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GEOTOURISM

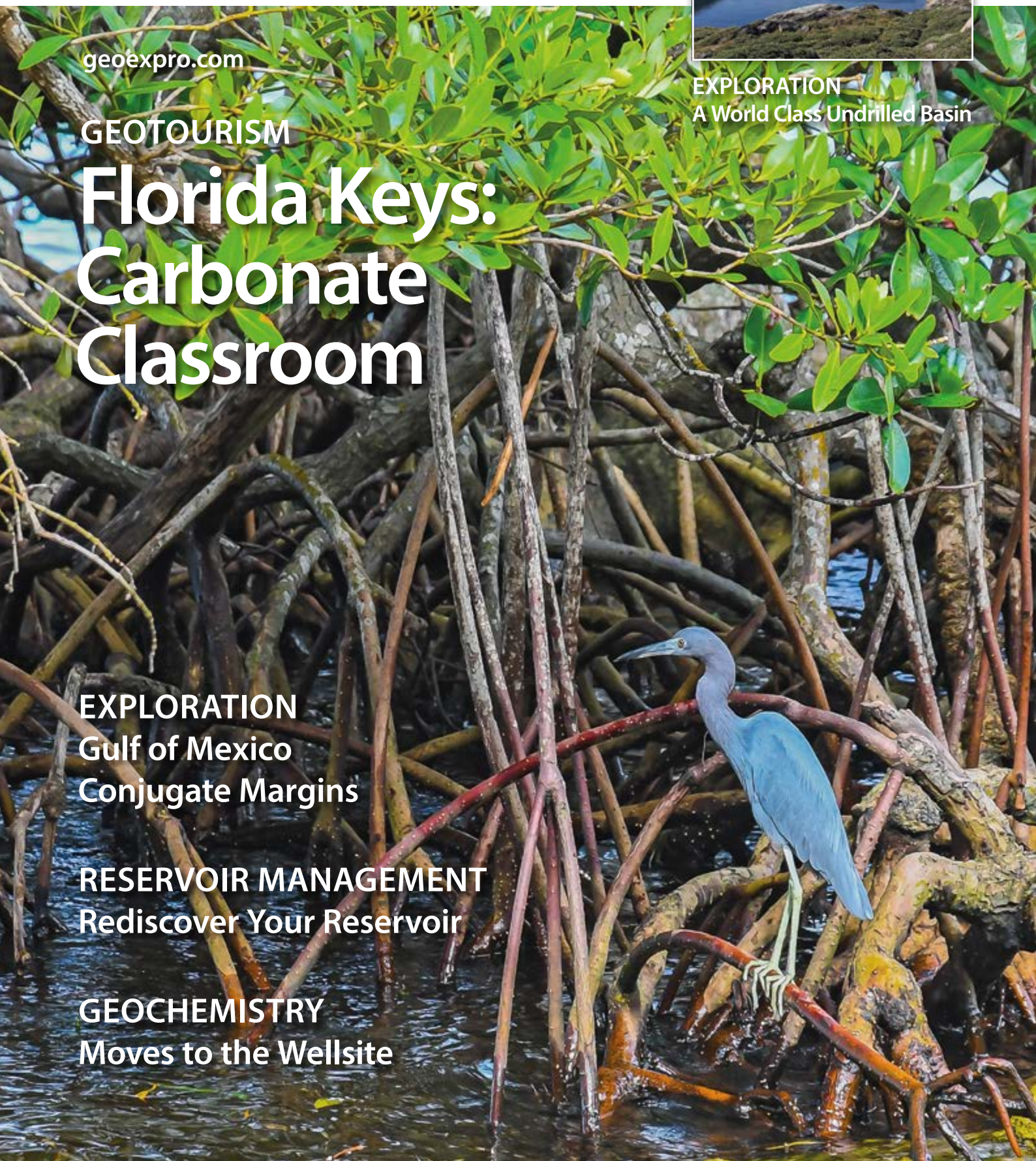
EXPLORATION
A World Class Undrilled Basin

Florida Keys: Carbonate Classroom

EXPLORATION
Gulf of Mexico
Conjugate Margins

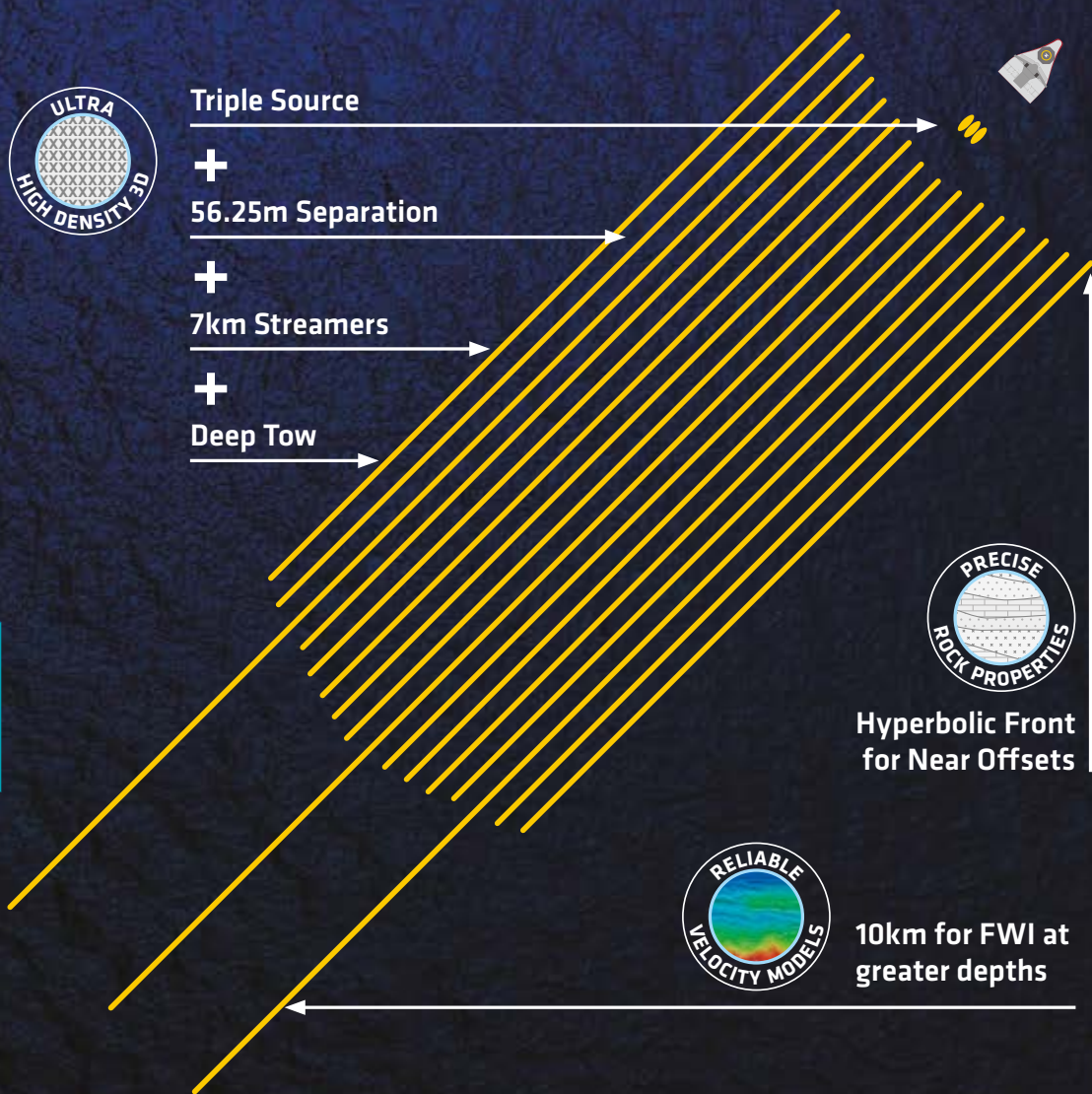
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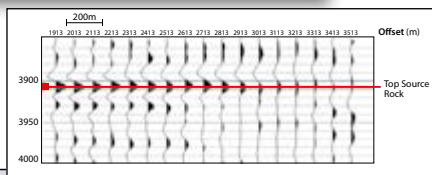
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Never mind the temperature – Bill Armstrong is having fun finding new high impact oil and gas fields.



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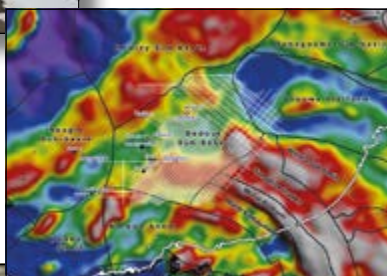
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Moving Forward

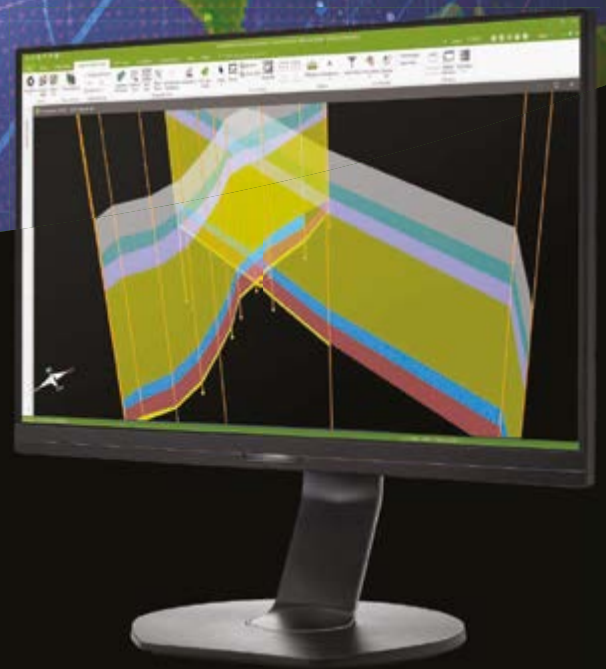
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Energy Conundrums

Last month, for the first time for many decades, the number of people in the world without access to electricity fell below one billion. At first glance, something to celebrate: but think of that number again. Almost one billion people, or 13% of the world's population, still do not have electricity in their homes. The link between access to power and movement out of poverty is well documented, so this depressing figure shows there is plenty yet to work on.

What is more, the rate of progress has been variable across the globe, with the biggest successes being in Asia, particularly India, where this year they announced that every village in the country was now connected to the grid – a significant achievement.

The story is very different in Africa. There have been successes – Kenya's access rate, for example, has increased from just 8% in 2000 to 73% today – but overall the picture is disappointing. According to the International Energy Agency, 600 million people in Sub-Saharan Africa – 57% of the population – still remain without access to electricity.

In addition, nearly 2.7 billion people lack access to clean cooking facilities worldwide, relying instead on biomass, coal or kerosene as their primary cooking fuel, which has serious health and environmental impacts. This disproportionately affects women and children and it is thought that about 2.8 million people die each year due to lack of access to clean cooking facilities; once again, the majority live in Sub-Saharan Africa.

And therein lies a conundrum: the region is richly endowed in oil and gas, and is a major exporter of these commodities to the rest of the world; how can a higher percentage of Sub-Saharan Africa's resources be channelled into improving local access to energy and clean cooking facilities, while still exporting sufficient quantities to feed the region's economy?

Inextricably tied into this is a second conundrum: reconciling the need for energy with the requirement for environmental protection in a region that is severely under pressure from a burgeoning and largely impoverished population, but one which clearly recognises the need for a sustainable solution.



Jane Whaley
Editor in Chief

The answer must lie in tying the two conundrums together through investing in research to improve efficiency in producing, storing and using energy from all sources: both fossil fuels and renewables. Only through working collaboratively across the energy sector and throughout the world will we even begin to solve this dilemma. ■



The three-stone open fire: still the main method of cooking in many homes.

FLORIDA KEYS: CARBONATE CLASSROOM

A Little Blue Heron stands in a tangle of mangrove roots in a Florida lagoon. Just one of the many fascinating sights on a trip through the Florida Keys, where you can also learn a lot about carbonate rock formation and diagenesis.

Inset: Greenland: the Jameson Land Basin is one of the last remaining undrilled Atlantic Margin basins.



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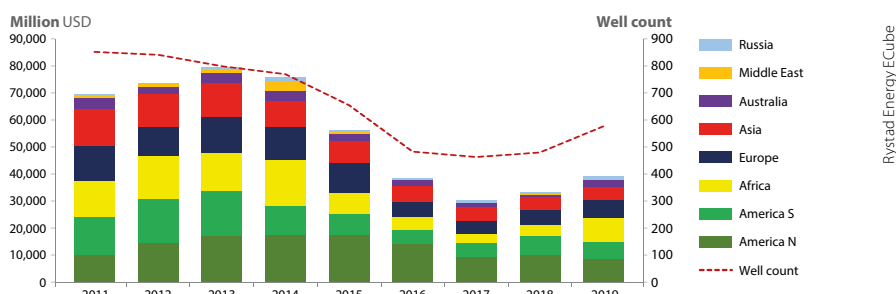




2018 – A Year of Transition

With Brent having traded above \$80 per barrel, global oil companies now hold record high cashflows, allowing them the opportunity to realign their exploration portfolios and revive the long-capped exploration outlays.

Global offshore E&A well count in 2018 has witnessed a moderate rise (5–7%) after bottoming out in 2017. Norway, Brazil, US Gulf of Mexico and Africa are contributing to the additional offshore spending in 2018. Majors, NOCs and IOCs continued to dominate the exploration successes across geographies, with some junior players like Savannah Petroleum and Quadrant Energy adding noteworthy finds this year, in Niger and Australia respectively. Global discoveries of conventional oil and natural gas are seeing good momentum in 2018, with discovered resources already passing 6 Bboe in the first three quarters, compared to 7.5 Bboe in 2017. Average monthly discovered volumes this year are estimated at 725 MMboe, up approximately 15% from 2017.



Global offshore exploration expenditure and number of exploration wells.

However, E&P players are currently facing a very low reserve replacement ratio, on average 10%, indicating that, regardless of signs of revival, arresting decline in the volume of new oil and gas discoveries will continue to be a major supply-related challenge for the industry long term.

High Impact Exploration

Improved market conditions and operational efficiencies, along with sustained cost deflation, allowed many E&P players to move forward with promising high impact exploration campaigns in 2018. Successes include Eni’s Calypso-1 gas find offshore Cyprus, PDO’s large gas-condensate discovery at Mabrouk North East onshore Oman, Quadrant Energy’s Dorado-1 well offshore Western Australia, and Equinor’s discovery of oil at its high-profile wildcat in the pre-salt Santos Basin.

West Africa, however, saw some major disappointments this year. Tullow’s Cormorant well in the frontier Walvis Basin offshore Namibia encountered non-commercial hydrocarbons, while three wells targeting multi-million barrel resources – Lamantin (Kosmos Energy; Mauritania), Rabat Deep (Eni; Morocco) and Requin-Tigre (BP; Senegal) – were all dry. One to watch is Gazprom’s well targeting the Bautinskaya structure offshore Russia, which might yield significant reserves.

Licensing Activities

The Americas witnessed momentum in licensing activities, with Brazil, Mexico and the US seeing majors, NOCs and independents competing intensely for deepwater blocks. Brazil gained almost \$5 billion in aggregated signature bonus from its three deepwater bid rounds this year. In Europe, the UK and Norway saw renewed interest from a range of companies, with 212 offshore blocks awarded in 2018, compared to 103 blocks in 2017. In Asia, India’s licensing policy reforms yielded success; all 55 blocks, selected through EOIs submitted by companies, were awarded to nine domestic companies. New exploration acreages and work programme commitments from these rounds will catalyse exploration investments.

Overall, amidst volatility and political uncertainties, 2018 has been a year of transformation for the exploration industry. The modest recovery of 2018 brings optimism ahead of the expected resurgence of activity in 2019.

Rohit Patel, Senior Analyst, Rystad Energy

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

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BGP is a leading geophysical contractor, providing geophysical services to our clients worldwide. BGP currently has 57 branches and offices, 6 vessels and 19 data processing and interpretation centers overseas. The key business activities of BGP include:

- * Onshore, offshore, TZ seismic data acquisition;
- * Seismic data processing and interpretation;
- * Reservoir geophysics;
- * Borehole seismic surveys and micro-seismic;
- * IT services.
- * Geophysical research and software development;
- * GME and geo-chemical surveys;
- * Geophysical equipment manufacturing;
- * Multi-client services;



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Dr. Munim M. Al-Rawi



The Editor and colleagues were devastated to hear that their friend and contributor, Dr. Munim Al-Rawi, died suddenly but peacefully on 1 November 2018 at his home in Ireland. A true gentleman and passionate geologist, he will be sadly missed by all who knew him.

His sons, Mukrim and Basil, have written the following obituary for us: Dr. Al-Rawi was born in Iraq and acquired a B.Sc. in geology/physics from the University of Baghdad in 1965. He furthered his studies at Imperial College in London, achieving his M.Sc. in 1967 and Ph.D in 1972. He fondly recalled his time spent studying there, his field work in Ireland, and the many colleagues and friends he met.

Munim's career started with Seagull Exploration UK, evaluating E&P opportunities in the UK, Middle East and North Africa, before becoming assistant professor in geology at Kuwait University in 1974. After eight successful years there, he moved to Ireland to work as MENA specialist for Petroconsultants, and was also Visiting Professor in Petroleum Geology at universities in Saudi Arabia and the UAE. He then became Project Coordinator for the European Union and Jordan Co-operation project in Science and Technology in Amman, Jordan. Returning to Ireland, he used his many years of academic and professional experience as a consulting petroleum geologist in the oil industry.

In addition to writing on petroleum geology, Munim developed a strong interest in Islamic heritage and the contribution of Muslim scholars to the earth sciences. He enjoyed travelling and loved Petra, writing *Petra The Rose Red Wonder* for *GEO ExPro* in 2013, as well as many other articles for the magazine. He wanted to instill a passion for petroleum geology and earth sciences in all he met.

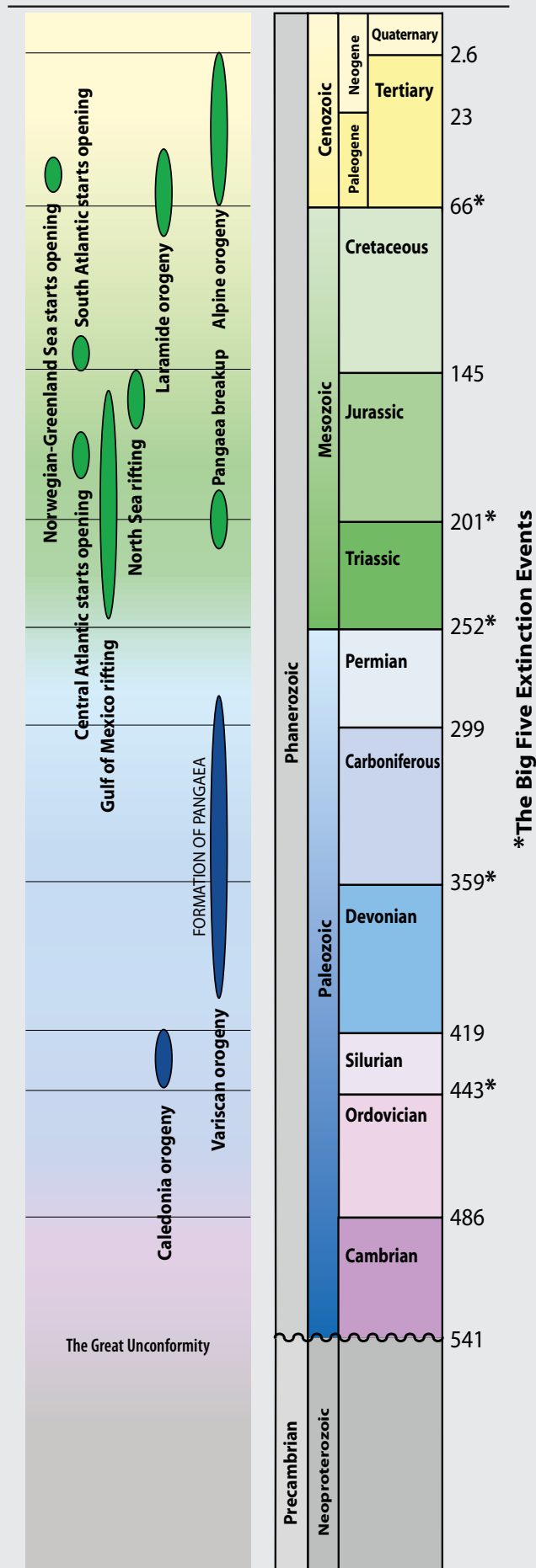
Dr. Munim M. Al-Rawi was a father, a gentleman, a pioneering geologist and a scientist. He had an abundance of energy, knowledge, and patience for his work, and great respect for the many people he came in contact with from different cultures and faiths.

He is sadly missed by his loving wife Mary, sons Mukrim and Basil, daughter Safia, daughter-in-law Deirdre, mother, brothers, sisters and extended family, esteemed professors, colleagues, neighbours and friends across the world.

He left an impression with anyone he met, summed up by his favourite phrase: "Stay positive, be optimistic".

Rest in Peace, Munim.

A longer obituary is available online. ■



Explore Madagascar's open acreage

Let the bidding commence!



OMNIS, in partnership with TGS and BGP, are pleased to announce the opening of a Madagascar 2018-2019 Licensing Round.

Exploration in Madagascar began in the early 1900s with the discovery of hydrocarbon-rich sedimentary basins in the west, including the Tsimiroro heavy oil field and the Bemolanga tar sands. In spite of more than 100 years of exploration, the offshore of this frontier region remains largely under-explored. The Island shares a maritime boundary with Mozambique, a hydrocarbon province where large quantities of natural gas have been discovered.

Studies conducted on new data, in collaboration with TGS and BGP, suggest there is significant potential for future discoveries offshore.

Highlights:

- **Blocks:** 44 offshore blocks in the Morondava Basin, located on the western margin of Madagascar
- **Timing:** The Licensing Round will run from 7 November 2018 until 30 May 2019
- **Roadshows:** Will be held in Houston on Tuesday 19 February 2019, and in London on Tuesday 26 February 2019
- **Data access:** Existing seismic, gravity/magnetic and well data will be available for viewing via physical data rooms held at the TGS offices, in London and Houston; data packages will also be made available for clients

For more information:

info@madagascarlicensinground2018.com
www.madagascarlicensinground2018.com





Sharing Advances in Geophysics



Paul Mitchell from TAQA is the 2019 conference chairman.

SPE Aberdeen are delighted to be hosting the **Seismic 2019 Conference** in a larger venue to accommodate demand. Next year's conference will explore the entire spectrum of seismic technology from exploration, through development and production, to abandonment – the lifecycle of the asset.

The conference will focus on advances in seismic acquisition, processing and quantitative interpretation and how these are being applied and provide value. Other themes include machine learning in seismic interpretation to complement manual interpretation; seismic aspects of integrated reservoir modelling; borehole seismic; and non-seismic technologies.

If you have experiences to share then we invite you to submit a short 200-word abstract before the closing date of 30 January 2019.

The conference takes place on **14–15 May** at the **Aberdeen Exhibition and Conference Centre**. For more information, along with sponsorship and exhibition opportunities, visit the SPE website. ■

The Digital Subsurface

Welcome to **#DigEx2019** – a conference for geoscientists that focuses on how digital technology is enabling the oil and gas industry to completely change the way we work, how it impacts our daily jobs – and the possibilities that come with it. It includes concrete examples on how companies are embracing the possibilities within this emerging domain and how they are changing their workflows and approach to the entire value chain from a subsurface perspective.

Sessions cover a range of topics, including: digitalisation roadmaps and architecture; enabling data sharing; and new

digital workflows, as well as a number of case studies where industry frontrunners will present what they have achieved and how far they have come in the digital transformation process. It will be an arena for inspiration and learning from the innovators and an opportunity to hear how digitalisation will enable the industry to take advantage of the enormous amount of data we have available in order to make better decisions throughout the entire value chain.

The conference will be held at the **Quality Airport Hotel Gardermoen, Oslo**, on **30–31 January 2019**. ■

Speakers Confirmed for IP Week

One of the biggest events in the oil and gas calendar, **International Petroleum (IP) Week**, organised by the **Energy Institute**, will be on **26–28 February 2019** at the **Intercontinental Park Lane, London**. This event brings over 1,500 attendees from all over the world to hear the most powerful voices in the energy industry debate key issues, share new ideas and network to form partnerships with operators, clients and investors.

High-level industry figures and thinkers on energy will help senior leaders to assess the state of play and prognosis across three key themes – **geopolitics, sustainability and technology**, with a focus on how digitisation, data management and analytics are driving change and optimising operations along the value chain. Confirmed speakers include Bob Dudley, Group Chief Executive Officer, **BP**; HE Mohammad Sanusi Barkindo, Secretary General, **OPEC**; Arnaud Breuillac, President, Exploration and Production, **Total**; Dr Fatih Birol Hon FEI Executive Director, **IEA**; and Ade Adeola, Managing Director, Oil & Gas, **Standard Chartered**.

Attend IP Week to learn how to adapt your business model to respond quickly to rapidly changing market conditions and network with high-profile senior figures from across the oil and gas industry. ■

The IP Week dinner.



APPEX Global 2019

As 2018 has marked a resurgence of upstream international deal making and a return to more buoyant E&P activities, **APPEX – AAPG’s Prospect and Property Expo** – returns to **London’s Business Design Centre on 5–7 March 2019**.

Perennially referred to as the “best event in Europe for identifying new deals, new basins, and new ideas,” the 18th edition of APPEX promises to deliver a new outlook on the global energy A&D scene with a fresh, forward-thinking perspective. Under the guidance of Honorary Chair, Mike Lakin, Co-Chairs Jon Fitzpatrick and Gabe

Myhneer, and a committee of experts representing the operator, financial, broker, and supplier communities, APPEX 2019 will retain its classic, intimate feel, while fully embracing the new trends, technologies and players driving 21st-century deal-making. If you are looking for the right mix of inspiration, opportunities and networking, APPEX is the place to be.

Check the APPEX website for more info about the event, registration and networking events. For exhibition and sponsorship enquiries, contact the AAPG Europe office. ■

Libya: Eni and BP Agreement

Since the fall of Ghadafi, **Libya**, once one of the world’s top oil suppliers, has struggled to keep up supply levels, with exploration in many areas still suspended. The country is now producing around 1.25 MMbopd, well below its pre-civil war capacity of 1.6 MMbopd. The recent signing of a Letter of Intent with **Libya’s National Oil Corporation** by supermajors **Eni and BP** is therefore an interesting development.

In 2007 BP signed an exploration and production sharing agreement (EPSA) to explore onshore in the Ghadames Basin and offshore in the Sirt Basin, a total of about 54,000 km², but did not progress towards production before it ceased operations in Libya in 2011 due to civil unrest. With this new agreement Eni plans to acquire a 42.5% interest in BP’s Libya assets and will become operator of the EPSA, where

BP currently holds 85% working interest, with the Libyan Investment Authority holding the remaining 15%. Eni has been operating in Libya since 1959 and is currently active in six contract areas in the country, producing 384,000 boepd in 2017. It is also involved in programmes to support local communities, in areas like health, water and energy access. ■



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Chemostratigraphy and Provenance of the Greater Grand Banks 2019

Chemostratigraphy and Provenance Characterisation of Grand Banks Tertiary Successions

Regional Basement Characterisation of the Greater Grand Banks



Wells: ● Grand Banks 2018 ● Grand Banks 2019 ● Hope Basin 2019 ● Nova Scotia 2019



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Promising Outlook for Africa

Africa Oil Week 2018, the leading event dedicated to the African oil and gas industry, successfully closed with a promising outlook for the future of the industry on the continent. Over 1,500 delegates from more than 70 countries attended the event during its five days. They exchanged the latest insights in Africa and the future of oil and gas, with sessions focused on African production and exploration, the energy transition outlook to 2050, technology, finance, and even a live CNBC broadcast panel.

A total of **17 government ministers** attended including officials from South Africa, Nigeria, Mali, Uganda, Gambia, Congo, Niger, Côte d'Ivoire, Guinea, Namibia and Sudan, with more than 200 speakers participating. Luminaries such as Hon. Minister Jeff Radebe, Minister of Energy for South Africa, and Dr. Fatih Birol, Executive Director, IEA, outlined their commitment to a sustainable future. The Hon. Minister Kachikwu confirmed the direction of the Nigerian upstream

and the American government reiterated their commitment to African energy development.

Africa Oil Week delivered both insights and tangible take-aways for operators, banks, service companies and governments alike. ■



Upcoming Super Basins Conference

AAPG has convened a two-day conference on the **Permian Basin** and the lessons learned that can be applied to basins across the globe. **Global Super Basins 2019: The Permian** focuses on the Permian Basin, a prototype onshore unconventional super basin that has seen recoverable resources more than double over the last ten years. Attendees will benefit from hard-won lessons by a community of dedicated oil and gas professionals who had the vision and expertise to understand these complex reservoirs and successfully reduced costs while up-scaling production.

With the success of horizontal drilling in the Wolfcamp and Bone Spring and favourable oil and gas prices ten years ago, the pace for drilling these formations accelerated and other horizons were tested, including the Spraberry, Clearfork and San Andres. The conference will look at the technical aspects of these horizons both from the geological and the engineering perspectives, including how stimulations have changed through the years to make areas that were sub-economic become very profitable.

The event will take place in **Sugar Land, Texas** (just south of Houston) at the **Sugar Land Marriott, 22–24 January 2019**. ■

Strategic Partnership



Seismic multi-client specialist **TGS** and **Axxis Geo Solutions (AGS)** have announced a strategic collaboration for ocean-bottom node projects in the North Sea. The area of mutual interest covers the core part of the central North Sea up to and including the **Utsira** area. Under this agreement, the parties will work together to develop opportunities to co-invest in multi-client ocean-bottom node projects. TGS will have a right to process all new node data acquired under this collaboration.

Norwegian company AGS is focused on the ocean-bottom seismic market. The company has a proprietary technology-agnostic node handling system and is currently operating four vessels with more than 9,000 nodes. The company's technology and capabilities are complementary to TGS' multi-client experience, client relationships, existing data and subsurface knowledge in this region.

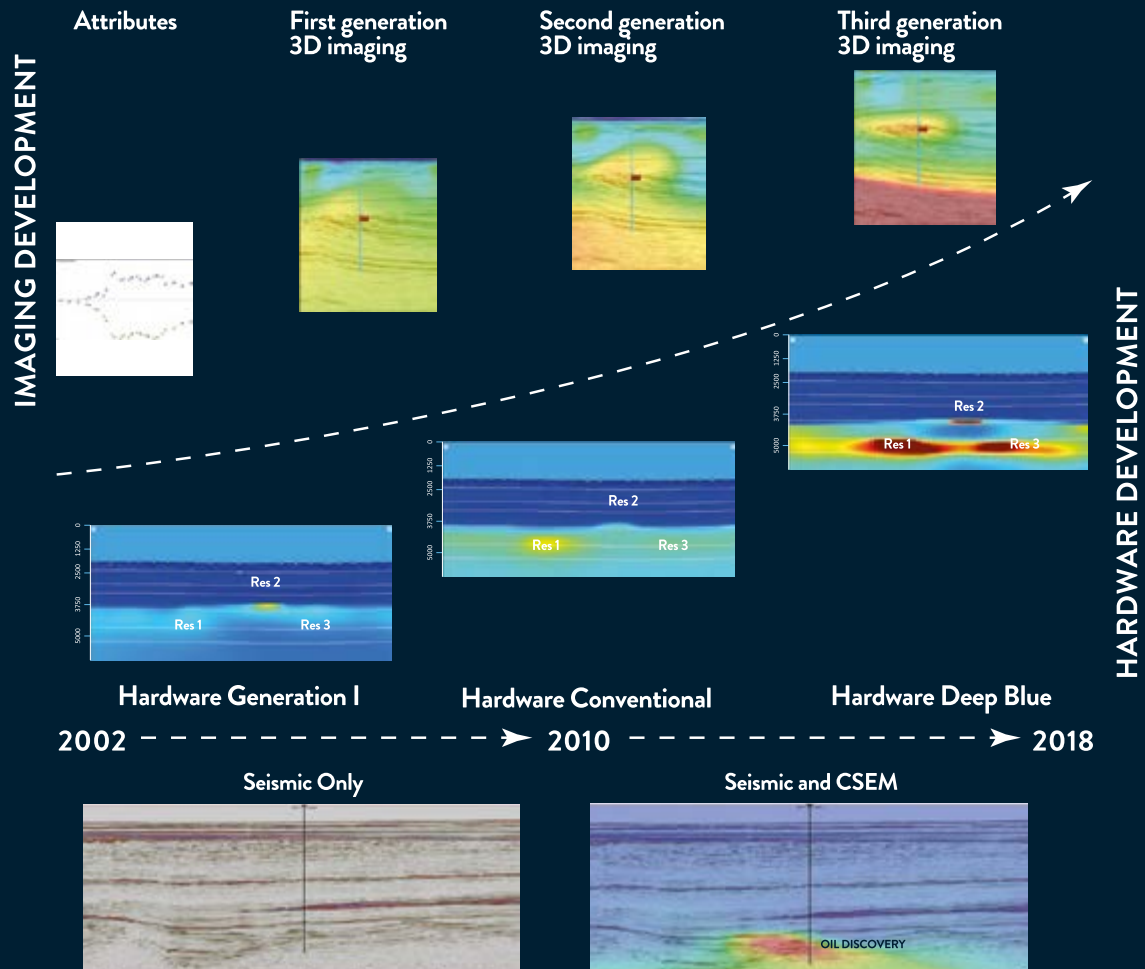
As part of this collaboration, TGS will join the 1,560 km² Utsira node multi-client project which is currently being acquired by AGS in the Norwegian North Sea. ■

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Carbonate Classroom

A string of pearls in a turquoise sea: as well as being picturesque, the unique Florida Keys offer the petroleum geologist a masterclass on carbonate sedimentary processes.

