THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

VOL. 20

GEO ExPro

6 2023

TALKING ABOUT STEP-OUT WELLS...

EXPLORATION OPPORTUNITIES

Santos Basin, Brazil

North of Troll, Norway

The next Buzzard, UK

GEO ExPro

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When is it content, when is it an ad?

AS AN EDITOR, I often find myself navigating the question - Is this content too much of a sales pitch or not? In one way, I understand when people criticize content that positions a certain product or service in such a way that the reader is made to believe that it will solve all problems. The real world is a little more complicated than that. But, let us not forget that many companies exist because they offer a product or service that successfully competes with similar offerings elsewhere. And being successful often comes with having a competitive edge, which in turn revolves around innovation.

"..that is what we as a magazine want to achieve – telling the story on how individuals drive innovation in the energy sector."

When the story behind these innovations is being told, presenting a case history on how the penny dropped with someone, the narrative all of a sudden becomes more like an adventure, showcasing the highs, lows and perseverance to reach that competitive edge. And that is what we as a magazine want to achieve: telling the story of how individuals drive innovation in the energy sector. To shine the light on what it takes to ultimately be able to produce an ad for a magazine.

Henk Kombrink

BEHIND THE COVER

Using social media to source content has proven to be a very powerful tool. For the cover story on step-out wells, we put out a call on LinkedIn asking what is the longest step-out in the world. We got a very interesting response from Calin Dragoie from Chinook Consulting Services in Canada. He shared an image showing a well trajectory of a Canadian oil sand well. And what a well! It has 47 legs for a total length of over 25,000 meters; a great candidate for the front cover. Design by Fabio Crameri - *undertone.design.*

Comments: magazine@geoexpro.com
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Website: geoexpro.com

A truly global event focused on prospecting, business transactions, and deal-making for the oil and gas E&P sector

The 2024 AAPG/GESGB Business & Exploration Opportunities Show (BEOS) to be held at the Business Design Centre in London will be a unique and unmatched chance to generate new business opportunities

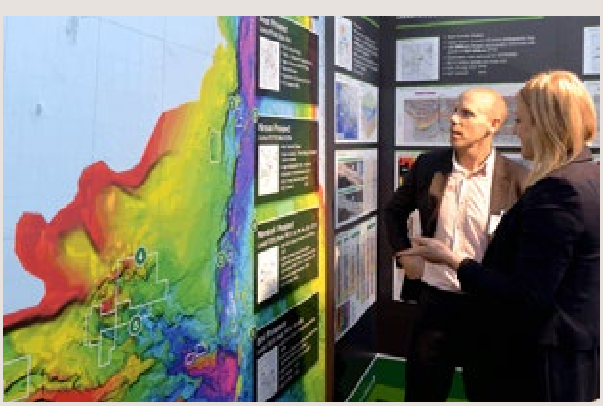
A CATALYST FOR DEALS to be struck and new ventures to be undertaken, BEOS will bring together Oil and Gas Majors, IOCs, NOCs, Independents, E&P firms and Governments, whilst also attracting many of the world-leading banks, financiers, advisory and law firms. BEOS is a two-day event jointly conceived by the AAPG and the GESGB, which brings together the best of APPEX and PROSPEX into one great show.

The Oil and Gas industry remains a critical "Energy" bridge to a Just Transition over the next decade and beyond. Further, predicted global supply and demand dynamics for oil, gas/LNG require material near-term prospective resources to replace existing production declines.

BEOS is an important multifaceted platform at a critical time, to reach out to a wide and diverse audience of stakeholders in the International Upstream Exploration and Business and New Ventures part of the Industry.

The two-day show will cover the ongoing financial, commercial and people-related transition impact on oil and gas but as importantly allow for showcasing and marketing of opportunities and exploration assets/prospects across two streams each day. In addition, sessions will cover a variety of themes from resource holder overviews to UKCS fiscal updates, panel energy debates and technical and commercial case histories.

Further information at: beosevent.com



Unearth the Energy Future with GeoConvention 2024

Hosted from Calgary in Canada, GeoConvention 2024 offers a truly hybrid conference through an immersive virtual experience

EMBARK ON AN IMMERSIVE earth science and energy journey at GeoConvention 2024! This premier gathering invites geoscientists, engineers, and industry leaders to delve into cutting-edge insights, forging connections with global visionaries. Dive into diverse sessions, case studies, workshops, and exhibits showcasing the latest energy trends and innovations, providing hands-on learning experiences and a comprehensive understanding of the interconnected energy ecosystem for professionals and students alike.

From the latest in oil, gas and critical mineral exploration to the advancements in geothermal technologies and sustainable solutions in carbon capture, GeoConvention is a melting pot of ideas that go beyond industry silos.

Set against the stunning backdrop of Calgary in the Canadian Rockies, GeoConvention offers more than a conference—it's an exploration of ideas and a catalyst for advancement.

The Call for Abstracts is now open; seize your opportunity to shape the future by contributing to discussions on sustainability and carbon capture, advances in discovery, evaluation and sustainable extraction, critical minerals, and the future of energy.

Further information at: geoconvention.com

PHOTOGRAPHY: GESGB; GEOCONVENTION

Sharing knowledge to unlock potential

The 8th Conjugate Margins Conference 2024 to be held in Lisbon, Portugal, 27 to 29th May 2024, brings together geoscientists from academia and industry working on Conjugate Margins from all around the World

THE FIRST Conjugate Margins Conference was held in 2008 and has continued every second year since, except during the COVID pandemic. The conference attracts delegates from E&P companies, geological and geophysical service companies, consultants, university researchers, government agencies and departments. Students are strongly encouraged to participate through discounted registration with the best oral and poster presentations recognised with prizes for presentation excellence.

The 2024 Conjugate Margins Conference will be held in Lisbon, Portugal, following the successful event in Marrakesh, Morocco in 2022. We expect to attract participants from a variety of countries, public and private institutions, students, researchers and professionals.

While the industry participation in past events was centered around hydrocarbons, we have widened the scope to include new forms of energy and its storage in a geological context. The main scientific/technical topics are Geodynamics and Structural Geology, Stratigraphy and Depositional Systems, Sustainable GeoEnergy on continental margins and New Methods to unravel continental margins.

Further information at: marginsconference2024.com

Advancing seismic exploration: The rise of one-step probabilistic inversion

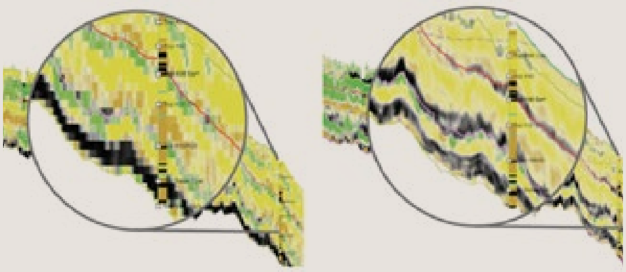
Both the accuracy of seismic interpretation and identification of geological features below the traditional seismic limits are possible with a new way of inversion

AS THE INDUSTRY seeks accurate reservoir characterisation of more and more subtle subsurface features, "direct" or "one-step" probabilistic methods have emerged as a promising solution. By embracing uncertainties and integrating geological insights, these methods are reshaping seismic exploration, propelling it into an era of uncertainty-aware seismic quantitative interpretation in the presence of thin beds and ambiguous elastic responses.

One-step probabilistic methods integrate geological a priori information into the inversion process. Operating on Bayesian inference principles, they provide a flexible probabilistic framework, allowing for the incorporation of diverse prior knowledge from logs, core samples, and geological studies.

In contrast to both deterministic and stochastic or geostatistical seismic inversions, direct one-step methods ensure robust propagation of uncertainties through the inversion process. The additional prior knowledge not only enhances the accuracy of seismic interpretations but also enables the resolution of geological features well below traditional seismic resolution limits.

Ask Jakobsen, Henrik Juhl Hansen and Anders Bruun, Qeye



Example from Cambo field West of Shetlands, UK, showing the traditional workflow (left) and a direct probabilistic inversion (right). Note that the thin coals (black) are properly resolved by the probabilistic inversion where the traditional method delivers the package response.

PHOTOGRAPHY: SICCAR POINT

Seismic 2024 – Seismic in the evolving energy landscape

From new acquisition and processing technology, via reservoir characterisation & QI to exploration in the energy transition, Seismic 2024 in Aberdeen is the platform to hear the latest developments in the geophysical arena

SPE ABERDEEN'S Seismic conference continues to be Scotland's premier geophysics event. Established in 2017, it was the first conference of its kind in Aberdeen to focus on seismic acquisition, processing, and interpretation.

The event not only brings together the local geoscience community, but also reaches out to the global geoscience industry. As such, it has become increasingly popular over the years amongst not only geoscientists and geophysicists, but also those in non-geo-related roles such as engineers and senior decision-makers within operating and service companies. With the introduction of a dedicated session for Young Professionals in 2019, Seismic aims to inspire and encourage the next generation of young engineers and geoscientists too.

Seismic 2024 will cover the role of geophysics in the energy lifecycle from exploration, appraisal, development, and production through to decommissioning and repurposing. It recognises the continued importance of oil and gas, but also looks to the future of sustainable energy sources in a positive and balanced way. Seismic 2024 will take place at the P&J Live in Aberdeen on 1 – 2 May 2024.

Further information at: spe-aberdeen.org/events/seismic-2024

Aramco to host key global petroleum event in 2024

IPTC 2024 offers an unparalleled opportunity to engage with the leading minds and influencers who are spearheading the energy transition

THE INTERNATIONAL Petroleum Technology Conference (IPTC) is set to make a remarkable return to the Dhahran Expo, situated in the heart of the Kingdom of Saudi Arabia, from 12-14 February 2024. This exclusive event, proudly hosted by Aramco, will be embracing the thought-provoking theme of "inventing solutions > leading the transition," reflecting the conference's commitment to pioneering innovation and transformative change in the industry.

With expectations of drawing over 18,000 attendees, IPTC 2024 promises to be a momentous gathering of industry professionals, experts, and thought leaders. Established in 2005, IPTC has grown into a major technical event in the Eastern Hemisphere, showcasing cutting-edge advancements in petroleum technology and fostering collaboration among key stakeholders in the energy sector.

Participants can look forward to connecting with industry giants and visionaries, facilitating the exchange of ideas, and fostering collaborations that will drive the future of the energy landscape. Mark your calendars and be part of the transformative dialogue and groundbreaking advancements at the International Petroleum Technology Conference (IPTC) 2024.

Be part of one of the most influential energy events in the Eastern Hemisphere!

Further information at: iptcnet.org

PHOTOGRAPHY: SPE; IPTC

EGYPES 2024 - Driving Energy Transition, Security, and Decarbonisation

Under the distinguished patronage of His Excellency Abdel Fattah El Sisi, President of the Arab Republic of Egypt, the Egypt Energy Show (EGYPES) 2024 is poised to open its doors next February, bearing the theme: "Driving Energy Transition, Security, and Decarbonisation

AS THE EPICENTRE for global energy dialogue in Africa and the Mediterranean, EGYPES 2024 is underway to be the most pivotal edition to date.

Supported by the Egyptian Ministry of Petroleum and Mineral Resources, this exceptional show will convene from 19-21 February at the Egypt International Exhibition Center. Anticipating participation from over 35,000 attendees and 2,200 delegates spanning the entire energy supply and value chains, EGYPES 2024 will engage in comprehensive discussions concerning worldwide energy dynamics, the latest industry trends, regional progress, and collective actions to achieving net-zero emissions.

His Excellency Tarek El Molla, Egypt's Minister of Petroleum and Mineral Resources, underscored EGYPES's transformative role in the regional energy landscape, stating, "EGYPES has evolved into a cornerstone of the African and Mediterranean energy ecosystem, acting as a catalyst for business and investment in the regional energy market. Each year, we witness substantial growth, increased interest, and the formation of invaluable partnerships, thereby accelerating Egypt's ascendancy as a regional energy hub."

Africa, the Mediterranean, and the Middle East have emerged as focal points for discussions on the role these markets play in the global energy landscape with a focus on climate-conscious solutions. Urgently addressing net-zero agendas, EGYPES 2024 welcomes all to get involved, and be part of the conversation to advance rapidly to accelerate collaborative action, driving energy transition, security and decarbonisation.

Further information at: egypes.com

Creating low-carbon strategies for a sustainable future

The 2024 Carbon Capture, Utilisation, and Storage event in Houston, Texas, is set to explore the latest CCUS work and address related challenges and opportunities. Plan now to network and collaborate with industry leaders and experts

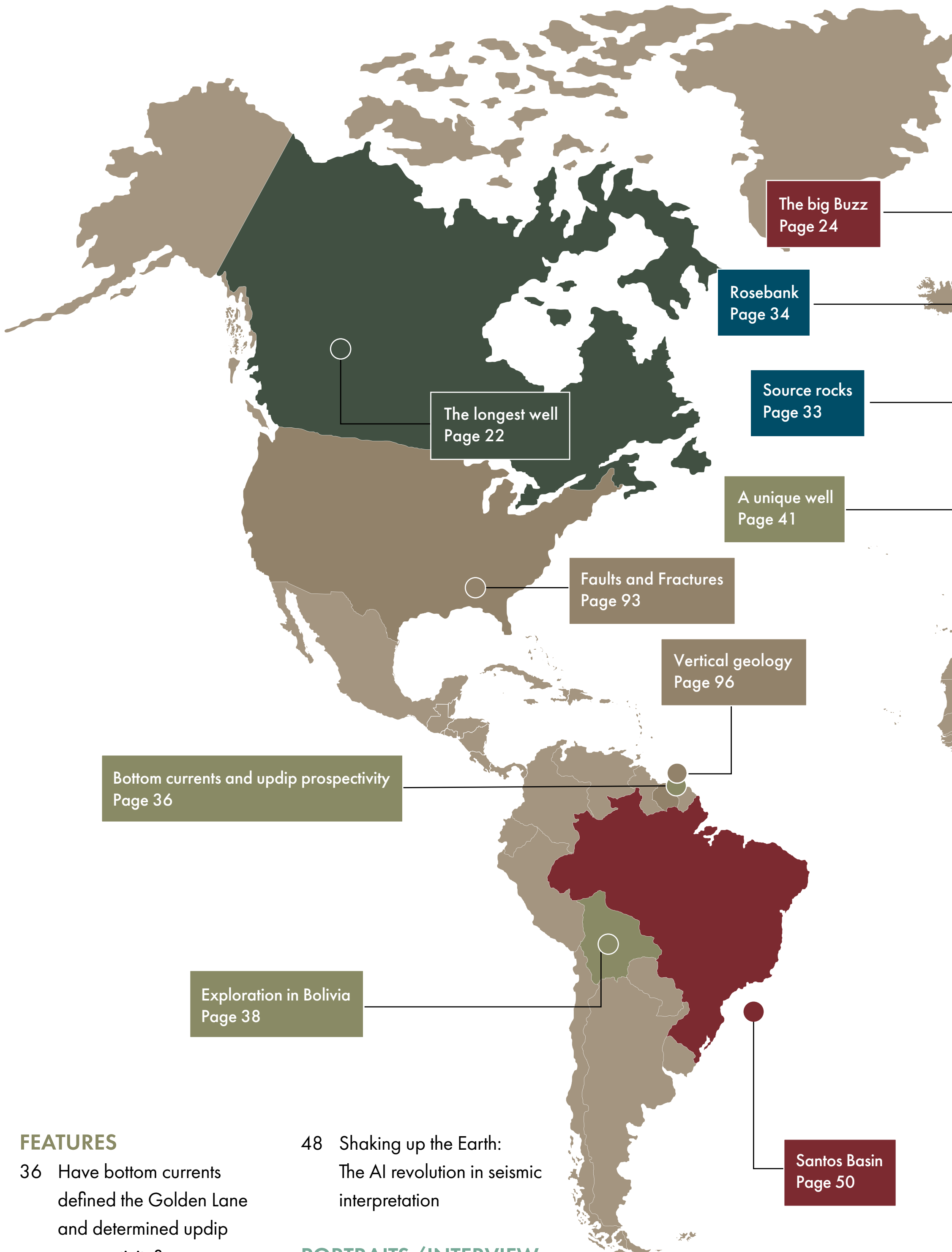
THE MATURING carbon market has been a major driver for the deployment of carbon capture, utilisation, and storage (CCUS) projects within the geosciences and energy arenas. Both the subsurface technical knowledge and related data sets of the petroleum industry are major inputs required for the world to successfully move towards a carbon-neutral and sustainable energy future.

CCUS has experienced growing interest over the past two decades, due to the desire to reduce CO_2 emissions and to make industrial sources more environmentally sustainable. More recently, policy instruments and carbon credit mechanisms are providing opportunities that offset deployment costs and can result in CCUS being a potentially profitable enterprise.

Fully understanding the technical and business aspects of CCUS such as subsurface geologic storage and site selection, CO_2 enhanced hydrocarbon recovery and utilisation, and reservoir modeling monitoring and risk assessment are critical in helping lead the way for successful net-zero operations and developments. These topics, and more, will be discussed elaborately at the event.

Further information at: ccusevent.org

PHOTOGRAPHY: EGYPES; AAPG



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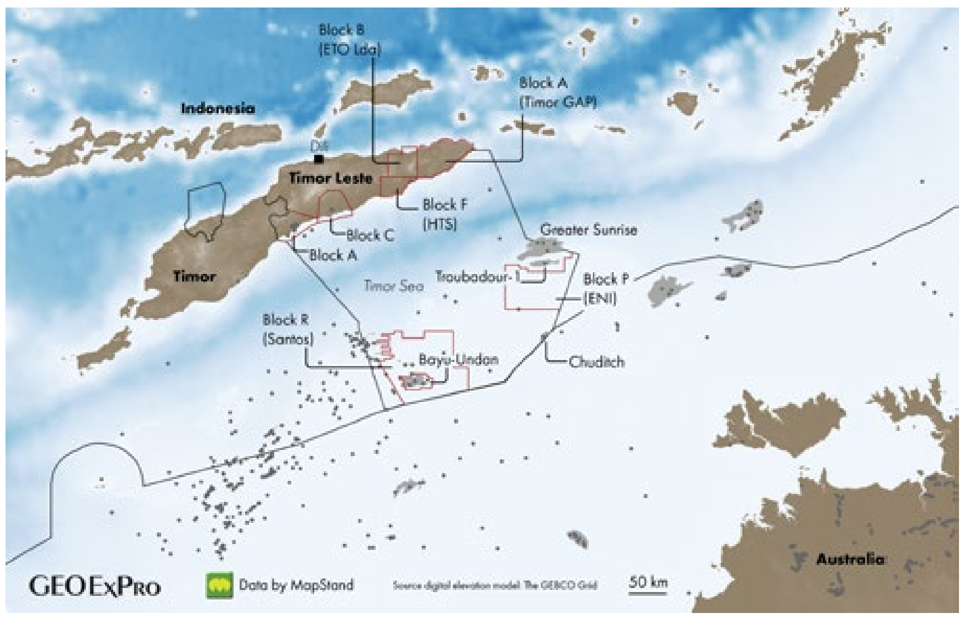
The future looks bright for the world's fourth-youngest country

With appraisal drilling planned on a multi-TCF cluster and the signing of contracts for newly awarded blocks imminent, Timor Leste is expecting a ramp-up of activity in the years to come



TIMOR-LESTE was quick to capitalise on its oil and gas resources after it became independent in 2002. In the same year, a treaty was signed with Australia for a Joint Petroleum Development Area (JPDA) in the Timor Sea. Importantly, the JPDA contained the Bayu-Undan and Greater Sunrise fields.

Brought on stream by Conoco in 2004, the Bayu-Undan gas-condensate field is near the end of its life, and current operator Santos is working with the government on plans to convert the facility into a Carbon Capture and Storage (CCS) hub project.

Meanwhile, the development of Greater Sunrise, which is operated by Woodside, in partnership with national oil company TIMOR GAP and Osaka Gas, continues to be stalled over lack of agreement on a development plan. The issues revolve around whether the gas should be processed for export at a liquefied natural gas (LNG) plant in Australia or Timor-Leste. The Greater Sunrise complex was discovered in 1974 by the Woodside Troubadour-1 wildcat and is reported to hold gross contingent resources of over 5 trillion cubic feet (TCF) of gas and 225 million barrels of condensate.

An offshore project which is moving forward in Timor-Leste is in the SundaGas-operated Chuditch PSC. SundaGas, which is a fully owned subsidiary of Baron Oil, is preparing to drill an appraisal well on the 1.15 TCF Chuditch gas discovery in 2024. There is reported to be significant follow-up potential to Chuditch in the block with aggregate estimated recoverable resource estimates of more than 3 TCF. A success at the Chuditch appraisal well is considered sufficient to fast-track development of the field with a target of first production in 2028.

Onshore, Timor Resources holds Blocks A and C, which also have a small offshore portion, and following seismic surveys in 2018 and 2019 three exploration wells have been drilled. All three wells are reported to have encountered oil and gas and Timor Resources has announced that 2P certified reserves from these wells, supported by four historic wells, is 21.1 million barrels of oil.

As a result of the Second Licensing Round in 2019-2020, a total of six companies bid on five blocks out of the 18 on offer. Winners in the round included ENI (Block P) and Santos (Block R) in the offshore, and TIMOR GAP (Block A), ETO Lda (Block B) and HTS Exploration (Block F) in the onshore. Signing of contracts for the blocks is expected soon, with ENI expected to be first to sign, and the future looks bright for the world's fourth youngest country. ■

Ian Cross - Moyes & Co

Ghawar keeps on going

With tight gas now also being produced from the largest oilfield in the world, it shows that Aramco continues to move forward in the unconventional space

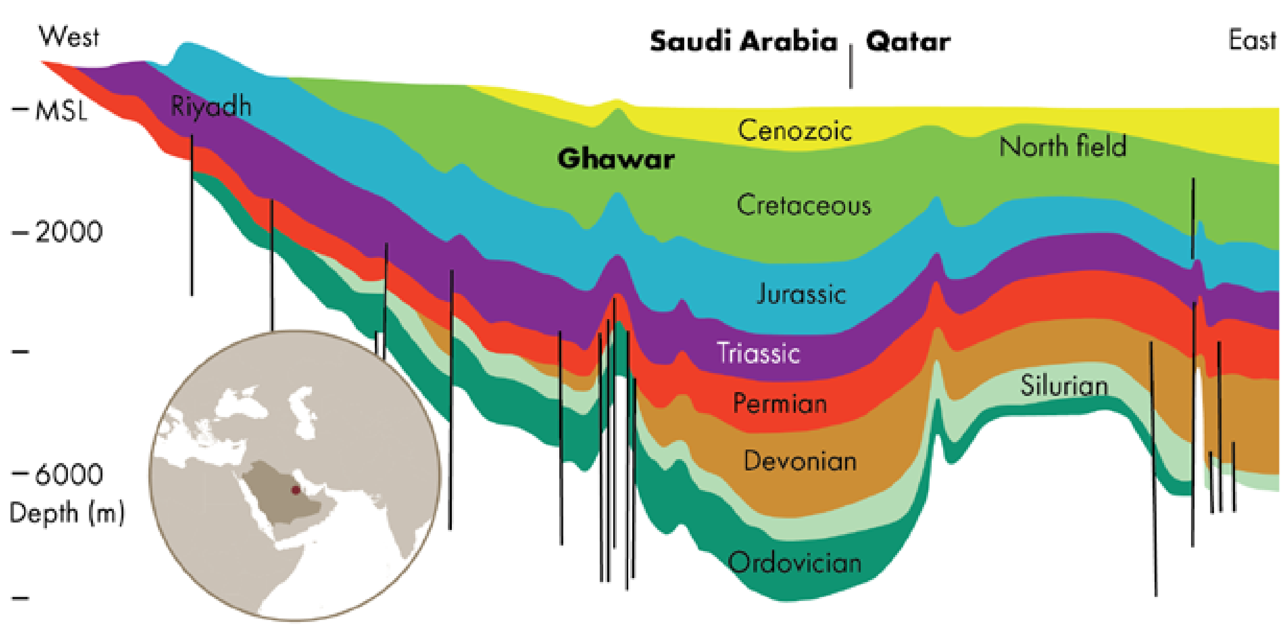
In November, Aramco announced that it produced its first unconventional tight gas from the Ghawar South project, producing up to 300 million scf/day of gas and 38,000 b/day of condensate. It is the second project of this kind after the commencement of gas production from the North Arabia field in 2018. And it is not the last one either; work is also ongoing at the Jafurah unconventional gas field, which is supposed to be in the largest shale gas play in the Middle East.

But let's take a closer look at Ghawar and where the unconventional gas may be reservoired in. First of all, the conventional oil in Ghawar is produced from the so-called Middle to Upper Jurassic Arab-D lithofacies, which is a carbonate succession deposited in a shallow marine ramp setting. Thanks to the large structure, which is a large north-south trending Hercynian basement horst, and preservation of excellent reservoir quality, Ghawar has proven such a prolific producer. However, it was soon realized that the field also had gas potential, with both the Permian and the Devonian having tested positive for gas. Conventional gas production from these reservoirs has taken place for a number of years already, in addition to production of associated gas.

A WIDE RANGE IN FACIES

The Permian succession below the Ghawar field is characterised by two different gas reservoirs. The Khuff, which is of Late Permian age, consists of a series of stacked shallow water carbonates, whilst the slightly older Permo-Carboniferous Unayzah consists of eolian and fluvial sandstones. In both cases, Silurian shales are thought to be the main source rock. The third and last gas reservoir is the Devonian Jauf, which is a series of estuarine and near-shore sandstones, again sourced by Silurian shales. As the cross-section shows, the Devonian succession is thinning or may even be absent in places across the crest of the horst block. It is therefore likely that this reservoir is mainly found along the flanks of the horst block.

As a publicly available presentation from Abdulkader M. Afifi from Aramco notes at the end, the main challenge related to the Ghawar Paleozoic gas play is the prediction of areas with good reservoir quality. This clearly suggests that there is ample tight reservoir across the Ghawar field, which may have been avoided until recently. Now, with Aramco tapping into that resource, and combined with the observation of the enormous size of the closure (~7,200 km²), it is logical to assume that there is enormous potential for the production of tight gas from the largest oil field in the world. ■



Regional E-W cross-section through the Ghawar field, clearly illustrating the horst block nature of the accumulation.

MAP: ADAPTED FROM ABDULKADER M. AFIFI, AAPG PRESENTATION

COVER STORY

"If we would consider total horizontal displacement as a sum of multiple lateral legs, well PENN WEST HZ WALRUS 15-1-83-18W5 takes the cake."

Calin Dragoie - Chinook Consulting Services

The world of step-out wells

From finding a multi-Tcf gas field nearby to efficiently tapping into shallow oil sands, there are some intriguing cases to show when it comes to drilling step-out wells

What is the longest well drilled along hole?

UPPER ZAKUM FIELD - ADNOC - 2022

15,200 m MD

SEA OF OKHOTSK - ROSNEFT - 2017

15,000 m MD

SAKHALIN - EXXON - ~2010?

14,129 m MD

AL SHAHEEN - MAERSK - 2006

10,902 m MD

If we would consider total horizontal displacement as a sum of multiple lateral legs well PENN WEST HZ WALRUS 15-1-83-18W5 takes the cake. Drilled by Obsidian Energy (PennWest at the time) in 2016 in the Peace River oil sands area of Alberta, Canada, it targeted the Bluesky formation. The well has 47 legs for a total length of over 25,000 meters, all drilled at a TVD of approximately 685 meters. Heel is at less than 1000 meters MD, so step out ratio is over 24.

This may be challenged by Clearwater multilateral wells drilled currently by Tamarack Valley in Marten strike area. While a bit shorter overall, the 8-leg wells, 2 miles per leg, are placed at 610mTVD, bringing the ratio at over 30.

Source: Calin Dragoie (Chinook Consulting Services)

HENK KOMBRINK

A step-out well is a well that shows a significant horizontal displacement relative to the vertical depth it is drilled to. Sometimes, step-out wells are being drilled to explore for smaller satellite prospects adjacent to large fields, such as company OKEA is doing in the Norwegian sector in an attempt to arrest the decline of mature assets.

In other cases, the development of certain fields requires lengthy step-outs in order to efficiently produce the hydrocarbons. The Sakhalin project in Russia is a famous example, with a step-out distance of more than 14 km. More recently, it was ADNOC which claimed to have drilled the longest oil and gas well in the world at the Upper Zakum oil and gas field, with a more than 15 km long borehole. Whether this beats Sakhalin's horizontal step-out has not been further researched by us, but it shows that technology has progressed far when it comes to reaching hydrocarbons at places that were never thought to be accessible some decades ago.

For this article, we will not be too strict on the definition of step-out wells. The main aim is to show a variety of examples where a step-out, being a horizontal, a vertical or a more "geological" step-out, has proven of value to the operator.

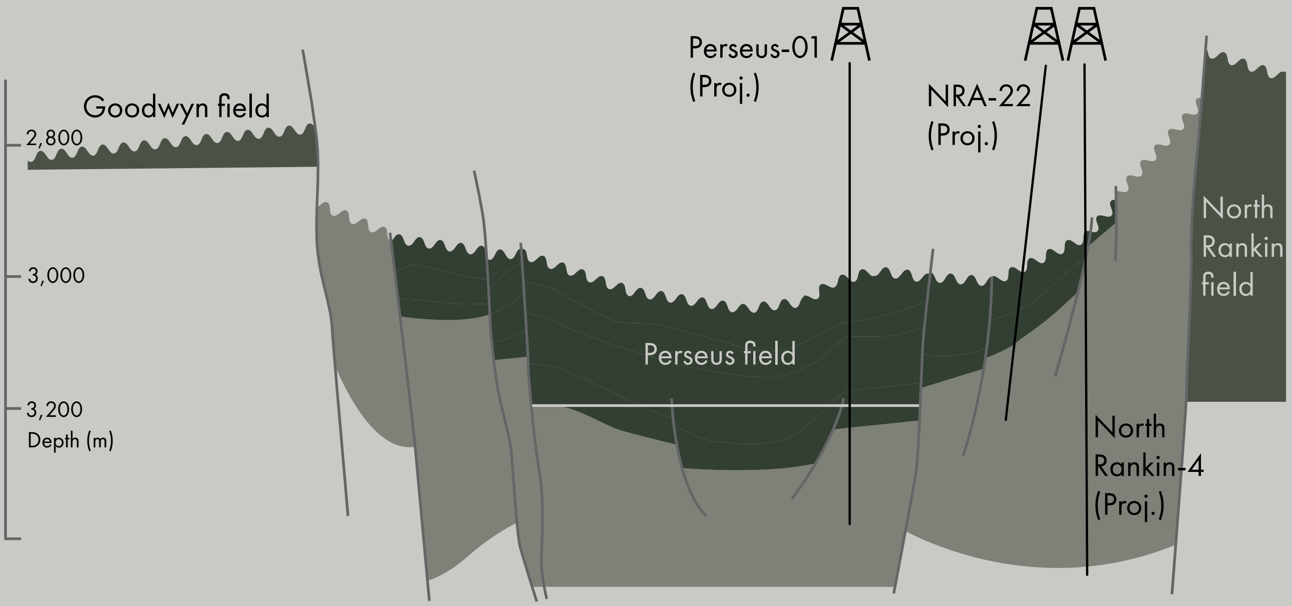
We start off with a great example from Australia, where Woodside got an indication of a surprise hiding somewhere nearby when an intern analyzed production data.

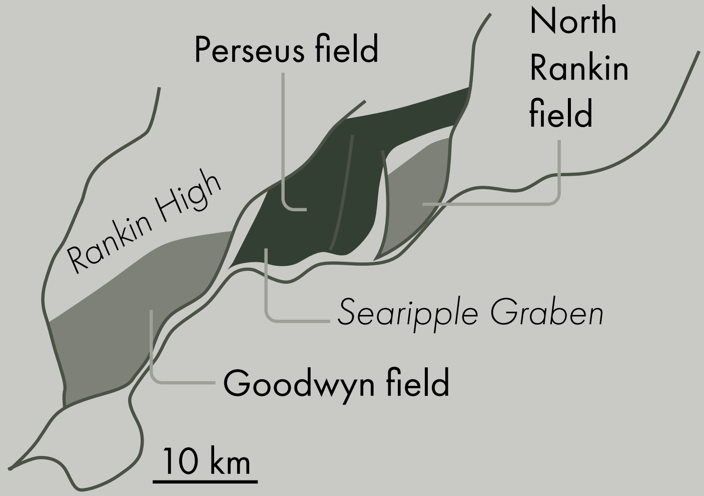
WHAT PRESSURE DATA CAN DO

Most fields across the Rankin structural trend on the northwest Australian Continental Shelf are characterised by Triassic reservoirs. So was the North Rankin field, which was discovered in 1971. However, it turned out that there were other reservoir candidates too.

The ENE trending Rankin High is dissected by a series of sub-parallel Lower to Middle Jurassic basins, of which the Searipple Graben to the west of NW Rankin is an example. An early exploration well drilled into the Graben in 1972 – North Rankin-4 – found gas-bearing shoreface sandstones of the Middle Jurassic Legendre Formation. Yet, even though the well produced 7.5 MMscf/day, the reservoir quality was deemed too poor for future development and the area disappeared from the radar.

