VOL. 16, NO. 6 – 2019

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

GEOTOURISM
Traversing the Southern Sierra Nevada

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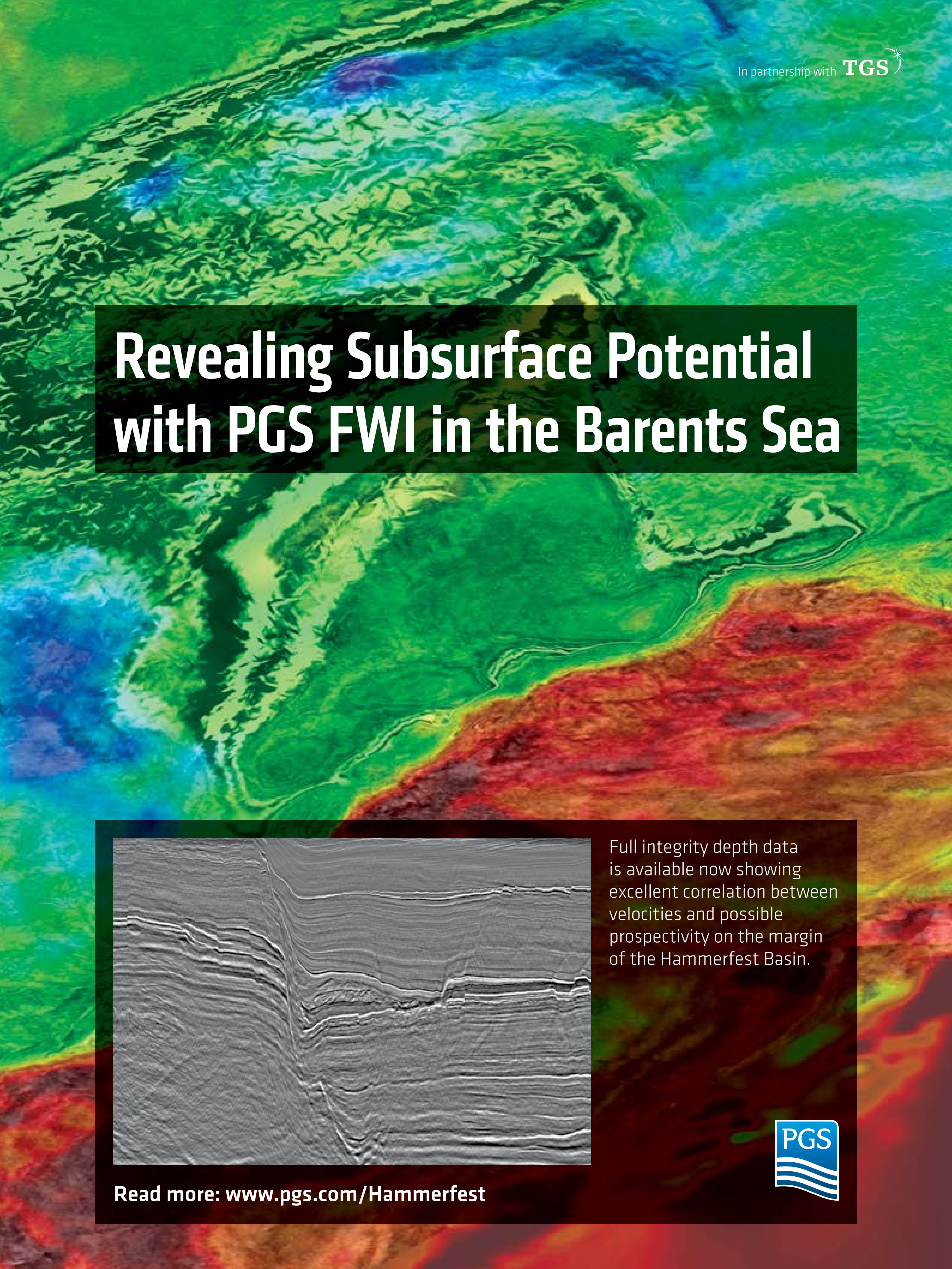
COUNTRY PROFILE

Manx Gas for the Isle of Man

GEOCHEMISTRY
The Origin of Shale Gases

GEOPROFILE
Solving the Alaska Puzzle

GIANT FIELDS
Advances in Stratigraphic Trap Exploration


In partnership with TGS
Revealing Subsurface Potential with PGS FWI in the Barents Sea
Full integrity depth data is available now showing excellent correlation between velocities and possible prospectivity on the margin of the Hammerfest Basin.
Read more: www.pgs.com/Hammerfest
PGS

Previous issues: www.geoexpro.com

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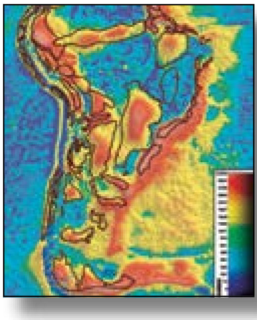
EFSA



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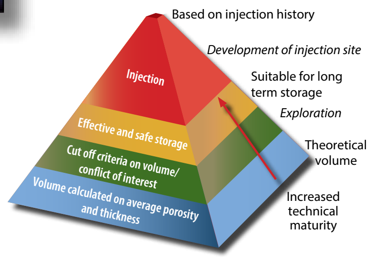

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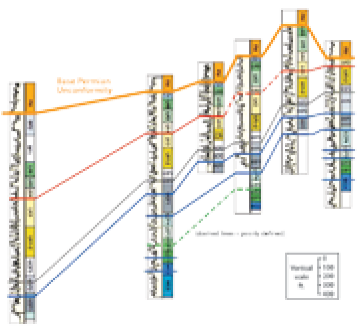

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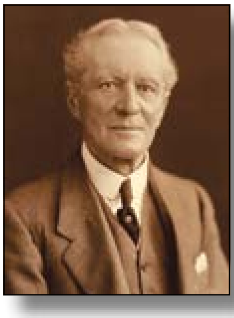

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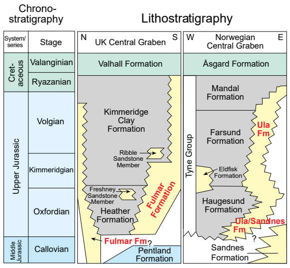

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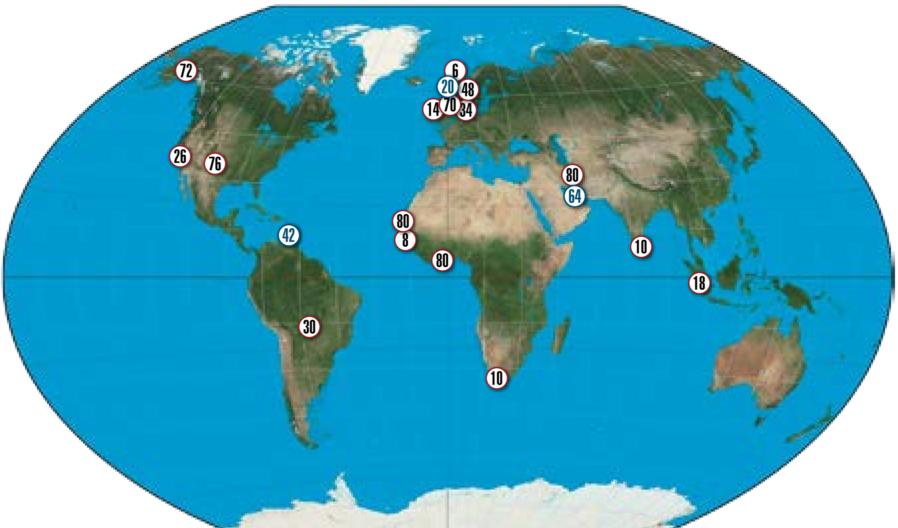

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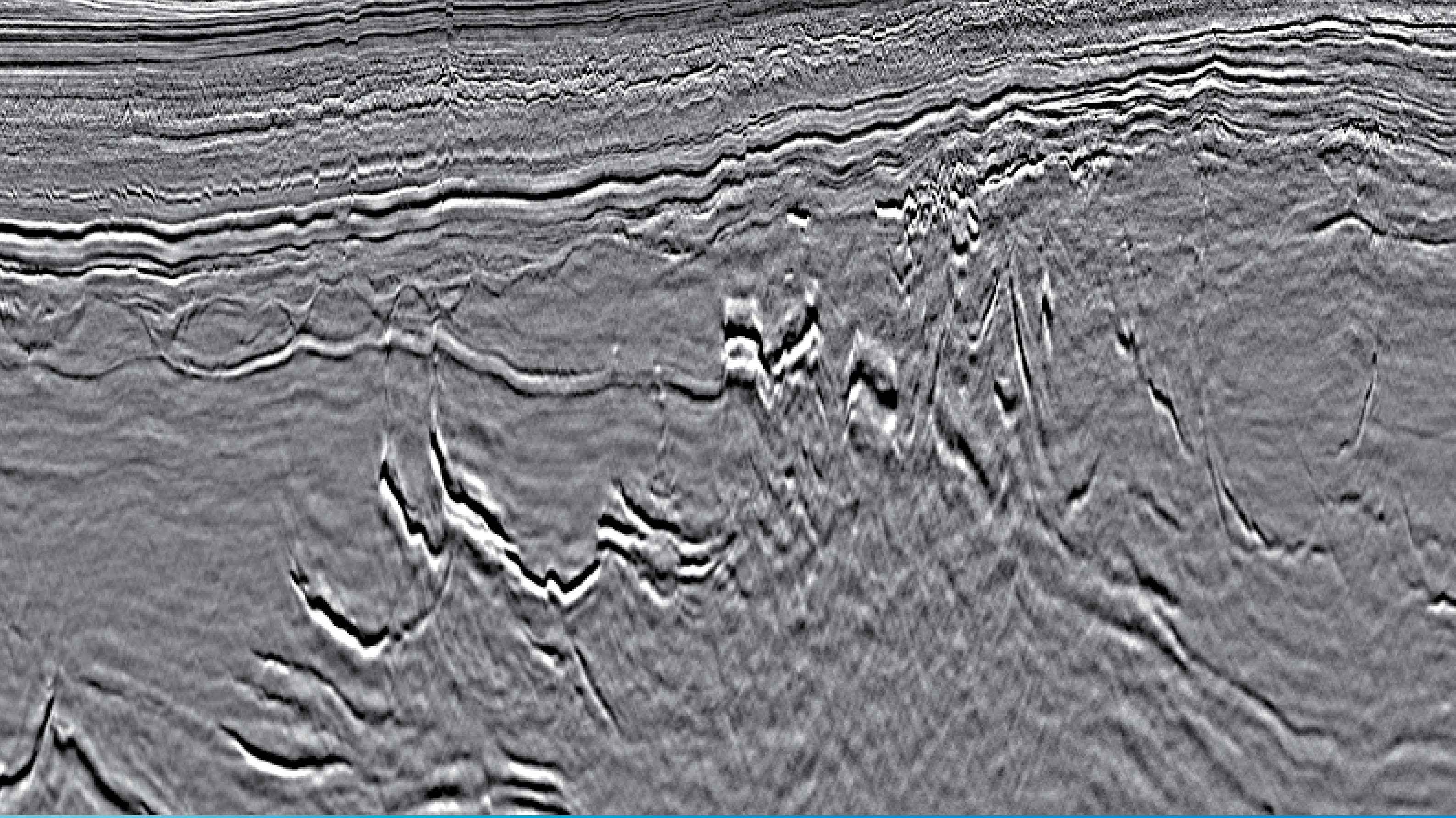

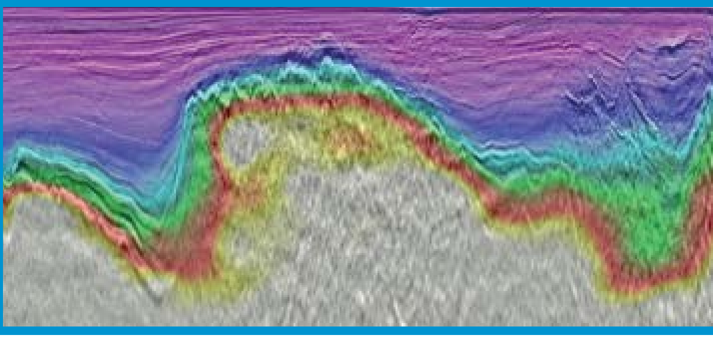

Energy Transition and the Community

The Editor with fellow panellist Andrew Grant in the BBC studio.

I recently had a very interesting and, to be honest, nerve-wracking experience, when I was asked to participate in a recorded panel discussion to be broadcast around the globe by the BBC World Service. Challenging, because I was not told in advance what the questions would be, except that the topic was 'The Future of Oil' – a rather wide theme – but exciting nonetheless, as I saw the inside of the iconic BBC Broadcasting House in London and learnt more about how radio is made.

My very knowledgeable fellow panellists came to the discussion from a variety of angles, including a researcher into renewable technologies, an analyst looking at the impact of the energy transition on capital markets and a consultant on the global energy industry, so the ensuing discussion was both informative and stimulating. However, the questions that the interviewer threw out brought home to me how little the majority of people seem to understand about the industry that underpins so many aspects of their lives in so many ways.

One of the underlying recurring themes appeared to be "why doesn't the oil industry just stop exploring for and pumping out oil?" The fact that demand for energy, particularly in rapidly developing regions like India and China, is growing at a fast rate and cannot easily be put into reverse seems to be one that is hard to grasp. Equally poorly understood is the concept that the move to more sustainable fuels is a transition that the whole world is engaged in, including, of course, the oil and gas industry; the idea that people within the industry understand that they are vital cogs in moving the energy transition forward was possibly a surprise to some listeners. I also realised that all the conversation is about oil; the important role of gas is not often talked about in the wider community.

Why is this? What can we do to improve understanding? Let me know your ideas. ■

Jane Whaley
Editor in Chief

MANX GAS FOR THE ISLE OF MAN

Chicken Rock Lighthouse on the southernmost point of the Isle of Man sits on Ordovician slate. About 60km away, off the north-east coast of the Island, a group of entrepreneurial Manx energy industry experts hope to find the gas that will help supply the Island through the energy transition.

Inset: A journey from the giant oil fields near Bakersfield, over the high Sierra Nevada Mountains and into Death Valley takes in the oldest living tree yet discovered, among many other wonders.

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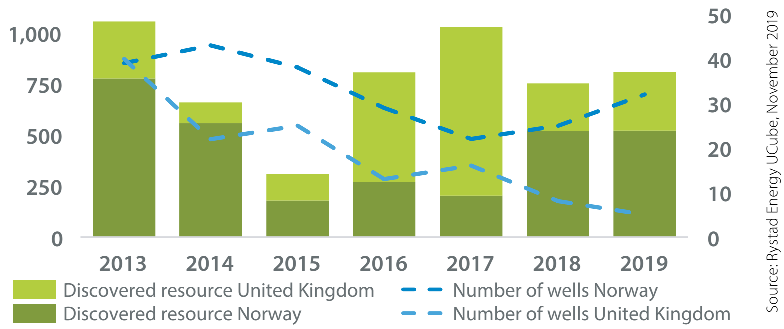
Unlocking the Frontier

RYSTAD ENERGY

Recently, the upstream industry overall has been reluctant to invest in exploration, especially in wildcat wells, yet between 2013 and 2019, the north-western part of Europe (particularly Norway and the United Kingdom) has seen some success in unearthing additional resources through wildcat exploration. These additional volumes have been dominated by liquids, contrary to the global discovery gas trend. Norway and the UK booked cumulative conventional recoverable resources of ~5.3 Bboe during this period, around 6% of total global discovered volumes. Norway spudded 228 wildcats between 2013 and September 2019, evenly spread across those years, compared to 129 in the UK over the same period, with 40 in 2013 decreasing to a mere eight exploration wells in 2018, and just five so far in 2019. Many of these discoveries have resulted in small or marginal finds, indicating that exploration activities have primarily focused on mature basins and areas within close proximity to existing infrastructure.



Discovered resources (MMboe) vs total number of wildcat exploration wells drilled, 2013–2019 (well count based on completion year).

Norway has managed to maintain a steady 40–50% success ratio, pointing towards the paradigm shift in the country's exploration strategy, with operators adopting a more conservative approach towards prospect selection. 2019 has marked a new high for the country since the oil price crash of 2014, with 520 MMboe of recoverable resources discovered, surpassing 518 MMboe discovered in 2018.

Remaining Frontier Areas

Over the past few years, both the NCS and UKCS have seen some exploration activity in their respective frontier basins, where a meaningful discovery with substantial volumes could act as a catalyst. Remaining frontier areas include:

- **The Barents Sea**, Norway's most successful region in recent years, with 1.1 Bboe discovered between 2013 and 2019. The province is estimated to hold more undiscovered oil and gas than the Norwegian North Sea and Norwegian Sea combined – nearly 64% of the total estimated undiscovered resources on the NCS. Equinor has been persistent in the area but has not experienced much success since its 434 MMboe Wisting discovery in 2013.
- **Lofoten Islands,** a vital spawning ground for cod, where in a controversial drilling campaign Wintershall DEA's Toutatis well failed to encounter commercial hydrocarbons; a big setback for Norway's offshore industry, but received enthusiastically by environmental groups. Time will tell whether Wintershall DEA or other players decide to follow up with further wells in the area.
- The UK Oil and Gas Authority is pushing hard to open up the country's frontier areas, including the **Faroe-Shetland Basin, Moray Firth, East Irish Sea, East Shetland Platform, Mid North Sea High** and **English Channel**. It has provided several incentives for E&P companies, including new data and analyses, digital maps, prospect and discovery reports, and well and seismic data.
- However, the underexplored **West of Shetland** is poised to be the primary focal point of frontier exploration moving forward, although the remoteness, deeper water depth, and complex geology all pose challenges to unlocking possible discoveries.

Palzor Shenga, 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

Senegal: First Licensing Round

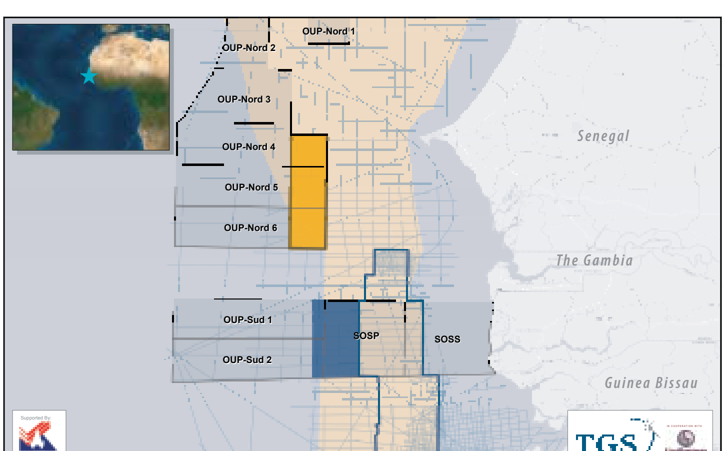
Senegal has been propelled to the forefront of industry news in recent years after several major discoveries in its offshore waters, including two ‘basin opening’ oil discoveries, FAN and SNE. Since then, further hydrocarbon discoveries in Senegalese waters and in those of its neighbours, such as the 25 Tcfg Greater Tortue Ahmeyim project and the Yakaar-1 gas well – the largest gas discovery of 2015 and the largest global discovery of 2017 respectively – have increased interest in the potential of the country. The recent announcement by Petrosen, the National Oil Company of Senegal, that it will launch the country’s first offshore licensing round in 2020 has therefore been met with some excitement by the industry.

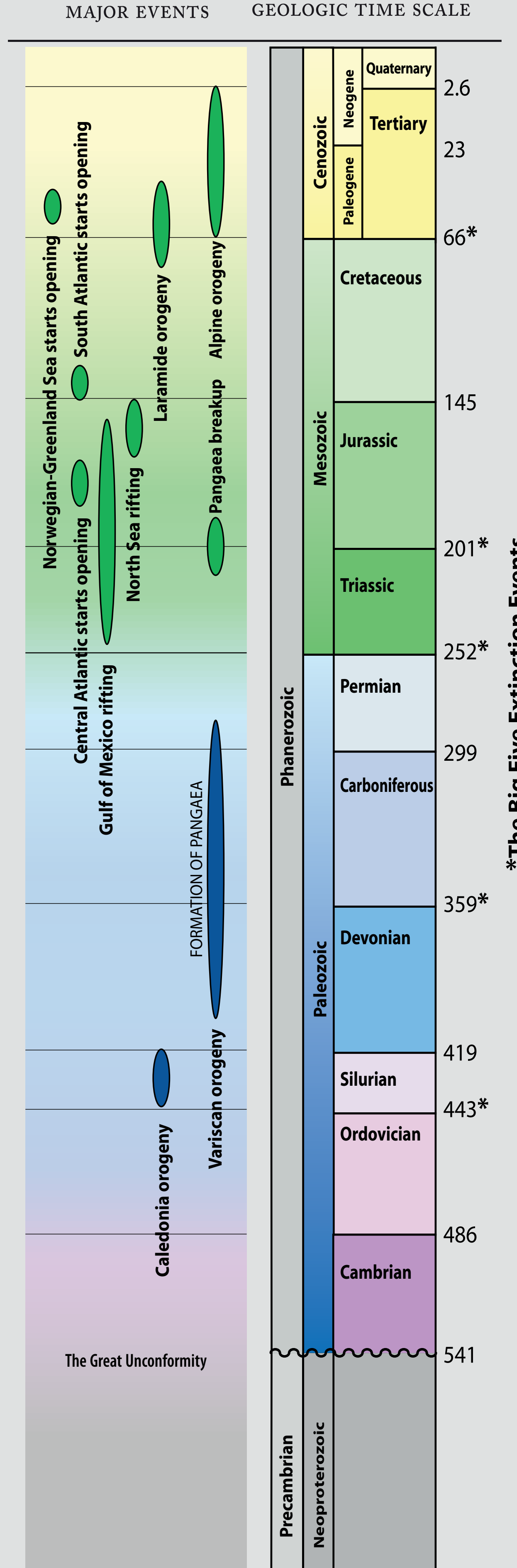
Senegal is situated in the north-west African Mauritania-Senegal-Guinea Bissau-Conakry Basin, a passive margin basin of Middle Jurassic to Holocene age, which overlies a Palaeozoic basin. It has experienced three broad tectonic phases: the Palaeozoic pre-rift, followed by a Triassic-Early Jurassic rift and a mid-Jurassic to present drift phase. The post-rift section comprises a Middle Jurassic to Early Cretaceous carbonate platform overlain by an Early to Late Cretaceous transgressive and regressive sequence. A globally regressive Upper Cretaceous clastic sequence terminates at the Base Tertiary Unconformity.

Known source rocks are found in the Early, Middle and Late Cretaceous, and source rock character is thought to improve westwards with the establishment of more anoxic conditions. Reservoirs range from Upper Cretaceous deltaic sands and Lower Cretaceous outer basin sands, as found in the recent discoveries, while the deeper offshore is expected to have Upper Cretaceous turbiditic reservoirs.

Petrosen have partnered with seismic companies TGS, GeoPartners and PGS and as a result over 14,000 km of 2D and 10,000 km^2 of 3D data are available, as well as over 50,000 km^2 of multibeam data with associated shallow cores and geochemistry.

On offer are ten offshore blocks varying in size from 2,050 km^2 to nearly 8,000 km^2 and totalling over 66,600 km^2. The majority are situated in ultra-deep water of 3,000-4,000m, with only one block lying in waters less than 1,000m deep. The round will officially open on 31 January 2020 and will close on 31 July 2020. The initial time period is of four years and Petrosen have a carried interest of 10% during the exploration phase and up to 30% working interest after a commercial discovery. ■





Record-Breaking Attendance at AOW 2019

The first week of November saw the 26th annual **Africa Oil Week (AOW)** take place in Cape Town. This year's edition boasted record-breaking attendance figures of 1,853, almost double those of five years ago.

Several African countries used the event to make major announcements, including **Senegal**, whose Oil and Energy Minister Mahamadou Makhtar Cissé announced the launch of a licensing round of ten blocks – an historic first for petroleum exploration in his country. **Mozambique** was also amongst the nations making licensing round announcements. The Chairman of the country's upstream regulator, INP, Carlos Zacarias, told delegates that the country's long-awaited sixth licensing round is due to be launched early next year. Meanwhile, **Angola's** newly formed national oil, gas and biofuels agency announced that the country has formed a consortium with five international oil companies, including Eni and Chevron, to develop LNG for its Soyo plant. The consortium's project, costing an initial $2 billion, is expected to start production by 2022.

The conference will be back in **Cape Town 2–6 November 2020**. Delegates can expect more announcements, more networking and a wider attendance than ever! ■

AOW

Comprehensive Modern Seismic Database

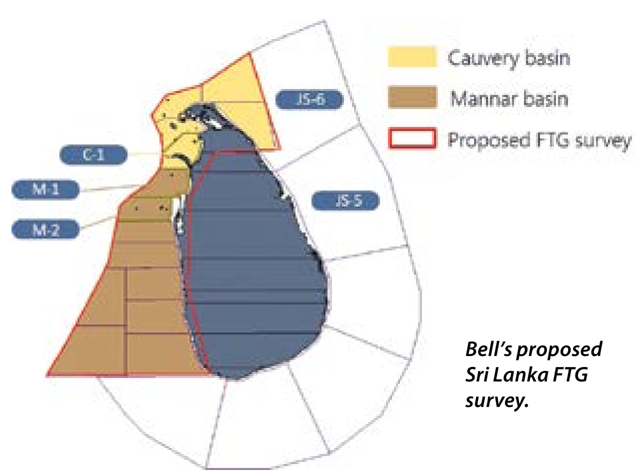
The recent merger between seismic companies **TGS** and **Spectrum** has resulted in the industry's most **comprehensive modern seismic database** with widespread coverage in all mature and frontier basins, since the two companies had previously covered complementary areas.

The Spectrum acquisition builds on TGS' values of quality and service. In addition to the world's largest multiclient library, it will allow the company to offer more exploration opportunities, enhanced seismic imaging quality and, from seismic to well data, more data and more coverage in all major basins worldwide. The combined business will lead to greater value creation compared to the companies operating as separate entities and will help accelerate TGS' data analytics strategy. Such comprehensive subsurface data will enable operators to capitalise on recent discoveries, will assist in knowledge of licence rounds and will apply G&G expertise to unlock frontier regions. ■

New Era for FTG

Full Tensor Gravity Gradiometry™ (FTG) has entered a new era with multiclient acquisitions. **Bell Geospace's Pan-Malaysia Multiclient Air-FTG** and **Air Mag** surveys form the largest FTG multiclient data library in the world, covering 370,000 km^2 of onshore, offshore and transition zone areas, including all of the Malaysian 2020 bidding round acreage. Bell's industry-leading full tensor gravity gradiometry data, with its cutting-edge interpretation technology exploiting all the tensor components, enables the interpretation of geology across large areas of Malaysia for a fraction of the cost of seismic data. Air-FTG and magnetic data can help unlock the geology of Malaysia and minimise exploration risks.

In 2020, Bell Geospace will further increase its multiclient coverage in Asia, having signed a service agreement with the Petroleum Resources Development Secretariat of **Sri Lanka** for gravity, Air-FTG and magnetics acquisition on a multiclient basis. The initial phase of the project will focus on the offshore Mannar and Cauvery Basins and boost exploration over the 2019 bidding rounds blocks C1, M1 and M2. This data will help revisit existing seismic data and shed new light on the basins' structure and basement geometry, as well as provide an invaluable tool to plan any future seismic surveys. ■



Bell's proposed Sri Lanka FTG survey.

Bell Geospace

APPEX 2020 – Reboot: Opportunity Showcase

APPEX Global 2020 will bring together upstream decision-makers and exploration opportunities, ideas and event-makers. It will be an opportunity to meet fellow professionals, investors, senior managers and government representatives to find common interests and become partners for success in the future, whilst gleaning the latest on licence rounds, policies and commercial terms from senior representatives of key countries. Farm-outs are back in force, with an emphasis on quality, significance and creative new ideas and insights.

The APPEX programme will showcase opportunities in the pipeline today; who is farming-out what globally; why featured deals are important; where the most recent discoveries have been made and what their consequences will be. The speaker programme covers licence rounds, open acreage, the evolution of the world's E&P market, and key strategic market trends. Companies will add succinct presentations detailing new orogenies in data and tech that have already been tested. The three high-energy days cover key innovations in activity, play-making, opportunity access and commercial terms from West and East Africa, Latin America, Europe, Mediterranean, Caribbean and Asia-Pacific.

If you plan to attend only one conference with global access opportunities that will revolutionise your forward strategy and tactics, make it APPEX Global in **London 3–5 March 2020**. ■

High-Res Characterisation of Unconventional Reservoirs

Unconventional activities constantly require **new technological** approaches and quick answers to optimise well placement, completion strategies and address future drilling campaigns. Unconventional reservoirs show a high level of heterogeneity and complexity, entailing high resolution tools.

Geolog

Integration of fluid characterisation with organic facies and rock facies distribution can provide key information for the most efficient exploitation of assets, adopting the best completion solutions. For this, **GEOLOG** has developed an innovative workflow, integrating wellsite activity with laboratory work to define a comprehensive picture of reservoir properties. Laboratory studies can define a detailed distribution of organic matter (OM) facies, based on OM characterisation and analyses of autochthonous and migrated hydrocarbons. The further step is to combine organic facies distribution with that of rock facies, obtained through rock characterisation using XRD, XRF and SEM analyses and interpreted in the frame of chemostratigraphic criteria.

The final result of this exercise is a deep integrated knowledge of reservoir features that can be used for **better, faster interpretation** of data obtained while drilling, to take timely decisions, especially for completions. The investment in lab analyses is largely remunerated by greatly added value while drilling and by the optimisation of operations and of future production. ■

Defining the Industry's Future

As one of the biggest events in the energy sector, the **Energy Institute's International Petroleum (IP) Week**, brings together over 1,500 industry professionals from over 50 countries, making this internationally renowned event the place to hear the latest news and updates, debate key issues, share new ideas and network to form partnerships with oil and gas operators, clients and investors.


Energy Institute

IP Week 2020 will be held **25–27 February 2020** in **London** and the conference theme will be '**Defining the Industry's Role, Delivering a Low Carbon Future**'. Discussions will explore how the oil and gas industry can be a key player in delivering a low carbon future and look at which organisations, technologies and operations are helping to shape the plan for a cleaner future.

Confirmed speakers include H.E. Mohammad Sanusi Barkindo, Secretary General, OPEC; Dr Fatih Birol, Executive Director, International Energy Agency; Craig Bennett, Chief Executive, Friends of the Earth and Yu Jiao, Vice President, Economic and Development Research Institute, SINOPEC, among many others.

Head to the IP Week website for further information. **GEO ExPro readers get 20% off the registration fee**: please use discount code **GEXIP20** when booking. ■

Lifetime Contribution Award

Africa Oil Week this year introduced the **Adrian Bligh Memorial Award** to give recognition to someone who has made a '**Lifetime Contribution to Africa**'. The first award was made posthumously to Adrian Bligh, who sadly passed away in September this year. Adrian had worked for **PGS** for many years, focusing on Africa, and he had many friends and colleagues from the continent – he is hugely missed both there and in PGS. He was described during the award ceremony as having a passion for Africa and for driving successful partnerships with companies and ministries – and it was also remembered that he was always great fun to be with.

The award was accepted on his behalf by his PGS colleagues Rob Holden and Dawn van Zeelst, and was presented by Paul Sinclair, Conference Director at Africa Oil Week. ■

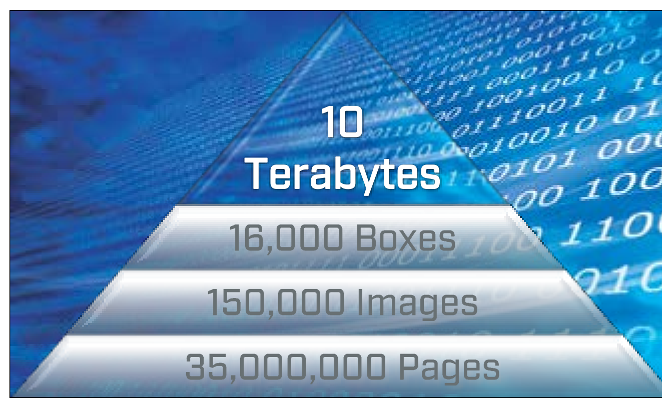
Invest in Big Data

In a typical oil and gas **digital transformation project**, ten terabytes holds the equivalent of 35,000,000 pieces of paper full of text and images. That is roughly 16,000 boxes of paper. Add another terabyte of subsurface maps and seismic sections: that is an additional 15,000 images and 350 boxes of paper. Just the storage fees for all of those boxes could cost hundreds of thousands of pounds annually.

Fuelled by the demands of artificial intelligence, ten terabytes is what some data management companies are processing each month in support of the new digital transformation world, and that number is growing. **Katalyst Data Management**, for example, globally stores **40 petabytes or 40,000 terabytes of data**. As you can imagine, 40 petabytes is a lot of data:

- 140,000,000,000 pages
- 60,000,000 TIF images
- 65,400,000 boxes
- 75,000 semi-trucks of paper data
- 10,000 man-years of scan and name time (at 3 seconds/page)

Talk about big data! Consider the fuel cost and people involved in moving and storing all of that information. The business value to transform all of this subsurface data into a digital format is tremendous, and well worth the investment. ■



The World's Richest Energy Basins

AAPG's Global Super Basins Leadership Conference in 2020 will bring together experts on the world's richest energy basins to study the geoscience architecture, explore the technology, and to anticipate opportunities in basins that have unrealised potential. The Global Super Basins Leadership Conference will focus on some of the top questions surrounding the most petroliferous basins in the world. Some of the questions to be addressed include:


AAPG

- What makes super basins special and unique and what can we learn from them?
- What critical geoscience elements contribute to success?
- What are the major plays with remaining potential: conventional, unconventional, and field growth?
- What key innovations in each super basin, such as horizontal drilling, hydraulic stimulation or seismic imaging, helped unlock the potential and what is needed to grow it further?
- How do 'above ground' issues like politics, access, mineral ownership and geography influence realising the full resource potential of each super basin?
- Will the basin be a regional or global disrupter?

Join AAPG in **Sugar Land, Texas** on **11–13 February 2020** to connect actionable insights from the world's great basins. ■

Manx Gas for the Isle of Man

The role of gas in the transition to renewables is the driver behind a local energy company on the Isle of Man, with the backing of local business, government and the community.

JAMES KEGGIN, Crogga Ltd and
DARREN JONES, British Geological Survey

In line with the UK and Ireland, the Isle of Man, a self-governing British Crown dependency lying in the Irish Sea, has committed to achieve net-zero carbon emissions by 2050. However, while the transition to renewables is taking place, the Island will remain dependent on hydrocarbons for electricity, heating and transport, and until an economic solution is found for energy storage, there will be a continuing need for gas as a back-up due to the intermittent nature of renewable energy generation.

Right now, 97% of the Isle of Man's energy comes from oil and gas – and every molecule is imported. With only minor contributions from hydroelectricity, energy from waste, biomass and imported electricity, it therefore has a long journey ahead in the energy transition.

The Economics of the Transition

The gas required for heating and electricity generation in the Isle of Man is currently imported through a link into the Scotland-Ireland 'Interconnector 2' pipeline. As well as being expensive, the carbon footprint of imported gas – much of the gas being delivered originates in Russia – is obviously significantly more than that of locally produced natural gas. For example, it has been estimated that Russian gas imported to Ireland creates 34–38% more greenhouse gas emissions than using Irish gas, while LNG from Qatar, which is also a supplier, creates 22–30% more emissions as a result of losses and transport required en route. In addition, being dependent on foreign gas, the Isle of Man and Ireland would find themselves literally at the end of the pipeline should gas supplies be disrupted.

The discovery of local natural gas could provide energy security to the Island and also offer an additional local supply for Ireland, as Manx natural gas could be exported there through the very same pipeline that is currently used for gas import.

Using local natural resources is therefore not only good for energy security but also for the environment and jobs.

The Irish Taoiseach (Prime Minister) recently said, "Recognising that we end exploration for oil in Irish waters, we will continue to explore for natural gas given that it's a transition fuel that we are going to need for the next few decades, as new technologies are developed and deployed."

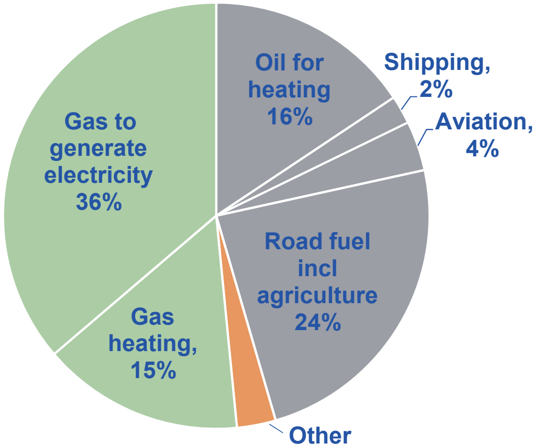
Manx Gas Needed

The transition to renewables is clearly an enormous task, requiring time and an investment of several hundred million pounds or more. With a strong demand from Ireland for Manx natural gas in addition to local demand, the Isle of Man could follow Norway's lead and use the tax revenue from sales of any gas found in its territorial area to fund the required infrastructure and provide subsidies if necessary. This opportunity has been recognised by the Isle of Man government, with Chief Minister, Howard Quayle, recently stating "… should there be enough gas found in our waters, then any income stream from that money should be put aside for the building of a green renewable energy source for the Isle of Man".

Luckily for the Isle of Man, there could be a significant source of natural gas within Manx territorial waters. In 1982, BP drilled an exploration well off the Island targeting Triassic sands as an analogue to the Morecambe Bay gas fields. Although these sandstones were disappointingly water-wet, the deeper Permian sandstones contained a 50m column of gas in 220m of gross sand, in

Doug Felmeri

Maughold Head Lighthouse, the easternmost point of the Isle of Man, looking towards Crogga's acreage.