JANE WHALEY

Made up of over 800 islands, none more than 5.5m above sea level, and stretching in a gentle arc nearly 200 km from Miami south-westwards into the Gulf of Mexico, the Florida Keys are known for their distinctive ecology, clear waters and beautiful coral reefs; a famous playground for fishermen and snorkellers alike. However, this unique environment, the result of repeated episodes of flooding and exposure during the Pleistocene, also allows us an insight into limestone formation throughout the world.

Corals and Oolites

The relatively young Florida Keys have much older foundations. Precambrian-Cambrian igneous rocks were overlain by Ordovician-Devonian sediments and Triassic-Jurassic volcanics, deposited as the Florida basement separated from the African plate to join North America. Subsidence of the passive continental margin resulted in carbonate deposition about 160 million years ago in the late Jurassic, which continued through the Cretaceous and Tertiary to create the Florida Platform, an accumulation

of nearly 5,000m of shallow-water carbonates and evaporites with only minor components of terrigenous sediments.

Carbonate sedimentation continued through the Pleistocene and Holocene and on into the present, interspersed by glacial and interglacial periods and subsequent marine incursions and withdrawals. It is these variations in sea level, starting 125,000 years ago when the sea level was about 7m higher than at present, which have been primarily responsible for the geology and topography of the Florida Keys. At that time the sea was warm enough to allow coral to grow and reefs and sandy bars formed on the shallow shelf. Sea levels fell during the last ice age, so that about 20,000 years ago these reefs and ridges were exposed and vegetation grew on the once-submerged areas. The glaciers gradually melted, sea levels rose again, until now only the highest points of the ridges are visible, and both fossil and modern coral reefs lie submerged to the east and south of the arc of islands.

Two Pleistocene formations form the Keys: the coralline Key Largo Limestone and the oolitic Miami Limestone. The

A boat and a tranquil sunset: that's what a trip to the Florida Keys is all about.

Jane Whaley



former is described as an elevated coral reef rock that was submerged as sea levels rose. It consists of hermatypic corals (i.e. corals which deposit hard calcareous material to form the stony framework of the reef) with intra- and interbedded calcarenites and thin beds of quartz sand, and is thought to be up to 60m thick. The younger oolitic Miami Limestone is composed of millions of ooids, formed in clear current-swept waters supersaturated with calcium and carbonate that precipitated out around a nucleus grain to form these tiny spherical pellets. Coring has shown that the oolite is underlain by the older coralline limestone.

Both these limestones have undergone alteration and diagenesis due to subaerial exposure, which has produced widespread minor karstification and in places a reddish-brown laminated calcrete crust, known as caliche. This forms when aragonitic mud and sand dissolve in damp organic-rich peaty soil. As the water drains downwards, picking up oxidised iron and clay material, and the soil dries, the dissolved calcium carbonate precipitates as a thin iron-rich layer of calcite on the underlying limestone.

The Keys can be divided into the long linear islands of the Upper Keys, covering the south-west trending crescent from just south of Miami to Bahia Honda Key, where the Key Largo Limestone is at the surface; and the roughly east-west trending line of larger islands of the Lower Keys, composed of the Miami Limestone.

To see some of these features, let's



Coral and fish at Molasses Key, near Seven Mile Bridge.

take a (virtual) road trip down the iconic Interstate Highway 1 from where it joins the archipelago at North Key Largo to its terminus at Key West.

Heading Down the Keys

A boat trip to the reefs and corals on the ocean side of the islands is a good way to start your tour. Running roughly parallel to the Keys offshore oceanwards are several discontinuous ridges. The outer ones are composed primarily of massive Pleistocene and Holocene coral species, while the inner ridge is a backreef marine sand belt. Diving or snorkelling at the popular Grecian Rocks, about 7 km off Key Largo, allows you to see that this inner ridge is composed of coral, algal and molluscan sand flats and sand waves, with some massive corals.

The ridges are separated by the Hawk

Channel, a calm passage of water about three kilometres wide, which extends all the way from Miami to beyond Key West. It is a limestone ledge with a covering of fine-grained sediment and probably represents a palaeo-shoreline. It is dotted with patch reefs of mainly massive corals which lie just a few metres below the water surface – so be careful where you go with that boat! Further south, Tavernier Key Bank is another good place to explore the inner ridge.

While still in the Upper Keys, take a look at the 'lakes', mud banks and islands of Florida Bay: a famous laboratory for discovering how fine-grained limestone forms. The sticky H₂S-rich mud lining the shallow (less than 4m deep) bay is composed primarily of the faecal pellets of marine organisms, mainly worms. When reef corals first started forming at the end of the Pleistocene, this area was probably a limestone platform supporting a swampy freshwater marsh, but seawater slowly flooded it and limey mud began to accumulate. Topographic highs where mangrove islands had been present are now the mud banks and low islands seen dotted around the bay. Warm shallow seas like this are responsible for thick sequences of organic-rich carbonate rock, found worldwide and so important to petroleum geology.

As you travel down the Keys you will note the transition zone along the coasts, moving from low energy shallow water to a complex of mangrove swamps

Satellite image of the Florida Keys identifying places mentioned in the text.



and other salt-tolerant plants. Mangroves are very important to the ecology of the region, as they trap and stabilise fine sediment in their complex root systems, provide substrate for carbonate-secreting organisms, shelter a wide range of vertebrate and invertebrate organisms and protect the coastline from waves, storms and hurricanes. Destruction of mangroves for development removes this vital natural protection, sometimes with disastrous effects.

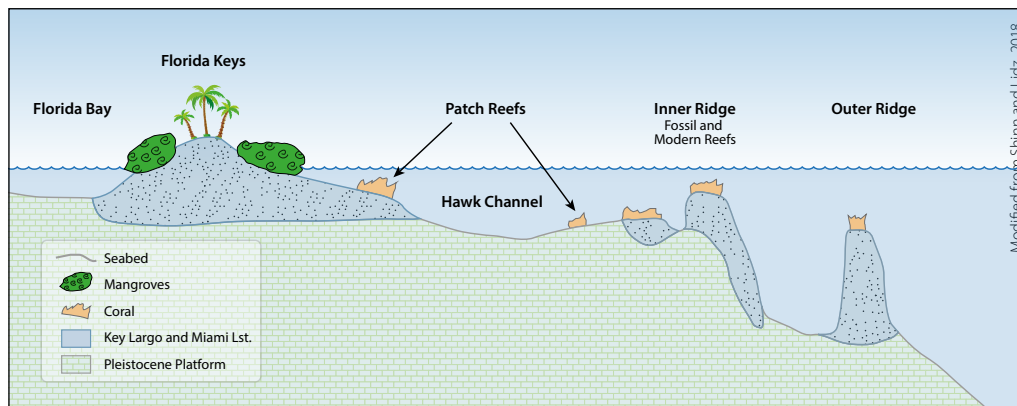
Windley Quarry to Key West

The best place to see clear exposures of the Key Largo Limestone is the disused Windley Bay Quarry near Islamorada, where visitors can inspect the coralline rock in the quarry walls. The rock is a white to light grey, moderately hard limestone composed mostly of coral heads with fossil molluscs and bryozoans, encased in a matrix of sand-sized grains. Although it is usually described as a coral reef, there is evidence that not all the corals are in their original growth positions, and the depositional environment may well have been a carbonate sand bank with patches of coral. Within some of the quarry walls there are layers of red soils, known as terra rossa. Over thousands of years, naturally acidic rain water dissolved some of the limestone, leaving behind a residue consisting mainly of African dust that had blown across the Atlantic Ocean and been deposited along with the carbonate sediments. The

Mangroves are vital for the environment of the Keys.



Jane Whaley



Modified from Shinn and Lidz, 2018

Sketch cross-section roughly north-west to south-east across the Florida Keys.

phenomenon of African dust storms in the Caribbean continues to this day.

After crossing Seven Mile Bridge (one of the longest bridges in the world when it was built over 100 years ago) you come to Bahia Honda Island, site of one of the only really good sandy beaches in the Keys (closed at the time of writing due to hurricane damage), where you can study Holocene aeolian dunes, beach ridges, and modern carbonate systems.

From this point the line of islands gradually starts to trend east-west: we have arrived in the Lower Keys. No longer elongate along the arc, the islands are larger and sculpted by north-south trending channels into sand bars. This reflects the fact that Big Pine Key, just to the west of Bahia Honda, marks the transition between the Key Largo coral and the Miami Oolite; the southern tip of the island is the most westerly outcrop of the older formation.

About 25 km before you reach Key West is Sugarloaf Key, an area where dolomitisation can be observed occurring, a discovery which has helped petroleum geologists recognise

analogous supratidal environments in ancient carbonate rocks. Dolomitisation increases carbonate porosity, so understanding its diagenesis is key.

Although the road ends at Key West, the reef system continues westwards a further 64 km to a shallow Pleistocene limestone platform called Halfmoon Shoal, where the sediment is thin, and sponges grow directly on the bedrock. Beyond this is a 30-km wide swathe of Holocene limey mud, known as the Quicksands, where mega-ripples move with the tides, possibly a cause of a number of shipwrecks in the area. It is possible to take a boat right out to the Dry Tortugas, although there is debate as to whether this atoll is actually part of the Keys' reefal system.

Unique Environment

The Florida Keys has a unique ecosystem with many species, on land and at sea, that are found nowhere else. These include the Lower Keys marsh rabbit, the Key Largo cotton mouse, the tiny Key deer, the Key ring-neck snake and the Stock Island tree snail, among many others. The Florida Keys National Marine Sanctuary is home to over 6,000 species and Florida Bay hosts a variety of birds, as well as sharks, dolphins, and manatees. But this is a fragile and ephemeral environment, and many of these species are endangered as their equally unique habitats have been encroached upon through development for tourists, retirees, hunters, fishermen and divers, as well as natural disturbances like hurricanes.

Nothing shows this as clearly as the coral reef, which has been in decline since at least the 1970s. Sewerage, pesticides, small boat pollution, and

Key West: Wreckers' City

The town of Key West, which has 32% of the entire population of the Keys, is now the epitome of 'laid back', but it has a much tougher history. After Florida was ceded by Spain to the United States in 1821, Key West became an important military outpost guarding the entrance to the Gulf of Mexico. It grew into a trading centre, but many of the island's inhabitants supplemented their trading and fishing income by recovering goods from shipwrecks – some of which they may have actually caused – and it became famous for rum, drug and people smuggling. By 1889, Key West was the largest and wealthiest city in Florida, and the beautiful Victorian wooden mansions of what is now 'Old Town' bear witness to that wealth.

One of the many beautiful colonial cottages in Key West's historic Old Town.



even an excessive use of oily sunscreens and the like have all contributed. The most serious danger comes from the gradual increase in sea water temperature and acidification and a continuing rise in sea levels, which could return these islands to the submerged condition in which they originally began to form, 125,000 years ago.

References available online. ■

Sunset at Key West.



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Bill Armstrong: Chasing Unicorns

THOMAS SMITH

Independent geologist Bill Armstrong and his small Denver exploration company's quest was 'old school': simply to find new high impact oil and gas fields. They did, and their latest of a long string of successes may turn out to be the third largest field ever discovered in the US.

"I was informed early on in our pursuit that most, if not all, of the large, onshore, conventional fields have been found," says Bill Armstrong, founder and owner of the Denver independent that bears his name. "I was told 'You might as well be looking for unicorns'. Well, we found one!"

What Bill is referring to was the discovery of the Pikka/Horseshoe field on Alaska's North Slope. This field could ultimately rank near the top of US conventional oil fields, behind only the Prudhoe Bay and East Texas fields. With the more recent discovery by ConocoPhillips of the 750 MMbo Willow oil field to the west of Pikka, Bill thinks that "Unicorns not only exist but potentially run in herds!"

Long Road Ahead

Bill Armstrong grew up an 'oil field

brat' in Abilene, Texas. His dad was an independent working West Texas at the time, giving Bill opportunities to meet the likes of T. Boone Pickens, the late Tom Brown and others; he even caddied for some of them at the Abilene Country Club. His dad told Bill these people he met were independent oil and gas guys. Right then, Bill knew he wanted to be a part of that fun group: full of life, full of energy and fun, fun, fun. "Up today, down tomorrow but having fun all along the way.

"Since graduating in geology in 1982 from Southern Methodist University (SMU) in Texas, my definition of 'making it' has changed substantially," says Bill. "I started Armstrong Oil and Gas in 1984 when I was 24 years old and oil prices had collapsed below \$10/bbl. I had no backing, no friendly bankers,

and my only partner was my wife Liz who I met in Geology 101 at SMU. All I knew was that I wanted to hunt for buried treasure."

Bill focused those early years "crawling along deal to deal for the first decade", chasing small prospects in Kansas, Colorado, Wyoming, North Dakota and other independent-friendly regions. At times while pitching deals, Bill met and hired some 'awesome talent'. "This 'band of brothers' has been with me for the last 20 years or so," says Bill. "We have never had a contract between us and we have drilled lots and lots of wells."

This geological and geophysical talent allowed Armstrong Oil and Gas (AOG) to focus on internally generating, assembling, and drilling large company-impact exploration opportunities. "Most everyone told me I was crazy to have this business model," says Bill. But the unique business model for this small independent has turned out to be very successful. AOG has been involved in the discovery of new fields with ultimate recoveries approaching five billion barrels. Their exploration activity ranges from the North Slope of Alaska down to the Gulf of Mexico. "Along with a lot of dry holes, we have found new fields in over a dozen different geologic provinces," says Bill. "It has been mostly fun, with the wins overshadowing the losses."

Focus: The North Slope

"I first dipped my toe into Alaska in 2001 and have been pretty busy up there since," says Bill. "Big conventional fields are hard to find, with only 30 in the US having an EUR in excess of 500 MMbo. Seven of those were found on Alaska's North Slope, making it a great place to find large fields. Another interesting fact is that all these fields were found by accident while actually pursuing other plays and are predominately

Bill Armstrong dressed for success and having fun at the Horseshoe well with a wind chill of -57°C on Alaska's North Slope.



stratigraphic traps. Compared to the other places I have worked, the Slope is wide open with opportunities and lots and lots of running room.”

AOG partnered with Pioneer in 2002/3 targeting the Kuparuk reservoir. Instead, they found oil in the Upper Jurassic Nuiqsut Formation (a secondary objective) and the Oooguruk field was discovered. A second discovery, with AOG partnered with Kerr McGee, was made in the Late Cretaceous Schrader Bluff sands at Nikaitchuq. AOG chose to sell their positions in those fields to ENI and the two fields now are producing just under 40,000 bopd.

“We took some time away from Alaska to look into all of the hoopla around the unconventional ‘mania’ but kept coming back to the North Slope,” says Bill. “This time we wanted to stay onshore, close to infrastructure and drill from 3D seismic. We acquired or shot a lot of 3D seismic data and eventually, based on this data integrated with well control, we assembled leases totalling about 344,000 hectares. We invited Repsol to help us explore and over the last five years have drilled 19 wells, all successes.”

Pikka vs East Texas

Bill Armstrong really likes to compare the Pikka and East Texas fields. The latter was discovered in 1930 by the independent ‘wildcat driller’ Dan Joiner against all odds and ‘smart money’ (see *The Great Black Giant*; *GEO ExPro* Vol. 12, No. 2). The field was a stratigraphic

trap on the west flank of the Sabine uplift that would ultimately be found to be 64 km long by 8 km wide and produce more than 5.4 Bbo.

In North Slope, Alaska, some 83 years later, Repsol and AOG drilled the Q3 well. They had a great prospect with multiple play objectives hitting oil in a shallow zone (Cretaceous Nanushuk Formation) that did not show up clearly seismically and turned out much thicker than anyone suspected. Like the East Texas field, Pikka was a stratigraphic trap but a mirror image of East Texas, pinching out east to west.

“We followed the discovery well with an extension 8 km north (Q7), then another 6.4 km further north (Q6), then went 4.8 km south (Q8),” says Bill. “Just this past year, we started really believing in our geologic model and seismic and stepped out an additional 34 km to the south at our Horseshoe well – and found over 30m of pay in the same huge tank, same sand, same oil water contact, same pressures... so, kinda fun.”

As it turns out, both the Pikka and East Texas fields are roughly the same length and width, both are stratigraphic traps, both are Cretaceous-aged deltaic sands draped over the flanks of a high, have similar type crude oils, same depth, same original bottom hole pressures, same gas to oil ratios. But Pikka holds about 14 Bb original oil in place, being three times thicker than East Texas; however, recovery at Pikka will be less because the Woodbine Sand at East Texas has much better permeability. Bill thinks this field will eventually become the third largest conventional field in US history.

The Basics

“Alaska is not easy and it is not always fun,” says Bill. “Things up north happen way slower than I think they should; it’s very expensive, and even some of

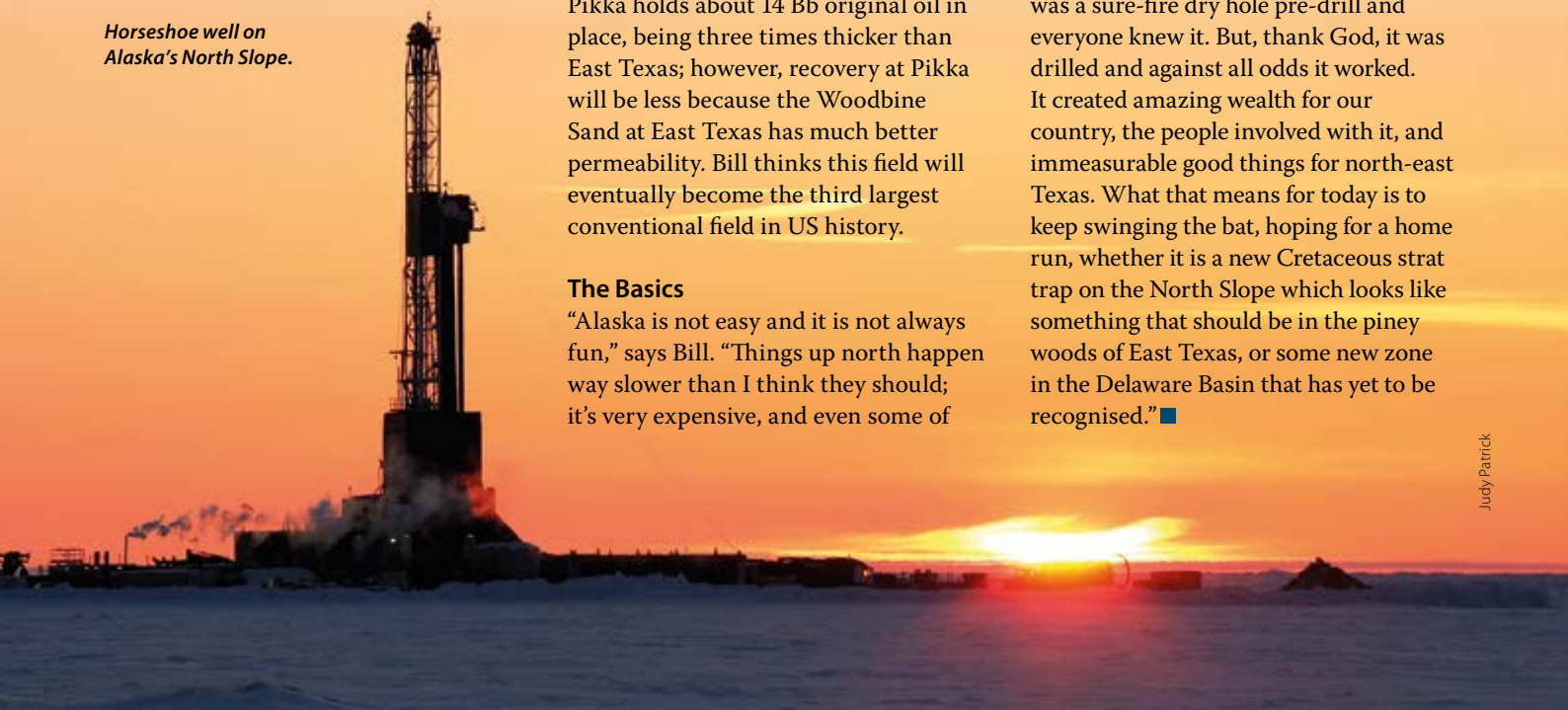


Bill at the East Texas discovery well, Daisy Bradford #3. He loves reading about oil exploration and the discovery of large fields.

the seemingly most mundane things are somehow more complicated. But unlike most conventional areas there is still lots of grass on the playground. I had plenty of sleepless nights trying to figure out how I was going to pay for all of this development until I sold a large chunk of the discovery to Oil Search.” (Oil Search is a multinational oil and gas exploration and development company founded in 1929 and incorporated in Papua New Guinea. They currently operate all of Papua New Guinea’s oil fields and have operations in Yemen, Egypt, Libya, Iraq, and most recently on the North Slope of Alaska.)

“What this is about is that there are still big fields to be found, and the best way of not finding them is not drilling wells. The East Texas discovery was a sure-fire dry hole pre-drill and everyone knew it. But, thank God, it was drilled and against all odds it worked. It created amazing wealth for our country, the people involved with it, and immeasurable good things for north-east Texas. What that means for today is to keep swinging the bat, hoping for a home run, whether it is a new Cretaceous stratigraphic trap on the North Slope which looks like something that should be in the piney woods of East Texas, or some new zone in the Delaware Basin that has yet to be recognised.” ■

Horseshoe well on Alaska’s North Slope.



Seismic Detection of Source Rocks

Identification of potential hydrocarbon source rock horizons is the first and most important step in the evaluation of frontier basins.

IAN DAVISON, Earthmoves Ltd.; KARYNA RODRIGUEZ and DAVID EASTWELL, Spectrum Geo Ltd.

Even modest amounts of total organic content can significantly change the physical properties of shales, providing clues for source detection on seismic data. This article discusses how seismic analysis can be used to identify source rock, using examples from the South Atlantic.

The deepwater South Atlantic margin (south of the Walvis Ridge) is notable for the lack of sediment-filled syn-rift half grabens and the presence of large seaward dipping reflector packages (SDRs) which when drilled proved to be predominantly subaerial

basalts. The accommodation space produced during extension was filled by magma rather than sediment, which implies an absence of syn-rift source rocks. However, the presence of good quality post-rift Aptian/Barremian-age source rocks has recently been proven along the deepwater Namibian margin (Melo, 2012; Guiza et al., 2016). This has significantly improved the perceived hydrocarbon potential, with several major oil companies recently moving into the area. Unfortunately, there have been no commercial hydrocarbon discoveries so far. Some of these well

failures can be attributed to lack of source rock presence and complex migration pathways.

However, examining the nature of the Aptian/Barremian source rocks in the Murombe-1 well (offshore Namibia) and correlating them to the seismic data allows their seismic reflector characteristics to be used to predict their presence elsewhere, thus significantly reducing the exploration risk.

The conjugate South American Atlantic margin extends some 2,300 km from the Florianopolis Arch southward through the Brazilian

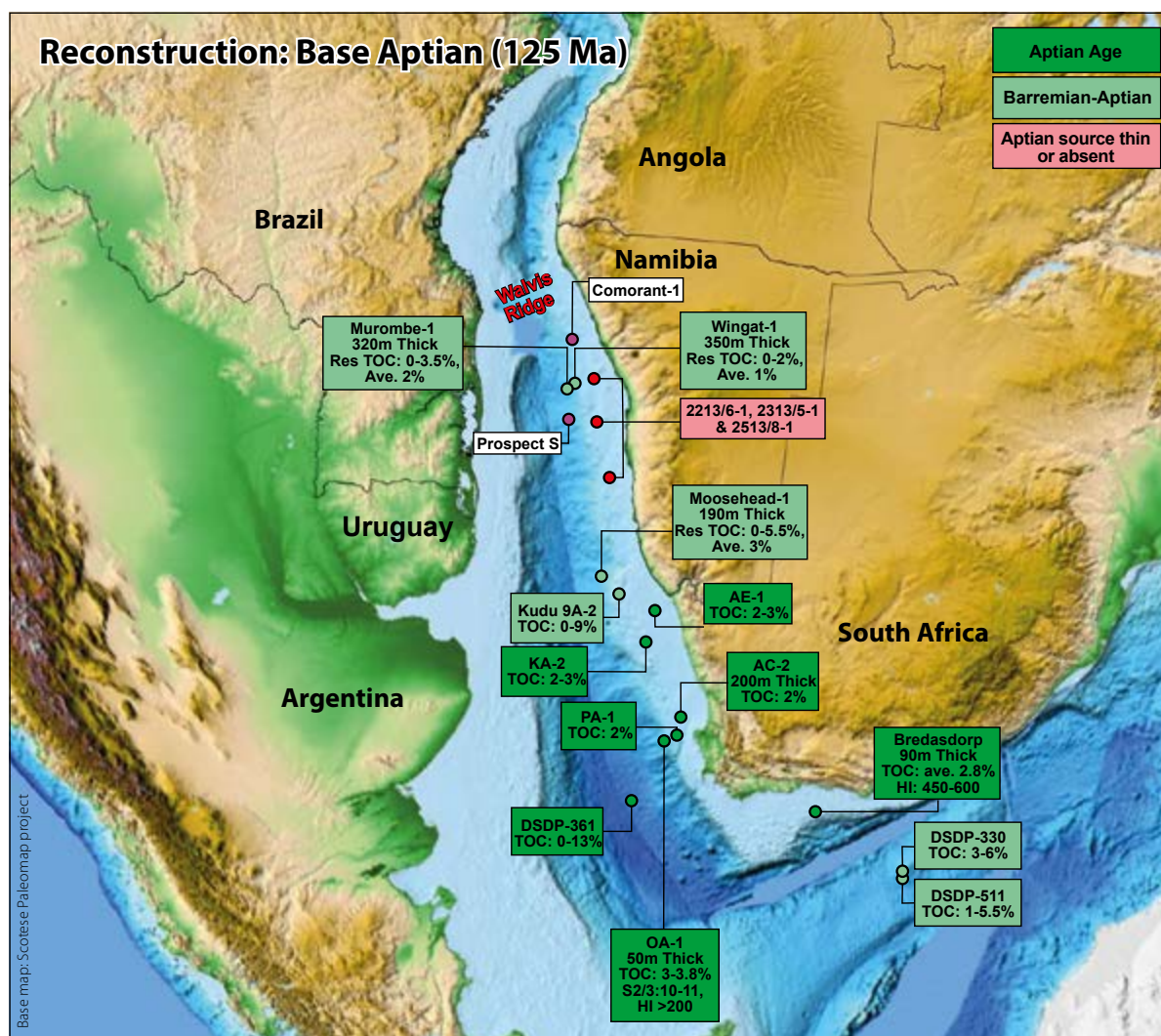


Figure 1: Map of the southern South Atlantic margins showing locations, source rock thicknesses and residual TOC levels from wells on the African margin.

Pelotas Basin into Uruguay and Argentina (Figure 1). Licence rounds are planned later this year and open blocks will also be offered. So far, no wells have been drilled down to the Aptian-Barremian potential source level along this segment of deepwater Atlantic margin. Analysis of seismic data will be crucial to reducing risk of source rock presence, quality, and maturity across these vast areas prior to wells being drilled.

Source Rock Characteristics

The Aptian/Barremian source rocks are widely distributed along the south-west African margin: this time period is well known as an important worldwide anoxic event. Source thickness can reach up to 350m, with the highest TOC values up to 10%, and hydrogen index values up to 550.

Sidewall core samples of the source rocks are composed of hard, silty, micaceous, non-calcareous, pyritic, dark grey to black shales. The highest gamma ray readings in the Murombe source rock shales are greater than 150 API units, and the sidewall core descriptions indicate these high gamma zones are the darkest coloured shale. The individual high gamma-rich source rock intervals are generally less than a metre thick and are interbedded with medium grey claystones spread over a 320m-thick gross interval. Residual TOC values average 2% with maximum values of 3.5%. These values were measured from drill cutting samples taken at 9m intervals, so it is worth noting that individual 1m-thick organic-rich source beds probably reach much higher TOC values of 10% or more. Also, the measured TOC can be

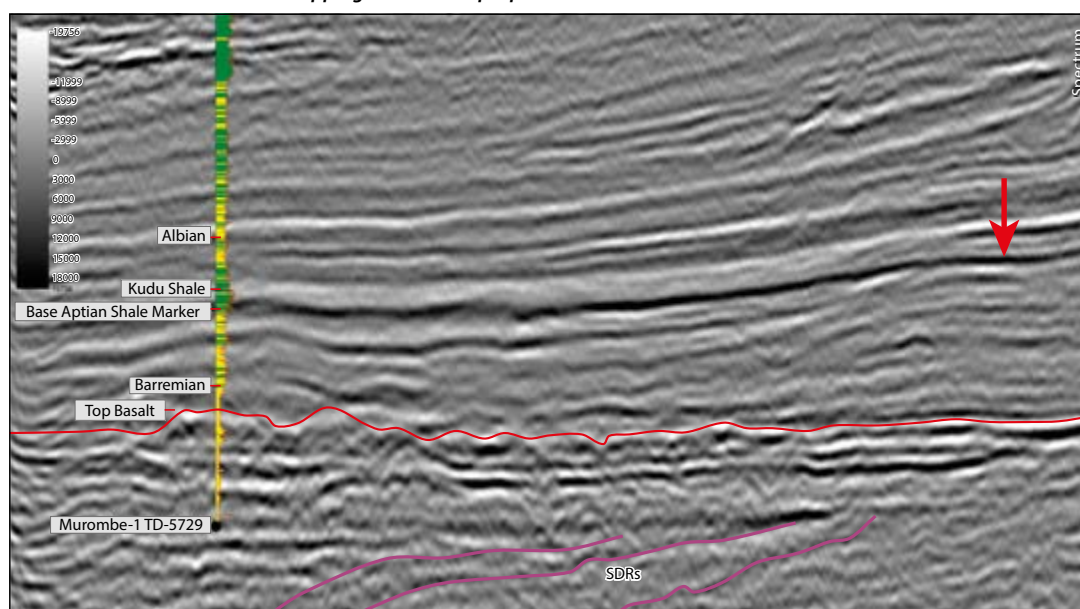
considered to be residual values, as some hydrocarbons have likely already been expelled from the source rock.

Kerogen has a low density of 1,100 to 1,400 kgm⁻³, half the average mineral density of the shales, so the organic matter content, by volume, is twice the TOC value by weight. The low-density kerogen also has a low compressional seismic velocity, resulting in an anomalously low acoustic impedance (AI) contrast at the top of the sequence. Shales exhibit a non-linear decrease in AI with increasing TOC; AI values can reduce by almost 30% compared to an average shale, even at TOC values as low as 2% (Løseth et al., 2011). Hence,

the top source rock should exhibit a large negative (soft) reflection and the base of the source rock a positive (hard) reflection. The source rock interval encountered in the Murombe well can be correlated on SEG negative polarity seismic data with a strong black (positive amplitude) reflection (Figure 2) and can be mapped over wide areas. The source rock reflector pinches out on the paleo-Aptian shelf edge and is not present in the shallow water. The reflector also loses amplitude on the ocean abyssal plain. Importantly, a similar negative reflection has been identified along the conjugate South Atlantic margin at a similar vertical

Source Rock Property	Seismic Response	Seismic Clue to Detection
Low compressional velocity and low density in source rock due to high kerogen content.	Decrease in acoustic impedance at top of source rock sequence (mode changes compression (P) to shear wave (S) at interface) and increase in acoustic impedance at the base.	Extensive, high amplitude 'soft' reflection associated with decrease in AI at the top of the source rock sequence. Extensive, high amplitude 'hard' reflection associated with increase in AI at the base of the source rock sequence.
Highly anisotropic , bedding-parallel aligned clays, mica and squashed kerogen.	Low seismic velocity orthogonal to bedding and high parallel to bedding.	Anomalously large AVO effect at top of source rock sequence. Amplitude dims with offset, due to increased incidence angle resulting from anisotropic ray-bending.
Low density due to high kerogen content.	Change in frequency, primarily due to increased anelastic absorption.	Marked and constant decrease in frequency of seismic wave in and below source horizon.
High malleability due to high kerogen content.	Increase in seismic wave attenuation.	Relatively lower amplitude reflector sequence in and below source horizon.
Increased porosity and lower density pore fluid fill with onset of oil generation.	Further decrease in acoustic impedance contrast.	Relative increase in negative seismic amplitude correlates to area where source rock enters oil window.

