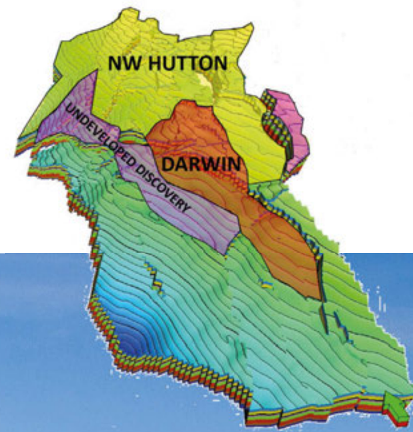
VOL. 17, NO. 6 – 2020

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



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EXPLORATION
MER: The Race to Find Proven Oil

GEO TOURISM
Red Rocks Revealed

EXPLORATION
Using Super Basins as Analogues

INDUSTRY ISSUES
How is Natural Gas Priced?

RESERVOIR MANAGEMENT
Broadband 4D Seismic

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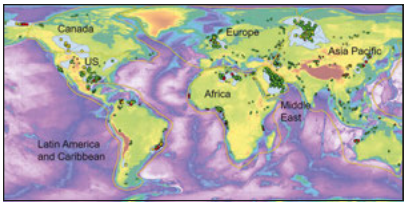

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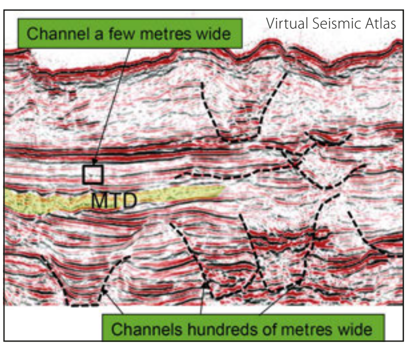

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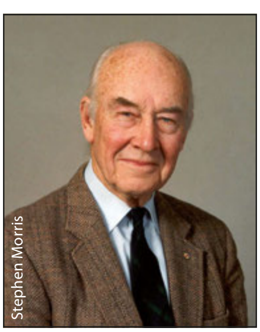

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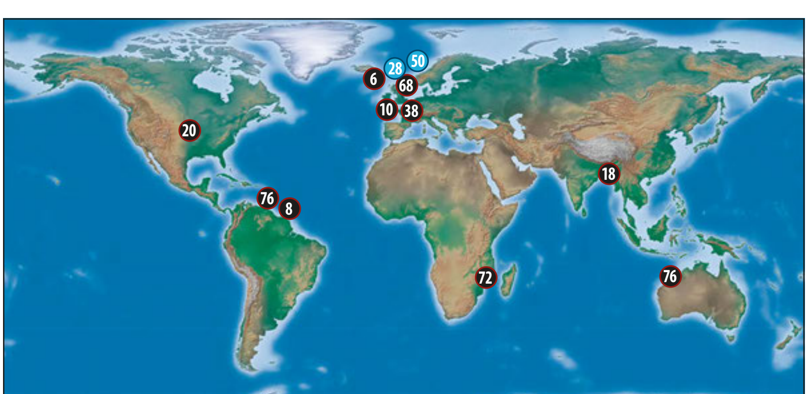

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The End of an Era

Jane addressing an industry meeting.

A decade is a long time in the oil industry. Ten years ago the price of Brent crude was $75 and the rollercoaster of several years of over $100 oil, followed by a massive crash in 2015 and the present Covid-19-related problems, were all ahead of us. The giant deepwater fields off Brazil had only just started to produce, broadband and ocean bottom seismic were in their infancy, and the exponential rise in production of gas and tight oil from US shale formations was just beginning. Digitalisation and 'the intelligent oil field' were occasionally mentioned, while the energy transition was only discussed in fringe meetings.

And a decade ago I became Editor in Chief of *GEO ExPro* Magazine; ten years that have flown by in a whirl of magazines (63 editions, to be precise!), conferences, exhibitions, meetings and fun. I have been to some fascinating places; met some amazingly interesting people, many of whom I have profiled; learnt so much about the oil and gas and energy industry and the dedicated people who work in it; and seen it and them progress through many challenges, including embracing that important energy transition.

However, I have decided it is time now to step back and let someone else propel *GEO ExPro* through what looks to be an exciting future, and I would like to welcome Iain Brown as the new Editor in Chief. I know he is looking forward to working with all our contributors and using his many years in the oil and gas industry to propel the magazine forward to new heights. I leave the magazine in safe hands and I wish him every success in the future.

I would like to take this opportunity to thank my colleagues in *GEO ExPro* for all their support, advice and guidance over the past decade – I could not have managed without them. I would also like to thank the many people who contribute to the magazine; their informative, well written and fascinating stories and illustrations are what makes it. And finally, I would like to thank you, the reader, for your many encouraging and complimentary comments about *GEO ExPro* – after all, without you, there would be no magazine – and I look forward to many more years of reading 'complex stories in simple words'.

Jane Whaley
Editor in Chief

A note from Tore Karlsson, Managing Director
I would like to say a big thank you to Jane as Editor in Chief of *GEO ExPro* for the last ten years! She has played a vital role in the continued development of the magazine, resulting in numerous messages from our readers with very positive feedback about the content and quality. We are also pleased that Jane will be contributing articles in *GEO ExPro* going forward.

I would like to use this opportunity to welcome Iain as our new Editor in Chief. Iain has a very valuable geoscience background and solid experience from our industry, so we look forward to a successful next phase for *GEO ExPro*. ■

RED ROCKS REVEALED

The bright red Old Red Sandstone of south Pembrokeshire, spectacularly exposed at the coast, makes the south-west corner of Wales a Mecca for geologists. This photograph of the Moor Cliffs Formation, with the Rooks Cave Tuff marker horizon in the part-eroded hollow, demonstrates the rich variety of these fascinating rocks.

Inset: Structure model of the prematurely decommissioned North West Hutton field in the North Sea, now revitalised as the Galapagos field; maximising economic recovery in action.

GEO ExPro

www.geoexpro.com

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

Managing Director
Tore Karlsson

Editor in Chief
Jane Whaley
jane.whaley@geoexpro.com

Editorial enquiries
GeoPublishing
Jane Whaley
+44 7812 137161
jane.whaley@geoexpro.com
www.geoexpro.com

Sales and Marketing Director
Kirsti Karlsson
+44 79 0991 5513
kirsti.karlsson@geoexpro.com

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

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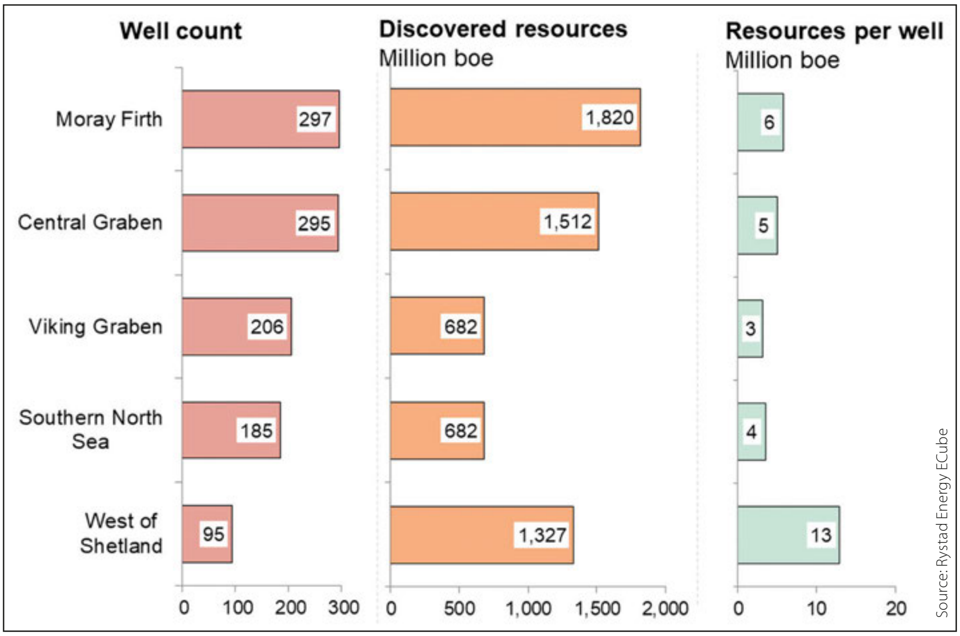
Potential Impactful Discoveries

Underexplored West of Shetland has potential for big discoveries in newly awarded UK licensing round.

The recently concluded 32nd offshore licensing round in the United Kingdom has been one of the most successful lease rounds for 2020, a year when many others were delayed or cancelled. Around 113 licences were awarded in 260 blocks or part-blocks in offers distributed amongst 65 companies. The awarded blocks are scattered across the most prospective and mature basins on the United Kingdom Continental Shelf (UKCS), including the Southern North Sea, Central Graben, Moray Firth, Viking Graben and West of Shetland.

The Moray Firth and Central Graben Basins have been the most active in terms of exploration drilling in the past two decades, with around 300 wells drilled in each, while West of Shetland is the area with the least activity during this period, with about 95 wells. Nevertheless, the West of Shetland has had an excellent rate of success, with around 1.3 Bboe in newly discovered volumes, compared to around 1.5 Bboe in the Central Graben and 1.8 Bboe in the Moray Firth Basin.

Benchmarking basins with awarded blocks in UK's 32nd licensing round (2000–2020).



Most of the volumes in the Moray Firth and Central Graben were discovered in the early 2000s, while the West of Shetlands dominated the 2010s. The Central Graben is slowly gaining some momentum with discoveries such as Glengorm (250 MMboe) in 2019 and Isabella (90 MMboe) in 2020. Glengorm is the largest discovery on the UKCS since Culzean was found in 2008, while Isabella is the largest discovery on the UKCS so far this year.

The Moray Firth Basin has delivered 34 new discoveries between 2000 and 2020, but only the 1.07 Bboe Buzzard find from 2001 is significant in size, making up about 61% of the discovered volumes. No significant discoveries have been announced in the Viking Graben and Southern North Sea Basins, with the average discovery size hovering around 20 and 15 MMboe, respectively. By comparison, the 18 discoveries in the West of Shetland Basin include Rosebank, found in 2004, with 500 MMboe of resources, as well as Halifax from 2017 with 88 MMboe and Glendronach from 2018 with 102 MMboe. This makes the West of Shetland area the most productive in terms of volumes discovered per unit well drilled.

Going by its historic performance, the blocks awarded in the 32nd round within the Central Graben and West of Shetland have the potential to deliver some impactful discoveries. In addition, the proximity of the awarded blocks to existing infrastructure could enhance the economic viability and facilitate development of small- to medium-sized finds. ■

Aatisha Mahajan, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

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

Liquids
barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day

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

Ma: Million years ago

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

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

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

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

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

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

Underexplored Suriname

Staatsolie recently announced Suriname's first Shallow Offshore (SHO) Licence Offering, with the webpage going live on 16 November and registration opening on 30 November 2020. The Licence Offering encompasses eight blocks covering some 13,524 km² of the coastal waters of western Suriname immediately to the south of the significant string of deepwater discoveries and to the north of the billion barrel in-place onshore oil fields.

Staatsolie is now inviting qualified international and national oil companies to bid for one or more of the blocks on offer, based on a minimum work programme obligation to acquire 3D seismic in the initial exploration term, followed by drilling in subsequent terms. A 60% interest and operatorship is available in each block, where Staatsolie will be carried through all exploration for its retained 40% equity.

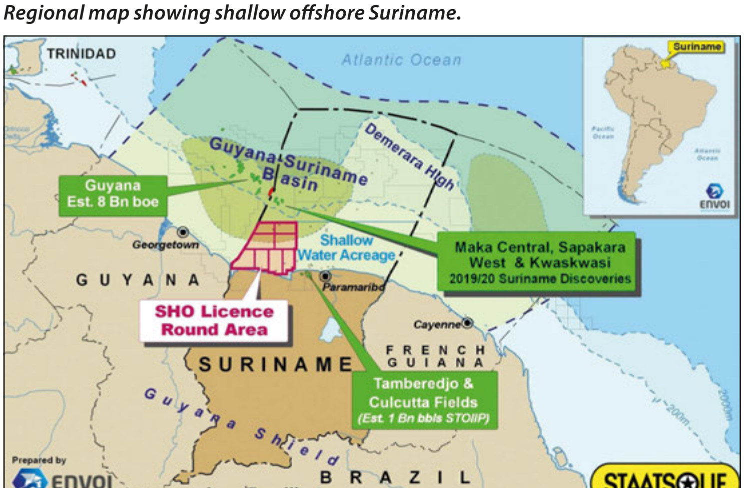
The shallow water acreage on offer is located in the migration pathway immediately updip from the mature Cenomanian–Turonian source kitchen which charged the fairway containing the Apache/Total Maka Central, Sapakara West and Kwaskwasi discoveries and where the Apache/Total Keskesi East and Shell/Petronas Sloanea wells are currently drilling. Significantly, the oil being produced from the existing Tambaredjo, Tambaredjo North-West and Calcutta oil fields onshore Suriname has also been typed to the Cenomanian–Turonian source rock, so realistically can only have migrated through the largely undrilled shallow water acreage being offered. Additional Cretaceous and Jurassic sourced oils have also been typed in the onshore wells, demonstrating that the basin has multiple mature source intervals.

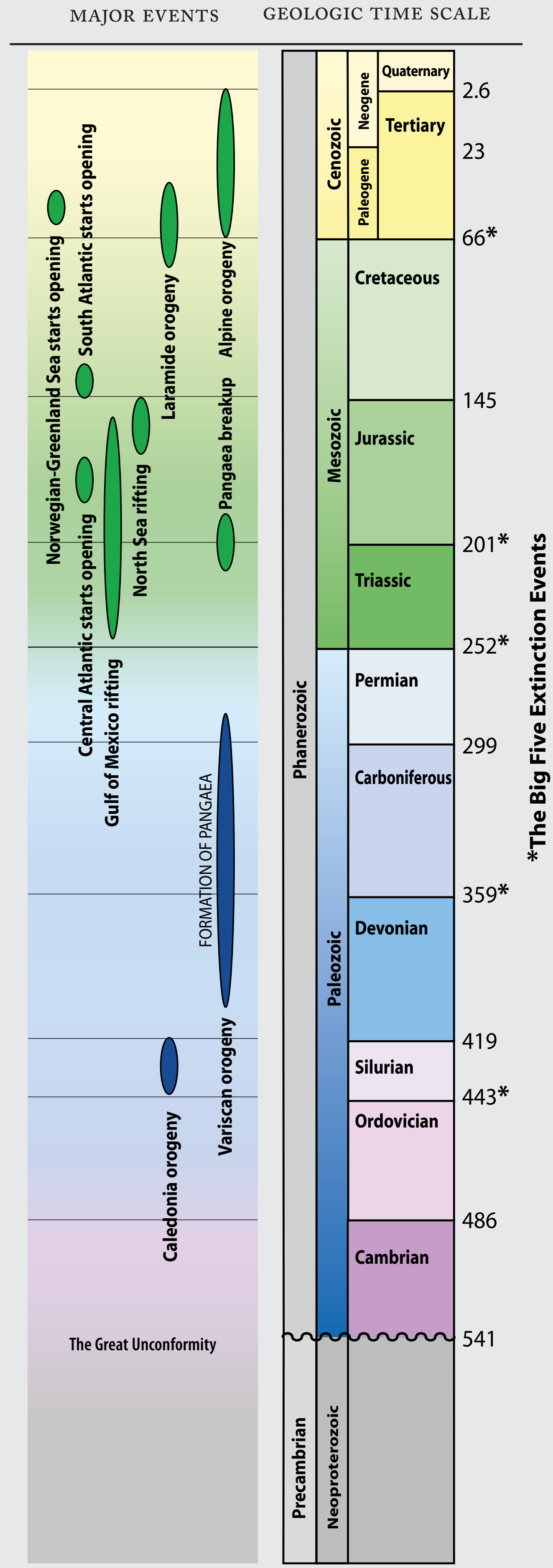
Other than a small 3D survey on the shelf edge, the SHO area is covered by a sparse grid of 2D seismic data and has seen only six historical wells drilled in such a large area, and is thus considered underexplored, although all wells encountered hydrocarbons. One of them, AKT-1, encountered 205m of shows in the Santonian equivalent to the deepwater discoveries, overlying another 87m of shows in the Albian.

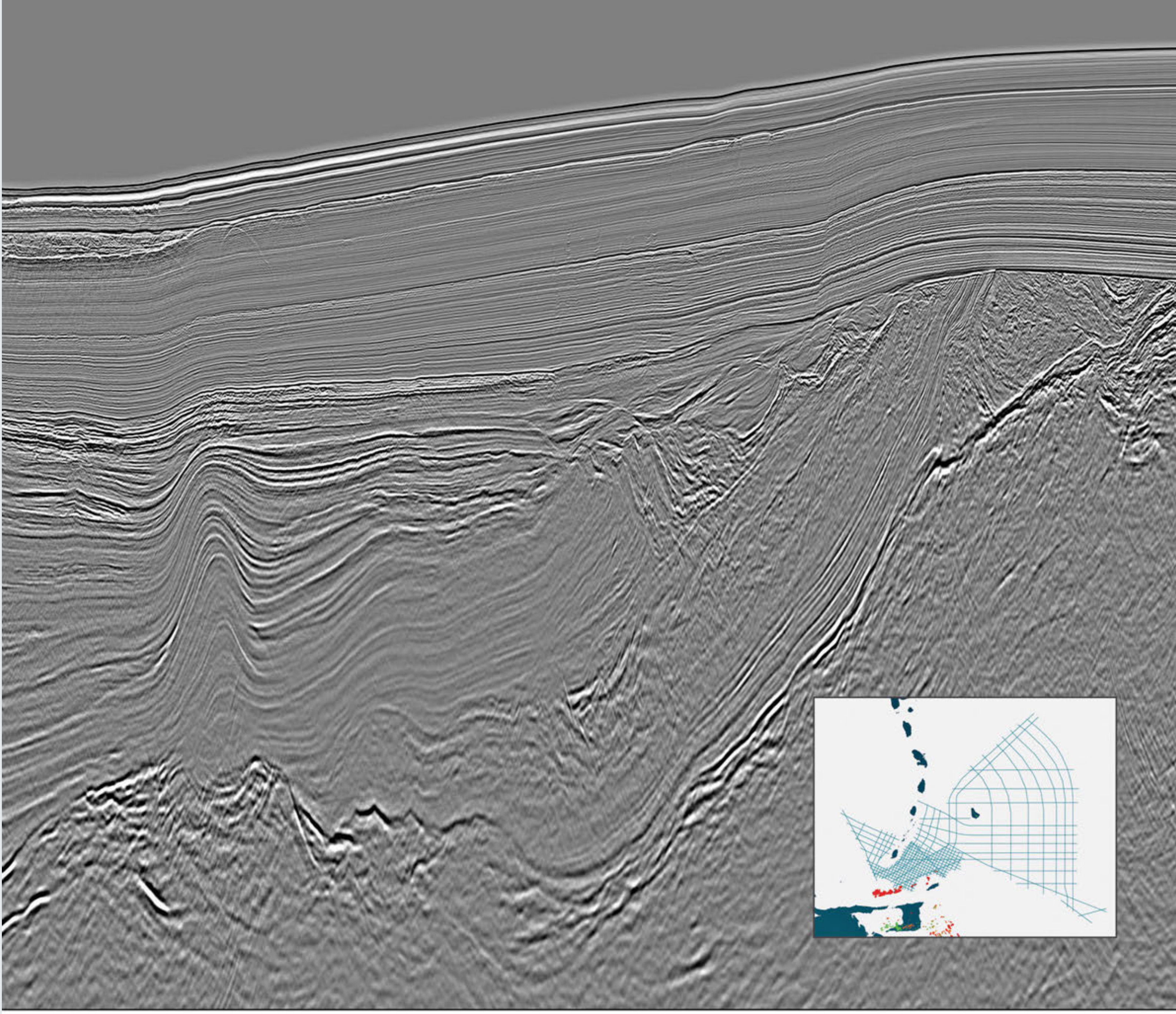
Staatsolie's most recent evaluation has defined numerous stratigraphic and structural prospects over the SHO acreage. These are not penetrated by the existing wells, offering large single and stacked play potential. High quality 3D seismic is now needed in order to unlock the full potential and define suitable drilling locations.

The Virtual Data Rooms are now open until mid-March 2021, with bids due by 30 April 2021. For more information visit the Staatsolie website or contact ENVOI Limited in London, which has been commissioned as A&D advisor for the Licence Round. ■

Regional map showing shallow offshore Suriname.







New Dates Announced for Africa Oil Week

Due to ongoing uncertainty caused by the Covid-19 pandemic, the rescheduled February 2021 edition of **Africa Oil Week (AOW)** has been cancelled. The event will now return to its regular date line, **1–5 November 2021**. The organisers took the view that delegates' experience would have been significantly impacted, considering ongoing international travel restrictions and current limitations on the number of people allowed at events in **South Africa.**

In 2021, AOW will be held in its usual venue, the CTICC2. The show will take place in accordance with the latest health and safety and government guidance. Simon Ford, Portfolio Director at Africa Oil Week and its sister event Mining Indaba, said, "Our focus is now on delivering an unbeatable live event in November 2021, which will reunite the industry, as well as provide the leading platform to help rebuild the future of oil, gas and energy in Africa. We would like to thank all those who have supported us in the last 27 years, we can't wait to see you!"

In the meantime, the AOW team is busy working on some exciting initiatives aimed at facilitating strategic conversations and delivering world-class digital content in the coming months. Visit the AOW website for details. ■

Total: First Carbon Neutral LNG Cargo

Total has delivered its first shipment of **carbon neutral liquefied natural gas (LNG)** to the **Chinese National Offshore Oil Corporation (CNOOC)**. The loading operation was carried out at the Ichthys liquefaction plant in Australia, and the shipment was delivered on 29 September 2020 to the Dapeng terminal in China.

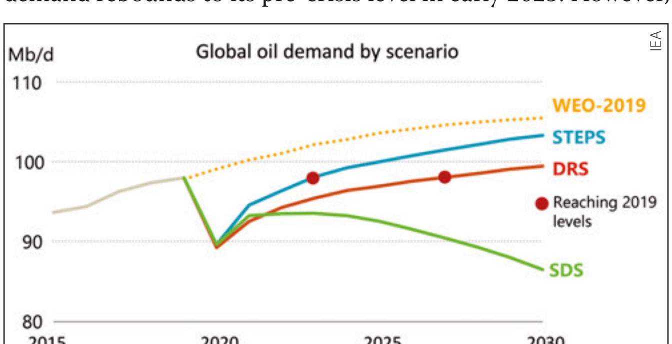
This first LNG shipment, whose carbon emissions have been offset throughout the value chain, represents a new step for Total as the company seeks to support its customers towards carbon neutrality while recognising that the development of LNG is essential to meet the growth in global demand for energy.

The carbon footprint of the LNG shipment was offset with VCS (Verified Carbon Standards) emissions certificates financing two projects. The first of these is the **Hebei Guyuan Wind Power Project**, which aims to reduce emissions from coal-based power generation in northern China. The other one is the **Kariba REDD+ Forest Protection Project**, which tries to protect Zimbabwe's forests, more than a third of which have already been lost, mostly to subsistence farming. The Kariba project protects what remains while equipping the local communities with the necessary resources and skills to safeguard their future and the future of the planet. ■

IEA 2020 World Energy Outlook

The **International Energy Agency (IEA)** recently released its annual **World Energy Outlook**, which provides a comprehensive view of how the global energy system could develop in the coming decades. It offers analysis through four long-term energy scenarios and targets the key uncertainties facing the energy sector in relation to Covid-19 while mapping out the choices that would pave the way towards a sustainable recovery. The new report provides a sobering review of the pandemic's impact: global energy demand is set to drop by 5% in 2020, energy-related CO_2 emissions by 7%, and energy investment by 18%.

In the **Stated Policies Scenario (STEPS)**, which reflects today's announced policy intentions and targets, global energy demand rebounds to its pre-crisis level in early 2023. However, this does not happen until 2025 in the event of a prolonged pandemic and deeper slump, as shown in the **Delayed Recovery Scenario (DRS)**, with large falls in investment increasing the risk of future market volatility. The **Sustainable Development Scenario (SDS)** puts emphasis on renewables, with solar being the main source of growth, although the report shows that strong growth of renewables needs to be paired with robust investment in electricity grids. The fourth scenario is the **Net Zero Emissions by 2050 case**, which extends the sustainable Development Scenario analysis to model what would be needed in the next ten years to put global CO_2 emissions on track for net zero by 2050. ■



World's Geoscientists and Engineers Gather Online

The **European Association of Geoscientists and Engineers (EAGE) Annual Conference and Exhibition Online**, on **8–11 December 2020**, brings together the global geoscience and engineering community to confront the extraordinary challenges facing oil and gas technology, business and academia in the Covid-19 era. Awaiting them will be the specially adapted technical programme, forum sessions, community activities, a student programme and more.

The innovative online format provides an exceptional opportunity to participate in the parallel technical sessions on offer. Around 450 pre-recorded presentations are made available to registered delegates prior to the event. During the event, sessions will consist of a video stream of presentation summaries followed by an interactive Q&A discussion.

The online exhibition will support the event. Companies will showcase their latest technological developments, products and services via an interactive set-up. Event participants can join the exhibitors' live presentations, read about their offerings, interact via audio and video, or arrange individual virtual meetings.

Inside the 'Community Hub', EAGE will offer an engaging set of activities on career development open to all delegates. For students there will be recruitment advice and networking with university and company representatives.

Learn more about all aspects of the event at the EAGE website. ■

The Value of Mentoring

A recent '**Women in Global Energy**' study, supported by **POWERful WOMEN**, highlighted the importance of **mentoring** in ensuring women fulfil their potential in the energy industry. Respondents to the survey on which the study was based saw the absence of mentoring as a key reason why women may struggle to climb the career ladder.

Having your own personal support network to help navigate through career bumps and allow you to realise your potential can be the difference between coping and thriving – this is the value of mentoring. Of the female respondents, 43% said they were neither a mentor or mentee, as compared to 26% of men, and 53% of female energy professionals said that their company does not offer formal mentoring programmes. Interestingly, 63% of women, as opposed to only 37% of men, said that they found the mentoring programmes offered by their employer useful.

POWERful WOMEN is one of the many organisations in the industry that promote mentoring, usually through networking events, and they encourage women to step forward and ask someone to support them, whether or not they are part of their organisation. ■

Building Training Resilience

As the effects of the pandemic deepen, companies are adjusting to the new business landscape of remote working and online meetings: training is no longer 'on hold' until normal activities resume. Many were reluctant to replace face-to-face courses with online learning, fearing the interactivity of the learning experience would be compromised.

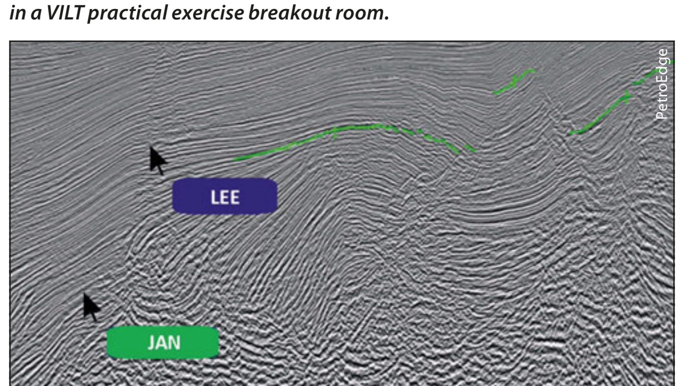
Using a variety of platforms, **PetroEdge** has continued with **a fully supported learning experience** through live **virtual instructor-led training (VILT)**. Participants are given orientation instruction before the courses to ensure full access and interaction with each other, the instructors and the resources available. Instructors have had to rethink their materials and practical exercises and adjust the way they work with learners. Teamworking in 'breakout rooms' allows colleagues to interact and learn from each other, connecting a dispersed workforce. Group activities and discussions foster engagement and help instructors gauge participants' level of comprehension.

VILT courses are cost-effective and easy to organise with no need for travel, meeting rooms or accommodation. Trainees return to their normal work at the end of the sessions and can view video of any parts of sessions they may have missed.

Feedback from participants is 100% positive; over 75% rated the communication, effectiveness and interactivity as very good to excellent. Trainees particularly appreciated the quality of materials, group activities, interactivity and communication.

PetroEdge has also developed bitesize and multi-instructor programmes, taking advantage of the flexibility of VILT and easier access to instructors. ■

The cursors of an instructor and trainee discussing seismic interpretation in a VILT practical exercise breakout room.



Red Rocks Revealed

Prof. BRIAN WILLIAMS and
Dr GARETH GEORGE

The rocks which form the beautiful cliffs and beaches of south Pembrokeshire give a snapshot into the Variscan Orogen of south-west Wales.

South Pembrokeshire records a splendid cross-section through the Mid- to Upper Palaeozoic sedimentary sequences contained within the east-south-east to west-north-west Variscan Orogenic Belt. This is enhanced by the presence of major long-lived, synsedimentary dip-slip faults and thrusts, in particular the Ritec Fault, that were important in controlling the location of depocentres for the accumulation of the Siluro-Devonian sedimentary sequences during the Mid-Palaeozoic.

Additionally, the Variscan deformation generated large scale macrofolds, such as the Marloes/Winsle Inliers and the Burton Anticline, north of the Ritec Fault; and the Ridgeway and Castlemartin–Orielton Anticlines with the intervening Pembroke Syncline south of it. The macrofolds contain parasitic mesofolds on their flanks, often in couplets (Figure 1) and commonly plunging over 20°. The folding is associated with both right- and left-lateral-slip (wrench) faulting and has become a classic study area for structural geologists. In addition to the faulting, the 2–5 km amplitude of the Variscan anticlines has culminated in a modest horizontal tectonic shortening up to several kilometres, compared with about 22 km of cross-strike width to the region in the present day (Figure 2).

The Welsh Old Red Sandstone

The Pembrokeshire 'Red Rocks' are of Siluro-Devonian age (427–358 Ma) and referred to as the Old Red Sandstone (ORS) magnafacies and are magnificently exposed throughout the county. The ORS dominates central South Wales with an outcrop area of over 20,000 km2.

Theb ulk of the South Wales ORS is dominated by the Lower ORS, deposited on the southern margins of the ORS Continent, a land mass that formed by mid-Silurian times (around 430 Ma) due to the closure of the Iapetus Ocean and the plate amalgamation of Laurentia with Baltica and the microcontinent Avalonia. TheL ower ORS Anglo-Welsh basin fil l comprises predominantly continental red-bed sediments that record diffe ring depositional architectures refle cting variations in subsidence, tectonic history, provenance and depositional mechanisms. TheL ower ORS in south Pembrokeshire ranges in age from Upper Silurian (427 Ma) to Lower Devonian (400 Ma), with a transitional lower contact with marine Silurian rocks north of the Ritec Fault and an unconformable contact on marine Silurian rocks in the Pembroke Peninsula. TheL ower ORS comprises a broadly upward-coarsening sequence, both north and south of the Ritec Fault, its depositional termination being designated by a major unconformity generated in Late Lower Devonian times by the Acadian deformational event.

Oldest ORS: Marloes Inlier

Th e Marloes Peninsula provides some of the most spectacular viewpoints from the coastal path (Figure 3). Th e Marloes Inlier is bounded by the Musselwick and Ritec Faults. Within this area, grey mid-Silurian shallow marine sediments pass transitionally into red sandstones of the Red Cliff Formation, the change in colour marking the incoming of fl uvial facies characteristic of the Lower ORS. Th is 50m-thick succession also contains incipient calcretes (pedogenic carbonate soil horizons), burrows and mudrocks that have yielded Upper Silurian palynomorphs. Abruptly overlying this is the 100m-thick Albion Sands Formation, comprising multi-storey and multilateral, very coarse-grained lithic arenites that are extensively channelled and trough cross-bedded and contain volcanic detritus, transported from a westerly source area by sediment-charged rivers.

Thus, the Marloes Inlier preserves the oldest representative ORS facies seen anywhere in southern Britain, and may only be matched in age by ORS sediments deposited in intermontane basins in north-east Scotland within the heart of the ORS Continent.

Figure 1: A Variscan mesofold anticlinal–synclinal asymmetric couplet on the southern limb of the Pembroke Syncline at Cobblers Hole, Dale Peninsula, south of the Ritec Fault.

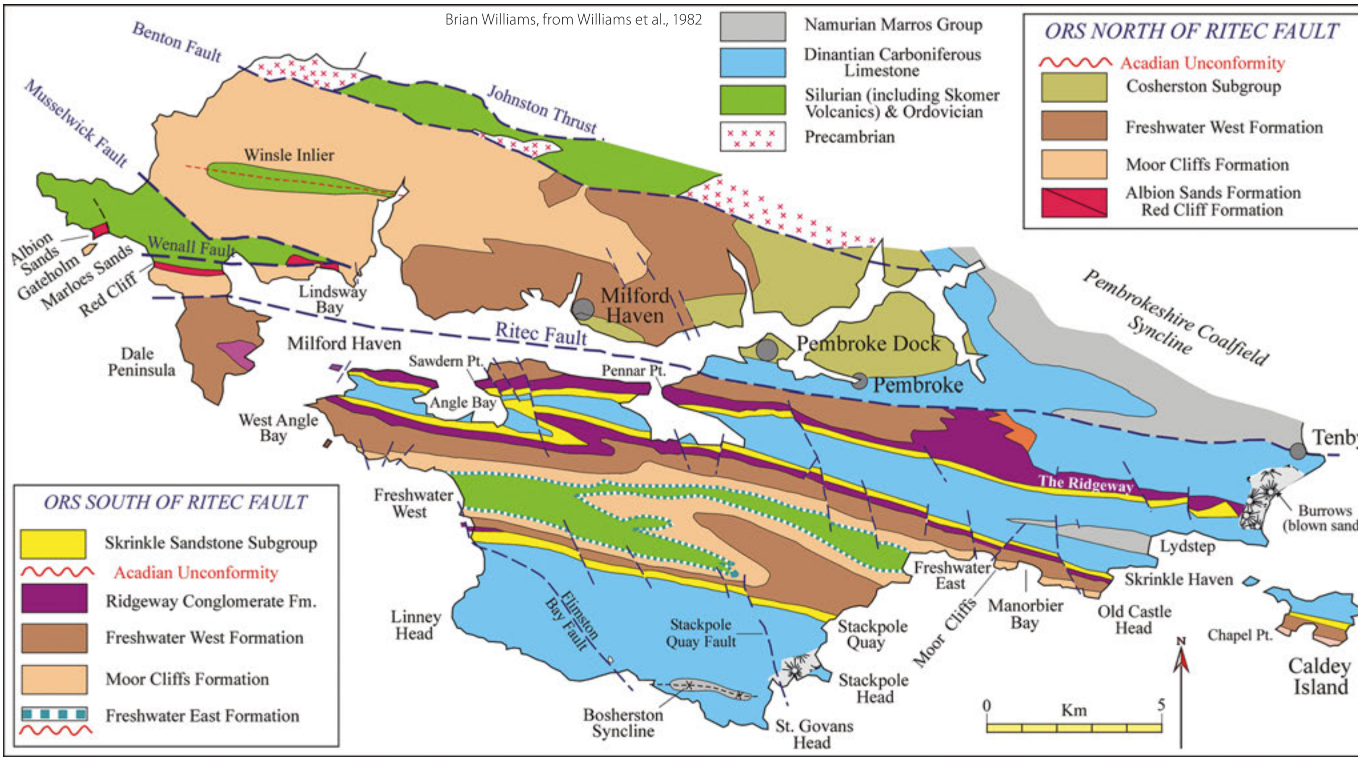


Figure 2: Geological map of south Pembrokeshire showing Mid–Upper Palaeozoic stratigraphy and major Variscan structures.

