THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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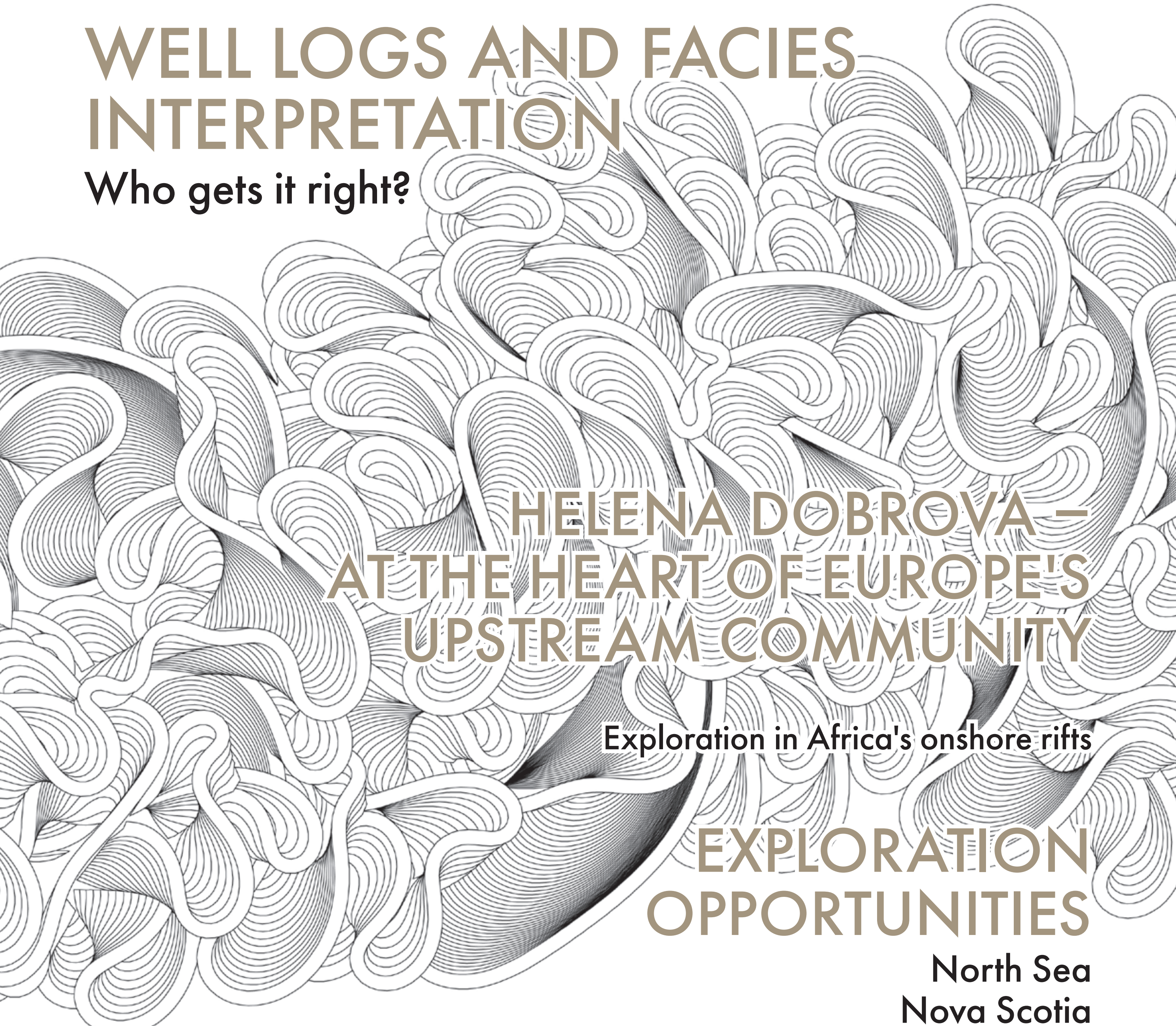


WELL LOGS AND FACIES INTERPRETATION

Who gets it right?