Figure 2: 2D seismic section in TWT, tied to the Murombe well log (gamma ray and lithology) showing that the source rock interval encountered in the well correlates on SEG negative polarity with a strong (soft) black reflector on the seismic data (red arrow). Murombe is projected from 2.5 km onto the line. SDRs are visible at the well TD which terminated in basalts. Seaward dipping reflectors in purple.



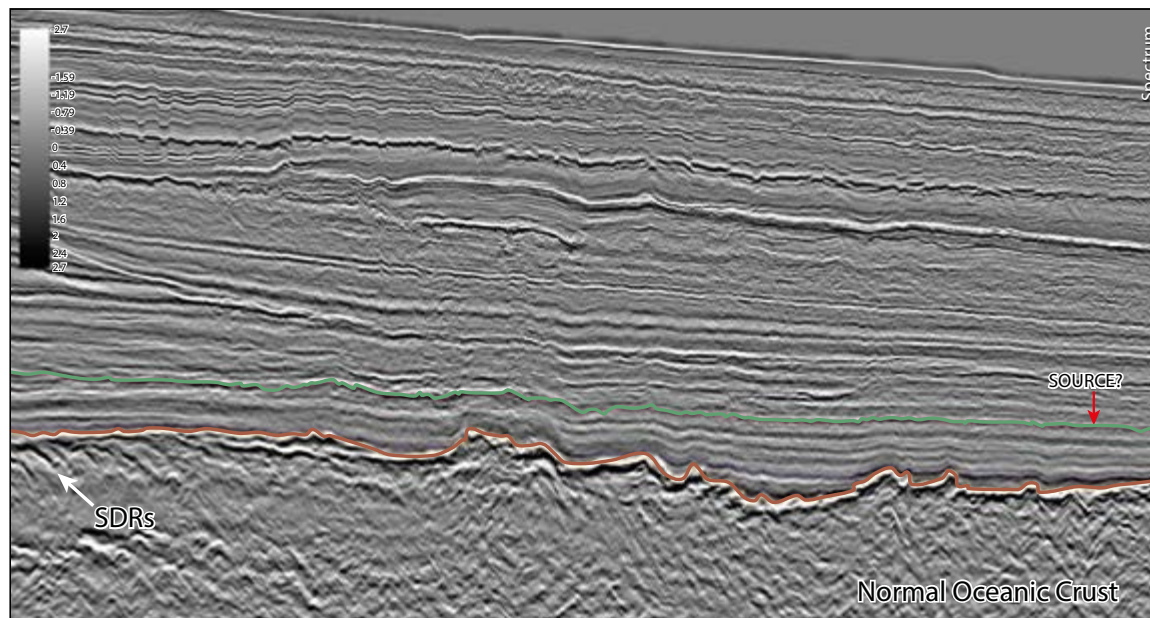
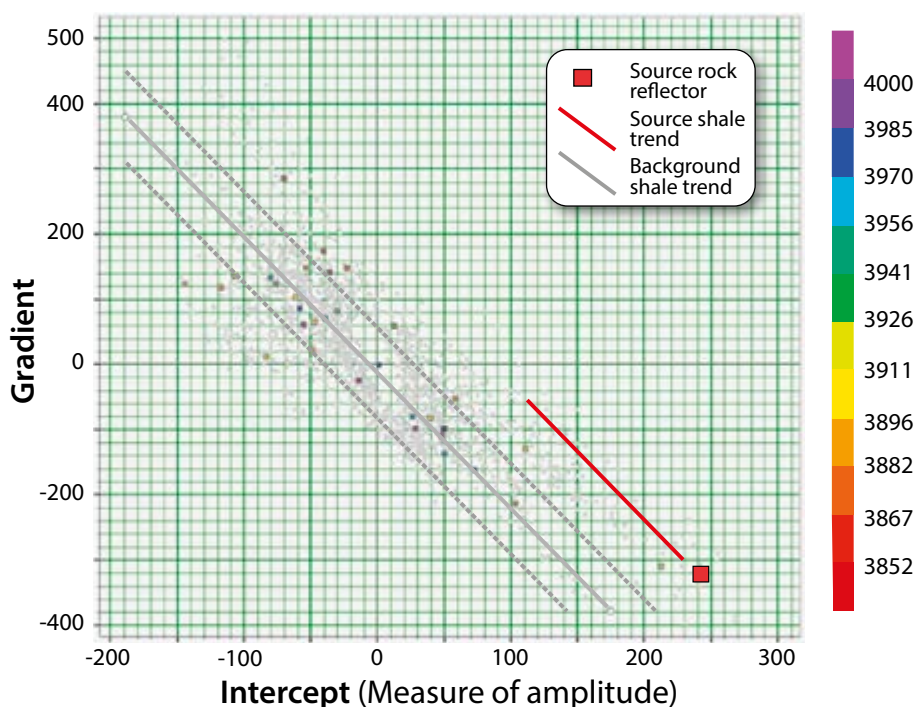


Figure 3: Seismic section along the Argentina margin. Potential top Aptian source rock is arrowed red and outlined with a green line.

Figure 4: AVO analysis of the source rock reflector and 'background' shale reflectors using the Hampson-Russell tool kit around the Moosehead-1 well in Namibia. The horizontal intercept axis is an approximation of the amplitude at zero offset. The vertical scale (gradient) is a measure of the amplitude dimming effect with offset. The red square represents the top source horizon at zero offset for one CDP gather on the analysed seismic line. The cloud of grey points represent background shale measurements with the grey diagonal line showing the average background AVO effect in normal shales (two parallel lines indicate error bars). The red diagonal line indicates the source rock trend, which lies well above the background trend.



distance above the SDRs (Figure 3).

Oil generation significantly increases both kerogen porosity and overall shale porosity, which causes a further reduction in seismic impedance (Vernik and Landis, 1996; Sondergeld et al., 2010). A useful test for the presence of a source rock is, therefore, to compare the seismic amplitude of the top source reflector with the predicted limit for the onset of oil generation. If there is a marked increase in amplitude which coincides or is approximately parallel to the calculated zone of oil maturation, this is further proof of source rock presence.

Seismic Anisotropy and AVO Analysis

Kerogen-rich shales consist of fine laminations on a micron to millimetre scale, composed of alternating 'squishy' kerogen and harder detrital and clay minerals. This hard-soft layering results in a strong intrinsic anisotropy in the source interval. Bedding anisotropy is also present at the centimetre to metre scale in the form of richer kerogen beds alternating with more siliclastic-rich lighter grey shales, as seen on the gamma ray plot for the Murombe well. This anisotropy at all scales means the source rocks will have

a higher compressional wave velocity parallel to the bedding, compared with a lower velocity orthogonal to bedding. Velocity anisotropy (parallel/orthogonal ratio) can reach up to 1.25 (Vernik and Landis, 1996). Strong anisotropy is also responsible for more pronounced mode conversion of P to S waves on the downgoing and upgoing paths through the source interval, and at the top and base source rock interfaces, primarily due to the increased incident angles at the interfaces, resulting from increased refractive ray-bending.

Geochemistry at wellsite

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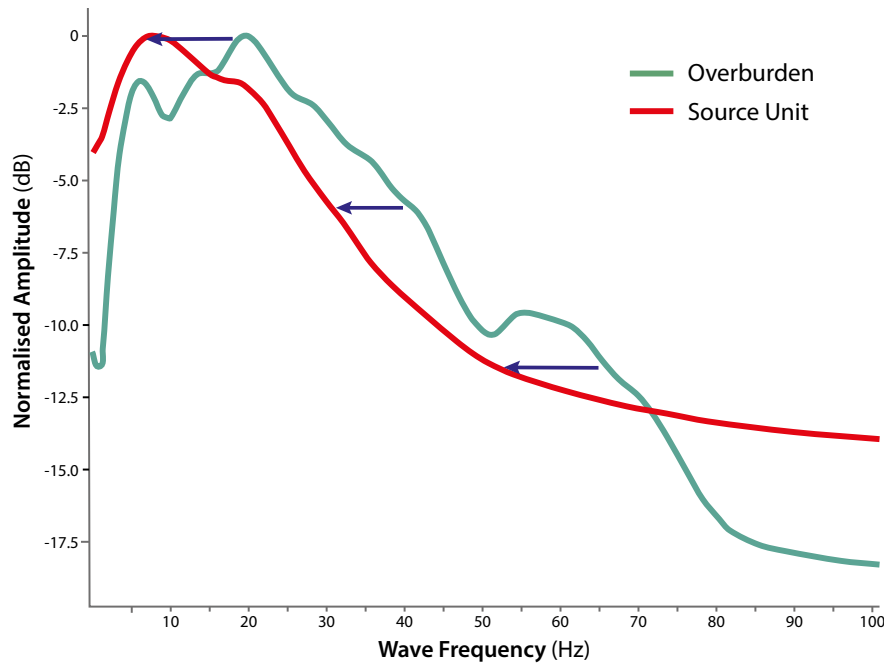


Figure 5: Plot of seismic wave frequency (horizontal axis) versus normalised amplitude for the overburden and source rock shales (vertical axis) on a seismic line from Argentina. There is a 10 Hz frequency drop (blue arrows) from the overburden into the source rock shale. Window size analysed was 600 ms TWT.

The seismic velocity anisotropy and wave mode conversion creates a large reflection amplitude dimming effect with increased source to receiver offset (AVO effect), which has been shown to increase with TOC content. The significant decrease in AI coupled with the strong dimming of amplitude with offset is known as an AVO Class 4 response, which is not very common in sedimentary rocks. However, all shales exhibit an AVO effect, so the source rock reflector has to be compared with 'background' shale reflectors. This analysis has been performed around the Moosehead well in Namibia and for the top source reflector in Argentina, both showing that amplitude dimming with offset is much greater for the top source rock reflector compared to the background shales (Figure 4).

Seismic Attenuation

A high TOC source rock should increase the intrinsic seismic attenuation due to the high kerogen content. The malleable kerogen will permit relative grain movement to occur more easily, absorbing the kinetic energy of the seismic wave, which should produce a sharp reduction in the both the amplitude and frequency of seismic reflections below the source rock. However, other

factors such as overall transmission loss due to the waveguide effect of interbed multiples, scattering, and composition may outweigh the effect of intrinsic absorption. Analysis of seismic wavelet frequency from a seismic line in Argentina (Figure 5) indicates a distinct and constant drop of approximately 10 Hz below the top potential source rock reflector. If all else is equal this could be attributed to the increased seismic attenuation of a source rock.

Analysis De-risks Source Presence

Once seismic data have been acquired, amplitude, frequency and AVO analysis may significantly de-risk source rock presence and maturity at very little extra cost and effort. These are underused tools that deserve more attention. Seismic detection becomes even more valuable and better constrained once a well has been drilled; if a good source has been identified this can then be independently verified and mapped using the methods outlined here.

Acknowledgement: Ian Jones kindly provided very useful comments on this article. Duncan Wallace and Robert Fox are acknowledged for their insightful discussions.

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Rediscover Your Reservoir

How much do you really know about your reservoir? Rediscover it through Raman spectroscopy and drill more productive wells.

MARYBETH WEGNER,
GRANT A. MYERS, Ph.D. and
NATHAN NICHOLAS; WellDog

In today's competitive market, reservoir rock characterisation has become a critical success factor. Understanding the reservoir's heterogeneity as well as the intricacies of the rock could make the difference between profit or not. Measurements that the industry has used in recent times include mineralogy (minerals present and in what quantities), total organic carbon (TOC), thermal maturity, brittleness, microfossil identification and distribution, and porosity. Understanding how these change throughout the reservoir is important for reservoir evaluation and completion designs. Data such as these are utilised for determining where to land a lateral and exactly where and how best to stimulate the well.

Another critical success factor is the interaction between the chemical composition of the fluids and solids used in completing or stimulating a well and those that exist in the subsurface. These interactions can affect the physics and chemistry of a well and impact its producibility. By combining intimate knowledge of the well's fluids with the geochemical profile of the formation, a company can more efficiently plan stimulation plans, or even secondary recovery.

Raman Spectroscopy – A Brief Introduction

Raman Spectroscopy is an old technology, but modern optics and computing technologies are opening new applications that were previously off limits. It is named after Sir C.V. Raman, one

of the scientists who discovered it in the 1920s, earning him the Physics Nobel Prize in 1930. In the classical description, photons of light inelastically scatter off molecules, resulting in the transfer of a small amount of energy. When energy is transferred to the molecule, the molecule begins to vibrate, and the scattered photon is red-shifted in colour (termed Stokes Raman scattering). The magnitude of the Raman shift is characteristic of the molecular vibration. In modern times, a monochromatic laser is used as the excitation source and specialised filters along with sensitive photon detectors are used to capture Raman scattering for chemical fingerprinting of materials. The colours of the scattered photons are different for each molecule and are based on the chemical bonds within the molecules.

Raman spectra can be acquired using a petrographic microscope that focuses a laser onto the surface of the sample, an area as small as one square micron. The light scattering from the sample passes through a filter and a Raman spectrum from the material in that area is recorded on a CCD-detector (Figure 1).

Raman spectra can be used to identify and quantify a variety of materials on a molecular vibrational basis. This includes thousands of minerals, as well as organic material in source rocks and gases. The Raman shift is based on molecules and the arrangement of the molecular bonds, the advantage being that it is possible to differentiate

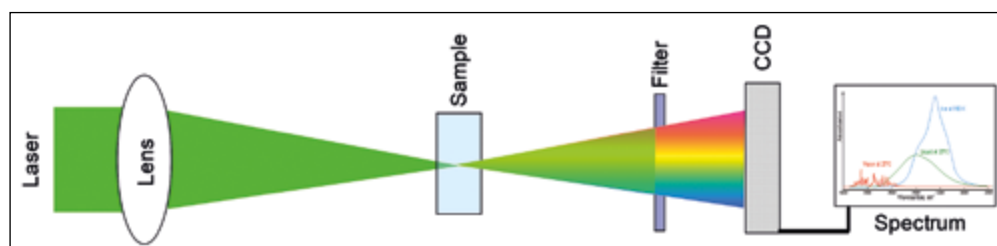


Figure 1: Overview of how Raman spectra are captured and an example of the Raman spectrum of water, which shows three Raman-active molecular vibrations: bending, symmetric stretching, and asymmetric stretching.

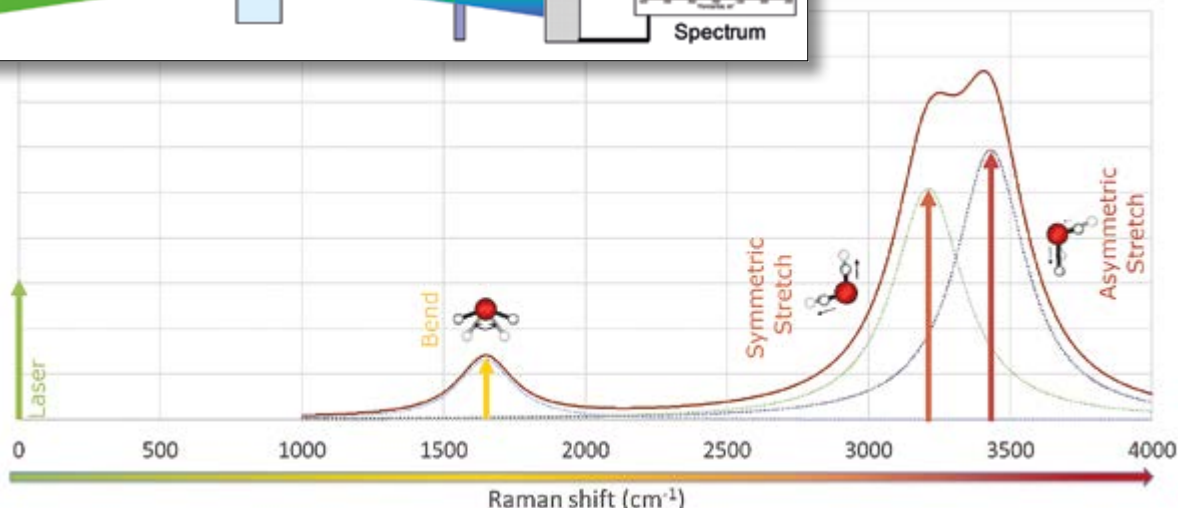


Figure 2: (a) Raman spectra of various gases. (b) Example spectra of some clays, micas and quartz. (c) Because this technique is based on molecular vibrations, elemental equivalent polymorphs can be differentiated.

between minerals which have the same elemental composition but different structures. The atoms in those crystals are arranged differently, and therefore the vibrations are different: for example, polymorphs of titanium oxides and iron sulphides are easily distinguished in Raman spectra.

In Figure 2a, Raman spectra are shown from a variety of gases important in the oil and gas industry, including light hydrocarbons, carbon dioxide, nitrogen and hydrogen sulphide. These can be measured in a variety of ways: dissolved in formation fluids in situ, at the surface through a pressure manifold and even mid-stream in the pipeline. Reservoir Raman Spectroscopy technologies, such as those performed by WellDog, can be applied to a wide range of well prospecting, development and production scenarios.

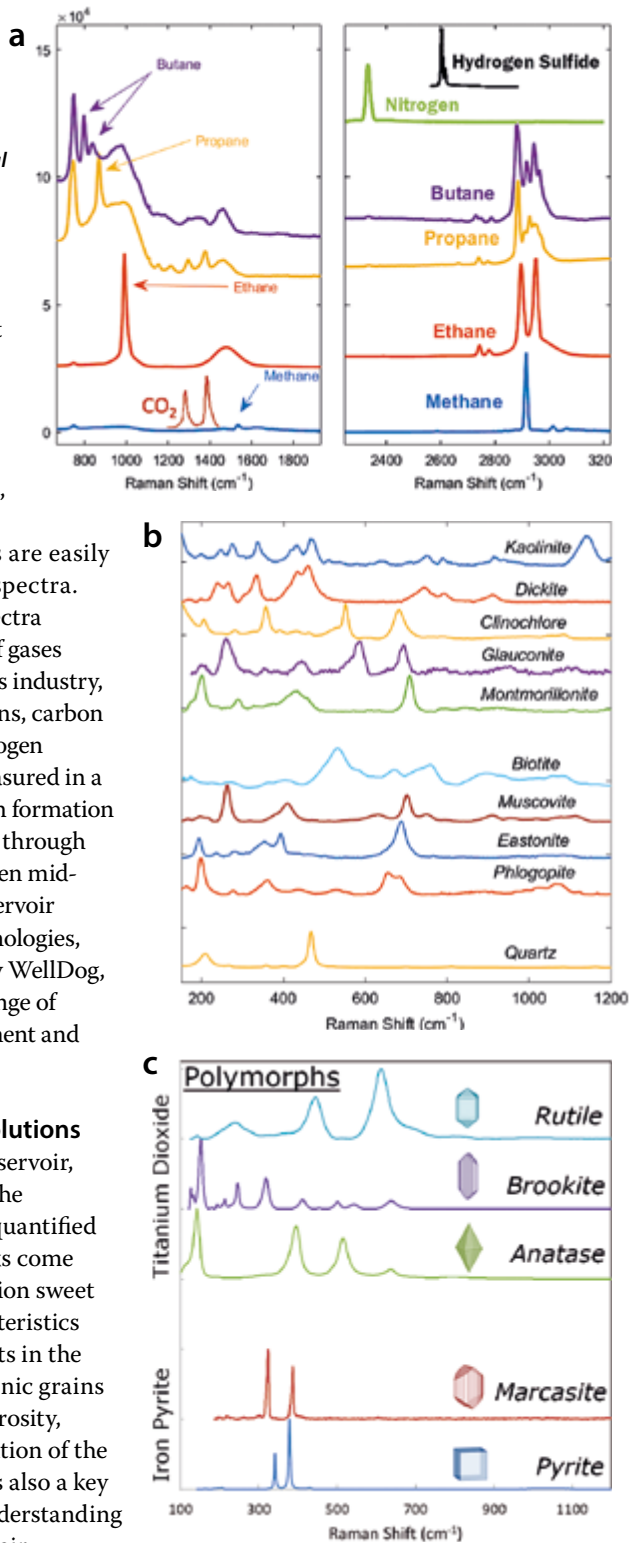
Raman Spectroscopy Solutions

To fully understand the reservoir, certain characteristics of the reservoir rock need to be quantified to determine how the rocks come together to create production sweet spots. The primary characteristics are the organic constituents in the rock, mineralogy of inorganic grains and associated cement, porosity, permeability, and composition of the fluids. Thermal maturity is also a key piece of information in understanding the best targets in a reservoir.

Raman microscopy yields information about the solids and pore spaces of the reservoir, as well as thermal maturity. It is a non-destructive, repeatable, objective way to look at cuttings, core, plugs or thin sections.

There are many challenges in determining thermal maturity for the purposes of source rock assessment. Important factors are temperature, time, and pressure; temperature being the most sensitive parameter in hydrocarbon generation. Reconstruction of temperature history is essential when evaluating petroleum prospects.

Vitrinite is a powerful method favoured by petrographers looking for coal, where that woody maceral is commonplace, but in shales – marine shales in particular – vitrinite can be extremely rare, if it exists at all. Vitrinite reflectance



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Reservoir Management

is a tedious measurement. Anisotropy affects it, as the material polishes up differently based on which face is oriented upwards. This forces the petrographer to locate and perform measurements on at least 50 bits of vitrinite, ideally more, all the while being careful to avoid recycled material, or solid bitumen, which can polish to a similar lustre, but has a different correlation to thermal maturity. Raman spectroscopy, however, provides a direct method of measuring thermal maturity and WellDog has participated in various studies to determine how Raman thermal maturity results compare to other methods. Initial results are promising, and more data points continue to bring enhanced confidence.

Reservoir Raman spectroscopy therefore not only determines the composition and quantities of the minerals present in the reservoir, but it can also measure TOC and thermal maturity.

Know Your Reservoir Rock

An example of the use of Raman spectroscopy is the non-destructive lab service provided by WellDog's Reservoir RockHound, which can discern the minerals, microfossils, organic matter, and pore spaces (including their contents) in core, cuttings, plugs or thin sections. It can also help determine thermal maturity.

The instrument is built around a petrographic microscope which can capture conventional optical images of the sample, as well as focus a Raman excitation laser to a single-pixel spot (Figure 3a). The sample is mounted on a digital encoded stage with sub-micron precision, which allows one to collect and characterise the Raman spectra from the material in the focused spot. Samples are studied in an automated, methodical fashion either by a point, line, or grid scan.

Figure 4: Optical view of a sample (a), and three Raman parameters differentiating various mineral and organic components: pseudofluorescence (b); carbon index (c); and G-Cluster width (d). Bitumen streamers can be seen in each photo as light gray (a), dark blue-black (b and c), and yellow-orange (d). Bright framboids in the optical view are pyrite, which can also be identified in each photo.

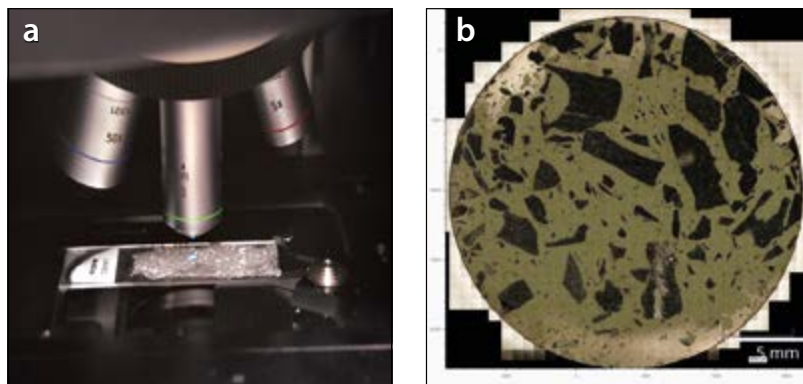
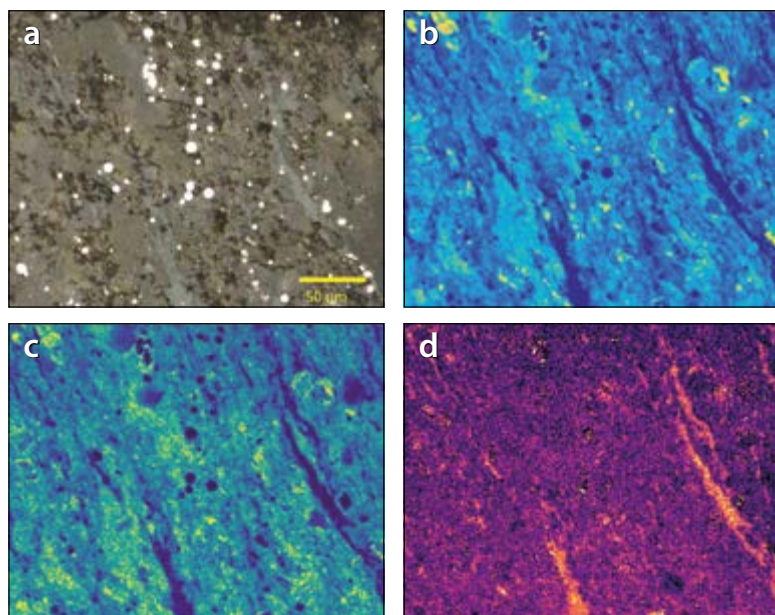


Figure 3: (a) Photograph of the laser spot-focus onto the surface of a thin section sample. (b) Composite view of multiple passes.

Using a grid provides a thorough analysis of the rock and its components. Various spectral maps can then be created to show exact minerals present in the sample, including their location. This leads to quantifiable mineralogic composition.

Figure 4a shows the highest resolution on the microscope. Bright pieces in the photo are pyrite (some rounder framboids). The stringy lighter grey colour is the solid bitumen. The rest is additional organic matrix material. A hyperspectral map consisting of Raman spectra in every square micron over this region (about 200 x 250 square microns) has been collected and analysed. Figure 4(b–d) shows three maps of Raman spectral parameters. The first can be termed pseudofluorescence and is a false-colour map showing the range of fluorescence intensities. The second and third are Raman characteristics of the organic material which distinguish carbon types and can be correlated with thermal maturity.

What Can This Do For You?

Practical, fit-for-purpose technology can help one achieve optimal wells. Not only can the downhole fluids be identified and quantified, but the reservoir rock itself can also accurately be described. Additionally, since the source of the fluids is known, the composition of the reservoir from which those fluids flow can also be determined.

What does that mean for the bottom line? How might these technologies benefit oil and gas exploration and appraisal?

If the features of the fluids in the well are known – composition, quantities, and where each is coming from – and the solids are also understood, then exploration and appraisal teams can more accurately determine which zones to target within the reservoir. Reservoir, production, and drilling and completions engineers can understand the best places to stimulate in the well and which fluids might be most effective in the process. Future secondary recovery efforts can also be maximised. This will save millions of dollars and significant time and resources. More environmentally sound decisions and perhaps even better public relations will result.

Armed with full knowledge of the reservoir, oil and gas producers can drill fewer wells while increasing production. ■

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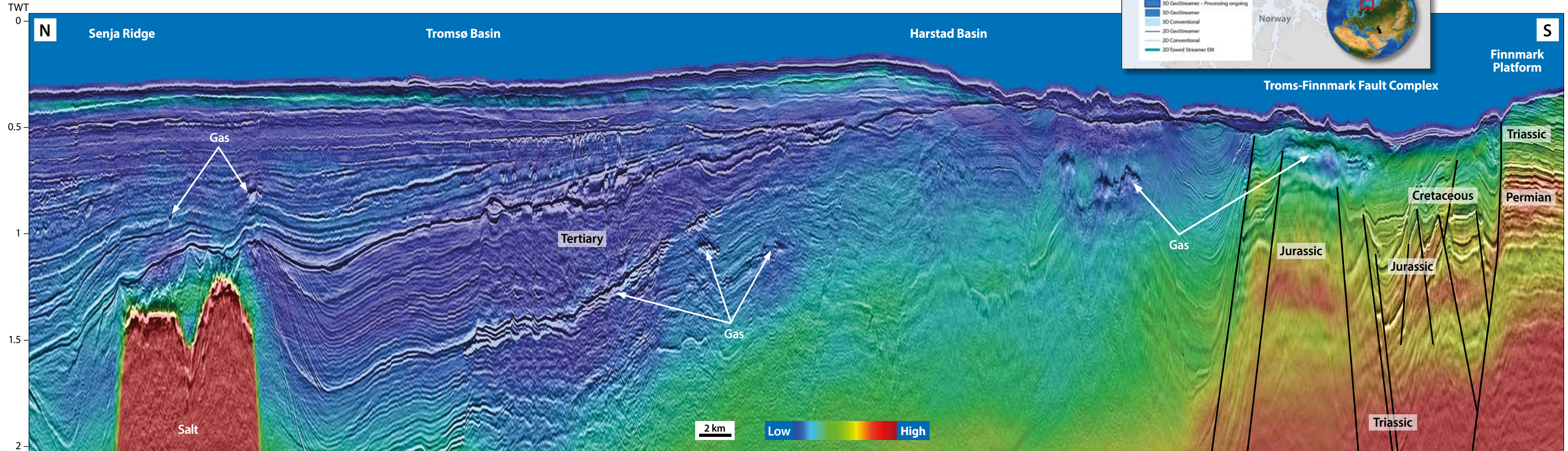
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Barents Sea

A First Look at New High Resolution 3D Multicomponent Seismic

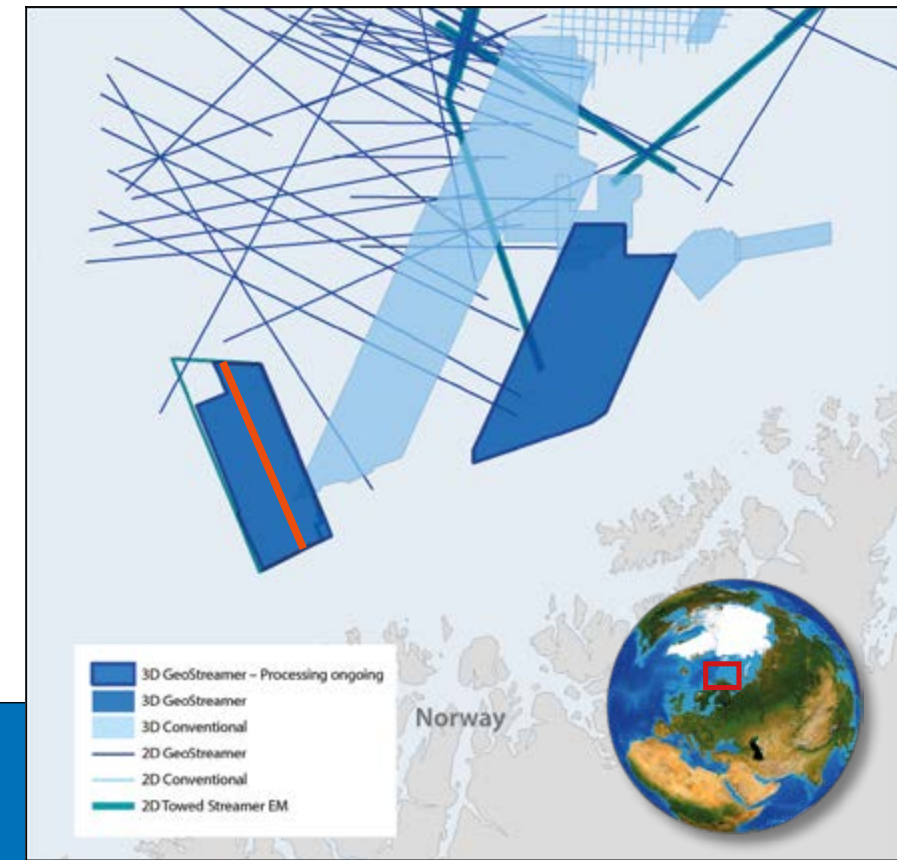
Figure 1: Seismic section extending from the Finnmark Platform and the Troms-Finnmark Fault Complex in the south-south-east, crossing the Harstad and Tromsø Basins and ending towards the Senja Ridge in the north-north-west. The fullstack KPSDM stretched back to time seismic data is overlaid by the detailed refraction FWI velocity model.



The far south-west Barents Sea is one of the few remaining frontier basins. There is little exploration activity and the data coverage is sparse. Until now, almost all existing seismic data was 2D, of variable data quality and as a result, the geology and hydrocarbon potential of the area is not fully understood.

PGS has now covered parts of this area with the first 3D GeoStreamer MultiClient broadband seismic dataset to enhance the geological understanding of the area and as a tool for unlocking new potential in this virtually unexplored and exciting part of the Norwegian Barents Sea. Through advances in data acquisition and imaging, and building on experience of acquiring data in the Barents Sea, this newly acquired dataset illuminates the geology and the exploration potential.