Isle of Man total energy consumption for 2017 (total 2,138 GWh). Data from IOM Dept. of Infrastructure (https://www.gov.im/media/1361698/isle-of-man-in-numbers-2018-report-v2.pdf) with air and shipping estimated from 2017 traffic volume.

The ambition: to be self-sufficient in energy from renewables. Walney Extension , which lies about 50 km east of the Isle of Man off the English coast, is the world's largest operational offshore wind farm, generating electricity for nearly 600,000 homes. But it will be years before the Island will be able to rely on such sources totally, and until then gas is the preferred transitional energy source.

a similar sub-salt play to those seen in the Permian Rotliegend sandstones of the southern North Sea. In the 1980s and 1990s, the economics of a stand-alone gas development in the Isle of Man were not as attractive as they are today, so in 1996 BP relinquished the acreage, which has sat undeveloped until now.

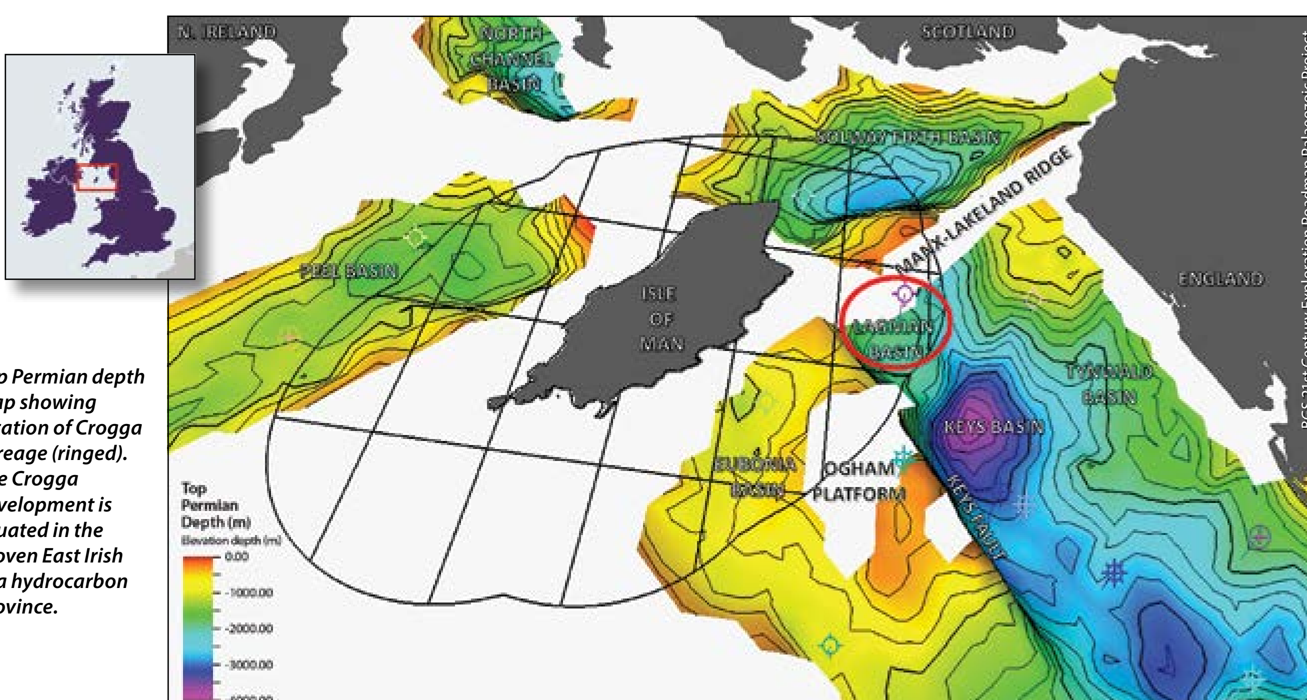
Offshore Geology

The offshore waters within the Isle of Man's 12 mile (~19 km) territorial limit contain four main basins: the Solway and Peel Basins located to the north-east and west of the island; and the Lagman and Eubonia Basins to the east and south-east.

The structural history of this region is relatively complex. Initial compression during the Caledonian Orogeny created a major north-east to south-west suture as the micro-continent of Avalonia collided with Laurentia, closing the Iapetus Ocean. North-west to south-east extension caused the opening of the Peel and Solway Basins to the north and the formation of major north-east to south-west trending faults that inherited the underlying Caledonian trend. Further reactivation of these Early Carboniferous structures occurred during the Variscan Orogeny, causing inversion structures to form parallel to the Eubonia-Lagman Fault System and along the Solway and Peel Basins, as is evident through the presence of the Manx-Lakeland Ridge.

During the Permian and Triassic, east-west extension formed the Eubonia and Lagman Basins, segmented by a series of north-west to south-east *en-echelon* faults, including the main bounding Keys Fault. The Eubonia and Lagman Basins formed part of the larger East Irish Sea Basin graben system, with sedimentation continuing until the Jurassic.

Uplift occurred in the Palaeocene, associated with opening of the Atlantic Ocean and with the input of lavas, which form a series of north-west to south-east-trending dykes that are found across the Isle of Man. This uplift continued due to the Alpine Orogeny,



Top Permian depth map showing location of Crogga acreage (ringed). The Crogga development is situated in the proven East Irish Sea hydrocarbon province.

The Isle of Man

Isolated in the Irish Sea equidistant between England, Scotland and Ireland as the glaciers of the last Ice Age retreated, the Isle of Man has a rich history and distinctive culture and heritage. Populated originally by Celts, Manx Gaelic was the everyday language of the people until the 19th century, although the last native speaker died in the 1970s. Vikings arrived in the 8th century, first to raid but then to settle and rule and their burial mounds are a feature of the modern landscape. They established the Manx parliament, Tynwald, which is the oldest continuous parliament in the world.

In the 13th and 14th centuries control of the Isle of Man passed regularly between the warring nations of England and Scotland, settling permanently with the English Crown in the 15th century, and government over the years gradually evolved to the present democratic system in which the island is a self-governing British Crown dependency with the British monarch as nominal head of state. Its inhabitants are British citizens but it is not part of the United Kingdom, although closely allied in governance, international affairs and security. Nor is it a member of the European Union, and the island has used this unusual political status to develop a low-tax economy based around insurance, gaming, IT and banking. It is also home to the annual Isle of Man TT motorcycling races, in which bikers approach speeds of 200 km as they negotiate the tight bends and steep climbs of the mountains.

With dramatic rugged cliffs, beautiful beaches, outstanding natural scenery and over 40% of its land unpopulated and uncultivated, the Isle of Man, which is 52 km long and 22 km at its widest point, is a popular tourist destination. In 2016 it was awarded status as a UNESCO Biosphere, recognising its plethora of diverse natural habitats and unique culture. ■

The four-tiered Tynwald Hill is one of the Island's most distinctive landmarks and a signal of the Isle of Man's independence as a self-governing crown dependency, hosting an open air meeting of the Tynwald once a year.

creating inversion anticline structures along with hanging wall blocks in the Solway Basin. In the Eubonia Basin, evidence for inversion is shown by the appearance of the Ogham Platform.

Plenty of Potential Reservoirs

Current exploration is focused on the Lagman Basin, which is an uplifted terrace of the Keys Basin lying to its south-east: a proven hydrocarbon-bearing province. The Lagman Basin benefits from close proximity to the main kitchen of the East Irish Sea Basin in the Keys Basin, where Namurian deep marine shales act as the source rock.

The main play is the Permian Collyhurst Sandstone, which is at shallower depths here than in the Keys Basin, and should therefore act as a more effective reservoir with preservation of better porosity and permeability values. The area is highly structured due to folding of the Carboniferous strata, fault reactivation and unconformities related to the Variscan Orogeny.

Permian-age halite is found in the St Bees Evaporites, which provides an effective seal to the Collyhurst sands. It is present across all Manx waters, except on highs such as the Manx-Lakeland Ridge. There are also potential Carboniferous reservoirs at deeper levels which have not undergone as much Palaeozoic to Mesozoic burial and Cenozoic uplift compared to the Keys Basin. Further analysis is required to confirm this play. The Ormskirk Triassic play, which is commonly hydrocarbon-bearing in the East Irish Sea Basin, was found to be water-bearing at the 1982 well location, but could be prospective elsewhere in the Lagman Basin.

A stone circle on the Isle of Man dating from c. 3,500 BC.

The Story So Far

In 2014, a small group of Manx-based

oil and gas professionals recognised the size of the prize for both the Isle of Man and investors and formed Crogga Ltd. Then, along with supportive residents, they promoted the opportunity to the Isle of Man government. Using venture capital funds raised on the Isle of Man, Crogga Ltd applied for and were awarded a production licence in a 2017 competitive licence round.

Since the licence award, the results of additional technical work have been encouraging. Further mapping of the legacy 2D seismic data has confirmed possible reserves of over a trillion cubic feet of gas in the Collyhurst reservoir with considerably larger upside potential in the Permian, Triassic and Carboniferous. More detailed analysis of Permian reservoir core data from the 1982 BP well shows porosities of 8–12% with permeabilities in the 0.3–0.6 mD range. With water depths between 10m and 30m, and with the Permian reservoir at a depth of about 2 km, the appraisal and development of the field should be straightforward and cost effective.

After liaising with all relevant environmental groups, commercial fishing organisations and the UK government, a 360 km^2 3D seismic survey is planned for 2020. Planning has also commenced for exploration and appraisal drilling, which it is hoped will occur in 2021.

View over the Manx countryside.

Should the appraisal drilling campaign be successful, field development activities could follow. One option is a sub-sea development with a pipeline connecting directly to the Isle of Man that will allow natural gas to be used locally for generating electricity and heating. Any remaining natural gas could be exported through the existing interconnector pipeline to Ireland, with the Isle of Man government benefitting from the tax revenues.

Local natural gas will provide energy security for the Isle of Man and a cleaner alternative to oil and imported gas during the transition to renewable energy. ■

Malaysia: Exciting Times Ahead

Proven barrels up for grabs in Malaysia's next world-class acreage offering

JOHN WILKINSON, Editor, Asia Pacific Region and PETER ELLIOTT, NVentures Ltd.

Following on from a successful 2019 bid round, and carrying on the well organised and thorough bid round procedures Petronas is now associated with, the Malaysian state firm has launched its 2020 Bid Round. Petronas, and the country's Petroleum Management Unit in particular, have held rounds almost annually over the last few years, each time releasing more data, and inviting bids on ever more valuable acreage.

What makes this Round more attractive is Petronas' continued move towards releasing lower risk acreage, drilled resources, and marginal fields ripe for development. There are few places in the world where companies can invest in line-of-sight production opportunities. After decades of carefully managing the domestic E&P sector within the Petroleum Management Unit and Petronas Nasional, the sector is gradually being opened up to further international investment, albeit under careful regulation. Now the state firm has provided access to data, acreage and opportunities that appeal to a much wider cohort of companies seeking to bolster their bottom line in the market place with contingent and proven reserves.

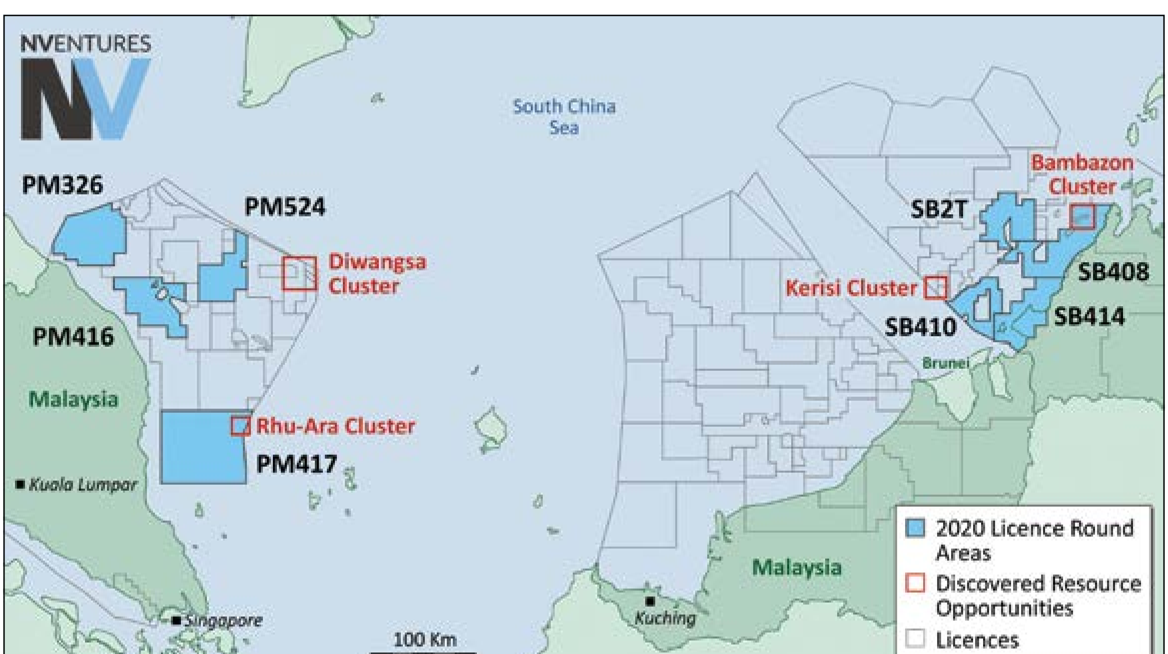
The appetite for deal making is starting to tell here, and the Malaysian sector is set to benefit hugely. Since 2016 major transactions have been helping to reshape the upstream landscape in Malaysia, with companies like PTTEP making big entrances. Hibiscus took a group of fields off Shell in Sabah, and Murphy sold their prized Kikeh field and four other assets to PTTEP in a $2.1bn deal. Coro, a small UK-based firm, entered into a Joint Technical Study with Petronas over the prolific Central Luconia province offshore Sarawak – an impressive step for a small AIM-listed explorer. After the 2019 Bid Round, Petronas say that four PSCs have been assigned, and three more are in mature negotiations. Latest rumours suggest that ExxonMobil will seek a buyer for its entire Malaysian subsidiary, a massive opportunity that is comparable to the large supermajor divestments in the North Sea and Gabon.

Plenty on Offer

These are exciting times for a mature province previously heavily regulated, and for oil firms starved of low risk assets in other global theatres. Analogous to the re-opening of the Mexican upstream sector, and in marked comparison to stumbling deregulation in Indonesia and closed-door opportunities in the Middle East, this hot area of Asia Pacific could well outstrip the transaction potential of other mature basins across the world.

In the 2020 offering, Petronas include four discovered fields and four mature DRO development clusters: PM416 includes the Ipoh discovery and PM524 has the Laba and Laba Barat discoveries; Block SB410 incorporates the Ziosit discovery; the Diwangsa Cluster includes four fields with combined proven reserves of 56 to 111 MMboe; the Rhu-Ara Cluster includes the Rhu and Ara discoveries with an HIIP of 140 to 232 MMboe. In addition, the Bambazon cluster offshore Sabah has proven hydrocarbon potential and good reservoir quality with an HIIP of 210 to 338 MMboe. The deepwater Kerisi Cluster, also offshore Sabah, includes oil, gas and condensate discoveries with an HIIP of 196 to 426 MMboe.

Expect a long queue from opportunity-hungry small- and mid-caps ready to embrace the new resource-rich offerings in Malaysia when data rooms open in January 2020. ■



Norway:

New play models for Patch Bank Ridge, East of Utsira High

Figure 1: A broadband seismic line running from the Utsira High across the Utsira East Fault System and southwards over the Patch Bank Ridge to the Ling Depression and Sele High in the eastern part of the northern Norwegian North Sea. It displays a detailed stratigraphic section from the Quaternary to the Caledonian faults in basement. The improved resolution compared with older data demonstrates the value of broadband seismic acquisition and imaging.

CGG's broadband seismic data acquisition and advanced imaging technology is driving exploration in the northern Norwegian North Sea. The combination of its North Viking Graben (NVG) and North Viking Graben South (NVGS) surveys, two large continuous and consistent sets of high-quality broadband 3D data totalling 44,000 km², with revised well and new gravity data, are instrumental in maturing proven exploration models, as well as developing new ones.

High-quality seismic data is a key requirement before deciding whether to enter an underexplored province of the North Sea. To help with this process, CGG recently added a southward extension (red polygon, Figure 3) to its existing NVG survey (blue polygon) using its latest broadband seismic acquisition and imaging technology. The resulting state-of-the-art dataset, known as NVGS, reveals detailed stratigraphy from the Permian salt to the Quaternary section for stratigraphic and lithological interpretation. In the seismic section below, old basin configurations can be mapped, including Caledonian folds and faults and Palaeozoic basins. The regional scale of the dataset makes it ideal for establishing a geological model for this region, including prediction of potential source and reservoir rocks. The broadband seismic is complemented by re-evaluated well data, a surface geochemical survey and gravity data.

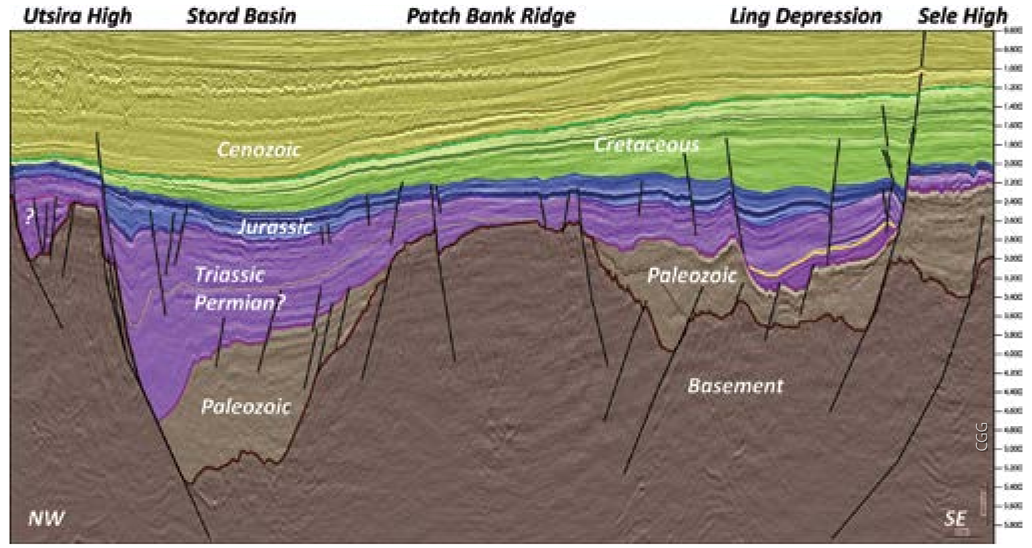


Figure 2: Coloured overview showing geological interpretation of the foldout seismic line in Figure 1. Line location indicated by yellow line in Figure 3.

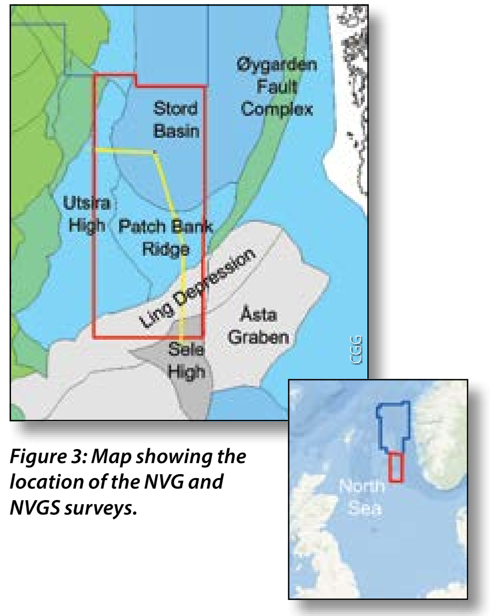
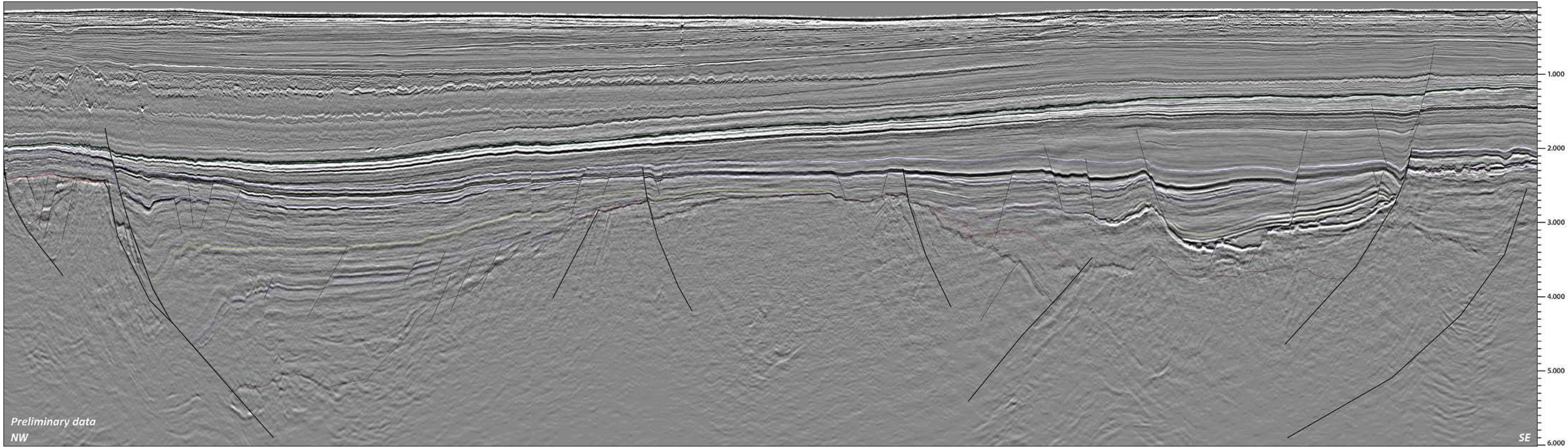


Figure 3: Map showing the location of the NVG and NVGS surveys.



New Insights into Norwegian North Sea

A new regional broadband dataset allows the evaluation of Patch Bank Ridge play elements.

MARIT STOKKE BAUCK, IDAR A. KJØRLAUG, SILJE ROGNE and ANNA RUMYANTSEVA; CGG

The application of recent advances in seismic acquisition and imaging technology, such as broadband seismic, to the acquisition of large regional datasets helps the geologist to understand subsurface structure, stratigraphy and rock properties in greater detail. CGG recently acquired a new 8,600 km^2 broadband survey, known as NVGS, in the eastern part of the northern Norwegian North Sea, adding to its existing North Viking Graben (NVG) dataset of over 35,000 km^2. It deployed its proprietary BroadSeis™ solution for this survey, combining a unique acquisition technique and high-end imaging technology, to ensure delivery of the highest-quality image.

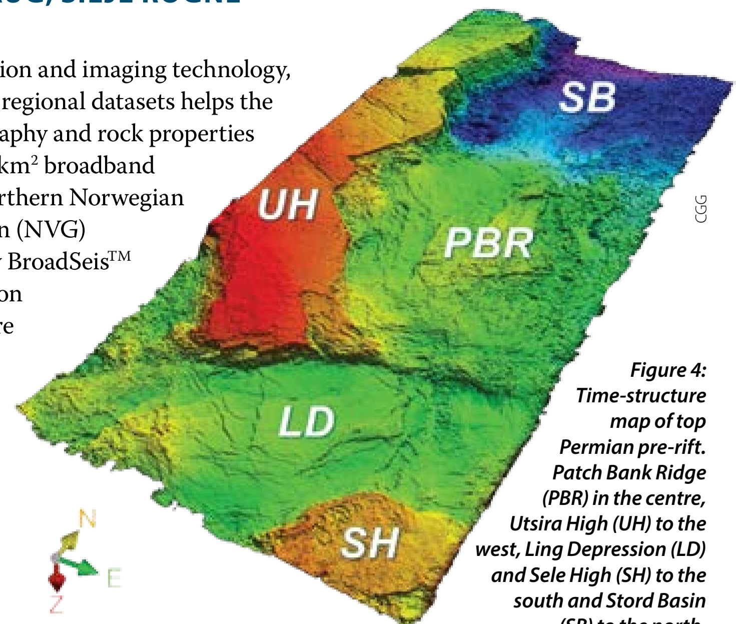


Figure 4: Time-structure map of top Permian pre-rift. Patch Bank Ridge (PBR) in the centre, Utsira High (UH) to the west, Ling Depression (LD) and Sele High (SH) to the south and Stord Basin (SB) to the north.

Structural Framework of Patch Bank Ridge

The Patch Bank Ridge (PBR) is located east of the Utsira High (Figure 4). Thinning of Palaeozoic to Mesozoic strata onto the Patch Bank Ridge from the north, east and south indicates that it was part of the greater Utsira High until the Mesozoic rifting.

The Utsira and the Hardangerfjord Shear Zones, trending north-north-east along the eastern flank of the Utsira High and east-north-east along the northern flank of the Ling Depression respectively, provide the structural framework for the development of Palaeozoic basins in the Patch Bank Ridge area. Fossen (2016) and Fazlikhani et al. (2017) conclude that the Devonian extension known onshore Norway continues into the northern North Sea. The Hardangerfjord Shear Zone shows a similar west-south-west to east-north-east trend to that of the Highland Boundary Fault in the UK. The development of Palaeozoic basins surrounding the Patch Bank Ridge may therefore be comparable to the Palaeozoic basins identified on the UK side of the North Sea, such as the Orcadian Basin.

The mapped termination of the Zechstein salt onto the southern flank of the Patch Bank Ridge illustrates the northern termination of a Permian salt basin. The foldout line indicates rift structures and related deposits in the late Permian-early Triassic, with possibly late Permian clastics north of the Patch Bank Ridge.

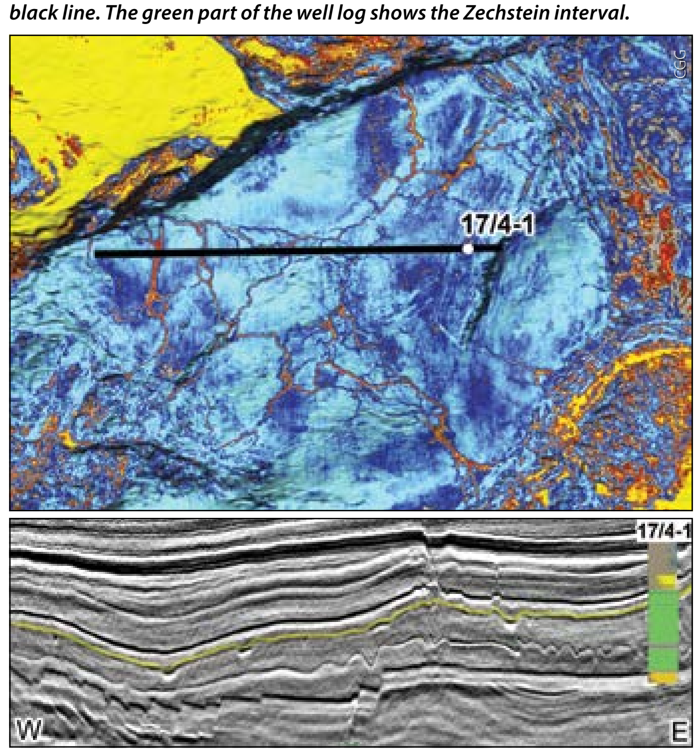
The late Permian-early Triassic east-west extensional rifting phase was followed by a second rift phase that initiated during deposition of the Middle Jurassic and locally affected early Cretaceous strata. The late Permian-early Triassic rift is more prominent, setting up the main rift elements, which were reactivated during the late Jurassic.

A local graben similar to the half-grabens on the Utsira High has been identified on the Patch Bank Ridge.

Stratigraphy of PBR and Palaeozoic Basins

The stratigraphy of the Palaeozoic basins identified here is unknown, although in the UK both Devonian and Carboniferous sediments are found in local Palaeozoic basins. In Norway, positive dating of Devonian sediments has been recorded in the Embla Field (Block 2/7), where the sediments are interpreted to have been deposited in a floodplain/lacustrine environment. Carboniferous sediments penetrated in

Figure 5: Intra-Zechstein sweetness attribute map showing a channel-like feature (top). The seismic section (bottom) shows the interpreted horizon in yellow, and intersecting well. The location of the section is shown by the black line. The green part of the well log shows the Zechstein interval.



well 2/10-01S are thought to have an alluvial-to-marginal marine depositional environment (Knight et al., 1993). In the re-evaluation of well 25/12-1, the lowermost section has been tentatively assigned to Devonian 'Old Red Sandstone', without positive stratigraphic data to confirm dating.

The Permian section is believed to consist of a Rotliegende sandstone section and Kupferschiefer and Zechstein evaporites, carbonates and shales (as seen in well 17/4-1 in the Ling Depression), with clastics replacing the salt north of the Ling Depression.

The late Permian-Triassic sequences were overlain by a Middle Triassic-Middle Jurassic section of continental-to-marginal marine sediments, followed by a relatively thin late Jurassic-to-earliest Cretaceous sequence. A Cretaceous clastic, carbonate and chalk section is overlain by a thick Cenozoic post-rift sequence.

New Models to be Established

Reservoir – Proven and New Opportunities: Proven reservoirs include the Palaeozoic ones that are producing at the Embla field and the Rotliegende sandstones, which have been penetrated in the Ling Depression. An interesting observation can be made in the Zechstein Salt sequence in the Ling Depression in Figure 5. The 'channel system' is associated with the marker that ties with the mid-Zechstein anhydrite-shale and dolomite sequences in well 17/4-1. A possible interpretation for this is a tidal flat environment with channels cutting into the underlying salt. In the Auk field (UK North Sea), the Zechstein stromatolite and dolo-mudstone that are part of the producing reservoirs are interpreted to have been deposited in an inter-to-supratidal, highly-saline environment similar to the modern sabkhas of the Persian Gulf (Vahrenkamp, 2008).

Syn-rift reservoirs, with fair-to-good reservoir quality, exist in the late Permian-early Triassic and Middle Jurassic section in the nearby wells. Late Jurassic sand, similar to the sand on the flank of the Utsira High, may be found on the flank of the Patch Bank Ridge and in the local graben. In the late Cretaceous-early Palaeocene Limestone interval, an area of rafted/slumped sediments has been identified and may be of reservoir quality.

Injectites and mobilised sand have been identified in the Cenozoic section (Figure 6), in addition to shallow marine and gravity flow sediments.

Source: The Critical Component: The Palaeozoic rifts may hold Devonian-Carboniferous source rocks, as seen in the Inner Moray Firth, UK. Oil in the Beatrice field has been analysed to be of Jurassic and Devonian origin. The Devonian setting of the Inner Moray Firth can be compared to the Patch Bank Ridge and its related Palaeozoic basins, with accommodation space for deposition of potential lacustrine source rocks in the local basin centre.

Late Cenozoic uplift of the easternmost North Sea has to be considered when estimating the maturity of source rocks. The Jurassic source rocks of the Tau, Bryne and Fjerritslev Formations may be early-to-mature for oil generation. Long-distance migration from the west is possible, and a fill-and-spill from the Johan Sverdrup field up into younger strata has also been suggested.

CGG's 2016 geochemical seafloor study supports the presence of a mature source rock in the basin or long-distance migration from the west into the region.

Seal and Trap Identified: Seals on a semi-regional scale are provided by the Zechstein evaporites and shale sequences, Upper Jurassic Draupne Formation and Cretaceous and Cenozoic shale sequences.

Traps on the Patch Bank Ridge are rotated fault blocks and incised valleys, with rotated fault blocks on the flank. Down-faulted clastic wedges can be trapped against the Utsira Fault Zone. The Cretaceous-Palaeocene Limestone traps will be stratigraphic, as will the Paleogene and Neogene injectite traps.

A Powerful Tool

This new broadband seismic dataset integrated with well, gravity and geochemical data demonstrates the considerable value of high-quality modern seismic data at a regional scale in order to develop new play models and de-risk existing ones.

The area to the east of the Utsira High is an underexplored part of the North Sea that warrants new exploration initiatives in the years to come. By taking a regional approach integrating high-quality data, new play models can be developed. For example, the riddles of the Palaeozoic and Mesozoic basins in this area are only partly understood. These could be scrutinised further with the support of the first-class NVGS dataset, benefitting from CGG's leading seismic technology and geoscience expertise, and by applying models from comparable working petroleum systems.

References available online. ■

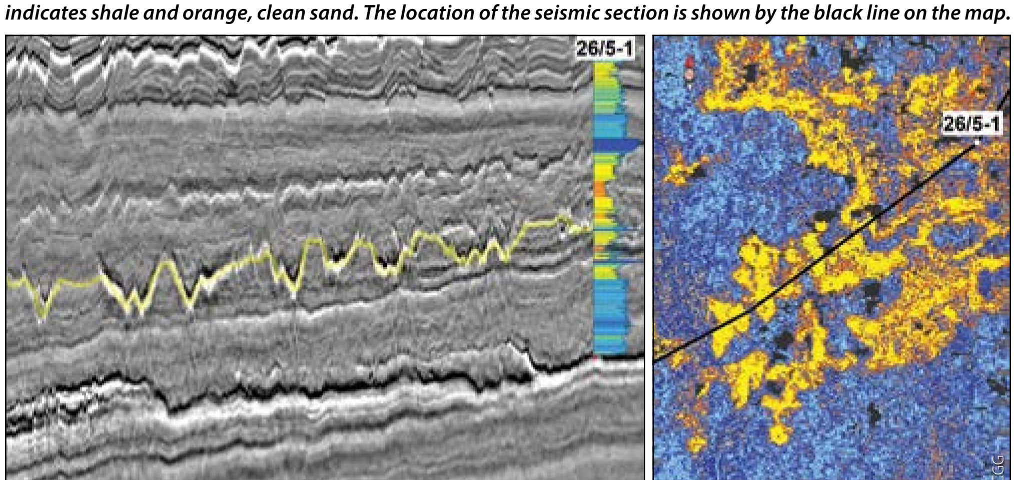


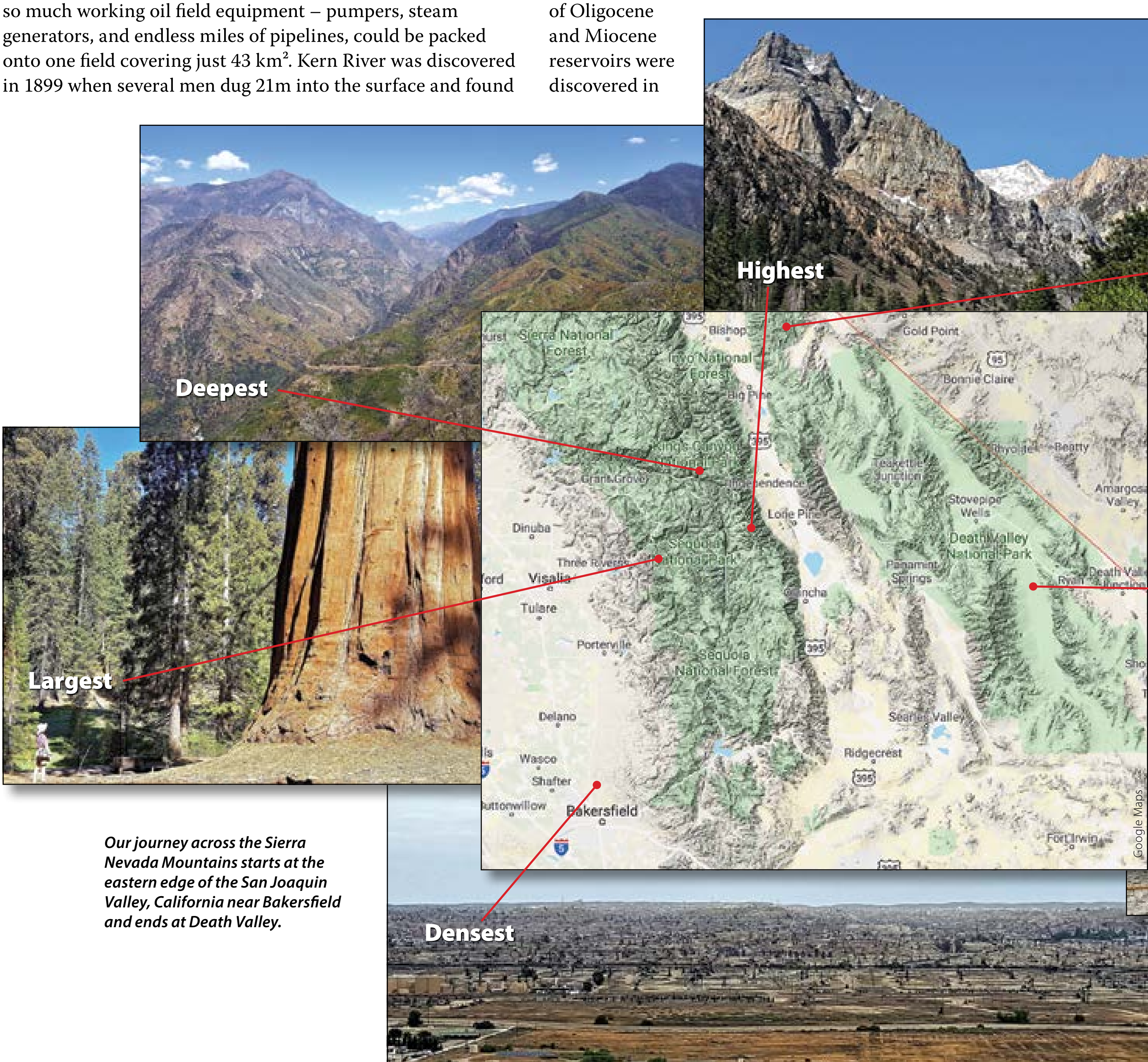
Figure 6. Sweetness attribute map (right) showing the interpreted injectites and mobilised sand distribution. The seismic section shows the interpreted horizon in yellow and intersecting well, with gamma log displayed. Blue indicates shale and orange, clean sand. The location of the seismic section is shown by the black line on the map.