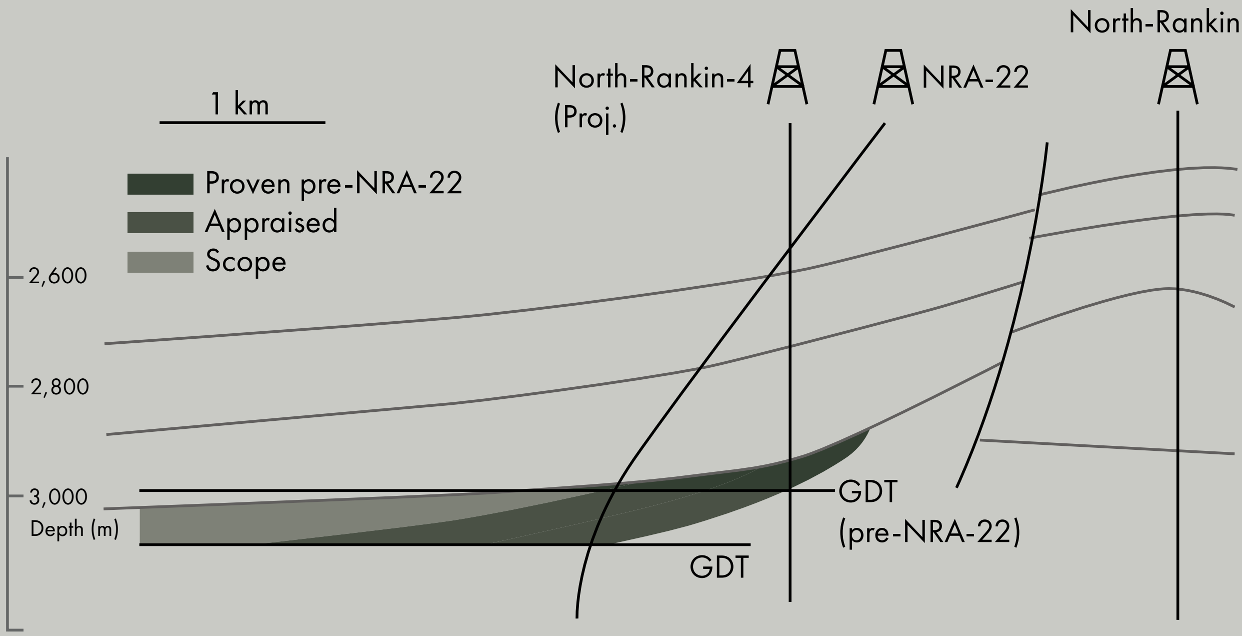
Years later, after the reprocessing of 3D seismic data across the North Rankin field in 1989, the North Rankin-4 discovery re-surfaced as an opportunity after amplitude studies and geological modelling had suggested that reservoir quality could actually be better than initially foreseen.





WHY PERSEUS?

The Woodside team chose the name Perseus because in Greek mythology it was Perseus who killed Gorgon. At the time, the discovery of Perseus and the large additional proven volumes meant that the NW Shelf LNG project could expand, cancelling the business case for Chevron's plans to build the Gorgon LNG terminal. In a revenge move, Chevron's asset manager took a dive into Greek mythology to find out who killed Perseus. It happened to be Chrysaor, which then became the name of Chevron's next find.



It led to the mapping of a small prospect around the North Rankin-4 well, which was subsequently drilled by a step-out well from the North Rankin A platform – NDR-22. At the time, because this prospect was regarded as just a satellite of the North Rankin field itself, the prospect was given the prosaic name North Rankin West.

As the modelling results had already suggested, the NRA-22 well, drilled in 1991, found an excellent Bathonian reservoir. And even better, a 144 m gas column without even encountering the gas water contact. It led to a total reserve estimate of 0.62 Tcf.

THE CRITICAL WORK OF AN INTERN

Well NRA-22 was put on production through the North Rankin facility soon after completion. Again, it took some time before people started realizing that there was something special going on. It took an intern or graduate who was tasked to analyse the NRA-22 production profile to find out that the depletion of reservoir pressure progressed at a much slower rate than initially foreseen. Only then the North Rankin team woke up and concluded that the connected volume around the well should be much larger than anticipated and a plan to drill more wells on the field was soon put together.

The drilling of Perseus-1 then showed that the gas resource within the Searipple Graben was much larger than the initial estimate based on the NRA-22 well. A few more appraisal wells were drilled after Persues-1 to further narrow down volumes. It is not a surprise that multiple wells were required to do that; it only needs inspection of the cross-sections and maps shown here to see that there is a complex trapping mechanism involved in holding a gas accumulation in this setting. After all, would you have chosen to drill in the Searipple Graben when looking at the cross-section without any prior well information?

To round up the story for now, after drilling of the appraisal wells on Perseus, a single contact was established. Although some stratigraphic compartmentalization was observed, juxtaposition of different strata through faulting meant that the field turned out to be well connected throughout. A remapping exercise in 1996 thus resulted in a ten-fold increase in booked reserves to a whopping 6.48 Tcf (183 Bcm). It formed an important motivation to significantly extend the Northwest Shelf LNG project at the time.

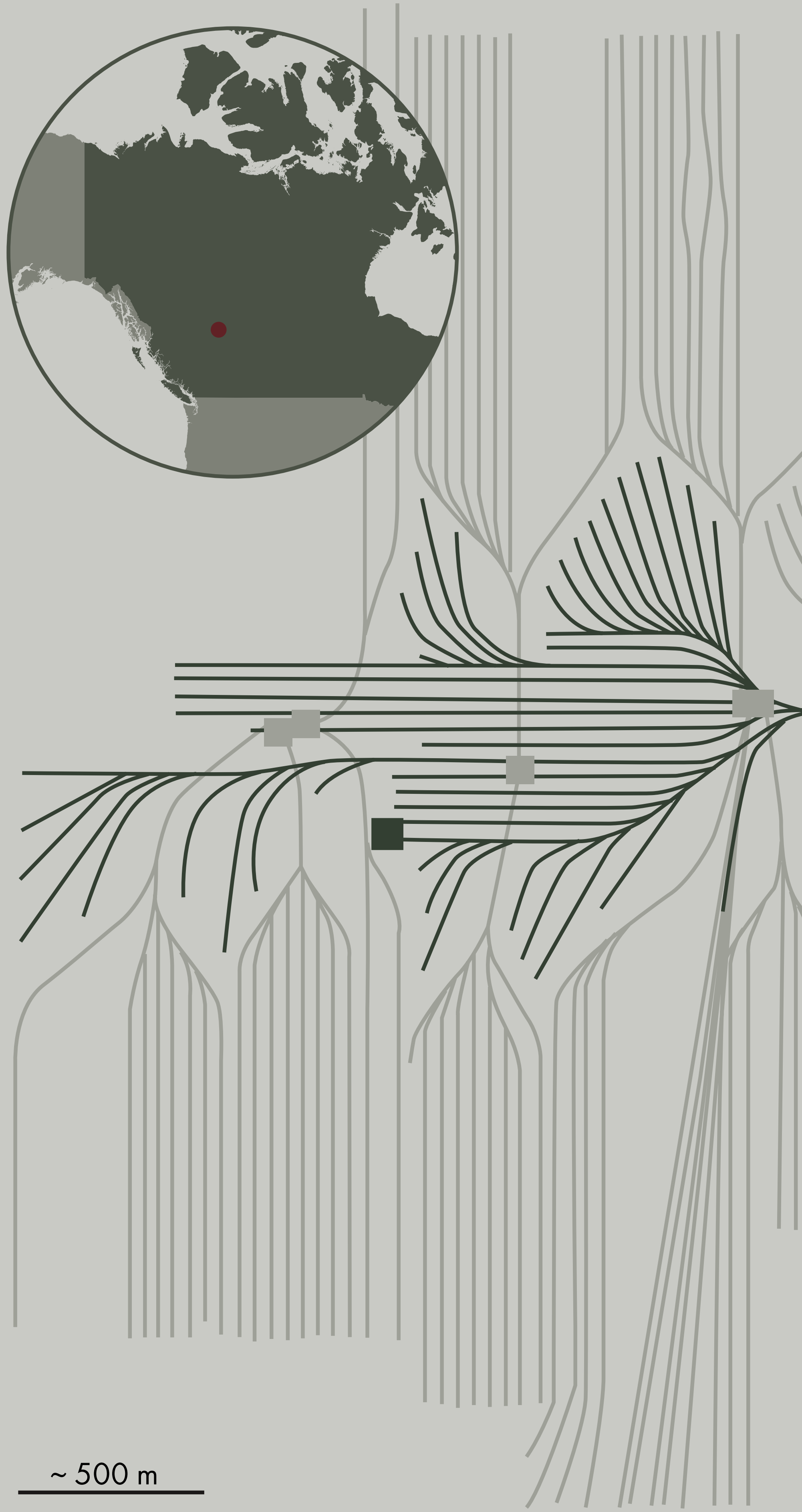
All figures redrafted after Taylor et al. (1998): The Perseus field, North West Shelf, Australia: A Giant Gas Accumulation in a complex structural/stratigraphic trap. APPEA Journal, p. 52-67.

STEP-OUT WELLS – A DRILLER'S PERSPECTIVE

From a driller's point of view, in terms of execution step-out wells are normally not very different from a development well. As the wells are drilled in areas where the subsurface is better known than in the case of a wildcat exploration well, step-outs do not tend to carry the same risks as a traditional exploratory well. Nevertheless, some operators might have some extra contingencies when drilling step-out wells, mainly to prevent and minimize risks of well control incidents.

A few examples of actions that can be taken are using slightly heavier mud-weights, drilling on slower parameters in specific sections of the well - especially if long open-hole sections are planned - and potential changes in the casing program.

Traditionally, step-out wells were mostly drilled using oil-based mud in order to effectively carry cuttings back to the drill floor. However, with environmental rules becoming stricter, there are cases where long step-out wells have been successfully drilled using water-based mud, such as the H9 well on the Morcambe Bay field in the Irish Sea that reached a total depth of 5,489 m at a depth of 1,061 m, resulting in a high step-out ratio of 5.17.



Map showing the first generation of long horizontal wells – in light tones - in the Walrus field of the Canadian Peace River Bluesky formation oil sands. It is clear that the development reached a mature level, given that wells such as the PENN WEST HZ WALRUS 15-1-83-18W5 well – darker tone - were drilled in areas that were initially ignored. The map was drawn using information from the Petro Ninja Map website in combination with a map showing the PENN WEST HZ WALRUS 15-1-83-18W5 well by Chinook Consulting Services.

LONG HORIZONTALS

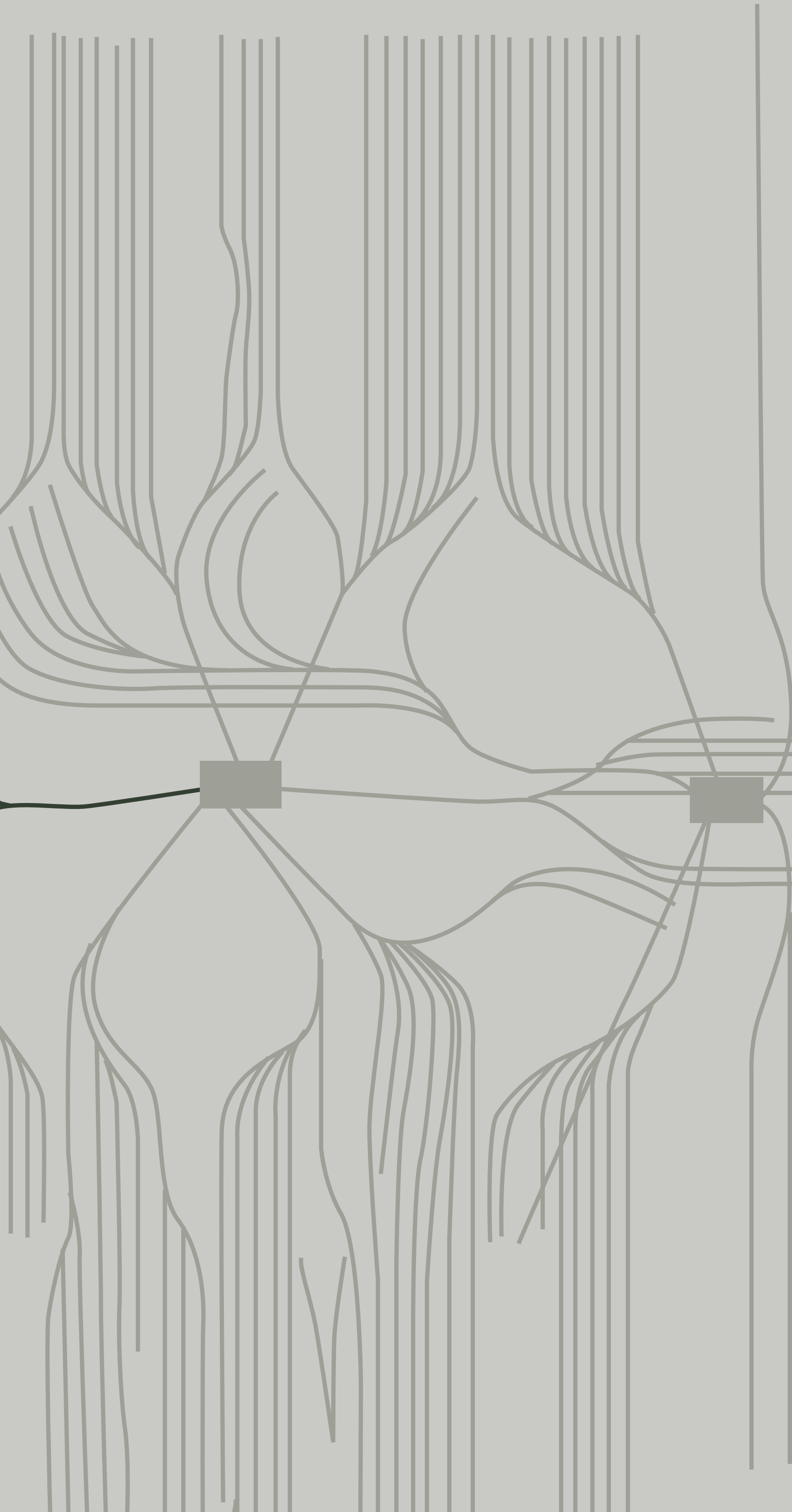
Based on a post on social media, in which we asked our followers to name the well with the highest step-out ratio – the ratio between horizontal distance and vertical depth – we got a good number of replies. The graphic on the opening pages of this article reflects the results, with the 15.2 km well drilled on the Upper Zakum field in 2022 as the likely winner at the moment, even though the step-out ratio could not be calculated because of the unknown depth of the well.

Calin Dragoie from Chinook Consulting Services in Calgary, Canada, also added a great bit of information in the comments and drew attention to the major number of horizontal wells that have been drilled in the Canadian oil sands in recent decades. There is one particular well that stand out, he commented.

When all lengths of the 47 legs of the so-called PENN WEST HZ WALRUS 15-1-83-18W5 well in the Bluesky sand of the Walrus field would be added up, he argued, this well would certainly be beating all the other wells drilled in the world, arriving at a step-out ratio of more than 24.

On his company's website, Calin writes that the Walrus well is a collector multilateral well, a type of well that was drilled before fishbone and feather wells became more common. The long straight legs act as collectors, from which a series of curved legs branch off into previously undrained areas.

This type of well was drilled to drain areas between already existing pads, as the map here nicely illustrates. In that sense, the collector type well can be seen as an infill well to ensure that any remaining oil left behind after the first phase of development can be produced.



WEST HZ WALRUS 15-1-83-18W5

PEACE RIVER OIL SANDS

The Bluesky Formation is a Lower Cretaceous marine transgressive sandstone that was deposited during an Albian sea-level rise that caused the western Canadian foreland basin to drown from north to south. The formation attains a maximum thickness of 46 m and is buried to around 4,000 m close to the Rocky Mountain deformation front, but is found at much shallower levels – less than 1,000 m - in areas where the sandstones form the reservoir for the Peace River oil sand deposit. It is in the latter area where the Walrus field is located.

Initial in-place volumes of the Peace River oil sand deposit – hosted by the Bluesky and underlying Gething Formation was estimated to be 69 billion barrels of oil. Commercial production of oil in the Peace River area commenced in 1986.

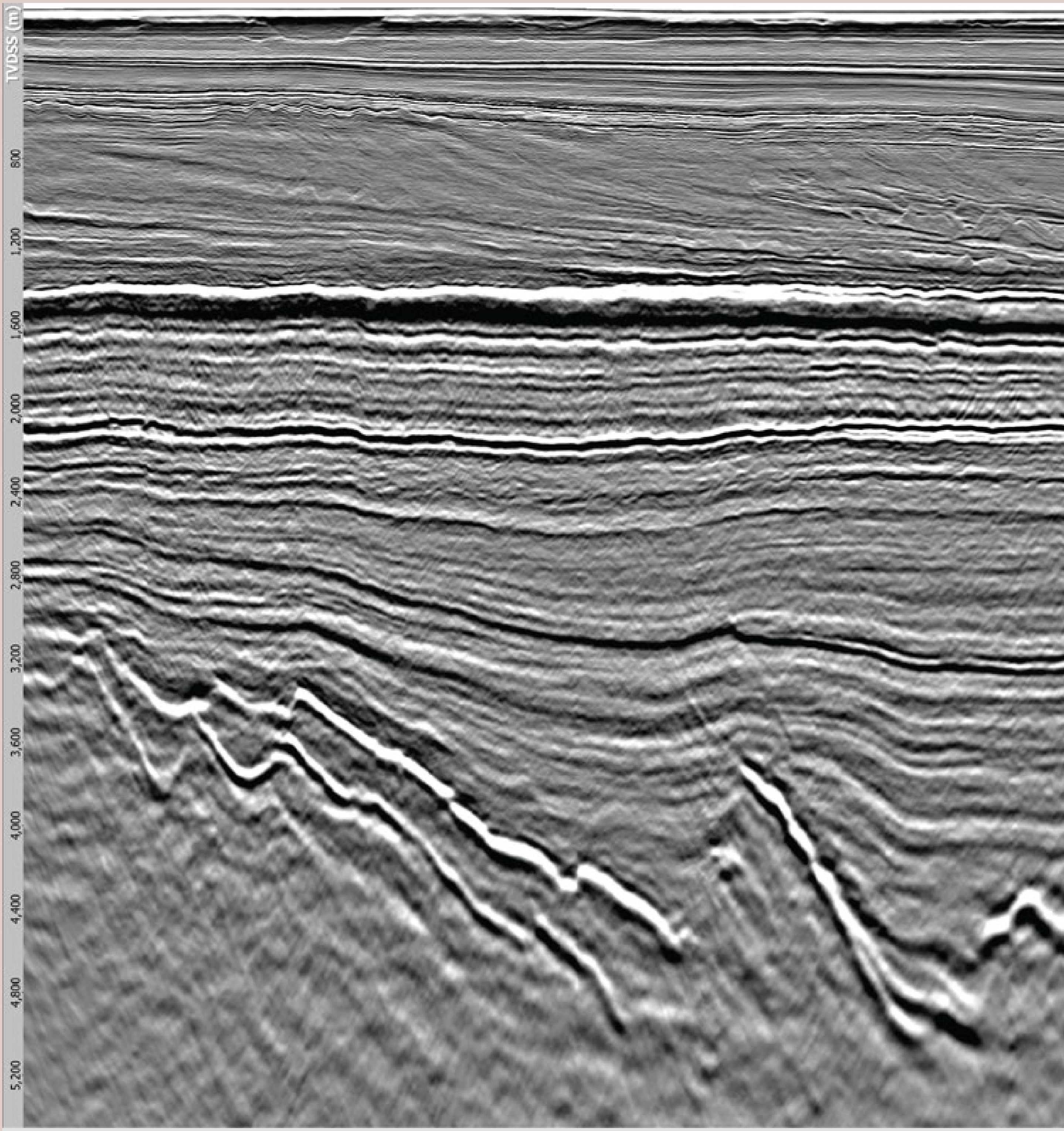
GOING DEEPER

It's not always a long horizontal well that is needed to discover or tap into additional volumes further away from an existing field. Sometimes, it is also worth just drilling a little bit deeper below the reservoir.

For instance, Equinor and Shell drilled around 1,000 m below the giant Ormen Lange gas field in the Norwegian Sea in 2022 to test the potential of the Upper Cretaceous interval beneath the Danian reservoir. It turned out to be an unsuccessful attempt.

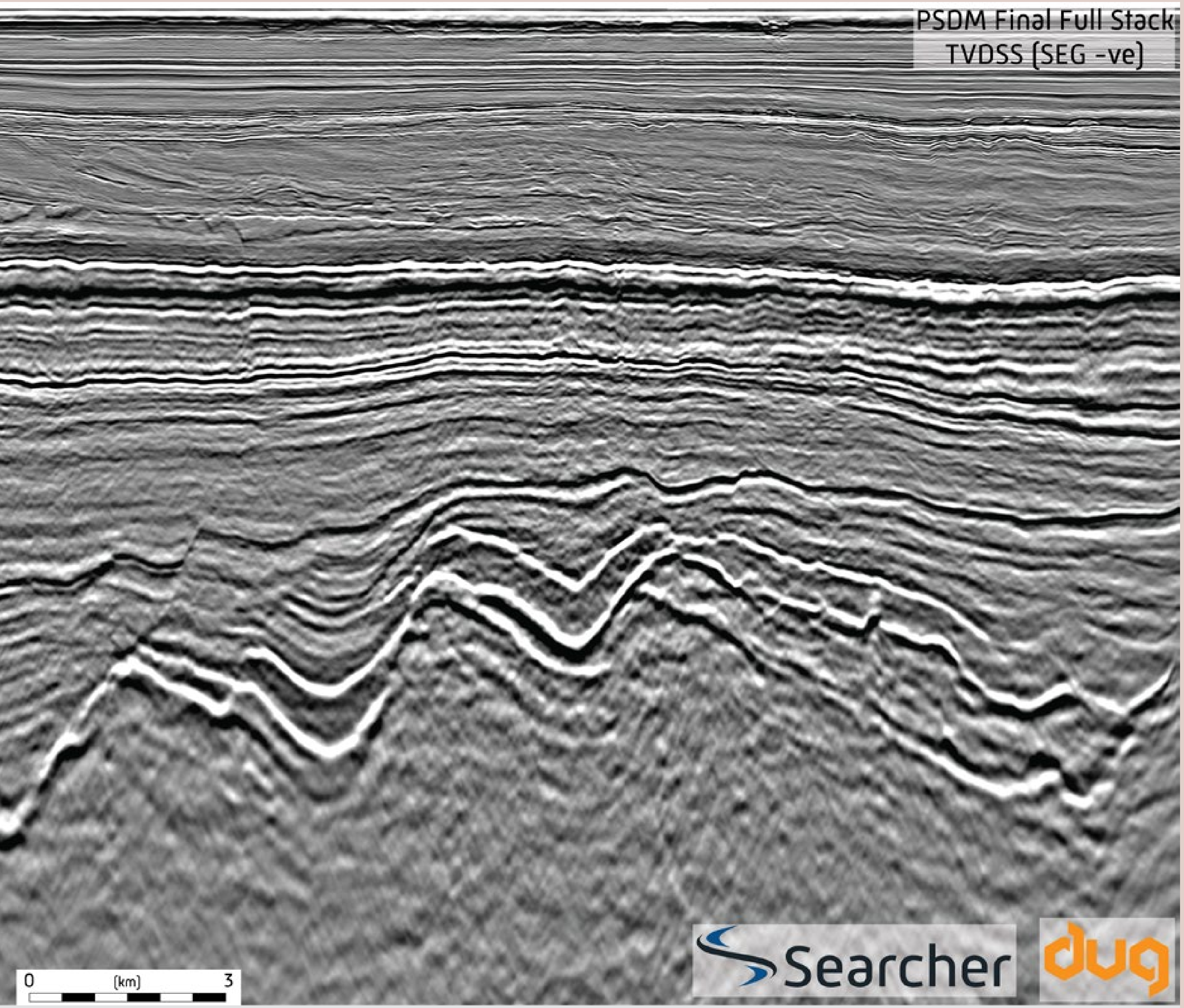
A positive and maybe more serendipitous example is a well that was drilled in 2020 in Tunesia. A new well drilled in the Buguel field, located in the Chotts Basin and which produces from a Middle Jurassic reservoir, tested the underlying Permian succession. In contrast to common belief that the Permian in the area only consists of tight non-reservoir facies, hydrocarbon-bearing carbonates were encountered in carbonates with good reservoir properties. The most important carbonate interval was tested at 4.1 MMSCFD and 336 BOPD.

The Big Buzz of



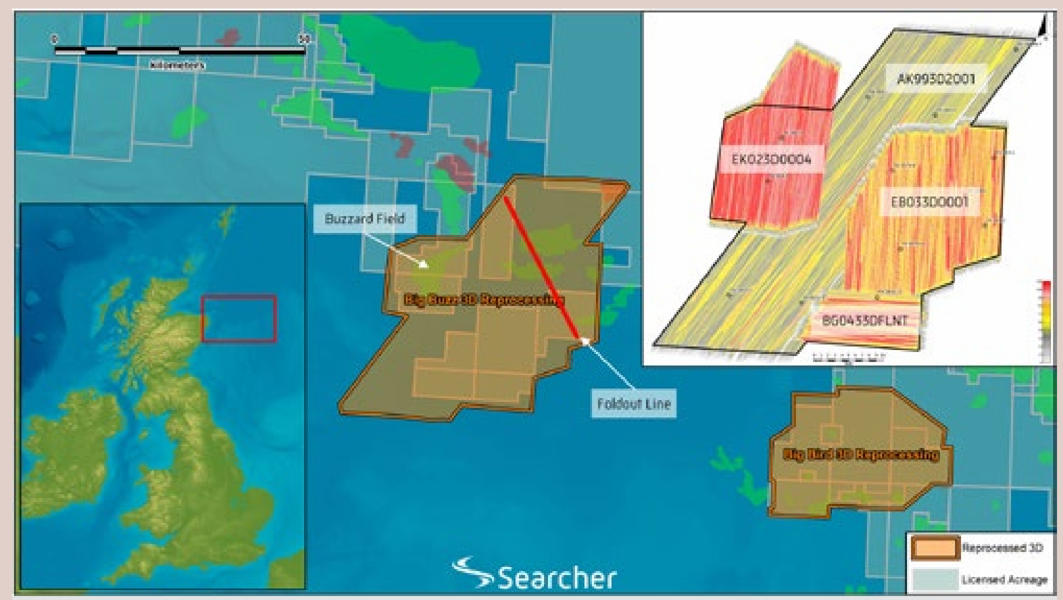
Searcher's 2022 reprocessed 3D seismic running NW-SE across the Ettrick Field and showing the Ettrick Sands pinching out onto Buzzard like structures to the northwest. Line length approximately 30 km. PSDM.

Buzzard II



In 2011, Dave Bamford reported the old adage in this magazine: "The best place to find oil is in an oil field!" Dave was writing about methods of improving recovery, and of course, the simplicity of the observation is what makes this powerful. So, in the spirit of stating the blindingly obvious to reveal a subtle truth: 'The best place to explore for oil is next to the last oil field you found." Whilst patently untrue in the case of the UK's giant onshore geo-unicorn of the Wytch Farm Field, it is absolutely true just about everywhere else.

With these words in mind, Neil Hodgson, Lauren Found and Karyna Rodriguez find that the best place to explore for oil is next to the Buzzard oil field in the Outer Moray Firth of the UK's North Sea, especially now that a reprocessed vintage seismic dataset is set to change an old narrative.



Four 3D seismic surveys comprising the "Big Buzz" dataset.

Buzzard II: The sequel

How about looking for another Buzzard field, next to the one that was found over 20 years ago?

NEIL HODGSON, LAUREN FOUND AND KARYNA RODRIGUEZ, SEARCHER

OUR GEOLOGICAL understanding is only ever a transient one – based on integration of well and seismic data at any given time. To change the story we have two choices; re-understand the integrated models we build, or change the data. In the Buzzard Field area of the North Sea there are many wells that tightly constrain the geological models so they are resilient and obdurate to change. Adding more well data is expensive - so to find the next Buzzard we needed to change the seismic dataset.

THE NEW SEARCH FOR BUZZARD II

To discover another Buzzard, Searcher re-processed as a multi-client survey, a total of 1,560 km^2 of 3D from four overlapping 3D seismic surveys vintage acquired between 1999 and 2004, located to the west of the Buzzard field. This dataset is called "Big Buzz".

DUG were awarded the contract for the reprocessing of these data, and the product of their work is truly astonishing (Figure 1 and foldout). The four surveys had been acquired on different azimuths, so multi-azimuth imaging was possible in areas of survey overlap. The re-processing sequence included deghosting, 3D SRME, Radon demultiple, noise attenuation, 3D TTI prePSDM, FWI velocity model building and Kirchhoff PSDM. The results are stunning from the sea floor down and have led to the re-imaging of the Jurassic plays in this area.

A NEW ETTRICK

One of the primary targets for re-imaging was to reveal the relationship between the Buzzard sands and the slightly younger Ettrick sands. Ettrick sands provide a thick reservoir interval in the Ettrick Field to the north but pinch out to the SW before reaching Buzzard. Imaging the pinch out of the Ettrick sands and locating a new Ettrick stratigraphic trap was not possible on the vintage data, which is noisy at the point of pinch out making the play somewhat ambiguous. Fortunately, the new processing images this pinch-out well and a prospective trap has been defined on acreage held by Finder Energy, an early adopter of the reprocessed seismic and beneficiary of seeing how the new data changes an old story.

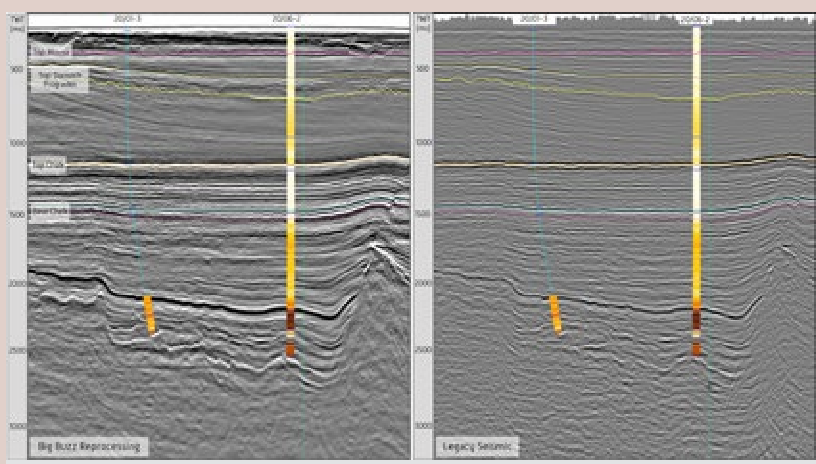


Figure 1: Comparison of Buzzard field geology on vintage seismic (Right) and Reprocessed "Big Buzz" (Left).

BUZZARD FIELD

The 2001 Buzzard discovery well 20/6-3 is located in the North Sea, about 60 km northeast of Aberdeen. This well drilled a stratigraphic trap and made one of the largest oil discoveries in the UK for the last 40 years. Lying 50 km east of the Scottish mainland in shallow water (<100m), the discovery well encountered high quality 32° API oil in Oxfordian to Volgian age Jurassic, base of slope, submarine gravity flow sands. This reservoir is known now as the Buzzard Sandstone Member and displays excellent porosity and permeability (ca 1.5 D).

The trapping mechanism for the field involves a complex up-slope stratigraphic pinch-out of reservoir sands to the west combined with a downthrown faulted closure against Palaeozoic basement. This stratigraphic trap was considered high-risk pre-drill. The risk of not imaging a thief sand in the stratigraphic bypass of the channel systems feeding the base of slope fan was high in 2001 despite 3D having been collected. On that early data, the imaging of a large number of channels cutting the slope would have unnerved the bravest of us. Yet, the bravest of us drilled the prospect and, as they say, the rest is history.

THE MOST ATTRACTIVE PLAY

However, the most attractive new play on the data is the imaging of an Upper Jurassic depositional system and potential 'Buzzard II'. Both the new imaging and a study by Lyme Bay using spectral decomposition (Figure 2) have revealed not only a large fan down-dip of the basement framing the basin, but also it has revealed the detailed sedimentology within this fan. A new 'Buzzard' age sand fairway appears at last to have revealed itself. Lying close to existing infrastructure this target, constrained by the most modern seismic available looks extremely attractive (Figure 3). The imaging of Buzzard II reveals super-steep feeder channels, devoid of sand and more likely to represent bypass zones than even those on the Buzzard accumulation.