The multicomponent seismic survey was acquired in 2017 and is processed with an innovative workflow using complete wavefield inversion (CWI). This is a processing flow developed by PGS which integrates advanced technology for high-resolution velocity model building and depth imaging using reflections, refractions and multiples. The new high resolution 3D seismic data is revealing geological details never seen before in this area thanks to the acquired broadband data and the state-of-the-art imaging workflow.



A Vast, Underexplored, Complex Geological Province

New high quality seismic data in the far south-west of the Barents Sea.

RUNE SAKARIASSEN, NICOLA O'DOWD and SÖREN NAUMANN; PGS

A Need for High Quality Seismic Data

According to the Norwegian Petroleum Directorate, almost half of the undiscovered resources on the Norwegian Continental Shelf are to be found in the Barents Sea. It is still deemed to be a frontier basin, with only parts of it considered to be semi-mature (e.g. Hammerfest Basin, Polheim Sub-platform and Hoop Fault Complex). The availability of modern, high quality 3D seismic data over the area will help highlight the exploration potential that exists in this vast, underexplored, complex geological province. High resolution data provides the missing details and with the CWI workflow implemented in this survey, the overburden heterogeneities, common within the Barents Sea, are resolved and the imaging of features beneath is vastly improved.

The PGS17011NBS dataset is the most recent addition to the PGS MultiClient data library in the Barents Sea and is positioned to open new arenas and de-risk future exploration drilling. Through several seismic acquisition campaigns in the Barents Sea, PGS have refined the acquisition parameters and processing workflows to produce a dataset that tackles the imaging challenges in this area, whilst retaining the integrity of the data. This campaign started in 2011 with a 2D multicomponent acquisition. In subsequent years, the company has trialled various acquisition technologies and survey design parameters to determine the optimal parameters to image the complex geology beneath the shallow heterogeneities.

Overcoming Imaging Challenges

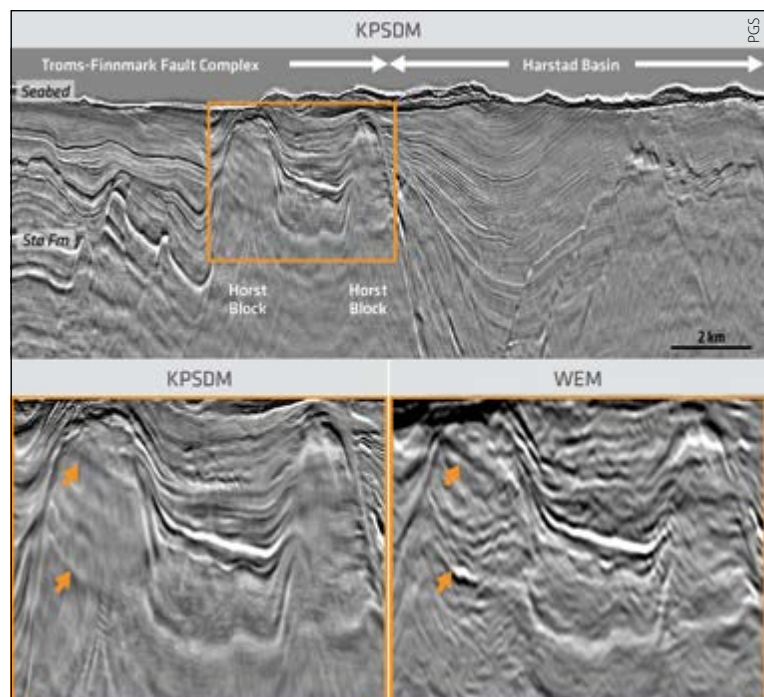
The areas of most interest within the Troms-Finnmark Fault Complex are also the most difficult to image. The large horst blocks present, which hold the greatest potential for trapping hydrocarbons, are masked by the shallow gas clouds sitting in the overburden. This, together with the overall hard seabed found in the Barents Sea, has made confident interpretation of these horst blocks difficult. The imaging challenges arising from the high levels of attenuation/absorption of the seismic energy, leading to loss of the higher frequencies, have meant the internal stratigraphy is difficult to map clearly with

conventional Kirchhoff migration. The survey design, alongside shooting in the dip direction to the major fault trends, has maximised the energy penetrating through to these horst blocks by enabling rays to dive underneath the highly attenuating shallow gas. This has allowed the recording of a broader seismic bandwidth to be input into the state-of-the-art processing workflows.

The CWI workflow is designed for accurate velocity model building and high resolution depth imaging. It is particularly suited to areas with a complex geological overburden and the resulting depth-migrated dataset accurately depicts the subsurface without compromising the integrity of the dataset. CWI is a combination of reflection tomography, full waveform inversion (FWI) and separated wavefield imaging (SWIM), using the up- and down-going wavefield recorded by the multicomponent streamers to improve resolution and illumination, especially for the shallow section.

To extract more information beneath the shallow gas, Wave Equation Migration (WEM) and Reverse Time Migration are also being applied. These techniques have previously been used to illuminate structures

Figure 2: Preliminary advanced processing to extract energy within the horst blocks. Kirchhoff migrated fullstack data (top and lower left image) including SWIM data blended in the top part of the section and preliminary wave equation migrated (WEM) (lower right) without SWIM. Uplift of internal stratigraphy within the horst blocks is clearly seen in the WEM image.



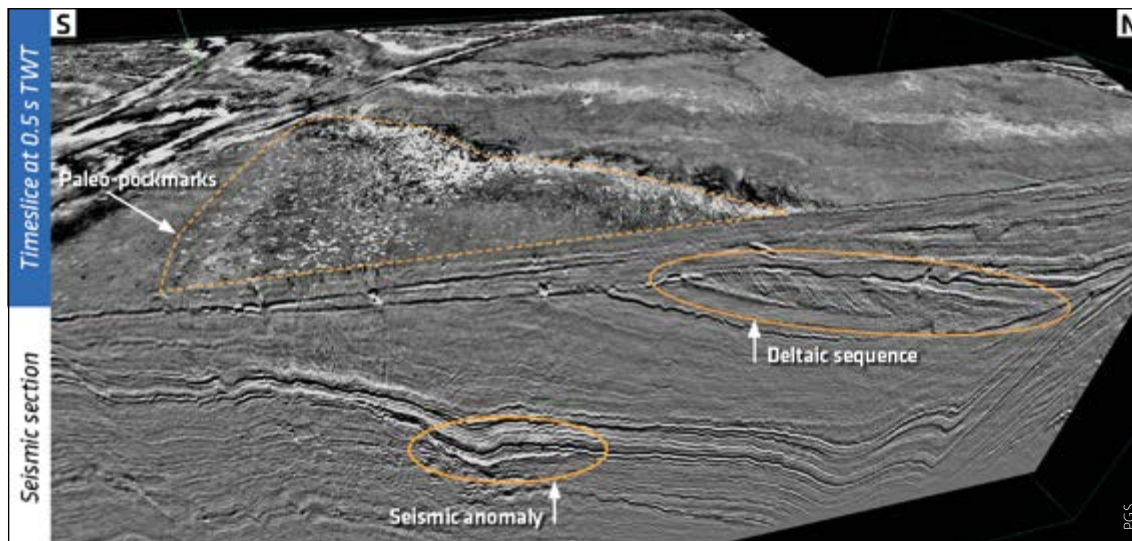


Figure 3: 3D image of the KPSDM data showing a timeslice at 0.5 seconds TWT and a seismic section (cut at 0.5 seconds TWT) running south to north within the Tromsø Basin. On the timeslice several palaeo-pockmarks are seen and the seismic section reveals a large deltaic section and an interesting seismic anomaly.

beneath ooze bodies in the Norwegian Sea, around the Aasta Hansteen discovery, and have been adopted here to enhance the signal underneath the shallow gas bodies. Figure 2 shows the preliminary uplift in the target areas where energy up to 60 Hz has been retained (by applying a bandlimited migration) on the internal stratigraphy underneath the attenuating surfaces. Following the application of the preliminary WEM results, a more stable reflector is evident between the horst blocks and this can be correlated across the structures.

PGS has also acquired towed streamer electromagnetic data over the area and this data indicates resistive anomalies (up to 70 Ohm m) confined within these structural closures.

Revealing Complex Geological Features

One result of the advances in imaging technology is the vastly improved resolution, revealing intricate geology in this previously underexplored area. The dataset over the Harstad and Tromsø Basins has exposed a thick cover of Tertiary sediments where there are indications of a high level of geological activity throughout the period. Numerous unconformities and faults cut through the Tertiary sequences, and there is a large deltaic sequence with well-imaged clinof orm beds, probably deposited in Eocene times (Figure 3). In addition, many channel systems can be seen at various depths, which are good indicators of the presence of sand in the basin.

There are several potential seismic anomalies present within the Tertiary, giving high confidence for the presence of a working petroleum system in the area. For example, Figure 3 shows large areas littered with palaeo-pockmarks. These fluid escape features can be seen on different palaeo-seabeds in large areas within the basal part, suggesting that they are related to several episodes of fluid expulsion and upward migration. Other fluid escape features, related to the deeper salt bodies present in the northern part of the dataset, are also evident. Some large potential seismic anomalies appear to occur within a series of rotated fault blocks that clearly detach from a distinct surface in the Tromsø Basin.

Structural Complexity and Potential Petroleum Systems

This dataset also images many structures in the Troms-

Finnmark Fault Complex, with both faults and stratigraphy sharply imaged, enabling more confident interpretation. The faulted terraces and horst structures are believed to have the greatest hydrocarbon-bearing potential within the pre-rifted Late Triassic to Mid Jurassic Realgrunnen Subgroup. Here, the Stø Formation is expected to have good quality sands deposited in a shoreface and coastal plain setting. In addition, the Early–Mid Triassic Havert, Klappmyss and Kobbe Formations might have potential in fluvial deltafront deposits. The seismic data also indicate evidence of sand facies in the Early Cretaceous pre-rift sequence together with the syn-rift sequences of Mid to Late Cretaceous.

It is likely that the deeper plays found in neighbouring regions in the Barents Sea may also be prospective here. On the Finnmark Platform Late Permian shoreface sands of the Røye and Ørret Formations are thought to be present, potentially underlain by karstified carbonates similar to those observed on the Loppa High, offering additional potential prospectivity here.

Time to Improve Exploration Decisions

The discovery rate in the Norwegian Barents Sea is still slow after almost 40 years of exploration and more than 100 wells, even with increased industry interest over the last few years. It is still difficult to make good exploration decisions using only poor quality vintage data. Therefore, it is time to acknowledge the need for higher quality seismic data to be able to de-risk future exploration.

The PGS17011NBS dataset, with its advanced imaging workflow together with a tailored acquisition setup, is solving complex imaging challenges to deliver a dataset that clearly exhibits many features of interest, both from a geological and petroleum prospectivity perspective.

Fast-track data is available now together with the high resolution KPSDM (stretched back to time) for the first 2 s. This enables immediate assessment of the Troms–Finnmark Fault Complex and the Tertiary section of the Tromsø and Harstad Basins. ■

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The Custom Data Solution

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Low-cost, non-proprietary solutions are needed to capture, organise and analyse oil and gas data.

Over the last 120 years building exploration prospects and data acquisition have changed dramatically. In the beginning, most technical professionals had no previous datasets, wells, formation evaluation methods, previous production, stratigraphic correlations, seismic, 3D models, logs or mapped horizons. Through observation and persistence, overwhelming amounts of data have been obtained to better understand and evaluate prospects in order to make better decisions. It used to take months or even years for a technical professional to build and understand a prospect which now only takes a few hours, thanks to software.

Software is great – so what's the problem? Software rigidity is one. Software companies have built in restraints: import and export of specific formats only, old formats are removed, navigating seas of menus, lack of custom data importation, limited database architecture, lack of user permission management, tedious complex templates – and sometimes the lack of a database altogether.

Data obtained from some subscription-based companies is not owned by the company paying for it. Regardless, users put months of work into rebuilding the data through an internal quality controlled and quality assured process. However, these companies also put built-in restraints on software contracts and features meaning that, if users are not subscribed to their data farms, they must delete their hard work upon unsubscribing.

Archiving, Evaluating and Understanding

Archiving hard work and making the next decision when looking at recorded data is ultimately the main focus of software. Technical professionals are required to obtain data from any and all sources, correlate, and finally evaluate which actions are best. They are required to find the 'nexus point' in the datasets.

Today, everything revolves around data capture and visualisation. Viewing large datasets in spreadsheets is important, but visualising that information is paramount. Seeing the results of data on a map adds depth and better understanding. Analysis using visualisation is particularly useful: an example of this would be viewing production data for each well during the analysis of a producing formation across a basin, field or region (see figure right). Multiple ways to view and associate data is imperative.

Customisation is the Nexus Point

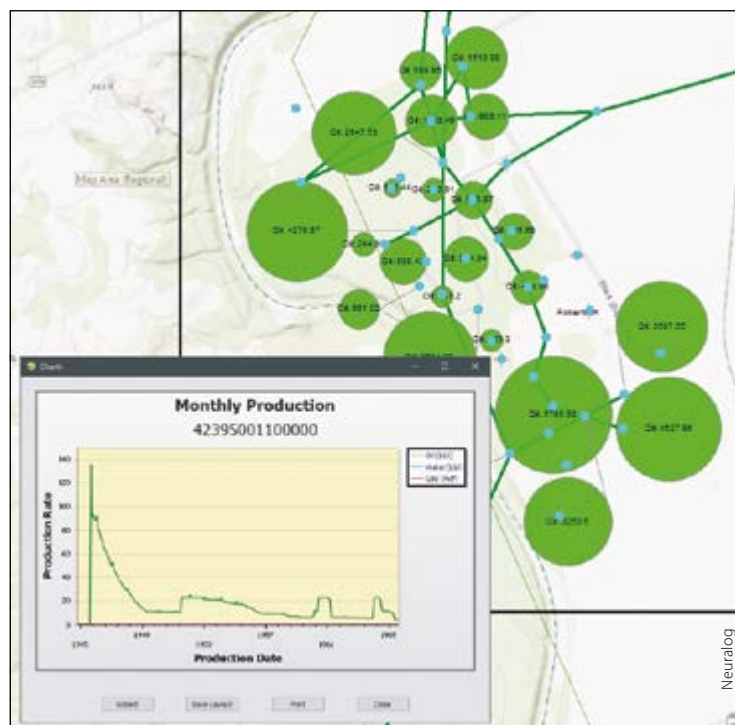
The answer to the future of software is through customisation of data and not restricting types of data for importation. A company that is looking at this future is Neuralog, which was founded in 1991 with one goal in mind: to convert legacy paper data into useful information in the form of digital data to solve problems in the petroleum industry through client-driven workflows and the application of emerging computer

technologies. Neuralog Desktop, for example, is a standalone ESRI GIS-based interface which allows customisation and visualisation of gathered data, including configuration of user permissions per project. Data can be stored at many different levels: data and documents can be stored relative to the well, lease/owner, field, basin, state/county, country or custom created topics. Various types of data, such as PDF, Excel or SEGY, can be saved or created and stored in the entities or as a custom entry. Logs, documents, production, seismic data and all other ancillary well data can be organised by well, field, lease, user defined entity or spatially tied to shapefiles.

The custom Ascii and Excel importer in Desktop allows creation of new custom datasets, tables or document types in the database. Files can be associated in multiple databases across other software packages, organised or unorganised file folders, out on a server (structured or unstructured), and/or in numerous applications. Linking documents (e.g. legacy 2D seismic lines, theses and state reports) directly to shapefiles is spatially very convenient. Users can simply expose the classification type and open any of the stored data, which will invoke the native handler for that document type.

Whether building a simple log library, capturing well headers, tops, seismic or a research document database or all of the above, what is needed is customisation. Since Neuralog is not tied to a subscription-based company, it can help you archive your data and hard work to get you to that sought-after 'Nexus Point'. ■

Prospect production data visualised in bubble charts and graphs adds significant value to the data, which in turn is helpful to anyone who needs to understand their producing prospects.

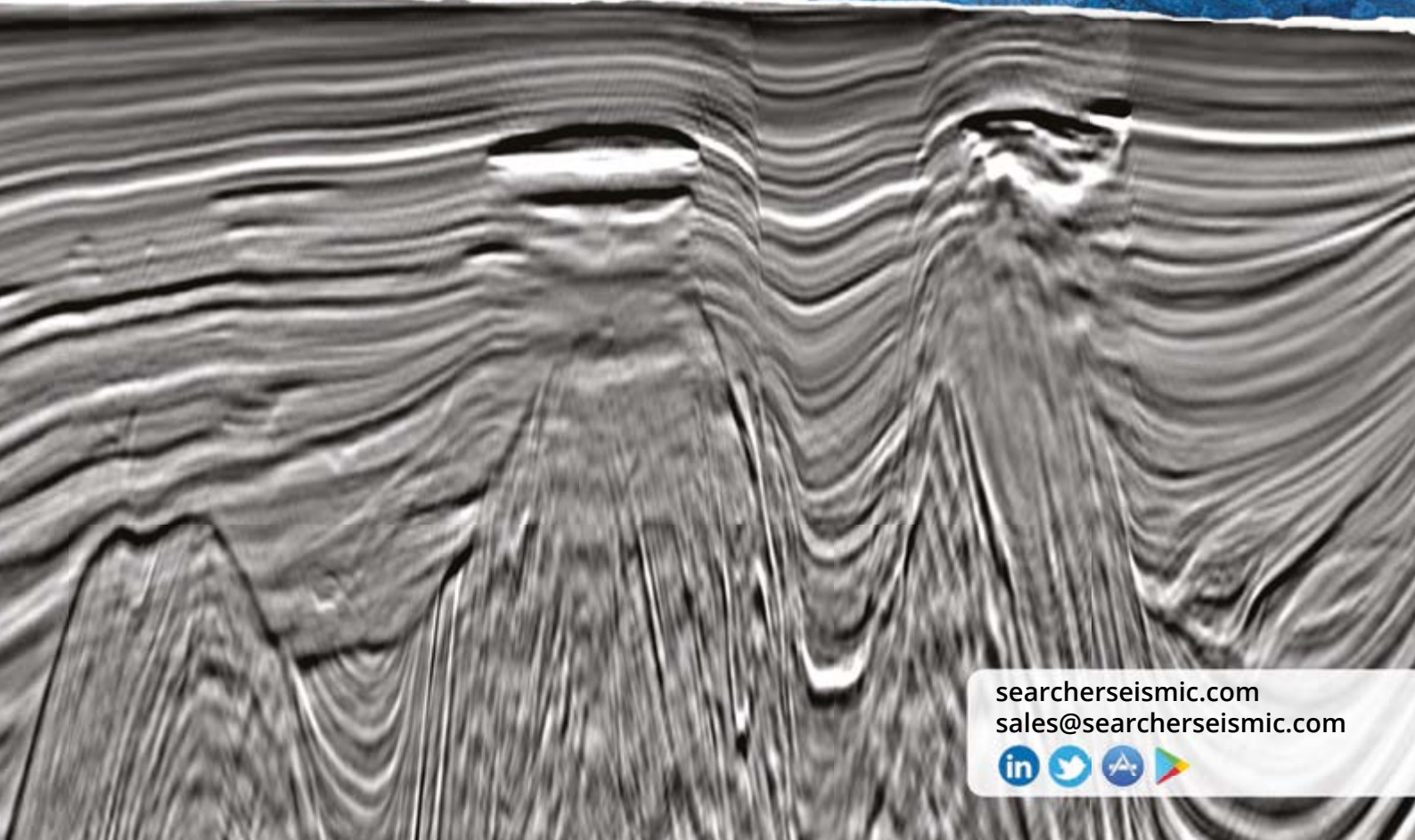




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A Potentially World Class Undrilled Basin

Dr JOHN M JACQUES, Greenland Gas & Oil and JMJ Petroleum;
Dr MARK BILSLAND, Greenland Gas & Oil;
and RUTH HOULT, JMJ Petroleum

A series of Late Palaeozoic-Mesozoic basins, which formed as the result of rifting between Greenland and Norway following the Caledonian Orogeny, are exposed in East Greenland between 70° and 76°N (Stemmerik et al., 1993). The onshore Jameson Land Basin is one of these basins and is located along the south-eastern continental margin of East Greenland (Figure 1), representing one of the last remaining undrilled North Atlantic Margin basins. Based on seismic, gravity and magnetic data, together with regional surface fieldwork mapping, the basin contains up to 17 km of Upper Precambrian to Upper Mesozoic sediments.

Palinspastic restoration of the conjugate margins of the North Atlantic Rift System clearly demonstrates the significant pre-tectonic fit of the Jameson Land Basin with the petroliferous Haltenbanken area of Mid Norway (Figure 2). Spatial and temporal relationships observed through

palaeogeographic mapping further increases the hydrocarbon potential of the Jameson Land Basin. This includes several key plays that have been fairly recently identified by drilling, such as Permian carbonates and Triassic-Jurassic clastics on the Loppa High, south-west Barents Sea, found by Lundin Petroleum. Other analogues include oil-bearing Lower and Mid Jurassic sandstones of the Trondelag Platform, Haltenbanken region of Mid Norway (e.g., Heidrun Field), and Lower Triassic Otterbank Sandstones of the Strathmore Field, East Solan Basin, UK Continental Shelf.

In light of these remarkably strong genetic relationships, and the wealth of play opportunities, the Jameson Land Basin provides a unique opportunity to drill one of the last remaining North Atlantic Margin basins, which once sat closer than you probably thought to the heart of the prolific North Sea Hydrocarbon Province.

The Jameson Land Basin, East Greenland is one of the last remaining undrilled Atlantic Margin basins.

Multiple Play System Identified

In 1972, based on detailed field mapping, Atlantic Richfield (ARCO) ranked the Jameson Land Basin as having the highest potential for hydrocarbon accumulations in East Greenland. Remember, in 1957 ARCO was the first company to discover oil in Alaska, and in 1968, with Humble Oil, was responsible for discovering one of the largest oil fields in the circum-Arctic region, the Prudhoe Bay oil field on Alaska's North Slope. In the '80s, ARCO's international arm made the first commercial gas discovery in offshore China, further demonstrating the company's insatiable appetite for finding major oil accumulations in remote frontier basins.

For a five-year period ending in 1990, ARCO as operator undertook numerous field mapping, sedimentological and geochemical outcrop studies, and the acquisition of seismic, gravity and magnetic data in the central part of

Upper Jurassic exposure in the southern part of the Jameson Land Basin.



the Jameson Land Basin. During this time the company, partnered with ENI, accumulated a wealth of data across the entire basin through a focussed and diligent exploration campaign, which culminated in the identification of a multiple play system with very attractive estimated cumulative reserves for both oil and gas. ARCO's principal focus at that time was the Upper Permian shallow marine platform carbonates and reefal build-ups of the Wegener Halvø Formation, which from seismic mapping appear to provide significant trap potential. Several drillable large closures have been identified that are both surrounded and draped by oil-prone shales of the Upper Permian Ravnefeld Formation, which provides a very favourable juxtaposition of both source and seal.

A number of in-depth field-based studies have also been carried out by the Grønlands Geologiske Undersøgelse (Greenland Geological Survey), and subsequently by the Geological Survey of Denmark and Greenland (GEUS), all supporting the existence of a multiple play system in the Jameson Land Basin.

So the big question has to be "why did ARCO relinquish the Jameson Land asset in 1990 after almost 20 years of considerable interest and spend?"

It appears that the driving force for ARCO to relinquish the block in 1990 was due to a number of mitigating circumstances, instigated by the downturn in oil and gas prices and the need to fund several more favourable major development projects, such as the China–Hong Kong pipeline. In other words, bad timing for the Jameson Land technical exploration G&G team, who had devoted so much time, effort and enthusiasm into a long-term project that was just moving into the final drilling phase.

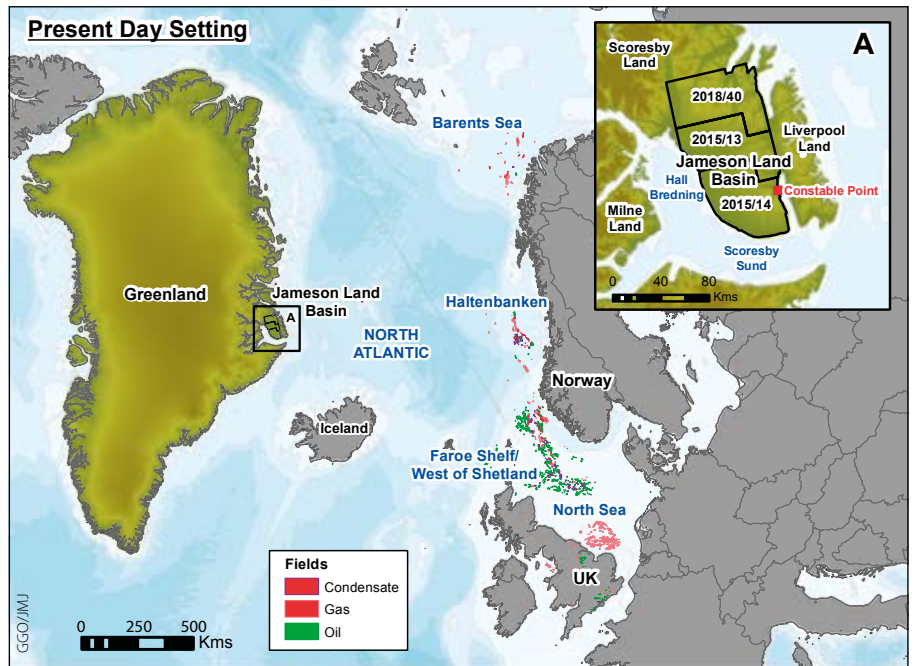


Figure 1: Location of the Jameson Land Basin.

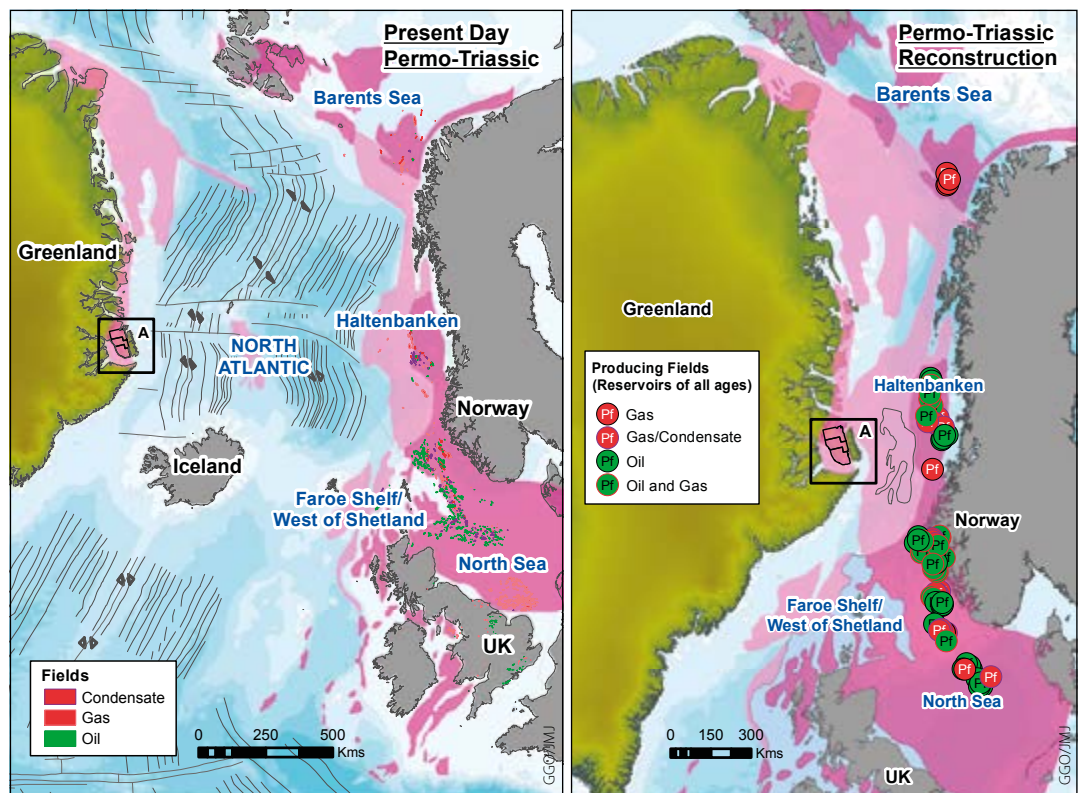
G&G Datasets – Old and New

Over the past five years, Greenland Gas & Oil has undertaken several regional to field-scale studies to evaluate the hydrocarbon potential of the Jameson Land Basin. In addition, more focussed geological and geophysical work has been carried out on two operated licences, 2015/13 and 2015/14, with a view to

identifying potential drillable oil and gas targets. The initial phase of this work incorporated existing data from ARCO and its partner ENI, including 2D seismic data (Figure 3) and extensive field work, more recent field work and studies conducted by GEUS, as well as technical papers and reports in the public domain.

The entire 2D seismic dataset

Figure 2: Restoration of the conjugate margins of the North Atlantic Rift System.



Exploration

(1,798 km) has been recently reprocessed and reinterpreted, and has identified many potential exploration opportunities across the basin's sedimentary section, from the Carboniferous through to the Jurassic. Viable play concepts have been identified and the risk and uncertainty of all the key essential play elements – source, reservoir, seal, trap, charge and preservation – for each individual play evaluated.

Airborne full tensor gravimetric, magnetics and LiDAR data were acquired by Bridgeport in August 2017, and are currently being integrated into the new seismic interpretation to provide an enhanced insight into the structural geometry of the basin. Both the gravity and magnetics (Figure 3) are proving to be invaluable with regards to identifying major compositional basement changes, depth to basement estimates, and defining the extent and distribution of Tertiary igneous intrusive sills and dykes that are prevalent in the southern parts of the basin. The LiDAR data has also been useful in the mapping of the surface expression of these doleritic dykes, together with other major lineaments that often represent faults and fractures.

Current Geological Evaluation

Greenland Gas & Oil has built a consistent and detailed regional geological database and has undertaken a petroleum systems evaluation of the entire area, including source rock evaluation and basin modelling. These studies, integrated with the seismic interpretation, have provided an invaluable new insight into the petroleum system of the Jameson Land Basin and has identified over 50 key prospects and leads in eight independent plays.

This work indicates that all essential play elements are present in the basin, and more details are given in the online extended article.

The exploration highlights of this currently undrilled basin in terms of its perceived hydrocarbon potential

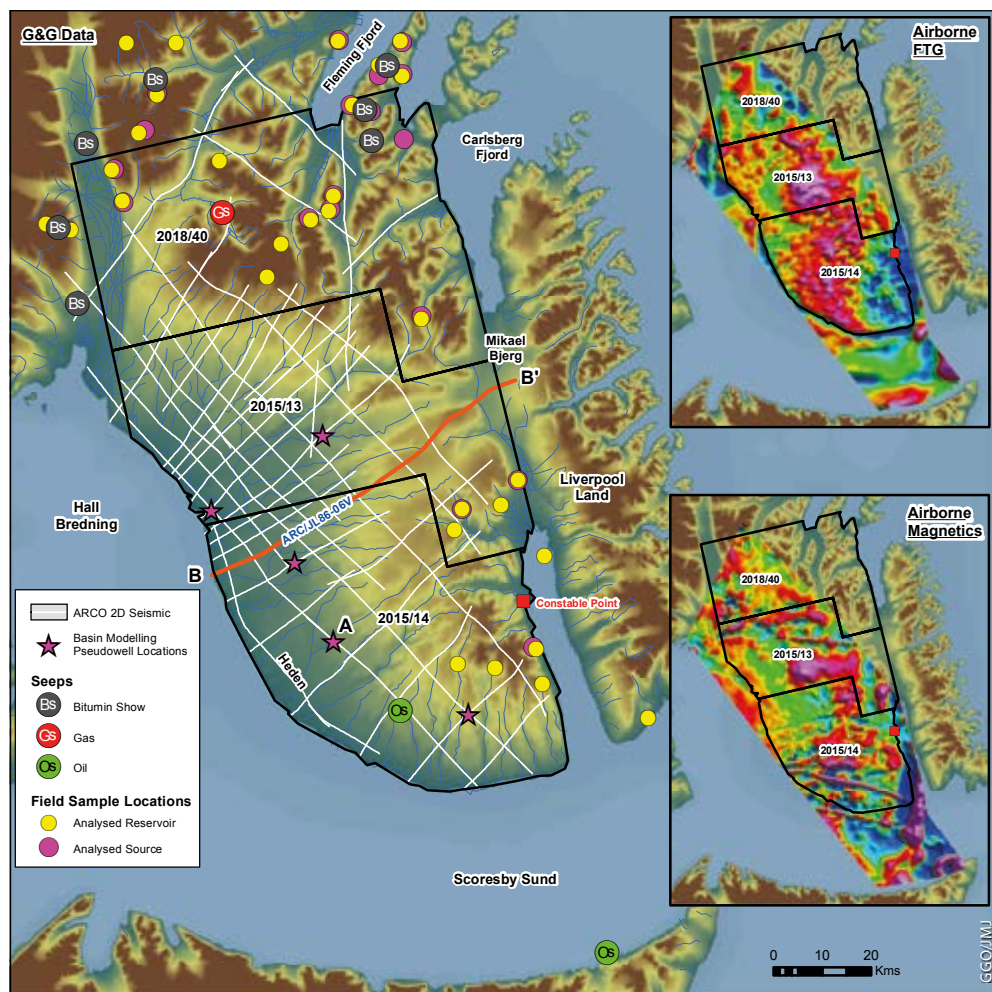


Figure 3: Data availability for the Jameson Land Basin. A indicates the location of an oil-filled belemnite from the 'Blokelv' core at a depth of 105.25m. B is the location of the seismic line shown in Figure 4.

include the following:

- Multiple play systems with the potential for stacked clastic reservoirs ranging in age from the Carboniferous to Jurassic, and Upper Permian carbonate build-ups and reefs (Figure 4);
- Evidence for an active petroleum system with gas and oil seeps identified within the basin, and bitumen staining (remnant oil) along its flanks (Figure 3);
- Detailed laboratory analyses devoted to type-sourcing the bitumen and asphalt shows from across the basin, including cores and analysed source rock outcrop samples, all demonstrate a geochemical link (isotope and biomarker data) between Upper Jurassic source rocks (Hareelv Formation) of East Greenland and co-eval source rocks of Haltenbanken, offshore Mid Norway;
- Two oil seeps, one in Jameson Land and a second at Kap Savoia, have also

been correlated to Upper Jurassic source rocks;

- A very large basinal area, with multiple play systems, all individually spatially and temporally associated with good to excellent organic-rich shales that can act as major oil-prone source rocks, with the shales themselves providing very effective seals;
- Jurassic clastics with very good reservoir potential have been identified at outcrop on the margins of the basin;
- Numerous exploration opportunities have been identified throughout the sedimentary section of the basin (Figure 4);
- Several optimally positioned wells have already been identified, which would test four key plays, including several of the largest currently mapped structures in those plays, with a resource range of >1 Bboe P50 unrisked resource across >4 plays.