Traversing the Southern Sierra Nevada

While wandering 240 km across California from Bakersfield to Death Valley, the geotourist can marvel at a range of superlative wonders, from the densest developed oil field to the deepest canyon and the lowest point in the United States.

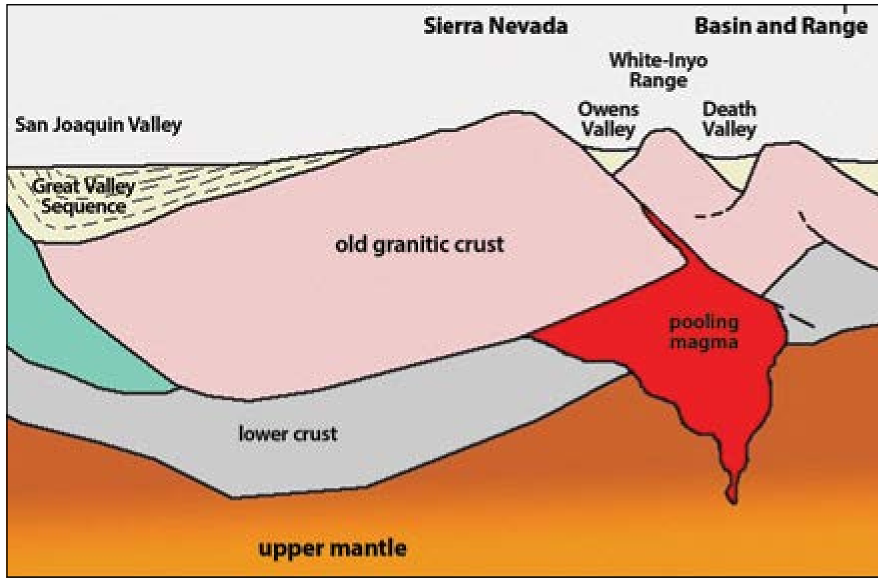
THOMAS SMITH

The journey begins in the lower Sierra foothills at Panorama Park, on a bluff located in north-east Bakersfield overlooking the Kern River oil field. Looking west, it is a wonder that so much working oil field equipment – pumpers, steam generators, and endless miles of pipelines, could be packed onto one field covering just 43 km². Kern River was discovered in 1899 when several men dug 21m into the surface and found oil and the first well was drilled that same year to 120m depth. The field is still producing from the primary reservoir that is Pliocene and Pleistocene in age. Deeper and older pools of Oligocene and Miocene reservoirs were discovered in



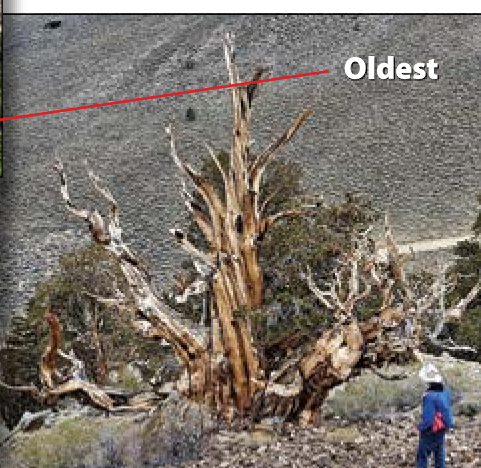
Our journey across the Sierra Nevada Mountains starts at the eastern edge of the San Joaquin Valley, California near Bakersfield and ends at Death Valley.

the 1980s. It is THE DENSEST developed field in California with over 9,000 active wells and is the 5th largest discovered in the US.



Sequoia National Park

After passing through these densely packed oilfields and heading north-east, one travels through rich farmland and citrus orchards that thrive in this Mediterranean-type climate. The Quaternary and Holocene sediments of the Central Valley were derived from erosion of the Sierra Nevada Mountains to the east. As the road climbs into the Sierra foothills, farmland gives way to oak and chaparral. After driving up some very curvy and steep roads into conifer forests, you enter Sequoia National Park on the Generals Highway. The park is named after the *Sequoiadendron giganteum*, or giant Sequoia, and was the country's second National Park, established in 1890 to protect the trees from logging. The Generals Highway, opened in 1926, enabled visitors to drive their cars into the park.



These giant trees grow along a narrow 420 km strip on the western slopes of the Sierra Nevada Mountains between 1,500 and 2,100m in elevation. The bark of the Sequoia is up to a metre thick, protecting the species from fires and pestilence such as wood-boring beetles. A high presence of tannic acids make the trees extremely hardy. These spectacular trees have a large, shallow root system which collects the nutrients that allow them to grow quite fast and this, coupled with a long life span, allows them to grow to their massive size. A stroll through the Giant Forest at Sequoia National Park leaves one in total awe. This large grove, named by naturalist John Muir in 1875, contains close to half of the Earth's largest trees. The stand of about 8,000 colossal Sequoia trees is in the heart of the park and remains the wonderful spectacle that Muir viewed nearly 150 years ago.

The General Sherman Tree, located at the north end of the Giant Forest, is THE LARGEST tree and also the largest living organism by volume on the planet. The tree is an incredible 2,100 years old, weighs 1.2 million kilograms, is 84m tall and just over 31m in circumference at its trunk.

Kings Canyon National Park

After leaving the Giant Forest and travelling north-west on the Generals Highway, you enter Kings Canyon National Park. Established in 1940, this park is home to the Earth's second largest tree, General Grant, and offers a fascinating look into Sierra Nevada geology.

Upon entering Kings Canyon National Park and driving past Grant's Grove, the main road descends more than 1,000m down to the bottom of Kings Canyon, THE DEEPEST canyon in North America. Panoramic Point near Grant's Grove and the Canyon road provide excellent views of Kings Canyon and the high Sierra Nevada, THE LARGEST single mountain range in the lower 48 states.

Over a dozen peaks exceed 4,267m (14,000 ft) in this 600 km-long and 100 km-wide mountain range along the eastern borders of Kings Canyon/Sequoia National Parks. Some of the peaks can be seen from park roads; however, the highest of these and also THE HIGHEST peak in the lower 48 states, Mt. Whitney, cannot be seen from the park. The best views of it are from the east side of the Sierra, west of the small town of Lone Pine in an area called the Whitney Portal. The trail head to the mountain starts at 2,550m and ends at Whitney's summit at 4,418m.

White Mountains and the Oldest Living Trees

The Sierra Nevada range takes the form of a huge, west-tilted block with steep slopes along the east side bound by a series of active faults. This feature makes the journey east by road from the Kings Canyon/Sequoia area a rather lengthy one to Bakersfield, north-east up the Kern River, and finally into the Owens Valley.

Driving north in Owens Valley to the small town of Big Pine offers spectacular views of the massive eastern side of the Sierra Nevada including Mt. Whitney. From Big Pine turn east into the White Mountains where THE OLDEST living non-clonal (individual tree) organism on the planet, the bristlecone (*Pinus langaeva*) pine tree, inhabits the landscape. (Clonal colonies differ from individual trees in that each tree in a colony is genetically identical and connected via a root system that can be very old. A colony of quaking aspen trees in Utah called Pando is the oldest living organism in the world, being at least 80,000 years old, even though individual trees live only about 130 years.)

Thomas Smith

Once into the bottom of Kings Canyon and just upstream from the canyon's deepest point at 2,442m, is an amazing exposure of the chevron folded, calc-silicate phyllite in the Kings/Kaweah Terrane. This terrane also contains marble that has been cut into numerous caves in Kings Canyon. Boyden Cave is located about 800m downstream.

Searching for Climate Patterns

A steep and curvy paved road ascends above 3,000m into the White Mountains to the Schulman Grove and visitor centre. This grove encompasses the oldest trees and is named for Dr. Edmund Schulman, a climate scientist who started his career in dendrochronology in 1932 and for the next 20 years conducted climatic research throughout the western states. At that time, tree-ring records only went back a few centuries. Schulman sought to push the science of chronology further into the past.

In his search, he discovered trees dating back nearly 1,000 years. With this longer date, Schulman began to see a 200-year cycle of flood and drought, but he still needed to go back further in time. In 1953, after discovering a limber (*Pinus flexilis*) pine in Sun Valley, Idaho with 1,700 growth rings, he made a detour to the White Mountains based on a rumour that very old trees existed there. In 1957, Schulman found the world's oldest living tree ever discovered, a bristlecone pine, subsequently named Methuselah, at 4,723 years. He died a

Deborah Bertossa

The oldest bristlecone pines grow on the dry, south-facing slopes in a rocky, dolomitic soil that is interlaced with reddish quartzite. These remarkable trees grow very slowly in this high, harsh and cold climate. The wood is very dense and resistant to insects, fungi, rot and erosion. Some of these trees look dead; however, small portions remain living. Erosion exposes the roots of these trees at a rate of about 0.3m per 1,000 years. The person is sitting on an exposed root of this ancient tree. The Sierra Nevada range is in the background, including the southernmost glaciers remaining in the US.

The giant General Sherman sequoia.

Sierra Nevada Geology

A series of terranes (four have been identified in the Kings Canyon area) ranging in age from latest Proterozoic to Triassic-Jurassic comprise the oldest rocks in the Sierra Nevada Mountains. These fault-bound blocks of crust were docked to the North American continent as the floor of the Pacific Ocean was subducted beneath the continental margin. The Sierra Nevada Batholith is also related to subduction along the west coast of North America, being part of a series of batholiths extending from British Columbia to Mexico. The magma was generated from the sinking slab of ocean crust that released superheated water into the overlying continental crust, melting that crust to form granitic plutons that intruded the earlier placed terranes. The intrusions range from latest Triassic to late Cretaceous.

All this tectonic activity resulted in an ancestral mountain range that was deeply eroded during a long tectonic quiescence, exposing the batholithic rocks. By Eocene times, the range had been eroded to a series of low hills. At some time between 10 and 3 Ma, the Sierra block began to rise again. It is believed the uplift was the result of a mantle delamination event, when the eclogite-rich mountain root of the Sierra Nevada broke away and sank into the mantle. Freed of this dense mass of rock, the overlying continental crust buoyed upwards. West-flowing rivers began to cut deep canyons into the underlying rock. Over the last two million years, glaciers have cut into the rocks to form the current alpine topography of rugged horns, arêtes and cirques. ■

Glaciated exposures of the plutonic rocks of the Sierra Nevada Batholith can be seen near the Sequoia groves and provide excellent viewpoints across the Sierra foothills toward the Central Valley.

year later at the age of 49 of a fatal heart attack, but brought worldwide attention and protection to these ancient trees. In 2012, THE OLDEST living tree yet discovered was found in the area near the Methuselah tree. Exceeding 5,000 years old, this bristlecone pine germinated approximately 500 years before the construction of the Pyramids of Giza.

Final Destination – Death Valley

All great trips must end somewhere and what better place to end than at THE LOWEST point (86m below sea level) in North America. Badwater Basin in Death Valley National Park is an expansive salt flat, remarkably located only 136.3 km south-east of Mt. Whitney.

From the giant oil fields near Bakersfield, over the high Sierra Nevada Mountains, and descending into Death Valley, the geotourist has witnessed incredible geological and topographic highs and lows, and the largest and oldest living trees on earth. No other place can offer such wonders and spectacular scenes. ■

References:

Phil Stoffer, 2019, Great Valley Sequence; Regional Geology of North America: Geology and Oceanography Textbooks website, Miracosta Community College, Physical Sciences Department, Oceanside, California: https://gotbooks.miracosta.edu/geology/regions/great_valley.html

New Life to Old Maps

Regional maps combining both vintage and modern interpretations are vital tools for both students and professionals.

WILLIAM DICKSON, DIGS

What Do We Need?

Exploration geoscientists understand the need for regional comprehension to frame key risks before undertaking drilling obligations. Often the relevant material is scattered or buried in corporate archives so lack of background and time pressure forces the abbreviation of that critical first step, resulting in a well that fails to answer key questions. Major oil companies long depended on dedicated regional staff to address this concern and to their credit they have also released selected maps.

Such releases not only provide valuable background for basin and prospect evaluation; they also offer a platform upon which academics can build while engaging and instructing their students. Ready access to fundamental field work and resulting geological mapping allows progress on formulating new questions and discovering new answers rather than simply retracing prior footsteps. When such material can be made available inexpensively and with audit trails within their metadata, research is facilitated at every level of funding and capability.

Where Does It Come From?

In 1989 geologist Ed Purdy published a set of litho-printed maps illustrating working hydrocarbon plays on the continent of Africa, drawing from his career with Esso (now ExxonMobil). More than a thousand copies of his *Exploration Fabric of Africa* set were distributed. In 2010, as a memorial to Ed, who died in 2009, the Exploration Fabric of Africa (EFA) project was initiated to reproduce his original maps as a multi-platform GIS and to chart discoveries and exploration results across Africa from 1990 onwards. EFA's GIS version, with contributions from AAPG, has 44 sponsors (and counting) and contributions from the proceeds of licensing have been made to charities Africa Now and, latterly, MapAction. Sponsored project copies were installed at African universities as a public relations gesture by selected sponsors, benefitting students and researchers.

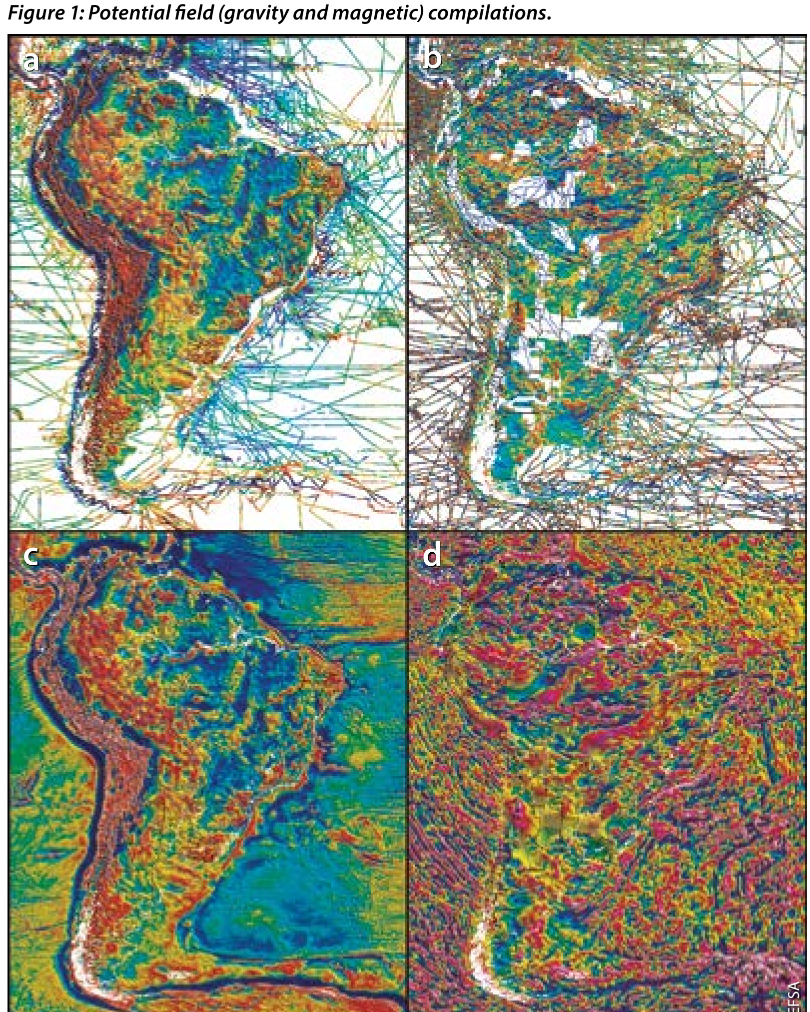
With the partnership of two EFA supporters, Ed's companion maps, *Exploration Fabric of South America* (EFSA), are now digital and an EFSA GIS project is largely compiled. Additional contributions from local expert Dr Carlos Maria Urien augment the Purdy work with that of a classic Southern Cone field geologist. As with the Africa project, the continental overview of EFSA's geological relationships allows the inferring of structural setting and history and sediment provenance, and illustrates exploration trends. Basin-to-basin analogues can be compared, and even, given joint EFA-EFSA licences, cross-Atlantic conjugates can be examined. Consequently, students and explorationists will be able to harness the mapping expertise of Ed and Carlos while incorporating their own insights.

Some Examples From EFSA

EFSA includes gravity and magnetic compilations. Point data were carefully re-levelled from on- and offshore surveys (Figures 1a and 1b) and then gaps were filled from separate compilations of global gridded data (Figures 1c and 1d). The end product offers improved accuracy over the public domain global grids alone, permitting a better assessment of basement fabric through magnetics and structure through gravity. Each data type has also been inverted (with constraints) for depth to basement.

Figure 2, derived by subtracting topography and

Figure 1: Potential field (gravity and magnetic) compilations.



bathymetry from basement depth, represents the total thickness of all sediments, thus highlighting basins; the thickest parts are shown in red. The combination of both gravity and magnetics data can image basement where seismic data is difficult to interpret, such as below volcanics or where thick dense carbonates have poor density contrast with the layers beneath. This map offers a key input to general basin modelling efforts. Note the brown basin outlines from Ed Purdy's maps which agree well with the areas of maximum sediment thickness, except farther offshore where Purdy's data was limited.

The series of maps in Figure 3 illustrates the importance of basement control on discoveries in the important Vaca Muerta unconventional play. Basement fabric appears to correlate with the productive natural fracture systems. The RTP-THD (total horizontal derivative of reduction to the pole) magnetic anomaly map in Figure 3a shows how basement fabric (black dashes) is identified through magnetic trends and how discoveries (triangles coloured by discovery age) seem to be clustering along these basement trends. The lower resolution EMAG2 image (Figure 3b) shows general agreement and the GI-AGC (isostatic residual anomaly automatic gain control) gravity data in Figure 3c also suggests similarities to the magnetic fabric. Figure 3d shows how topography correlates with basement structure, as illustrated by the change in drainage orientation north and south of the black dashed line, indicating that basement fabric has influenced the entire sedimentary column. These basement trends typically play a role in well productivity and merit further investigation.

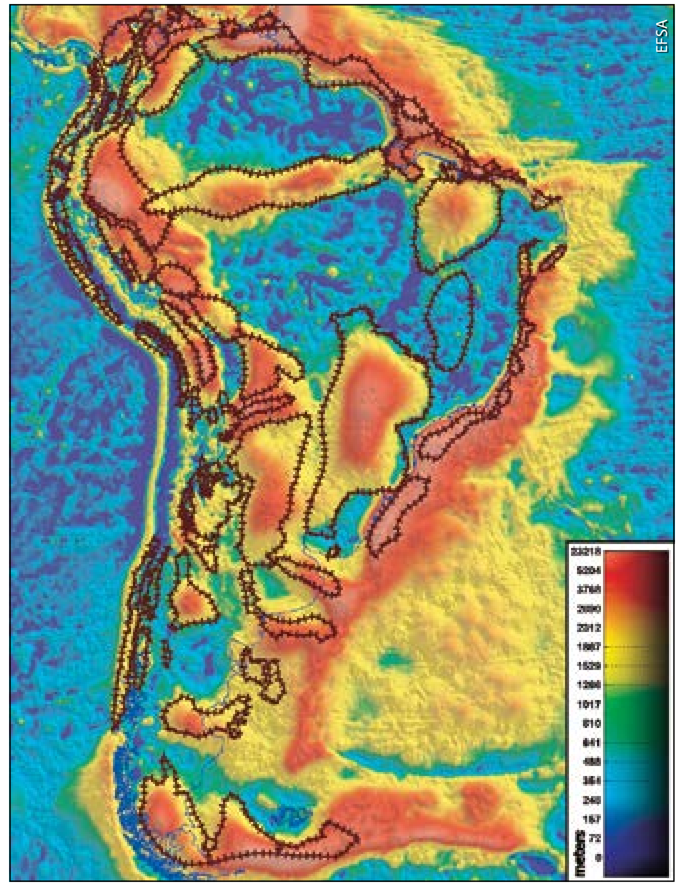


Figure 2: South America: basin outlines, after Ed Purdy, on sediment thickness backdrop.

Who Does It Benefit?

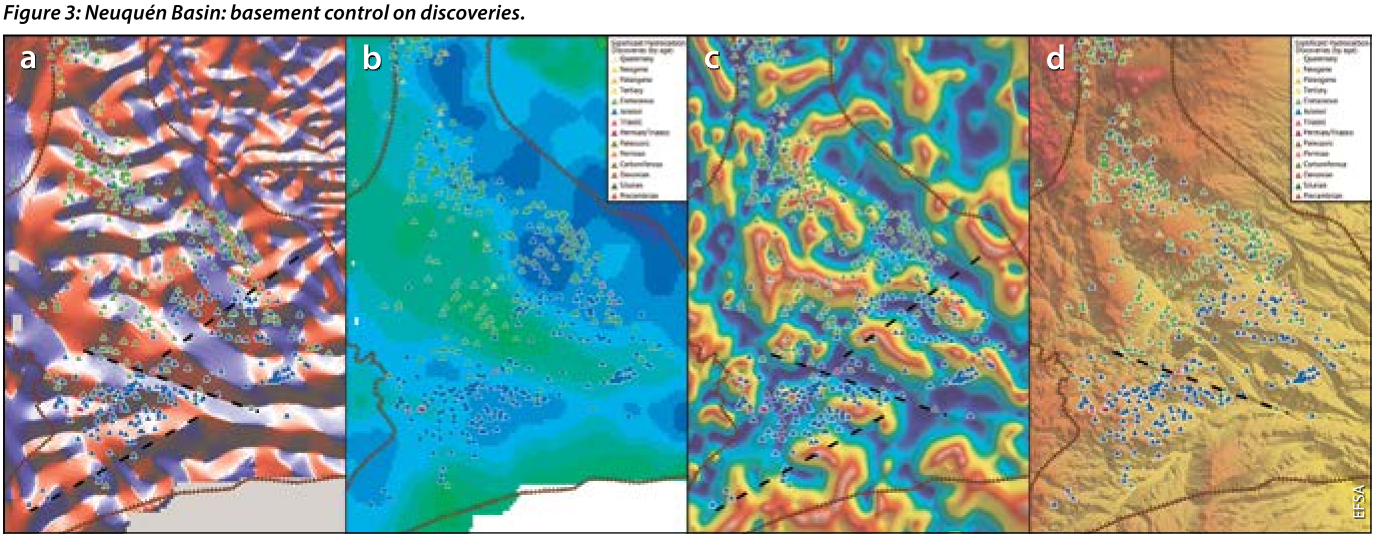
Time is of the essence. For academics, that means the duration of archival searches for prior knowledge in accessible formats. For exploration teams, there is the more burdensome effort of obtaining management, partner and regulatory body permissions for each element.

Both needs are addressed in this project because both EFA and EFSA are built in GIS formats, offering map-based search capabilities. Data attribute tables support text-based searches by including references and citations, helping to form audit trails back to primary information. EFSA contains map elements which, like EFA, focus on basins and plays, not prospects, yet with sufficient clarity for use in meeting presentations and publications. EFSA and EFA content does not require *Permissions for Use*, other than acknowledgements, beyond the original licence, and student presentations can be created, largely or entirely, from EFA and EFSA material.

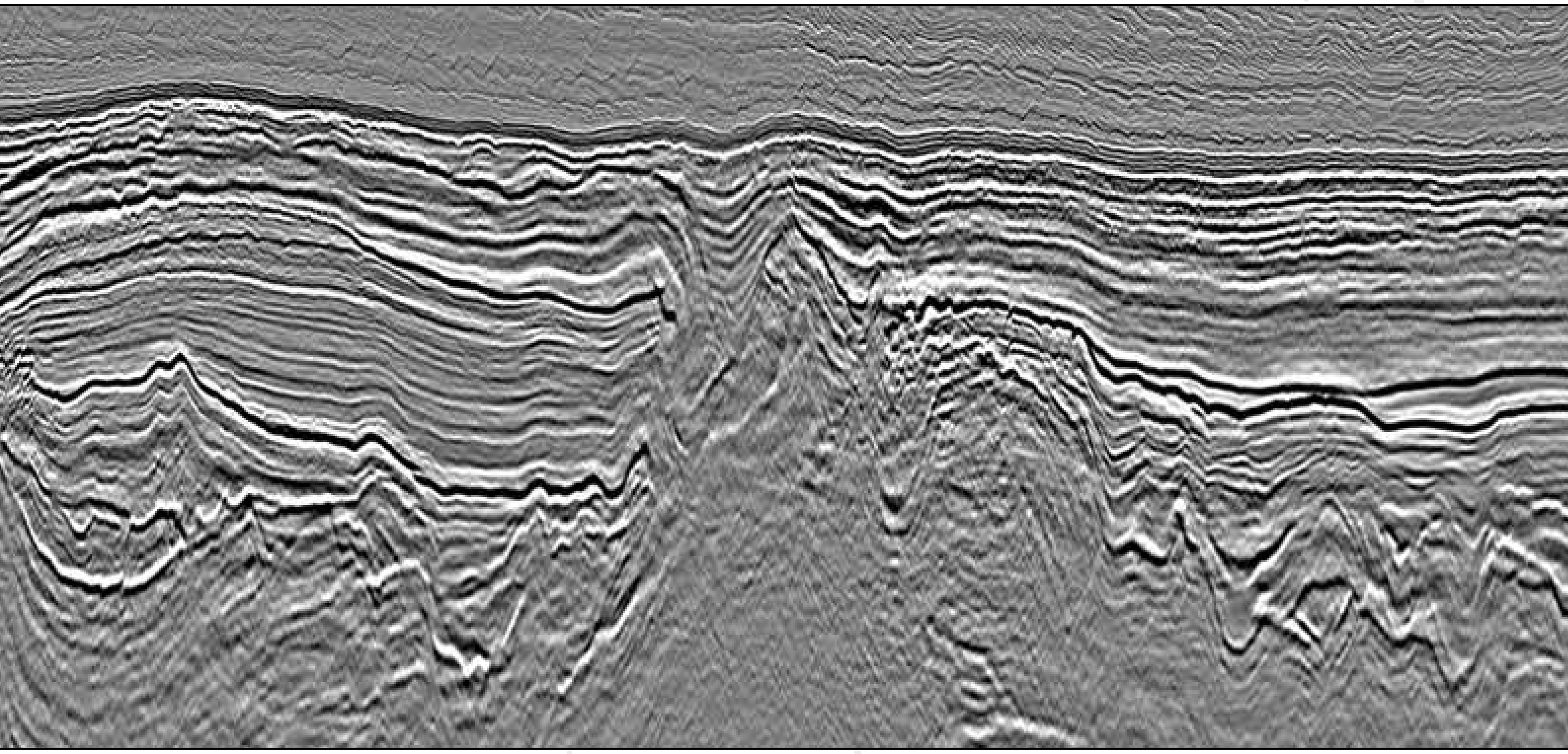
References available online.

Acknowledgements:
Lynx Information for digitising the Purdy maps.
Grizzly Geosciences LLC for generating the potential field and sediment thickness images. ■

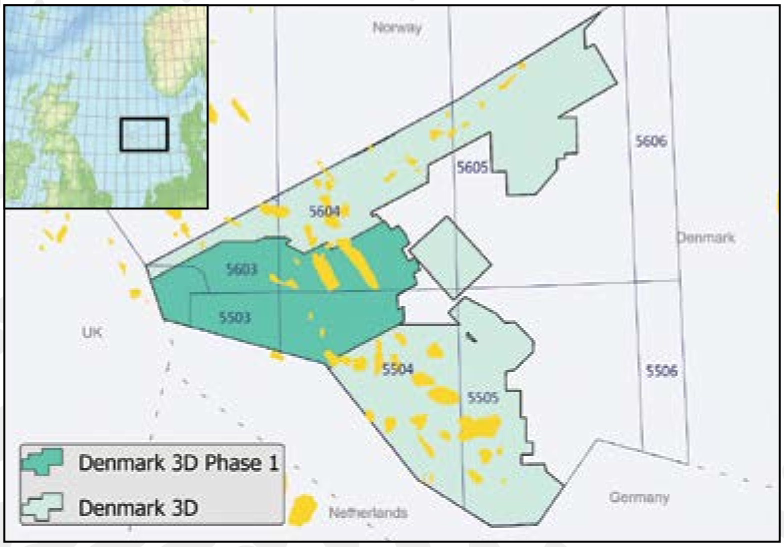
Figure 3: Neuquén Basin: basement control on discoveries.



Explore the North Sea with Denmark 3D



Outer Rough Basin | Inge High | Heno Plateau



All Eyes are on Denmark

Denmark has a rich exploration history with numerous hydrocarbon discoveries totalling over 100 MMboe in recoverable reserves. Recently reprocessed vintage 3D data provides the perfect platform to support any renewed exploration efforts in Denmark.

WILLIAM REID, EMILY KAY and KAREN ROMAND; ION Geophysical

After 53 years of hydrocarbon exploration in Denmark – the first North Sea well was drilled by the DUC (Dansk Undergrunds Consortium) in 1966 – the varied geology, stabilisation of operators and an oil price that at over $50 per barrel is now favourable to North Sea exploration have combined to encourage new exploration activity, as new wells have been or will be drilled offshore Denmark in the coming months.

These include the recently completed Jill-1 well (Figure 6) drilled by Hess on Licence 06/16, which was targeting the chalk interval at approximately 3,400m depth. This was the first well in the Danish North Sea since 2015, and it will be followed by the High Pressure-High Temperature Vibe-1 well in the Central Graben targeting an Upper Jurassic fan complex, which is planned by Wintershall-DEA for 2020. Wood Mackenzie has recently described North Sea exploration as, “making a comeback in 2019”, adding, “bigger budgets and company portfolios are brimming with prospects matured through the downturn” (Wood Mackenzie, 2019).

Geological Challenges

Denmark has a rich exploration history with numerous hydrocarbon discoveries totalling over 100 MMboe recoverable reserves from nearly 20 fields, including Harald, Hejre, South Arne, Valdemar, Roar, Tyra, Gorm, Skjold, Halfdan and Dan (IHS Edin, 2019). Production first started in 1972 and the country has been a net exporter of oil and gas since 1997.

The larger of these discoveries were found across multiple stratigraphic levels, ranging from Early to Late Jurassic, and Lower and Upper Cretaceous, predominantly within the chalk, while a significant number of smaller discoveries have been made within the Permian, Triassic and Palaeogene clastics, as demonstrated in Figure 2. The hydrocarbons in the first producing field, Dan, are reservoired in Upper Cretaceous chalk, which is characterised by high porosities and very low permeabilities, demonstrating the challenging geological environments typical of much of the North Sea.

Therefore, this varied and interesting geological setting, with plays in multiple stratigraphic intervals, makes Denmark the perfect location to demonstrate the value of a regional depth reprocessing project recently undertaken by seismic company ION, which has a long and successful history of 3D proprietary processing, with a significant amount of experience – over 140 surveys – in the North Sea. The company is leveraging this vast North Sea experience to produce the highest quality depth product out of the contiguous surveys that make up the Denmark 3D project.

Rejuvenating Legacy Datasets

Denmark 3D is a multi-client survey that covers about 10,650 km^2 of the Danish offshore area, from the Mid North Sea High to the Tail End Graben, in quadrants 5605, 5604, 5603, 5503, 5504 and 5505 of the Danish North Sea.

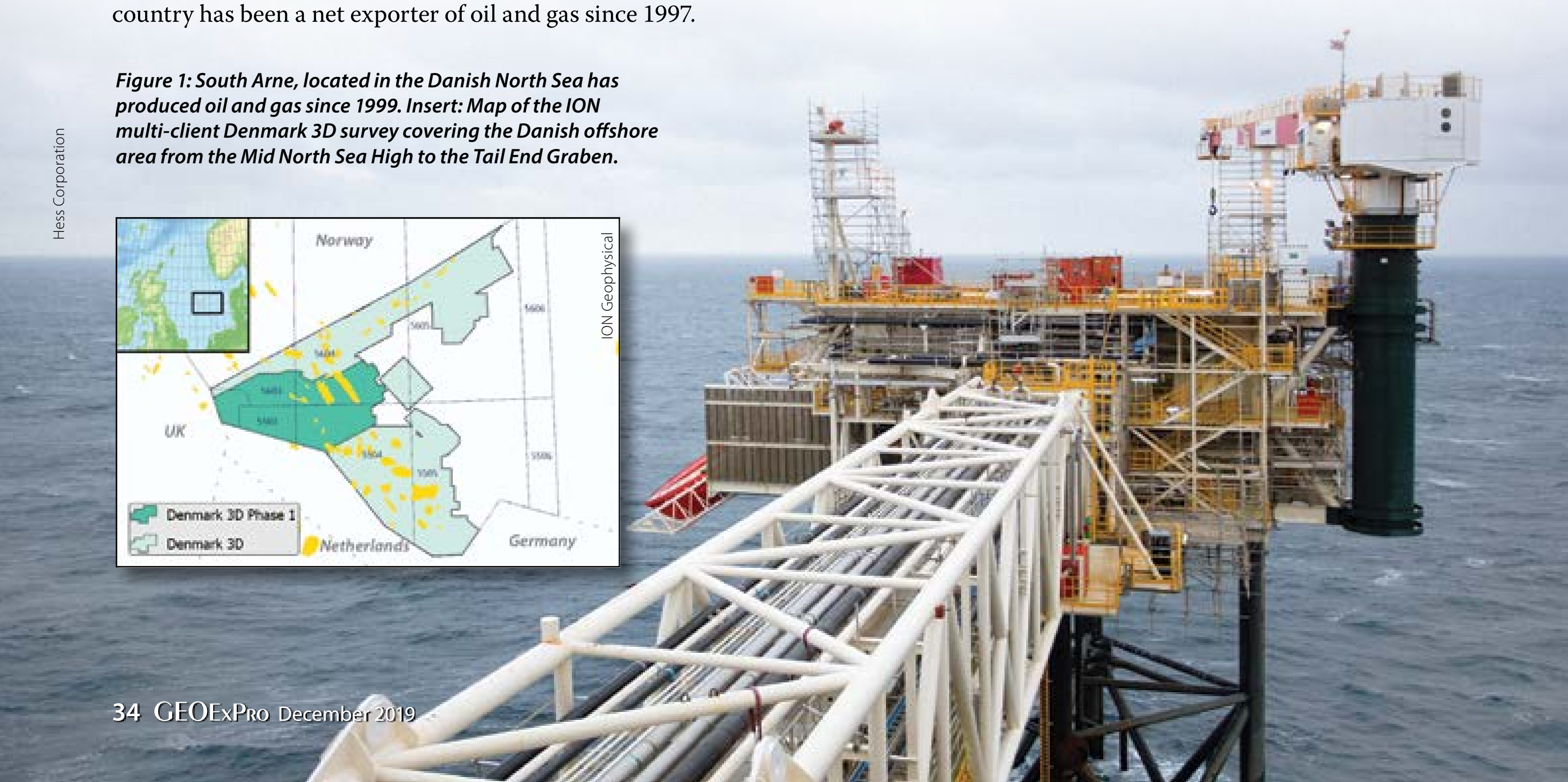


Figure 1: South Arne, located in the Danish North Sea has produced oil and gas since 1999. Insert: Map of the ION multi-client Denmark 3D survey covering the Danish offshore area from the Mid North Sea High to the Tail End Graben.

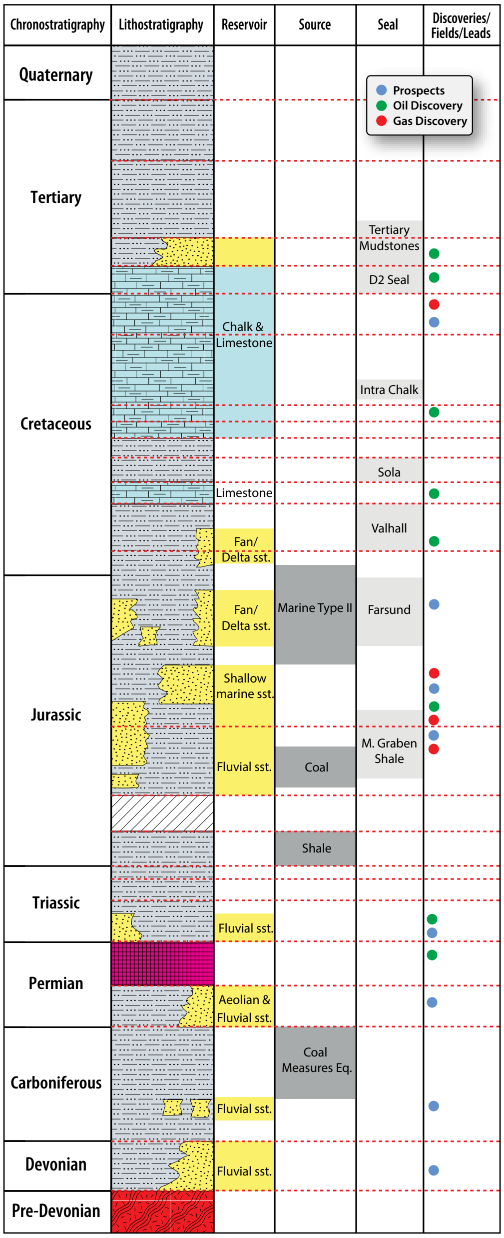


Figure 2: Chronostratigraphic chart modified from Hemmet (2005), showing the main petroleum elements of the Danish Central Graben with stratigraphic intervals of known fields, discoveries and leads highlighted.