Other prospects have been defined by Finder Energy as leaping out of the new data too, both within the Jurassic and below in the Zechstein where there is a very large and distinctive carbonate buildup with a karstic dendric network below the Kimmeridge Clay Source rock.

THE NEXT BIG BIRD

The stratigraphic play-led future of North Sea exploration is looking in the best place for any exploration; next to the last place you found oil! With the benefit of reprocessing the vintage 3D datasets, we have a chance to change the narrative of the past that was based on the data of the past. Buzzard II will only be the beginning, and re-imaging legacy datasets like "Big Buzz" is the start of finding the next big bird nesting by the previous big bird in the UK's North Sea.

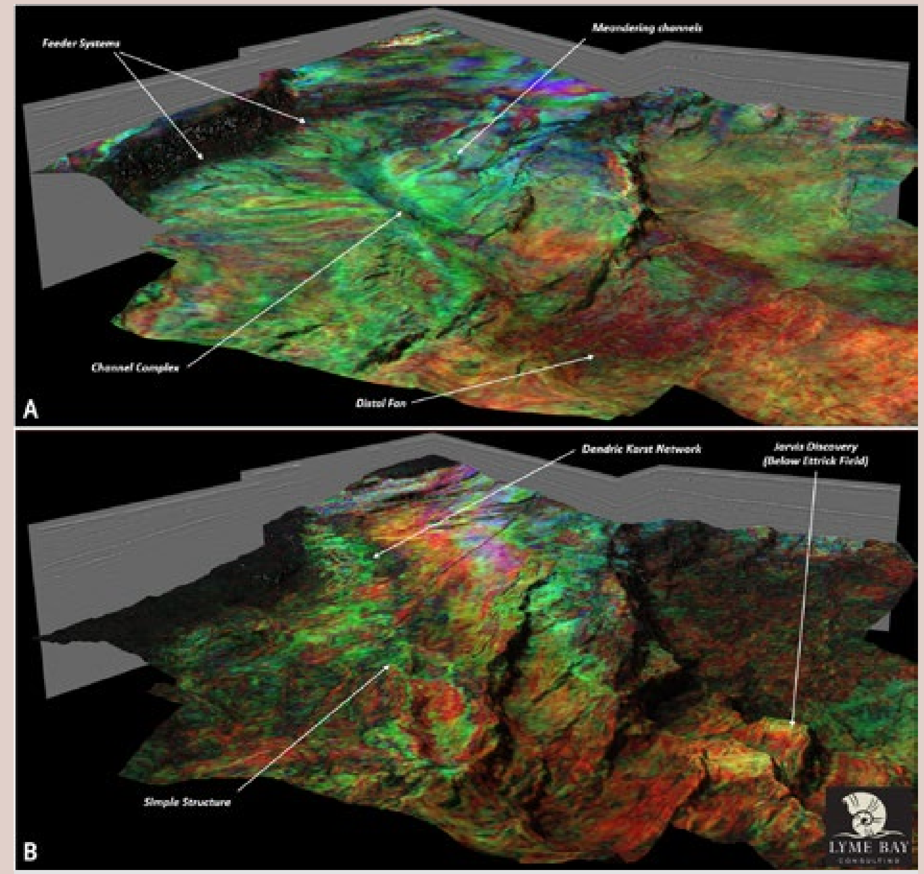


Figure 2: Lyme Bay Spectral Decomposition of Big Buzz reprocessed 3D multi-client dataset. a) Upper Jurassic depositional fairway b) Zechstein Karst features

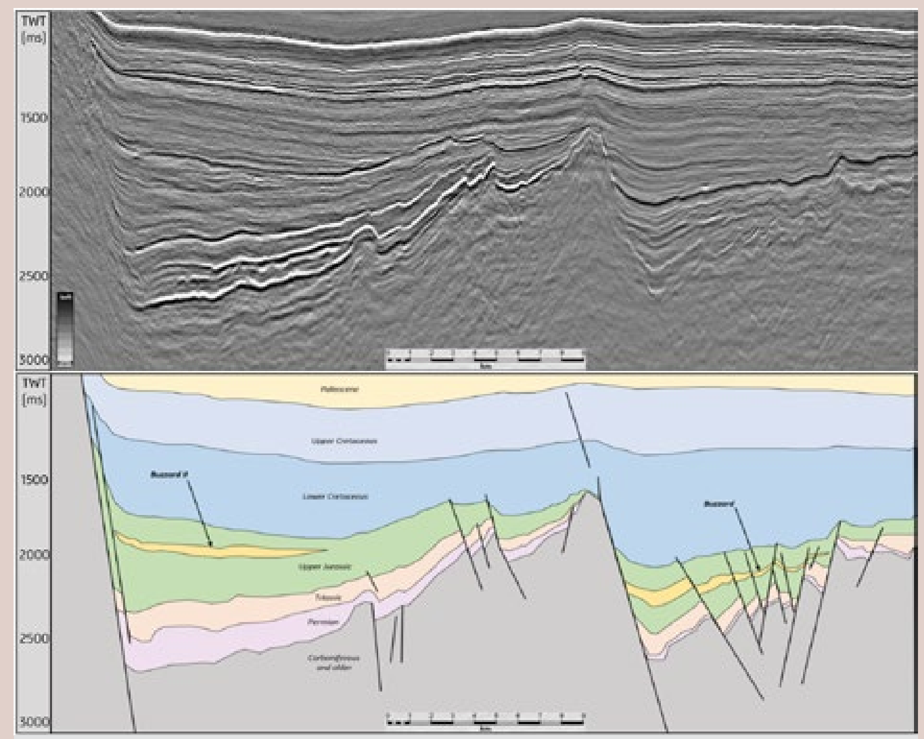


Figure 3: Reprocessed "Big Buzz" Seismic through Buzzard II and the Buzzard field with geo-section.

NORTHWEST EUROPE

"Just because you can't see volcanic intrusions in seismic data doesn't mean they aren't there!"

Prof. Nick Schofield – Aberdeen University

More wells

In October this year, the biannual meeting of the Continental European Energy Council (CEEC) took place in Tirana, Albania. Here, we share the highlights of the conference, emphasising that Europe is not sitting still when it comes to oil and gas developments and geothermal, with many wells to be drilled.

Text: Gehrig Schultz

HIGH-IMPACT

New player MCF will drill two high-impact wells in Germany in Q1 2024. One will be a development well in the Lech area Bavaria, Germany. A previously drilled well at Lech flowed at rate of over 20 mmcf/d of gas. The other well will be in the Erlenwiese concession in the Rhine Graben in western Germany, which is prospective for oil and gas at multiple stratigraphic levels.

120 APPLICATIONS

Hungary's recent geothermal bid round received over 120 applications for licenses. Five awards have been issued and the remainder are expected to be made by December. CEEC members offer several geothermal farm-in opportunities. For more info contact us at contact@ceecsg.org

DRILLING IN AUSTRIA

ADX will be very active in Austria with two appraisal and development wells and two high impact gas exploration wells. The high-impact Welchau well targets a structure covering over 100 km^2 and could contain 807 BCF of gas.

HELIUM AND HYDROGEN

Pioneer in exploring for helium and natural hydrogen in Europe, 45-8 ENERGY operates two exploration licenses for helium and related resources, in the Nièvre and Doubs regions respectively, one of which will go into pilot production in 2024. 45-8 ENERGY has obtained several exploration and production permits, in France, Germany and Kosovo.

ALBANIA

Energy Development Group, who hosted the CEEC meeting in Tirana, is working on redeveloping the Delvina, Frankulla and Povelca gas fields in Albania with 3D seismic and drilling planned for 2024. In addition, both ENI and Shell have ongoing deep exploration programs in the country.

EUROPE'S LARGEST yet-to-be TESTED PERMIAN STRUCTURE

Central European Petroleum (CEP) is planning to drill its Wolin Project offshore Poland in the Baltic Sea, following acquisition of new 3D seismic data. The Upper Permian (Zechstein) Main Dolomite reservoir, developed in shallow-water facies, will be targeted by two new wells - Wolin West 1 and Wolin East 1. Wolin forms Europe's largest yet-to-be tested Permian-age structure with potential of >300 MMboe.

SUCCESFUL EXPLORATION

Despite the dire situation in Ukraine, Naftogas drilled 28 exploration and appraisal wells in the Dnieper Donets Basin so far this year, in addition to redeveloping old assets. As an example, two wells were drilled on a field that was discovered 40 years ago, with combined flow rates of 15.2 MMcf/day of gas per day and an expected peak of over 32,000 boepd in 2025.

POTENTIAL DEALS

Romania is the only country in the region that is not covered with long-offset 2D lines. Therefore, it looks like a good place for a contrarian investor to search for deals.

NEPTUN DEEP

A real highlight from the region is OMV's announcement of the final investment decision for natural gas deep-water project Neptun Deep in Romania's Black Sea. Neptun Deep will be one of the largest natural gas projects in the European Union. First production is expected in 2027 and plateau production is estimated at ~140,000 boe/day for 10 years. Planned project investment totalling up to EUR 4 bn.

PLAY EXTENSION

Anticipating an extension of the large discoveries in Turkish waters, Bulgaria announced the launch of a tender for an oil and gas prospecting and exploration permit in Block 1-26 Khan Tervel, in the Black Sea. The project envisages conducting 3D seismic surveys, preparing a geological model to identify prospective drilling sites, assessing petroleum potential and drilling an exploratory well.

Unlocking Permian and Carboniferous petroleum systems of the Southern North Sea

New insights from new analyses

PATRICK BARNARD, APT

THE NORTHERN part of the UK Southern North Sea (SNS) and the adjacent Mid North Sea High (MNSH) have seen a recent revival when it comes to exploration activity, with the Pensacola oil and gas discovery and an appraisal well on Crosgan as two tangible examples.

Even though the 33rd Round awards are yet to be announced for the SNS and MNSH, APT has finished a new study focusing on the proper identification of the different source rocks in the area, as it is the source rocks that have always been a matter of debate in this part of the UKCS. Whilst the source for most parts of the SNS is dominated by Upper Carboniferous coals and the oil in the Central North Sea is mostly from the Upper Jurassic Kimmeridge Clay, the MNSH, with its particular Zechstein reef and karstified dolomite reservoir facies, is characterised by an oil source that can either be of Permian or Carboniferous age.

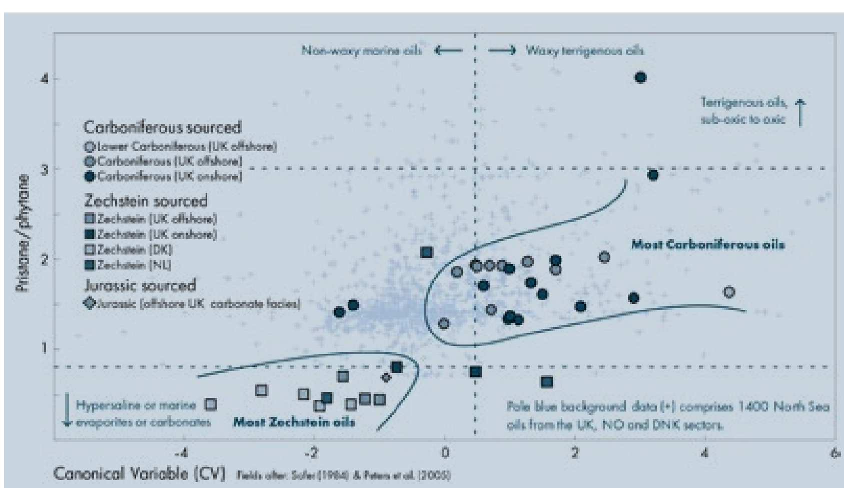
From wells across the area of interest, APT performed new analyses on 150 source rock samples. The results showed that 21 samples flowed oils and condensates. In addition, 159 oil-stained samples have proven that distinct and multiple petroleum systems are present across the MNSH and SNS, enabling the parameterisation and quantification of the potential of the Permian and older Carboniferous source rocks. In doing so, the risk around charge in these poorly understood play fairways can be better assessed.

Oil stain quality varies considerably across the MNSH and SNS, but good quality, robust oil stains have been identified throughout the Zechstein interval, having a distinct carbonate and sometimes hypersaline signature in places. Oil stain quality increases towards the southern extent of the MNSH where the Zechstein becomes increasingly mature.

The Zechstein and Carboniferous hydrocarbon families can be readily differentiated based on a range of diagnostic parameters including isoprenoid, standard and non-standard biomarker, and carbon isotope data. Supplementary statistical analyses have aided with the identification of hydrocarbon families. Good quality oil- and gas-prone source rocks have been proven in the Zechstein and Carboniferous intervals. Additional petrophysical analyses have further

supported the presence of these source rocks across the MNSH and SNS.

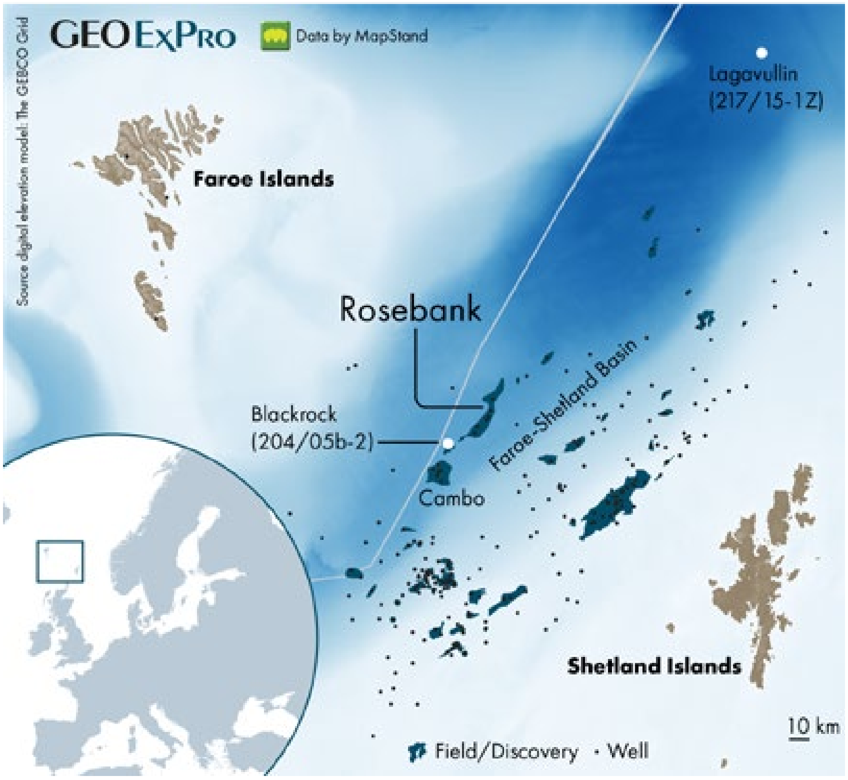
Key findings include the identification of multiple source intervals and charge systems within the Zechstein and the recognition that understanding the regional depositional systems will be crucial to finding the sweet spots. ■



Geochemical Evaluation of the Zechstein and Carboniferous Petroleum Systems of the MNSH and the Western Southern Permian Basin.

Why did it take so long to develop Rosebank?

Above-ground factors may have caused a delay in getting Rosebank over the line recently, but it is the geology that is the key as to why it took almost 20 years to get to this point



ROSEBANK was discovered in 2004. The reservoir quality of the Paleocene/Eocene Colsay Sandstone Member was shown to be around 20%, permeabilities around 3 Darcy and an average oil quality of 37° API did not leave too much room for doubt either. Yet, it took almost 20 years to get more clarity on whether the 300 MMboe accumulation could be developed or not.

IT'S THE GEOLOGY

Even though the Rosebank discovery is in good quality reservoir sands, the reservoirs are separated by a series of basaltic lava flows. And it is the seismic imaging problems related to these lava flows that have complicated building an accurate picture of the architecture of the field, which consists of four different reservoir intervals separated by volcanic units.

VELOCITIES

Velocity variations in the overburden have also been known to be an issue in the area. As was demonstrated at Cambo only a stone's throw away from Rosebank, two wells that are only 3.5 km apart plotted at significantly different levels in time domain whilst in depth the top of the mapped Hildasay turned out to be at nearly the same level.

ROLE OF VOLCANICS

Despite the imaging problems that the Rosebank basalts caused, the presence of the volcanic intervals may also have had a positive influence on the field. In most sedimentary systems where volcanic influence is missing, fluvial systems tend to erode into each other. In the Rosebank area, the cycle between southerly-derived siliciclastics and northerly-derived basalts may have resulted in the preservation of a more extensive reservoir section than would have occurred otherwise.

SEAL OR NO SEAL?

Then there is the question to what extent the lava flows contribute to the pore space. At the end of the day, the recently drilled Blackrock well nearby found oil in time-equivalent lava flows. In the Lagavullin exploration well, open pore structures in the basalts have been encountered, leading to mud losses. The wells drilled on Rosebank did not result in similar losses, which could indicate that in this case the volcanics are more likely to be tight and form a seal rather than a reservoir. It could also better explain the different fluid contacts across the field.

In conclusion, based on the geological uncertainties briefly discussed above, it is understandable why it took so long for Equinor and partners to get Rosebank to FID. ■

FEATURES

"Despite the frontier nature of the well, the prognosis Exxon made – based largely on seismic stratigraphic work - turned out to be very accurate."

Pat Shannon – Emeritus professor at University College Dublin

Have bottom currents defined the Golden Lane and determined updip prospectivity?

An alternative viewpoint to solely channel-supplied deepwater sands in Guyana and Suriname

NICK CAMERON, GEOINSIGHT

SINCE THE PROLIFIC Cretaceous oil kitchen of the Canje Formation offshore Guyana was demonstrated by Lawrence and Bray (1989), an anomaly related to the lack of exploration encouragement away from the Corentyne region has been present (Figure 1). This picture in Guyana contrasts with Suriname where significant volumes of heavy oil were proven in the onshore Tambaredjo cluster.

The discovery of Liza in 2015 finally demonstrated where the oil had migrated to: Lower slope stratigraphic traps. A steady flow of commercial discoveries followed the discovery of Liza, yielding a narrow northwest-southeast trend that continues into Suriname, hosting an estimated 11 billion barrels of oil. Figure 2 shows the nearly 200 kilometres of deepwater discoveries, contrasting the lack of up-dip encouragement.

AN ALONG-SLOPE CURRENT CULPRIT?

Trude et al. (2022) found that the linearity of the deepwater Liza trend discoveries appears to be associated with sand barrier traps formed by seabed relief created by the inversion of coast parallel basement faults. This depositional pattern is further illustrated by Cronin (2021), who also indicates upslope feeder channels. For Liza, Price et al. (2021) show, using a stratigraphic slice, that a decrease in slope determines the channel-to-lobe transition.

The linearity of the deepwater discoveries evolved from a few discrete, north to north-northeast heading, channel forms into a nearly continuous, northwest-southeast

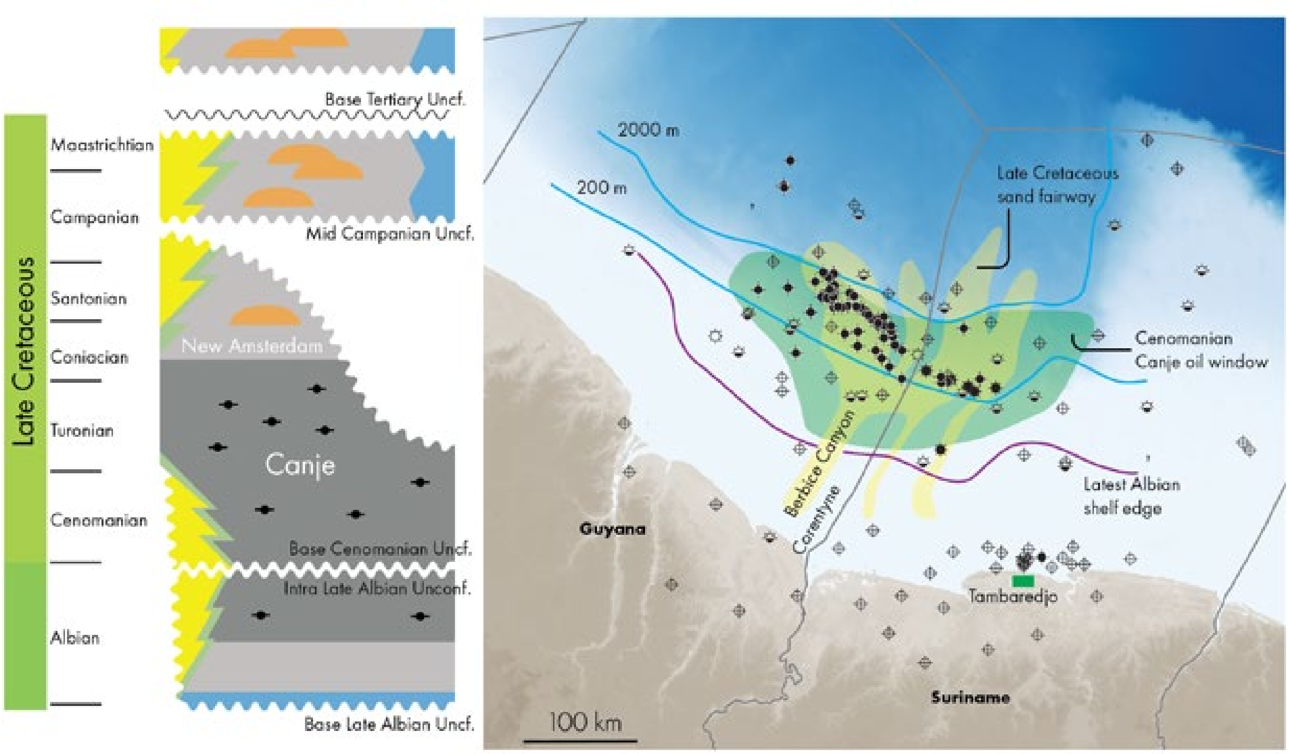


Figure 1: Guyana's wells and their relationship with the Cenomanian Canje Oil Window (Repsol, 2004) and Berbice Canyon delivered sands (Anon, 2018). Kombrink (2023) was used for the base map base with the onshore wells and water depths added using Workman and Birnie (2015). Casson et al. (2021) provided the shelf edge track as well as the stratigraphic column.

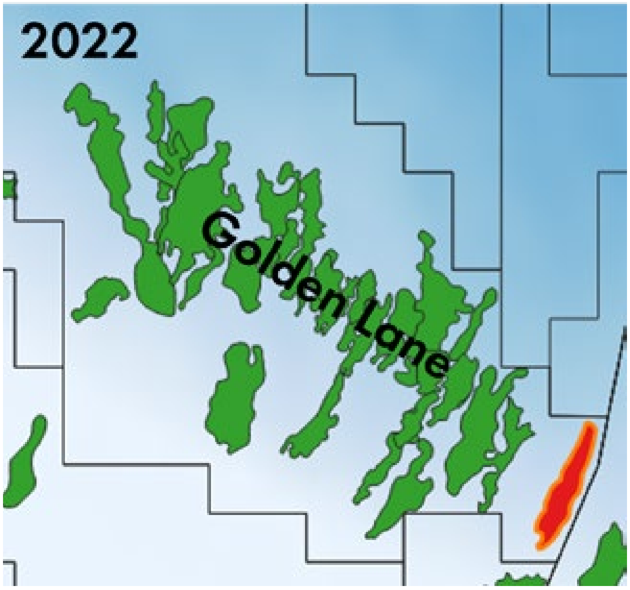


Figure 2: The fields that have been discovered since the discovery of Liza in 2015, now collectively known as the Golden Lane.

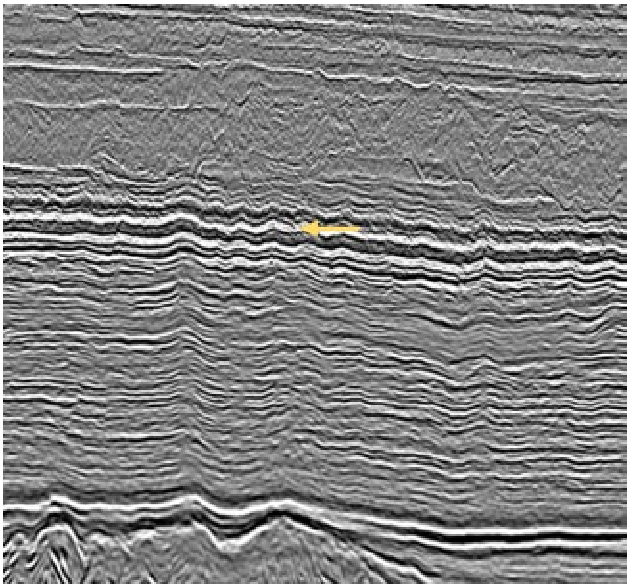


Figure 3: Screenshot from a seismic line in the Guyana area, showing a seismic character that can be interpreted as being caused by seabed waves.

orientated zone of pay sands (Figure 2) that is now collectively known as the Golden Lane. This swathe format of laterally linked fields points either to overlaps between channel-fed fan lobes or trap mergers fostered by syn-depositional contour currents.

Age-equivalent fields along the conjugate margin of Africa that were also deposited in a lower slope setting, have been demonstrated to host along-slope drift sediments. For instance, sediment waves have been observed within the Cenomanian and Albian succession of the Greater Tortue Gas Field that straddles the Mauritania/Senegal border. These sediment waves formed in lower and middle slope environments and were created by a southward flowing contour current that reworked and cleaned sands supplied to the deepwater by feeder channels.

Until recently, the larger vertical scale lines required to examine bed forms did not extend across and beyond the Golden Lane. Two examples now do (PGS, 2023 and Ministry of Natural Resources, 2022). Both lines, though unscaled and unlocated, suggest that seabed waves generated by currents existed at the end of the Cretaceous (Figure 3), with the PGS line hinting that current activity commenced before that time. In addition, Nibbelink et al. (2020) noted that dune-forming current activity commenced from the Upper Maastrichtian.

ALONG-SLOPE CURRENTS AND EXPLORATION CONSEQUENCES

With along-shore drift likely having played a prominent role in Guyana's and Suriname's deepwater area, the sand supply to the area could have been dominated by a single river rather than multiple smaller ones. Should this be the case, the Berbice (Figure 1), with its exit in the Corentyne, is the optimal candidate. Its history reveals a Late Albian drainage initiation, followed by the formation of the Berbice Canyon during the Coniacian. The infill of the canyon is some 2,000 metres thick and contains multiple channel-related plays.

Could the sand from the Berbice Canyon make its way to where Liza was found? A figure released by Kosmos Energy illustrates that the Berbice delivered sand through a northwest flow towards the Liza area and beyond (Figure 1). Likewise, a single dominant Santonian sand source also originating from the Berbice is illustrated by Casson et al (2021).

ONE DOMINANT FEEDER SYSTEM

What is the potential implication of one dominant sand feeder system for Guyana and Suriname's offshore? First of all, it means that sands will be primarily concentrated within its current lower slope trend. Furthermore, it forms a potential explanation for the lack of success when it comes to more up-dip drilling attempts: the Cretaceous sand-filled channels required to reliably supply oil from the Canje kitchen to reservoirs in shallow waters may be missing altogether.

The zone where additional prospectivity could be expected though is the upper slope and shelf edge away from the Berbice Canyon. With an active and voluminous Canje kitchen and perhaps additionally an older precursor, and the lack of onshore seeps, it is likely that more oil was generated than can be hosted by the reservoirs currently found. This was demonstrated by Tullow's recent wells that demonstrated substantial volumes of up-dip migrated oil. ■

References available online.

SEISMIC FROM PGS (WEBSITE)

Why it is not a slam dunk to ramp up gas production in Bolivia

Exploration in the Andean foothills comes with challenging reservoirs at challenging depths that are difficult to image

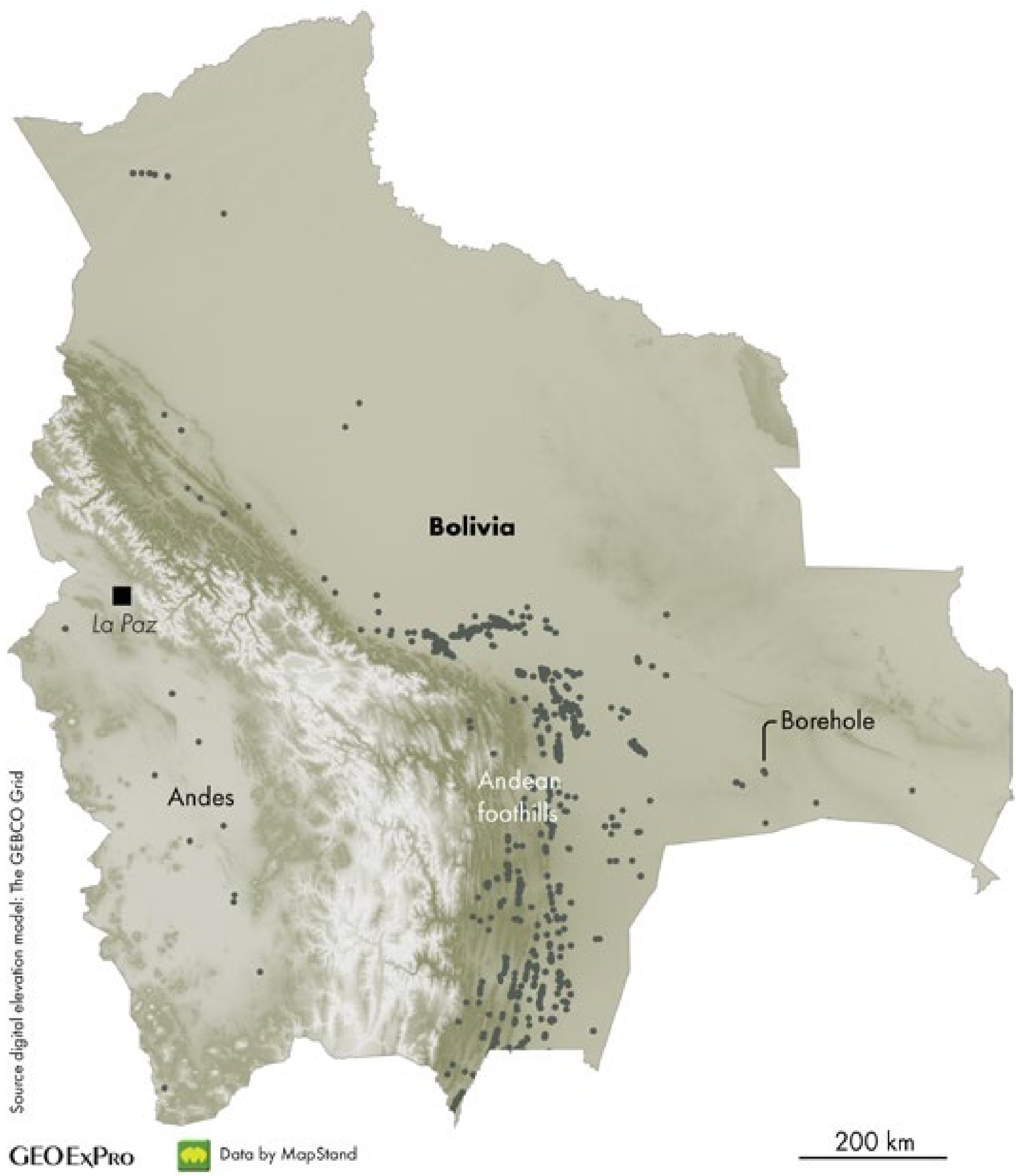
BOLIVIA IS STILL a gas-exporting country, with Brazil and Argentina being the two customers. But, with production on a long-term decline, and with Argentina now developing its own resource in the Vaca Muerta, the flow of gas will soon stop towards the Argentinian market. However, in order to continue meeting its domestic and the Brazilian demand, Bolivia realises that something needed to be done.

In that light, the so-called Upstream Reactivation Plan was launched a few years ago, with the ambition to ramp up both oil and gas production in the Subandean fold and thrust belt, Bolivia's most important petroleum play, and the further development of more mature assets. However, given the geo- ▸

TWO REMARKABLE EXPLORATION ATTEMPTS

A spectacular example of recent exploration in Bolivia is the drilling of the deepest well in South America by a consortium of Repsol, Shell and Panamerican to almost 8,000 m depth, again targeting a Devonian reservoir. Whilst the well was drilled successfully, no commercial gas was found, unfortunately.

Another not-so-successful well was drilled by Shell in 2020, but it was unsuccessful for another reason. Whilst the bit had already exceeded the 5,000 m mark, the Anglo-Dutch company decided to leave the country and quit well operations. "It was a shame to see this happening whilst we were getting so close to our target", says Fernando.

