zone upwards. Hence, it is important to monitor these complex systems over time. Since gas hydrates represent the biggest hydrocarbon accumulation on earth, it is important that one follows their development closely, especially in Arctic regions. The CAGE study concludes that the source of the gas system is partly thermogenic.

> *The universe is not required to be in perfect harmony with human ambition.*

Carl Edward Sagan (1934–1996), American astronomer, cosmologist, astrophysicist, astrobiologist, author, and science popularizer.

Pockmarks are craters in the seabed related to the escape of fluids and gases through the seabed. They were first discovered off the coasts of Nova Scotia, Canada in the late 1960s. Today, we know that pockmarks represent common seafloor manifestations of fluid flow on continental margins around the world. Pockmarks show a great variety of shapes and sizes, ranging in diameter from 1m to over 1,500m, with depths up to 150m, although the majority are between 10 and 250m in diameter and 1–25m deep. Because of their association with seepage of methane-rich fluids and gases, active pockmarks are usually characterized by precipitated authigenic carbonates and chemosynthetic communities.

Vestnesa Ridge Pockmarks

Located west of Svalbard at 80° N, the Vestnesa Ridge is a 100 km long, 3 km wide sediment drift deposited on young oceanic crust. It is one of the northernmost gas hydrate provinces along the Arctic continental margins. First discovered and described by Vogt et al. in 1994, a strip of the ridge about 1.3 km wide and 50 km long is dotted with giant pockmarks ranging in size from a few to hundreds of meters in diameter and up to tens of meters in height. This strip seems to be underlain by a deposit of methane hydrate 200–300m thick. Vogt and co-workers thus proposed that the pockmarks were formed by active or recent upward-rising methane flow collecting in the ridge-crest trap.

The occurrence of gas hydrate-bearing

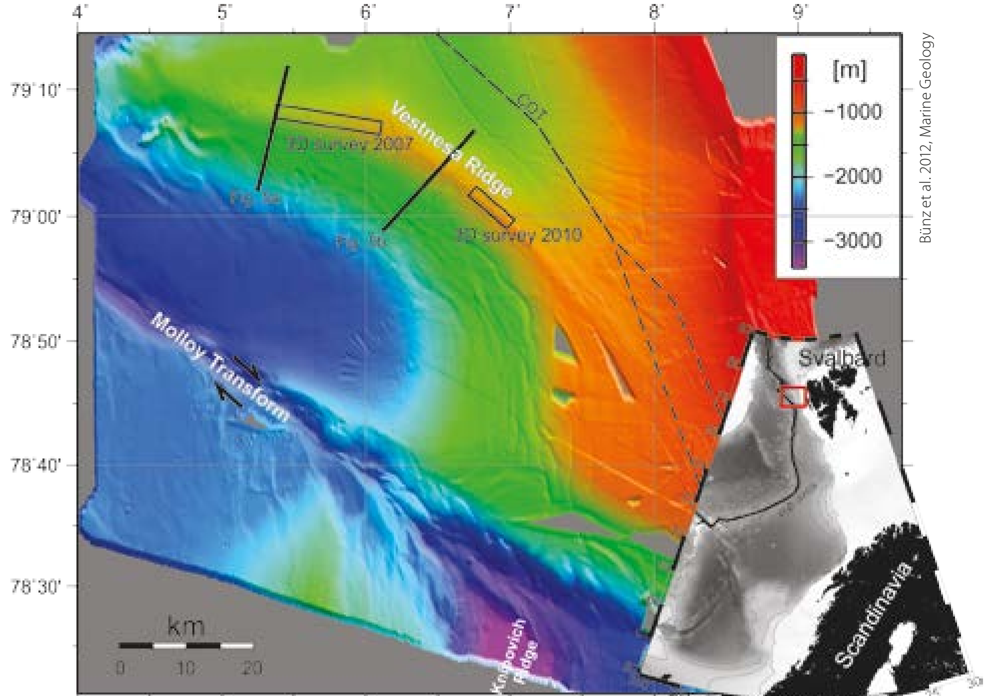
sediments, the evidence for active fluid flow and the geological setting on a young and sedimented ocean ridge today make the Vestnesa Ridge a key location to study the interaction of gas hydrate formation and focused fluid flow as well as the possible impact of methane seepage on Arctic environments.

At a water depth of 1,200m, the research team from the Arctic University of Norway in Tromsø at the Centre for Arctic Gas Hydrate, Environment and Climate (CAGE) has managed to map gas leaking directly into the water using echosounder data. Four clear active gas chimneys are visible, all of them slightly dipping to the north due to the water current, which was measured to be 8 cm/s. The corresponding seismic shows clear discontinuities for the seabed reflection exactly at the locations of the 'root' of the gas chimneys. These chimneys might have a time-lapse effect: they behave as geysers, although on a different time scale (see image on page 46). The interpreted base of the hydrate stability zone (BHSZ) is shown in the lower right corner of the figure below right.

It can be noted that the first observations of rising hydrate and bubble plumes were made in the Guaymas Basin in the Gulf of California around 1985. Since then, bubble plumes have been seen rising from hydrate deposits around the world.

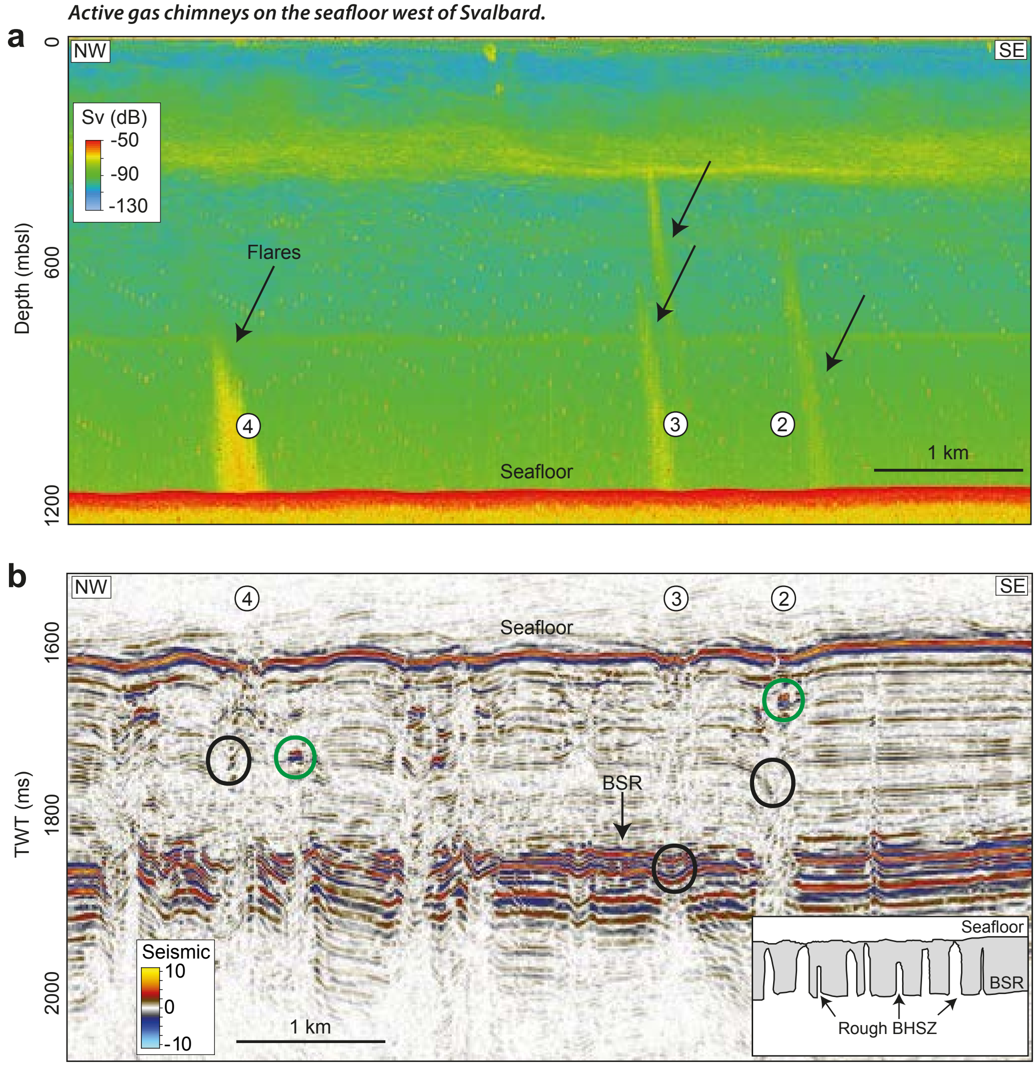
Potential Causes for Change

A typical stability curve for the Barents Sea is shown in the figure on the next page, where the cross-over point between frozen gas hydrate and free gas is at 492m. If the temperature within the shallow sediments is changed, due, for instance, to an increase in the temperature of the sea water, then this stability point might be shifted upwards, meaning higher risk for gas leakage through the hydrate layer. It is therefore reasonable to assume that the amount of gas hydrate stored below the



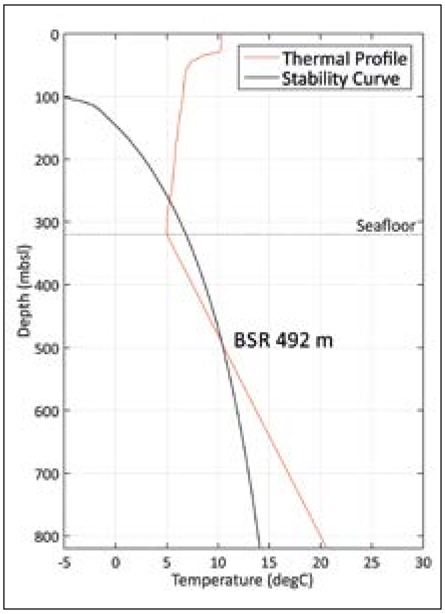
Overview map of the Vestnesa Ridge area on the west Svalbard margin. COT denotes Continent–Ocean Transition.

Active gas chimneys on the seafloor west of Svalbard.

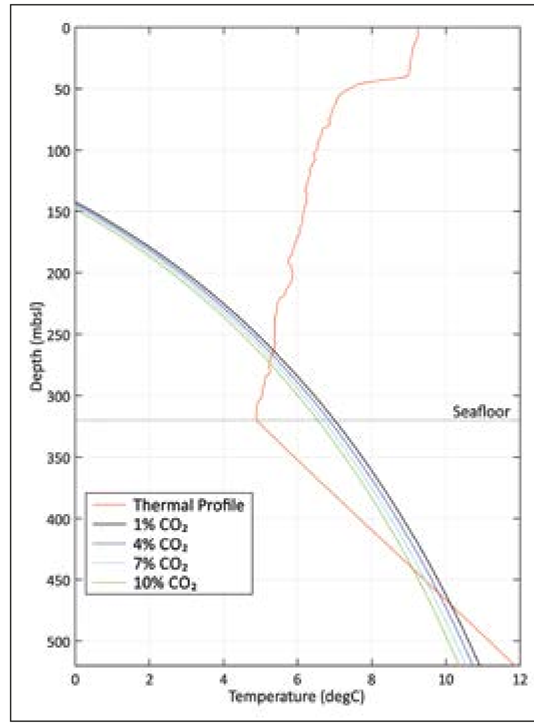


sea bottom has varied due to climate changes in the past.

What happens if leakage occurs at a greater depth? The figure far right, which represents theoretical hydrate stability curves in the south-west Barents Sea, shows a hypothetical case with leakage from a deeper CO_2 storage site which demonstrates how CO_2 increases might alter the stability of the hydrate stability zone. The modeling suggests that the stability curve would be shifted due to an increased amount of CO_2 within the hydrate zone. We see that the stability zone is slightly shifted to the left as the CO_2 concentration increases, indicating that the hydrate stability zone will decrease. The effect is probably moderate, but it should be investigated if CO_2 storage sites are planned close to areas where large amounts of gas hydrates are known to be present.



Typical thermal profile (red line) and the stability curve for hydrate (black line), showing that hydrates might exist from the seafloor to, in this case, as deep as 492m.



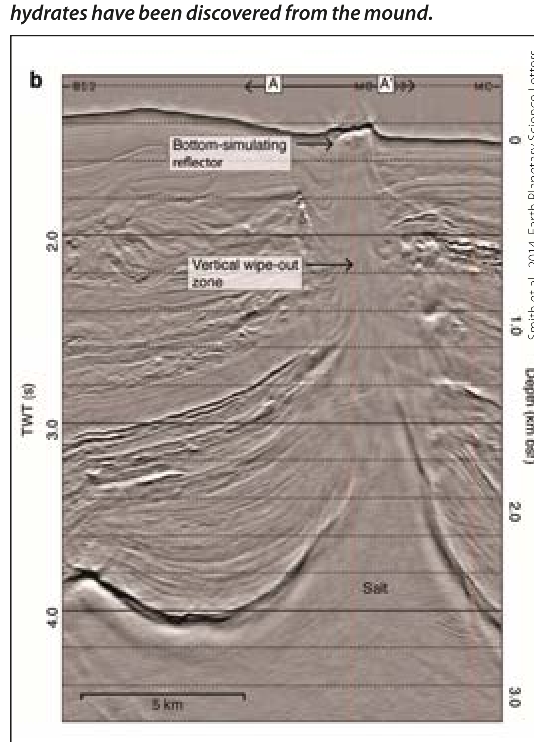
Starting from an assumed gas composition of 95% methane, 2% ethane, 1% propane, 1% butane, and 1% CO_2, a gradual increase in CO_2 percentage and decrease in the amount of methane accordingly thins the gas hydrate stability zone. The top of the GHSZ (10% CO_2) lies in the water column at ~ 270m BSL (below sea level) and the base in the sub seabed at ~ 445m BSL.

Methane Vents and Gas Hydrates

In an interesting example taken from the northern Gulf of Mexico (Ursa vent at 1,070m water depth), a huge gas vent can be seen piercing the hydrate stability zone. This vent exhibits a bottom-simulating reflection (BSR) close to the seafloor and the vent sediments expel gas bubbles upon disturbance. Elevated salinities and temperatures at this location enable existence of free gas near the seafloor, contributing to a high hydrocarbon flux. Mass fluxes of gas from the vent are approximately 3.2 to 9 x 10^4 tons per year, coming from an area of approximately 0.8 km^2, which is equal to a maximum of 113 kg per square meter per year. Close to such vents the salinity and water temperature are found to be increasing.

In the Gulf of Mexico, most of the vents are characterized by a high hydrocarbon flux so that the amount of hydrocarbon output to the water column becomes significant. When extrapolated to the entire Gulf region, the estimates correspond to 14–120% of the average discharge rate of the Macondo oil spill. Such large natural hydrocarbon output to the ocean should have an impact on the carbon cycle and biological system. Deep sea microbial communities thrive at these vent localities, where they sustain populations of hydrocarbon-degrading bacteria.

Seismic reflection profile showing salt dome, vertical wipe out zone and seismic reflection with a negative polarity event and cross-cutting. The seismic characteristics suggest a bottom-simulating reflector indicating the base of the gas hydrate stability zone that rises from the vent boundaries at ~ 2.0s TWT towards the vent edifice. Thermogenic gas hydrates have been discovered from the mound.



Smith et al., 2014, Earth Planetary Science Letters

References:

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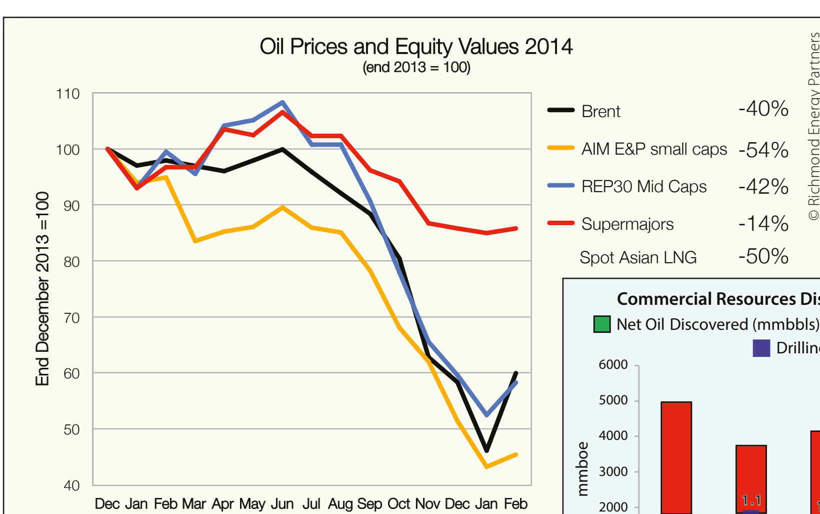
Time to Invest or to Panic?

As everyone knows, the oil price has plummeted in recent months. Spiraling ever downwards alongside it has been the value of E&P stocks and shares – but is this correlation justified? Is it a good time to invest in exploration?

KEITH MYERS, Richmond Energy Partners

Markets are fickle and the market for E&P equities is no exception. Investors tend to like smaller oil companies when oil prices are rising but abandon them for the safe haven of dividend-paying supermajors when oil prices fall. Linking the **short-term** oil price to the **longer-term** value of subsurface assets is not logical and this pattern of investor behavior can result in the mis-pricing of assets and share price volatility.

The value of small E&P companies on the London AIM Stock Exchange has dropped 54% in the past year – more than the drop in the oil price over the same period. Meanwhile, shares in the supermajors have proved more resilient, losing a mere 14% of their value in 2014, and have outperformed smaller oil companies over the last seven years due to their ability to pay dividends. The small and mid cap E&P sectors on average have delivered positive returns only in years when the oil price increased and investors had an appetite for risk. The unpredictability of individual stock performance makes effective stock picking very difficult, with a number of companies losing as much as 95% of their value in the past year while a few, like Cairn Energy who made a significant discovery, were able to maintain their February 2014 value (at least until they were hit by a hefty Indian tax demand).

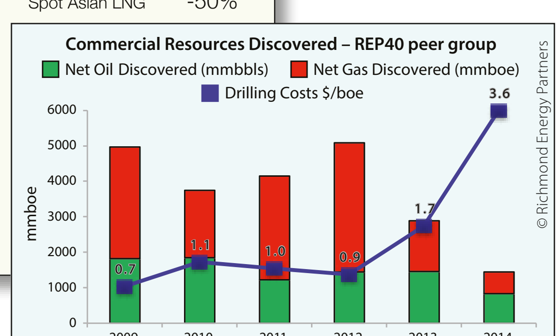


The truth is that exploration is not completely out of favor with investors, but it has not been delivering sufficient high impact discoveries to make it a good investment. It could be said that investors sowed the seeds of capital destruction by encouraging too much exploration and the creation of too many start-up oil companies during the last oil price 'up' cycle. This has added to competition and the consequent cost inflation. It is now difficult for the smaller companies to access equity capital when oil prices are flat or falling.

Those Elusive New Plays

The commercial success rate of exploration wells dropped from 40% in 2009 to only 30% in 2014 with discovered volumes at a seven-year low. Using REP40, the Richmond Energy Partners peer group of 40 mid-cap and large cap companies, chosen to test the pulse of global exploration, drilling finding costs have shot up, from an average $0.9/boe between 2009 and 2012 to $1.7/boe in 2013 and $3.6/boe in 2014 – an increase of 260%, and unlikely to create value at current oil prices. Performance in the 2009 to 2012 period featured declining average discovery sizes and increasing numbers of very high-risk, high-cost deepwater frontier wells, which have had a negative impact on success rates and finding costs.

The industry has been drilling record numbers of wells in frontier basins and plays, particularly in deep water, seeking elusive new oil plays. The 47 frontier wells in 2014 delivered only four new potential commercial plays (in Norway's Barents Sea, the Potiguar

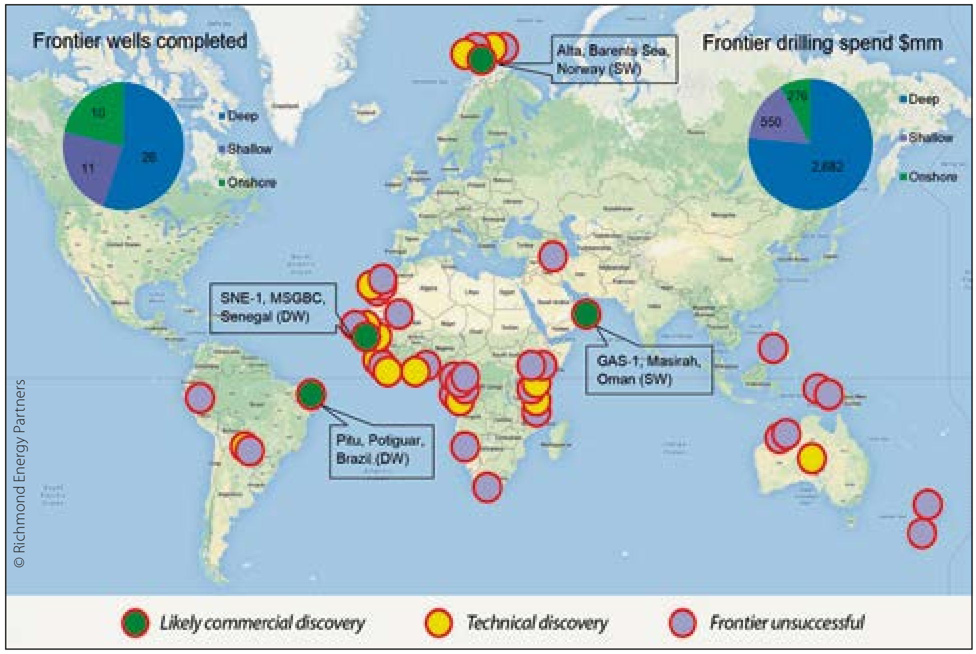


Commercial discovered resources have plummeted since 2009, while finding costs (in $/boe) have risen dramatically (source: Wildcat database end February, 2015).

Basin off Brazil, offshore Senegal and possibly Oman). Richmond Energy has analyzed $17 billion of drilling spend on frontier wells since 2008 and found that the frontier program delivered a creditable technical success rate of 33% – but a commercial success rate of only 10%.

Whilst the frontier gas discoveries have led to 170 Tcf of follow-on discoveries in East Africa and the Eastern Mediterranean, the frontier oil provinces discovered have been modest in size. Only the pre-salt of the Kwanza Basin has so far opened an oil province bigger than a billion barrels, but even here recent dry holes have limited the scale of the province. The total oil volumes discovered in these new provinces found so far is only equal to 80 days of current world oil production. Disappointingly, few of these emerging provinces have built on their early promise through subsequent drilling.