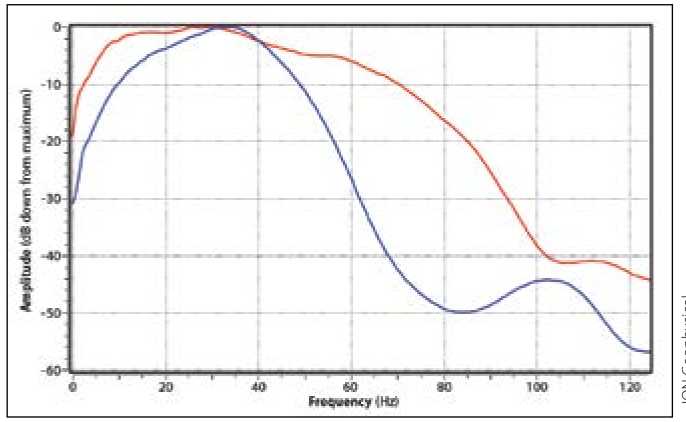


Figure 3: Amplitude spectra showing the broader frequency range after the application of WiBand compared to the vintage.

The 3D dataset is comprised of multiple contiguous vintage surveys that are currently being reprocessed to create a continuous regional volume from field tapes to PSDM. Phase 1 (see Figure 1) will be completed in January 2020 and the data shown in this article is an enhanced fast track version, with velocity model building (VMB) complete down to base chalk. The aim of this phase was to combine three different surveys, in order to demonstrate what can be achieved by applying a modern depth processing workflow to existing legacy surveys.

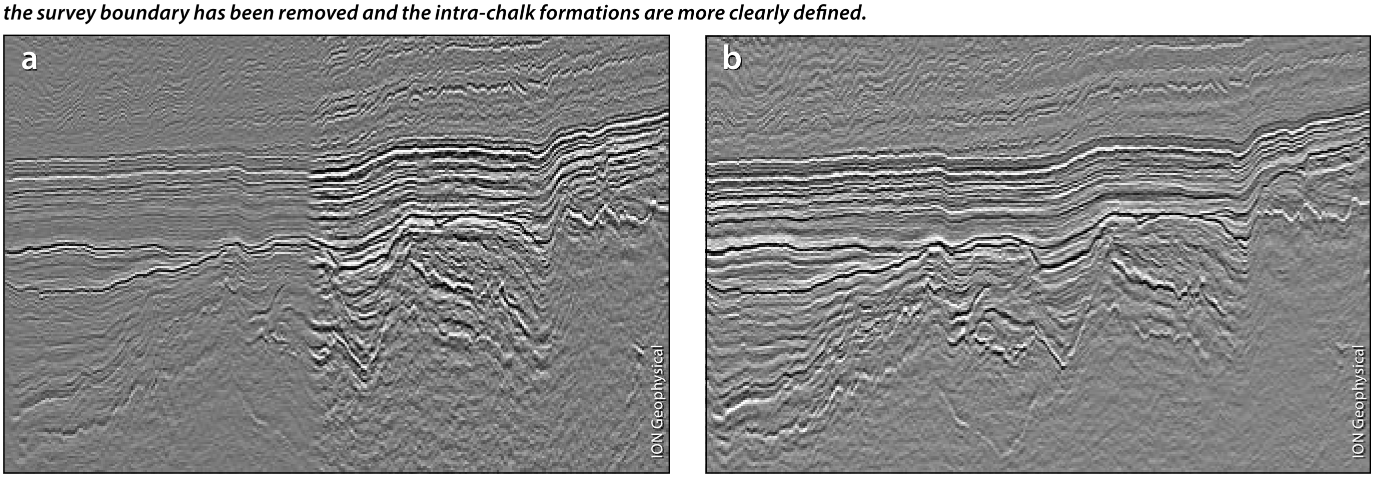
Prior to imaging work, a fully tested pre-processing sequence was applied, incorporating denoise, debubble, deghosting, zero-phasing, shallow water demultiple and regularisation. Special attention was paid to the application of WiBand (ION's deghosting technique), resulting in a broader frequency range compared to the vintage (Figure 3), and allowing better matching between the three input surveys due to the removal of the source and receiver ghosts (Figure 4).

PreSDM model-building was required to adequately resolve the structurally and lithologically complex subsurface of the project area. This was done in an iterative, top-to-bottom approach, with each iteration addressing specific intervals of a complex anisotropic model. The PreSDM model was built using automatic picking and gridded tomography as well as using full wavefield inversion (FWI) and key horizons at strong impedance boundaries or velocity contrasts in order to better constrain the velocity regimes.

Water depths in the region are around 50m and shallow channels are prevalent, meaning extra care was required during VMB in the shallow section in order to resolve the numerous velocity anomalies. This resulted in a marked improvement in some of the stack distortions seen in previous work.

Two tomographic iterations were carried out for the chalk velocity

Figure 4: a) Cross-line through a post stack merge of the Angelina (2007) and South Arne (1995) surveys. b) ION PSDM input to VMB down to Base Chalk; the survey boundary has been removed and the intra-chalk formations are more clearly defined.



estimation, with FWI also being incorporated for the chalk and pre-chalk velocity derivation.

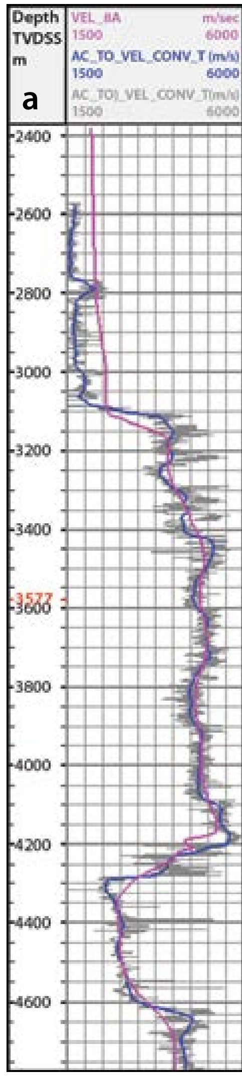
The success of the velocity model build is highlighted by a good match at the wells from the area, including Bertel-1 (see Figure 5). Good matches were also identified with Isak-1, Katherine-1, Nora-1, Ophelia-1, Sten-1 and Svane-1A.

What Next?

A change in the dynamic of hydrocarbon exploration and development in the Danish offshore, precipitated by the 2015 decline in the oil price, has seen takeovers and mergers amongst operators (Nordsøfonden, 2019). Most noticeable of these were the acquisition of Maersk Oil by Total in 2017, the INEOS purchase of DONG Energy's entire oil and gas business in 2017 and the recent Wintershall-DEA merger in 2019. This has resulted in a hiatus in exploration drilling so that, until Jill-1, Maersk's 2015 drilling of Xana-1X was the most recent (IHS EDIN, 2019). This well successfully demonstrated the presence of hydrocarbons in Upper Jurassic sandstone in Licence 9/95 in the Central Graben, but since then operators have taken time out to take stock of their assets and plan strategies for future hydrocarbon exploration.

All eyes are on Denmark, and not just because of the recent industry comeback, but due to hesitation on the most recent licence round. On 5 February 2019 the Danish Energy Agency announced it had received five applications from four companies in the 8th Licensing Round: Ardent Oil, Lundin Petroleum, MOL and Total. The award of these licences was expected in August 2019, but at the time of writing no awards have yet been made.

The impact of this is not yet clear, but ION's newly reprocessed PSDM 3D seismic provides the perfect platform to support any renewed exploration efforts in Denmark. This product will be available at an affordable rate and specifically targeted for the licensed and unlicensed acreage west of 6° 15' E, which can only help stimulate the growth in the Danish offshore. ■



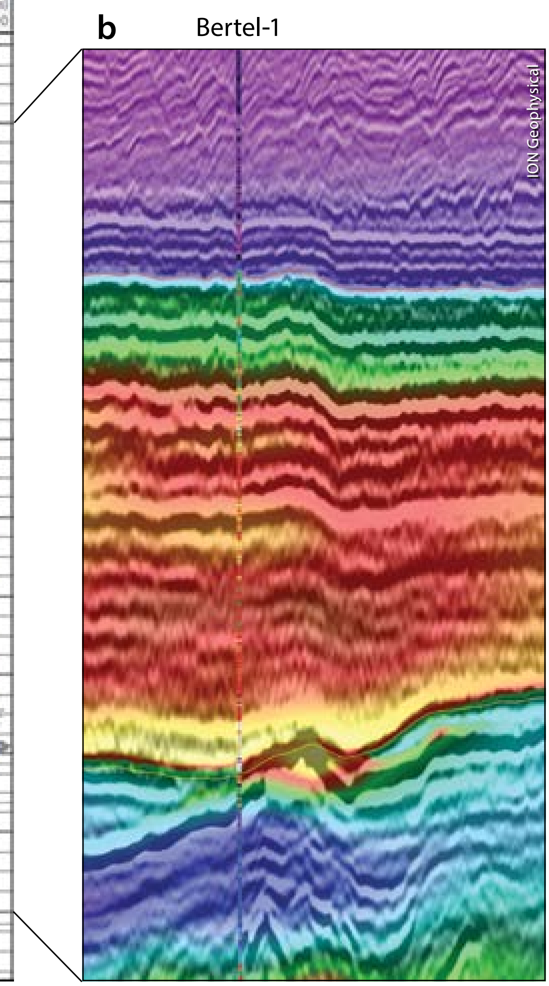
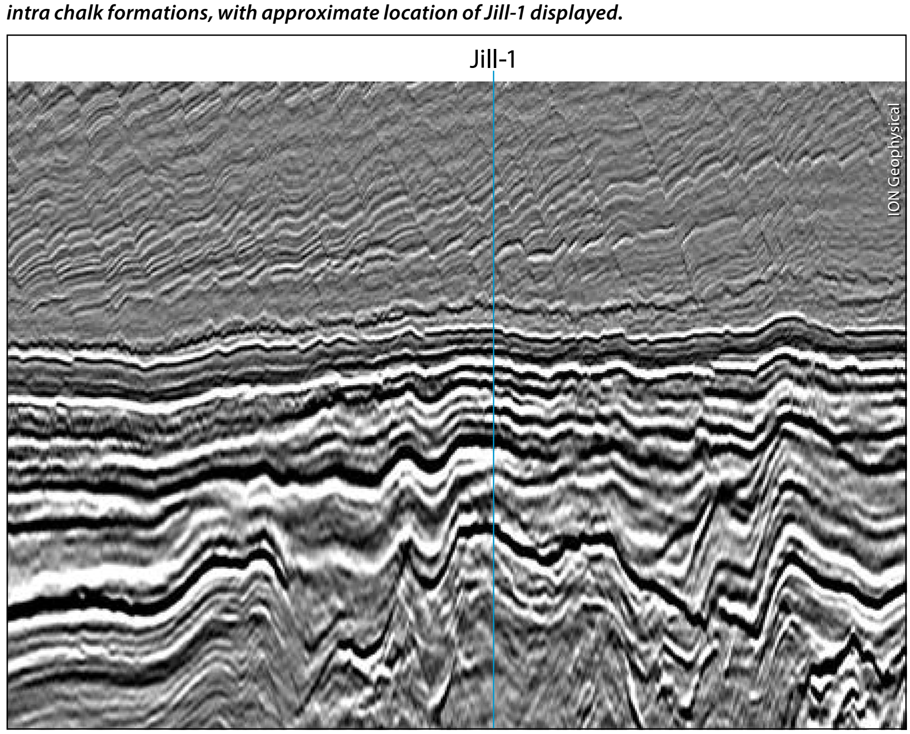


Figure 5: a) Bertel -1 well showing sonic and ION velocity. b) Velocity seismic overlay at well location, showing the good match with the Bertel-1 well.

Figure 6: A) In-line through the Jill intra-chalk target showing the high resolution imaging of the intra chalk formations, with approximate location of Jill-1 displayed.




UNLEASH YOUR DATA'S POTENTIAL℠

New Reservoir Modelling Workflow

An innovative new modelling workflow for reservoir characterisation has been developed that is capable of producing an advanced 3D geomodel of any subsurface zone of interest and can identify potential sand gas or oil zones that have previously lain undetected within a producing area.

Dr. AKM EAHSANUL HAQUE, Dimension Strata Co. Ltd.

Reservoir modelling requires the incorporation of data from various sources, along with the integration of knowledge and technical skills from a multitude of disciplines. Successfully incorporating 3D seismic data, in particular, is key to modelling any hydrocarbon field, as it provides critical insights into spatial distribution and various geological reservoir properties. Common challenges in hydrocarbon exploration and field development centre on the complexities and uncertainties embedded within the subsurface structure and associated formations, which may include structures such as channel bodies, beaches, dunes, turbidites, faulting and other associated depositional and structural features that need to be incorporated into the model.

In recent years geocellular reservoir modelling has therefore become an essential tool throughout the life cycle of any field. Continuing improvements in the algorithmic logic of subsurface petroleum geological software is always key to achieving greater accuracy in delineating potential prospects and fields. With this in mind, an advanced 3D geomodelling algorithm has been developed by Dimension Strata and has subsequently been successfully tested on several prominent hydrocarbon fields, most recently as a study on a producing gas field in Brunei.

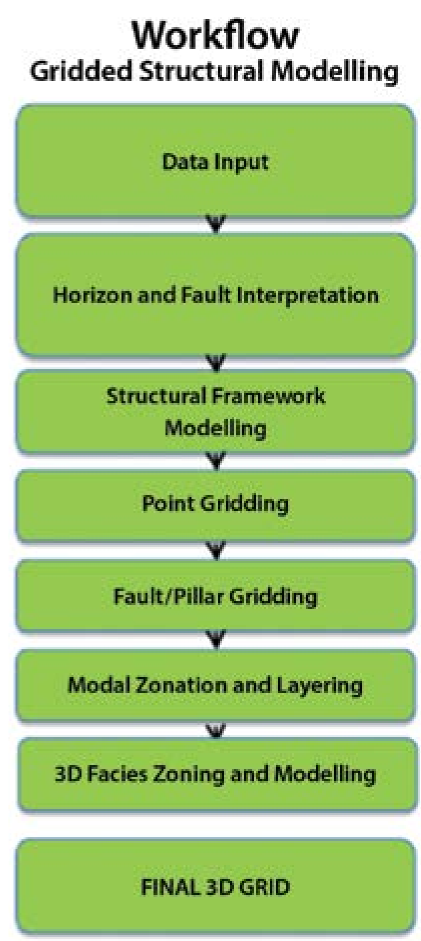
This study deliberately used a very limited dataset, consisting of a single 3D seismic depth cube and one geological report, yet the geomodelling algorithm was able to accurately delineate probable structural features and identify prospective depositional geobodies within the field. It was decided to use a small dataset to demonstrate that it is possible to get useful interpretational outcomes using this method even for an area known to have limited data. The study demonstrates that using this workflow enables the modeller to geologically 'guess' the subsurface despite having a relatively small amount of data, allowing us to explore in challenging subsurface scenarios. It also found that by using additional information, such as well log data, in the existing geomodel, it was possible to successfully correlate and calibrate the results.

Facies Palaeo-Trend Modelling Workflow

A two-phased approach was used for the study. Initially, a model structure was developed using lithological characteristics based on differences in seismic amplitude responses within the interpretational framework. This was followed by facies palaeo-trend modelling (FPTM), which uses a detailed trace-cell-analogue approach for the modelled grids of the reservoir, thus incorporating interpreters' understanding of the subsurface geology within the workflow. FPTM comprises structural qualitative and quantitative geobody and reservoir geomodelling and incorporates interpreted layers such as 3D horizons and available faults within the 3D, ultimately giving a more advanced output in terms of cellular gridded models. In addition, a novel stochastic method was used along with Dimension Strata's advanced 3D geomodelling algorithm, which provided considerably improved structural and 3D facies frameworks of the studied field.

The study combined volume-based modelling with Dimension Strata's proprietary 3D seismic interpretation and reservoir geomodelling system, in which amplitude anomaly-based seismic interpretation, together with amplitude anomaly factor, are used to determine different amplitude classes for specific horizons and/or fault interpretation. Amplitude anomaly factor is a 'patent-pending' term used to describe the part of the new geomodelling workflow that is capable of building an amplitude classification database from 2D and 3D seismic data.

Geomodelling workflow for the study.



Geobody Modelling

Structural reconstruction was an important aspect of this study because it acted as the primary basis for the geobody modelling. The first step in creating a structural framework network was developed using the 3D seismic cube with interpreted seismic horizons. Utilising the new workflow, it was possible to grid the model to the surprising level of 50m^2 per grid cell without any loss of resolution in the interpreted structural and geobody parameters across the entire 3D volume. Quality checks were rigorously applied during the modelling phases. The volume-based structural model was then used as a base for the final facies palaeo-trend modelling.

The potential reservoir zones were initially identified using integrated seismic analysis within the horizon modelling phase. This incorporation ultimately enabled the placement of the zone boundaries of all the modelled layers of the study field.

Although the data provided for the study was limited to a single seismic cube, the present-day depositional pattern in the area and previously studied depositional settings were also used in the model to help develop the FPTM trend. This study was entirely based on the geometric inputs that control particular geobody shapes, such as thickness and width.

The facies modelling workflow for the studied reservoir followed three robust steps. During the initial stage, depositional bodies were generated using the FPTM algorithm, and this was followed by the definition of the boundaries of the interpreted geobodies. In the last step, the internal geometry and heterogeneity of the facies were developed in order to generate the final FPTM of the studied reservoirs.

Mapped Horizons

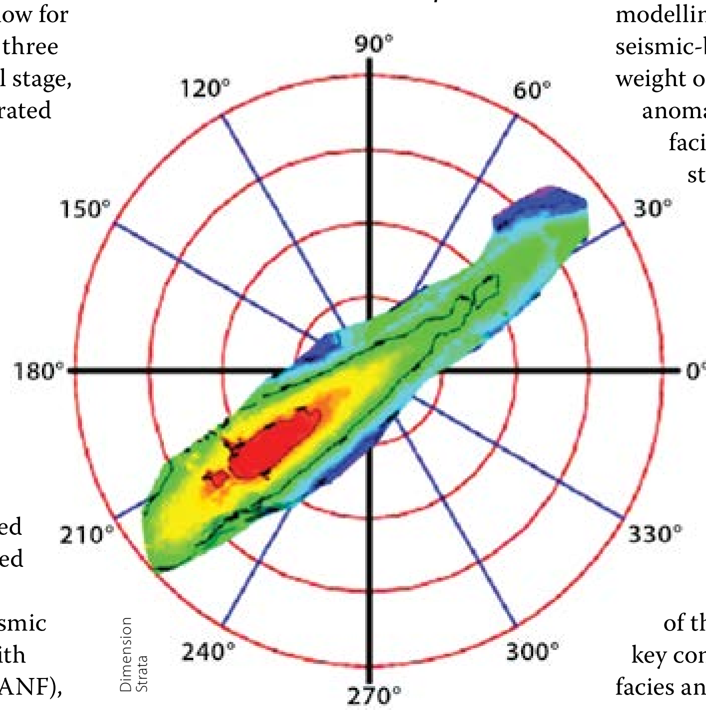
Three horizons were interpreted for the study using the advanced geomodelling algorithm. A geodatabase incorporating seismic amplitude anomalies, along with amplitude normalised factor (ANF), calculated through the algorithm, was used to determine these target horizons. ANF is a module of the company's OrbStrata software that uses a specific statistical formula to classify probability of occurrence of sand versus non-sand facies. The number is a unitless derivative from 0 to 1, in which lower fractions correlate to higher possibilities of shale/mudstone and higher fractions represent lower possibilities of shale. As the study was based exclusively on seismic data (in depth), this meant the determination of ANF helped to delineate probable lithofacies classes within the field. The application of amplitude classification, whereby amplitude from the seismic data is used to develop a lithology-specific classification, means it is possible to segregate potential lithologies while the seismic interpretation process is being performed. Amplitude class was developed for the study area based on the zone of interest and exclusively involves the classification within that zone's boundaries.

Amplitude classification using Dimension Strata's algorithm. Class IA is most prospective, Class III least prospective.

Ampiltude Anomaly Occurrence (m)	Amplitude Range	Amplitude Normalised Factor	Amplitude Class
2,800–2,900	Narrow (600–800)	Shale (0.05–0.14)	Class III
2,950–3,000	Narrow (800–1,000)	Sand Gen-I (0.10–0.20)	Class II
3,000–3,050	Wide (-17,000–5,000)	Sand Gen-II (0.50–0.54)	Class I
3,050–3,150	Short / Wide (1,000–4,000)	Sand/Mixed (>0.6)	Class IA

Structurally, the reservoir zone, situated between the top and bottom reservoir surfaces, was interpreted to be devoid of any faults. It is a classic 4-way dip closure structure oriented roughly north-east to south-west and is thicker in the central part of the structural model and thinner either side. The average azimuth of the structure is N40°E.

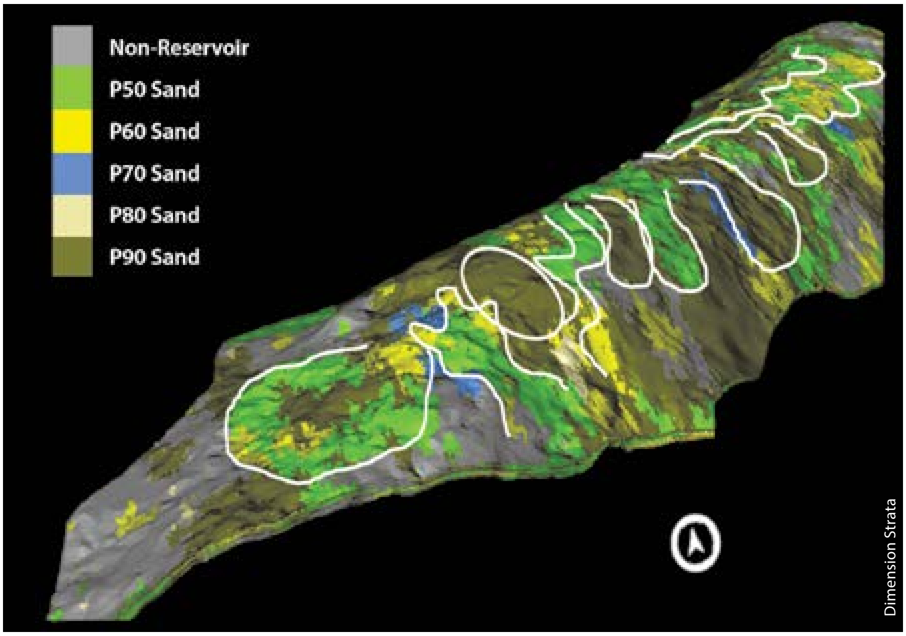
Structural orientation of the interpreted horizons.



Modelling the Target Zones

The algorithm uses a combination of sequential indicator simulation (for flexibility in defining different variables within the model), truncated Gaussian simulation, and the facies palaeo-trend modelling algorithm, to develop 3D seismic-based facies, putting more weight on the seismic amplitude anomaly in order to determine logical facies distribution spatially. The study was able to use all available modelling parameters, with only the use of seismic data in the depth domain. Taking into consideration the constraints set for the study, such as limited area and database, it is remarkable to note that the geomodels that it has produced accurately coincide with the known subsurface features of the target zone of the study field.

Determining 3D geometries of the interpreted horizons was a key component of this study. As the facies and facies classes were directly



Facies dimensions and distribution within the modelled output of the field. The white solid lines represent potential siliciclastic sand or mixed clastics lobes, where the probability of sand is from 45 to 75%. White oval represents area of 90% probability of reservoir sands, modelled in those particular cells.

related to the quality of the prospective reservoir zone, facies geometries needed to be carefully interpreted.

According to the facies associations and a review of previous research undertaken in this area, the study concluded that the prevalent depositional setting was an offshore deep sea fan environment. This was also evident from the seismic facies modelling. From the topmost surface of the target reservoir zone, it was evident that different sand facies were distributed in a fan shape along the south-west and south-east portion of the model.

The resulting model clearly describes the crucial changes in geometry of the facies, which potentially is of great importance for future drilling campaigns within the modelled zone. As can be seen in the figure to the right, potential sand deposits with a higher probability of containing hydrocarbons were present in Layer 5, especially in the south-west and central north-eastern part of the model.

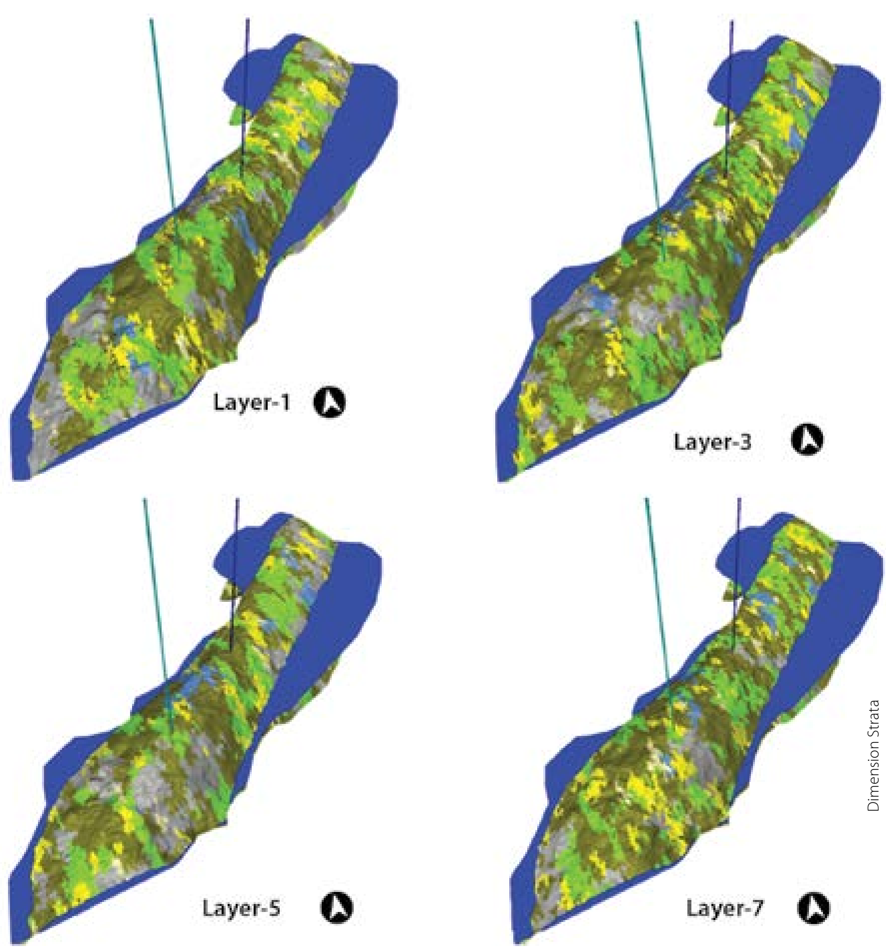
The facies model has been compared to the known gas-water contact (GWC) for the studied zone and found to be consistent with it, paving the way for hydrocarbon exploration and development within the facies above the GWC level. Applying the major interpretational modules of the new algorithm, the depositional facies above the GWC were found to have a high probability of a sand percentage of over 45%, based on the seismic amplitude anomaly identification and from interpreted attributes.

The spatial distribution of the potential sand facies derived through this workflow has been interpreted and the overall interpretation of the different probabilities of sand occurrence within the model suggests that P50 and P60 sands (i.e. the probability of the occurrence of potential siliciclastics) are more likely to occur within the middle layers, whereas P70 and P80 sands are found in the deeper layers of the model and P90 sands within the middle and upper layers of the model.

Workflow Shows Potential

This advanced geomodelling workflow equipped with facies palaeo-trend modelling has been tested on several prominent hydrocarbon fields and prospects in the Asia Pacific region and has demonstrated great potential to help resolve complex depositional facies interpretations, with substantially improved exploration outcomes. ■

Seismic facies occurrence in different layers identified within the model.



Caribbean Atlantic Margin Deep Imaging

In March 2019 MCG completed acquisition of 16,433 km of long-offset high resolution 2D seismic data in the south-eastern Caribbean. Potential field data were acquired jointly with the seismic.

The survey is designed to provide a new, deep, regional seismic and crustal study of the highly prospective yet underexplored basins along the south-eastern Caribbean and Western Atlantic margin off north-east South America. This is an area that holds tremendous hydrocarbon potential with several proven commercial oil and gas fields. The survey area covers Barbados, Grenada, Trinidad and Tobago and St. Vincent, and will provide explorationists with a new view of the regional structure and stratigraphy. Cretaceous La Luna age-equivalent oil-prone source rock is believed to have been identified and it is expected that the La Luna charges prospects in the area. High quality pre-stack time and pre-stack depth data is available, as well as gravity and magnetic data. This survey is in a position to support the upcoming licence bid rounds in Barbados and Trinidad and Tobago.

A Geoex Company

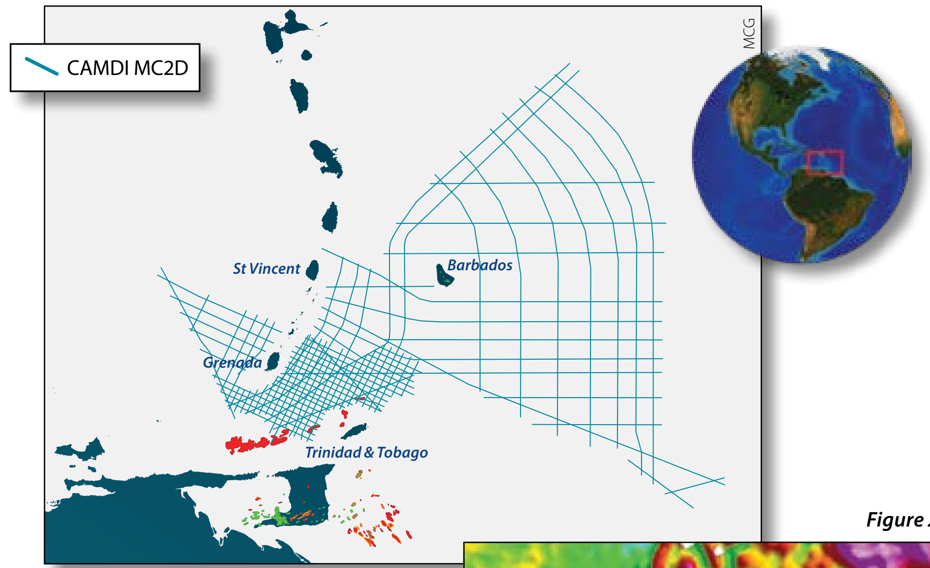


Figure 2: Free air gravity anomaly map.

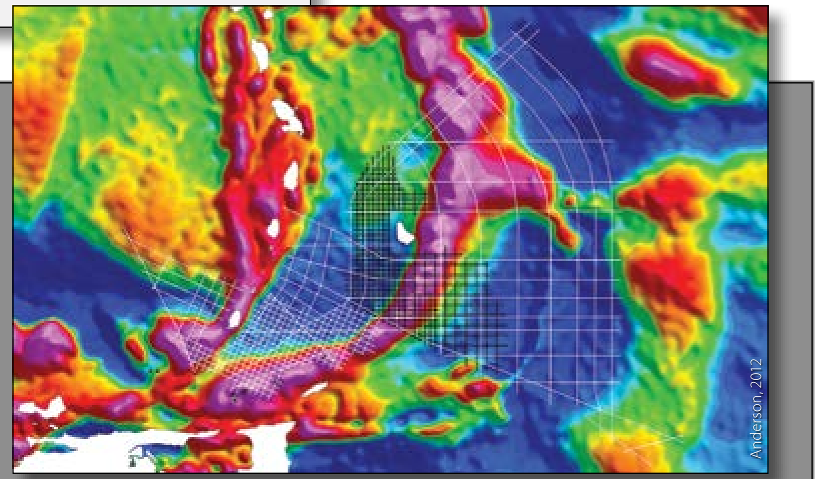
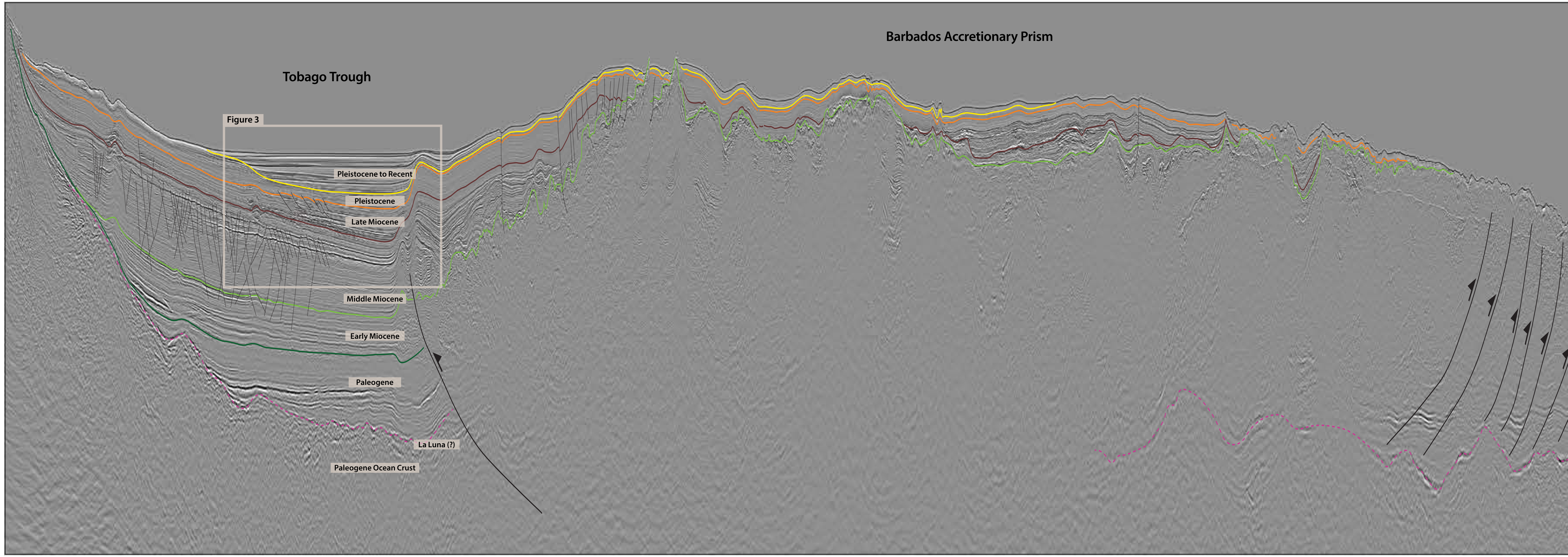


Figure 1: Seismic line extending from the Tobago Trough, though the Accretionary Prism and onto the Atlantic Abyssal Plain.



South-Eastern Caribbean Exploration Opportunities: A New Regional Study

JENIFFER MASY, TOM WOLDEN AND ROBERT SORLEY; MultiClient Geophysical AS (MCG)

During the break-up of the supercontinent Pangaea, Barbados was geographically positioned in the south-east corner of the open North Atlantic Basin just prior to the opening of the South Atlantic. At this time, a large seaway opened that extended to the Gulf of Mexico in the Middle Jurassic (roughly 166 million years ago). During the Cenozoic, the Caribbean plate converged obliquely with the North and South American plates. The point of collision shifted from western and central Venezuela in the Paleogene to eastern Venezuela in the Neogene. The Atlantic lithosphere has been subducting beneath the Lesser Antilles throughout these epochs and into the present day. The collision between these plate boundaries created a range of geodynamic processes such as subduction, transpression and transtension, creating a large accretionary ridge which established the regional geology.

A free air gravity anomaly map shows the major crustal blocks of the south-eastern Caribbean region (Figure 2). The Aves Ridge is expressed as a positive gravity anomaly, while the Grenada and Tobago Basins are expressed as negative anomalies. The crustal variations are probably due to the complex interactions of this triple junction. Rich petroleum systems within this geologically complex region possibly result from this complex plate interaction.

New Multiclient 2D Survey

During 2018 and the first quarter of 2019, MultiClient Geophysical AS (MCG) acquired the Caribbean Atlantic Margin Deep Imaging seismic survey (CAMDI). This survey consists of 16,433 km of multiclient 2D long-offset seismic data. This transnational survey covers acreage across the maritime borders of Barbados, Trinidad and Tobago, Grenada and St. Vincent. It was designed in two grids. The regional grid is meant to assist exploration companies to gain a better understanding of the regional tectonic framework of the different basins along the south-eastern Caribbean and Western Atlantic Margin of north-east South America. The detailed grid, which covers offshore Trinidad and Tobago and Grenada, is designed to provide more detail, enabling explorationists to outline potential prospects, and ties the producing areas in Trinidad and Tobago to the underexplored deeper part of the Tobago Trough.

The survey was acquired using very long offsets (12 km) and deep records (18 seconds) with a view to providing a deep regional understanding of the entire basin(s) architecture. PSTM data became available in early October 2019, and PSDM will be available in December 2019. The processing sequence used a state-of-the-art broadband solution, and detailed velocity grids were input into both the pre-stack time migration and the pre-stack depth migration.

The CAMDI survey can be integrated with the 2013 MCG Barbados MC2D survey and used as an integrated dataset to conduct a regional play fairway analysis, with a view to high-grading prospective exploration areas. The survey provides clear imaging and broad coverage of all play elements in the region, including the oil-prone La Luna source rock or its regional equivalent.