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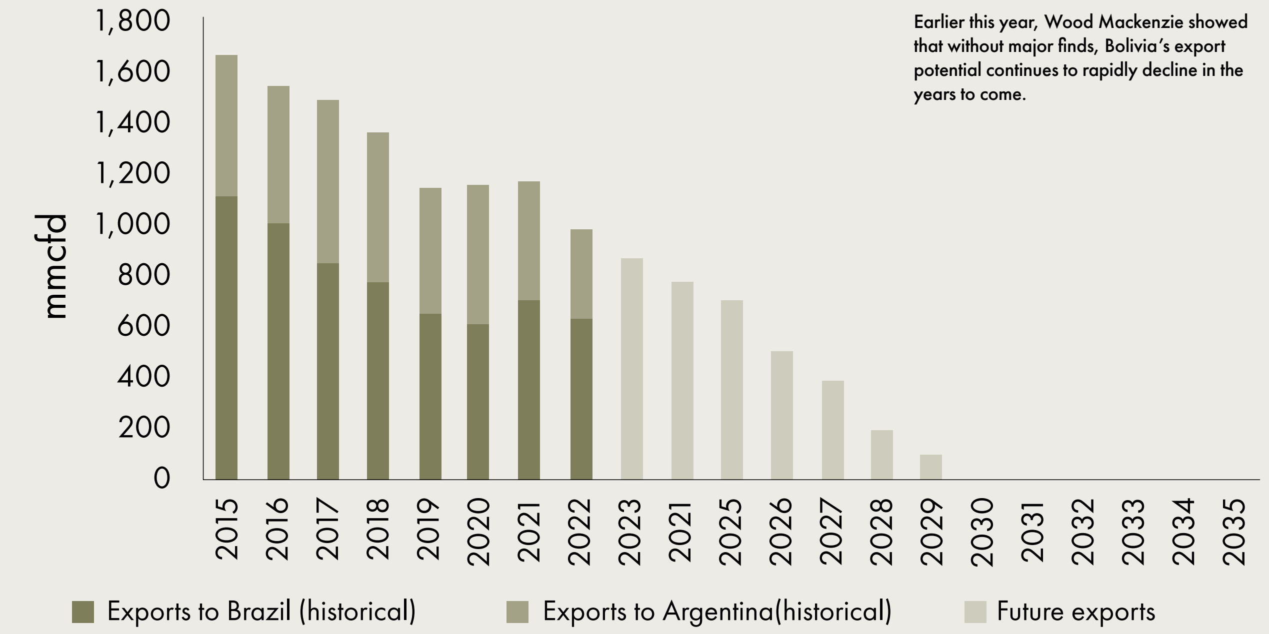


Earlier this year, Wood Mackenzie showed that without major finds, Bolivia's export potential continues to rapidly decline in the years to come.

SOURCE: WOOD MACKENZIE

logical setting of the main petroleum system in Bolivia, it is not that easy to just start drilling many wells at the same time.

FRACTURED SANDSTONES

"Our main reservoirs are naturally fractured sandstones of Devonian age", says Fernando Alegria, exploration manager at state-owned company YPFB Chaco, part of Yacimientos Petrolíferos Fiscales Bolivianos (YPFB). "These reservoirs are often buried very deeply, with 4,000 to 5,000 m being a fairly common target depth. Together with the very consolidated nature of the overburden, its complicated structural history with many thrust faults and the associated low ROP's, it is not a trivial exercise to drill to these depths."

The company is currently drilling an exploration well in the south of the country close to the Argentinian border. "We expect to hit our target at some point next year, being at 6,200 m depth", Fernando adds, pointing out that these wells easily cost between 50 and 150 million USD and take more than a year to complete. It is the depth of these targets that makes exploration a costly exercise in Bolivia.

USING YOUR IMAGINATION

One of the other reasons why exploration is sometimes challenging is the fact that especially in the Andes fold and thrust belt, the acquisition of seismic is very costly and the quality is not as good as marine seismic to put it that way. "Geologists have to use their imagination to a large extent to come up with the definition of a prospect in these areas", laughs Fernando. In contrast, in the foothills to the east, it is easier to acquire 2D and even 3D, but yet so far the fields discovered in that area tend to be smaller than the ones found in the fold and thrust belt.

The main focus of activity at the moment is the south of the country, where traditionally most oil and gas drilling has taken place and where most of the infrastructure resides as a result. "A few wells were drilled in the northern part of the Subandean fold and thrust belt, but all of these were unfortunately dry. We have also looked at the potential of shale oil and gas, also in the north of the country close to the border with Peru, but this is mainly in an area that has a protected environmental status, complicating or even prohibiting access to the area." ■

THE OPERATOR LANDSCAPE

Apart from YPFB Andina and YPFB Chaco, the two companies that fall under the YPFB umbrella, the main international oil companies with a presence in Bolivia are Repsol, Petrobras and TotalEnergies. Repsol has focused on the production of its assets and does not have exploration licences at the moment.

Petrobras operates two big gas fields in the south of the country, but since production is also declining from these assets, the company is weighing up the question whether to stay or to sell their assets, even though they have got a number of drillable prospects in their portfolio.

Vintage (Oxy) is active in Bolivia too. More recently, Canacol – Canadian and Colombian oil company – has also made its entry in Bolivia and are going through the paperwork to gain the rights to operate in some areas.

A unique well at a unique time

How did Exxon manage to drill a frontier well offshore Ireland so close to prognosis?

It is easy to reconstruct the rifting and drifting history between South America and Africa. Similarly, it is straightforward to piece together the extensional history between Norway and Greenland. But looking at how things fit offshore Ireland and its Newfoundland conjugate margin, with several blocks rotating at the same time and various pre-break-up orogenic trends superimposed, it is fair to say that even today there is uncertainty as to how things exactly looked in Jurassic times, says Pat Shannon, emeritus professor at University College Dublin.

In the middle of this jigsaw of moving continental slivers is the Goban Spur. And it was in the Goban Spur where Exxon drilled well 62/7-1 in 1982, against a backdrop of hardly any well completions on the Atlantic margin and at a time when the concept of plate tectonics had just arrived.

"In fact", Pat says, "the Goban Spur, situated to the south of the Porcupine Basin and to the west of the Celtic Sea Basins, really finds itself at the crossroads of Mesozoic and Paleozoic structural grains. For that reason, it was very hard to predict the geology of the area."

A NEW APPROACH

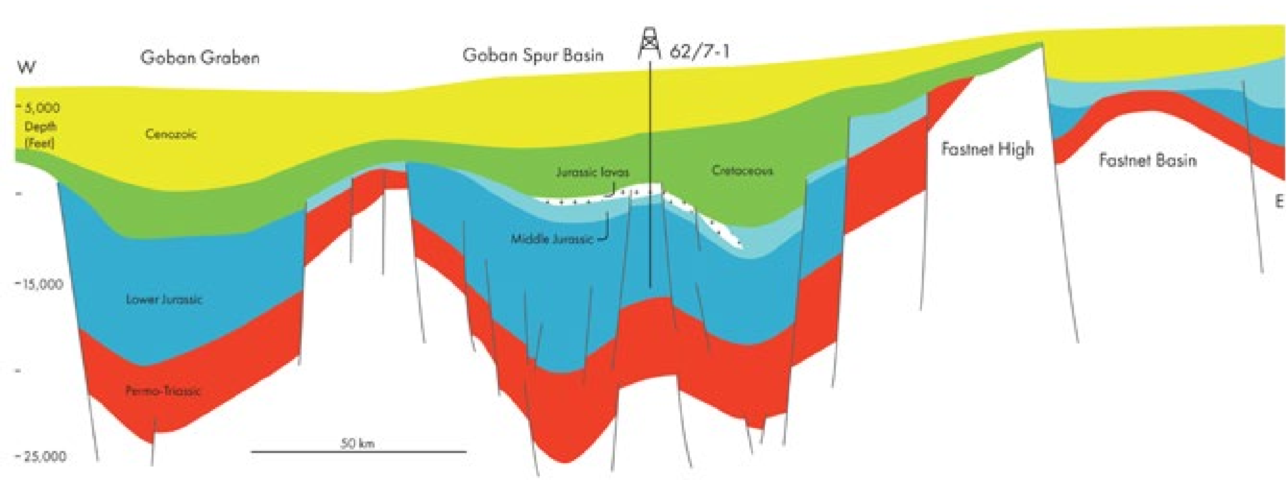
Because of the virtually unknown geology of the area, de-risking required a totally new approach. "At the time, it was only the Celtic Sea Basins and the northern part of the Porcupine that had seen some wells drilled, but the geology could not be easily extrapolated beyond these areas. We did not know anything about the middle and southern part of the Porcupine Basin, so it was real frontier territory."

"What Exxon subsequently did was quite interesting", Pat continues. "The seismic data acquired in 1981 was being interpreted from a seismic stratigraphic perspective, interpreting potential sands and source rocks. It was very new in those days. Peter Vail, who worked for Exxon at the time, only published his famous AAPG Memoir on seismic stratigraphy a few years before that."

"Another thing Exxon did was bring in academic work, which contrasted the approach taken by many other companies not to engage too much with academic researchers and their results. For instance, the company looked at dredged seafloor samples from French Research Institute Ifremer and took an interest in the work by Roger Scrutton from Edinburgh University who had studied gravity data from the area. Based on that, Exxon began to piece together a story that could explain whether the Goban Spur was underlain by continental, transitional or oceanic crust."

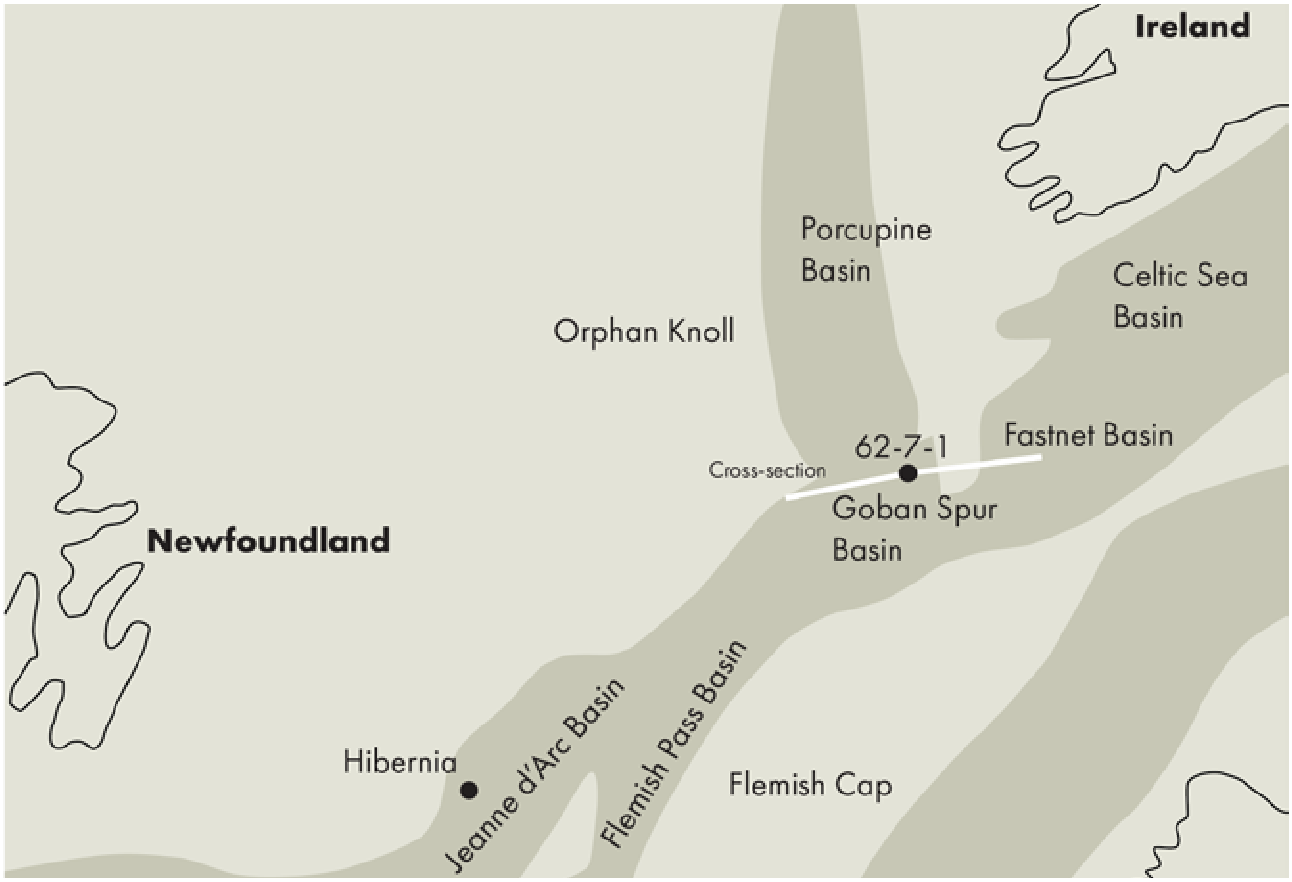
"Bear in mind", Pat reiterates, "hyper-extension as a concept to explain continental rifting processes did not exist in those days; it was rather a matter of rigid blocks that they were trying to piece together to see where things would have been at the start of rifting."

As the seismic lines acquired in Irish waters were interpreted, successful exploration drilling had already resulted in a major oil discovery in the Jeanne d'Arc Basin offshore Newfoundland - the Hibernia field. ▸



ADAPTED FROM FIGURE 2 IN COOK (1987): THE GOBAN SPUR – EXPLORATION IN A DEEP-WATER FRONTIER BASIN

Cross-section showing the position of the 62/7-1 well drilled by Exxon in 1982.



Continental reconstruction of the North Atlantic during the Triassic.

ADAPTED FROM FIGURE 4 IN COOK (1987): THE GOBAN SPUR – EXPLORATION IN A DEEP-WATER FRONTIER BASIN

And that was interesting, because Exxon's reconstruction suggested that the Jeanne d'Arc Basin and the Goban Spur were connected before the onset of stretching. This subsequently opened up the possibility that reservoir sands and source rocks could be present on the Goban Spur as well.

AN ACCURATE PREDICTION

"Despite the frontier nature of the well, the prognosis Exxon made – based largely on seismic stratigraphic work - turned out to be very accurate", Pat says. Even though the well did not find commercial quantities of hydrocarbons, a mature Lower Jurassic source rock was proven, alongside some decent Middle Jurassic reservoirs. "The problem was that the presence of lava flows, which had a detrimental effect on the presence of siliciclastic sands."

"Another good thing about the well was the fact that Exxon did not stop drilling immediately after hitting the volcanics, which would have happened in many cases", continues Pat. "Instead, they drilled into Sinemurian limestones, close to the top of the Triassic."

"To me", Pat concludes, "the well is a great example of collating all the bits of information required to put together a consistent story. The area was relinquished soon after the well was completed, but the story and the science behind it remain."

A RENEWED INTEREST

The well continued to be an important source of information that heavily influenced the way companies expressed interest in Porcupine Basin acreage during the last offshore Irish licensing round in 2017. "Based on the results of the well, a renewed interest was seen in the deepest parts of the basin too, including the Goban Spur", Pat adds.

Has the geological reconstruction of the area changed significantly since completion of the well? "It has changed a bit", says Pat, "particularly when looking at the Flemish Cap and the Orphan Knoll. Exxon positioned the Flemish Cap south of the Goban Spur in Triassic times. Current models suggest it was located to the west of the Goban Spur, which has implications on whether the Porcupine Basin was connected to either the West Orphan Basin or the Jeanne d'Arc Basin. It was quite a topic of discussion in the last number of years."

"Another aspect that we now have a better understanding of is that the rigid block model of Exxon should be replaced by a model of hyperextension when it comes to understanding how continents rift and drift apart. But it is still an open question as to exactly how things fit together", concludes Pat. And will another well be drilled in the area? Given Ireland's current moratorium on further exploration drilling offshore, that is looking quite unlikely. ■

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Seismic velocity – A strong identifier of gas prospects

Using a dataset of major oil and gas fields across the globe, the authors demonstrate that Vp is a powerful tool to differentiate between oil and gas-filled traps, which helps de-risk future drilling targets

MARTIN ESSENFELD, EGEP CONSULTORES AND RAFAEL SANDREA, IPC PETROLEUM CONSULTANTS

P-WAVE VELOCITY (Vp) is an essential parameter for constructing seismic velocity models for geophysical exploration data, and porosity is the single most important factor affecting it, along with the type of pore fluids.

Until recently, seismic velocity was only used for migrating seismic data and time-depth conversion. However, with recent new technologies like Full Waveform Inversion (FWI), the accuracy of the velocity data has improved. This advance now should provide an opportunity to estimate dependable key reservoir characteristics and at the same time detect any gas traps or accumulations from the seismic survey.

Here, we focus on analysing Vp to identify gas accumulations during the early exploration phase, prior to spudding the first well, when only seismic data is available. One of the driving forces for this project was the consideration of the future role of natural gas in a global context.

For this analysis, our approach was to analyse field seismic data, in particular Vp values, from randomly selected conventional gas fields around the world. We used P-wave velocity data available in the public domain and referred to as the velocity over the whole sedimentary hydrocarbon interval of the field. We looked at 32 oil and gas fields from 16 countries; most are giants, and the others are qualitatively world-class (Table 1).

IS THE VP VS POROSITY RELATIONSHIP ALL PURPOSE?

The first step in our analysis centers around verification of the Vp vs porosity relationship, which is well established at the experimental level and also at the multi-layer level of individual oil fields (Table 1). Here, we take it to another level and examine directly the Vp - porosity relationship at several major oil fields across the globe. Theory and lab testing can only take you so far.

Figure 1 demonstrates a strong and characteristic correlation between the two parameters (blue). This field bond is especially important because it fundamentally integrates all multiple minor and major factors – lithology, depth, rock characteristics, pore fluids, pore-pressure gradients and others – that affect it in different ways.

THE GAS EFFECT

With the basic background information provided above, we can now guide our analysis on the road to the gas reservoirs – do they affect the rock-solid Vp vs porosity relationship for gas fields?

Figure 1 also illustrates the basic Vp-porosity relationship for gas (red) ▸

Figure 1: Vp vs Porosity – Big Oil and Gas Fields

Field, Disc. Yr., Country	Age	Depth TVD (ft)	Lithology	Net Thick (ft)	Ø %	k (mD)	Pg (psi/ft)	Vp (ft/s)
OIL FIELDS								
Thunder Horse, 1999 (USA)	Miocene	27000	sandstones	520	18-33	500-3000	0,72	16100
Spraberry, 1949 (USA)	Permian	6800	siltstones	250	12-25	2	0,46	16300
Jack/St. Malo, 2003 (USA)	Eocene/Paleo	26500	sandstones	700	20-25	10	0,57	14700
Great White, 2008 (USA)	Eocene	22200	turbidites	90	18-22	10	0,32	14760
Ghawar, 1948 (Saudi Arabia)	Jurassic	6400	carbonates	200	16	620	0,52	15430
Kirkuk, 1927 (Iraq)	Oligocene	2600	carbonates	1000	15-25	100	0,42	14500
Girassol,1996 (Angola)	Oligocene	9400	sandstones	360	30	>1000	0,43	11830
Bonga, 1996 (Nigeria)	Miocene	11940	turbidites	110	30	770	0,44	12750
ACG, 1958 (Azerbaijan)	Pliocene	11980	sandstones	150	15-25	500	0,53	13500
Lula, 2006 (Brazil)	Cretaceous	24600	turbidites	1040	15-28	>1000	0,46	17600
Marlim, 1985 (Brazil)	Oligocene	15060	sandstones	560	30	>1000	0,53	12800
Cantarell, 1976 (México)	Cretaceous	8420	carbonates	1530	7	>1000	0,58	17980
Tecominoacan, 1980 (México)	Jurassic	14245	carbonates	1405	3	100	0,58	18880
El Furrial, 1986 (Venezuela)	Oiligocene	14770	sandstones	905	14-23	600	0,74	12630
Lama, 1957 (Venezuela)	Eocene	9300-9600	sandstones	700	27-30	300	0,45	13300
Guafita, 1984 (Venezuela)	Mio-Oligocene	6000-8500	sandstones	60-120	28	240-1000	0,45	12000
GAS FIELDS								
Boonsville, 1949 (Texas, USA)	Pennsylvanian	4500-6000	carbonates	230	12	3	0,37	10620
Groningen, 1959 (Netherlands)	Permian	8720-10240	sandstones	640	14	150	0,55	10630
Troll, 1979 (Norway)	Jurassic	4260	sandstones	300	34	2100	0,36	8400
Quesqui, 2019 (México)	Jurassic	19840	carbonates	790	4	1500	0,60	8480
Shah Deniz, 1999 (Azerbaijan)	Pliocene	17920	sandstones	300	9	0.1 - 10	0,63	9600
Karachaganak, 1979 (Kazakhstan)	Permian	16400	carbonates	1900	10	14	0,49	8640
North Dome, 1964 (Qatar)	Permian	9600	carbonates	1260	20	10	0,53	8960
Kish, 2006 (Irán)	Permian	9000	carbonates	200	7	7	0,53	8000
Gorgon, 1980 (Australia)	Triassic	10580	sandstones	400	16	700	0,52	9700
Perla, 2009 (Venezuela)	Mio-Oligocene	8780	oolites	787	18	45	0,54	9620
Yucal Placer, 1948 (Venezuela)	Oligocene	7000-9000	sandstones	150	4 - 12	< 1	0,53	7400
Copa Macoya, 1994 (Venezuela)	Oligocene	6200-7000	sandstones	130	14-20	< 1	0,53	7720
Carito, 1988 (Venezuela)	Oligocene	12300-17300	sandstones	233	13	40-1000	0,74	6800
Loran-Manatee, 1983 (Vzla-Trinidad)	Pleistocene	2000-5900	sandstones	300	18	90-700	0,46	8320
Rio Caribe, 1982 (Venezuela)	Pliocene	7800	sandstones	20-80	26	120-390	0,45	8500
Ambrosio, 1934 (Venezuela)	Eocene	6680	sandstones	120	16	15	0,46	9100

Table 1: Geologic, Reservoir and Seismic Attributes - Major Oil and Gas Fields

fields in this study. Broadly, a Vp tier of 11,000 ft/s seems to be the dividing line between oil and gas fields. It represents the upper domain of gas fields and the ground value for oil fields.

This indicates a huge gap of around 2 to 1 between Vp values of oil and gas fields. Perhaps the most striking of the field results is the high dispersion of gas field data points. Unlike the rock-solid trendline consistency noted for oil fields, there is no clear trend for gas fields. Obviously, the extreme compressibility and low density of gas seem to be overcoming the major influence of porosity on Vp.

SOME GENERAL OBSERVATIONS

From the above discussion and the different issues brought up, some "broad" statements follow.

From Figure 1, there is no question that regardless of the different factors outlined, there appears to be a very solid correlation between Vp and porosity, over a very wide range of porosity values and porosity-types, when the existing rock plus fluid system is non-gaseous i.e. contains a liquid in the pore space. Further, the slope of the correlation line obtained is to be expected, since the lower porosity systems contain basically more of the solid part, which will transmit the seismic wave at a higher velocity. For those systems with a higher porosity, filled with liquids (oil and water), the impact of the attenuation caused by the liquid part of the rock-pore filled system is evident.

Further, for this large group of oil (liquid containing) consolidated reservoirs, in the wide range 10-30 % porosity values, the seismic Vp values are definitely above 11,000 ft/s.

When the porous system is not liquid but rather gas-dominated, a different condition is to be expected, as follows.

From Figure 1, the interval seismic velocity measured and reported in a significant group of reservoirs containing free-gas is definitively below 11,000 ft/s. Thus, in the gas reservoirs - over a wide range of porosities - the data indicate the expected Vp attenuation induced by the gaseous nature of the contained fluid. However, the clear correlation of Vp versus porosity described for oil reservoirs is not as evident for gas reservoirs. It thus appears that the attenuation of the seismic velocity induced by the gaseous phase is sizeable enough to impact the Vp level over the same porosity range (10-30%).

As a matter of fact, in spite of the spread in interval velocity Vp values in the 6,500 to 11,000 ft/s range, the "average" typical level is close to 9,000 ft/s. This is certainly a low enough average level to allow the use of Vp from seismic as a solid discriminator for gas-containing accumulations, when in search for this hydrocarbon fluid as opposed to oil-containing accumulations.

AN INEXPENSIVE TOOL

In the field, the presence of any kind of natural gas, such as free gas or gas caps, affects radically Vp values above and beyond the effects of a broad spectrum of parameters and attributes. Low Vp values – below 11,000 ft/s – alone are not diagnostic of gas-bearing sands but are definitely significantly lower, by a factor of almost 2 to 1, than values for oil and/or water-saturated sands and salt layers. If the Vp is below 11,000 ft/s, that red light for gas should be used as a decision support tool. It is a powerful, inexpensive early identifier of gas during the early exploration phase when only seismic data is available. ■

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Shaking up the Earth: The AI revolution in seismic interpretation

In the race to secure energy, decarbonise operations, and achieve net-zero targets, a seismic shift is underway. Embracing cutting-edge technologies, particularly Artificial Intelligence (AI), isn't just an option—it's an urgent necessity

RYAN WILLIAMS, GEOTERIC

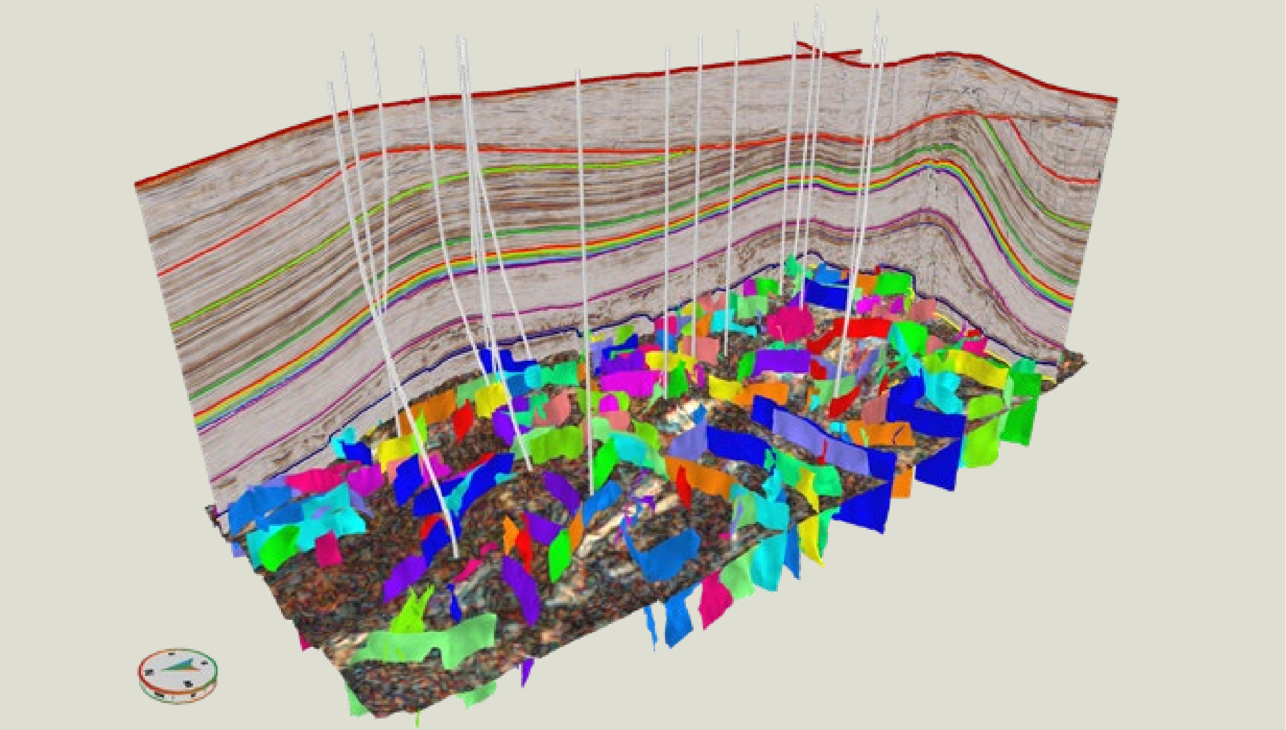
AI'S TRANSFORMATIVE role in seismic interpretation is not merely illuminating the subsurface; it's fast-tracking one of the energy industry's most business-critical phases. The interpretation of seismic data requires a comprehensive understanding of geology and geophysics. It's a complex and at times laborious process when undertaken manually, with high stakes – the interpretation of seismic data directly impacts drilling decisions, field commercialisation or new energy ventures such as the identification of subsurface locations for safe carbon capture and storage (CCS).

AI IS A CO-PILOT, NOT A COMPETITOR

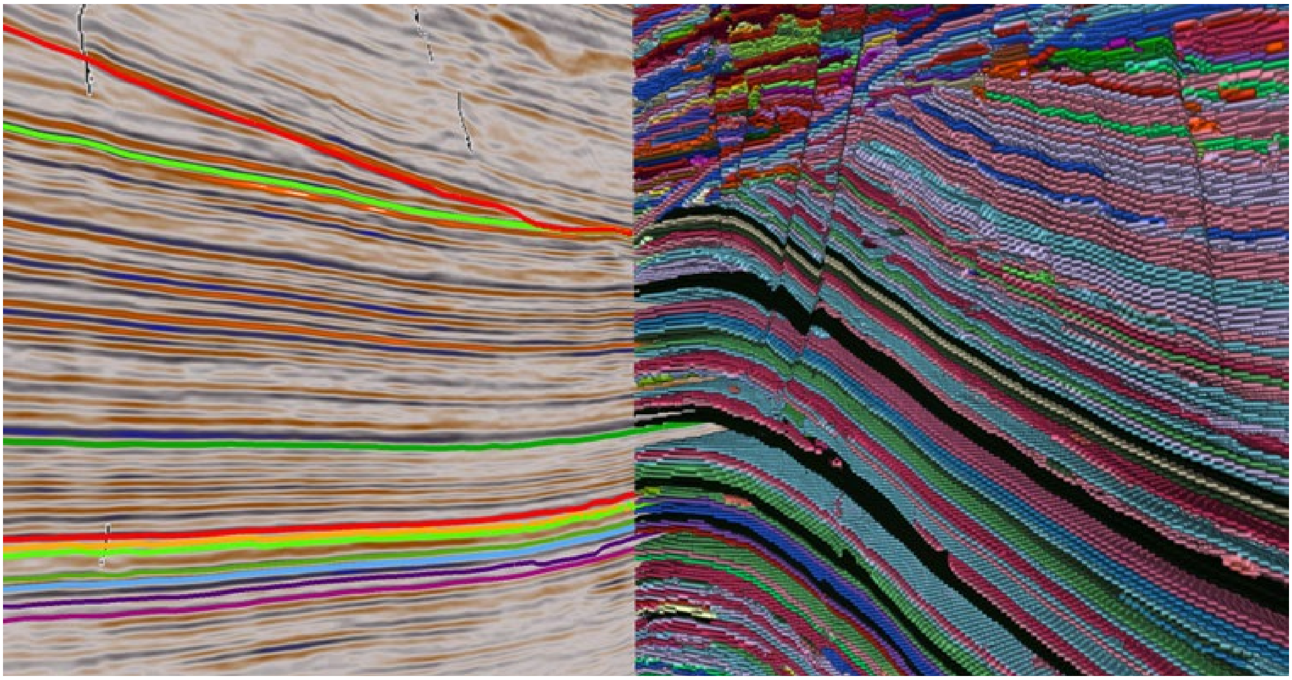
The recent surge in demand for AI in this space stems from increased pressure on G&G teams to accurately interpret more seismic data in less time and often, with fewer resources. No longer feared as a black-box solution to replace the human interpreter, AI is now considered as a co-pilot to the geoscientist, a team member to take on the monotonous, repetitive tasks. This ultimately allows interpreters to apply their expertise and skills to further de-risk opportunities that benefit the whole business.

CHATGPT FOR THE G&G COMMUNITY?

One analogy might be how ChatGPT can be used to produce anything from complex code to legal documents. The content it delivers provides a considerable head start but may require editing, calling upon the skills and knowledge of the interpreter to accept the result or make improvements. AI for seismic interpretation is much the same despite the complex challenges.



Geoteric AI seismic interpretation powered by multiple 3D convolutional neural networks (CNNs) completed in one day. All elements of the interpretation are easily transferable to 3rd party modelling software as horizons, fault sticks, or fault planes for a continuation of the workflow. The speed and high quality of interpretation enable high-quality models to be built extremely quickly, revolutionising modelling time. The sub-salt horizon is draped with a high-definition frequency decomposition (HDFD). Seismic data: 1993 Viking presdm full stack Courtesy of National Data Repository (NDR).



For the first time ever, an incredibly detailed and accurate multi-cycle interpretation is possible. Geoteric AI Horizons detects every event from surface to region of interest in just hours, significantly accelerating the starting point for geoscientists. Left – Reflectivity data with user-guided AI Horizon extraction visualised as surface overlays. Right – AI Horizon volume generated from the reflectivity data. Delivered with an extremely high density and accuracy of interpretation, illustrated by the angular unconformity.

In an industry first, leveraging multiple 3D convolutional neural networks (CNNs), Geoteric AI generates an out-of-the-box result that significantly accelerates the starting point for geoscientists, reducing project times from years and months to weeks and days, even in challenging data. Initial insights are gained in hours and with easy-to-use workflows the geoscientist is empowered to tweak, fine-tune or edit the results if needed. Crucially, AI learns from geoscientists; subsurface teams benefit by sharing trained networks and transferring knowledge from one dataset to another.