Richmond Energy Partners expects exploration drilling to be down about 40% overall in 2015 and so 2014 should prove to be the high water mark for frontier drilling. Nonetheless, over 30 frontier wells are still expected to complete in 2015.



Frontier wells in 2014 – only four were potential commercial discoveries.

	2009–13 Average	2014	Change on 5-year Average
Technical Success	49%	45%	-8%
Commercial Success Rate	36%	30%	-17%
Average Discovery Size mmboe	100	40	-60%
Hydrocarbons per well mmboe	36	12	-67%
Drilling Finding Cost $/boe*	1.0	3.6	+260%
Average Well Cost $m	37	44	+19%

*Exploration performance for the REP 40 companies – 2014 was not a good year. (*Finding costs include discovery drilling costs only and are for 2C resources. Source Wildcat database end February, 2015.)*

Blip – or the Future?

So is it time to invest – or to panic? Well, that depends on your perspective. Exploration certainly needs to deliver higher returns to restore investor confidence.

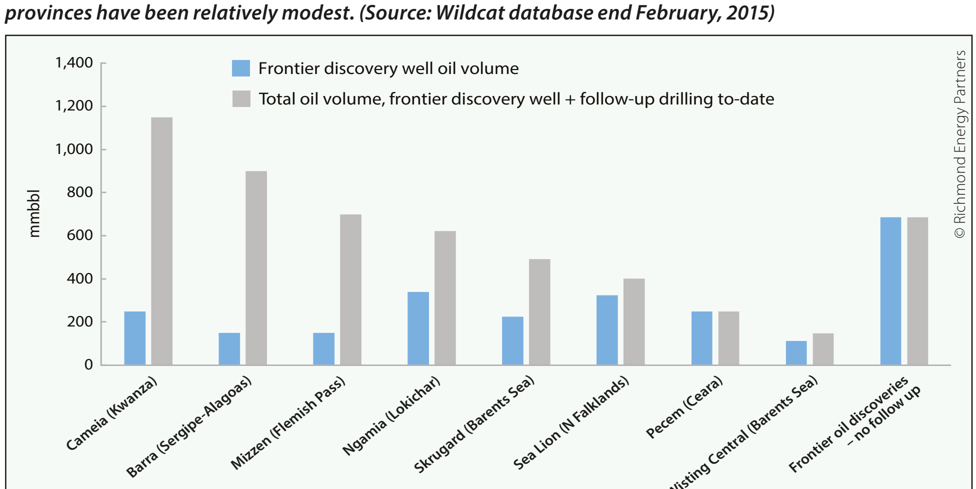
If you are convinced that oil prices will recover and that 2014 is only a blip in the exploration cycle, meaning that investor risk appetite and interest in the sector will rapidly return, then this is a good time to invest. You would be able to take advantage of lower competition and costs. Of course, it is definitely time to invest if you happen to know where the next big play is going to emerge.

However, high debt business models combined with high cost assets (both operating costs for mature assets and capital costs for assets currently under development, sanctioned in the previous high oil price era) leaves little for equity investors to get excited about. Companies holding high-risk acreage with big work commitments without the necessary funds available are also in a vulnerable position.

And feel free to panic if you think that 2014 may not be a blip in performance but is, in fact, the future.

This article is based on Richmond Energy Partners 2015 Exploration Performance Report, which analyzes international conventional exploration performance over a five-year exploration cycle, together with drilling plans for 2015. ■

Frontier oil discoveries by basin 2009–2014 and follow-up drilling: discoveries in the new emerging provinces have been relatively modest. (Source: Wildcat database end February, 2015)



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23rd Norwegian Concession Round:

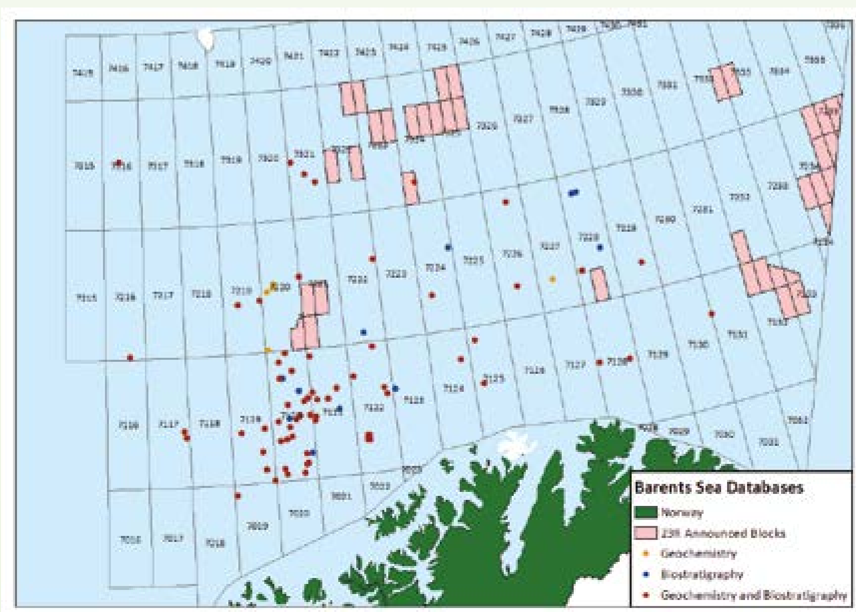
Barents Sea Databases and Multi-client Studies

Non-proprietary Database Leasing

Geochemistry data (72 wells)

Biostratigraphy data (82 wells)

Combined Geochemistry and Biostratigraphy Data (67 wells)



Barents Sea Multi-client Studies

- **Petroleum geochemistry of fluids from the Loppa High and the Eastern Norwegian Barents Sea.**
- **Carboniferous Source Rocks.**
- **Petroleum geochemistry of Loppa East/Bjarmeland platform.**
- **1D petroleum systems modelling.**
- **Apatite fission track analyses: Loppa High wells 7120/1-1R2, 7120/1-2, 7120/2-1 and 7120/2-2.**
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Duncan Clarke:

Economics and the Oil Game in Africa

Duncan Clarke is one of the best known names in the upstream oil industry: author, founder and chairman of Global Pacific & Partners, co-host of the landmark annual Africa Oil Week/Africa Upstream Conference in Cape Town. But how did an economist from southern Africa get involved with the oil industry at all?

JANE WHALEY

Growing up in Africa in the ’50s and ’60s gave Duncan Clarke an early appreciation of his surroundings and the wider environment – but very little indication of the significance the oil industry would have in his later life.

”I was born in what was then known as Southern Rhodesia, now Zimbabwe, where four generations of my family are buried and which I still think of as home,” Duncan explains. His father and grandfather had both been civil servants in the Rhodesian government, and as he says in his book *Three Decades in the Long Grass: The Story of Global Pacific & Partners*, “I never thought to leave this mix of lush high veld, arid low veld and seductive savannah.”

He went to St. George’s College in Salisbury (now Harare), the oldest school in central Africa, but in 1965, his final year, the Republic of Rhodesia made a unilateral declaration of independence from the United Kingdom, and life changed forever. The ensuing civil war lasted until 1980, when Zimbabwe declared independence.

Although initially called up for military service after school, Duncan went to Rhodes University in South Africa – and his travels began.

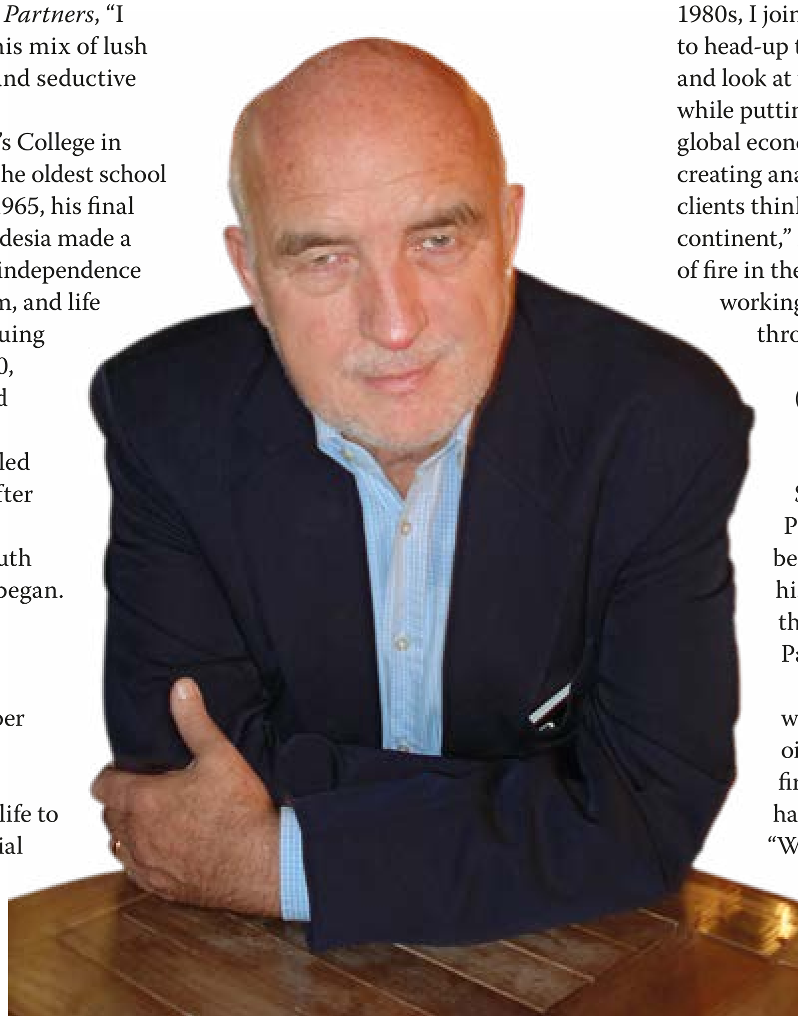
Political Upheavals

At Rhodes he studied economics under a number of notable South African economists, whose ideas remain significant in his life to this day. Equally influential were his travels around southern Africa: “By the time I left university I had covered about 50,000 km, mostly hitchhiking, observing the social and political pressures in the region at first hand.”

His first venture out of Africa was to St. Andrews in Scotland to do a Masters degree, before returning to Rhodesia, where he became a junior economics lecturer at the University College of Rhodesia and, as he says: “If things had been different, I should never have wanted to leave, neither home nor academe.”

But by 1975 things were different, and Duncan’s post at the university was terminated. With the guerrilla war in the bush escalating, and another call-up for military service looming, he took a position in economics in South Africa, but the political situation there was also in upheaval. In early 1977 he found himself on a plane with a ‘one-way ticket’ to Europe, with the clear implication that return was not an option. He still does not know why: “possibly a piece written on a sensitive issue, or just having the ‘wrong friends’.”

Duncan landed in Geneva on a stop-over (which lasted eleven years!) and began to work in the UN’s International Labour Office as an Africa economics specialist, later becoming an independent advisor, with frequent visits across that continent. Oil was inevitably part of Africa’s economic story and, as he puts it, “slowly the fragments of the oil game in Africa unfolded before my eyes.”



Global Pacific & Partners is Born

Being in Geneva and interested in the economics of oil, Duncan inevitably drifted into the orbit of Petroconsultants (now absorbed into IHS). “After two joint ventures with them in the early 1980s, I joined Petroconsultants in 1985 to head-up their Economics Division and look at their offerings on Africa, while putting together a platform for a global economics advisory practice and creating analytic tools for oil industry clients thinking about moving into the continent,” he explains. “It was a baptism of fire in the industry, but I ended up working with Petroconsultants throughout the world.”

By 1988, tired of Geneva (“cold winters, northern hemisphere, dour Swiss!”), Duncan emigrated to Sydney to head-up the new Petroconsultants entity there, before leaving to reconstruct his own firm specializing in the economics of oil – Global Pacific & Partners.

“One of our initial projects was a major report on national oil companies worldwide, the first time such a compilation had been attempted,” he says. “We built up an enormous quantity of research, working hard to obtain it. In the days before Google you had to go to each country and just talk to the right people. On the back of this and much other research effort on the developing world we were asked to work as advisors to JNOC, PTTEP and many other state oil firms, plus private players."

The company has grown and anmorphed in different ways over the years, but some things remain, as Duncan explains. "We have never been in debt or called in investors; we are self-financed and re-invest in our business, operating with good people and partners. We've grown into areas that we are interested in and ridden the industry cycles with a unique portfolio, built on a model modified over time, as done by the best oil companies.

"I was brought up in a landlocked frontier culture which encouraged self-reliance. In Africa the first objective is survival, a lesson which has proved very useful to me in our business life. Many people believe that business is a game of success, but it isn't – it's about survival first. This concept is embedded in everything we do."

The Clarke family farmhouse in the Inyanga Mountains near the Mozambique border. The photo shows Duncan, aged five, with his older brother and sister.

Conferences and Strategy Briefings

In 1994, Duncan fortuitously met Babette van Gessel, a young South African events organizer, and out of that meeting came the first Africa Upstream Conference, held in South Africa the same year. "It was a humble beginning," he remembers, "about 300 delegates in a large marquee in Camps Bay, very different from our 20th annual event in 2013, held in the large Cape Town International Conference Centre, with 1,600 attendees from all over the globe." From this developed one of the most significant senior management conference organizations in the oil and gas upstream business, with events held annually throughout the world, although with a strong emphasis on Africa.

"We believe it is important to have a good knowledge base in a country or region when we organize an event," Duncan explains. "To ensure we continue to attract a high calibre of speakers and attendees, we visit the countries involved before an event and work with our relationships and key contacts.

"For larger regional events, we use neutral venues like London, Singapore or Cape Town, where there are less political or cultural issues and it is easy for people of many nationalities to visit. Holding a conference in the US, for example, post-9/11, created problems for many of our overseas or African delegates because it became difficult to obtain visas.

"At our conferences we like to offer a wide range of themes, mixing strategy, new ventures, oil policy, history and geopolitics with economics. However, we never cover geoscience, despite the fact that many geoscientists attend our events, because many other conferences cover those areas and we prefer to stay within our area of expertise," he continues.

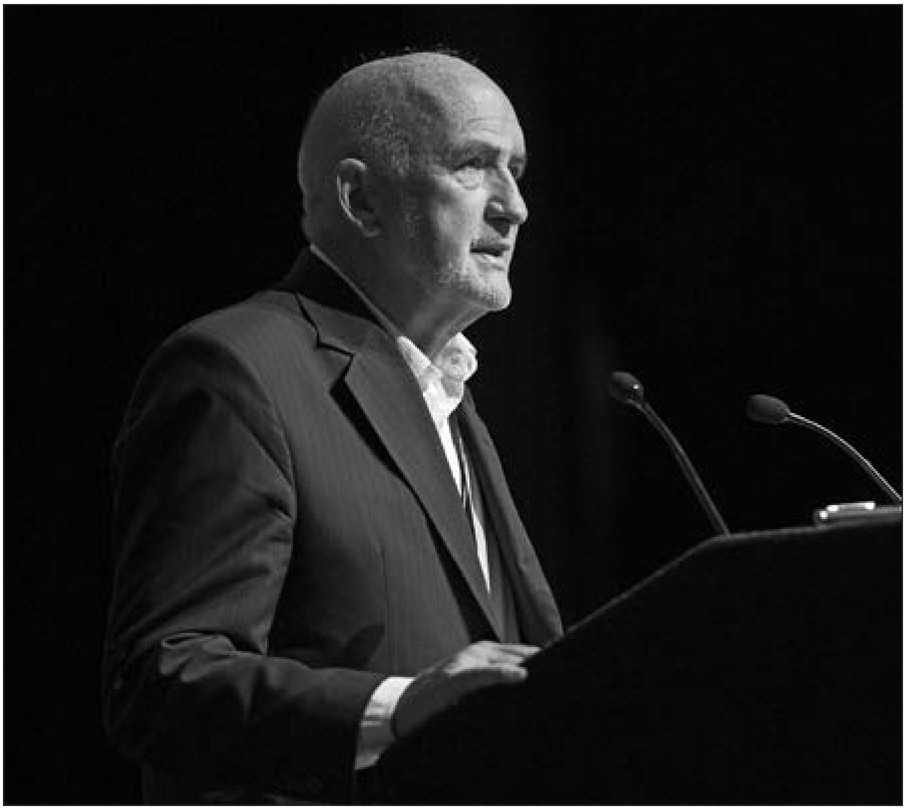
In 2001 Global Pacific & Partners abandoned the formulaic paper-based research model they had been using to deliver insight, knowledge and economic advice – "what I call 20th-century research" – in favour of dedicated strategy briefings closely allied to the events agenda. "The notion was simple," says Duncan. "We could not be everywhere, nor visit all the corporate and state entities enough, so henceforth we would bring the clients to us. At the same time the dot.com boom and the internet changed the face of access to data and information – if not quality analysis – so it proved a prescient move. Over the years we have worked for a range of blue-chip clients in an advisory capacity, from national oil companies to the majors and small independents."

Five Books

Despite having visited so many places in the course of this work, Duncan still enjoys traveling, particularly in Africa. He also loves going into the bush and on safari.

Another, more recent, interest is writing, and he now has five published industry books to his name – *Africa Crude Continent: The Struggle for Africa's Oil Prize* most significantly, a 100-year historiography of the complexities of the oil game in Africa. "Writing books is a very different process from penning advisory reports and conducting briefings, which are obviously purely commercial," he explains. "I write more because of passion about the subjects and to convey original or interesting ideas. One was a critique of peak oil and another on worldwide corporate/state oil shifts, both done in order to give a different take on them, as I did, for example, in *Empires of Oil*, which compared the then-emergent trajectory of the global oil industry with analogs from Gibbon's classic work on the rise and fall of the Roman Empire."

In another work, *Africa's Future: Darkness to Destiny*, Duncan took an in-depth look at the economics of his home continent. "I decided to focus on what makes Africa tick, and how it was constructed," he says. "There are a lot of sound bites around on this topic, and I wanted to make a more profound analysis, looking at the topic from a longer-term, more Darwinian, evolutionary angle. It ended up going



Duncan addressing delegates at the Africa Oil Week conference in 2013.

against a lot of the accepted analyses, which don't have sound economics or fundamental understanding behind them. It's not that simple in Africa; there are myriad contemporary challenges built on past and present complexities."

Passion for Africa

Although Duncan has lived in Europe and Australia, and with Global Pacific & Partners has visited over 120 countries throughout the world, Africa always draws him back, and until recently he was based in Johannesburg, although now he has returned to London. "I have become a sort of nomad, I realize", he says, "with over 2,700 nights spent so far over the last 30 years in over 200 cities on six continents.

"Africa may be a cartographic reality, but other than that, it's a convenient myth which cannot be thought of as a single entity. It is very diffuse and divided, with each country (55 at last count) or separate ecology having a different economic profile and trajectory, and it does not necessarily make things easier in diagnosis to just aggregate them," he says. "Economic theory when applied to Africa has tended to be weak, with too many relying on cross-country economic regressions for empiricism in order 'to explain' realities, but without enough deeper-level historiography or understanding.

"People talk too glibly about the 'resource curse'. Resources per se are not an inherent curse – it's above ground where the basic problem lies. Companies moving into Africa now may have better regulations and laws than their predecessors, helping to avoid some of these difficulties, but they must still have stability to be successful. All countries have issues to be addressed, and even once-stable places, like Libya or Sudan, can suddenly fall apart. The perils of history often return.

"There is a lot of talk about 'resource nationalism' at the moment," he continues. "I don't consider it either a good or a bad thing: critical balance is what is needed. Yet many current initiatives in Africa may seriously undermine GDP growth and block the maximal flow of needed exploration capital from abroad. Shifting demographics too mean that these economies will have to support much larger populations, so unless countries are better managed we might encounter more fragmentation, often due to embedded socioeconomic or ethnicity issues. Many states in Africa also still have legacies left over from Cold War divisions, plus new schisms shaped by post-independence turbulence. Most are seeking to create better structures for exploiting their hydrocarbon resources, but it is interesting to note that none of the national oil companies in Africa have been privatized, which is what has happened elsewhere."

So what does the future hold for Duncan Clarke?

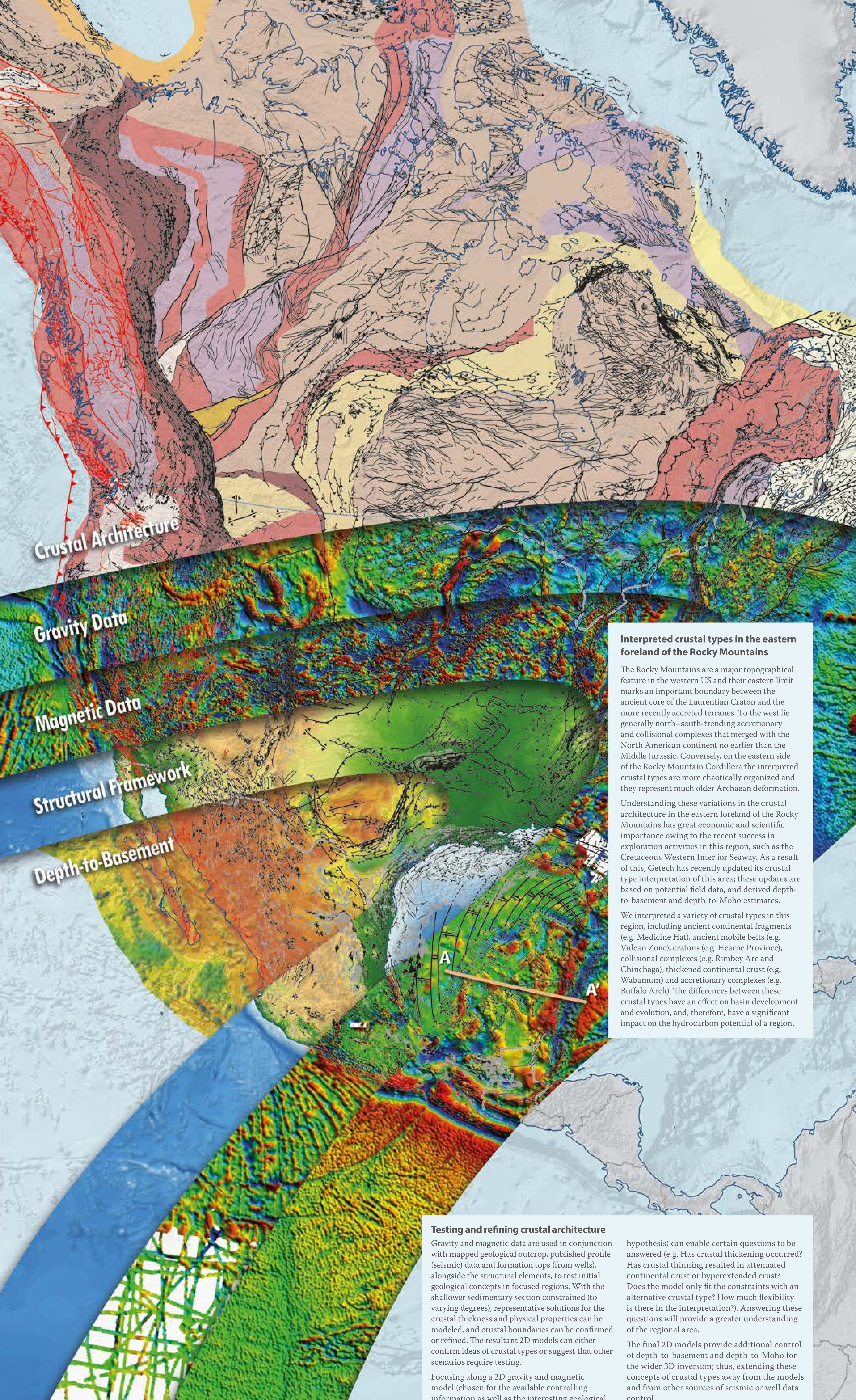
"Hopefully, I will go on doing what I'm doing now – working, traveling, and adjusting our strategy and portfolio in oil and gas while adapting to ever-constant change. We will continue to fine-tune the company, and probably focus more on our core in Africa, keeping risk well-balanced as we upgrade the organization. We may also deepen our interests in selected arenas – there are several options.