New Plays and Large Prospects

All the components for successful exploration are present offshore south-eastern Caribbean. The seismic

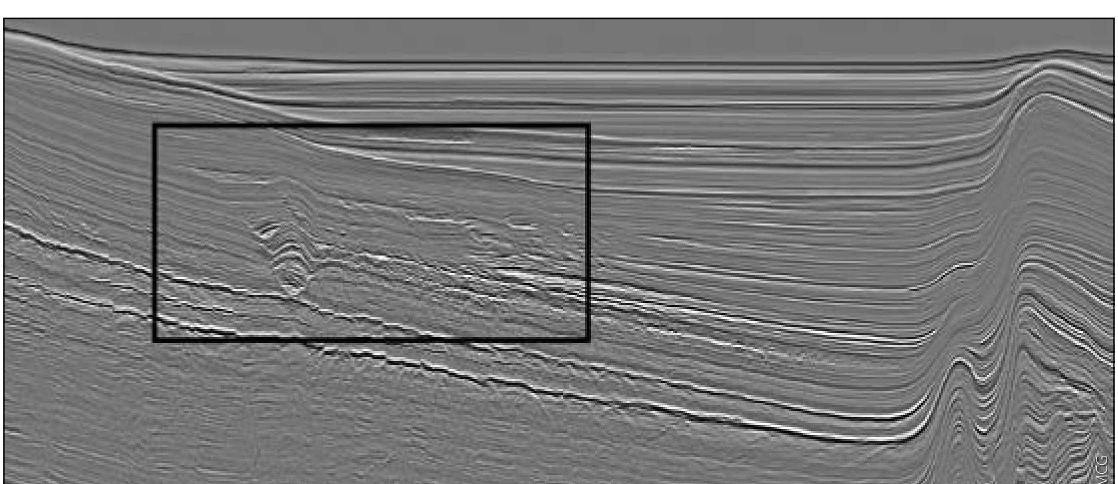


Figure 3: Miocene channels on the Tobago Trough.

line shown in Figure 1 (foldout line) is located south of Barbados, running from the Tobago Trough, through the Accretionary Prism and into the Atlantic Abyssal Plain. Several trapping configurations can be identified, including channels, rollover structures and anticlines.

The Tobago Trough is an underexplored area flanked by oil and gas production to the east and south in Barbados and Trinidad and Tobago, with a new gas discovery offshore Grenada. Based on an integrated seismic interpretation of the 2013 MCG Barbados MC2D survey and the new CAMDI survey, a thick sedimentary sequence can be observed in the Tobago Trough. During the middle late Miocene, the Orinoco and Amazon rivers drainage systems were created, supplying a large volume of sediments, including high quality, quartz-rich sands, into the deep Caribbean basins. An example of the channels identified within the Miocene section in the Tobago Trough is shown in Figure 3. These channels have distinctive amplitude anomalies, with respect to their surroundings, that may indicate the presence of hydrocarbons within the Miocene channels.

Pre-stack depth migration continues, and due to the lack of available well data in the area, a detailed velocity model has been estimated by tomography. The final velocity model is structurally consistent and highly resolved, containing detailed shallow geological features such as mud volcanoes, well-defined faults, and potential gas anomalies (Figure 4).

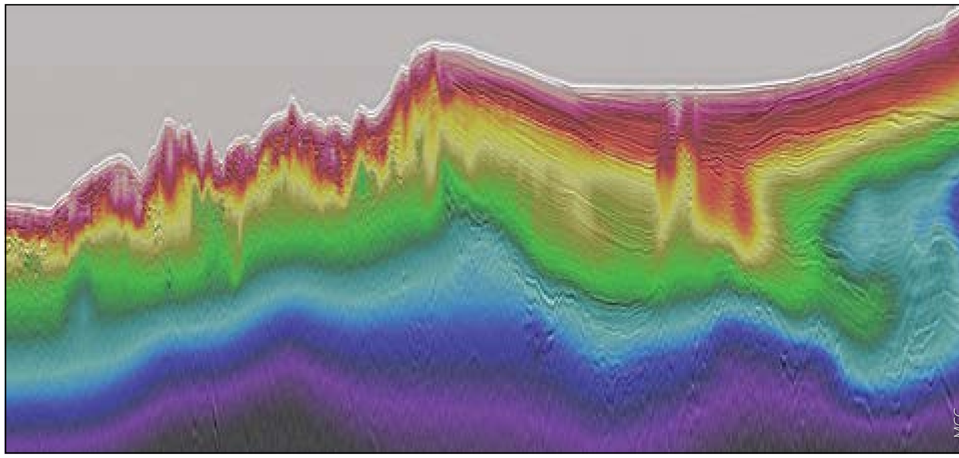


Figure 4: Velocity structure estimated by global tomography from deepwater Trinidad and Tobago to the Tobago Trough.

Source Rock

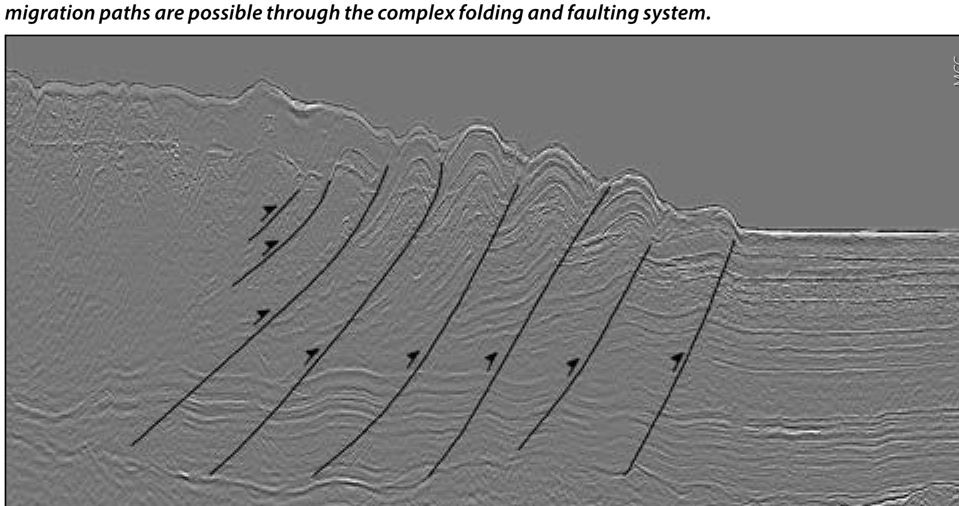
Oil production onshore Barbados commenced in the last century and continues to this day. Barbados production derives from Eocene sandstone reservoirs from the Scotland Group and the sweet, light crude oil is geochemically proven to be from La Luna-equivalent source rocks. Multiple large prospects have already been identified in the regional CAMDI data and ongoing investigations support the theory that the Cretaceous La Luna source rock (or its equivalent) is present, and charging these prospects.

La Luna source rock (or its equivalent) can be interpreted thoughout the entire CAMDI survey (Figures 1 and 5). Basin modelling derived from the 2013 MCG Barbados MC2D survey suggests the presence of the La Luna Formation, or its equivalent within the oil window, along with good quality sandy reservoirs likely originating from the Orinoco Delta. Structural and stratigraphic traps have been mapped and Direct Hydrocarbon Indicators (DHIs) can be observed in connection with many of these traps (Figure 5). The area covered by the new seismic survey is underexplored due to lack of regional deep data. The Tobago Trough has only been tested along the margin in Trinidad and Tobago, and intriguing, deeper oil plays are present in an area soon to be made available for exploration.

An Excellent Opportunity

The south-eastern Caribbean area is an excellent exploration opportunity, with only a few exploration wells drilled in this vast, untested area. Several world-class leads have been identified by the new MCG CAMDI seismic data. Deep water licence rounds are anticipated in Barbados and Trinidad and Tobago during the first quarter of 2020. Clearly, good quality offshore reservoirs are evident in the data, optimising the 'below-ground risk'. In addition, regional governments have developed policies to enhance accessible opportunities, with a view to creating an exploration climate improving the 'above-ground risk'.
References available online. ■

Figure 5: Deeper seismic reflectors suggest the presence of a La Luna-equivalent source rock. Potential migration paths are possible through the complex folding and faulting system.



From Arrhenius to CO_2 Storage

Part V: Underground Storage of CO_2

EVA K. HALLAND, Norwegian Petroleum Directorate
Series Editors:
MARTIN LANDRØ and **LASSE AMUNDSEN**, NTNU/Bivrost Geo

> *"It is important that carbon storage is carefully regulated, that the process is transparent to the public, and that there is a clear accounting of what happened to the CO_2. This is particularly true of underground storage, where there is always a small chance that pressurised CO_2 could escape."*
>
> *Klaus Lackner, Director CNSE (Center for Negative Carbon Emissions)*

By building on knowledge from the petroleum industry and experience over 23 years of storing CO_2 in deep geological formations, we can make a new value chain and a business model for carbon capture and storage in the North Sea Basin.

Storage of carbon dioxide is about keeping the CO_2 secured underground in a geological reservoir. Carbon capture, transport and storage (CCS) is a process whereby carbon dioxide (CO_2) is captured from energy production or industrial plants, transported in pipelines or by ships, and deposited so it will not enter the atmosphere. Deep underground storage is the only current means of disposing of large amounts of CO_2 safely and permanently.

CO_2 Storage on NCS

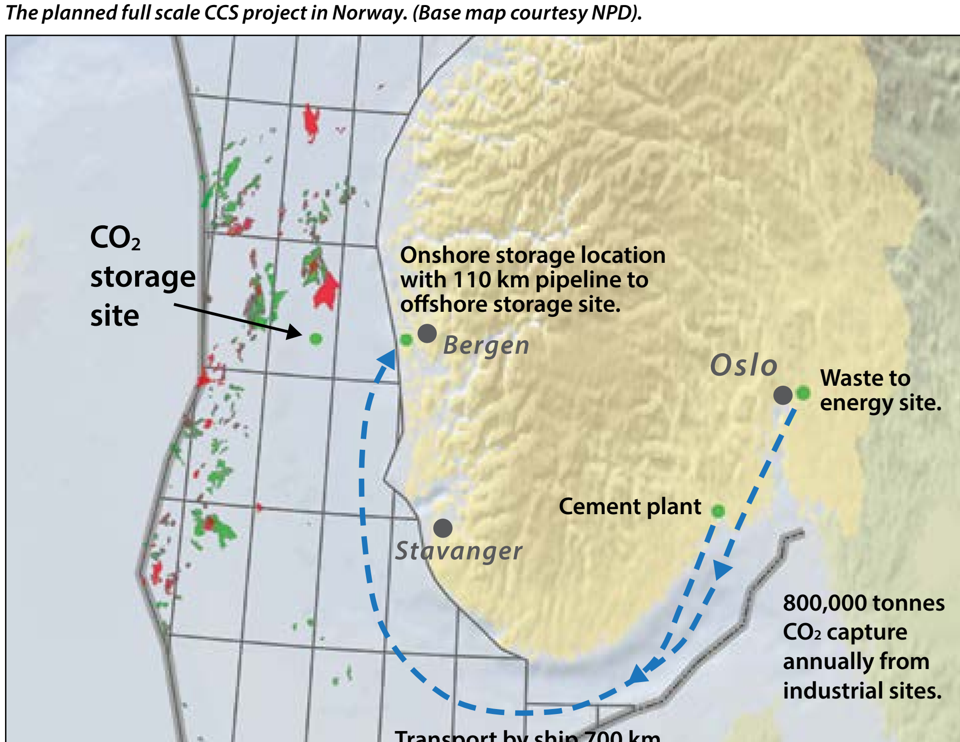
A new CO_2 storage site is now under development on the Horda Platform, in the Johansen geological formation south of the Troll Field. This is part of the Norwegian government's initiative to develop a full-scale demonstration CCS project.

The government issued feasibility studies on CCS solutions in 2016 with the ambition of developing a full-scale CCS value chain in Norway. This project includes the capture of CO_2 from industrial sources in the Oslo Fjord region, ranging from cement and waste to energy, and the shipping of liquid CO_2 to an onshore terminal at Kollsnes on the Norwegian west coast. From there, the liquified CO_2 will be piped and injected into the Johansen Formation south of the Troll Field area for permanent storage.

This is the first industrial CCS project to develop an open access infrastructure with the intent and capacity to store significant volumes of CO_2 from across the European continent. It was initiated when the Ministry of Petroleum and Energy awarded EL001, the first CO_2 exploitation licence on the NCS, to Equinor in January 2019. Together with partners, Shell and Total, the company is responsible for the transport and storage part of this government-initiated CCS project.

Two CO_2 storage sites have already been developed and are in operation on the Norwegian Continental Shelf today. These projects were established to meet the requirement for a maximum CO_2 content allowed in exported gas, and as a result of the CO_2 tax imposed on petroleum activity in 1991. The first project was designed to capture CO_2 from the produced gas at

The planned full scale CCS project in Norway. (Base map courtesy NPD).



Gas is piped from the Barents Sea Snøhvit field to the Melkøya LNG processing plant, where the CO_2 is separated out and sent back to be injected into the depleted reservoirs.

the Sleipner Vest gas field in the North Sea through the Sleipner T capture facility and inject it into the Utsira Formation; this was the world's first offshore CCS project. Today, three hydrocarbon fields capture CO_2 through the Sleipner T facility and inject through the same well. These fields are Sleipner Vest, which started CO_2 injection in 1996, the Gudrun Field, from 2014 and the Utgard Field, which started in 2019.

The second storage site was developed in the Snøhvit area in the Barents Sea, where CO_2 is captured from the separated gas at the onshore LNG processing plant at Melkøya in northern Norway, and then piped back offshore for injection through a subsea well.

regulator, to avoid any unacceptable risks to the environment.

Depending on their properties, several types of geological formations can be used to store CO_2. On the NCS different aquifers and structures can be distinguished according to their geometry and storage efficiency; for example, they could include structured or dipping aquifers, drilled and water-bearing structures, or abandoned gas or oil fields.

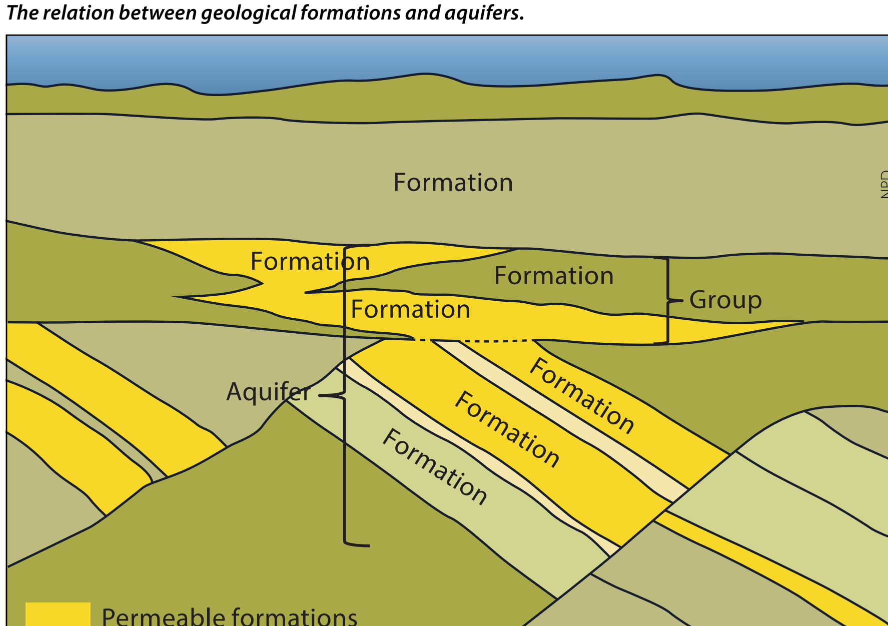
Ultimately, CO_2 is held in place in a storage reservoir through one or a combination of five basic trapping mechanisms: stratigraphic, structural, residual, solubility, and mineral trapping.

A Suitable Storage Site

To be suitable for CO_2 storage, reservoir formations need to have sufficient porosity and permeability to allow the defined volumes of CO_2 to be injected and stored, preferably in a supercritical state. No less important is the requirement of a caprock of good quality and integrity, in order to prevent leakage from the reservoir. The design and development of a good monitoring system is also of paramount importance.

The CO_2 storage site selection process needs to demonstrate that the site has enough capacity to store the expected volumes and sufficient injectivity for the anticipated rate of CO_2 to be captured and supplied. The integrity of the site must also be assessed for the period required by the

The relation between geological formations and aquifers.

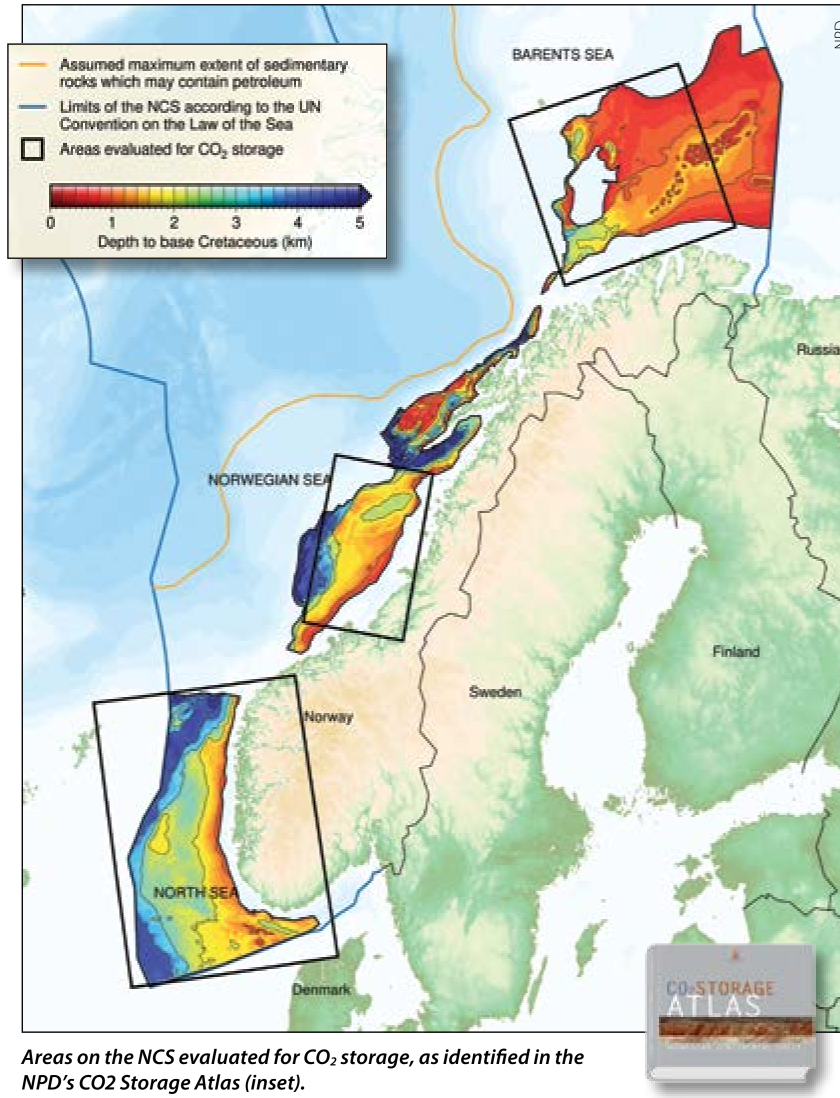


Characterising Potential Sites

CCS has strong ties to the oil and gas industry. What we know about the offshore geology and its potential to store CO_2 builds on decades of research and experience from oil and gas activity. The Norwegian Petroleum Directorate (NPD)'s database, overviews and analysis make up a large and important information source based on more than 50 years of oil and gas activities and 23 years of CO_2 injection on the NCS. The Directorate has access to all data collected on the NCS related to petroleum activity and has a national management responsibility for these data, vested in the Norwegian Petroleum Law. The data available for the CO_2 storage studies covers 2D and 3D seismic, data from exploration and production wells such as logs, cuttings and cores, as well as tests, production data and reservoir simulation models. These data, together with many years of dedicated work to establish geological play models for the NCS, are a good basis for characterisation and capacity estimation to help in the evaluation of suggested CO_2 storage sites.

The characterisation of potential sites is an important step in ensuring the safety and integrity of a CO_2 storage project. The methods used for characterisation of reservoir properties are similar to the well-established methods used in petroleum exploration. Characterisation of cap rocks and injectivity, for example, is typically conducted in field development studies and to some extent in basin modelling. Aquifers and structures can similarly be characterised in terms of capacity, injectivity, and safe storage of CO_2. To complete the characterisation, the aquifers are also evaluated according to the data coverage and their technical maturity. Some guidelines have been developed to facilitate the characterisation.

Those aquifers that may have a relevant storage potential in terms of depth, capacity and injectivity have been considered. The most attractive aquifers and structures were investigated by geomodelling and reservoir simulation. For estimation of storage capacity in all models, it is assumed that there will be no water production from the reservoir.



Areas on the NCS evaluated for CO_2 storage, as identified in the NPD's CO2 Storage Atlas (inset).

The Norwegian CO_2 Storage Atlas

The NPD published a *CO_2 Storage Atlas* for the Norwegian Continental Shelf in 2014, the main objective of which was to identify safe and effective areas for long-term storage of the gas.

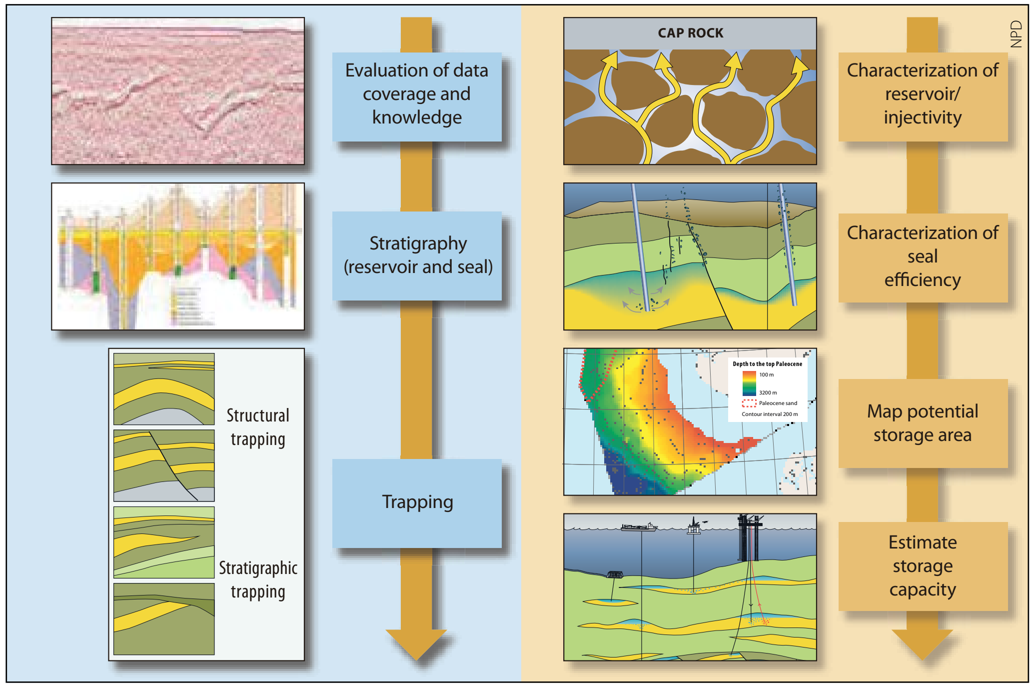
Pairs of potential aquifers and seals were identified, evaluated and characterised for their CO_2 storage prospectivity. Each parameter was rated with a score described in detailed checklists and summarised on the characterisation score chart for reservoir and seal.

Evaluation of faults and fractures through the seal, the thickness of the seal, number of seals, composition, faults zones and geometry needs a thorough evaluation, in addition to ensuring the integrity of existing wells penetrating the seal. For the evaluation of regional aquifers in CO_2 storage studies, the mineralogical composition and the petrophysical properties of the cap rocks are rarely well known, so they will then be based on knowledge of the regional geology.

The volumes of CO_2 that can be injected are constrained by the fracturing pressure, which is based on a large database of leak-off tests and observed pore pressures in exploration wells. Pressure differences across faults and between reservoir formations and reservoir segments are commonly observed in NCS exploration wells. Such pressure differences give indications of the sealing properties of cap rocks and faults.

Storage capacity depends on several factors, primarily the reservoir pore volume and the fracturing pressure. The relation between pressure and injected volume depends on the compressibility of the rock and the fluids in the reservoir. The solubility of CO_2 in the different phases will also play a part. It is important to know if there is communication between multiple reservoirs, or if the reservoirs are in communication with larger aquifers because the pressure will increase when injecting fluid into a closed or half-open aquifer. Pressure increase can, however, be mitigated by production of formation water.

Based on this evaluation and characterisation, selected potential storage sites were mapped and the storage capacity was calculated for structures and aquifers. The evaluation presented in the CO_2 Storage Atlas does not provide an economic assessment. The storage capacities are presented in a pyramid diagram, where the highest level in the pyramid represents the capacity of sites that are already used for CO_2 storage, while the lowest level represents theoretical capacity in lesser-known aquifers.



Evaluation process for safe CO_2 storage sites.

Monitoring

An important matter when injecting CO_2 is to ensure that the gas is contained in the reservoir according to plans and predictions and that there is no leakage to other geological formations or into the sea. When the aquifer is defined and characterised, the migration pathways and the plume development of the injected CO_2 can be modelled in the selected storage area.

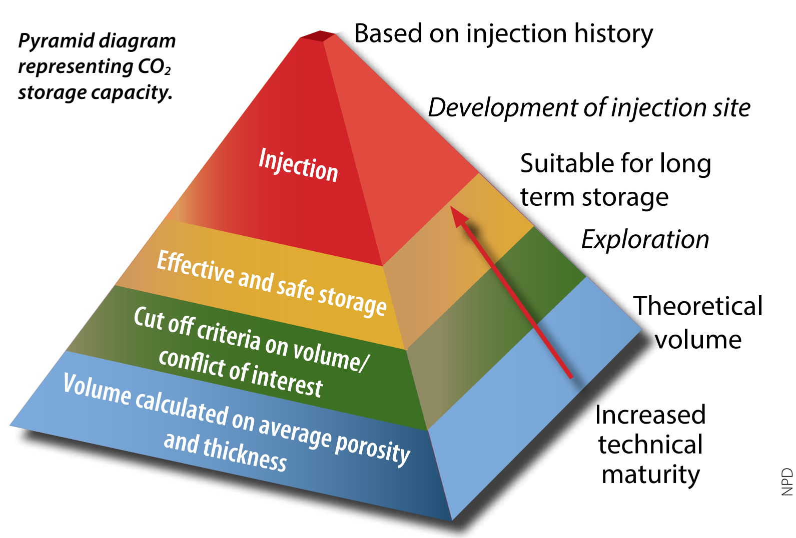
Natural seepage of gas is observed in the hydrocarbon provinces in the NCS. Such seepage is expected from structures and hydrocarbon source rocks where the pore pressure is close to or exceeds the fracture gradient. Seepage at the sea floor can be recognised by changes in biological activity and by free gas bubbles or, on seismic, by gas chimneys or pipe structures. The seepage rates at the surface show that the volumes of escaped gas through a shale or clay-dominated overburden are small in a time scale of a few thousand years. Rapid leakage can only take place if open conduits are established to the sea floor. Such conduits could be created along wellbores or by reactivation of faults or fractures. Established natural seepage systems are also regarded as a risk factor for CO_2 injection.

A wide range of monitoring technologies have been used by the oil and gas industry to track fluid movement in the subsurface and these techniques can be adapted to CO_2 storage. For example, repeated seismic surveying provides images of the subsurface, allowing the behaviour of the stored CO_2 to be mapped and predicted. Other techniques include pressure and temperature monitoring and down-hole sensors, as well as seabed monitoring. An extensive programme to monitor and model the distribution of injected CO_2 in the Utsira Formation has been undertaken by a number of organisations (partly funded by the European Union). The Utsira monitoring programme includes a baseline 3D seismic survey and several time-lapse (4D) seismic surveys and they provide a good picture of how CO_2 moves horizontally and vertically.

Regulation

NPD's evaluation of the geological formations, aquifers and structures for potential CO_2 storage will form the basis for any terms and conditions set for the development of a storage site offshore Norway. A new regulation for CO_2 transport and storage was published in 2014, regulating the exploitation and operation of a CO_2 storage complex, which adopted the EU CCS Directive and the regulatory system from the Norwegian offshore petroleum regulation. ■

Pyramid diagram representing CO_2 storage capacity.



What is Chemostratigraphy?

Chemostratigraphy has evolved and grown from a niche, often misunderstood, speciality into a comprehensive, inclusive, game-changing technology that delivers real insight.

PAUL CAREY and TIM PEARCE, Chemostrat Ltd

The rapid expansion of global oil and gas exploration from the early 1960s was accompanied by the expansion of the areas being examined by explorationists towards more challenging, often frontier, plays with the concomitant risks associated.

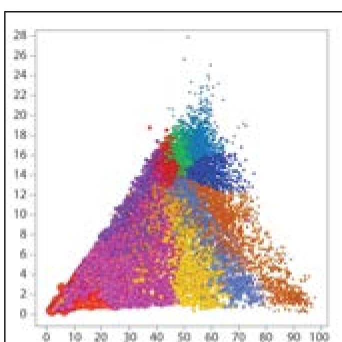
In the North Sea, for example, early success resulted from standard approaches in the Rotliegendes and Chalk plays that were comparable to onshore successions. However, the discoveries of the Montrose, Forties and Ninian fields resulted from the efforts of the highly skilled and pioneering exploration geologists utilising what were then new approaches to stratigraphic modelling and exploration.

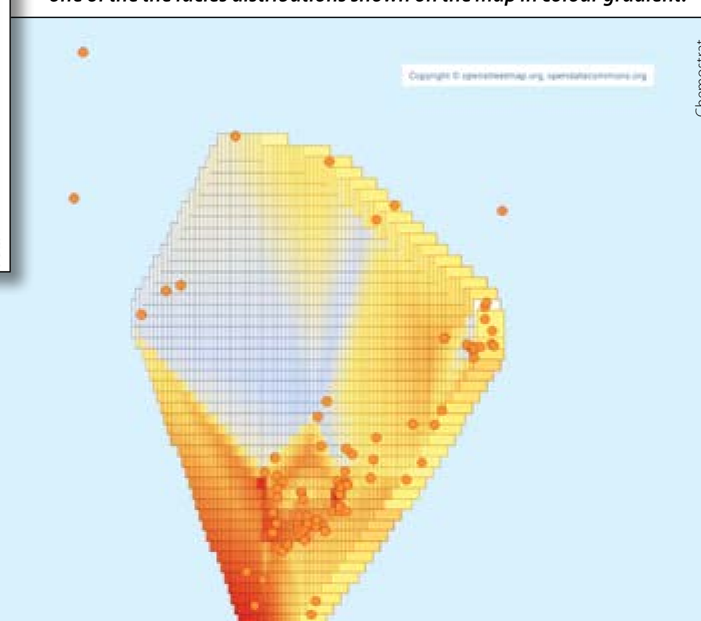
The main stratigraphic techniques employed during the 1960s were lithostratigraphy, wireline logging and biostratigraphy, which, when combined with 2D seismic data, provided the foundation for the stratigraphic frameworks on which most stratigraphic correlations were based. In some circumstances however, these tools alone were unable to produce reliable field- and reservoir-scale correlations, particularly with respect to the predominant sandstone architectures found in the Triassic, Devonian, Upper Carboniferous and Rotliegendes successions in the North Sea. Operators began to look to alternative stratigraphic and correlations tools that could be successfully applied to these successions. Extensive pilot studies were undertaken using various techniques, including magnetic stratigraphy, heavy mineral stratigraphy, clay mineral stratigraphy and whole rock geochemistry incorporating elemental chemostratigraphy.

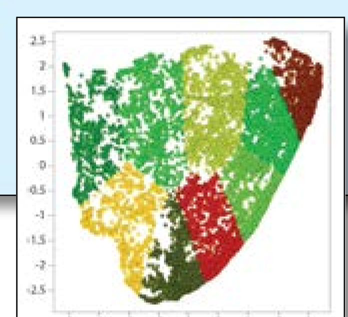
First Large-Scale Applications of Chemostratigraphy

The potential for characterising sedimentary rock successions using geochemistry has long been known and the significance of the stratigraphic variations in rock geochemistry was already a mainstay in hydrocarbon exploration, using the gamma ray tool and interpreting the resultant logs. Even so, a much more refined approach was required in order to differentiate and correlate lithologically-repetitive strata. At the time, Wavelength Dispersive X-ray Fluorescence (XRF) utilising fused discs and pressed pellets was the chief method for acquiring quantitative data for elements. Large sets of accurate data were obtained, but the process proved to be slow and expensive and depended on relatively large volumes (~4 gm) of sample material being available for analysis. Alternative analytical approaches such as atomic absorption and neutron activation proved likewise sub-optimal for

The accurate collection of high-resolution chemical data allows definition of chemical facies and the construction of facies maps for integration or comparison with existing solutions. Different chemical facies in a complete sandstone dataset are shown by different colours below, and one of the the facies distributions shown on the map in colour gradient.



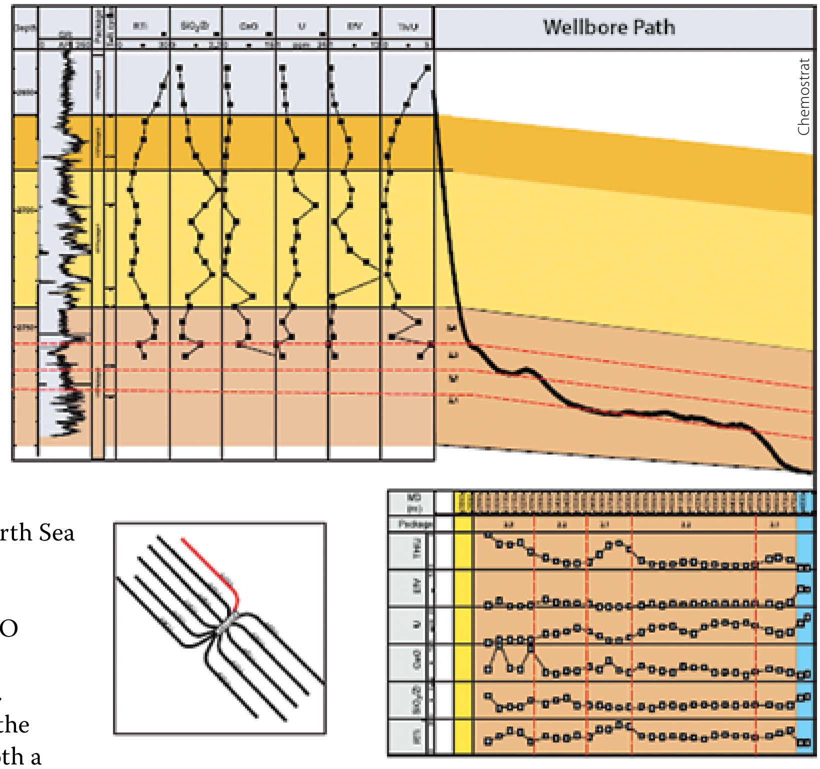




the large-scale, multi-element analytical programmes required by the petroleum industry.

The advent of inductively-coupled plasma (ICP) technology, used with optical emission spectrometry and mass spectrometry, transformed elemental analysis. These techniques enabled accurate and precise simultaneous measurements of over 50 elements from tiny sample sizes. One of the earliest full-scale deployments of this technology for chemostratigraphic purposes was in 1991 by Tim Pearce (Chemostrat's CEO International), who applied the technique to Quaternary sediments in the Atlantic, drawing on innovative research conducted by Dr Ian Jarvis and colleagues in the late 1980s. This led to the first large-scale application of chemostratigraphy to the offshore North Sea Triassic sequences in 1992 for Phillips Petroleum.

The success of this application resulted in the technique being adopted by Conoco, Shell and ARCO to help correlate the Upper Carboniferous Barren Red Measures in the North Sea Southern Gas Basin. Detailed interpretation of the elemental data led to the stratigraphy of these formations being refined on both a reservoir- and field-scale and it soon became clear that chemostratigraphy was a valuable and proven addition to the stratigraphic workflow in the context of barren successions or those with poor biostratigraphic control.



Chemostratigraphic interpretation of the build and lateral section of selected wells. Lower left inset shows the wellbore pathways in plan view, with the well in this figure highlighted in red.

Chemostratigraphic data and interpretations complemented existing biostratigraphic schemes and in doing so, effectively initiated the first multidisciplinary approaches to stratigraphy, and during the 1990s chemostratigraphy became adopted by enthusiastic advocates within several oil companies.

Despite the success of chemostratigraphy during the 1990s, the technique remained a little known, and even less understood, niche application, the subject of active and vociferous debate between its supporters and detractors. Stratigraphy remained synonymous with biostratigraphy, while geochemistry remained synonymous with organic geochemistry for many years.

Choose Carefully

The recent significant rise in the deployment of chemostratigraphy in global exploration largely reflects more rigorous approaches to the generation of geochemical data. Much previous work was hampered by poor understanding of sample quality management, instrument calibration and the critical importance of selecting the correct analytical instruments for the particular situation. Geochemical data can be obtained from sedimentary rocks in several ways and each analytical method can produce accurate and significant data, but the ultimate suitability of any analytical technique is governed by the technical and commercial objectives of the study in question. Focus on particular analytical techniques often results in solutions being deployed that are inappropriate because of a lack of sensitivity of the analytical instruments, or the use of instruments that are not calibrated or monitored correctly for the range of geochemical compositions encountered over the successions being analysed. Understanding the geological setting and basin development, plus the depositional and sedimentological architecture development on a regional basis, is of huge importance in selecting the appropriate analytical tool on which to carry out a chemostratigraphic workflow.