HELENA DOBROVA – AT THE HEART OF EUROPE'S UPSTREAM COMMUNITY

Exploration in Africa's onshore rifts

EXPLORATION OPPORTUNITIES

North Sea

Nova Scotia

CCS in Gulf of Mexico

The clash between academia and industry

LATE MARCH, I attended the two-day Dutch Geoscience Conference in Utrecht. With a programme dominated by climate-related research, sustainability issues, and work on biodiversity, this conference is entirely different from the more industry-focused events that I mostly participate in.

It is a place where one can feel hostility against anything that hints to oil or gas, and there was no escape from it during the award ceremony on day one.

When the Royal Dutch Society of Geologists and Mining Engineers (KNGMG) awarded the prize for the best master thesis written at one of the Dutch universities with a geology curriculum, a small number of people from the audience stood up and protested heavily. Why? Because the prize was sponsored by Shell.

The recipient of the prize was quick to say that he would donate the money to a sustainable source. What else could he say without losing face to the audience?

To me, it showed the complete gridlock we are in as a society. Yes, a critical attitude towards oil and gas producers is understandable and is needed. But at the same time, entirely banning these companies from public space, companies that still fulfil more than 80% of our energy requirements, is that the way to go? I don't think so.

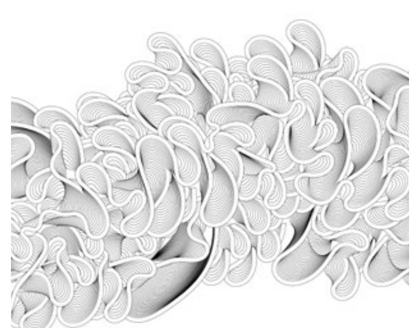
"...entirely banning energy companies from public space, companies that still fulfil more than 80% of our energy requirements, is that the way to go?"

BEHIND THE COVER

Geoscientist Zoltán Sylvester from Austin, Texas, combines science and art to create beautiful river plots of meandering river systems, such as the one featured here. This plot perfectly introduces the theme of this issue's cover story.

As a geoscientist working with subsurface data, you must have participated in discussions that centred around facies interpretation of well logs – and the consequences this has on the 3D architecture of reservoirs. The distinction between meandering and braided river deposits is one of those frequent debates.

Through a poll on social media, we asked to what extent people think it is possible to make this distinction based on well logs alone. Read the cover story to find out the results. And for now, please follow Zoltán on Twitter (@zzsylvester) for regular updates on his fantastic work.



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Energy Geoscience Conference

From 16 to 18 May 2023, Aberdeen will be the place to be for all geoscientists working in energy, be it from the fossil fuel or renewable sector.

THE ENERGY GEOSCIENCE CONFERENCE – EGC - is a new conference series launched by the Geological Society and the GESGB under the strapline 'powering the energy transition through subsurface collaboration'. Replacing the landmark Petroleum Geoscience Conference series that ran from 1974 to 2015, it reflects the shifting energy mix and role of geoscience in energy supply.

EGC is designed to support geoscientists in their day-to-day work and their evolving careers. A dedicated geoscience conference covering leading edge research, case studies, techniques and workflows, it offers tremendous in person networking opportunities plus a virtual attendance option.

In-depth sessions cover exploration for hydrocarbons, hydrogen, helium, carbon and energy storage, geothermal energy, nuclear waste sequestration, hydrocarbon field development/production, ground modelling for offshore wind, salt and fracture characterisation.

The broad and in-depth technical programme encompasses around 150 talks and 70 posters, future-looking lunchtime talks, 'net zero challenge' debates, field trips and core workshop options.

Launching EGC is an ambitious and forward-looking move by the organisers. The intention is to create a lasting conference series that continues the UK petroleum industry's long tradition of scientific sharing and innovation whilst bridging to new subsurface applications in which geoscientists will become increasingly involved as the energy transition progresses.

Graham Goffey, EGC1 Conference Board Chair

Further information at energygeoscienceconf.org

Orkney Flags.

Geothermal development programs in Alaska

Formation evaluation and drilling expertise from GEOLOG to be used for assessment of geothermal potential of Alaska's volcanoes.