ACHIEVING THE IMPOSSIBLE

With an unprecedented reduction in interpretation cycle times and the subsequent boost in interpreter productivity, energy companies can begin to realise a much faster return on their seismic data investments. AI processes not only 100% of the seismic data, but also multi-azimuth, multi-angle and 4D seismic data without sacrificing accuracy, a previously impossible task. AI unearths the secrets of the subsurface, hidden in the most challenging seismic data and sometimes so subtle they are invisible to the human eye. The implications for companies with AI in their interpretation armoury could not be more powerful and relevant to the global demand for energy security; operators can bring new assets online faster than ever before.

AI UNLOCKS THE EARTH'S PAST FOR A LOW-CARBON FUTURE

The way AI has advanced our subsurface understanding and the subsequent implications for oil and gas extraction is nothing short of remarkable. This seismic shift is not limited to hydrocarbon exploration, development and production, the benefits of AI reach across the whole E&P lifecycle as well as low carbon and renewable energy. CCS is considered one of the key strategies to achieve net zero carbon emissions and operators are capitalising on government incentives to take on CCS projects quickly and safely.

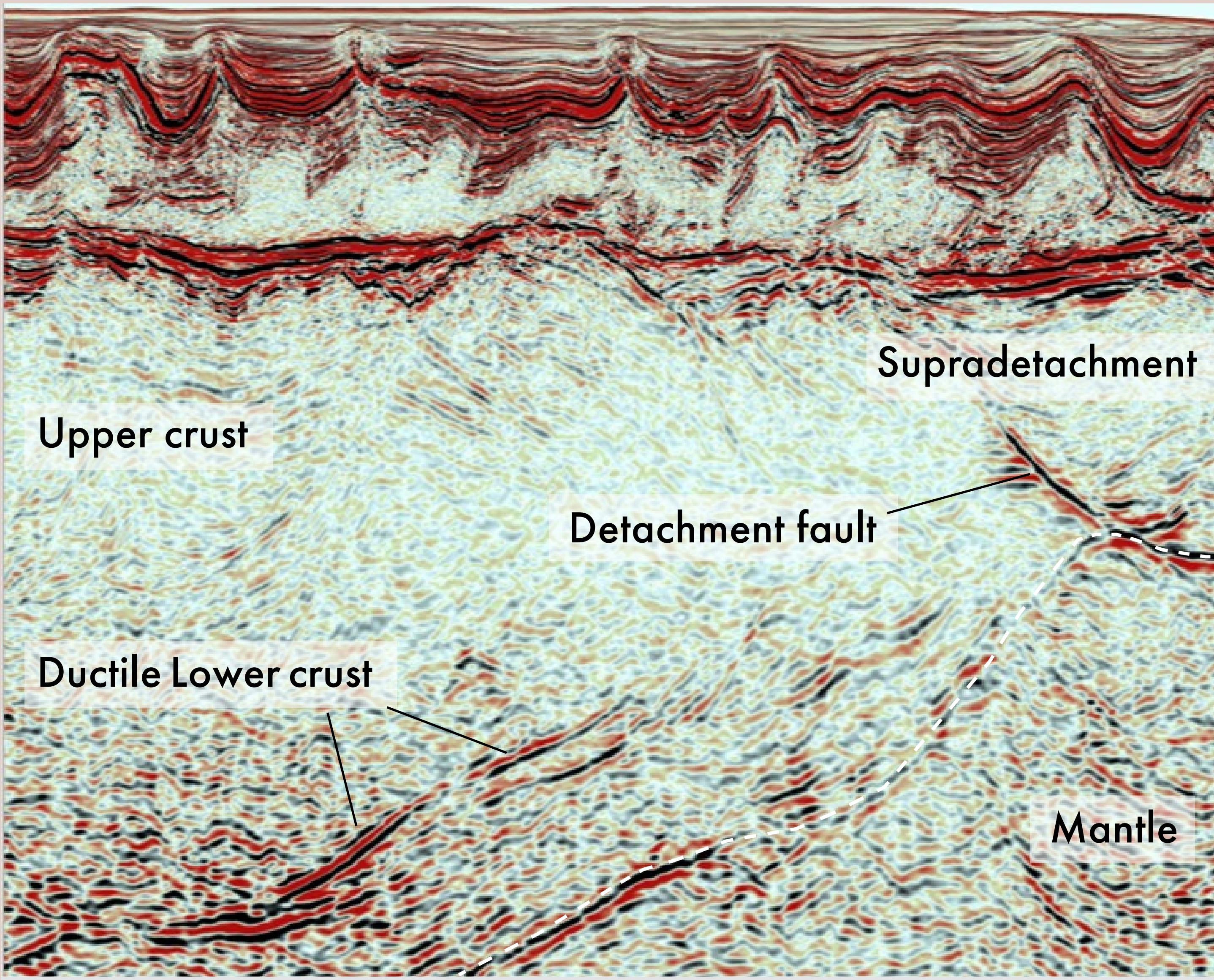
ILLUMINATING THE SUBSURFACE

Techniques used in hydrocarbon extraction can be applied to CCS where a detailed interpretation of seismic data is necessary to illuminate the subsurface. Subsequently, AI is readily deployed to quickly and accurately appraise CCS site integrity and monitor plume fill and migration using 4D seismic data to ensure successful trapping. Similarly, the same methods are transferred to identify shallow hazards in offshore wind farm placement or detect locations of geothermal energy sources below the earth's surface.

EMBRACING AI

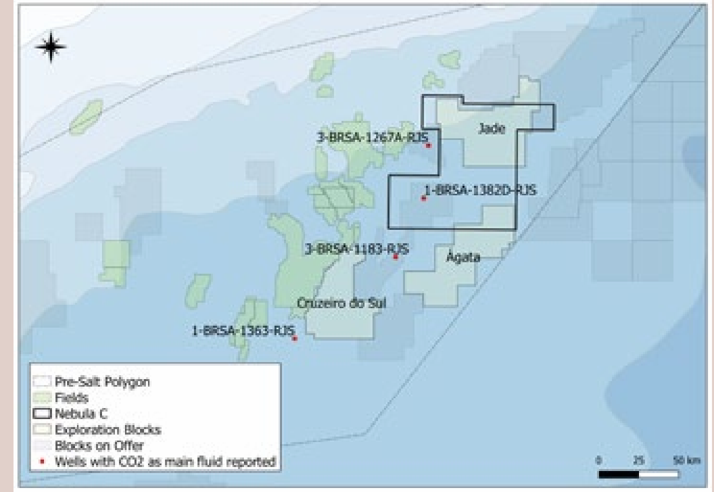
Progressive industry leaders are already adopting AI to accelerate their E&P and CCS strategies; change will only come when decision-makers do more than just acknowledge the numerous advantages of AI. It's time to fully embrace this powerful advancement in technology and what it can do for the planet; not only to improve the way we recover the earth's resources today, but for the way we fuel humanity tomorrow. ■

Santos Basin, Brazil: Understanding the CO_2 exploration risk with ultra-deep seismic

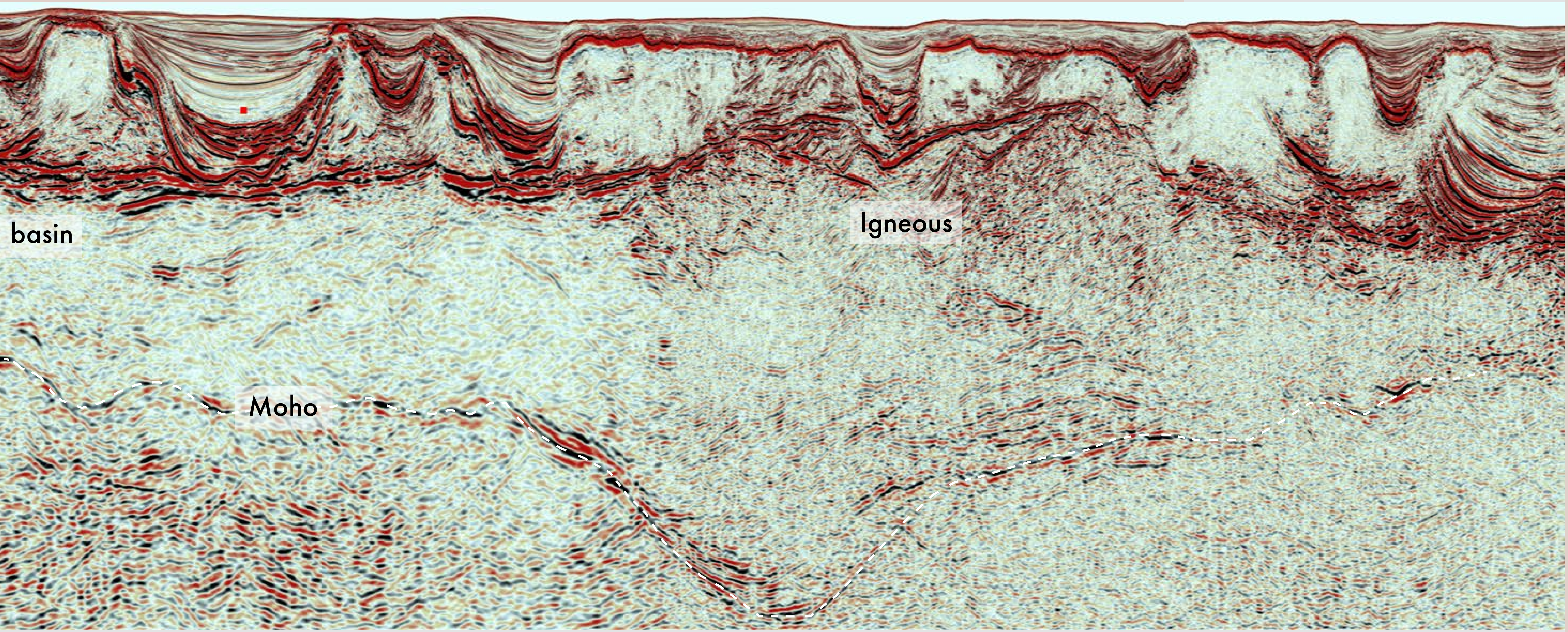


Nebula C seismic section displaying a hyper-extended crust dissected by deep detachment faults extending from the pre-salt sequence down to the mantle. In the region surrounding the upper tip portion of the detachment fault, a high CO_2 content was reported in the pre-salt wells.

An increasing number of discoveries with high CO_2 content offshore Brazil highlight a new exploration risk for the pre-salt play. New seismic data is fundamental to understanding deep geological features to address this risk. CGG's Nebula-C data set provides images down to 20 km in depth and shows ultra-deep crustal features in high definition. Mapping the Moho and deep-seated faults is essential to understanding possible paths of mantellic CO_2 migration to pre-salt reservoirs. A de-risking study was performed using Nebula-C to map where the deep-seated faults connect Moho and the reservoir, and where the lower crust is not offset by faulting, allowing prospect identification with lower risk of CO_2 contamination.



Location of pre-salt blocks in the Santos Basin, the Nebula-C polygon and exploration well results.



Santos Basin:

New seismic data helps de-risk CO_2 contamination for pre-salt exploration

CGG's latest imaging technology delivers unprecedented detail of the deep structure in the pre-salt rift basin to support the identification of mantle CO_2 migration pathways, allowing operators to de-risk pre-salt exploration

ROBERTO JUNCKEN, BRUNA LYRA, MARIANO GATTI, ABRAHAM RODRIGUEZ, CGG, AND NATASHA STANTON, ANDRES GORDON, UNIVERSITY OF RIO DE JANEIRO STATE

THE DISCOVERY of the giant pre-salt fields in the Santos Basin (See foldout map) positioned Brazil among the world's ten largest oil-producing countries. However, recent ultra-deepwater frontier exploration has revealed high carbon dioxide (CO_2) content in some pre-salt oil fields, introducing an important new risk that has undermined the appetite for exploration in this region.

Several studies proposed that magmatic processes and deep crustal faults might act as pathways for CO_2 migration from the mantle to the sediments. The strongest evidence comes from the isotopic composition of the CO_2 analyses in the Santos Basin, which corroborate mantle degassing as the primary origin process. Regions of intense crustal thinning and significant mantle rise, where the crust is dissected by deep faults, show higher mantellic CO_2 content. De Freitas et al. (2022) showed evidence of a structural control on the occurrence of CO_2 concentrations, particularly in the hyperextended regions of the basin, and postulated that mantellic CO_2 reached the pre-salt reservoirs through a deep fault system. These arguments and data supporting the mantellic origin of CO_2 in the pre-salt allow operators to assess the geographic distribution of high CO_2 accumulations.

The scarcity of good seismic images of intra-crustal features and mantle rise has ended with the **Nebula-C 3D survey,** which visualizes the deep crustal structure and Moho with unprecedented detail. Benefitting from the latest acquisition and imaging technologies, it improves our knowledge of the deep structure in the pre-salt rift basin, identifying the structures related to CO_2 migration to pre-salt reservoirs, and enabling an important exploratory risk to be assessed.

NEW NEBULA-C 3D DATA INSIGHTS

For the Nebula-C 3D survey, covering 45,000 km^2, CGG applied its advanced imaging technologies to combine legacy and newly acquired narrow-azimuth towed-streamer (NATS) datasets into a single dual-azimuth (DAZ) image. The aim of the survey design was to improve seismic illumination by using longer cables for enhanced full-waveform inversion (FWI) and an orthogonal azimuth to achieve high-quality images of the sedimentary sequences, deep crust and upper mantle.

The Nebula-C data images the deep structure with the greatest detail to date, bringing greater insight for exploration. The pre-salt comprises regional North-South striking, synthetic, low-angle fault systems that sole either at shallow or deep crustal levels (Figures 1 and 2). The geometry of the intra-crustal structures varies considerably across the area. The detachment faults affect the lower crust (deep detachments) and secondary synthetic fault systems affect the upper crust (shallow detachments), creating uplifted "domed" crustal blocks, known as core complexes that, in specific areas, are exhumed to lower crustal levels (Figure 2). In those regions, the fault crosses the entire crust, potentially facilitating the CO_2 migration between mantle and pre-salt reservoirs. In other areas, the detachment faults sole at shallower levels in the upper crust, limiting migration paths for CO_2 (Figure 1). Additionally, some reactivated detachment faults (Figure 2) may have created pathways for magma ascent during the Upper Cretaceous-Paleogene.

As the structural link between mantle and pre-salt strata varies spatially, CO_2 contamination is not pervasive across the entire distal basin. Both deep and shallow detachment faults can be interpreted in the Nebula-C data. Visualization of the deep crustal architecture is fundamental as it enables the definition of existing pathways between the mantle and pre-salt strata, which is key to de-risking CO_2 contamination in prospective regions.

CONCLUSION

With the recent examples of CO_2-charged reservoirs being encountered by pre-salt wells in the Santos Basin, the ability to de-risk the presence of CO_2 has become crucial. By applying the latest subsurface imaging technologies to newly available long-offset and multi-azimuth data, the Nebula-C 3D dataset can provide clear images of the entire crust and Moho. This has made it possible to map crustal faults and identify faulting style below each prospect and assess the risk of CO_2 contamination. Specifically, we have been able to identify regions of intense crustal thinning with a detachment fault system and pre- and post-salt volcanics with potentially high CO_2 content, as well as areas with a shallower detachment fault system with a lower risk of CO_2. This same mapping workflow can be applied to other areas of the Brazilian pre-salt to enable operators to conduct future exploration with confidence.

References available online.

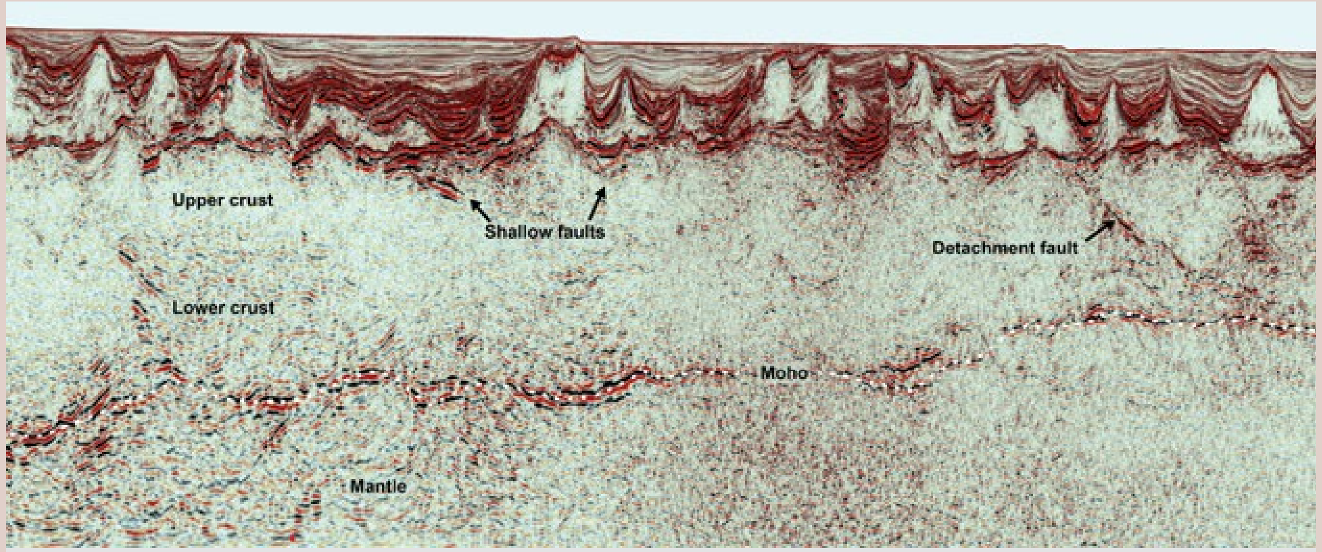


Figure 1: Section showing a two-layered crust of constant thickness to the west, preserving the reservoir from a direct pathway with the mantle, resulting in a low-risk area for CO_2 contamination. Eastwards, the faults cut through the entire crust and reach the mantle, configuring a higher CO_2 risk area.

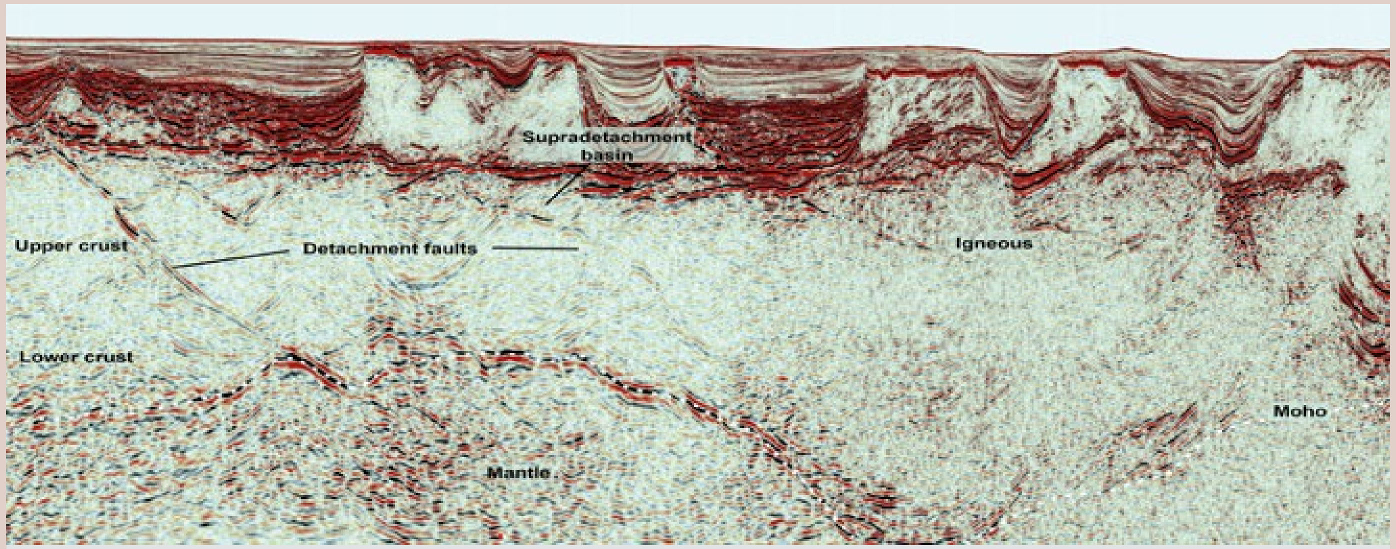


Figure 2: Seismic section displaying an abrupt crustal thinning and deep detachment fault connecting the Moho. In this area, high CO_2 content has been observed in wells. A basement high to the east evidences a large igneous construction on thickened crust.

PORTRAITS AND INTERVIEWS

"In so many cases, one does not need expensive kit to do real science and penetrate the physics of things."

Guy Wheater – GAIA Earth Technologies

Guy Wheater and the standoff tool he developed.

RIGS ARE FANTASTIC PLACES FOR R&D

Guy Wheater tells the story of how he started off studying turbulent combustion but ended up designing a system to prevent cable fishing in the world's most challenging wells

I HAVE ALWAYS wanted to have one foot in the field and one foot in the lab, to better solve practical problems in the oilfield", says Guy Wheater on a few occasions during our conversation.

Guy works for GAIA Earth Technologies, where he invented and developed their cable protection system. At its core, it is a seemingly simple tool called a wireline standoff that prevents cables from sticking in wellbores during wireline logging operations.

It took many years of development and thousands of hours of hands-on labour and field trials before it got to the stage where it is now: a market leader for a niche product that is used by 25 oil and gas companies internationally.

Here, we tell the story of how Guy got the idea of developing the cable protection system and the business activities that spinned off from it. It is a story of having a vision, keeping things in your own hands and gaining the trust of customers. But before we dive into how Guy got to the idea to develop this standoff tool, let's take a look at his formative years first.

WANNABE ENGINEER

"I grew up on a farm in Yorkshire, gaining many skills and lessons from my father; by my early teens I was a competent welder, I could lay concrete and sink a straight line of telegraph poles for a fence. My father ▸

See page 82 for a short technical outline of the main causes for cable sticking and what can be done to prevent it.

PHOTOGRAPHY: GAIA EARTH

managed to plant a deep will to succeed in me", says Guy. "Secondary school was a distraction from my apprenticeship; lessons were tedious and felt irrelevant to me. Without much consideration, I drifted into Sixth Form, which was an even bigger academic challenge; I left there with D & E grades at A-level, but with a growing desire to become an engineer. I was generously offered a place at Coventry Polytechnic for a Bachelor degree in Engineering Studies - my only offer, unsurprisingly, with such dismal grades! I threw myself into it, consistently studying up to 18 hours a day. Summers were spent in Yorkshire, picking potatoes during the day and working in bars at night – money was always tight. Three years later, just after turning 21, I walked into Cambridge University to start a PhD in mechanical engineering. I was an unlikely candidate but I was offered great support and encouragement by my tutor Professor K.N.C Bray and my peers."

Cambridge changed Guy's life and perspectives in many ways. "I met so many stunning individuals and had conversations that made me giddy; the people there had so many new and interesting ways of looking at things."

A WOODEN SPOON

"Early on in my research on turbulent diffusion flame structures, I was invited to a fluid mechanics seminar. A visiting scholar from the US showed his incredible lab facilities during a slide show and for a moment I thought I might be in the wrong place. Until someone at the back shouted out: "What is it all for?" It was quite a provocative question – the professor was taken aback and muttered 'model validation.' The physicist had made his point."

"Then, a rather scruffy guy came on stage, contrasting heavily with the person we just saw", continues Guy. "He talked about vortex-object interaction, which is of value to many industry sectors. After presenting a series of complex equations on an overhead projector, he picked up a wooden spoon and whipped up a water vortex in a circular glass tank. He dropped in a small stick, and just as he had described mathematically, it tumbled erratically and then damped down. There was applause, the physicists approved!"

"In so many cases, one does not need expensive kit to do real science and penetrate the physics of things."

"It amazed me", Guy says, "and until this day, I hold that experience close to my heart. I was in the right place after all. In so many cases, one does not need expensive kit to do real science and penetrate the physics of things."

YEARS IN THE FIELD

Before he embarked on the challenge to develop the standoff tool though, Guy first spent about 10 years with Schlumberger. "I was told that they drive around Libya in Land rovers and make a lot of money, which sounded rather appealing!", he laughs.

Guy visited their research centre in Cambridge and they offered him a job in the fluid mechanics department. "After 6 months, appreciating my practical approach, they suggested I go into the field for a couple of years, to bring that experience back into the lab. I joined the field after attending wireline training school and I soon realised there was no going back – wireline was a full-on adventure that I had a huge appetite for."

Guy worked offshore and UK onshore for 2 ½ years, followed by remote desert locations for another 6 years in Oman and Yemen, then to Tanzania and back to Oman as a base manager.

"Being in the field makes you appreciate not only the nuts and bolts of operations, but also the significant challenges that may come with the environment", says Guy. "It was a rich and addictive experience, from 250-hour logging operations with minimal sleep to dealing with security situations in Yemen. I watched the sun come up in the desert so many times, huddled with my crew, all of us filthy and exhausted, wondering how the hell we would get through the next 24 hours. But there was no place I would have rather been; physical challenges bind people together like nothing else."

SPECIAL PROJECT

"In 1999, I was coming to the end of my assignment as the base manager in South Oman", says Guy. "I heard I was going to be offered a special project by the brass in Schlumberger. The advice given was: "You can't say no." They wanted me to join a start-up business in Edinburgh, to market Scottish distance learning programs, and to help establish a Petroleum University overseas.

On paper, it was a great opportunity: to develop new skills whilst creating important access channels for U.K. Petroleum Engineering courses in Iran, India, U.A.E and Malaysia. However, I was fundamentally unsuited to the role, I did not like the people involved, nor did I see it as a win to remove my coveralls. For 3 years I faced serial difficulties but I completed the project as tasked.

Guy returned to his box apartment in London for nine months and pondered his future. "The main question was how to become the old me again?", he says. "One day, I got an unexpected phone call from an old colleague with whom I'd worked in Yemen, asking if I knew someone who could go to Algeria to supervise a wireline logging job. The role was offered to me by Stuart Huyton, the founder of Gaia Earth Group. Stuart's decency was immediate and authentic. He gave me purpose, a long-missed sense of belonging, and great optimism for the future. After what seemed like an interminable drought, the thunder had clapped and the bounce was back in my stride."

"During that week in Algeria, I realised so many things: I had missed the action so much, the desert was a comforting déja-vu and I felt useful again - all of it made me really happy. It took four months before another job came along, and it was a hard wait, but I knew I had made the right choice. Now, I could help build a new company, define our own culture and become the engineer I always wanted to be: something was going to be "Made in Great Britain" – but I did not yet know what it was going to be."

"THOSE WIRELINE STANDOFFS, I NEED THEM"

During the first decade with Gaia, Guy mainly worked on job planning and wellsite supervision projects all over the world. "In 2006, I did a fair bit of work on the Buzzard field in the North Sea, where we experienced repeated cable sticking during wireline logging operations", he continues. "And then I realised, what am I going to tell the operator - Nexen? We don't know why it's happening and we don't know when it's going to happen again and the only solution is to pull and hope. We loggers should be able to do much better than that!"

Nexen were positive to Guy's initial suggestion to work on a solution to this problem and even offered some funding. Guy refused that, he already had a "wooden spoon" in the works – nothing more was needed at that stage.

In the meantime, he moved to Dubai for Gaia in 2007, where he found a machine shop able to build a prototype wireline standoff. "I took an amateurish picture of it on my balcony and sent it to Nexen. The photo of the prototype made its way to a few desks within the organisation until it ended up with Nexen's drilling manager in the Gulf of Mexico. He called me at 11 PM one night, saying: "Hey Guy, those wireline standoffs, I need them."

THE FIRST TRIALS

Within thirty days of hard work in the workshop, Guy managed to produce the kit needed for the Gulf of Mexico job. "We ran the standoffs in a well with two sidetracks, where the main hole had experienced cable fishing. The standoffs eliminated all signs of sticking, even though the same wireline tool, mud, formation and overbalance were used. It was an early indication we might have a promising solution." Field trials carried on for the next five years with continued success, leading to the establishment of Gaia Earth Technologies in 2016 as a spin-off to Gaia Earth Sciences – now forming Gaia Earth Group.

An example of the mess caused by stuck cable.

PHOTOGRAPHY: GUY WHEATER

> "I watched the sun come up in the desert so many times, huddled with my crew, all of us filthy and exhausted... But there was no place I would have rather been; physical challenges bind people together like nothing else."

ANOTHER BUSINESS OPPORTUNITY

The success of the standoffs quickly led to another business opportunity. "Clients appreciate our standoff technologies", emphasises Guy, "but they were even more interested in engineering due diligence for well planning, i.e. what are the sticking risks on my next logging job and do I need an intervention with wireline standoffs? That is always the question that needs answering."

This made Guy aware that a software package was required to simulate well design and make a sticking risk assessment. This led to the development of Wire-pro, a tension and sticking package and a geological benchmarking framework, employing statistical data from global sticky wells. As such, Gaia's Cable Protection System was born (GCPS), ▸

a synthesis of hardware, software, and wireline operations expertise. Since then, GCPS has seen ~ 30% annual growth in activity worldwide.

Building Wire-Pro was all done using the money made through the standoff deployments. It made Guy even more convinced of the decision to create the software from scratch rather than trying to improve an already existing package on the market. “When you control the code, you can explore the physics and truly innovate – extracting the practical risk metrics that really matter”, he says.

THE DIFFICULTY OF GAINING ACCESS

Thanks to GCPS, Gaia has now delivered many hundreds of wireline conveyance and sticking risk assessments, resulting in > 400 deployments and > 16,500 standoffs in the hole, with 99% efficacy. But even though GCPS is highly effective in predicting and mitigating cable sticking, many companies continue to clock up sticking-related NPT during their wireline operations. Why is that?

“On the service provider side, we are not yet included in their logging menus or standard workflows”, Guy says. “Cable sticking risk may not be assessed at the planning stage of a logging operation in some wells. This lack of oversight can be a colossal mistake.”

“On the client side, it can be difficult for a small business to gain access to the right people within an organization, unless you already know somebody on the inside. There are traditional methods of communication, such as websites, SPE papers and conferences, but nothing beats sitting around a table with a client and letting the conversation flow in the direction they deem necessary. Their perspectives, concerns and challenges drive the direction of our future R&D, which goes far beyond cable sticking mitigation.

Guy (right) on an MDT sampling job in Yemen, 1997.

“Without the American support we would have no business to speak of, no active R&D and no investment in UK manufacturing.”

PUT THE MONEY WHERE YOUR MOUTH IS

The Gulf of Mexico is the basin that has seen the most widespread uptake of Guy’s inventions. Is that a coincidence? “Two words are enough to describe that”, says Guy: “Can do!” Americans love innovation, and love saving money. They are practical people who ask the right questions and are very open to new ideas and methods. I wish Europeans would be more American; dynamic, demanding, unashamed of making-hole and bringing the best tech to the table. Without the American support we would have no business to speak of, no active R&D and no investment in U.K. manufacturing.”

“I had never thought that the people in Houston would be so receptive to tools made by a Brit in his spare room in Dubai. But somehow the guys trusted me and were ready to put money on the table after a 30-minute phone call. It is something that I will always be grateful for, and it is something the world can take a lesson from.”

And as Gaia works on expanding their technologies and services portfolio, growing their business globally, Guy concludes: “You don’t need an expensive lab to do great R&D - any rig will do. What you need is curiosity and tenacity, a love of creativity and problem-solving - and maybe a $3 wooden spoon!” ■

GEOTHERMAL ENERGY

"In a sense, (..) the "low-hanging fruit" was picked. It is not possible to predict when or if growth will resume, and whether it will be as strong as in the last decade. It will depend on how many new "fruit trees" are discovered in new areas so far unexplored.."

Umran Serpen - Istanbul Technical University and Ronald DiPippo - University of Massachusetts

Exploration drilling – for geothermal energy

A multi-well exploration campaign has kicked off in the Netherlands in an attempt to better characterise the subsurface for geothermal energy production

THE FIRST WELL in the campaign that will see around 7 wells drilled was spudded in October at a very prominent location close to the Ajax football stadium in Amsterdam. And while Ajax finds itself at the very bottom of the football premier league, something that is unheard of and has generated a national outcry, the drill bit a couple of kilometers away deliberately tries to reach rock bottom as soon as possible.

The well is not a "normal" oil and gas well, it is a geothermal exploration well – part of the SCAN project. Operated by state-player EBN, another first, the well aims to de-risk the subsurface for future geothermal development drilling. As such, the well is purely exploratory and will not be part of a future doublet.

The idea is to drill a series of these geothermal exploration wells throughout the country at places where "conventional" exploration drilling never took off. The drilling locations were further narrowed down using the results of an extensive 2D seismic acquisition campaign – also part of the SCAN programme – that aimed to fill the initial gaps in subsurface understanding of the areas that were never heavily targeted by the oil and gas industry.