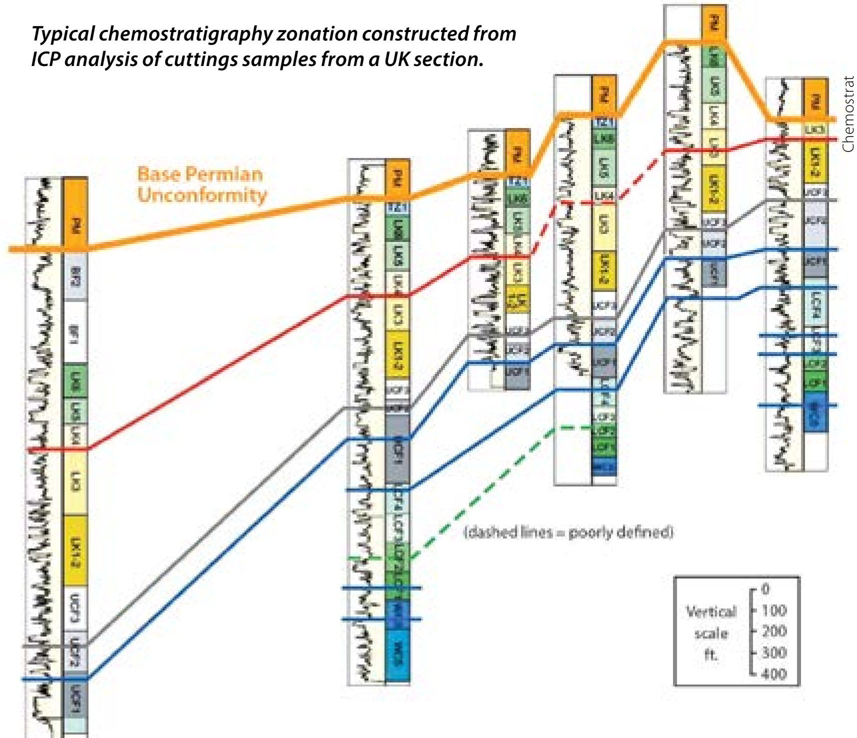
Not all geochemical data currently reported benefit from the care needed in selecting carefully the appropriate technical workflow to analyse cuttings samples in particular, or provide confidence in the reliability and quality of the data. Programmes run by the International Association of Geoanalysts review data to ensure that claims of accuracy and suitability of specific systems are benchmarked, helping explorationists to understand when particular techniques are suitable, and analysts to avoid having to defend specific techniques against less expensive, and sometimes much less suitable, data.

The need for high quality data to be acquired quickly and cheaply has created a drive to develop additional portable and scanning tools. Each technique has its own role to play, but the choice as to which one to use needs to be made with advice; cases abound of organisations buying equipment and attempting to use it in-house, before finding they lacked the requisite experience in analysis and chemostratigraphy, and possibly dismissing the technology.

By carefully selecting the appropriate tools, considering the questions requiring an answer, and bearing in mind budget constraints, it is possible to apply the range of analytical workflows best suited to the problem at hand. In this way chemostratigraphy been rejuvenated within the industry and is applied now throughout conventional and unconventional exploration.

An important point to understand is that chemostratigraphy is not the analytical technique or the instrument used; it is the skilled and experienced interpretation of the data generated and the knowledge of what can and cannot be done with each potential analytical tool. It is the role of chemostratigraphers to showcase to the petroleum industry the immense value of these techniques, which can be very powerful indeed, when carried out with care and skill and combined with geological knowledge. Perhaps the most important challenges faced are created by the fallacious correlation of chemostratigraphy with XRF or ICP or any of the other techniques. An analytical tool generates chemical data, not chemostratigraphy.

Typical chemostratigraphy zonation constructed from ICP analysis of cuttings samples from a UK section.



Variety of Uses

Chemostratigraphy is especially useful when used in conjunction with other stratigraphic techniques. In most cases, chemostratigraphy is not tied to chronostratigraphy and therefore should be considered as a rock characterisation tool that can be linked to sequence stratigraphy, palaeoclimate and provenance when employed on a regional scale, with the chemostratigraphic interpretations being constrained by either biostratigraphic or isotopic chronostratigraphic frameworks.

Throughout the 2000s, laboratory-based chemostratigraphic services were routinely applied to carbonate plays, particularly across the Middle East, focusing on providing a geochemical characterisation of the carbonate successions that had sub-biostratigraphic resolution. The technique was also employed to correlate 'tight' sandstones in North Africa and the Middle East, where interpretation of geochemical data provided insights into facies differentiation, stratigraphic and lateral variations in grain size and mineralogy and possible controls on reservoir quality. The application of chemostratigraphy continues to provide critical information to explorationists as the understanding of its relationship with other techniques is better demonstrated and understood. In conventional exploration, chemostratigraphy is now applied from early wellsite through to production and EOR phases of the oil cycle, with the initial datasets providing key information to geologists, engineers, geophysicists and other disciplines.

The concept of wellsite chemostratigraphy (not to be confused with wellsite XRF) was developed at Chemostrat back in the late 1990s and is now widely applied as a backup option to other wellsite techniques and as a drilling control tool in its own right. This obviously provided the experience and knowledge to apply the technique to the growing shale revolution in the USA in particular. Of course, the shale revolution has provided an entirely new set of defining requirements for geochemical techniques, and chemostratigraphy has proved as robustly valuable in this sphere as it has elsewhere.

When shale exploration first started, chemostratigraphy was routinely used as a correlation tool within a multi-disciplinary approach to stratigraphy. However, once such drilling entered the production stage, the requirement for quantitative data relating to 50 elements diminished. It became clear that rock mechanics needed to be determined more accurately along the length of the lateral boreholes. Traditionally, the analysis of cuttings would involve a lengthy laboratory-based analytical programme, but Chemostrat and others developed bespoke, near real-time analytical procedures that provide an elemental, mineralogical and total organic content data package entirely fit for purpose in this different and challenging sphere of exploration. The data acquired relates to the major elements and some trace elements; these data have moderate analytical resolution compared to data obtained via laboratory-based ICP analyses, but their accuracy is constantly monitored throughout a drilling campaign to ensure they are of sufficient quality to map reservoir brittleness across a field and to constrain a targeted completion programme.

Opportunities Abound

The last oil price decline forced companies to seek increasingly high value for money throughout their workflows, with chemostratigraphy similarly needing to demonstrate a more flexible approach. Prior to the crash, typical pilot deployments of the technique would include five or six wells for international clients, and a significant application could run over many wells and take up to three years. These sorts of approaches have faded, and in some ways explorationists have dismissed the geological workflow in all but select cases. However, the revolutionary approach developed for shale successions will transform the workflows for frontier tight rock and traditional conventional fields alike and will provide additional boosts to ongoing enhanced oil recovery technology. These changes should be recognised as opportunities to deploy more innovative and robust, faster, cheaper technologies and solutions to provide the new drivers of the industry with critical data. ■

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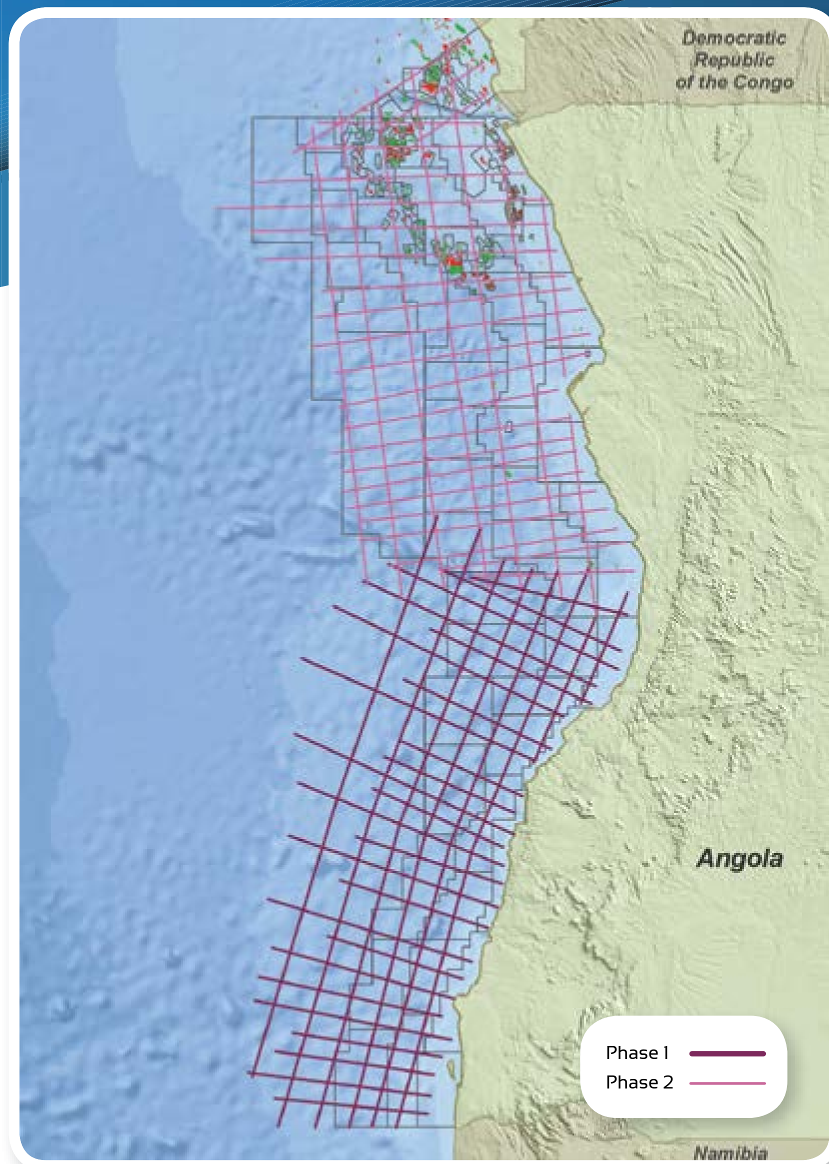
Angola 2D 2019-2020

First Announcement – New 2D Seismic Survey

ANPG



GeoPartners, in partnership with Agência Nacional de Petróleo, Gás e Biocombustíveis (ANPG) of Angola, is pleased to announce a new 2D seismic survey offshore Angola to support the 2019 Offshore Petroleum Licensing Round in the Namibe and Benguela Basin areas.

The new survey, to be acquired in 2 phases, will comprise over 21,000 km of new ultra-long offset broadband data and cover the full extent of the offshore area of Angola. The first phase, covering the Namibe and Benguela basins, is planned to start in Q4 2019 and will comprise an initial 10,000 km, from near shore to ultra-deep.

Jim Gulland, Director, GeoPartners, said: "We are proud to have been awarded this contract by the ANPG to support their ongoing exploration efforts and specifically the forthcoming Licence Round for blocks in the Namibe and Benguela Basins". The Phase 1 survey grid is planned to provide new 2D data in an area of previously limited exploration but which is attracting great interest from international oil companies.

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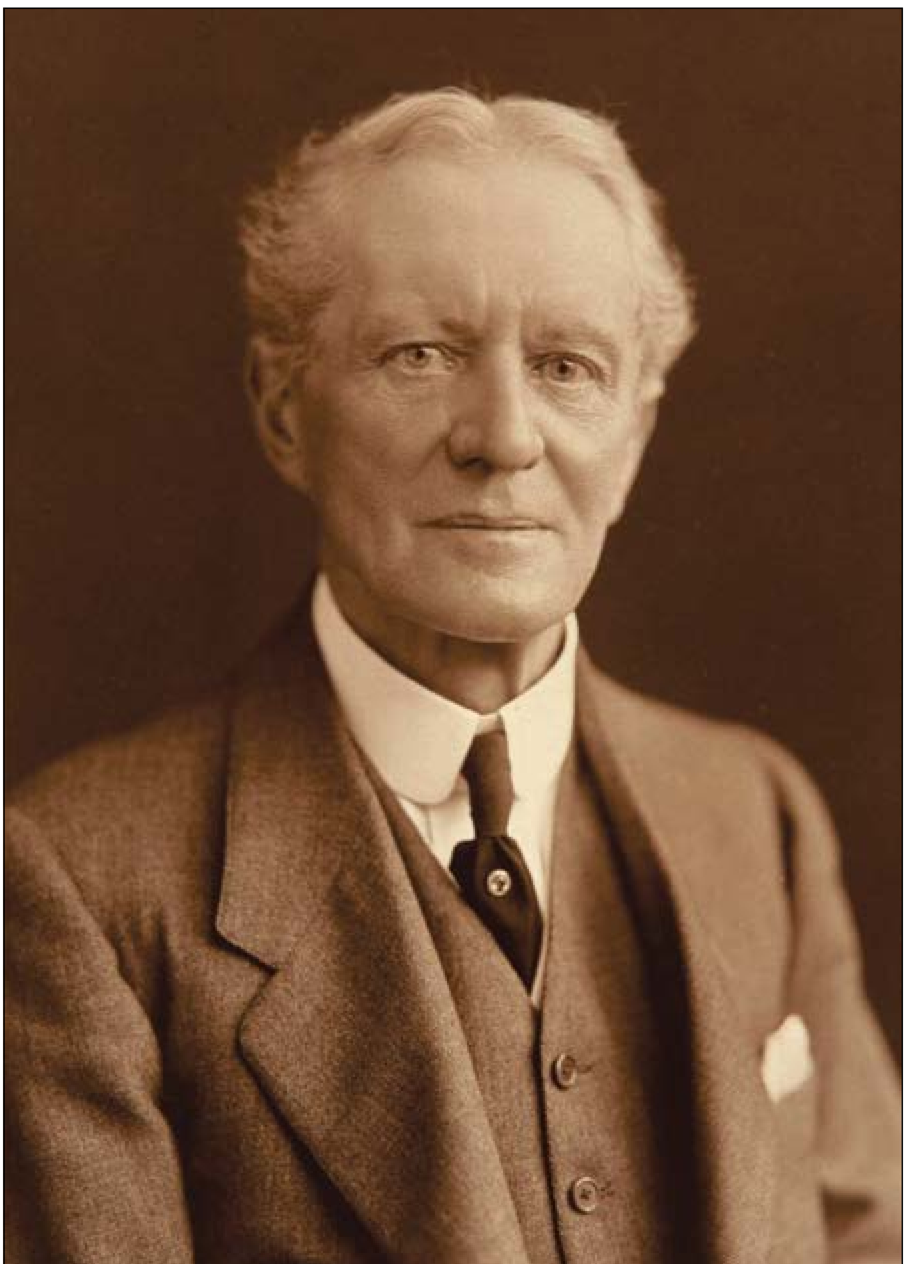
A Pioneer in Petroleum Engineering

Sir Thomas Boverton Redwood, arguably the father of petroleum engineering in Britain and a giant in the history of the petroleum industry, died 100 years ago in 1919. We take a brief look at his life and his contributions to oil and gas.

RASOUL SORKHABI, Ph.D

T.A.B. Corley, author of A History of the Burmah Oil Company, remarks that Redwood was "a walking encyclopedia of oil knowledge, some of which he put into his authoritative works on petroleum, while some he kept in his head."



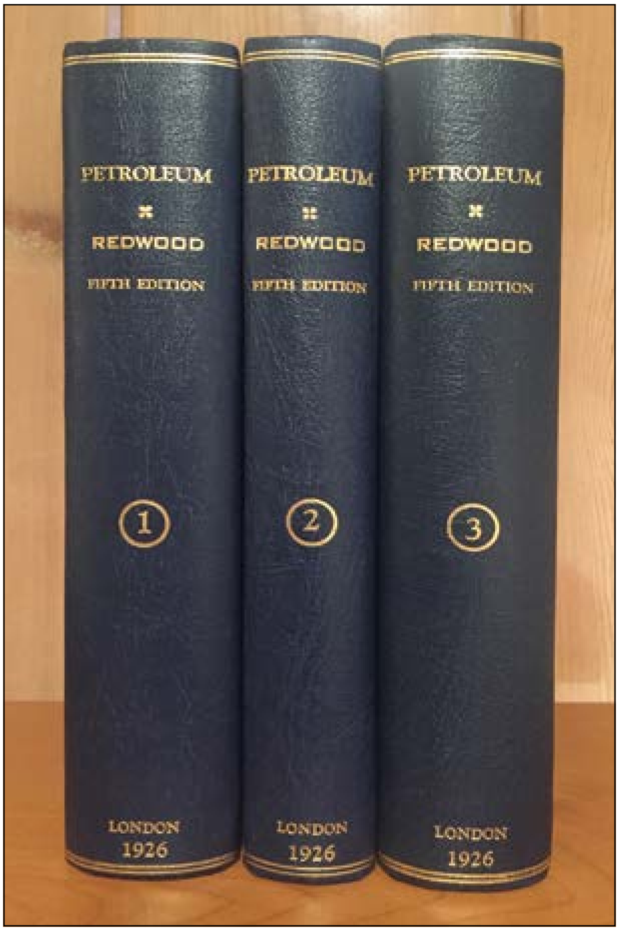
Thomas Boverton Redwood was born on 26 April 1846, in London. His father Theophilus Redwood (1806–1892), who was born in Boverton in Wales, was a professor in the School of Pharmacy of the Pharmaceutical Society of Great Britain and editor of the *Pharmaceutical Journal*. His mother Charlotte Elizabeth was the daughter of Thomas Newborn Robert Merson, who owned a pharmaceutical company in London. Thomas Boverton was the eldest in the family of six boys and two girls. He studied at the University College School, Hampstead from 1857–1862, and then worked in his father's pharmaceutical laboratory. In 1866 he joined the Petroleum Association; three years later, he was appointed its secretary. This was a turning point in his life and he rose to become an eminent analytical chemist in the emerging oil industry. Redwood married Mary Elizabeth in 1873 and the couple had two daughters and a son.

Many Achievements

In 1877, Redwood joined Sir Frederick Augustus Abel (1827–1902) in conducting laboratory experiments to standardise methods of testing the flash points of various oil types. In the same year he went to the USA to undertake further research on the subject, which led to an improved Abel instrument. In 1881, Redwood investigated the effect of barometric pressure and climate on dissolved gases in oil, travelling to conduct these tests in the cold high Alps and in warm humid India.

In 1883, Redwood accompanied Colonel Vivian Majendie (1836–1898), Chief Inspector of Explosives to Queen Victoria, on a tour of Europe to study different methods of oil storage, and followed that a few years later with a trip to the USA for the same purpose. In 1885, Abel and Redwood submitted recommendations for the manufacturing of safe oil lamps to the Metropolitan Board of Works and in 1885–86 Redwood invented a new viscometer to measure the fluidity of various oils, which soon became the standard instrument in the British oil industry.

In 1889, Redwood and Sir James Dewar (inventor of, among other things, the vacuum flask) patented a process for distilling and condensing oil under high pressures. This enabled the production



Redwood's Petroleum: A Treatise, published in 1896, was the first major systematic book on various aspects of the petroleum industry, and trained several generations of petroleum experts in the early 20th century. The book is still a valuable source of historical information on oil. Sir Frederick Black, president of the Institution of Petroleum Technologists, in a foreword to the fifth (1923) edition of the book wrote: "This Treatise on Petroleum by Sir Boverton Redwood will always remain a monument to his very extensive expert knowledge of this wide-reaching subject. It is the recognised standard all the world over, and has become a classic in the libraries of all technical men in the petroleum history."

of lighter oil from the heavier grades, and laid the foundation of the modern cracking process.

Redwood visited Egypt in the early 1890s to investigate the possibility of transporting oil through the Suez Canal and, following this, in 1894 he designed an apparatus for testing the pressure of oil vapour in tanks, which was an important issue for the transport of oil by ship. This won him the Telford Medal from the Institution of Civil Engineers. In the same year, Redwood, together with his brother Robert and Mr. H. Barringer, invented the Redwood water finder, which determines the amount of water collected beneath the oil in tanks.

Redwood set up a petroleum consulting and service company in London – probably the first of its kind – and employed geologists and engineers who provided expertise to various petroleum companies both in the UK and overseas. In the 1900s, when oil companies cared little for geologists, Redwood's initiative was ahead of its time.

His work took him to various parts of the world, including continental Europe, Russia, India, Egypt, and the USA. He served as a technical advisor for a number of companies, most notably Burmah Oil, D'Arcy's Concession in Persia, which developed into the Anglo-Persian Oil Company in 1908, as well as Weetman Pearson's oil exploration in Mexico. He also served as an advisor to the Home Office, the Admiralty, the India Office, and the Colonial Office.

A Masterpiece

Redwood wrote more than 70 articles and reports related to different aspects of oil chemistry and engineering. He also published six books on petroleum. His first book, *Cantor Lectures on Petroleum and Its Products* (1886), was based on his lectures for the Society of Arts; the book was published (without the author's consent) in New York in the same year.

Redwood's masterpiece *Petroleum: A Treatise*, first published in 1896, was a detailed description of the history, geology, chemical and physical properties, exploration, transportation, and uses of oil. Dedicated to the author's father ("in whose laboratory I received my early instruction in practical chemistry"), the two-volume book ran to 900 pages. Its fifth edition in 1923 consisted of three volumes and 1,353 pages and cited 8,804 references (the bibliography for the second edition in 1906 was originally compiled by W. H. Dalton, a geologist working for Redwood (see *Early textbooks of Petroleum Geology*, *GEO ExPro*, Vol. 8, No. 6). Redwood's last book (with Arthur Eastlake), *Petroleum: Technologist's Pocket-Book*, published in 1915, was also a comprehensive work with a second edition that came out in 1923.

World War I

Redwood had close relationships with academic, industrial and political circles in Britain. From this mediatory position, in the 1880s to 1900s he was able to play a leading role in the development of petroleum technology as well as Britain's oil operations around the world. In 1912 he told an Admiralty committee that "every reasonable encouragement that is possible should be given to the development of supply of fuel oil under the British flag." Geoffrey Jones in *The State and the Emergence of the British Oil Industry* (1981) writes that Redwood believed that Britain's oil supply "should be developed by independent oil companies and not by the foreign combines. He developed a strong dislike for both Shell and Standard Oil, an attitude probably related to his long association with smaller British companies threatened by these giants."

When William Knox D'Arcy (1849–1917) obtained an oil concession in 1901 from the Persian government (now Iran), Redwood served as his technical consultant and suggested that he hired George Bernard Reynolds to lead the exploration and drilling in south-west Iran. After three years of unsuccessful drilling, D'Arcy wanted to sell his concession, even to non-British companies. But Redwood stepped in and orchestrated a deal between D'Arcy and Burmah Oil (a Scottish company operating in Burma, modern Myanmar), enabling the formation of a joint company, the Concessions Syndicates, and the continuation of oil exploration in Iran. The plan was supported by Sir John Fisher, who in 1904 became the First Lord of Admiralty and planned to convert all Royal Navy ships from coal to oil; the Admiralty was thus in need of a secure and cheap supply of oil. In 1908 an oil gusher put Iran on the world map and the Concessions Syndicate became the Anglo-Persian Oil Company, 51% owned by the British government (see *GEO ExPro*, Vol. 5, No. 5). Redwood was appointed a technical advisor to the Admiralty from 1904 to 1913.

In 1914, when World War I broke out, all that planning worked to the British advantage. Lord Curzon (1859–1925) once remarked that Great Britain and the Allies won the war because they "floated to victory on a sea of oil." During the war, Redwood's expertise was much in demand; he worked hard serving various committees for British government and parliament. Indeed, exhaustion from the work he undertook during 1914–1918 is believed to be largely responsible for his illness and death in 1919.

Late Years and Legacy

For his contributions to the British petroleum industry and interests, Redwood was knighted in 1905.

Redwood was affiliated with a number of professional societies in the UK, USA and Russia. He was a founding member of the Institute of Petroleum Technologists and served as its first president from 1914–1915. (Renamed the Institute of Petroleum it still continues to operate in London and published the *Journal of the Institute of Petroleum Technologists* until 1973.) Redwood and his son Bernard loved automobiles and steam-yachts and Redwood was a founding member of the London-based Royal Automobile Club (RAC) in 1898.

Sir Thomas Boverton Redwood died on 4 June 1919 at his residence in London. Obituaries described him as a pleasant, polite, friendly, knowledgeable and reputed man who would take time to help young men starting their career in the petroleum industry. His wealth at death was about £165,013 (about $448,000 at today's value). Redwood apparently looked like the British actor Sir Henry Irving (1835–1905), and people sometimes mistook him for the actor, which gratified him.

The Redwood building, home to the school of pharmacy at Cardiff University in Wales, is named after the Redwood family, including Theophilus and his son Boverton, as well as Lewis Redwood, Theophilus' younger brother, and his son Thomas Redwood, who were renowned medical doctors. Boverton Redwood's younger brother Iltyd Isaac Redwood (1863–1910) was also an eminent chemist who wrote several books on petroleum chemistry.

Only a few days before his death, Redwood was examining the results and samples of the first successful oil well in England – the Hardstoft No. 1 in Derbyshire, which was struck on 17 May 1919 – also a hundred years ago. ■

Redwood in a cartoon by Spy, 25 March 1908.

Advances in Stratigraphic Trap Exploration

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Analysis of the AAPG giant fields database reveals that there has been a step change in volumes of oil attributed to non-structural traps in the last 20 years. Why is that – and where should we be looking for them?

Next year marks the end of another decade of global oil and gas exploration, which will be highlighted in 2020 in an upcoming AAPG Memoir, Giant Fields of the Decade 2010–2020. In the last decade, 89 giants have been discovered, and 226 since 2000. With 60% of global production coming from giant fields (defined as those with more than 500 MMboe recoverable), geoscientists owe it to themselves to understand their discovery history, basin setting, petroleum system and trapping mechanisms.

AAPG has maintained a GIS database of giant fields discovered up through 2009 (Horn, 2011) and this database has been updated since then for the upcoming memoir and provides new insight into changes in exploration focus and technological advancements. Analysis of trap types of recent giants has, surprisingly, shown a substantial contribution from combination and stratigraphic traps; this is a true step-change from prior decades.

3D Seismic the Key

It has been almost 40 years since Michel Halbouty published his landmark paper on subtle trap exploration (Halbouty, 1981). Historically, only 10–15% of global giant fields were found in stratigraphic and combination traps. Multiple seals and a limited number of pay zones are the size-limiting factor in these kinds of plays. Single pay traps require large areas in order to become giants, or thick reservoirs like carbonate reefs or deepwater turbidites. The biggest barrier, however, has been limited seismic resolution to make these subtle traps obvious. Inherently, there is no reason to sink money in subtle traps that are poorly imaged or understood – so the key is to make them easy to see.

Those of us who started our careers with hard copy logs, 2D seismic and hand-contoured maps, relied heavily on geological intuition to contour both structural and stratigraphic elements to find stratigraphic traps. The result was a high failure rate, with most well locations being concept driven, rather than data driven with good reservoir and seal imaging from seismic. Many of the giant stratigraphic traps drilled without 3D seismic were initially located either too far up-dip in tight waste zones, or low on the trap where relative permeability and high water saturations tested water with poor shows. In these cases, many of the fields went unrecognised for years, as operators dismissed the oil and gas shows as indicative of failed traps. In addition, structure maps from 2D seismic often bear little resemblance to geometries mapped from 3D data. Even

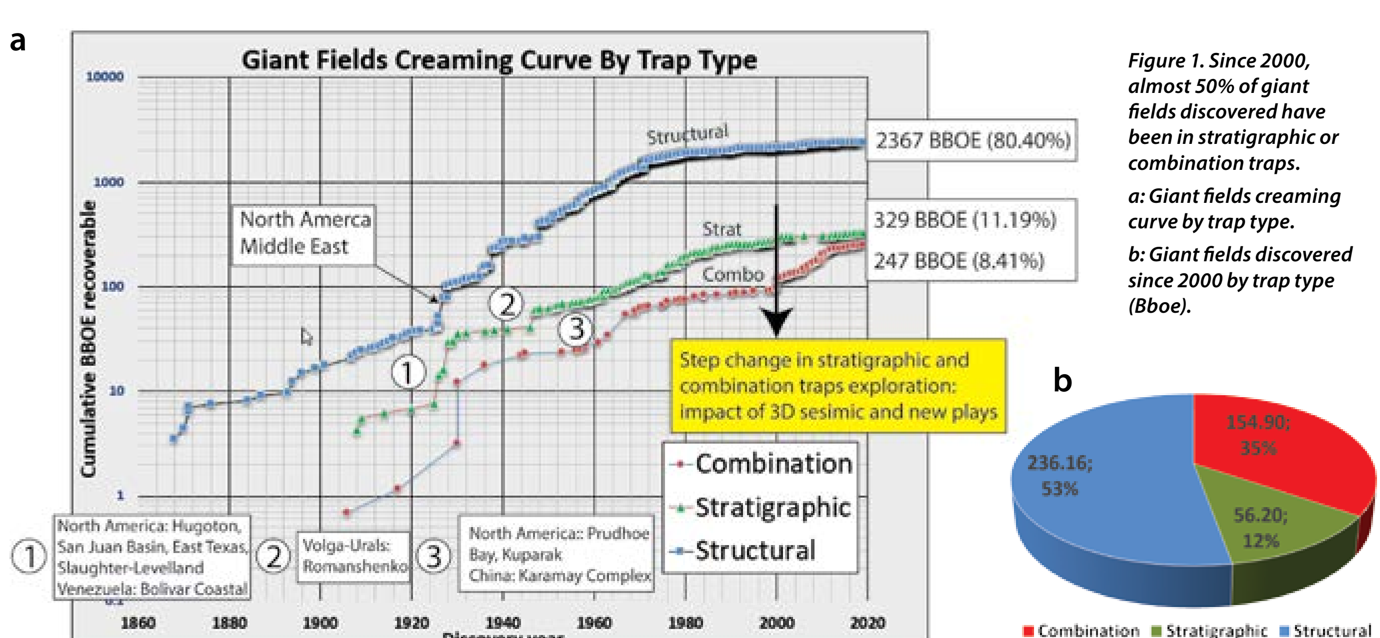


Figure 1. Since 2000, almost 50% of giant fields discovered have been in stratigraphic or combination traps.

a: Giant fields creaming curve by trap type.

b: Giant fields discovered since 2000 by trap type (Bboe).

today, many dry holes provide the keys to finding new, big fields from wells abandoned by operators failing to understand their own oil and gas shows. Lag time from initial discovery to full realisation of the size of big traps often exceeded a decade. It is no wonder than many exploration managers advised against stratigraphic trap exploration.

With the start of widespread acquisition of 3D seismic data, however, success rates began to pick up. In 2003, at the age of 95, Michel Halbouty edited AAPG Memoir 78, in which he noted that stratigraphic trap exploration success had jumped to 22% in the 1990s, a clear result of better seismic imaging. This trend has continued. As Figure 1 shows, these non-structural discoveries have accelerated in the last 20 years. Nearly 50% of the giants discovered since 2000 were in combination and stratigraphic traps.

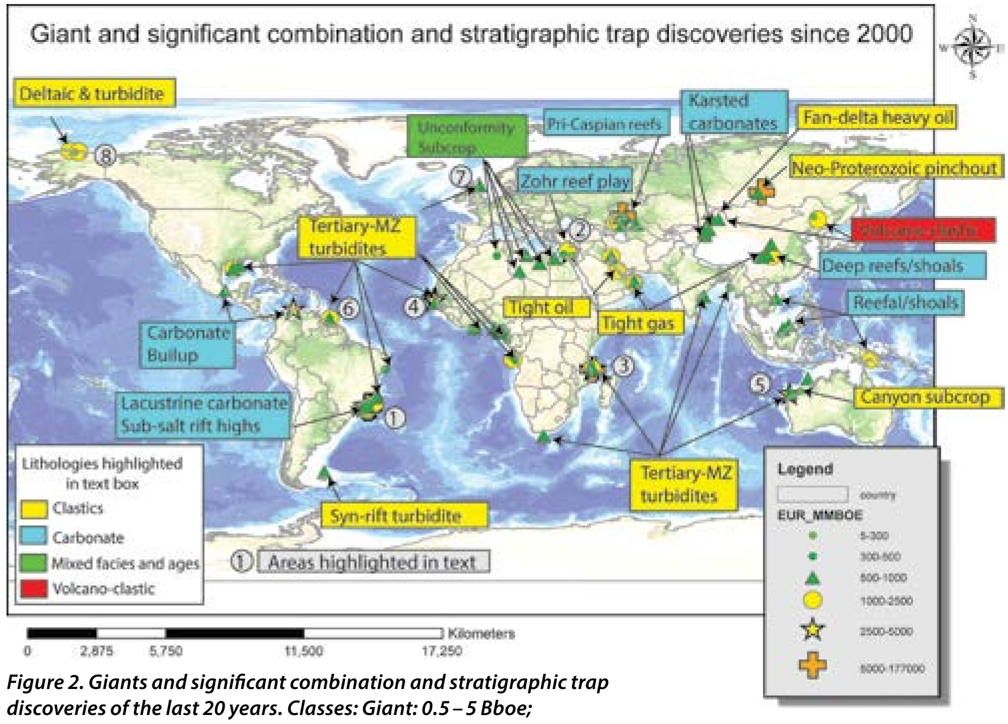


Figure 2. Giants and significant combination and stratigraphic trap discoveries of the last 20 years. Classes: Giant: 0.5 – 5 Bboe; Super Giant > 5 Bboe; Mega giant: > 50 Bboe.

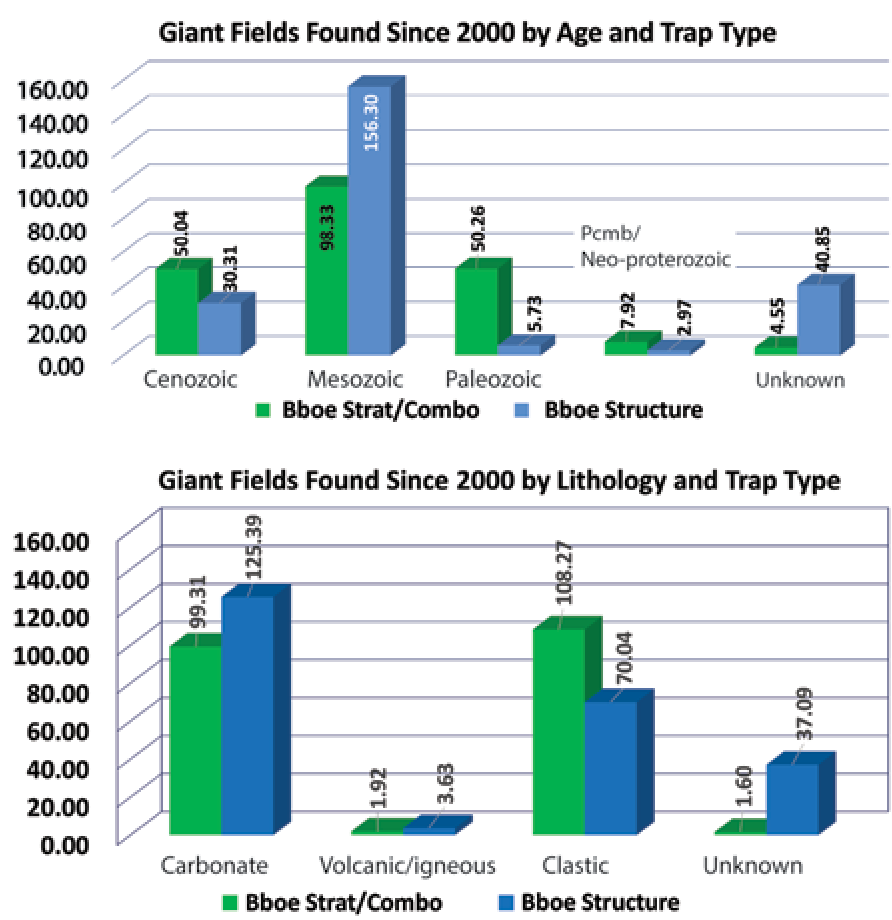
Where Are They Found?

Where are these fields? The map in Figure 2 shows the global distribution of stratigraphic and combination traps discovered in the last 20 years, including some fields that are less than 500 MMboe in size but are considered significant potential play openers. The summary numbers given in subsequent figures, however, are only for fields with a minimum recoverable resource of 500 MMboe. The decade from 2000–2010 is covered in detail in AAPG Memoir 113 (Merrill and Sternbach, 2017) and Mann et al., 2007. A more thorough treatment of the discoveries to the end of 2016 is in Dolson et al., 2017.

Figure 2 shows a wide variety of play types but with a concentration of giant fields in passive margin and cratonic settings. These traps are not limited by age (see Figure 3), but Mesozoic petroleum systems dominate, with Cenozoic and Palaeozoic traps usually being smaller, while, surprisingly, a major Neo-Proterozoic gas discovery has been reported in East Siberia. Carbonate and clastic reservoirs essentially comprise similar volumes, but analysis of the traps indicates that reefs, turbidite and tight gas are where major reserve additions have been made.

Reefs and passive margin turbidites provide thick, readily identifiable targets on seismic, with seal being the major risk factor. Mesozoic plays benefit from rich source rocks in Lower Cretaceous

Figure 3. Giants fields found in the last 20 years, by lithology, age and trap type.



through Upper Cretaceous shales, which formed during the early break-up of Pangea, aided by the hot-house climates prevalent in the Campanian-Turonian period.

Major hubs of carbonate reef exploration are the Santos-Campos Basin sub-salt lacustrine carbonates, the Miocene/Cretaceous Zohr trend offshore Egypt and Cyprus, and the northern Caspian Basin (Pri-Caspian Carboniferous). Successful Mesozoic and Tertiary turbidite plays have been found in many coastal settings, notably in the northern Caspian and the Rovuma Basin, offshore Senegal and Mauritania, the north-west shelf of Australia and the prolific Lisa area offshore Guyana.

High quality 3D seismic and DHI plays have helped make the turbidite plays less risky. Pri-Caspian reefs and the Zohr complex were so large and easily imaged that they were drilled on 2D data. The prolific sub-salt carbonates of the Santos Basin, however, were essentially not visible on pre-2000 2D seismic data. Long offset data acquired in the 2001–2002 period imaged the pre-salt rifts and high shoulders. However, the discovery of the Libra Field (Figures 4A and 4B) was a surprise, as it was located in lacustrine carbonates with multi-darcy reservoirs, often hydro-thermally altered.

Tight gas has seen substantial reserve growth, particularly in China, as well as in Cambrian and Neo-Proterozoic strata in Oman. The Sulige field in the Ordos Basin, for instance, has seen reserve growth approaching 134 Tcf of gas, although the trap itself is still poorly understood. A giant tight oil shale and siltstone discovery in Bahrain in 2018 appears to be either a new stratigraphic or unconventional trap.