Freshwater West: The Reference Section

The Lower ORS of south Pembrokeshire has recently been stratigraphically re-assigned to the Upper Silurian to Lower Devonian (427–400 Ma). Continental deposits of this time period are beautifully displayed throughout the Pembroke Peninsula, in repeated outcrops produced by the large amplitude Variscan folding.

The two main localities in the Pembroke Peninsula in which these amazing suites of rocks can be studied in detail are Freshwater West, a dip section on the vertical southern limb of the Castlemartin Anticline, and between Manorbier Bay and Skrinkle Haven, an extraordinary strike section through the youngest Silurian rocks (420 Ma) on the vertical southern limb of the Pembroke Syncline. The superlative reference section at Freshwater West is described in detail here, with links to other Lower ORS localities within south Pembrokeshire.

Arguably the finest continually exposed section through Mid-Palaeozoic rocks in southern Britain (Figure 4), this easily accessible sequence displays the entire ORS succession together with patchy outcrops of the Lower Ordovician black, deepwater graptolitic shales that form the core of the Castlemartin Anticline. An 11m-thick shallow marine, mid-Silurian sequence rests with marked unconformity on the Ordovician mudrocks, in turn overlain by the basal unconformity and conglomerates of the Lower ORS.

Basal Conglomerates: Freshwater East Formation

To the north of Little Furzenip, the mid-Silurian shallow marine Gray Sandstone Group is unconformably overlain by the ORS basal unit, the Freshwater East Formation (FEF), named after its type locality 15 km along strike in the lovely bay of Freshwater East, where it is 50m thick, although only 18m at Freshwater West. It comprises green–grey conglomerates composed of quartzitic and lithic sandstone clasts, up to 450 mm, with vein quartz and olive green mudstones, reminiscent of underlying Silurian strata. They are succeeded by fine-grained sandstones with brachiopods, plant remains, arthropod tracks and other fossils.

Figure 3: Panorama of north-west end of Marloes Sands, showing basal ORS of Horse Neck promontory (right) and the islands of Gateholm (centre) and Skokholm (left); the Ritec Fault passes just south of Gateholm.

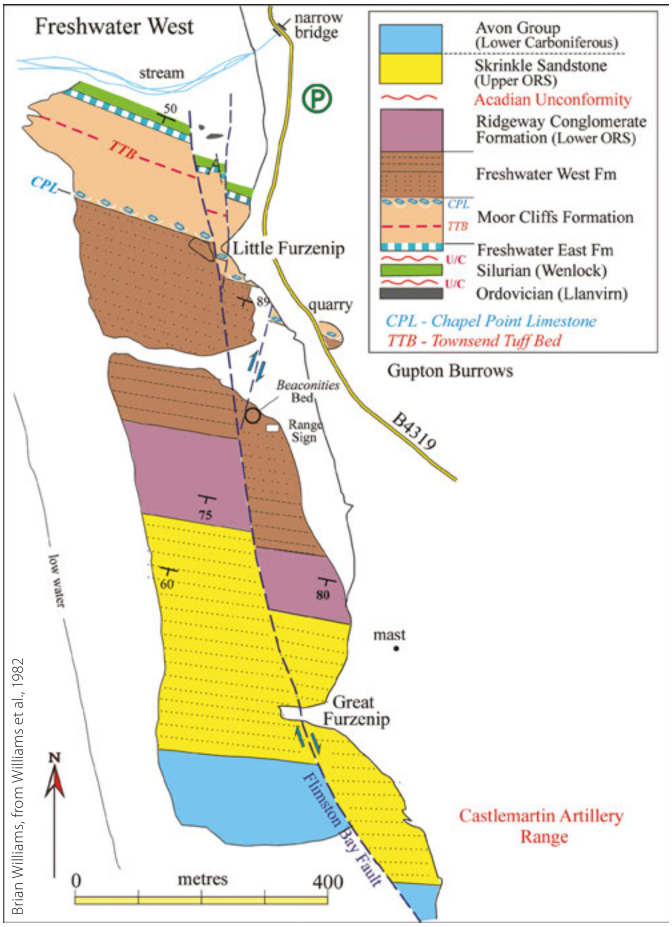


Figure 4: Geological map of Freshwater West: note the trace of the Flimston Bay Fault. This is the ORS section most visited by geologists and students in the UK because of its completeness and the superb, wave-polished exposure of formations best appreciated from the road above the section.

Recent research identified the FEF on Gateholm Island, allowing its correlation across different fault blocks for the first time. Its interwoven relationship with the Moor Cliffs Formation on the island has suggested that it represents part of a simple incised valley fill system, which was basin-wide, structurally-controlled, up to 60m deep and partly filled with conglomerates deposited from south-east-flowing braided rivers.

Into the Mud: Moor Cliffs Formation

The Moor Cliffs Formation (MCF), named after the excellent strike sections that crop out in West Moor and East Moor cliffs near Manorbier, has a transitional contact with the underlying FEF, crosses the Silurian/Devonian boundary in age and varies in thickness across the Ritec Fault, from 120m at Freshwater West to 371m nearer Marloes.

Although over 70% mudrock, the MCF exhibits an array of fascinating microfacies that helps understand its depositional setting within a tropical dryland alluvial and coastal plain environment subject to repeated, prolonged emergence and carbonate soil formation of varying maturities. It is punctuated by multi-storey, exotic, fluvial sandstone packages and individual sheet sandstones, together with major volcanic event horizons (described below) and a multilayer calcrete complex at its top.

Several types of mudrock microfacies have been identified in the MCF, including pedified units; burrowed horizons; brick-red massive units and heterolithic units. These suggest a two-stage dryland model, where the main streams were anastomosing, though ephemeral, and flood events, dust storms, pedified and ponded areas all contributed to this array of depositional styles. Conversely, the exotic sandstone bodies in the lower and upper parts of the MCF demonstrate dramatic mega-flood events from a northern hinterland. These are coarse-grained litharenites with plane-bed or cross-bedded internal structures.

Explosive Events: Townsend Tuff Bed

One of the most important discoveries in the ORS of the Anglo-Welsh Basin in the last 40 years was of a key stratigraphic marker horizon within the Moor Cliffs Formation: the Townsend Tuff Bed (TTB), which was subsequently mapped throughout the basin (Figure 5). The product of huge volcanic events, it has a very distinctive internal stratigraphy, facilitating ease of correlation over such an extensive area. It is one of several volcanic ash falls recorded in the MCF; most are thin, impersistent horizons but two others are of importance in south Pembrokeshire: the Rooks Cave Tuff, which occurs 40m below the TTB and is best seen in the Manorbier to Conigar Pit strike section (see front cover) and the Pickard Bay Tuff, 15–30m above the TTB.

The TTB is between 1 and 4m thick and is generally thinner to the west where depth of burial of the ORS was greater and Variscan tectonic flattening more pronounced. Its mineralogy and diagenesis indicate its origins in a series

Figure 5: The 2.29m-thick Townsend Tuff Bed completely exposed just north of Little Furzenip, Freshwater West. (Prof. Brian Williams for scale).

of volcanic explosions, and a regionally developed scoured surface in the middle is interpreted as a tsunami horizon. It is thought that the volcanic vent(s) were situated 250–800 km to the north-west. The oldest part of the TTB has recently been radiometrically dated (420 Ma) to be well within the generally accepted age of the Silurian/Devonian boundary, so the bed is a good proxy for this within the ORS of the Anglo-Welsh Basin.

The widespread nature of both the Townsend and Pickard Bay tuffs presents a correlation window for alluvial architectural analysis over a narrow stratigraphic interval of 15–30m. A very detailed analysis is afforded by six laterally persistent tuff markers within this interval, which has helped distinguish both aggradational and incisional fluvial sand bodies with possibly some tidal influence.

The Rocks Cave Tuff Bed is up to 2.5m thick and was probably deposited in floodplain ponds and inter-pond areas with a high density of infaunal burrowing organisms.

Basin Shutdown: Chapel Point Limestone Member

Of stratigraphic importance across the entire Anglo-Welsh Basin is the Chapel Point Limestone Member (CPLM), named after its superb type section on Caldey Island. It comprises a stacked sequence, up to 20m, of calcretised vertisols, approximately 100m above the TTB.

These calcretes reflect a period of significant stability and tectonic quiescence across the whole Anglo-Welsh Basin. It marks the top of the MCF; its upper surface is extremely abrupt and coincides with a profound change in lithofacies, faunal types, depositional environment and sediment provenance. The thick development of calcrete was created by reduced subsidence rates and erosion and may indicate a period of extended aridity. However, it is possible that parts of the former Lower Palaeozoic Welsh Basin and Irish Sea areas were being tectonically inverted at this time, with fluvial palaeoflows from the north and north-west. Whatever the main driving force, the basin was shut down and not receiving new sediment supplies for probably over 100,000 years. Thus, the top of the CPLM is a significant hiatal surface in the evolving story of the Lower ORS basin fill.

Evolving Fluvial Styles: Freshwater West Formation

The early Lower Devonian Freshwater West Formation (FWF) is 1,000–1,500m thick north of the Ritec Fault and 346–580m to the south. It comprises two distinctive facies associations: the Conigar Pit Sandstone Member (CPSM) and the Rat Island Mudstone Member, beautifully displayed as wave-polished surfaces in the rock foreshore at Freshwater West. An important historical note is that the sandstones at Manorbier Bay provided one of the first analyses and interpretation of upward-fining cycles as the deposits of meandering river systems.

Immediately above the FWF/MCF hiatal surface the basal sandstones are coarse-grained and heterolithic with internal bedforms and show the first introduction of exotic detritus from a new northerly source area following basin shutdown. Between the sandstones the mudrocks are varicoloured with both biogenic and pedogenic destratification.

Figure 6: *Beaconites* ***burrows in CPSM. The way-up arrow is 12 cm long.***

Traversing up-section, a second fluvial sandstone style is encountered: overlying low-relief erosion surfaces draped with intraformational conglomerates, the product of sluggish meandering rivers. Again, the intervening mudrocks are variously calcretised and bioturbated. These packages are frequently interrupted by upward-fining sheetflood units, commonly disrupted by very large *Beaconites* burrows, up to 20 cm in diameter and 2m long. These remarkable trace fossils are abundant in the CPSM and are ascribed to a now-extinct group of arthropods known as Euarthropleurids (Figure 6).

An additional style of fluvial architecture in the CPSM at Freshwater West are medium to coarse-grained sheet-like sandstone packages, up to 13m thick. They contain small-scale internal erosion surfaces, have extraformational conglomerates at their bases, are flat or cross-bedded on a large scale and are the product of lunate dunes migrating down braided river channels. The extrabasinal conglomerates and sandstones comprising these braided river channel and bar deposits contain the first major occurrence of fish fragments.

At the top of the FWF at Freshwater West is the 81m-thick Rat Island Mudstone Member (RIMM). Although mainly mudrock, it reveals stacked cyclic packages of four facies lithotypes: intraclast conglomerate; heterolithics; pedified mudstone and mudstone. These occur in distinct upward-fining units 2.5 to 5m thick. Near the top of the RIMM at Freshwater West there are incursions of exotic detrital sand grains; a precursor of the overlying Ridgeway Conglomerate Formation, associated with the first pulse of the Acadian deformation event.

End of the Lower ORS

The Ridgeway Conglomerate Formation (RCF) is the first example of southerly-derived coarse sediment to be emplaced into the Anglo-Welsh Basin from a landmass then situated in the Bristol Channel area. It is only found in the Pembroke Peninsula, south of the Ritec Fault. Due to the lack of faunal, floral or datable volcanic ash horizons, its age has been difficult to ascertain but recent re-mapping and research indicates a Lower Devonian age.

The RCF at Freshwater West is 115m thick but thickens drastically into the Ritec Fault, indicating its control on sedimentation. It thins to the west and is absent on Caldey Island, where the Upper Devonian Skrinkle Sandstones overlie the FWF with marked unconformity. This thinning and overstep of the RCF reflects the fan-like geometry of the conglomerate and the impact of the Acadian deformation event in the mid-Devonian.

The RCF outcrop at Freshwater West is the most proximal to its southerly source. It is broadly upward-coarsening and 11 petromict conglomerate bodies, from 0.6 to 9m thick, make up 30m of the formation. They overlie erosion surfaces and are flat to crudely cross-bedded with clast imbrication.

Other beds in the conglomerate are matrix-supported, with bright red, ill-sorted gritty mudstones with irregular seams and pods of outsize clasts. The sandstones are medium to coarse-grained, massive or cross-bedded and locally burrowed by *Beaconites*. As with many alluvial fans, a high volume of mudstone in the RCF is calcretised by pedogenic processes or groundwater.

A half-graben topography initiated the deposition of the RCF in a hanging-wall alluvial fan sourced from a Lower Palaeozoic/Late Precambrian hinterland to the south. The conglomerates were deposited by laterally extensive sheetfloods and bars in low-relief channels. Most of the sandstones were also of sheetflood origin, whereas the gritty mudrocks represent cohesive debris flows. Calcrete development throughout the formation indicates semi-arid conditions.

A Snapshot

The Freshwater West section in the Pembroke Peninsula provides an excellent snapshot into the Lower ORS Red Rocks of south-west Wales. To see such a variety of continental sedimentation responding to both climatic and tectonic changes from Late Silurian to end Lower Devonian times in one huge, accessible outcrop is quite remarkable. The story of red-bed initiation on the southern margins of the newly-formed ORS Continent to its conclusion with the Acadian deformation event and its subsequent overprint by the Variscan Orogeny is wonderfully displayed in this south Pembrokeshire area.

An extended version of this article with references and acknowledgements is available online. ■

(This article is dedicated to the memory of Professor John Allen FRS, a great friend and close research colleague, who passed away on 18 October 2020.)

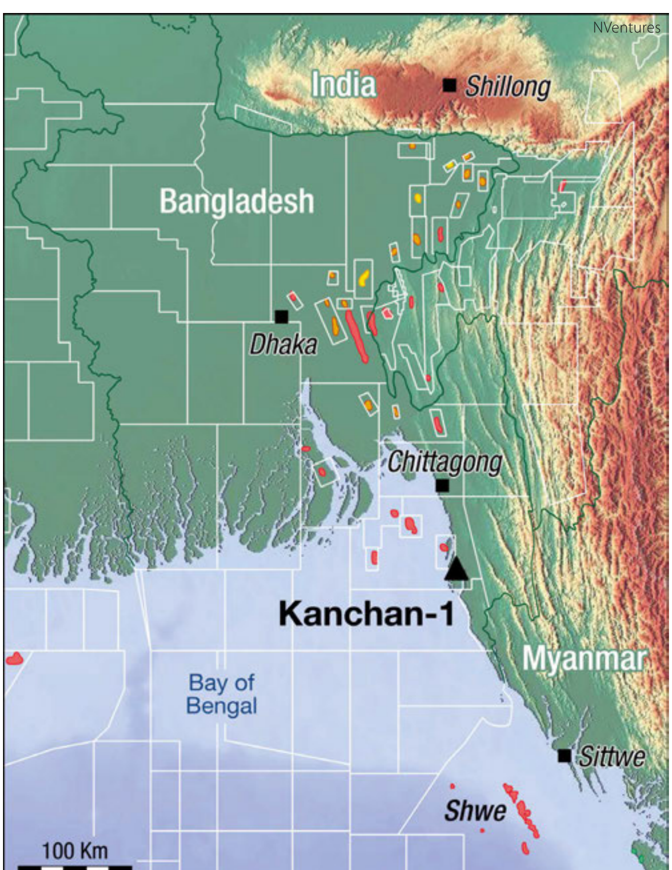
Bangladesh Upstream: Delayed but Not Out

MADELEINE SLATFORD, Middle East/South Asia Editor, NVentures Ltd

The further open-ended delay to Bangladesh's 2020 licensing round, anticipated to have been announced in September 2020, should not come as a surprise given the international Covid situation and low oil price, though it may be a disappointment for a country whose exploration acreage map looks in need of a makeover. However, the expected end 2020 spud of an exploration well, ONGC Videsh Ltd (OVL)'s Kanchan-1 in the south-east of the country (Block SS-04, onshore), may serve as a boost to reinvigorate interest in a country in which gas demand has recently outstripped supply and which, despite some renewable initiatives such as wind, has committed itself to a medium-term energy policy dependent on natural gas.

Well Positioned for Gas

Bangladesh is geologically well positioned to pursue a strategy fuelled by natural gas. It has numerous producing gas fields onshore and, formerly, offshore, all sourced and trapped within the massive Neogene fluvio-deltaic system of the Bengal Fan, a product of, and in places a part of, the lengthy Himalayan collision. To the east of the country, fields are expressed as compressional surface anticlines in the Tripura-Cachar fold belt, a north-west to south-east trending curvilinear mountain range extending eastward into India and Myanmar. The main risks with these anticlinal structures are seal breach, and drilling challenges due to overpressure caused by the massive vertical relief on the structures, as well as risk of low saturation 'fizz gas', in part due to the overpressure.



Further west the structures become less pronounced and stratigraphic or combination traps are more common. These can be difficult to identify, given the excessive level of canyon cutting in the deltaic sediments. The canyons tend to be mud filled, resulting in an atypical stratigraphic play in which a muddy canyon seals a remnant sand. Seal is again high risk in this setting.

The orientation of the folds and the slightly offset orientation of the modern Ganges Brahmaputra drainage system further complicates exploration operations. The superimposition of a standard north–south aligned exploration licensing grid adds to the numerous challenges in acquiring complete high quality seismic datasets. Technical challenges such as tidal statics and feathering of streamers in the tidal channels exacerbate the problem. Seafloor acquisition and transition zone (TZ) technology is required.

Fortuitous Delay?

Perhaps due to these challenges, the IOCs active in the country in the 1990s and 2000s, including Shell, Cairn, Tullow and Santos, have all abandoned exploration, transferring operatorship of the discovered producing fields to smaller players such as KrisEnergy. While this is a reasonable field life-cycle strategy, exploration is now largely in the hands of a few regional NOCs such as Gazprom, OVL and local state-owned BAPEX, and it is important to note that the earlier international players all left before geophysical acquisition advances became practical, cost-effective, solutions. On that basis it is expected there is a lot more to find. Further along the same trend, for example, the Shwe field offshore Myanmar has numerous similarities with the Bengal Fan combination traps, and now benefits from modern 3D and AVO work (though it too was discovered on 2D data).

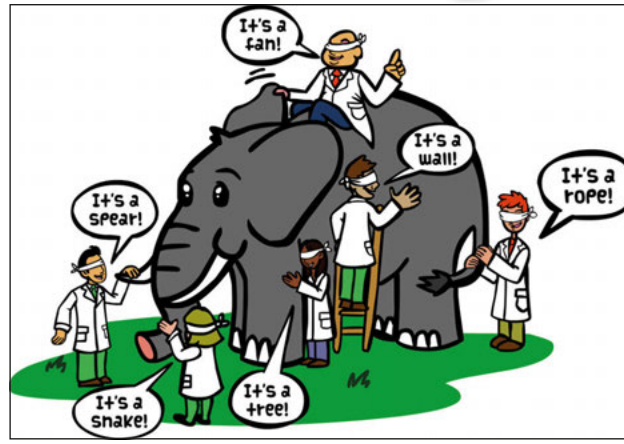
OVL's onshore prospect, along trend from Cairn's 2008 well Magnama-1 (gas shows), is reported to benefit from modern TZ data in and around the Moheshkhali (Maiskali) island and estuary. This will be critical in defining trap and enabling AVO techniques to highlight hydrocarbon responses, though gas saturation and overpressure could still be risks.

If the Bangladesh authorities review the historically low price paid for domestic gas and the restrictions on the international market, and Kanchan-1 is a discovery, the delay of the licensing round could end up to have been fortuitously timed to attract a renewed interest by international players and acquisition contractors. It would also avoid direct competition in terms of timing with currently active bid rounds in neighbouring India and Pakistan. ■

Using Super Basins as Analogues

What can we learn from the world's best petroleum basins – and what can we bring from them to the areas we explore?

CHARLES A. STERNBACH



When searching for hydrocarbons we need to be able to see and keep in mind the whole picture.

The foundations underlying the business of finding and producing oil and gas are basins and plays: they define where we work and many of our workflows. Whatever we do in the exploration process, we need to have a vision of where we fit in and how our work leads to the prize of an informed and successful drilling decision.

Super basins can be used to help us do just that. 'Super basin thinking' is an overview of the methodologies used to find and produce more hydrocarbons from the world's greatest petroleum basins.

As discussed in *GEO ExPro* Vol. 16, No. 5 and defined by Fryklund and Stark (2016), a super basin is "an established basin with at least 5 Bboe produced and at least the same volume of recoverable remaining reserves; two or more petroleum systems or source rocks; stacked reservoirs; existing infrastructure and oil field services; and good access to markets".

Super basins are not only a great place to find oil and gas; they are also excellent for anyone actively looking for hydrocarbons to learn more about their own area by seeking analogues through them. Reading widely is the best way to find an analogue to a basin and by immersing themselves in all the detail of analogue basins, geoscientists will quickly find new actionable ideas that they can test and apply to their own basins. To fuel our creativity, it is important to study as many basins as we can and to learn from the experts in each basin (Sternbach, AAPG Presentation 2018).

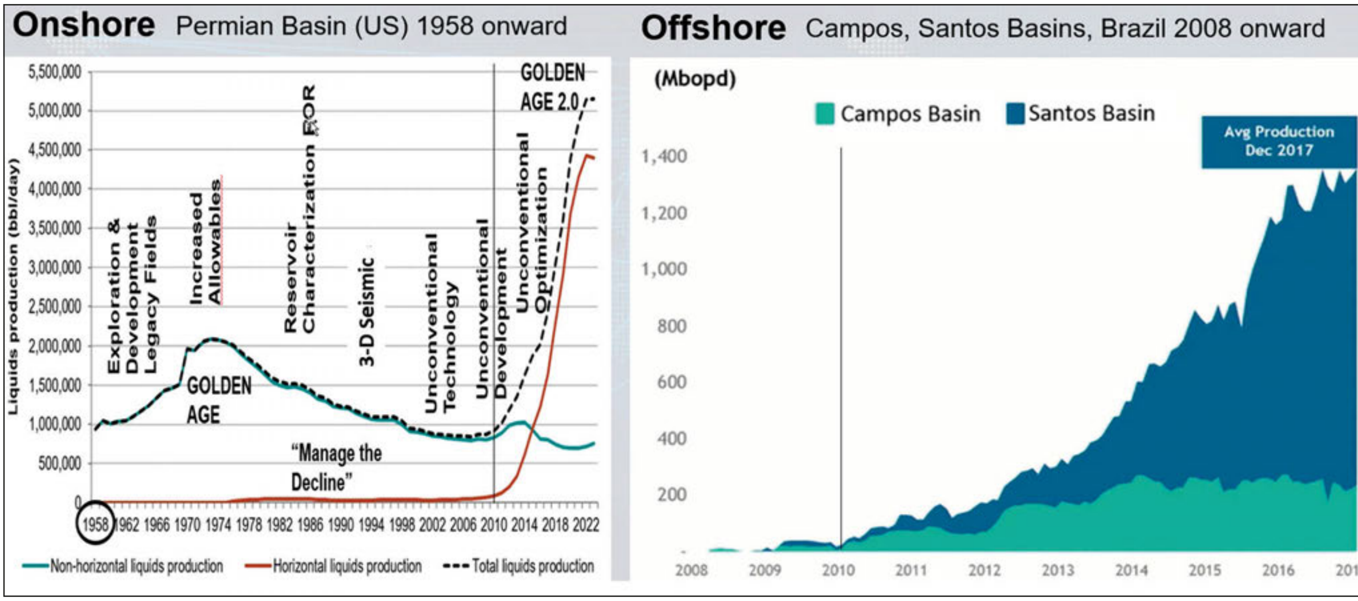
The geology of the vast West Siberian Basin lives up to the maxim: 'a super basin is a simple basin'.

Technology – The Game Changer

New technology has been the game changer that has converted already great basins into super basins, and has already revealed an estimated 860 Bboe of technically recoverable reserves waiting to be found in them (Fryklund and Stark, IHS Markit, AAPG presentation 2017).

Take, for example, a mature basin like the Permian Basin in the US. Having started producing before 1958, by the beginning of the 21st century the basin was in decline. Managing that decline was the order of the day, using what were then new technologies, such as reservoir characterisation, enhanced oil recovery and 3D seismic. With the development of horizontal drilling and fracturing and other technologies associated with unconventional exploration, however, a whole range of untapped reserves were released, and the basin is now producing more than ever before.

Technological innovation tends to happen in times of low oil prices – so it is good to remember that we are enjoying a time of peak innovation right now. Developments in engineering, like drilling further and in deeper water; in geophysics to reveal long hidden reservoirs; and exciting advances in



The Permian Basin is an example of a super basin with two 'golden ages', while offshore Brazil's production graph demonstrates the revolution in seismic imaging that allowed us to visualise under the salt. Courtesy IHS Markit, Bob Fryklund, and previously published in AAPG (Sternbach, in press).

geochemistry, all help increase our success rate.

The US Gulf of Mexico is another long-established producing basin – but for many years some of the best reservoirs were hidden, until improvements in geophysical imaging allowed us to see through thick layers of salt. Similar examples can be found in Mexico, Brazil and West Africa, all revealed by enhanced seismic imaging enabling us to visualise this previously hidden world.

Other recent developments include ocean bottom seismic and full waveform inversion, which together have produced a step change in imaging, allowing for enhanced fault identification and reflector continuity and enabling us to make better depth ties to wells and target new wells more accurately.

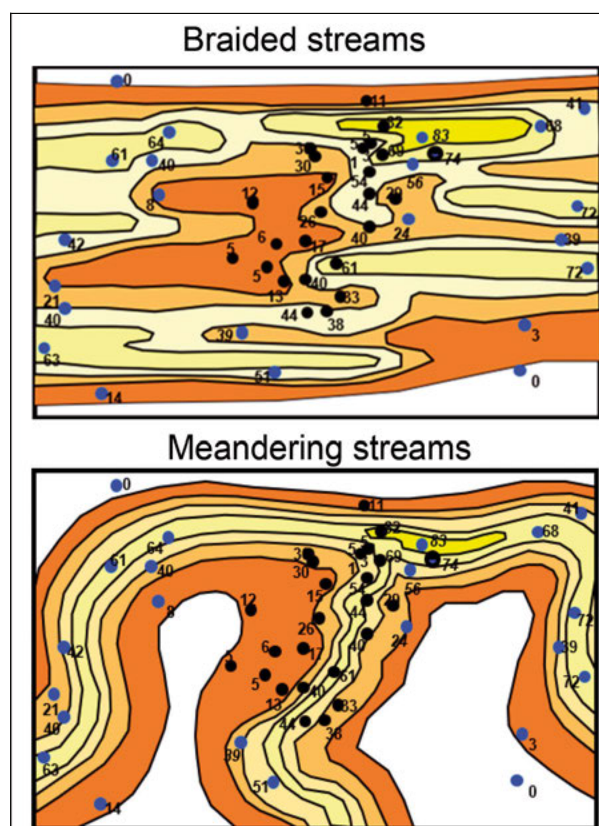
Geomodelling and big data have played a useful part in super basin exploration, but it is important to remember that the human mind is always needed to confirm the interpretation. We need to understand whether something in the super basin analogue can relate to a feature in the depositional model for our own area and then use our creative minds to guide the data, rather than just rely on the model output. As the example right shows, you cannot just contour the data – you need to interact with it.

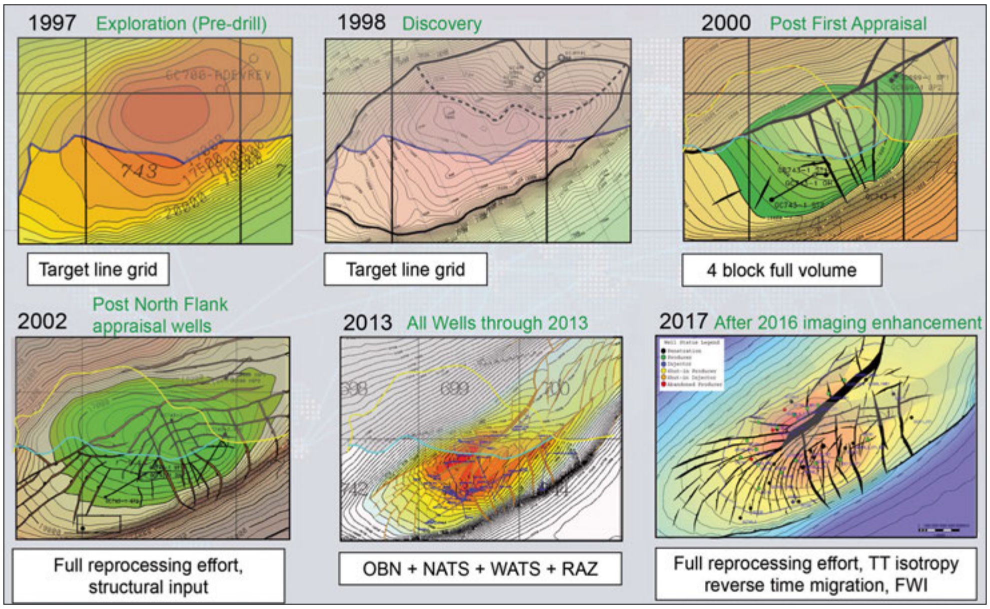
Super Sources Fuel Super Basins

Some of the world's richest source rocks are responsible for the hydrocarbons in super basins throughout the world, including formations like the Marcellus in the Appalachian Basin, the Kimmeridgian in the North Sea, the La Luna in South America and the Tannezuft in North Africa. But with such prolific sources, it is easy to overlook hidden or deeper potential sources that are not explored, even when there has been a 'whisper' in the geochemical analysis that another source rock may be responsible for some of the oil and gas. In some super basins this has indeed been the case, with several Devonian and Cambrian formations proved to be sources in the Appalachian Basin, sources older than the Cretaceous La Luna being found in South America, and many Permian to Devonian sources have been found to underlie the Jurassic Kimmeridgian in the North Sea.

For many years we only looked for oil in reservoir beds, into which it had migrated and been trapped, ignoring

Braided or meandering streams? The contouring works for both, but only the experience of the geoscientist who has seen many analogues can tell us which is the correct interpretation for this particular area. (Courtesy R. C. Shoup (personal communication), and Subsurface Consultants Associates, SCA.)





An example of progress in interpretation through enhanced seismic imaging. (Figure from J.-P. van Gestel et al. (personal communication), courtesy BP and BHP and Sternbach 2020, AAPG Bulletin.)

the potential of both the rocks in which the oil had originally been formed, and also those through which it had travelled. By extrapolating from super basins where hydrocarbons have been found in these in-situ rocks, such as shale plays, and in hybrid situations, maybe more can be found in other established basins. This is particularly relevant where there has been a late tilting episode, as seen, for example, in the Permian Basin, and although this can allow fresh water to flush oil through the migration beds, some oil will be left behind, to be extracted using established unconventional exploration techniques.

Another example is the Western Canada Basin, where much of the oil production has been focused on the oil sands exposed at the surface but where residual hydrocarbons have been retained in the Devonian migration carrier bed, obtainable with horizontal drilling and hydraulic fracturing.

From Source to Sink

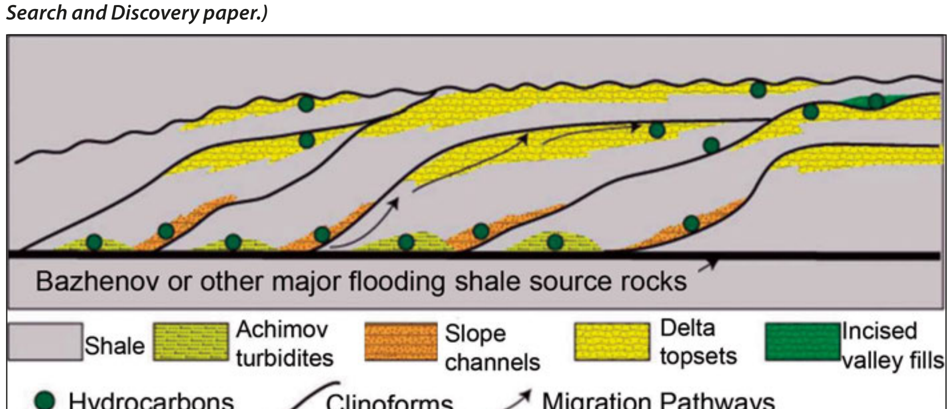
As we all know, to understand sedimentology we need to understand first where the sediments originate, and then how and where they end up in the basin. The richest fields are those that have the highest concentration of hydrocarbons, as they can be developed with fewer wells. There has been a lot of work recently on fan distribution in super basins, which can give ideas about underexplored areas; for example, there are a number of sub-basins in the Chicontepec Basin in Mexico that have very similar sediment fans to those of the prolific Spraberry Formation in West Texas. The area is virtually undrilled, demonstrating the huge potential a good analogue can suggest (Cheatwood and Guzman, 2002).