"One thing's for sure, I'm certainly not retiring!" he says. "I don't fish or play golf, so what would be the point? Age is just a state of mind." ■

Duncan Clarke with senior partner and chief executive of Global Pacific & Partners, Babette van Gessel. Their 22nd Africa Oil Week will be held this year from October 26–30.

The Tectonic Fabric of North America Uncovered

Peter Webb and David Sagi from Getech explain the useful insights to be gained from mapping crustal architecture.



Interpreted crustal types in the eastern foreland of the Rocky Mountains

The Rocky Mountains are a major topographical feature in the western US and their eastern limit marks an important boundary between the ancient core of the Laurentian Craton and the more recently accreted terranes. To the west lie generally north–south-trending accretionary and collisional complexes that merged with the North American continent no earlier than the Middle Jurassic. Conversely, on the eastern side of the Rocky Mountain Cordillera the interpreted crustal types are more chaotically organized and they represent much older Archaean deformation.

Understanding these variations in the crustal architecture in the eastern foreland of the Rocky Mountains has great economic and scientific importance owing to the recent success in exploration activities in this region, such as the Cretaceous Western Inter ior Seaway. As a result of this, Getech has recently updated its crustal type interpretation of this area; these updates are based on potential field data, and derived depth-to-basement and depth-to-Moho estimates.

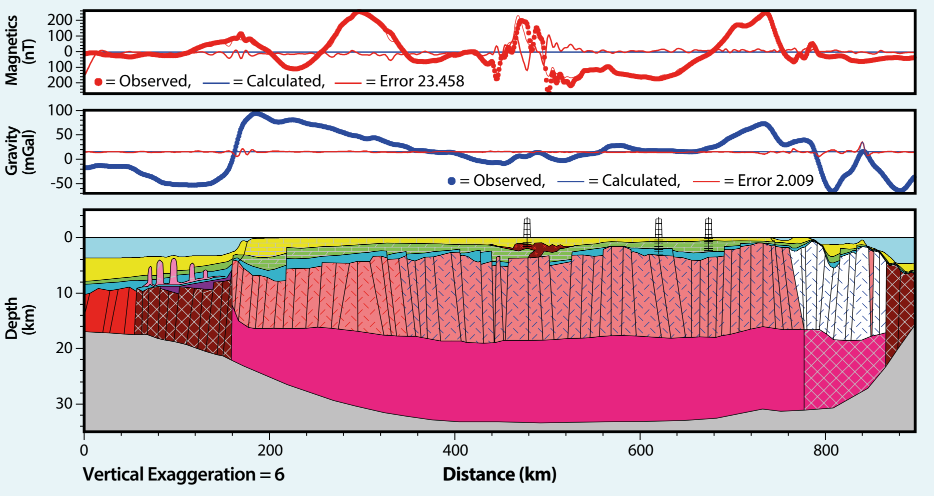
We interpreted a variety of crustal types in this region, including ancient continental fragments (e.g. Medicine Hat), ancient mobile belts (e.g. Vulcan Zone), cratons (e.g. Hearne Province), collisional complexes (e.g. Rimbey Arc and Chinchaga), thickened continental crust (e.g. Wabamum) and accretionary complexes (e.g. Buffalo Arch). The differences between these crustal types have an effect on basin development and evolution, and, therefore, have a significant impact on the hydrocarbon potential of a region.

Testing and refining crustal architecture

Gravity and magnetic data are used in conjunction with mapped geological outcrop, published profile (seismic) data and formation tops (from wells), alongside the structural elements, to test initial geological concepts in focused regions. With the shallower sedimentary section constrained (to varying degrees), representative solutions for the crustal thickness and physical properties can be modeled, and crustal boundaries can be confirmed or refined. The resultant 2D models can either confirm ideas of crustal types or suggest that other scenarios require testing.

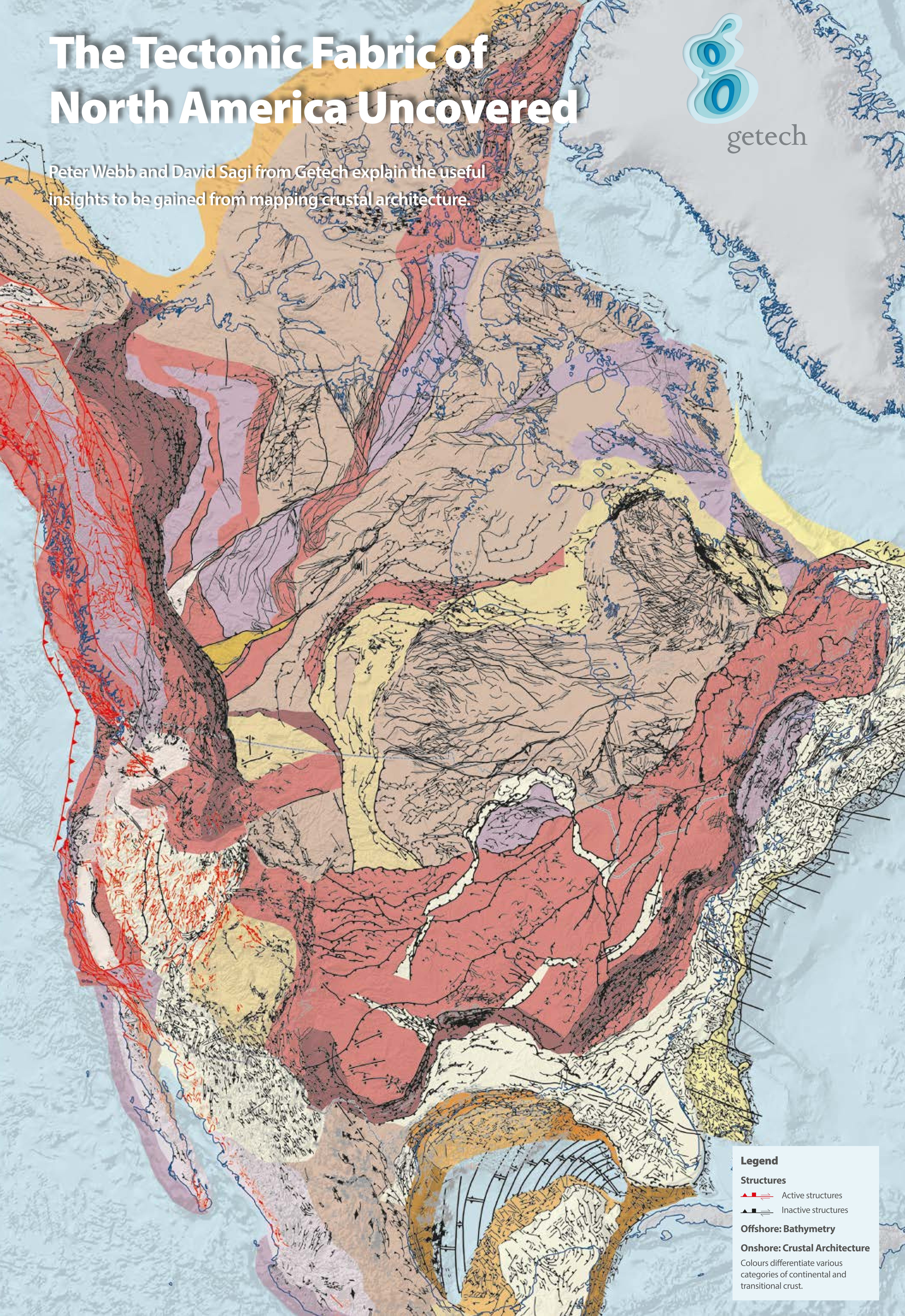
Focusing along a 2D gravity and magnetic model (chosen for the available controlling information as well as the interesting geological hypothesis) can enable certain questions to be answered (e.g. Has crustal thickening occurred? Has crustal thinning resulted in attenuated continental crust or hyperextended crust? Does the model only fit the constraints with an alternative crustal type? How much flexibility is there in the interpretation?). Answering these questions will provide a greater understanding of the regional area.

The final 2D models provide additional control of depth-to-basement and depth-to-Moho for the wider 3D inversion; thus, extending these concepts of crustal types away from the models and from other sources of seismic or well data control.



The Tectonic Fabric of North America Uncovered

Peter Webb and David Sagi from Getech explain the useful insights to be gained from mapping crustal architecture.



Crustal architecture describes the spatial and temporal distribution of crustal rheology, composition and geometry. It is these factors, along with the structural fabric, that dictate how the crust responds to changes in the stress field that will ultimately lead to basin formation, and the development and distribution of accommodation space, uplift and sediment supply.

In this article we look at how the crustal architecture is built up using the Getech workflows and how this is then applied to plate modeling and basin dynamics.

Underlying Data

Crustal architecture is defined by the composition and rheology of the crust, and these reflect its tectonic history. Crustal architecture can be identified from the surface and sub-surface geology, but also has a strong expression in potential field data, specifically gravity and magnetics. Gravity and magnetic data form the primary underlying datasets in the workflow described here, with hypotheses constrained by 2D seismic, gravity and magnetic profiling, well data and other observations. The first step is to build a detailed structural framework. Major faults can indicate the boundaries between crustal blocks of different types as far back as the Proterozoic; the faults are documented through an activation table linked to each structural feature which provides its evolution through time.

3D iterative inversion of potential field data is used alongside seismic and well data to generate grids of depth-to-basement and depth-to-Moho. Magnetic data are particularly useful for identifying the depth-to-basement owing to the large susceptibility contrast between basement rock and overlying sediment. Gravity data are preferred for depth-to-Moho because of the larger density contrast between crust and mantle. Together the two grids can be used to calculate crustal thickness, an essential part of crustal architecture.

Passive Margins

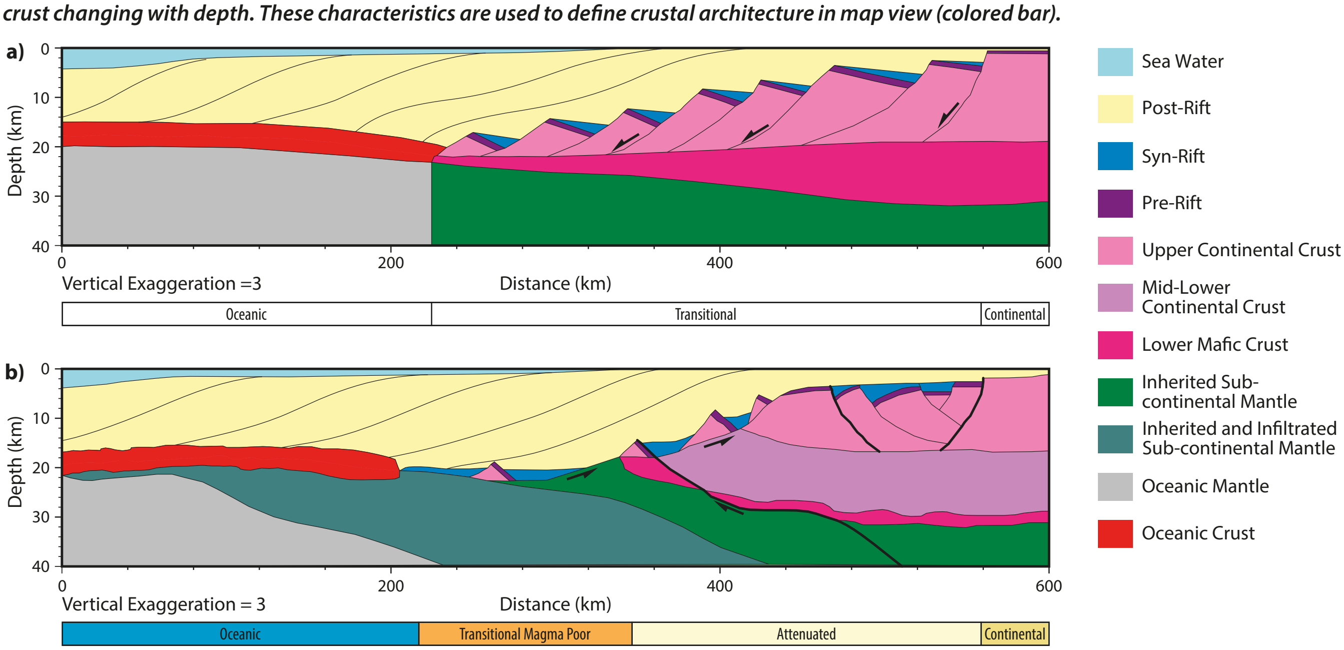
At passive margins the term 'transitional' is frequently used for crust that has been affected in some way by the processes of extension, but this covers a wide variety of processes and consequences – from attenuated continental crust, to underplated and intruded crust, to exhumed mantle. Getech's new classification scheme for crustal architecture at passive margins incorporates the latest scientific thinking for passive margin dynamics. A passive margin is no longer considered to be a simple transition from continental to oceanic crust with sharp linear boundaries identifying where oceanic crust starts. Geophysical techniques indicate a complicated transition involving one, or more, of the following: complex faulting, ultra-thin continental crust, depth-dependent stretching, voluminous volcanic addition, and exhumation of mantle peridotites and serpentines. Getech's Crustal Architecture Database identifies crust at passive margins in four domains: continental crust, attenuated crust, transitional crust and oceanic crust. Within the transitional domain there is subdivision into magma-rich, magma-poor or mixed-transitional crust.

Using Crustal Architecture

Crustal architecture assists when generating tectonic models of rifting; margin widths can be used to quantify the amount of continental extension prior to break-up. In continental areas, the crustal type and boundaries of Precambrian terranes are used to infer where crust has been stable for long periods and where crust has undergone compressional or extensional deformation in previous supercontinent cycles. Crustal architecture can also be used to identify smaller-scale features which do not directly affect the kinematics of a plate model. Changes in crustal type within the attenuated and transitional domains reflect changes in composition, density and thickness, which do not necessarily affect plate kinematics but are essential for basin exploration. Crustal architecture definitions have also allowed for the identification of new basins in underexplored areas, such as the Horn of Africa.

When combined with high-resolution structural coverage and detailed tectonic models, crustal architecture becomes a powerful tool for understanding both the nature of the crust in complex areas and the regional tectonic setting of basins. It is a fundamental component to better understand how mantle processes influence heat flow and vertical motions in extensional settings. ■

Traditional (top) and modern (bottom) conceptual models of passive margin geometry. In cross section the colors refer to the nature of the crust changing with depth. These characteristics are used to define crustal architecture in map view (colored bar).



Resolving Uncertainty:
The Importance of Mud Logging

NEIL CARDY,
Baker Hughes

Mud logging is vital for rig safety and gives the first indication of the potential success of a well, but its role is not well known or understood, especially by people outside drilling operations.

Thirty years ago, when I first joined the oil industry, a colleague told me that after telling his bank manager about his new job as a mud logger, the only question was "where are the trees you're going to be cutting down?"

For many geologists working in the oil industry, their introduction to the oil field has been as a mud logger, logging geologist, formation evaluation geologist or surface logging geologist – a multitude of titles for what is essentially the same job. Yet, for a role that is vital for maintaining the safety of the rig, and gives the first indications of what formations are being drilled and of any shows, it is not that well understood, especially by people outside drilling operations.

In truth, I was not that much better informed when I was first interviewed for a mud logging job. I knew it involved looking at and describing rocks on an oil rig, and I had spent the last few years describing rocks, so how hard could it be? A few weeks later, looking through a microscope at what appeared to be an undistinguishable mass of soft grey lumps which I had to describe in the next couple of minutes before dashing off to catch another sample, I began to understand the answer.

Therefore, the aim of this article is to try and explain what mud logging is, why it started and how it developed through to today. Most importantly, I want to explain why I think it is such a valuable introduction to the oil industry which can lead on to a range of careers.

The History of Mud Logging

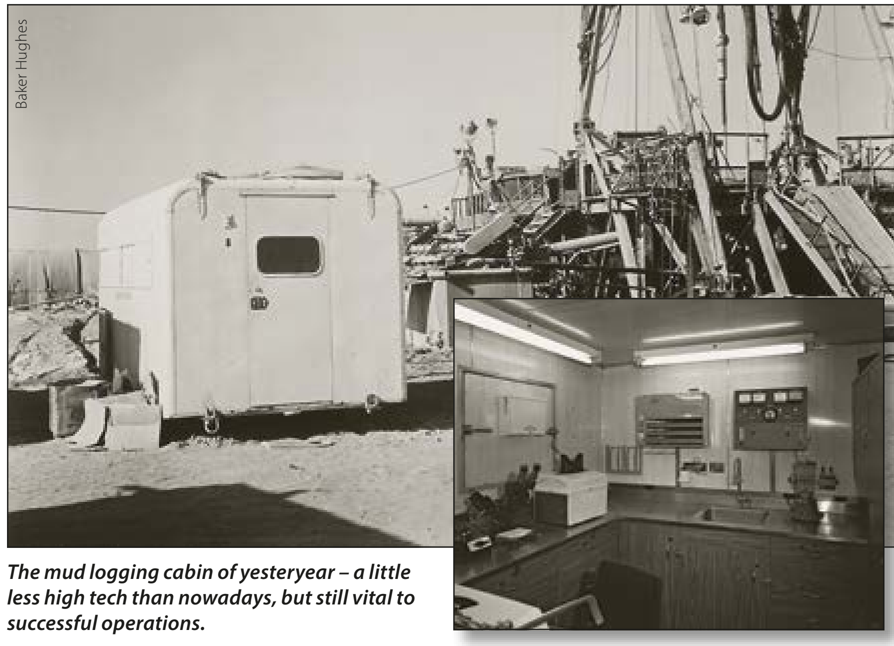
So where did mud logging begin? In the early days of the modern oil industry, wells were drilled where there was evidence of hydrocarbons, such as natural oil seeps, and drilled until oil was found or the money ran out. As the industry developed, geological knowledge was increasingly used to identify potential oilfield locations, but the process of drilling a wildcat well was still essentially blind. The early wellsite geologists had little in the way of evaluation tools and would work by 'sitting the well' – literally sitting and observing the drilling mud returning to surface, looking for an iridescent surface sheen indicating oil, or bubbles and foam indicating gas.

In the mid-1920s the first 'gas trap', a device attached to the end of the flow line to separate the gas from the mud for analysis, was developed. In the early thirties, ultraviolet light started to be used to detect oil on cuttings by fluorescence. Later that decade it was realized that the returning mud and cuttings could be correlated with depth, by measuring the circulation or

Baker Hughes

lag time of the drilling fluid. In 1940, J. T. Hayward presented a paper entitled 'Continuous Logging at Rotary-Drilling Wells', which describes a commercial mud logging unit, still recognizable now.

Today the job of the mud logger has become much more comprehensive and demanding. It is still based around formation evaluation and gas monitoring, but now also includes operations and fluids monitoring.



The mud logging cabin of yesteryear – a little less high tech than nowadays, but still vital to successful operations.

Formation Evaluation

Geology remains the foundation of all mud logging services. The mud loggers are the first and in some cases the only people who actually look at the rocks being drilled. Until recently, rigsite evaluation of cuttings had not changed appreciably from the 1940s.

The loggers collect the cuttings from the shale shakers, wash and sieve them to remove any drilling mud and oversized cavings (rock fragments from above the bit). The washed samples are then examined with a microscope for lithological classification and percentages, and under ultraviolet light for indications of oil shows. This analysis is usually done quite quickly, and is dependent on the knowledge, skill and experience of the geologist looking at the sample. As such, it is a subjective, qualitative analysis, which when done by an experienced geologist who is familiar with the local geology can be invaluable.

Over the last few years there has been an increasing interest in using more advanced laboratory analytical methods at the rigsite. Technologies such as x-ray fluorescence and x-ray diffraction give a quantitative analysis of the elemental composition and minerals present in the cuttings sample. Combined with techniques like pyrolysis to analyze the type, origin and maturity of hydrocarbon material in the cuttings, it is now possible to get a detailed quick analysis at the rigsite in order to identify potential zones of interest.

Gas Monitoring

From the earliest days, wellsite geological analysis involved looking for evidence of gas. Once the gas trap came into use, the drilled gas was analyzed with a simple 'hot-wire' or Wheatstone bridge detector, which gave a basic indication of the percentage of combustible gas.

Throughout the 1950s and 1960s gas detection improved and by the 1970s gas chromatographs had become compact and reliable enough to be used at the rigsite. Typically methane, ethane, propane, butane and pentane are identified, but this technique can also be used to identify higher weight hydrocarbons. More recently, mass spectrometry is being used in mud logging units, allowing the identification of hydrocarbons as well as other gases such as helium, carbon dioxide, and hydrogen sulfide.

Gas is usually contained in the pore spaces of the drilled rock, the gas seen in low permeability formations such as clays and shales giving a background value. When a more porous, permeable formation such as sandstone is drilled, gas levels will increase if it contains hydrocarbons. This indicates that hydrocarbons are present, but not how much or what kind. However, by examining the ratios of the gas chromatograph data we can identify what types of hydrocarbons are present in the reservoir and also identify features such as the gas-oil contact.

