GEO ExPro

VOL. 19, NO. 2 – 2022

GEOSCIENCE & TECHNOLOGY EXPLAINED

PALAEONTOLOGY
"Gone Fossil Hunting…"

EXPLORATION
OBN Seismic Unlocks New Play Potential

ENERGY TRANSITION
Sustainable Aviation Fuels

RESERVOIR MANAGEMENT
Who Owns the Oil?

The Future of Gas Exploration in the Transition

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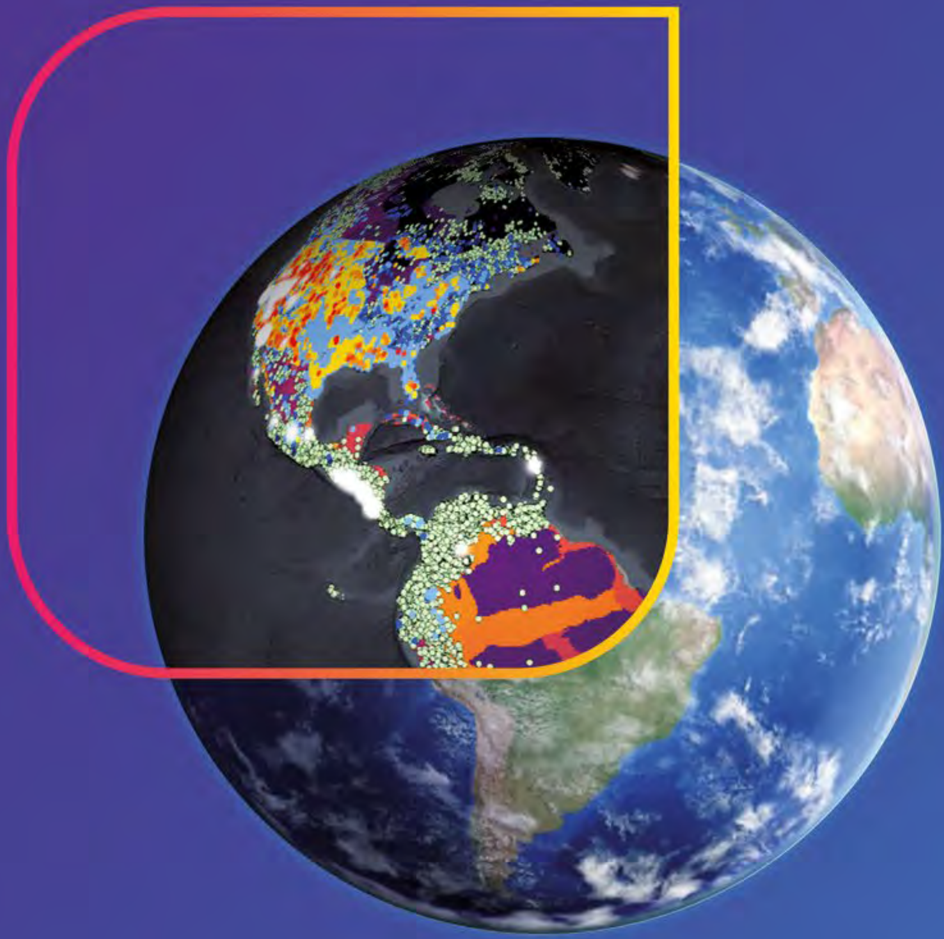

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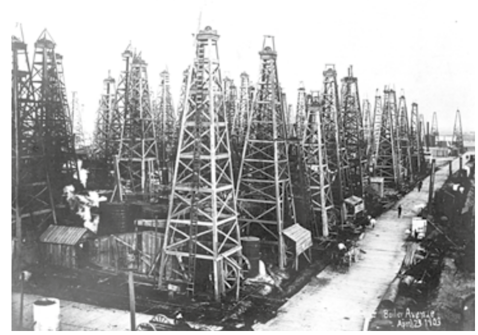

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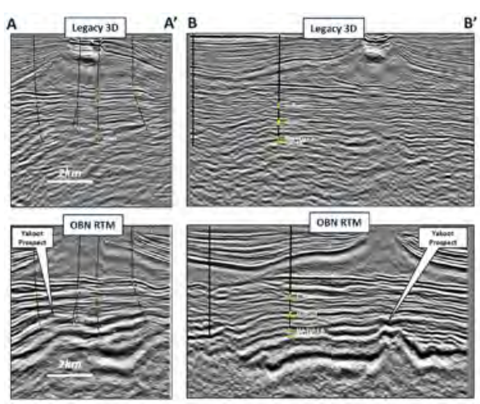

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Whether collecting fossils for academic research, applied industrial analysis, commercial gain or just good old fun, there are lots of things to consider in planning, collecting and preparing specimens to ensure success!


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SHUTTERSTOCK

ENERGY SECURITY IN NORTH WEST EUROPE

Iain Brown
Editor in Chief

The world has watched the events unfolding in Ukraine with horror and the threat of a broader European conflict still feels very possible. What this dreadful situation surely tells us is that reliance on another country for energy is unwise at best and potentially catastrophic at worst.

We need to consider this in the context that Russia is the world's second largest producer of fossil fuels and provides Europe with between 35–40% of its natural gas. The impact of worldwide underinvestment in oil and gas exploration and development, and a global revival from the pandemic which has seen commodity prices rise sharply, has been evident since this conflict started and is intensifying. At the beginning of March this year, Brent stood at US$113 per barrel, one week later it had risen above $139 and a current realistic scenario is that a large portion of Russian crude oil will no longer be palatable to the market and will create an even larger supply deficit for the duration of the armed conflict and likely far longer.

Whilst President Putin has chosen not to interfere with gas supplies to Europe (at least at the time of writing), this is clearly a possibility as European and American sanctions start to inflict real damage on the Russian economy.

The climate crisis has dramatically changed Western attitudes towards traditional fossil fuel energy sources, and particularly in the UK, this momentum may appear unstoppable. However, the war in Ukraine may cause UK and European governments to reconsider energy security and consequently, where these energy sources are derived from in the future (see the article on Responsible Upstream Investment in the UKCS on page 48).

More than 80% of homes in the UK rely on natural gas for heating and during 2021 40% of electricity in the UK National Grid was generated using gas turbine generators. Most of this gas is imported via pipeline from Norway (40% in 2021), and through LNG imports by sea (18% in 2021). The UK's own production has gradually but substantially declined and is now only producing around 38–40% of annual demand. Norwegian gas production is at maximum capacity and the only way more gas could be supplied to the UK would be if exports were diverted from another export pipeline to mainland Europe. Gas storage is also a significant issue, with the UK failing to invest adequately for decades in storage infrastructure. To illustrate this, continental Europe has storage capacity for approximately 22% of their demand, while the UK has capacity for a mere 1% of annual demand (or roughly four days' worth of gas).

This situation exposes the UK to extreme gas price volatility, and the only way it can meet the challenges of variable demand, domestic supply decline, or changes in volumes supplied by Norway, is through LNG imports purchased on the spot markets. This is not the ideal recipe for energy security, even before considering the wider oil and gas supply implications of Russian aggression in Ukraine – time for a serious rethink in European energy policy?

NORTH AFRICA ROUND-UP

The North Africa region offers huge opportunities, but the bottom line is a that its social challenges need to be solved. The region is the venue of one of the world's current hottest regions, namely Egypt. With the catastrophic energy shortage gripping Europe, Egypt is considered well positioned to be the regional hub supplying gas to the hungry European market. However, Egypt's domestic gas consumption is high and this restricts exports, but the country has set goals to be a significant exporter in the future.

Ian Cross
Moyes & Co
icross@moyesco.com

Eni is the largest player in North Africa, with one of its major assets being the Zohr gas field in the Mediterranean Sea offshore Egypt in some 1,450m of water. Zohr is located within the Shorouk concession and Eni has a 50% stake in the block. The other partners are Rosneft (30%), BP (10%) and Mubadala Petroleum (10%). The field was discovered in 2015 by the Zohr-1X well which encountered gas in a giant Miocene reef. The deepwater field is reported to contain 30 Tcf with first production in 2017, impressively just two years after discovery, and reached its peak production capacity of 2.7 Bcfd in August 2019.

In a significant move in 2021 Capricorn Energy (formerly Cairn Energy), with its partner Cheiron Petroleum Corporation, acquired Shell's Western Desert production and exploration portfolio in Egypt with significant potential for production growth.

Egypt has continued to attract investment and in January 2022 it was announced that eight blocks were awarded in the first international digital bid round in the Mediterranean, Western Desert, and the Gulf of Suez. The 2021 round had included 24 blocks. Eni dominated and was awarded five of the blocks, four as operator. Meanwhile, the Egyptian Natural Gas Holding Company (EGAS) held a Limited Bid-Round for the North King Mariut Offshore, in the western part of the Nile Delta Basin, between November 2021 and February 2022.

In Morocco, patience has paid off for Chariot Limited when in January 2022 it announced a significant gas discovery at its Anchois-2 exploration/appraisal well located in the offshore Lixus Licence in the Rharb Basin. The well confirmed gas that Repsol had encountered in its 2009 Anchois-1 wildcat but also discovered gas in deeper horizons. Subsequently in February 2022 Chariot announced it had been awarded the Rissana Offshore Licence which surrounds the Lixus Licence. The success at Anchois-2 will have had a major impact in de-risking prospects in the Lixus and newly awarded Rissana licences and could set up a potential gas hub.

In a boost to the Algerian industry, Eni continued its activity in North Africa by signing a new oil contract related to the onshore Berkine Basin area. The contract, which is the first ever signed under the new Algerian oil law, is situated in the southern part of the basin, near Eni's current production assets.

SOURCE: CHARIOT

ABBREVIATIONS

Numbers
(US and scientific community)

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

Time
Ma: Million years ago
Ga: Billion years ago

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
stoiip: stock-tank oil initially in place

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

LNG
Liquefied Natural Gas (LNG) is natural gas (primarily methane cooled to a temperature of approximately -260 ºC.

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

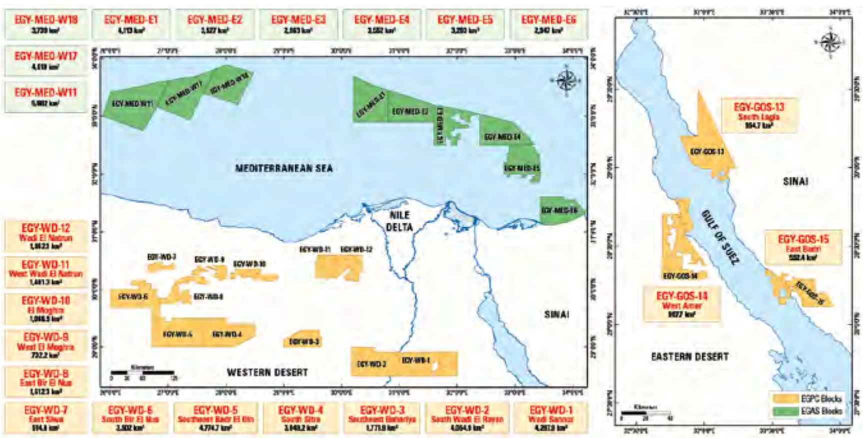
P3 reserves:

Quantity of hydrocarbons believed recoverable with a 10% probability

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

EGYPTIAN ACTIVITY BUOYANT WITH A 2022 EXPLORATION BID ROUND EXPECTED

The Egyptian Oil Ministry began 2022 by concluding its 2021 licensing round which offered three blocks in the Gulf of Suez, twelve in the Western Desert and nine in the Mediterranean Sea. This was the first round to use Schlumberger's Egypt Upstream Gateway, intended to provide a modern repository for Egypt's subsurface data.



EGPC/EGAS

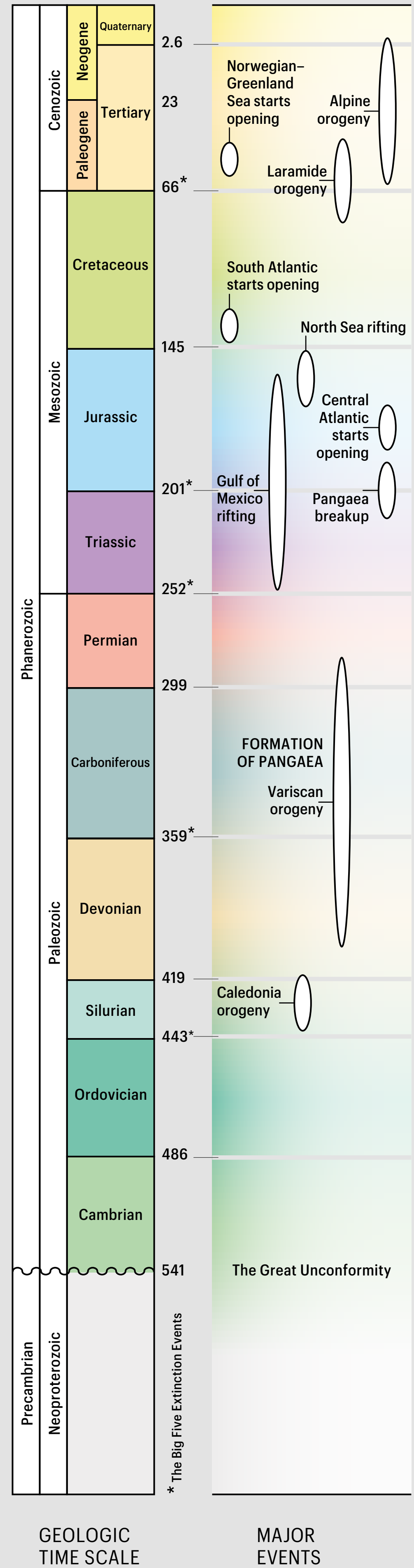
2021 bid round blocks

Seven international energy companies including BP and Eni were awarded eight of the 24 oil and gas exploration blocks which were included in this round, which ran from mid-February until the end of July last year. The status of the other 16 concessions put up for auction has not been announced, and the assumption is that that these will not be awarded at this time. The Limited Bid-Round for a unique block, the North King Mariut Offshore, in the western part of the Nile Delta Basin had its deadline extended until the end of February 2022 on the request of potential bidders.

This latest round follows on from the first international Red Sea Offshore Bid Round which announced its results at the end of 2019. In this offer, Chevron won Block 1, while the Dutch Shell Company was awarded Block 3, and an alliance of Shell and Mubadala Emirates Company acquired Block 4. In total an exploration area of about 10,000 square kilometres was leased.

Recently, Egypt has seen significant activity. At the end of 2021, the Oil Ministry signed a US$3.5 billion agreement with Apache and Sinopec, and Italian energy firm Eni committed to invest a minimum US$1 billion on oil production in the country. Canadian firm TransGlobe and London-based Pharos Energy this year signed exploration and production agreements worth US$506 million. The ministry wants to attract US$7 billion of foreign direct investment into the oil and gas sector next fiscal year, Oil Minister Tarek El Molla, said earlier this week.

New oil and gas exploration rights will be up for grabs in in the first half of 2022. The government plans to launch a new global tender for oil and gas exploration before June, Bloomberg reported Tarek El Molla as saying during a press conference at the end of January. No further details were disclosed on the upcoming tender.



Optimise Your Unconventional Resource Plays

Plan now to attend the Unconventional Resources Technology Conference (URTeC), 20–22 June 2022 at the George R. Brown Convention Center in Houston, Texas.

URTeC is the premier event focused on the latest science and technology applied to exploration and development of unconventional resources, with special emphasis on integration of the technical / professional disciplines. URTeC continues to be the best opportunity you'll have to exchange information, formulate strategic ideas and solve problems to manage and optimise your unconventional resource plays.

A combination of 12 of the world's leading professional societies has brought both depth and breadth to the technical base of the conference which has led to URTeC's collaborative platform and innovation exchange sustaining and propelling our industry's ongoing success.

Visit the URTeC 2022 website to learn more and to see the full line-up of talks, sessions, panels, short courses, and more.

TRANSITION CAUSES SUPPLY CRUNCH

Numerous products including cars, smartphones and many other electronic items, rely on semiconductors and critical key metals such as copper and currently there isn't sufficient supply to meet manufacturing demand. As a result, many electrical consumer products are scarce and becoming more expensive.

Car manufacturers have been hit hard but it is interesting to note that the take up of electric vehicles (EVs) appears to be gathering pace. Volkswagen Group for example, despite fewer overall car sales, delivered close to 500,000 EVs in 2021, a 96% increase over the previous year. Some manufacturers are now predicting that one car in two sold worldwide by 2030 will be electric.

This all sounds positive for the transition to lower CO_2 emissions, but is it sustainable? Global demand for copper, an essential component in EV manufacturing, as well as consumer electronics, will outstrip supply by more than 6 million tonnes by 2030, according to projections by Rystad Energy. A deficit of this magnitude would have wide-reaching implications for the energy transition as there is currently no commercially viable substitute for copper for these electrical applications. This would suggest that significant investment in copper mining is required to avoid a global shortfall.


SHUTTERSTOCK

The growing renewables and EV markets have increased copper demand and prices have risen to almost 75% during the Covid-19 pandemic leaving prices at all-time highs entering 2022. Copper demand is projected to rise 15–20% by the end of the decade, reaching 30 million tonnes per annum by 2030, compared with some forecasts suggesting up to a 15% decrease versus 2021 levels. Estimates based on current and expected projects show supply will be at around 18 to 22 million tpa, falling significantly short of the quantity required to meet projected demand. These increases are largely driven by the growth of renewables such as solar, wind, and EVs, construction and electronics.

Investment in copper mining is risky as current operations are close to capacity due to ore quality and reserves exhaustion causing both production costs and emissions to rise. However, copper prices are currently high, which might encourage investors to accept greater risk.

As the energy transition builds momentum and EV adoption grows in populous countries such as China and India, copper mining will come under extreme pressure as will other critical extractive industries such as lithium and cobalt.

OIL AND GAS DISCOVERIES PLUMMETED IN 2021 BUT HOPE FOR 2022?

Global oil and gas discoveries plummeted in 2021 to their lowest levels in 75 years as the Covid-19 pandemic and climate change concerns forced oil companies to slash their exploration budgets. Less than 5 billion barrels of oil and natural gas were discovered in 2021, the lowest level since 1946, according to Rystad Energy. This is a dramatic decline from the 12.5 billion barrels discovered in 2020 and the 20 billion barrels in 2014.

Oil companies discovered less than 410 million barrels of crude and natural gas per month in 2021, down from an average of 1.7 billion barrels per month in 2015. Despite several major discoveries last year such as Exxon Mobil's in Guyana and Lukoil's offshore Mexico dicovery, the lack of reserve replacement through exploration and new discoveries is a challenge for the industry, which is continually under pressure to replace depleting reserves to maintain production revenues. Also, oil companies are making smaller discoveries because of the dual impacts of underinvestment in exploration after oil price collapses and a shift to infrastructure led exploration. Following crude demand decline and low prices at the start of the pandemic, oil companies slashed spending by almost 30% to USD 335 billion in 2020, a decline from USD 462 billion in 2019. Although spending rose slightly in 2021, it remained about 25% lower than pre-pandemic levels, according to some estimates.

Significantly reduced capital spending and lack of major oil discoveries might not matter as the world transitions from fossil fuels with the International Energy Agency warning that the world will need to stop drilling new oil and gas wells immediately to meet its net-zero target by 2050. Some analysts also predict global oil demand could peak this decade with the increasing uptake of electric vehicles and renewable energy. But the huge rise in global oil and gas prices fuelled by renewed economic activity and the conflict in Ukraine does remind us that when energy security is considered, the outlook is far less obvious.

EAGE Presents 2022 Annual Conference & Exhibition with Strong Focus on the Energy Transition

The European Association for Geoscientists & Engineers (EAGE) will host its 83rd edition of the Annual Conference & Exhibition at IFEMA in Madrid, Spain, between 6-9 June 2022, bringing together geoscientists and engineers from across the globe to collectively discuss the energy transition in the energy sector.

EAGE

The EAGE Annual Conference & Exhibition is organised with the purpose of presenting the latest discoveries in terms of geophysics, geology, reservoir engineering, integrated subsurface, mining & civil engineering, digitalisation, and HSE & sustainability. An extensive technical programme will be presented as well as a large exhibition enlisting leading companies in the energy field, as well as start-ups, universities, governmental entities, amongst many others.

The theme EAGE dedicated to this edition is 'Leading Geosciences into a New Era', meant to be the catalyst for the development of the future of energy and address how the geoscience community can tackle the energy transition to meet climate goals.

The Conference & Exhibition is accompanied by a large side programme. The strategic EAGE Forum Sessions are discussions addressing the most pressing issues affecting the wider geoscience and engineering field. Technical workshops and field trips are organised for a more hands-on learning experience. Additionally, the event features an extensive Community programme with dedicated activities for a series of technical disciplines, students, women in geoscience, young professionals, and many more. Last but not least, EAGE understands the importance of networking and has planned a social programme, including the icebreaker reception, afternoon drinks, special networking lunches, a conference evening in an incredible venue, and more.

AAPG EUROPEAN CONFERENCE, BUDAPEST, 3–4 MAY 2022

The theme we have chosen for this conference, **'Revitalizing Old Fields and Energy Transition in Mature Basins',** refers to the challenge we face in our industry in many of the hydrocarbon basins and folded belts across the European region these days. Therefore, special focus is placed on topics revolving around the global energy transition such as advantaged hydrocarbons, hydrogen exploration, geothermal energy utilisation and carbon capture, utilisation and storage.

While Europe has many mature to super-mature basins, significant discoveries are still being made with new exploration thinking and/or cutting-edge technology. A deeper understanding of the proven reservoirs, either siliciclastic, carbonate or fractured, combined with a systematic petroleum systems approach could result in unexpected breakthroughs in basins where exploration was already assumed to reach the point of diminishing returns.

AAPG
EUROPE REGIONAL CONFERENCE 2022
3–4 May 2022 • Budapest

The energy transition themes of this conference have turned out to be very timely as reflected by the large number (150+) of abstracts submitted. We have organised these into three parallel technical sessions, comprising 14 sessions with 100+ oral presentations and 40+ posters. Also, there will be two one-day field trips offered, the pre-conference focusing on the structural geology around Budapest and the post-conference trip one highlighting the Cenozoic basin fill of the Pannonian Basin.

We hope that all the explorers and geoscientists working in the broader European region will not only enjoy this conference and but also find some extra time to visit Budapest and other parts of Hungary as well. This is the very first time the AAPG has hosted a conference in Budapest. Unfortunately, the ongoing war in Ukraine affects everyone in Europe, but we feel very confident that it will not disrupt our conference in the Hungarian capital. We are looking forward to seeing you there!

OGA RENAMED AS THE NORTH SEA TRANSITION AUTHORITY

The UK **Oil and Gas Authority (OGA)** was founded in 2015, tasked with maximising the value of the industry in the UK. In March last year the **North Sea Transition Deal** set out a programme for this path to net zero emissions and the crucial role that the UK's oil and gas industry should play.

As of March, this year, the OGS changed its name to the **North Sea Transition Authority (NSTA)**. The new name embraces this new context and the expanding role in energy transition, including as the **carbon storage licence and permitting authority**, monitoring emissions, assessing a net zero test for new developments, and stewarding domestic production.

Oil and gas currently meets around three quarters of the UK's energy requirements and current forecasts show they will be needed for decades to come. The UK, though, is expected to be a net importer of both up to 2050. At the same time, ongoing global and geopolitical events have made it clearer than ever that security of supply remains important as the transition is achieved.

The NSTA will continue to play a vital role in ensuring energy security as the body which stewards the oil and gas industry, both on and offshore, with energy transition issues already playing a significant and increasing role in the organisation's day-to-day activities.

The industry is expected to play a key role in the energy transition and support energy security through producing domestic oil and gas over the coming decades as well as reducing its own carbon footprint, while government and regulators must provide clear leadership and bolster confidence for the necessary continued investment.

NATURE SHOWS OFF

Phreatomagmatic eruptions are a type of explosive eruption that results from magma erupting through water. The second phase of the infamous Icelandic Eyjafjallajökull eruption in 2010 was phreatomagmatic because of magma erupting under ice. This eruption caused global disruption to flights and ash deposited dissolved iron into the North Atlantic, triggering a plankton bloom.

Iain Brown

Surtseyan Eruptions

A Surtseyan eruption is an explosive style of phreatomagmatic volcanic eruption that takes place in shallow seas or lakes when rapidly rising and fragmenting hot magma interacts with water and with water-steam-tephra slurries. The magma is commonly basaltic and fragments into small pyroclasts (such as ash and lapilli), and these accumulate around the crater to form a small cone or ring-shaped heap.

Surtseyan eruptions are characteristically unsteady, with phases of short, rapidly repeated, violent explosions separated by more quiescent phases dominated by steam generation and condensation. Ash and lapilli are emplaced by ash fall and by short-duration, pyroclastic density currents. Much of the wet tephra produced, repeatedly slumps back down into the volcano's crater to be re-ejected by further watery explosions.

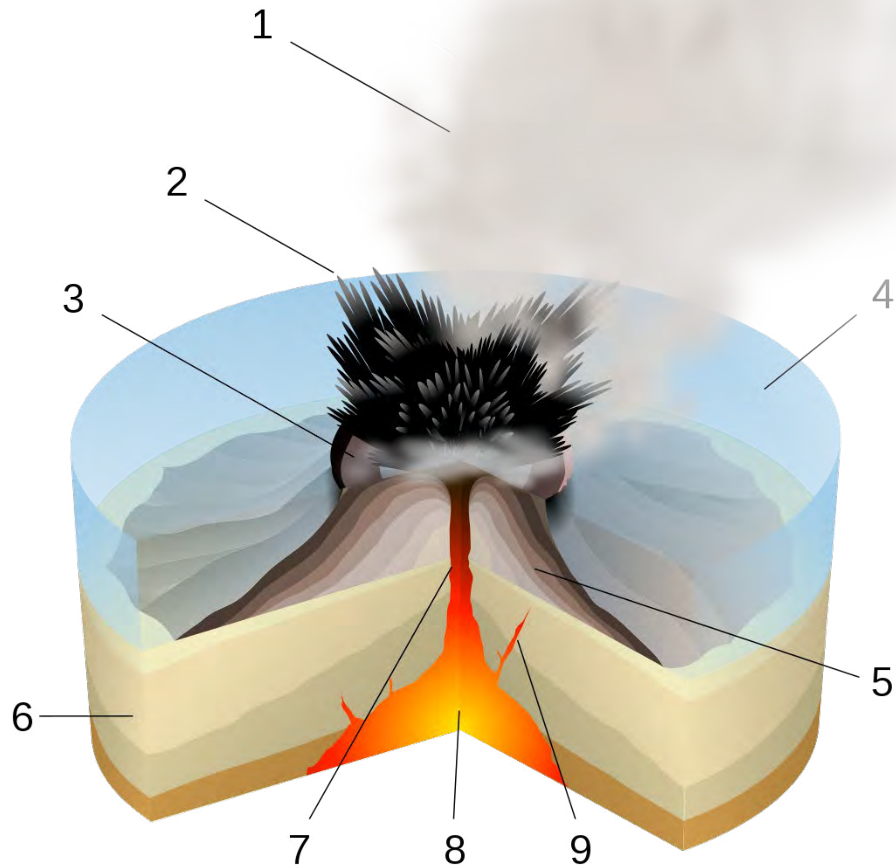


Figure 1: Surtseyan eruption. 1. Water vapour cloud, 2. Cupressoid ash, 3. Crater, 4. Water, 5. Layers of lava and ash, 6. Stratum, 7. Magma conduit, 8. Magma chamber, 9. Dyke.

Hunga Tonga–Hunga Ha'apai

Most Surtseyan-style eruptions involve a relatively small amount of water encountering magma. But the explosion in January this year at the Hunga Tonga–Hunga Ha'apai volcanic island, located about 30 km (19 mi) south-southeast of Fonuafo'ou island in Tonga, erupted in a particularly spectacular fashion and the cause is not yet fully understood. According to NASA scientist Dr James Garvin, it may be that something weakened the dense rock in the foundation of the volcanic chamber and caused a partial collapse of the caldera's northern rim. Garvin likened this to the bottom of a pan dropping out, allowing huge volumes of water to rush into the underground magma chamber at very high temperatures.

> *The mixing of the two can be incredibly explosive*

The temperature of magma usually exceeds 1,000°C, whilst seawater is closer to 20°C. The mixing of the two can be incredibly explosive, particularly in the confined space of a magma chamber.

An Unusual Eruption

According to Garvin this was not a typical Surtseyan eruption because of the large volume of water involved.

As a result of the explosion, a huge ash plume is now calculated to have risen around 55 km above the summit and coated Tonga in a layer of volcanic ash. This is an extreme height for a volcanic plume and is at the boundary of the stratosphere and mesosphere layers in the atmosphere.

Aerosols from the plume have persisted in the stratosphere for over a month after the eruption and could remain for a year or more, according to scientist Ghassan Taha of NASA's Goddard Space Flight Center. Volcanic emissions can potentially affect local weather and

NOAA AND THE NATIONAL ENVIRONMENTAL SATELLITE, DATA, AND INFORMATION SERVICE

Time-lapse satellite view of the eruption (GOES-17 imagery courtesy of NOAA and the National Environmental Satellite, Data, and Information Service).

global climate. However, Taha noted that it is unlikely the Tonga plume will have significant climate effects because it was low in sulphur dioxide content (the volcanic emission that causes cooling) but high in water vapour, which accounts for its impressive height.

Specialist weather-monitoring satellites orbiting the Earth at ~35,000 km can scan an entire hemisphere every few minutes and captured the event with some incredible time-lapse images.

When the eruption occurred, there were numerous reports of loud booms across Tonga and other countries, such as Fiji and even as far away as New Zealand. Tonga was badly impacted

MODIFIED FROM USGS AND SMITHSONIAN INSTITUTE

Location map showing the 'Ring of Fire' volcanic arc with active volcanoes that have erupted since 2000.

by a tsunami or meteotsunami with waves of over a metre in height which, combined with extensive ash fall, meant that power was cut to most of the island, and as far away as Japan the tsunami was recorded in the Kominato district of Amami-Oshima Island.

Imaged from Space

The EU's Sentinel-1A radar-based satellite can image through obscuring cloud and ash and showed that much of the crater rim that had previously stood above the ocean waters had been destroyed by the blast. It is also speculated that the tsunami may have been due to an unseen collapse of part of the volcano below sea level. Sentinel-5 and TROPOMI satellite-based measurements of sulphur dioxide concentrations in the atmosphere detected an estimated 9 kilotons extending to the north of the volcano.

The volcano is part of the highly active Tonga–Kermadec Islands volcanic arc, a subduction zone extending from New Zealand north-northeast to Fiji and lying some 100 km (62 mi) above a very active seismic zone and part of the 'Pacific Ring of Fire'. The island arc is formed at the convergent plate boundary where the Pacific Plate subducts under the Indo-Australian Plate.

The volcano itself is a submarine volcano that breached sea level in 2009 due to an eruption and lies underwater between the two islands (Hunga Tonga and Hunga Ha'apai), which are the remnants of the western and northern rim of the volcano's caldera. The longer-term impacts of the event on Tonga are uncertain, but the volcano will no doubt be under constant monitoring and study for the foreseeable future.

THE FUTURE OF GAS EXPLORATION IN THE TRANSITION

Drilling flat spots in the North Sea, with a minimal CO_2 footprint can rejuvenate Dutch offshore sector.

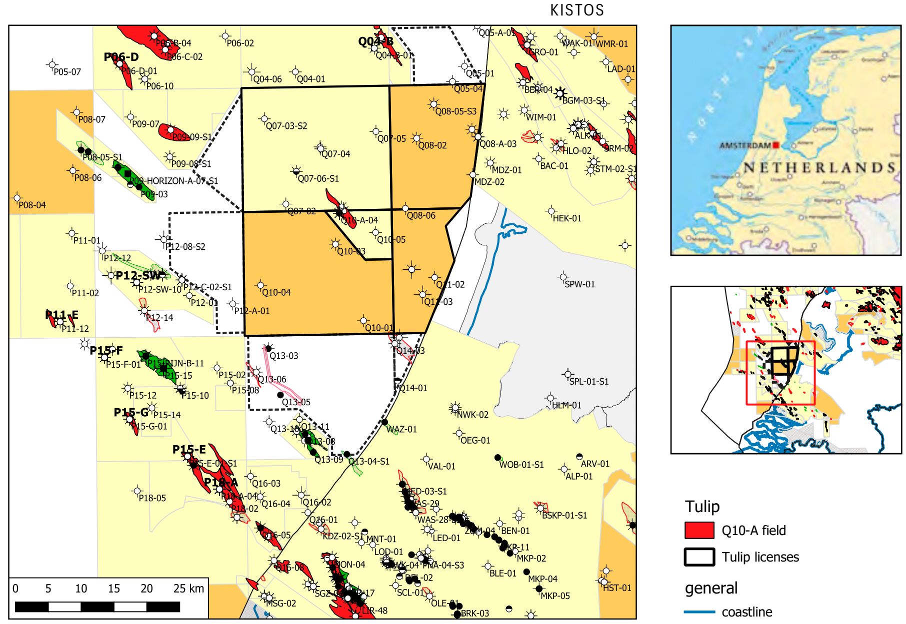
The Q10-A development, 20 km off the Dutch coast, demonstrates how it is possible to secure and develop essential, European gas resources from a mature area with minimal carbon footprint. Powered by an onboard solar farm and wind turbines, it demonstrates how critical gas resources help to fulfil a primary objective of supporting the energy transition in Western Europe.

Kike Beintema, Kistos Energy

Kistos PLC was established in 2020 to create value for its investors through the acquisition and management of companies or businesses in the energy sector. Its first acquisition was that of Tulip Oil Netherlands in 2021, where Kistos became the operator of several exploration and production licences in the Dutch offshore sector, including the producing Q10-A gas field and several near-field appraisal and exploration objectives located off the coast of Amsterdam (*Figure 1*).

This acquisition fits well with the company strategy and objectives: to acquire assets with a role in the energy transition. A desire to produce cleaner, affordable energy, coupled with the new geopolitical landscape following the events in Ukraine, has exposed Western Europe's dependency on imports of Russian gas as well as the need to transition away from coal and other forms of energy generation.

KISTOS



SHUTTERSTOCK

Figure 1: Location of Kistos licences and Q10-A field.