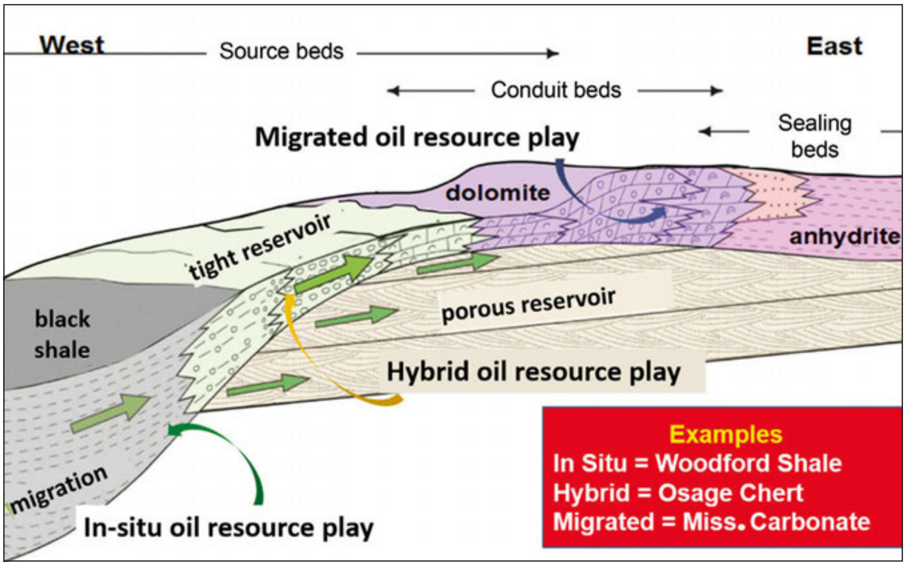
Studying the source-to-sink depositional systems of super basins reveals how important clinoforms are in understanding petroleum potential. They can produce in many different ways, from the toeset beds, as in the Bakken play, and the Vaca Muerta bottomset, to the clinoforms themselves, seen in the Anadarko Basin. The West Siberian Basin source rock is so prolific that hydrocarbons are found throughout the profile, from basal sediments through the clinoform to the topset. So, look at analogues to whatever basin you are working in and think about all the ways clinoforms can produce.

Similarly, keep looking for analogues to those elusive stratigraphic traps that have proved so productive in many super basins. The number of discoveries in these traps has increased hugely in recent years, helped by enhanced seismic imaging. Both the Permian and the West Siberian, though apparently simple basins, proved prolific. Their success relies on a lightly structurally deformed basin architecture that features multiple prolific source rocks deep in the sedimentary section and abundant reservoirs, many with clinoforms. A regional topseal is the icing on the cake. To make matters more interesting, as seen in the US Permian Basin, a late uplift on one side of the basin can introduce hydrodynamic flow, creating tilted oil water levels and creating large reserves of residual oil zones that await enhanced oil recovery.

Analogues to the Appalachian and Western Canada compressional fold and thrust belts can be found throughout the world. In these systems the key rich source rock is heavily deformed and set within the thrust belt but the reservoirs are in the less structurally complex undeformed area. Hydrocarbons have migrated via overpressured channels and reservoirs between the

The prolific clinoforms of the West Siberian Basin. (Figure from Hafizov et al., and John Dolson, AAPG Search and Discovery paper.)





Schematic cross-section showing resource classification unconventional reservoirs and carbonate source-migration model. (Courtesy R. D. Fritz, 2018 (personal communication); modified from Stone, 1967.)

two, and these intermediate beds may still hold considerable reserves.

Fulfilling Potential

E&P workflows have changed over the years, and are now split into what we can describe as short or long cycles. Short cycle workflows, which are mostly in the unconventional plays, are action-oriented; one can drill as many as 100 wells in a single year, which does not leave the geoscientist much time to spend on thinking or research. The long cycle, as epitomised by deepwater exploration, can take up to ten years to evolve from prospect identification to first oil. They are very different – but every geoscientist should experience both and work in as many super basins as possible, as what you learn from one you will carry with you to the next. Creative thinking brought from one basin can lead to success in the other. Even if a company is working in a single basin, it is important to learn from others in order to enhance your thinking.

Super basins have been found to have many commonalities (Fryklund and Stark, in press, AAPG 2020, special Super Basins issue, and Sternbach, in press, same issue). They tend to have a simple deformation history, with an early structural phase followed by a later phase of infill that serves as a really effective seal. What steps are needed, then, to take these observations on super basins and move from understanding and analysis to creative thinking and long-term strategy? How can geoscience attributes like structural setting and source, timing, reservoir, and seal architectures anticipate future energy? How can super basins fulfil their potential in the most efficient manner? These questions require many perspectives, coming from businesses of various levels of capitalisation, national oil companies, the service sector, individual geoscientists and organisations like the AAPG.

Analogues are vital in this learning process. By comparing and contrasting different basins we gather insights quickly. Geoscientists play a key role in identifying new reserves and as they study each super basin and share the knowledge they will help the world to have abundant and affordable energy for a long time to come.

Continuing to learn and study these basins fuels our creativity, and that is the most important energy source we have.

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Further references available online. ■

Try Before You Buy!

Benefits of seismic forward modelling: mitigating risk is always a focus within our industry but it becomes even more crucial in these times, with an ongoing pandemic and ensuing low oil price.

LARS ZÜHLSDORFF and TROND HAUGLAND, NORSAR

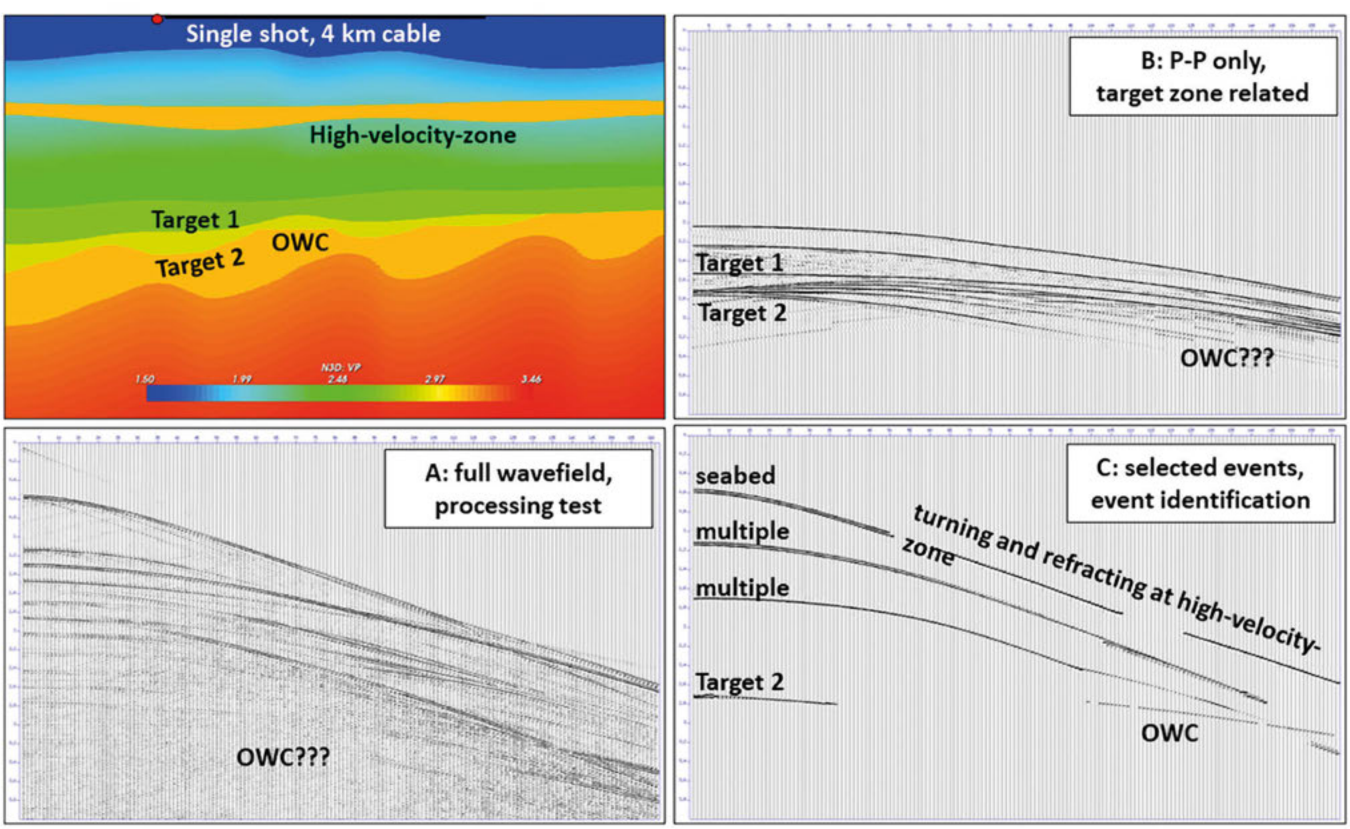
Petroleum exploration and production are both enterprises that require considerable budget, and with ever-growing complexity, the risks are many. Applying seismic forward modelling can eliminate guesswork, and ultimately help avoid insomnia when commencing cost- and time-intensive operations like seismic surveying, processing, interpretation and ultimately drilling, all based on potentially equivocal information. In short, performing a modelling study first is significantly cheaper than failing in the field.

Different Approaches for Different Objectives

There are different concepts of seismic forward modelling, which are unfortunately tenaciously misunderstood as being competitive when they are, in fact, complementary. The various applications of the different concepts and the problems they aim to resolve can be somewhat obscure, and the ranges in cost and efficiency are vast. In practice, the different approaches are intended for different objectives, even though seemingly similar products (like synthetic seismic records) can be generated by all of them.

To simplify, one can distinguish between two major concepts: full wavefield modelling and ray tracing. Full wavefield modelling (which is often referred to as FD modelling) is known as the most comprehensive way to simulate seismic data and has been undisputedly successful for decades. Processing tests are among its major applications, as these typically require complete synthetic records, ideally containing primaries, multiples, converted waves, or different types of noise. However, when generating these for field-size surveys or higher frequency signals, reconstructing the full wavefield can be prohibitively expensive and remains computationally demanding, even in the era of ever-growing computer clusters. Luckily, the modelling effort can be significantly reduced if only selected parts of the wavefield are required. In such cases, ray tracing (or ray-based modelling) would be a far less expensive and time-consuming approach, lowering the threshold for usage.

A single shot gather for a similar model and survey, using FD modelling (A), Kirchhoff modelling (B), and ray tracing (C). FD modelling generates the most comprehensive results but also is most time consuming. Kirchhoff modelling can be limited to P-P reflections from the target zone and is good for migration and velocity sensitivity tests as diffractions are included. Ray tracing is most efficient and dedicated to event identification, as the part of the wavefield to be modelled can be pre-selected. Image created using NORSAR Software Suite and PGS Nucleus+ software.

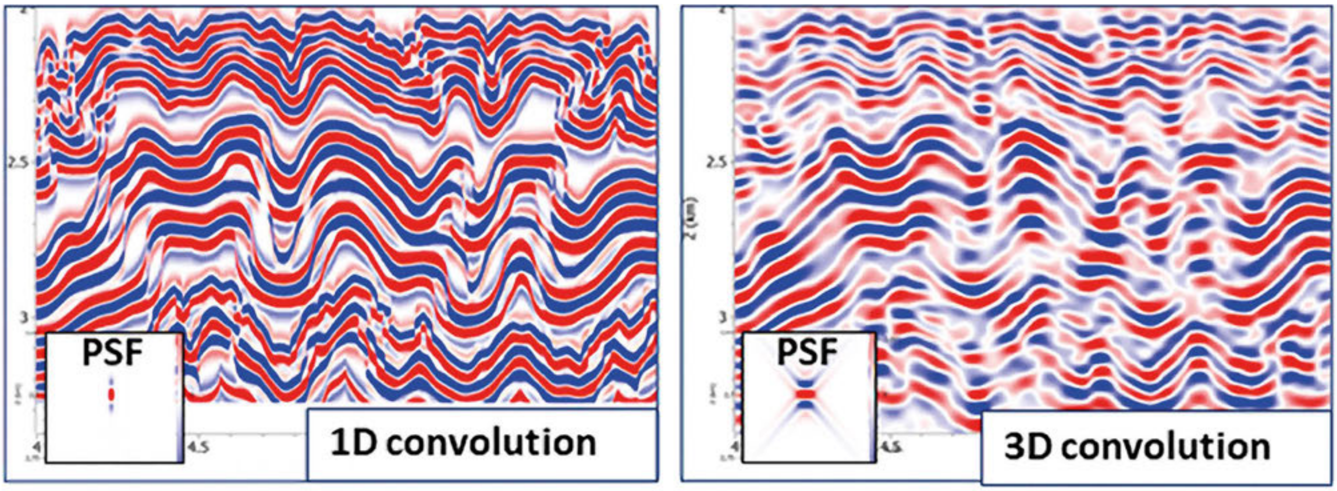


Advantages of Ray Tracing

Ray tracing not only has advantages in cost, speed and flexibility but also provides information that would not (or not as easily) be available from full wavefield modelling. For example, reflection points are known for all modelled rays, which makes illumination studies a core application. In contrast to just calculating nominal fold, which is fully defined by the survey parameters, ray tracing allows for the generation of attribute maps right on the target area of interest. This enables the identification of shadow zones and low-fold areas, undertaking infill analysis and estimating the expected signal to noise ratio. In addition, reflection events can be migrated on the fly, quickly simulating expected relative amplitude distribution along a target. Other common mapping attributes are travel time (indicating required listening time), the lateral distance between common mid-point and common reflection point (indicating required migration aperture) and the relationship between offset, incident angle, and azimuth (indicating suitability for dedicated amplitude studies or determining anisotropy from seismic data). In principle, all parameters that are stored along the rays can also be filtered, sub-selected, and mapped, which provides a great deal of flexibility.

Most ray tracing studies are carried out for either survey planning or survey evaluation. Survey planning would focus on finding the required survey parameters to sufficiently illuminate a specified target area or volume of interest. This does not necessarily provide final shot and receiver spacing, but macroscopic parameters like required offset, most efficient survey azimuth, most efficient locations of shots and receivers, and – of course – the required size of the survey, all of which has significant impact on acquisition costs and quality. On the other hand, survey evaluation indicates whether a given survey is fit for purpose and also helps us to understand why it was not, after field operations completed – such as when evaluating multi-client data. Fit for purpose, in this context, means that the survey will result in seismic data that contain all the information required to carry out needed analysis. Thus, survey evaluation either intends to ensure that appropriate acquisition parameters were used, or provide guidance for both processing and interpretation – making sure that one is getting the most out of the collected data. This methodology could also be used to determine possible uplift before procuring additional seismic data.

Often a point of confusion is the generation of synthetic gathers, which typically is considered a task for full wavefield modelling, but can be based on ray tracing as well. Being aware of the differences between approaches will help to decide which application is best suited for the task at hand. Ray tracing requires the pre-selection of parts of the wavefield to be modelled (e.g., certain primary reflections, specific multiples, or P-S converted components). It is possible to combine many different parts within a single modelling run. This is the ray tracing advantage – first because it inherently leads to the efficiency of ray-based modelling, and secondly because any part of the wavefield that can be separated can



Comparison between 1D convolution and 3D convolution as based on the same wavelet and reflectivity grid. 3D convolution takes both illumination and resolution into account. The 3D convolution operator is generated from overburden, survey and wavelet using ray-based modelling. It is also referred to as a point-spread function, providing a direct measure of both lateral and vertical resolution. Modified from Figure 16 in Lecomte et al., Ray-based seismic modeling of geologic models: Understanding and analyzing seismic images efficiently, Interpretation*, Vol. 3, No. 4, 2015.*

also be identified in field data. As such, event identification is a task that ray-based modelling is ideal for, e.g., distinguishing between primaries and multiples when doing processing tests. Ray tracing could even be required for understanding full wavefield modelling results, which makes both modelling approaches highly complementary.

It is also worth pointing out that ray tracing requires slightly different models to work than those required for full wavefield modelling. While the latter can use gridded elastic property fields at various levels of detail, albeit more computer intensive, ray tracing requires smooth macro models that typically are horizon-based. As several tens of metres of wavelength are assumed for seismic signals, the smoothness requirement is no major drawback. However, ray tracing models need to be built carefully, require representation of sharp impedance contrasts through interfaces, and are often optimised for a dedicated task. If both ray tracing and full wavefield modelling are combined in a complementary approach, it is typically recommended that the ray tracing model is built first, as it can later be easily gridded into elastic property cubes, including attenuation and anisotropy if needed.

The Best of Both Worlds

As ray tracing is so quick, one could be tempted to combine the most important parts of the wavefield to carry out processing tests without spending the time and computer resources on full wavefield modelling. Clearly it is possible to migrate ray-based modelling data, but typically caustics and triplications are not well represented, and amplitudes may be artificially boosted close to critical angles. Depending on the model, migrated ray tracing data may therefore suffer from systematic artefacts that sometimes are tolerable and sometimes not. However, advanced ray modelling packages have managed to overcome this limitation by way of Kirchhoff modelling, intended to combine the best of both worlds. Kirchhoff modelling is typically not applied to a full section but rather a selected reservoir model at depth, and is often limited to primary P-wave reflections for simplicity and efficiency. As such, the process is quicker than full wavefield modelling but focuses on ray-based generation of diffractions that later can be migrated. Typical applications include velocity sensitivity tests, as seismic migration – like pre-stack modelling – requires a velocity field. Using the same velocity field that was initially used for generating pre-stack data would provide a perfectly migrated image. However, using deviations from the ‘perfect’ model for migrating the same pre-stack data will indicate how velocity perturbations affect the final image. Kirchhoff modelling therefore is a powerful tool for evaluating velocity.

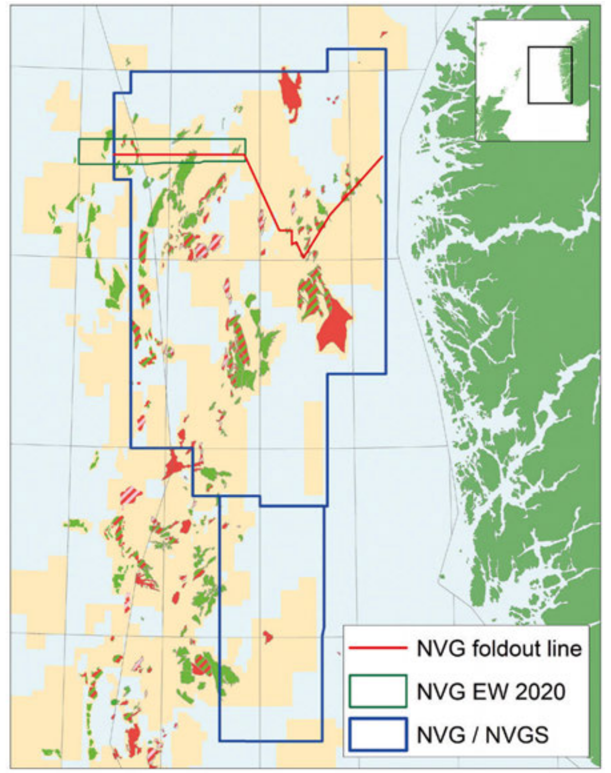
Similar approaches are used for doing even quicker simulations of depth migrated sections. Ray-based modelling can simulate point-spread functions that are subsequently used as 3D convolution wavelets, integrating both illumination and resolution effects. That way, classic seismic processing is completely avoided, as depth migrated sections can be directly estimated from a given reservoir model. Naturally, this cannot entirely replace full wavefield modelling and imaging but is useful in cases that require many different seismic simulations within a short timeframe. Typical applications would be resolution studies using the point-spread function, and time-lapse feasibility modelling, where the focus is on production-related changes between a base case and a monitor case, where processing effects are considered static between the different time steps.

Useful and Efficient Alternative

In summary, before investing in seismic operations that are both time consuming and costly it could be pertinent to investigate the potential of forward modelling. Furthermore, full wavefield modelling, although most comprehensive, is also the most expensive and time consuming. Ray-based methods have a much lower threshold, precipitating its use in a range of applications. Depending on the task at hand, ray-based methods may in many cases provide an equally useful and much more efficient alternative. ■

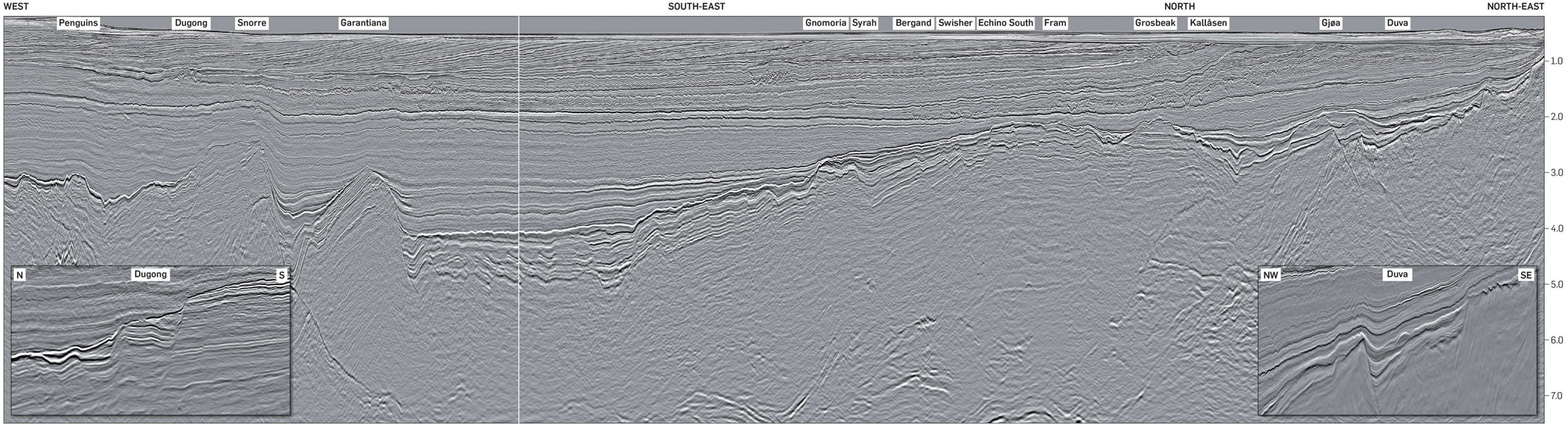
Norway: The North Sea Super Basin Story Continues

Exploration in the Northern North Sea has been extremely successful, with important discoveries such as Statfjord in 1974, and Oseberg, Snorre, Gullfaks and Troll, discovered in 1979. More recently, several smaller but still very valuable discoveries have been made, demonstrating the remaining potential of the area. This has been achieved through further maturation of established plays, as well as the addition of new plays being identified and explored within different stratigraphic levels. Between 2014 and 2018 CGG undertook acquisition of a north–south 44,000 km² 3D broadband survey over the Northern Viking Graben, known as 'NVG'. Recently, CGG has completed the first phase of a multi-year east–west acquisition project over the existing survey to generate a dual-azimuth (DAZ) volume. This initiative comes in response to industry demand for improved data quality and regional coverage, which will be particularly important going forward with the increased focus on near-field exploration and the hunt for less obvious targets.



This map shows the location of the foldout line (red) and the original north–south NVG survey (blue). The green polygon shows the location of the new east–west survey, acquired in 2020.

This seismic line, from the PSDM processing of the original north–south NVG data, passes through a number of new discoveries in the Northern Viking Graben, such as Dugong, Echino South (Lower–Upper Jurassic), Gnomoria, Kallåsen, Syrah, Swisher, Grosbeak (Upper Jurassic) and Duva (Lower Cretaceous). Close-up examples of the Dugong and Duva discoveries are taken from other sections extracted from the NVG PSDM north–south data.



NVG: Igniting Exploration

How a high quality seismic dataset can impact regional exploration in a mature basin.

MARIT STOKKE BAUCK, JASWINDER MANN-KALIL, IDAR A. KJØRLAG, ANNA RUMYANTSEVA and THOMAS LATTER; CGG

After the 2013 Exploration Revived Conference in Bergen highlighted the need for improved data quality and regional seismic coverage in the Northern North Sea, CGG acquired the Northern Viking Graben 3D BroadSeis™ seismic dataset in a north–south direction in several phases (NVG and NVGS), from 2014–2018. This contiguous dataset enables seamless interpretation of the petroleum provinces and structural elements, from the Stord Basin across the eastern Utsira High to the Northern Viking Graben. An example of the latest PSDM data can be seen in the main foldout line. Several discoveries made in the Northern North Sea since the survey was acquired, testimonies from E&P companies and acknowledgment from the Norwegian Petroleum Directorate, attest to the impact of the dataset. With several of the producing fields having their lifetime extended by 10–20 years there is a drive to develop additional resources. This, in combination with the recent success rate, suggests a continued high level of exploration and development in the area for many years to come. To assist this, CGG recently completed the first phase of acquisition of east–west new data over the existing NVG that, together with a complete reprocessing of the existing data, will create a dual-azimuth volume over the Northern Viking Graben, with the plan to continue east–west acquisition in the coming years.

Developing Plays

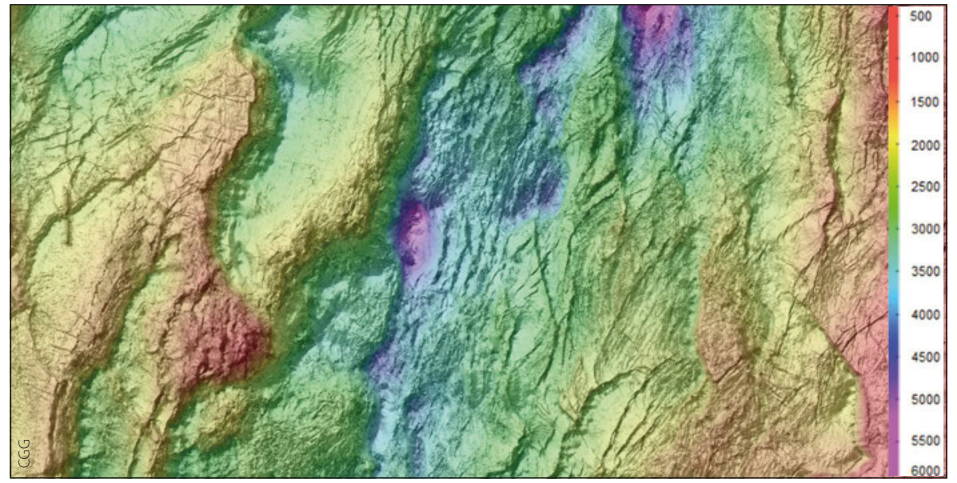
Exploration in the Northern North Sea has a long history with several hydrocarbon plays present, yet new fairways are still being identified and exploration models developed. The Middle Jurassic Brent Group is an example of an established producing play holding important reservoir rocks. Figure 1 highlights the fault complexity at the top Brent Group which hosts multi-directional fault systems. In fields such as Snorre, the entire Jurassic section is eroded and not present. The Dugong oil and gas discovery (2020), which encountered hydrocarbons within the Rannoch Formation (Brent Group) on the northern flank of the Snorre structure, opened up an underexplored region for the Brent play. This, and the Echino South discovery (2019), highlights the importance of having a high quality dataset to identify new targets in proven mature structural plays through detailed mapping of the trap elements.

The Upper Jurassic Intra-Heather Formation sands (Sognefjord, Fensfjord Formation and equivalents) have been re-explored over the Horda Platform, the Uer and Lomre Terraces and in the Måløy Slope in the past decade. Wells targeting these sands have resulted in many recent discoveries (see seismic foldout line). The high number of new discoveries and remaining potential within these sands show the continued impact of a high quality regional seismic dataset, especially at depth.

Imaging of the Upper Jurassic Munin sands (and equivalents) over the Tampen area pose significant challenges, as they sit just below the BCU (Base Cretaceous Unconformity) and often below the hard limestones, marls and reworked carbonates that make up the Mime Formation (Lower Cretaceous). This is where some improvements are expected to be seen from imaging of the dual-azimuth data volume, which will result in a better signal-to-noise ratio, and enhance illumination and resolution, which are important for unlocking the remaining potential of this play.

After the initial discoveries of the Lower Cretaceous sands in the 1990s, the Agat play was not developed further. The sands and their relationship to basement structures and Jurassic canyons are now easily mappable with seismic on a regional scale. The Schweinsteiger, Duva (Cara) and Presto wells have tested the play more recently while others, such as Havhest, are planned and other prospects are yet to be defined.

Figure 1: Top Brent time structure map (colour bar in ms), blended with coherency to highlight the fault complexity across the Northern Viking Graben.



The Paleocene Lista Formation sandstones are producing from the Gullfaks field and oil shows have been encountered at this level in the Tordis and Borg fields. Dual-azimuth data may help with regional mapping of this complex play. These sands, which have been identified within the Tampen area and on the eastern margin of the basin, require further investigation to mature this play further.

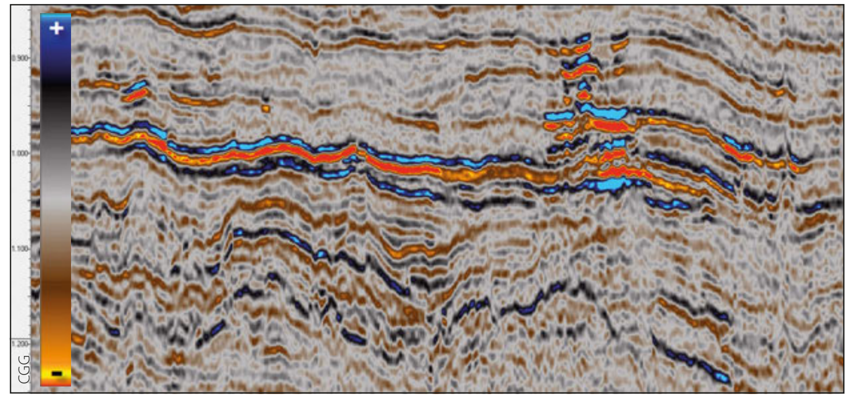


Figure 2: Arbitrary seismic section from the north–south NVG PSDM through Liatårnet, showing clear brightening at top reservoir and the approximate extent of the discovery.

Establishing New Plays

One of the most recent exciting oil discoveries in the Northern North Sea was Liatårnet (2019), which proved petroleum in the Miocene Skade Formation with an appraisal well planned for 2021/22. With the Eocene Frigg sands commonly being the main producing interval within the Cenozoic, the Liatårnet well has ignited interest in a shallower play in the NVG area. Figure 2, taken from the NVG north–south PSDM dataset, shows brightening at the reservoir level where the approximate lateral extent of the discovery can be identified. The new dual-azimuth data volume should significantly improve seismic imaging of the Cenozoic sands.

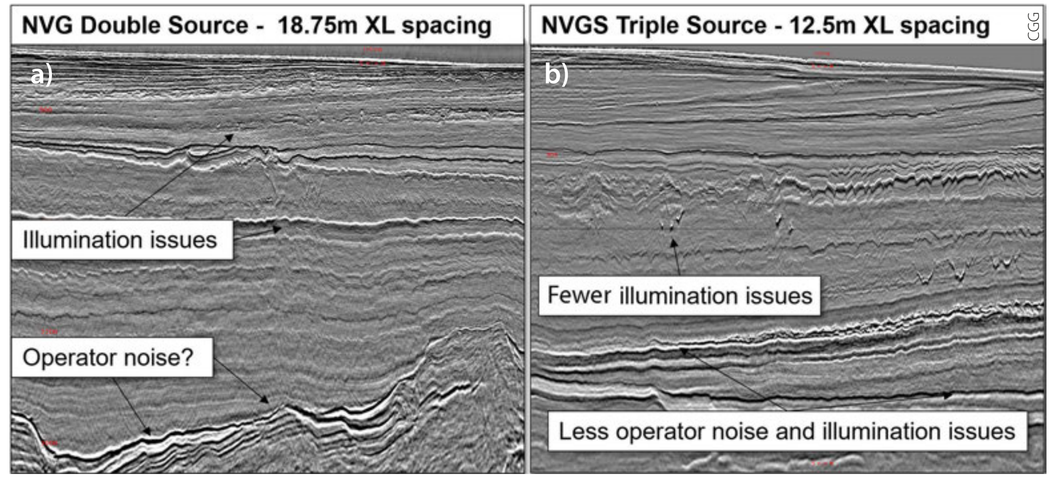
The Next Phase

CGG's initiative to add a regional state-of-the-art dataset in the east–west direction will be an important step in enhancing exploration in this region. This next phase of acquisition and reprocessing will bring a step-change in both resolution and structural imaging through a multi-faceted approach. The first clear benefit will be enhanced illumination of key target level faults from the second azimuth. The many regional stress fields in this part of the North Sea have aligned key structures in the north–south direction. This is particularly important sub-BCU, where the complexity of the fault systems increases and illumination of reservoirs is heterogeneous. East–west acquisition should significantly improve the available recording aperture to aid identification of these faults, especially when combined with the original north–south BroadSeis data in a full multi-azimuth reprocessing flow.

Further imaging enhancements are anticipated from having the more densely sampled triple-source data. This increases the ability to sample spatial reflectivity changes and hence mitigate corresponding operator noise. This is seen in Figure 3 comparing the NVG (north–south PSDM, double-source) and the NVGS (north–south PSDM, triple-source) data. Beneath injectites and along complex structures such as remobilised chalk or the BCU, the triple-source data shows fewer illumination issues and less operator noise. Beneath shallow attenuating bodies and under injectites, signal-to-noise ratio and resolution will benefit from a complementary azimuth, especially when combined with targeted dual-azimuth processing techniques. Reprocessing of the underlying data is also expected to significantly enhance imaging. Modern techniques such as 3D source and receiver deghosting, and multi-channel 3D deconvolution imaging and multiple modelling are likely to improve resolution and demultiple in this region.

The reprocessing of the underlying north–south BroadSeis data, combined with the illumination and resolution-enhancing benefits of the densely sampled wide triple-source multi-sensor east–west data, is expected to overcome multiple imaging challenges. This new dual-azimuth dataset will aid continued exploration for years to come, with the hope for new discoveries and further development of the area. ■

Figure 3: (a) Operator noise and illumination degradation beneath injectites and towards the target interval in the NVG data; (b) NVGS data showing that triple-source acquisition enhances imaging beneath the injectites, which could be improved further by a second acquisition azimuth, with potential for undershooting shallow obstacles.



From Arrhenius to CO_2 Storage

Part X: How quickly does atmospheric CO_2 mix into the ocean and biosphere?

"What is time then? If nobody asks me, I know; but if I were desirous to explain it to one that should ask me, plainly I do not know."
Augustin, 332–430.

MARTIN LANDRØ and LASSE AMUNDSEN; NTNU/Bivrost Geo

We know that the atmospheric content of CO_2 has increased by 30% since 1958. It is much harder to measure and know where the extra CO_2 ends up after being emitted to the atmosphere. The nuclear bomb tests performed by the USA and the Soviet Union in the period from 1950 to 1962 led to a significant increase in radioactive carbon (^{14}C) in the atmosphere. The radiocarbon dating laboratory in Trondheim initiated a large data acquisition effort in the 1960s aimed at monitoring the changes in radiocarbon that lasted until 1995. In this article we revisit this unique dataset and discuss briefly why this is of importance to our understanding of how CO_2 is circulating between the atmosphere, biosphere and the oceans.

The Trondheim Radiocarbon Dating Laboratory

The radioactive carbon isotope ^{14}C disintegrates by emitting electrons (beta-decay). This process is slow, and it takes approximately 5,700 years before 50% of a given population of ^{14}C atoms disintegrates, making it perfect for radiocarbon dating within a time range up to 50,000 years.