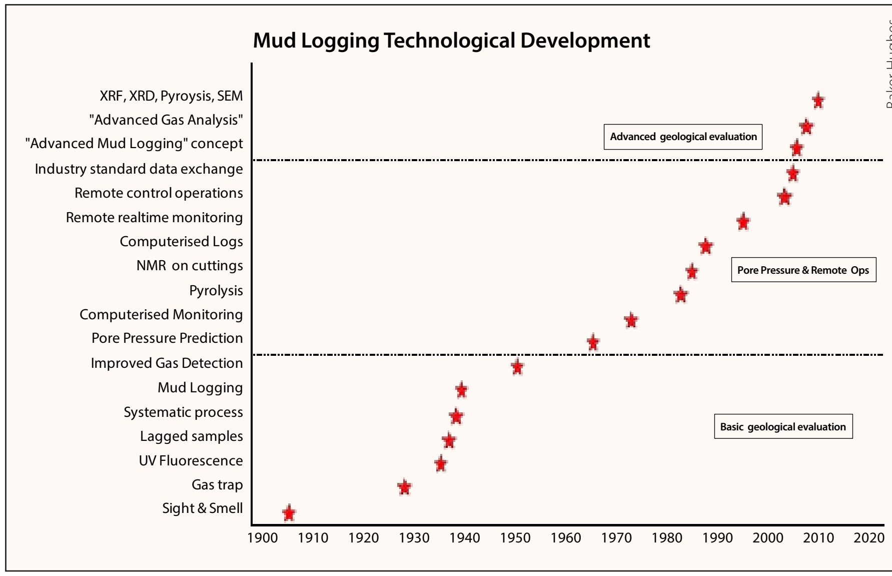
If the mud weight in the borehole is too low to counter the formation pore pressure then gas will travel into the annulus if the formation is permeable enough. There is the risk that in an impermeable formation such as a shale or mudstone the pore pressure can increase above the mud weight. If a permeable formation such as sand is

Washing and sieving the cuttings.

Lithological classification by microscope.

then encountered the fluids within the sand can flow into the well and cause a 'kick', which, if not controlled, could result in a blowout.

We therefore need to identify increases in formation pore pressure as quickly as possible. During the 1960s it was realized that there was a relationship between porosity and depth under normal compaction conditions, and that increased porosity resulted in an increase in pore pressure. This resulted in a variety of techniques being developed to analyze the drilling parameters in order to identify changes in porosity and so pore pressure. As the one place on the rig where the geological and drilling information was collected and analyzed, it was natural that pore pressure evaluation became another mud logging service, albeit run by specially trained engineers. Today, pore pressure prediction is a specialist technical discipline using formation evaluation data such as resistivity and acoustic data rather than drilling data, and is usually run by experienced specialists, many of whom started their careers as mud loggers (see *GEO ExPro*, Vol. 12, No. 1).



Operations Monitoring

The mud logging unit described by Hayward in 1940 includes instrumentation to monitor the basic drilling parameters: hole and bit depth, rate of penetration and the pump strokes (essential for tracking the lagged samples). These can all be seen in any mud logging unit today, along with drilling parameters such as hook load, weight on bit, surface torque, pump pressure, return flow rate and mud pit levels. The mud logging unit is therefore the one place on a rig where all the drilling and geological information is seen and recorded.

Originally the sensors were simple analog devices such as the block or kelly height sensor which calculated the rate of penetration using pressure changes from a water bottle fixed to the kelly or travelling block hydraulically attached to the drill floor. These basic measurements have now been replaced with more accurate reliable digital systems.

The engineers continually monitor, record and analyze the sensor data. All operations are recorded and displayed both on the rig and back in town. This allows the drilling team to watch operations and identify shifts in trends that could indicate problems.

As operations monitoring has grown it has led to the development of data engineers – experienced mud loggers who have moved from the 'wet end', catching, preparing, and examining the cuttings, to the 'dry end' of the unit, where they concentrate on monitoring the equipment and operations. Data engineers perform an increasing amount of drilling engineering, running calculations for drilling hydraulics, torque and drag and drilling exponents such as DXc and Mechanical Specific Energy.

As they monitor all the operations on a drilling rig from spudding, drilling, tripping, casing, cementing and testing a well, the data engineers get a far wider understanding of rig operations than most service company engineers. In consequence, they are highly sought after for a multitude of other jobs from mud, application or drilling engineer to company representative.

In recent years the need to reduce the number of people at the rigsite, especially offshore, has resulted in the growth of remote operations. By using high speed data connections a well data engineer can now sit in an office in town or in a client's remote operations centre working in an integrated team with the client and other service companies.

Safety Monitoring

One of the most important functions of a mud logging unit is safety monitoring. As the unit monitors data from all around the rig, including pit levels, return flow and gas in the mud (toxic gases such as H_2S as well as hydrocarbons), mud loggers have always been responsible for spotting potential dangers.

Decreases in either the return mud flow or the mud pit levels could be the first signs of mud losses downhole, while increases could indicate a potential kick. Continuous gas monitoring enables the mud loggers to have the first indications of high levels of explosive or poisonous gas. They must remain vigilant, quickly identify potential problems and inform the driller and company representative. It is therefore a common requirement that the unit is manned continuously.

In conclusion, mud logging is an essential part of any drilling operation, combining practical geology, drilling knowledge and engineering to help ensure a safe and successful well.

In this article, I have shown how mud logging offers a great opportunity to gain a wide knowledge of oilfield drilling and geology and can act as a stepping stone to a range of careers. However, many loggers find a rewarding and fulfilling career within mud logging itself, either in the field, in operations coordination, training or other roles and who bring a wealth of experience to help develop the next generation of oilfield geologists. ■

MCG DATA FOR THE 23rd ROUND

- Barents Well Tie - Eastern Extension
- Russian Reprocessed Data
- Super High-Resolution Hoop

M C G

Barents Well Tie Eastern Extension

The 2014 extension of the BWT data set is 3 600 km and goes through the main structures in the Norwegian Barents Sea South-East. The Barents Well Tie data is acquired with a 8 100 m streamer, 9 seconds recording length and is run through modern PSTM processing.

Russian Reprocessed Data

In 2014, 3 300 km of Russian vintage data was reprocessed by SMNG and tied with the Norwegian Barents Well Tie data. These reprocessed data ties known discoveries and structures in the Russian Barents Sea and will give you a tie from Shtokman in the East to the Tromsø Basin in the West.

Super High-Resolution Hoop

The Super High-Resolution Hoop data set consists of 5 620 km of high-resolution 2D seismic data acquired with a 2 000 m streamer in a 2 × 8 km grid. The 1 ms sampling rate is kept throughout the broadband processing which gives detailed imaging of the shallow Cretaceous, Jurassic and Triassic prospects. The data is suitable for prestack analysis, AVO analysis and inversion and will enable you to identify and to do final ranking of prospects in a cost efficient way.

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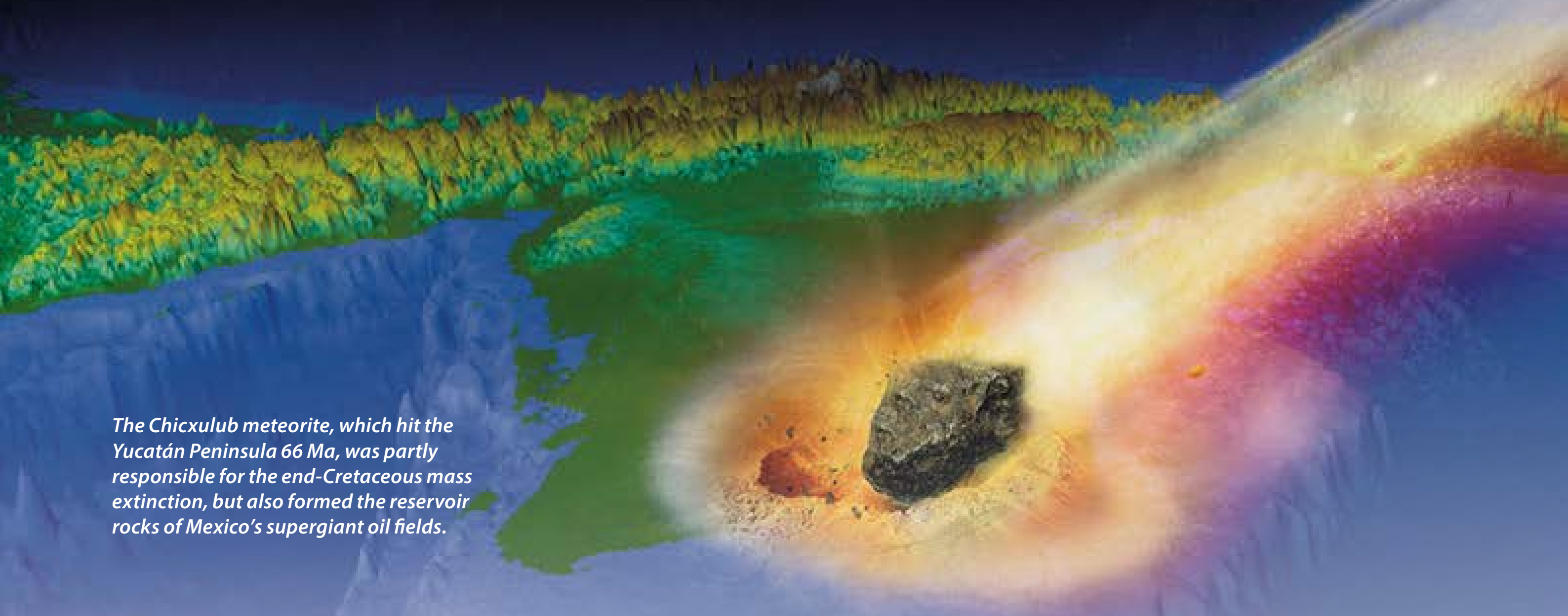
Vast Potential: Mexico’s Offshore Ronda Uno

An insight into some highlights of the offshore hydrocarbon potential available in almost virgin exploration territory.

IAN DAVISON, EOIN O’BEIRNE, THEODORE FAULL and IAN STEEL, Earthmoves Ltd.



The Chicxulub meteorite, which hit the Yucatán Peninsula 66 Ma, was partly responsible for the end-Cretaceous mass extinction, but also formed the reservoir rocks of Mexico’s supergiant oil fields.

Earthmoves

The Mexican Comisión Nacional de Hidrocarburos (CNH) announced its first ever licensing round (Ronda Uno) in August 2014, with a view to bolstering exploration investment, especially in the offshore region, but also onshore where unconventional resource exploration has been initiated in the Burgos Basin.

The round is phased, with shallow water blocks in the South East Basin being offered first, and data packages are now available. The CNH is looking for participation with a minimum bid that must comprise at least two commitment wells on the first phase of released blocks. Despite these requirements the round is expected to be highly competitive because of the prospective acreage on offer.

The Ronda Uno blocks are scattered throughout most of the offshore basins in Mexico. A vast amount of 3D seismic data now covers most of the prospective areas offshore Mexico, so future exploration will be accelerated by access to these data sets (Figure 1). There are very few wells in the deep offshore, including fewer than 10 wells in water depths greater than 1,500m, so this is almost virgin exploration territory in basins with vast petroleum potential.

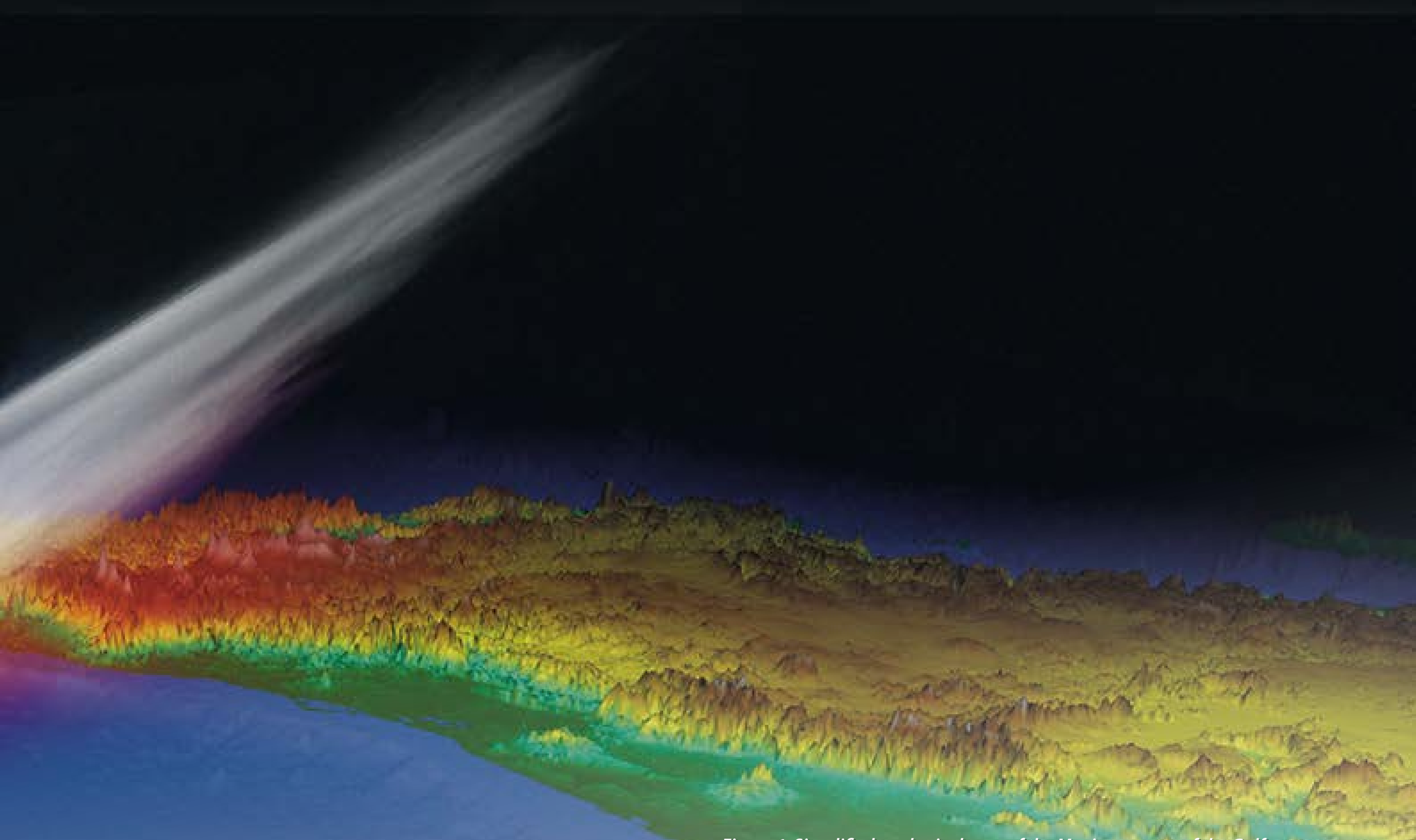
We will now look at the geology and potential of the prime areas offered in this round.

Perdido Fold Belt

Some outstanding blocks are being offered in the Perdido Fold Belt, where Pemex has made five new light oil discoveries in the last two years, since the ground-breaking Trion-1 discovery in August 2012, which is believed to contain 350–500 MMbo in place.

The offshore Perdido Fold Belt was produced by downslope gravity gliding during the Oligocene, which followed the Laramide (Hidalgoan) orogenic mountain-building event in the latest Cretaceous to Paleogene. The eastern Sierra Madre Fold and Thrust Belt created a topography probably 3–4 km high onshore along the western shores of the Gulf of Mexico, which destabilized the margin. A 4–5 km thick section of sediment had already been deposited on top of the Callovian-age salt before folding, which occurred after deposition of basin floor stacked channel fan complexes with turbidite sandstones in the Eocene and early Oligocene Wilcox Formation. Reservoirs can therefore be expected to be present across the crests of some of the fold structures. The reservoirs in the Trion-1 well were reported to have 18–25% porosity, 250 mD permeability, and capable of flow rates of 10,000 bpd, although to our knowledge no drillstem tests have been performed to date.

All of the Perdido blocks currently offered in Ronda Uno sit in the frontal part of the fold belt where the folds detach on autochthonous Callovian salt. The main source rocks for the light oil is believed to be the Tithonian-age Pimienta Formation, but could also be possibly derived from



Kimmeridgian-Oxfordian marine shales which are buried to 5–6 km depth. Localized extensional faults were generated in the outer arc area of the fold crests, which provide migration pathways for the oil into the overlying Wilcox reservoirs.

Burgos Basin

Farther up dip, in the Burgos Basin, the same Wilcox play is predicted to occur below a thick canopy (3–4 km) of allochthonous salt (Figure 2). Seismic imaging is good enough to identify large sub-salt folds.

The Jurassic source rocks are buried to depths of 8–9 km below seabed, which, at first glance, would suggest the basin would be gas prone as the source rocks are overmature, but the extrusion of the salt in the Miocene could have cooled down the sub-salt section since this time. This is because salt is approximately three times more thermally conductive than shale at shallow depths, and the geothermal gradient through the salt will be only 8°C/km. Hence, the Tithonian and Cenomanian-Turonian source rocks may still be mature for light oil generation, even at this great depth.

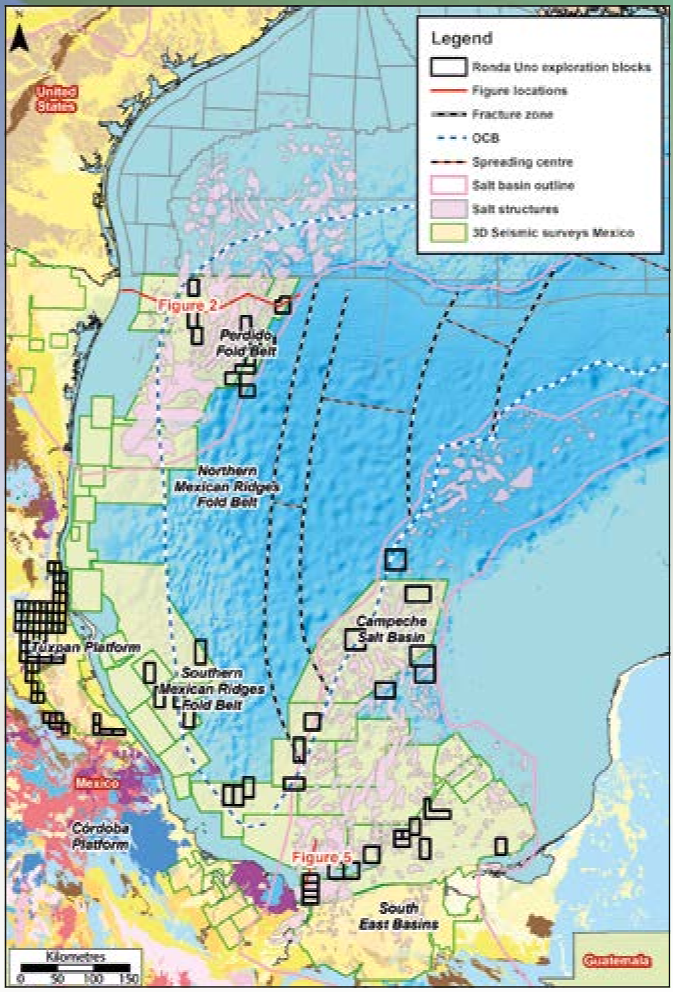
Sub-salt targets will be located 6–7 km below seabed, but the reservoirs may be highly overpressured, which may have preserved some porosity in the deeply buried Wilcox reservoirs.

Three blocks have been offered in this basin, which are all thought to have allochthonous salt sheets present.

Mexican Ridges Fold Belt and Veracruz Basin

The Mexican Ridges Fold Belt and the Veracruz Basin were also affected by the important gravity gliding which started in the Oligocene with updip listric faulting and downdip folding and

Figure 1: Simplified geological map of the Mexican sector of the Gulf of Mexico, showing the location of the Ronda Uno blocks and the large amount of 3D seismic coverage.



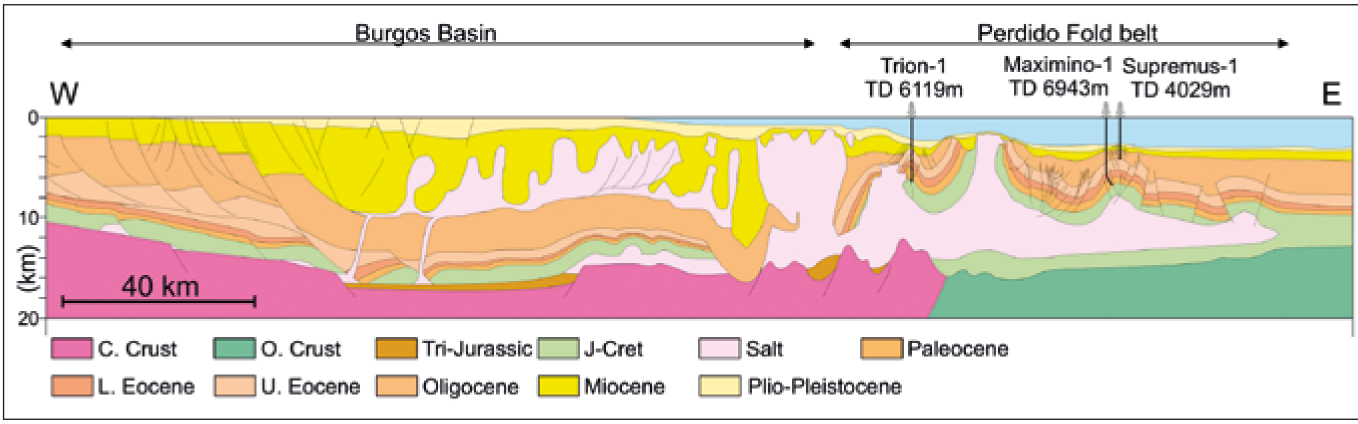


Figure 2: Cross-section through the Burgos Basin and Mexican Perdido Fold belt, showing some of the important new discoveries.

thrusting. The gliding sediments were detached on a Paleogene shale horizon which is probably still overpressured, as gliding is still occurring at the present day, causing important folding of the seabed. This raises a question as to whether an oil play will be present in this basin, because the Tithonian and Cenomanian-Turonian age oil-prone source rocks lie below the detachment which probably acts as a regional seal horizon. Oils trapped below the detachment would migrate landward to the shelf break where extensional listric faults provide a migration pathway to roll-over anticline structures. Surface oil slicks are present along the extensional fault trend, but there is a notable absence of surface oil slicks in the fold belt.