Revisiting Subsurface Potential

Accelerating domestic gas production is high on the political agendas in Western Europe as countries try to maintain a reliable and affordable energy supply. The urgency of local gas development is driven not only by ongoing demand and short supply; the window of opportunity for offshore gas production is also closing because much of the ageing infrastructure in the North Sea is nearing its end of life.

Southern North Sea gas fields can be produced very efficiently through small, normally unmanned platforms powered by solar and wind, making use of existing export infrastructure. The Q10-A development located 20 km offshore the coast of the Netherlands was designed to do just that and has been in operation since 2019 (*Figure 2*), achieving Scope 1 emissions during 2020 of 0.01 kg CO_2/boe. To illustrate how low these emissions are for the Q10-A development, see Figure 3.

KISTOS

Figure 2: Block Q10-A unmanned platform with solar panels and wind turbines.

Carbon intensity emissions

OGA

Carbon Intensity, kg CO_2/boe

	Q10-A, 2019/2020	IOG SNS Aspiration	Johan Svedrup	NW Europe Gas, 2019	UKCS Extracted Gas	Imported LNG
Carbon Intensity, kg CO_2/boe	0.01	0.20	0.20	14.00	22.00	59

Figure 3: Carbon intensity emissions data for Block Q10-A, UKCS and European gas and imported LNG.

Furthermore, facilities at several existing third-party offshore platforms are exploring plans to be electrified with the use of power generated by nearby wind farms, through integration with the power infrastructure to-and-from shore. This would ultimately reduce lifecycle emissions and could potentially extend the economic limits of certain offshore facilities. Kistos plans to develop nearby appraisal and exploration targets with a similar strategy and development concept, with continued focus on minimising the carbon footprint.

Reappraisal of Geology

It is not just opportunities for low-emissions developments that are the attraction of the Dutch Q-blocks. The subsurface is also very interesting. Figure 1 shows the area to be an empty corridor with a striking lack of hydrocarbon developments, despite the presence of well-known hydrocarbon plays described below.

During the 1960s–1980s several 'dry' wells were drilled, and operators abandoned the area for what was perceived to be more productive acreage elsewhere. However, the team at Kistos and its predecessors have extensively reviewed the old well archives and discovered several wells that did encounter hydrocarbons despite being classified as 'dry'. The team believed that one of the reasons for this appeared to be that some of these wells were drilled in suboptimal positions, off-structure.

The central Q-blocks are situated at the southern edge of the Broad Fourteens Basin. The Carboniferous including the Westphalian source rock is present everywhere and overlain by the Permian Rotliegend as commonly seen in this area. In the central Q-blocks, the southern fringe of the Broad Fourteens Basin hosts a unique Zechstein sequence consisting mainly of clastic sediments, topped by the Platten Z3 Dolomite (*Figure 4*).

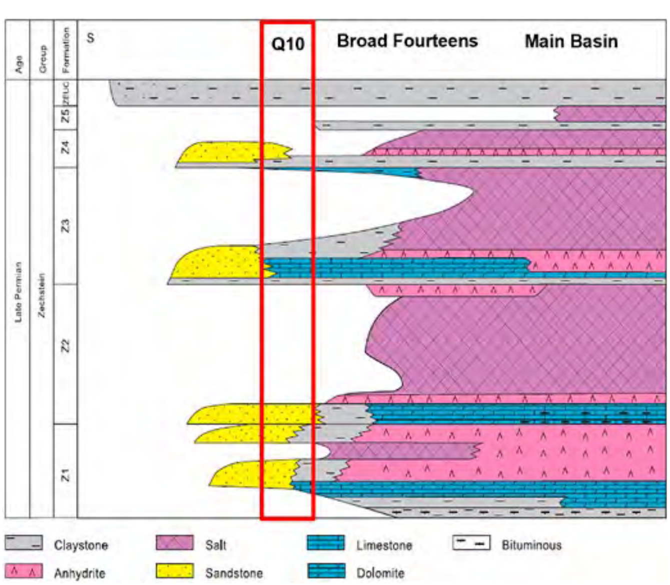


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Figure 4: Permian and Triassic stratigraphy across Block Q10-A.

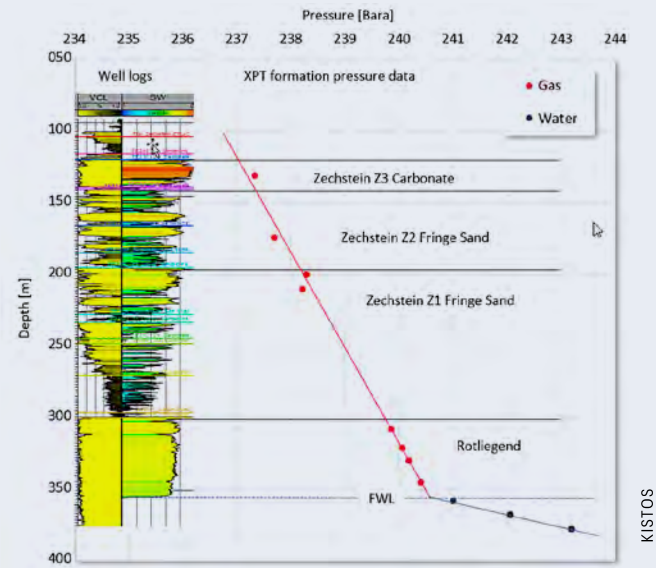

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Figure 5: Log and pressure plot Q10-A-06.

Due to the absence of salt in the Zechstein, the Rotliegend has no top seal of its own and therefore the combined Rotliegend-Zechstein Clastic and Carbonate reservoirs rely on the Main Bunter Shale as a top seal. This results in a single connected gas column in the Rotliegend and Zechstein reservoirs (*Figure 5*).

In addition, the lower Triassic Volpriehausen is a known producing reservoir in the region. Reservoirs and top seal can be mapped reliably, but fault seal and juxtaposition of waste zones across the bounding faults form a key exploration risk. The complex tectonic history of the area has led to multiple phases of burial, uplift and fault reactivation, resulting in diagenesis and variable reservoir preservation.

Figure 6 shows an example of 2D seismic data from 1960, which was shot in the Q-blocks as a marine survey show with dynamite.

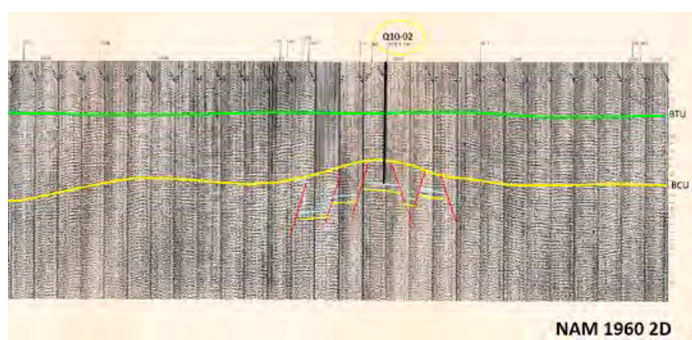

Figure 6: Q10 section SW–NE, NAM 1960 2D seismic line.

This highlights some of the imaging challenges that were faced when many of the exploration wells were drilled in the area. The archive well files of Q10-02 (1962) and Q07-01 (1973) contained information about logging and well-testing operations that led the team to the conclusion that the Q10-A structure must be gas-bearing after all. To de-risk the opportunity that thus far had only been mapped on sparse 2D seismic lines, a 3D seismic survey was shot and processed by 2011. This led to a much better definition of the structure: a slightly tilted Permo-Triassic fault block, flanked by Jurassic grabens and overlain by a gentle Cretaceous anticline.

The newly acquired 2010 3D seismic not only allowed for a much more detailed mapping and improved structural definition of the Q10-A horst block; it also revealed a ‘flat spot’ and amplitude anomaly in the main target reservoir: the Permian Rotliegend Slochteren Formation.

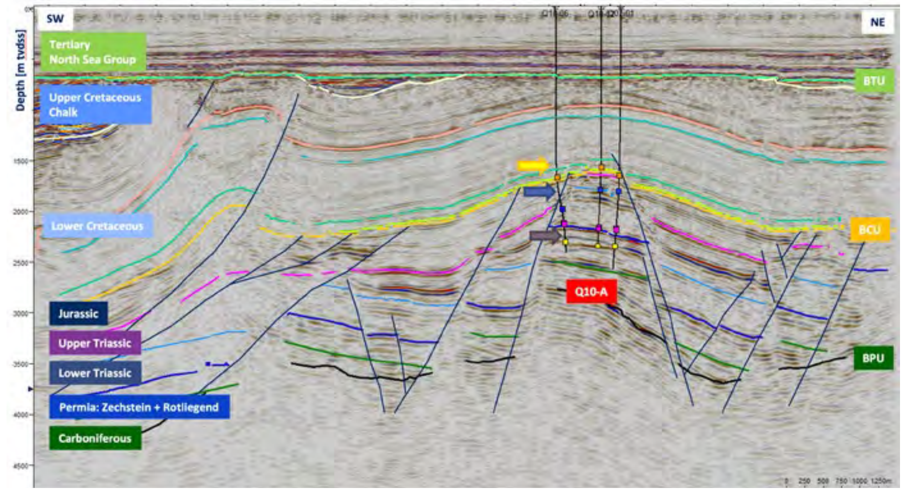

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Figure 7: Regional seismic section from 2010 data.

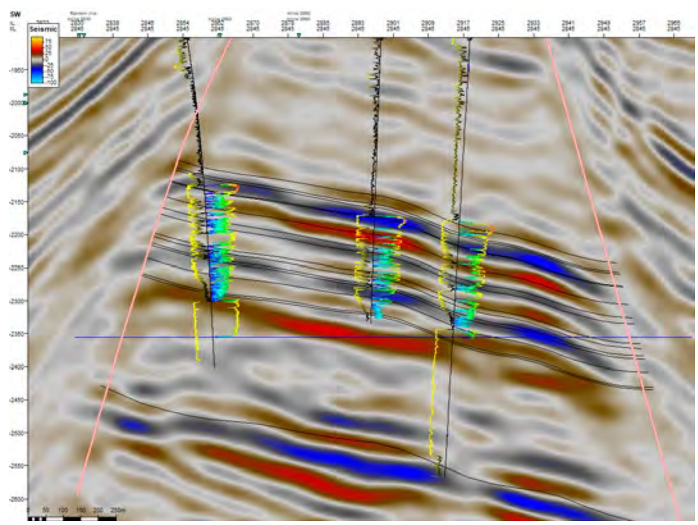

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Figure 8: Seismic section showing Q10-A flat spot.

Wedge modelling confirmed that a seismic response could be visible in the Slochteren Formation; the contact should stand out as a hard kick while the top of the reservoir should dim above the contact (*Figure 7*).

Further Quantitative Seismic analysis included the generation of a Vp/Vs cube. Analysis revealed a very strong response to gas in the Slochteren Formation while acoustic impedance models added surprisingly little value (*Figure 10*).

These three direct hydrocarbon indicators in the Q10-A targets de-risked the opportunity sufficiently to take the decision to drill an appraisal well in 2015. The well Q10-A-01 confirmed and tested gas in all target reservoirs. The depth of the observed flat spot in the Rotliegend, the structure-conform amplitude anomaly at the top of the Rotliegend, and the bottom of the Vp/Vs anomaly all coincided with the depth of the logged gas-water contact in the Q10-A-01 well.

Fast Track Development

A final investment decision (FID) for full field development of the Q10-A field was taken in January 2018. Within six months the 42 km export pipeline to P15-D was in place, and the newly constructed unmanned platform was installed six months later. Five additional production wells were drilled, targeting the various stacked reservoirs and first gas was achieved in February 2019; just over a year after taking FID. The ability of the team to deliver this project with a uniquely fast turnaround time, safely and within budget was a great success, and will allow Kistos to leverage the retained

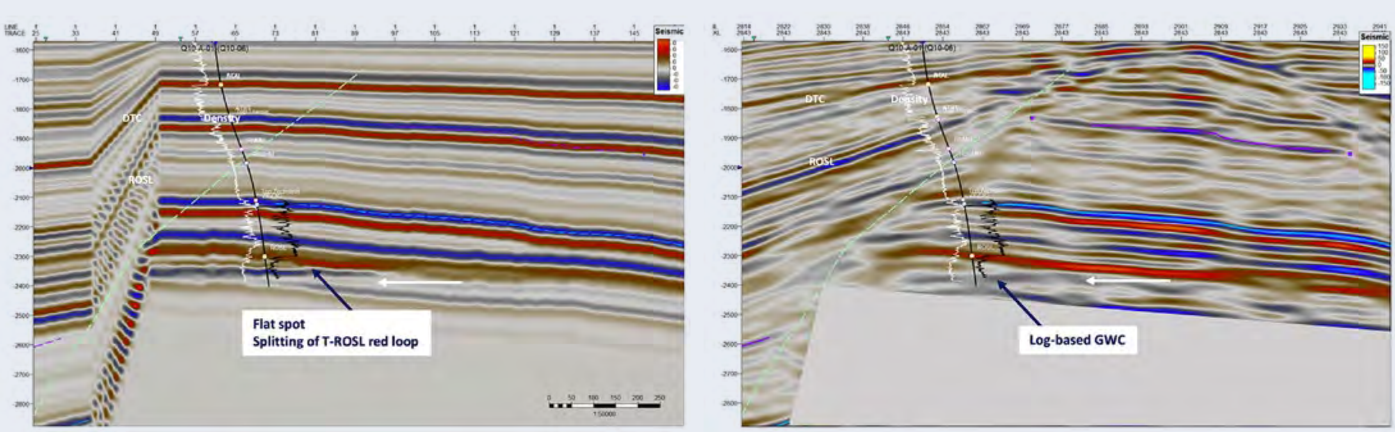

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Figure 9: Q10 wedge models.

experience and expertise to develop similar fields through near-field appraisal and exploration.

Following the success of Q10-A, a large reprocessing project was undertaken; six legacy seismic datasets covering the Q07-Q08-Q10-Q11 blocks were merged and reprocessed into a high-quality PreSDM product. This dataset allows for detailed mapping and de-risking of prospects, allowing for a better dry-hole analysis and an improved understanding of the structural complexity prevailing in the area. The new mapping effort resulted in a sizeable portfolio of undeveloped discoveries, prospects and leads within the acreage of the Q-blocks.

The nearby Q11-B field is a tilted fault block resembling the Q10-A field which was discovered in 1969; producing gas to surface from the Lower Volpriehausen Formation from well Q11-01-S2. Q11-01-S2 was also planned on 2D seismic dating from 1960, and the operator at the time struggled to maintain the planned trajectory causing the well to land far down dip on the Q11-B structure. Furthermore, petrophysical analysis of the 1969 log data indicated that in addition to the Volpriehausen Formation, the Zechstein Clastics and Carbonates were also gas-bearing.

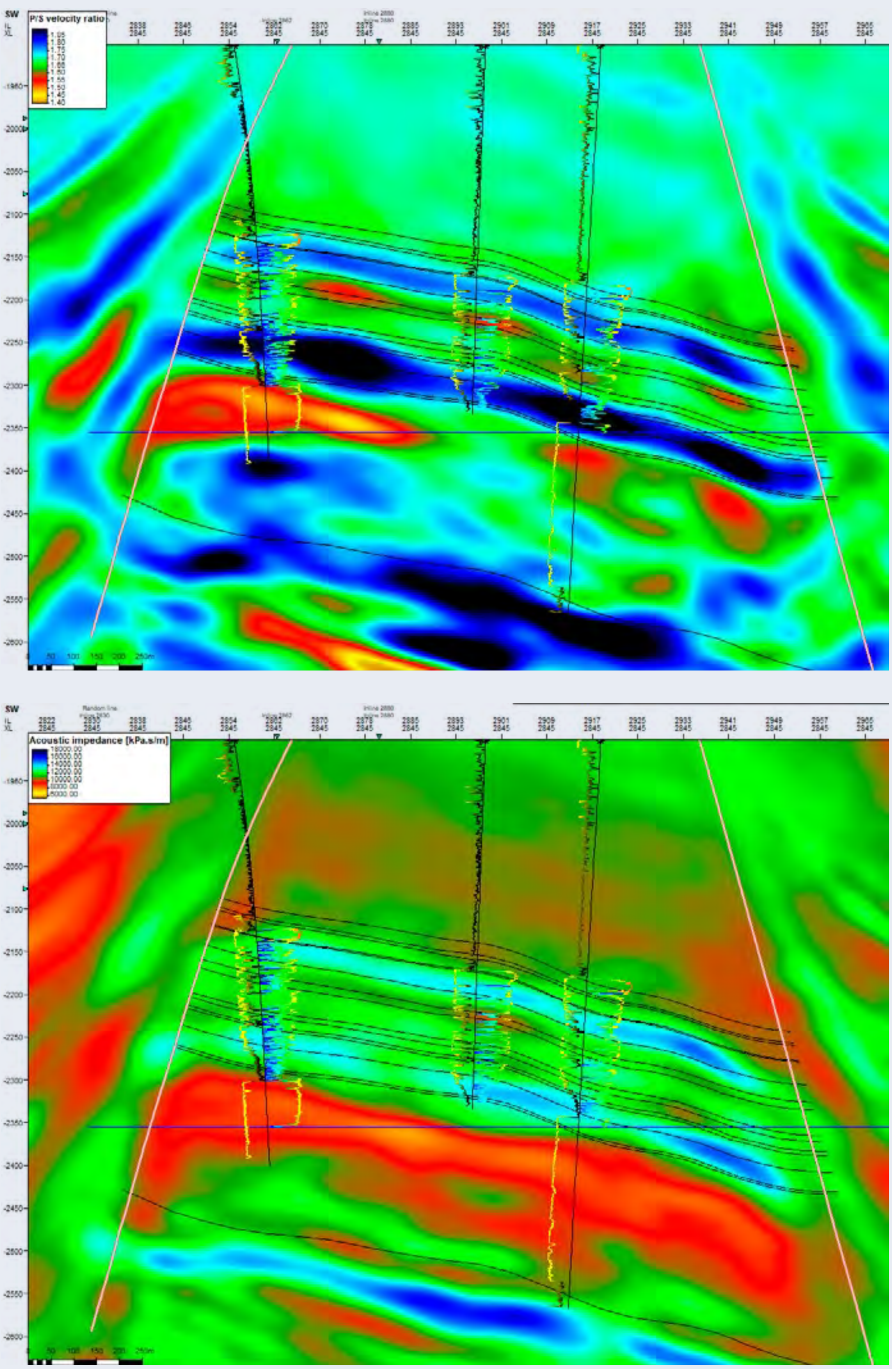


Figure 10: Vp/Vs section, 2019.

Appraisal well Q11-B-01 was spudded by Kistos in November 2021 and targeted the stacked reservoirs in the Q11-B field in a more favourable up-dip position than the 1969 discovery well. Q11-B-01 confirmed gas in Triassic and Permian reservoirs, both of which were stimulated and tested, and produced gas to surface in early 2022. Kistos is currently working on a field development plan for Q11-B.

Further Upside

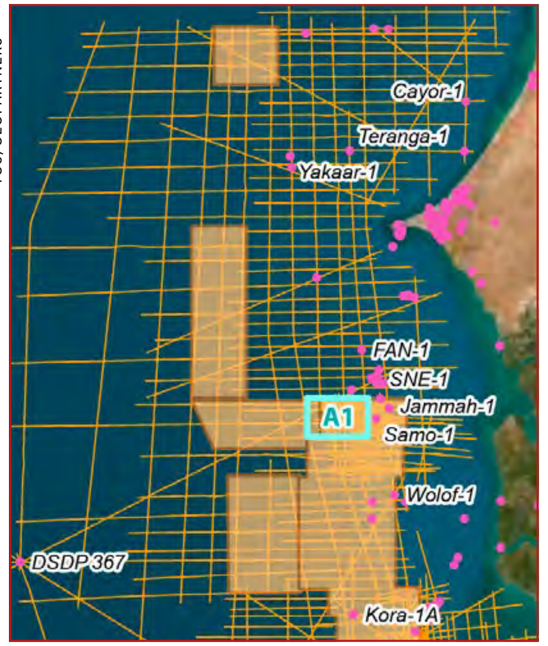
Appraisal and exploration efforts in the Q-blocks are continuing and the learnings from the recent Q11-B-01 well will be considered for de-risking and ranking the portfolio going forward, with the potential for appraisal and exploration drilling in 2022–2023. One high-ranking prospect is the Q10-Gamma structure: an undrilled tilted fault block with the same proven Permian and Triassic reservoirs and located within reach of the Q10-A platform (*Figure* 7). A successful exploration well has the potential to be brought onto production immediately at the Q10-A platform. Similarly, several undrilled fault blocks are located close to the Q11-B location, providing the opportunity for future exploration successes to be tied into the Q10–Q11 cluster quickly, and at low cost.

Through the strategy described, Kistos intends to strengthen its position as a leading independent producer of clean, domestically sourced gas through future exploration and appraisal activity in the North Sea, in order to fulfil its primary objective of supporting the energy transition in Western Europe.

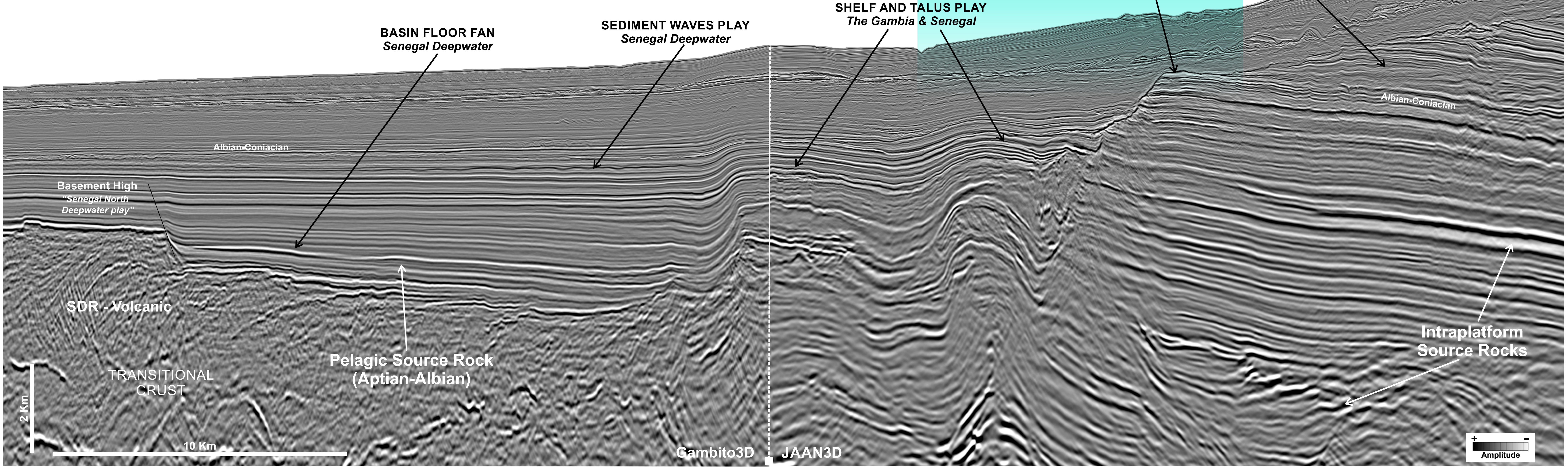
EXPLORATION OPPORTUNITIES IN THE GAMBIA AND SENEGAL

In 2020 and 2021 TGS acquired and processed more than 4,000 km² of broadband 3D seismic offshore The Gambia and in deepwater Senegal, adding to an extensive 3D and 2D seismic library, and complemented by a regional multibeam survey and seabed coring samples. TGS data enables the hunt for new exploration opportunities, leading to the generation of untested prospects and to extend the discovery trends identified by the FAN and SNE wells. The knowledge gained from the latest exploration can be combined seamlessly with historical phases through the entire Mauritania, Senegal, Guinea-Bissau, and Republic of Guinea Conakry regions (MSGBC).

TGS, GEOPARTNERS



North West Africa has revealed world-class petroleum systems with a variety of targets and trapping mechanisms. The Sangomar field development has proven their commerciality and added over 330 MMbbls of oil reserves to the world class gas discoveries of Tortue, Takaar and Orca-1. The Gambia bidding round of Block A1 is the latest opportunity to chase these prolific plays into newly released acreage, and additionally, the blocks available in deepwater Senegal allow extension of those plays into the outboard area.



TGS, GEOPARTNERS

CONNECTING THE SHELF TO THE DEEPWATER

A flurry of activity continues in The Gambia and Senegal, and it is fuelled by drilling successes.

Felicia Winter, Anongporn Intawong and Paolo Esestime, *TGS*

The Gambia, Bid Opportunity Prospects

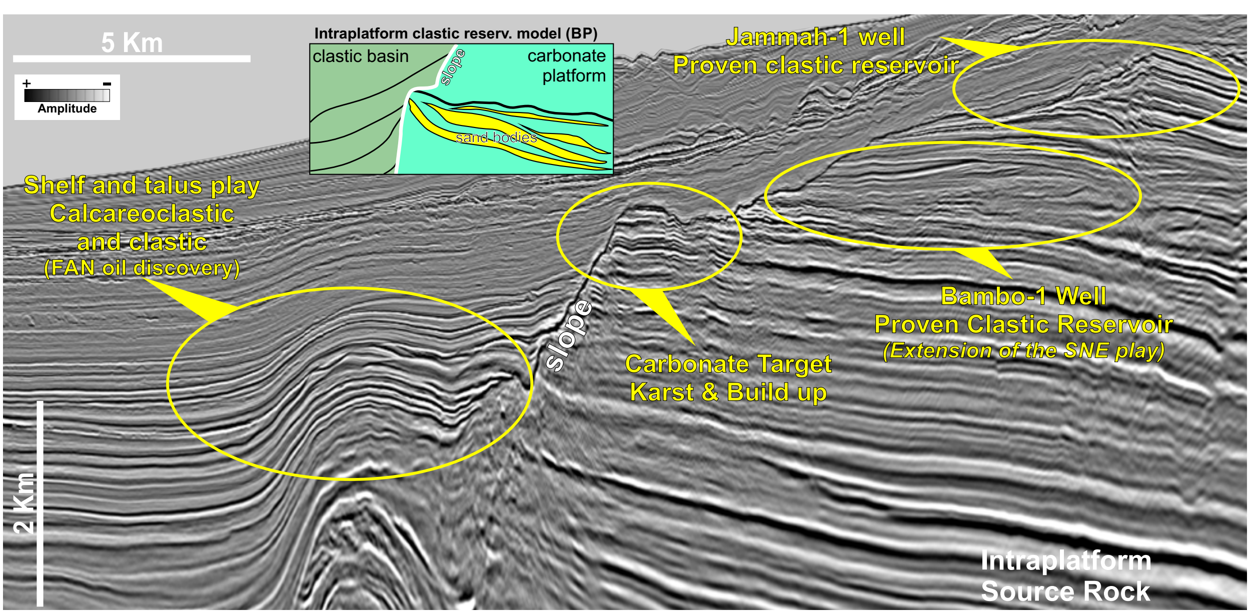
Block A1 is now open to exploration, with several untested prospects, combining mixed structural-stratigraphic closures. The hydrocarbon charge is provided by two different source rock systems: within the carbonate platform and in the pelagic environment (*Foldout and Figure 1*). The pelagic shales are easily recognised by seismic character and are widely distributed throughout the deepwater areas, over transitional and onto the neighbouring oceanic crust, allowing oil maturity at multiple burial depths due to different thermal regimes. The intraplatform source rocks are deeply buried underneath the Cretaceous shallow water limestones.

Migration pathways converge at the uplifted crests along the palaeo-shelf edge of the landward dipping shelf, where most of the structural and stratigraphic closures present themselves. Porous, karstified limestones and coarse-grained clastics present reasonable trap sizes and reservoir properties, as highlighted by their geophysical responses, and can be associated with viable target volumes. The good quality of intra-platform clastic reservoirs has been proven by wells Bambo-1, Samo-1 and Jammah-1, offshore The Gambia, and future successes are expected in mixed stratigraphic-structural prospects – analogous to those in the discoveries of the SNE and FAN wells (*Figure 1*).

Deepwater Senegal North, New Plays

Organic-rich shales can be unequivocally mapped, by the seismic signature of kerogen as a low frequency trough and its respective AVO response, from the carbonate shelf far into the most distal areas of the abyssal plain (confirmed by DSDP-367) and are directly deposited on basaltic basement and the SDRs (Seaward Dipping Reflectors of extrusives). Seismic amplitude analysis in conjunction with basin modelling suggests the presence of a play with a working petroleum system at around 3–4 km below seafloor with an oil-mature Aptian-Albian source rock (*Figure 2b*).

Several deepwater channel and lobe systems have been identified



TGS, GEOPARTNERS

Figure 1: Depth migrated seismic section (Kirchhoff) and related play fairways in The Gambia, Block A1. The existing wells have proven the reservoir and trapping mechanism of the shelf edge (BP reservoir model), while carbonate reservoirs capping clastic aprons draping over anticlines and sealing against the margin (in the extension of the FAN trend) are currently underexplored.

within the Albian to Coniacian intervals on 3D seismic data (*Figure 2*).

The main potential reservoir intervals are within the Albian and Turonian channel and lobe systems. RMS amplitude extractions along the Albian reservoir targets show numerous channelised bodies, interconnected forming a broader lobe system (*Figure 2a*). The deepwater turbidite lobe reservoirs have massive hydrocarbon potential and represent one of the most promising exploration targets for hydrocarbon industry.

These Cretaceous deepwater turbidite channel-lobe fairways not only deposited above the Early Cretaceous source rock intervals, but they are also directly connected to the basinal source rocks by gravity faults which are developed on a regional basement high. This basement structure possibly is associated with a movement of a major transform fault.

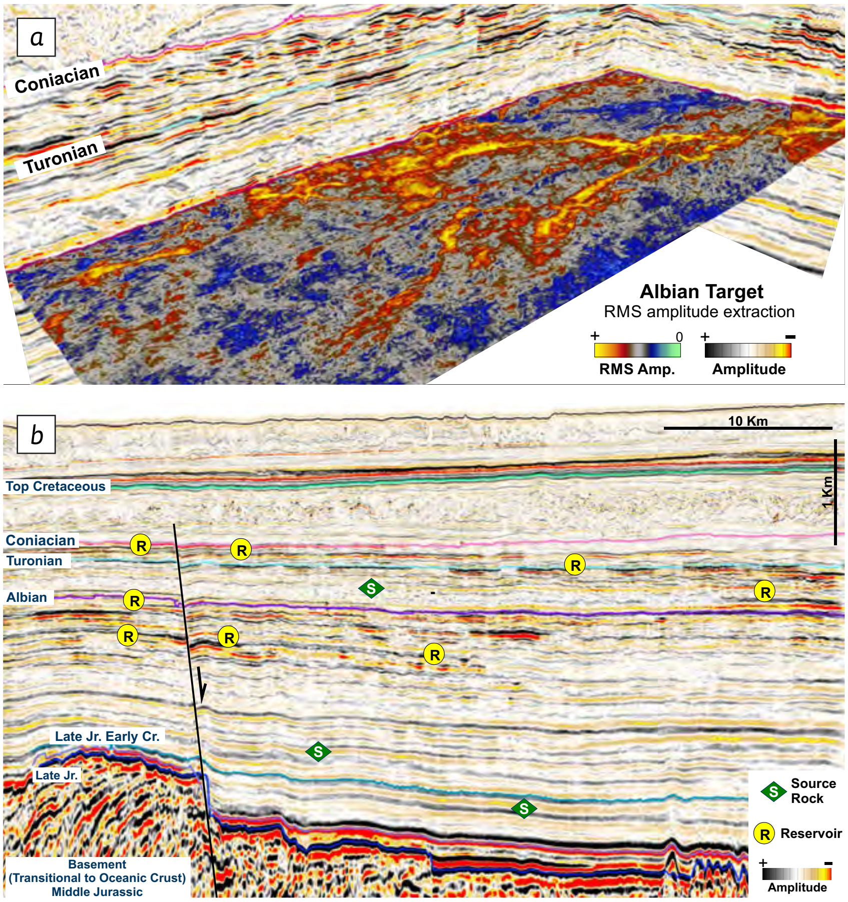


Figure 2: Senegal North deepwater.
a) Albian channels and deepwater basin-floor fan.
b) Deepwater plays identified by amplitude anomalies.

The faults would be a perfect migrating route for hydrocarbon to travel up to the directly above reservoir intervals.

Deepwater Senegal South, Extensive Plays

Deepwater offshore southern Senegal, the Mid–Late Cretaceous turbidite influx sediments have been redistributed by bottom currents, reworking them into mixed turbidite and contourite systems, in this area present as sediment waves. Geomorphological analyses of the 3D seismic data suggest that high amplitude sediment wave plays are characterised by a climbing ripple relief in the seismic section, and a distinct geometry in aerial view, especially well defined by in the spectral decomposition RGB blends (*Figure 3*). The identified closures are associated with coarse-grained cores of the waves, determined by high amplitudes on the stack and mixed frequencies on the spectrum. Sediment waves may be developed into leads and even prospects for the closing nature of their deposition, delineated and corroborated by amplitude brightening and AVO anomalies.