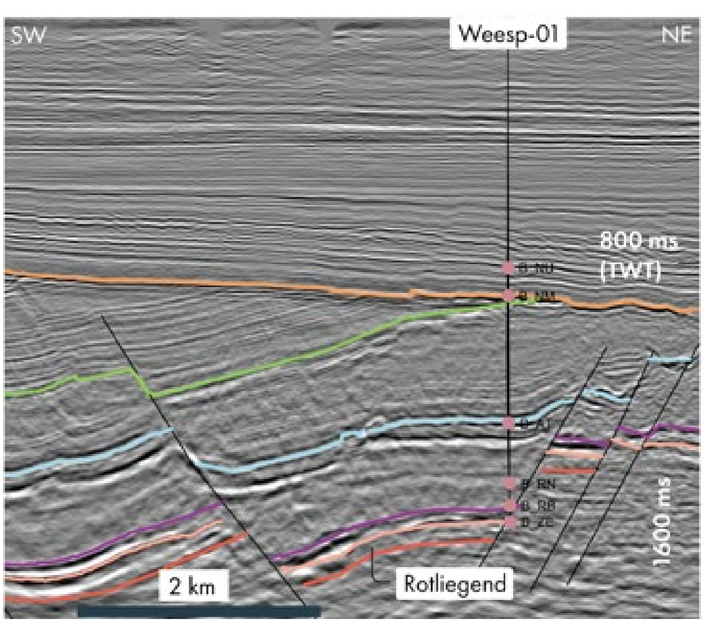
FAULTED OUT

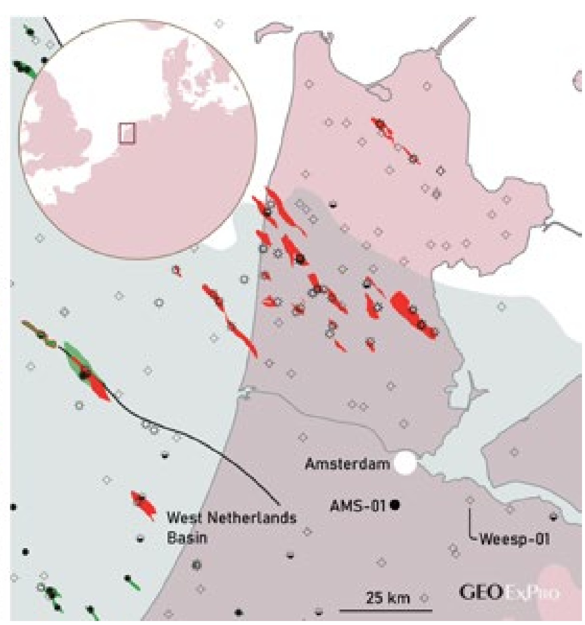
Geologist Marten ten Borgh from EBN presented about the Amstelland-01 well, which is abbreviated to AMS-01, at the Energy Geoscience Conference in Aberdeen in May this year. He showed that previous mapping exercises suggested that the Upper Permian Rotliegend would be very thin in the area. However, a more detailed analysis of the nearest offset well Weesp-01, in combination with the SCAN seismic line that was shot over this well, made clear that the Rotliegend is faulted out in the well. The seismic data now suggest that the expected thickness of the Rotliegend is around 140 m, much more than the 5 m found in Weesp-01.

At the time of going to press drilling had finished and a Rotliegend interval of more than 100 m was found. Lab and well testing results were still to be released.

A secondary target of the well is the Lower Cretaceous, with an expected temperature of around 62 C°. The Rotliegend is expected to be found at a temperature of 87 C°.

Is there a chance to find gas, or maybe oil, in these wells? "That is unlikely", said Marten during the conference. "We planned the wells in such a way to avoid any closures. We need to find a 500-600 column for there to be a hydrocarbon discovery, which seems very unlikely." ■





Monitoring a geothermal motor

The Olkaria field in Kenya is reaching a mature state of development and therefore requires monitoring to ensure any future wells are drilled in the right location

FOLLOWING the drilling of successful exploration wells into the Kenyan Rift Valley in the 1970's, the flagship Olkaria geothermal field has seen a steady development to a capacity of around 800 MW today. It is still the main geothermal project in Kenya, supplying around 80% of the geothermal energy produced in the country.

The geologically young East African Rift (EARS) is an ideal location for the development of geothermal projects because of the high subsurface temperatures at relatively shallow depths. At Olkaria, the reservoir from which steam is being produced consists of porous and permeable volcanic rocks – rhyolites, trachytes and basalts - which overly magmatic and intrusive bodies at a greater depth.

GEOTHERMAL MOTOR

Fluids flowing within the volcanic succession at Olkaria are known to show convective circulation from the base to the top of the reservoir interval. This is what is often referred to as the geothermal motor of the system, transferring heat from closer to where the magmatic bodies are to shallower regions.

As with many volcanic geothermal areas, the reservoir succession at Olkaria is overlain by a claystone that consists of hydrothermally altered minerals. In that sense, the reservoir has a clear upward limit, comparable to oil and gas fields.

IMBALANCE

Even though the produced steam is re-injected as fluids into the volcanic succession, there is an overall mass imbalance between produced and injected fluids. As a result, there is concern that this could negatively impact fluid circulation patterns on which the production of geothermal energy relies.

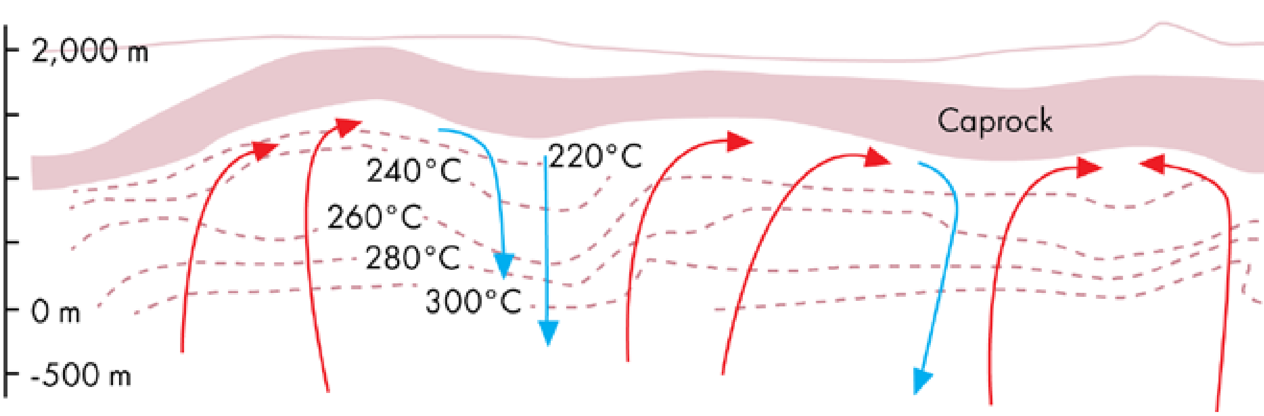
In addition, as the development of the geothermal field has now reached a mature stage in the Olkaria field, there is an increasing risk of well interference and drilling of unproductive wells.

For these reasons, it has become more and more important to better characterize the geothermal field and map where future opportunities may exist. This was done using an ambient seismic noise tomography approach by a consortium led by Twente University in the Netherlands. Whilst the results

have not yet been published, the shear wave velocity model has resulted in additional insight in the structure of the Olkaria geothermal field.

MATURE GEOTHERMAL FIELDS

In combination with our report on the mature state of geothermal developments in Turkey (see page 64), it does suggest that what the West Anatolia rift system is for Turkey, is the Olkaria field for Kenya: the low-hanging fruit that enabled relatively quick and profitable production of geothermal energy. Whilst there are multiple projects underway in Kenya, it seems that these are not as big or "easy" to produce from as Olkaria. ■



REDRAFTED AFTER: HECKER ET AL. (2021), EOS

Schematic cross-section showing the fluid flow paths and temperatures across the volcanic reservoir section in the Olkaria field.

Geothermal resources show their limits

Development of geothermal capacity in Turkey has seen a rapid increase over the past decades but has recently slowed down

TURKEY IS amongst the main players when it comes to geothermal energy production worldwide, with more than 1,600 MW of installed capacity. The favourable geological setting in the Western Anatolian region is the main reason for this success. The area that is known for its extensional tectonic regime shares some important characteristics with another geothermal hotspot, the Basin and Range in Nevada, USA, where elevated temperatures at relatively shallow depths have also allowed for the development of many geothermal projects.

But the growth in installed capacity in Turkey has now eased. As the below graph suggests, which was sourced from a 2022 publication in the journal *Geothermics* by Umran Serpen and Ron DiPippo, the years between 2010 and 2020 in particular saw a rapid increase. This led to ambitions to hit the 2,000 MW mark by the end of this year and 4,000 MW by 2030. However, as the authors of the paper already conclude, with the main graben areas (see map) reaching a mature state of exploration, it will now become harder to tap into new resources if the same exploration risk profile is maintained.

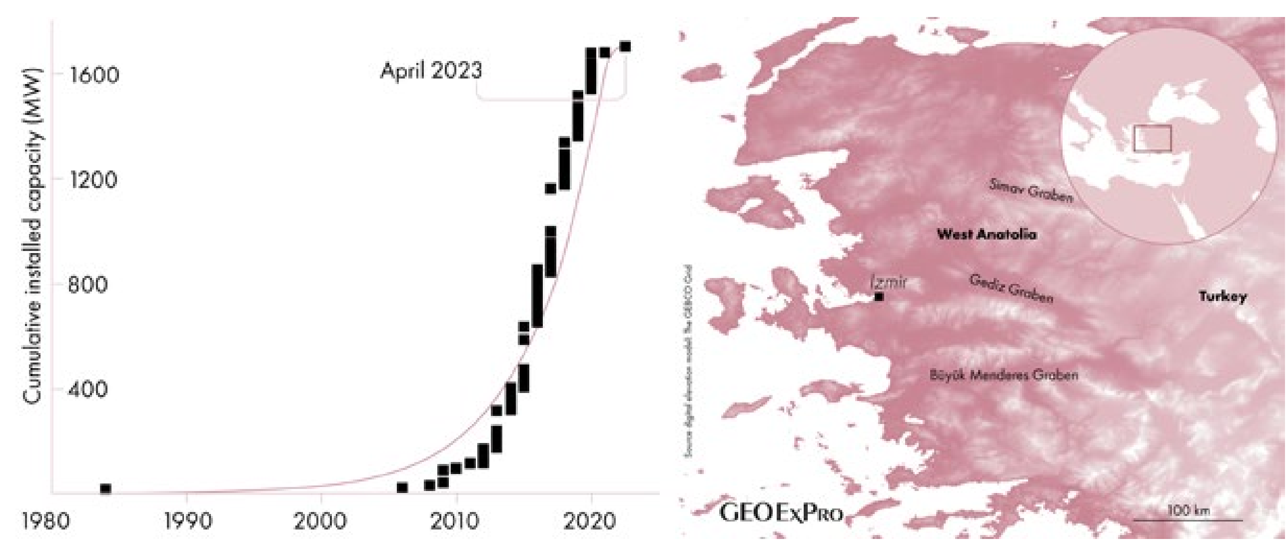
> "..there is the possibility to drill deeper, but this comes with a risk of lower permeability."

DRILLING DEEPER

Of course, there is still potential, but this will come with higher costs of exploration and exploitation. Drilling more wells close to the existing projects will only result in the risk of interference and is therefore no real solution. As DiPippo and Serpen note, there is the possibility to drill deeper, but this comes with a risk of lower permeability than the reservoirs from which production currently takes place.

It is interesting, and not at all surprising in a way, that the development of geothermal energy is showing a similar pattern as oil and gas developments in most basins, with a similar pattern of exploration and maturation stages. The lesson that can clearly be learned here from Turkey is that the low-hanging fruit is always developed first, and whilst that is ongoing, people without too much knowledge on the matter may be led to believe that the rate of development is set to continue in the same way. But it is not, so unless the economics change in favour of more risky drilling, it looks like the two decades of exponential growth is over for one of the world leaders in geothermal energy production.

On that basis, the authors recommend to start looking at the volcanic potential of Turkey as a way to tap into new geothermal plays. ■



Left: Installed geothermal capacity in Turkey from 1980 to present day, adapted from Serpen & DiPippo (2022). We added the last datapoint, which was derived from an article published by ThinkGeoenergy. Right: Digital elevation map clearly showing the graben areas where most geothermal projects in Turkey have been constructed.

Extended reach drilling for geothermal energy production

As the geothermal industry in the Munich area matures, more collaboration and new drilling techniques will be required to meet ambitious growth targets

Extended reach drilling does not mean that horizontal wells will be drilled into the Upper Jurassic reservoir; production from the dolomitized carbonates is generally very good, also because of the karstification of the reservoir, which means that there is no need for horizontal producers.

THE ENERGY TRANSITION is about pipe, lots of pipe. Where gas can be transported across the globe, geothermal energy, especially the low-temperature version of it that is mainly used for heating purposes, has to be consumed where it is produced. That is already happening in the city of Munich in Southern Germany, as we wrote about in the last two issues.

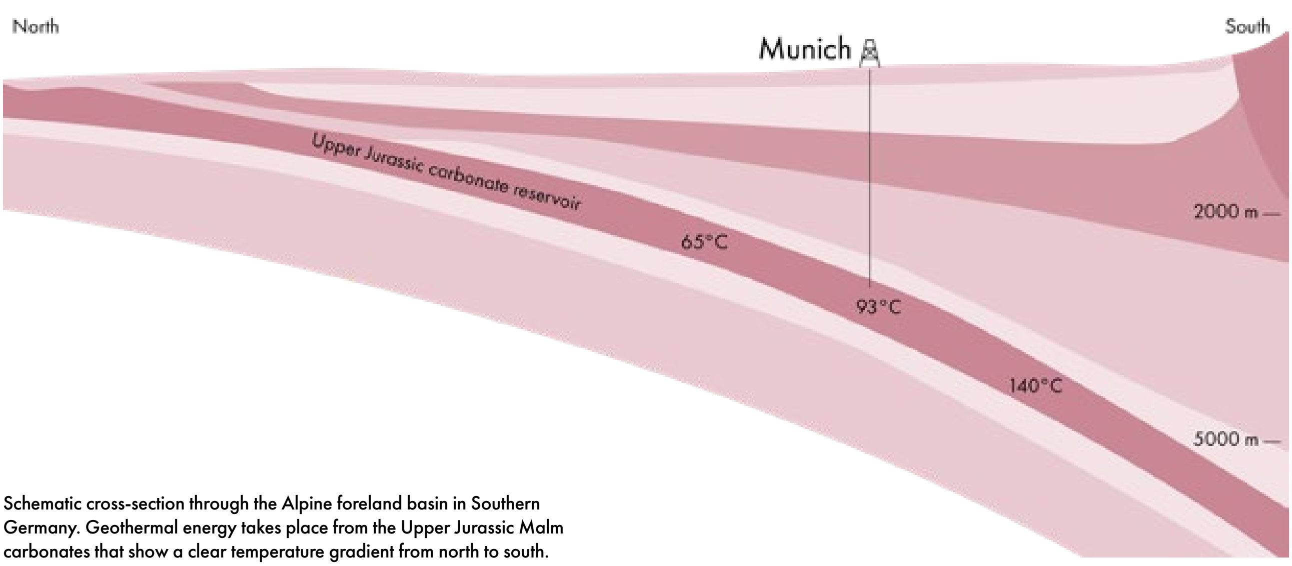
But as the Süddeutsche Zeitung published recently, due to the number of existing projects within the city limits, operators are now also looking further into the city's periphery to tap into the geothermal reservoirs there and bring it into the city center using pipelines. Or, as was mentioned in the same article, to drill extended-reach boreholes to effectively do the same.

NEXT LEVEL

It is a clear example of how geothermal energy production is going next level. At the moment, the city is dotted with individually operating geothermal projects that tend to compete with each other rather than collaborate. One of the goals of the so-called Giga-M project, initiated by Stadtwerke München, is to try and connect these networks into larger ones. This would present the system with much more contingency; when an ESP (Electric Submersible Pump) in one production well fails, neighbouring systems can make up for the loss of production when heating networks are connected to each other.

But it is not only about connecting networks, it is also about producing geothermal energy from areas a little further away from the city than what is currently happening. The 17 projects that are currently active already have deviated wells in order for the producer and injector to reach the reservoir at a sufficient distance from each other, but extended reach drilling has not happened in the Munich area yet. However, in order to increase the desired production to 1 GW from the current 400 MW, it is no surprise that these solutions are now being put forward for the area.

The Giga-M project is therefore a good example of how clean energy production is maturing further, which comes with the need for operators to collaborate more and implement new drilling technologies at the same time in order to maximise the local geothermal resource. ■



Schematic cross-section through the Alpine foreland basin in Southern Germany. Geothermal energy takes place from the Upper Jurassic Malm carbonates that show a clear temperature gradient from north to south.

REDRAFTED AFTER GEOTHERMIE-ALLIANZ BAYERN

Shallow geothermal energy is also thriving in the Munich area

And again, this is thanks to a favourable geological setting

THE MUNICH AREA in the south of Germany is situated in a genuine hot spot when it comes to geothermal energy production. Karstified Upper Jurassic carbonates have already formed an attractive target for deep geothermal energy production for a few decades, but now an entirely different part of the subsurface has also proven to be a suitable source for thermal energy. And this interval is much easier to reach.

The succession in the spotlight is a shallow up to 35 m thick interval of gravelly Pleistocene unconsolidated sediments at a depth up to 100 m, through which groundwater flows rapidly from south to north at rates 5-50 m/day. Open-hole doublets using a similar architecture to deep systems are being increasingly constructed here, with production and injection wells tapping into this shallow resource with a water temperature varying between 9 and 17° C. Because of these low temperatures, heat pumps are needed to ramp up temperatures.

But it is really thanks to the high groundwater flow rates that annual performance of these systems is so favourable, varying between 4 and 6. This means that with 1 kW of energy required to operate the system, between 4 and 6 kW of thermal energy is being produced.

The rapid groundwater flow enables quick and efficient heat exchange, enabling systems to be built much closer to each other than would otherwise be possible. That is very favourable for a densely populated area. It also allows testing new well designs, such as one-well systems that both inject and produce water from the same borehole.

One shallow geothermal doublet provides energy – which can be used for both heating and cooling - for small houses (8 kW) up to whole neighbourhoods. The biggest project that is now being prepared in the Munich area is 3 MW, but there are already bigger ones planned in the city. ■

PHOTOGRAPHY: AYLA HERNÁNDEZ

The concrete rings of this shallow geothermal project in the Munich area are stacked on top of each other, after which the sediments are being excavated from the inside. When they reach a certain depth, the horizontal drilling starts, in several directions. These pipes are much smaller.

HOW DOES A 3 MW SHALLOW GEOTHERMAL PROJECT LOOK LIKE?

Instead of a "conventional" system that involves one vertical producer and one vertical injector, these projects will rely on a grid of wells being connected to one heat exchanger. "We are also looking at drilling these wells horizontally to increase the output per well", says Ayla Hernández from Stadtwerke München. "However, the bigger the system, the more extra parts are required such as circulation pumps and frequency converters. Also, it depends if the system is only used for heating, cooling or both, and if the groundwater then carries "waste" heat to other buildings like a local thermal network."

Quad 35 Hybrid MC3Ds: Innovative multi-parameter FWI for near field exploration

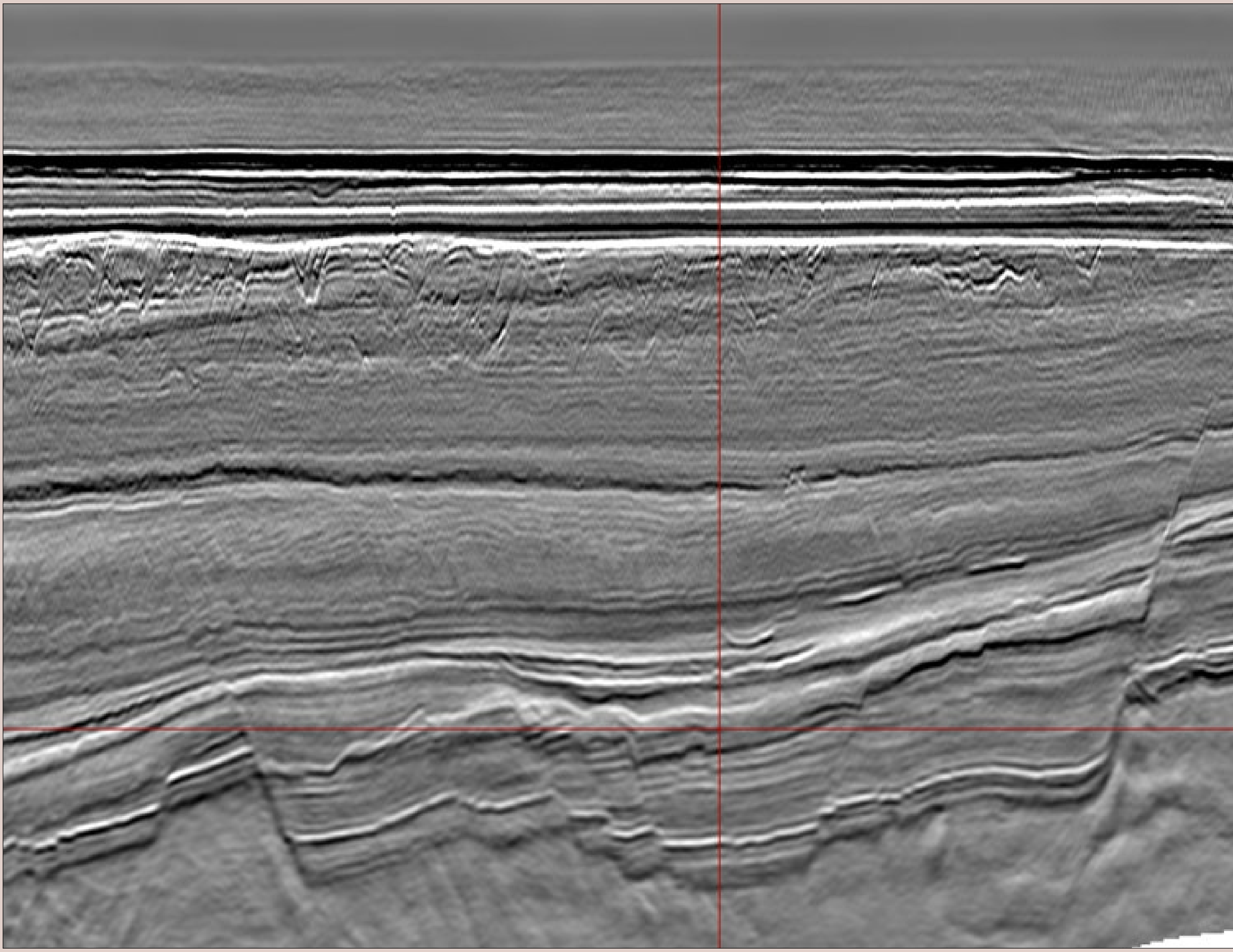


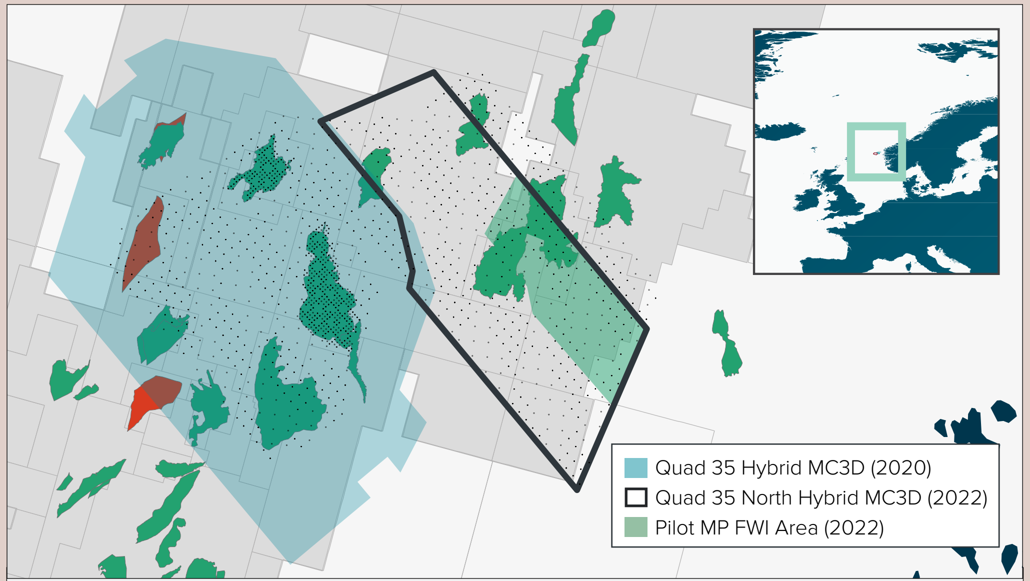
Figure 1a: Inline showing well defined Jurassic and Cretaceous sections.

Geoex MCG and partners Seismic Partner, BGP, Magseis, Reach, PXGeo and DUG have acquired two Hybrid MultiClient 3Ds (Q35 & Q35N) in the Norwegian North Sea, Quadrant 35 area, in 2020 and 2022. The 2020 survey covered the Nova, Vega, Aurora, Grosbeak and Orion/Beaujolais fields and discoveries. This was the world's first true Hybrid 3D acquisition, whereby ocean bottom nodes (OBN) and high-density streamer data were acquired simultaneously. Here, the streamer vessel was utilised as the OBN source vessel whilst also acquiring streamer data. Further acquisition of Q35N was completed in 2022 spanning 420 km^2 and covering part of the Gjøa field and the Titan and Tethys discoveries. Due to the significantly improved imaging demonstrated by the 1st acquisition, Q35N was acquired in a similar fashion.

This article will focus on the Q35N Hybrid MC3D. The acquisition parameters were upgraded from 2020, providing a high-density result. Bin sizes were reduced to 7.50 m x 6.25 m and fold increased to 128 within the 46.9 square m area. A pilot project of 100 km^2, also shown on the map, was selected for DUG's Multi Parameter FWI processing.

Geoex MCG

Seismic partner



Map: Quad 35 (2020) and Quad 35 North (2022) Hybrid MC3D Surveys.

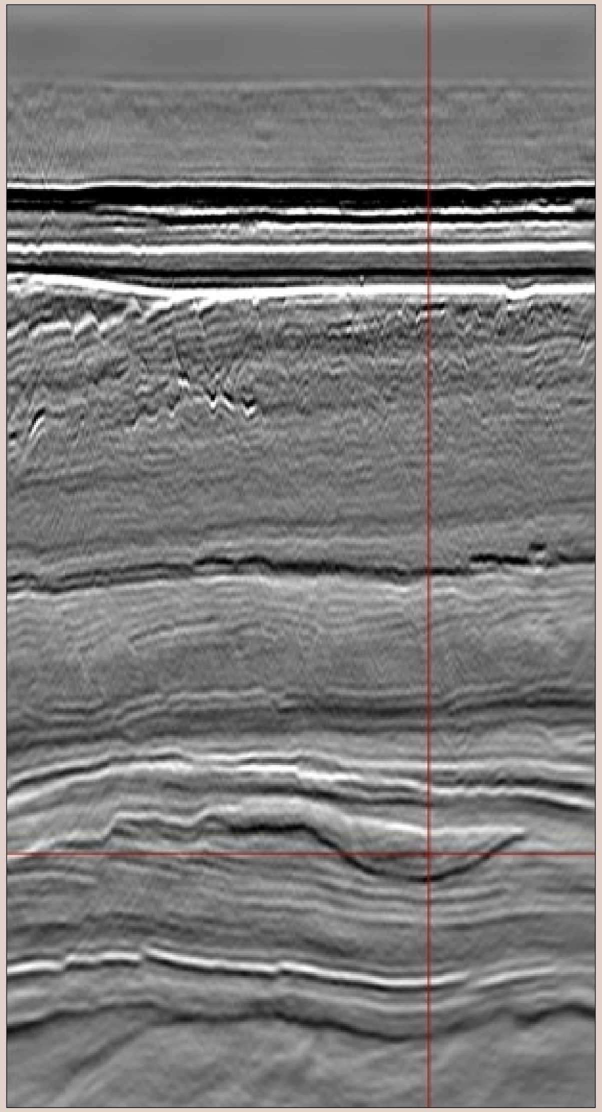


Figure 1b: crossline showing well defined unconformities in Jurassic and Cretaceous sections.

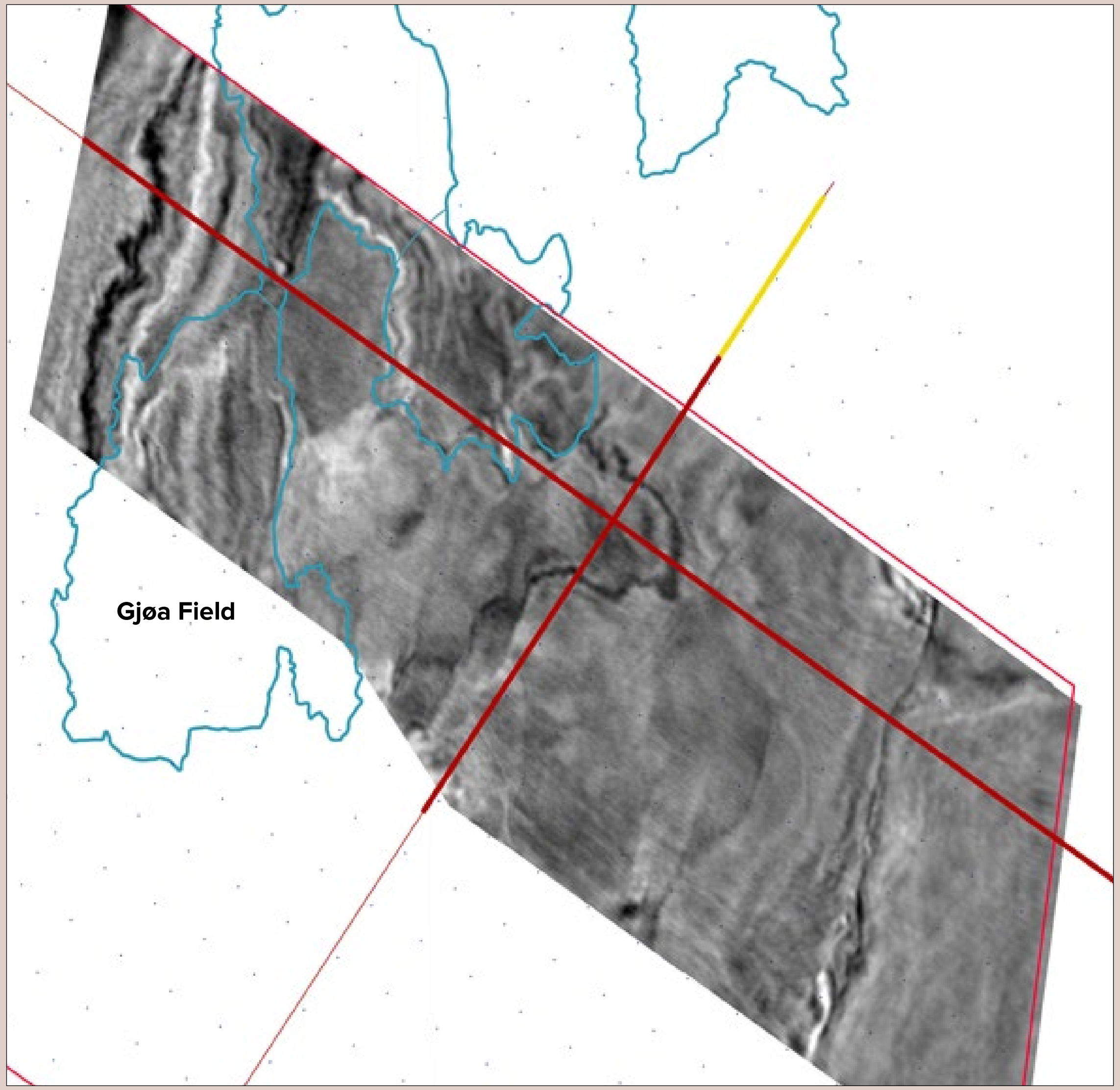


Figure 1c: Quad 35 North Pilot Area Timeslice.

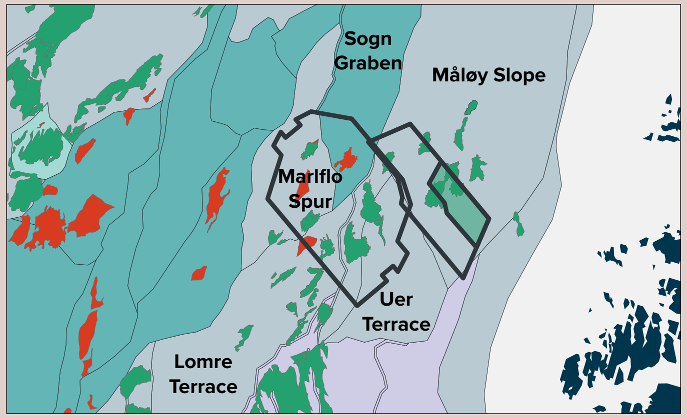


Figure 3: Map of Geological Structures Around Quad 35.