Campeche Salt and the South East Basins

The offshore Campeche and South East Salt Basins cover a vast area (230,000 km^2) of the south-east offshore area. The Callovian-age salt is the conjugate to the USA and Burgos Basin salt, with the two salt basins subsequently separated by ocean floor spreading which began in the Late Jurassic. The basin is bounded to the east by the Yucatán Peninsula, a continental block which rotated anticlockwise by at least 30° during ocean formation.

The oil is quite heavy (10–25° API) in the Cantarell and surrounding areas, which is believed to be due to early expulsion of the oil from the Tithonian source rock, rather than biodegradation. Folded and thrusted Mesozoic carbonates are present throughout the Campeche salt basin and the Cantarell type play has not been tested in the deepwater so far.

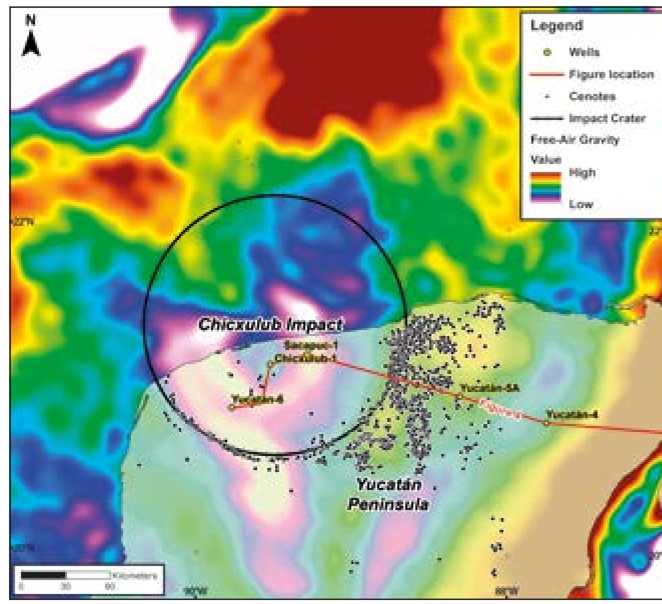


Figure 3: Map of the Yucatán Peninsula and the Chicxulub meteorite impact. Cenotes are natural sinkholes resulting from the collapse of limestone bedrock due to meteorite impact.

The deepwater Campeche Salt Basin has been hardly explored to date, with only two ultra-deep water (>1,500m)

The Chicxulub Meteorite Impact

The Chicxulub meteorite hit the Yucatán Peninsula and the shallow offshore carbonate platform about 66 million years ago. The bolide is calculated to have been approximately 10 km across, and it gouged out a crater 177 km wide and up to 1,400m deep, causing ejection of some 32,000 km^3 of rock (Figure 3). The impact produced a melted layer up to 690m thick, which was originally identified as volcanic andesite lavas when it was first drilled (Figure 4). The impact induced a massive shock wave that caused destabilization of the carbonate platform edges, and this resulted in catastrophic collapse with debris flows of carbonate and sandstone blocks, reaching up to 400m in thickness (Tanambra Formation). The debris flows were then reworked by several rebounding tsunami waves, and finally a very thin layer of iridium-rich fall-out dust was deposited (Grajales-Nishimura et al., 2000).

Not only did the Chicxulub meteorite play a part in the mass extinction of the dinosaurs at the end of the Cretaceous, but it also formed the reservoir rocks of the supergiant oil fields in Mexico (Cantarell, 40 Bboip; and Ku-Maloob-Zaap, producing 850,000 bopd). The collapsed breccias can be found all around the Yucatán peninsula and also occur in Cuba. The intrinsic permeability and porosity of the Tanambra breccias is not particularly high. However, another phase of compression affected the Campeche and South East Basins provoked by the initiation of the Cocos-Nazca Mid Ocean Ridge spreading center and the Galapagos Hot Spot in Mid-Miocene times (ca. 16 Ma). The folding and thrusting (Mitra et al., 2005) fractured the carbonate breccias, and uplifted them near to sea level so they were also leached and karstified, to enhance their reservoir potential. Several Ronda Uno blocks are located along the Yucatán shelf edge, where the breccias may also be present.

wells, both drilled in 2014. Yoka-1 was drilled in the frontal folds along the western edge of the salt basin and was reported to be a sub-commercial gas discovery and Lakmay-1 was a dry hole drilled in the center of the salt basin. There are many allochthonous salt sheets in Campeche and the South East Basin, but to our knowledge no sub-salt wells have been drilled so far. The allochthonous salt sheets were mainly extruded in mid-Miocene times and then folded, with compression continuing to the present day.

Rapid deposition of Pliocene to Recent clastic sediments further enhanced the deformation of the salt sheets, forming deep minibasins in the South East Basin; up to 5 km of sediment has been deposited in the last two million years. The corrugated base and top of the salt sheets have different shapes which makes single azimuth 3D seismic imaging very difficult, and the underlying structures are poorly imaged (e.g. Gomez-Cabrera and Jackson 2010, Figure 5). Better quality multi- or wide-azimuth 3D seismic data will be required to image the structures below the salt sheets to image the traps and identify if mid- and early Tertiary sandstone reservoirs are present. Fourteen of the blocks being offered in the South East Basin are dominated by deformed allochthonous salt sheets.

The blocks are also in a region of large Miocene channel systems which transported sand from the uplifted Chiapas massif and fold belt and this area is considered to have excellent potential for sub-salt plays in shallow water.

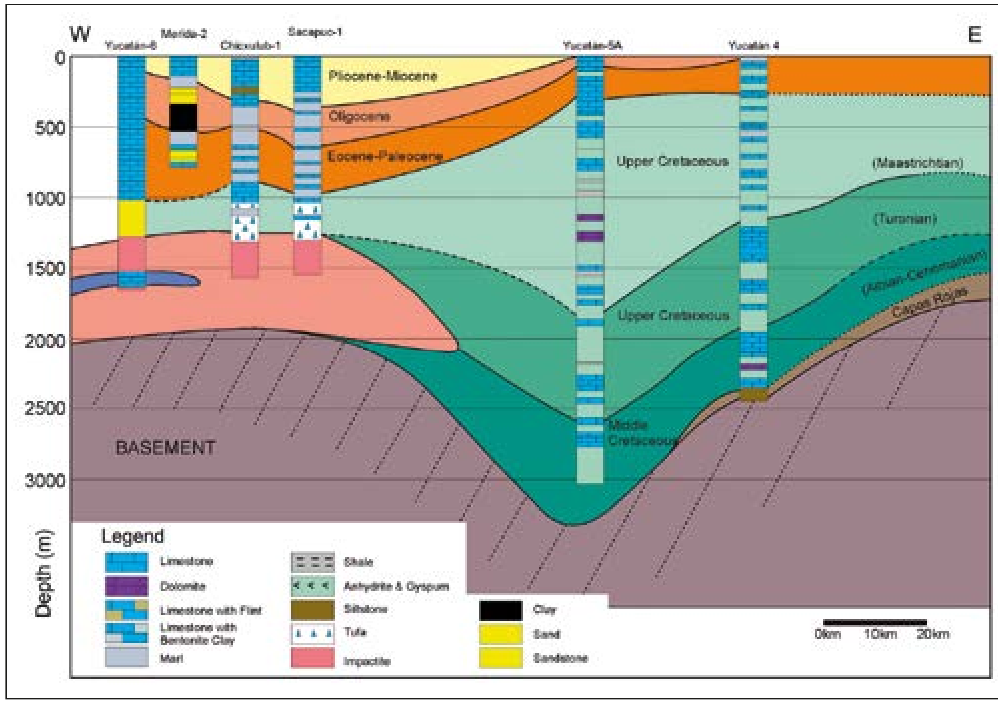


Figure 4: Cross-section across the Yucatán Peninsula. See Figure 3 for location (From Lopez Ramos, 1975).

An Historic Event

The opening of the Mexican offshore for exploration is a historic event and undoubtedly the better blocks in the opening Ronda Uno will be highly contested. A recurring theme in many of the offshore areas is the presence of large allochthonous salt sheets which have complex deformed geometries. The use of new seismic acquisition techniques using multi-azimuth,and/or wide-azimuth shoots will hopefully reveal much more of the underlying structures and lead to some bold wells testing these large sub-salt plays in the coming years.

This article stems from a regional multi-client study of the hydrocarbon potential of Mexico; further details can be obtained on the Earthmoves website.

References available online at www.geoexpro.com ■

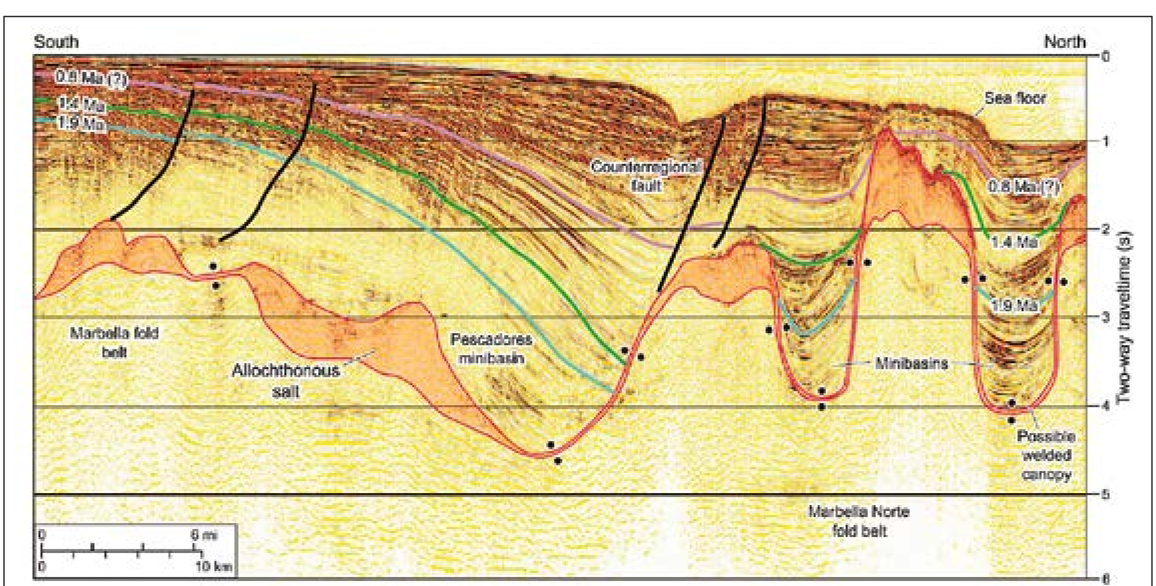


Figure 5: Cross-section through the South East Basin. (From Gomez-Cabrera and Jackson, 2009, AAPG©2015.)

Reducing Risk in Offshore Planning and Development

Ultrahigh resolution 3D seismic methods not only bridge the gap in continuity between the shallow subsurface and seafloor, but also the gap in communication between geoscientists and engineers.

BRIAN BROOKSHIRE, JR., LARRY SCOTT, NCS SubSea

Responsible development of offshore hydrocarbon resources demands an in-depth understanding of the risks associated with shallow geohazards. These hazards include seafloor and shallow subsurface geologic features such as shallow gas and shallow water flows, mass transport complexes, shallow faulting, shallow buried channels, mud volcanoes, gas hydrates and mounds, incompetent sediments, and over-pressured zones. Particularly, as exploration and development have moved into deeper and more complex offshore settings, the potential impact of failing to understand and mitigate these hazards has increased dramatically. Often, these failings are the result of economic factors, and the associated inefficiency of using multiple imperfect tools to produce a composite image of the intermediate depth subsurface and seafloor. Here, we propose a different strategy, utilizing the relatively new tool of ultrahighresolution 3D seismic (UHR3D) for geohazard delineation and characterization pertaining to planning and offshore development.

Legacy Geohazard Methods

Historically, the industry has widely embraced the combined use of conventional 3D seismic data reprocessed for high resolution, high-resolution 2D seismic and AUV (autonomous underwater vehicle) mounted sensor suites (such as chirp subbottom profiler, dual-frequency side-scan sonar, or multibeam echosounder) for the planning and site-specific/drilling/installation/as-built stages of development. The AUV provides excellent, sub-meter scale, bathymetric, seafloor texture and very shallow subsurface information. However, the sub-bottom profiler is still a 2D tool with a widely variable and limited penetration in the order of 5–150m. The highresolution 2D provides a nice profile, usually down to 2 seconds or more, but these data are inadequate and potentially dangerous since any seafloor or subsurface features with cross-line dip will be incorrectly located and imaged. Moreover, the typical line spacing of conventional 2D geohazard surveys (~150m to 300m) is so coarse that the geohazards of interest may not even have been recorded, much less imaged. And finally, the reprocessed 3D, though enhanced in frequency content, is often distilled from data collected at low sampling rates and large bin sizes. Here, in many cases, significant hazards are blurred, inscrutable or simply unresolved.

The overarching problem with the above methodologies is continuity, both spatially and in resolution. None of these tools, alone or in combination, provide a complete, continuous

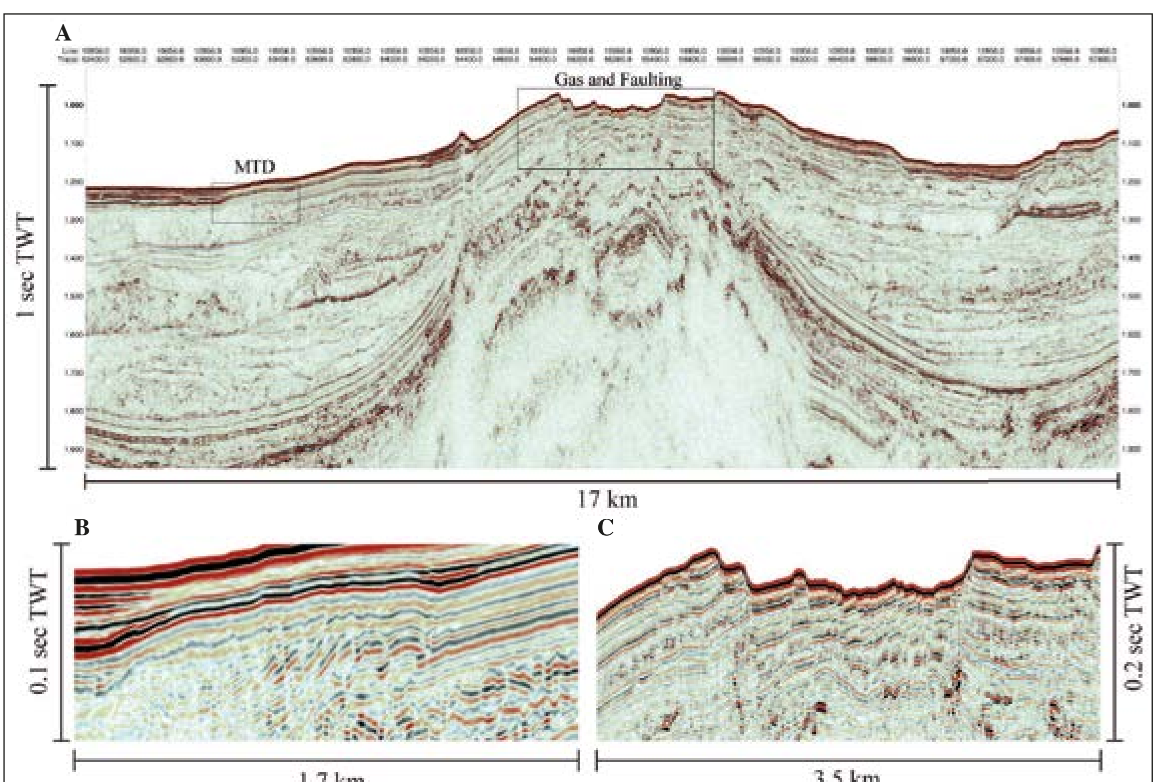


Figure 1:

A) Representative profile from the preliminarily processed SAFE-BAND Phase 1 3D cube. Two areas of particular interest are highlighted;

(B) Blow-up illustrating the upper horizon of a mass transport deposit (MTD);

(C) Blow-up illustrating successive faulting and graben features forming an intra-slope/collapse basin over the top of a salt feature. Note the small, discrete gas anomaly at around 1.130 seconds TWT.

picture from the shallow subsurface through to the seafloor. This is of paramount importance to the interpreter for accurately characterizing hazards, but almost as important, this complete picture is essential in creating the visualizations and products necessary for effective communication between geoscientists and engineers.

UHR3D provides the solution to the issue of continuity. It comprehends the 3D nature of both the seismic wavefield and the geologic features of interest, thereby enabling the accurate imaging of these features in their true subsurface locations. And, as an added benefit, this technology yields hydrographic quality bathymetry which rivals that of a ship-mounted multibeam echosounder, and is quite suitable for planning, and in some cases, development.

Gulf of Mexico UHR3D

As an example of this type of dataset, a consortium consisting of NCS SubSea, Geotrace, and Spec Partners recently conducted a regional UHR3D survey in the central Gulf of Mexico near the four corners area of Alaminos Canyon, Mississippi Canyon, Ewing Bank, and Green Canyon (Figure 2). This survey, known as SAFE-BAND, was acquired with P-Cable technology employing an 18 x 100m streamer spread with a group interval of 6.25m and a cross-line spacing of 12.5m. This configuration, totaling 288 receiver groups, yielded four-fold coverage at a shot spacing of 12.5m with a natural bin size of 3.125m x 6.25m. The data were collected with a 0.25 millisecond temporal sampling interval, and were later subsampled to a 0.5 millisecond interval during processing.

The fine detail that UHR3D is able to image in this complex geologic setting is particularly impressive given the limited offset range of the recorded data, which can lead to illumination issues for steeply dipping events. This offset limitation precludes the measurement of seismic velocities from the recorded data, and as a result, stacking and migration velocities must be obtained from an external source – in this case a velocity model developed by Geotrace using check shot data. The quality of the imaging results obtained using this velocity model validates the soundness of this approach and the suitability of this type of velocity data for ultrahigh resolution imaging applications.

Although processing of this dataset is still underway, preliminary time migrated results show an astonishing level of detail and clarity in imaging the shallow subsurface geology and the seafloor geomorphology. Of particular interest are the shallow faulting, shallow gas, mass transport deposits and fluid expulsion features.

Figure 1 shows a broad-scale representation of the complex subsurface geology with blow-ups illustrating the high resolution in which mass transport deposits, gas and faulting are resolved.

Figure 3 illustrates the subsurface and seafloor expressions of multiple fluid expulsion features. This figure presents five hypothetical stages of maturity resolved in the preliminary SAFE-BAND data. The two upper images (A and B) represent two portions of the interpreted seafloor horizon picked at the first zero crossing from negative to positive. These sections of seafloor lie immediately above two areas of salt diapirism,

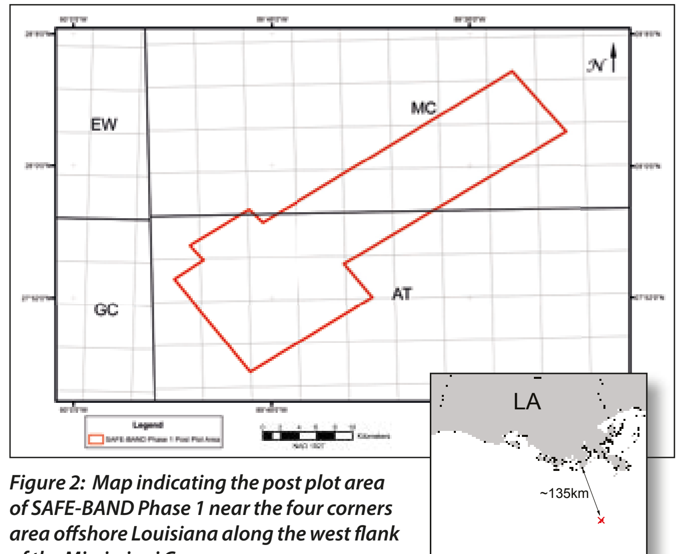


Figure 2: Map indicating the post plot area of SAFE-BAND Phase 1 near the four corners area offshore Louisiana along the west flank of the Mississippi Canyon.

and highlight not only the fluid expulsion features, but also fault scarps and very subtle drainage pathways. From left to right, figures 3C through 3G represent mound initiation, rapid flux/mud volcanism, hydrate formation and free gas, exposed hydrate with nearly breaching free gas and, finally, collapse. The definitive nature and exact flux level of these features is still the subject of ongoing research. However, these features certainly present a multi-faceted engineering concern in regard to both seafloor stability and gas-charged, over-pressured subsurface zones. In addition to the engineering concerns, the seafloor geomorphology expressed here is almost certainly prime habitat for chemosynthetic communities which must be avoided. Accurately delineating and characterizing this type of feature, and the wide range of variability, is critical for successful subsea planning and development.