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Time Will Tell

We consider the Jameson Land Basin to have significant potential for both oil and gas. A number of sizeable prospects and leads have been identified and mapped, suggesting the potential for multi-billion barrel prospective resource volumes within the current licensed areas, occurring at viable drilling depths. Initial prospect mapping and volumetric calculations identified gross un-risked P50 recoverable resources in the region of 3.5 Bboe.

The Jameson Land Basin provides an exciting opportunity to explore and drill one of the Atlantic margin's last remaining untested basins, which appears to contain multiple plays and all the essential play elements required for significant hydrocarbon resources. Play analogues, such as those from the Barents Sea and Mid Norway, strongly support this concept. As with all basins, there are differing degrees of uncertainty and risk; however, we feel that the geology and rewards on offer make the Jameson Land Basin a potentially world class petroliferous basin ready to drill. ■

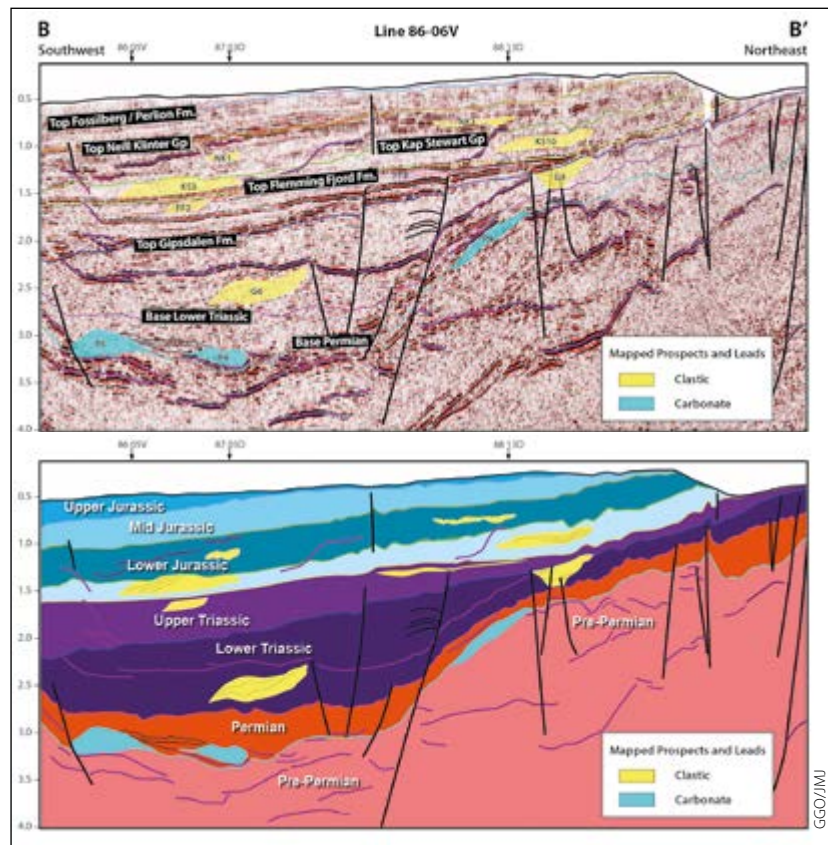


Figure 4: Reprocessed seismic line 86-06V and interpreted section, showing both clastic and carbonate prospects and leads. Location of line shown in Figure 3.

Developments in Middle East Exploration

The small Gulf states and UAE have had a 'hot' 2018.

PETER ELLIOTT

With global exploration delivering slim pickings for organic reserves replacement, focus for the sovereign, state and parastatal oil companies moves to the vast proven reserves of the Middle East.

Striking Abu Dhabi Developments

The most striking developments are within Abu Dhabi, which recently initiated an unconventional gas project with Total and signed a major strategic partnership with Baker Hughes, but where allegiances have also been re-balanced from European to Asian partners. Eastern giants in India and China continue to stretch their considerable financial influence over this region, buying reserves and developing long-term strategic alliances, crude storage deals and multi-decade LNG commitments.

Abu Dhabi aims to increase its production to 4 MMBopd by 2020 and 5 MMBopd by 2030. Until 2018 the offshore fields of Lower Zakum, Umm Lulu and Nasr Umm Shaif were managed as a single offshore concession owned between state company ADNOC (60%), Total (13%), BP (15%) and Inpex (12%). To replace this long-held arrangement, ADNOC have carried out at least nine transactions in 2018 and raised over \$8bn. The concession has been split into three: Lower Zakum; Nasr Umm Shaif; and Sazeh el Razboot (SARB) and Umm Lulu, with ADNOC retaining 60% of each. Inpex holds 20% of the Lower Zakum field, whilst CNPC and Total both bought into the Lower Zakum and Nasr Umm Shaif concessions, taking 20% for around \$1.4bn each. The Indian coalition of OVL, IOL and Bharat took 10% of Lower Zakum for \$600m, while OMV (Austria) took 20% of SARB and Umm Lulu for \$1.5bn. Cepsa, now owned by Mubadala, took a similar stake in SARB and Umm Lulu for \$1.5bn. Given the

stated aim of ADNOC to retain 60% across all three concessions, it could be said its work is finished offshore.

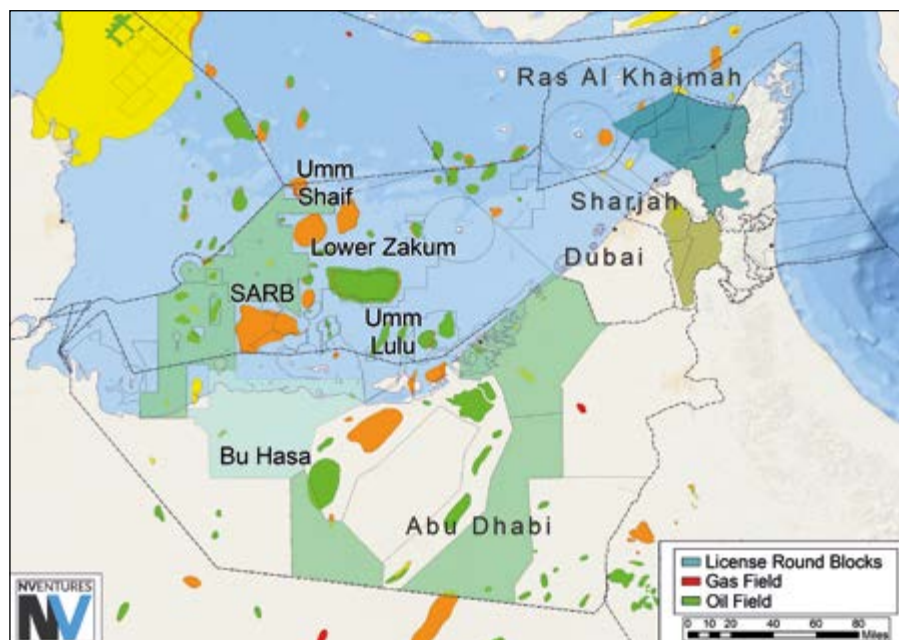
Onshore, ADNOC has similarly ambitious goals looking to reserves replacement for both oil and gas. Total has signed a 6,000 km² concession to launch an unconventional gas exploration programme in the high potential Ruwais Diyah play to the west of the prolific ADNOC Onshore concession. Elsewhere onshore, ADNOC is investing in redeveloping its giant onshore fields, such as the recently announced \$1.4bn contract award to Technicas Reunidas for the giant Bu Hasa Field. Further exploration is also planned; earlier this year the company awarded contracts worth \$1.6 bn to BGP to conduct the world's largest 3D onshore and offshore seismic survey (53,000 km² in total) in a bid to find new oil and gas reserves.

Bidding Rounds Planned

Three of the emirates, Abu Dhabi, Ras al Khaimah and Sharjah, have taken a major step and introduced competitive bidding rounds in 2018 with a view to

encouraging grass roots exploration on their concessions. Once again, ADNOC appears to be blazing ahead of the crowd, with 39 bids or expressions of interest registered for their very first round (two offshore blocks and four onshore). Ras al Khaimah's licence round commenced in April 2018, with four offshore, two onshore and one onshore/offshore blocks offered, supported by newly acquired 3D and FTG data. The bid deadline was apparently mid-November 2018. Finally, the Sharjah Petroleum Council launched an offering for three onshore concession areas (A, B and C) under 30-year contracts in the Thrust Zone play trend. Area A includes an unappraised deeper gas discovery below the Sajaa gas-condensate field. Sharjah National Oil Company (SNOC) is preparing to drill a well in Area B and is offering participation in this exploration opportunity. 3D seismic was shot in 2016/2017 to support exploration here.

Further A&D activity is expected in the region, as the industry participates in exiting new exploration offers in the UAE and the broader Gulf region. ■





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Confronting the Elephant

Dorado-1 and the prospectivity of the offshore Canning area in Western Australia

SAID AMIRIBESHELI, Discover Geoscience Pty Ltd;
ANDREW WELLER, Searcher Seismic Pty Ltd

The recent oil, gas and condensate discoveries in the Bedout Sub-basin of the Roebuck Basin have caused a change in thinking in this hitherto underexplored region. In 2014 Phoenix South-1 discovered oil, closely followed in 2015 by Roc-1 (gas and condensate) and in 2018 by Dorado-1 (oil). These discoveries targeted reservoirs in the Triassic Lower Keraudren Formation (Fm) that are older than the traditional Triassic plays on the North West Shelf (Figure 2; Thompson et al., 2018). These achievements are helping remedy the historically poor understanding of this region and now stand as analogues for further lookalikes.

Searcher Seismic's modern Bilby Non-Exclusive 2D Seismic Survey acquired long-offset, high resolution seismic in this area, providing high-quality data to help identify prospective stratigraphic and structural trends. It also ties the recent hydrocarbon discoveries and generally sits inboard of them (Figure 1). The Bilby data addresses multiple issues with the vintage data in the area by using an 8 km streamer with improve frequency response, a larger source array to improved signal penetration, and a broadband

anisotropic PSTM processing workflow.

Integration of the recent discoveries with regional geology, this new data, and geophysical quantitative interpretation (QI) techniques suggest that the entrapment and sealing mechanisms are the key elements to understanding the region's petroleum systems. The Bilby data reveals several potential reservoir-seal pairs in the Mesozoic strata, as well as deeper Palaeozoic character, much of which has been previously assumed not to be present and was unimaged to date (Figure 2). This article discusses both the underexplored Mesozoic and unexplored Palaeozoic hydrocarbon potential in the area.

Recent Exploration

Early Triassic sedimentation in the region is dominated by the Locker Shale, grading upwards into the Lower Keraudren Fm, which is dominantly fluvio-deltaic with interbedded low energy organic-rich lagoonal to higher energy facies. The Lower Keraudren Fm's differing characteristics mean that it can be subdivided into eight informal units, of which

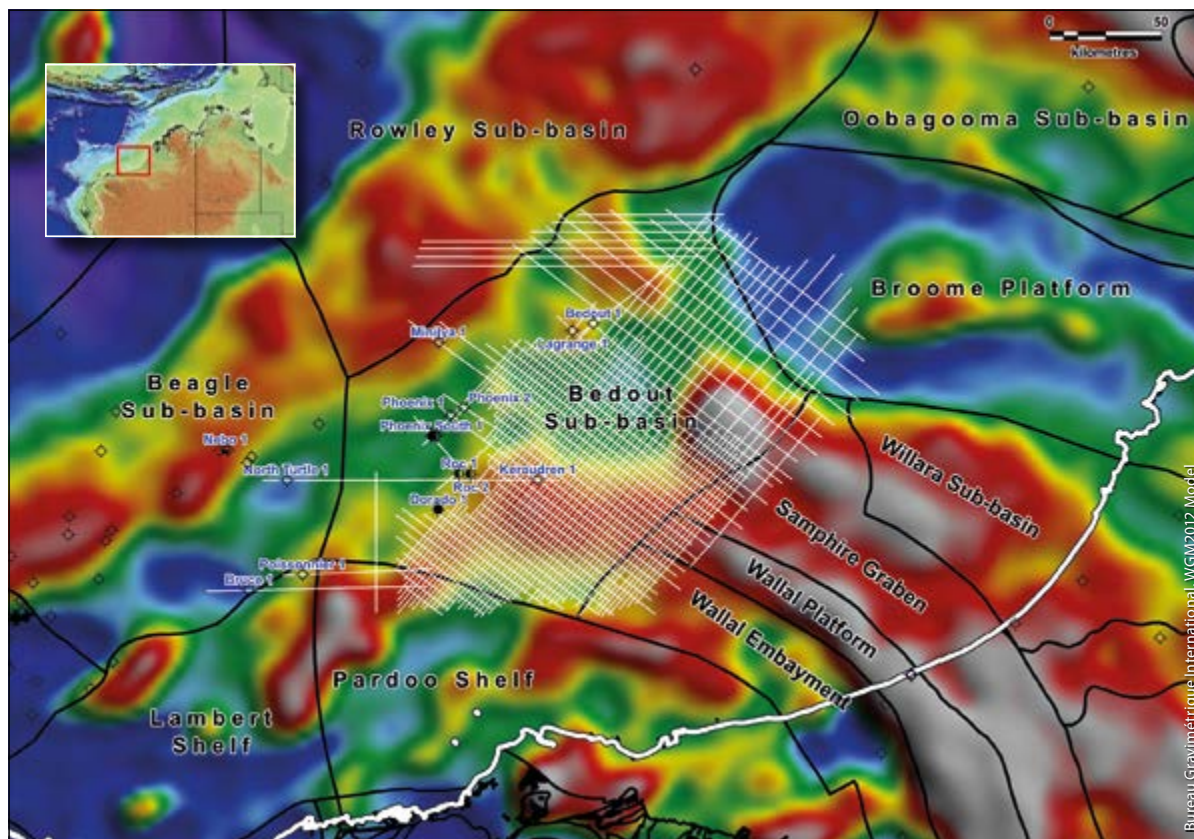


Figure 1: Bilby survey data (white lines) and structural elements of the Offshore Canning Area (black lines) overlaying the free-air gravity anomaly (relative highs in whites/reds, lows in blue).

the Caley Sandstone has emerged as the key reservoir (Woodward et al., 2018). This was most recently shown in Dorado-1 where it displayed excellent reservoir and fluid characteristics in highly porous (~20%) and permeable (100 to 1,000 mD) sands. Further evaluation demonstrates that Dorado is one of the largest oil discoveries in the history of the North West Shelf (Carnarvon Petroleum, 2018).

The cyclical sedimentation of the Lower Keraudren Fm implies that the potential for several source, reservoir and

seal opportunities exist (Thompson et al., 2018). Prior to the Dorado-1 oil discovery, one major source rock interval of lagoonal facies origin had been intersected within the Caley Member (Woodward et al., 2018). However, deeper drilling in Dorado-1 encountered additional oil discoveries such as stacked plays in the older Crespin and Milne Members (Carnarvon Petroleum, 2018).

At the unconformable Caley-Hove boundary, several large incision canyons have cut into the shelf, some of which are over

Figure 2: Generalised stratigraphy of the Bedout Sub-basin. Note: a) Lower Keraudren Fm (yellow star); b) absence of Carboniferous and Devonian stratigraphy; and c) general thick homogeneity of units that may contain interbedded facies (e.g. Jurassic Depuch Fm).

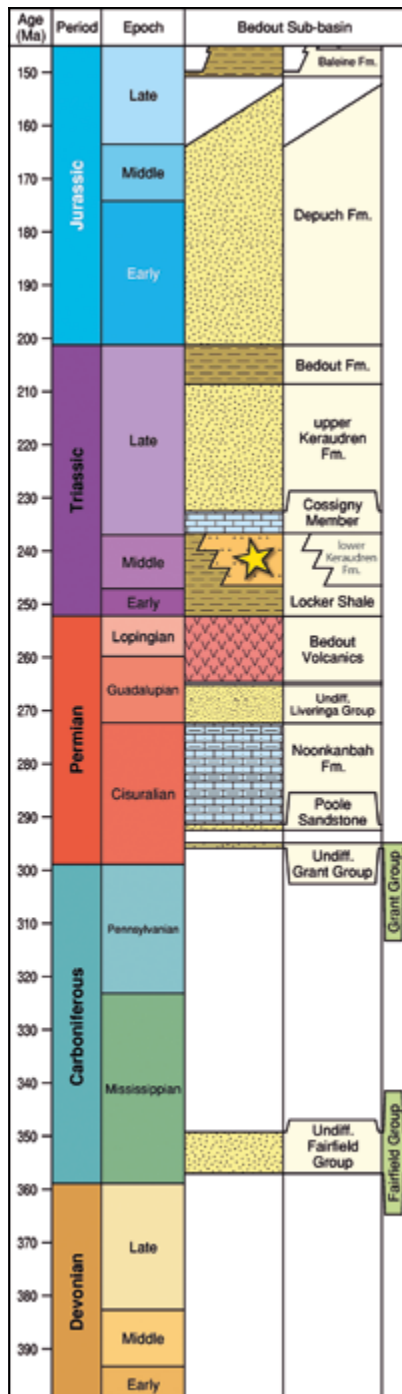
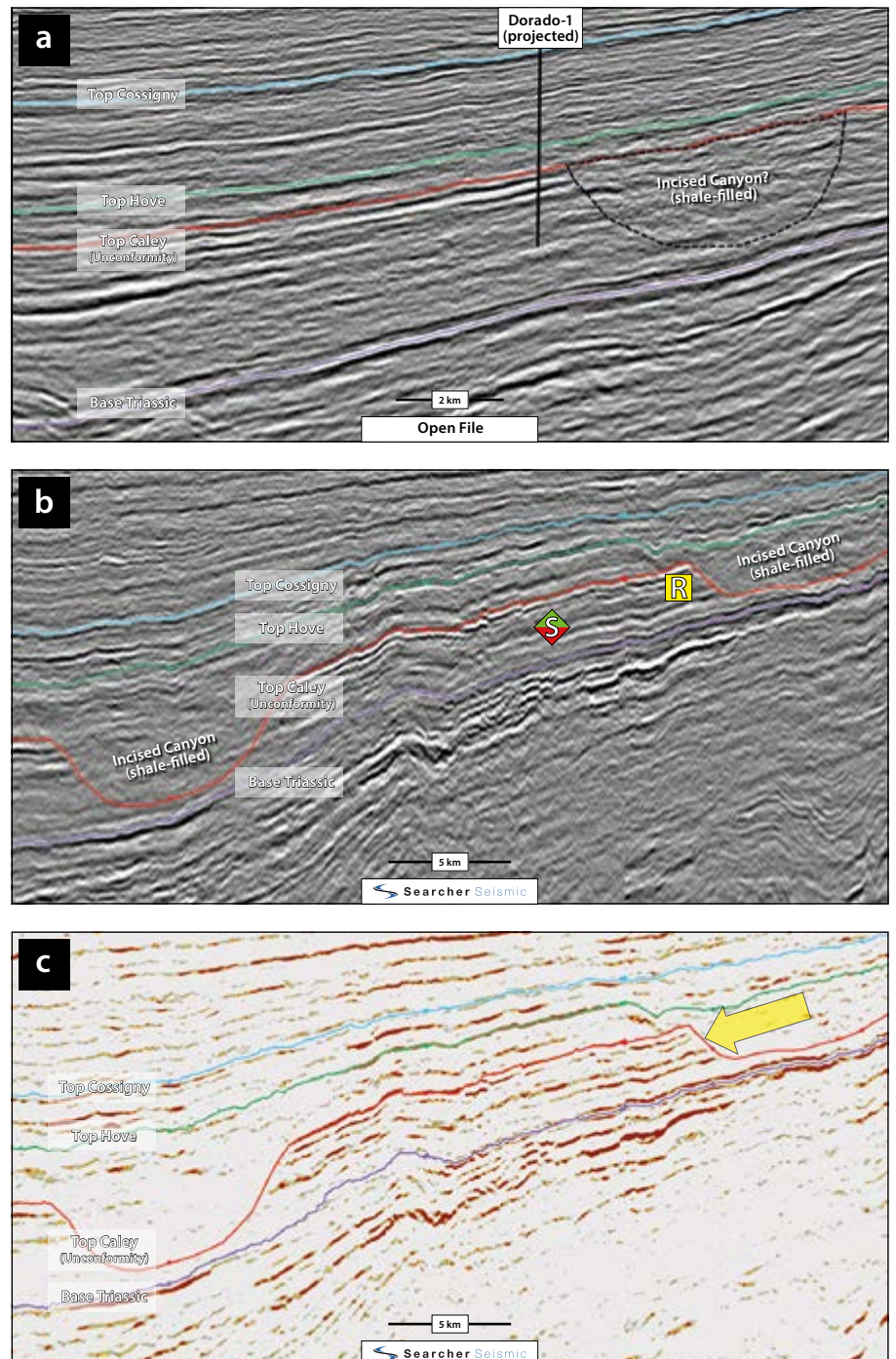


Figure 3: Dorado-1 in the vintage 2D seismic data and lookalikes in the Bilby data. a: The incised canyon is not apparent on the open file 2D seismic. b: Clear definition of geometry of an example incised canyon in the Bilby data. c: Amplitude variation with angle (AVA) acts as lithology indicator for the main Caley reservoir (reds) and the Hove seal (nothing). Here the AVA attributes suggest the presence of good multi-layer stacked reservoir in the Lower Keraudren Fm sands highlighted by the yellow arrow. 'S' means potential source; 'R' means potential reservoir.



Exploration

500m (Minken et al., 2018). These canyons were later filled with the laterally continuous, fine-grained, hemipelagic shale Hove Member that provides a regional seal, as found at Dorado-1.

Underexplored Lower-Middle Triassic

Prior to drilling Dorado, the structural-stratigraphic trap was perceived to be high risk as the features unequivocally relied on sealing facies (i.e. Hove Member) to be present in the large incised canyon. Like Dorado-1, exploration success relies on good quality seismic data for delineation of prospects in relation to trapping mechanisms, sealing capacity (top, base and lateral), as well as reservoir presence and quality. Review of the vintage open file seismic data demonstrates that the canyon geometry of Dorado is not obviously evident (Figure 3a). However, the Bilby data provides a high-quality image to help identify similar prospective trapping mechanisms across the region (Figure 3b).

The Caley Sandstone at Roc-1 exhibits a class 2p AVO response (Woodward et al., 2018), which warrants similar seismic investigations in the area. The Bilby data enables a robust lithology discrimination through QI techniques.

Figure 3c demonstrates Dorado lookalike features where lithological content of both reservoir and seals can be discriminated through AVA attribute analyses (which can be extrapolated across the region). The presence of multiple source and reservoir-seal pairs in the Lower Keraudren Fm and the proven stratigraphic trapping mechanisms provide encouragement to further examine the Triassic hydrocarbon potential elsewhere in the area.

Unexplored Palaeozoic Potential

The Palaeozoic sequences for the region are best described from the Onshore Canning Basin where they are over 11,000m thick in the Fitzroy Trough, thinning to <5,000m on the Broome Platform.

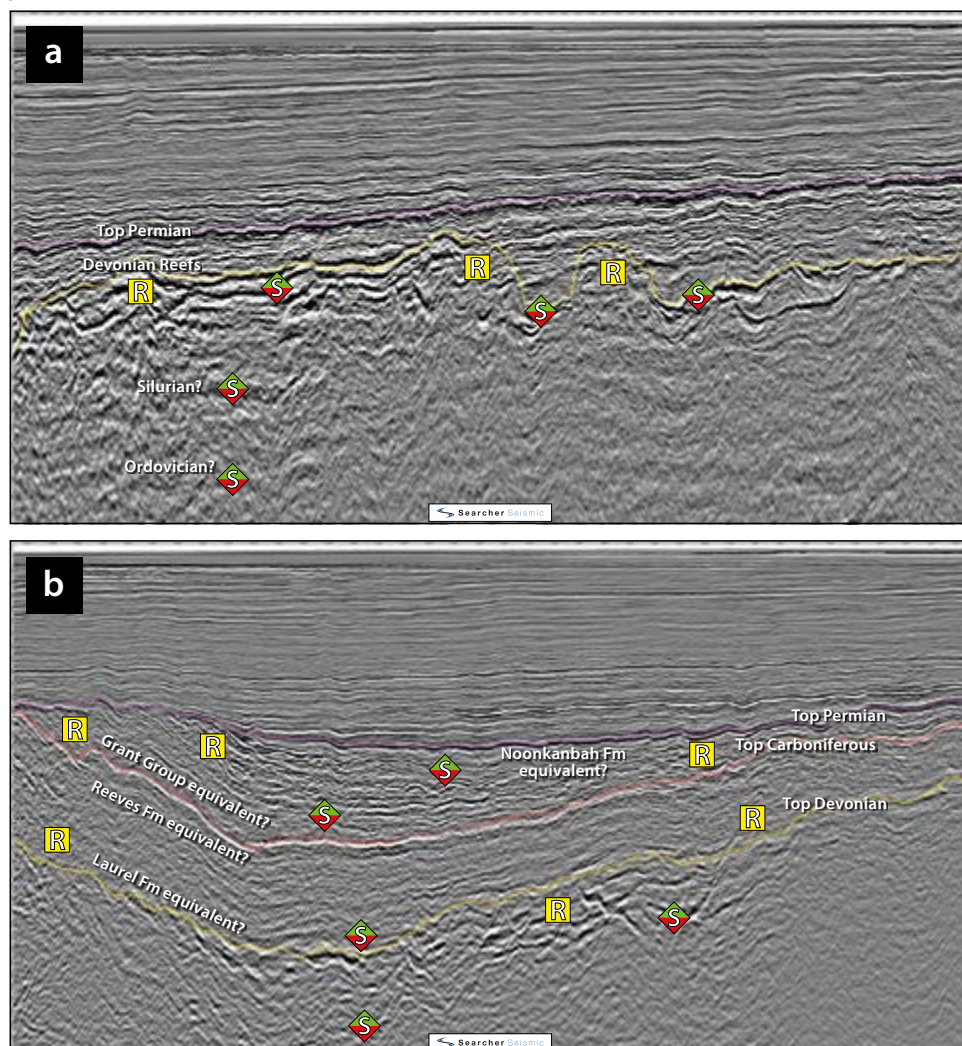
The oldest sedimentary sequence known in the Canning Basin is the Early Ordovician to Silurian (Figure 5). Above the Base Devonian unconformity, the megasequence includes a Late Devonian syn-rift succession comprising an Upper Devonian Reef complex. The onshore Blina oil field was discovered in 1981 in an Upper Devonian Reef complex and Playford (1982) hypothesised that these reef complexes also exist offshore. The vintage seismic data in the area is plagued with

short streamer lengths, so imaging of the Palaeozoic is non-existent. With an 8 km streamer, the Bilby data has imaged what is believed to be the offshore extension of the Devonian Reef complexes that potentially sit in the oil window (Figure 4a), which warrant further investigation.

The Carboniferous Laurel Fm, consisting of carbonates and shoreface clastics overlain by marine carbonates and shales, hosts most of the oil and gas occurrences on the Lennard Shelf. From a geochemistry perspective, the Lower Carboniferous looks ambiguous with fair-to-good total organic carbon readings (Ghori, 2013), although it is prospective (Kingsley and Streitberg, 2013). Offshore, the Carboniferous (and older) is generally assumed not to be present over much of the area (Figure 2). However, Carboniferous character is observed offshore in the Bilby seismic (Figure 4b), suggesting that this data can therefore answer questions about the extension of the Laurel Fm into the area.

The sedimentary sequence overlying the Carboniferous unconformity consists of the Reeves Fm, the fluvial and glacial Grant Group, and the Noonkanbah Fm marine shale. Organically-rich marine shales within the upper

Figure 4: Palaeozoic character and potential observed in the Bilby data (depth). a: The offshore extension of the Devonian Reef complexes. b: Generalised Palaeozoic character highlighting the Devonian, Carboniferous and Permian sedimentary sequences. The Laurel Fm, Reeves Fm, Grant Group and Noonkanbah equivalents highlighted remain untested in the area. 'S' means potential source; 'R' means potential reservoir.



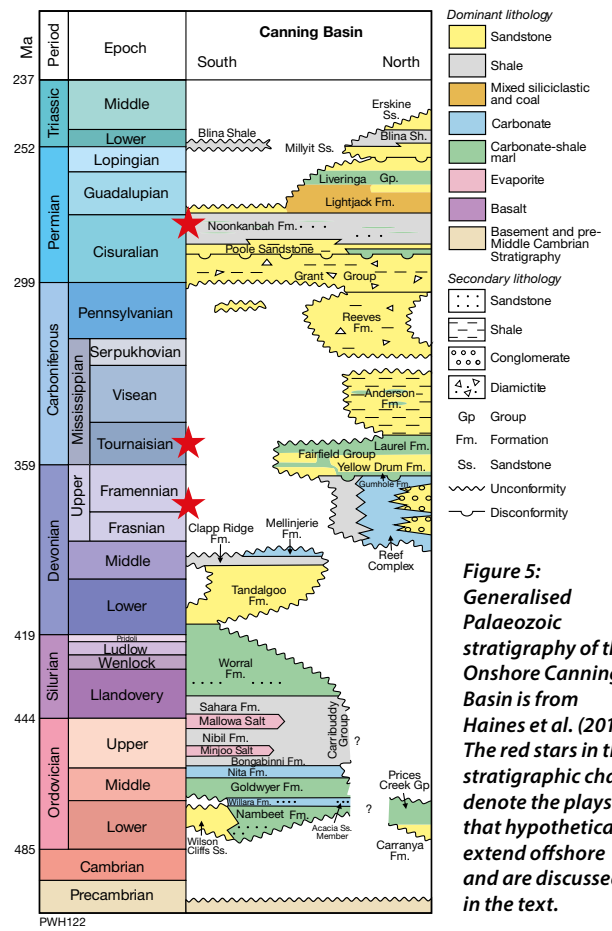
Grant Group are the main source rock interval within the Upper Carboniferous and Lower Permian onshore. Moreover, the Permian Noonkanbah Fm has demonstrated good source potential onshore although it is immature (Mory, 2010). Noonkanbah and Grant Group character is observed offshore on the Bilby data (Figure 4b) and is found at a deeper level than is observed onshore and is therefore potentially more mature in the offshore section.

High Quality Seismic Key to Success

The recent breakthrough discoveries in the Bedout Sub-basin unequivocally shed light onto a hitherto underexplored region. Historically, the lack of hydrocarbon exploration in the region has been attributed to a lack of source rocks, a hypothesis that was overly simplified. The recent discoveries suggest that entrapment and sealing mechanisms are the key to exploration success, which ultimately requires high quality seismic data. Dorado-1 is a classic example where the vintage seismic data failed to reveal entrapment and a sealing mechanism, while the recent Bilby data clearly shows the trap geometry and reservoir-seal content through high quality seismic and QI techniques.

The deeper Palaeozoic potential in the region has also been overlooked due to a lack of understanding of the petroleum systems and a paucity of seismic data. The recent Triassic discoveries as well as the Palaeozoic play potential is fundamentally changing the 'moose pasture' status of the Offshore Canning Area into true elephant hunting ground!

References available online. ■



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Geochemistry Moves to the Wellsite

The prolific marriage of mud logging with reservoir geochemistry results in a better reservoir characterisation in real time, improving performance and reducing costs.