In the early 1950s a laboratory for ^{14}C-dating was built in Trondheim at the Norwegian University of Science and Technology (NTNU) using solid carbon as the source. After several years, they could not show any positive results using this technique, so in 1955 professors Sverre Westin, Harald Wergeland and Reidar Nydal (Figure 3) decided to build a new laboratory based on CO_2 instead of carbon. This decision was based on a general recommendation from the radiocarbon dating conference that was held in Cambridge in July 1955. The professors in Trondheim asked for continued support from the Norwegian Research Council, and got a one year extension of the contract, and a strict message that if there were still no results within that time, the support from the council would end. The first sample that was tested in the new lab was a piece of wood from Caligula's ship, which sank on Lake Nemi in Italy approximately 1,900 years ago. The size of the ship, designed as a luxury boat sailing on this small lake in Italy, was 70 × 20m. Caligula was Roman emperor from 12 to 41 CE, so in 1956 the age of the ship was probably around 1,925 years old (Figure 2). In the laboratory, Nydal and Sigmond estimated the age of the ship to be approximately 2,000 years, a result that secured continued support from the Norwegian Research Council.

One of the first archaeological tasks for the laboratory was to determine the age of a monument built using timber, known as Raknehaugen, in Ullensaker in Norway that was formed as a huge cone, 95m wide and 15m high. The wood samples were determined to date from 540 +/– 50 years (CE).

In 1961 professor Anatol Heintz contacted the laboratory and asked them to determine the age of several mammoths from Siberia, who it was thought had fallen into ice rifts and died approximately 5,000 years ago. Several samples from various mammoths were analysed. Only one of the samples gave an age younger than the last ice age

Figure 1: In 1946 Willard F. Libby (right), proposed an innovative method for dating organic materials by measuring their content of carbon-14, a newly discovered radioactive isotope of carbon. Known as radiocarbon dating, this method provides objective age estimates for carbon-based objects that originated from living organisms.

University of Chicago Photographic Archive, apf1-03868, Special Collections Research Center, University of Chicago Library.

(11,450 years +/– 250 years), while six other specimens were dated as older than 30,000 years. Later, several mammoth samples were discovered in Norway, all of which were determined to be older than 40,000 years.

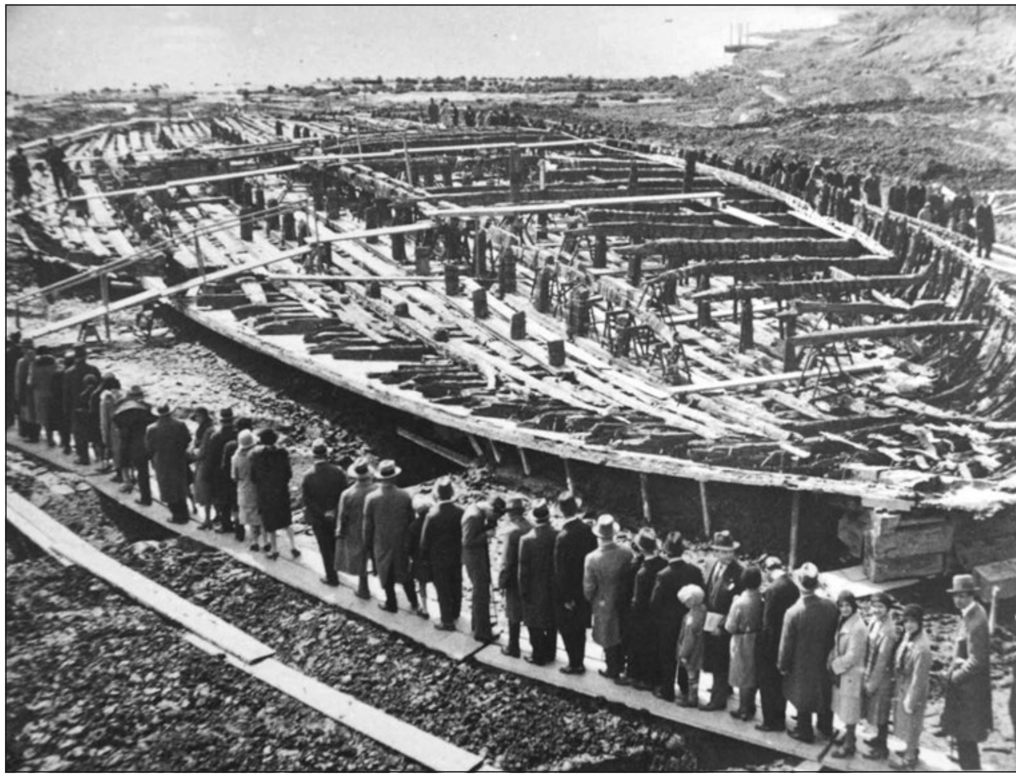


Figure 2: Italians viewing emperor Caligula's ship (Prima Nave), which was found in 1932. As early radioactive dating techniques proved, the ship sank more than 1,900 years ago.

Background Radiation and Sample Contamination

It was evident from the beginning that the natural background radiation influenced the accuracy of the radiocarbon dating method significantly, especially for samples that were over 20,000 years old. Early in 1959 the typical background radiation for the laboratory in Trondheim was 10 events per minute. By improving the counters (electronics) as well as the surrounding screening (lead and steel) it was possible to lower the background radiation to approximately 0.5 events per minute. Similar laboratories in Bern and Seattle opted for locating the laboratory 50m below ground, to reduce the background radiation. When one of the Trondheim counters was tested in the subsurface laboratory in Bern it showed a rate of 0.3 pulses per minute. It was decided that the construction cost related to building a new underground laboratory in order to decrease the background radiation from 0.5 to 0.3 was not feasible.

Most of the samples are fairly easy to prepare and produce CO_2 from. A sample made of wood is burned while oxygen is added in a closed system, and liquid nitrogen is used to freeze the resulting CO_2 so it can be transported into the counter chamber. If the sample is a shell, the CO_2 can be released by adding acid. It is very important that the CO_2 gas is clean, because when organic material is burned or turned into CO_2, other gases like sulphur dioxide, chlorine gases and excess oxygen might capture some of the beta-radiation originating from a decaying ^{14}C atom. Radon is another gas that will disturb a clean measurement. Fortunately, the radioactive radon gas has a short decay time, with a half-life of 3.8 days. This effect is simply solved by storing the CO_2 for approximately a month prior to the measurement.

Radiocarbon from Nuclear Tests

In 1962 the leader of the laboratory, Reidar Nydal, initiated a campaign to measure the increased ^{14}C-levels in the atmosphere resulting from the nuclear bomb tests performed by the USA (from 1950–1959) and the Soviet Union (1961–1962). A treaty was signed 5 August, 1963, and both countries stopped testing these large hydrogen bombs. However, China, France and the UK did not sign this treaty and these countries continued to undertake nuclear bomb tests in the period from 1964 to 1974.

Nydal's great acquisition plan covered stations all over the world, including Norway, Madagascar, Ethiopia, Senegal, Chad and the Canary Islands. In addition, he established an agreement with the Norwegian shipping enterprises

Figure 3: Reidar Nydal in the laboratory in 1955, testing Libby's method for radiocarbon dating.

Fortiden i søkelyset : 14C datering gjennom 25 år

Wilhelmsen and Fred Olsen whereby crew on board the ships were trained to produce CO_2 from seawater samples. To get a sufficient amount of CO_2, typically 200 litres of seawater was needed. One of the authors of this article (ML) was a laboratory assistant for the academic year 1977–1978. He found it a pleasure to work with Reidar Nydal, and exciting to prepare and analyse the seawater samples that had been gathered by the ships.

In 1996 Reidar Nydal and Knut Løvseth organised all the data that has been acquired relating to ^{14}C measurements in a database. Figure 4a shows measurements of ^{14}C (increase above normal) for the period between 1963 and 1993. In the first couple of years we observe a seasonal oscillation that is less pronounced later. These oscillations are observed in Norway, being close to Novaja Zemlja where the Soviet Union detonated bombs equivalent to a strength of 337 Mtonnes. The distance from Novaja Zemlja to Fruholmen in Northern Norway (where one of the stations was located) is approximately 1,000 km.

We notice that the radiocarbon levels in Norway and Africa are equal in 1966–1967, three years after the treaty was signed. The figure also includes all the seawater samples that were acquired between 1966 and 1993. These samples cover a huge part of the oceans including the Atlantic and Pacific. Ship routes including passages through the Panama and Suez channels are included in this dataset. All seawater samples were taken close to the surface, so there are no depth variations in these data. After 30 years we observe that the relative increase in radiocarbon is equal for the atmosphere and the ocean.

Figure 4a: Measurements of increased ^{14}C in the atmosphere and the ocean. Data source: Nydal and Løvseth, 1996.

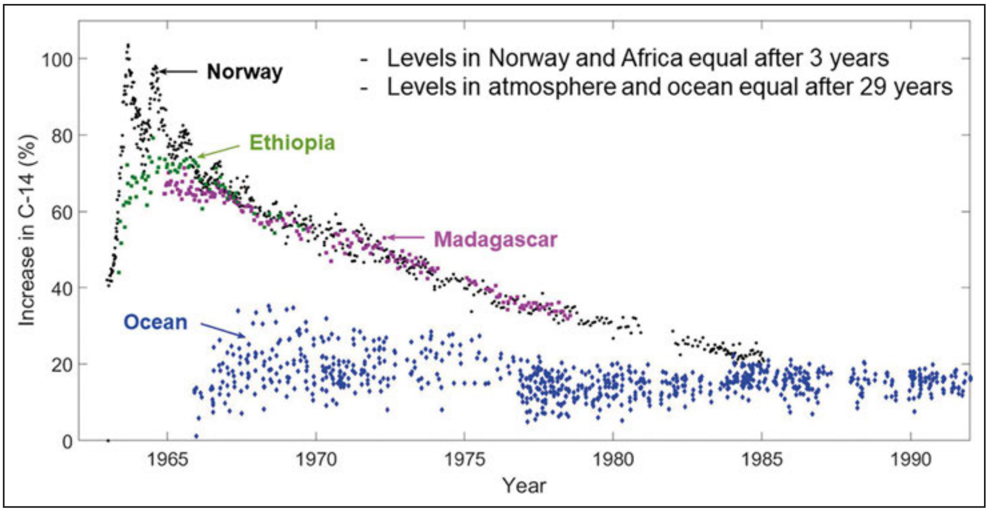


Figure 4b: Variation in ^{14}C above normal between 1963 and 1985, measured in the atmosphere in Norway and in human blood and hair samples from Norwegian citizens.

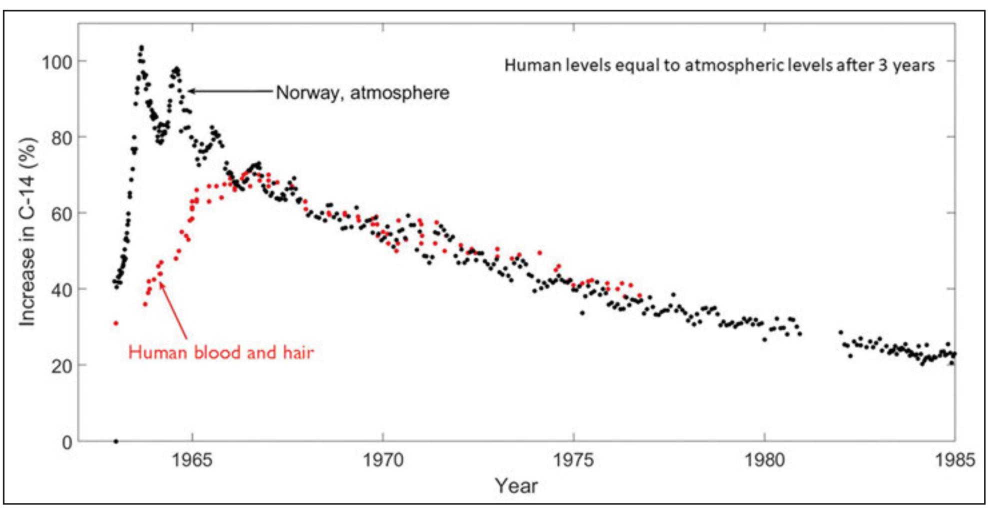
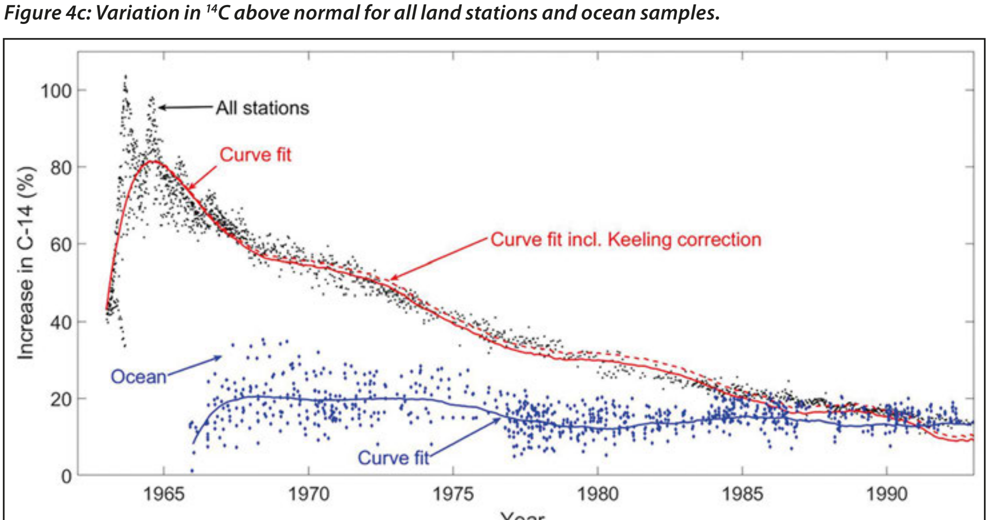


Figure 4c: Variation in ^{14}C above normal for all land stations and ocean samples.



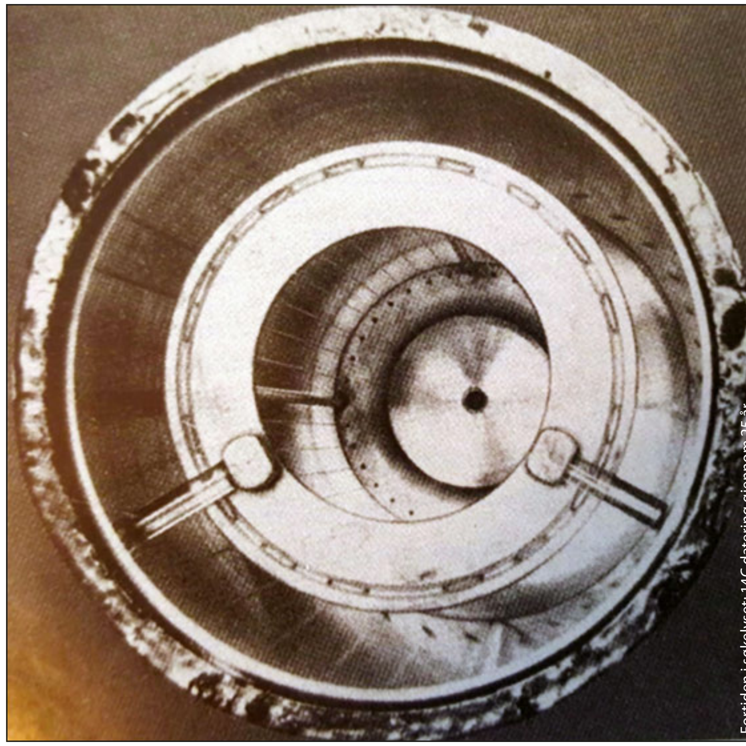
Radiocarbon Absorbed in Humans

Nydal acquired blood samples from two people in Trondheim from 1963 to 1978. He also analysed hair samples from one person within the same period. The blood and hair samples show similar behaviour, and 2–3 years after 1963 the levels in the human body seem to follow the atmospheric levels, as shown in Figure 4b.

Nydal made a simple box model including the stratosphere (10–30 km), the troposphere (0–10 km), the biosphere and the ocean. He concluded that radioactive carbon emitted by bombs that were detonated in 1961 and 1962 had an average lifetime in the stratosphere of two years, followed by a one-year lifetime in the troposphere. The average life of a carbon atom in the atmosphere that enters into the ocean is approximately seven years. How the CO_2 mixes with deeper layers in the ocean cannot be studied using these data.

All Land and Ocean Samples

If all 14 land stations are included as well as all the ocean data, we clearly see in Figure 4c that the radiocarbon levels approach a 15% increase above normal after approximately 30 years. A simple curve fit to the data is also shown in this figure, and we observe that the curves for the atmosphere and the ocean cross each other around 1992. In the period from 1963 to 1993 the CO_2 level in the atmosphere rose from 315 ppm to 356 ppm (a 13% increase). The CO_2 emitted by fossil fuels is neutral with respect to radiocarbon content. The red dashed line shows the curve fit assuming that the total amount of CO_2 had been constant at 315 ppm over the whole period.



Fortiden i søkelyset: 14C datering gjennom 25 år

Figure 5: The first ^{14}C- counter device used by the radiocarbon dating laboratory in Trondheim. The inner cylinder is filled with CO_2 gas and the ^{14}C atoms are counted in an electric field between the outer lattice and the centre cord (not visible on the photo).

Reference

Fortiden i søkelyset : 14C datering gjennom 25 år. https://cdiac.ess-dive.lbl.gov/epubs/ndp/ndp057/ndp057.html# ■

AI: Game-Changer in Development or Exploration – or Both?

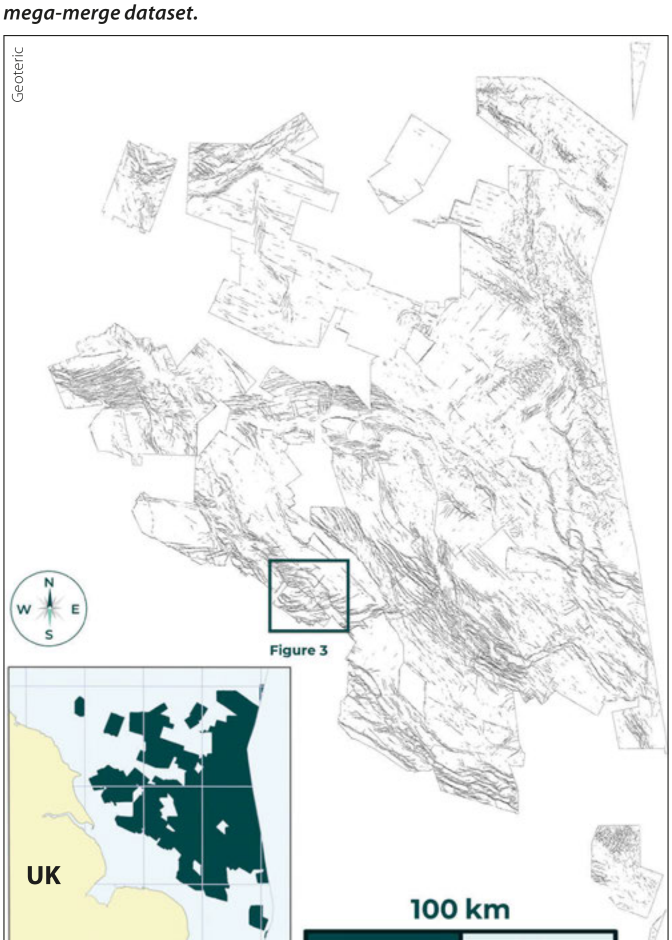
Many may argue about the best use for Artificial Intelligence: is it in the exploration or the development space? This article illustrates with case studies that AI sits comfortably in both, and forms a bridge between the two, allowing interpretation continuity.

MARK BROWNLESS and RYAN WILLIAMS, Geoteric; DAVE BRETT, Ithaca Energy

There is no doubt that Artificial Intelligence (AI) has a significant future in the energy business, whether it be in oil and gas or the renewables sectors. The need for a quick, accurate and reliable interpretation tool would help exploration and development teams worldwide, especially as datasets become more extensive and the geotechnical challenges become more complicated.

The benefits of AI for exploration studies are relatively straightforward to identify, as large datasets are becoming common workspaces. Naturally, these substantial datasets are going to require a significant amount of time to interpret, for the immediate purpose of a petroleum system analysis. So, having the ability to interpret the geology quickly through the medium of AI can speed up an interpreter's workflow. Another benefit of AI is its ability to interpret across the entire seismic cube with the same vigour from section to section. It has infinite stamina, so a strong level of consistency is held across the volume.

Figure 1: Time slice at 800 ms of AI fault confidence throughout the SNS mega-merge dataset.



It is important to note that AI is not here to replace a geologist or geophysicist but enables them to be more efficient with their time. The best integrated AI seismic solutions harness the knowledge and present the opportunity to learn and do more, providing support when users need it most. In this way, interpreters can add more value to the business by a more thorough understanding, drive operator growth through new levels of decision-making and more confidently outline the difference between a good and bad prospect.

Surely, It's All Geology: Exploration, Appraisal, Development?

Development and exploration interpretations primarily differ in scale and interpretation density. Both workflows require an accurate interpretation of structures but for very different purposes.

Exploration studies aim to identify the way hydrocarbons migrate into traps, either structurally or stratigraphically over large datasets, and the possibility of a subsequent leak. In comparison, development studies are more focused on individual structural features, as the aim is to get the hydrocarbon fluids out of the trap in a safe manner, so an increased level of detail is required. Both environments are illustrated below. One case study focuses on the Southern North Sea (SNS), where a regional mega-merge dataset has been investigated using AI fault interpretation tools, to gain an understanding appropriate for regional petroleum system analysis. The development case study looks at a Central North Sea (CNS) field focusing on the importance of structurally constrained reservoir connectivity and the implications for future well planning.

Exploration: Southern North Sea Case Study

The SNS mega-merge dataset (available through the UK National Data Repository) is a regional volume which spans 78,000 km² across the UK sector of the Southern North Sea (Figure 1). The benefit of having such a large dataset is that it allows interpreters to better understand the interaction and interplay of geology across vast areas that may have otherwise been limited by licensing restrictions or data availability. This enables interpreters to identify and interpret key components of the petroleum system, such as hydrocarbon kitchen areas and structural closures. The time slice image through the SNS (Figure 2) highlights a number of these critical events. Several structures can be identified, such as the Dowsing Graben System and crestal faulting above salt diapirism.

The structures are revealed throughout with equal consistency, something difficult for a human to achieve, as AI does not suffer from interpretation fatigue, nor is it influenced by mood or external pressures. The ability to reveal the entire structure and better understand the impact of the faulting can be fundamental to a fuller comprehension, as opposed to interpreting only a small seismic cube that only contains a portion of the feature.

When zooming in over an area of interest (Figure 3) even more detailed structural information is revealed, and by comparing it to gas fields such as Lancelot and Excalibur it is possible to get a sense of scale. By looking at Figure 1, it is clear that this is just a postage stamp of an area on a rather large envelope. However, the detail observed when the fault confidence volume is rendered in 3D is quite spectacular. The complex nature of the faulting is brought out in all of its glory, making subsequent interpretation far more accessible and informative.

As we whittle the volume down to that of a development style project, the need for a detailed interpretation does not change; if anything, it becomes even more important. Now that the petroleum system is defined and the highest calibre traps identified, it is all about getting the hydrocarbon fluids out of the ground safely. In doing so, interpretation will become even more focused on fine detail – where the presence of even the smallest fault can play a significant role in fluid transmissibility or reservoir compartmentalisation.

Development: Central North Sea Case Study

Faulting plays a crucial role with regards to development planning, whether it be the impact of an open or closed fault for fluid flow or the effect of faults on well safety. There are many examples where faults have caused production problems, history mismatching or the collapse of wellbores. This case study illustrates how AI has been used to address some of these issues.

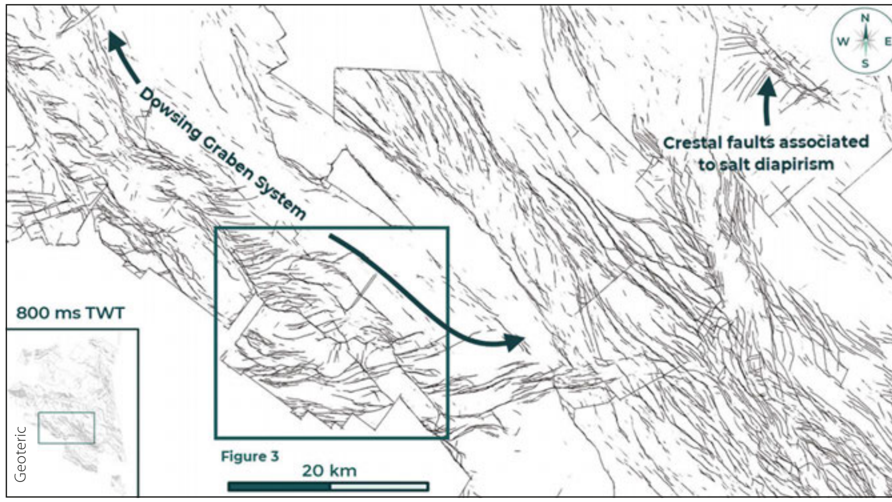
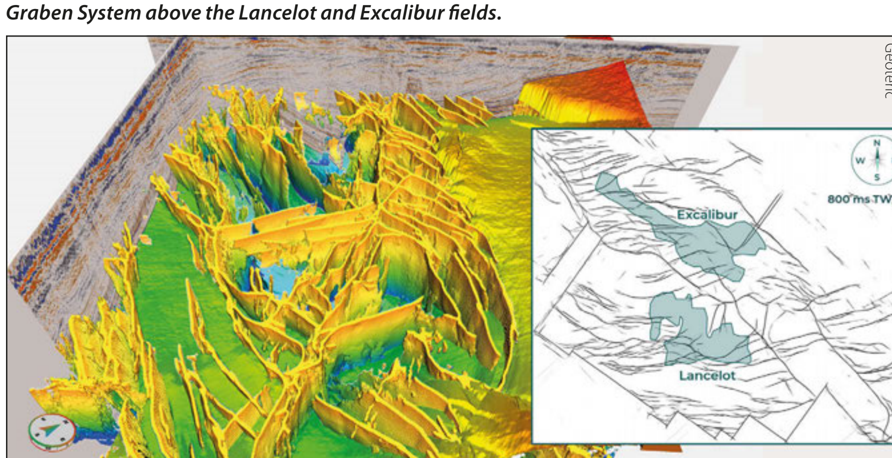


Figure 2: Time slice highlighting the thin-skinned tectonics of the Dowsing Graben System to the south-west of the image. These faults, although post-salt, impact on the deeper petroleum system and their delineation are subsequently important for basin analysis.

The CNS has a complex geological history with many fields containing elements of extensional rifting, salt halokinesis and shallow soft sediment remobilisation (injectites). The interaction of faulting and salt movement can create a wide range of structural features, some of which can appear unusual. In this case study, the primary trap is a fault-bound structural high containing several faulted panels, which are limited to the east by a stratigraphic 'scoop' feature, heavily influenced by the underlying salt movement. Before this study, there were inconsistencies in the structural interpretation of the field, be it inherited from previous operators to variations based on newly acquired/reprocessed seismic data. This makes decision-making very difficult, even more so if there are time pressures associated with licence demands.

The AI frault confidence results are observed in Figure 4, where the original and fine-tuned results are displayed on the top reservoir horizon slice. The foundation network fault confidence results quickly reveal the structures which can then be checked and confirmed as geological structures. The foundation network can be fine-tuned to the style of faulting observed in the dataset using fault stick interpretations to ensure the most geologically accurate results. This interaction between the interpreter and AI is critical to ensuring the best results can be achieved. As should be expected after fine-tuning, some differences can be noted. Firstly, the faults identified appear more confident (redder), and several low confidence (blue) responses in the south-west are removed. Interestingly, one feature identified in the centre of the field has been removed (yellow

Figure 3: 3D render of the AI fault confidence volume revealing the detailed faulting in the Dowsing Graben System above the Lancelot and Excalibur fields.



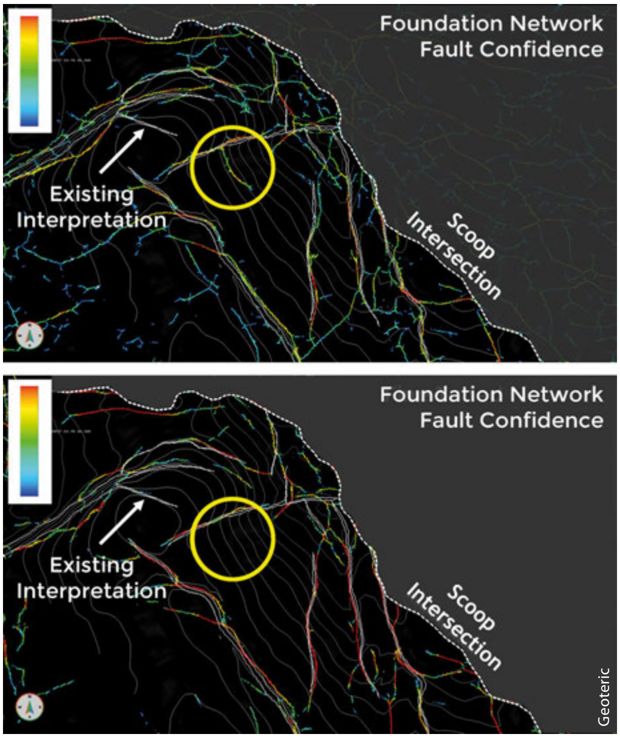


Figure 4: AI fault confidence draped onto the top reservoir horizon. The 'fault' highlighted in the yellow circle was removed after fine-tuning as it was deemed not a structural lineament in the foundation network review. The confidence of the fault responses increases after fine-tuning with the detected faults having a more red response.

circle). After reviewing the foundation results, it was deemed that this is not a structural lineament, and as such, was not included in the fine-tuning process.

Rendering the results in 3D allows the structural complexity to be uncovered, showing a series of splayed faults (Figures 5A and 5B) which might have been interpreted as a singular fault had traditional interpretation techniques been used. This example illustrates the fine level of detail that can be achieved with AI fault interpretation. This highly accurate interpretation can be used to analyse reservoir connectivity between fault blocks (Figures 5C and 5D). Reservoir connectivity/compartmentalisation is crucial in determining optimal well positioning and future field development. Both the foundation and fine-tuned networks highlight the presence of a relay-ramp structure between these two fault blocks, suggesting the two blocks are in communication. The fine-tuned network creates a clearer image with lower confidence results removed, making the interpretation process considerably easier.

Implications for AI Usage

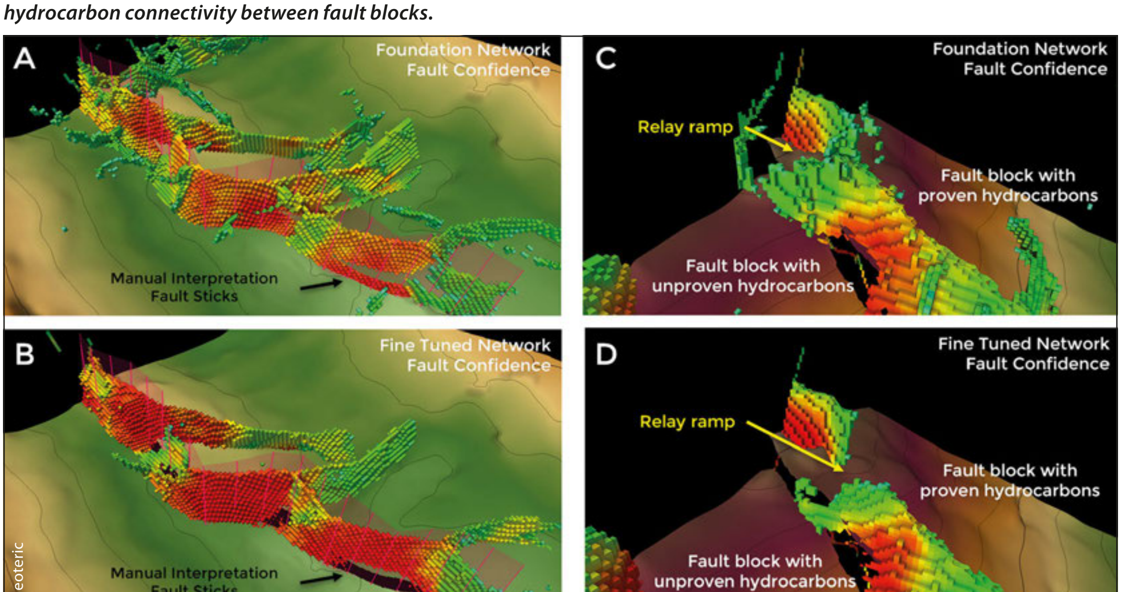
Both case studies illustrate that AI interpretation works for development and exploration. The SNS case study highlighted that the AI results could be used to demonstrate regional structure (Figure 1) and that these results are also beneficial for detecting detailed amounts of fault information (Figure 3). Other benefits include the ability to train or fine-tune the AI network to a specific dataset to improve accuracy, as shown in the CNS case study. AI's ability to interpret vast amounts of data can free up interpreters to focus on the geologically complex components of the interpretation task.

Retaining high quality interpretation when moving from an exploration setting to a development environment is of significant value. Often, information can get lost or left behind when project transfer occurs; however, an AI fault confidence volume has value in both settings.

The time saved in utilising AI to undertake structural interpretation is twofold. Firstly, it takes considerably less time to start the interpretation work. Secondly, with the time saved, it allows interpreters to absorb the results of the interpretation and incorporate any changes into any existing interpretations/models. Having the time to make informed decisions based on an unbiased study from the seabed to reservoir target can be used for a variety of projects. Whether it be defining kitchen basins, structural highs, migration pathways, trap/seal integrity analysis, shallow hazard detection or well safety, AI fault analysis can be used and fine-tuned to improve the interpretation.

As these case studies show, Artificial Intelligence is the next big game-changer within seismic interpretation.

Figure 5: Increased detail can be resolved using AI fault analysis. A series of splayed faults have been identified in the fault confidence volume (A and B), which was interpreted as a single fault using manual interpretation techniques. Figures C and D illustrate the presence of a relay ramp in both AI fault detection networks, which can be used to de-risk the potential of hydrocarbon connectivity between fault blocks.



Acknowledgements
Thanks to PGS for the use of the CNS dataset and the UK National Data Repository for access to the SNS mega-merge. ■

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How is Natural Gas Priced?

The basis on which gas is priced varies dramatically between global markets. As it becomes an increasingly important source of energy, an understanding of gas pricing concepts is crucial.

VIVEK CHANDRA, Texas LNG

Although natural gas and oil share many characteristics, the way in which they are sold and priced is very different. Oil is sold by volume or weight, and different grades and sources of crude oil have different prices, determined by the amount refiners are willing to pay. Global oil markets are very liquid, relatively transparent, and involve numerous intermediaries and open exchanges.