Economic Benefits

Beyond the scientific merit of this technology, economic benefits also come into play. The acquisition costs of UHR3D are roughly equivalent to deepwater AUV acquisition or conventional 2D high resolution seismic acquisition. There are many scenarios, especially in the planning stages for lease acquisition, well placement and pipeline routing, that sub-meter scale, AUV-acquired, hydrographic data is overkill. However, the sub-bottom penetration is insufficient to illuminate the subsurface hazards that may pose an eventual failure risk. In these cases, such as intermediate to deepwater pipeline route assessment surveys, UHR3D may be the perfect and most economical tool. As opposed to the combination of AUV and 2D seismic data, UHR3D provides a three-dimensional swath of coverage penetrating to well beyond the depths necessary for successful assessment of route viability. The relevance of UHR3D for such applications is infinitely enhanced by the availability of real-time binning and on-board, near real-time geophysical QC and preliminary imaging products such as near trace gathers, brute stacks and seafloor arrival to echosounder reconciliation. With these products available, the client representative, party chief and lead geoscientist can make on-the-fly decisions about further route development while on site. And, given the swath coverage of UHR3D, the route

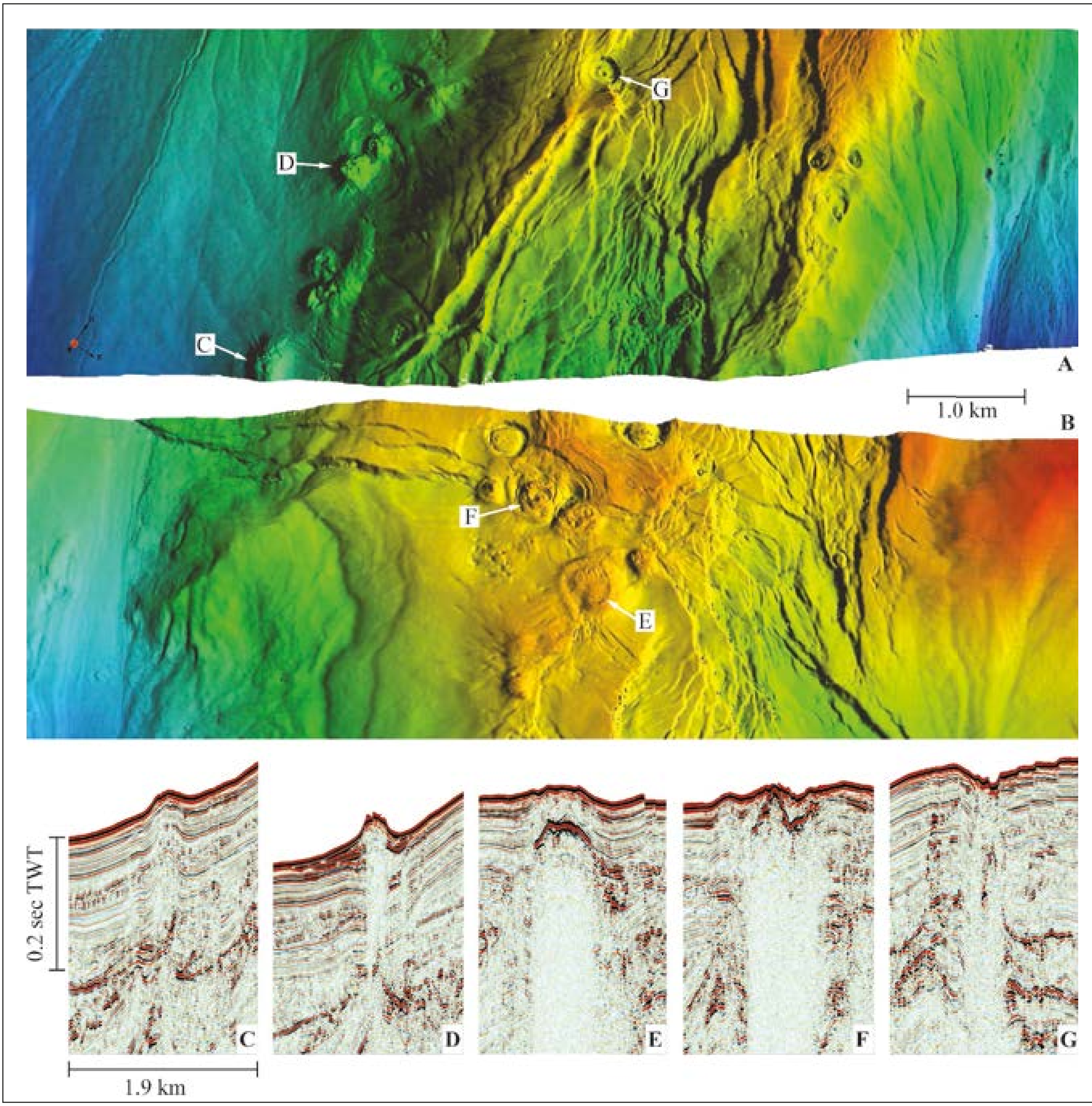


Figure 3: A, B – Portions of the interpreted seafloor horizon taken from the south-west (A) and north-east (B) portions of the SAFE-BAND Phase 1 area (see Figure 2). Area A corresponds to the salt feature imaged in Figure 1 A and C. Five features are designated by letter with a corresponding profile presented below. C – Expulsion mound initiation. D – Rapid flux/mud volcanism. E – Hydrate formation and free gas. F – Exposed hydrate with nearly breaching free gas. G – Collapse feature.

development can be undertaken efficiently and with minimal further passes beyond the initial route corridor.

The same concept of practical and economic suitability also applies to large-scale lease surveys in intermediate to deep water. Here again, AUV level hydrographic precision is costly, unnecessary, and does not paint a complete picture, requiring the addition of reprocessed 3D and/or highresolution 2D seismic. In this scenario, UHR3D can provide all of the data necessary for planning, and in many cases, can take the place of further AUV and 2D seismic surveys often necessary for development. UHR3D data also provides a complete, 3D regional perspective allowing for easy correlation between successive well locations.

Currently, there are very few major operators reaping the benefits of UHR3D. However, as more geoscientists and engineers are exposed to this type of data and the communication it fosters between them, the tide will ultimately turn, and UHR3D will become the norm. There is no substitute for the continuity of data and fit for purpose applicability that this technology provides. And, where safety and environmental considerations dramatically influence the bottom line, how can one afford not to make an investment in UHR3D? ■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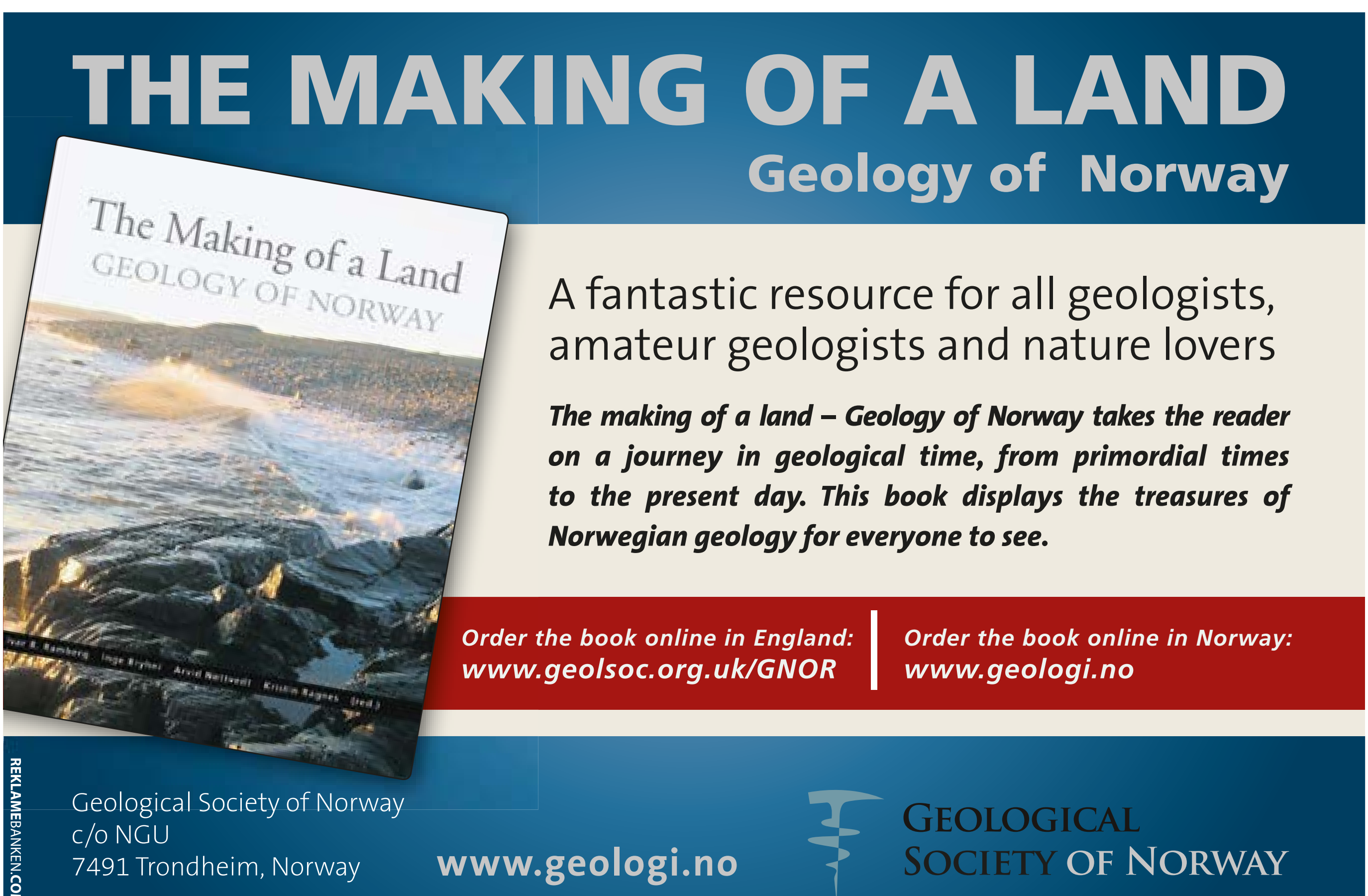
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The Great Black Giant

On a dream – and a bit too close to her garden – the old wooden derrick was skidded to its third location on Mrs. Daisy Bradford's 970 acre, East Texas farm… this would be the one.

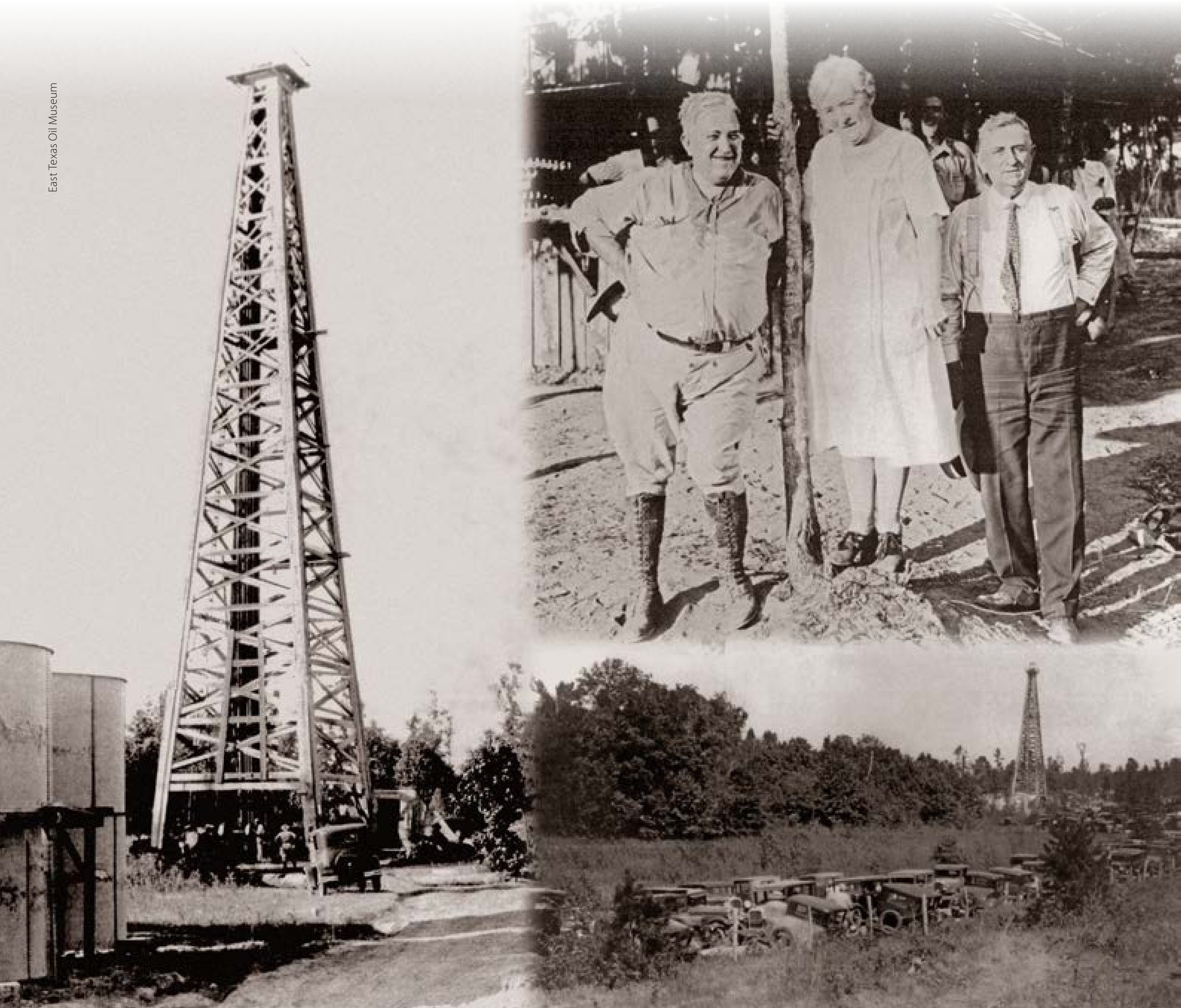
THOMAS SMITH

By 1930, Texas was already the nation's leading oil producing state, yet East Texas remained the only area of the state that had not obtained high-volume oil production in spite of having the state's first oil discovery. The Daisy Bradford #3 would change that, triggering Texas's largest oil boom yet.

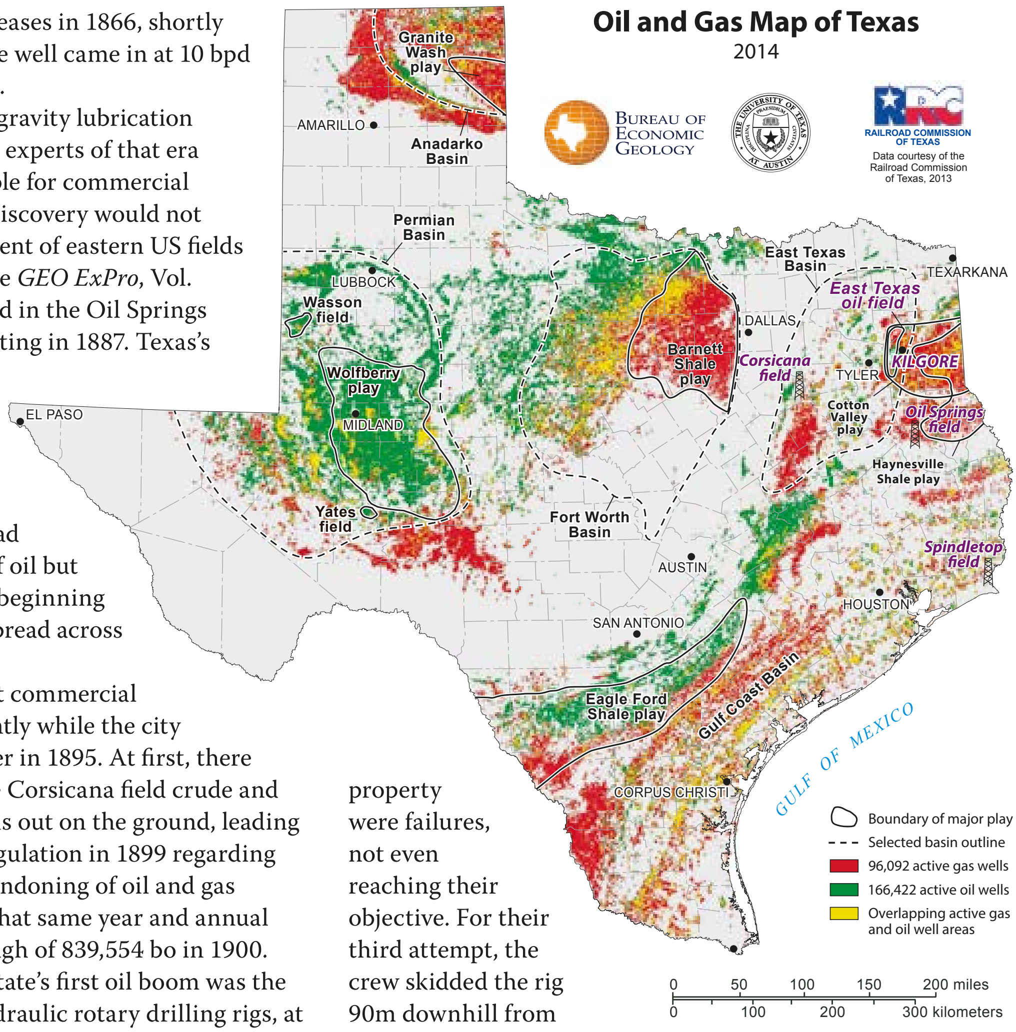
Driven by Oil

Before the Civil War, explorers in East Texas noted oil floating on the waters of Oil Springs and in December 1859, only four months after the Drake discovery at Oil Creek, Pennsylvania, Lyne Barret leased 279 acres near the springs. He drilled

Left: Believed to have been taken during the reaming phase of the well prior to testing. Top right: Columbus M. (Dad) Joiner and A. D. 'Doc' Lloyd, the wildcatters, pictured with the land owner, Daisy Bradford. Bottom right: Cars line the roadway in anticipation of the Daisy Bradford #3 October 3rd testing. These photos are believed to be taken by C. S. Nicks, who travelled the Texas countryside equipped with his own darkroom.



East Texas Oil Museum



Texas oil and gas map showing locations of current oil and gas activity as well as some of the original discoveries.

Texas's first oil discovery on the leases in 1866, shortly after the end of the Civil War. The well came in at 10 bpd at a depth of 32m, but soon failed.

Oil Springs yielded rich, high-gravity lubrication oil and remained a teaser, but the experts of that era never considered the area favorable for commercial production. Exploitation of this discovery would not occur until widespread development of eastern US fields following the Drake discovery (see *GEO ExPro*, Vol. 6, No. 3). Ninety wells were drilled in the Oil Springs area over a three-year period starting in 1887. Texas's first oil production came from wells at depths that ranged from 30 to 76m and initial production ranged from one to six barrels per day. By 1890, this noncommercial field had produced only about 54 barrels of oil but is significant in that it marks the beginning of the oil fever that would soon spread across this huge state.

South of Dallas, the state's first commercial oil discovery occurred inadvertently while the city of Corsicana was drilling for water in 1895. At first, there was a limited local market for the Corsicana field crude and operators would dump the surplus out on the ground, leading to the passage of the first state regulation in 1899 regarding drilling, casing, plugging and abandoning of oil and gas wells. A refinery was completed that same year and annual production soon increased to a high of 839,554 bo in 1900. An important outgrowth of the state's first oil boom was the development of more efficient hydraulic rotary drilling rigs, at the time known as 'Corsicana rigs', that replaced cable tools in the field in 1898 and were soon used throughout the oil and gas industry.

The Texas oil-driven economy really got going when, on January 10, 1901, a geyser of oil erupted from the drilling site at Spindletop in the Gulf Coast region of Texas. Oil exploration expanded from the Gulf of Mexico Coastal Plain, north to the Texas Panhandle, and to the Permian Basin of west Texas. This was a time when oil discoveries were fueling growth all over the state; by 1919, 28,000 wells had been drilled, and 85% were paying producers.

The Discovery

While in Galveston in 1926, Columbus M. 'Dad' Joiner had a dream, one so vivid he sketched the rolling hills and the small stream where he knew he could 'get a well'. A wildcatter and schemer, Dad Joiner had earlier teamed up with A. D. 'Doc' Lloyd, who claimed to be a Fort Worth geologist, to make an oil discovery in Oklahoma in 1917. Joiner had leased Daisy Bradford's farm in 1922 and his 'dream', along with Doc Lloyd's advice, cemented the drilling location.

The first well was started in 1927 and a second in 1928. They were always plagued with drilling problems and a constant shortage of funding: after all, interest in the area was waning after the drilling of 17 dry holes into the prospective reservoir, the Woodbine sand. Both the early wells on the property were failures, not even reaching their objective. For their third attempt, the crew skidded the rig 90m downhill from the first well and started drilling on May 8, 1929.

They made 366m in the first two days, then progress slowed due to lack of funds to keep the crew and rig working. The team sometimes burned tires to keep the boilers going and worked Sundays so visitors and possible investors could see the well in operation. It would take nearly a year and a half and several lease extensions to reach a depth of 1,095m. Oil shows were encountered in the Woodbine, but a local scout believed the cuttings had been 'salted' in order to get more interest in their underfunded operation and leases. On September 5, 1930 a drill stem test showed some oil and gas in the mud.

A decision was made to upgrade the drilling rig and run casing in an attempt to make a well out of it. Once word got out that they were drilling out the plug of cement, eight to ten thousand East Texans made the trip to 'see something happen'. Locals rented parking for 25 cents a car and vendors sold food, soft drinks, and local corn liquor. The first day passed and the bailing operation continued for a second day, removing all the mud from the hole, yet still no oil. The crew started swabbing the well on the third day and some black fluid was beginning to show. After countless trips, a gurgling sound could be heard by the crowd. Finally, on October 3,

Kilgore and the World's Richest Acre

Located about 200 km east of Dallas, Kilgore was feeling the effects of the Great Depression. Its population had been cut in half, from 1,000 in 1929 to below 500 by the middle of 1930. The late fall discovery of the East Texas field changed Kilgore in just a few days. The town's population swelled to over 10,000, people flocking in from all over the world, erecting tents and shacks on any vacant space they could find. Located near the geographic center of the East Texas field, this rural, declining community became an important processing, supply hub and service center for the oil industry. By 1939, nearly 1,200 oil derricks crowded within the city limits with one well actually drilled through the old floor of the Kilgore National Bank.

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Kilgore Street in 1940.

East Texas Oil Museum/Hunt Oil Company

Cars and people gathered in downtown Kilgore just before drilling commenced.

Thomas Smith

Kilgore Street and the 'world's richest acre' park with restored derricks in the background, Kilgore, Texas, 2014. Notice that the buildings along the street look pretty much the same as they did in 1940; only the vintage of the cars has changed.

East Texas Oil Museum/Hunt Oil Company

Once the cars were gone and some of the buildings demolished, at least 24 drilling rigs were put in one square block in the center of Kilgore, which became the 'world's richest acre'.

1930, oil spirted from the casing and over the crown block, and those gathered there also gave vent to their emotions with a loud cheer. The crew worked through the night and made over 5,000 bpd. The boom was on and, at least in this area, the Great Depression was all but forgotten.

Rapid Appraisal

After area operators became familiar with the structure and subsurface conditions, wells were completed in a short six days. Only two months after the discovery, the No. 1 Ashby came in at 3,000 bopd 1.6 km west of the Daisy Bradford well. In late December, 1930, near Kilgore, Texas, 16 km from the initial discovery well, Bateman Oil Company's well blew in at 22,000 bopd, and a third well 24 km further north came in at 18,000 barrels each day in January, 1931. The distance between the discoveries convinced most geologists and engineers that these wells had found separate oilfields. It would not take long for wildcatters to drill more wells and the supergiant East Texas field to be delineated. Within six months of these


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discoveries, 100 wells were completed each day and production climbed to over 1,000,000 bopd by August, 1931. Texas Governor Ross Sterling ordered the entire East Texas oil field shut down on August 17, 1931 to stop rampant illegal production and to prevent waste. The field resumed production on September 5 under a new proration order that limited production to 400,000 bopd, enforced by the Mounted Texas National Guard and Texas Rangers.