MARIO A. CHIARAMONTE, Geolog International

The Evolution of Geochemistry

Petroleum geochemistry became a consolidated discipline in the oil industry only in the 1970s, but its real boom was in the '80s. At that time, it was mainly focused on understanding the origin of oil and gas, but it quickly evolved through time to become a fundamental technology in exploration; biomarkers, source rock evaluation and gas isotopes all became very popular tools, adopted by almost every oil company. In the middle of the '90s geochemistry started to be considered as a suitable tool for reservoir evaluation and for production optimisation. Detailed fluid and rock characterisations, obtained through different and advanced analytical tools, began to be used to better understand reservoir heterogeneities and to support production strategies. Reservoir geochemistry has become more and more widespread and is recognised as a useful tool in petroleum engineering.

The rapid evolution of instrumental analytical chemistry in those years greatly supported the growth of reservoir geochemistry. The availability of high resolution Gas Chromatography (GC) and Gas Chromatography Mass Spectrometry (GC-MS), assisted by ever more powerful computers and the accessibility of many other innovative analytical instruments, significantly increased the reliability of reservoir geochemistry, making possible its dissemination and extensive adoption.

Recent impressive improvements in instrumental analytical

chemistry can be considered a real game changer, supporting further the development of reservoir geochemistry. This extraordinary progress in analytical instrumentation is due to two concurring factors. The first is the growing need for the urgent issue of environmental monitoring, which requires compact, portable and high performing equipment. Many instruments developed for this purpose can easily be adapted for oil industry use, improving sensitivity and resolution standards. The second factor is the continuous development of nanotechnologies, with spectacular consequences on analytical capabilities; the 'labs-on-a-chip' device is a clear but not unique example of this. Finally, a significant contribution to analytical capabilities comes from space exploration: one of the commonest types of XRD equipment, used by many service companies at wellsites, was created for mineralogical analyses on Mars.

This new generation of instruments has made possible a further important step in reservoir geochemistry: activities are moving from the lab to the wellsite. Compact and robust instruments, designed to run environmental analyses in any location, can be easily installed in mud logging units at wellsites. This is a great example of cross fertilisation, with technologies developed in one industrial sector being easily adapted to the needs of the oil industry and quickly adopted.

This is, in short, the reason for the marriage between reservoir geochemistry and mud logging.

A mud logging-geochemical unit operating in the USA for an unconventional well.

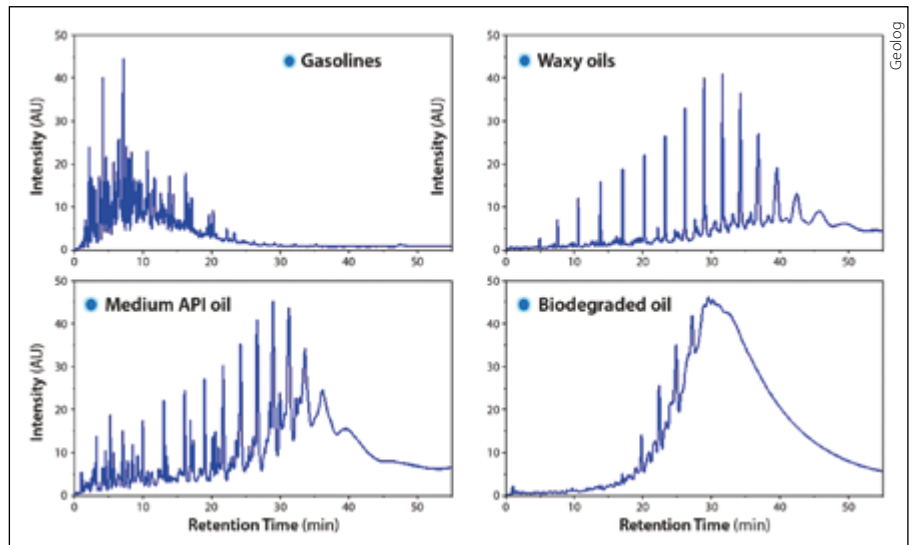


Geolog

Mud Logging Evolution

By comparison, mud logging was born many years ago, long before geochemistry. Originally, it was a basic tool for detecting hydrocarbon hints in drilling mud: any fluorescence or gas bubbling, discovered at the surface, was considered a positive sign, indicating possible hydrocarbons. At the very early stage of petroleum exploration, this was one of the few tools available to detect hydrocarbon presence in the drilled sedimentary sequence. When, many years later, in the '60s, gas detection became quantitative and more accurate, mud logging turned out to be a fundamental service for monitoring the amount of gas entering the hole, to prevent kicks and possible blow-outs due to changes in mud density. Thereafter mud logging was considered an important and essential tool for safety, but the growing accuracy in gas detection, including quantitative distinction among different gas species in the range C1–C5, extended its application further to reservoir evaluation. Over time mud logging became a common tool both for safety and reservoir characterisation, although for the latter task wireline logging, and later logging while drilling (LWD), has always been considered to be the reference tool.

Nowadays, mud logging is continuously growing and



TE-GC analyses: different types of oils from cuttings.

constantly gaining credibility, thanks to a systematic approach using well-calibrated and standardised devices for gas extraction at a constant temperature, pressure and volume, and to a full and reliable chemical characterisation of extracted hydrocarbons in the range C1–C8. This is eroding the predominance of wireline logs and LWD.

Marrying Mud Logging and Reservoir Geochemistry

Reservoir geochemistry and other lab activities have been moved to the mud logging units at the wellsite, already

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designed to host analytical instruments. The logical next step was to integrate mud logging and reservoir geochemistry to provide more reliable and exhaustive answers to technical issues.

An example of this is the integration of chemical analyses performed on gas extracted from mud with isotopic carbon analyses. This additional characterisation of gas composition can be used to get important information. In the case of gas shows in the cap rock, the isotopic value can clarify whether the gas was generated in situ, if the isotopic composition indicates abiogenic gas; or whether it is escaping or has escaped from the reservoir, if the isotopes show the isotopic signature of a thermogenic gas, similar to that of reservoir gas. Isotopes can also highlight whether oil and gas in the reservoir migrated to the trap together or if they are the products of two different phases of source rock maturation or even show that the gas has a different origin to the oil. All these pieces of information have a direct impact on exploration, but also on field development and on the evaluation of the petroleum potential of an area.

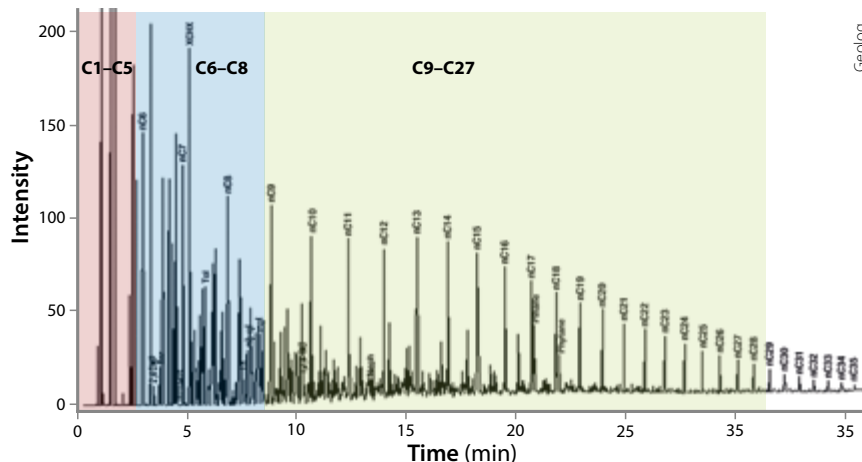
Another example is the integration of mud gas data and geochemical analyses on cuttings. Very recently Thermal Extraction Gas Chromatographic (TE-GC) analyses of cuttings were introduced at the wellsite. This type of analysis is a very powerful tool for discriminating between different types of oils, providing in real time important information about oil type in the reservoir. The figure above is a clear example of this.

Simultaneously, additional information about the oil can be obtained by using pristane/phytane ratio. These are two biomarkers that can easily be detected through TE-GC analysis and their ratio can be used to understand oil origin and, when combined with the concentration of other molecules like C17 and C18, to give an indication of oil thermal maturity.

Similar information can also be indirectly obtained from light hydrocarbon (C5–C8), extracted from mud. By combining these two pieces of information together uncertainties can be drastically reduced and the final interpretation highly improved. The light fraction of hydrocarbons is always lost in cuttings during preparation for TE-GC analyses, so by combining light hydrocarbons extracted from mud and TE-GC trace we can have a full and complete analysis of hydrocarbons trapped in the reservoir, as shown in the image above right.

Sometimes mud contamination, mainly coming from oil-based muds, can heavily interfere with both methodologies, but their integration greatly reduces uncertainties and avoids misinterpretations. In the case of different migration phases from the same source rock at a different level of thermal maturity, or from different source rocks, integration of the two methodologies can help the whole process of defining the true petroleum potential of the area.

Another example of fruitful integration between mud



C1–C5 and C6–C8 analyses are performed on hydrocarbons extracted from mud, C9–C28 analyses on hydrocarbons from cuttings.

logging and reservoir geochemistry is the combination of mud gas data and X-ray diffraction (XRD) and X-ray fluorescence data (XRF). XRD provides a mineralogical characterisation of the reservoir by using cuttings, whereas XRF performs a chemical elemental characterisation of them. Both these techniques have been applied at wellsites for a few years, but nowadays dramatic improvements have been introduced by companies like Geolog. The combination of mud logging and reservoir geochemistry allows a detailed zonation of the reservoir according to different facies, based on mineral occurrence and different ratios of elements detected by XRF, all using well-established interpretation criteria defined in the frame of chemo-stratigraphy.

A combination of reservoir zonation, obtained through XRF and XRD, and hydrocarbon occurrence from mud logging data, can be very useful to determine and characterise the most favourable intervals in the reservoir, to be easily recognised in appraisal or development wells.

Recent improvements obtained in clay mineral quantification through using new advanced instruments and sophisticated software for XRD data processing also makes possible and fruitful the application of this integrated approach in unconventional resource plays, where source rock and reservoir are the same geological object and clay minerals can be particularly abundant.

The Way Ahead

It has been demonstrated by several field applications that the marriage between mud logging and reservoir geochemistry is very fruitful and can generate a lot of added value, but the process of integration is still ongoing. Many other analytical techniques are likely to be moved to the wellsite over the few next years and this will offer other opportunities like those just described.

Many more pieces of information with lab quality will in future be provided at the wellsite in real time, allowing us to take better decisions at the right time, to reduce costs and to improve integrated reservoir characterisation. There will be additional clear benefits not only for exploration but for field development and production optimisation; all this by exploiting technologies developed in other industrial sectors. ■



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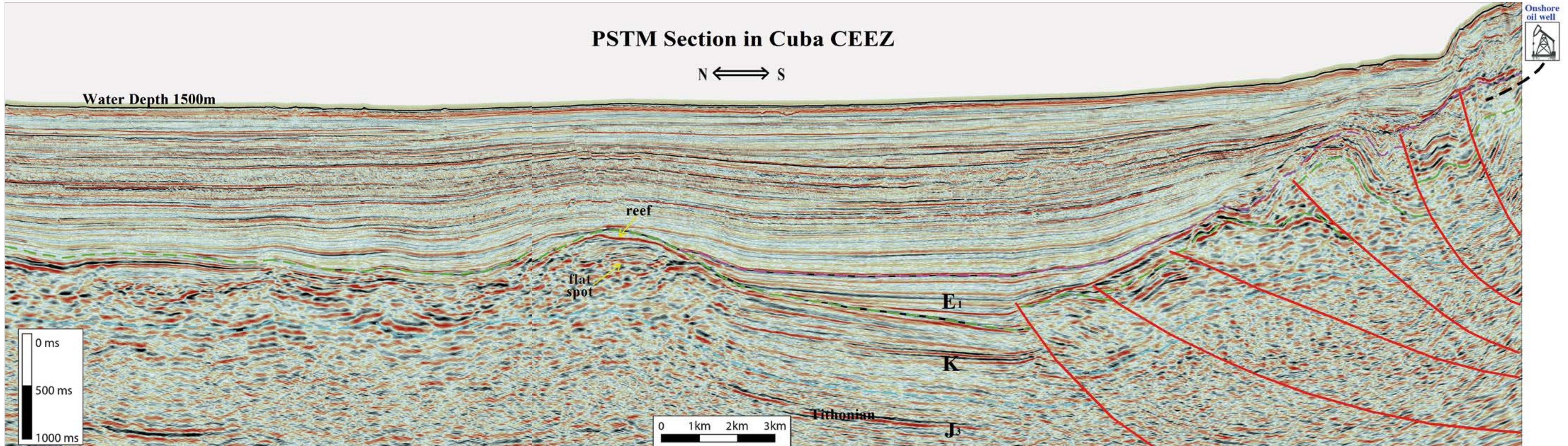
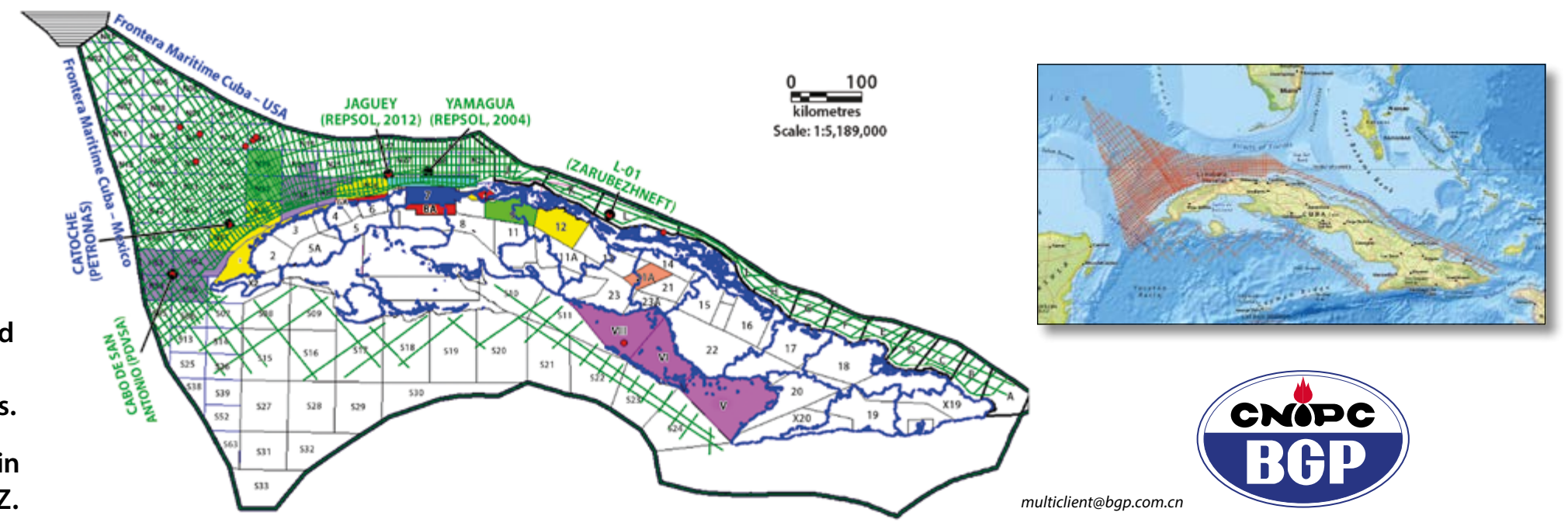
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Cuba Re-launches Offshore Oil Exploration

A fresh look at a clear image.

New PSTM data reveals significant exploration potential of the Cuba Exclusive Economic Zone (EEZ). The section below shows a series of structural traps in the thrust belt of the EEZ, which have favourable reservoir and seal assemblage. The newly drilled oil discovery near this area has proved its potential. In this section, a reef is clearly indicated and there is also a flat spot reflection, which probably indicates the existence of hydrocarbons.

With these new understandings and discoveries in this area, it is time to take a fresh look at the EEZ.



Explore Madagascar's Open Acreage

The West Morondava Basin: Let the bidding commence!

After over 100 years of exploration, the offshore part of the West Morondava Basin remains largely underexplored. Only six exploration wells have been drilled in the region, all in shallow water. Three of these reported gas shows, while oil and gas shows have been reported in wells throughout the onshore part of the basin, where two heavy oil fields, including the giant Tsimiroro field, lie within 100 km of the coast. These fields are sourced from the Triassic Sakamena Formation, and further source rock potential is thought to lie in the Upper and Lower Cretaceous, and in the Upper and Middle Jurassic. Multiple oil seeps have been reported offshore.

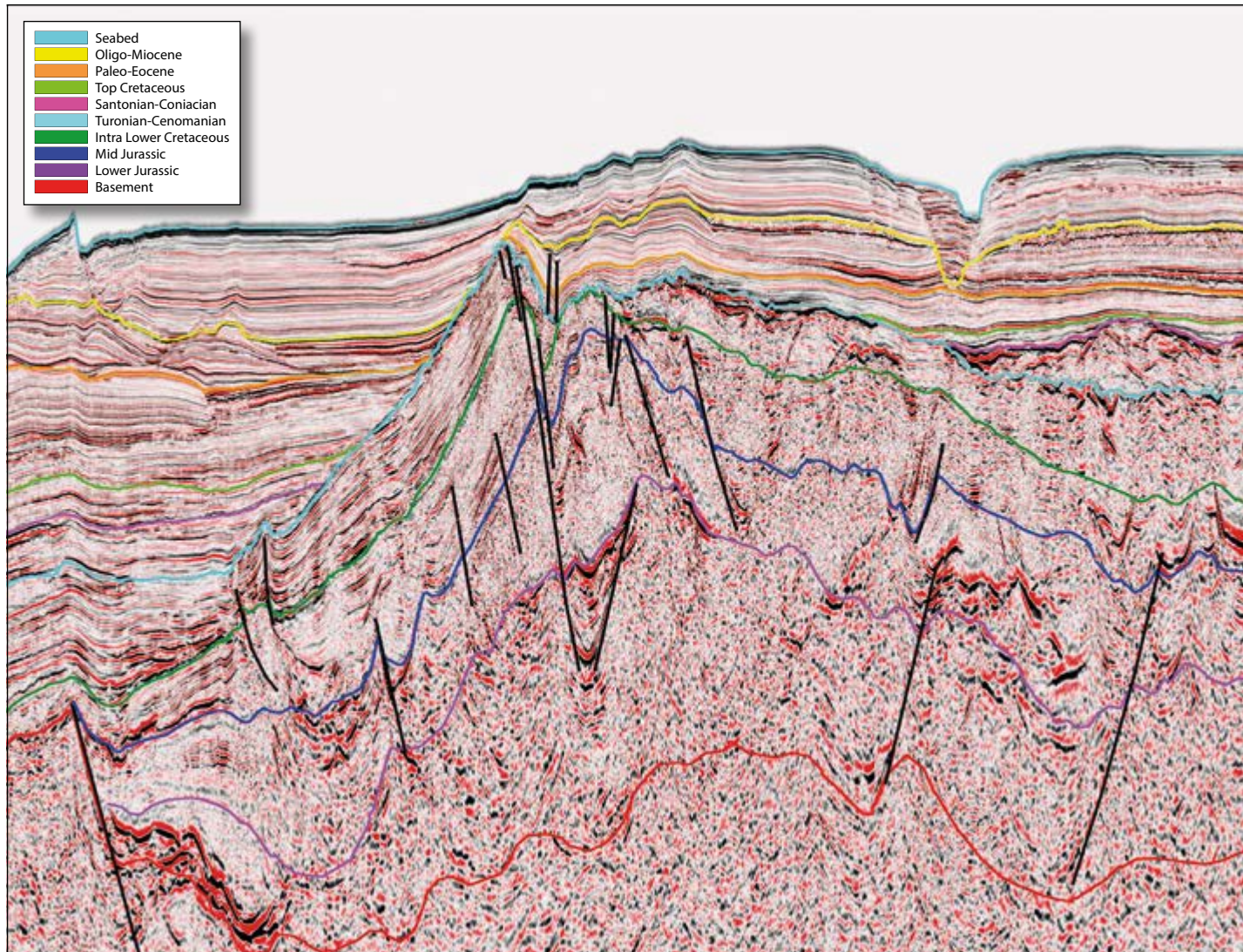
It is believed that the Davie Fracture Zone was still active during the Turonian-Santonian, which has allowed

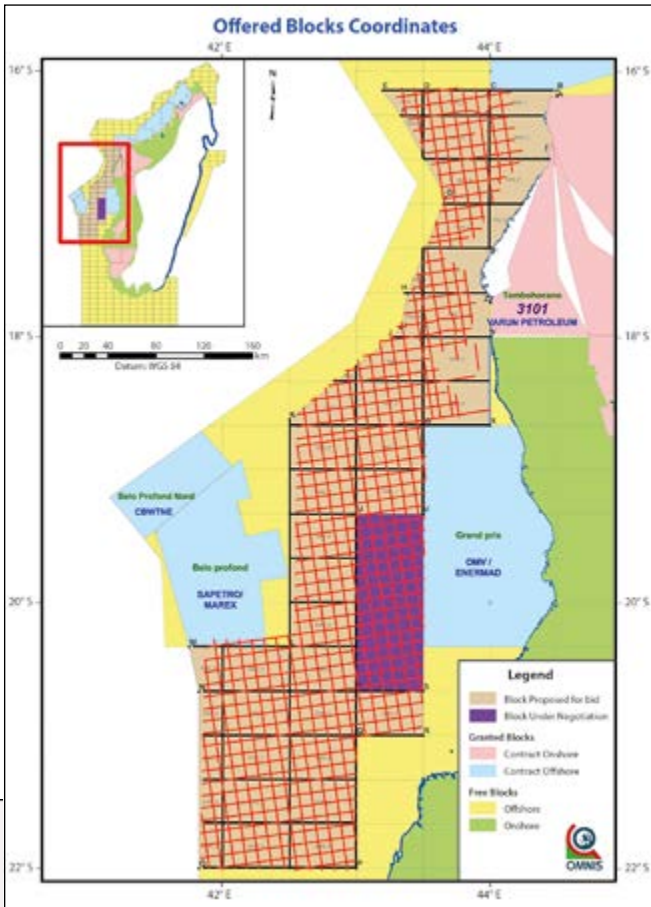
the creation of trap structures and the migration of hydrocarbons from older source rocks. Potential traps include reef structures, tilted fault blocks, fan complexes and intrusion related uplifts.

Recent studies on new data conducted in collaboration between BGP and TGS confirm there is significant potential for future discoveries offshore the West Morondava Basin.

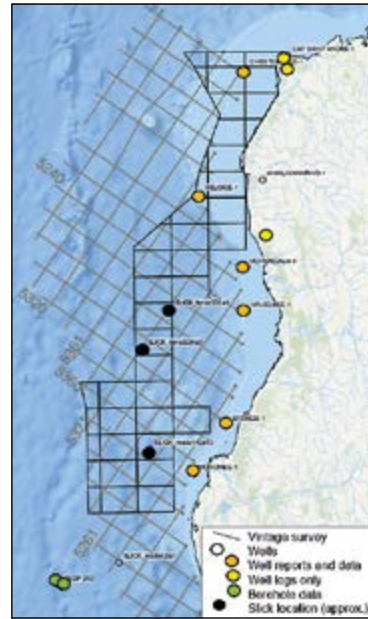


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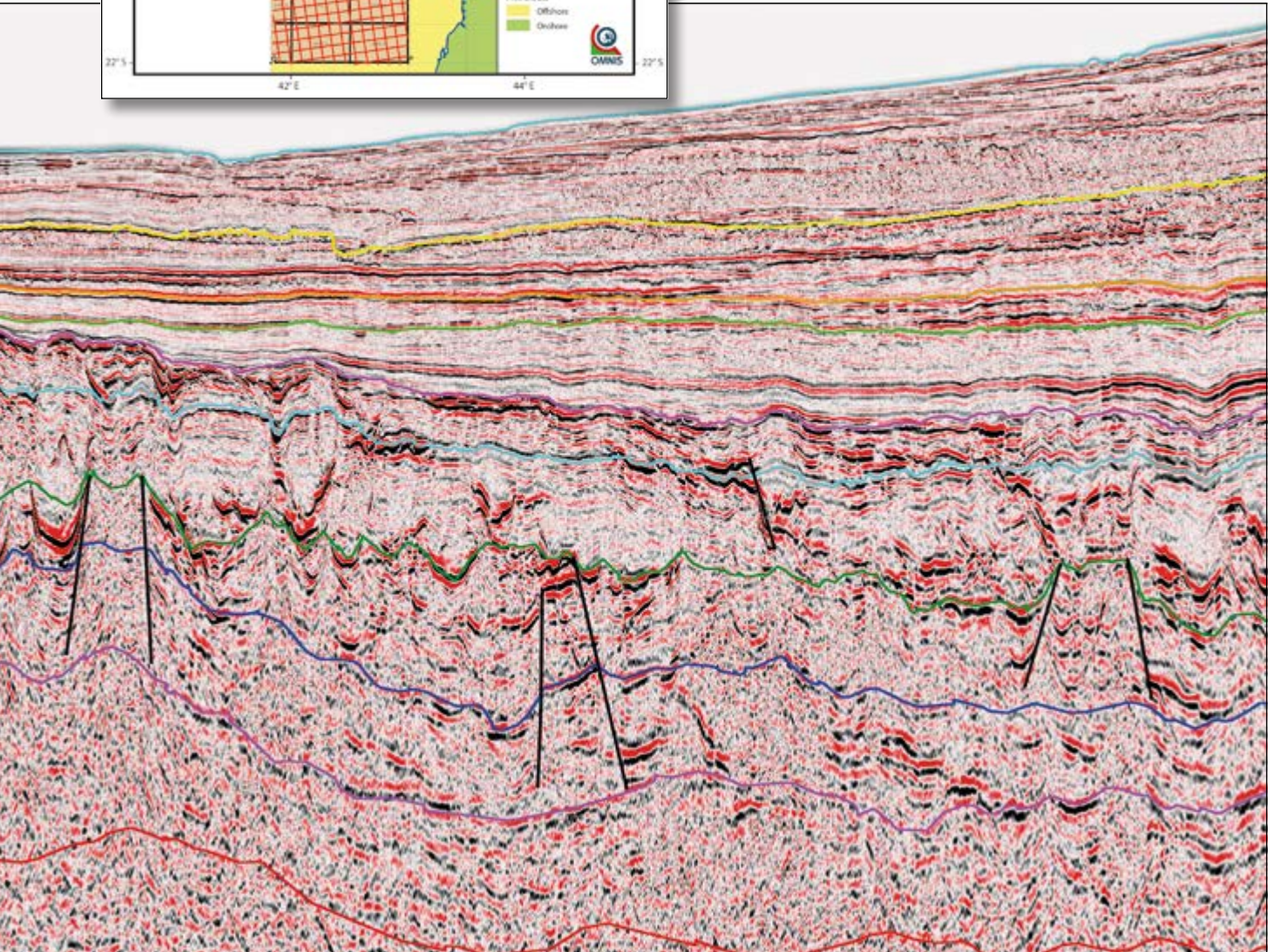




A total of 44 offshore blocks in the Morondava Basin, located on the western margin of Madagascar, are offered in the Madagascar Licence Round, which opened on 7 November 2018 and will close on 30 May 2019.



The offshore Morondava Basin is essentially unexplored.





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GOM

Conjugate Margins Revealed

THOMAS SMITH

Enhanced mega-regional hydrocarbon play and reservoir fairway maps in the Gulf of Mexico have resulted from improved tectonic restorations of its US and Mexican conjugate margins.

The Gulf of Mexico (GOM) petroleum system is one of the most productive and studied ‘super basins’ in the world, yet uncertainties remained with regard to its fundamental crustal structure. For decades, the 15 km-thick sedimentary and evaporitic infill had obscured the accurate observation of the deeper continental and oceanic basal structure, making it difficult to unravel the Triassic to Jurassic opening phases and their precise directions of opening. Observations that long puzzled geoscientists studying the area included a wider zone of thinned continental crust in the northern GOM and a corresponding narrow zone along the Yucatan margin; a deep central GOM

underlain by oceanic crust; and a salt province separated into two unequal parts. (The larger Louann salt province covers most of the US continental margin while Campeche salt covers a smaller area of the Mexican margin.)

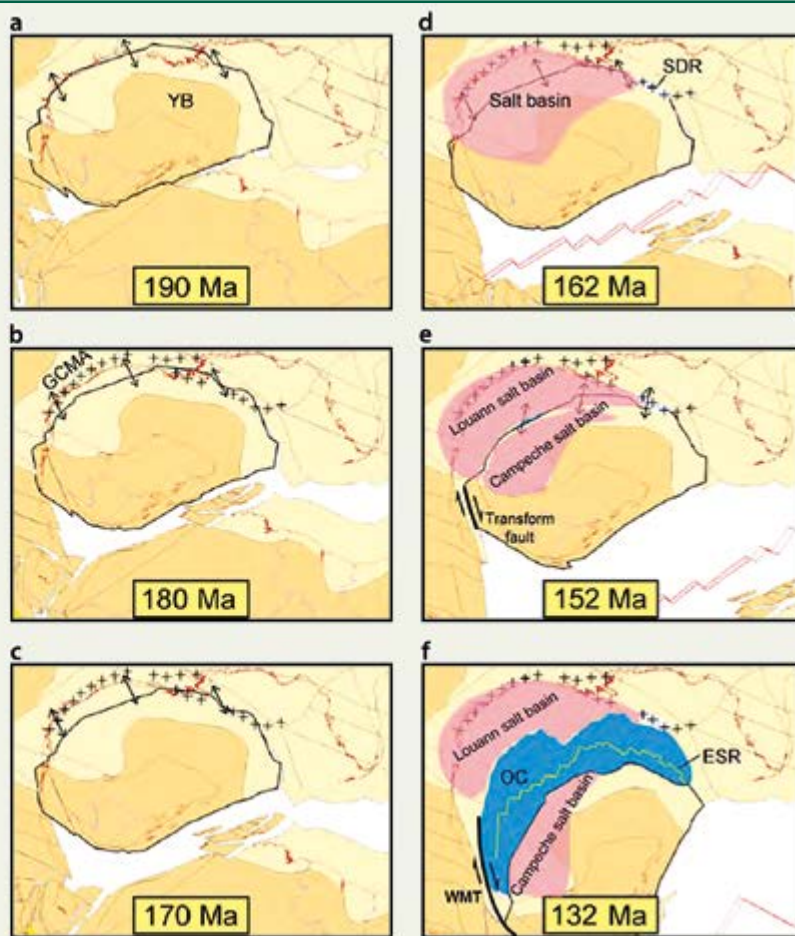
The 2014 publication of high-resolution satellite images of marine gravity data by Dr. David Sandwell of Scripps Institute of Oceanography and colleagues has led to greatly improved mapping, including the locations of fracture zones and spreading ridges. Previous plate models by Dr. James Pindell and colleagues provided the overall plate framework for the crescent-shaped oceanic crust that resulted from the late Jurassic, counterclockwise rotation of the Yucatan Peninsula. The

new gravity data provides the precise location of fracture zones, allowing researchers to match the well-known and highly productive northern margin to its underexplored southern conjugate. This concept has helped geoscientists discover productive new petroleum basins across other conjugate margins such as those on either side of the South Atlantic Ocean (see: *Is a Conjugate an Analog?* *GEO ExPro*, Vol. 15, No. 4).

Eastern Gulf

The central and eastern GOM contains a whole host of plays and this offshore region produces about 17% of US oil. The Norphlet and overlying Smackover formations in the eastern portion of the

“With the new images, the long puzzling GOM observations suddenly made more sense,” says Dr. Paul Mann, director of the Conjugate Basins, Tectonics and Hydrocarbons Consortium (CBTH) at the University of Houston. “A ‘two phase opening model’ was presented in a series of papers by Drs. Gail Christeson, Ian Norton and colleagues at the University of Texas. The first phase separated North America from the Yucatan-South American Plate in a north-west to south-east direction (diagrams a-c) in the late Triassic to early Jurassic (190–170 Ma). Near the end of rifting in the Middle Jurassic, salt was deposited in a large sag basin overlying rifted continental crust (diagram d). In the late Jurassic (second phase of rifting) the motion changed from north-west to south-east to north-south along the Mexican margin as the Yucatan Block began to rotate in a counterclockwise direction. That motion can now be accurately traced along mapped fracture zones (diagrams e and f). The two-phase model helped explain the much wider area of continental extension in the US GOM and the deposition of salt into a sag basin overlying that area of extension. The second phase of rifting was more confined to the edges of the oceanic crust in the central GOM. By earliest Cretaceous, strike-slip motion along the Western Main Transform (WMT) and seafloor spreading ceased.”