By contrast, natural gas is sold by units of energy (Btu, Therms and Joules). Natural gas is predominantly methane plus various heavier hydrocarbons and undesirable impurities. The relative proportion of heavier hydrocarbons determines the energy content of the gas when combusted and thus its ultimate value; customers pay for energy derived from gas, not a specific volume of gas.

Because gas is difficult to transport, prices are set locally or regionally. For most gas transported by pipeline (55%), prices are set by negotiation, regulation, or open-market mechanisms similar to those used in oil markets. The remaining portion of the natural gas trade is shipborne Liquefied Natural Gas (LNG), with the majority of cargoes sold on a long-term contractual basis at prices either indexed to the cost of feed gas, a floating price in the destination market, or to oil or other commodities.

Where there are many buyers and sellers of gas, traded prices are most influenced by supply and demand. In countries with deregulated markets, like the US and Europe, prices may be set by traders at dedicated physical or electronic exchanges, pricing gas at location-specific hubs. This is becoming the standard in Canada, continental Europe, the UK, and parts of Australia – all regions with extensive gas infrastructure, large numbers of gas sources and consumers, clear regulations, and limited government influence on the markets. There have been attempts to create hub prices elsewhere, such as Singapore, China, and India, but until gas can be easily and transparently transported, gas regulations are harmonised, sufficient volumes are traded, and the cloak of secrecy surrounding gas prices in these regions is lifted, it is unlikely that suppliers and buyers outside the local market will trade on these hub prices.

Supply and demand factors that can influence natural gas prices include production levels, gas storage injections and withdrawals, weather patterns, pricing and availability of competing energy sources, and market participants' views of future trends in these or other variables. Where gas is used for heating, gas prices may rise in the winter months; conversely, if most of the gas generates power for air conditioning, demand will rise in the hotter summer months. If gas is used primarily by industrial consumers, weather has a minimal impact on demand unless disruptions limit supplies.

Natural gas markets around the world can be broadly divided into four main groups, as described below.

Gas-on-Gas Pricing

In this group gas prices are set in relation to regional gas supply and demand, where gas competes with other

Nearly half of all gas traded is transported by tanker as LNG.

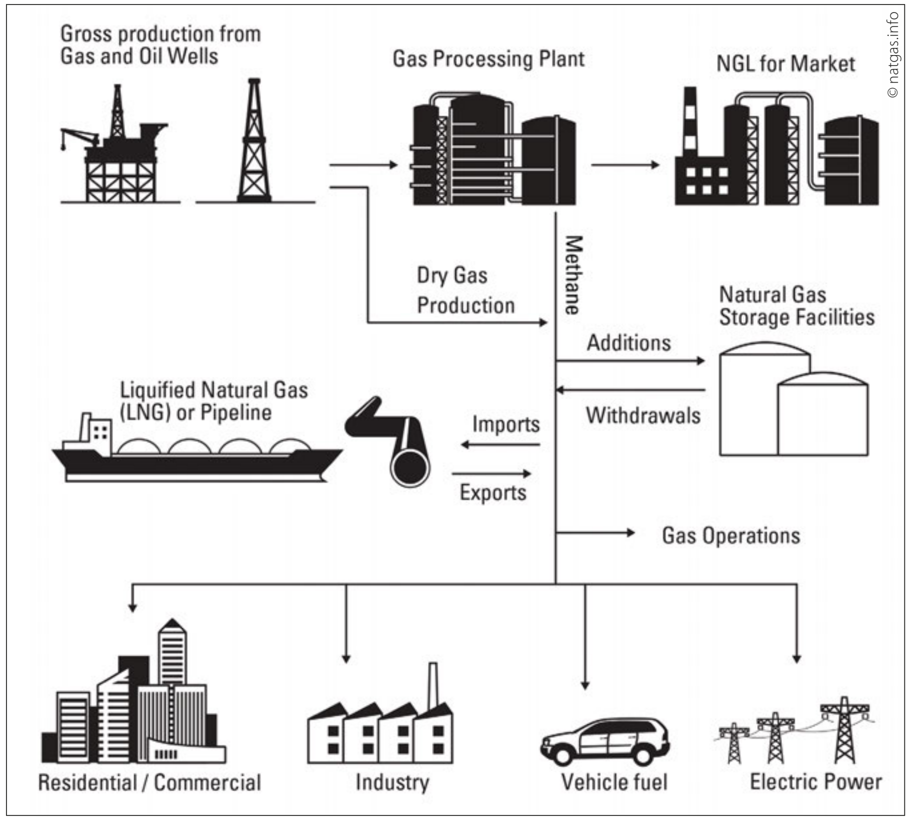
Wojciech Wrzesien/Shutterstock

gas. It includes North America, the UK and north-west Europe, the most liberal and traded gas markets in the world. North-west Europe has been recently added to this group because since 2010 much of the gas sold and consumed in this region has switched from formula-based oil product-linked prices to hub gas-on-gas prices, largely because of the development of common regulations, standardised contracts, increased infrastructure, government support and market liberalisation. Remarkably, this transition has occurred despite the resistance of major gas suppliers like Russia and Norway, who had benefitted from the previous regime.

These regions are characterised by large numbers of buyers and sellers, largely competing without governmental intervention. Gas is traded on open exchanges and there are established benchmark or hub prices where information is transparent, readily available, and updated regularly. Infrastructure is openly accessible and usage fees are either regulated or fairly priced.

Because North America and, to a lesser extent, the United Kingdom and north-western Europe, have extensive pipeline and gas storage systems with opportunities to both export and import gas from outside the markets, gas can be traded on both current and future contracts; a buyer can purchase a defined volume of gas, to be delivered at a specified location, at a future date, at a price established today. This sophistication allows the gas market to maximise usage of infrastructure and enables both buyers and sellers to plan their financial future. Risks can be managed; however, short-term gas prices tend to be volatile, continuously reacting to supply and demand.

An advantage of a highly traded system is that different parties can own different parts of the chain – from upstream to gas processing to pipelines, storage and local distribution – because pricing is transparent and all services are competitive. In theory, no individual supplier or buyer is able to control prices, and the presence of intermediary parties, such as gas traders, usually results in more efficient markets and lower prices.

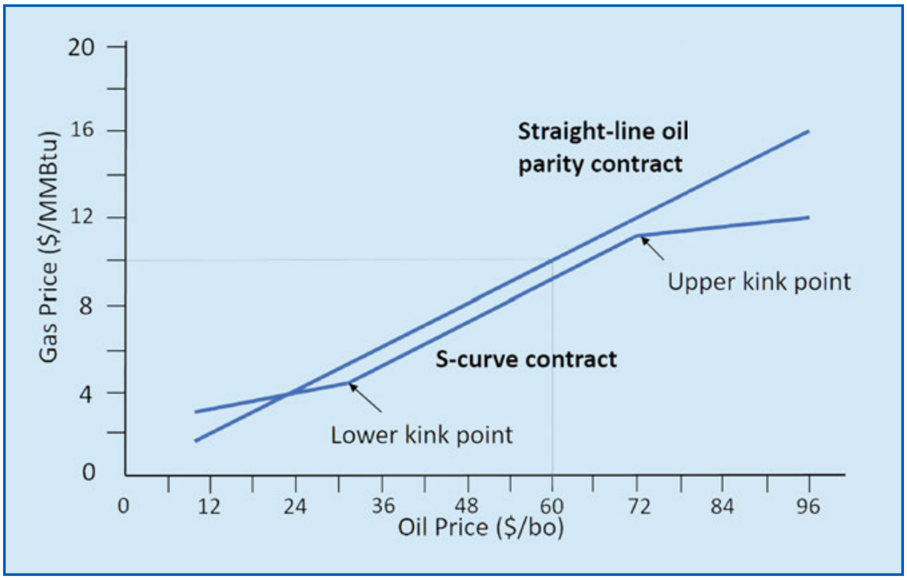


The natural gas chain.

US LNG is exported on a US hub plus cost structure, not formula-linked to oil or oil products; although there have been some attempts at contracting with these indices, they have, so far, proved difficult to implement. A typical US LNG export pricing formula is $P_{LNG} = P_{US\ Hub}$ + feed gas pipeline tariff + energy retainage + liquefaction costs + shipping cost, where:

- P_{LNG}: price of exported LNG;
- $P_{US\ Hub}$: feed gas-on-gas price at a defined hub location;
- Feed gas pipeline tariff: the tariff paid to a pipeline operator to transport feed gas from the pricing hub to the liquefaction facility;
- Energy retainage: fee, quoted in monetary tariff or gas volume, paid or retained by the liquefaction plant to compensate for in-plant fuel usage (up to 10% of feed gas is consumed by gas-drive turbines to power the compressors for the liquefaction trains) and could also be charged as a percentage of hub prices;
- Liquefaction costs: fees charged by the liquefaction facility to convert feed gas into LNG, plus any storage or loading fees. Only a few LNG projects in the world consume electricity from the local electricity grid instead of using feed gas to drive their liquefaction compressors. This benefits tolling model consumers as they suffer less energy retainage and have an added advantage of having much lower carbon emissions than their peers. Texas LNG is one of the few LNG project plants under development with these 'green' credentials.

At a \$3/Mcf (approximately equivalent to \$3/MMBtu) feed gas price, US LNG could be delivered to North Asia for less than \$8.00/MMBtu and to Europe for around \$7/MMBtu, assuming a \$2.50/MMBtu tolling fee, 10% retainage, and shipping costs of around \$0.75/MMBtu to Europe and less than \$2.00/MMBtu to Asia. This price range is significantly lower than costs predicted by new LNG suppliers in Australia and Russia, but higher than break-even prices from legacy projects in South East Asia and the Middle East that enjoy low ongoing costs, depreciated capital costs, benefits from NGL sales and generous tax and fiscal systems. Most legacy projects, however, have very limited potential to increase volumes, and many are



Innovative S-curve linking oil and LNG prices. The straight oil parity line is based on 1 bo = 6 MMBtu and 1 ft³ = 1,000 Btu. Thus, the energy equivalent gas price at $60/bo ≈ $10/MMBtu.

facing difficulties in sustaining volumes because of declining reserves.

Indexed to Substitute Energy Prices

This group of gas markets includes Central and Southern Europe, South Africa and to a lesser extent, South East Asia; regions where there is a limited but growing gas grid, some gas storage facilities and an emerging traded gas market. However, most gas remains priced in relation to other energy such as oil products, coal, or even electricity, explicitly linked by formulae under long-term contracts.

The net effect of relating gas prices to oil products is that gas is usually sold at a discount relative to the oil fuel, on an equivalent energy basis. The reasons for this are largely historical because gas production and consumption began after oil and coal markets were established. By linking the markets and ensuring that the formulae price gas at an energy equivalent discount, gas producers convinced reluctant buyers to switch to gas from traditional fuels like oil and coal.

Predictably, during periods of relatively high oil prices, when oil product-linked gas prices rise more than supply-versus-demand fundamentals would suggest, gas buyers question the value and logic of linking these disparate commodities. However, when oil prices are low, gas buyers, enjoying cheaper gas prices, mute their complaints and accept the link even though the rationale remains questionable. Nevertheless, the trend toward delinking oil and gas is established and growing.

Pure Oil-Linked Pricing

This group is largely characterised by the traditional LNG markets of North Asia, especially Japan, Korea, and Taiwan, and emerging LNG markets, such as India and China. The North Asia region, excepting China, has limited domestic energy resources and lacks the infrastructure to import gas by pipeline, so essentially all their gas is delivered via LNG imports. China has significant domestic production and pipeline imports, but its growing LNG long-term contracted gas is largely priced on oil linkage on the model set by Japan.

Prior to the introduction of LNG in the late 1960s, Japanese power utilities relied on imported crude oil and coal for power generation. These risk-averse buyers insisted on a guaranteed discount to persuade them to substitute liquid and solid fuel for LNG and also wanted a price cap so that future oil price shocks would not translate into immediately higher gas prices. In return, they agreed to long-term contracts and a guaranteed minimum LNG price.

The solution was the innovative S-curve concept, which links oil and gas prices by a formula. The horizontal axis of the graph is the weighted average of the crude oil import price. The vertical axis is the imported LNG price. The relative slope, or angle, of the line gives the relationship between oil prices and LNG prices. When the slope of the line is 16.7%, LNG is priced equally to crude oil on an energy equivalent basis. Thus, if the market valued gas and oil on an energy equivalent MMBtu basis, then gas should be priced as 16.7% × oil price. Slopes less than 16.7% imply that LNG is sold at a discount relative to oil, whereas slopes greater than 16.7%, though rare, imply that LNG will sell at a premium price relative to oil. The oil parity line shows that when the oil price is $60/bo, the energy equivalent gas price is $10/MMBtu.

Typical 'S' curve pricing formula:

$P_{lng} = A * P_{Crude\ Oil} + B$, where:

- A: The 'slope' linking oil and gas prices. A slope of 16.7% indicates energy equivalent parity between oil and gas prices. Most LNG contracts have slopes between 12%–15%;
- $P_{Crude\ Oil}$: Crude oil price, often a weighted average of a 'basket' of oils, such as Japan Crude Cocktail (JCC) over a defined period, a month or more;
- B: A constant added to reflect fixed costs, often related to shipping costs from LNG plant to importing port.

The formula also includes 'kink' points – the upper and lower limits where the slope flattens – thereby decreasing the impact of further oil price change to the LNG price. When oil prices rise above the defined upper kink point, the slope may flatten out, shielding the buyer from the full impact, while if oil falls below the lower kink point, the seller is protected because LNG prices would not fall as far.

From the 1970s to 2000, the S-curve slope was 4%–15%, implying a relatively large LNG price discount to oil on an energy equivalent basis. As the markets tightened, the slope increased closer to 16%, indicating that consumers valued oil and LNG equivalently and both kink points were reset to the new 'normal' range for expected oil prices. The oil price decline in 2015–2016 resulted in a drop to around 12%–13%. The introduction of non-oil price-linked US LNG in early 2016 has further declined the slope of oil-linked contracts from non-US sources, who feel the pressure to discount to maintain market share. It remains to be seen whether this is the beginning of a long-term trend or a nadir in gas prices reflecting the Covid-led drop in global gas demand.

How this pricing formula will survive the continuing onslaught of US LNG into the Asia-Pacific region is debatable. The key driver for change would be the relative price of US domestic gas, which determines the feed gas prices for US LNG export projects, versus the global price of oil, which drives non-US LNG prices into North Asia. However, the dominance of S-curve LNG pricing is clearly fading and future LNG pricing will involve a healthy mix of different indices and links.

Regulated Markets

Regulated markets dominate where gas markets are relatively immature and largely controlled by the state, along with all infrastructure. There is little private sector involvement in the sale or pricing of gas and prices may be set nationally or regionally. The state manages differences in supply prices, and all supply is added to a pool of gas volumes available to consumers. It may choose to sell gas at prices less than the average price for political reasons; all supply is added to a pool of gas volumes available to consumers. There is no transparency, no active gas markets and little incentive for private sector investment in supply or infrastructure. If the mandated gas prices are artificially low, as in the Middle East, inefficient energy consumption often results. Low prices discourage new exploration and production and may ultimately lead to gas shortages and distorted economics.

China is included in this group, even though the government released new gas pricing formulae linking natural gas price to fuel oil and LPG, because these are still set by the state, which owns most of the infrastructure. Over the next few years, as private enterprises build LNG-receiving terminals and local gas grids, this may change.

Regulated markets tend to be inefficient because gas is usually priced below its costs, encouraging waste and decreased investment in E&P. Gas subsidies cost governments large sums of money, do not meet their social objectives and place price risks on the state. The lack of pricing transparency and open markets are detrimental to private sector investments and encourage monopolistic policies by state-owned entities. As governments around the world face budget shortfalls, there is pressure to reduce gas price regulations but the social impact of raising energy prices after decades of subsidies would be considerable.

Future of Gas and LNG Pricing

Predicting future gas prices is undoubtedly a fool's game. They are set by supply and demand in only a few places and elsewhere they are linked to oil prices or products, substitute energy, or regulated by government decree. The number and breadth of variables that impact gas prices are thus impossible to predict with any certainty.

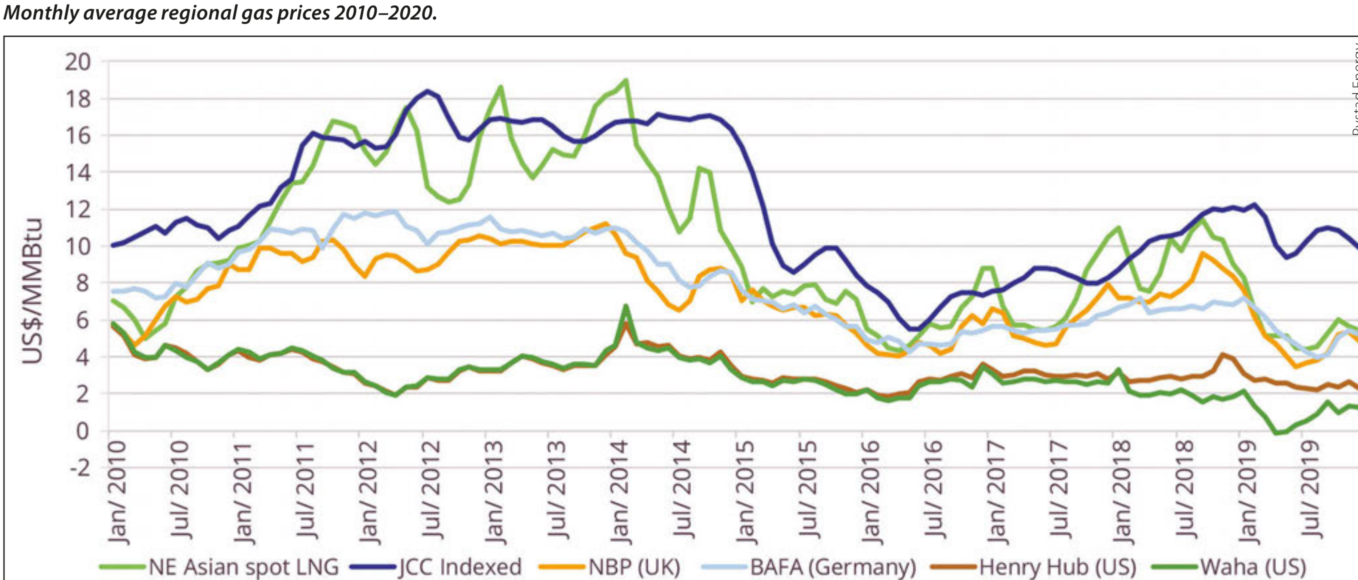
Over the past few years, there has been a steady increase in short-term and spot trades in LNG markets. Currently, over 30% of global LNG is sold on these terms, with prices individually negotiated. Short-term prices reported by agencies like Platts and Argus are increasingly influencing perceptions of gas prices. Other recent trends include increasing volatility, growing convergence between markets, continued growth of pricing hubs, increased LNG contract flexibility allowing increased trading opportunities, and continued delinking of gas prices to oil and oil products.

In summary, global gas and LNG markets are undergoing structural changes. We have gone from a period of convergence in 2009–2010, to one of divergence during which oil prices were high, and since 2015 back to a period of convergence. We can expect the next few years to hold more price volatility as innovative commercial models are tested and new players enter the market. However, the end results will be more transparency, higher impact of supply-and-demand forces, less linkages to unrelated commodity prices, and greater global price convergence.

Exciting times are ahead!

An extended version of this article can be read online. ■

Monthly average regional gas prices 2010–2020.



A Simple Guide to Seismic Horizon Interpretation

GIL MACHADO,
Chronosurveys Lda

Reflection seismic is one of the fundamental ways of imaging the subsurface from a geological perspective. 2D and 3D seismic data are major sources of information in the oil industry for both onshore and offshore activities. Recently, this type of data has also been used in geothermal energy activities, carbon sequestration in geological reservoirs and wind energy, especially offshore. Other uses include mapping salt structures for their use as natural gas reservoirs (gas caverns), delimiting mineral deposits among other activities involving imaging of the subsurface.

In this short article we will cover the basics of seismic horizon interpretation and how this is used to obtain stratigraphic information.

Why are Some Reflectors Bright?

The amplitude of a seismic horizon will depend on the impedance contrast of the geological layers that define that horizon. When there is a large contrast of impedances, the absolute value of the amplitude of the corresponding reflector will be high; in other words, it will have a high absolute value of reflectivity. On a seismic trace this will correspond to a pronounced peak or trough. This type of reflector is called a hard event or a hard kick or a bright reflector. The best example is the seabed, where the low impedance of sea water and the much higher impedance of sediments will originate what is referred to as a 'very bright' reflector, with very high amplitudes.

Another example of very strong reflectors are igneous bodies (dykes, batholiths, etc.) intruded in sediments. The impedance of igneous rocks is much higher than that of most sediments, resulting in very bright contacts (i.e. seismic reflectors), with high reflectivity.

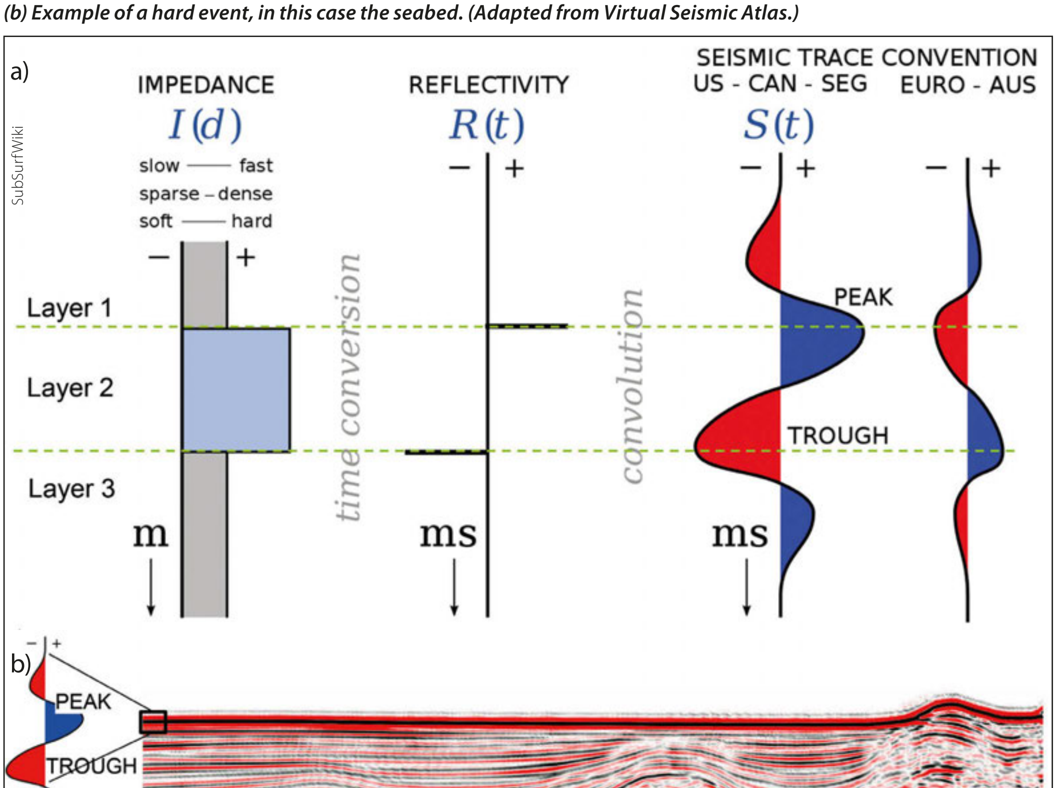
Mineralisations of various types are also often visible in seismic as bright reflectors because they have different characteristics to those of the surrounding rocks. In mineral exploration, if the regional geology is not a sedimentary basin, seismic quality is generally worse, but it can be very useful in identifying and characterising mineralisations, along with gravimetry and geomagnetic data.

Carbonate sediments, especially when they are compacted and lithified, generally have a higher impedance than other sediments like sandstones and shales, so they often appear as bright reflectors. Depending on whether they are reefs or more continuous structures (e.g. carbonate platforms) they can be discontinuous or continuous reflectors.

Other examples of bright reflectors are those originating from layers of coal, where very low impedance results in a very low amplitude reflector.

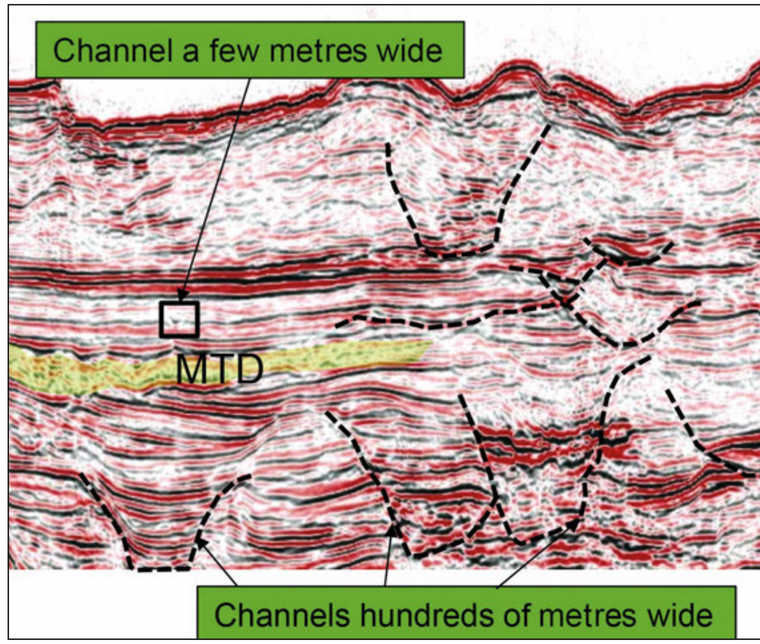
Diapirs and other bodies of mobile salt are very important in hydrocarbon exploration, in the storage of gas (and more recently hydrogen) and for some mineral resources. The salt, because it has high impedance, usually causes a bright positive reflector at the top, but the lateral and base limits of the salt are generally more difficult to identify.

(a) Variation of impedance, reflectivity and seismic profile according to various types of geological layers. (b) Example of a hard event, in this case the seabed. (Adapted from Virtual Seismic Atlas.)



Fluid Contacts and Hydrocarbon Reservoirs

Hydrocarbons in a reservoir will be arranged according to their density. Gas is at the top, followed by oil and associated water is at the bottom. The contacts between these fluids within the reservoir will be horizontal and in some cases they are visible in seismic. These contacts generally have limited lateral continuity, are horizontal (known as a flat spot) and have a different impedance to the layers above, below and laterally. This is a direct hydrocarbon indicator, or DHI. CO_2 in carbon sequestration sites can also be monitored using seismic.



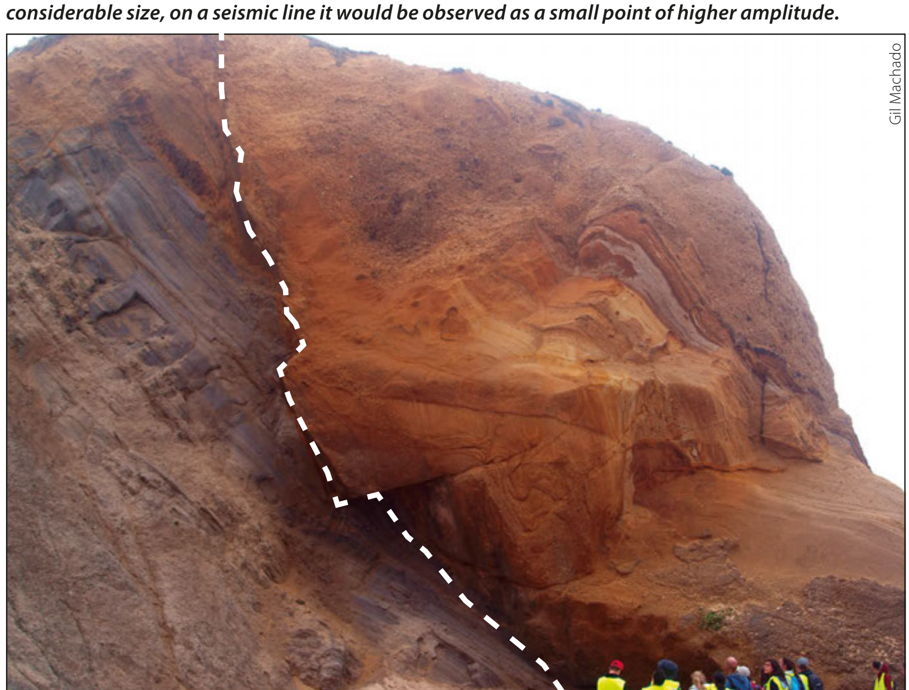
Example of a cross section (parallel to the coast) of a slope area, showing several sets of channels and a mass transport deposit (MTD). (Adapted from Virtual Seismic Atlas/Rob Butler, Jamie Vinnels.)

Horizon Interpretation Techniques

Seismic horizons can be interpreted in 2D lines or in 3D volumes. There are numerous interpretation techniques that can be used, depending on the data and software available. However, after the initial quality control check of the data is made, the polarity noted and the existing wells displayed, the general steps are as follows:

- Define the horizon to be interpreted. This could be a top defined in the wells, based on lithostratigraphy or biostratigraphy; an unconformity; reservoir top or base; or another event that is visible on seismic. The definition of the concept of what is being interpreted is important when doubts arise on which reflector to follow in the interpretation, or whether the horizon's extension is limited or not or similar issues.
- It is recommended that at least the main faults are interpreted. Small throws can be easily perceived and do not greatly affect the horizon mapping, but larger throws can originate mis-ties and erroneous interpretations.
- Start the interpretation from a point where you are sure of what you are interpreting – a top in a well or a seismic section with clear imaging and geometry.
- Define an interpretation spacing and interpret inlines and crosslines in a regular grid. The standard for 3D is to pick every 25 lines, but it can be tighter if more detailed mapping is needed or more spaced if you are working on a regional mapping project. In 2D data, all relevant lines should be mapped.
- Regular quality control checks should be carried out between inlines and crosslines, to avoid mis-ties.
- With 3D data the filling of the mapped grid spaces can be done by propagation or tracking; i.e., by getting the programme to automatically follow the mapped horizon, which all interpretation programmes allow. It can be undertaken in one go for the entire area, but it is recommended that it is done in portions to control the quality of the tracking. Seismic interpretation software has improved greatly over the years, with more 'geological' mapping algorithms, but human control is still key to ensuring reliable results.
- At the end of the propagation it is likely that there will still be spaces that are not interpreted, due to poor quality seismic, locally different seismic facies or other factors. Only in this situation, when it is impracticable to fill all spaces manually, should an interpolation (gridding) be made, which follows the mapped horizon rather than the seismic data. With 2D data, interpolation of the mapped horizon is the only way to obtain a 3D object.

Example of a sandy channel outcrop cutting a clayey sequence in a slope area. Despite its apparent considerable size, on a seismic line it would be observed as a small point of higher amplitude.



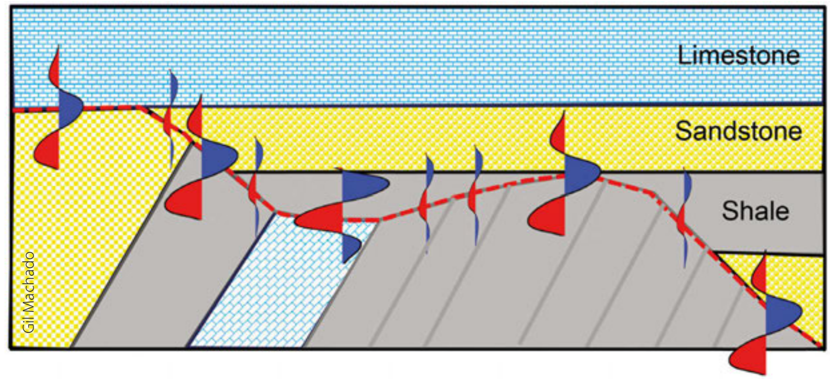
Observing Scale and Continuity

The mapped horizons can extend laterally to occupy the entire seismic area or they can be found in only a part of it.

The principle of lateral continuity of strata was defined based on field observations, at the outcrop. This is valid across short distances, but at the seismic scale – kilometres – terminations of strata are observed. In fact, no stratum is truly continuous laterally; it always depends on the scale of observation. Similarly, the original horizontality principle is a good approximation for most observation scales, but in many cases, seismic horizons were not deposited in a manner that formed strictly horizontal features. The scale of observation at an outcrop rarely allows us to see stratal terminations, significant lateral variations or geometric relationships between strata, but on seismic data, due to its kilometric scale, these are often seen.

One of the best examples of horizons with limited lateral extension (at the seismic scale) are internal channel reflectors. Longitudinally they can be very continuous, but in section they can be from several hundred metres to just a few metres wide, the latter being near the limit of the seismic resolution.

An example of sediments displaying lateral variations are mass transport deposits, which have internal chaotic facies such as discontinuous reflectors with different inclinations, but they can laterally grade to more continuous reflectors, corresponding to the terminal portion of the deposit. Other examples of discontinuous horizons are those that are eroded by more recent events. Often it is also possible to observe pinch-outs – lateral terminations of a reflector or set of reflectors. They can be channels, mass transport deposits, fans or other sedimentary mega-structures.

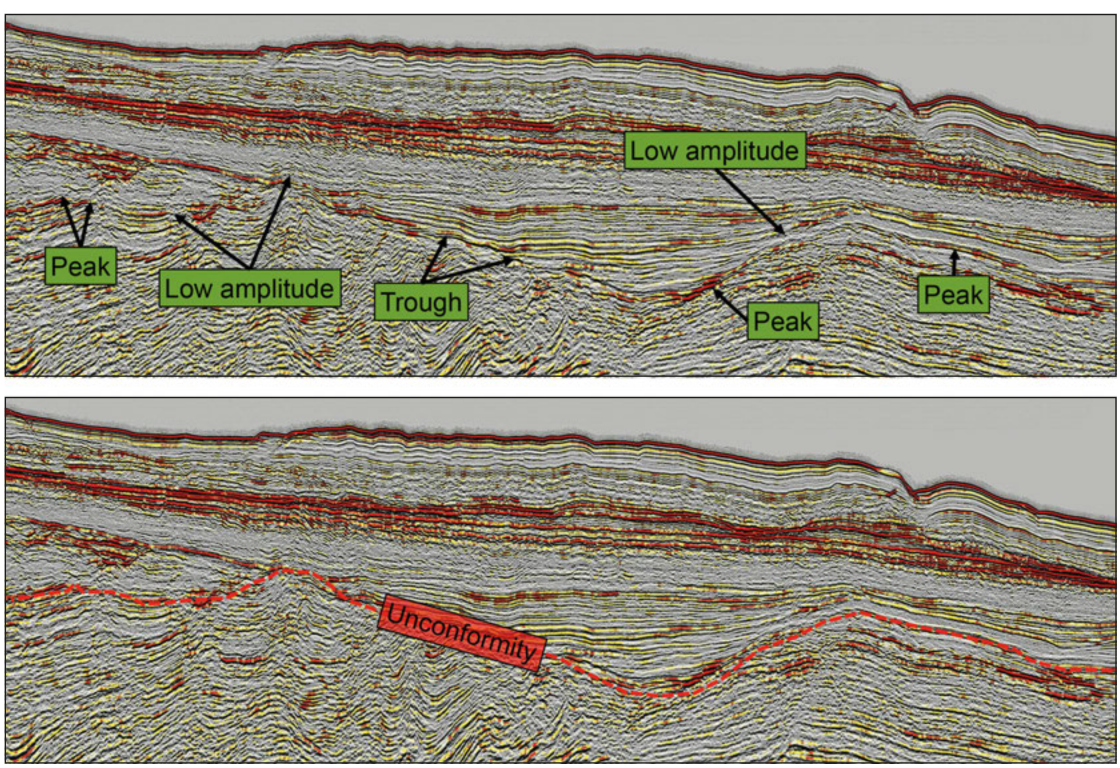


Scheme illustrating an unconformity (dashed red), putting in contact different lithologies and the expected seismic profile according to the impedance contrast.