In spite of the brief field shutdown in 1931, the next year would be the field's busiest, averaging 22.6 completions each day and ending up with 9,384 producers, a gain of 5,652 wells that year. This would turn out be the largest and most productive field ever discovered in the contiguous US with over 5 billion barrels produced from a field 70 km long and 20 km wide.

The men that made it possible. Pictured with the drilling crew are Doc Lloyd shaking hands with Dad Joiner and to the right, with the hat and cigar, is Haroldson Lafayette 'H. L.' Hunt, who helped finance the testing of the discovery well. This photo is believed to have been taken by C. S. Nicks during the first drill stem test on September 5, 1930.

H. L. Hunt's 'Greatest Business Coup'

Haroldson Lafayette 'H. L.' Hunt got his start in the oil business in El Dorado, Arkansas, arriving in town shortly after Busey-Armstrong No. 1 discovered oil on January 10, 1921. To start, he borrowed $50 and joined the lease traders and speculators meeting at the Garret Hotel. By 1925, at 36 years old, Hunt had become a successful oil man, and was married with three children.

Meanwhile, Dad Joiner was across the border in East Texas acquiring leases. He formed additional 'syndicates' and sold far more lease certificates than he could possibly redeem in order to keep the drilling operation going.

On the invitation of Daisy Bradford's brother, Hunt drove from Arkansas to observe the drill stem test on the No. 3 well. Even though it was not successful, it did have a surge of mud, oil, and gas; enough that Hunt bought nearby leases. After the Daisy Bradford No. 3 blew in, Joiner was in a Dallas court with the legal mess that the oversold syndicate certificates created. His holdings were put in receivership by the court.

Knowing previous wells to the east of Joiner's discovery were dry, Hunt was convinced a sizable field lay to the west. He knew the No. 1 Ashby was drilling 1.6 km west of the discovery and sent scouts to monitor its progress. Hunt borrowed $30,000 from a close friend and met Joiner at the Dallas Baker Hotel on November 25 and 26, 1930. On November 26, Hunt's scouts reported the Ashby well found an oil-rich Woodbine sand. Four hours later, Joiner sold all his holdings, including 5,000 leased acres, to Hunt for $1,335,000. For Hunt, this was his 'greatest business coup'.

It took Hunt ten years to settle all the lawsuits associated with the lease holdings, but put him in the middle of the East Texas field, which provided the financial base for starting Hunt Oil Company in 1934. Originally headquartered in Tyler, Texas and moved to Dallas, the Hunt family of companies became one of the largest privately held companies in the world. ■

The original East Texas discovery well still pumps oil for the Hunt Company from a field that was, at the time, the largest ever discovered and remains the largest and most prolific oil reservoir ever found in the contiguous US.

The Exploration Country Manager

Mfon Udofia, Shell's Exploration Manager for Algeria, gives us a few insights into the role and the skills and experience it requires.

"This is a really exciting job, and one that I feel uses the full suite of experience I have built up in my 14 years working for Shell," says Mfon, who originates from Nigeria.

Building Experience

In both her degree and PhD Mfon combined geology and geophysics, so when she joined Shell, she was not sure which way her career was going to take her. Initially opting for geophysics, after a couple of years working as a processing geophysicist she realized her passion really lay in bringing both disciplines together to decipher the geology behind the seismic images. She therefore moved into exploration geology so she could interpret the lines she had previously been processing.

"In Shell we cover the full range of geological studies, from large scale regional geology focused on play-based exploration, to detailed prospect maturation to define drillable prospects," she explains. "I was back to looking at 'real' geology again, applying innovative play concepts to define new frontier success arenas, for example offshore Gabon. The experience I gained by working from regional to prospect scale and in real-time operations geology turned out to be invaluable in my present job, as it made me a well-rounded geologist who can look at a project through the full exploration life cycle."

Having gained the technical background, Mfon felt she needed a better understanding of how it all fits into the bigger picture of the oil and gas industry. In search of more business experience, she became a portfolio analyst and business advisor to Ceri Powell, Shell's Executive Vice President Exploration International. "This gave me the opportunity to see how all the Royal Dutch Shell businesses collaborate and the unique leadership that brings it all together," she says. "So essentially where the geology meets the money!

"With this background, I had the right experience to take on my present role as Exploration Manager, Algeria, and to create a successful business. This is a frontier region for Shell – the onshore fold and thrust belt of the Atlas Mountains, a unique setting in a part of the country we've never had acreage in before."

Managing the Interfaces

"As a country Exploration Manager, my prime responsibility is to lead my team to successfully execute the venture through the implementation of a technical work program that identifies and de-risks prospects to deliver value to Shell and our partners. In ventures like this, we also seek to offer expertise to our partners, such as through our technology and technical capabilities," Mfon continues. "Exploration is a risky endeavor and timelines are crucial. An important part of my job is to identify risks and plan mitigations in the most efficient way to avoid schedule delays.

"Another vital part of the role is to uphold Shell's HSE standards," she adds. "All aspects of the project must be managed safely, deploying the best standards and procedures. The manager must show leadership in this area, ensuring everyone is committed to their safety and that of their colleagues, as well as the care of the environment. In Shell we call this 'Goal Zero', which aims to ensure everyone goes home safely to their families."

Mfon has a small team of a geologist and a geophysicist working directly with her, but she also calls on the wide range of expertise within Shell to complement their work whenever needed: not only technical expertise, but also people experienced in government liaison, stakeholder communication and HSE, all aspects which are vital to the effective execution of the venture. As she says: "A big part of the job is managing the interfaces between people, ensuring that critical information is fed through to the right people at the right time to enable collective delivery of the project."

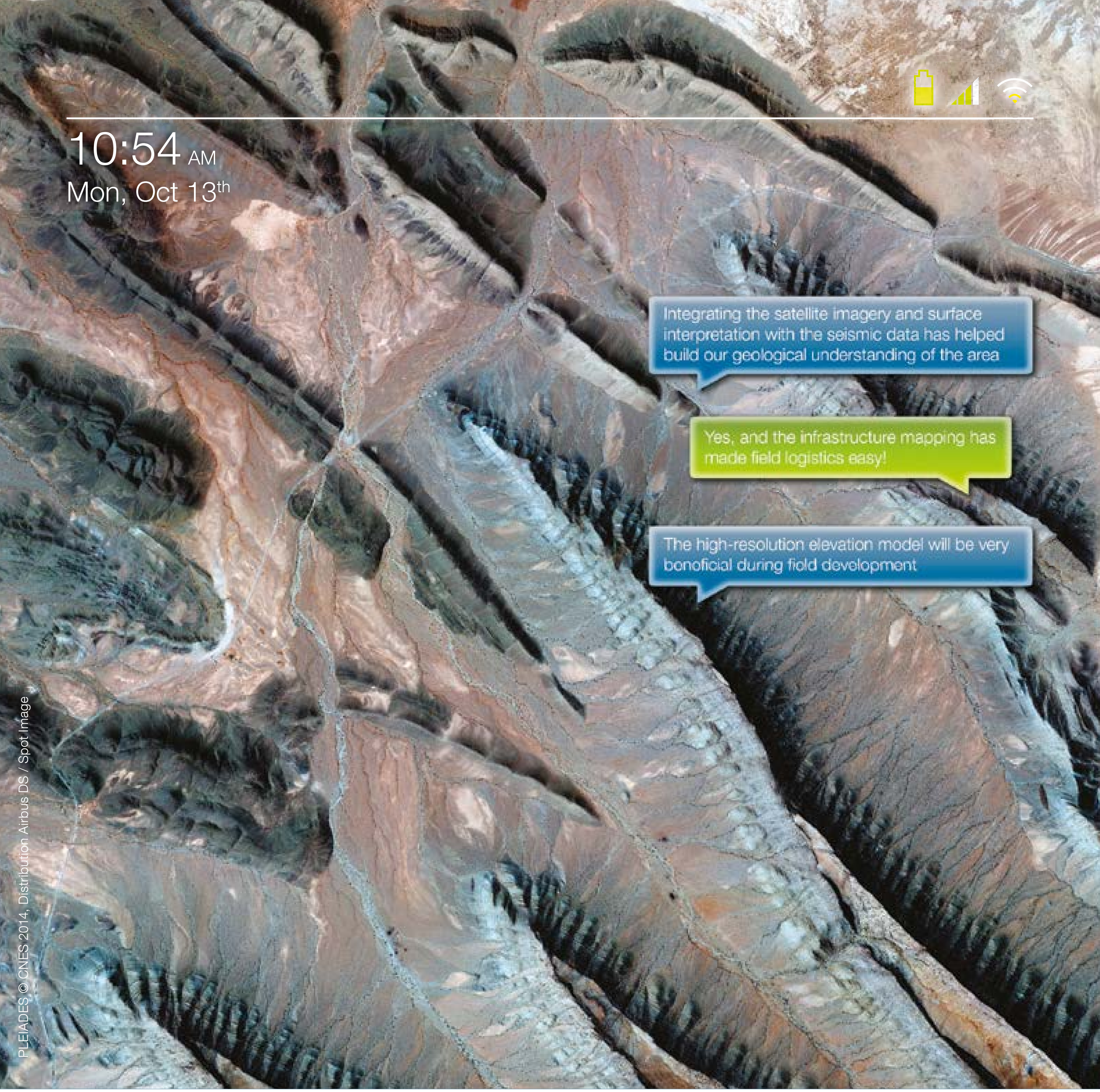
The majority of exploration projects are joint ventures, and Mfon's work in Algeria is no exception, so a key aspect of her work is developing good relationships with partners in order to arrive at mutually beneficial decisions. "We all look at the same data, so to work effectively together we must have a trust-based relationship from the beginning, with respect for each other's opinions and judgement," she says. "It is also important to be transparent about what works for each company; strong interpersonal skills are important and the ability to be a clear, factual communicator is a key ability."

Fascinating Job

"What I love about this job is that it is a new venture in a technically complex arena, so the opportunity to innovate and steer it in the right direction is very exciting. I can use my geological knowledge in technical government meetings and workshops, in collaboration with our partners to lay the technical foundation for a successful venture.

"It is indeed a very fascinating and satisfying job," concludes Mfon. "Given the frontier setting, success will mean a lot to Shell and the industry and I feel privileged to be given the opportunity to play a part in this." ■

Mfon Udofia enjoys visiting Algeria, where she is Exploration Country Manager for Shell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Big D

Dazzling Dallas rose up from the north Texas plains as a technical and financial center for the oil industry following the 1930 discovery of the supergiant East Texas oil field.

THOMAS SMITH

In 1839, John Neely Bryan, a Tennessee lawyer looking for a place to create a trading post, wandered into north Texas. He found the area to be a perfect setting for his purposes: plenty of raw land, Native Americans for commerce and, most of all, a river. Returning in 1841, he claimed 640 acres (2.6 km^2) and sketched out a town. Incorporated as a city in 1856, Dallas started out like many other western settlements during the early to mid-1800s – just another small frontier town. It was not until it attracted both the major north-south and east-west railroad routes, that Dallas became a viable commercial center. The city remains a transportation hub supporting the giant Dallas/Fort Worth International Airport and is crossed by four major interstate highways.

By the turn of the century, Dallas was the leading market center for the entire south-western US. Pharmaceuticals, jewelry, liquor, cotton, grain, buffalo and cattle formed the bulk of the trade. It became the world's largest inland cotton market and led the world in the manufacture of saddlery and cotton gin machinery. The city attracted banking, insurance, and high-end shopping centers such as Neiman Marcus, which opened in the downtown area in 1907. The Federal Reserve Bank was located there in 1914 and Ford opened an auto assembly plant, adding to the area's rapid growth.

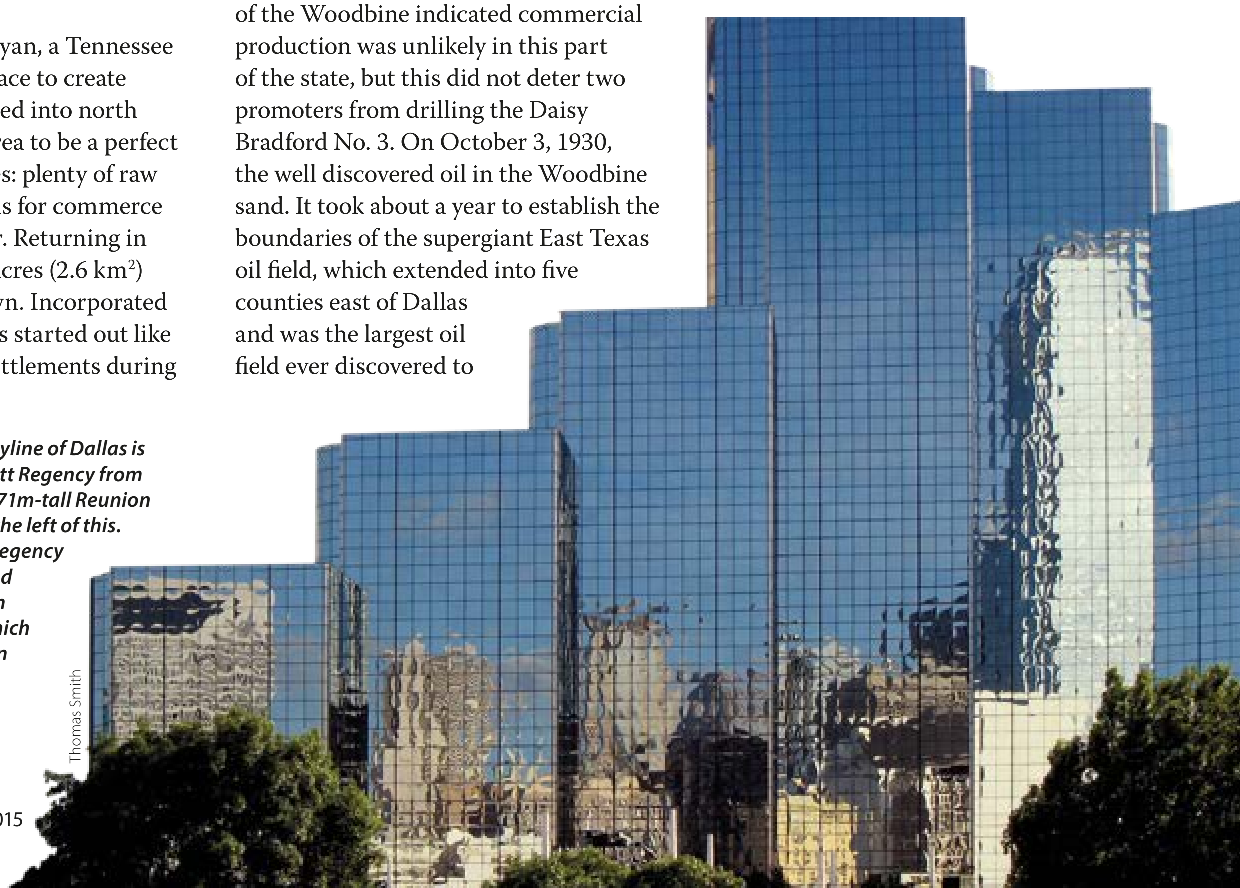
Oil-Fueled Growth

While significant hydrocarbon discoveries were being made across most of the state, early exploration in East Texas had been largely unsuccessful through early 1930. The area's only field was discovered near the town of Van in the Woodbine sand in 1929. Other tests of the Woodbine indicated commercial production was unlikely in this part of the state, but this did not deter two promoters from drilling the Daisy Bradford No. 3. On October 3, 1930, the well discovered oil in the Woodbine sand. It took about a year to establish the boundaries of the supergiant East Texas oil field, which extended into five counties east of Dallas and was the largest oil field ever discovered to that date (see article on page 76).

The Great Depression hit at about the same time and Dallas would have been as badly affected as any city across the country had it not been for this important oil discovery. Nathan Adams of the First National Bank in Dallas was one of the first to loan money to oil companies using reserves in the ground for collateral. So, even without a working oil well, Dallas became a financial center for the oil industry, attracting more oil and service companies to the area. The East Texas Refining and the Central Refining companies were established in Dallas to process a bulk of the production from the East Texas field.

Diversifying Economy

Still, Dallas did not grow during that decade; it would take WWII to establish the city as a major manufacturing hub. Immediately after the war, Dallas began growing in leaps and bounds with five new businesses opening each day and thirteen manufacturing plants every month. With companies like LTV Corporation and Texas Instruments, Dallas became one of the nation's largest technology centers. The 1974 completion of Dallas-Fort Worth International Airport attracted even more corporate headquarters to Dallas,



The modern downtown skyline of Dallas is seen reflecting off the Hyatt Regency from Dealey Plaza. The iconic 171m-tall Reunion Tower (not pictured) is to the left of this. The tower and the Hyatt Regency at Reunion were completed in 1978 as part of an urban redevelopment project which included the historic Union Station serving the city's railway system.

Thomas Smith

further cementing the city's standing as a diversified financial and business center.

While most cities reeled from the late 1970s to early 1980s real estate and banking bust and an economic recession, Dallas continued to grow very rapidly. Many new businesses moved in to take advantage of the very low real estate prices, coupled with the 'Sun Belt' effect, where many northern US factories closed and moved their businesses south along with the jobs. Dallas ranked first in the country in new or expanded corporate facilities, including a considerable tourist and convention industry.

Since the 1990s immigration has been and is still an important driving force for the Texas and Dallas economy. "The Texas economic success story wouldn't be possible without migration from abroad and from other US states," said Pia Orrenius, a senior economist for the Dallas Federal Reserve Bank in 2013. Over 60% of these immigrants are from Mexico. This immigration also made Dallas much more youthful, increasing the percentage of large families with children. During this period, the city's population increased 18%, but its suburbs grew at an amazing 40%. Now, the Dallas-Fort Worth Metropolitan Area is the nation's 4th most populous at 6.8 million, although Dallas remains the primary business hub with most of the area's jobs remaining in the central city.

Recovering from Tragedy

Like many frontier towns, Dallas has had its share of catastrophes, fires, floods, and infamous citizens like bank robbers Bonnie Parker and Clyde Barrow. However, none had the effect on the city as did the November 22, 1963 assassination of President John F. Kennedy. Most of us living at that time can remember where we were when the news was announced. Harsh world attention came to Dallas, dubbed 'the city of hate'. For more than 15 years, the city did little to acknowledge the event; visitors found only an abandoned warehouse from where Lee Harvey Oswald waited in ambush. Dallas kept growing but the wounds were still evident.

Today, Dealey Plaza, adjacent to where the President was shot, is one of America's most popular tourist destinations with more people visiting there than any other place in the city. The Texas School Book Depository, from where those fatal shots were fired, now houses The Sixth Floor Museum that documents this tragic story. It took forward-looking city planners in the 1970s to keep the warehouse from being demolished. To save the building, the city purchased it in 1977 for additional county offices. Still, in spite of a growing visitor interest in the area, a place to explain that tragic time in the city's history was a difficult sell. It was not until President's Day in 1989 that the museum opened at a site that many wanted destroyed. Dallas had finally embraced its history and stepped out of the dark shadows of that tragic day in November, 1963, a proud and vibrant metropolis. ■

Pictured from Dealey Plaza on the west side of Dallas, near where John Neely Bryan first settled in 1841, is the Texas School Book Depository and Elm Street where President John F. Kennedy was assassinated.

Thomas Smith

KEN WHITE

Gulf of Mexico: Chevron Extends Lower Tertiary Trend

Chevron has hailed its wildcat on the **Anchor** subsalt prospect in **Green Canyon Block 807** in the deepwater of the central Gulf of Mexico as a significant oil discovery, but has yet to reveal any details on the field size. The well was drilled in 1,580m of water to a total depth of 10,287m and encountered oil pay in multiple Lower Tertiary Wilcox sands. Lower Tertiary wells are renowned for being technically challenging, as they are marked by high pressures and extreme reservoir depths.

Chevron plans to begin appraisal drilling at the Anchor prospect in 2015. Perhaps more significantly, the success of the Anchor discovery extends the Lower Tertiary (Paleogene) trend into the Green Canyon area, about 48 km north-east of Anadarko's Shenandoah discovery. This 2009 Wilcox oil find in the Walker Ridge area is now under appraisal with 2P contingent resources estimated at 455 MMboe.

In an investor presentation in 2014, Chevron's partner **Cobalt International** described the Anchor prospect as a large, well-defined three-way inboard Lower Tertiary prospect with Miocene potential, with gross un-risked potential of 200 to 500 MMboe. Chevron subsidiary Chevron U.S.A. Inc. is the operator, with a 55% working interest in the Anchor prospect, together with Cobalt International Energy Inc. (20%), Samson Offshore Anchor LLC (12.5%), and Venari Resources LLC (12.5%). ■

Chevron in the Lower Tertiary

Anchor is located approximately 225 km off the coast of Louisiana.

Poland: First Commercial Gas Find for 2015

While its reserves may not be considered world class, the **Rawicz** field is ranked as the first conventional gas field to be declared commercial in Poland for some time, a result that bodes well for 2015. Operator **Palomar Natural Resources** declared commerciality after the drilling of **Rawicz 12 SL 1** in the 39/2009/p Rawicz contract in the south-western part of the country. Drilled to a total depth of 1,902m, the well flowed up to 4.1 MMcfgpd from the Lower Permian (Rotliegend) sandstone on an 80/64" choke. Results of test data gathered to March include a maximum test rate of 5.3 MMcfpd with an average 24-hour steady flow rate of 4.5 MMcfpd. This flow rate and pressure data collected prove a significant gas accumulation at the Rawicz field and the flow rates recorded in Rawicz 12 SL 1 are an order of magnitude better than the results known from two wells that were produced on the field in the past. Upside potential could exist in the Upper Permian (Zechstein) series and in the nearby Zakrzewo pool. The group anticipates drilling three to five additional wells to develop the field, with the second well on the field already in planning.

The Rawicz project is operated by Palomar Natural Resources (Palomar), with 65% equity, and San Leon Energy (35%). For both companies this is seen as a transformational result: a significant gas discovery in one of the highest-priced gas markets in Europe with existing gas infrastructure nearby.

The field was initially discovered in the mid-1970s by domestic operator Polskie Gornictwo Naftowe i Gazownictwo, but it was never produced. At the time it was assessed to hold some 57.5 Bcf (P-mean) recoverable of methane gas in the Lower Permian (Rotliegend) succession, but this may now be revised. ■

Rawicz-12 flow test.