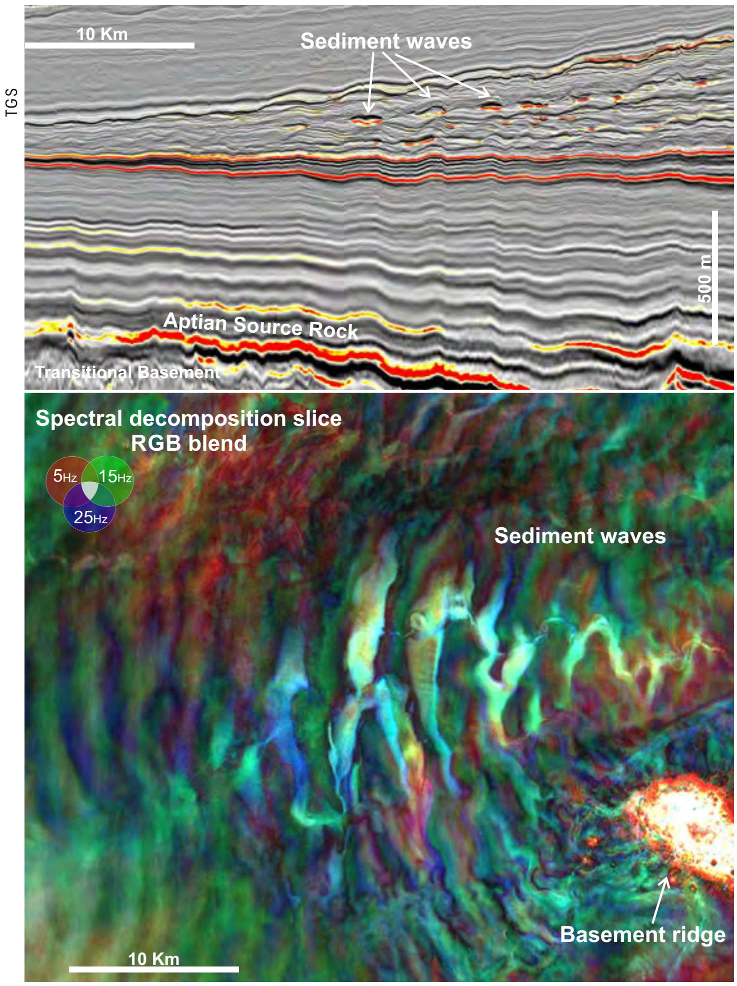


Figure 3: Senegal South deepwater, the TGS SS-UDO 3D depth migrated volume revealed the presence of high amplitude sediment waves, related to ocean-bottom currents.

OBN SEISMIC UNLOCKS NEW PLAY POTENTIAL

Rejuvenating exploration in the Gulf of Suez through the application of modern wide azimuth OBN seismic technology.

The Gulf of Suez is a prolific rifted hydrocarbon province that has been actively explored and developed since 1922. Oil exploration in this area hit its peak between 1960 and 1980 with the discovery of several billion-barrel oil fields such as Morgan, July, October and Ramadan. Since the 1980s the number of new discoveries has slowly tapered off. Unlike most prolific basins, this region did not undergo a rejuvenation of new discoveries through the application of 3D seismic technology employed from the 1980s to present. One explanation for this may be attributed to the complex seismic imaging problem posed by the presence of thick irregular geometries of interbedded salts and anhydrites in the overburden.

Grant Byerley, Ayman Rehan,Kareem Mondy, Oliver Cheshire, David Ginger; *Neptune Energy , and* ***Abdalla Ibrahim Abouelela;*** *Schlumberger*

It has been extremely challenging to image through this overburden section using the narrow azimuth and short offset 3D towed streamer configurations deployed in the past. We highlight in this article how Neptune Energy and Schlumberger Multiclient, working in collaboration, have used modern 3D ocean bottom node (OBN) seismic technology to image beneath the salt and unlock further exploration potential within the North West El Amal (NWEA) Block of the Gulf of Suez.

In February 2020, Neptune Energy signed an operated exploration licence with the Egyptian General Petroleum Corporation for Egypt's NWEA Offshore Concession located in the southern part of the Gulf of Suez (*Figure 1*).

The work programme for this concession included a commitment to acquire new seismic over the block. A model-driven approach was used to understand the impact of different acquisition geometries and help select an optimal survey design that would meet the demanding pre-salt imaging objectives (Gruffeille et al., 2020). The final acquisition design employed a high density, wide azimuth multiclient OBN seismic survey operated by Schlumberger Multiclient in 2020 (Byerley et al., 2021). A portfolio of new prospects has since been worked up using this new dataset and Neptune Energy is now preparing to drill the first exploration well into the Yakoot prospect later this year where the primary target is the pre-Miocene Nubia Sandstone.

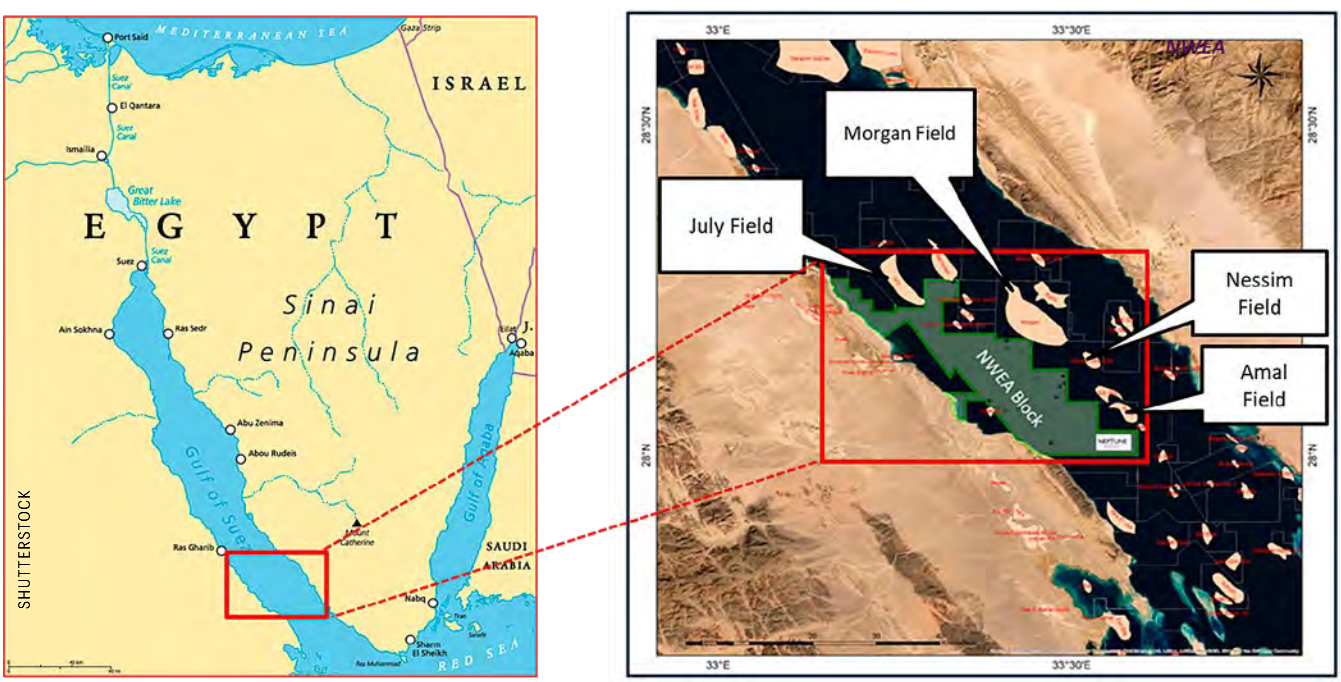
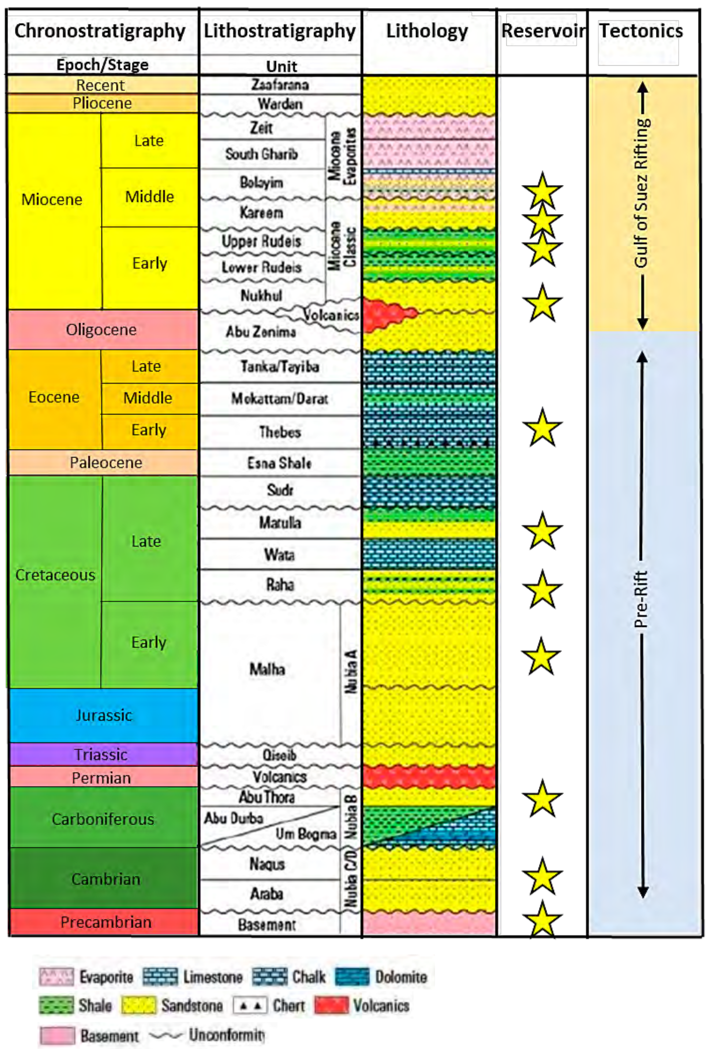


Figure 1: Maps showing location of North West El Amal concession along with surrounding major oil fields.



AFTER MOUSTAFA, A.R. AND KHALIL, S.M. 2016

Figure 2: Gulf of Suez stratigraphic section.

Geologic Setting

The Gulf of Suez is a Late Oligocene – Early Miocene age failed continental rift basin, located between the Sinai Peninsula and the Eastern Desert of Egypt. The basin lies at the northern end of the Red Sea – Gulf of Aden rift system, formed through the divergence of the Arabian and the African plates (Coleman, 1993: Hempton, 1987).

The pre-rift sedimentary section unconformably overlies Precambrian crystalline basement and ranges in age from Palaeozoic to Eocene (Moustafa, 1976; Bosworth, 1995; Patton et al., 1994; Moustafa et al., 2016). The oldest pre-rift sedimentary unit is the Palaeozoic – Lower Cretaceous Nubia Sandstone which is one of the main producing reservoirs in the basin, along with secondary reservoirs in the Matulla, Waha and Raha Formations. World class source rocks in the Thebes and Brown Limestone Formations overlie these reservoirs.

The syn-rift section is sedimentary and includes a clastic section of sandstones, including reservoir targets in the Kareem and Lower Rudeis sand, interbedded with shales and anhydrites transitioning to a section of thick evaporites at the top. The evaporites section consists of the Belayim, South Gharib, and Zeit Formations. The post-rift, post-Miocene section of the overburden is characterised by poorly consolidated dominantly clastic rocks.

The NWEA Block lies in the southern part of the Gulf of Suez within the proven Nubia Sandstone petroleum system. Neptune has estimated that, within NWEA, more than 3.5 to 5 billion barrels of oil have been generated. The block is surrounded by major oil fields including Morgan, July, Ramadan, Amal, Gamma, Shukheir and GS345 fields, all of which produce oil and gas from Miocene and pre-Miocene reservoirs.

The most prospective intervals of the NWEA Block are the pre-Miocene reservoir sands with the primary target being the Nubia Sandstone. The Nubia Sandstone is at approximately 3 km depth within the rotated fault blocks set up by the sequence of rifting mentioned above.

Seismic Processing

Full-waveform inversion (FWI) started as soon as the field data had been received and geometry corrections were applied. Minimal data pre-conditioning was applied for FWI; this included data deblending, anomalous amplitudes removal and some signal enhancement. All offsets were kept for FWI reaching up to 25 km in the middle of the NWEA area.

The processing flow started with node positioning, rotation and timing QC, then progressed to tackle the noise. The main noise attenuation steps took place in the receiver domain to make use of the fine sampling of the shots. For wavefield separation and surface multiples removal, up-down deconvolution (UDD) was used (Brunellière et al., 2004).

Interbed multiple prediction was a significant challenge as almost all the layers from the water bottom up to the salt body are considered as strong multiple generators. Both streamer and OBN data were used to predict the interbed multiples through the extended interbed multiple prediction technique which is an extension of general surface multiple prediction (GSMP) (Jackubowics, 1998). Streamer data were used as a source and interbed term while the OBN data were used as the receiver term. All multiple generators were included in the prediction process.

The velocity model building was done using a cascaded top-down approach; the initial model contained a representation of the four main layers of Gulf of Suez: shallow sediments, evaporites, salt and pre-salt sediments. FWI used early arrivals, and guided waves to update the shallow sediment velocities, then mid-offset refractions to update evaporites and mid-to-far offset refractions were used to update the salt velocities. Short streamer data were used to update the shallow sediments before the evaporite updates. Reflection data were used after that to fine-tune the thin evaporite intercalations.

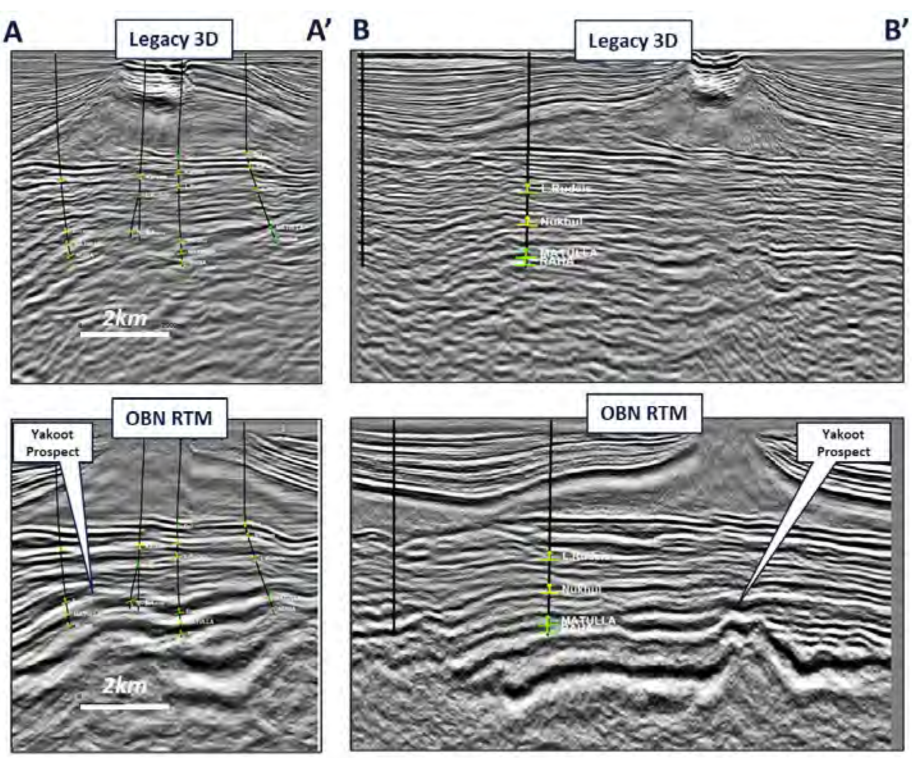


Figure 3: Comparison of crossline (left) and inline (right) seismic cross-sections between the legacy PSDM (top) and the new OBN RTM (bottom). OBN seismic courtesy of Schlumberger Multiclient.

Results and Interpretation

The first results from the reverse time migration (RTM) images of the new OBN dataset showed credible images of the pre-Miocene rotated fault blocks which became the focus of further improvements during processing. Further seismic calibration to well data confirmed that the dips observed along the main seismic horizons beneath the salt agreed much better with the interpreted dip-meter data acquired in the existing wells. Figure 3 shows an inline and crossline comparison between the legacy towed streamer seismic (top) and the new OBN seismic (bottom) across Neptune's Yakoot prospect, which quickly matured from a lead to a drill-ready prospect once it was mapped.

Pre-Miocene Play

One can argue this is the first time these pre-Miocene structures have been imaged and mapped in this area with any confidence. The ability to do this has also improved Neptune Energy's capacity to de-risk the structural trap, which is a critical risk that underpins the probability of geologic success of prospects across the whole area. It is important to note that even the best seismic data comprises imperfect information with irreducible uncertainties. The value gained from the OBN data will ultimately come down to demonstrating an improved chance of success over several prospects within the survey area.

One example of this is the Yakoot prospect (*Figure 4*), located in the south-eastern part of the block approximately 10 km south-west of the Morgan field and 8 km west of the El Amal field. The prospect is structurally controlled by a pre-Miocene Nubia and Nezzazat horst

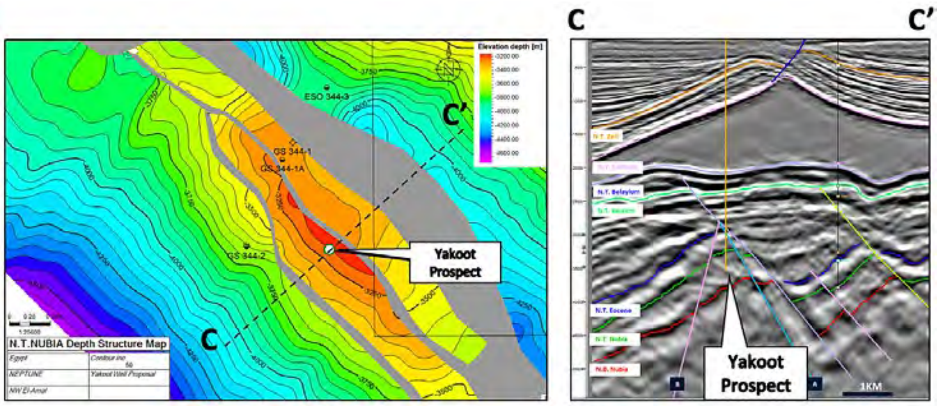


Figure 4: Top Nubia structure map (left) and OBN seismic cross-section through the pre-Miocene Yakoot prospect (right). OBN seismic courtesy of Schlumberger Multiclient.

block situated up-dip of logged reservoir pay identified in adjacent wells GS 344-1 and GS 344-1A. The improved imaging of the pre-salt section delivered better confidence in the fault interpretation over the prospect. The assessed probability of success on the Yakoot prospect improved significantly from 33% to 66% following the interpretation of the new OBN seismic.

Unlocking Miocene Play Potential

The Miocene clastic section within the North West El Amal Block consists of interbedded sandstones, with reservoir targets in the Kareem, Rudeis and Lower Rudeis Formations, with the nearby Morgan field producing from Kareem Formation fan/lobe sandstones. The latest OBN seismic has improved the image below the salt and therefore the ability to map these key horizons. It has also helped to visualise sand geometries and pinch-outs and the identification of more complex stratigraphic and combination traps within the Miocene section, rather than simply relying on structural trapping geometries. One example is shown in Figure 5 where Kareem and Rudeis sands were mapped to define the Coral prospect. Extracted amplitudes from some of these Miocene horizons appear to show channel and fan morphologies which have become the focus of ongoing reservoir characterisation studies aimed at predicting sand presence directly from the seismic. This work will play a critical role in further de-risking the presence of reservoir and stratigraphic traps within the Miocene play.

Rejuvenating Exploration in a Very Mature Basin

A thorough evaluation of the new OBN seismic data has focused on the interpretation of multiple play types through the Miocene and pre-Miocene sections. This effort has helped replenish a portfolio of new exploration opportunities in very a mature basin. The evaluation has added new prospects with resource potential of approximately 200 million barrels of oil (unrisked) within the NWEA Block of the Gulf of Suez.

Improved imaging of both structural and stratigraphic traps on the new OBN data has helped de-risk several of these opportunities into low-risk exploration opportunities. The first exploration well impacted by the new OBN seismic data is to be drilled later this year, while several other prospects are being high-graded into drill-ready prospects to provide additional running room on the back of a successful outcome.

Acknowledgements

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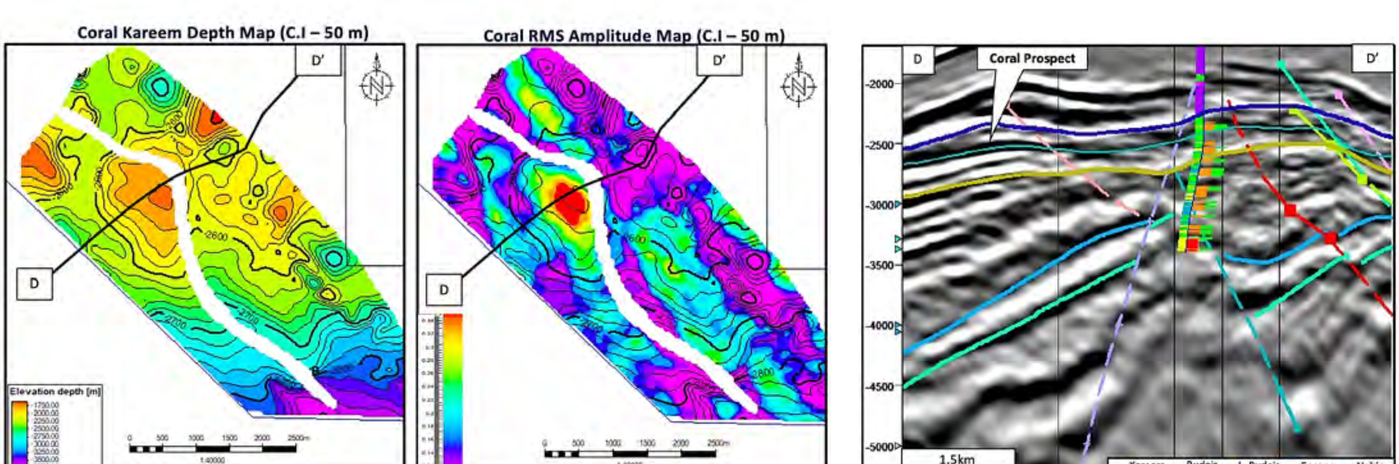

Figure 5: Kareem structure map (left) with extracted RMS amplitudes from the seismic (middle) and seismic cross-section across the Miocene Coral prospect (right). OBN seismic courtesy of Schlumberger Multiclient.

SUSTAINABLE AVIATION FUELS: CARBON-FREE FLYING?

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For the sake of the planet, I am happy to consider an electric car, to change my electricity supplier and to install solar panels or a heat pump – but I have to confess that I find it difficult to consider giving up flying to far-flung parts of the world. There are just so many wonderful places out there I have always wanted to visit. So, what are the chances of guilt-free flying in the near future?

The global aviation industry produced just over 2% of all human-induced carbon emissions and 12% of those from all transport sectors in 2019 (Covid and the resulting grounding of many flights mean that annual figures after that date are not truly representative). It doesn't sound a huge amount but to put it in perspective: a return flight from London to San Francisco emits around 5.5 tonnes of CO_2 equivalent per person – more than the emissions produced by a family car in a year, and about half the average carbon footprint of someone living in Britain. Planes also affect the concentration of other gases and pollutants in the atmosphere, resulting in a long-term decrease in ozone as well as emissions of water vapour, soot and sulphur.

Rising Demand = Rising Emissions

The aviation industry has committed to reducing carbon emissions by 50% from their 2005 level by 2050. One positive factor is the increasing efficiency of plane engines, which has been rising faster than associated emissions have been doing, but this is wiped out by the rapid increase in passenger numbers, projected to double in the next 20 years. Efficiency alone will not be enough; blending lower-carbon sustainable aviation fuel (SAF) with fossil jet fuel (meaning that no changes are required in aircraft or engine fuel systems) will be essential to meeting the goal. This is not a totally new idea; in fact, the first test flight using blended biofuel was back in 2008, and in 2011 jet fuels blended with up to 50% biofuels were allowed for commercial flights.

The challenge of finding an alternative way to keep flying

It is proving a hard area to decarbonise at scale, however, and we are still some way from finding the innovative solutions that will 'green' air transport. An aviation fuel needs to be stable in temperatures ranging from -40°C to over 40°C, with good combustion and flow characteristics, and have sufficient energy density to supply the high energy demand of long-haul flights. This means that gaseous biofuels and electrification are not very appropriate, especially for long-haul flights, and liquid biofuels derived from either plants or waste are considered the most viable low-CO_2 option for substituting kerosene in aeroplanes.

Plants, Algae and Household Waste

A number of different processes can be used to convert the carbon content of source material into the chemical components needed to fly a plane. These can be divided into biological processes, such as fermentation and microbial conversion, and thermo-chemical processes, including gasification, torrefaction, pyrolysis and catalytic conversion.

Source material for aviation biofuel includes plants such as jatropha, babassu

ZERO PETROLEUM/RAF

Achieving a place in the Guinness Book of World Records, the first flight by an aircraft powered entirely by synthetic fuel was undertaken by the Royal Air Force and Zero Petroleum Ltd in Kemble, Cirencester, UK, on 2 November 2021.

and palm oil, most of which do not compete with food crops or natural forest, although there are environmental questions over the use of palm oil. Jatropha oil, for example, is an inedible plant of the Euphorbiaceae family, native to central America but found in many tropical and subtropical areas throughout the world, where it thrives on marginal land where few other plants survive. It has already been used as an SAF and is estimated to lower CO_2 emissions by 50–80% compared to jet fuel. This type of biofuel is the only technically mature and commercialised SAF at the moment, but it has a low energy density compared to fossil fuels and therefore requires a significantly larger volume of source material to generate the same amount of energy.

Research into processing solid biomass derived from wood and industrial, agricultural and household waste using pyrolysis to make SAF is underway. Since these feedstocks are more abundant and generally cost less than specially grown plants and also have a low water footprint, this could prove to be a more cost-effective source for SAF. Technologies to convert these to aviation biofuel do exist but they have not yet been taken to a commercial level. The organic portion of municipal solid waste is another environmentally friendly potential source for SAF and experiments have shown it works and has the potential to lower greenhouse gas emissions by 85–95% compared to traditional fossil-based jet fuel, as well as reduce the amount of waste going to landfill. However, the process is expensive, there are issues with the safe transport and storage of the waste and little research has gone into it as yet.

More efficient again would be biofuels derived from photosynthetic algae, which have no food value, provide high yields with virtually no land requirement, are relatively cheap to grow and have a very low carbon output. However, the technology for large-scale production remains immature.

TON RULKENS, CC BY-SA 2.0

The seeds of Jatropha curcus contain up to 40% oil, which can be processed to make SAF.

Totally Green Fuel

A very promising technology is the creation of synthetic SAF using fossil-free electricity to produce hydrogen from water by electrolysis, which is combined with atmospheric or recycled CO_2 by an advanced version of the well-known Fischer–Tropsch method to directly manufacture fuel suitable for aeroplanes. The first flight totally powered by a synthetic fuel of this type was undertaken in late 2021, and in February this year, KLM operated the world's first passenger flight powered partially by synthetic kerosene.

Also called power-to-liquid or e-fuels, these synthetic fuels are considered a potential long-term sustainable option, due to their low lifecycle emissions and other environmental impacts. They are especially attractive environmentally if captured CO_2 is used, an area which is of particular interest to geoscientists. If the technique can be made economically viable, with the scale up of both renewable power generation and captured carbon, it is possible that e-fuel could provide a carbon neutral circular solution to the problem of aviation emissions.

Investment Needed

We still have a very long way to go; despite the research being undertaken throughout the world and the achievements so far, estimated current production of sustainable aviation fuels is only 0.05% of current aviation fuel consumption. In 2019 IATA (the International Air Transport Association) announced that it was aiming for a 2% penetration of 'green' fuels by 2025. This is a modest but achievable goal, with a number of major airlines, including United, Quantas, SAS, British Airways, Virgin Atlantic and Lufthansa, already mixing some SAF with their jet fuel.

A major issue at the moment is distribution, with only five airports – Bergen, Brisbane, Los Angeles, Oslo and Stockholm – having the facilities for regular biofuel distribution. However, the fact that aviation fuelling is very centralised, with less than 5% of all airports handling 90% of international flights, means that a small expansion in the number of airports supplying SAF could cover a lot of demand.

Further investment is needed, not just in research into the techniques to create SAF, but also in associated green technologies like renewable electrical sources. At the moment, SAF costs between three and nine times more than jet fuel. Scaling up from pilot projects to commercially-sized facilities may well require subsidies or similar assistance to prove the viability of SAF and to transform it from being a long-term goal to a near-term solution.

References available online.

FROM ARRHENIUS TO CO_2 STORAGE

Part XV A Greenhouse Model for Stratospheric Cooling

It should be apparent from the title of this article that the author does not like the use of the word 'photon', which dates from 1926. In his view, there is no such thing as a photon. Only a comedy of errors and historical accidents led to its popularity among physicists and optical scientists … There are very good substitute words for 'photon', (e.g., 'radiation' or 'light').
– WILLIS E. LAMB JR. (1913–2008), AMERICAN PHYSICIST AND WINNER OF THE NOBEL PRIZE, IN HIS ARTICLE 'ANTI-PHOTON' (1995)

Increased concentrations of greenhouse gases are warming Earth's surface and troposphere. But more greenhouse gases seem to lower temperatures in the higher layers of the atmosphere: the stratosphere (above 15–20 km), the mesosphere (above 50 km), and the thermosphere (above 90 km). This cooling, often referred to as 'stratospheric cooling', is evident from measurements and considered to be one of the fingerprints of anthropogenic global warming. Here, we present observations. In a second part, we introduce the 1D window-grey radiation model of the atmosphere, which illustrates the physical essence of the mechanism by which a CO_2 increase cools the stratosphere and mesosphere.

Lasse Amundsen* and Martin Landrø, NTNU/Bivrost Geo

Figure 1. Cooling of the stratosphere results in the formation of more polar stratospheric clouds (PSCs). Also known as nacreous or mother-of-pearl clouds, they are composed of ice crystals and form in the altitude range 10–25 km during the winter and early spring when frigid temperatures are below the ice frost point (typically below –83°C). PSCs play a central role in the formation of the ozone hole in the Antarctic and Arctic by providing surfaces upon which chemical reactions occur that chew away at the ozone layer. These reactions lead to the production of free radicals of chlorine and bromine which directly destroy ozone molecules. As CFC gases are declining thanks to the banning of these substances in 1987, the stratosphere should start to warm, and ozone levels should recover. But the release of carbon dioxide in the troposphere implies cooling of the stratosphere. One may speculate if more carbon dioxide indirectly could contribute to the formation of the ozone hole?

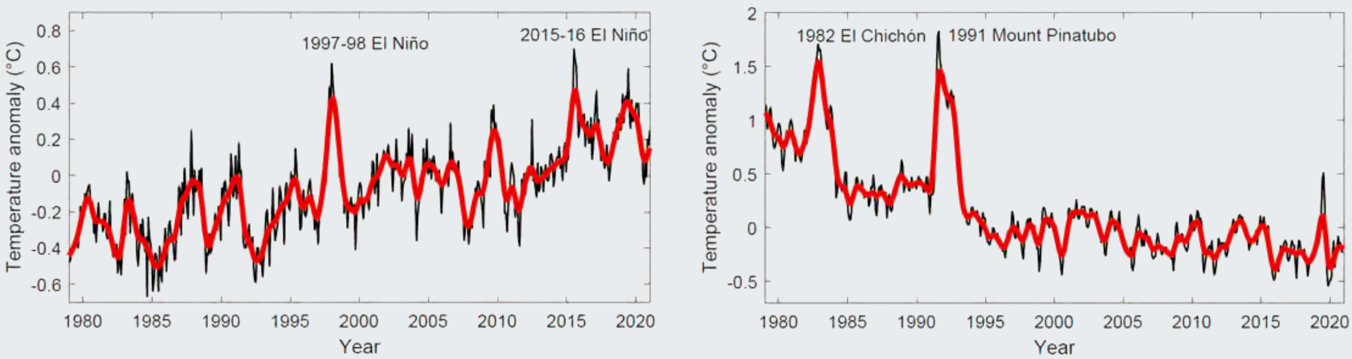
Figure 2 shows annual global temperature anomalies (with respect to 1981–2010) from NOAA polar orbiting satellites for lower troposphere (left) and stratosphere (right). The numbers, worked out from the satellite measurements by scientists at the University of Alabama in Huntsville (UAH), express the difference between the average temperature in a given month and the long-term average between 1981 and 2010 for that month. The differences are called anomalies and they indicate how temperature is changing over time. On Earth's surface, where we live, and in the troposphere, global warming means long-term increases in temperatures. About 80% of the mass in our atmosphere resides in the troposphere, including most of the greenhouse gases. Since 1979, the lower troposphere has warmed by 0.14 degrees per decade (*see Figure 3*).

If you lived in the stratosphere, around 25 km above the Earth's surface, you would have experienced cooling temperatures over the past few decades. If you think this could compensate for global warming, you are wrong. The graphs in Figure 2 show that stratospheric cooling has not neutralised the warming trend of the troposphere. What is going on exactly?

The answer is twofold: the depletion of stratospheric ozone is probably the main driver of the cooling in the lower stratosphere. In the middle and upper stratosphere (and beyond), the CO_2 increase is believed to be the most important reason for the temperature decrease.

Ozone Depletion

Stratospheric cooling over the past 50 years can be attributed partially to human emissions of ozone-depleting substances (ODS) like chlorofluorocarbons (CFCs). CFCs were developed in the 1920s–1930s for use as refrigerants, solvents and aerosol-spray propellants. In the late 1950s, they were emitted in substantial quantities but have since 1987 been banned. Consequently, most ODS concentrations peaked in the 1990s and have been declining since then.

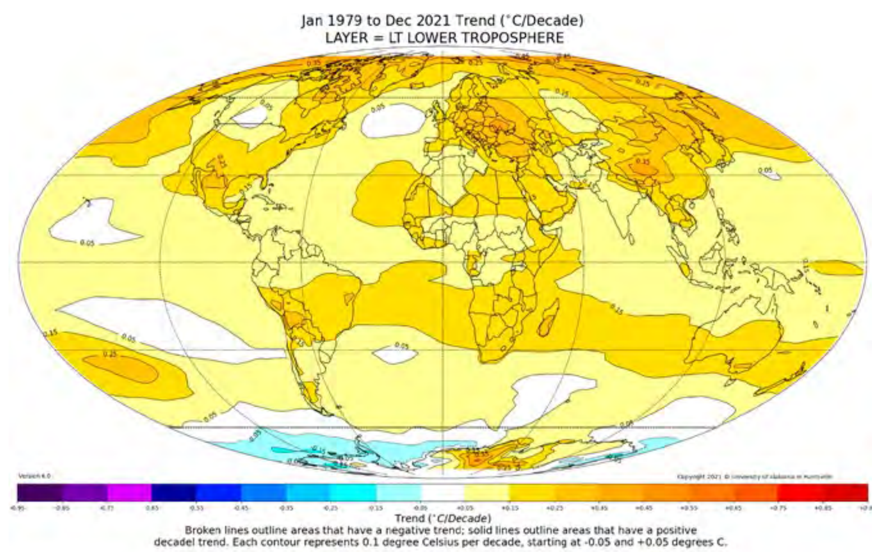


LASSE AMUNDSEN (Data from National Centers for Environmental Information)

Figure 2. Global monthly average lower troposphere (left) and stratosphere (right) temperature anomalies 1979–September 2021 shown by the black lines. The red lines are the running 13-month average. The large temperature spike in 1998 in the tropospheric series is caused by one of the strongest El Niño on record. Unusually strong El Niño episodes occurred also during 1982–1983 in the eastern tropical Pacific and the winter of 2015–2016 in the Northern Hemisphere. The tropospheric record does not capture the observed faster warming in the Arctic. The large spikes in 1982 and 1991 in the stratospheric series are due to the volcanic eruptions of El Chichón (Mexico) and Mt Pinatubo (Philippines), respectively. These volcanos ejected huge quantities of sulphuric acid dust into the stratosphere which absorbed large quantities of solar radiation, heating the stratosphere over a period of one to two years. For the lower troposphere, one sees a slightly declining global monthly temperature anomaly data trend over the last few years.