An unconformity, of either sedimentary or tectonic origin, puts different lithologies in contact. The seismic representation of an unconformity will depend on the impedance contrast at each point. If they are very similar lithologies (e.g. shale with shale) the contrast will be low and the reflector that marks the unconformity will be of low amplitude. However, if it is a limestone–shale contact, the contrast will be very high and the reflector will be a very pronounced trough. If it is a shale–limestone contact, the contrast will also be great, but marked by a pronounced peak. So the result of an unconformity on seismic is usually a horizon with changes in amplitude.

An Important Source

Seismic interpretation is a fantastic source of geological information for both commercial and academic work. Many other aspects can be explored, including seismic attributes, structural interpretation, quantitative geophysics and fluid flow, among others. ■



Example of a seismic line with an unconformity that puts different lithologies in contact. The horizon that corresponds to the unconformity will be positive (peak), negative (trough) or have a very low amplitude depending on the lithologies above and below. (Adapted from Virtual Seismic Atlas/ CGG.)

MCG's Regional Deep Imaging Project: Norwegian Sea 2019

A 'Need-to-Have' for understanding the regional and detailed geology of the Norwegian Sea.

The RDI19 Dataset

The RDI19 data was acquired with Rosgeo's *Akademik Lazarev* in the late summer of 2019. To image the very deep structures, such as the Moho, MCG applied a large source of 6,270 in³ and a 12,000m-long streamer. The first part of the streamer was towed slanted from 15m to 30m, while the last part was towed flat at a depth of 30m. This was done to acquire high frequencies in the front and weaker signals from the Moho in the deep part of the streamer. Data was recorded in continuous mode with a record length of 16s TWT. The data was processed by DUG in London using the newest deblending and deghosting techniques. Processing was completed in June 2020.

M C G

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NORGES GEOLOGISKE UNDERSØKELSE
- NGU -

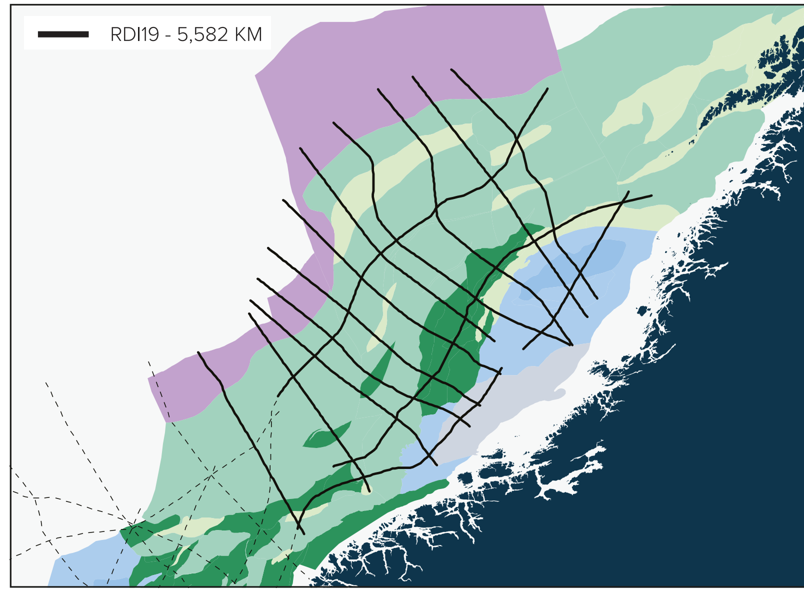


Figure 2: Location map showing RDI19.

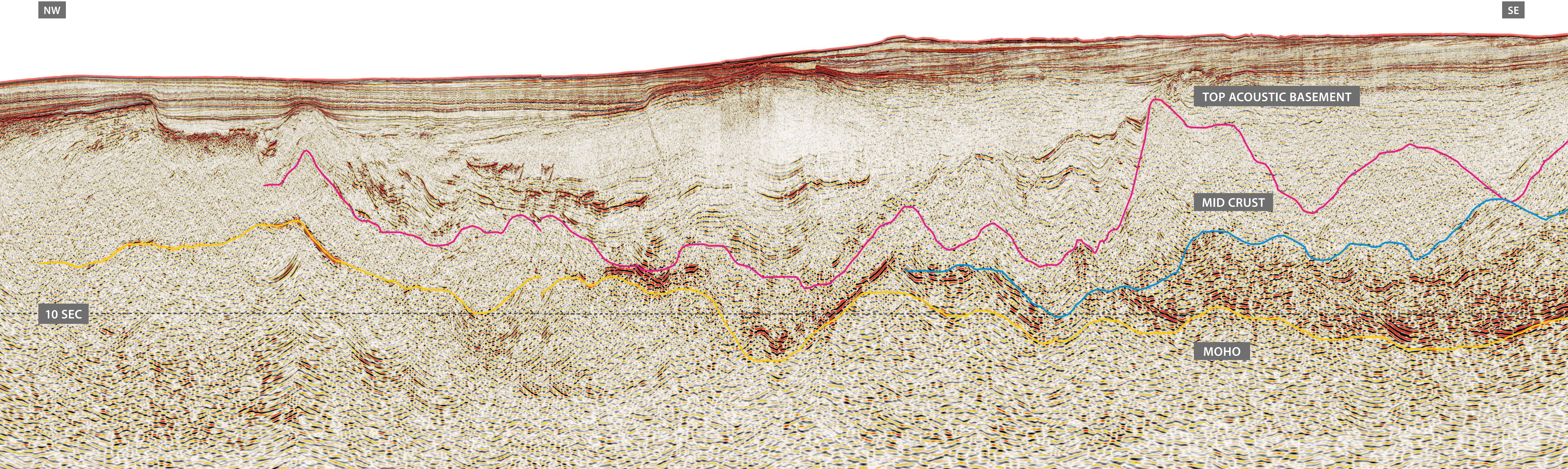


Figure 1: RDI19 seismic line in the Norwegian Sea.

Understanding the Structural Evolution of the Norwegian Sea

Every continental margin deserves a consistent, regional 2D seismic dataset, which images the mega-structures, including the Moho. MCG's Regional Deep Imaging (RDI) MC2D project is just the data needed for this task. With recording lengths down to 16s TWT and meticulously geologically designed survey profiles, a full view of the mega-structures can be mapped. In this article, we will focus on the RDI19 dataset in the Norwegian Sea.

GWENN PERON-PINVIDIC, NGU; TOR ÅKERMOEN, MCG

The Norwegian Extensional System

The Mid-Norwegian Møre and Vøring rifted margins record a tectono-sedimentary history that is exceptionally long, spanning more than 400 million years. It can be summarised in three major geological stages, including an orogeny, its gravitational collapse and a successful rifting that led to the establishment of the northern segments of the North Atlantic oceanic ridge system. The geodynamic evolution of the Møre and Vøring margins is obviously polyphase, and the interpretation of the offshore imaged geometries is not straightforward. The basement and sedimentary structures have been shaped by various geological processes, including brittle and ductile deformation modes, magmatism and metamorphism of various degrees, sedimentation in both shallow nearshore and deep offshore contexts, particular uplift and subsidence histories. Geometries are complex and misunderstanding of the accurate architecture and evolution is easy when studied on a standard dataset. The analysis, interpretation and modelling of this unique rift system therefore requires a specific first-class dataset.

As introduced above, the geodynamic evolution of the Møre and Vøring margins is polyphase: the pre-Mesozoic rift setting is structurally extremely heterogeneous, including inheritance from the previous orogenic and collapse tectonic phases (e.g. Bartholomew et al., 1993; Faleide et al., 2010). It was early assumed that the offshore Mid-Norwegian area, which previously corresponded to the Caledonian orogeny, encompasses significant remnants of structures related to the orogenic collapse, such as shear zones, basement fault systems, and paleo-highs, which controlled, or at least influenced, the subsequent development of the rift basins (Fossen et al., 2016). The correct identification and mapping of these structures is thus fundamental to a proper understanding of the tectono-sedimentary evolution of the rift basins lying above.

From Mesozoic times, rifting in the Norwegian Sea is presumed to have evolved in a 'classical' way with a succession of distinct deformation phases, as often assumed in conceptual models (e.g. Peron-Pinvidic and Osmundsen, 2018). These are:

1. A stretching deformation mode that formed a new series of high angle normal faults, cutting or reusing the former 'collapse' detachment faults (depending on activation/reactivation structural context);
2. The necking operated by a combination of brittle and ductile deformation, similar to the collapse deformation mode, although in a more local context;
3. Once the crust was sufficiently thinned, the rift system passed the 'coupling point' and entered the hyperextension/exhumation mode and ultimately the break-up mode.

These distinct deformation phases affected the extensional system successively, each involving specific tectonic structures leading to distinct sedimentary record contexts. Geometries issued from previous rift stages can additionally be reused, reactivated, deactivated and/or cannibalised by the subsequent deformation phases giving rise to complex architectures (e.g. Naliboff et al., 2017). Within that context, the quality, resolution, and coverage the RDI19 dataset made available to the study is crucial.

Unprecedented Possibilities

The RDI19 dataset allows for an unprecedented imaging of the Mid-Norwegian margins. Not only does it provide an excellent imaging of the major sedimentary and basement structures of the Møre and Vøring margins, it also gives access to unique information about the overall basement thinning evolution, sedimentary record, and uplift-subsidence history at margin scale.

The major strength of the RDI19 dataset is that it, for the first time, images the entire crustal section of the rifted margins at a regional scale. To perform a robust and accurate study and mapping of a rift system, the interpretation must include the first order interfaces: the seafloor, the acoustic top-basement and the Moho. These interfaces are the fundamental envelopes delineating the core architecture of every rifted system. They enable us to determine and quantify key parameters such as the amount of basement thinning, accommodation space and subsidence, sedimentary and magmatic input, and newly accreted basement. All these parameters are of crucial importance for any mapping and modelling purpose. Even though the focus area for some projects can be extremely local and at smaller scale (e.g. reservoir), the correct calibration of the study within the regional structural framework is fundamental. It will also help to avoid any misinterpretation and misunderstanding of the mapped geometries.

Modern seismic reflection datasets, acquired during the last two decades, have enabled us to identify and map some of these main basement geometries. The RDI19 dataset now allows for a correct and robust calibration of these geometries by including a proper structural mapping of the entire basement, including the deepest geometries (crust and mantle) and the Moho. The RDI19 is the first dataset providing clear imaging of the Moho interface at margin scale. The high quality seismic profiles image the Møre and Vøring margins in dip and strike directions and allow for robust and accurate mapping and studying of the base of the crust, from the proximal to the most distal settings, revealing unprecedented geometries. The underlying mantle is also clearly imaged and can be investigated. Dip and along-strike facies variations, together with internal structures are identified, pointing to a tectonic history that is not yet constrained.

The RDI project may look academic at first glance, but the mapping of deeper geological layers and rocks, understanding the temperatures and heat flow, mapping the regional deep faults and correlating the sedimentary mega-sequences have a serious impact on play and prospect analyses.

References available online. ■

Figure 3B: Zoom to illustrate detailed imaging in the shallow part of the section.

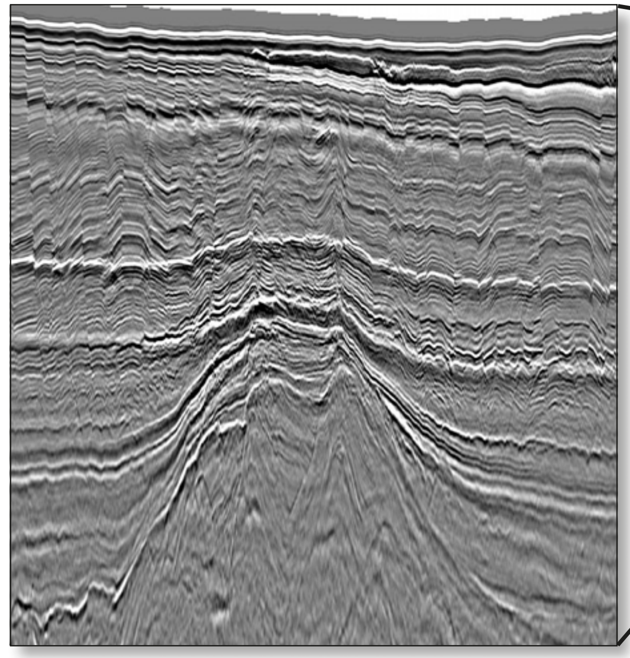
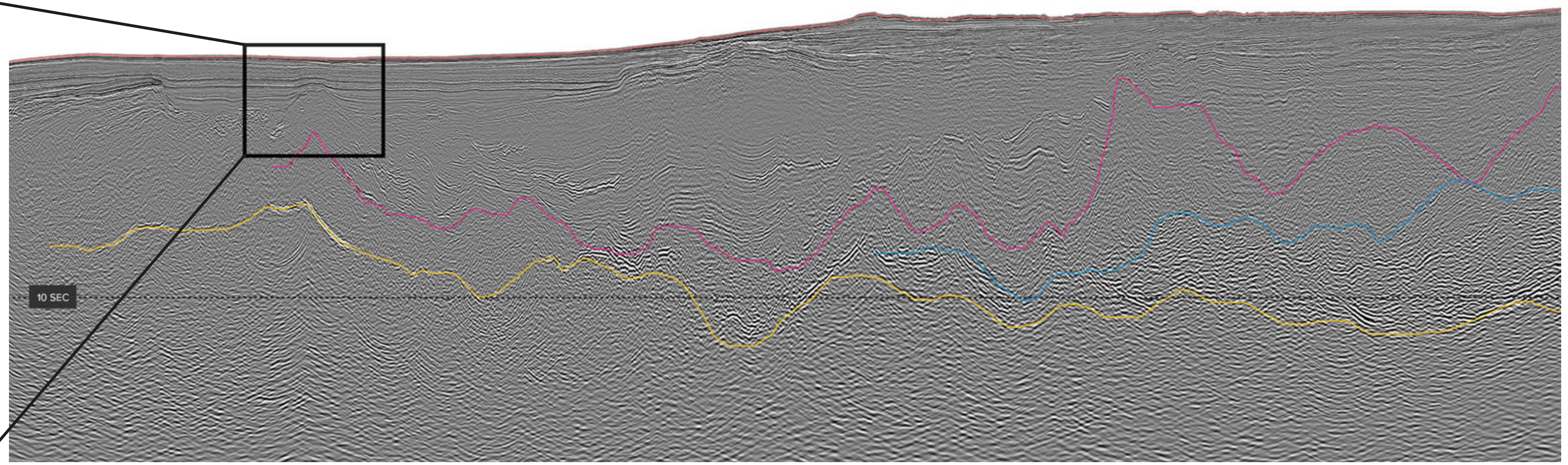


Figure 3A: Greyscale alternative of the foldout image for better displaying the continuity of the reflectors.



Unlocking University–Industry Collaboration

How do we release the full potential of university–industry collaboration in creating relevant innovations in petroleum and geoscience?

KRISTOFFER J. ZIEBA and KRISTOFFER LUND VIK-LANGLIE; Norwegian University of Science and Technology

The petroleum industry is going through a transformative period related to intensified digitalisation, economic pressure and an increasing degree of environmental regulation. A successful transformation requires innovative technology and business models, 'out-of-the-box' thinking and solid domain expertise. This cannot be achieved, or at least will not be efficient, by use of in-house expertise and resources alone – it needs input from the world outside. Possibly the most natural partners in this process are universities that can offer both the drive and creativity of students and young staff, as well as the scientific and domain excellence of seasoned employees. The industry has a long tradition of collaboration with universities but has not yet unlocked the full potential in transforming knowledge and technology into practical solutions: new products, services, processes or industry standards – i.e. innovations. Despite the establishment of a host of new innovative start-up companies, often with roots in academia, organic technology adoption and transfer as a part of university–industry collaboration can be enhanced.

Improvement of the technology and innovation transfer from universities to the industry is in the interest of both parties. It can create market-relevant projects for researchers and give access to genuinely novel ideas and technology for the industry, all at relatively low cost. However, unlocking the full potential of collaboration requires actions from both sides. Here, we challenge the status quo and attempt to answer the question: what conditions can favour the creation of more relevant research-based innovations that support transformation of the petroleum geoscience industry?

Our reflections are supported by views voiced in numerous discussions and interviews with employees at the Department of Geoscience and Petroleum (IGP) at the Norwegian University of Science and Technology (NTNU) over the last two years. In addition, our views are supported by a survey performed among 13 inventors from IGP in early 2020 (see table).

Importance of Industry Feedback

Our survey shows that the most important driver for pursuing innovation work by researchers is a deep belief in the commercial success and novelty of their own ideas. This requires an ability to spot commercial potential and usefulness beyond scientific publications. We see, however, that few researchers can actually identify the innovation potential or believe in their idea's commercial success from the very beginning. Most academics need to get some advice on initial idea refinement, market/user fit and ways of transferring ideas to potential users.

Researchers also need to test the value and novelty of their own work by validating it with the users. Industry representatives have the best overview of

The BRU 21 programme at the NTNU: an example of a large university–industry collaboration initiative in digitalisation of the petroleum industry.

Egil Tjåland, NTNU

Innovation Driver	Importance			
	Mean	Median	Standard deviation	Characteristics
Strong belief in the idea and willingness to get it developed	4.2	4	0.8	Very important for all.
Innovation/entrepreneurship/own business was a new thing to me that seemed tempting to try out	3.1	3	1.2	Mostly important for all.
Innovation/entrepreneurship/own business seemed to be an admirable thing at work or in the social environment	2.5	3	2.1	Important/very important for most. Unimportant for some.
Limited opportunities in the job market or no job offer after finished contract	1.5	0	2.3	Unimportant for most. Very important for some.
"I wanted to have a side project in addition to my ordinary job"	1.4	0	1.8	Unimportant for most. Important for some.
Other	1.4	0	2.2	Unimportant for most. Very important for some.
Spare time at work or did not have projects to fill whole working day	0.3	0	0.9	Unimportant for most. Important for some.

Results of the survey of inventors from NTNU, who were asked to score (between 0 and 5) seven potential innovation drivers preselected by the article authors, based on initial discussions as well as key factors for innovation commonly identified in innovation literature. Accumulated results from all inventors, including some statistical description and characteristics, are summarised in the 'importance' column.

their needs, know of existing solutions and their respective disadvantages. Without the involvement of the industry, researchers could not suggest relevant solutions, being unaware of trends, business focus and technical framework.

University–Industry Co-Creation on Innovation

In practice, relevant innovations are born as a part of synergetic idea exchange between inventors and potential users of the invention – in our context, the industry – rather than born in a vacuum. More and more innovations are being created as a part of open inter-organisational collaboration ('open innovation') including the oil and gas sector. Many major oil companies have changed focus from outsourcing R&D to more open innovation, giving them the opportunity to acquire new, future-relevant competence through collaboration. An example is the open innovation initiatives of Eni, where multiple external collaborators have been engaged by the company since the early 2000s. In a university–industry context, collaboration that relies on synergetic cooperation and deep industry engagement favours the development of new ideas and technological solutions.

Moreover, openness in data and results can strengthen development of genuinely innovative solutions thanks to broader participation in the innovation process. Developments in this direction have been made in the industry recently, chiefly thanks to a willingness from oil companies to open up traditional knowledge silos. Equinor's open-source code repository, for instance, facilitates new contributions to the code and its use by external parties, including academia. Another good example of enhanced interplay between academia and industry that helps create innovative digital solutions are 'hackathons'. These are creative problem-solving events that have been supported by major stakeholders such as the Norwegian Petroleum Directorate and the UK Oil and Gas Authority, as well as multiple oil companies. In recent years, participants of these hackathons have created thousands of novel solutions and several million lines of open-source software code used in digital advancement and energy transition.

Our survey shows that researchers are open to trying new forms of knowledge transfer, such as entrepreneurship or innovation work. This was mentioned as our respondents' second most important driver for innovation. The main prerequisite here, however, is time to pursue collaboration, experimentation and application of the research results beyond traditional scientific deliverables. Academia, including open-minded employees and students, is an ideal space to explore the possibilities that lie within open innovation. Furthermore, open access is more of a university ideal and open access to data is receiving increasing focus in research and also by governmental funding institutions.

Access to Resources Vital

Curiosity and creativity are favoured by safe environments, low personal risk and incentives. Incentive systems and ownership of intellectual property for academic work are different across countries and universities. However, at many universities scientific staff are not sufficiently incentivised to pursue innovation work, as their achievements are assessed by scientific publications, while technology transfer and innovation work are rarely taken into consideration. We cannot

The UK OGTC's TechX programmes attract start-ups for a net zero North Sea, providing support from idea generation, validation, field trials, investment, commercialisation and growth, as wells as access to experienced business mentors, co-working space, forward thinking business partners and showcase events (pictured).

therefore expect temporary researchers to pursue extra innovation work if their work is assessed on traditional scientific merits only. The same applies to permanent staff who are fully booked with their primary tasks such as teaching, supervising and research. As a result, some universities have introduced special incentives that can be used solely for pursuing innovation work. For example, NTNU has established several internal incentive schemes to promote and facilitate both technology innovation and market validation, which have supported multiple innovators in the petroleum and geoscience domains. There are also examples of similar incentive schemes in the Norwegian context, including specific calls funded by the Research Council of Norway.

Although a lack of jobs was not found to be a major innovation driver according to our survey, it was still considered very important for some temporary employed researchers, typically PhD and post-doctoral candidates. Innovation work sponsored by a university can be a positive career move for those who have not yet secured a new job after their temporary research contract runs out. This should be regarded as an opportunity for universities to put into practice ideas and technology developed during such research projects that might otherwise not be used. To utilise this opportunity, researchers need to have access to financial schemes and support for early phase technology development from universities, as previously mentioned, or to have easier access to resources from the industry, which has recently started investing in creative teams, offering both financing and access to resources such as mentors and workshops. One of the examples is the Equinor and Techstars start-up accelerator for those "who work on disruptive solutions within oil and gas, renewables, new business models and digitalisation". Another example is the Oil and Gas Technology Centre TechX Accelerator programme and their Innovation Hub.

Social Recognition and Role Models

The third most important innovation driver indicated by the survey is high social recognition of those who pursue innovative work. Geoscientific and petroleum communities know that digitalisation, energy transition and transformation of the oil industry need innovative ideas and creative specialists who can think outside the box. Entrepreneurship and innovation have become important terms not only in the geoscience and petroleum communities but also in the broad public sphere. Universities need to promote innovative thinking, show success stories and facilitate dialogue with successful innovators. Entrepreneurial professors have a very strong impact on their academic environments and can act as examples for other employees, so 'investment' in the top academic staff is possibly one of the most effective ways to boost innovative thinking in scientific environments.

A Way Forward

Results based on the survey and extensive discussions made at IGP NTNU, suggest that innovation from the personal perspective of researchers is driven by belief in the idea, curiosity about the practical application of research and appreciation for innovation work in an academic environment. It also shows that researchers need the opportunity to validate their own ideas with potential users of their innovations and that academia–industry co-creation is a very suitable environment for creating relevant technological advances. Efforts should be made to enhance synergies between researchers and industry professionals on a technical level and researchers need to have access to a range of different resources. Securing funding is important, but so is access to mentors and the need to learn about technology commercialisation.

Of course, some of these resources can be found today, in different forms, and from different sources. In our opinion however, there is potential for improvement in university–industry collaboration aimed at the creation of future-relevant innovations. As such, we see the ideas expressed in this article not as a clear-cut way forward, but rather as an invitation to a more detailed discussion on the topic of creating innovation for a changing geoscience and petroleum industry. And as with any good innovation, we need user feedback going forwards – or, in our case, the industry perspective. ■

The Wilson Cycle and Petroleum Plays

RASOUL SORKHABI, Ph.D.

The Wilson Cycle describes the opening and closing of oceanic basins as a result of plate movements. It provides a scientific framework to follow the creation, development and destruction of sedimentary basins and how these processes impact on petroleum plays.

Earth processes are cyclical, both on a tiny scale as biogeochemical cycles and on a large rock cycle scale. Plate tectonics is no exception. The Wilson Cycle, named after the Canadian geoscientist John Tuzo Wilson (1908–1993), is one facet of the cyclical operation of plate tectonics over geologic time. It is often described in terms of tectonic events, but it also has direct bearings on sedimentary basins and the generation, preservation and destruction of petroleum plays.

In 1966, Wilson, already well known for his idea of transform faults in mid-ocean ridges, published a paper in *Nature* that argued, based on geological evidence, that the North Atlantic Ocean opened twice. Its former version, 'Proto-Atlantic' (or Iapetus Ocean), existed during late Precambrian and early Palaeozoic times, roughly 600–400 Ma. The closing of 'Proto-Atlantic' brought together North America and Western Europe to form a new continent, Laurentia, at the end of the Palaeozoic. Laurentia began splitting during the Late Jurassic to gradually open the modern North Atlantic Ocean. This opening and closing of an ocean was later named the Wilson Cycle by John Dewey and Kevin Burke in 1974 (*Geology*, 2: 57–60). It is divided into several stages, briefly described below with emphasis on petroleum basins (for Basin Classification, refer to *GEO ExPro* Vol. 16, No. 2).

Fissure caused by the divergent movement of the North American and Eurasian plates in Iceland.

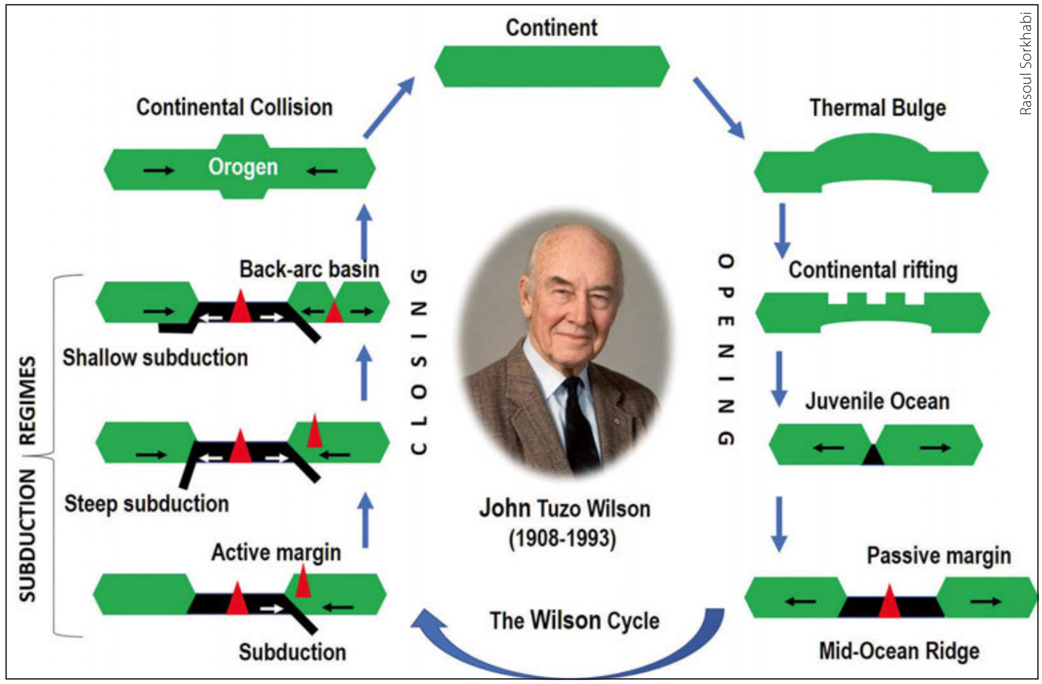

Jane Whaley

Continental Rifts

The opening of an ocean begins with continental rifting, which can be an active or passive process. In active rifting, the upward flow of hot magma from the mantle triggers the rifting; this may be a deep mantle plume ('hot spot') or asthenospheric rise as part of the convection currents associated with plate tectonics. In either case, the hot molten mass impinges the lithosphere from below and produces a thermal bulge on the continental crust, followed by volcanic eruptions and widespread normal faulting, creating collapse structures. The thermal uplift exhumes all or parts of any sedimentary pile present on the continental crust and hence leaves a pronounced unconformity in the stratigraphic record. Flood basalts and Large Igneous Provinces formed in this process, like the Deccan Traps in India, actually destroy petroleum systems.

In passive continental rifting, the movement and interaction of tectonic plates provide a trigger. This typically occurs in a continent–continent collision setting where the thickened continental crust undergoes gravitational spreading and produces rift valleys (for example, the Rhine Graben in Europe or similar grabens in southern Tibet), or in the development of transtensional (strike-slip and extensional) faults due to plate movements, as in the Baikal Rift in central Asia. In passive rifting, igneous activity may be absent or very limited.

As the continental crust stretches and thins, a series of normal faults produce horsts (uplifted blocks) and grabens (collapsed blocks). Grabens become important sites for the accumulation of sediments shed from rift shoulder uplifts and continental highlands. They may be 'full-grabens' (bounded on both sides by horsts), which indicates symmetric rifting, or 'half-grabens' (bounded by a normal fault on one side), suggesting asymmetric rifting. The East African Rift has a symmetrical rift structure, while the Basin-and-Range in south-west USA is a textbook example of non-symmetrical rifting, with half-grabens distributed over a wider zone above a major detachment fault.



Stages of the Wilson Cycle.

Grabens create linear, narrow river valleys filled with sand-rich fluvial sediments, but as the grabens widen and deepen, they may form lakes which are excellent locations for deposition of organic-rich mudrocks. High geothermal gradient (~40° C/km) associated with continental rifting, contributes to thermal maturity of petroleum source rocks in these basins. In addition, if the water column in the rift lake is stratified into an upper layer of warm, fresh water and a lower one of cold, saline or dense water, anoxic conditions at the lake bottom produce black shales – the best source rocks.

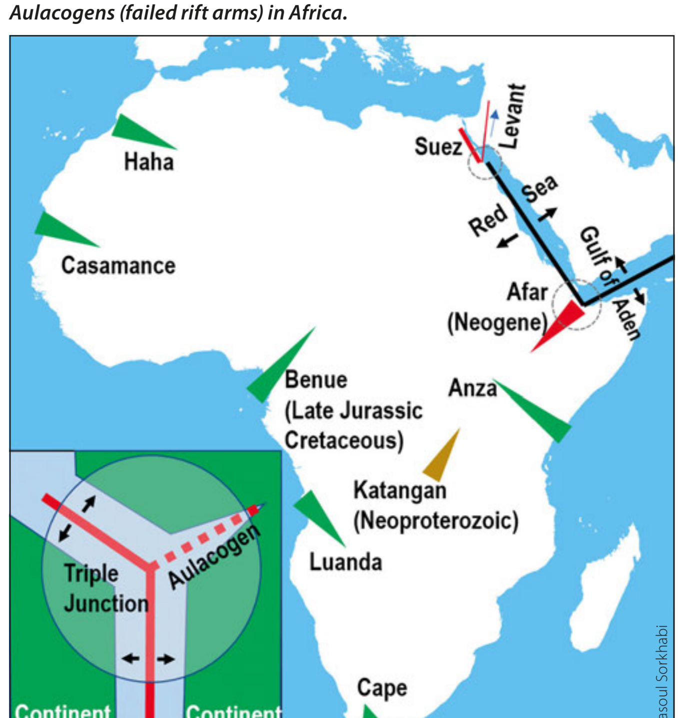
Continental rifts are sometimes associated with 'triple ridge junctions', in which, for geometric and physical reasons, one of the rifting arms fails, while the other two arms (rift valleys) continue widening to eventually form an ocean basin. The failed rift is called an aulocogen (Greek, *aulax*, 'furrow'), a term introduced in 1946 by the Russian geologist Nikolay Shatsky, but revived in the plate tectonic context by Kevin Burke and John Dewey in the 1970s. The western and eastern margins of Africa, for example, contain several aulacogens that trend almost perpendicular to the coast line. Aulacogens can continue to receive sediments for millions of years and may act as sites of major river deltas, thus hosting both lacustrine and fluvial depositional environments.

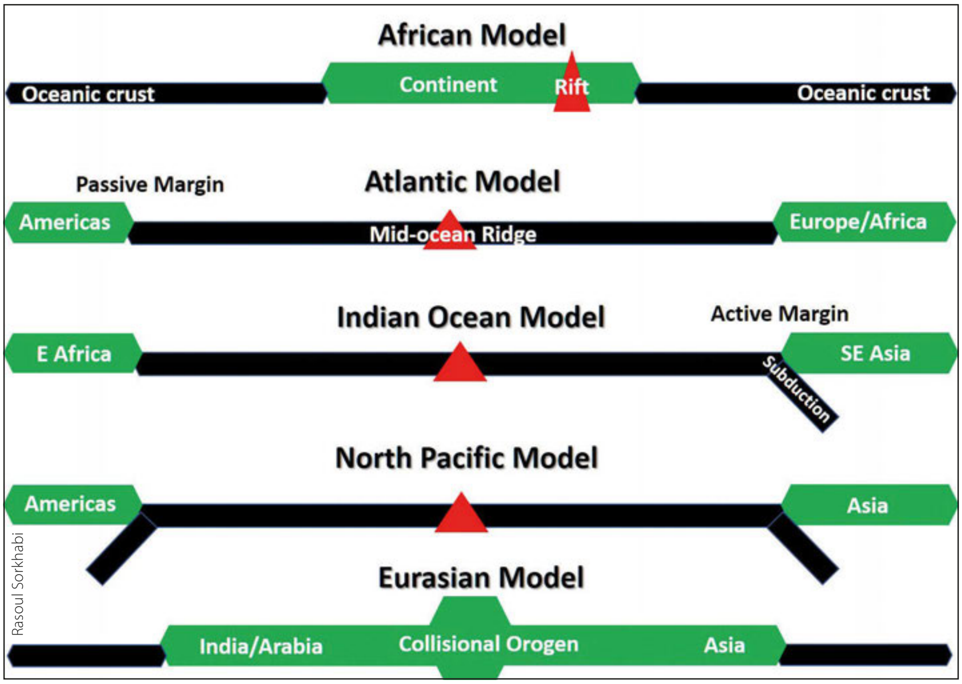
Open Seas and Passive Margins

As extensional tectonics proceed, the continental rift turns into a spreading centre pouring out basaltic magma and creating a young oceanic floor. Initially, it is a narrow sea floored by oceanic crust. A modern example is the Red Sea, where tectonic extension began about 20 Ma ago and oceanic crust was generated about 5 Ma ago. This juvenile oceanic sea marks a new stage in the Wilson Cycle: that of drift and divergence of two plates from each other along the spreading centre. These narrow, long, proto-oceanic seas are important sites for deposition of petroleum source, reservoir and cap rocks.