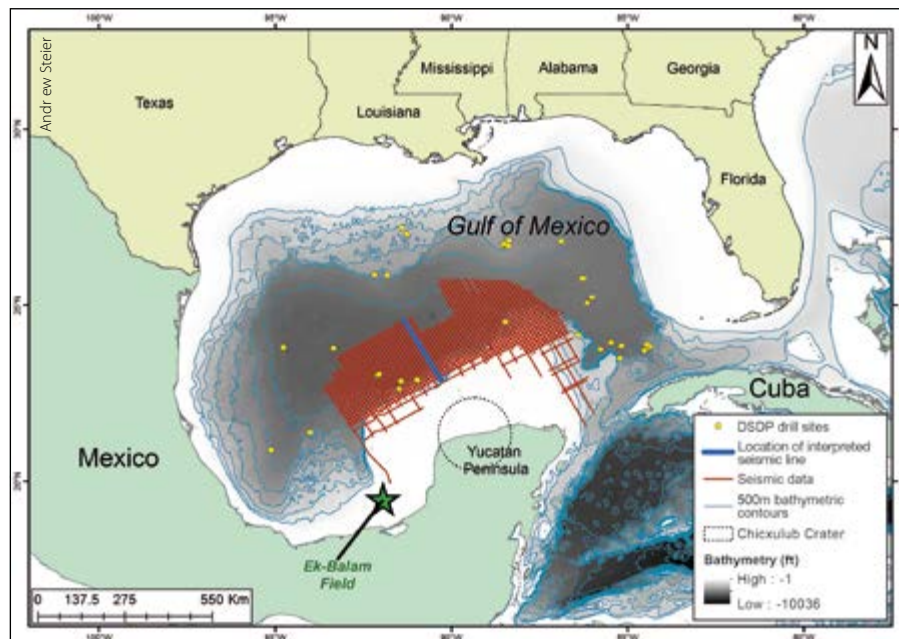
Nguyen and Mann

petroleum province west of the Florida margin have been relatively recent additions to the GOM's growing list of successful plays. The Upper Jurassic aeolian sandstones of the Norphlet Formation have been a prolific onshore play and geoscientists postulated that it could extend into the deep waters of the eastern GOM. The Smackover Formation is the primary source for Norphlet oil and also acts as an effective reservoir seal. Drilling has proved the geoscientists correct, with Shell making a series of discoveries starting in 2003 (see: *Puzzling Salt Structures; GEO ExPro* Vol. 12, No. 2). The 2017 Chevron and Total Norphlet discovery at Ballymore is the most recent find in this impressive play. Leasing further offshore is scheduled and could extend the Norphlet fairway.

Available Data for Southern Gulf

Much explored, the central and eastern GOM has impressive grids of seismic data that has been tied to an equally impressive number of wells. The Florida margin is currently off limits to exploration, but still has abundant seismic data tied to wells. The Yucatan conjugate remains largely underexplored, with Spectrum Geo's 2016 seismic data being the only regional grid available in the area. None of this deepwater acreage in the Mexico GOM has yet to be offered for lease.

"Spectrum Geo supplied 24,500 line-km of 2D seismic reflection data for my study of the Yucatan margin," says Andrew Steier, who was supported at the time as a CBTH research assistant and a masters student at the University of Houston and is now with the GOM exploration team at Total in Houston. "The seismic grid covers approximately 117,000 km² along the northern Yucatan margin with 10 km spacing. The dataset spans the shelf, slope, and basinal areas in water depths from 50m to 3,800m. There are no published industry wells and just seven Deep Sea Drilling Project (DSDP) wells. Four were drilled in deep water, but none penetrated the Mesozoic section. I relied upon published regional seismic lines that have been tied



Available data for the southern GOM study, including the 2016 Spectrum Geo seismic lines in red, DSDP drill sites in yellow, and the Ek-Balam field. Location of the interpreted seismic line below is highlighted in blue.

to wells penetrating the Mesozoic to tie into this study's data set. The top Jurassic pick is speculative being approximated from the thickness of post-salt Jurassic and Cretaceous sections observed in the deepwater US GOM."

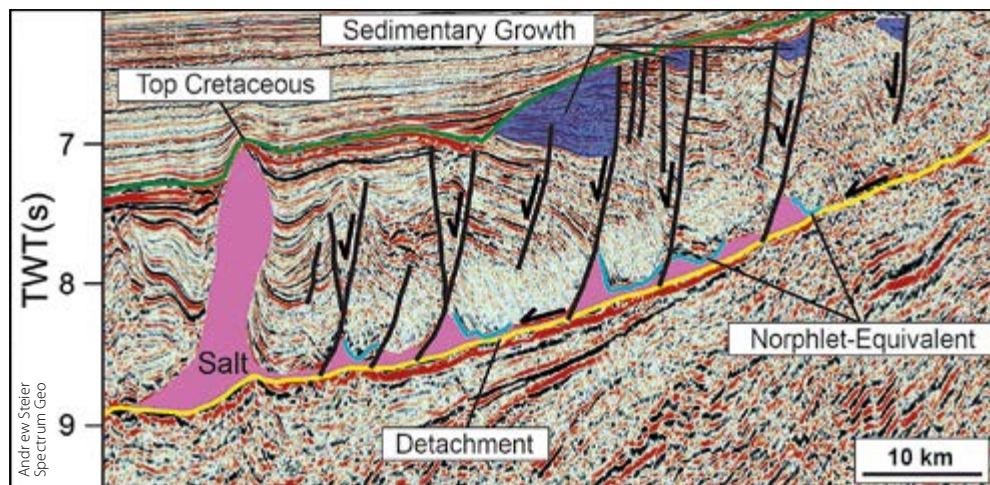
Structural Evolution

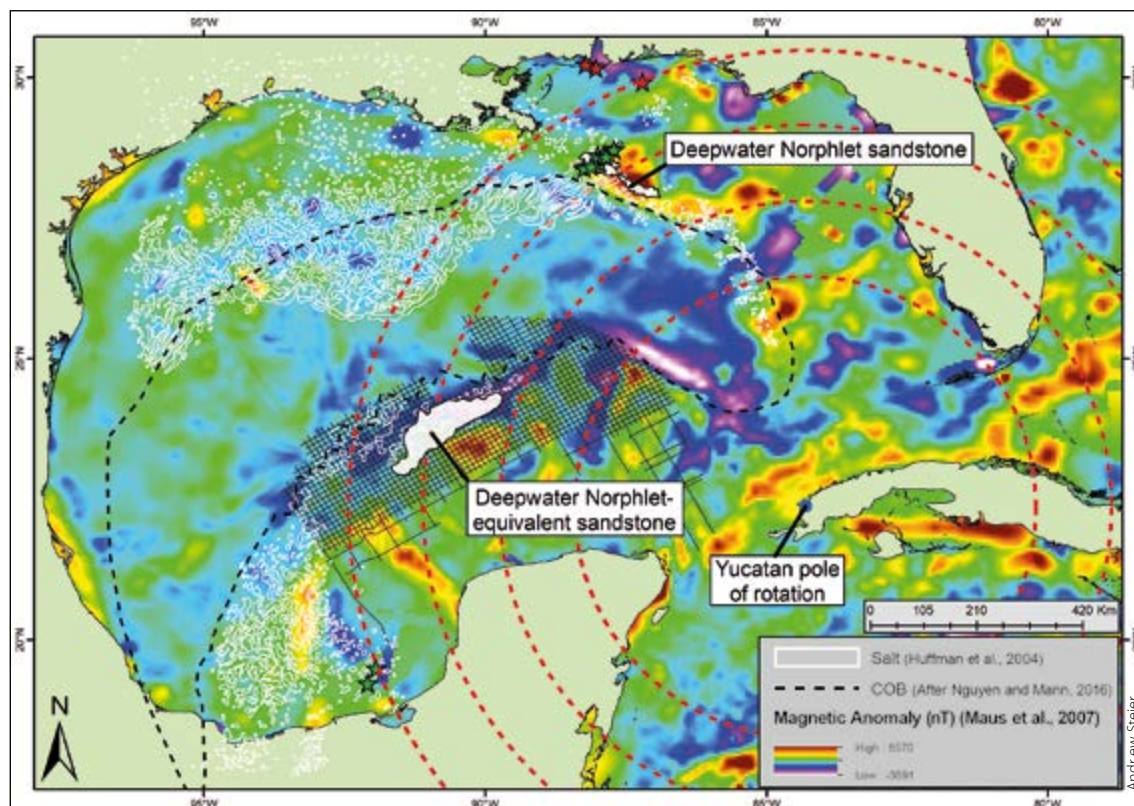
"The structural evolution of the northern Yucatan margin varies with the relative thicknesses of salt," says Andrew. "The north-eastern margin exhibits minimal salt and the late Mesozoic section is relatively undeformed. The central area is notable

for the development of salt rollers and associated sedimentary growth wedges. Finally, the south-western area features few salt rollers but numerous diapirs large enough to deform Holocene strata. This area exhibits the most complex salt deformation in the region."

Salt deposited in the GOM sag basin has been assumed to have been deposited with little topographic relief at its top. Norphlet and Smackover formations and equivalents that were deposited above the salt exhibit only a slight wedge geometry. The early and late Cretaceous strata exhibit substantial thickening toward

Interpreted dip seismic line. The basal detachment (yellow) is shown lying below low-amplitude, often chaotic seismic reflectors. This gently basinward-dipping peak forms the base of frequent listric, normal faults in the overlying section. Bodies of chaotic reflectors are interpreted as salt (pink). The Norphlet Formation equivalent (blue horizon) is a discontinuous, high-amplitude trough directly overlying the salt. The Top Cretaceous unconformity (green) frequently represents the upward termination of the salt-related faulting.





Present-day location of GOM margins. The blue dot at the western end of Cuba is the Yucatan pole of rotation from the 2016 Nguyen and Mann paper to which the dashed red circles have been drawn in order to rotate margins to original positions. Significant Norphlet or equivalent oil (green stars) and gas (red stars) discoveries are shown on the map. Potential deepwater Norphlet is represented by areas of filled, white polygons.

Andrew Steier

updip, normal faults and Cenozoic strata are largely undeformed. “These thickness changes and deformation indicate the majority of downslope movement on the salt detachment occurred during the Cretaceous,” says Andrew, “and was likely accompanied by progressive subsidence and deepening of the late Jurassic oceanic crust underlying the central GOM. The deep GOM formed by slow and steady subsidence over the past 140 Ma with the dense oceanic crust acting as an anchor pulling down the adjacent areas of thinned continental crust.”

Norphlet Reservoir Fairway

“Potential hydrocarbon trap and seal combinations abound in the salt-deformed late Jurassic to Cretaceous section on the northern Yucatan margin,” says Andrew Steier. “The trapping styles are similar to those utilised at the deepwater Norphlet sandstone discoveries of the north-eastern GOM. For these reasons, my study focuses on the palaeogeography (the location of a potential Norphlet equivalent fairway) and structural evolution of the Mesozoic section rather than the subhorizontal, gradually onlapping Cenozoic section.” This is not to say the Cenozoic section

is not prospective. In a 2017 article (see: Regional Play Types in the Mexican Offshore; *GEO ExPro* Vol. 14, No. 4), TGS geoscientists identified numerous play types in the Mexican offshore, including the Mesozoic section covered in detail in this article. They also identified undrilled prospects in the Paleocene to Eocene Wilcox sands as well as younger prospects in Miocene to Pliocene sands, all of which are major players in the US sector of the GOM.

“By using fracture zones, we have been able to rotate the Yucatan continental block back to its pre-rotational location,”

Conjugate Basins, Tectonics, and Hydrocarbons Consortium

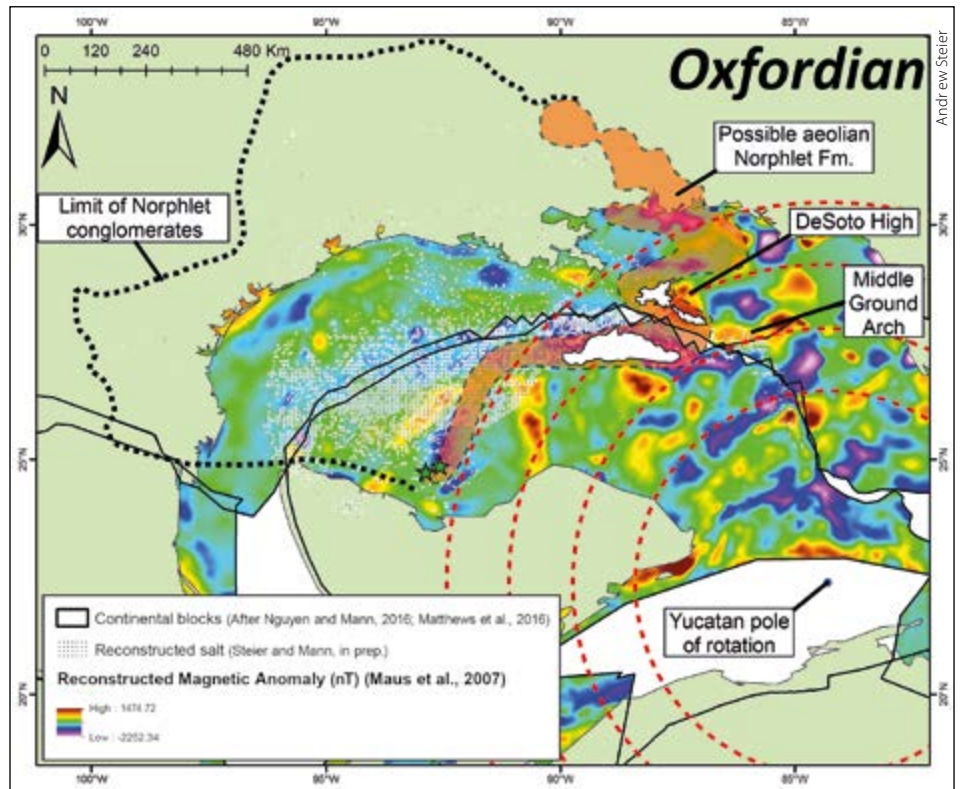
After working on other tectonic settings of the Caribbean and the northern South American region since 2005, Paul Mann, director of the industry Conjugate Basins, Tectonics, and Hydrocarbons Consortium (cbth.uh.edu) and his group began working the GOM in 2012. They started studying the eastern GOM because the thinner salt and sediment thickness produced better seismic imaging and the availability of extensive grids of industry seismic data. Seismic data from Spectrum and Dynamic Data Systems allowed geoscientists supported by the consortium to map the Florida margin from the north-eastern Gulf to the area north of Cuba. In one study, Pin Lin (PhD, 2018) used Spectrum seismic and released well data to map fracture zones and spreading centre locations

in the eastern GOM, along with the crustal structure of the oceanic crust to Moho depths.

With the publication of the Sandwell gravity data, the CBTH team was able to focus on mapping and modelling of the continent-ocean boundaries including the WMT along the margin of eastern Mexico. In 2016, new Spectrum seismic data along the Yucatan margin allowed them to set up their first southern conjugate margin study, presented in this article. Future CBTH supported work includes students working on the Florida-Yucatan margin north of Cuba and continuing gravity-magnetic work on refining the extent of oceanic crust in the eastern GOM and restoring the two margins to the pre-rift locations.

says Andrew. “These linear fracture zones equate to small circles around the late Jurassic to earliest Cretaceous pole of rotation and trace the path of the Yucatan block during seafloor spreading. Basically, these small circles connect the two conjugate margins of Yucatan and Florida and reunite the Norphlet equivalent mapped north of the Yucatan margin with the deepwater Norphlet discoveries along the northern GOM conjugate margin.

“Using the Oxfordian reconstruction, the known production from aeolian sandstones equivalent to the Norphlet in the Bay of Campeche at the Ek-Balam and Caan fields, along with the current known extent of the Norphlet sandstone and production in the north-eastern GOM, suggests a continuous fairway of late Jurassic, aeolian sandstone deposition in the GOM basin,” says Andrew. “This would increase the known southern GOM reservoir fairway by 48,000 km² in this underexplored region lying off the Yucatan margin of Mexico, greatly improving the area’s hydrocarbon prospectivity.” ■



Oxfordian (Late Jurassic) palaeogeography showing the proposed extent of possible aeolian Norphlet sandstone deposition (mapped in brown). Magnetic data was used to identify palaeotopographic highs (yellow to red colours are at the DeSoto High and the Middle Ground Arch) which controlled deposition of the Norphlet equivalents. This reconstruction uses a fixed North American plate and restores the Yucatan block to its pre-drift position.



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Finite Difference Modelling: Part III

Time-Step n-Tupling

“My aim is to convince a skeptical reader who may regard using finite differences as the last resort of a scoundrel that the theory of difference equations is a rather sophisticated affair, more sophisticated than the corresponding theory of partial differential equations.”

Peter Lax (1926–): The American Mathematical Monthly, February 1965

LASSE AMUNDSEN, ØRJAN PEDERSEN, and MARTIN LANDRØ

To solve wave equations using FD solutions one must first determine the spatial and temporal sampling criteria. Spatial sampling of the physical velocity model is generally chosen to avoid numerical grid dispersion in the wavefield solutions. Having chosen the spatial mesh, the time sampling is selected to avoid numerical instability. In Part I, we noticed that as we increase the time-step while keeping the spatial grid mesh fixed, the FD method eventually becomes unstable. Clearly, the choice of time-step cannot be independent of the grid mesh.

In this part, we consider the generic formula for the wave

equation in time-space in the form:

$$\left(\frac{\partial^2}{\partial t^2} - L(x)\right)u(x,t) = s(x,t) \quad (1)$$

where $L(x)$ is the system operator that contains material parameters and spatial derivatives, and s is the source term. For acoustic wave propagation, $L=c^2\nabla^2$, where $c=c(x)$ is the velocity, and ∇^2 is the Laplacian given by the sum of second partial derivatives of the wavefield with respect to each of the space variables. The FD solution of the wave equation (1),

In spite of the impressive developments in numerical methods for wave equations from the 1990s onward, in which the Lax-Wendroff method played a historic and landmark role, there are at present substantial research activities aimed at further improvements of wave equation numerical methods. In this light, the work of Amundsen and Pedersen (2017) represents a small contribution towards time-marching the wavefield by using larger time-steps. Their solution, in fact, is a generalised Lax-Wendroff correction scheme for wave equations. Calling their method ‘Time-step n-tupling’, they show here how the time-step in FD modelling can be doubled, tripled, quadrupled, quintupled, and so on. This leads to a family of FD modelling solutions, where the time-step generally is ‘n-tupled’; n being any positive integer number.



Peter Lax received the Abel Prize In 2005 for “contributions to the theory and application of partial differential equations and to the computation of their solutions.” As one of the most important mathematicians of the 20th century, Lax is applauded here in Oslo, by Norwegian H.R.H. Crown Prince Haakon. The Abel Prize is named after Norwegian mathematician Niels Henrik Abel (1802–1829) and directly modelled on the Nobel Prizes.

discretised in time, most often uses the classic second-order accurate temporal discretisation:

$$\frac{\partial^2 u(x,t)}{\partial t^2} \approx \frac{D^2 u(x,t)}{Dt^2} = \frac{u(x,t+\Delta t) - 2u(x,t) + u(x,t-\Delta t)}{(\Delta t)^2} \quad (2)$$

By inserting equation 2 into 1, and reordering the terms, we obtain the famous FD time-marching scheme which calculates the next value of the wavefield at the discrete time $t+\Delta t$ from current values known at time t and the previous time $t-\Delta t$ through the formula:

$$u(x,t+\Delta t) = (2 + (\Delta t)^2 L(x))u(x,t) - u(x,t-\Delta t) + (\Delta t)^2 s(x,t) \quad (3)$$

Modelling with computers starts at time zero, and the time-stepping continues until the desired recording time is met. In other words, repeated application of equation 3 gives the wave response time history of the system. For the acoustic-wave equation, in which spatial derivatives are calculated by the pseudospectral method (Fornberg, 1987), the explicit method 3 is known to be numerically stable and convergent whenever the Courant–Friedrichs–Lewy (CFL) condition is fulfilled:

$$\frac{c_{max}\Delta t}{\Delta d} \leq \frac{2\nu}{\pi\sqrt{D}} \quad (4)$$

where c_{max} is the maximum velocity of a given model, Δd is the mesh size (spatial grid sampling), and D is the spatial dimension of the simulation. Furthermore, ν is a constant parameter that depends on the type of FD scheme; for the scheme in equation 3, simply $\nu = 1$. We now know how we must change the time-step with changes in mesh size in order to maintain stability. The stability condition is a first topic in numerical analysis; everyone knows its importance – and computations make that clear. Violate equation 4, and the solution given by equation 3 explodes in a few time-steps.

To get a feeling for realistic Δt in seismic modelling, assume that the mesh size can be chosen to $\Delta d = 20m$ in a model with maximum velocity of 5,000 m/s. In 3D simulations, then $\Delta t < 1.47 ms$ to avoid numerical instability. When we need to model 10 seconds of data, we need to run 6,800 time-steps in the computer. If we need to model a huge number of shots, the simulation time may get prohibitive.

Lax-Wendroff Schemes

The search for stable time-stepping methods with a large allowable time-step has been an active area of research over the past two decades. One popular time integration is based on the Taylor series method (see box overleaf), commonly referred to as the Lax-Wendroff method (Lax and Wendroff, 1960). This approach begins by using a Taylor series expansion of the wavefield in time; the time derivatives are then replaced by space derivatives using the wave equation. With high-order Lax-Wendroff schemes, much of the practical difficulty comes from the necessity of defining and calculating high-order spatial derivatives of the wavefield.

The Taylor series expansion of the wavefield yields:

$$u(x,t \pm \Delta t) = u(x,t) \pm \Delta t \frac{\partial u(x,t)}{\partial t} + \frac{(\Delta t)^2}{2} \frac{\partial^2 u(x,t)}{\partial t^2} \pm \frac{(\Delta t)^3}{6} \frac{\partial^3 u(x,t)}{\partial t^3} + \frac{(\Delta t)^4}{24} \frac{\partial^4 u(x,t)}{\partial t^4} + O(\Delta t)^5 \quad (5)$$

Equation 5 describes two equations. By summing these, one obtains:

$$u(x,t+\Delta t) - 2u(x,t) + u(x,t-\Delta t) = (\Delta t)^2 \frac{\partial^2 u(x,t)}{\partial t^2} + \frac{(\Delta t)^4}{12} \frac{\partial^4 u(x,t)}{\partial t^4} + O(\Delta t)^6 \quad (6)$$

Then, from equation 1, time derivatives in equation 6 are replaced by space derivatives, and we obtain the first-order Lax-Wendroff correction to the classic FD equation 3:

$$u(x,t+\Delta t) = \left(2 + (\Delta t)^2 L(x) + \frac{(\Delta t)^4}{12} L(x)L(x)\right)u(x,t) + u(x,t-\Delta t) \quad (7)$$

Higher-order corrections are obtained by using higher-order terms in the Taylor series. Equation 7 has the CFL stability condition given by equation 4 when setting $\nu = \sqrt{3}$.

Comparing the CFL stability conditions of the Lax-Wendroff corrected equation 7 and the classic FD equation 3 ($\nu = \sqrt{3}$ versus $\nu = 1$ respectively) shows that the time-step in the Lax-Wendroff corrected equation 7 can be increased by the factor $\sqrt{3}$; that is, made 71% larger than the time-step of the classic FD equation 3. However, the enlarged time-step comes at a price: the cost of introducing more spatial computations per time-step. As observed in equation 7, we need to compute $L(x)L(x)u(x,t)$, in addition to $L(x)u(x,t)$. In the classic FD method 3, it is sufficient to calculate $L(x)u(x,t)$.

Time-step n-tupling

Amundsen and Pedersen (2017) derived a new family of modelling schemes which they called Time-step n-tupling, having similar computational burden per time-step as the Lax-Wendroff schemes. The n-tupling scheme marches the wavefield in time to time $t+n\Delta t$ from current values known at time t and the previous time $t-n\Delta t$; $n=2$ implies doubling the time-step, $n=3$ tripling the time-step, and so on, with CFL stability conditions given by equation 4 when setting $\nu=n$.

Doubling the time-step ($n=2$) gives a modelling method that is $2/\sqrt{3}$ or 15% faster than the first-order Lax-Wendroff scheme (see Chu et al., 2009; Amundsen and Pedersen, 2017). Time-step tripling is 50% faster than the second-order Lax-Wendroff correction of the same spatial order. The improvements are particularly prominent when the solutions contain large numbers of wavelengths in the computational domain. The computational burden per time-step is the same as for Lax-Wendroff schemes, but the n-tupling method allows significantly larger time-steps.

The n-tupling method is so simple to derive that any high-school student (already an FD expert after having read Part I of this series!) can figure it out. Doubling of the time-step is achieved by letting $t \rightarrow t \pm \Delta t$ in equation 3. This substitution gives two equations, which can be added; then, the time-step

Recent Advances in Technology

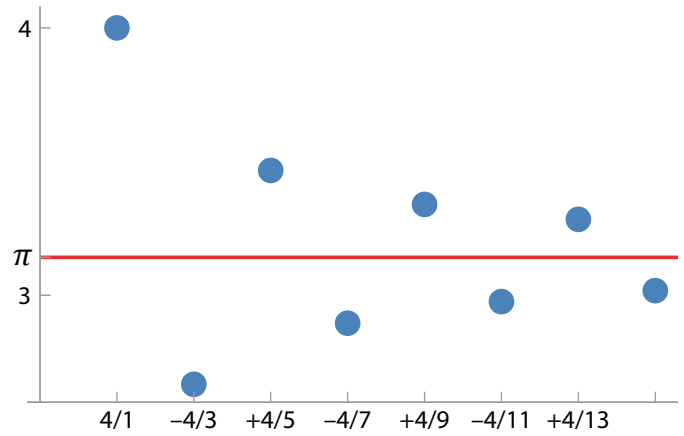
values of the wavefield at $t \pm \Delta t$ are eliminated by one more use of equation 3. Then, let $\Delta t \rightarrow \Delta t/2$. The magic equation where Δt can take the double value of Δt in equation 3 now is:

$$u(x, t + \Delta t) = \left(2 + (\Delta t)^2 L(x) + \frac{(\Delta t)^4}{16} L(x)L(x)\right)u(x, t) + u(x, t - \Delta t) \quad (8)$$

Observe that the FD equation 8 has the same form as the famous Lax-Wendroff equation 7. Only one number is changed; $1/12$ is replaced by $1/16$. That doesn't seem much, but the stability increases by allowing a time-step which is 15% larger. The procedure for n-tupling the time-step is the same as that just sketched (see Amundsen and Pedersen (2017) for the general formula).

Numerical Example

We solve the 2-D acoustic wave equation by using the



Madhava of Sangamagrama (see box), among others, found the infinite series expansion of $\pi = 4/1 - 4/3 + 4/5 - 4/7 + 4/9 - \dots$. If this process is continued indefinitely, through all odd number fractions to infinity, the approximation will hit π exactly.

Theorem of the Day

The Taylor series is named for the English mathematician Brook Taylor. Taylor's *Methodus Incrementorum Directa et Inversa* (1715) added a new branch to higher mathematics, now called the 'calculus of finite differences'. In his work, we find the first systematic treatment of differential calculus and the famous Taylor theorem for expansion of a function – for which the derivatives of all orders exist – into an infinite series: the Taylor series. However, the importance of Taylor's formula remained unrecognized until 1772, when the French mathematician Joseph-Louis Lagrange (1736–1813) realised its powers and proclaimed it the basic principle of differential calculus. We note that in 1712, Taylor as a fellow of the Royal Society of London, sat on the committee for adjudicating Sir Isaac Newton's and Gottfried Wilhelm Leibniz's conflicting claims of priority in the invention of calculus (see Part I).

In fact, Taylor's theorem was discovered by the Scottish mathematician James Gregory who, in 1671, wrote to John Collins, secretary of the Royal Society, to tell him of the result. Gregory's actual notes exist on the back of a letter he had received on 30 January 1671 from an Edinburgh bookseller. This letter is preserved in the library of the University of St. Andrews, the oldest of the four ancient universities of Scotland and the third oldest university in the English-speaking world. Today, Gregory's series is known as the infinite Taylor series expansion of the inverse tangent function, but Gregory discovered infinite series representations for several trigonometric functions.

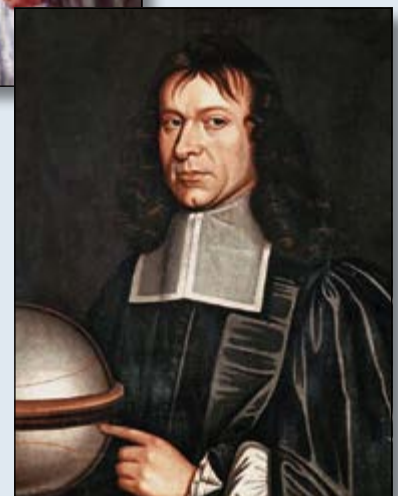
The earliest person to whom such types of series can be attributed with confidence is the Indian mathematician Madhava of Sangamagrama (1340–1425). Later Indian mathematicians wrote about his work with

the trigonometric functions of sine, cosine, tangent, and arctangent. Madhava also discovered applications of his infinite series. One of them was his formula for π , popular by the name of Madhava-Leibniz series or Leibniz formula for π or Leibnitz-Gregory-Madhava series due to its rediscovery by Gregory in 1671 and later by Leibniz in 1676.

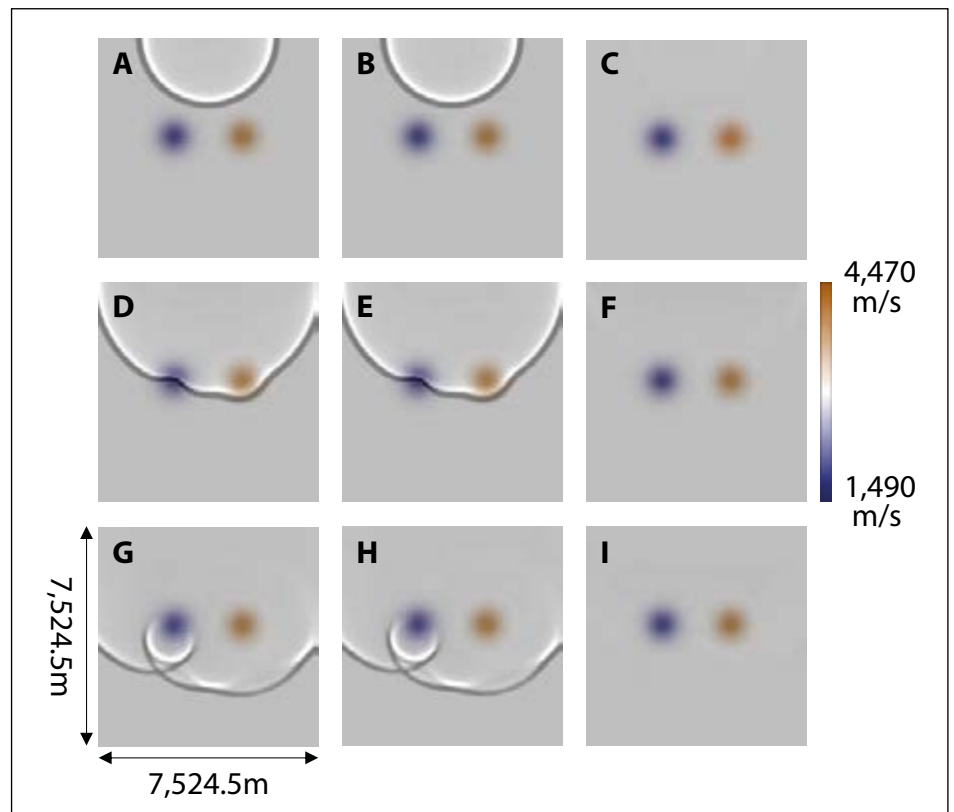


Portrait of Brook Taylor (1685–1731) by French painter Louis Goupy (1674–1747).

James Gregory (1638–1675).



pseudospectral method to calculate the spatial derivatives of the wavefield. We consider the double time-step scheme given in equation 8, and we carry out a numerical experiment on the model shown in the figure (right) with two circular velocity anomalies in a constant background. The lowest and highest velocities are 1,490 and 4,470 m/s, respectively. The grid mesh is $\Delta d = 37.25$ m in the horizontal and vertical directions. The CFL stability condition for the classic time-stepping algorithm in equation 3 has the maximum allowable time-step $\Delta t = 3.75$ ms. We run the classic algorithm at time-steps just beneath the CFL limit, at 3.5 ms. Next, we run the double time-step method in equation 8 with twice the time-step of the classic method. The double time-step method results in a stable solution, and in the figure we display snapshots at times 1.25, 1.77, and 2.33 s from both simulations together with the difference, which is negligible. ■



Three snapshots of wave propagation overlain velocity model, shown at times 1.25, 1.77, and 2.33 s. A, D and G show the conventional method; B, E and H, the n-tupling method with time-step doubling; and C, F and I the difference between the conventional and n-tupling methods.

Walk among the lines



Energy and Climate Change

Energy and Climate Change: An Introduction to Geological Controls, Interventions and Mitigations.