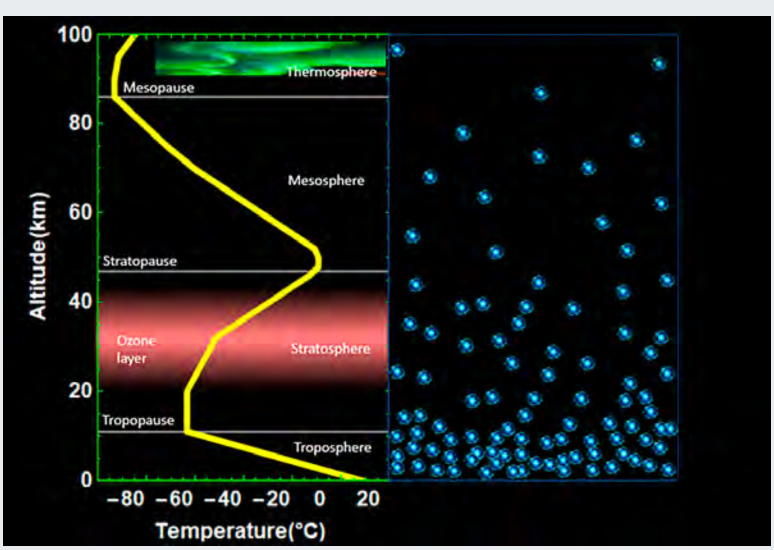
The ozone layer (*Figure 4*) resides in the stratosphere where it forms a protective blanket which shields life from solar ultraviolet radiation. Before ODS were regulated, the amount of ozone steadily decreased in the stratosphere. As the ozone decreased, the ability of the atmosphere to absorb solar radiation lessened. When less energy was absorbed, then the equilibrium stratospheric temperature lowered, resulting in a cooling of the stratosphere. Ozone also acts as a greenhouse gas in the lower stratosphere. Less ozone implies less absorption of infrared (IR) heat radiation and therefore less heat trapping.

Recent research demonstrates a stratospheric ozone recovery (see, e.g., Banerjee et al., 2020).



JOHN CHRISTY AND ROY SPENCER, UNIVERSITY OF ALABAMA, HUNTSVILLE

Figure 3: Map of temperature trends in the lower troposphere from 1979 to end of 2021 in ºC per decade. The global climate trend over this period is +0.14 C per decade.



LASSE AMUNDSEN

Figure 4: A representation of the temperature (left) and the density of gas molecules (right) in the atmosphere. The density of the atmosphere lowers exponentially with altitude. The number of molecules of gases in one cubic metre decreases by one million from the surface to 100 km altitude. In the troposphere a lot of molecules are packed together. The IR photons cannot travel far before being absorbed; therefore, the troposphere is quite opaque to IR radiation. In the middle atmosphere (stratosphere and mesosphere, between 15 and 85 km altitude) the molecule density is much lower. The molecules collide and interact less, and they cannot efficiently exchange heat. As a result, there is no thermal equilibrium in the mesosphere: different gases can have different temperatures. Because of the much lower CO2 density, the mean free path is much larger, indicating that the IR photons can travel much longer distances before being blocked – and eventually reach outer space. The ozone layer sits in the stratosphere between roughly 20 and 40 km. The Northern Lights occur at altitudes 80–500 km.

Increase in CO_2

The second effect is more complex. To explain we need to go back to basics and look at previous learning in this series. We know that everything that has a temperature gives off electromagnetic radiation. Atmospheric radiation is the flow of electromagnetic energy between the Sun and the Earth's surface (*see Figure 5*). It includes both shortwave solar radiation (sunlight) and terrestrial radiation. Terrestrial radiation, also called thermal infrared radiation (IR) or outgoing longwave radiation (OLR), is the electromagnetic radiation of wavelengths from 3–100 μm emitted from the Earth and its atmosphere. Generally, the atmosphere absorbs IR radiation due to the capacity of water vapour, carbon dioxide, and ozone to absorb IR energy. However, assuming no cloud cover, in the so-called infrared atmospheric window, from 8–13 μm, there is relatively little absorption of radiation by atmospheric gases.

The radiation processes in the atmosphere play a significant role in Earth's energy budget, which describes the energy and radiation balance of the whole earth-atmosphere system. The downward radiation, due to the direct sunlight and the back radiation from the atmosphere, causes heating of the Earth's surface. In this series, we have seen that the back radiation is the source of the atmospheric heating effect. The upward radiation ensures that the absorbed energy from the Sun and the terrestrial radiation can be rendered back to space. It ensures cooling and stabilises the Earth's temperature.

CO_2 molecules are very efficient at absorbing and re-emitting IR radiation. In the lower atmosphere, air molecules are tightly packed together. In 'Part XI: How Earth's IR Photons are Transferred in the Atmosphere in the Presence of CO_2' (*GEO ExPro Vol. 18, No. 1*) we described the CO_2 molecule's absorption and emission process of photons (sorry, Lamb) in the troposphere. First, when photons having wavenumbers in the band around 667 cm^{-1} (at a wavelength of 15 micrometres) are absorbed by CO_2 molecules, only a very small percentage re-radiate radiation, in a random direction. The rest loses that energy to the surrounding bath of atmospheric molecules. In turn, the atmospheric molecules collide with CO_2 molecules so that they get excited to a higher vibrational state. A very small percentage radiates new photons, again in a random direction, and the rest loses the energy by collision. The process repeats forth and back rapidly, and around 5–6% of the CO_2 molecules present in the bath, radiate. This leads to the greenhouse effect, an overall heating of the troposphere.

In Part XI, and additionally, in 'Part XIV: The Doom of a Photon on a Random Walk' (*GEO ExPro Vol. 19, No. 1*) we calculated the *mean* free path, or the mean distance travelled by a photon before being absorbed. We found that a photon close to the centre of the absorption band, between 650–690 cm^{-1} travels a distance of metres before being stopped. Concerning the photon's travel upwards, the bottom of the troposphere might be seen as an impenetrable wall of CO_2. However, even though CO_2 has a strong photon-trapping band centred at around 667 cm^{-1}, the band has 'wings' that spread out 150–200 cm^{-1} on either side. The probability of absorption, or the ability of a CO_2 molecule to absorb a photon of a particular wavenumber, is represented by the CO_2 absorption cross-section shown in Part XI. Photons having wavenumbers at the wings of the band are less likely to be absorbed and have mean free paths of hundreds of metres.

Further, in Part XIV we learnt that the absorption length is inversely proportional to the density of CO_2 molecules at the location. Rising levels of CO_2 add more CO_2 molecules to participate in the process. The absorption at the centre of the band is already so strong that this band plays a small role in causing additional warming. However, more photons now are absorbed at wavenumbers in the wings of the band. More photons are re-radiated, causing heating of Earth's surface and troposphere.

In the middle and upper atmosphere, air density and therefore the number of CO_2 molecules is much less (*Figure 4*). Also here, around 5–6% of the CO_2 molecules radiate in the bath of molecules. Due to the much lower number of CO_2 molecules, the mean free path is significantly larger, and photons can travel a much longer way before being blocked.

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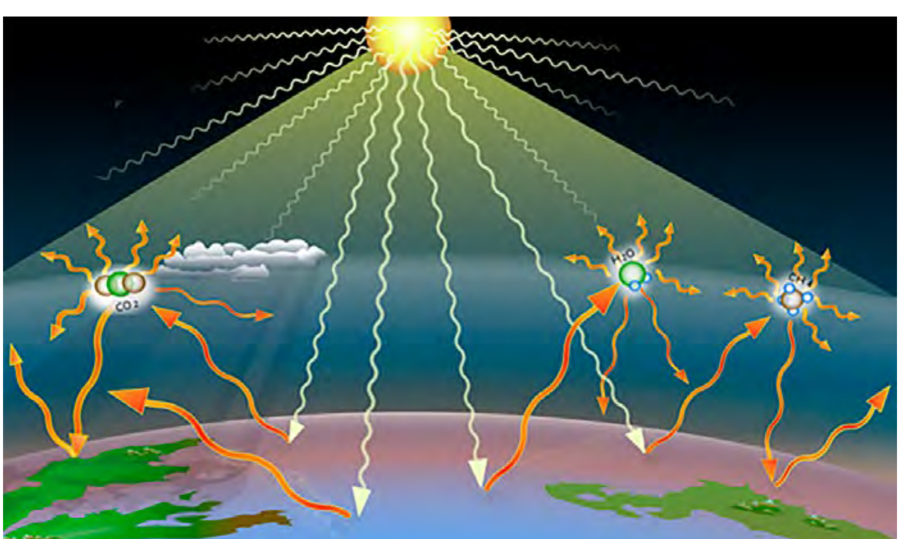

Figure 5: The Earth's climate is a solar powered system. Most of the Sun's radiation arrives at the Earth in the visible portion of the electromagnetic spectrum. The surface absorbs some of this energy and re-radiates it as infrared energy, which we feel as heat. Greenhouse gases like CO_2, H_2O and CH_4 absorb part of the IR radiation, re-emitting some of it back towards Earth and some of it out into space.

The mean free path of a photon depends on the wavenumber (or frequency) of the photon and the CO_2 concentration at the location of the photon. In Part XIV the definition of the mean free path led us to introduce the 'number of layers' of the exponential atmosphere that an IR photon has to traverse from Earth's surface to outer space. The photons with wavenumbers in the centre of the absorption band are 'seeing' thousands of layers while photons with wavenumbers at the wings of the band are meeting only a few layers. In each 'layer' photons are absorbed and re-emitted in the way that we have described above. The more layers that are present, the less chance the photon has to escape to space.

In response to an increased CO_2 level the mean free path of IR radiation is reduced, or equivalently, the atmosphere (in particular, the troposphere) is divided into more layers, each becoming thinner.

What is the Effect of CO_2 Increase on the Stratosphere?

Since the number of layers has increased in the troposphere, and each layer absorbs and emits radiation, the upward radiation received from below must come from higher – and thus colder – levels of the troposphere (compared to the levels related to the pre-increase of CO_2). While the CO_2 molecules absorb radiation from the colder upper troposphere – and recalling that the CO_2 gas emits according to the local temperature – the CO_2 gas must emit radiation with the higher temperatures of the middle atmosphere.

Consequently, in the stratosphere and the levels above, the emission of energy (heat) becomes larger than the energy received from below by absorption. As a result, there is a net energy loss from the stratosphere and a resulting cooling. Therefore, increased CO_2 concentrations impose an IR cooling tendency.

When the whole Earth system is in balance, Earth's surface temperature has increased due to the increased CO_2 concentration. When the surface and troposphere gradually warm, it results in an increased upward IR radiation at the tropopause which slightly warms the lower stratosphere. This warming however does not compensate for the initial cooling phase in the middle and upper atmosphere, so that the net effect of the CO_2 increase is 'stratospheric cooling' when the planet is in overall equilibrium.

* *Lasse Amundsen is a full-time employee of Equinor.*

References available online.

THE HIGH IMPACT POTENTIAL OF THE ORANGE BASIN

NVENTURES

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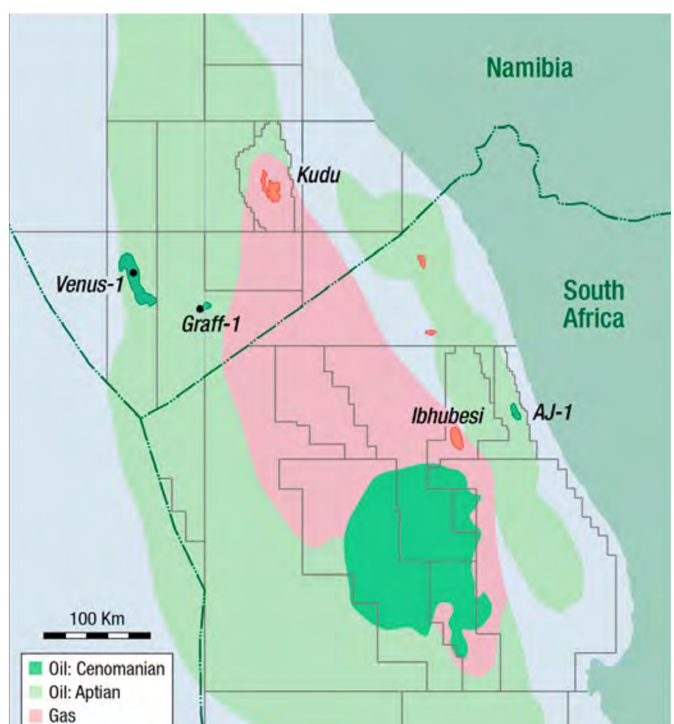
At the terminus of every major river is a major delta, and these large sedimentary depocentres invariably host prolific oil and gas basins. While the Mississippi, Congo, Nile, and many others around the world have been, and are being, successfully explored and developed, the vast Orange Basin offshore South Africa and Namibia has only recently started to reveal its enormous potential.

The Orange Basin hosts over 7 km of sediment, delivered there throughout the Cretaceous from the Orange and Olifants Rivers. It extends from the Luderitz Arch in Namibia to the Agulhas Fracture Zone in the south of South Africa covering an area of about 160,000 km². The structural setting is a rifted-volcanic passive margin created after the breakup of the South American and African continental plates during Late Jurassic – Early Cretaceous, followed by rifting and drifting of the South Atlantic Ocean, creating huge accommodation space for marine anoxic shales and marine clastic successions over various cycles. Several petroleum systems have been proven in this basin previously. The A-J-1 well (1981) targeted the synrift graben near the coast, and found the only oil prior to 2022, a coast-aligned rift with 10m oil pay near the base of the syncline. In the 1970s Chevron discovered gas (Barremian) at the Kudu field in Namibia, sadly still undeveloped to this day. Soekor found small gas fields at A-F1 and A-E1 in Block 1, against the maritime border, and a larger field to the south at Ibhubesi in a 1986/87 campaign, but again currently not commercialised.

In a basin where petroleum explorers were divided on prospectivity, the results in February 2022 have spectacularly blown holes in most theories. Whilst some observers feared a lack of oil-prone source rock south of the Walvis Ridge, where the Cenomanian and Turonian was either not deposited or too shallow (both cases proven in some of the 24 wildcats drilled to date offshore Namibia), others could not successfully model the Lower Cretaceous anoxic Kudu Shale to hit the sweet spot of burial history (for good source and charge conditions) coinciding with good quality sand deposition. The results of Shell's drilling campaign at Graff, in 1,900m of water, define a classic Upper Cretaceous passive margin slope sand system charged directly from the Aptian Kudu Shale, with amplitude support. Venus-1X, drilled in 2,900m of water, is less conventional, and took a great deal of modelling and finessing to map a low relief deep marine basin floor fan sitting on a similar Aptian source rock. Both plays have worked in the last few months, catapulting Namibia, and in time perhaps South Africa, into the super league of global prolific oil basins. Venus especially is a step beyond the ordinary, with a large, distal fan creating a huge target; a play that will reverberate for years around many passive margin abyssal basins.

There are many more opportunities to test in this enormous Cretaceous delta. The Upper Cretaceous source may yet be found to be mature in some areas, while the deepwater basin floor fan model is often repeated from here to South Africa. The 'Kudu' shale is seen to persist as far north as the Walvis Ridge, where basin modelling strongly suggests a burial history resulting in a mature source rock. Recent events have shown that several wells are required to find the sweet spots, and south of the Walvis Ridge several wells have come close, with oil recovered at Wingat and good source rock results in the Aptian at Murombe, while well 2012/13-1 revealed trace live-oil in the Maastrichtian.

With energy costs surging across the world, and the appetite for rapid large-scale deepwater developments strengthening, the future is bright for the Orange Basin.



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More information on the exploration history available online.

WHO OWNS THE OIL?

The Why and How of Unitisation

Nature does not respect the licence boundaries drawn on a map by humans. Oil and gas accumulations straddling licence boundaries are common. The size and shape of blocks, in combination with the nature of the geology and hydrocarbon accumulations, impacts the prevalence of straddling fields. Further licensing activity, field delineations, unitisation agreements, relinquishments and relicensing will further fragment this picture, often creating ideal conditions for straddling situations.

Doug Peacock, GaffneyCline

I Drink Your Milkshake

In the 2007 Hollywood feature film, 'There Will Be Blood', Daniel Day-Lewis plays the part of an oil prospector in the California oil boom of the early 20th century. Some readers may recall the well-known scene where oil production from different licences is likened to drinking the same milkshake from two different straws; the entire milkshake can be drained from just one straw. This is known as the 'rule of capture'.

Finders Keepers

The 'rule of capture' is the situation where hydrocarbons become the property of whoever recovers them, even if they have migrated from the subsurface in adjoining lands. Rule of capture was prevalent in the early days of the oil industry, especially in the United States.

The rule of capture encouraged land-owners to drill and produce oil and gas quickly and before their neighbour did. This led to inefficient recovery, duplication of effort, too many wells and reservoir problems including coning, fingering and premature loss of reservoir energy. The figure below shows the result of rule of capture in Spindletop's Boiler Avenue in the East Texas oil field of 1903 and illustrates what happened when the rule of capture was prevalent.

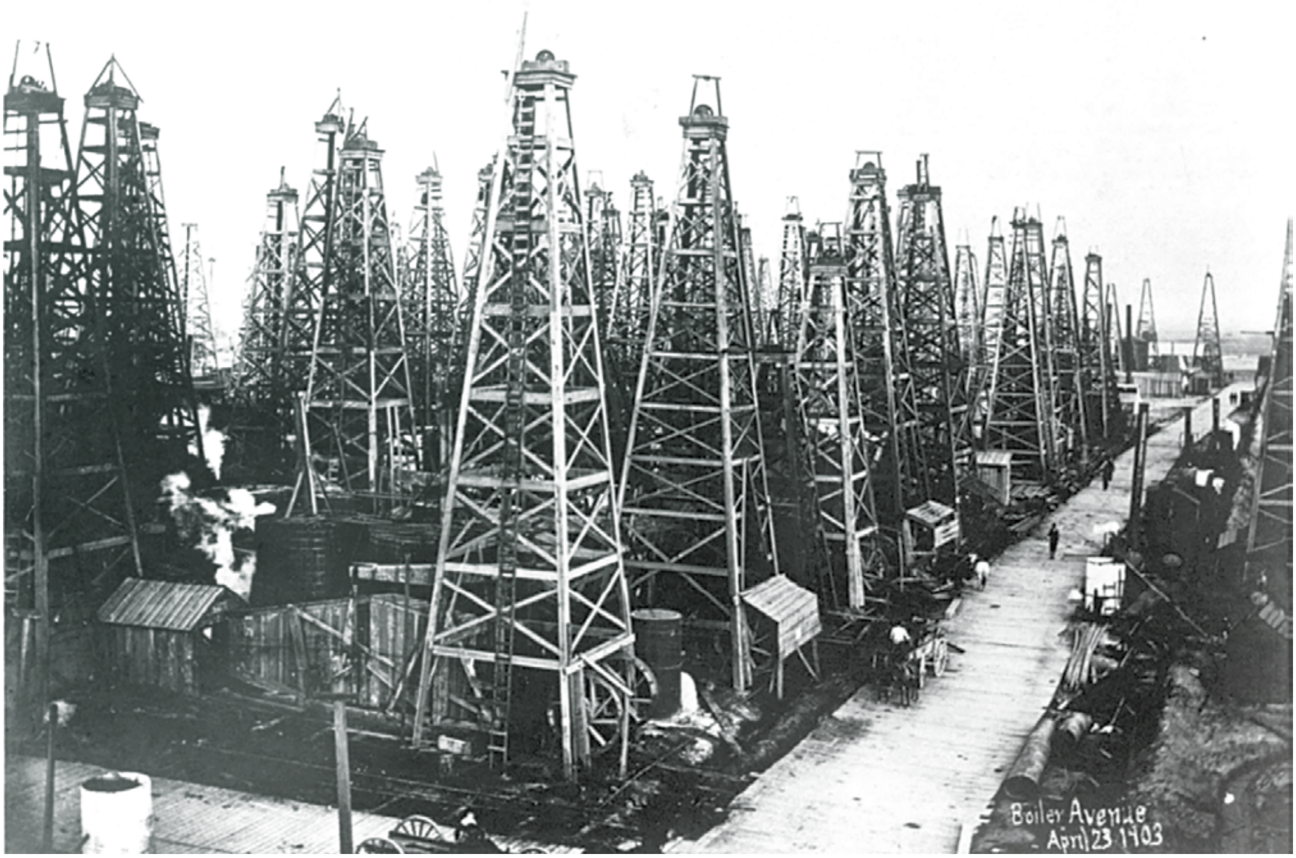

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Figure 1: Densely packed derricks in Spindletop's Boiler Avenue.

Many stakeholders and people involved in the oil industry at the time, such as Harry Doherty, founder of Cities Services, called for an end to these "extremely crude and ridiculous" production practices. In the US, regulatory provision was introduced at the state level through bodies such as the Texas Railroad Commission. These measures included compulsory pooling of leases, well spacing rules (e.g., 40-acre spacing) and restrictions from drilling closer than a certain distance from a lease boundary.

Although rule of capture is now less prevalent in the oil and gas industry, there are several situations where it still occurs. These may include international situations with no agreement in place, in countries with no regulatory unitisation provisions, or where regulatory provision is in place but not implemented. There can also be situations where parties are aware it may be occurring but prefer to keep quiet and avoid the cost and hassle of formal unitisation.

Why Do We Do It?

Unitisation, and other measures, such as minimum well spacing and pooling, are designed to avoid rule of capture, and ensure that the petroleum resources of the state or country are developed in an optimum and efficient manner, which includes:

- ***Maximising the economic recovery of petroleum from the accumulation, for all parties.***
- ***Ensuring a fair allocation of resource revenues and costs.***
- ***Sharing and making best use of technical information.***
- ***Reducing development costs and improving project efficiency.***

Providing an equitable split between parties is not the main driver behind unitisation, although it may also be a desirable outcome.

What is Unitisation?

Unitisation is the process by which development of a field that crosses one or more licence (or international) boundary(ies) can take place as a single 'unit' (*see Figure 2 for a cartoon example*). Licensees of neighbouring leases pool their individual interests in return for an interest in the overall unit. Development proceeds as if the original licence boundary does not exist. The share of production, and cost, allocated to each side of the original licence boundary is known as the tract participation.

In many jurisdictions a state energy regulator will require that straddling fields be unitised as a pre-condition for field development approval.

Although domestic unitisation is a contract between private parties, with limited state involvement, a strong and proactive regulator can step in and impose agreement on parties who would otherwise be unable to agree. For the Zama field in Mexico, it was reported that if parties could not arrive at an agreement within a specific timeframe, the energy ministry

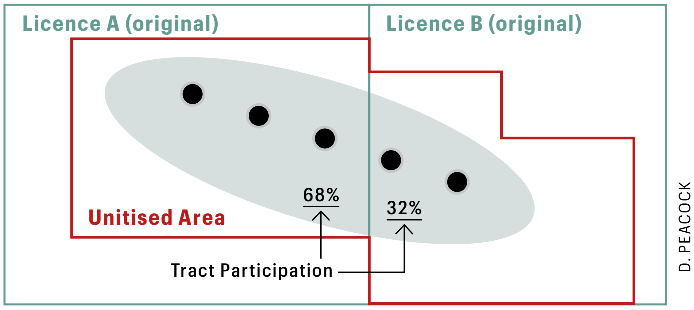


Figure 2: Cartoon illustration of Unitisation.

would propose the terms of a unitisation and unit operating agreement (UUOA).

Unitisation is often problematic with multiple technical and commercial challenges, and in practice there is no perfect solution for all the problems and difficulties associated with unitisation.

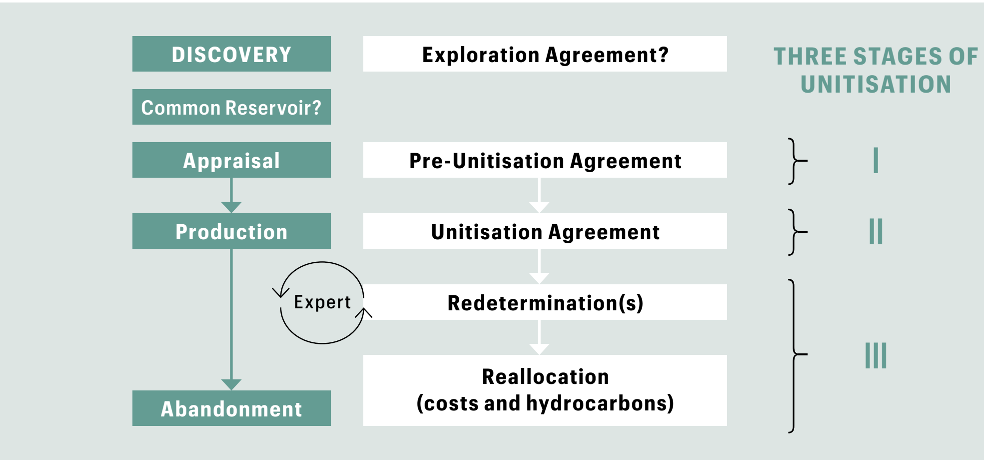
Modern Best Unitisation Practice

Although many measures were introduced in the US and other countries from the 1930s, modern international best practice for unitisation developed primarily in the North Sea during the 1970s and 1980s and included both domestic and international straddling fields. Early international agreements included the Frigg Agreement for the large gas field straddling the UK/Norway boundary. During the 1980s and 1990s, many unitisations took place here such as Statfjord, Nelson, Balmoral and Armada.

The unitisation process is usually governed and defined by a UUOA, or equivalent, which sets out how the unit is managed. A UUOA replaces a Joint Operating Agreement (JOA) in a unitised field, but includes the unitisation provisions.

> *The unitisation process is usually governed and defined by a Unitisation and Unit Operating Agreement (UUOA)*

Ideally, a UUOA should be executed prior to development and prior to approval of a field development plan. Although unitisation can, and does, sometimes occur post development, it is not an ideal situation as the main benefits of an efficient development would already have been compromised. A UUOA may have evolved from a pre-unit agreement (PUA) used during the appraisal stage. PUAs are useful as they establish many of the key issues which will be required in the UUOA and allow activities to proceed efficiently, which might include data-sharing, appraisal activities, preparation of development plans etc. An outline for a UUOA is provided by



D. PEACOCK

Figure 3: Agreements typically applicable for the lifecycle of a straddling field.

the Association of International Petroleum Negotiators (AIPN), which also includes consideration of exploration activities in its most recent update in 2020. Figure 3 shows which agreements are typically applicable for the lifecycle stage of a straddling field.

Redetermination and Technical Procedures

Redetermination is the process whereby the tract participations are revised at some time after the initial unitisation and is typically triggered by defined events such as additional data being acquired, e.g., a major drilling programme or new seismic acquisition, a specific time after production start-up or a specified amount or percentage of estimated ultimate recovery. A field may have one or more redeterminations throughout its life.

Although the concept of redeterminations is simple, the process can be expensive, time-consuming, and contentious. The preparation of a submission to an expert often takes an integrated team of dedicated staff many months or in some cases years. This can be a considerable cost. Add in the opportunity cost of taking staff away from their regular jobs, the cost of the external expert, and the risk of litigation, and the investment can be considerable, not to mention the intangible costs of potentially damaged relationships within a joint venture. Such costs can then be weighed against the potential value of a change of tract participation. However, in a large field even a 1% change of equity interest might be worth hundreds of millions of dollars.

It is worth noting that the redetermination process does not produce any more oil or gas; it is simply re-adjusting the share.

Perhaps the most common, and well-known use of an external expert is for the redetermination of tract participation, whereby the basis for tract participation, usually hydrocarbons in place, and the technical procedures have already been agreed and are specified in the unitisation agreement.

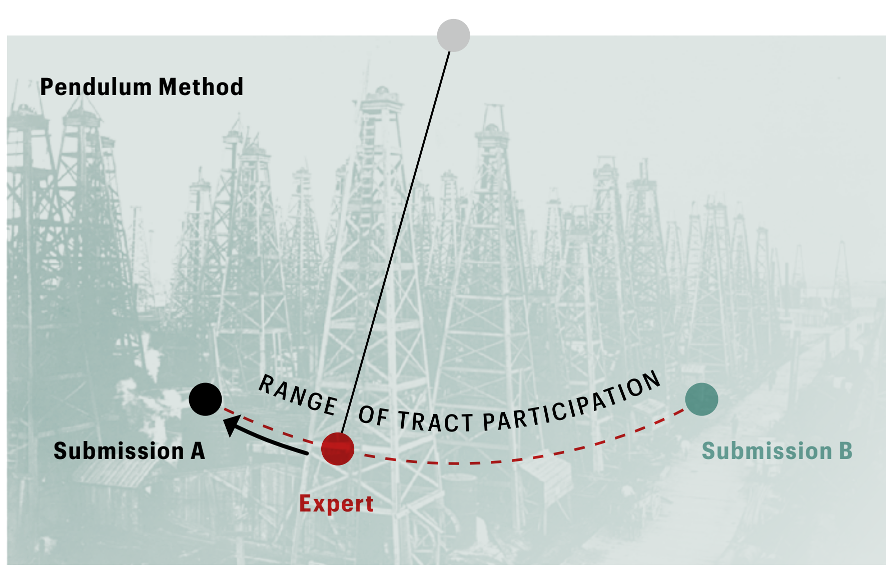
The Expert and the Pendulum

The expert must deliver their decision according to the protocol of the unitisation agreement. There are various ways in which this can be done. These may include an expert delivering their own decision, which may be different from submissions by individual parties, or sometimes within a prescribed range. A common method, promoted by the AIPN, is the pendulum method, which is intended to discourage extremism in submissions. In the pendulum method, the expert must choose the submission closest to its own determination. In Figure 4, Submission A would be selected. The pendulum method works best when there are only two parties, as with additional submissions there is opportunity for manipulation of outcomes.

The Winner Takes It All?

Unitisation, and in particular, redetermination is often considered as a zero-sum game, with clear winners and losers. Most UUOAs contain payback clauses such that an increase in equity also requires a back-adjusted payback of costs.

During the first redetermination of the Balmoral field in the UK North Sea, the 'winning' party, that increased their equity share, commenced legal proceedings as they preferred to lose. At the time of the redetermination, low commodity prices coupled with high development costs meant that an increase in equity resulted in a considerable loss of revenue.



D. PEACOCK

Figure 4: Illustration of the pendulum method.

Furthermore, payback of costs is often made within a specified, limited time, which is usually much shorter than the remaining life of the field. Thus, there may be times, such as during a period of low product prices, when losing, and receiving cash, and a reduction of potentially limited revenues over a longer timeframe, was preferable to winning and having to pay back cash now.

Is It Avoidable and Are There Alternatives?

In mature provinces such as the North Sea, the heyday of unitisation is long gone. As new fields become smaller, the size of the prize often no longer justifies the time, and cost of a unitisation. Alternatives to formal unitisation are often considered and implemented. One solution is fixed equity; one of the first fixed equity agreements, in 1994, was for the Armada gas complex in the Central North Sea, a situation with multiple fields, multiple owners, and a complex ownership structure. Another solution is asset swaps whereby parties exchange assets to simplify ownership structure. More recently, the Peik field, which straddles the UK/Norway, has an agreement that states the Tract Participation will not be adjusted or amended unless unanimously agreed by the parties, removing the need for redetermination, and providing an agreed fixed equity.

Other solutions include buyouts or cash payments; in fact, anything that can be agreed between the parties.

International Issues

Fields straddling international boundaries introduce a whole new level of complexity and require cooperation between governments. If the border itself is not agreed, then a first step is typically a delimitation agreement. In the North Sea, a series of delimitation agreements preceded unitisation of individual fields. If the border cannot be agreed, then various options are available. Even if a boundary is not formally agreed between the countries, a boundary can be agreed solely for the purposes of unitisation to allow development to proceed. Another common solution is to create a joint development area to allow exploitation of resources. There are many examples of these including: Malaysia–Thailand, Australia–Indonesia, and Nigeria–São Tomé and Príncipe. Without any agreement, prospective acreage can remain unexplored and undeveloped such as that in the Cambodia–Thailand overlapping claims area. An example of multiple redeterminations, from the Statfjord field, offshore Norway, is shown in table 1.

Table 1: Statfjord Field – Multiple redeterminations.

	Licence Interests %	
	UK	Norway
Unitisation (1974)	11.12	88.88
Redetermination (1979)	15.91	84.09
Redetermination (1985) (1)	11.9	88.1
Redetermination (1989) (2)	12.9	87.1
Redetermination (1989) (3)	(A) 15.7	84.3
Redetermination (1991)	(B) 14.76	85.24
Redetermination (1995)	14.53	85.47

Back to the Future?

There are many high-profile international unitisations at various stages of maturity around the world. Some examples include: the Zama field in Mexico, several fields in the eastern Mediterranean, Jubilee and Afina-Sankofa in Ghana, Areas 1 and Area 4 in Mozambique and sub-salt fields in Brazil.

There have also been several high-profile government agreements in recent years. In 2010, after years of negotiation, Norway and Russia signed a maritime delimitation treaty and in 2018 Brunei and Malaysia announced a unitisation framework agreement for several fields straddling their border.