With continued divergence and drift of the plates facilitated by ridge push, the narrow sea widens into a mature, open ocean where the spreading centre is now a mid-oceanic ridge –

Aulacogens (failed rift arms) in Africa.





Various tectonic settings related to the Wilson Cycle.

a zone of volcanic eruption, earthquakes and extensional and transform faulting. The relatively thin veneer of sediments in abyssal ocean plains is of little interest for petroleum exploration; however, the passive continental margins bordering the ocean are excellent exploration targets. These margins contain thick sedimentary wedges that are tectonically stable. The passive continental sediments are superimposed on the previous continental rift basins. Basin subsidence or 'sag' in the passive continental margins is aided by two factors: the isostatic bending of the crust under the weight of sediment load, especially in deltaic settings, and the sinking of the oceanic floor beneath the sedimentary pile, as the oceanic crust ages and becomes colder and denser. This sag basin creates accommodation space for enormous amounts of sediments that are eroded and transported from the continental highlands.

Sea-level changes, as well as deltaic retrogradations or progradations, control the nature and volume of sedimentation on passive margins. Seismic and sequence stratigraphy provide important tools for the identification of various sedimentary facies and packages in passive margins, including pre-, syn- and post-rift, maximum flooding surfaces and turbidites. A well-developed continental margin consists of a coastal area, continental shelf, continental slope and continental rise. In contrast to narrow continental rifts, sedimentation on passive margins is widespread. Structural traps provided by growth faults, salt or shale diapirs and deepwater toe-thrusts, as well as stratigraphic traps, are important hydrocarbon accumulation sites at passive margins.

Subduction and Active Margins

The transformation of a passive continental margin into an active margin marks an important stage in the Wilson Cycle as it is the beginning of the end for the ocean basin. An active margin is characterised by a trench, along which the oceanic lithosphere subducts beneath the continental plate. The formation of incipient subduction is poorly understood, as we do not know of definite live examples of this process. It occurs because the dense, cold oceanic crust pushes against the light, buoyant continental crust. This creates a totally new tectonic setting, consisting of an accretionary prism or wedge of deepwater sediments together with accreted ocean-floor basalts, and a volcanic arc on the continental side generated from the partial melting and dehydration of subducting oceanic slab. Other features created include forearc basins in front of the volcanic arc, and possibly back-arc basins on the continent behind the volcanic arc. Active continental margins have not been found to be suitable targets for petroleum exploration, mainly because of their tectonic deformation and volcanic activity. Nevertheless, hydrocarbon shows have been observed in deep-sea drilling of active margins, and some forearc basins in Indonesia also contain petroleum fields. Forearc basins may have poor quality reservoir rocks because of detrital input from volcanoes.

The most relevant aspect of an active margin for petroleum exploration is not the oceanic but the continental side, behind the volcanic arc. Here, the juxtaposition of a cold, old continental crust against a juvenile hot magmatic crust may cause underthrusting of the continent, thus forming a mountain belt as well as 'retro-arc' foreland basins in front of the mountain. This is how the Cordillera belt and associated foreland basins from the Rockies in North America to the sub-Andean basins in South America formed during Cretaceous–Eocene times. These basins are among the most prolific petroleum basins in the world.

Subduction may occur on one or both sides of the ocean facing the continent. The subduction may be high or low angle; the latter would create wider magmatic activity in the upper plate (the continent).

Continental Collison and Foreland Basins

Subducting oceans eventually close and two continental plates collide with each other along boundaries called 'suture zones'. The ocean then reduces to a shallow sea (for example, the Persian Gulf) and river plains like the Indus and Ganges plains, are formed in front of high mountains uplifted by continental collision. This is what has happened in the European Alps, the Bitlis–Zagros mountains in the Middle East, and the Himalayas in India, as the Tethys ocean closed and the African–Arabian–

Indian plates collided with Eurasia. The peripheral foreland basins in front of these mountains contain thick wedges of fluvial and alluvial sediments, which lie atop the shallow marine sediments of the waning ocean.

Continental collision may be 'soft' or 'hard' – a distinction that has important implications for petroleum basins. In soft collision, the continental deformation is restricted to the sedimentary cover of the colliding plate and the foreland basin develops above the passive margin sediments of the colliding plate. This is the case in the Middle East, where the Zagros foreland basin sits upon the Arabian plate passive margin (shelf) sediments – an ideal situation for the generation and accumulation of oil and gas (see *GEO ExPro* Vol. 9, No. 1). In hard collision, the leading edge of the colliding plate experiences massive basement uplift, deformation and partial erosion of shelf sediments, as in the Himalayas, where the present foreland basin has developed atop the Indian basement, not on the Tethyan shelf sediments. Continental collision creates thrust faults and folds which act as structural traps for oil and gas accumulation in foreland basins.

Life Span of a Wilson Cycle

How long does it take for a full Wilson Cycle? This depends on two factors. The first is the time lapse between continental rifting and ocean-floor subduction; the longer this is, the wider and more long-lasting the ocean. The second is the relationship between rates of ocean-floor spreading and subduction; faster ocean-floor spreading implies a wider ocean, while faster subduction indicates a shrinking one.

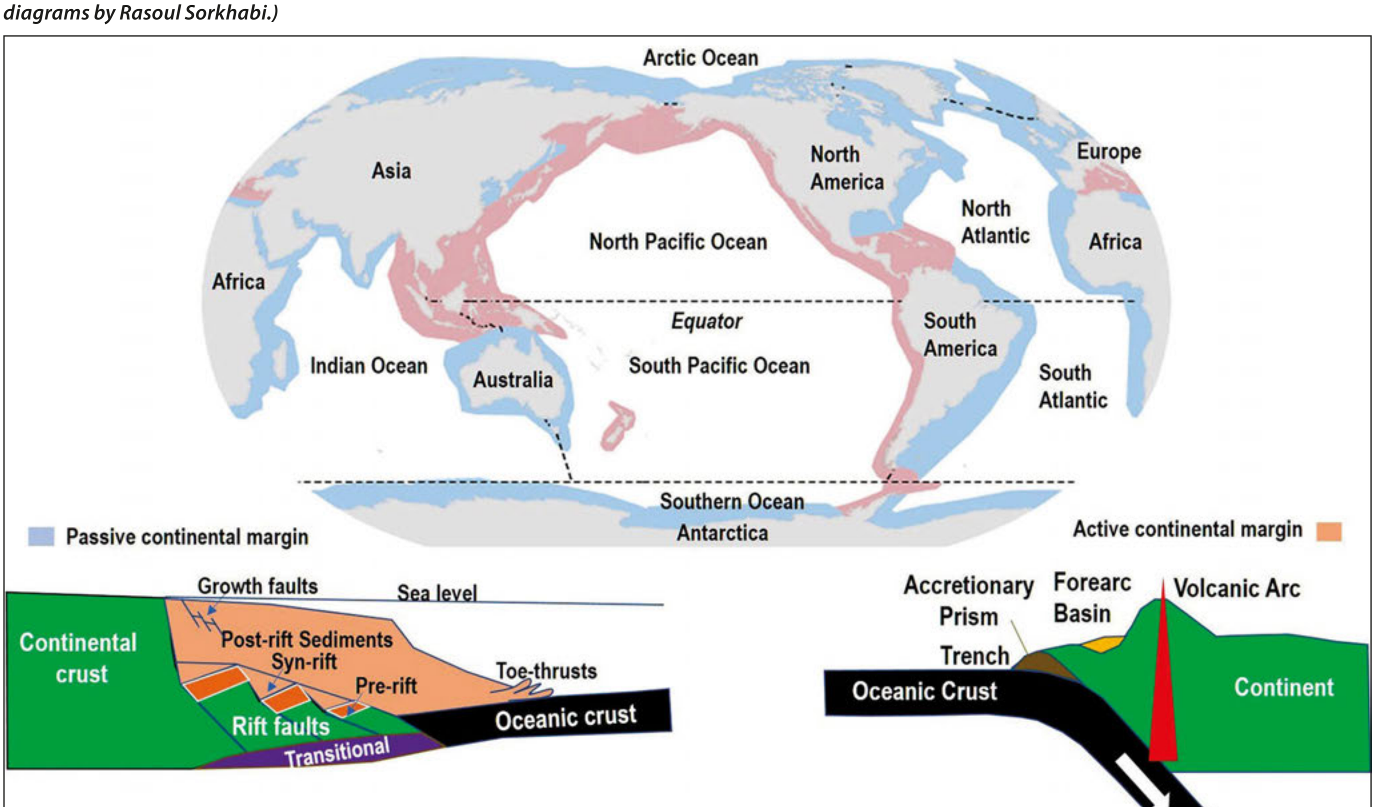
Currently, the oldest ocean floor in spreading oceans is about 180 Ma, along the continental margin of the North Atlantic. Since the Atlantic Ocean is still spreading, a full Wilson Cycle will require a longer period of time.

Given that Earth is 4.6 billion years old, there were Wilson Cycles prior to the present oceans. We find the records of these in ophiolites (deep ocean rocks) now outcropped on continents, which suggest that the Neo-Tethys Ocean between India and Asia opened in the Permian and closed in the Eocene over a period of 250 Ma. Larger oceans probably take about 500 Ma to complete a Wilson Cycle; for instance, the entire Tethyan Ocean emerged about 550 Ma (ProtoTethys) and closed about 50 Ma (NeoTeothys). The Pacific Ocean opened 300 Ma and is expected to close 200 Ma in the future.

The life span of a Wilson Cycle is divided into opening and closing phases, which have different processes and impacts. During the opening phase, normal faulting and rifting are dominant. Volcanism associated with rifting and sea-floor spreading outpours carbon dioxide and contributes to the greenhouse effect, as happened in the Cretaceous during the fragmentation of Gondwana and opening of the present oceans. Global warming raises sea levels and enables phytoplankton to flourish, favouring deposition of organic-rich, thick black shales through oceanic anoxic events and upwelling of nutrients close to continental margins (see *GEO ExPro* Vol. 6, No. 5).

During the ocean closing (subduction) and consequent continental collision, fold and thrust structures dominate the basins. The closing of oceans may also lead to the formation of supercontinents – another facet of plate tectonics. ■

Passive and active continental margins. (Map modified from Harris et al., 2014, Geomorphology of the oceans. *Marine Geology****, Vol., 351, 4–24. Tectonic diagrams by Rasoul Sorkhabi.)***



Broadband 4D Seismic Provides New Level of Detail

Understanding new details in the 4D seismic signal uncovered by a broadband time-lapse dataset at Gullfaks Main Field in the North Sea.

YULIA BIRYALTSEVA, TOR VEGAR MÅRDALEN and PER-HARALD SAURE-THOMASSEN, Equinor; MARTA WIERZCHOWSKA, ANASTASIYA TANTSEREVA and JULIEN OUKILI PGS

The Gullfaks area is in Block 34/10 on the western flank of the Viking Graben in the Norwegian North Sea (Figure 1). The main reservoirs are located below the Base Cretaceous Unconformity (BCU) in the Brent Group and the Cook and Statfjord formations and production from those levels started in 1986. The younger secondary reservoirs, in the Shetland Group and the Lista Formation, came into production in 2012.

Time-lapse seismic monitoring is a key technology to secure future field production, with a 4D strategy defined by various needs and targets. The Gullfaks asset has been running a successful seismic monitoring programme for decades. Since 1995, eight vintages of streamer data and nine Ocean Bottom Seismic (OBS) surveys have been acquired at regular intervals.

The 4D repeatability and data quality have directly benefitted from the evolving technology. Recent broadband multisensor streamer solutions have delivered better, clearer images with a higher level of detail than conventional seismic. While broadband has become a standard for 3D seismic interpretation, its application is still new for time-lapse seismic and the number of case studies is limited.

In 2019 Equinor ran a time-lapse broadband proof of concept, using the latest 2016 and 2019 GeoStreamer surveys, which together with Ocean Bottom Cable (OBC) seismic data, provides an extensive dataset for interpretation and strengthens our understanding of the potential broadband 4D uplifts for future application.

The area of interest underwent several development stages between 2016 and 2019. Gas injection was already underway when the 2016 4D monitoring survey was acquired. Near wellbore pressure increased between 2016 and 2019 and a gas saturation effect was visible in the reservoir on both the 2016 and the 2019 4D seismic. A pressure depletion during this period is expected.

Two Comparative Datasets

Two datasets were acquired and used in this study. The broadband multisensor streamer dataset was used for the main analysis, while the OBC seismic was used as a reference dataset.

In 2016, the upgrade from conventional hydrophone-only streamers to GeoStreamer multisensor streamer technology set a new milestone in the Gullfaks monitoring programme, and this technology was used to provide the analysis dataset. A high-density streamer spread (17 × 50m), using multisensor streamer technology and sophisticated source and streamer steering systems, allowed for high geometrical repeatability and deeper towing depths. This resulted in improved signal-to-noise ratio and acquisition efficiency without compromising the bandwidth. In 2019 a similar acquisition setup was used which enabled a unique opportunity to quantify the uplift of 4D broadband.

The two latest GeoStreamer surveys were processed in two ways:

Figure 1: The location of the Gullfaks Main Field and a 3D view through the reservoir, below BCU.

conventional non-deghosted (H-REC) and broadband fully deghosted (P-UP). Both H-REC and P-UP were processed using similar, though not identical, processing sequences. Free of the receiver ghost, the P-UP data only requires full source deghosting. For H-REC, both source and receiver ghosts are not compensated for; however, the H-REC data still carries the multisensor deep tow acquisition benefits of reduced noise level, better recording and higher signal-to-noise ratio on low frequencies.

The reference Ocean Bottom Cable dataset, covering the same time interval (2016–2019), was processed as part of an OBS monitoring programme by a different contractor. OBC acquisition has continuous seismic coverage below rig holes in the area of interest and was used as additional input. This allowed cross-validation of the various streamer scenarios and strengthened understanding of the broadband 4D uplifts.

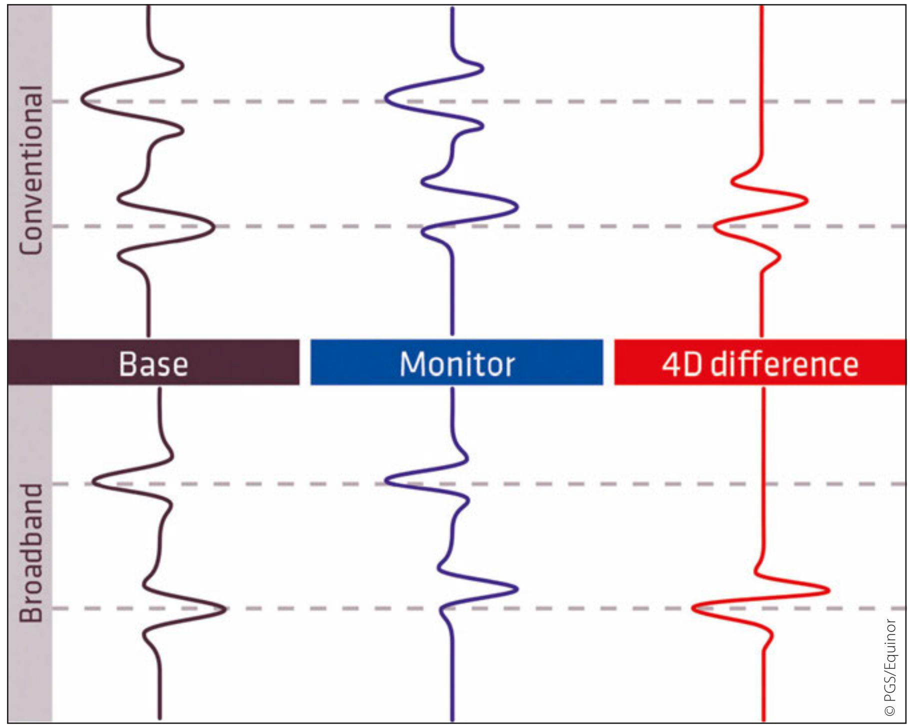


Figure 2: Modelling of 4D response for broadband and non-deghosted datasets. Broadband seismic is much more focused and has stronger maximum amplitude than the conventional seismic.

Comparing the Datasets

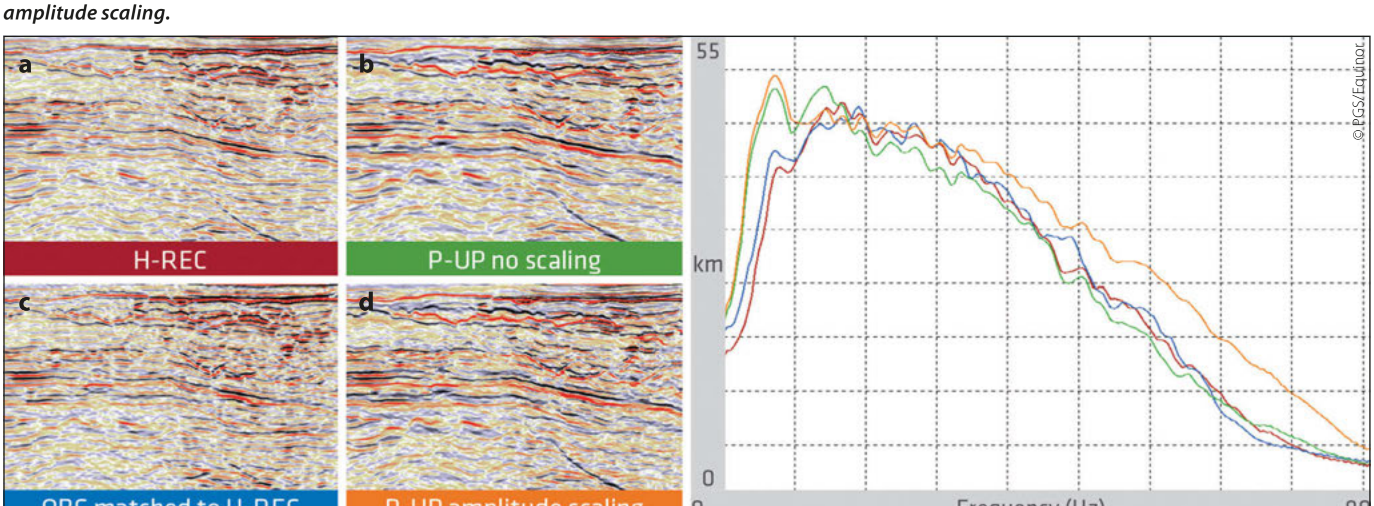
In the context of 4D interpretation, isolating the 4D signal from background noise is key in defining the applicability of the monitoring programme, as accurate positioning and delineation of the signal may become critical in determining the next development step in the life of the reservoir. Figure 2 illustrates that the 4D difference obtained using conventional seismic is much less focused and has weaker maximum amplitude than the one from broadband seismic. This might lead to very different conclusions about the state of the reserves in place or difficulties in matching the observed effects with the production/injection history.

The expectations from the broadband dataset were broader bandwidth, a consistent level of detail with at least the same amount of information as non-deghosted streamer data, and a consistent interpretation result between non-deghosted and deghosted broadband and the OBC data.

The bandwidth of broadband deghosted data is wider than conventional non-deghosted data. To make the deghosted dataset more comparable to the non-deghosted one, an extra version of the data was produced, applying additional amplitude balancing to the final stack (P-UP amplitude scaling).

Figure 3 shows 3D stack seismic sections that are zoomed in on the

Figure 3: 3D stack of target sections (2019 monitor, zoomed to target area) and corresponding amplitude spectra of the datasets: (a) non-deghosted streamer (H-REC); (b) broadband streamer (P-UP) without amplitude scaling; (c) OBC matched to non-deghosted streamer; (d) broadband (P-UP) with amplitude scaling.



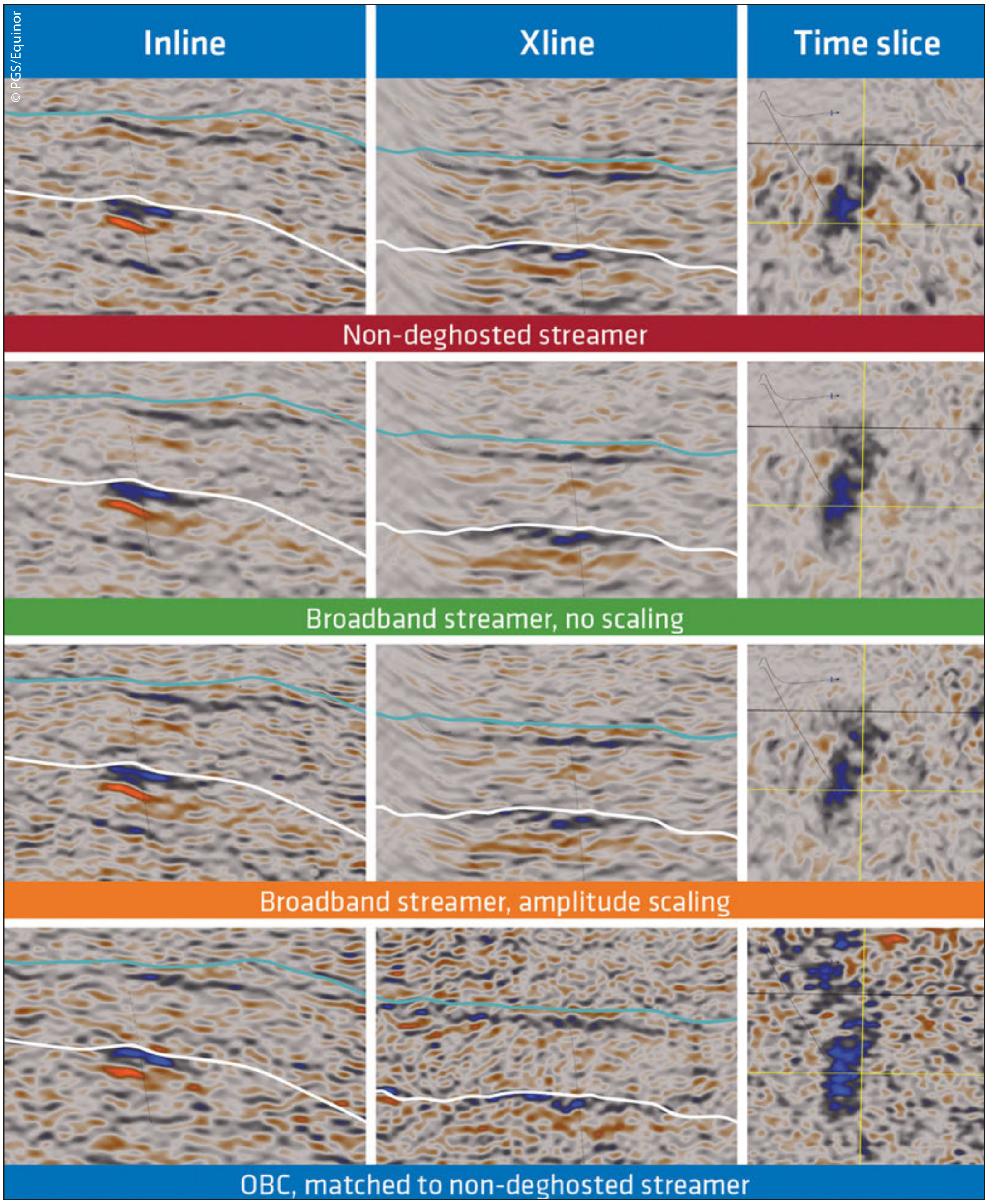


Figure 4: 4D differences in inline, crossline, and time-slice dimension, zoomed to target area. The left side of the crossline images on the streamer data is influenced by migration aperture from the platform hole. Broadband and OBC dataset show better continuity and amplitude discrimination of the 4D effect than the non-deghosted data.

target area from the 2019 vintage. Corresponding amplitude spectra are also shown. GeoStreamer broadband data has considerably higher amplitudes at 0–16 Hz, but all spectra converge at higher frequencies. Amplitude balancing boosts the high frequency end of spectra and scales down the area of 10–15 Hz to make it more comparable to non-deghosted streamer. However, when assessing the 4D differences (Figure 4), the amplitude scaling did not add useful information but boosted the background noise.

Figure 4 shows 4D differences in inline and crossline sections through the target area. Overall, 4D effects in each comparison are similar and match the well production history: the Shetland Formation (light green) near wellbore pressure build-up effect between 2016 and 2019 results in acoustic softening. This 4D effect, positioned slightly on the side of the well, is mainly observed in the inline direction. The 4D effect in the Cook Formation (white) is dominated by a pressure reduction with expected hardening of the 4D signal. This can be seen in both inline and crossline directions.

When comparing 4D signal in the crossline direction between the OBC and streamer data (Figure 4), we observe the expected contribution of the platform hole. The OBC 4D effect is more continuous and coherent than the streamer data. However, the broadband data (Figure 4, rows 2 and 3) show better continuity, similar to the OBC extent of the hardening at the Cook level, than on the non-deghosted streamer data (Figure 4, row 1). The broadband dataset without additional amplitude scaling (Figure 4, row 2) gives better amplitude discrimination of the 4D effect, lower background noise, and brighter and more isolated amplitudes of the 4D effects on the Cook Formation. This is also supported by the NRMS and amplitude scaler target window attributes, shown on Figure 5. The 4D signal in the inline display also looks more continuous on the broadband data at the Shetland level and is comparable to the OBC data.

Overall, at this stage, we observe good continuity and improved resolution in the broadband data. Improvement of the fine details and reduction in the 4D noise increases confidence in the 4D results. Minimising the uncertainty of the reservoir models can help to improve the production plan.

Future Strategy

The current Gullfaks licence period continues to 2036. Future field plans include further development and maturation of the gas and oil reserves. The Gullfaks 4D strategy aims to acquire a new seismic survey every three years, to validate and monitor the existing reservoirs and to find new targets or bypassed hydrocarbons.

More work is needed to fully understand the benefits and take advantage of the broadband 4D data on the Gullfaks field. However, a conclusion can be made that availability of modern, high quality seismic data enables more thorough analysis and provides new insights into this established area. Employing up-to-date acquisition and processing technologies, including broadband solutions, sets a path towards future high-resolution 4D projects. ■

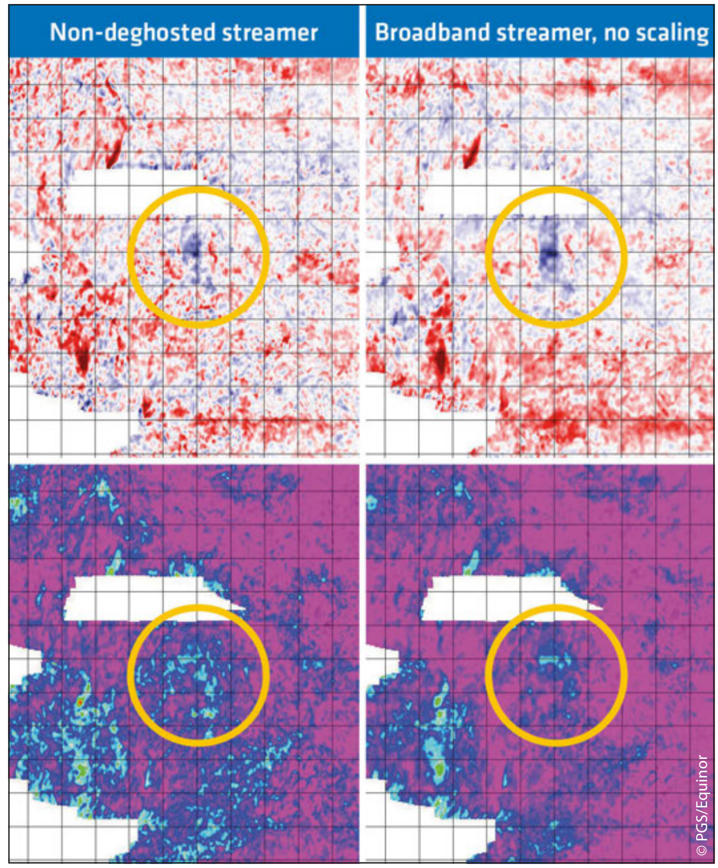


Figure 5: RMS scaler and NRMS for non-deghosted and broadband dataset, showing the broadband dataset gives lower background noise and brighter and more isolated amplitudes of the 4D effect.

MER: The Race to Find Proven Oil

As North Sea fields reach the end of their lives and face decommissioning, can their infrastructure be used to invigorate stranded undeveloped reserves and discoveries?

"The best places to find oil are in spots where it's already been found"

MATT MULCAHY and FAZRIE WAHID, Bridge Petroleum

Maximising Economic Recovery (MER) – the race to exploit oil where oil has already been found – is nothing new. In the US, the ageing long-forgotten fields and acreages both on land and shallow state waters have seen significant activities over the last ten years – a quiet revolution during the shale boom era. Across the world, similar trends were seen dotted across hydrocarbon basins in Latin America and Russia, with South East Asia and West Africa recently jumping on the bandwagon. Closer to home in the North Sea, the brownfield revolution started in the early 2000s with great fanfare, with redevelopment of brownfield sites at Forties, Dunlin and Don taking centre stage.

Nevertheless, the maxim of "the best places to find oil are in spots where it's already been found" is never more relevant than in present times, where recurring cyclical conditions such as depressed oil price and challenging market fundamentals are again upon us. The adage of 'safe bets in brownfields' has been clearly evidenced, with close to $10 billion-worth of assets changing hands in the last five years. The common theme of going back to brownfield sites remains the same today; improvements in technology and the abundance of proven hydrocarbons left behind makes it attractive and clearly seen as a hedge against the risky boom and bust prevalent in our industry.

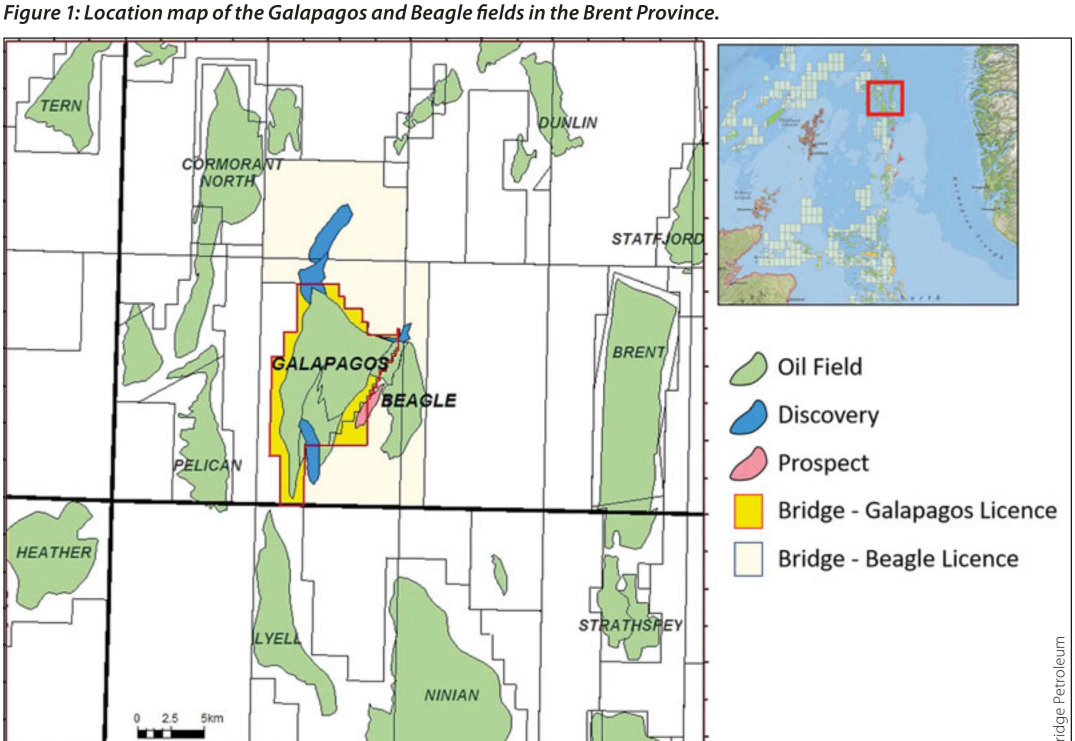
Tieback Opportunities

In focus in this article is the Brent Province in the Northern North Sea of the UKCS, a world-class prolific play, explored and exploited principally in the 1970s–1990s. The backdrop for this activity was the industry cutting its teeth in drilling and development techniques and the emergence of 3D seismic acquisition and processing. To further add to the mix, the economic environment was of generally low oil price and increasing costs due to safety upgrade requirements following the Piper Alpha disaster. The resulting legacy is a series of giant Brent oilfields with associated infrastructure that are rapidly approaching Cessation of Production (COP) in the next decade or are already decommissioned.

Where successful development campaigns were employed, high recovery factors have been achieved. Benchmarking highlights this trend and identifies fields which are not realising their present potential as an opportunity for redevelopment. Bridge Petroleum Ltd (Bridge) has identified the prematurely decommissioned Galapagos (North West Hutton) and Beagle (Hutton) fields as such an opportunity, together with a raft of other infrastructure-led tieback opportunities.

The establishment of a tieback of the Galapagos field, with 81 MMboe 2P certified resource and further upside potential in the region of 60 MMboe, is MER in action for this mature region of the UKCS. The tieback will have multiple benefits to the region, with the potential to reduce OPEX per barrel costs on host infrastructure and terminal. It will further extend the life of these mature assets, allowing for increased base production, additional incremental development projects

Figure 1: Location map of the Galapagos and Beagle fields in the Brent Province.



and further tieback opportunities to nearby accumulations which would otherwise be deemed marginal to develop as a standalone.

Revitalising Galapagos

The North West Hutton part of the Galapagos field was discovered in 1975 and developed in the 1980s–1990s. In 2012, successful appraisal wells on the southern Darwin extension proved continuation and communication of the field to the south (Figure 2). Evaluation of production data finds the historic development only achieved a 14% recovery (from 883 MMbo in place), leaving a significant undeveloped prize when compared against a benchmarked 30% expected recovery.