Human Insight Still Needed

Seismic imaging of reservoir facies has now become a required skill set of any interpreter. Seals, reservoirs and traps become more apparent and can be modelled quantitatively and then used in petroleum systems migration modelling. Integration of petroleum systems elements, tested and validated with wells and field data, should be a standard workflow for any company.

Nothing, however, replaces the human insight that leads to new ideas, often in old areas. The prolific >100 Tcfg Rovuma Basin turbidite play, Figure 4C, was visualised by three experienced geoscientists at Cove Exploration, and then farmed-out to majors for funding. Increasingly, this has become an exploration model for larger companies, who rely on the experience and intuition of proven explorers in small companies to envision new plays and then provide the cash to test them.

The Buzzard Field combination trap was made possible by examination of a downdip well with 3–5m of oil pay abandoned behind pipe. Likewise, the Horseshoe-Willow area topset play in Alaska offset a 2002 dry hole with pay behind pipe in shallow Cretaceous horizons virtually ignored by the industry. Caelus Energy's Smith Bay giant turbidite field, also in Alaska, was made by transferring knowledge of Cretaceous source rock and interbedded fan plays on the west coast of Africa to similar tectonic and stratigraphic settings in Alaska. It apparently took 'outsiders' to 'think out of the box' and find oil where the major operators had missed it for over 50 years.

More details of these trends and others will be available soon in AAPG's next Giant Fields Memoir, scheduled for completion next year. In the meantime, more giant fields will be discovered, made possible by creative insight and steady improvement in seismic imaging and petroleum systems migration and charge modelling.

References available online.

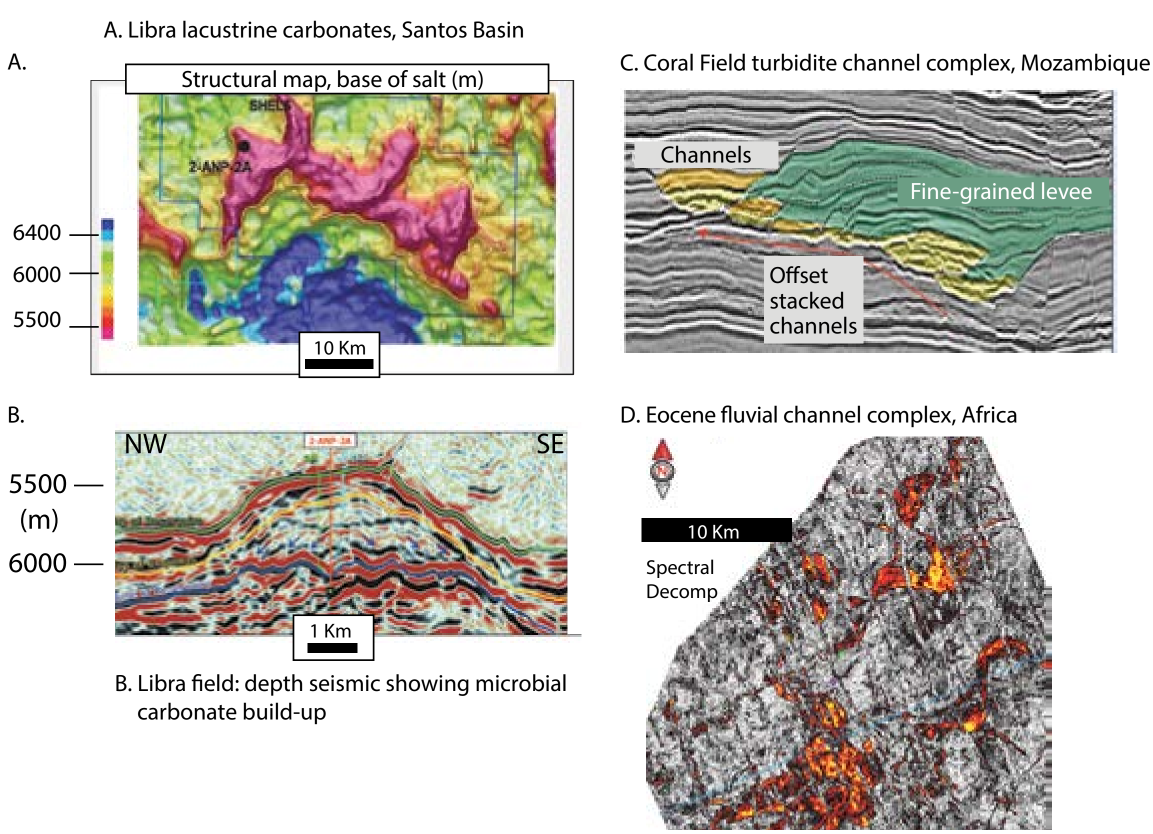


Figure 4. Examples of improved 3D seismic imaging of reservoirs and seals. Figure 4A is modified from Rassenfoss (2017); 4B from Carlotta et al. (2017) and Figure 4C modified from Palermo et al. (2014). The fluvial channel example shown in 4D is courtesy of UHCL, by permission of the Ministry of Energy of Chad.

Filling in the Blanks

Overcoming imaging challenges in highly congested areas by combining streamer and node operations.

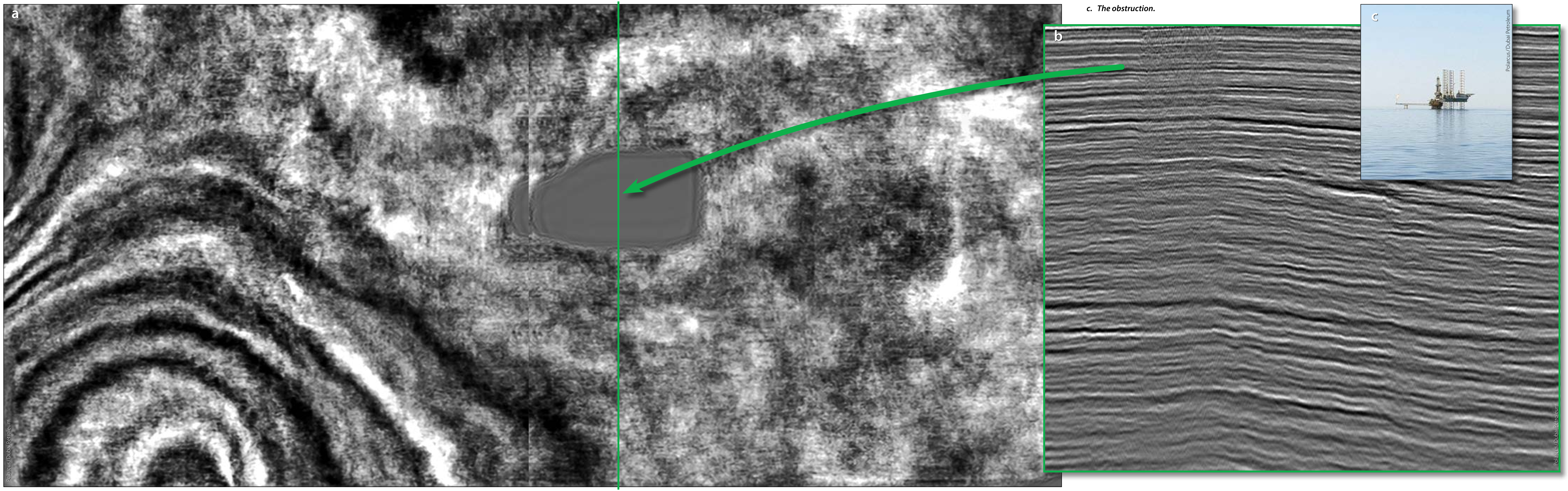
This year, Polarcus was challenged by Dubai Petroleum to provide a high-resolution, fast-turnaround, seismic image in a highly congested shallow water survey area. The targets were stratigraphic plays in the Mishrif and Thamama carbonate formations typical of the Arabian Gulf area. The objective was to image an area in a short time-frame that would enable infill well placement.

This challenge could only be achieved by careful planning of the acquisition methods that underlie the processing, and through the processing and data imaging itself.

a. Time slice Priority Processed PreSTM streamer data, showing blank due to obstruction. Green line shows location of seismic in image b.

b. Crossline of preliminary merged Hybrid Streamer/OBN, filling the blank.

c. The obstruction.



Hybrid Thinking

PAUL SANDVIK and ED HAGER, Polarcus;
MUHAMMAD ADNAN and DANIEL STURKO, Dubai Petroleum

Providing fast, high-resolution seismic in a congested area.

The acquisition technique chosen to provide a high-resolution, fast-turnaround, seismic image in a highly congested shallow water area was a hybrid survey, using an XArray™ Penta Source streamer design with ocean-bottom nodes (OBN) around the obstructions to fill in the holes. This hybrid approach would give the best of both the streamer and OBN worlds: fast, reliable data from the streamer, and flexible receiver placement around the obstructions from the OBN.

Given the symmetrical bin sizes that Penta Source gives, economies in cost and duration were achieved by shooting orthogonal lines that would 'box-in' the obstructed areas, minimising the node effort. The nodes were used to replicate the inline streamer geometry, not to produce a classic orthogonal-geometry survey, which further reduced the cost and duration of the project.

Make it Good

High-resolution meant a target frequency range of 2–100 Hz, which would allow the interpretation of the pinch-outs and reef build-ups of the main structures. To achieve this, high-trace density streamer data was combined with overlapping shots, providing a natural bin size of 6.25 x 6.25m with fold of 84. This equated to over 2 million traces per square kilometre, ensuring that the required signal-to-noise ratio (SNR) could be achieved with the appropriate processing.

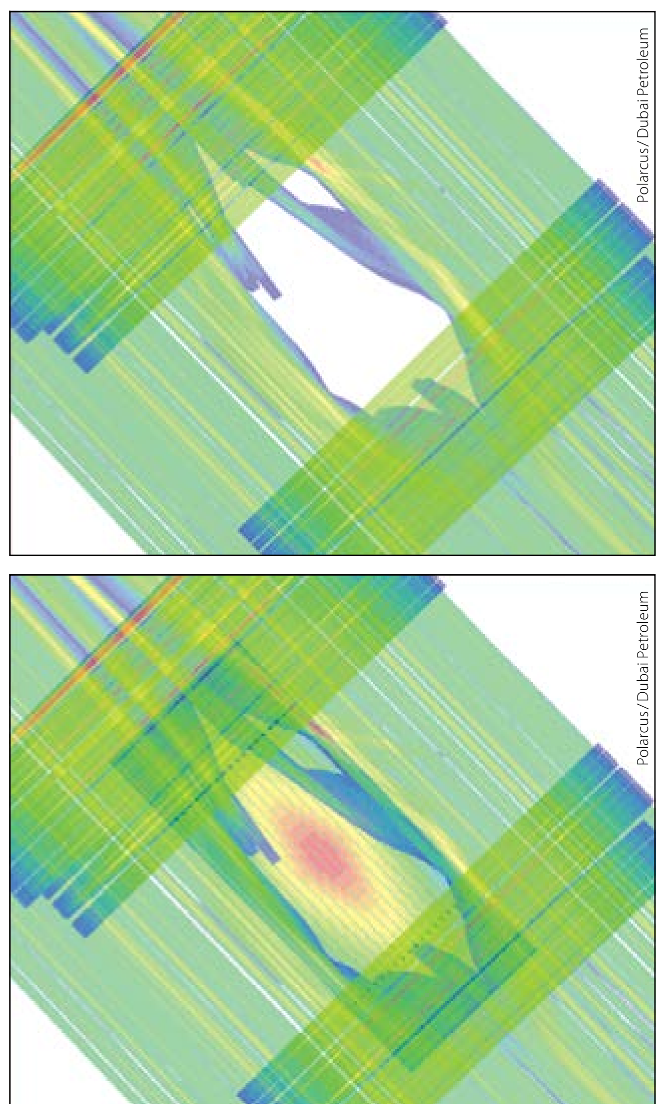
Make it Fast

The processing turnaround time required was ten weeks after the last shot. Typically, this would mean an onboard fast-track but, in this case, that approach would have failed for several reasons. The high-trace density would mean that processing onboard would have to rely on trace-decimation so that the data volumes would match the onboard computing power, but that would obviously negate the advantages of the high-trace density, while a conventionally processed volume executed onshore would be too late to meet the drilling timetable. The high-trace density is achieved with five sources, which can only work if the shot interval is smaller, at four seconds or 8.33m, than a traditional survey with nine seconds or 18.75m. This leads to the shots overlapping each other, and to proceed with processing they need to be separated by deblending. This also requires significant compute resources and would not be possible with an onboard computer system. The deblending process itself has benefits in not only removing interfering energy from the next shot but also the 'noise' of the previous shot – mostly multiples at this point – which adds to an already heavily multiple-contaminated dataset.

The challenge in these very shallow waters (less than 20m deep) are the surface multiples and the strong interbed multiple from the carbonates, which dominate and obscure the underlying structures, not to mention subtle stratigraphic plays. The best way to process data in these circumstances is to interact with the interpretation team, who can use their experience and well-ties to guide the processing and, crucially, the velocity picking. Collaboration in this regard is challenging, as the opportunity to live screen-share or meet face-to-face with a remote onboard team is limited.

To overcome the onboard compute limitations and to maximise collaboration, a cloud-based processing workflow was proposed. Data could either be transferred via satellite directly from the vessel or shipped to shore

Top: Field fold coverage map of streamer acquisition. Bottom: Field fold coverage map of hybrid acquisition.



via boat on disk packs and then transferred to a dedicated processing cloud. Capitalising on the project being at close proximity to the shore, the latter option was chosen as the most cost-effective solution. Equipped with significant compute power, the cloud solves the first problem of onboard limitation.

Enabling onshore and offshore teams to access the data, the cloud also resolves collaboration obstacles. Data processors can work remotely from anywhere in the world, provided that they have an internet connection. For this particular project, Polarcus placed their processors in the company's headquarters in Dubai, conveniently located close to the client's offices. The proximity of the teams was beneficial not only in driving the processing but also to the asset team's confidence in the final images. The live collaboration throughout the project assured the teams of the integrity of the data.

Given that the processing was performed on remote computers, processors can easily be embedded in the client's own offices for similar projects. Alternatively, the client's own processing and interpretation experts can be granted access to the full fidelity data set via downloads or web-browsers.

What About the Nodes?

The OBN part of the survey was acquired after the streamer acquisition was completed. Indeed, the node placement was decided based on the actual streamer coverage achieved, rather than pre-plot coverage around obstructions that can often be difficult to predict. These sections were not part of the primary area of interest, so processing of this data was not considered a priority. Instead, the streamer and node data would be merged during the traditional onshore processing.

The Nitty Gritty

This article has already touched on the processing aspect, but there are further benefits that the unrestricted compute power of cloud processing can bring to a project such as this.

Already mentioned was the deblending of the data and the demultiple sequence which included SRME, shallow water demultiple, tau-p deconvolution and radon methods.

The denoise sequence could be made substantially more extensive than normal, addressing a number of specific noise types from environmental to strum noise and specifically streamer turn noise, as the vessel navigated past surface obstructions. This ensures the signal was optimal for the deghosting stage where a good SNR ensures the highest bandwidth is recovered. Like any good processing sequence, deghosting reduces the complexity of the signal for both the primary reflections and the multiples of them. This makes the demultiple process easier, as the adaptive subtraction has not just a simpler wavelet to deal with but also a more stable one, with sea-surface and tow depth variations removed.

Another crucial step was the ability to apply 4D regularisation. This creates traces at the exact centre of the CMP bin, where some noise rejection can occur, but the main reason for doing this is to honour the requirement of migration that the spatial sampling is regular. The better this process is, the less migration noise is generated; again improving the SNR of the data.

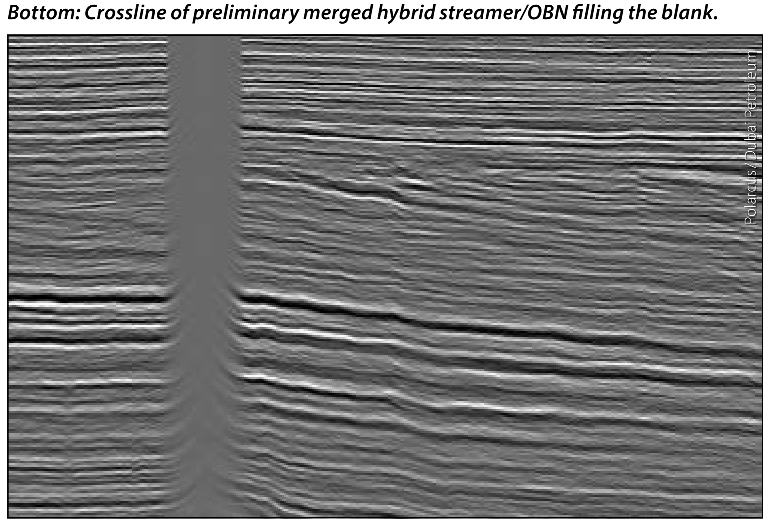
The migration itself could be run without trace or temporal decimation, and took into account vertical transverse anisotropy (VTI) with a picked anisotropic 'eta' field.

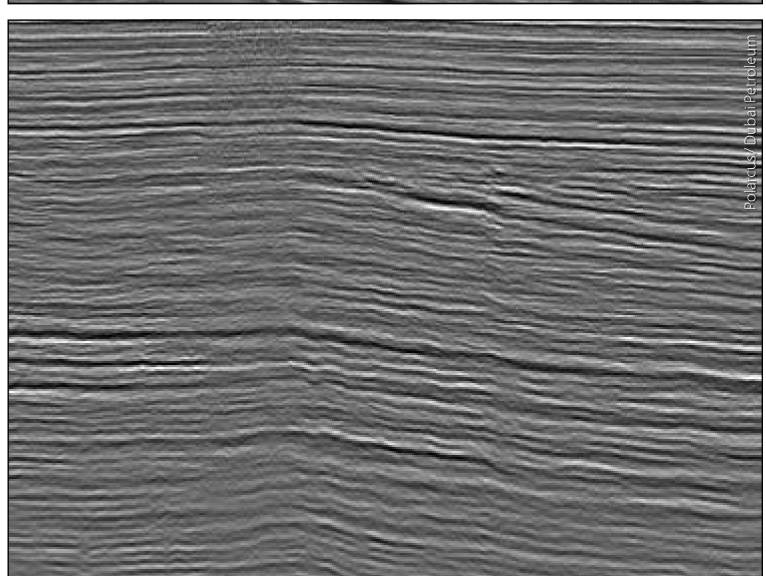
Did it Work?

So, was it simply good planning and the power of the cloud? No, the good result came from the people involved – the crew onboard the vessel, the processing team and the client, who remain core to any project, regardless of its nature.

Initial indications deemed the project a success and show that the objectives were met. This was achieved by taking the onboard fast-track data and redefining it in a new age. We call it Priority Processing. ■

Top: Crossline of Priority Processed streamer data, with blank due to obstruction. Bottom: Crossline of preliminary merged hybrid streamer/OBN filling the blank.





Improving North Sea Understanding

Why do we need a regional stratigraphical framework for the North Sea?

JOYA L. TETREAULT, CARSTEN ELFENBEIN and TOMAS KJENNERUD; Exploro Geoservices

The UK-Norway North Sea is a mature basin both in terms of petroleum exploration, data availability and geological studies. The first oil discovery in the Central North Sea was the Ekofisk Field in 1969, which spawned decades of research and exploration. Since then, both industry and academia have heavily researched the development of the Viking Graben, Central North Sea and Moray Firth, at the same time advancing our understanding of rifting and basin development. However, this does not mean that a fully developed and clear understanding as to how the North Sea basin developed exists.

The Issues

Most studies have either been focused on smaller areas or been limited to one side of the UK–Norway border. Unfortunately, the border between British and Norwegian waters lies right along the North Sea basin axis, so regional studies have been hampered by the lack of availability of cross-border data. This has improved in recent years; however, a large knowledge gap still exists with respect to stratigraphic understanding. A regional lithostratigraphic framework representing the entire North Sea basin has yet to be produced, which creates problems when correlating lithostratigraphic nomenclature regionally or even between neighbouring sub-basins.

Many studies have attempted to solve this problem and have created their own basin-wide stratigraphical nomenclature for certain Periods, but these are mainly based on well data. This approach has certain limitations: it relies on the assumption that many group and formation tops are defined by log signatures that can be recognised regionally. More importantly, it assumes that the age of deposition for formations and groups are synchronous across the entire North Sea. These assumptions fail in settings where tectonic and depositional processes vary temporally and spatially, such as in the North Sea basin. Regional maps of the North Sea cannot be based on these lithostratigraphic schemes because they will introduce fake sedimentary thicknesses and negatively impact our geological understanding, consequently reducing our ability to come up with viable drilling targets for exploration and production. It is therefore crucial to have a basin-wide stratigraphical scheme that is both regionally consistent and grounded in geological observations so that we can make better predictions.

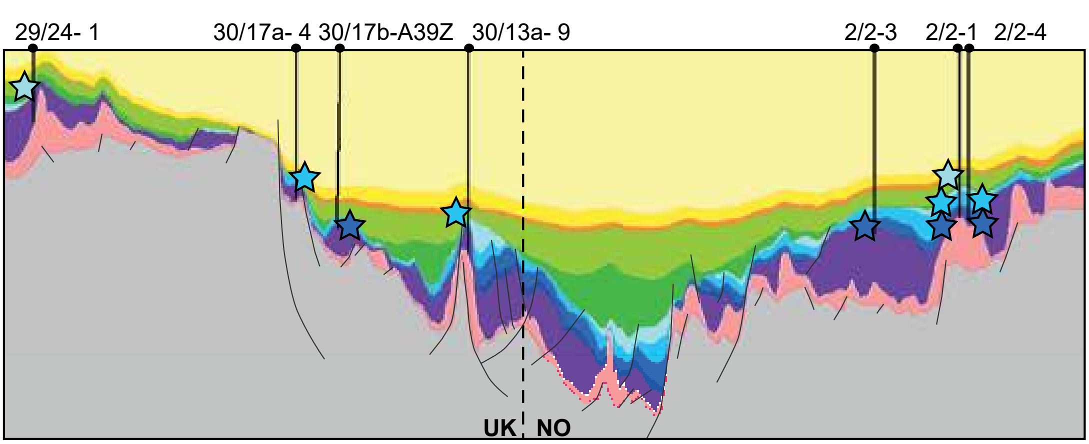
Regionally Correlatable Markers

Norway-based Exploro has developed a stratigraphic scheme for North West Europe based on new and re-analysed biostratigraphy, legacy chronostratigraphy and wireline log data, rather than lithostratigraphy. This regional framework is based on regionally-correlatable stratigraphic markers such as unconformities and maximum flooding surfaces (MFS), using the transgressive-regressive cycles of Partington et al. (1993).

By relying on 1st and 2nd order maximum flooding surfaces, it is possible to map regional events in both wells and seismic data across the North Sea and the rest of North West Europe. This takes advantage of 2D and 3D seismic data, in addition to all publicly available wells (~11,000), using numerical methods for data-mining and corrections. The complete regional framework is built from combining all data and interpretations, ranging from MFSs, seismic interpretation, well logs, chronostratigraphy, seismic data, velocity, and literature and well reports. The resulting chronostratigraphic framework can be used to properly define and predict the age and extent of reservoirs, seals and source rocks, as well as timing and extent of tectonic events, burial histories, and hydrocarbon maturation, expulsion and migration.

The Ula-Fulmar Formation Sands

No play has greater variation in trapping style than the Upper Jurassic play in the Central North Sea, ranging from pure stratigraphic to combination traps and four-way structural closures above mobilised salt. The reservoirs vary from deep marine to shoreface sands, while seals consist of Upper Jurassic and Lower Cretaceous shales. The

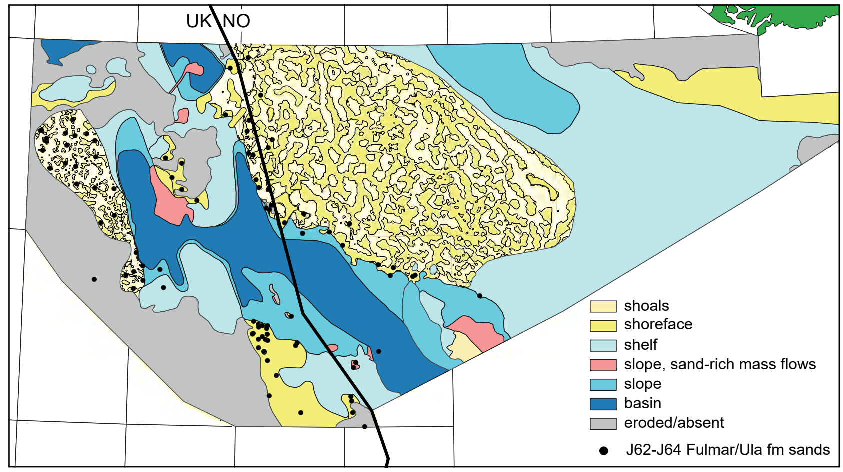


Geosection across the Central Graben based on Exploro's regional stratigraphic framework. Ula and Fulmar Formation sands of different Jurassic intervals penetrated by wells are shown in stars corresponding to the interval colour.

Upper Jurassic is characterised by significant over-pressures in the grabens, which have contributed to preservation of porosity at depth, while increasing cost and risk of drilling operations. The initial discoveries were the giant Fulmar (1975) and Ula (1976) fields, but many more have been made since then. Some recent discoveries of note are Oda (2011), which is now producing, King Lear (2012) and the high impact Glengorm (2019).

Identifying and mapping the Upper Jurassic sands in the Central North Sea is a well-known challenge. When sandstones are encountered in the Upper Jurassic, they are often just termed Ula, Fulmar, Sandnes or Eldfisk formation sands without consideration of the age of deposition or their stratigraphic relationship with other formations. As a result, the sands assigned to these formations cover a time span from the Callovian to the Volgian. In addition, these sands are notoriously difficult to correlate as their local deposition is controlled by tectonic movement, halokenesis or local subsidence. Mapping of these plays becomes impossible when connecting sands of different ages and environments lithostratigraphically. A regional and detailed stratigraphic approach is necessary to ensure that the MFSs are consistent basin-wide, and that information is captured from beyond small sub-basins where studies are usually focused. For the Central North Sea, MFSs were interpreted in 435 wells in order to construct regional maps for the Jurassic.

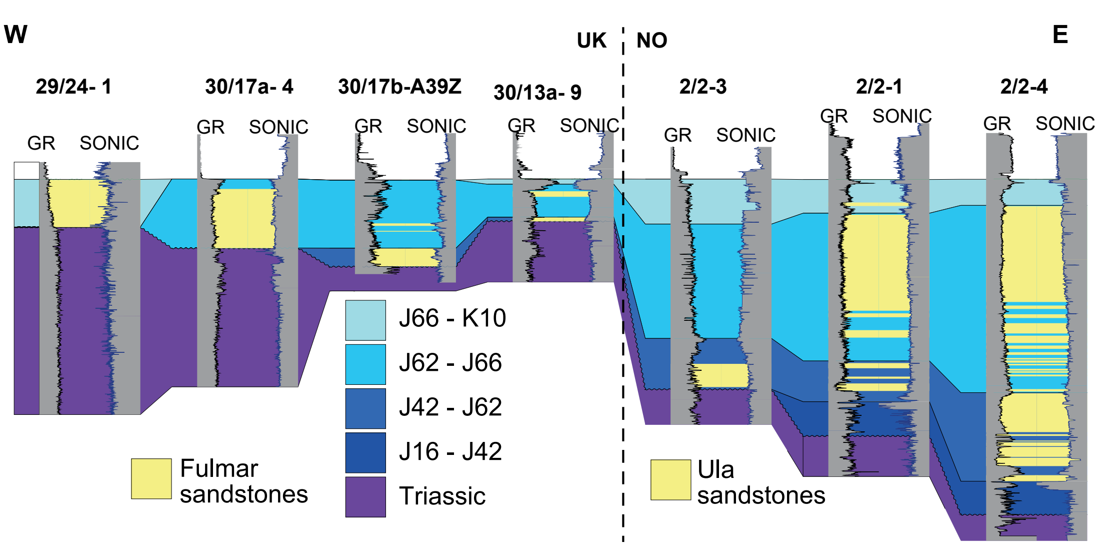
The resulting cross-border framework for the Jurassic highlights the backstepping and retreating shorelines through time earlier observed by Partington et al., 1993. Within the correct stratigraphical framework we can distinguish basinal turbidites, shoreface sands or interpod mini-basins. In the Callovian, shoreface and shelf sands were deposited in the shallow basins of the Feda Graben and East Central Graben. As rifting continued, we observe backstepping of the shorefaces and shelf, reflecting the tectonically-controlled transgression of the Central North Sea. Sediments are shed from the uplifted Triassic deposits in the terraces to source turbidites and salt pod-controlled shorelines. Many of the Late Kimmeridgian sands were turbidites, shed off the terraces into shallow basins. In the Volgian, the Central Graben became a linked deep marine setting, and flooding occurred over the majority of the Norwegian Central North Sea. Contemporaneous shoreface sands are limited to the highs of the West Central Shelf and Auk Ridge.



Gross depositional environment for the early-late Kimmeridgian in the Central North Sea. The sands deposited during on the Jæren and West Central highs were related to salt interpods.

The Solution

By placing the entire North Sea in a regional stratigraphy, we can reconstruct the basin architecture, depocenters and erosional areas and develop geological models describing the timing and depositional environments relevant for the sands of the Fulmar and Ula Formations. In this framework the lithostratigraphic names Ula and Fulmar Formations become irrelevant, and we instead focus on defining sands within Jurassic sequences. Additionally, the resulting chronostratigraphic framework can constrain timing of fault movement and halokenesis that controlled the deposition. By combining seismic and well data, Exploro has improved the stratigraphical understanding of the North Sea and overcome the challenges of dealing with locally derived stratigraphy. ■



West-east well section across the Central Graben with GR and sonic logs, lithostratigraphic subdivision on group level and correlated Upper Jurassic sequences. Upper Jurassic sandstones with similar log patterns occur in three different chronostratigraphic sequences.

Solving the Alaska Puzzle

The USGS's Senior Research Geologist, David Houseknecht, is working to unlock the underexplored petroleum systems on the North Slope in the wake of recent giant discoveries.

HEATHER SAUCIER

In 1968, the state of Alaska made global headlines when the discovery of Prudhoe Bay confirmed that the frozen, once discounted North Slope was home to the largest oilfield in North America.

Yet a decade before Alaska joined the ranks of world-class oilfields, a surprising discovery of 150 MMbo on a dairy farm in Jonesville, Michigan made headlines as well. Michigan's only giant oilfield to date lay beneath land that belonged to a woman named Ferne Houseknecht. At night, the bright lights on the rigs that towered over the landscape mesmerised one of Ferne's distant relatives – a seven-year-old David Houseknecht, who first encountered them on a family vacation in 1958.

This happenstance introduction to the industry awakened in him a passion for geology that later would take him to Alaska in search of more headline-worthy discoveries.

Houseknecht, now 68 and a senior research geologist for the United States Geological Survey (USGS), is chief of the Alaska Petroleum Systems Project and arguably the most active expert on Alaskan petroleum geology. For more than 20 years, he has overseen the North Slope's sequence stratigraphy, basin evolution, and petroleum resource assessments. Often mapping the geology himself, perched atop the jagged outcrops of the underexplored Brooks Range, Houseknecht's work has helped lead today's explorers to giant discoveries – and his expertise tells him that more are waiting to be found.

Twists and Turns

It was a psychic who planted the seed in Ferne's mind that oil was in her future, encouraging her to raise enough money to drill a wildcat well in 1957.

The site of oil rigs and nodding donkeys fascinated David Houseknecht, who left his Muncy, Pennsylvania home every summer, eager for hands-on tours of the operation by Ferne's brother, George Houseknecht. "No one in my family had ever gone beyond high school. So, none of us even knew what geology was," Houseknecht said. "George encouraged me to go to college and study petroleum engineering."

Houseknecht enrolled at The Pennsylvania State University in 1969, studying petroleum engineering and also becoming a self-confessed 'party boy'. His grades suffered, but the summers he spent roughnecking in the Michigan oil patch – alongside Houseknecht Oil Producers and explorers from Shell and Mobil – became his saving grace. There, he observed

David Houseknecht

David Houseknecht admiring the Alaskan view while eating lunch in the field in 2007 on the Nanushuk Formation, an analogue for recent giant oil discoveries 100 miles to the north-west. This location overlooks the Trans-Alaska Pipeline System, with pump station in background.

that “the geologist was always spreading out maps and seismic sections on the hood of a car. I just loved maps. This visual content of the science appealed to me.”

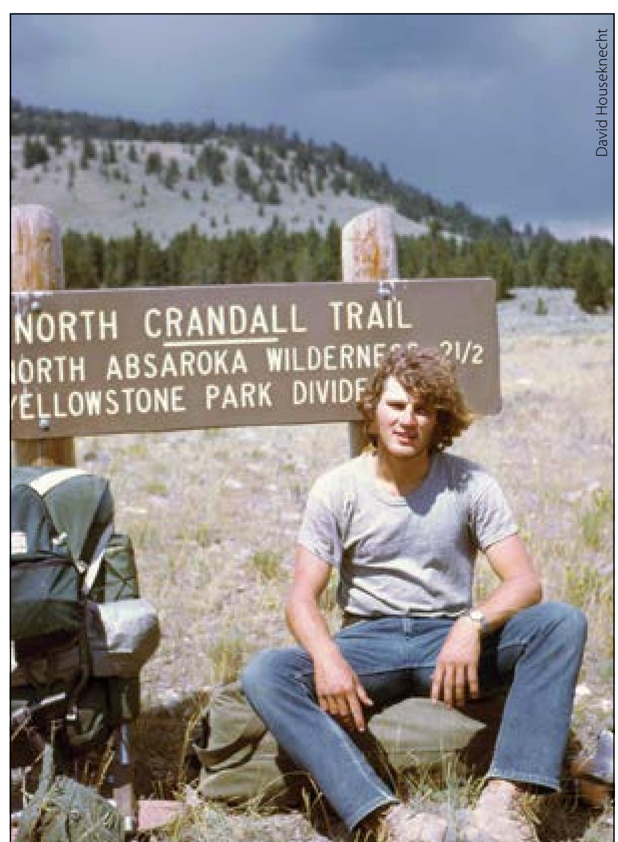
After changing his major to geological sciences, his grades improved. A course in stratigraphy and sedimentology sealed the deal. Houseknecht was strongly urged to apply for graduate school by a professor who saw undeniable potential in him. Before heading to Southern Illinois University in 1973 to begin his master’s programme, Houseknecht got married and the following day took his new wife, Stephanie, to Connecticut for a USGS internship mapping metamorphic rocks.

He later accepted a second internship with Amoco in Houston where he quickly discovered that he strongly disliked the cut-throat, political atmosphere of the industry. He knew his honest and straightforward style would not be gracefully received.

While opportunities for higher education didn’t exist for his Depression-era parents, both supported their younger son’s academic appetite. His father put his skills for refurbishing antique cars and engines into overdrive, selling coveted rebuilt magnetos (which were eventually replaced by spark plugs) at flea markets to fund his son’s undergraduate degree. Little did they know their son would return to The Pennsylvania State University to pursue a PhD in geology.

Ferne Houseknecht was told by a psychic that oil would be in her future – as proved by the successful wildcat Houseknecht #1.

Houseknecht at the completion of an independent project culminating the 1972 undergraduate field geology course in western Montana.



David Houseknecht

Road to Research

In 1978, Houseknecht accepted an assistant professor opportunity at the University of Missouri. He spent long hours looking through a microscope at core samples and providing basin analyses from reservoirs all over the world. “The research I did in Missouri is what many people regard as the best work I ever did,” he said.

A paper he authored titled, “Assessing the relative importance of compaction processes and cementation to the reduction of porosity in sandstones,” which was published in the American Association of Petroleum Geologists’ (AAPG) Bulletin in 1987, won the J.C. ‘Cam’ Sproule Award. Cited 568 times (and counting), the article presents a method for determining if reduction of porosity is a result of compaction or cementation, by looking at a reservoir rock through a microscope. “It makes it possible to predict before drilling how much porosity a sandstone reservoir might have,” Houseknecht explained.

The following year, his paper “Intergranular pressure solution in four quartzose sandstones” in the *Journal of Sedimentary Petrology* won the Outstanding Paper Award. Those two victories crystalised Houseknecht’s career path in research as he climbed the ranks to full professor.

He later accepted a position as manager for the USGS’s Energy Program in Reston, Virginia, for six years, and became a research geologist for the Survey in 1998.

Discovering Alaska

When the USGS published a national resource assessment in 1995 that included the Arctic National Wildlife Refuge (ANWR), numbers were lower than expected, sending a wave of disappointment through parts of the US Department of the Interior and some congressional delegates. A few months later, the USGS sent geologists to gather more data in the remote federal lands widely believed to contain the nation’s greatest energy potential. Houseknecht was one of them.

"One of the best things that happened to me was that trip to Alaska," Houseknecht said. "Little did they know that when I got there, I would jam my foot in the door and take over the project," he said facetiously.

Using new data, the USGS published a detailed assessment of ANWR in 1998, which reflected the presence of more resources.

Compelled to piece together a more detailed geological framework of the North Slope, Houseknecht began leading field sessions, disappearing from civilisation every summer since 1995 (missing just two summers to date!) to conduct basin history modelling, reconstruct the burial history of the rocks, and determine when and where oil was generated. He taught himself how to interpret seismic data and threw himself into petroleum systems analysis.

Kate Whidden, a supervisory research geologist with the USGS, has attended many field sessions with Houseknecht and recalls him working at midnight when the need for sleep felled the rest of the team. "He loves the science, but being a frontier basin, he loves the wildness of being up there where few people have been," she said. "He's transmitted that love to the project, and he's taught me that love."