Money Really Isn't Everything

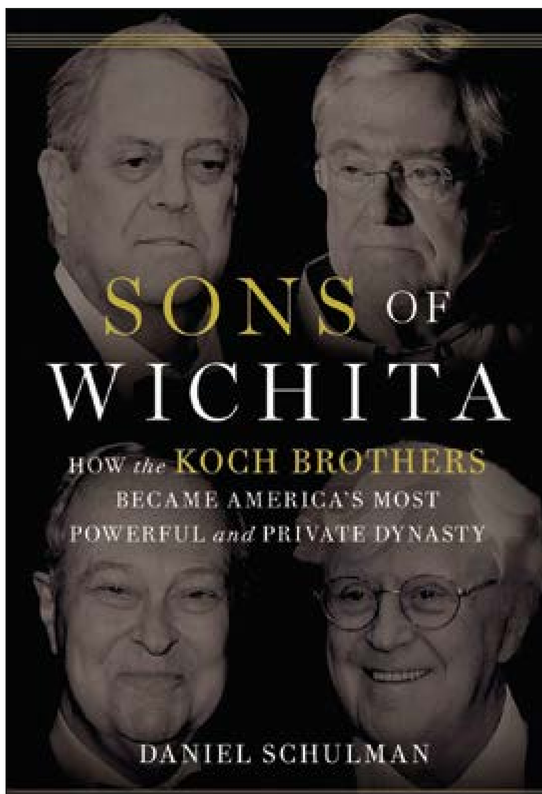
Sons of Wichita
Daniel Schulman
Grand Central Publishing, Hachette Book Group

NIKKI JONES

The story of the infamous Koch brothers is both riveting and cringe-inducing, a painful confirmation of everything your mother told you about the evils of money, its power to destroy families and corrupt the soul. Put it on TV as a drama and nobody would believe it: it is the modern-day real-life unfinished soap opera that has been shaping US politics, society and corporate culture over the last fifty years. The story is told with clarity and objectivity, and a marked lack of salaciousness, by investigative journalist Daniel Schulman.

Explosive Relationships

What a plot! Four sons born to a rags-to-riches industrialist and a wealthy socialite, four boys competing for the attention and love of a father whose mantra was work and discipline, a father who encouraged his children to physically fight. The eldest, Frederick, an art-loving confirmed bachelor, never understood by his father; second child Charles, who swallowed his father's philosophy whole – the 'evils of government' rhetoric and the relentless focus on the bottom line; twins David and Bill, competitive and jealous, still playing 'King of the hill', a battle for dominance, decades into adulthood.



Where did it take them? Koch Industries exploded from a $70 million annual revenue company in the early '60s to an extraordinary $115 billion today, from employing 650 people to over 100,000 in 60 different countries. It has become the second largest private corporation in the US, topped only by Cargill. The engineering company that Fred Koch started in the 1920s focused on improving refinery thermal cracking; the sons – led by Charles – have expanded it into manufacturing, distribution and the trading of key commodities and chemicals. Its products are consumed by every American every day. Charles and David are believed to have fortunes of over $40 billion each, holding joint sixth place in the list of wealthiest men on the planet. Frederick and Bill are multi-millionaires.

But with explosive growth has come explosive relationships. The courtroom has been the stage for the unraveling of the family. The one lesson the sons didn't learn from their father – who himself endured two decades of patent litigation – was to avoid lawyers. There have been decades of lawsuits, starting with their father's property and control of his charitable foundation. Each has involved armies of private investigators, the pilfering of each other's trash, the bribing of janitors and the planting of bogus evidence. Bill even subpoenaed their mother shortly after she had suffered a stroke.

Corporate Outlaw

In true Dallas/Dynasty style, the perception of unequal inheritances developed into a boardroom war and an attempted hostile takeover by Bill and Frederick. A corporate 'divorce' was inevitable but achieved only after Bill brought a 'laundry list' of mismanagement charges into the courts. Two years later the two brothers again took Charles and David to court on charges of devious accounting and deception. A new settlement was reached, followed by Bill bringing a whistle-blower case, exposing Koch Industries' extensive theft at wellheads. "They are the biggest crooks in the oil industry… this is organized, white collar crime," he is reported to have said.

The image of Koch Industries as a corporate outlaw was fueled by the revelation of a corporate culture of 'working the oil' to the advantage of the company – millions of dollars of systematic theft, much of it on Native American lands. There has also been a swathe of environmental litigation. 'Wheel-washing' to mask slicks in water and the covering of land spills was, apparently, commonplace. When quizzed in court about deliberate cover-ups, many employees have pleaded the 5th amendment. Other court cases have found the corporation guilty of rigging a lottery of oil and gas leases, overcharging, and the dumping of toxic waste.

In the late '90s Koch Industries again hit the headlines with the largest ever wrongful death judgment in US history, following the explosion of a butane-filled pipeline that ran yards from residential areas. The corporation's policy of deliberately neglecting basic maintenance, in this case 583 areas of corrosion, was laid bare, resulting in a public beating and a punitive £296 million verdict, almost three times what the prosecution was asking for.

Political Differences

Political differences between the brothers have been the catalyst for much of the discord. Bill, who considered standing as a Democrat in the '90s, is far out of line with Charles and David's low-tax, small-government libertarianism. David and Charles have become infamous for their battle-plan to change American society, founding the Americans for Prosperity foundation and the Cato Institute, plus multi-million dollar support for universities, think tanks, policy institutes, and candidates. They are believed to have far outspent corporations such as ExxonMobil and have become the scourge of the left and the climate change lobby. However, even in this formidable movement there has been a marked lack of harmony: Charles and David have found themselves at odds with Tea Party members over issues of gay marriage and immigration, and even within their own Cato Institute, the battle for control became nasty and personal. "What I learned is, never piss off a billionaire," an exiting director quipped.

Now in their 70s, the brothers are believed to have reached a level of peace, but the three youngest have a collection of tragedies and misadventures between them: acrimonious divorces, accusations of domestic violence, a son's speeding that killed a child, an aircraft accident, illness, a lawsuit for abduction, $2m spent on espionage to win a boat race, a need for bullet-proof cars to take children to school.

With regard to Koch Industries, the corporate mantra is now, apparently, 10,000% compliance with environmental regulations: there has been a widescale offloading of leaky pipelines. Schulman abstains from comment but notes that the company is now focused on the less regulated commodity and energy markets.

To read Schulman's book is to bring to mind so many popular aphorisms, the most obvious of which is 'Money isn't everything'. This is a very readable soap opera with a moral – many morals. It is also an invaluable insight into America's current political and corporate culture. And of course, the story isn't over yet. ■

Daniel Schulman has written on a range of topics, including bioterrorism, information warfare, private military contractors, corporate espionage, federal whistleblowers, and money in politics. He is a senior editor in the Washington, DC bureau of Mother Jones, and a founding member of the magazine's investigative journalism team. Sons of Wichita is his first book.

The Role of Consultancy in the Exploration Industry

Why and when do we need to use consultants? Philip Angell, Managing Director of Dubai-based consulting firm Vision Project Services DMCC, explains.

How do you define the role of a geophysical consulting firm?
We are the piece of the puzzle that fits in between the client's technical and commercial project management and the seismic acquisition contractor, whether land or marine. Our personnel ensure that the technical specifications, commercial budget and HSE performance objectives are met and managed effectively, whilst applying our experience and knowledge to the overall exploration task. We have to weigh up the pros and cons of sometimes relaxing certain technical parameters, or widening the aperture, against an increase or decrease in cost in order to obtain the required outcomes. With that comes the requisite geophysical or geological justification which is presented in conjunction with peers for the client's approval. In short, we act as the technical infield specialists on behalf of the client, which could be an oil company or a multi-client collaborative effort.

What range of services do consulting firms offer?
For the most part, the consulting sector offer a broad suite of complementary expertise that encompasses the entire exploration task. From initial survey design to project management through to post processing supervision and, where required, interpretation services. We also provide health and safety representation and environmental mitigation measures such as Marine Mammal Observers and Passive Acoustic Monitoring.

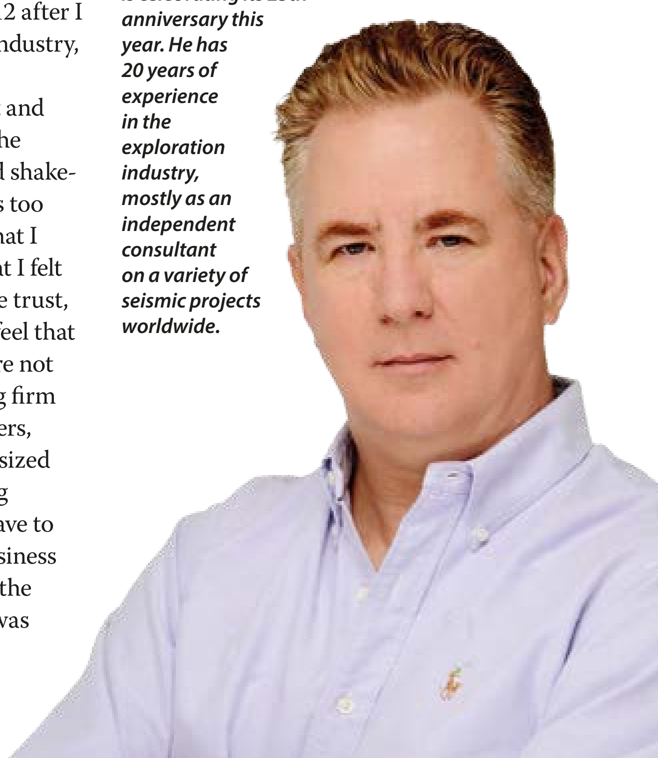
In-house or outsourced to a consultancy: the pros and cons?
It is quite common for a client to rely on outsourcing all of their field supervisory requirements to consulting firms that specialize in these disciplines. Previously it was normal for a staff member from a client company to be present for the project (and some still do), but with high speed internet and near-real time project management applications, electronic project overview 'at a glance' is widely available. However, having the human element of expertise on site will always be necessary in my opinion. As projects are often short-lived, it is a matter of convenience for the client to be able to call upon expertise for only the time required.

What experience and skills does a consultant need?
First of all, physical health: you need to be fit and healthy to work in the field. Academically, it's generally expected for a consultant in any discipline to be fully qualified in discipline and to have at least ten years' field experience. This always brings up the discussion of qualifications versus experience. A formal education will always provide the bedrock of knowledge that can be combined with actual field experience. People and communication skills are also highly desired. From a management side, having the field experience and knowledge in-house allows us to select and offer the best people for the task.

Why did you decide to manage a geophysical consulting company?
We opened the Dubai office in 2012 after I had spent 17 years in the seismic industry, predominantly in marine seismic.
After experiencing many different and challenging situations, I thought the consulting industry needed a good shake-up. As a very clear (and sometimes too clear) communicator, the values that I apply daily are the same values that I felt were missing in the field. These are trust, transparency and making people feel that they want to work with you. We are not aiming to be the largest consulting firm out there, we will leave that to others, rather we aim to be a manageable sized firm with a real focus on delivering expertise and professionalism. I have to give enormous gratitude to my business partner Bob Lane. He has been in the business for a very long time and was the person who facilitated a head start for myself as a business owner. Finally, in answer, to the question: freedom, flexibility, making a difference and the daily challenges of success and being fortunate to share that success with others.

Are some areas of the world more in need of your services than others?
The industry is global and the business follows the industry. We provide expertise on all continents.

Are there too many or too few consulting companies?
Whether or not there are too few or too many consulting firms is not an easy question to answer. A better question would be how many have stopped trading in the past? Quite a few! We are celebrating our 25th year of business in 2015 and that is testament to constraining overheads and running our business in an efficient and professional manner. We are looking forward to the next 25 years with excitement!



Phil Angell is Managing Director of oil industry consulting firm Vision Project Services, which is celebrating its 25th anniversary this year. He has 20 years of experience in the exploration industry, mostly as an independent consultant on a variety of seismic projects worldwide.

Kurdistan Iraq
Plenty of Potential

With an export agreement in place, and development costs of a mere $5 a barrel, exploration in Kurdistan delivers results.

MUNIM AL-RAWI, PhD, Carta Design Ltd.

The exploration for hydrocarbons has played a crucial role in Kurdistan Iraq's economic development since 2005. Despite continuing strife in the Middle East, including ongoing battles between Kurdish Peshmerga forces and ISIS on the outskirts of the Kurdistan region, oil production continues to increase, and more and more energy companies are either returning or coming afresh to the region.

Long Time Underexplored

The Kurdistan region sits on about 50 Bbo and more than 106 Tcfg. There are proven source rocks from the Tertiary, Cretaceous, Jurassic and Triassic, and multiple stacked reservoirs of late Tertiary to Triassic age, although the majority of reserves found to date in Kurdistan have been discovered in the Cretaceous and Jurassic. It sits in the prolific Zagros Fold Belt complex, which developed from the Late Miocene to Pliocene, although the area started undergoing regional compression from the Late Cretaceous.

The Iraq Petroleum Company (IPC) explored the area extensively between 1927 and 1961 and found it promising, but for a number of reasons, primarily hostile terrain, nothing was developed. In 1972, the Iraqi government nationalized all the assets of the IPC, including those in the present Kurdistan region in Iraq, and there was little serious independent oil exploration, with a meagre total of only 28 wells drilled between 1901 and 2003, when the Kurdistan Regional Government (KRG) began to encourage foreign companies back. Even then, it was hard work for exploration companies, as there were no data rooms or packages, and precious little data; in fact, all exploration wells drilled to date have been based on 2D seismic, satellite imagery and field work.

The KRG passed its oil and gas law in 2007, and by 2010 almost all blocks were licensed. The first post Iraq war well, Tawke 1, was drilled in 2005, finding a field that proved to have 2P reserves in excess of 650 MMbo, and since then the area has developed into one of the world's most active areas for onshore exploration, with over 100 wells drilled. Success rates are high, with more than 50% of the discoveries being proved commercial, and over 25 oil and gas fields have been discovered.

Export Deal

Oil exports started in 2012, via the Turkish terminal at Ceyhan. The official KRG report for 2014 activities said that from 2003 until the end of August 2014, production grew steadily and sustainably, with almost 400,000 bpd being exported in December 2014, adding that by the end of the first quarter of 2015 that figure is expected to rise to 500,000 bpd, with a target of 1 MMbopd by end 2015/early 2016.

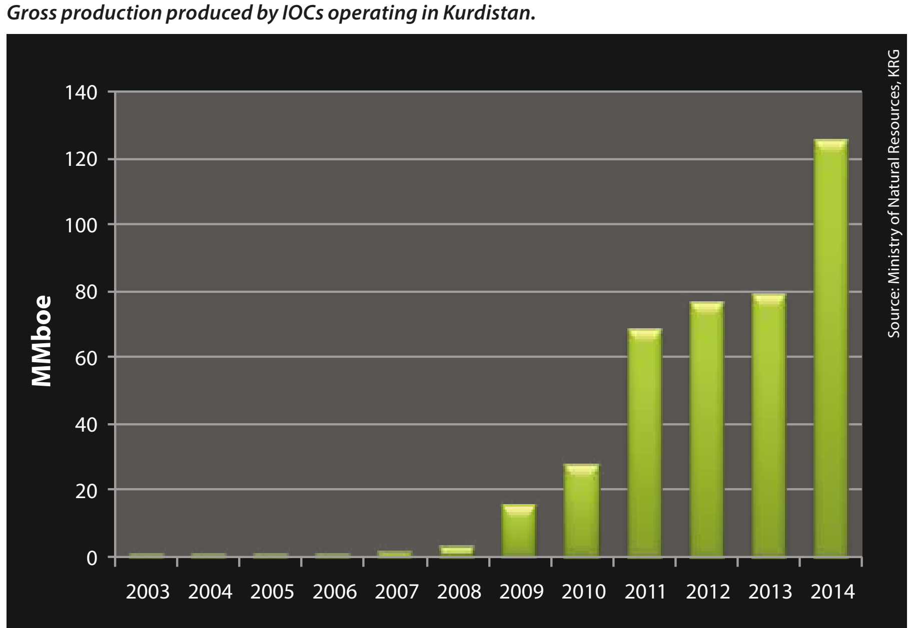
Having disagreed for many years as to how to divide up the revenues of KRG oil, in December last year the KRG and the Iraqi government finally came to an agreement to share the profits, with the Kurds receiving 17% of Iraq's federal budget, something Kurdistan has sought for many years. Under the agreement, from January the Kurds would ship 250,000 bpd directly to Turkey and 300,000 bpd through the Baghdad-controlled pipeline which runs from Kirkuk to Ceyhan, the Kurds having seized the giant Kirkuk field after ISIS retreated from it last June.

In March, the KRG announced that it is on schedule with the implementation of its part of the deal, but claims that the Iraqi government had paid less than 20% of the KRG share of the budget for January and nothing for February. There is therefore some danger that the deal may unravel.

However, the region still offers great promise for oil exploration particularly in the present environment of low prices, since it costs an estimated $5 a barrel to develop and produce – a big contrast to deepwater or US shale production costs.

For more on this region see GEO ExPro, Vol. 11, No. 2, Memories of Iraqi Kurdistan; and GEO ExPro, Vol. 9, No. 6, Understanding the Zagros. ■

Gross production produced by IOCs operating in Kurdistan.



An Increase of 20 MMbopd in 25 Years

OPEC foresees a substantial increase in oil demand over the next 25 years – meaning that oil companies need to find more oil.

Oil will continue to play a major part in satisfying world energy needs, OPEC says in their 2014 World Oil Outlook.

The reason is that the global economy is set to more than double in size as population grows (the UN predicts a rise from 7.1 billion in 2013 to almost 9 billion in 2040) and prosperity expands everywhere.

Oil demand will reach **111 MMbopd** by 2040, according to OPEC, corresponding to an increase of around 800,000 bopd per year from now, with the highest growth happening in Asia. This prediction is partly based on the assumption that gasoline and diesel engines will continue to dominate, so that the world will have more than 2.1 billion cars by 2040, with a dramatic rise in developing countries (more than a billion additional cars in the next 25 years). The largest rise in passenger car volumes is in China, as it moves from 53 cars per 1,000 in 2011 to a predicted figure of over 380 cars per 1,000 in 2040 (a sevenfold increase!), a similar level to many OECD countries in the 1990s. By 2040, oil use per capita in developing countries will average just 3.3 bo, compared to 10 bo on average in the OECD countries.

OPEC also foresees total energy demand growing from 256 MMboe in 2010 to 410 MMboe in 2040, a 60% increase. About 78% is expected to come from fossil fuels; while almost 16% will come from renewables, where biomass predominates with 10%.

In other words, fossil fuels will continue to be the world's primary energy provider in years to come – assuming that OPEC is correct.

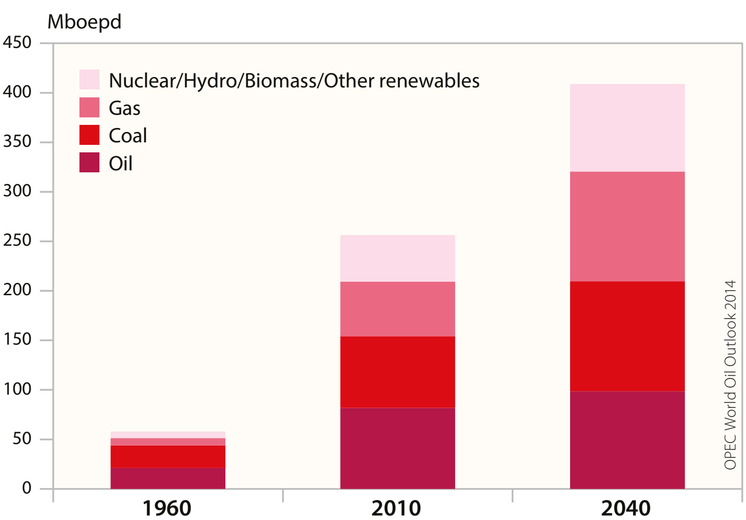
So where will the new oil come from? According to OPEC, non-OPEC countries will not be able to contribute to an increase in oil spending. Their forecast is that these countries will produce as much oil in 25 years as they do now, close to 50 MMbopd.

In the long-term, OPEC is therefore expected to supply the majority of the additional required barrels, with the OPEC liquids supply forecast increasing by over 13 MMbopd up to 2040. In terms of the global energy mix, renewables – from hydropower and other renewables, such as wind and solar – are expected to continue to grow at a fast pace, due partly to government support. However, given the low initial base, their share of the global energy mix is expected to remain – at best – modest by 2040.

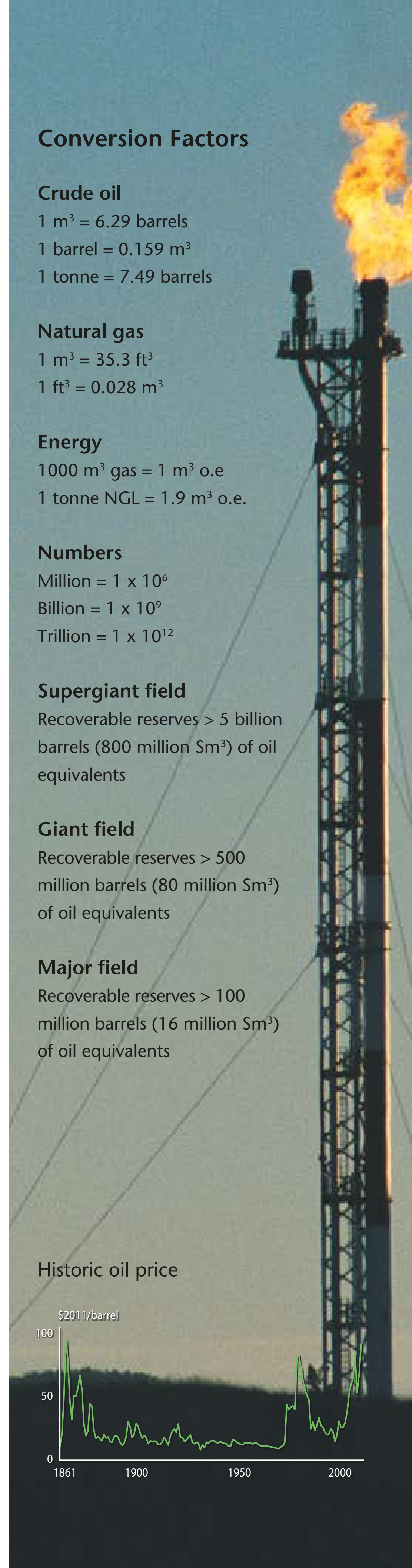
It is therefore not in doubt that fossil fuels will continue to play the leading role in satisfying world energy needs in the foreseeable future, and oil will remain a preferred energy source.

Go out and look for it!

Halfdan Carstens



World supply of primary energy by fuel type.



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