By Michael Stephenson. Elsevier 2018

DR. NICK RILEY

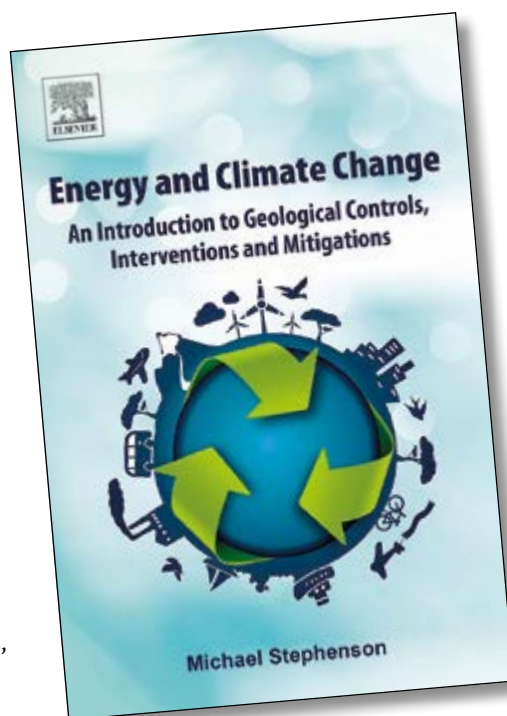
Professor Michael Stephenson is Director of Science and Technology at the British Geological Survey, but before becoming a leading international research geoscientist, Mike worked as a school teacher in rural Africa (Botswana). It is therefore no surprise that his text book targets students, particularly those at advanced level and undergraduates. His aim is “an introduction to a number of connected issues in energy and climate change, including the carbon cycle, climate change in deep time, the ‘fossil economy’, the role of geology in climate change abatement and adaptation, and the importance of geological measurement and system understanding”.

Logical Structure

The nine chapters are well structured for learning and further study. There are numerous references, illustrations and tables to support the text. Each chapter follows a similar structure: there is an introductory section which sets the chapter’s context and aim, followed by a logical sequence of topics, ending in a summary highlighting the main learnings. A bibliography follows referencing text books, primary research and review papers, and policy outputs, thus providing a gateway into deeper study.

The first chapter describes how fossil fuels are formed and how, as their name implies, they are intrinsically related to biological processes and to the long-term geological carbon cycle, while Chapter 2 demonstrates that “the huge span of geological time shows many instances of natural climate fluctuations that have an endogenous Earth system origin, such as volcanicity, some of which have been severe enough to affect the continuity of life on Earth”. Chapter 3 reveals how important human activities are in relation to climate change; in fact, just as influential as natural processes. “The problem is that humankind short circuits

the long-term geological carbon cycle by burning fossil fuels and upsetting a complex balance or equilibrium,” he says, explaining how changes in the rate of human consumption and manufacturing in the 1950s have apparently generated an ‘inflection point’ known as the Great Acceleration. The next chapter continues



with this theme, looking at how this Great Acceleration might proceed, “given that the developing world is probably poised to industrialise and to experience changes in living standards, wealth, and energy usage”. Chapter 5 describes how geological processes and materials are not only intrinsic to the long-term carbon cycle, and therefore to energy and climate change, but also can be part of the solution to climate change, with much of the chapter discussing carbon capture and storage and how it could be a counterbalance to the fossil-fuel short circuit. Chapter 6 “looks at how the subsurface could play a part in how humankind adapts to climate change. The main ‘vector’ of climate change is likely to be water, and

groundwater in aquifers provides backup for surface water variability in relation to seasonal variation and perhaps to more long-term climate change”. Chapter 7 perhaps shows most clearly the need to understand and study the processes of the past, but including the recent industrial human past as well as geological history. It discusses how human energy systems and economies built around hydrocarbons contain mechanisms that operate in similar ways to the physical science feedbacks and tipping points of the natural climate system and many other natural systems and cycles. The next chapter focuses on technology, which, as well as having lifted living standards and health, has placed humankind at odds with its environment, yet also delivers the means to help us to adapt better through enabling us to monitor, measure, and understand the environment. The ability to intervene in an intelligent way to reduce climate change, or better adapt, can only come from a greater understanding of Earth processes. Mike believes that this chapter contains the most important message of his book.

Well Recommended

Chapter 9 reviews the previous chapters, again reinforcing learning, and the author reveals some of his personal views on the way forward: “I summarise the main points of the book and clarify the role that geological science plays in energy and climate change, specifically in controls, interventions, and mitigations”. At the end of the book is a useful glossary of technical terms.

I recommend this book for anyone curious about how our planet works and how we are disturbing its ability to remain in life-sustaining equilibrium. It gives a good grounding into how geoscience will be vital in our ability to solve and adapt to the damage we have done and how to avoid making things worse. ■

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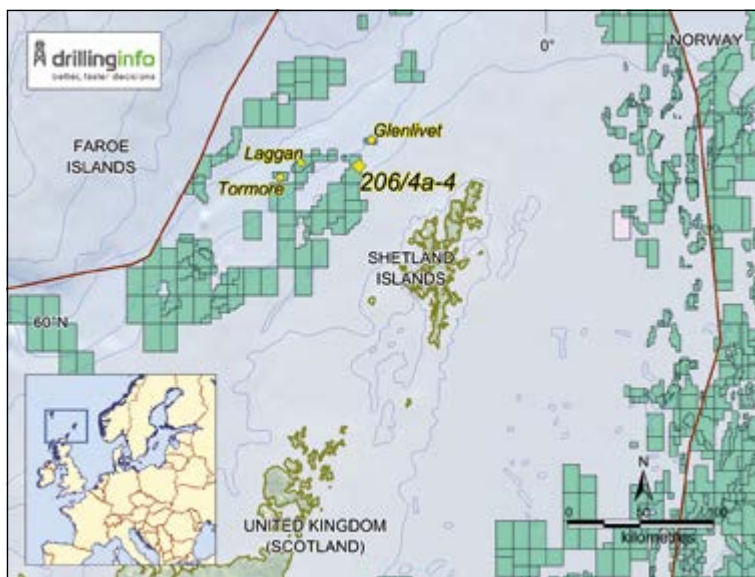
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UK: West of Shetlands Discovery

Total has discovered an estimated **1 Tcfg** recoverable resources with a NFW on **West of Shetlands Block 206/4a**, encountering 42m net pay in a high quality Early Cretaceous reservoir. The well was spudded on 27 May 2018 from a location on the nearby Edradour field. It reached TD at 4,312m MD in August and Total announced the result in late September following logging and preliminary testing.

The field is named **Glendronach** after a Scottish whisky, as are the nearby Laggan, Tormore, Glenlivet and Edradour discoveries. It is the largest conventional gas field found in the UK since 2008.

Block 206/4a is in Total's P1453 licence, which is shared with INEOS E&P UK (20%) and SSE E&P UK (20%). The block lies about 50 km north-west of the **Shetlands** and covers more than 200 km². The acreage contains the Edradour gas field, discovered in Cretaceous Albian turbidites in 2010. The Edradour and Glenlivet fields have been developed through a tie-in to Laggan and Tormore infrastructure and came onstream in August 2017. Combined, these fields have



65 MMboe estimated reserves and will produce up to 56,000 boepd. ■

Trinidad & Tobago: Two Gas Discoveries

On 18 July 2018, **BHP** reported that the **Victoria-1** NFW in **Trinidad and Tobago's TTDAA 5 Block** encountered gas. The company revealed the news in its operational review for the financial year, which ended on 30 June 2018. The well reached a final TD of 3,282m and it forms part of the company's Phase 2 deepwater exploration drilling campaign, aimed at assessing the commercial potential of the Magellan play. The well was drilled in a water depth of 1,828m and was targeting gas in Pleistocene/Pliocene-age rocks. BHP holds 65% operated interest in TTDAA 5 and Shell holds the remainder.

Transocean's *Deepwater Invictus* drillship spudded the Victoria-1 well on 12 June 2018 in a water depth of 1,828m, around 3.2 km south of the LeClerc 1ST gas discovery in the north-east of the block, drilled as part of the Phase 1 drilling programme in 2016. It was plugged and abandoned at a TD of 3,282m on 18 July 2018 and the drillship subsequently moved to the Bongos-1 well location in TTDAA-14, in order to drill the second well in the Phase 2 drilling programme.

Bongos-1 NFW, located in water of 1,910m, was planned to be drilled to a TD of 5,351m, targeting a Pliocene/Miocene gas play, but it experienced mechanical issues shortly after spudding. **Bongos-2** spudded two days later on 22 July 2018, approximately 60m north-east of the original well. Unconfirmed industry sources report that it found three gas pay zones and BHP said in its Q3 2018 operational

review that the NFW was plugged and abandoned after reaching a TD of 5,151m and encountering hydrocarbons. A vertical seismic profile may also have been included at the Bongos-2 well location, which is in the western portion of the TTDAA-14 Block. BHP holds operatorship of TTDAA-14 with 70% WI with BP holding the remaining 30% WI.

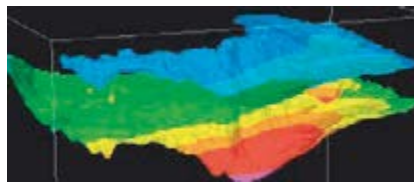
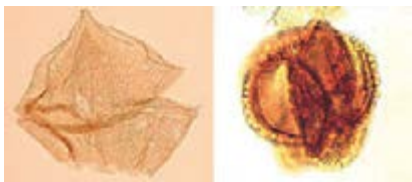
The third and remaining well in the Phase 2 programme, the Concepcion-1 NFW, planned to further test the Magellan gas play, is due to be drilled in the 2019 financial year in TTDAA 5, not far from Victoria and LeClerc. ■





Our scientific staff cover a wide range of expertise gained from many parts of the globe, dealing with many and varied projects. The unique combination of in-house geological services and a staff boasting extensive offshore and oil company experience provides a competitive edge to our services. We offer complete services within the disciplines of Petroleum Geochemistry, Biostratigraphy and Petroleum Systems Analysis, and our customers expect high standards of quality in both analysis and reporting.

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APT has gained extensive experience in Petroleum Systems Analysis using the "PetroMod" suite of programs. Projects range from simple 1d modeling of a set of wells to complicated 3D models with maturation, kinetics, generation, expulsion, and migration and accumulation issues to be resolved or predicted.

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- Exploration Solutions
- Petroleum consulting services

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- Routine biostratigraphy
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Petroleum System Analysis

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SEC2019
For the Industry : By the Industry

Provisional Conference Programme

APRIL 3-5TH
Fairmont Hotel SINGAPORE

PGSEA: 3.5 Days Petroleum Geology SEA Course	
0900-1700	Saturday 30 March to Monday 1 April 2019
0900-1300	Tuesday 2 April 2019
Conference Thumb Drives Sponsored by DrillingInfo Lanyard Sponsored by Ocean Reach Advisory	
Tuesday 2 April 2019	
Internet Sponsored by RISC Advisory Registration Desk Sponsored by JX, TGS, AGS, Leap Energy	
1300 onwards	Registration Open - Delegate Badges Sponsored by Total E&P
1030-1300	Asia Pacific Scout Check
1430-1700	Farmout Forum and NOC Presentations
FarmOut Forum Signage Sponsored by Fugro	
1800-2100	Ice Breaker Sponsored by Searcher Seismic, DUG, Ikon
Wednesday 3 April 2019	
08:30	Introduction and Welcome Sponsored by SEAPEX
Session 1: Commercial Environment	
08:45	Global Energy Landscape - Jarand Rystad (Rystad)
09:10	Exploration Update and Global Fiscal Terms - Andrew Latham (Wood Mackenzie)
09:35	Host Government Contracts Disincentives - Chris Moyes (Moyes & Co)
10:00	Where do Producer Companies in Asia go Next? - Rachel Calvert (IHS Markit)
10:35	Coffee - Sponsored by OMV
Session 2: Myanmar and Bangladesh: Success and Potential	
11:00	New Perspectives and Learnings from Three Years of Successful Drilling in Myanmar - Tony Almond (Woodside)
11:25	Where Did They Come From, Where Did They Go? Oligocene Fluvio-deltaic Sediments of the Salin sub-basin, Myanmar - Amy Gough (SE Asia Research Group, RHUL)
11:50	The Hydrocarbon Potential of Undrilled Channel Filled Sands and Basin Floor Fans of Block SS-11, Hatia Trough, Offshore Bengal Basin - An Insight from 3D Seismic and Inferences from the Genetically-related Multi-TCF Shale Gas Field - Mike Whitley (KrisEnergy / JIMJ)
12:15	Lunch - Sponsor Opportunity
Session 3: Regional Frameworks	
13:15	Plate Tectonic Reconstructions of SE Asia: Bacon, Salami or Baloney? - Robert Hall (SE Asia Research Group, RHUL)
13:40	Integrating Basin Evolution and Plate Tectonics in SE Asia - Jon Teasdale (Geognostics)
14:05	Final Separation of Eastern Gondwana - Implications for Frontier Exploration - Jamie Highton (Halliburton)
14:30	A New Direction for Asian Stratigraphy - Peter Lunt (Petronas University)
14:55	Coffee - Sponsored by OMV
Session 4: Papua New Guinea	
15:45	Papua New Guinea Exploration - Nigel Wilson (Oil Search)

16:10	Results of Muruk Drilling - Muruk Discovery in Western Foldbelt of PNG - Glen Nash (ExxonMobil)
16:35	New Constraints on Basement Provenance Lead to an Improved Understanding of Tectonics and Basin Development in Papua New Guinea - Rob Holm (Frogtech)
17:00	An Active Petroleum System in the New Ireland Basin: Papua New Guinea's New Frontier - Brent McInnes (PeakOil)
17:25	The Hydrocarbon Potential of the Frontier Cape Vogel Basin, Papua New Guinea - Andrew Weller (Searcher)
Evening	Quiz Night - Sponsored by MCG
Thursday 4 April 2019	
Session 5: Australia NW Shelf	
09:00	New Triassic Tectonostratigraphic Observations over the Central NW Shelf - Tom Bernerke (Geoscience Australia)
09:25	Dorado. An Overview of the Largest Oil Discovery on the NW Shelf in the last 30 years - Ian Cockerill (RISC)
9:50	Late Triassic of the Roebuck Basin, NW Shelf of Australia - another Birds Head? - Claudia Valenti (Carnarvon Petroleum)
10:15	Exmouth Sub-Basin: New Data, New Insights - Alex Karvelas (WesternGeo)
10:40	Coffee - Sponsored by OMV
Session 6: Banda Arc and Timor Sea	
11:15	Geological Development and Hydrocarbon Prospectivity of the Southern Banda Arc - Peter Baillie (CGG)
11:40	The Seram Fold Belt: An Emerging High Impact Play in Eastern Indonesia - Kim Morrison (Lion Energy)
12:05	West Malita Graben - The Ugly Duckling or Another Phoenix? Julian Mather (Spectrum)
12:30	Lunch - Sponsor Opportunity
Session 7: Indonesia	
13:30	Indonesia - Title TBA - Woody Wilson (BP)
13:55	Creative Exploration in a Mature Basin: Jangkrik and Merakes Discoveries (Kutei Basin) - Lorenzo Meciani (ENI)
14:20	The Next Big Discovery in West Natuna, Indonesia - Amir Mahmud (Concord Petroleum)
14:45	New Data Brings New and Deeper Play Insight for North Madura, Indonesia - Adriana Sola (PGS)
15:10	Coffee - Sponsored by OMV
Session 8: Sumatra Revisited	
15:45	Extended Carbonate Play Revealed by New 3D Data, Deep Water North Sumatra Basin - Ait Ascaria (Repsol)
16:10	Dual Petroleum System in the Central Palembang Sub-Basin, South Sumatra - Ally Duncan (Mandala Energy)
16:35	Uncovering The Overlooked Gumai Play Potential At Jabung Betara Complex - I Gusti Agung Aditya Surya Wibawa (PetroChina)
17:00	Sumatra Deep Basin Gas and Meeting Indonesia's Growing Gas Demand - Jerry Sykora (Canadian International Energy)
Evening	SEAPEX Pub Crawl

Friday 5 April 2019	
Session 9: Showcasing G&G Techniques in SE Asia	
09:00	Reservoir Characterisation with Ocean Bottom Seismic: A South East Asia Case Study - Rob Ross (Q-Eye / Petronas)
09:25	SE-Asian Fault Seal Case Studies - Titus Murray (Southern Highlands)
09:50	Sand Body Characterisation in Tidal Marine Settings - Examples from the Malay Basin - Melissa Johansen (Geode Energy)
10:15	Application of Machine Learning to Facies Classification of Carbonate Core Images - Sharinia Kanagandran (Imperial College)
10:40	Coffee - Sponsored by OMV
Session 10: Vietnam and Cambodia	
11:15	Cambodia's Hydrocarbon Prospectivity - An Insight from Block A - Katherine Kho (KrisEnergy)
11:40	A Revised Chronostratigraphy for the Cuc Long Basin, Based on the Interpretation of Climate-driven Depositional Cycles during the Late Eocene/Oligocene, and VIM Depositional Cycles during the Mio-Pliocene - Bob Morley (Palynova/Murphy/VPI)
12:05	Petroleum System of Phu Quoc Pre-Cenozoic Frontier Basin Offshore Vietnam Tran Ngoc Lan, MSc (PVEP)
12:30	Lunch - Sponsor Opportunity
Session 11: New Frontiers	
13:30	Frontier Exploration in Mongolia - The Search for Oil-stained Marmots - Mike Buck (Petro Matad)
13:55	Insights from New Geophysical Data in the North South China Sea - Patrick Ravaut (TOTAL)
14:20	New Zealand's Canterbury Great South Basin - An Emerging Deepwater Province? - Alex Wunderlich (OMV)
14:45	Depositional Architecture, Sequence Stratigraphy and the Quantification of Hydrodynamic Fractionation as a Tool for the Prediction of Reservoir Quality in a Deep Marine System: An Example from the Miocene Moki Formation in the Msaari/Manala Field Area, Southern Taranaki Basin, New Zealand - Alex Wunderlich (OMV)
15:10	Coffee - Sponsored by OMV
Session 12: NW Borneo and Philippines	
15:45	Real Time Isotope Logging in Central Luconia Province, Offshore Sarawak; Assessing Seal Competency Using Contrasting Results from Two Recent Exploration Wells - Bob Davis (Mubadala Petroleum)
16:10	Philippines SC 49 - From Exploration to Exploitation - Ed Cuttonog (Polyard Petroleum)
17:00	Frontier Sabah Unveiled - Petroleum Potential of Offshore Sabah - Tad Choi (PGS / WesternGeo)
Evening	Closing Networking Evening
General Sponsors: CGG, Murphy, ShearWater, ExxonMobil, Premier Oil, Mubadala Meeting Rooms Sponsored by Spatial Monkey	
*This program is preliminary and subject to change	

What Does the Future Hold?

As a founder of E&P intelligence company Drillinginfo and with a wide range of experience in the industry, Allen Gilmer is uniquely qualified to predict future trends.

As a serial entrepreneur, what motivates you to start a new company?

Filling needs that aren't being met. It helps if you are a consumer of those products or services. I started and ran a seismic company that took working interest in return for providing 3D surveys and interpretation all over the US. I had an acute need of the services and products that we all take for granted because of what we do today at Drillinginfo.

Why did you start Drillinginfo?

The advent of the digital age resulted in big companies trying to create various digital data monopolies, selling to the top of the market. I thought this was bad for the oil business. The US oil patch is notable for its resistance to being 'consolidated'; a small E&P company is nimbler than a large one and can operate lower producibility fields. The benefit of a wide range of operational capabilities is *exactly* what enabled the US to take advantage of unconventional resources. Lots of operators and explorers are the other secret of US oil and gas, together with private ownership of minerals and the fact that licensing is around small, rather than large, blocks, unlike the rest of the world. I believed that any movement to marginalise the small operator was bad – it turned out I was right, thank goodness.

What advice would you offer someone starting their own company?

Play to your strengths, be willing to adjust your business plan, and partner with people who bring different skills to the table to yours. It's never easy. When I started my E&P business, I didn't have access to a lot of capital – a major oil company geophysicist isn't exactly on top of anyone's list to invest in! But I knew how to shoot, process, and interpret seismic data. I could parley what would fund ten square miles of 3D into a small crew that ultimately shot hundreds of square miles of data. I was always interested in the "if this works, we can change the industry" type of thing; playing back from this 'bleeding

edge' is the real wealth creation sweet spot. Folks who see where the pack is going and get in front of it just early enough are the ones that make money. The desire to "change the direction of the herd" is rarely worth it.

What are the current most important trends in US exploration?

My teams have strong opinions on this and we have had some great conversations recently. On the US side it is multi-pronged:

Operations: The effective use of services and utilities – something the industry has not had to deal with before; how to work in places that do not have infrastructure to keep lifting costs low. It's the classic long-term development vs. flash returns. Companies are improving overall economics by thinking of how to best utilise their footprint and costs. This is almost like Uber on steroids: how to move hundreds of pieces of equipment, people, food, etc. in a way that maximises returns. I think we will soon see Silicon Valley in this space.

Drilling optimisation and safety: More companies are using 'smart rigs' to improve safety. Such a rig can set itself up and drill where people have problems, like mountains and areas with high security issues. You need only one or two engineers on site and the rest is done remotely.

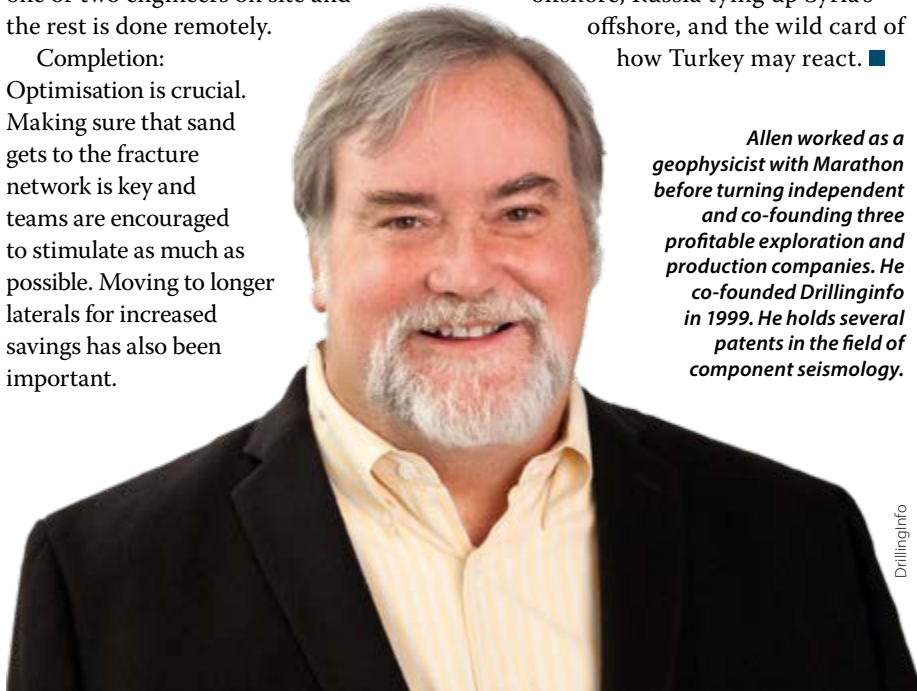
Completion: Optimisation is crucial. Making sure that sand gets to the fracture network is key and teams are encouraged to stimulate as much as possible. Moving to longer laterals for increased savings has also been important.

Economics/finance: Private equity is shifting to operator mode, which is new for them. They are issuing investment grade bonds and debt to pay back shareholders and holding assets, putting stress on 'buy and flip' teams to get their costs down and stay for the long haul. We are also seeing more companies buying minerals under their own properties – a natural hedge in a downturn, with fewer overhead costs and an increase in NRI, giving an instant return on value. Consolidation is also key: companies are conducting less exploration and focusing on what they have their money in today.

How about worldwide; where will the next big new frontier be?

Malcolm Steel in our Cotswolds office is my go-to guy internally on what is happening globally. Offshore is still the place for substantive reserves. I think the ones to keep an eye on include the North West African Atlantic Margin; Newfoundland and Nova Scotia, where several majors have big dollar, big potential exploration programmes; the Barents Sea; north-west Latin America, following Exxon's Guyana success; large targets in Brazil's Santos Basin; and the Eastern Mediterranean, following ENI's Cyprus discoveries, with Greece and Lebanon opening up offshore, Russia tying up Syria's offshore, and the wild card of how Turkey may react. ■

Allen worked as a geophysicist with Marathon before turning independent and co-founding three profitable exploration and production companies. He co-founded Drillinginfo in 1999. He holds several patents in the field of component seismology.



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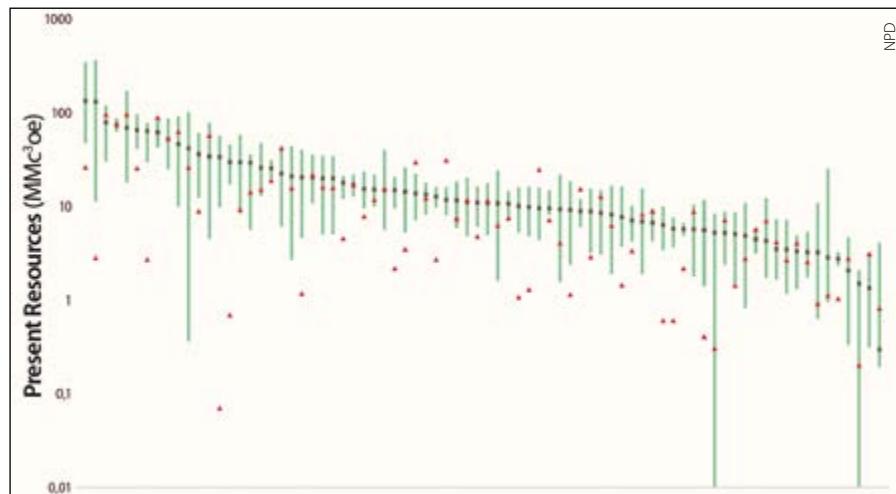
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The Irrational Optimists

Is it time for AI to take a hand in estimating prospect sizes?



Comparing company pre-drilling resource estimates for oil-in-place with post-drilling discovery size reveals a significant misfit. The green lines show the P10–P90 range, the line of squares are the expected discovery size pre-drilling, while triangles represent the estimated size post-drilling.

Explorationists are optimists. It’s a proven fact. It must be part of their genes.

The truth is that they just cannot avoid overestimating the size of their prospects. It has been said before, and it was reiterated at the NCS Exploration Strategy Conference in Stavanger in November.

The Norwegian Petroleum Directorate has statistics from several decades of exploration on the Norwegian continental shelf (NCS). Hans Martin Veding, statistician at the organisation, referred to 33 wells drilled from 2015 to 2017 that had drilling targets with comparable pre- and post-drill estimates. Only two (!) of them found more than was originally projected; the remaining 31 were decidedly overestimated. Veding showed the same to be true for prospects drilled in acreage allocated from the 8th to the 22nd round on the NCS. Prospects were massively bigger than the discoveries.

Paul Herrington, Exploration Portfolio Manager with the Oil and Gas Authority in the UK, reported the same observations from the UK sector. Herrington based his statistics on 750 fields and discoveries across the UKCS since the first well was drilled in 1965, and there is absolutely no doubt that the oil companies are consistently far too optimistic.

One might speculate that without such overrating, many wildcats would not have been drilled, resulting in fewer discoveries.

However, the oil companies are not alone in making false predictions. Graeme Bagley of Westwood Global Energy Group referred to studies by USGS that show pre-drill resource estimates for sedimentary basins around the world. Out of some 20 selected basins, USGS has been wrong in all of them, except for the offshore Guyana Basin where ExxonMobil is in the process of proving up some 10 (to 20?) billion barrels of oil, possibly more. In all the other basins investigated by USGS, the actual volumes are far less than the USGS P10 estimate. The USGS screening cannot therefore be judged as meaningful.

Given that USGS does not have access to lots of data, this is perhaps easy to understand. For the oil companies, however, there must be another reason. Unsupported optimism is here suggested as one possibility that very few would argue against. It would be interesting to know if using artificial intelligence – on huge amounts of data – could help explorationists come up with more realistic estimates. Should the oil companies possibly rely less on the human brain and leave it to computers to take history into consideration? ■

Halfdan Carstens

Conversion Factors

Crude oil

- 1 m³ = 6.29 barrels
- 1 barrel = 0.159 m³
- 1 tonne = 7.49 barrels

Natural gas

- 1 m³ = 35.3 ft³
- 1 ft³ = 0.028 m³

Energy

- 1000 m³ gas = 1 m³ o.e
- 1 tonne NGL = 1.9 m³ o.e.

Numbers

- Million = 1 x 10⁶
- Billion = 1 x 10⁹
- Trillion = 1 x 10¹²

Supergiant field

Recoverable reserves > 5 billion barrels (800 million Sm³) of oil equivalents

Giant field

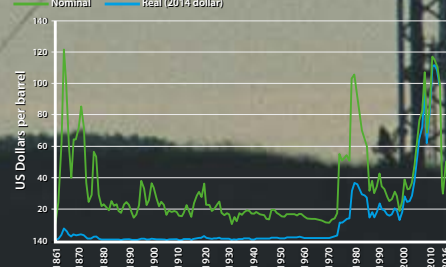
Recoverable reserves > 500 million barrels (80 million Sm³) of oil equivalents

Major field

Recoverable reserves > 100 million barrels (16 million Sm³) of oil equivalents

Historic oil price

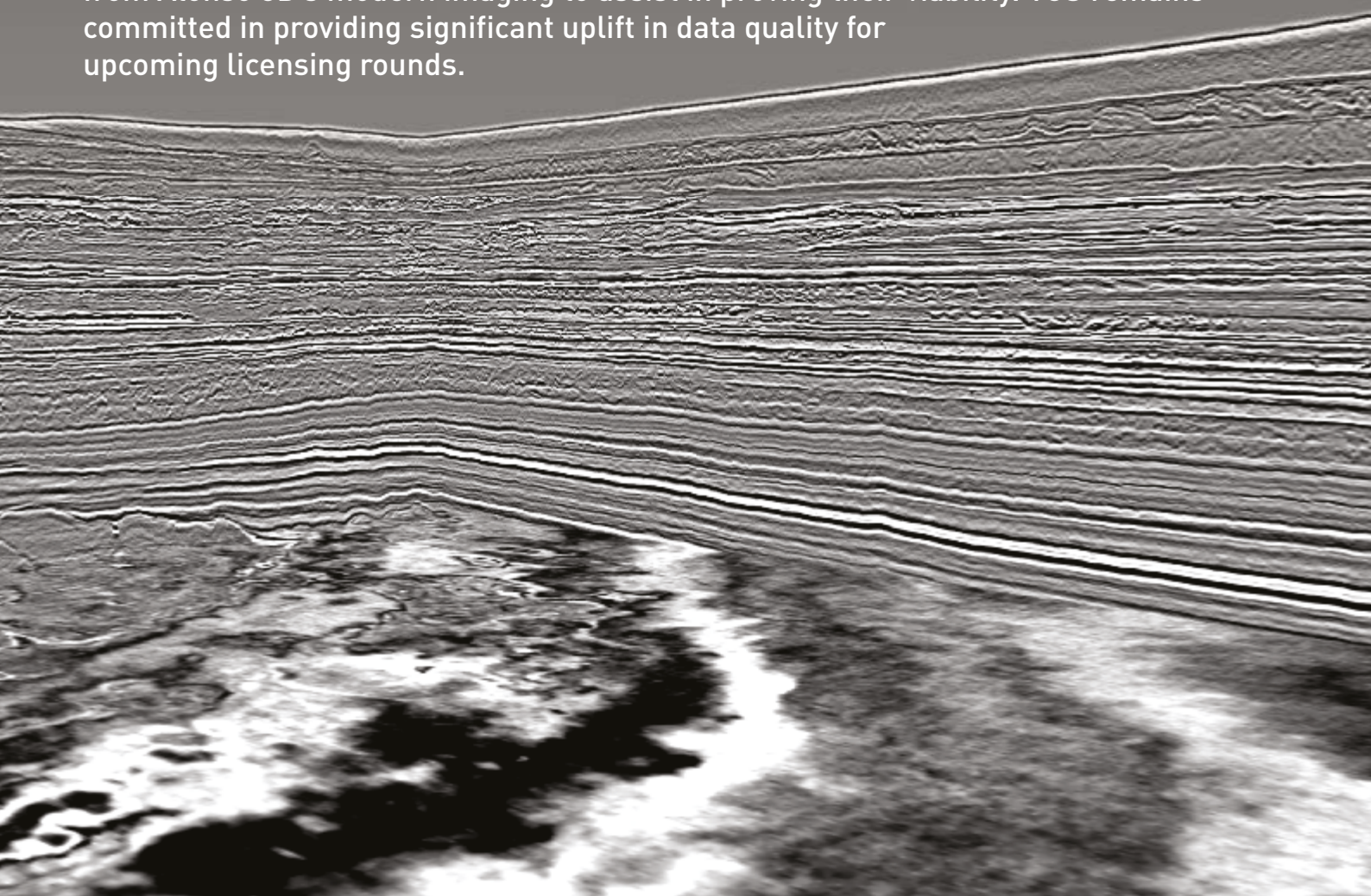
Crude Oil Prices Since 1861



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