When Houseknecht accepted his official post as research geologist, he began working on the Alaska Project, which was led by renowned Alaskan geologist Ken Bird. They conducted research to increase understanding of Alaskan petroleum systems, published assessments of undiscovered resources, and delivered energy-resource information to land and resource managers, policy makers and the public.

"I was an outdoorsman. I loved making maps, and Alaska just seemed like the pot of gold at the end of the rainbow," Houseknecht said. "Doing helicopter-supported fieldwork, I was in hog heaven."

Because Bird was a paraplegic, injured during fieldwork years before, Houseknecht became his eyes and ears on the ground – both in Alaska and in Washington, D.C., where he often briefed government officials and members of Congress on their findings. If explained clearly, using creative visuals to bring a blurry subject matter into focus, the chances of acquiring federal funding to further research were generally more favourable.

"He's a superb communicator," said Bird, who is now retired. "He's a master at creating illustrations in his talks and publications. He's also got a sharp eye. Many of his photos have ended up on the cover of the *Explorer*," added Bird, referring to the AAPG publication.

Houseknecht, who took over as chief of the Alaska Project in 2010, continues to create a forward momentum that has drawn operators from all over the world to the North Slope in search of what seems like an endless supply of oil.

Giants, Giants Everywhere

When the Alpine Field was discovered on Alaska's western North Slope in the 1990s, attention immediately turned to the National Petroleum Reserve – Alaska (NPRA). "I jumped on that," Houseknecht said, tearing into the sequence stratigraphy in seismic data of the Kingak Shale, and then the Brookian strata, in the Colville Foreland Basin.

Giant discoveries in the Nanushuk Formation, particularly the recent Pikka and Willow discoveries – believed to contain up to 2 billion barrels of recoverable oil combined – have prompted Houseknecht to re-evaluate a 2010 NPRA assessment.

"We never dreamed that a shallow formation previously penetrated 150 times, with the largest accumulation found being in the order of 70 million barrels of oil, would ever yield between half a billion to over one billion-barrel discoveries," he said. "All we can do is make adjustments and keep moving."

He added, "We think significant resources are yet to be discovered in the Nanushuk reservoir, both in NPRA and state lands just to the east. And based on looking at seismic

David Houseknecht

Houseknecht in 2000 'at home' in a field camp in Brooks Range foothills near Ivotuk Creek, 260 km west of the Trans-Alaska Pipeline System.

Houseknecht in 2018 collecting oil-stained rock on the coastal plain of the Arctic National Wildlife Refuge.

data offshore, there could be potential there in a different trap not yet tested in the Outer Continental Shelf. There may be potential in state waters, too."

Time for Fun

At Houseknecht's request, the USGS is actively looking for his successor – if there could be such a person. He wants to have "more fun" by setting aside administrative and political duties and focusing solely on piecing together Alaska's petroleum puzzle.

Over the last decade, Houseknecht has managed to have the USGS acquire additional seismic data of the North Slope, and he's obtained state-of-the-art data from the Siberian Shelf, the Chukchi and Beaufort shelves, and the Canadian Beaufort and Mackenzie shelves. He grows giddy when speaking of the 2D and 3D seismic data on his workstation – "more than I'll ever be able to interpret" – but awaits it with glee.

Over the course of his career, he has earned many honours and awards, the most recent being the Distinguished Service Award from the Department of the Interior in 2018. The self-professed workaholic has authored, co-authored and contributed to several hundred papers, articles, abstracts and other publications, including a chapter in the book *The Sedimentary Basins of the United States and Canada*, edited by Andrew Miall, that synthesises Houseknecht's decades of work and progress in Alaska.

While he has never consulted a psychic for the next giant discovery, David Houseknecht's own intelligence, passion and resources have proven to be trusted guides to the ever-unfolding finds in the mystery that is Alaska. ■

The Origin of Shale Gases

The origin of shale gases has important implications on their ability to provide hydrocarbon reserves

ALEXEI V. MILKOV and GIUSEPPE ETIOPE

As we all know, the discovery that gas formed and locked in shale source rocks can be released and extracted has revolutionised the US energy scene. According to the EIA, large-scale natural gas production from shale began around 2000, when it became a commercial reality in the Barnett Shale in north-central Texas; by 2005, this formation was producing almost half a trillion cubic feet of natural gas a year. Other US shale gas plays followed and production ramped up rapidly, so that by 2019 average daily production was over 65 Bcfg.

Could this be replicated elsewhere? Shale gases have different origins, and to answer this question it is important to be able to identify the key elements in composition and origin that will turn a shale gas into a useful resource.

Although the wide body of petroleum geochemistry literature attests a general knowledge on how and why gas originates in a shale, there are several specific important processes and mechanisms that remain elusive. The following text attempts to clarify what is known and takes a look at the unknowns.

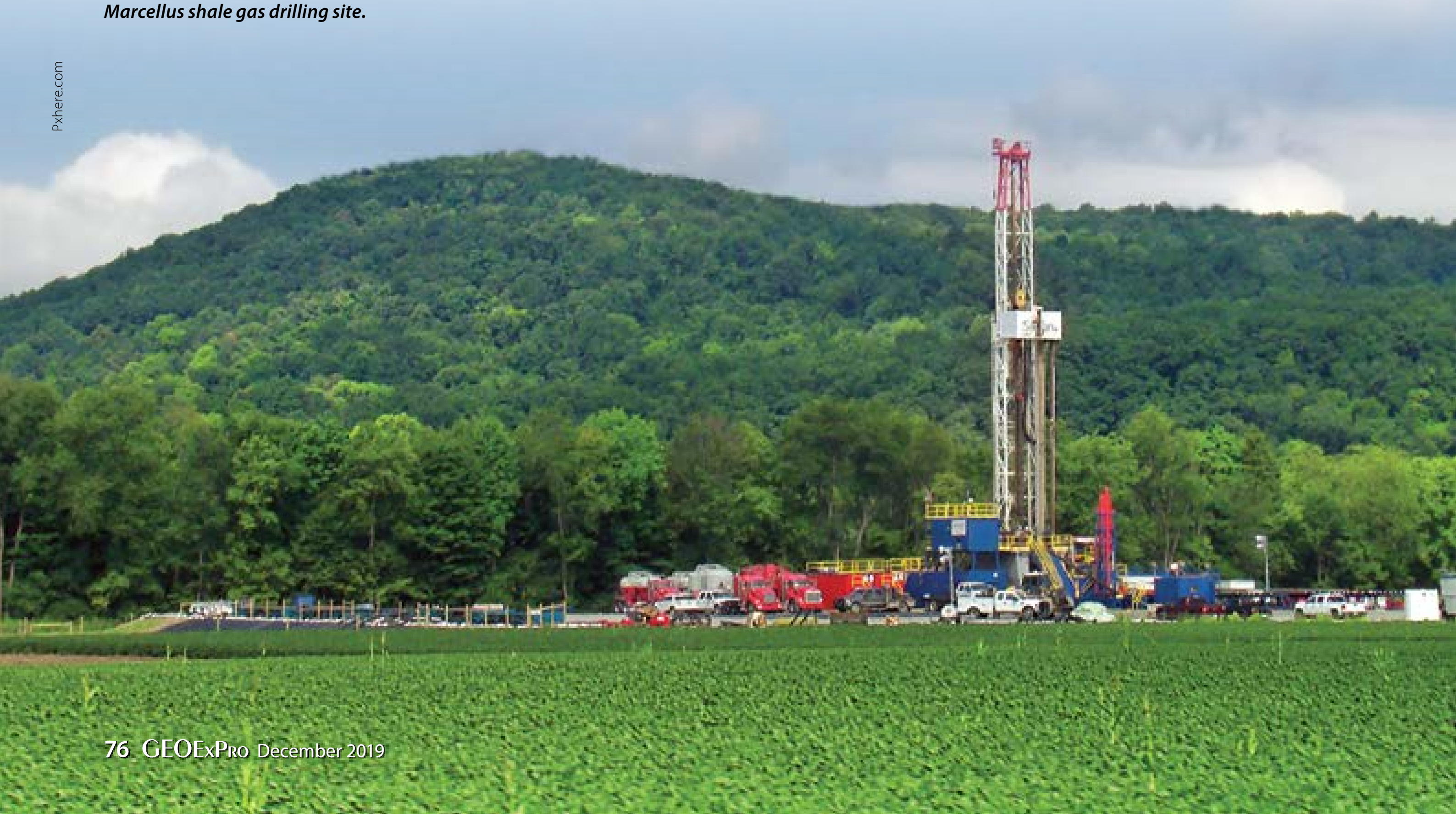
We know that natural gases in sedimentary rocks result from either microbial or thermogenic activity (abiotic generation mechanisms may play an important role in some igneous rocks), and are affected by post-generation processes such as oxidation, mixing, biodegradation and thermochemical sulphate reduction. Petroleum geochemists study samples from known producing formations and use the molecular and isotopic composition of these to begin to understand the processes involved in the formation of gas in shale and the implications for potential resources.

But, globally, how much shale gas is thermogenic, and how much is microbial? Does the origin and source rock maturity of a gas influence shale gas productivity? And can shales be economic sources of other strategic gases, such as helium?

Shale Gas Composition

Using a worldwide database of over 2,000 samples from ten countries across five continents and including China, Canada, Saudi Arabia, Argentina, the UK and Poland, as well as major US plays, it is possible to produce a summary of the composition of global shale gases. The data were collected from more than 80 peer-reviewed papers, government databases

Marcellus shale gas drilling site.



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and research theses and reports and predominantly were taken from production samples, with some data from degassed cores. The database covers more than 65 different shale formations that range in age from Proterozoic to Miocene.

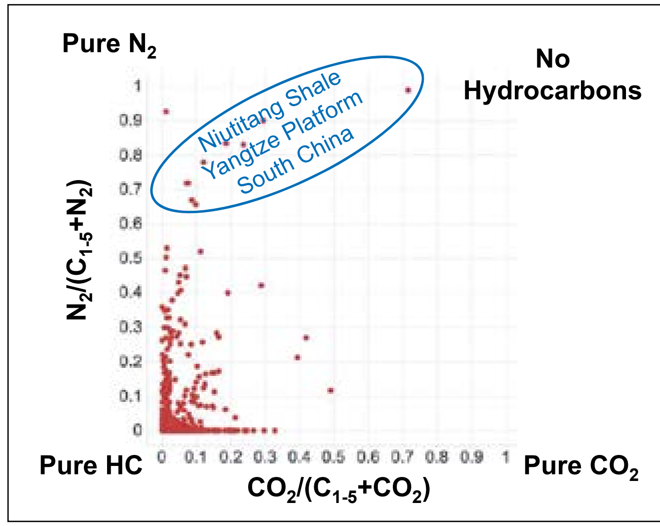
As can be seen from the diagram (right), globally hydrocarbons dominate in most gases, forming on average 92% of the gas composition, with methane being the main hydrocarbon gas. Average methane (C_1) is 85% and ethane (C_2) is 5%, which highlight the commercial value of shale gases. Some gases, particularly those desorbed from shale cores, are enriched with nitrogen (N_2), which may partially be related to air contamination. However, there are some nitrogen-enriched gases, such as in the Cambrian Niutitang Formation in China, in which nitrogen comprises up to 97% of total gas. It is thought that this may result from thermal transformation of organic matter and/or from NH_4-rich illites of the clay facies.

Some gases are enriched in CO_2, which may result from oil biodegradation, as has occurred in the US New Albany and Antrim shales. Also, when the gas is reservoired in carbonate-dominated tight formations, such as the case of the Canadian Pardonet and Baldonell Formations, it may be subject to thermal sulphate reduction, which leads to high CO_2 and hydrogen sulphide (H_2S). The Pardonet / Baldonell, for example, contains 7.5 – 29.5% H_2S, while the Horn River shale in Canada is believed to have up to 12% CO_2 as well as traces of H_2S.

Shale gases appear to contain very little helium, much less than is usually found in conventional or coal bed methane reservoirs. This is because shales do not interact much with the aquifers that supply noble gases to conventional reservoirs. Whatever helium is present in the shales is usually thought to be of crustal origin, as is evidenced by helium isotopes, while, in contrast, conventional reservoirs may have helium of magmatic origin.

Origins of Shale Gases

Plotting the composition of gases using genetic diagrams can help us interpret the origins of shale gas. The most commonly used diagram, developed in 1977 by Bernard et al., is based on hydrocarbon gas composition expressed as $C_1/(C_2+C_3)$ plotted against the isotopic composition of methane, and this has been modified (Milkov and Etiope, 2018; 2019) to the versions shown below. These diagrams allow us to identify whether



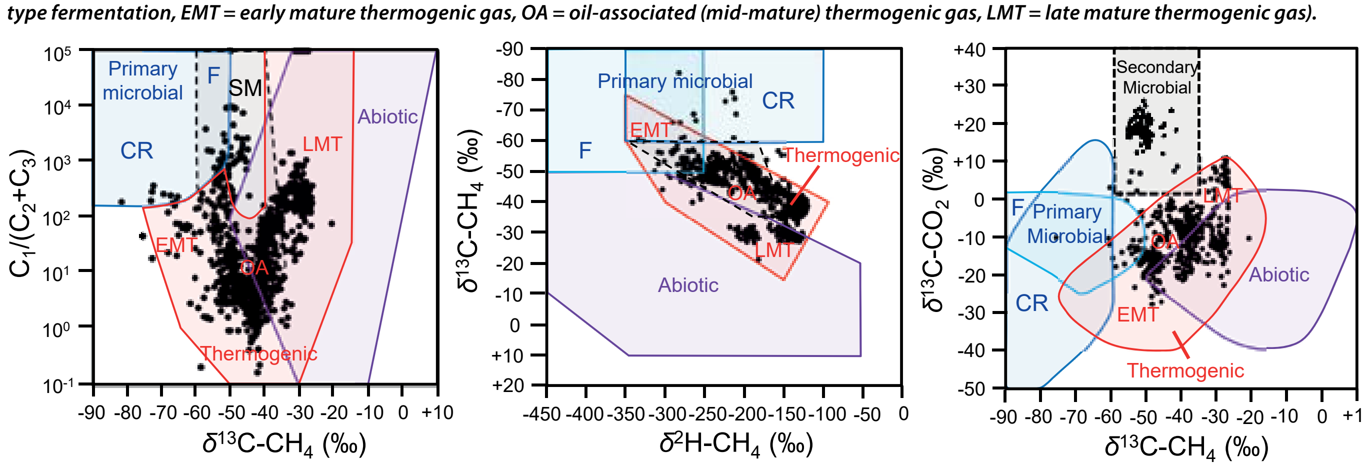
Summary of composition of global shale gases, methane (C_1) to pentanes (C_5); N_2 = nitrogen; CO_2 = carbon dioxide.

the gas is of either primary microbial origin, i.e., it formed as part of the initial diagenetic sequence of sedimentary organic matter; secondary microbial origin, originating from anaerobic biodegradation of oils; thermogenic, resulting from burial of organic material and its subsequent heating; or is abiotic gas, which is generated by magmatic and gas–water–rock reactions that do not directly involve organic matter.

The diagrams demonstrate that a large percentage of shale gases are of thermogenic origin. The maturity of these thermogenic gases varies widely from early to late-mature, although most gases appear to be mid-mature (i.e. oil-associated) or late-mature. While secondary microbial gases from petroleum biodegradation are abundant, there are few shale gases of purely primary microbial origin.

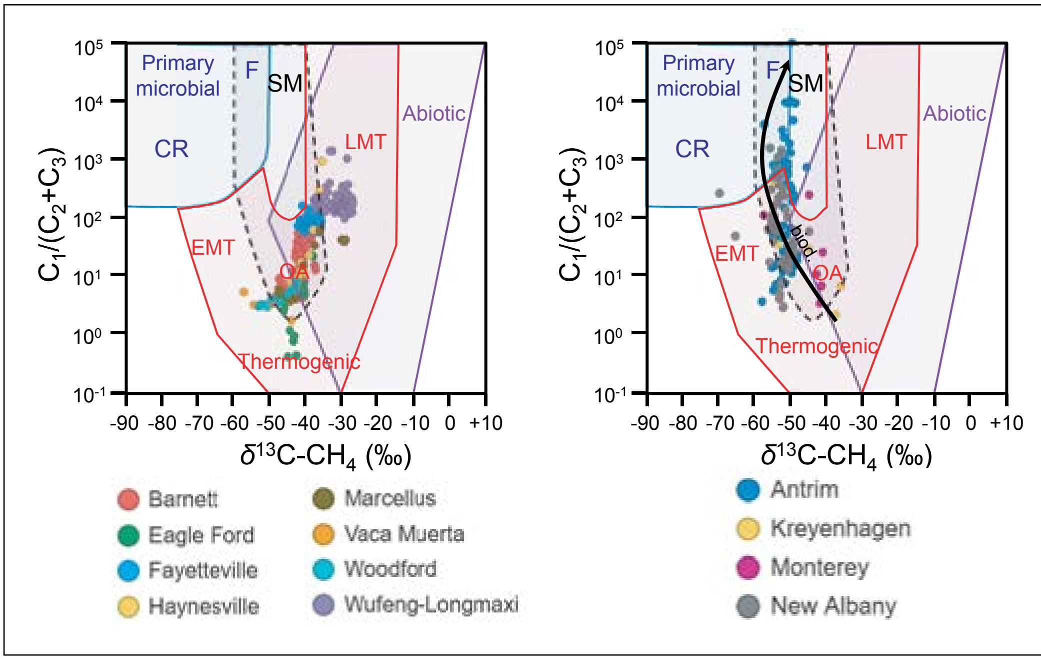
The use of a large database has enabled recognition of early-mature thermogenic gases and this has resulted in the re-evaluation of a number of plays. Early-mature thermogenic gases have been identified in the Tøyen Formation in Sweden and the Canadian Colorado Formation. Gases from the Antrim and the New Albany Formations in the US have often been considered to be primary microbial or early-mature thermogenic in origin, but the revised genetic diagrams suggest that these gases are in fact mixtures of early mature

A plot of all shale gases on revised gas genetic diagrams, showing that most are thermogenic with variable maturities (CR = CO_2 reduction, F = methyl-type fermentation, EMT = early mature thermogenic gas, OA = oil-associated (mid-mature) thermogenic gas, LMT = late mature thermogenic gas).



thermogenic gases and secondary microbial gases generated from biodegraded petroleum fluids. The main reason for such interpretation is that these gases have CO_2 that is highly enriched in ^{13}C, a feature that is typical for secondary microbial gases.

Identifying thermogenic gases and their maturity levels in shale plays is important. Right is a diagram of some of the most productive shale plays in the USA and around the world, including gases from the Barnett, Eagle Ford, Fayetteville, Haynesville, Marcellus, and Woodford shales in the US, the Wufeng-Longmaxi shale in China and the Vaca Muerta play in Argentina. From this it is easy to see that most commercially successful shale plays – those with the largest resources and greatest productivity – contain mid to late-mature thermogenic gases. Plays with late-mature thermogenic gas, such as the US Marcellus Formation and the Wufeng-Longmaxi Formation in China, appear to be the most productive.



Shale gases on gas genetic diagrams of $\delta^{13}C-CH_4$ vs $C_1/(C_2+C_3)$, showing that most productive and commercially successful shale plays have mid-mature and late-mature thermogenic gas (left) while less productive plays have early-mature thermogenic and secondary microbial gas (right).

However, gases with a secondary microbial origin also have a role to play; in fact, gases with early-mature thermogenic origin and secondary microbial origin have been produced for many years. Examples include the fractured shale reservoirs of the Antrim Formation in the Michigan Basin, USA, which have been producing since the 1980s, and the New Albany Formation in the Illinois Basin, USA, has been exploited for gas for over 150 years. Most of the gas in these formations is early-mature thermogenic in origin, but with a significant contribution from secondary microbial gases that formed from biodegraded petroleum, mostly oil, generated in the early-mature thermogenic shales. However, gases originating through secondary microbial processes in shales are not considered to represent a significant resource because of the relatively low gas volumes generated through that process.

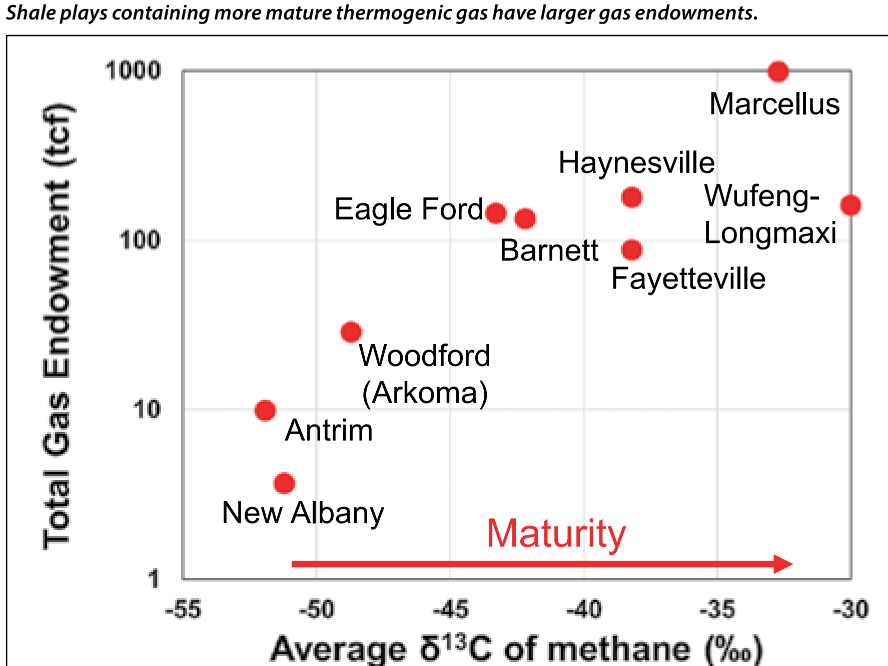
Shales with primary microbial gas are not common and, when found in shale gas reservoirs, to date they have not been produced. It would appear that the process of primary microbial gas generation is the least efficient at forming and preserving large volumes of gases in shale reservoirs.

A Useful Screening Tool

Shale gas exploration is driven, to a large extend, by the resource size of the play, the productivity of shale reservoirs and expected ultimate recovery of wells and their commerciality. The gas geochemistry plots generated through the use of a large global database can therefore be used to identify the origin of the gases and act as a screening tool to predict the potential of emerging shale plays.

References available online. ■

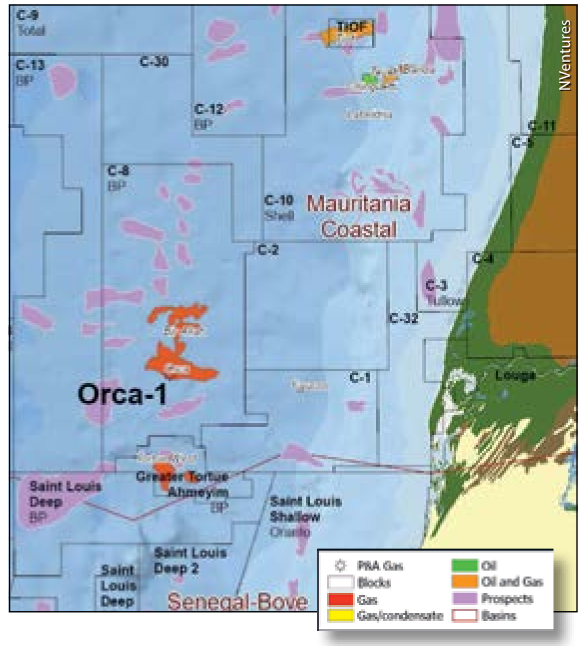
Shale plays containing more mature thermogenic gas have larger gas endowments.



Mauritania: Year's Largest Gas Find

The largest gas discovery of 2019 to date was announced in late October. **Orca-1** was drilled in 2,500m of water about 125 km off the coast of **Mauritania** in **Block C8** in the **BirAllah** area. It discovered 36m net gas pay in excellent quality reservoirs in a previously untested Albian play, before continuing down to find 11m gas pay in the main Cenomanian target. The well is approximately 7.5 km down-structure from the crest of the anticline drilled by the original Marsouin-1 discovery well and proved both the structural and stratigraphic trap of the Orca prospect, which has a mean gas initially in-place estimate of 13 Tcf or 1.3 Bboe. It is estimated that in total Orca-1 and Marsouin-1 have de-risked up to 50 Tcfg in-place from the Cenomanian and Albian plays in the BirAllah area, and a deeper, as yet untested Aptian play has also been identified in the area; this is thought to be more than sufficient resource to support a world-scale LNG project.

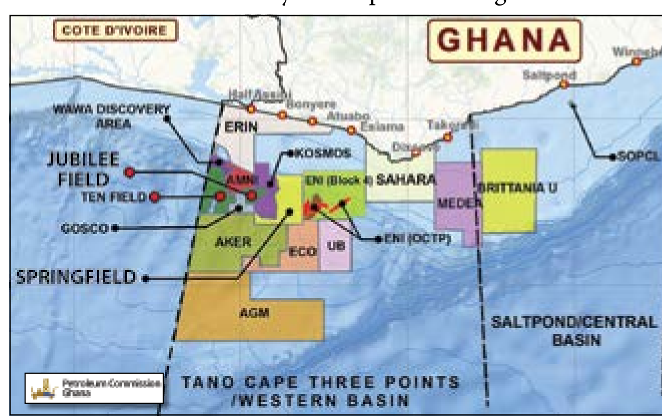
The BirAllah area is operated by BP with 62%, along with partners Kosmos, who are looking to divest some of their 28% stake, and state company SMHPM with 10%. This is the ninth successful well in succession drilled by the consortium along the 400-km-long Mauritania–Senegal seaboard. ■



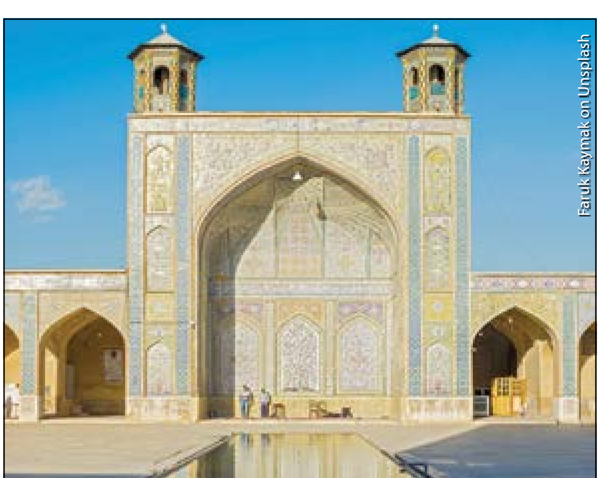
Ghana: First Independent Discovery

In November 2019 **Springfield Exploration and Production Limited** are reported to have made two discoveries totalling over 1.2 Bb of oil in its deepwater West Cape Three Points **(WCTP) Block 2**. If confirmed this is a significant discovery, not just because it would appear to be sizable, but because it would be the first offshore deepwater discovery in **Ghana** by an independent African-owned company.

The Stena Forth Mobile Offshore Drilling Unit commenced a two-well drilling campaign in waters over 1,000m deep in early October. The targets were the **Oak-1x** prospect, on trend with the Beech discovery, made on the Deep Water Tano Cape Three Points block to the south-west of WCTP Block 2, and **Afina-1x**, which tested the Cenomanian oil potential of a play fairway that is similar to discovered resources to the east of WCTP Block 2. The two wells were successfully drilled over a total of 40 days and both were oil discoveries, with an estimated 30–35% recoverable, in addition to commercially viable quantities of gas. ■



Iran: Giant Gas Field



Reports that Orca is the largest gas find this year have a competing claim from **Iran**, where in mid-October the **National Iranian Oil Company** announced that it had discovered a natural gas field with 19 Tcf of gas in-place. The field, known as **Eram**, is onshore south of the Fars province in the southern part of the country, about 200 km south of Shiraz, 60 km to the north of Assaluyeh and 25 km to the east of Khonj County.

The field is reported to cover an area 50 km long with an average width of 5 km and is reservoired at a depth of 3,900m, although there is no further information about the reservoir. Development will probably commence in two or three years and it is estimated that Eram contains enough gas to supply the capital, Tehran, for 16 years. Due to international sanctions Iran cannot easily export hydrocarbons, but there is strong demand within the country. ■

The Vakil Mosque in Shiraz.

Mapping the Future

Easy access to accurate maps is an important part of exploration. Francis Cram, founder and CTO of MapStand, a new open platform for easy tracking of oil and gas activities and live geo-tagged news, explains how open data access will transform the industry.

Why are you fascinated by maps?
I have always loved maps, from Winnie the Pooh's 100 Acre Wood as a child and Middle Earth as a teenager, to detailed geological maps of everywhere I have travelled since. Maps bring complex ideas to life and when done well can tell stories in amazingly simple ways. Over the past few years we have seen webmaps really take off, with people now using maps every day on their phones for navigating through cities, finding each other on dating apps, or using maps with augmented reality when playing games like Pokemon Go. As an industry where location is so important, it feels to me that we are quite far behind when analysing, understanding and engaging visually with what is happening.

Is open data important to the O&G industry?
The oil and gas industry has traditionally been very secretive about its activities, but this is changing fast. In the UK we have seen the amazing work being done by the OGA with not only the basic spatial data around activities such as licences and wells, but also government-funded seismic data and studies being published for free. These are designed to encourage innovation and activities, especially in frontier areas. MapStand is building on these great ideas and expanding around the world to help create a single integrated global dataset.

Has the industry accepted open data access?
Many people I speak to have realised that we need to be more open, in order to create new opportunities and to work more efficiently. People are now concerned that if we don't act today opportunities may disappear forever. Opening up data can get the right information to the right people, at the right time. This could be a farmout, the site of a multiclient 3D survey, or the location of a vessel or rig. Timing is everything.

What are the economic benefits to accessing more data?
More data is one thing. Open data is another and is something that is often misunderstood. For the oil and gas industry the benefits of having access to global reference datasets is enormous. By being open we enable people to use our data without the normal restrictions, which gives them the freedom to build products and innovate. Being open also gives the whole supply chain visibility of upcoming activities, enabling proper planning and better allocation of resources. This is one of the ways in which the industry will reduce cost through efficiencies and also reduce the environmental impact of our activities.

Why did you set up MapStand?
Ever since I started in the oil and gas industry I have been frustrated by a total lack of free spatial datasets, or apps and tools that enable me to quickly find out what the industry is doing; where the latest discoveries are, what companies are up to, what am I going to be asked in a job interview? This inability for people who enter the industry to understand and engage is a huge missed opportunity. So our product is for individuals. You can now create a career profile on MapStand by interacting with the map contents, building up detailed maps of your career and tracking experiences. MapStand is more than an activity map – it is a business network designed for the way we work, making expertise and knowledge searchable.

The company is part of the UK Open Data Institute (ODI). What is this?
The ODI are pioneers who are working with many different organisations and industries promoting the benefits of open data. They support research into important topics like the benefits and stewardship of open data, and also the ethics of data. At MapStand our terms and conditions are based on creative commons non-commercial attribution licences, to enable our users the maximum freedom to use our data and to innovate. Our ambition is for basic activity map datasets (licences/concessions and the locations of fields and wells) to be truly open and we will be working with the ODI to deliver this objective. For this to happen we are encouraging government agencies and NGOs around the world to embrace the possibilities that open data can bring, both social and economic. ■

MapStand

Francis Cram studied at the universities of Bristol and Manchester before embarking on a career as a petroleum geologist, working on international projects in Libya and Tanzania and the North Sea, where he learnt the value available in legacy datasets. This led him to found tech start-up MapStand, a platform mapping global oil and gas activities with open access to interactive asset maps and geo-tagged newsfeed and profiles.

Gas with a Difference

There are no simple solutions to transforming the world's energy systems.

Imagine using excess offshore wind energy to manufacture hydrogen on disused gas platforms. Fantasy? What about tapping into an existing pipeline infrastructure to get the hydrogen back to gas terminals before distributing the resulting electricity to homes and businesses? The reality as 2019 draws to a close is that plenty of blue-sky thinking is being employed by oil and gas companies who seek to diversify and update their offering.

As discussed in the last issue, Carbon Capture and Storage (CCS) is one option in a developed world search for cleaner energy (see the article on page 48 to read more about plans to make a new value chain and business model for CCS). You can keep your gas, even your coal, runs the thinking, but CCS – literally the trapping of carbon dioxide at the point of combustion – may well have to be part of the equation. The problem is, as we have considered, CCS is expensive and there's no sign that the demand for fossil fuels is going to nosedive anytime soon.

In its *World Energy Outlook 2019*, the IEA sounds a note of optimism. For the moment at least there are calmer markets despite an uncertain geopolitical outlook and well-supplied inventories. The upshot, notes IEA, is a more bullish outlook for 2020 and a sharp rebound in refinery activity. Business as usual?

Not quite. As the big investment funds consider their options, oil and gas majors must continue to give every indication that transition to cleaner energy is uppermost in their minds. By the beginning of 2019, almost 1,000 institutions with $6.2 trillion in assets had committed to jettison fossil fuels, according to the consultancy Arabella Advisors. Even in Norway, where hydrocarbons are so important to finance, the country's $1.1 trillion sovereign wealth fund is selling stakes in oil and gas explorers.

Back to hydrogen, the ultimate clean fuel given that the residue from burning it is water. If we accept that natural gas is going to be around and acceptable even longer than oil, then small wonder that certain oil majors are looking at how this processed bi-product of natural gas could be mixed with the original for a less polluting fuel. Mind you, if, as the IEA maintains, demand for energy keeps growing and demand for fossil fuels doesn't even flatten out until the 2040s, then there is still time to get the technology right.

As Dr Fatih Birol, the IEA's Executive Director, notes, "What comes through with crystal clarity in this year's *World Energy Outlook* is there is no single or simple solution to transforming global energy systems." Indeed. ■

Nick Cottam

153624612 © M-sur/Dreamstime.com

Conversion Factors

Crude oil

1 m^3 = 6.29 barrels

1 barrel = 0.159 m^3

1 tonne = 7.49 barrels

Natural gas

1 m^3 = 35.3 ft^3

1 ft^3 = 0.028 m^3

Energy

1000 m^3 gas = 1 m^3 o.e

1 tonne NGL = 1.9 m^3 o.e.

Numbers

Million = 1 x 10^6

Billion = 1 x 10^9

Trillion = 1 x 10^{12}

Supergiant field

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

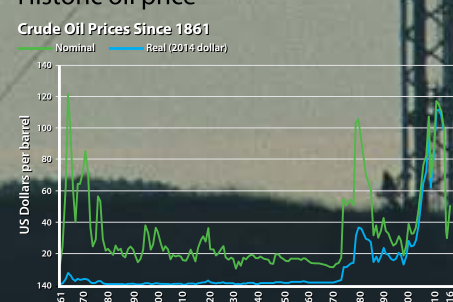
Giant field

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

Major field

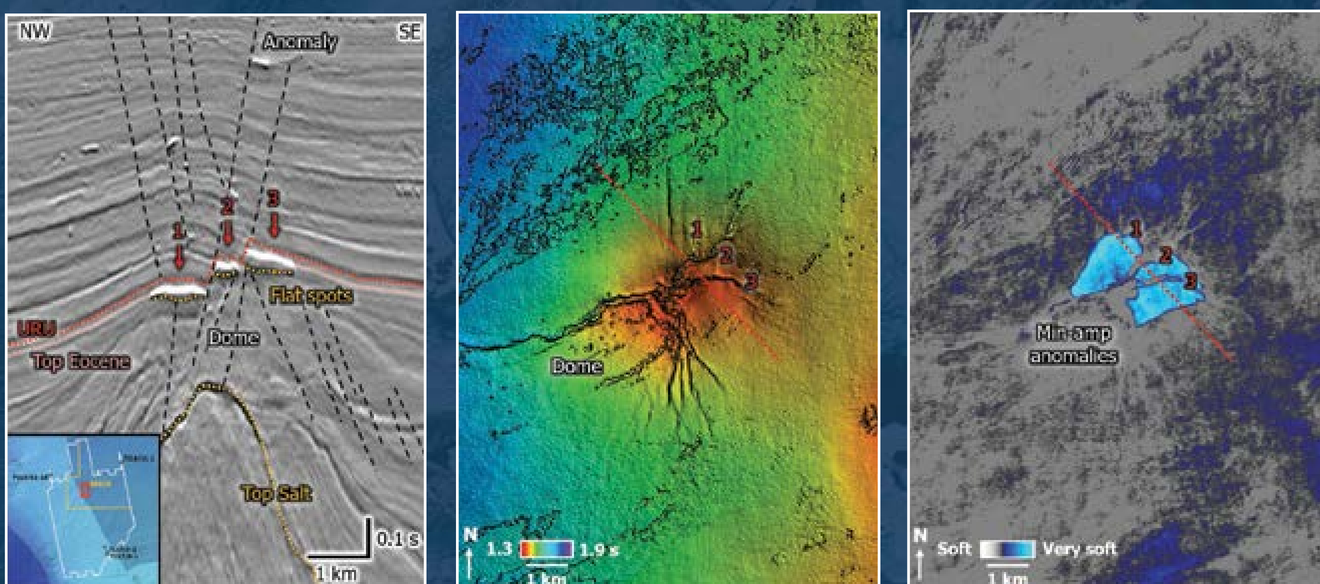
Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price



Derisk Your Area of Interest and Reduce Exploration Cycle Times

From subsurface interpretation to high-quality imaging, TGS has it covered.



Late Eocene | Dome Above Salt

For the last 20 years TGS and VBPR have worked together to unravel the prospectivity of volcanic margins around the world. Whether you wonder about the potential of the West Barents Sea, oil and gas plays along the Atlantic Margin, or increased exploration success in frontier basins worldwide, TGS and VBPR provide the most reliable geological, geophysical and geochemical understanding of the overburden.

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