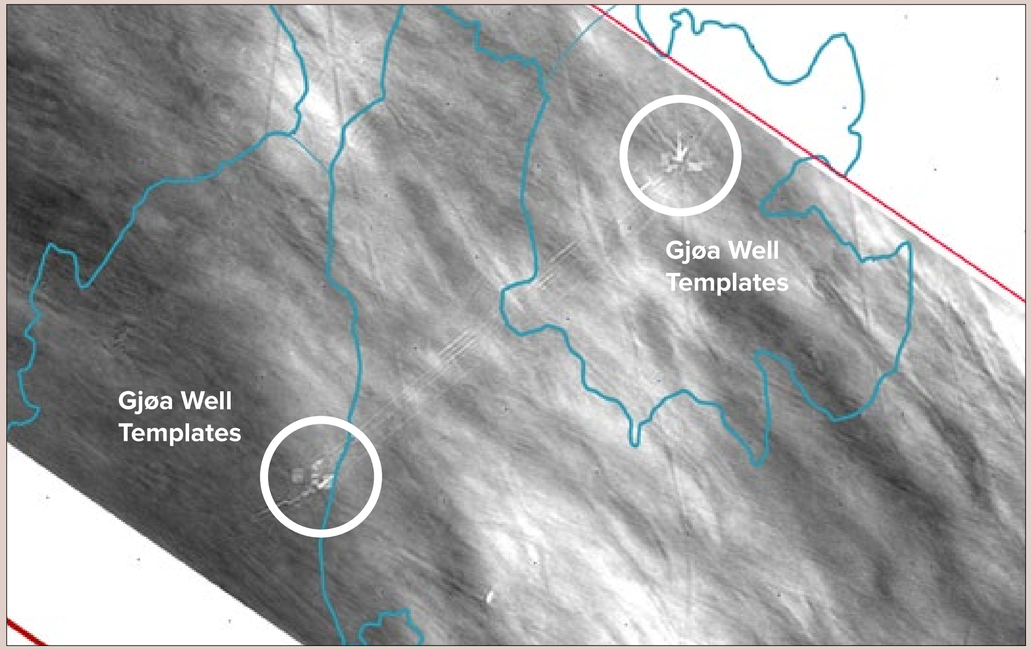


Figure 2: Gjøa Well Templates Show up on Timeslice 460 ms.

Utilising all hybrid acquired waveforms in a revolutionary MP-FWI processing approach

The Hybrid Q35N MC3D was acquired in 2022 in the Måløy Slope, towards the Uer Terrace, in the Northern North Sea. Spanning 420 km², the survey covers the Titan and southern section of the producing Gjøa field (Figure 3). This also envelops the Tethys discovery. Predominantly, the area is held by operators such as DNO and Neptune as well as the newly awarded PL1180 license from the APA 2022 Round

TOR ÅKERMOEN AND JEROEN HOOGEVEEN, GEOEX MCG, KRISTEN BERLI, SEISMIC PARTNER, AND TOM RAYMENT AND PERCY MELLAR, DUG

NOT ALL JURASSIC RESERVOIR IS CREATED EVENLY...

The Titan and Tethys are quite well understood discoveries in the Upper Jurassic. However, surrounding exploration has had varying success with different hydrocarbon types and reservoir quality in alternative intervals. This demonstrates that sand distribution is not yet fully understood due to the variation in age and deposition of the reservoirs.

For example, the Gjøa field was discovered by the 35/9-1 well in 1989, encountering hydrocarbons in the Upper Jurassic Viking Group, the Middle Jurassic Brent Group and the Lower Jurassic Dunlin Group. A further target was the Lower Cretaceous, which was unfortunately dry due to lack of reservoir. Subsequently, 35/9-2 confirmed Upper and Middle Jurassic reservoir presence showing variations of success within this interval. Further drilling of well 36/7-1, drilled in 1996, discovered oil and gas in both the Intra Draupne sandstones and the Sognefjord Formations of Late Jurassic age as well as in the Middle Jurassic, Fensfjord Formation. The Gjøa field came into production in November 2011 and has currently more than 50% gas production.

Further to the north-east, higher up on the slope, the Duva prospect was drilled in 2016 with oil discovered in the Lower Cretaceous Agat Formation. It came on stream in 2021 and is tied into the Gjøa field. Successful drilling of the Hamlet and Ofelia proved hydrocarbons in the Agat Formation northwards on the 'Gjøa Ridge' to the northeast of the Q35N region.

SOLVING THE JURASSIC CONUNDRUM

This demonstrates a highly prospective area but in order to understand and solve the challenges associated with which reservoir intervals are prospective and present, innovative seismic acquisition and processing is required. The Hybrid, LumiseisTM, Ultra High Density (UHD) 3D method has proved to resolve both the structural and stratigraphical challenges (i.e. thin reservoirs), while preserving the integrity of geophysical information.

Developing our experience from the 2020 Hybrid project, the new 2022 Hybrid acquisition was enhanced by using 5 sources and a streamer separation of 75 m. This resulted in very small bins of 7.50 m in crossline direction and 6.25 m in the inline direction. In these small bins (46.9 m²) we again obtained a high fold of 128. The nodes were placed in a 900 m x 900 m grid simultaneously receiving shots from a uniform source grid of 31.25 m x 60.00 m.

This Hybrid acquisition with UHD streamer and OBN data is ideal for velocity model building using diving waves in Full Waveform Inversion (FWI) and lends itself to new and innovative seismic processing, Multi Parameter FWI, as described in the text box on the opposite page.

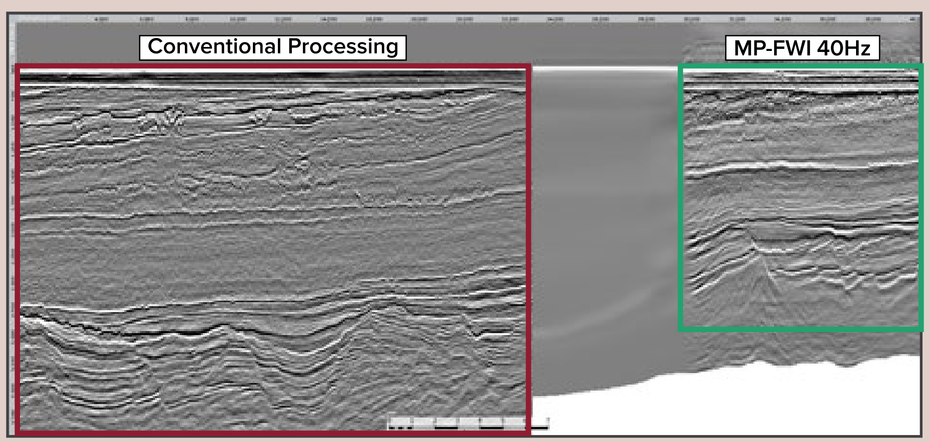


Figure 4: Example of processing results from the Quad 35 (in red) and Quad 35 North (in green).

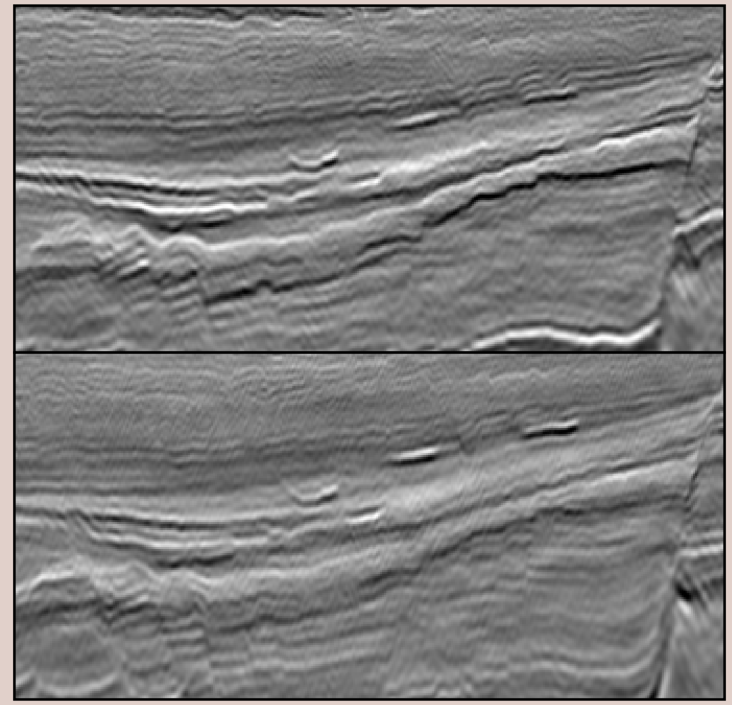


Figure 5: Near (top) and far (bottom) offsets from the MP-FWI.

PROOF IS IN THE SEISMIC

A 100 km² pilot test area was carefully selected to highlight both existing challenges on the Gjøa producing asset and to reveal potential new prospectivity in the recently awarded PL1180 license. The test cube at 40 Hz shows that the data has delivered the desired results. Examples of the well-defined Jurassic and Cretaceous sections are well displayed in Figures 1a (inline), 1b (crossline) and 1c (timeslice). The spectacular Upper Jurassic unconformities, shown as a white and a black event can clearly be seen, as well as the Agat and Kyrre sands. The resolution is significantly improved and the imaging is excellent. The MP-FWI processing has resolved multiple and noise issues, showing the primary data clearer and at the same time simplifying the interpretation. Figure 4 shows a comparison between 'conventional' processing, whereby the OBN has been used for velocity model building only and the innovative MP-FWI result. Figure 2 shows amazing detail just below the seafloor! The timeslice displays some of the well templates in the Gjøa field and possible trenching between them.

AVO PROSPECT MAPPING FROM MP-FWI

Having first generated the full fold data, we also generated angle stacks, showing that MP-FWI can deliver offset information as well, see Figure 5. This is particularly important in an AVO driven prospect mapping exercise. This frontier acquisition method, combined with state-of-the-art processing, is proof of the detail that can be achieved to solve problems in a complex basin.

Geoex MCG and partners are confident that this newly available data will assist near-field exploration in the region by finally answering questions surrounding the Jurassic and Cretaceous reservoir locations in this highly prospective region.

Multi-Parameter FWI imaging

A complete replacement of the conventional workflow

Traditional seismic processing workflows can be extremely time-consuming since subsequent stages only begin after extensive testing and QC of the current process. This serial approach takes the raw field data and passes it through a plethora of conditioning tools such as designature, deghosting, demultiple and regularisation to transform the data into a form that can be imaged by legacy migration algorithms, such as Kirchhoff or reverse time migration.

DUG Multi-Parameter FWI (MP-FWI) Imaging is a novel approach to seismic processing and imaging. This unique implementation of full waveform inversion delivers simultaneous model-building and full wavefield least-squares imaging directly from raw data, without the need for the conventional, extensive pre-processing and model-building workflow.

When including reflections in FWI, both the kinematics (timing) and dynamics (amplitudes) of the wavefield must be utilised as part of a simultaneous, multi-parameter inversion. DUG MP-FWI Imaging permits two significant improvements over traditional FWI to be realised. Firstly, it allows the kinematic part of the reflections, the so-called "rabbit ears", to generate velocity updates over the full depth range. Secondly, it enables least-squares imaging utilising the entire wavefield which includes ghosts, primary reflections, surface-related and interbed multiples. This is in contrast to traditional imaging algorithms which image primary reflections only. The output velocity and reflectivity volumes can be derived from multiple surveys as was the case here, with both the streamer and OBN data used as input.

At high frequency, this approach provides true-amplitude reflectivity images for both structural and quantitative interpretation (including angle stacks for AVA analysis), without the need for the subjective and time-consuming conventional processing and imaging workflow.

SUBSURFACE STORAGE

"I think it is going to be mission impossible."

Rafik Lazar - GeomodL International

"I think it is going to be mission impossible"

Geologist Raffik Lazar talks from first-hand experience when advocating to not look at abandoned fields for CO_2 injection

THE KEY challenge when it comes to storing CO_2 is containment", says Raffik Lazar, CEO of Dubai-based GeomodL International. "And the only element I can trust in the containment scenario is the geological one; legacy wells are not part of that. To be honest, I don't think anyone can guarantee that old wells are 100% safe when it comes to their ability to keep CO_2 in its place in the subsurface."

"There are so many factors that can play a role, for example how the abandonment was carried out. In the past, they may just have put a plug at the top and that was it. And even when you know where the plugs were set, how do you know what the integrity is? And what happens when you inject fluids in the reservoirs, resulting in a pressure rise?"

"There was almost nothing left in the hole, with the casing heavily corroded to about 80%."

Can old wells and their cement plugs withstand these rising pressures? "I am not so sure", continues Raffik, "because I have been in the field in Southeast Asia where I observed pressure build up in both the A and B annuli in many abandoned wells. This can express itself as the appearance of bubbles at the sea floor. If you are lucky, you can even monitor pressure increase in the annuli because a gauge was fitted when the well was abandoned."

"What concerns me even more is the possibility of CO_2 migrating behind casing, making its way up and possibly into other formations at a shallower depth."

But even when some leakage happens, especially offshore, is it really that bad? "The issue I have with it, says Raffik, is the fact that leakage at the surface is the top of the iceberg. How much CO_2 has already made its way to shallower aquifers in that case, for instance?"

Going back to old wells to do a workover is not a very straightforward thing either, not least because it incurs additional costs even before the start of injection. And the older the wells, the poorer the state it will be. "I worked on an old gas field with wells drilled in the 1960's and 70's", concludes Raffik. "There was almost nothing left in the hole, with the casing heavily corroded to about 80%. In addition, cement de-bonding could also be observed, creating space between the formation and the plug. With that in mind, I would strongly favour storage sites with a minimal number of well penetrations, and you see why I'm saying that!" ■

Are leaky pipes in the subsurface the norm rather than the exception?

IMAGE CREATED BY: DALL·E

Europe's first full-scale onshore CO_2 storage project

A unique project is being realised in Denmark, where CO_2 is planned to be stored down flank of a gas storage site. Read here about how this is being achieved

MIKAEL LÜTHJE, MARTIN PATRONG HASPANG,
GAS STORAGE DENMARK AND CARSTEN MØLLER NIELSEN, GEUS

Gas Storage Denmark (GSD) is currently in the detailed engineering phase of Europe's first large-scale, commercially operational onshore CO_2 storage facility (CO_2RYLUS). This initiative aims to accelerate the development of a full carbon capture and storage (CCS) value chain, thereby accruing invaluable insights, expertise, and know-how for others to learn from.

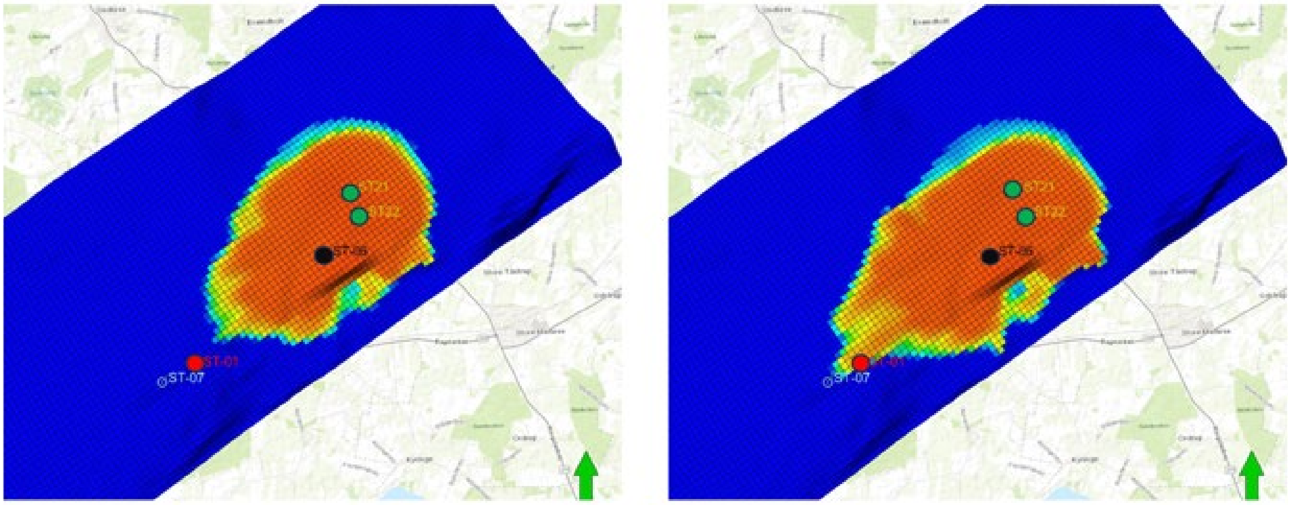
Operating within a stringent timeline, GSD's objective is to have a subsurface storage facility operational before 2026. The chosen site, the Stenlille structure, is situated in Central Zealand, Denmark, and provides a good starting point with more than three decades of experience in storing natural gas and an accepting local community. The Stenlille structure is a salt-induced anticlinal 4-way closure that provides excellent conditions for injecting and storing media such as natural gas or CO_2.

The data from Stenlille is considered the most comprehensive onshore dataset in Denmark and includes 2D and 3D seismic data as well as twenty wells with wireline log data. Fourteen of the wells are presently used for natural gas injection production, and the rest are used for monitoring. These data, coupled with the knowledge and understanding of the subsurface from operating the gas storage facility, are an ideal starting point to quickly establish a CO_2 storage facility.

THE RESERVOIR

The main reservoir in the Stenlille structure is the approximately 150 m thick Gassum Formation, comprised of mainly Upper Triassic to Lower Jurassic sandstones with some interbedded clay stringers. The top Gassum Formation is found at approximately 1,500 m below the surface. The reservoir is sealed off with around 300 m of the mud-dominated Jurassic Fjerritslev Formation,

Artist impression of the Stenlille structure.



The migration of the CO_2 plume 50 years (left) and 100 years (right) after the start of injection. Over five years, one million tons will be injected in the well marked with the black circle (ST-06). After that, two hundred thousand tons per year will be injected in each of the wells marked with green circles (ST-21 and ST-22) until a total injection of eight million tons is reached. The red circle (ST-01) marks the north-eastern border of the natural gas storage. The distance between ST-01 (red circle) and ST-06 (black circle) is approximately 2.5 kilometers.

which in turn is overlain by around 1,100 m of the limestone-dominated Cretaceous – Paleocene Chalk Group and less than 100 m of Quaternary deposits.

The Gassum Formation has excellent average porosities of around 25% and permeabilities up to 7 Darcy. The sealing capacities of the Fjerritslev Formation have been proven tight during the entire gas storage facility operations in Stenlille, which provides confidence in a competent seal. The additional c. 1,100 m of low porosity Chalk above the Fjerritslev Formation only adds to that.

The CO_2RYLUS storage project in Stenlille is designed to take advantage of the comprehensive knowledge of the Stenlille structure and its proven reservoir qualities. However, since it is also actively operated as a gas storage facility, some significant challenges also arise, such as making sure that gas storage and production can continue whilst CO_2 injection is taking place at the same time.

THE CHALLENGES

The planned CO_2 storage operation will be located down flank in the northeast of the structure to secure a safe distance between the injected CO_2 and the existing gas storage operation. This will be done to prevent natural gas contamination and to preserve the integrity of the existing wells. Simulations show that up to eight million tonnes of CO_2 will not reach the natural gas in the expected lifetime of the gas storage operations. Additionally, GSD is looking into potentially expanding the CO_2 storage capacity later by including deeper formations in the Stenlille structure. To be ready to operate in 2025, the project is planned as a 2-stage project where one observation well down flank will be converted to a CO_2-injection well followed by drilling new wells further down flank.

Dynamic storage capacity estimations are essential to constrain value chain cost estimations; how much capacity can be offered and how fast, and how many wells need to be drilled? Therefore, a geological model for the northeastern flank was developed and used to simulate different injection scenarios, specifically with the updip gas storage facility in mind.

CO_2 migration up-dip to the natural gas accumulation due to buoyancy will occur over time and hamper the natural gas storage business. Therefore, high permeability is not solely an advantage for the present case; it will help dissipate pressure buildup due to injection of CO_2, but it will also accelerate its up-dip migration. Dynamic simulations with the Eclipse 100 software were performed to balance the storage capacity with the timing of CO_2 arrival at the natural gas accumulation.

SEISMIC DATA AND WELL PLANNING

While substantial geological data exists for the Stenlille structure, knowledge gaps necessitate further investigation, particularly in the context of the northeastern flank. Specifically, better seismic data was needed since the existing 3D seismic only partially covered the area of interest. Therefore, a new seismic survey campaign was initiated to address this gap. Interpretation of the seismic data is taking place at the moment and plans for well design and monitoring strategies are all being worked on to have the first full-scale European onshore subsurface storage facility operational before 2026. ■

SOURCE: GAS STORAGE DENMARK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TECHNOLOGY

"I may be wrong, but I don't see that level of subtlety being likely to be forthcoming within the foreseeable lifetime of our industry."

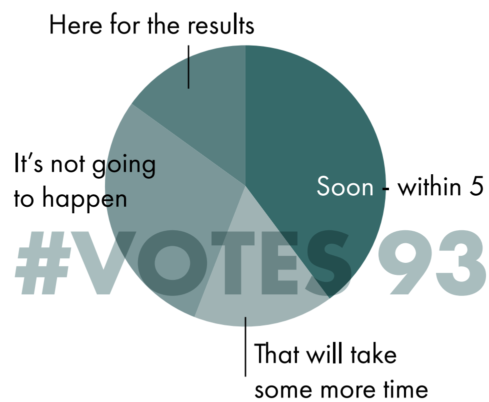
Kevin Schofield – GEO Advisors

When will the first prospect be drilled that was identified and de-risked through the use of AI?

That's the question we asked our followers on LinkedIn

THERE IS a buzz around artificial intelligence (AI). With routine tasks being increasingly taken over by machines, to the point that they are better trained than the human eye, when will an algorithm be able to spot a prospect hidden in a cube of seismic data? Exploration directors are eagerly following developments in this field, because who doesn't want to take credit for having identified a successful prospect based on smartly designed technology?

And it is an intriguing question indeed; will a well-trained algorithm be able to use the combination of rules from the petroleum play handbook in such a way that it cooks up something that most human explorers have never identified as an opportunity to date? Who knows.



Yet, it has to be said that not everybody is convinced of a future in which machines do the exploratory work for us. In a poll that was completed by 93 people, a sizeable group of 27 thinks that it will not happen at all. Fifteen voters think that it will take some more time to get there, be it more than 5 years, but still, 37 people do agree with the statement that within 5 years a drill bit will hit the ground testing a prospect that was identified and de-risked using AI.

Time will tell. If the company being responsible for it will be keen to share the results in the first place.

BLACK AND WHITE

As Alan Foum noted in a comment on LinkedIn: "A scenario in which a combination of traditional exploration and AI is used is a reality for some companies already as a way to check the validity of an identified prospect." Anton Starovoitov seems to be happier with such an approach than fully trusting AI: "I would not feel comfortable as Exploration Manager if the majority of prospect generation is done by AI", he commented. Kevin Schofield is more skeptical about the role of AI. Exploration is "not a yes/no answer", he comments. "I may be wrong, but I don't see that level of subtlety being likely to be forthcoming within the foreseeable lifetime of our industry." ■

HERE FOR THE RESULTS

As some people take a stronger interest in knowing what others think than throwing in an opinion themselves, we have introduced an option that allows them to see the results of the vote by selecting "here for the results." Amongst this group of voters, of which there were 13, are some people from fairly high up in exploration with major international oil companies, clearly suggesting that this very topic is indeed being followed by those working in the prospect-chasing business.

Shifts in the seismic acquisition space

Sercel is introducing a novel solution to adapt to the evolving methods of offshore seismic data acquisition, driven by shifts in end-user preferences

IN THE PAST, we as a provider of OBN and streamer technology would mostly liaise with seismic acquisition companies; our exposure to oil companies was very limited," says Gaetan Mellier, Vice President Marine Segment at Sercel. "This business model is evolving. The push for new technology is now coming more directly from operators, which means that we must also communicate directly with end users. In addition, operators want to monitor seismic acquisition projects more closely these days and in real-time."

"..it is especially in the OBN domain that we see sustained growth over the past couple of years."

For that reason, Sercel has recently launched a new data-driven collaboration solution called MetaBlue™. Sercel is a key player in providing software, technology, and services to support companies in the seismic acquisition process. 'The essence of MetaBlue is to connect with the end user, understand the key pain points, and propose the best solution to meet project goals', says Gaetan.

OPTIMAL USE OF SENSORS

The platform will not only facilitate communication between all project stakeholders. It will also ensure the optimal use of technology. For example, the use of MEMS sensors in a rapidly evolving Ocean Bottom Node technology is an enabler to optimise the quality of the acquisition. Gaetan adds: "Being able to communicate that to the end-client directly is a great benefit to us and is an enabler for real-time adjustments to ensure successful results."

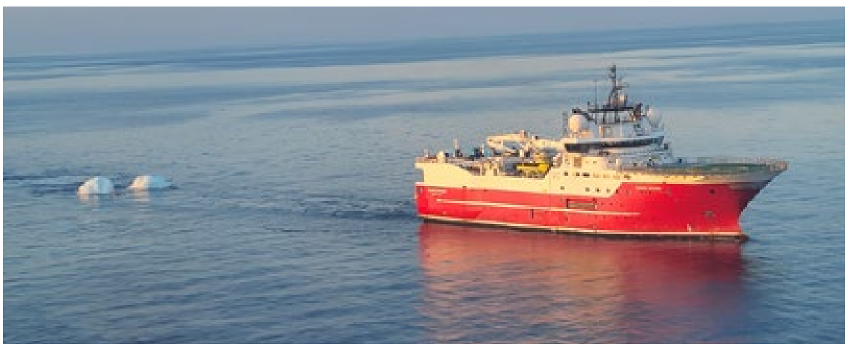
Gaetan Mellier, Sercel

DON'T FORGET THE SOURCE

It's not only the nodes themselves; it is also the source for the seismic signal that needs attention", emphasizes Gaetan. "It is easy to forget that a good source is of key importance to acquiring high quality data. We have seen that in some cases, airguns designed for streamer data were used for OBN acquisition, which is wrong. Therefore, we have made a significant investment in the design of the OBN source in addition to our capabilities in node technology. And again, being able to integrate all this into MetaBlue will be an asset for any user of our equipment."

PARTNERSHIPS

A final element where the new platform comes in is the changing way new technology is being developed. "We used to work on new things in a fairly solitary way, but now we try to form partnerships with companies to come up with technology that suits a specific business need. For example, we worked with Shell on developing a low-frequency source for complex exploration targets called TPS™. Thus, another essential aspect of MetaBlue is to serve as an avenue for creating partnerships that address a direct customer need and subsequently benefit other end users."



CONFIDENCE IN A VOLATILE MARKET

"The market is still volatile", admits Gaetan, "but it is especially in the OBN domain that we see sustained growth over the past couple of years. It is also reflected in the fact that we have invested heavily in the development of nodes capable of withstanding water depths of 700 m to 3,000 m, where the focus initially was on shallow water. At the same time, streamer data is certainly not over yet, as it remains the most cost-effective way to explore larger areas." ■

Why do cables get stuck during open-hole wireline logging operations?

Technology is not always about AI, sometimes it requires a very hands-on approach to find the solution to well-known industry problems

IN HIS BOOK "Oil Notes", geologist Rick Bass describes the importance of logging operations. Only after completing a log run, the well can be properly classed as a success or a dry hole. That is why it is so surprising that wireline cables get stuck in the wellbore so often, with costly delays and sometimes loss of data as a result. It is even more surprising when one considers that there is a solution on the market. And that solution was developed by Guy Wheater from Gaia Earth (see the interview with Guy on page 54-58).

BUT FIRST, HOW DOES WIRELINE CABLE GET STUCK?

There are two sticking categories. **Cable keyseating** is where the cable wears a slot in the formation which may then unleash a combination of sticking mechanisms, such as slot compression from borehole stress, slot swelling from reactive shales, mechanical binding from deep slots or differential sticking if the slot is permeable. **Differential sticking** may occur if the cable is in contact with mud-cake or permeable formation directly, or from loss zones. During a logging run, the abrasive action of cable or logging tools may damage the mud cake and induce sticking.

WHAT CAN BE DONE TO PREVENT THIS FROM HAPPENING?

"Many operators' wireline acquisition programmes are in the cable sticking risk envelope but they just don't know it. An early risk assessment is invaluable since cable sticking can be predicted and avoided with 99% efficacy", says Guy. "After more than 15 years of R&D, and ongoing modelling and monitoring of 1000s of hole-sections for our clients, we are very confident in our system. Furthermore, over 100 historical cable sticking and fishing post-mortems from around the world ensures our modelling is effective and dependable in a broad range of geological environments."

AND WHAT IF THERE IS AN ELEVATED RISK OF CABLE STICKING?

In wells with directional work and long open-hole sections, with weak to medium strength formations, or in wells with loss zones, overbalanced sands or fractured carbonates, there is an increased risk of cables getting stuck. To facilitate open-hole logging in these environments, Guy and his team at Gaia Earth Technologies developed the so-called wireline standoff tool. An array of standoffs can be attached to the wireline cable at pre-determined intervals. And this seemingly simple solution has proven to be highly effective on even the most challenging wells over the last 12 years, resulting in many days of saved rig time and GHG emissions. ■

A wireline standoff tool.

PHOTOGRAPHY: GAIA EARTH

DEEP SEA MINERALS

"We only want the nodules, everything else is waste..."

Tore Halvorsen, Loke

Leader in marine minerals

The Norwegian participation was significant during the conference on marine minerals in Rotterdam. Norway is one of the "hotspots" for the development of a new industry

Underwater Minerals Conference, Rotterdam.

THE UNDERWATER Minerals Conference (UMC) was held in the Netherlands for the 51st time this year, spanning six days. The number of participants has increased. And so has the number of talks.

There is little doubt that interest is on the rise. The global deep sea minerals industry is growing. So far, no production is taking place, but exploration is being carried out in some places. In other places, exploration may soon become possible.

Part of the motivation for looking to the deep sea for resources is that the global demand for metals and minerals is increasing, not least due to the energy transition. More focus on security of supply is also a factor.

It is hard not to notice the Norwegians. Both on the podium and in the hall. The Norwegian presence is a good indication that a new ecosystem for deep sea minerals is also developing in Norway.

HOTSPOT

Norway can be said to be one of three hotspots for activities related to marine minerals; the other two are the Cook Islands and the Clarion-Clipperton Zone in the Pacific Ocean, where exploration is carried out in both cases.

Norway has not opened for exploration yet, but is not far behind. It has a seabed mineral law, and work on an opening process has been ongoing for several years. This summer, the government submitted a report to the Storting regarding the opening of the Norwegian continental shelf for mineral activities.

Norway also has an estimate of possible resources. The Norwegian Petroleum Directorate attended the conference and presented its resource estimate for sulphides and crusts, which was published in early 2023.

The emerging Norwegian seabed mineral industry can also benefit from its world-leading technology and expertise related to oil and gas – much of this is transferable to deep sea mining. In addition, a strong onshore industry can potentially be useful for refining and producing raw materials for further processing.

Perhaps we will see extraction in Norwegian waters by the end of this decade? However, it requires that the government gives the green light for opening, and that the Norwegian actors can demonstrate that extraction is technically and economically feasible with minimal environmental degradation. ■

PHOTOGRAPHY: RONNY SETSÅ

What moves a grain?

Sediment plumes generated by deep sea mining are influenced by a multitude of physical processes over a wide range of spatio-temporal scales. A 2021 trial in the Pacific Ocean continues to provide new information and model input

PLUME DISPERSION is not solely a matter of distance from the mine site, physical processes are also important", said Thomas Peacock, professor at Massachusetts Institute of Technology (MIT) at the Underwater Minerals Conference (UMC) in Rotterdam in October.

One of the key environmental issues concerning deep-sea mining, whether it's polymetallic nodules, crusts, seafloor massive sulfides, or something more exotic like REE-enriched muds, is how mining equipment and activities on the seafloor may stir up sediments and produce plumes.