An interesting example is the Greater Tortue/Ahmeyim gas field which straddles the border between Mauritania and Senegal. An agreement was reached in 2018 which provides for development of the field with an initial 50/50 split of resources and revenues and a mechanism for future redeterminations. The agreement was reported as being based on industry best practice for development of cross-border resources and was therefore based on the landmark 1976 Frigg Agreement between the UK and Norway.

The Future of Unitisation

Many oil and gas fields straddle boundaries. The main purpose of unitisation will remain to ensure efficient development of these resources.

Regulatory provision for unitisation may need to be strengthened and properly enforced. This may require regulators to take a more active role. Unitisation is often, and should remain, a pre-requisite for development approval.

Unitisation protocols and common practices have been established worldwide, largely based on North Sea practice. These provide the industry with a basis for unitisation; however, other methods and processes may be more applicable in other areas.

Unitisations are often contentious and can have unintended consequences, such as damaging relationships within a joint venture. Alternatives to unitisation, such as fixed equity, assets swaps and buyouts are options that can be considered and may be preferable to a formal unitisation. It may be better to make the pie bigger for everyone rather than fight over the size of each slice.

However, for large accumulations with high potential values, unitisation will remain the most-likely process.

NORTHERN NORTH SEA: A DUAL-AZIMUTH SOLUTION

Enhanced 3D dual-azimuth seismic data is an important driver in the search for exploration opportunities and for evaluating the probability of success.

This seismic line from the new Northern Viking Graben dual-azimuth dataset is oriented north-west to south-east and passes through the Dugong discovery and Snorre field. The line is in the depth domain with overlying TLFWI velocities that isolates a higher-velocity layer in the Hordaland Group in the Paleogene and a lower-velocity feature in the Upper Cretaceous. The final processing of the Northern Viking Graben dual-azimuth data delivers outstanding results that provide significant uplift in the injectite imaging and clearer images of sub-BCU structures and fault architecture.

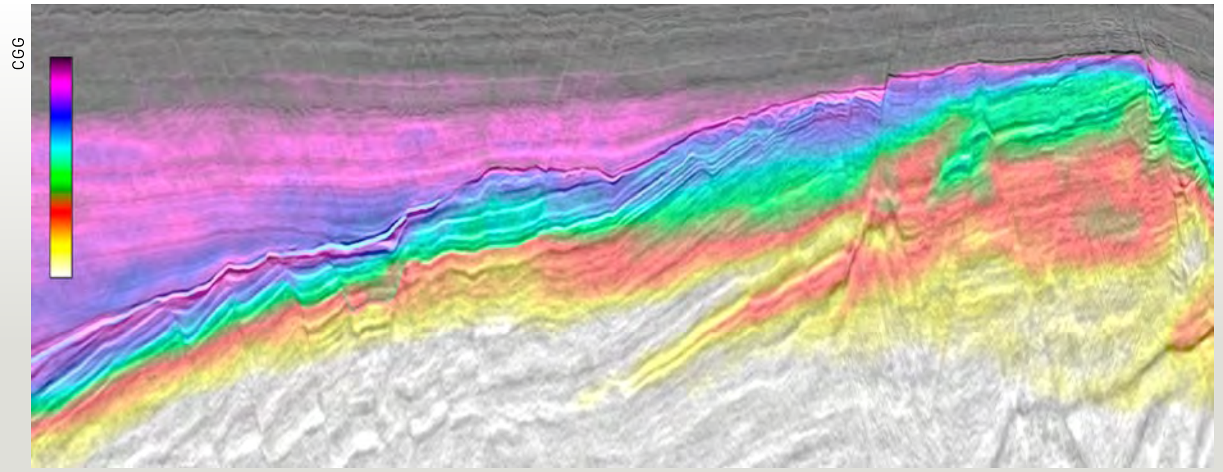


Figure 1: TLFWI velocities with frequencies up to 14Hz, draped over the prolific sub-BCU stratigraphy.

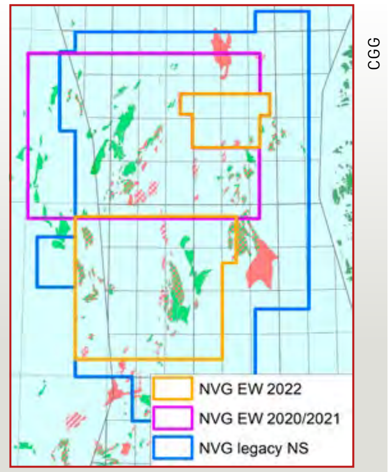
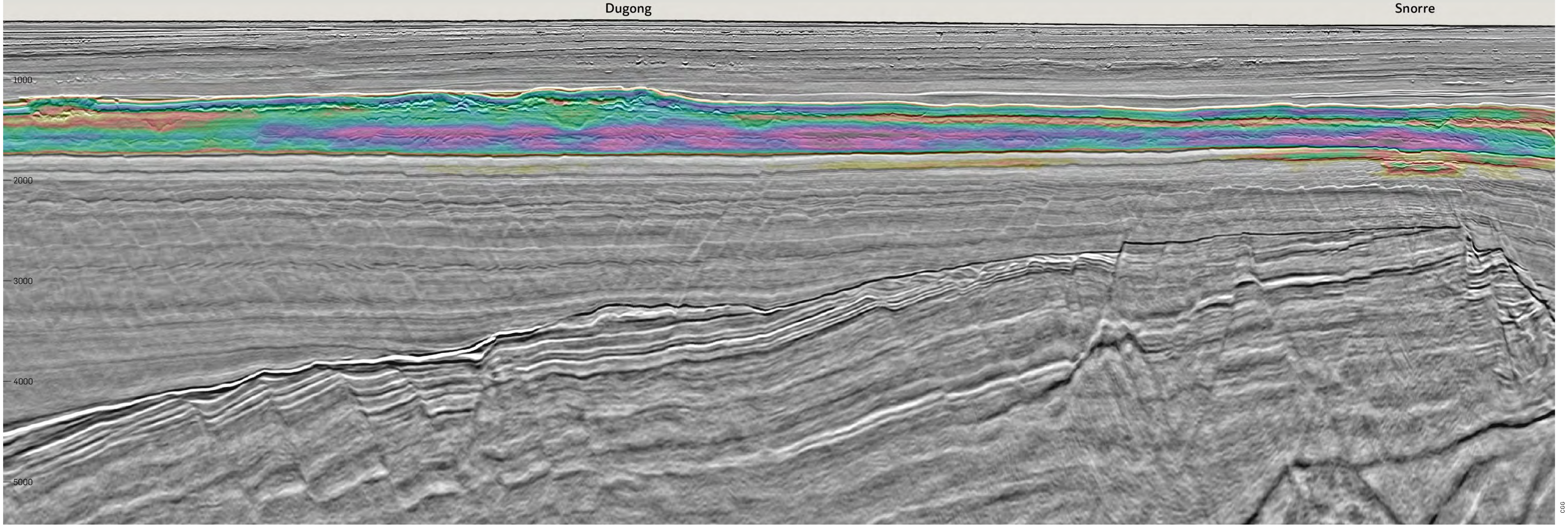


Figure 2: Overview map.



NORTHERN NORTH SEA: **A STEP-CHANGE IN DE-RISKING PROSPECTIVITY**

New seismic coverage and high-quality dual-azimuth data over the Northern Viking Graben reveal crucial details for de-risking prospects and encouraging activity.

Anna Rumyantseva, Jaswinder Mann-Kalil and Idar Kjørlaug; CGG

The Northern North Sea is very active for oil and gas exploration with several commercial discoveries made over recent years. CGG's Northern Viking Graben (NVG) multi-client survey provides more than 44,000 km² of coverage over this area.

The Need for Better Data

The focus on near-field exploration is increasing, driving the need for seismic data with improved imaging and resolution. Dual-azimuth (DAZ) seismic, based on a combination of high-density data acquisition and an advanced processing sequence, addresses these needs (see foldout and *Figure 1*). By applying high-resolution time-lag full-waveform inversion (TLFWI) to a dataset combining the two azimuths, the velocity field is significantly improved. This will give the interpreter and decision makers greater confidence in de-risking critical parameters with more accurate evaluation of stratigraphic pinch-outs and truncation through improved resolution and higher signal-to-noise ratio and evaluation of fault presence and seal through illumination of faults in multiple directions. Improved data will also allow for new plays and prospects to be identified in areas with challenging imaging conditions.

This need for better data has led CGG to start a new multi-year programme (2020 to present) with triple-source and multi-sensor streamer technology, to provide denser spatial sampling and multi-component data required for enhanced deghosting. The survey, acquired east–west (EW), adds a second azimuth to the existing NVG north–south (NS) survey.

A complete reprocessing of the original NS data is also underway. Both azimuths are used together in crucial processes such as TLFWI for velocity modelling, 4D cooperative noise attenuation, and a fully revised demultiple sequence. The final products are three datasets: a reprocessed volume of the legacy NS data, a new EW volume and a combined DAZ dataset along with a detailed TLFWI velocity model.

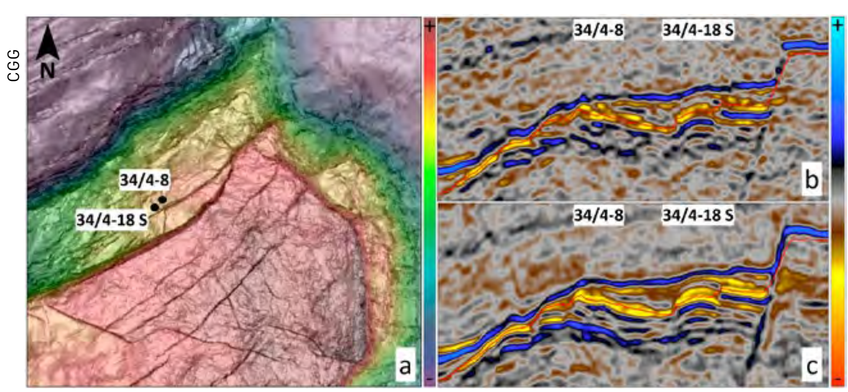


Figure 3: a) Top Statfjord time-structure map blended with a similarity seismic attribute to highlight fault architecture; new well 34/4-18S projected vertically from the surface; b) Legacy NVG NS and c) New NVG DAZ composite seismic section through well 34/4-8 and approximate location of the deviated well 34/4-18S (Statfjord Kile); to compare the two datasets.

Prospectivity and De-risking

Many exploration wells are planned for 2022, including the recently drilled 34/4-18S well on the 'Statfjord Kile' prospect. The well is located 3 km NW of the Snorre oil field.

Figure 3a shows the top Statfjord time-structure map overlying a similarity attribute, interpreted on the new DAZ data. Two large fault blocks oriented south-west to north-east can be seen. The northern fault block was drilled by well 34/4-8, which encountered no hydrocarbons in the Statfjord sandstones, and the southern fault block by the new 34/4-18S well, with similar results.

If we compare the well location on seismic sections from the legacy NS and new DAZ data (*Figures 3b and 3c*), the DAZ data highlights new details that were not imaged on the legacy data, such as an additional reflector above the top Statfjord horizon interpretation (as shown in red). Sub-BCU structures and fault architecture are much better imaged on the dual-azimuth data, as shown by the sharpness of the faults. This allows for improved interpretation of a spatial fault and cross-fault stratigraphy in addition to the identification of new minor, but potentially critical, faults.

Dugong is a recent discovery located west of Snorre with 40–120 MMboe of recoverable resources (Norwegian Petroleum Directorate). The reservoir is the Middle Jurassic Rannoch sandstones, with additional oil found by 34/4-15A in the Upper Jurassic Sjøpølse prospect. In 2021, CGG completed an early-out inversion study using an enhanced fast-track EW product and reprocessed legacy NS data. A massive and continuous sand layer was identified in the Rannoch Formation (*Figure 4*), as seen on the seismic section through Dugong with an overlay showing high probability of sand (*in blue*). CGG will continue with a second inversion study using the final processed EW and NS azimuths, and the newly detailed TLFWI velocity field to further improve imaging of the area. During data processing, attention is given to preserving true amplitudes and controlling the phase.

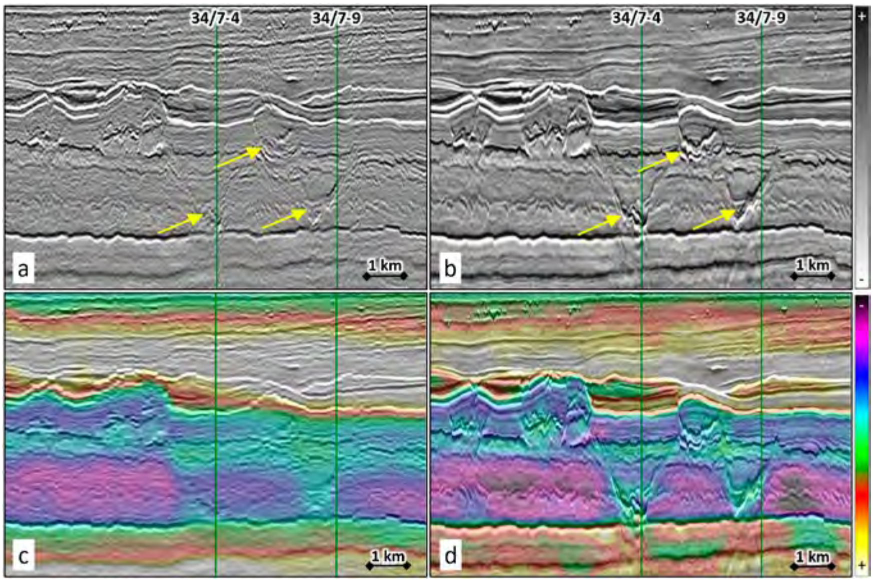


Figure 5: The EW seismic section shows Oligocene sands and high-relief mounds at the top Hordaland Group unconformity. Shallow gas anomalies and injectites can be identified on the seismic sections intersecting wells 34/7-4 and 34/7-9, where the NVG dual-azimuth data shows significantly improved imaging (b) compared to the single-azimuth legacy NS dataset (a); c) legacy PSDM velocity model; d) significantly improved TLFWI DAZ velocity model.

The NVG area contains a wide range of localised near-surface geological anomalies. Shallow gas anomalies typically exhibit high absorption, associated with amplitude attenuation and phase distortion resulting in imaging effects, such as dim zones, uneven image illumination and migration artefacts. Getting the velocity right in these anomalies has a significant impact on the ability to fully image the deeper underlying structures (*Figures 5a and 5b*).

The new DAZ data shows a significant uplift in the imaging of the injectite architecture with improvements in the sharp and continuous wings of its structure as well as the connectivity between the complex injectite systems (*Figure 5*).

Technology and Experience

With new advances in technology and insight gained from working with data in the Northern North Sea over many years, CGG can apply local geological knowledge and experience, a detailed velocity model and the very latest processing technology to the imaging of the new DAZ product and the two independent azimuths. As seen in the foldout, the final processing of the Northern Viking Graben DAZ data delivers outstanding results that provide significant uplift in the injectite imaging, clearer images of sub-BCU structures and fault architecture, sharpness of fault geometries and an improved ability to resolve the detailed stratigraphy. The three DAZ, EW and NS volumes provide a very good basis for de-risking prospects and identifying new prospective opportunities in a prolific mature area of the North Sea where assessing the subtle critical elements of an interpretation becomes ever more important.

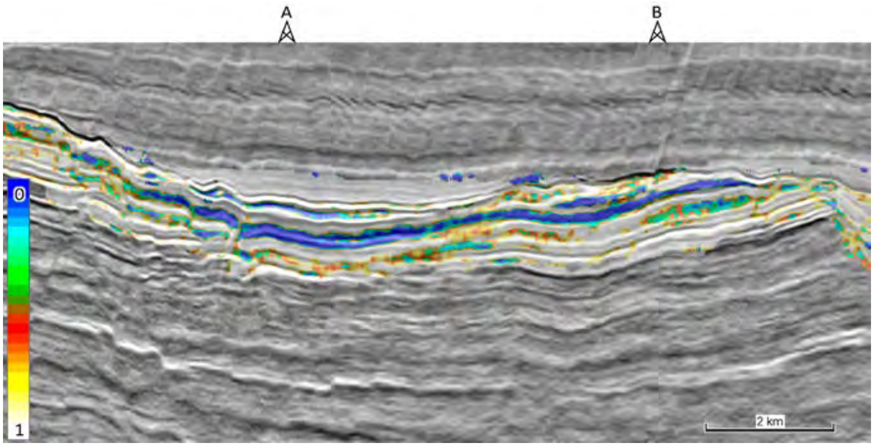


Figure 4: NVG DAZ seismic section oriented south-west to north-east through the Dugong discovery (drilled by well B) overlain with the probability of shale from the early-out inversion results over the target interval. Higher probability of sand is shown in blue.

New Data Acquisitions

In 2022, CGG will continue with new EW acquisition over the legacy NS survey, adding another 9,000 sq km to give the industry the information required to continue creating value from the region. CGG has a long history of bringing innovation to the Northern North Sea to support de-risking of exploration and production and will continue with this commitment into the future. In particular, as part of the 2022 acquisition, CGG plans to acquire sparse node data in the Oseberg area. This will provide data to further improve velocity modelling and imaging in a geologically complex area. CGG expects to deliver even further details for optimising production and supporting near-field exploration in the region.

RESPONSIBLE UPSTREAM INVESTMENT IN THE UKCS

In the UK's polarised energy debate, oil and gas exploration occupies an apparently conflicted position. To some, exploration signals future hydrocarbon supply despite the IEA saying that investment in new supply must cease. Conversely, elevated oil and gas prices are driven by demand, signalling the need for increased supply. In the UK's ambitious net zero regulatory context, exploration can make a positive contribution to energy security, emissions reduction, local employment and revenue and tax generation to facilitate and subsidise future renewables growth.

IOG PLC

Blythe platform and Dudgeon wind farm, UK, Southern North Sea.

Graham Goffey, *Exploration Task Force/Soliton Resources Ltd, and*
Nick Terrell, *Exploration Task Force/Carbon Catalyst Limited*

The UK's Exploration Task Force (XTF) is a group of industry volunteers collaborating with the regulator – the North Sea Transition Authority (NSTA), formerly the Oil and Gas Authority – to make the most of UK exploration through the energy transition. In 2021 the XTF issued information packs (utilised in this article), addressing E and A for CO_2 storage and the case for responsible upstream investment in the UK. These overlapping themes are contextualised here by the UK upstream industry's ambitious and uncommon commitment to net zero by 2050 and considerations including supply, demand and the global emissions impact of UK fossil fuel consumption.

Fast-Changing Global Picture

Prior to the Ukrainian invasion, a gas supply imbalance was driving a global energy price shock. Energy prices looked to remain elevated for some years and global emissions had increased via coal and oil substitution for gas. High energy prices via constrained supply are a blunt and socially brutal way to reduce demand and tend ultimately to lead to increased global supply. Thus, the energy price shock highlights limitations in focusing disproportionately on supply rather than demand reduction. Demand uncertainty is intrinsic to climate models, for example the IPCC's 1.5°C warming models encompass almost an order of magnitude variation in 2050 fossil fuel demand, bracketing the International Energy Authority (IEA's) net zero scenario. The uncertain pace of demand reduction and of renewables expansion highlight that oil and gas supply reduction is not a shortcut to net zero.

The unfolding tragedy in Ukraine, with loss of trust in the Russians as energy suppliers, have re-calibrated the urgency and need for energy market change. There was already a pressing need to accelerate renewable energy deployment and to prioritise demand reduction, as laid out in the IEA's net zero scenario. In parallel the upstream industry needed to increase the climate resilience of hydrocarbon supply. With high energy prices set to become the new normal, energy affordability and security have become paramount global issues and should give politicians an imperative to drive demand reduction and set policies to decarbonise energy supply.

The North Sea Transition Deal and Decarbonisation

The drive to increase upstream climate resilience and accelerate national decarbonisation were crystallised in 2021 via the NSTA's revised strategy and the North Sea Transition Deal (NSTD). Together these constitute a sea-change for the UK Continental Shelf (UKCS), imposing a net zero central obligation and a measurable pathway to net zero absolute emissions by 2050. This high level of UK ambition contrasts with the absence of even a national, let alone industry level, net zero commitment in most of the countries analysed in the United Nations Environment Programme (UNEP) 2021 Production Gap Report. This increasing environmental, social and governance differentiation of the UK upstream industry is also evident in NSTA, industry and government initiatives towards increased scope and clarity of climate-related financial and environmental reporting.

The NSTD additionally provided for a resurrection of carbon capture and storage (CCS), with early 'Track 1' projects now identified. The UK's potentially

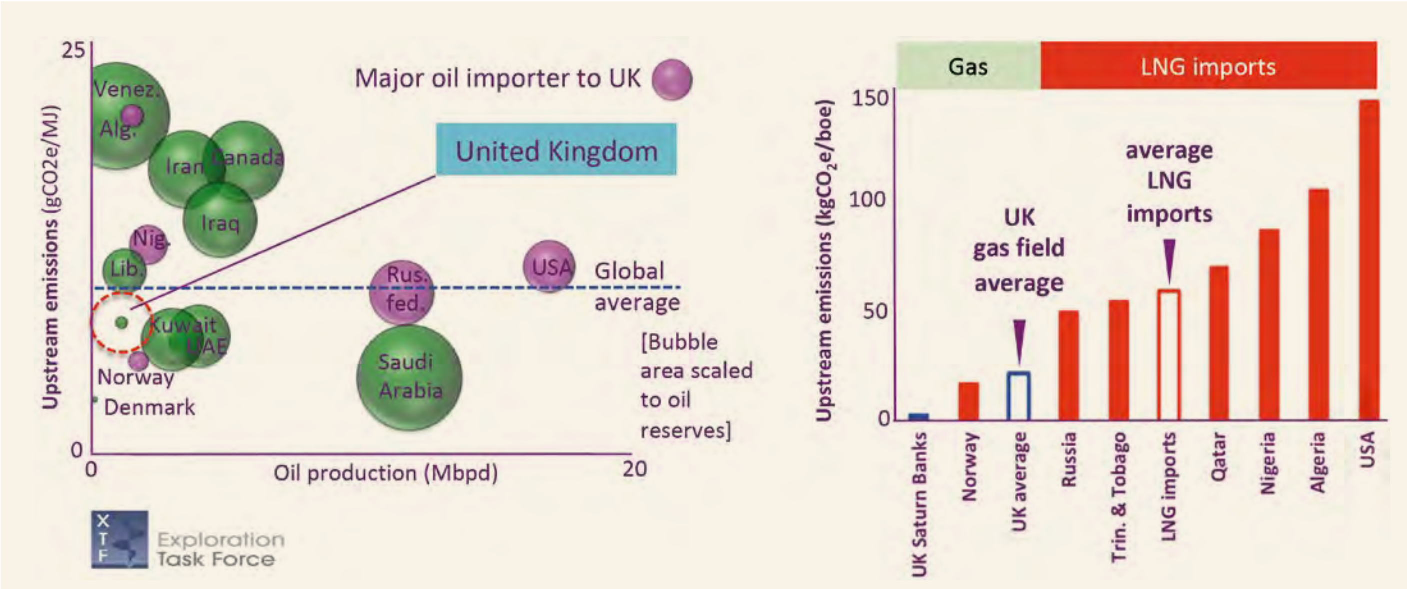


Figure 1: UK oil and gas production in context: a smaller scale, lower emissions oil producer and lower emissions gas producer.

world-class geological CO_2 storage resource has capacity that could meet hundreds of years of UK CO_2 storage demand and provide storage to those neighbouring countries with less favourable geology.

Hydrocarbon Supply, Demand and Emissions

The emissions intensities of UK oil and gas production are respectively more than 20% and 60% below those of global oil production and UK imports of liquefied natural gas (LNG) (*Figure 1*). The NSTD's targeted 50% reduction in absolute emissions by 2030 will be achieved via production decline, methane reduction per the Oil and Gas Climate Initiative, the elimination of routine flaring and up to £3 billion of expenditure on offshore electrification. Electrification can play a major role if economic, regulatory and cultural impediments can be overcome. With growing global demand for and reliance on LNG, the UK's indigenous, lower emissions gas and Norwegian imports are key to limiting the global emissions impact of UK fossil fuel demand over the next several decades.

The UK is one of only two UNEP-surveyed countries projecting falling near-term hydrocarbon production. Existing reserves can meet 25% of demand to 2050 – estimated at 17 Bboe in the central scenario of the UK's Climate Change Committee (CCC) (*Figure 2*). New exploration and the development of unsanctioned fields in line with the lower emissions regime could lift the net local share to perhaps 60%, limiting net imports to around 7 Bboe. This is not a 'ramping-up' of production, simply a slowing of decline, to around the 3–4% global reduction rates UNEP called for in 2021.

It is often argued that new oil and gas development will lead to economic stranding of assets during the energy transition. This risk is mitigated in the UK by measured fiscal terms, gas market undersupply and the lower emissions intensity of many fields. UK gas production now meets less than 50% of UK demand. Imported LNG meets around 20% of demand but its high emissions intensity makes it responsible for some 44% of upstream (i.e., Scope 1 and 2) global emissions associated with UK gas consumption. Despite undersupply, E and A activity in the Southern North Sea (SNS) is at historic lows. Yet new SNS gas – using existing infrastructure – has exceptionally low emissions intensities, as exemplified by IOG's Saturn Banks project (*Figure 1*).

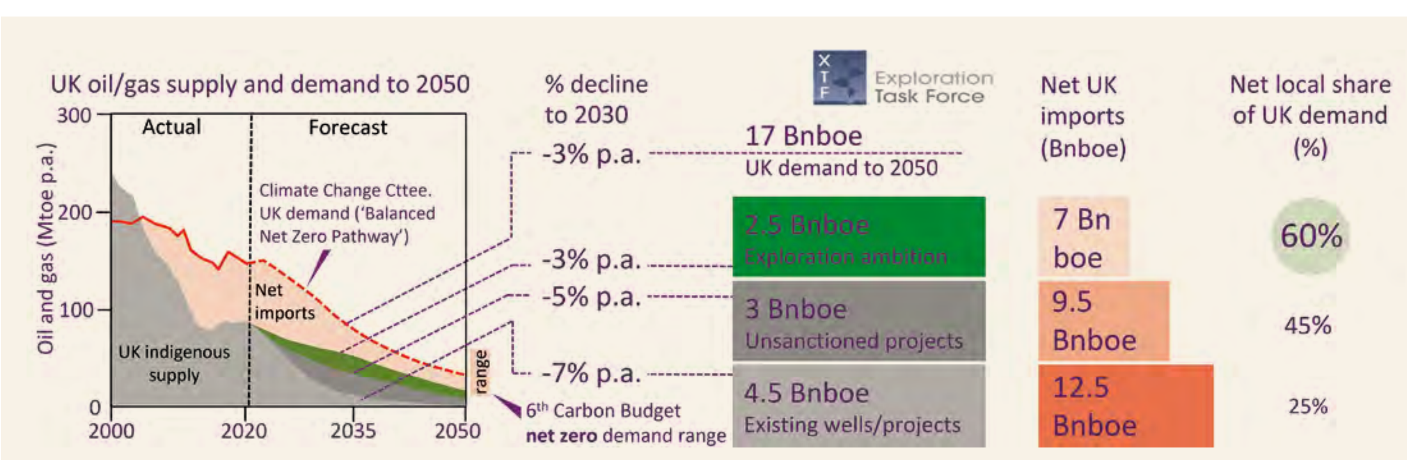
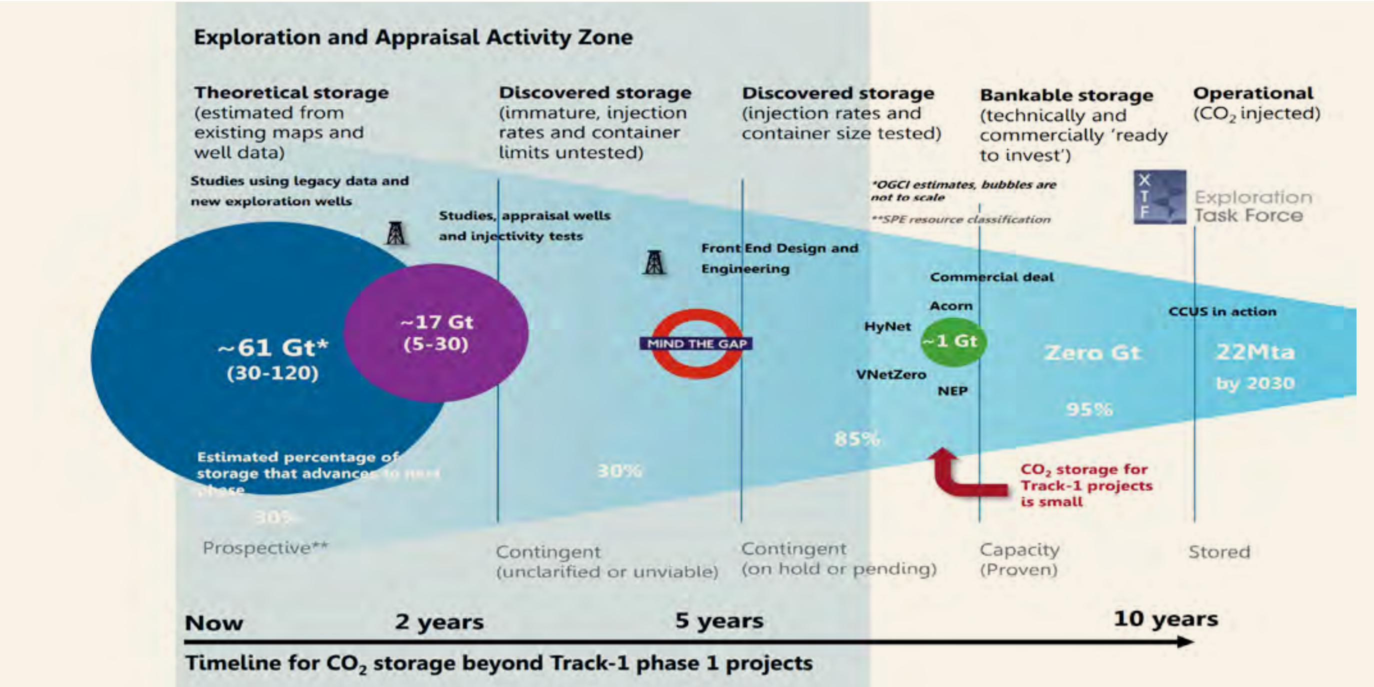


Figure 2: UK oil and gas supply and demand to 2050.



XTF

Figure 3: Maturation of theoretical CO2 storage to bankable (proven) storage through E and A.

Around 80% of UK oil is exported. UK oil imports are driven by commercial considerations and the crude requirements of a refinery/downstream complex that exports 40% of its output, particularly as petrol. These factors bias towards higher emissions oil imports from countries less committed to emissions reduction (*Figure 1*). Consequently, the CCC has called for carbon border tariffs or minimum import standards to reduce the global emissions impact of UK fossil fuel demand. Such measures to reduce the UK's 'offshoring' of emissions would reduce imports, support UK upstream emissions reduction efforts and promote emissions intensity as a differentiator in global hydrocarbon markets.

The Role of Carbon Capture and Storage

The UK's substantial geological carbon storage resource is estimated at 78 billion tonnes (mid case) of theoretical offshore capacity. CCS is critical to the UK meeting its binding commitment to net zero by 2050. It is key to reducing industrial emissions and to decarbonising gas-fired power generation, in addition to facilitating blue hydrogen production (i.e., hydrogen made from natural gas with stored CO_2 emissions). The CCC's 6th UK Carbon Budget calls for up to 180 Mt p.a. of CO_2 storage by 2050, with the Government's Net Zero Strategy setting an ambition to achieve 50 Mt p.a. by 2035.

The UKCS subsurface is well calibrated by petroleum industry data, but none of the theoretical storage capacity is proven storage underpinned by commercial agreements (*Figure 3*) and the proportion of theoretical storage resource which can achieve proven (or bankable) status remains uncertain. To remain consistent with the targets set in the 6th Carbon Budget, this emerging sector needs E and A seismic and drilling to mature sufficient resource. The UK government is actively developing its CCS deployment strategy, business models, regulatory framework and financial support packages to underpin the development of the sector. Success will need a fiscal regime that facilitates risked investment in storage E and A and which can carry the inevitable E and A failures that will accompany the maturation of theoretical resource to assured operational storage.

The Low Carbon Re-invention of the UKCS

The technical and economic basis for some claimed roles of blue and green (electrolytic) hydrogen needs further analysis and development. But hydrogen will undoubtedly play a role with CCS in driving the re-invention of the UKCS as an integrated energy supply and carbon storage basin, utilising existing infrastructure to reduce costs. The NSTA asserts that the UKCS could meet up to 60% of required UK net zero abatement through CCS, hydrogen, offshore renewables and their close integration with lower carbon oil and gas facilities. In this context, exploration can play a key role by prolonging lower emissions oil and gas supply, under a climate compatibility checkpoint process that validates the case for responsible exploration investment. Successful exploration can minimise the global emissions impact of UK demand, limit imports, support the challenging economics of offshore electrification, underpin blue hydrogen and extend infrastructure life. Additionally, the retention of subsurface knowledge and critical skills is essential to both the growth and long-term containment assurance of CO_2 storage.

The NSTD's high ambition leans heavily on UK upstream expertise, technology and capital to contribute substantially to national decarbonisation. Close integration of lower emissions indigenous oil and gas with emerging low carbon technologies and offshore renewables can accelerate decarbonisation, underlining the extent to which the upstream industry is an integral part of the UK's carbon reduction trajectory.

Extended version of article available online.

"GONE FOSSIL HUNTING…"

An introduction to safely looking for and preparing fossils.

Dr James Etienne
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In the first article in this series, I highlighted the staggering breadth of utility that fossils have, from academic research to applied industrial analysis, value in commercial trade and preservation in public and private collections. In all instances the fossils must be found, collected and prepared – but the end purpose and legal constraints will ultimately drive where, and how, specimens are acquired and what happens to them afterwards.