To understand the recovery shortfall, forensic analysis of historical well data revealed that well operational issues were significant and appear to be the major underlying factor in the field's low recovery – an artefact of old technology and historical know-how to address field challenges deemed common today, rather than due to poor rock quality. Over 20 years on, standard mitigation methods are commonplace, using mature proven technologies. In addition, the development strategy suffered from inefficient placement of injectors to provide pressure support to the producer wells, resulting in poor reservoir sweep and

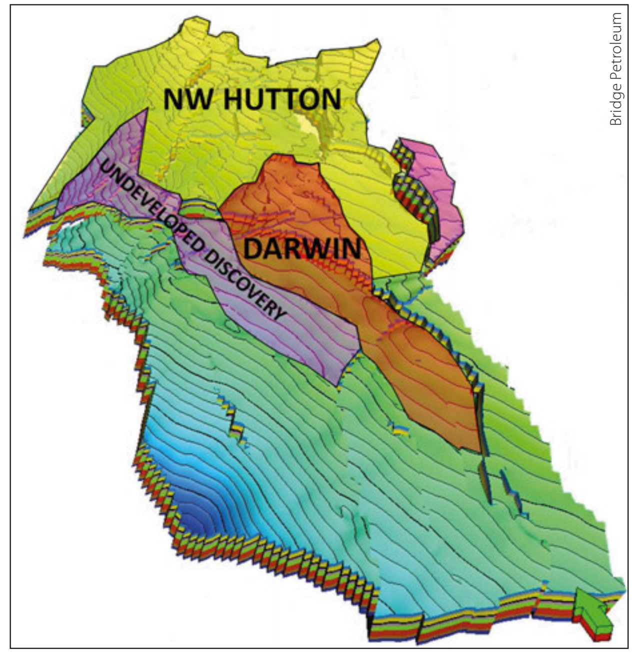
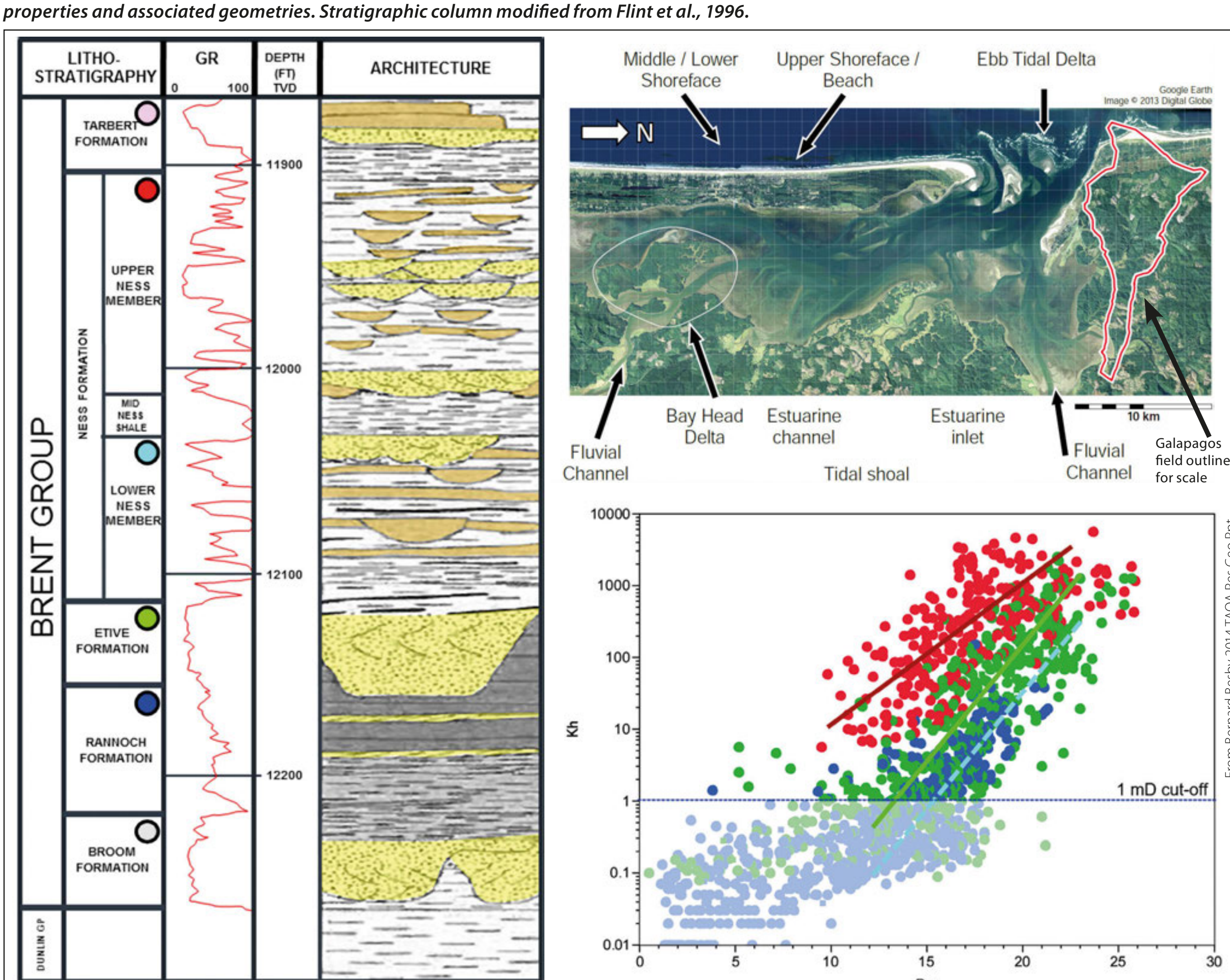


Figure 2: Galapagos field depth structure model and top Brent horizon, locating the North West Hutton and Darwin regions and illustrating the terraced nature of the field.

Figure 3: Brent reservoir facies in the Galapagos field and their impact on reservoir properties and associated geometries. Stratigraphic column modified from Flint et al., 1996.

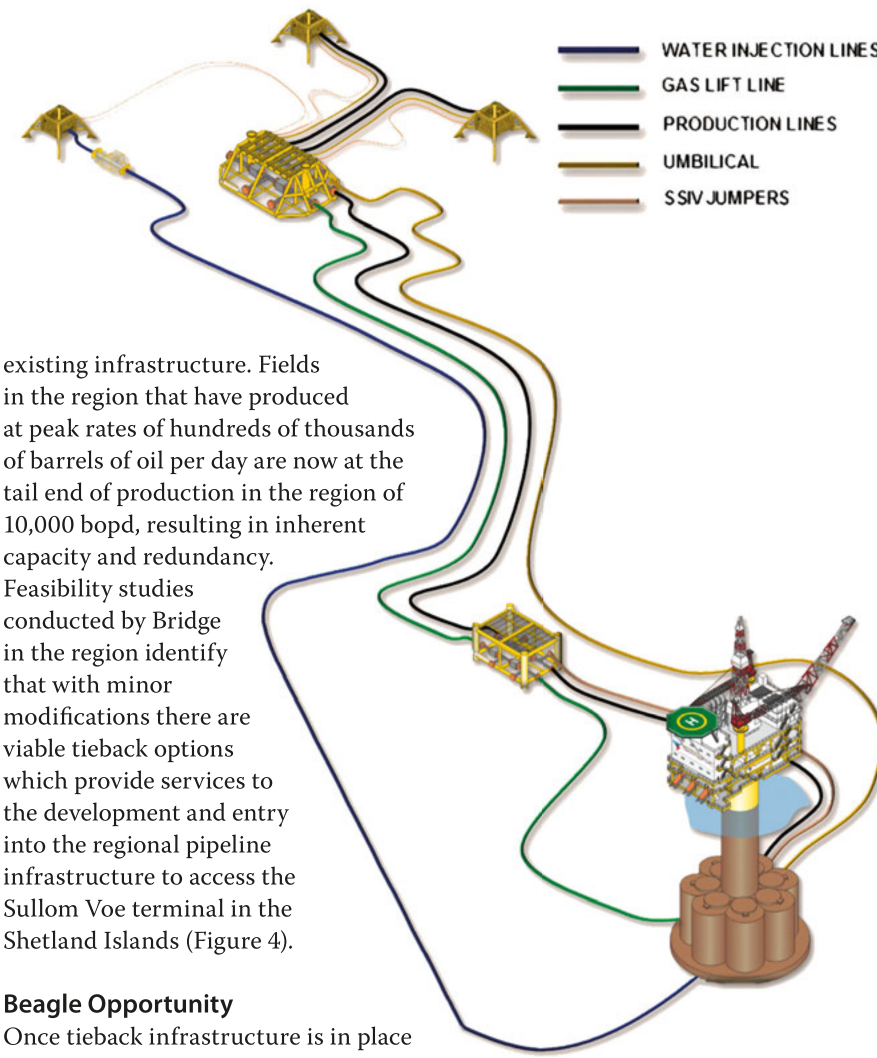


low voidage replacement ratios. A significant factor contributing to this was the very poor historic seismic, resulting in suboptimal well placement and missed attic potential. However, where suitable placement of producers and injectors occurred, good localised sweep and recovery was achieved. Due to the excellent multi-Darcy reservoir quality within the Middle Jurassic Brent Formations (Figure 3), top historical producers in the field can produce at very high initial rates and deliver around 15 MMbo from near-vertical wells.

Remapping of the field with new seismic data together with integration of production and well data highlights the field is a series of terraces on the flank of a large, tilted fault block (Figure 2). Each terrace is large (some over 100 MMbo in place) and provides discrete development regions with internal, terrace-wide pressure communication. Remapping of the new seismic also allows, for the first time, the identification of a smaller scale fault set within these discrete terraces, which have proven crucial in understanding the sweep pattern from the original development well stock. Further insight on the internal 'plumbing' of the reservoirs has been gained by integrating detailed sedimentological analysis. Core and well data confirm that all the formations of the Brent Group are present and acting as reservoir units and that the depositional environment has a significant control on reservoir quality, distribution and connectivity (Figure 3).

By combining the new insight from the remapped seismic data, insight gained from historical production data and incorporating reservoir architecture and properties from studies into geocelluar models, Bridge has been able to achieve the first known full field history match on this field. This is a powerful tool, enabling identification of numerous untapped and underdeveloped regions of the field that provide low risk well targets, prime for redevelopment.

A mature hydrocarbon province such as the Northern North Sea of the UKCS provides the opportunity for production offtake via tieback to existing infrastructure. Fields in the region that have produced at peak rates of hundreds of thousands of barrels of oil per day are now at the tail end of production in the region of 10,000 bopd, resulting in inherent capacity and redundancy. Feasibility studies conducted by Bridge in the region identify that with minor modifications there are viable tieback options which provide services to the development and entry into the regional pipeline infrastructure to access the Sullom Voe terminal in the Shetland Islands (Figure 4).



Bridge Petroleum

Figure 4: Tieback development for one of the Galapagos drill centres to nearby infrastructure.

Beagle Opportunity

Once tieback infrastructure is in place then the door opens to exploiting the remaining resource base in the region and previously uneconomic accumulations now have a clear line of sight to development infrastructure. Bridge has been actively working the region to identify such opportunities, one of which is the Beagle field (Hutton).

The experience and knowledge gained from working the Galapagos field redevelopment opportunity very quickly highlighted potential in the region. The obvious candidate is the now decommissioned Hutton field, renamed as Beagle. This was discovered in 1973 and developed in the 1980s–1990s and was still producing just under 10,000 boepd before it prematurely ceased production in 2001. Part of the same large, tilted fault block as Galapagos, the Beagle field shares many similarities in both structure and Brent reservoir (Figure 5). The field is again subdivided into large terraces and the reservoir units are directly correlative to wells in the adjacent Galapagos field.

Bridge is conducting a work programme to evaluate the full remaining potential of the Hutton field, which again has not achieved its benchmark recovery potential. Well targets have been identified that would currently be tied-back into Galapagos infrastructure. However, it is anticipated that results of ongoing analysis, including the impact of gravity segregation post-COP, may yield potential resources to allow an independent tieback if required.

MER – The Road to 2050

This mature region of the UKCS is rapidly reaching a critical point where loss of fields and pipelines through

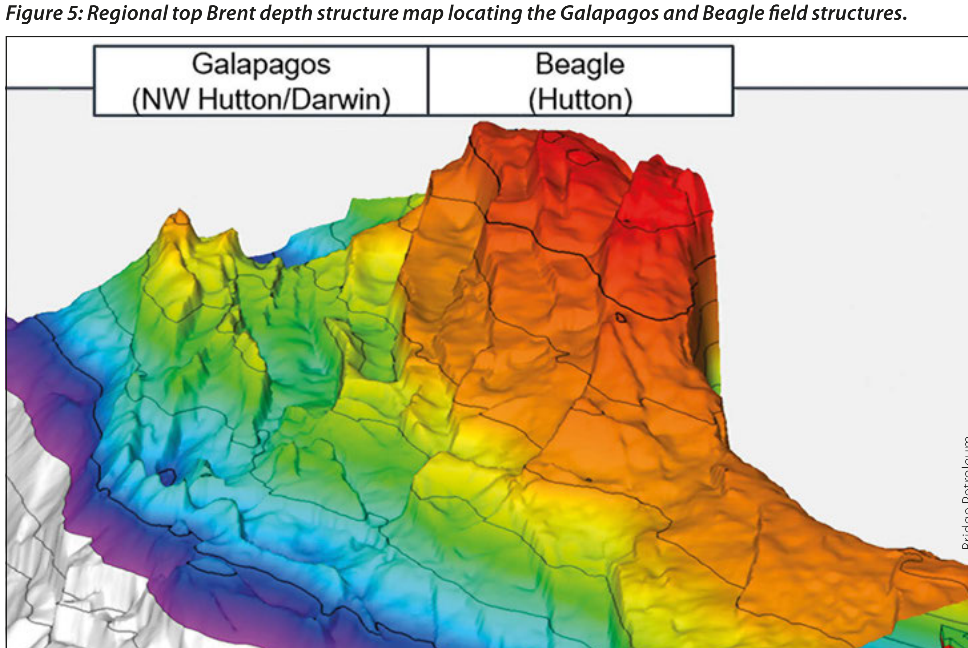
COP and decommissioning of fields and pipelines will occur. The loss of infrastructure will leave undeveloped reserves and discoveries together with undrilled prospects stranded without any economic development potential. Further reserves and infrastructure are needed in the region now to arrest this decline.

Bridge's analysis highlights that the recovery potential of both Galapagos and Beagle has not been achieved in the historic developments and remaining resources are sufficient to provide an economic redevelopment. Infrastructure associated with these redevelopments will be an enabler for the UK MER strategy in an area that has not previously been under the lens of infrastructure-led exploitation. Numerous discoveries and a low risk prospect have been identified within a short distance of tie-in points of the proposed full field Galapagos and Beagle developments. As a result, Bridge have identified a risked resource potential of 185 MMboe that can be targeted across these two adjacent licences. The additional tie-in hub value from surrounding fields has not been finalised but is estimated to be around 200 MMboe, and the potential for pushing back COP dates for the tie-in fields is significant, which in itself will allow further base production from the existing well stock and potential to endorse new well campaigns and MER activities. These volumes may also allow for reduction in cost per barrel throughout the infrastructure pipeline all the way back to Sullom Voe. This would benefit the region as a whole, acting as a catalyst for maximising economic recovery with further exploitation of mature fields and retaining infrastructure presence for any other future tieback opportunities in this highly prolific oil region.

As the UK goes through a once-in-a-century energy transition phase, focusing on tiebacks would not only help the economic viability of redevelopment of these brownfield and stranded licences, but would also reduce the environmental footprint when compared to installing significant new infrastructure in the region.

Brownfield redevelopment is no fad and is here to stay, as the old oilfield maxim keeps proving true time and time again: "The best places to find oil are in spots where it's already been found". ■

Figure 5: Regional top Brent depth structure map locating the Galapagos and Beagle field structures.



Could LNG Prove Transformational for Mozambique?

The LNG project in Mozambique started with the discovery of huge reserves of natural gas off the northern coast in 2010. This led to a $20 billion final investment decision in 2019, with the project expected to deliver first LNG in 2024. The enterprise will provide a range of social and economic benefits to Mozambique as well as diversifying its economic activities. Following his recent panel appearance at Africa Oil Week Virtual, we talk to Omar Mithá, special advisor to President Nyusi of Mozambique, about the importance of this project to the future prosperity of this emergent regional gas producer.

What was your reaction back in 2010 when you heard that the first ever deepwater well offshore Mozambique had found substantial reserves of gas?

The deepwater discovery sent a message that Mozambique would fulfil its destiny to be a significant O&G province. This came as no surprise, given the favourable supply and demand dynamics, the projected future growth of the world economy, and most importantly the Asian market when including China and India. At the same time, my mind was haunted by the past experience of the 'resource-curse' in other resource-rich countries in Africa.

The first exports of Mozambique LNG are expected by 2022. How important is this for the country and which countries does Mozambique expect to become its primary LNG export markets?

First LNG in 2022 will definitely set a precedent for the future in view of the forthcoming onshore projects. It will primarily impact on exports and the balance of trade, boosting economic growth. In addition, the government take from royalty fees and other forms of taxation, which includes its share held by the National Oil Company ENH, will improve the fiscal situation. The fiscal deficit that has deteriorated since independence will see an improved trend, reinforced by the upcoming large scale onshore projects.

For the country as a whole, the opportunity to link the offshore floating liquefied natural gas (FLNG) with suppliers from onshore and the ability of the regulator to set the proper scrutiny, will improve its state of preparedness to tackle the more complex integrated onshore projects.

With respect to the export markets, the off-taker for the first project is an aggregator, BP. Demand will be led by China and India as they have a strong commitment to reduce carbon emissions. Based on the off-takers from the Area 1 Project, the main buyers are from China, India, Japan and Indonesia which speaks to security of supply in fast growing economies, as well as the need to diversify and reduce the risk from reliance on the Middle East. In this way, Mozambique can position itself to become a leader in the global LNG market.

What are the plans for using gas within Mozambique and how will access to so much local gas affect the Mozambican economy and people?

The future plan includes the use of more gas in the energy mix, which currently is principally supplied by hydro with only one third from small gas fields in southern Mozambique. The plans look into the possibility of adding value by having a domestic industry in fertilisers, gas-to-liquids and other derivatives, as well as power generation. For Area 1, the plan is to supply three selected projects: power generation operated by Great Lakes Africa; fertilisers operated by Yara; and gas-to-liquids sponsored by Shell. Delay in gas supply agreements, caused by price fluctuations, will probably undermine progress. Yara has already stated that its breakeven price would not make it possible to establish a feasible venture, while Shell will most likely rethink and redirect resources elsewhere. My opinion is that this is a long-term venture, initially as exports to anchor the LNG projects, followed by domestic gas industries.

Currently, Mozambique is still a small market with underinvested off-takers, unable on their own to make a domestic gas project bankable and induce the upstream oil and gas companies to make a financial investment decision. The options on the table include the possibility of developing new domestic infrastructures, some of which are mutually exclusive. This boils down to the market volumes and credit ratings to ensure financial leverage underpinned by credible off-takers with long-term commitment.

The anchor market that needs gas volumes and has financially strong buyers is South Africa, which would require either a pipeline or a competing re-gas plant. There are plans for the second option, whilst the first one would be a long-term project. In each case, the scenarios carry uncertainty, as our neighbours have their own natural resources, including new gas discoveries in South Africa. On top of that, the lack of a clear vision from each individual country as to which plan to undertake adds commercial risk. Coordination from the Southern Africa Development Community (SADC) could bring consensus on how to integrate the whole system.

For the people in Mozambique, the most important outcome will be the gradual adoption of gas for cooking, alternative fuels for vehicles and reliable power in the energy mix. Population growth and rapid urbanisation will require the country to upscale power generation capacity. In addition, gas implies industrialisation that creates paid employment and the subsequent uplifting of people's welfare.

It is also important for the government to use the gas revenues for the building of health, education and transportation infrastructure, as well as for economic diversification, and to increase the productivity of labour-intensive sectors such as agriculture, fishing and tourism. This has a positive impact on the majority rural population at the bottom of the pyramid. It will also pave the way for developing the country, as current resources will be depleted by the time of the next generation.

What would you say to environmental activists like Friends of the Earth who want to stop Mozambique from developing LNG projects?

The message is that the Rovuma Basin undertakings involve financial institutions and IOCs that have stringent rules on environmental issues and cannot afford to jeopardise their reputations. Actually, this requirement comes first and independent audits are required. Without compliance to these rules, funding is impossible. The technology to be used is proven and there is a positive track record elsewhere in the world. This is a golden opportunity to transform Mozambique for the better and fulfil the dreams of its citizens. It will create a country without hunger, ensure medical care, and provide decent homes and employment for the young. Those who claim otherwise will undermine the country's progress, reinforcing its cycle of poverty.

Has Covid-19 had an impact on the country's LNG plans?

The travel restrictions and quarantine remain a challenge with a negative impact on the works at the site and the drilling campaign. Logistical solutions include initiatives such as ready-to-use camps for housing. Travelling to Mozambique has started again with the proviso that incoming workers present a valid negative test taken in the previous 72 hours. In general, the recession in most countries as a result of the pandemic has weakened the demand for oil and gas which might delay the Rovuma LNG project from Area 4. In addition, the appetite for future rounds of investments in new fields could wane.

Is there potential for further major discoveries of oil or gas?

New bidding rounds could take place, but the timing is unknown. Given the current situation, most major oil companies are facing cash-flow issues and are rethinking their portfolios to rebalance risk. Exploration is a high-risk venture and we might see delays in new exploration. From Mozambique's perspective, it is in our interest to maintain the momentum with exploration and development, not least because of the energy transition commitments made by most oil majors.

Finally, is Mozambique the world's next great energy superpower?

Mozambique has massive reserves and is well located to cater for the potential premium Asian markets, placing the country at a sweet spot. Therefore, over the next two decades, Mozambique could become one of the world's biggest LNG exporters and remain so for the next 30 years.

However, the future is uncertain as to whether the energy transition to renewables will accelerate, with huge implications for gas production globally, but gas could still play a key role for intermittent energy supply.

The idea of relocating energy-intensive industries to Mozambique, as was the case with the aluminium smelter in 2000, remains a possibility for new market creation. The proposal to build an 18,000-hectare Gas City in Palma, in the future Free Economic Zone, is part of the plan.

To hear more from Omar Mithá, watch "The Energy Debate: Natural Gas Vs Renewables", available on the Africa Oil Week website. ■

Omar Mithá is currently the Special Economic Advisor to President Nyusi and Chairman of the Investment Bank, Banco Nacional de Investimentos – BNI. Until January 2020, he was Chairman of the NOC, ENH. He holds a degree in Economics from Eduardo Mondlane University in Mozambique and a postgraduate degree in management from the University Institute of Lisbon, ISCTE. Prior to his current roles, Omar held senior governmental positions and was chief economist for the Investment Bank of Millennium.

Omar Mithá

Geopoetry 2020: A Celebration

Rocks have long inspired poets, so this event brought together poets and geoscientists to discuss how, in an era of climate change, their disciplines can influence each other and to further encourage the rocks to speak.

NEIL HODGSON

I had imagined a basement bar, beatnik black berets and Gauloises embers, maybe too many plaid shirts and unkempt beards. How wrong could I have been! As it happened, the plan was that Geopoetry 2020, held on National Poetry day (1st Oct) would be a walk through Edinburgh, and a climb to Arthur's Seat sharing geo-poems in a landscape of breathtaking geology. But the rain would have done for that if Covid had not have got there first, so we met, as we have all met this year, online in a delicious zoomery of talking heads and listening hearts for a day of celebration of all things geopoetical. And when I say all things, it reached out in pan-media from readings of new and classic poetry, videos, art and even folk music, bringing together souls condensing insights from and of geology.

This celebration is an occasional event, organised this time in a collaboration between the Geology Society of London, the Edinburgh Geological Society, The Scottish Centre for Geopoetics, Heriot-Watt University and the Scottish Poetry Library, sponsored by the Scottish Energy Forum. It is frankly a big deal poetry-wise, with a big openhearted agenda summarised by Bryan Lovell, the convenor of Geopoetry 2011 in the following call-to-arms:

"We have travelled from a feeling of mastery over all Earth's creatures, to passivity in the face of geological forces apparently way beyond our control, to a growing apprehension that we may be marking our own stewardship of the blue planet in a fashion we would not wisely choose. Poets and geologists have a common cause: a search for words to help us to understand what we do."

Just to be clear – I'm not going to list the 44 performances, or even pick out what the highlights were for me. It was a whole day to be considered as a whole day! If you are curious – sit down with a cup of tea and head to https://www.youtube.com/watch?v=Xzs5YMhJiAk&t=13s, to browse through on your own poetic field trip, picking up treasures as you go.

What I hope you will find are poems that will further allow you to explore the common cause of poets and geologists – to help us understand what we are for. And perhaps help shine a light on what we else we could be doing.

An Eon of Ardverikie

Standing in the river-gouged gorge,
Observing, mapping, eaten by midgies!
Amongst time-smashed ocean,
Psammites and schists;
I am suddenly transported,
To the inky depths of Iapetus.
Einstein said time is illusion,
Am I there and here?
So close, tangible that I
Could swim;
Then an evil midgie bite,
And I am back by the river.

Chris Jack

Most of the contributors pre-staged the readings of their work with an explanation of where they are coming from, or a background to the work. What comes across strongly is that the adventure to explore this linguistic space is inclusive – geologist or non-geologist, professional or amateur poet, young or old, from across diverse cultures and societies in our land and others. We can of course (like in everything) work harder to include other voices too, but it seems that there is no exclusivity in the smithed word. We all have tools to express our insights into how geology shapes us.

Yet, in with the myriad views through the prism of how we experience the earth and the wonder and our insignificance in the face of geology's time, what appeared from the day was a heart-felt connection with Place. With geography, locality and topology – the children of geology. Time and again the work resonated with Place – and especially in Covid times, revealed a deeper connection to where our feet are rooted than I thought anyone really noticed. Just follow the YouTube link and listen to the clever, fleet-footed words in the hands and accents of insightful souls.

So, there is potentially a technical bit in here on where the border between geopoetry and geopoetics lies. Scottish poet Kenneth White founded the International Institute of Geopoetics in 1989, "concerned, fundamentally, with a relationship to the earth and with the opening of a world". And there is a sense that a lot of Geopoetry 2020 sat within that and how people inhabit and connect to each other between rock and time.

Geology, I suspect, is where science goes when it feels like writing poetry. The past is an imaginary made-up world that we inhabit only in our minds, with the few facts we think are truths. It is here too our emotional hearts reside and it is no surprise that geology and love sat hand in hand, looking out from the volcanic plug of Arthur's Seat, in the Edinburgh rain, as we shared an awesome day of "poetry with some geology in it".

The author would like to thank Patrick Corbett for his help with this article. ■

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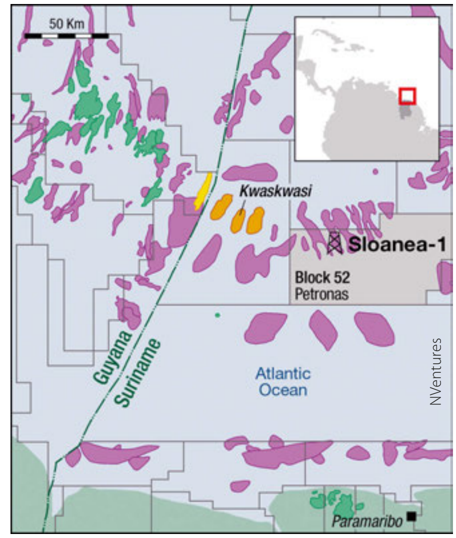
Suriname: Extending Cretaceous Fairway?

Petronas, with new farminee **ExxonMobil**, have now spud **Sloanea-1** on **Suriname Block 52**, along trend and 60 km south-east of Kwaskwasi in Block 58. Sloanea will help define or extend this 9 Bbo Cretaceous stratigraphic trap fairway, established by ExxonMobil in Guyana (Liza 1, 2015) and extended by Apache in Suriname, which is already over 210 km long. Nearby on Block 58, Apache has submitted appraisal plans for its first two discoveries and will submit for the third before the year end. Sloanea-1 spudded in October 2020, targeting Upper Cretaceous clastics in a slope/channel complex. Drilling is expected to last 2–3 months using the *Maersk Developer* semi-sub in ~1,000m water depth. Prognosed TD could be 6,500m or deeper (following the discoveries on Block 58), adding to the challenge here. Keskesi East on Block 58 is being sidetracked in November, with the operator citing hole stability problems.

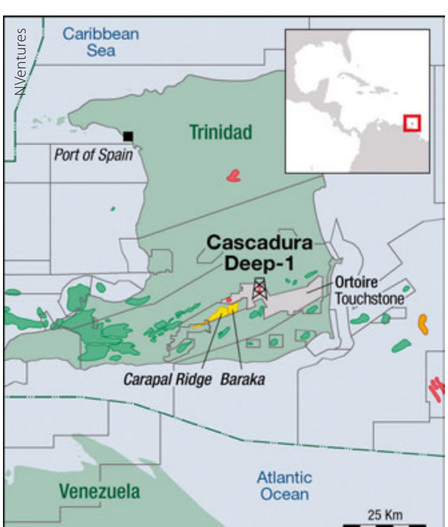
The operatorship shifts to Total in 2021 and plans call for two drillships under long-term contract for exploration, appraisal and development on Block 58. Their next wildcat will be Bonboni-1, in the north-central area of Block 58. The Kaieteur Block in Guyana, north of the Liza trend, is operated by ExxonMobil and brings a new non-operating partner to the fray, Ratio Petroleum, who released a Netherland Sewell 3D seismic-supported competent persons report touting a low-best-high prospective recoverable resource estimate range of 156-256-452 MMbo, excluding gas, for Tanager. Geologic POS ranged from 0.72 on Tanager to a low of 0.25, with a mean around 0.40. Resource estimates were aggregated from the reservoir level. ■



Trinidad: A Move to Gas

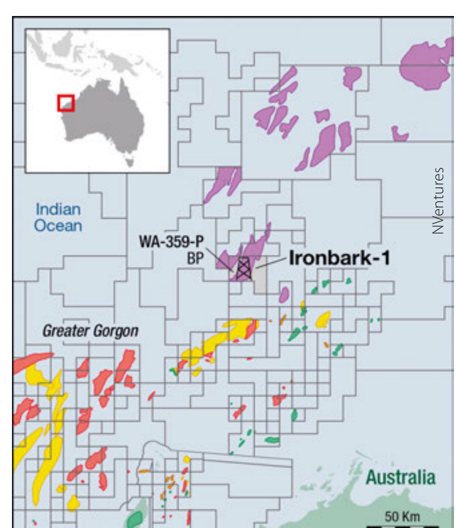
Since August 2019, **Touchstone Exploration** of Canada have been quietly logging impressive net gas pays and proving up significant gas reserves in **Trinidad**'s mature southern onshore trend. Characterised by a complex transpressive fold/thrust belt consisting of thick Tertiary clastic sequences, the province harbours an impressive amount of hydrocarbons, but the complex stratigraphic and structural geology, compounded by some poor reservoirs and challenging pressure regimes, has provided its share of challenges. Touchstone seemed to have cracked the nut on the eastern end of the trend on their **Ortoire Block** with the **Coho-1** well, logging over 30m net oil and gas pay, and testing on average 11.6 MMcfpd; the **Cascadura-1ST**, logging over 300m net oil and gas pay and testing on average 28.1 MMcfpd, and most recently the **Chinook-1**, logging 185m net pay and to be tested soon. Estimated 1P and 2P reserves for Coho and Cascadura to date total over 45 MMboe.

In this part of the trend, originally thought of as primarily oil-prone, Touchstone re-interpreted old well data, some from the 1950s, and twinned some wells. The original operators, including Shell, were looking for oil but recent market conditions in Trinidad encouraged Touchstone to acquire a gas focus and completed the wells with gas tests in mind. The 125 km² Ortoire Block, large by onshore standards, has significant room to run. Touchstone are at present drilling **Cascadura-Deep 1**, targeting Tertiary sands in three distinct thrust sheets. They then plan to test Chinook-1, and drill the Royston prospect, which will twin an old Shell well that found over 200m net sands with a strong gas effect, but was never tested. ■



Australia: Offshore Wildcat Spuds

BP's much-anticipated **Ironbark-1** offshore wildcat was finally spudded at the end of October 2020 offshore the **North West Shelf** of **Australia**. The well, in the **Carnarvon Basin**, Western Australia, is immediately north-east of the great Greater Gorgon LNG development fields, operated by Chevron and Shell. It is expected to take 70–90 days to drill and has a best estimate of 15 Tcf of prospective recoverable gas. Ironbark-1 has a TD of 5,500m and is targeting the Middle Triassic Mungaroo Formation, which is a fluvio-deltaic succession of sandstones and claystones. This formation is a common reservoir for other discoveries in the area. ■



Good Cop, Good Cop

Put aside the financials for a moment and consider what makes a good or a bad company. A good company comes up with the next arthritis drug and a bad company is in the arms trade. Too simplistic? A good company invests in the local community while a bad company invests in influence. Too nuanced? Perhaps – and indeed charges of bribery could be just around the corner.

Good companies, in the traditional sense, deliver good returns for their shareholders, whether they are refining oil or making baby wipes. Good companies do whatever it is they do responsibly. Targeting zero fatalities is a given for the responsible oil company but so too is carbon reduction and for some a tentative step away from fossil fuels altogether.

The Finnish oil company Neste, which was founded in 1948 to protect its country's oil supply, goes one step further. "We have a purpose to create a healthier planet for our children," said Salla Ahonen, the company's VP for Sustainability, somewhat disarmingly at a recent Frontier Energy event. "This is why the company exists."

Gosh! Here is an oil company, albeit partially state-owned, whose primary aim is to make the world a healthier place. In Neste's case this is ostensibly being achieved by moving toward renewable raw materials: for example waste fish fat – Finnish to the core – used cooking oil and fat from food industry waste. According to Ahonen, the company now makes 80% of its profits from renewable diesel businesses for road transport, aviation and shipping. Not content with this, "We're hoping to process a million tonnes of waste plastic annually from 2030 onwards," she says, "and we want to help customers reduce Greenhouse Gas emissions by 20 million tonnes by 2030."

With revenues of €15.8 billion in 2019, you could say that Neste is a good company on all fronts. They are on an already eventful transition journey and, adds Ahonen, "our investment decisions are designed to support carbon neutral growth." This would arguably be good news for the 300 institutional investors who took part in a recent EY survey on ethical investment. The survey reveals that investors want more disclosure around Environmental Social and Governance (ESG) risks. They want to see a positive response, for example, to climate change risk, and they want a plan of action in place. Good profits yes, but the good company ethos must go hand in hand. ■

Nick Cottam

Neste's renewable diesel (left) burns cleaner that its fossil neighbour.

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