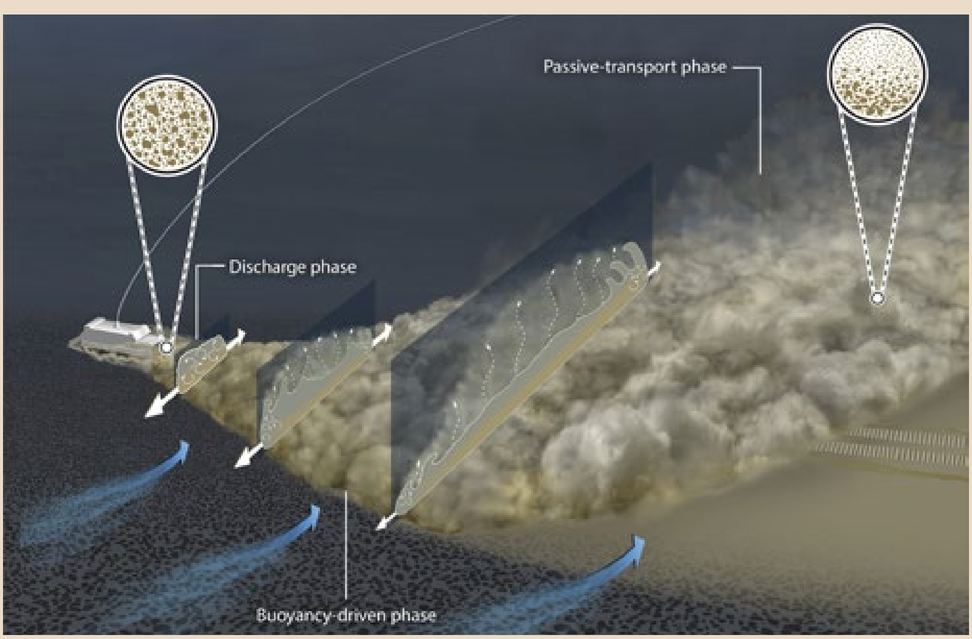
In 2021, a pre-prototype nodule collector (Patania II) was tested by Global Sea Minerals Resources (GSR). The trial was performed at 4,500 meters depth in the Pacific Ocean's Clarion-Clipperton Zone, which is considered the largest nodule field in the world where several state-backed companies currently hold exploration licenses.

Plume monitoring was performed by utilising instruments on the mining vehicle, on AUVs, and at fixed locations (moorings) at some distance from the mining test site. The various instruments recorded plume directions, heights, speeds, and densities while the collector was moving along the seafloor on a pre-planned path.

Last year, the MIT and Scripps Institution of Oceanography team published results demonstrating that the majority of the sediments in plumes remained below two meters above the seafloor, spread laterally for some tens of minutes, and then settled on the seafloor. The observations contrasted the general belief that the suspended sediments may rise higher into the water column and travel many kilometers.

However, it is too early to claim that the behaviour of plumes is well understood. Peacock stated that plumes are influenced by multiple physical processes, as he pointed to the mooring observations as an example. Not surprisingly, the moorings located downstream of the prevailing ocean bottom current detected the plumes at certain points in time following the test mining operations. However, a mooring located "upstream" of the mining site also detected a plume, meaning this particular plume moved against the current as a turbidity current powered by gravity.

That is why Peacock underscored the need for integrated monitoring and high-resolution near-field modeling of potential mining sites to assess the potential contribution of turbidity currents. ■



Conceptual sketch showing a nodule collector plume's discharge, buoyancy-driven and passive-transport phases.

SOURCE: PEACOCK AND OUILLON (2023)

Same, but different

Plume generation from a crust or sulfide mining operation is a different animal when compared to nodule extraction. This is mainly due to the variation of marine landscapes in which the different resources can be found

How far will a sediment plume travel from a seabed mining site? How high above the seafloor will it reach and how dense will it be? Research institutions and exploration companies are working diligently to answer these questions.

While most of these efforts have focused on nodule mining on the abyssal floor, there are other types of resources being actively considered for extraction in the marine realm too, namely cobalt crusts and seafloor massive sulfides (SMS).

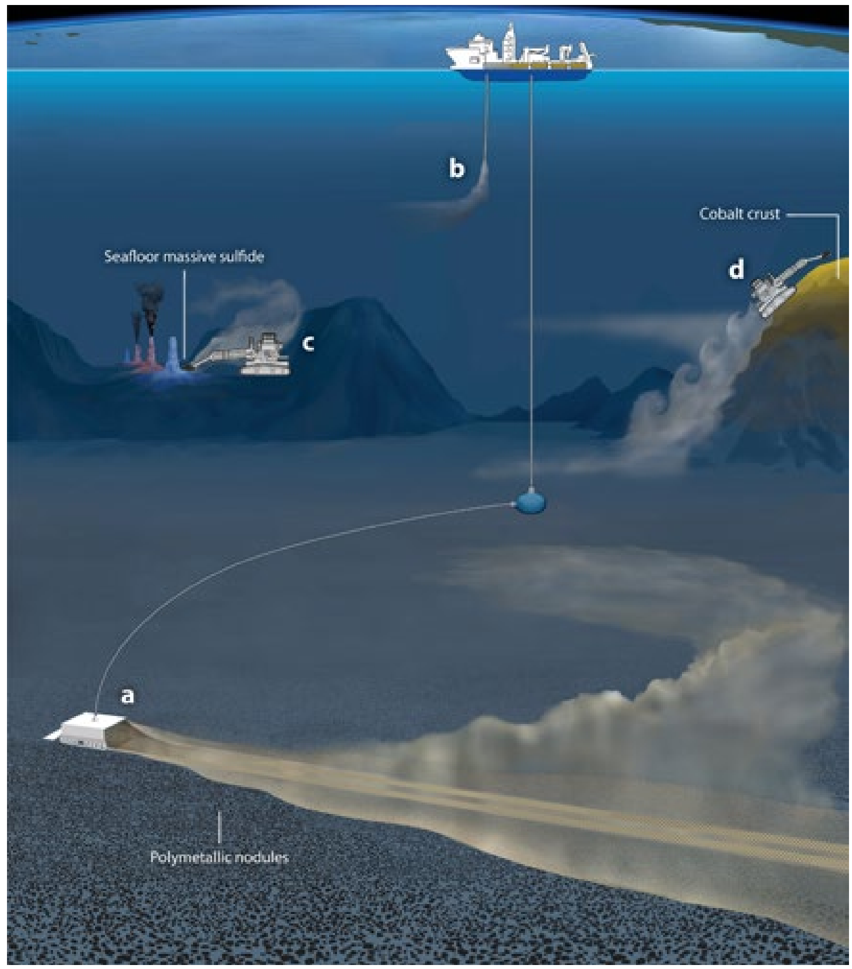
Unlike nodule mining, the extraction of crusts and sulfides may require drilling, blasting, and removal of the overburden. Sediment plumes specific to the two latter resources are currently less well-studied.

In an article published in the Annual Review of Fluid Mechanics, MIT researchers Thomas Peacock and Raphael Ouillon explain that crusts and sulfides typically occur in more rugged terrain such as ocean ridges, island arc systems, and seamounts, compared to nodules. The rough seafloor and sharply defined topographical features are often associated with strong internal tides and relatively high levels of turbulence.

They argue that the physical oceanography related to SMS and crust deposits makes extraction more complex and dynamic than that of nodule mining. Additionally, the topography encountered at these localities has the potential to significantly affect the buoyancy-driven phase of the collector plume if a turbidity current is generated.

The researchers point out that any future crust or SMS mining needs location and time-specific plume modelling efforts, as well as extensive monitoring. They write: "A single model is unlikely to be able to capture all the relevant physics of the plume, from discharge to far-field transport, and a multiphysics, multiscale approach should be adopted that resolves the near-field processes that control the discharge."

For SMS deposits, there is an opportunity to be guided by natural processes. Active hydrothermal vents produce natural plumes that have been studied in detail. Even though a hydrothermal vent plume rises while a sediment plume sinks, there is much to be learned. ■



Conceptual sketch showing plume generation from mining operations; a) nodule collection b) midwater discharge of sediments c) crust mining d) sulfide mining.

SOURCE: PEACOCK AND OUILLON (2023)

"A single model is unlikely to be able to capture all the relevant physics of the plume."


GEOPUBLISHING
EVENTS

Technology can solve environmental challenges

Reduction of the environmental impact of extracting minerals on the seabed is possible. The industry is developing new, innovative solutions to achieve that

COMPANIES and academic institutions are spending a lot of effort to better understand how sediment plumes are generated and dispersed due to anthropogenic activities in the deep sea. We are also seeing new concepts being developed for mining equipment that may considerably reduce the amount of suspended sediments generated.

The biggest environmental impact from the extraction of nodules is said to be sediment plumes that are stirred up when activities take place on the seabed. During this year's UMC Conference in Rotterdam, research on and modeling of sediment plumes was a hot topic, covered by several talks. There were also talks presenting new technology that may reduce or even eliminate plumes.

RAKING THE SEABED

Tore Halvorsen, Chief Technical Officer at the Norwegian exploration company Loke Marine Minerals (Loke), was one of the companies that presented new nodule extraction concepts. Loke is developing a concept for a nodule collector that will mechanically pick nodules with a form of a rake, rather than dredging. "We only want the nodules, everything else is waste. Raking is the most efficient way to pick up the nodules and leave the sediments", said Tore.

Loke believes that their concept will only lift sediments that are stuck to the nodules. That amounts to very little volume and can easily be transported together with the ore on ships. There will thus be no return of sediments into the water column, so-called mid-water plumes.

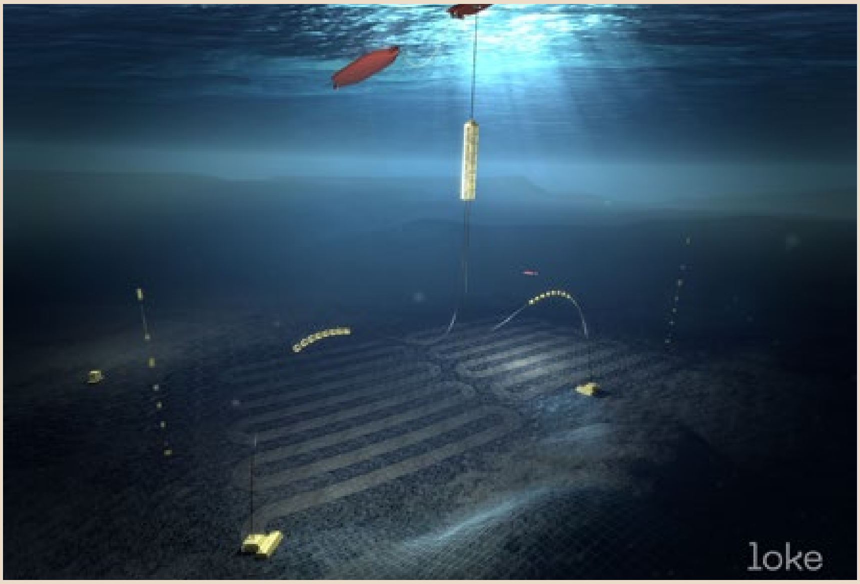
ROBOTIC ARMS TO PICK INDIVIDUAL NODULES

Impossible Metals is another company developing innovative nodule collectors. CEO and Co-Founder Oliver Gunasekara presented the company's vision of a fleet of autonomous underwater vehicles (AUVs) that can both pick nodules on the seabed and bring them up thousands of meters to a ship.

The AUVs are called Eureka and they are claimed to be an environmentally friendly solution for mineral extraction in the deep sea. Oliver said that the AUV can hover above the seabed and will use robotic arms to individually pick up the nodules. That results in minimal disturbance of sediments.

> "We only want the nodules, everything else is waste..."

Eureka will have a computer system with artificial intelligence that can recognize nodules and avoid picking up nodules that inhabit marine life and other types of rocks. The AUVs can also be programmed to leave a certain percentage of the nodules behind, for the sake of preserving the ecosystems. ■



Conceptual sketch of Loke's nodule extraction on the ocean bottom. Loke aims to begin production in the Pacific Ocean by 2030.

SOURCE: LOKE

PETRONAS DRO strategy continues to attract new domestic and overseas investors along with traditional exploration offers

NVENTURES

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In recent years, Malaysia has become a focus area in the Asia-Pacific region for new acreage acquisition through efficient bid rounds, offering a wide variety of opportunities assisted by access to data through the PETRONAS "myPROdata" portal. This has attracted familiar and new domestic and overseas investors, with Discovered Resource Opportunities (DROs) being particularly successful

MARK HARRIS, NVENTURES

A NOTABLE NEW entrant is Ping Petroleum, part of Malaysian entity Dagang NeXchange Berhad (DNeX). Ping represents the DNeX upstream arm which focuses on shallow water offshore production, specialising in brownfield redevelopment of producing fields.

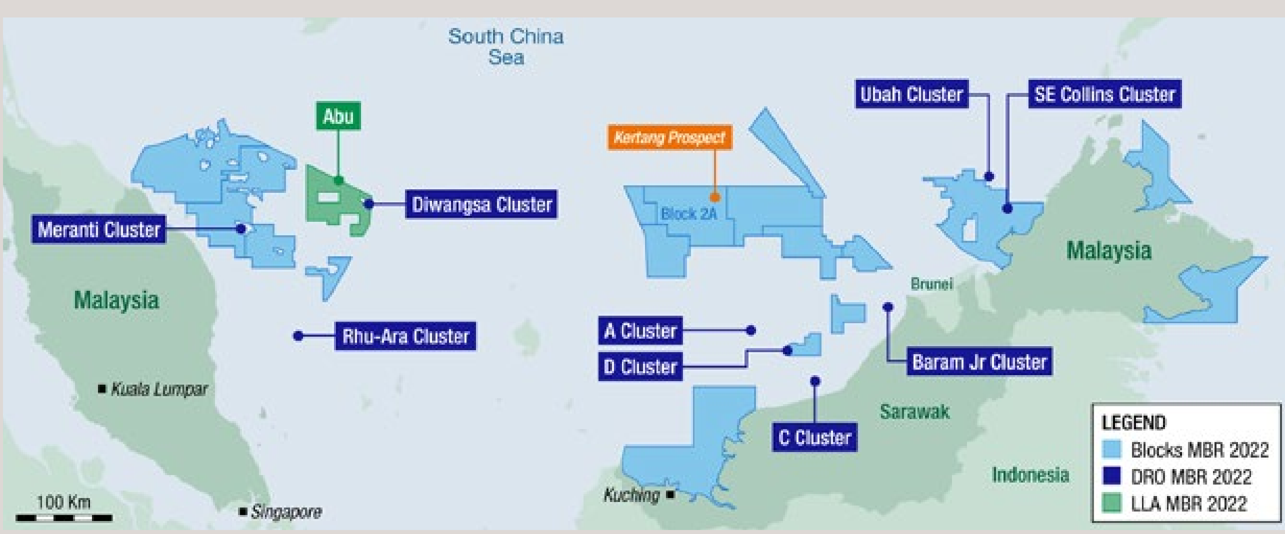
Subsidiary Ping Petroleum Sdn Bhd (PPSB) was awarded its third offshore Malaysia PSC of 2023 on 30 October, covering the Abu Cluster. This followed the awards of the Meranti Cluster PSC and the A Cluster PSC on 17 January.

All three assets were offered as DROs under the Malaysia Bid Round 2022 ("MBR 2022") by PETRONAS through Malaysia Petroleum Management (MPM). The DROs are offered to promote clusters of discoveries and small or marginal fields as Late Life Assets (LLAs) or Small Field Assets (SFAs) and to encourage innovation under tailored fiscal enhancements to the PSC model which were introduced in 2019 for LLAs and 2020 for SFAs.

ABU CLUSTER

The Abu Cluster consists of the shut-in Abu Main, Abu Kecil and Abu SW oil and gas fields which are located in the NE Malay Basin in about 60 m of water close to the maritime boundary with Vietnam. These were awarded as an LLA for 10 years under enhanced commercial terms which will include abandonment. Remaining reserves are estimated at 5 MMbo.

The fields were discovered by Esso in the early 1990s and developed by Petronas Carigali and partners under



This map clearly illustrates the success of the Discovered Resource Opportunities, with awards located across all of Malaysia's offshore.

Seismic example over the large Kertang prospect in Block 2A, Malaysia.

the PM-318 and AAKBNLP PSCs. The development comprised a single platform at Abu (Abu A) with long-reach wells used to drain the Abu Kecil and SW Upthrown fault blocks. Oil and gas were processed between 2007-2016 through the Abu FSO, which was subsequently decommissioned. Maximum production from the fields was about 15,500 bo/d in early 2009 from Early Miocene stacked lower shoreface sandstones in three discrete fault block traps.

A CLUSTER

The A and Meranti clusters were awarded to Ping as SFAs. The A Cluster is located 290 km offshore Sarawak in 65 m of water in the Tatau Province of the greater Balingian Basin and comprises the undeveloped A3 and A21 oil and gas discoveries which were drilled by Elf in 1990 and 1991 respectively. The PSC for the A Cluster is held by PPSB (70%, operator) and Petroleum Sarawak E&P Sdn Bhd (PSEP, 30%). Details regarding reserves and possible development options have yet to be announced.

The A3 gas discovery was appraised by Petronas Carigali in 2009 with two wells. Hydrocarbons are present in Lower Miocene clastics in a complex E-W trending faulted anticline. The A21 oil and gas discovery encountered an upper gas and condensate bearing reservoir and a lower oil and gas bearing zone, both in Lower Miocene clastics.

MERANTI CLUSTER

The Meranti Cluster is located 80 km offshore Kuala Terengganu in shallow water in the West Malay Basin and covers the previously developed Meranti and Kapal oil fields and the undeveloped Merpauh 1 oil and Ipoh 1 gas discoveries. The PSC for the Meranti Cluster is held by PPSB (60%, operator) and Duta Marine Sdn Bhd (DMSB, 40%).

The Meranti and Kapal fields, both discoveries in Middle Miocene clastics in NW-SE oriented structural traps, were drilled on trend with the Resak and Beranang fields in 1983 but were considered marginal under the original PSCs.

The new Meranti Cluster SFA includes the Merpauh 1 oil discovery in Middle Miocene clastics drilled by Coastal in 2017 and Ipoh 1 gas discovery in Middle Miocene clastics drilled by Petronas Carigali in 1997. Development is likely to utilise a Mobile Production Unit (MoPU) option with partner Duta Marine an established provider of services for brownfield developments.

OTHER SFAS

Since 2020, four other SFAs have been awarded by PETRONAS. The first was the SE Collins Cluster offshore Sabah which was signed in April 2021 by Vestigo Petroleum Sdn Bhd (100%), a subsidiary of Petronas Carigali established to specialise in small and marginal field development. This SFA covers the SE Collins and Lokan fields.

In August 2021, SFA PSCs covering the Diwangsa Cluster (Diwangsa, Bubu, Korbu, Lerek fields) and the Rhu-Ara Cluster, both located in the Malay Basin, were awarded to Singapore-based Rex International Holding Ltd (95%) and Malaysian partner Duta Marine.

Finally, the Baram Junior Cluster covering the Bario, Betty Timur, Fatimah, Hasnah, Lembuk, and Salbiah fields offshore Sarawak was awarded to Malaysia's Dialog Group (70%) partnered by PSEP (30%).

TRADITIONAL PSCS STILL ATTRACTING INVESTORS

Of the "traditional" exploration blocks offered under MBR 2022, deep water Block 2A has perhaps attracted the most attention since its award to UK-based Longboat Energy in February 2023. Longboat has since increased its equity in the block to 52.5% through the acquisition of the privately held original partner Topaz and its 15.75% stake. Operator Longboat is now partnered by Petronas Carigali (40%) and PSEP (7.5%).

Within Block 2A, the Kertang Prospect lies in 1,000 m of water and comprises a N-S trending anticlinal closure with estimated potential mean prospective gas resources of 8-10 Tcf in multiple stacked Cycle I and Cycle II/III reservoirs.

With prospects of the quality of Kertang and a further 10 exploration blocks and two DROs offered under MBR 2023, Malaysia can certainly be considered as an ongoing "Hotspot" in the APAC region. ■

Full circle

From handing out magazines at the very start to now leading the business's daily operations, Ingvild Ryggen Carstens has been involved from the beginning

PHOTOGRAPHY: SIMON ØSTERÅS

I WAS STILL a student in the US when the GEO EXPRO magazine was launched at the EAGE Annual Convention in Paris in 2004", says Ingvild Ryggen Carstens. "The year before, Halfdan Carstens, my father, a geologist and publisher of the Norwegian magazine GEO, ran into Tore Karlsson, a previous colleague from SAGA Petroleum, and his wife Kirsti – who most of you know very well. Halfdan pitched the idea of an international EXploration & PROduction magazine – and the rest is history…"

"It felt like pioneering, building up a name for ourselves and getting the magazine into the hands of as many geoscientists as possible", continues Ingvild. "But at the same time, it was a great challenge and we were a good team as well; there was the energy and spirit to make this a success amongst the two Norwegian families involved!"

"..it is great to be "home"

"After I finished college in 2006, I embarked on my career in the oil and gas industry, always keeping an eye on the magazine from the sideline. Following completion of my Master's degree in 2012, I joined the family business in Norway, publishing the Norwegian magazine GEO and our online news outlets geo365.no and geoforskning.no in addition to developing several conferences for the Norwegian geoscience community."

"But I have always had a soft spot for GEO EXPRO, and when Kirsti and Tore came to Halfdan and me in 2022, asking if we wanted to take over the magazine as they planned to retire, we jumped at the opportunity. Since then, Halfdan has also retired, working on other projects, and now I work in close tandem with our new editor, Henk Kombrink, on further developing the magazine. It is full circle – and it is great to be "home".

A MAGAZINE FOR A NEW ERA

"In step with the changing tides in the energy sector, we are carving out a new course for GEO EXPRO. Traditionally, the magazine covered exploration and technology in oil and gas. We have now expanded the topics the magazine covers, working under the new tagline "The Global Energy Sector from a Subsurface Perspective". In addition to exploration, production and technology, we now report on digitalization, geothermal energy, carbon capture and storage, deep sea mining and hydrogen on a regular basis – continuing to position the magazine as the geoscience community's favourite!" ■

Analysing a hydraulically fractured horizontal core to assess refrac candidates

Dr. Molly Turko,
TurkoTectonics@gmail.com

A recent study on the Eagle Ford Shale showed that refracs increased the EUR ~30-45% by stimulating new reservoir

MOLLY TURKO, CAMERON THOMPSON AND KOURTNEY BRINKLEY, DEVON ENERGY, AND JULIA GALE AND SARA ELLIOT, BUREAU OF ECONOMIC GEOLOGY

IS A REFRAC worth the investment? That is what we investigated in an extensive study. A key piece of data in the study included a horizontal core adjacent to a parent well that was already frac'd. The 128 m core was drilled prior to the refrac to analyse the condition of the original hydraulic fractures. The parent well had been on production for nine years prior to this study and is 67 m away from the horizontal core.

Within the core, about 9% of the fractures contained proppant, indicating that at 67 m away from the parent well ~90% of hydraulic fractures were not effectively propped. Where proppant was observed, we saw evidence for proppant embedment. Embedment is where the rock closes back down around a grain of proppant reducing fracture permeability. This usually occurs during the pressure drawdown and can be a risk for more clay-rich or ductile reservoirs. Additionally, fracture intensity throughout the core tends to correspond with cluster spacing from the parent well, indicating that untapped reservoir still exists between fracture swarms.

Figure 2: A cored hydraulic fracture.

DIMPLES AND RINGS OF MUD

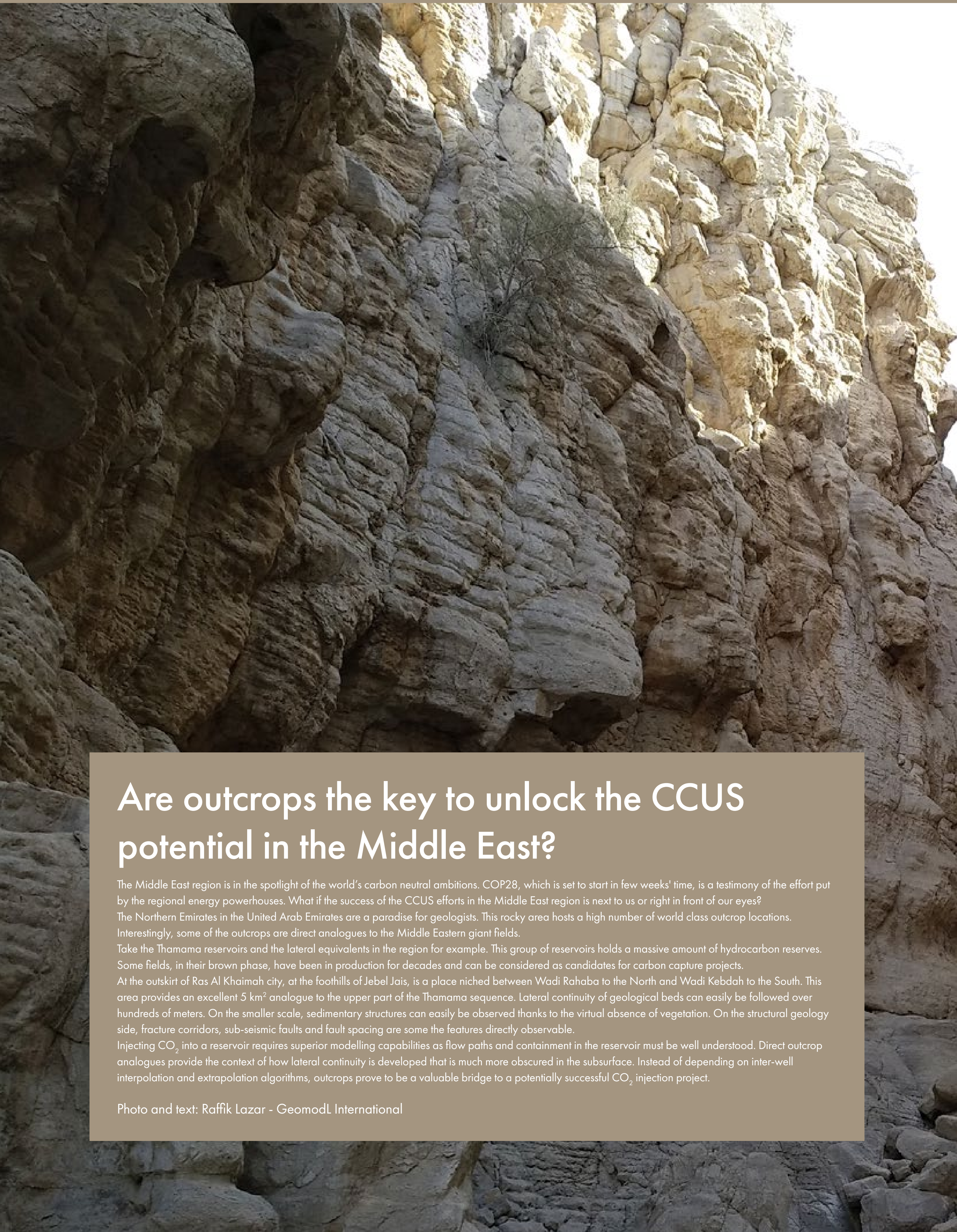
Figure 1 shows the "dimples" that are left behind once the proppant is removed indicating proppant embedment has occurred. Figure 2 shows hydraulic fractures that contain a ring of drilling mud around the edges of the core but lack any mud near the center of the core, indicating the fracture is completely sealed in the subsurface as a result of pressure drawdown.

Figure 1: Dimples that are left behind once the proppant is removed.

PHOTOGRAPHY: SARA ELLIOT, BEG

Lastly, the distribution of hydraulic fractures showed a relationship to the cluster spacing (15 m) of the parent well. Hydraulic fracture swarms occurred at fairly regular intervals with little to no hydraulic fractures between the swarms. This may indicate that reservoir was left behind between the swarms and may help with planning the cluster spacing of a refrac.

As such, the horizontal core proved to be a key piece of the dataset when making a decision on whether or not refracing a well could be economical. The core did indicate that reservoir was left behind between fracture swarms related to original cluster spacing and it indicated that many of the original hydraulic fractures are now closed either due to pressure drawdown or proppant embedment. The refractured parent well has now been online for nearly two years and has proved that we are able to access new reservoir with enhanced economic production. ■



Are outcrops the key to unlock the CCUS potential in the Middle East?

The Middle East region is in the spotlight of the world's carbon neutral ambitions. COP28, which is set to start in few weeks' time, is a testimony of the effort put by the regional energy powerhouses. What if the success of the CCUS efforts in the Middle East region is next to us or right in front of our eyes?

The Northern Emirates in the United Arab Emirates are a paradise for geologists. This rocky area hosts a high number of world class outcrop locations. Interestingly, some of the outcrops are direct analogues to the Middle Eastern giant fields.

Take the Thamama reservoirs and the lateral equivalents in the region for example. This group of reservoirs holds a massive amount of hydrocarbon reserves. Some fields, in their brown phase, have been in production for decades and can be considered as candidates for carbon capture projects.

At the outskirt of Ras Al Khaimah city, at the foothills of Jebel Jais, is a place niched between Wadi Rahaba to the North and Wadi Kebdah to the South. This area provides an excellent 5 km^2 analogue to the upper part of the Thamama sequence. Lateral continuity of geological beds can easily be followed over hundreds of meters. On the smaller scale, sedimentary structures can easily be observed thanks to the virtual absence of vegetation. On the structural geology side, fracture corridors, sub-seismic faults and fault spacing are some the features directly observable.

Injecting CO_2 into a reservoir requires superior modelling capabilities as flow paths and containment in the reservoir must be well understood. Direct outcrop analogues provide the context of how lateral continuity is developed that is much more obscured in the subsurface. Instead of depending on inter-well interpolation and extrapolation algorithms, outcrops prove to be a valuable bridge to a potentially successful CO_2 injection project.

Photo and text: Raffik Lazar - GeomodL International

FEATURE YOUR OUTCROP

In this series, we show a range of outcrops to give more context to what core interpretation typically allows. Do you have a suggestion for an outcrop feature? Get in touch with Henk Kombrink – henk.kombrink@geoexpro.com.

Tidal influence in a deep marine turbiditic succession

Core from deep-water offshore Suriname sheds new light on how far tidal influence can reach

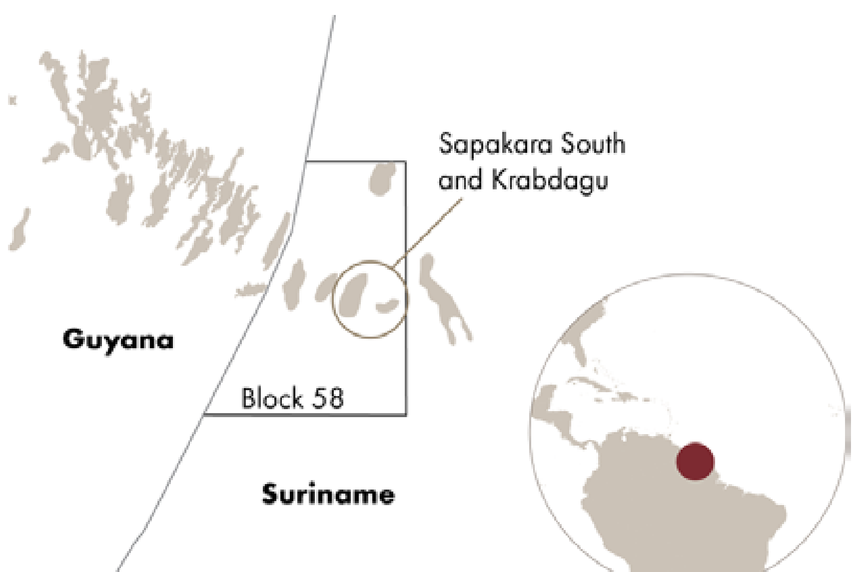
FRANÇOIS RAISSON, TOTALENERGIES

The Suriname-Guyana basin is a genuine exploration hotspot these days. But it is not only a hotspot from an economical point of view, it is also an area where new sedimentological insights emerge from as new seismic is being acquired and, as we show here, some core data are revealed to the public.

The core displayed here shows a sandy and oil-stained reservoir that is characterised by multiple cyclic mud drapes, some of them can even be described as double mud drapes. Given that this core is from the channel fill of a massive marine turbidite complex, it seems quite unusual to find double mud drapes, as these are often associated with tidal influence.

This suggests the turbiditic dynamic is not the only one to shape the deposit here. Continental margins are generally swept by contour currents that can reshape the turbiditic sediments by waning the turbidite flows and through transporting finer-grained sediment. In addition, deep bottom currents often comprise a tidal signal at any depth. Such tidal influence is already described in deep submarine valleys as a high frequency modulation of geostrophic currents. It is possibly the effect of tidal influence on bottom currents that has caused these double mud drapes to form here.

Thanks to TotalEnergies and APA for granting permission to share this core photo. ■



TotalEnergies (operator of Block 58, with a 50% interest) and APA Corporation (50%) annouced in September 2023 the launching of the development studies for a large oil project in Block 58, offshore Suriname. Combined resources close to 700 million barrels have been confirmed for the two fields under consideration, Sapakara South and Kabdagu. These reserves, located in water depths between 100 and 1,000 meters. will be produced through a system of subsea wells connected to a FPSO (Floating Production, Storage and Offloading unit) located 150 km off the Suriname coast, with an oil production capacity of 200,000 barrels per day. The project will represent an investment of approximately $9 billion.

Discover how on page 46 - 47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