Sometimes fossils are found through serendipity – someone just happens to be in the right place at the right time and spots something unusual that captures the eye. Some exceptional fossils have been found this way, including the recent discovery of the Rutland ichthyosaur by Joe Davis of the Leicestershire and Rutland Wildlife Trust. This specimen (*Figure 1*) is the largest and most complete ichthyosaur specimen ever discovered in the UK! Importantly, Joe and his colleagues recognised the significance of the find, reported the discovery, and a group of expert palaeontologists were brought in to help carefully plan, and execute the excavation in partnership with Anglian Water, Rutland County Council and the Leicestershire and Rutland Wildlife Trust.

A Moment for Mindfulness?

More often than not fossils are found by people that are actively looking for them. There's something exhilarating about hunting for, and finding, fossils – being the first person on Earth to discover a specimen and expose it to the light in what may be the first time for tens or even hundreds of millions of years. If you are really lucky you may even find something new to science that no one has ever seen before.
Fossil hunting can be very therapeutic – an opportunity to focus on something other than the constant demand of the digital age, get some fresh air and enjoy the great outdoors (*Figure 2*).

MATTHEW POWER PHOTOGRAPHY

Figure 1: The spectacular Rutland ichthyosaur – the largest and most complete ichthyosaur ever discovered in the UK. It was a find like this by Joseph and Mary Anning in the early 1800s that helped lead Mary Anning to a life dedicated to the discovery, preparation, study and commercialisation of fossils which now adorn the walls of museums around the world. Dean Lomax for scale sporting his Mary Anning Rocks T-shirt!

Not all fossil hunting looks like this – often it's extremely muddy, pouring with rain and you may find yourself questioning why on earth you are lugging a 50 kg lump of rock up a steep path back to your car! Nevertheless, whether you are looking for something to do with the kids on the weekend, collecting for serious scientific study or just for the enjoyment of it, there are lots of things to consider, and it is important to do at least some planning before you head out to explore.

Getting Started

To get started it's important to consider what you are targeting to collect, and for what purpose. These questions will probably govern most of the preparation that's necessary. For example, if you are doing a detailed biostratigraphic analysis of cuttings or core from a well-bore, you may be visiting a core shed that requires advance permissions, training, facilities bookings, payment, transport and accommodation, and materials for documenting observations and to collect samples for processing microfossils. On the other hand, if you are looking for Jurassic ammonites, you may just be driving down to the coast for a walk along the beach with a rucksack. If you have an interest in a specific group of fossils, do some research first to find where best to start exploring if you don't already know where to go. There's a wealth of information available online through social media, or connect with your local professional or amateur societies, many of which provide access to organised excursions. In the UK a great place to start is the UKAFH (UK Association of Fossil Hunters) that has a great website highlighting some key localities with information on the geology, likely find frequency and logistical considerations for site access.

Know Your Rights

Wherever you are planning to collect fossils it is important to know your rights and what is permissible by law. In most cases freedom to collect depends on who owns the land or mineral rights and their rules for collecting. Some localities have no constraints at all; some are governed by a general code of practice; some require a licence to be obtained that may require payment of a fee. At some public, state or federal locations collecting may be prohibited by law for conservation purposes.

There can be a lot of nuances, and collecting guidelines can get pretty complicated. For example, constraints may be tied to specific types of fossils (common fossils may be freely collected, but scientifically important specimens need to be declared). It is also common to be allowed to collect from loose material, but not specimens that are in situ without prior approval from a governing body. This prevents over-collection and needless damage to exposures that subsequently remain for others to enjoy.

It is impossible to cover the full range of legal considerations and jurisdictions here, but you should understand your rights, and certainly seek the necessary permissions or licences before you head out. There may be regulation over the disposal of specimens that have been collected (for example, if you plan to sell fossils, important finds may first need to be offered to domestic museums).

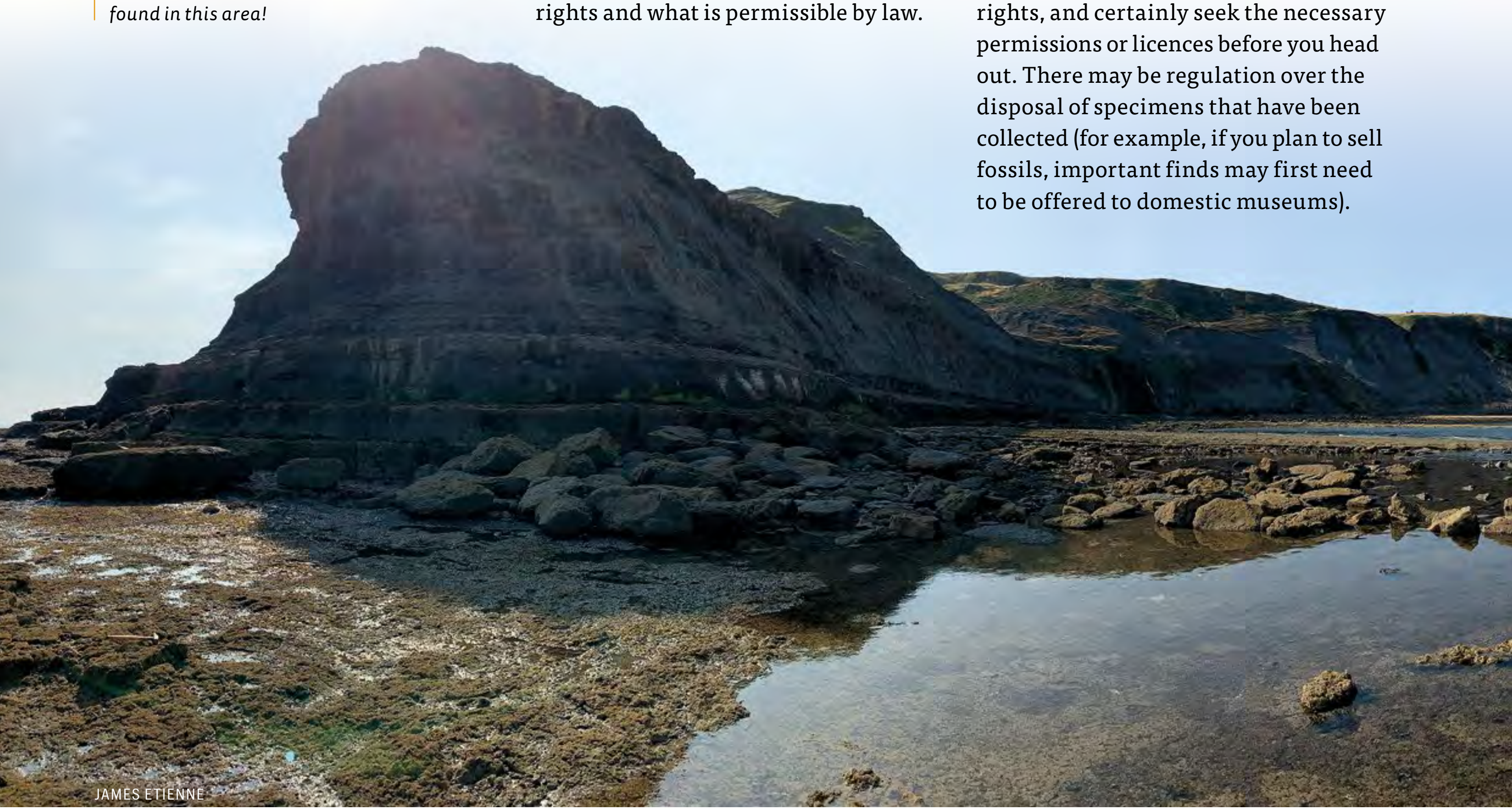


Figure 2: The stunning scenery of Kettleness in Yorkshire, looking back into Runswick Bay, UK. Only safely accessible at low tide, some beautiful Jurassic fossils can be found in this area!

JAMES ETIENNE

There are also some restrictions on the commercial sale or export of material that is of scientific or cultural significance. This is the case with some fossils from China, Mongolia and Russia.

Be Safe!

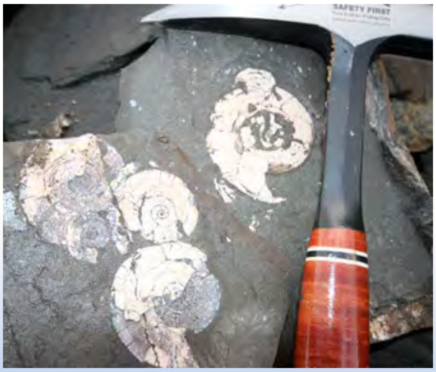
Fossils can be found in mountains, deserts, swamps, rivers, beaches, cliffs, road-cuttings, quarries, mines, offshore or anywhere else sedimentary rocks are being weathered, eroded, or mechanically exposed. So, whether you are collecting samples for a PhD thesis in micropalaeontology, megalodon teeth for commercial sale or trilobites for a private collection, chances are you're going to find yourself somewhere exciting… and potentially dangerous.

One of the most important things to do before you go fossil hunting is to perform a risk assessment. Where are you planning to go? How are you planning to collect (are you picking up loose fossils, hammering, sieving, using heavy duty kit like rock saws)? What are the potential hazards? What PPE (Personal Protective Equipment) do you need? What is your communications plan? What is your contingency if things go wrong? What emergency services are available? Where is the nearest hospital? Be prepared and don't be complacent. Always let someone know where you are going.

This may sound like overkill, but the great outdoors can be dangerous. Slips, trips and falls are the most common risks, and having slipped and badly dislocated one of my fingers while out collecting one day I know how fast a fun afternoon can deteriorate. For this minor injury it took support from the coast guard, the fire brigade and the nearest hospital (over an hour's drive away) to reset my finger.

Decent footwear, appropriate clothing, hard hat, gloves, safety goggles etc. are typical PPE (*Figure 3, left*). Of course, if you are diving for mastodon fossils in Florida, a kayak, wetsuit, snorkel and spotter for 'gators' might be more appropriate!

Since fossils can be found in a varied range of environments, you need to consider what risks are relevant. Think about your journey plan as well as the destination. What are the road conditions like (are there any roads?!); what kind of vehicle do you need? In addition to trips, slips and falls, look out for rock falls (stay away from unstable cliffs), slumps and debris flows, quick-sand, tides, storm surge, floods and other extreme weather events. You also need to consider the wildlife (sharks for offshore diving, alligators for hunting creeks in places like Florida, snakes, spiders and scorpions in desert environments, walrus and seals on the beach, polar bears in the Arctic and so on). With the exception of sharks, I have encountered nearly all of these on geological fieldwork. I've even seen monkeys throw rocks at people in the Himalaya! They will steal your spectacles too if you get too close… you have been warned!



IAIN BROWN

Left: Figure 3: Walking on the Hettangian (early Jurassic) sea floor in Somerset, U.K. These mudstones are full of spectacular Psiloceras ammonites (Right: Figure 4). Note – heavy duty wellies with steel toe caps, gloves, cap (good for all weather – avoids sunburn and eye strain on a bright day, keeps the rain out of your eyes on a wet day). Brightly coloured rucksack – easy to find if you put it down. It should contain PPE – hard hat if going near cliffs, hammer for loose samples, chisels, goggles, food and water, specimen bags, spare gloves etc.

Collecting

Collecting fossils can be exhilarating fun and academically rewarding. Remember that fossils provide the basis for our understanding of the age of rocks and provide a lot of palaeoenvironmental information. You should always record where you found a fossil as accurately as possible, both the physical location, and, if possible, what stratigraphic unit it was collected from. You never know – you may have just picked up something that no one has found from that location before, or it could be something completely new to science! The value of a fossil is significantly enhanced by good information on where it came from.

The Best Specimens May Be Hard to Spot!

Tap into local knowledge wherever possible. You may need to sieve sand to find sharks' teeth, split shale slabs to find fish, crack nodules for ammonites, or look for hints of fossils on the edges of rocks that can only be effectively prepared by experienced professionals using percussion and air-abrasion tools (*Figure 5*). It takes a trained eye to spot a good crab nodule, or a block containing an assemblage of bones. Reserve use of your hammer for collecting samples, splitting nodules or trimming down the rock on large finds so they can be carried home (think about how you may want the composition or display for the piece before you inadvertently remove a natural stand). Indiscriminate hammering rarely generates good material. If you find something spectacular (like Joe Davis did) and you are not sure what to do, contact a local regulatory body or museum to report the find before trying to collect it.

Preparation and Conservation

The style of preparation and preservation required for each fossil depends on the nature of the specimen and the sedimentary rock in which it is encased. Most professional level preparation requires advanced equipment, experience and a lot of patience. You can either pay a highly skilled preparator to prep a specimen for you, or you can buy the

TOP LEFT: JAMES ETIENNE; TOP RIGHT: JAMES ETIENNE; BOTTOM: NIC REAST

Figure 5: Spot the fossil! This large septarian nodule was caked in mud when I found it, but I could just see the cross-section of a couple of bones on the edge of the block (top left). In the bottom image, expert preparator Nic Reast is halfway through revealing the bones. Note the pneumatic pen, ear defenders and magnifying goggles for the work. Top right, the finished article, with an assemblage of plesiosaurid (likely pliosaur) bones including an articulated vertebral centrum with neural and ribs attached and other scattered rib, paddle and phalange bones.

equipment needed and learn how to do this yourself. Most kit needs to be operated by an adult, or at least under adult supervision. There are lots of safety considerations in fossil preparation, especially with the use of air compressors, pneumatic tools, acids, solvents, abrasive powders and so on, and dust extraction, eye, ear, skin and breathing protective equipment are essential. Some fossils can only be safely prepared in professional laboratories – this is particularly the case with palynomorph maceral preparation that may require use of extremely dangerous chemicals like hydrofluoric acid to remove silicate material.

Don't let this put you off though – for many specimens the simplest preparation can be done with water and an old toothbrush, or weak vinegar (acetic acid). Specimens collected from beaches need to be soaked in fresh water to remove any salt which can cause rocks to deteriorate.

Fragile specimens may need to be dried slowly. Beware pyrite – it often degrades over time due to oxidation. Once soaked to remove any salt, and thoroughly dried, coat with Paraloid B72 or use an inhibitor to stop pyrite degradation. Paraloid B72 can be purchased online ready-mixed in acetone for easy application. It is cheap, goes a long way and is an excellent thermoplastic resin. Paraloid brings out the natural colour of specimens, doesn't yellow or degrade with age and can be completely removed through dissolution in acetone solvent. It's a great preservation tool. Alternatively, beeswax is often used to polish larger ammonites and nautiloids which can bring out their natural colours and detail to great effect (*Figure 6*). For more information, there are lots of instructional videos on fossil preparation online, and distributors of equipment and chemicals are good at providing safety information and advice.

JAMES ETIENNE

Figure 6: A stunning nautilus fossil I found at Lyme Regis a couple of years ago. A huge storm came through one day in summer and washed this out of the cliff. The shell is partially crushed where it was predated upon which just adds to its character! I removed a thin carapace of gypsum covering much of the specimen and then passed it to Nic Reast for professional finishing – the wax coating shows it off in full glory.

In the next issue...

To help celebrate the upcoming unveiling of the Mary Anning statue in Lyme Regis, the next issue will focus on the apex predators of the Jurassic seas – the great marine reptiles – ichthyosaurs, plesiosaurs and pliosaurs!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SEISMIC FOLDOUT

UK MID NORTH SEA HIGH: DEFINING AND DE-RISKING EXPLORATION IN THE ZECHSTEIN PLAY

The ION MNSH Prime 3D program Phase 1 PSDM dataset, released in Q2 2021, was the initial phase in a much larger plan to cover wide areas of acreage previously served by only 2D or minimal 3D. With acquisition completing on two further phases in Q3 2021 (Phases 2 and 3, Figure 1A), processing work is ongoing and current results show that a similar quality of data is expected, leading to more opportunities to further understand this exciting area.

Partnering once more with premier acquisition providers and combining ION's SIMOPS management and survey planning with top level processing, imaging and interpretation, ION is looking forward to providing North Sea E&P teams with another high quality product.

MNSH Prime 3D Program

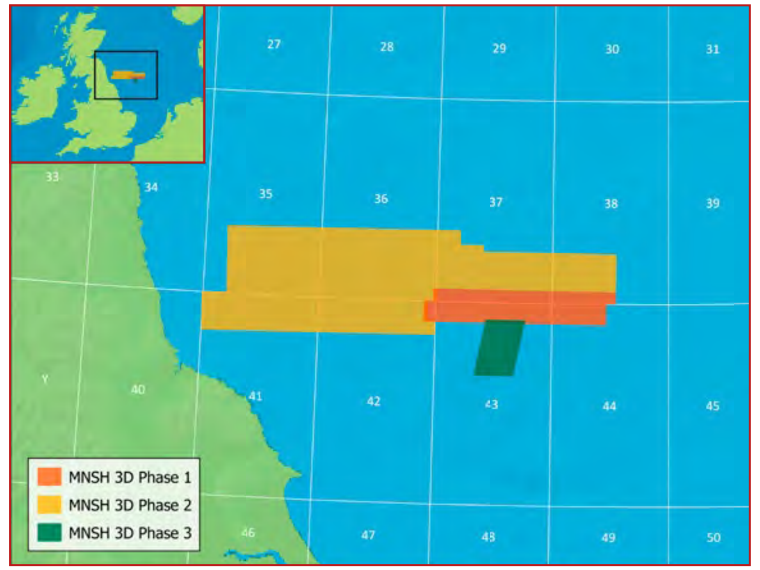
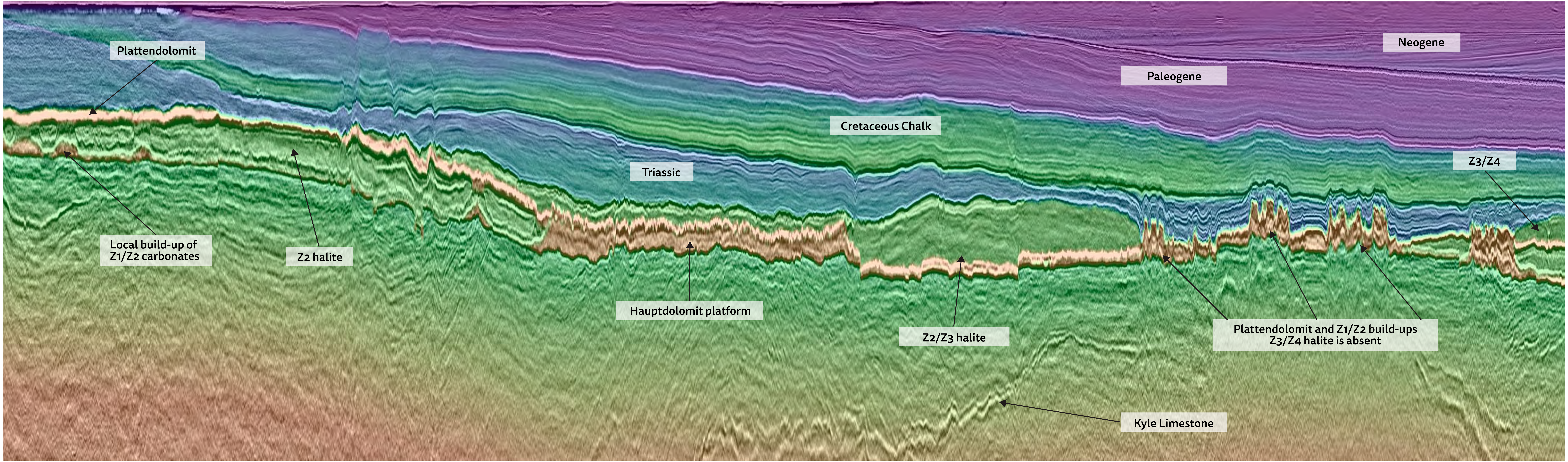


Figure 1: A) Location map showing Phases 1, 2 and 3 of the ION MNSH Prime 3D program. B) Interim depth section across Phase 2 of the ION MNSH Prime 3D program. Several lateral variations within the intra-Zechstein units are clearly observed across the survey, including areas where the Upper Zechstein Z3/Z4 halite is thin or absent with Triassic sediments downlapping onto the Plattendolomit. Seismic facies variations can also be seen within the Z1/Z2 units, distinguishing the basinal facies and promontories from the main platform area in the east. All seismic images North Sea Normal, white is hard.



NEWLY ACQUIRED, HIGH QUALITY 3D DATA ACCELERATES EXPLORATION INSIGHT IN THE ZECHSTEIN PLAY

Rosie Andrews, Dale Cameron, Emily Kay and Jonathan Denly; *ION*

The Zechstein play in the UK sector is increasingly in the industry spotlight after the 2019 Ossian-Darach well discovery and with Shell preparing to drill the Pensacola prospect later this year. The known imaging challenges in this area combined with the operational complexities of a tidally complex, shared-use environment required a range of technologies and methods to ensure the delivery of a 11,000 km², high quality seismic image within the timeframe to influence critical decisions as this play gains momentum.

The ION MNSH Prime 3D™ multi-client program of the greater Mid North Sea High is a primary acquisition campaign off the UK continental shelf that commenced in 2020 with the Phase 1 survey. Phases 2 and 3 were acquired concurrently in 2021, presenting numerous operational challenges given the proximity of the areas.

The presence of ION personnel and software onboard the two survey vessels ensured both operations were planned and managed effectively. The specialists on each vessel coordinated acquisition to ensure the seismic vessels maintained a minimum distance of 12 km between active sources to comply with Joint Nature Conservation Committee (JNCC) environmental requirements whilst also ensuring no downtime was incurred by either survey.

As these surveys were a continuation of the program started in 2020, lessons learnt from Phase 1 were carried forward to the 2021 acquisition with the two principal strategies implemented infield: tidal racetrack and tidal matching multi-swath matching.

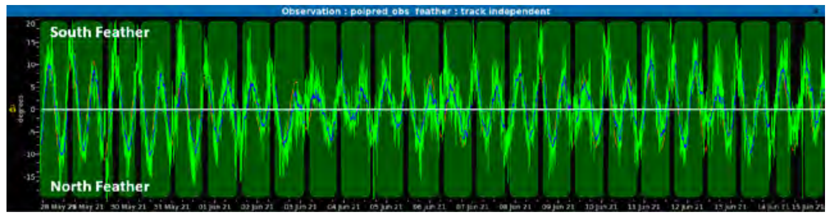


Figure 2: Current data (light green) and acquired streamer feather (blue) for duration of North area acquisition. Green bars represent accepted sequences.

The multi-swath technique seeks to reduce the elective infill by subdividing each swath and matching lines with similar feather direction and magnitude. As monthly feather amplitude changes, acquisition moves between sub-swaths to achieve an optimal feather match. This aims to reduce elective infill and replaces this with 'progressive' infill at sub-swath boundaries which are fewer in number and straighter to steer.

The surveys were broken down into three discrete areas to maximise potential efficiencies presented by the geometry. The line lengths in the north section were favourable for a straightforward two-swath tidal racetrack acquisition method. This allowed each line to be acquired at the same phase of the semi-diurnal tidal cycle as the adjacent line, resulting in minimal feather mismatch and reduced requirement for infill (*Figure 2*).

In the central area, a four-swath tidal matching strategy was employed. Each full line required an average of 24.5 hours to complete with a nominal line change time of 3.3 hours. This timing allowed the completion of four sail-line passes over nine full rotations of the semidiurnal tidal cycle with each line in tidal phase with the adjacent pass.

A multi-swath acquisition method was also considered for the southern sections. However, as the Phase 2 survey is in a heavily congested area, line selection was focused on working around extensive simultaneous operations. This included extensive fishing activity, a 2D regional survey, numerous site surveys and sub-sea construction.

To minimise the impact of these ongoing operations on acquisition, ION's Marlin™ software was installed on both vessels and received live AIS positions of all

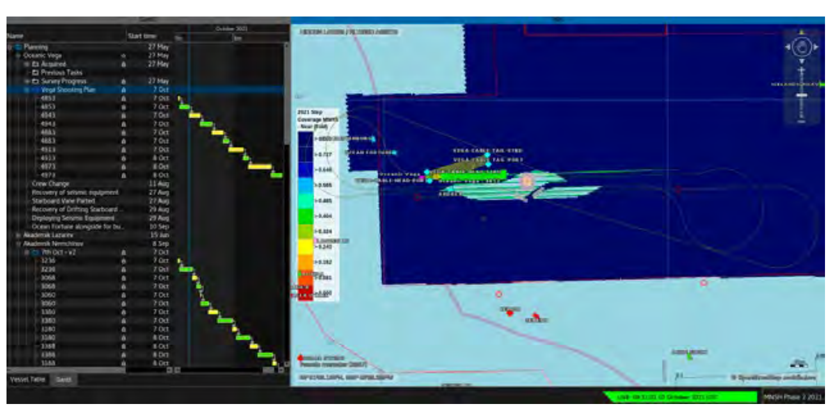


Figure 3: Oceanic Vega and towed equipment visualised in Marlin software alongside acquired coverage.

vessels in the area. This ensured that the ION specialists had a complete view of all vessels in the area to plan acquisition around the operations while maintaining tidal synchronisation where possible with the adjacent line.

ION's connected software was utilised to provide onshore personnel with near real-time survey progress and QC updates, providing valuable insights into the operations for informed decision-making (*Figure 3*).

Overcoming Imaging Challenges

The ION Imaging and Reservoir Services team uses a full range of up-to-date processing and imaging methods for the MNSH Prime 3D program.

Due to the triple source used in acquisition, the flow begins with deblending and an inversion-based approach. Denoise and deghost follow the deblending, prior to demultiple.

North Sea surveys are associated with shallow-water challenges and this project was no exception with some of the shallowest bathymetry in the Southern North Sea being found within the MNSH Prime 3D survey area. There was a demultiple challenge to overcome with the fast chalk outcropping in the western seabed combined with the shallow water depth across the entire survey. Careful modelling and subtraction of the multiple using wave equation and model-based technologies attack the short period water layer multiples, while muted surface related multiple elimination addresses the longer period multiples and interbed multiple elimination techniques remove internal bounces associated with specific horizons. Following demultiple, the data is regularised prior to migration.

Creating a velocity model to image over 10,000 km² whilst accounting for changes in the geological units and the structures requires attention to detail and experience. The challenges are addressed with a combination of machine learning first break full waveform inversion (FWI), guided move-out tomography, interpretation and reflection FWI. Within the areas, eight wells are used for velocity QC and mis-tie analysis. Products for Phases 2 and 3 include TTI Kirchhoff (90 Hz) and reverse time migration (40 Hz) stacks to merge seamlessly with the available Phase 1 data, offering 12,000 km² of high quality data (*Figure 1B*).

Interpreting Variations in the Zechstein Play

The imaging of Phase 2 builds on knowledge developed from Phase 1, revealing the expansive Zechstein Hauptdolomit platform area across the Mid North Sea High. The main platform can be mapped across the survey, stepping down towards the south (*Figure 4*). The platform is predicted to extend to the north and east outside the current 3D survey. There is a clear contrast between the extensive platform in the east and the slope to the basinal area in the west (*Figure 1B*). The platform is characterised by thick, high-velocity layers of (Z1/Z2) anhydrite and dolomite with halite lenses overlying the Hauptdolomit; these are linked to in-filling of structural depressions in the base Zechstein by sea

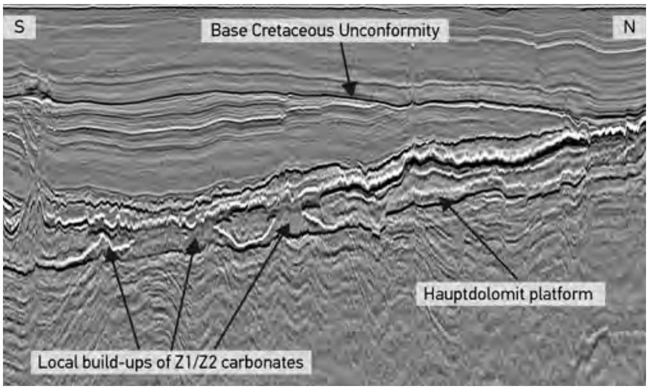


Figure 4: Crossline view showing the Hauptdolomit platform stepping down towards the south. Beyond the platform margin, several local Hauptdolomit build-ups are present above a Carboniferous high. The Triassic downlaps onto the Plattendolomit in the north, providing a thin cover between the Chalk and the Zechstein.

water. In the west, there is an increased amount of halite and polyhalite present below the Plattendolomit while the Hauptdolomit is represented by a series of promontories which are postulated to be relatively isolated build-ups above Carboniferous highs (e.g., the Ossian-Darach and Pensacola prospects).

In the east of Phase 2, there is a distinct zone where the upper Zechstein halite units are thin or absent and Triassic strata downlap directly onto the Plattendolomit. This zone is coincident with a Devonian high, potentially leaving this area emergent during the deposition of Z3/Z4 halite units (*Figure 5*). The upper Zechstein is also thin to absent in the shallow section to the west where the Zechstein is thinner overall as accommodation space was reduced. In the platformal areas, the Plattendolomit is characterised by the presence of sink holes formed through dissolution of underlying evaporate units and collapse.

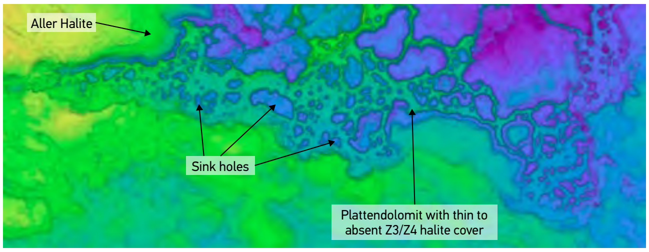


Figure 5: Map view of the Top Zechstein in the east of Phase 2 where the upper halite units are absent and the Plattendolomit represents the youngest Zechstein unit.

In the west of the survey, there has been uplift and erosion, resulting in the Triassic, Chalk and Tertiary strata outcropping at the seabed in rapid succession. Halokinesis in the Zechstein has formed collapse grabens in the overlying Triassic Bacton Group. The Triassic is highly faulted and folded in the shallow section to the west with thickness variations across the survey area. In the east, the Upper Triassic has largely been eroded by the Base Cretaceous Unconformity (BCU).

Our initial results show how high quality data is fundamental for mapping the internal lateral variations in the Zechstein play to define and de-risk future exploration targets at this play level.

All images courtesy of ION Geophysical Corporation.

THE HISTORY OF OIL AND GAS IN DRAGON COUNTRY

From cannel coal to offshore production – Wales has a colourful history of resource exploration and success.

Broadly, the offshore of Wales contains parts of six main Permo-Mesozoic basins which are the East Irish Sea, Caernarvon Bay, Cardigan Bay, St George's Channel, Celtic Sea and Bristol Channel. The onshore consists of slivers of the Permo-Mesozoic Cheshire Basin and Worcester Graben in Mid and Central Wales, and in the south, it is dominated by the Devonian–Carboniferous South Wales Coalfield Basin and the Silurian Usk Basin.

Ian Cross, *Moyes & Co*

Early Onshore Exploration

It is not commonly known but the oil and gas industry began in Wales in the 1860s in Flintshire in North Wales. There is a fascinating account of a seam of Carboniferous-aged cannel coal (or candle coal), a type of bituminous coal also classified as an oil-shale, being worked in the Leeswood Green Colliery, near Mold in North Wales. According to Giffard (1938) the cannel coal was used chiefly for the manufacture of 'illuminating oil' by distillation of the coal in cast-iron retorts at a low red heat. Lubricating oil and grease were also obtained. At the time the largest of the 20 or so coal-oil companies was the Flintshire Oil & Cannel Co. Ltd. However, the 'oil boom' was short-lived with cheap exports of oil coming from Pennsylvania leading to the bankruptcy of most coal-oil businesses in North Wales by the 1870s. In the current era this would have been classified as unconventional oil exploration and production.

The first well drilled in Wales targeting conventional oil and gas was Pontypridd-1, drilled in Licence 114 in South Wales in 1941 by Anglo-American, a company which later became part of Esso. The shallow exploration well, located without seismic data and on surface geology, targeted Carboniferous-aged Millstone Grit and Basal Grit as part of a wartime effort to find oil for Great Britain. *Figure 1* shows a location of the wells drilled in Wales. It reached a total depth (TD) of 1,973 ft but no hydrocarbons of significance were reported. Pontypridd-1 took some nine months to drill and was no doubt a stop-start process due to the situation at the time. The licence was relinquished in 1947. The drilling of Pontypridd-1 was probably in response to the D'Arcy Exploration Company (later renamed The British Petroleum Company) discoveries in the Carboniferous succession at Eakring (1939) and Kelham Hills (1941) in Nottinghamshire.

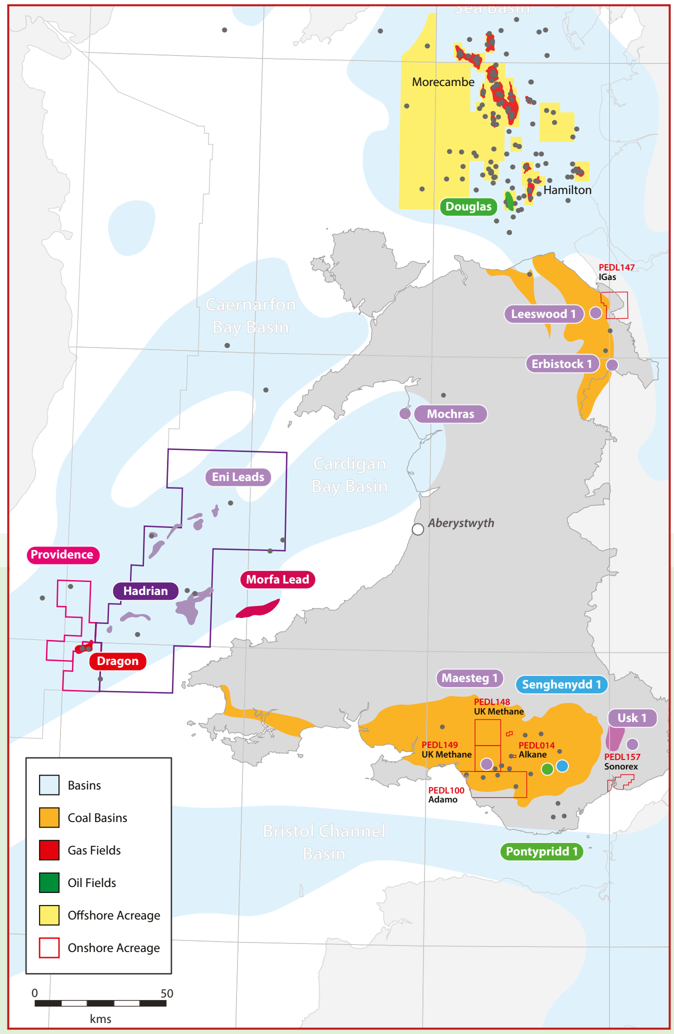


Figure 1: Basins, oil and gas fields and wells drilled in Wales.

GRAPHICS BY IAN PICTON

The second well drilled in Wales was Leeswood-1, drilled by D'Arcy in 1955 in Licence A100. D'Arcy had likely been encouraged by reports of the coal-oil in the Flintshire mines. The shallow well targeted the Carboniferous Limestone and Millstone Grit at a location near the River Alyn. The well reached a TD of 1,093 ft in around six weeks with no hydrocarbon indications. Plans to drill a follow up well on the Billberry Wood Prospect to test the same objectives were then scrapped by the operator.

In the early 1960s a Conoco and Marathon-led group (Envoy and Safari were involved in some of the licences) was awarded

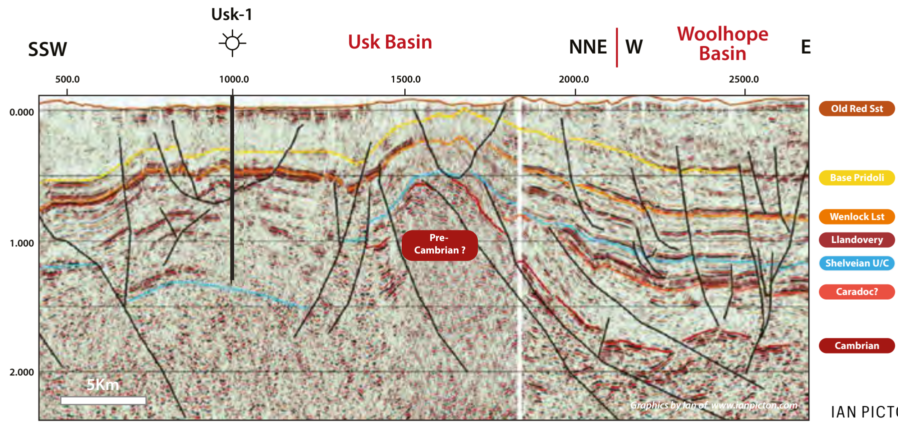


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Figure 2: Seismic line through Usk-1 showing the thick section of Silurian sediments.

acreage covering parts of Carmarthenshire, Glamorgan, Radnorshire, Monmouthshire and Brecon, and adjacent Welsh borderland counties. Trevor Thomas, in a publication in 1964, speculated that the group was optimistic of a Silurian source rock. The major Silurian source rocks discovered in the Middle East, North Africa, and the USA, may have driven these exploration efforts.

Between 1967 and 1969 an important geological discovery was made at the Mochras (or Llanbedr) borehole on the coast of Gwynedd, West Wales. The stratigraphic well was drilled on the edge of Cardigan Bay by the Institute of Geological Sciences, now the British Geological Survey (BGS), and encountered a thick succession of Jurassic rocks. The unexpected outcome of the borehole brought into play the Mesozoic hydrocarbon potential of the Cardigan Bay Basin, and a major re-think of the geology of Wales.

In 1972 Cambrian Exploration Ltd spudded the Senghenydd-1 exploration well in PL155 in South Wales. The well reached a TD of 9,331 ft in the Middle Silurian without encountering significant hydrocarbons in likely Carboniferous and Devonian sandstone objectives. Cambrian followed this up with Maesteg-1 in 1973 in adjacent PL154. The well seems to have targeted Devonian and Ordovician sandstones, reaching a TD of 8,690 ft in Ordovician sediments. There are again no reports of any significant hydrocarbons and the licences expired in 1978 without further drilling in Wales.

From the early 1970s attention moved to the North Sea, but BP continued to explore onshore and drilled the Erbistock-1 wildcat in 1986 in PL228. The licence was located near Overton Bridge, south of Wrexham, near the England border. Erbistock-1 was deviated and designed to test Carboniferous-aged Westphalian and Namurian sandstones, and the Dinantian dolomites on the western edge of the Cheshire Basin. BP had been encouraged by oil shows in the area; however, only poor hydrocarbon shows were reported in the Dinantian, which turned out to be sandstones rather than the anticipated shelf limestone and dolomite. It reached a TD of 6,196 ft.

In late 1988 Sovereign Oil Ltd, a successful offshore UK explorer at the time, spudded the eagerly awaited Usk-1 wildcat in EXL080 in the Usk Basin in south-east Wales. Sovereign had some heavyweight partners that included Union Texas and Amerada Hess. The well, located east of the north–south-orientated Usk Anticline, was designed to target Silurian sandstones but encountered weak gas shows only (*Figure 2*).

Usk-1 reached a TD of 10,040 ft in the Lower Silurian, and remains the last conventional oil and gas exploration well drilled onshore Wales. While disappointing, it did demonstrate the potential of a Silurian or older source rock with the gas shows encountered. A single Drill Stem Test (DST) conducted between 5,644 and 5,810 ft recovered mud filtrate and formation water only.

Gas from Coal

For several decades, the National Coal Board (NCB) had been involved in the draining of methane for safety reasons from active mines, but in addition it was a valuable clean fuel and used commercially. Mine gas only has medium heating value and was uneconomic to transport too far from the point of production. Morgan (1974) reported that initial trials were conducted in South Wales in 1950 and commissioning of a South Wales Methane Grid took place in 1957. In 1956 the Wales Gas Board and the NCB agreed to a 20-year contract for the supply of methane from the Point of Ayr Colliery in North Wales for use in the national grid. It seems that a similar joint venture was in place to supply methane from local mines to the Aberavon gas works in South Wales. The NCB had a methane gas grid of around 80 km of pipeline in the South Wales Coalfield, with the Afán colliery near Port Talbot used as underground storage.

In 1983 around 17 Bcf of pure methane is reported to have been drained from coal mining operations in the UK, with some 1.5 Bcf coming from South Wales. At the time the NCB reported that the South Wales network of pipelines was used to integrate the supply of coke oven gas and mine gas. These customers included Treforest Industrial Estate, Mid Glamorgan Hospital, Flextank (later known as Thompson Technik) and Ness Active Carbon Plant (*Figure 3*).

From the mid-1990s, following success in places like the USA, Australia, and China, several Coal Bed Methane (CBM) and Mine Gas licences were applied for and awarded, with some 17 shallow wells drilled. These are split into four CBM wells in South Wales and three in North Wales, and eight Mine Gas wells in South Wales plus two in the North, none of which have proved particularly successful according to public data. More recently, old coal operations have made the news with an announcement that the UK is in an exploratory stage with its mine water heat schemes. The UK Geoenergy Observatory (UKGEOS), based in Glasgow and run by the BGS, is one of the key research stations.

The Move Offshore

The first offshore well in Welsh waters was 103/21-1 drilled by Amoco in 1971. The wildcat was drilled to test potential Lower Cretaceous, Jurassic, Triassic, and Permian sandstone reservoirs in a poorly understood area in the South Celtic Sea Basin. However, the well failed to produce any encouragement.

By the mid-1970s, exploration in the North Sea had really taken off with success after success. The enthusiasm also spread to other basins in UK waters and from 1973 to 1978, nine exploration wells were drilled in Welsh waters by major companies including operators Deminex, Shell, Arco, Arpet, Conoco, Texaco and Hydrocarbons Great Britain (HGB).

While these wells in the Liverpool Bay area of the East Irish Sea Basin (HGB) were unsuccessful, a subsidiary of British Gas discovered the world-class 5 Tcf South Morecambe gas field in 1974. The significant discovery was made shortly after the surrender of the block in rather unusual circumstances by Gulf Oil. Gas was discovered in the upper part of the Lower Triassic Sherwood Sandstone Group.

Finally Offshore Success

The offshore area saw another burst of activity starting in 1989, and in 1990 Colorado-based Hamilton Oil discovered the Douglas oil field with well 110/13-2. The field is located some 24 km off the coast of North Wales in 28m of water. The wildcat had been designed to test a gas play following the success at South Morecambe, and the discovery nearby of the Hamilton and Hamilton North gas fields. Oil tested at the rate of 1,800 bopd of 44-degree API oil from the Triassic Sherwood Sandstone with the Carboniferous Namurian Bowland Shale Formation believed to represent the source rock. The Douglas field came on stream in 1996 and was the first oil field developed in the East Irish Sea and Wales's first and only oil production to date. At the time of discovery, the field was estimated to contain over 200 million barrels of oil in place.

By 2020 the field had impressively produced over 100 million barrels. The Douglas oil field is now operated by Eni after its acquisition of BHP Petroleum's East Irish Sea assets in 2014. The field was developed with 22 wells: 15 producers, six water injectors and a single sour gas and condensate disposal well.

In 1994 Marathon Oil made the 103/01-1 gas discovery (later named Dragon) in 96m of water in the St George's Channel Basin, some 40 km off the south-east coast of Ireland and 35 km off the coast of Wales. Marathon was awarded Block 103/1 in the UK 14th Round of Licensing in May 1993. Well 103/01-1 was drilled to test a Triassic Sherwood Sandstone prospect as well as a secondary Jurassic Bajocian objective. Due to drilling problems the Sherwood Sandstone was not reached, and the secondary target of the Bajocian Sandstone was absent due to faulting. However, hydrocarbons were found in Jurassic sandstones of Callovian to Oxfordian age. The well tested at the rate of 21 MMscfg and 120 bopd of 42-degree API oil. The source of the hydrocarbons are Carboniferous shales and coals.

At the time it was estimated that the Dragon field had gas in place of around 120 Bcf. Marathon undertook a 3D seismic survey in 1995 and a fault block up-dip of 103/01-1 was identified as a potential large structural trap. A drilling moratorium prevented the appraisal of Dragon until 2005. The deviated well 103/01-2 was drilled in 2005 by Marathon but sadly the sands proved to lack hydrocarbons and reserves in the field were downgraded to around 50 Bcf.

In 2007, Ireland-based Providence Resources was awarded a Standard Exploration Licence covering Irish Block 51/01 and began discussions with Marathon regarding potential development of the fault block drilled by the 103/01-1 well. Marathon's UK licence became listed as fallow and was subsequently relinquished in 2010 based on lack of commerciality. Providence submitted an out-of-round application for the block and were awarded the licence in January 2012 with its then partner Star Energy Oil & Gas Ltd. The structure of the Dragon gas field straddles the Ireland/UK median line

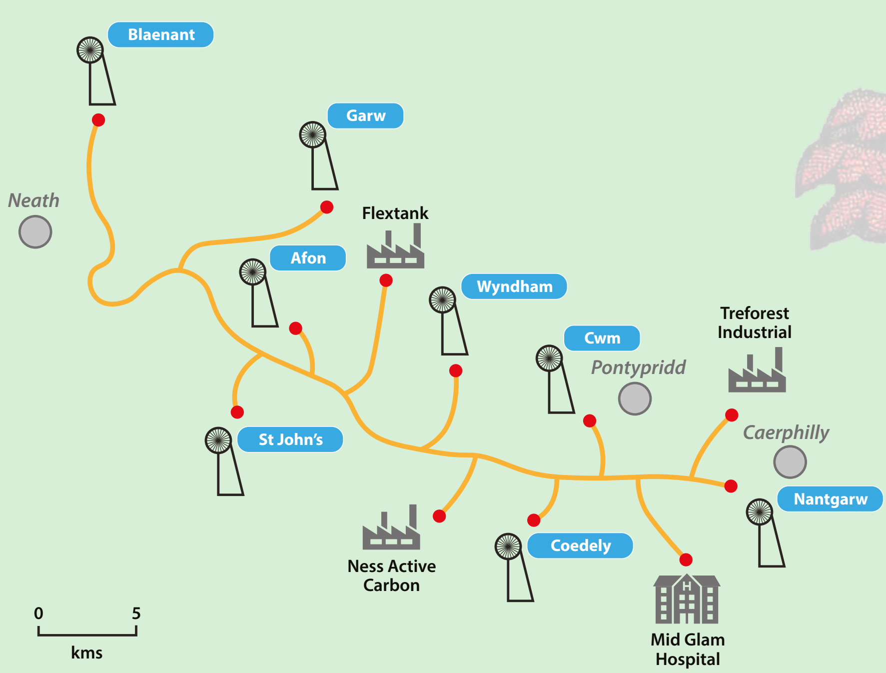

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Figure 3: South Wales gas grid (modified from NCB).

Figure 4: The Douglas oil field complex .

which was attractive to the partnership. Providence subsequently relinquished the Dragon field in 2016 as it was deemed uncommercial. The field is now in open acreage and with the pending energy shortage it could be time for another company to revisit the field.

The last exploration well drilled offshore Wales was 110/13b-21. The well was drilled by BHP, with Eni as a partner, on the Bel Air Prospect close to the Douglas field in 2010. This well is reported to have encountered a thicker than expected Permian-aged Manchester Marl sequence comprising interbedded shale and dolomite. However, hydrocarbons were absent in the well. The primary objective was Permian Collyhurst Sandstone in large fault block structure .

Today

Since 1 October 2018, Welsh Ministers are responsible for licensing the exploration and development of Wales's onshore petroleum resources. They have a statutory duty to manage the existing petroleum licences that were issued by the UK Government before 1 October 2018. As the licensing authority, Welsh Ministers are responsible for decisions on whether to issue new licences and the management of existing licences issued before 1 October 2018 in accordance with the licence model clauses.

The offshore is still the responsibility of the UK Government. Other than the area around the Douglas oil field in the Irish Sea, there are no current offshore licences in Welsh waters. With proven hydrocarbons, it is hoped that the open areas in the St George's Channel Basin will attract industry interest in the future. It is hard to conclude that Dragon is the only hydrocarbon accumulation in Welsh waters in the basin.

Potential plays exist in the Cardigan Bay Basin where the Lias and Carboniferous offer possible source rocks, but the challenge is getting the correct configuration of source rock, trap and reservoir. One such feature that may bring all these together is the Morfa Structure, a rollover anticline alongside the east north-east to west south-west Bala Fault. The location is shown on *Figure 1*.

The potential of these two basins was demonstrated by the award of 17 blocks to Eni in the 28th Offshore Licensing Round in 2015. Eni had planned a 955 sq km 3D survey to firm up several leads, named after Roman emperors and mapped to prospect status. The leads are shown in *Figure 1* which are taken from an Eni relinquishment report available via the OGA's open data site. Eni's largest lead is designated Hadrian and covers parts of Blocks 106/24,25 and 29, alongside the north-east to south-west St George's Fault. Hadrian has Jurassic and Triassic sandstone objectives and Eni estimated its recoverable reserves at around 40 million barrels of oil and 300 Bcf of gas. However, due to environmental issues the 3D survey was cancelled, and Eni subsequently relinquished the blocks in 2019.

There are currently five unconventional and only one remaining onshore conventional licence, which is held by UK-based Sonorex Oil & Gas Ltd. The full list of all current licences is listed below.

Operator	Licence	Location	Award	Type
Alkane Energy	PEDL014	Bridgend	1996	Unconventional
Adamo Energy	PEDL100	Neath–Port Talbot	2000	Unconventional
IGas Energy	PEDL147	Flintshire	2004	Unconventional
UK Methane	PEDL148	Neath–Port Talbot	2004	Unconventional
UK Methane	PEDL149	Bridgend	2004	Unconventional
Sonorex Oil & Gas	PEDL157	Newport	2004	Conventional

Table-1: Current licence holders onshore Wales.

It is worth noting that although the work programmes associated with each licence are broadly categorised as conventional/unconventional, the licensee is not contractually bound to deploy any specific techniques. In practice, the developer can modify plans as their understanding of the geology improves.

PEDL157 is now held until 2035 by Sonorex and it is intended to drill the Uskmouth-1 well. Sonorex acquired 28 km of new 2D regional seismic data in 2006.

The Uskmouth Prospect has a Devonian Old Red Sandstone primary objective and Silurian Wenlock sandstones offering a secondary target, with charge coming from Silurian or older shales. The overlying Carboniferous will provide the seal. The exploration well will be designed to simultaneously test for hydrocarbons, geothermal and Carbon Capture Storage (CCS) capabilities with a planned TD of 4,000 ft. The Silurian shales also offer an unconventional target. Sonorex estimate resource size to be in the range of 200 Bcf of gas. In 2000 there were reports of gas leaking into houses in the Ringland area of Newport which perhaps offers encouragement to Sonorex of an active petroleum system.

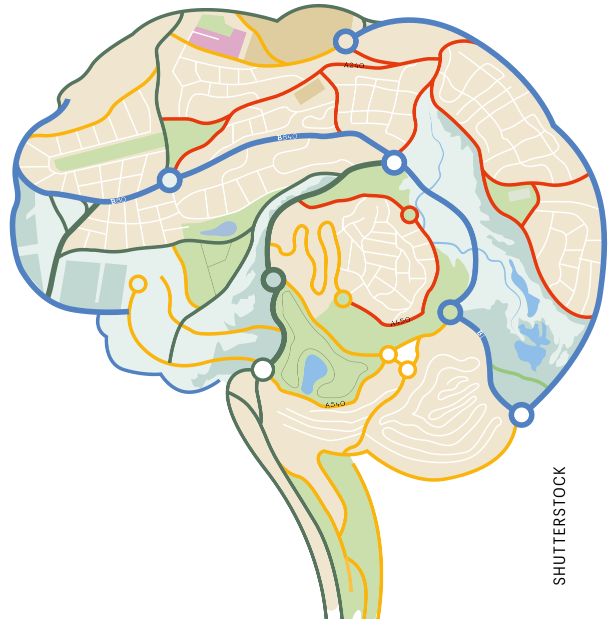
***References** provided online.*

Acknowledgements

Many thanks to Ian Picton, Malcolm Butler, Andy Butler, David M Thomas, Lyndon J West, Huw Evans, and Chris Atkinson.

ARTIFICIAL INTELLIGENCE – ITS USE IN EXPLORATION AND PRODUCTION

PART 2 Machine Learning: Magic or Mathematical Statistics?


SHUTTERSTOCK

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When film studios remake classic films, critics and audiences often ask why. GEO ExPro has previously printed articles on AI, most notably a three-part series in 2017, thus the reader might ask what this current series of articles can add. One response could be that much has changed in five years, and there is discussion to be had on these advances. But that is not the main point of this series. My purpose, when I set out, was first to de-mystify AI, in particular in its current incarnation as Machine Learning (ML), and then to set it in a geo-exploration context.

The former is difficult, as there is an impenetrable mystery at the heart of ML – we have no way, certainly at present and probably ever, of understanding why a ML AI makes the decisions it does. We can investigate around the periphery and perhaps discover useful clues: for example, the US government facial recognition software that failed to recognise faces that aren't Caucasian was trained on unrepresentative images, but we do not know the exact decisions the software was making during failures. Or, more relevant to this article, perhaps a porosity-permeability predictor was trained solely on clastic examples and so was unprepared for dealing with vugular porosity.

What is Machine Learning Really?

To set in a geo-exploration context is difficult, not least because there is no agreement on exactly what Machine Learning is. Stanford University defines ML as 'the science of getting computers to act without being explicitly programmed'. It is still not entirely clear, because the word 'explicitly' is not clearly defined. We are probably better-off thinking of examples: Satnav that stops telling you to turn right when it has observed you followed this route successfully on previous occasions; predictive texting that remembers that the last time you used the words 'I'm going' they were followed by 'home', are both illustrative of what we have come to expect from AI, but are they ML? Is the machine learning?

> *We do need to understand that Machine Learning is not magic*

The Satnav must have been explicitly programmed to know the number of times you needed to have followed that same route before it would stop telling you to turn left. Further, the entire effect could be achieved using just an 'if…then…else' Expert System approach. In the latter example, the machine has learnt from our answers when we were offered options, but still we could see how it works: if we repeatedly changed our response from 'home' to 'out', then this would become the AI's first choice. So, what is it about ML that is impenetrable?

Neural Networks – Driving the Current AI Renaissance

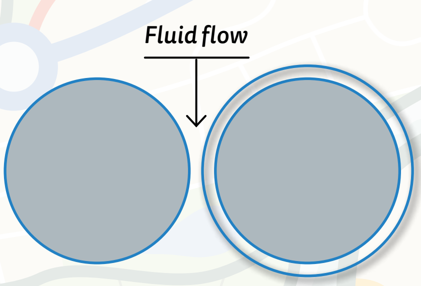
We now associate ML almost exclusively with Neural Networks (NN) or Genetic Algorithms. Indeed, Massachusetts Institute of Technology (MIT) defines ML as a subset of AI that is based on NN. So, whilst AI encompasses everything from expert systems through to deep learning, and therefore includes Satnav and predictive texting, it is NN that are driving the current AI renaissance and it is within NN where there is an impenetrable mystery at the heart of ML.

That impenetrable mystery aside, we do need to understand that ML is not magic. Clarke's third law says that 'Any sufficiently advanced technology is indistinguishable from magic'. To an early 20th-century geoscientist, remote sensing of the subsurface would have seemed like magic. Wireline logs and geophysical seismic surveys are not magic, but few of us fully understand the inner workings of a sonde (or, nowadays, more likely a measurement while drilling (MWD) tool). We should, however, know enough to be able to appreciate the limits of the data in our analyses. Knowing that a tool scatters neutrons into the surrounding rock should be enough to appreciate that the resultant measurement is of a large volume of rock. We do not need to understand the rate at which neutrons slow due to collision with formation nuclei, we just want to know the resolution of the tool, or the support (a geostatistical term for how much rock is being sampled to deliver a single measurement); which is around 2 ft vertically from the point of measurement. This is the level of understanding I am aiming at for these articles. The other part of this analogy is that we will want to know, later, about the support of a log tool, but again just in principle.

Predicting Permeability from Porosity

Returning to Archie versus AI from 'AI – Its Use in Exploration and Production. Part 1' (*GEO ExPro* Vol. 19, No. 1), and human intelligence contrasted with machine intelligence, we can look a little deeper into how NN work. By looking at a similar example, predicting permeability from porosity, we can examine why the reasons behind their conclusions are impenetrable.

A geoscientist would not need to look at data to realise that the relationship would not be linear. Therefore, it is usual to try to estimate the form first, transform the data to linear, and then use statistics. This is where the human



BARRIE WELLS

Figure 1: Grain overgrowth

mind can take advantage of knowledge of the physical process: Archie had a good idea of what form he wanted, from knowledge of the physics. We can see that porosity and permeability must be related in a non-linear way, simply from the geology and the geometry.' Heuristically, consider a mineral overgrowth on a grain (*Figure 1*).

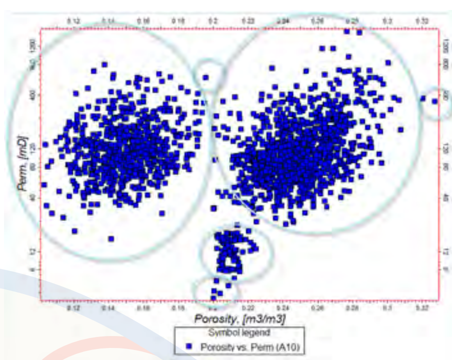
In 2D, for simplicity, we see that, as an overgrowth increases the grain size (and hence decreases the pore space) in proportion to the square of the radial change, the pore throat width, which is the critical dimension for permeability, decreases only linearly. Whilst it is a more complicated geometrical exercise in 3D, and considerably more complicated if we also take account of grain size and shape, it is nevertheless clear that we should seek a non-linear relationship. Referring back to Archie in Part 1 of these articles, if we were doing this using traditional computer-based methods, we would try different forms of the relationship (cube root, logarithmic, etc.) as well as different parameters for each (by which I mean the '***a***' and '***b***' and '***c***' in an equation such as $y = ax^2 + bx + c$), and then look for a combination that best fits the available data.

A NN would not treat this as separable steps, looking instead for abstract relationships connecting the input data (observed porosity, together with grain size and shape or tortuosity information) with the output (the permeability that was observed). A useful analogy is principal components analysis (PCA). This is a classical statistical method. It is not a learning algorithm; it gives the same answer every time, just as 2 + 2 is always 4. But in some ways the first principal component (PC) has more in common with a NN output than with a simple regression output (even though the first PC is the reduced major axis (RMA) regression line in 2D), because it is not, in general (i.e., in more than two dimensions), physically explainable in the same way as we can explain the individual steps of picking a functional form and then finding the parameters.

Blindly Searching for the Best Fit with the Data

The NN is better than human intuition backed up by traditional statistical calculations, in that the NN will try many more combinations and possibilities than a human ever could, but we cannot pick apart the steps to understand why it made the choices it did; its reasoning is impenetrable, blindly following a search for the best fit with the data.

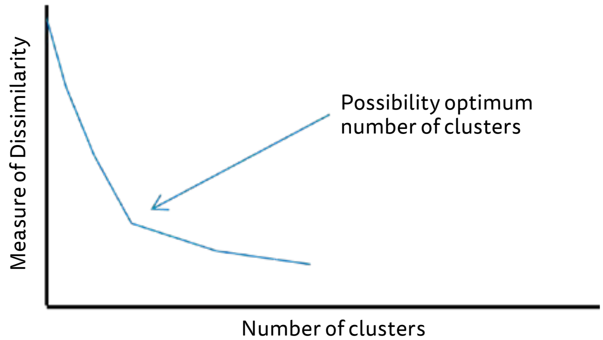
Which brings us right back to consideration of what is 'best'. We have to have a definition of 'best fit', or, more generally, an objective function, a measure against which each attempt by the NN can be measured. In games such as Go and Chess, this is simple: a win is good, a loss is bad. How are we to achieve this in exploration when we usually don't know the answer?



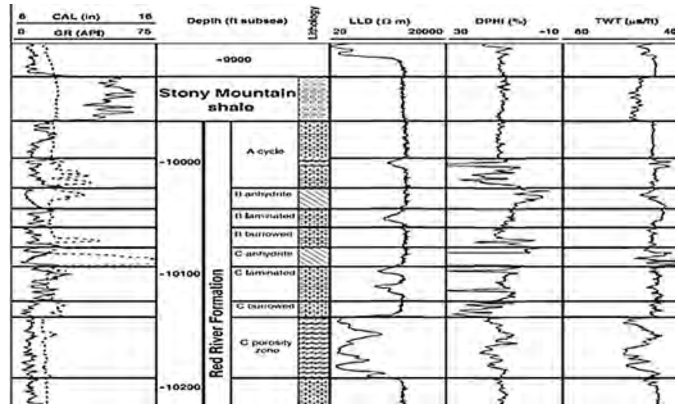
PETREL OUTPUT

In this dataset, we could use traditional statistical tools such as cluster analysis or discriminant analysis to try to determine how many distinct groups there are. The problem then is knowing when to stop.

Plotting the improvement, as a graph of our measure of 'good' against the number of groups, may identify a critical point and hence an optimum number of groups, but more usually this is far from clear. Geologists know this problem as lumpers versus splitters: at the microscopic level, every sample of rock is different, but to make progress in modelling and analysis we have to allow some amount of difference within a facies or formation. There is no correct answer: the geologist's answer rarely gets past the engineer and into the reservoir simulator model.



SCHLUMBERGER WELL LOG HANDBOOK



BARRIE WELLS

In statistical analysis, a distinction is made between unsupervised and supervised: allowing the software to find the optimum clustering (unsupervised) or telling the software the answer for a set of training examples and letting it classify new cases into one of these pre-determined classes (supervised). Supervised learning gets round the problem of lumping versus splitting but reduces the ability of the AI to spot things in the data that we did not expect.

One More Example

If we provide a set of examples (and one log run, as above, is a set of examples, it doesn't have to be multiple runs) in which we have given an answer at each point, then the NN can identify data combinations that are diagnostic of each answer. This is supervised. Alternatively, we might just give the NN the data and ask it to pick categories. This is unsupervised. In the latter case, the NN could easily provide a reason to distinguish every single data point as its own category: even if the values of all traces are identical, the gradient and higher order derivatives will not be identical. So, we still must supervise in the sense of arbitrating between lumping and splitting but we do have the possibility of finding new information. If the NN picks an extra facies, it could be that it has detected a thin bed, below the resolution of the tools, or it could just be trying to make sense of noise. Only we can tell, from our knowledge of the support and resolution of each tool.

So, has this Neural Network demonstrated learning? At this point, I would argue that it has not, and in Part 3 I will expand on how NN lead to ML and hence where the learning comes in.

SEISMIC FOLDOUT

SEISMIC IMAGING-LED SEDIMENTOLOGY INSIGHT REVEALS EXTRAORDINARY NEW POTENTIAL IN THE GULF OF PAPUA

Figure 1: Showing Mid-Miocene channel complexes transitioning into lobe systems.

The Papuan Plateau and Eastern Aure Moresby Fold–Thrust Belt is a frontier petroleum exploration province with no wells drilled to date. Regional, high resolution, broadband, PSDM multi-client 2D from Searcher and proprietary seismic data has transformed the understanding of the tectonostratigraphic evolution of the region and has uncovered a new Mid-Miocene turbidite play for Papua New Guinea (PNG). The remarkable imaging yields seismic facies characterising weakly to unconfined, laterally migrating, channel complexes at the base of slope and basin-floor lobe systems. The proximal fan reservoir units are overlain by thick intervals of hemipelagic shale and involved in thrust anticline traps which post-date deposition. High quality seismic data, outcrops, geochemical hydrocarbon seep analysis and challenging conventional wisdom have been keys to unlocking the huge potential of this frontier basin.

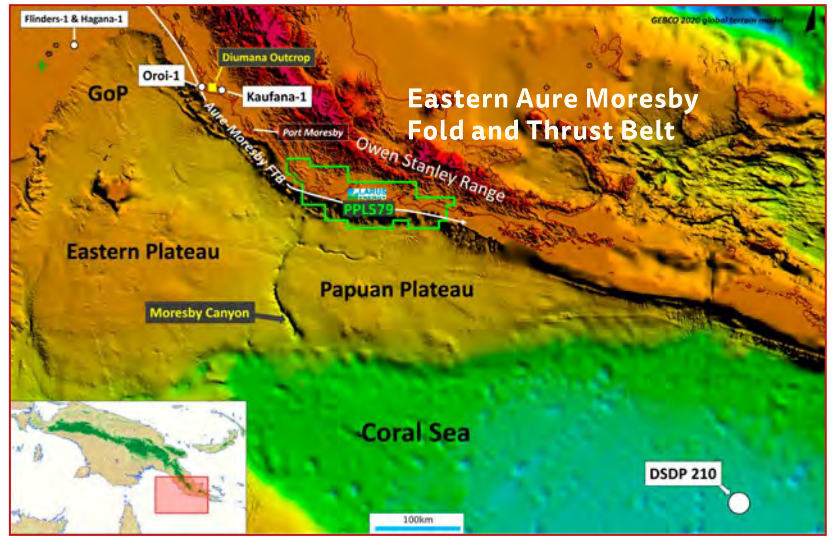
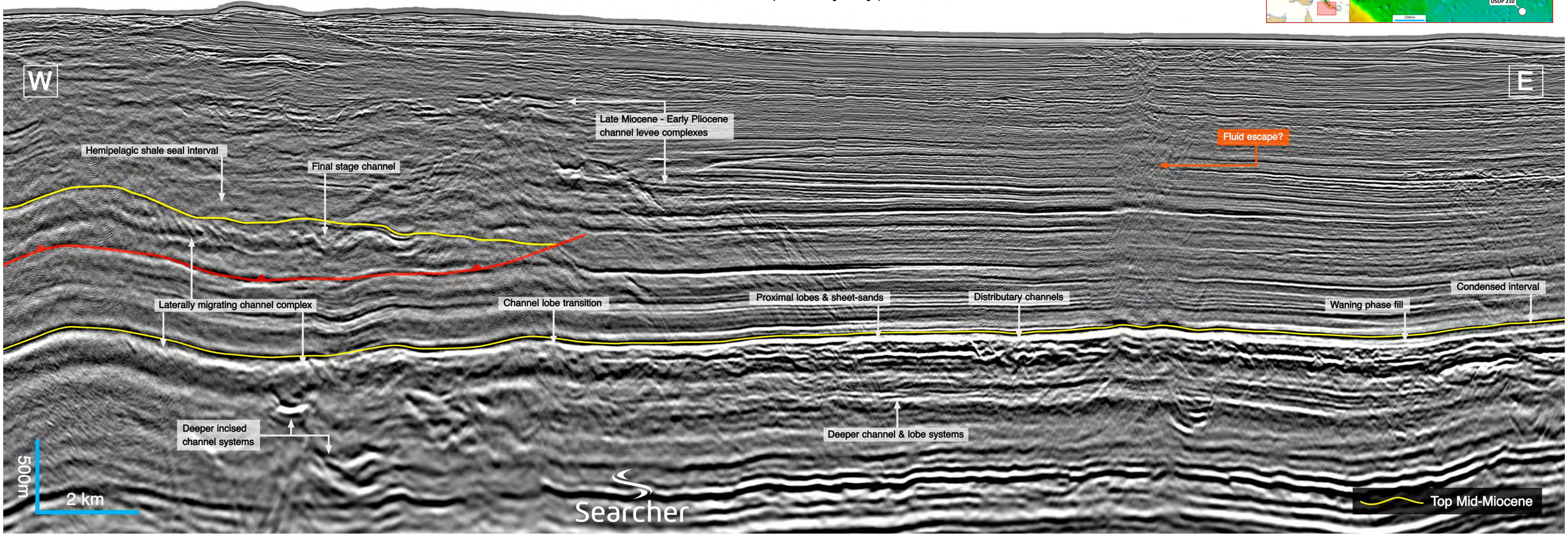


Figure 2: Location map and information. Foldout seismic line is located within PPL579.



STUNNING UNEXPLORED TURBIDITE PLAY REVEALED OFFSHORE PAPUA NEW GUINEA

Exceptional imaging from modern multi-client PSDM 2D seismic data in south-east PNG has uncovered exciting new reservoir potential within large-scale Neogene channel-fan turbidite complexes.

Alaister Shakerley, Tim Rady; Larus Energy Ltd and Neil Hodgson, Karyna Rodriguez; Searcher Seismic

Submarine fans and turbidite systems are important targets for oil and gas exploration and form prolific petroleum reservoirs in many sedimentary basins world-wide. Remarkable imaging from modern proprietary and multi-client PSDM 2D seismic data in south-eastern Papua New Guinea (PNG), has uncovered exciting new reservoir potential within large-scale Neogene channel-fan turbidite complexes.

Historic exploration in PNG has primarily focused on plays associated with the Jurassic Toro Formation and Miocene reef carbonates. Turbidites sourced from the north in the Late Pliocene from the Fly River Delta have been targeted in the Gulf of Papua (GoP), which led to the Flinders and Hagana discoveries in 2013. Yet despite the margin of the Aure Moresby Fold and Thrust Belt (AMFTB) stretching for over 800 km, and clear evidence for large sedimentary basins, exploration drilling has been limited to only the north-west AMFTB. Here the identification onshore of Mid-Miocene outcrops of fine–coarse, quartz, 'greywacke' sandstones, up to 122m thick in the Diamana village area, offered evidence for the presence of turbidite depositional fairways and the transport of quartz-rich material into deep water.

These encouraging outcrops and field mapping led to the drilling of two onshore wildcat wells: Oroi-1 in 1949 and Kaufana-1 in 1958 (see map inset on foldout). The wells were drilled on surface anticlines, without the benefits of modern seismic data and encountered off-axis turbidite systems, with limited reservoir potential. And yet, despite advances in our understanding of turbidite reservoirs, as well as advances in seismic acquisition and processing technology, in addition to the advent of new insights into basin modelling and charge effectiveness, there has been no exploration of the Aure Moresby Fold and Thrust Belt since the 1980s.

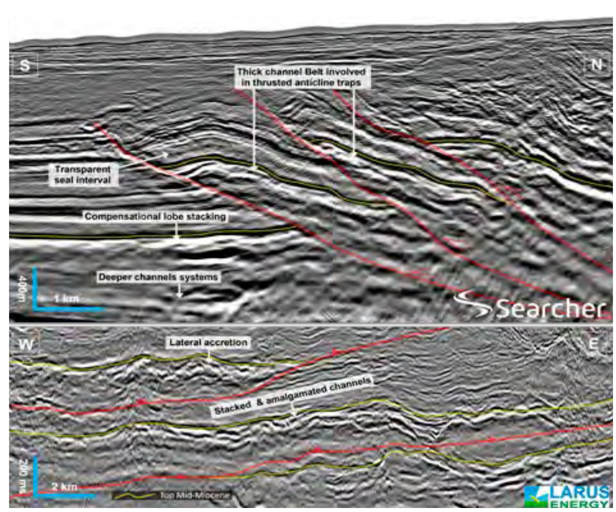
Indications of medial to distal turbidites and deepwater, nested, channel-levee complexes, have previously been recognised on deepwater seismic data. Indeed, a Mid-Miocene to Pliocene submarine fan system has also been cored on the abyssal plain of the Coral Sea (DSDP well 210) where fine-grained turbidites have been transported long distances (>400 km), from the fold belt via plateau-traversing deep water conduits, such as the Moresby Canyon. They represent the terminal lobes and mega-distal remnants of large-scale turbidite systems.

The presence of Mid-Miocene quartz-rich, turbidite sandstones onshore and terminal fans over 400 km from their provenance, indicates that major deepwater systems existed in the Neogene. This raised a question to PNG explorers: Where are the proximal turbidite plays located?

Shining the Light on Turbidite Reservoirs

Regional PSDM multi-client 2D seismic data acquired by Searcher in 2015–2016, has revolutionised the understanding of the Papuan Plateau and the offshore AMFTB, and has driven recent exploration efforts. The remarkable imaging from high resolution, broadband seismic data has enabled the division of the Miocene to recent interval into multiple sequences, which embody the evolution of a Neogene foreland basin to a fold–thrust belt and its cessation. Reservoir potential has been recognised within multiple, high-reflectivity turbidite pulses.

A distinctive Mid-Miocene system has now been identified, exhibiting impressive seismic facies that differ greatly from subsequent transverse and long-ranging axial systems. Large-scale channel and lobe complexes



SEARCHER AND LARUS ENERGY

Figure 3: Dip and strike sections located towards the base of the slope. Laterally extensive and thick, semi-confined to unconfined channel complexes can be observed, characterised by stacked and amalgamated channel bodies within a broad valley. The channel complex system is structurally repeated by thrusts which provide anticline traps.

SEISMIC - SEARCHER, INTERPRETATION - LARUS

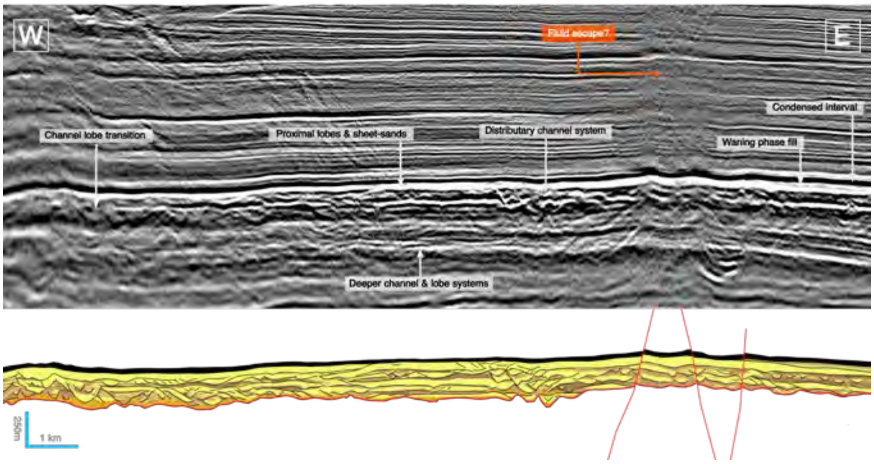


Figure 4: Strike section of the proximal fan, showing wel- imaged stratigraphic detail, with interpretation. In the central axis, we can see high-amplitude, high-frequency shingled peak-trough pairs, indicating lateral reworking. Is this the missing section chased by pioneering explorers nearly a century ago? Line Length 16 km.

are observed, which are involved in thrusted anticlines and overlain by a thick, seismically transparent interval, which is interpreted to be hemipelagic marine shale, deposited during a period of relative tectonic quiescence (*Figure* 3).

The major Mid-Miocene pulse of sediment transport into deep water can be subdivided into four phases, marking the initial incision and erosion, followed by the backfill, waning and abandonment phases. At the base of slope, weakly confined to unconfined channel complexes are observed, which are captured within a broad canyon or basal scour. A thick, gross reservoir interval can be characterised by laterally extensive, stacked, amalgamated channels and shingled reflector pairs. The shingled seismic reflectors dip towards a final stage channel and are indicative of active, lateral channel migration, within a meandering channel belt. Constructional levee systems appear to be absent, indicating that there was an abundant supply and deposition of flow-stripped, coarse-grained material to the proximal fan area.

The unconfined channel complexes transition on the basin floor into laterally extensive, amalgamated, stacked sheet sands and lobe systems. These are characterised by two, thick, High Amplitude Continuous (HAC) packages, interspersed with more discontinuous events which are interpreted to be distributary channels (*Figure* 4).

Basement highs form prominent bathymetric high-grounds during the Mid-Miocene, which ponded and diverted the course of the depositional fairway to the east. The switch in orientation resulted in the depositional axis of the proximal fan to parallel the strike of the advancing AMFTB. This configuration is favourable for reservoir continuity within E–W striking frontal thrust anticlines, which postdate reservoir deposition.

The AMFTB foreland depocentre effectively represents a very large and elongated perched basin. Bathymetric lows following inter-plateau depressions and interconnected graben systems, situate deepwater canyons and channels (*Figure* 5). These provide transport pathways for Mid-Miocene to recent, low density, fine-grained turbidites, to traverse the Papuan Plateau and form the terminal lobes in the ultimate sink, on the abyssal plain of the oceanic Coral Sea Basin.

Huge Potential

Integrating sedimentological insight with modern high-fidelity seismic has allowed the locality of a sand-rich proximal turbidite complex where it is held in thrusted structural closures of globally significant scale. The continuation of this study combined time-based structural reconstruction of the fold belt with basin modelling to show that the proven source rocks in this basin are in the oil-charge generative stage during and after structure formation. This innovative new modelling, combined with onshore light oil seeps and Searcher's offshore drop core geochemistry dataset, all point to an active thermogenic petroleum system.

Seated as it is in the new era of seismic imaging, the large scale of the thrusting and structuring in this area, has been integrated with a sophisticated hydrocarbon basin-model and the detailed analysis of a newly recognised sand rich proximal turbidite play fairway. The exciting opportunity presented by integrating these elements in an unexplored frontier basin, is that it generates the opportunity for the size of material discoveries that will make a difference on a globally significant scale.

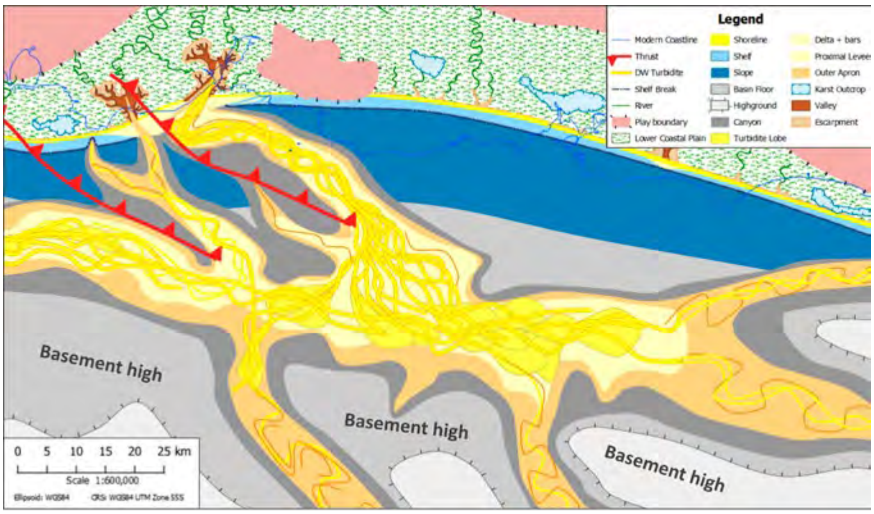


Figure 5: Mid-Miocene backfill phase GDE map showing diversion of depositional axis due to 'back-stop' basement high systems.

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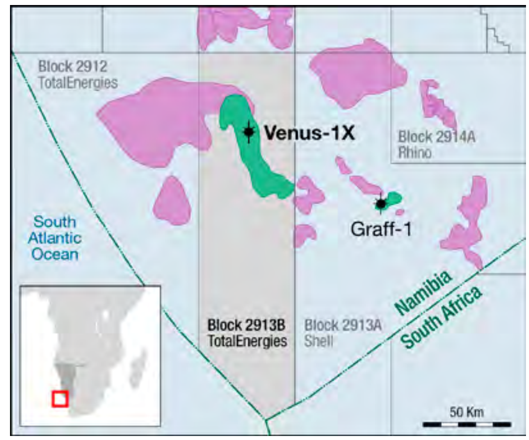
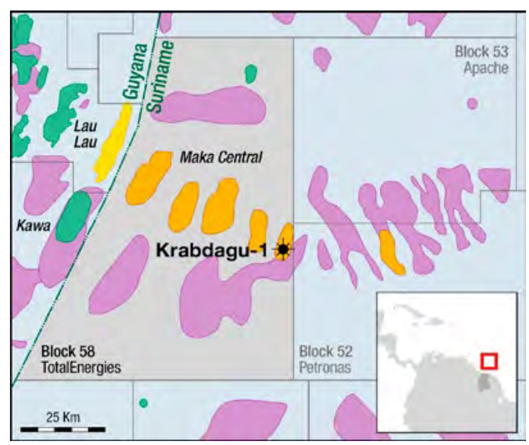
VENUS-1X: INTRODUCING A NEW DISTAL BASIN FLOOR FAN PLAY FOR MARGINS

TotalEnergies has made a significant discovery of light oil with associated gas on the Venus prospect, located in Block 2913B in the Orange Basin, offshore southern Namibia. The Venus-1X well (drilled with the Maersk Voyager to a TD of 6,296m in about 2,900m water) encountered approximately 84m of net oil pay in a good quality Lower Cretaceous reservoir. The reservoir and source rock are understood to be Aptian. The discovery represents an unprecedented success, where both source and reservoir sands were particularly high risk. Initial press reports suggest volume of up to 3Bbbls, the largest single discovery in West Africa perhaps. Without further detail, there is some debate on the actual volumes of oil versus gas, or if there is a condensate phase. TotalEnergies did carry out coring and logging, and refer to an appraisal programme, so hopes are high for commerciality in Namibia and adjacent in South Africa where the Orange Basin extends. Venus-1X was drilled between December 2021 and February 2022, where TotalEnergies is the operator with a 40% working interest, alongside Qatar Energy (30%), Impact Oil and Gas (20%) and NAMCOR (10%). Impact Oil and Gas have been working on this new play since 2014 and attracted larger firms via farm-in deals.

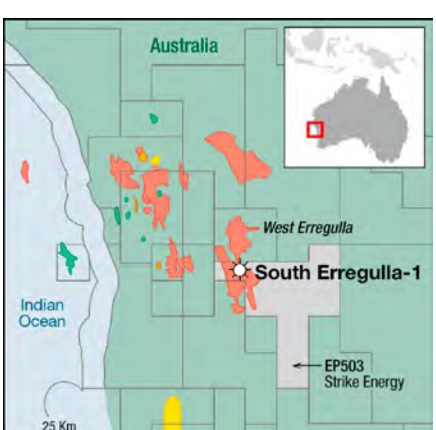


KRABDAGU-1: EXTENDING THE PLAY EASTWARDS IN SURINAME

TotalEnergies (with 50% partner APA Corp) announced in late February 2022 that their Block 58 well, Krabdagu-1, is a discovery, encountering ~90m net oil and gas pay in Campanian and Maastrichtian clastic reservoirs. Operations were carried out using the Maersk Valiant in 780m water depth, following completion work at Bonboni-1. Drilling and logging work is ongoing, and a DST will be performed. The well drilled to approximately 6,500m TD, a typical if challenging depth for most of the wells in this Upper Cretaceous Suriname play. The Krabdagu prospect has a similar seismic signature to the Sapakara and Keskesi wells. Krabdagu is the sixth exploration well on the block, following discoveries at Maka Central, Sapakara West, Kwaskwasi and Keskesi East. The Bonboni-1 well encountered 16m net oil pay, but is considered non-commercial, and Keskesi South, located nearby, missed the target. Appraisal is ongoing and a development is expected here soon. TotalEnergies has further acreage to the south, APA to the north-east, while Petronas are chasing similar targets to the east in Block 52.



SOUTH ERREGULLA-1: STRIKING SOUTH TO EXTEND THE PERTH BASIN PERMIAN GAS PLAY



Strike Energy (100%) has reported a discovery at South Erregulla in February 2022. The well was drilled with the Ensign 30 rig to a TD of 4,900m in the Block EP503. The firm reported two gas intervals in the Wagina sands (16m good quality pay and 61m net gasifier with lower poroperm) and Kingia sands (14m). The discovery is analogous to the results of the Beharra Springs, Red Back and Tarantula wells only ~14km to the west, where high flow rates are recorded. The well is being completed for testing. The North Perth Basin has provided several gas discoveries in recent years, with conventional gas fields being revealed east of the Mountain Bridge Fault. To the north, with partner Warrego, Strike is developing the West Erregulla gas discovery. The latter field has proven up to 400 Bcf gas, while Strike is chasing up to 1.6Tcf resources over this Permian play in licence EP503. Another recent discovery was chalked up at Lockyer Deep (MinRes and Norwest), while Beach and Mitsui had success at Waitsia. Further development work is expected, with Strike considering both conventional and innovative projects including a major urea processing plant (Project Haber) which could lead on to hydrogen and ammonia production, a significant growth sector for energy in Australia.

AN EXCITING FUTURE FOR GEOSCIENTISTS

Max Brouwers tells us about his journey with the energy transition.

Max Brouwers is an experienced geoscientist who spent 25 successful years with Shell. About six years ago, he began looking at the significance of the approaching energy transition, particularly for geoscientists.

Jane Whaley

"For some time, energy transition and digitalisation have been touted as the mega-forces that would shape our lives – which has turned out to be true!" Max Brouwers explains. "I was concerned, like many other geoscientists, that there would be no job for me in the not so distant future, so I began to look into it further."

In 2018, Max was asked to Chair the first AAPG Energy Transition Forum. "I did not know enough about the subject, so I jumped at the opportunity," he said. It proved so successful that AAPG held a session the following year, for which Max was once again the Chair, and he is now preparing to chair the 2022 Forum. This is a joint enterprise between AAPG and PESGB in London 19 – 20 May, focussing on 'Pathways for Geoscientists in a Net Zero Future.'

"At the first two forums there were still many questions over the future role for geoscientists. Things have moved fast, and now I see four crucial areas that will require geoscientists in order to be successful.

Multiple Roles for Geoscientists

"The closest to traditional oil and gas disciplines is carbon capture and storage (CCS); particularly the storage part, which is all about fluid flow through wells and in reservoirs. It requires regional geoscience skills to identify and prioritise potential CO_2 storage sites, as well as detailed field-specific integrated evaluation and modelling techniques. Regular monitoring has a larger role in carbon storage than in oil and gas to confirm the CO2 stays in the ground, needing skills such as 4D seismic and 4D gravity; all very transferrable with just a little tweaking."

The second area Max identifies is geothermal energy. "This has been quite a challenge economically but I think that will change," Max suggests. "The primary mover is technology. While CCS builds on traditional oil and gas practices, geothermal presents a greater technological jump, with completely different drilling methods and techniques, in many cases pushed by start-ups. Not all these new businesses will be successful, but some will achieve breakthrough technological advances and thereby make geothermal more economically

SHELL

Max Brouwers

attractive. Unlike wind and solar, geothermal energy is not weather dependant; we must develop a reliable baseload energy system, especially as many places turn away from alternative reliable sources. Heat flow predictions, reservoir quality assessments and 3D subsurface model building are some examples of geoscience skills required to harness geothermal energy.

"The third area relates to the critical minerals vital for the energy transition. I am worried that we are not training geoscientists for their role in looking for critical minerals, because mining companies cannot find geologists who can undertake the traditional field work needed to identify these new resources."

The fourth, and probably the least developed, area in the energy transition where Max feels geoscientists can make a difference is around longer-term energy storage. "We really need to start thinking about how we store energy when the wind's not blowing and the sun's not shining," he says. "That might include reusing old fields for gas storage, or storing green hydrogen in salt caverns. It will require, among others, geochemists who can understand the potential chemical reactions and rock mechanics experts to study the

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effects of repeated pressure and temperature changes."

Entrepreneurs Needed

Max believes that the energy transition needs people with an entrepreneurial mindset from outside oil and gas. "I like the idea of bringing technology from completely different sectors to help us make the innovations we need," he adds.

How can we inspire people with the vision required for this transformation, including geologists, to enter the energy industry? "We need to communicate better; we need to tell the story and every time we tell it, hopefully somebody will be inspired to take on this uncertainty about the future. Geoscientists are used to seeing opportunities in uncertainty; that is the mindset we need for the energy transition."

"Many ET start-ups are founded by oil and gas technical experts and executives, who recognise there is an opportunity to redeploy their skills and capabilities and make something new happen. This not only helps the energy transition and has a positive impact on the world; it offers attractive careers too."

Finding the Right Balance

"Universities worldwide are experiencing declining geoscience applications," Max continues. "Geology is seen as oil and gas related, which is out of favour at the moment in many places. We need to get across the critical role of geoscience in the energy transition and how that is aligned with our planet, so that young people can contribute by studying something integral to our future. How do we connect to students, to politicians, or the public? Each geoscientist has a role in telling that story.

"Subsidies and incentives will be required because the energy transition will not run purely by itself or be driven by commercial metrics, at least for a while. Some kind of stimulus is needed in order to make it happen, and governments must be aware of all stakeholders involved. Geoscientists in governmental and regulatory bodies will help to decide how much support should be offered to technologies at the early stages."

"Energy system integration is where I see the big next development coming," he continues. "Nobody I have come across in governments and regulators appears to have an integrated plan which effectively manages costs, carbon, reliability, energy security and all the other facets. This integration will come and, once again, it will create opportunities for geoscientists to be involved in something where they use their in-depth knowledge of one particular aspect, while developing a breadth of knowledge to understand all those other energy sources and uses, in order to come up with smart integrated solutions."

Changing Roles

Part of Max's most recent role with Shell was as global leader for energy transition in the exploration division, in which he was involved in setting strategy and looking at radical opportunities to generate new business models at the intersection of energy transition, digital and subsurface. After spending much of his time discussing the changing roles available to geoscientists, in 2021 he saw an opportunity to join a smaller company, Getech Group Plc (Getech), which applies geoscience and geospatial technologies to the energy transition, in the role of Chief Business Development Officer.

So, how has he found the change and would he recommend it? "Being part of a company supporting the energy transition is very satisfying," he says. "I'm concentrating on finding business openings in the new green energy areas, which is hugely exciting. The opportunities are large, move fast, and there are so many of them, which gives me a lot of energy. And yes, from my experience I would recommend any geoscientist to look beyond traditional petroleum jobs – there are plenty of tremendous opportunities."

Looking back to that first forum in Amsterdam, I ask Max what has surprised him in the changing energy industry since then. "How far and how fast we have moved since 2018," he replies. "We have made great progress, partly because the social pressures are strengthening as we see the impact that climate change is having on all of us. The pathways are much clearer, the universities have modified their courses, and industry associations and many large companies have made adjustments to the new reality. The energy transition is accelerating in many different ways and I think there's much more clarity about the opportunities and the vital role of geoscientists.

"As a global community we know we need to get to net zero. With commitment to find a cumulative solution, the push towards energy transition will only strengthen – which means that, for geoscientists, there's a very bright future ahead," Max concludes.

EXPLORING UNCERTAINTY IN SUBSURFACE MODELLING AND FORECASTING

The oil and gas exploration and production industry has transitioned from the legacy concept of a single case model of the subsurface, which was always doomed to be proven wrong at some time in the life cycle of a producing reservoir. This was due to the sparseness of the data, the noise inherent to the data collection process, and the cognitive biases that are intrinsic to the processing and interpretation of raw measured data. The need to quantify uncertainties became the next frontier, and many different methods were developed and deployed to improve the outcomes. However, this did not translate into a significantly better ability to forecast the future behaviour of a reservoir's performance.

Jon Sætrom, Philip Neri; *Resoptima*

High Stakes

To put this in context, we are deploying a complex process that takes a significant effort to provide predictive information that drives investments of hundreds of millions into infill drilling, injection programmes or other production management activities. Yet seldom is a rigorous and scientific appraisal of available data used to reach conclusions. Instead, convictions based on experience and comparisons to analogous petroleum systems become part of the decision process. While such empirical choices are necessary to jump-start projects and point the modelling process in a certain direction – what we would call a base modelling hypothesis – the error consists in promoting these initial assumptions from a status of educated guess to one of fact.

Overcoming Cognitive Bias

Beyond the flawed search for complexity characteristic of the single case model, its salient limitation is the excessive application of cognitive bias towards delivering a "best" solution.

Two main approaches have been used to overcome this:

1. *The multiple* ***stochastic approach*** *uses an automated framework to model realisations using probability distributions of the unknown reservoir parameters.*

2. *The* ***multiple scenario approach*** *uses a manual or semi- automatic method to build deterministic models.*

Each approach has strengths and weaknesses that can restrict the efficiency, scalability and validity of the method and the resulting models.

Systematically Managing Uncertainty

Cognitive biases are most at play in the single case model approach, in which the team needs to arbitrate choices and resolve uncertainties across the whole workflow before delivering the single result. The multiple stochastic approach requires a base hypothesis at inception, e.g., a zonation scheme or depositional environment, but the ensuing automated process is repeatable. The multiple scenario approach can use a choice of a different base hypothesis for some or all scenarios. However, the user is tasked with providing inputs to parameters and with steering the workflow to deliver the final model, which is feasible at an asset's early 'greenfield'

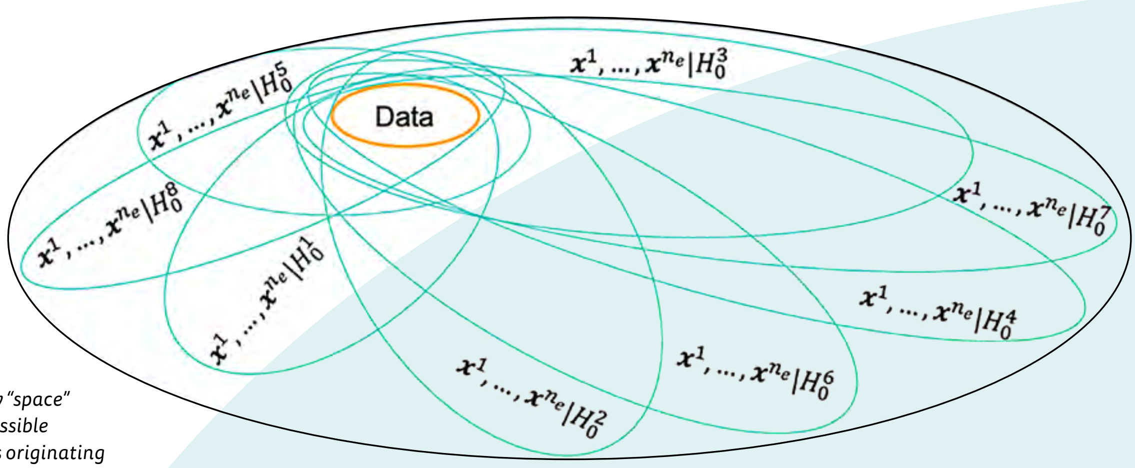

Figure 1: The uncertainty "space" encompassing all the possible ensemble-based models originating from the same data but using different base hypothesis.

RESOPTIMA

stage as static data prevails. As complexity increases for mature 'brownfields' the process takes more and more time and is increasingly difficult to manage systematically.

The comprehensive and scientifically rigorous solution is a combination of the repeatable methods of the multiple stochastic approach with the exploratory nature of the multiple scenario approach. The multiple stochastic approach is initialised with a given modelling hypothesis, and this risk is mitigated by exploring the whole space of possible ensemble-based models by evaluating multiple modelling hypothesis, all of which are plausible given the current data measurements.

This will correspond to a methodical exploration of the whole uncertainty space as illustrated in Figure 1.

This brings up another valid concern: if one run of ensemble-based modelling for an asset takes a few weeks, how can we execute numerous ensemble-based modelling runs, and perform comparisons to derive conclusions from this volume of data, knowing that the workload has grown ten-fold or more?

Speeding Up the Process

We need to further change our mindset regarding reservoir model building. Parkinson's Law, articulated in 1955, stated that 'work expands to fill the time available for its completion'. Over the years, as single case models have increased in complexity, a duration of many months became the norm for such projects. Ensemble-based modelling starts with an initial model that is only as complex as needed to honour the data and is therefore simpler and faster to produce – typically a matter of weeks. Faced with the need to generate tens of ensembles, it was possible to bring the time down to a few days:

- *Data curation can be made both more effective and less time-consuming by performing it concurrently and as a team as opposed to one data type at a time and in isolation.*
- *Ensemble-based modelling has always favoured starting with a model as simple as possible but not too simple, adding complexity only if the data dictates it.*
- *Finally, the construction of the workflow was given a very short time to come to fruition, in the order of two days, which in practice proved possible and broke from customary times of weeks or even months. Experience had shown that spending too much time on highly complex and detailed workflows was often thwarted by a realisation on completion that the process was invalidated by wrong assumptions related to the input data.*

Best practices can now be changed with the adoption of the sprint concept that is used in software development. An ensemble-based modelling sprint (*Figure 2*) will focus on generating multiple ensembles using often fundamentally different modelling hypothesis, with the goal of providing specific deliverables with a quantification of the prediction error.

Delivering Value

Ensemble-based modelling has been delivering value to the E&P industry for over ten years, causing a fundamental re-think of what exactly is needed to make decisions on developing and managing the production of hydrocarbon assets, namely a better grasp of uncertainties across hundreds of data- conforming realisations instead of an obsessive focus on detail within a single model. The mandate is now expanded to the appraisal of the whole space of uncertainties associated with different initial hypothesis for an ensemble, within the scope of short sprints focused on specific challenges.

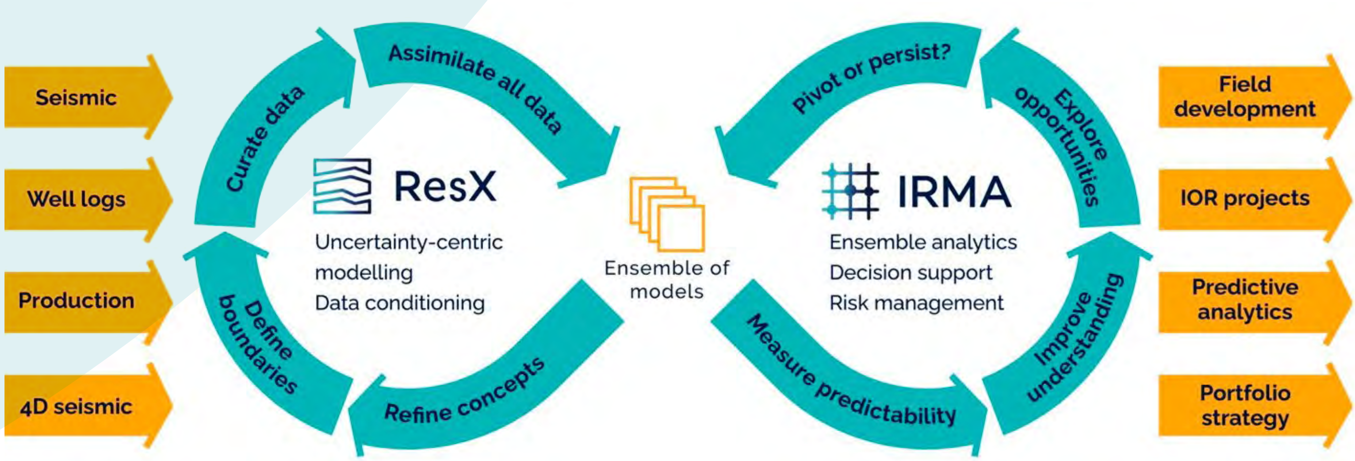

Figure 2: Ensemble-based modelling coupled to ensemble analytics.

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TRANSITION THAT'S FIT FOR PURPOSE

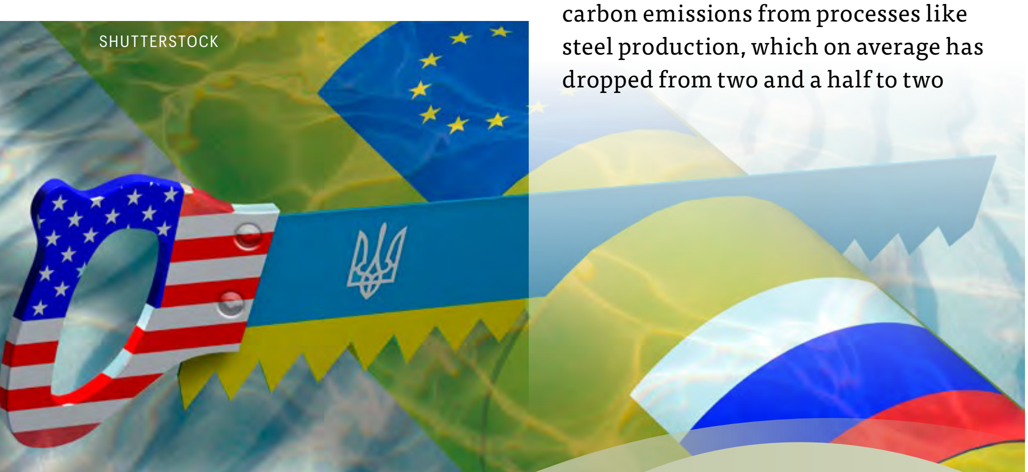
Transition is a word on many lips. Energy transition, certainly, but also of the alliances and relationships which keep the world secure, solvent and conflict-free. Can NATO be updated and expanded? Will China take a more active stance against military aggression? Can Europe wean itself off Russian gas? All this comes against a backdrop of war and a 10-year-plus high in the oil price, plus a new determination that fossil – albeit cleaner fossil – should stay part of the energy mix.

Russian gas you could say has become the heroin habit Europe is trying to kick. "Russia's use of natural gas resources as an economic and political weapon shows Europe needs to act quickly …" notes Fatih Birol in a recent IEA paper on the energy mix. Birol, the IEA's Executive Director, introduces a 10-point plan for reducing Europe's reliance on Russian fossil and fossil fuels generally. More renewables, of course, but also a series of practical measures which seek to promote non-Russian gas supplies and non-fossil energy use in equal measure.

The plan, says Birol, "provides practical steps to cut Europe's reliance on Russian gas imports by over a third within a year, while supporting the shift to clean energy in a secure and affordable way." What's not said – regardless of what happens in Ukraine in the short term – is that this will only work with strong government action and incentives, not to mention some degree of financial pain for the consumer.

Transition was again a key focus at this year's International Energy Week which took place virtually and in London at the end of February. "What can we do now and how can we speed it up?" asked Dr Lene Hviid, Global Key Accounts Manager for metals at Shell. Carbon capture, utilisation and storage (CCUS), blue hydrogen and less energy-intense production were all on the agenda. "There is no one size fits all solution here," Dr Hviid reminded her audience. "It's a question of how we can build mile-stones to see we're on the right path."

That path, she added, includes cutting carbon emissions from processes like steel production, which on average has dropped from two and a half to two tonnes of CO_2 for every tonne of steel produced over the last 10 years. It also means investing in CCUS and in hydrogen on the road to net zero. Oil companies are currently well placed to step up. Transition, we must accept in today's uncertain times, comes in all shapes and sizes.



SHUTTERSTOCK

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CONVERSION FACTORS

Crude oil
1 m³ = 6.29 barrels
1 barrel = 0.159 m³
1 tonne = 7.49 barrels

Natural gas
1 m³ = 35.3 ft³
1 ft³ = 0.028 m³

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

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

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

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

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

Historic oil price
Crude Oil Prices Since 1861