ALASKA'S MOUNT SPURR and Mount Augustine are two active stratovolcanoes closely monitored by the Alaska Volcano Observatory (AVO). Despite their geothermal potential, these volcanoes have yet to be fully explored or utilised for energy production.

Geothermal energy is generated by harnessing the heat produced by volcanic activity, and it has the potential to provide a clean and sustainable source of electricity. Unlike other renewable energy sources, geothermal energy can provide 24/7 baseload energy, making it a reliable option regardless of weather conditions or time of day.

To tap into this potential, GeoAlaska has partnered with Ignis Energy to explore and generate reliable, carbon-zero baseload energy that is sustainably produced and sensitive to local ESG policies and practices. This partnership, announced in March 2023, will focus on developing geothermal resources in Alaska, including those at Mount Spurr and Mount Augustine, which currently contribute little or nothing to the state's energy mix.

By harnessing the power of these volcanoes, GeoAlaska and Ignis Energy, supported by global energy service company GEOLOG, aim to provide a reliable and sustainable source of energy for Alaska's future.

Milan Vujić, Geolog

Further information at ignisenergy.com

A telescopic view of Shishaldin Volcano (Alaska) from the Bering Sea.

PHOTOGRAPHY: JON GLUYAS, NOAA; UNSPLASH

Fans of Senegal...

Open acreage with promising drilling results is now available in Senegal in close proximity to a soon producing asset.

SENEGAL IS DUE TO BECOME an oil producing nation later this year when Woodside brings onstream the Sangomar field. The SNE-1 well, which discovered Sangomar, was the second well drilled in Senegal in 2014, after the FAN-1 well discovered oil in a Lower Cretaceous base of slope turbidite fan.

The FAN-1 well found no oil-water contact in a gross oil-bearing interval of more than 500 m, with oil types ranging from 28° API up to 41° API. The gross STOIIP estimates for the FAN-1 well range from 250 MMbbl (P90) to 2,500 MMbbls (P10).

FAN-1 was followed up with the FAN South-1 well in 2017, which again encountered a Lower Cretaceous hydrocarbon bearing reservoir with 31° API oil recovered. These are the only two penetrations of the oil-charged turbidite reservoirs in the Sangomar Deep block, which is now open following Woodside's relinquishment in 2022.

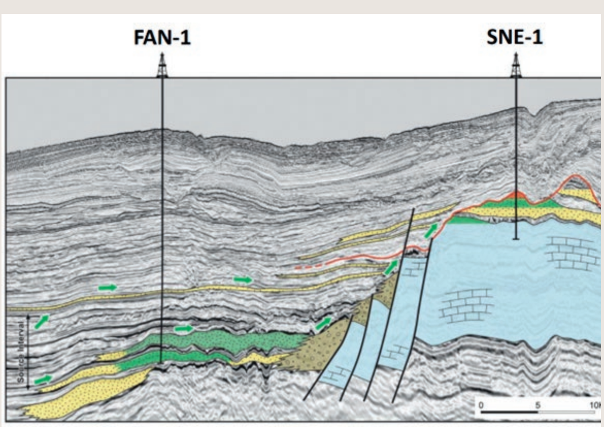
The high-quality 3D seismic data on the newly designated block is now available for Multi-Client licensing through GeoPartners. GeoPartners are currently interpreting the data and integrating the regional knowledge gained from the regional seismic interpretation study completed last year.

With proven oil on the block, API ranges indicating multiple active sources, and infrastructure and skills now available in country, is it time for FAN to be appraised and developed?

Get in touch with ben.sayers@geopartnersltd.com for more information or to book a data review session.

Ben Sayers, GeoPartners

Further information at geopartnersltd.com



Interpreted seismic section illustrating the geological setting of the FAN-1 and SNE-1 wells.

Optimise your unconventional resource plays

The 2023 Unconventional Resources Technology Conference (URTeC) in Denver, Colorado, is set to focus on the latest science and technology applied to exploration and development of unconventional resources. Plan now to engage with professionals in all aspects of the unconventional E&P lifecycle.

WITH THE INDUSTRY now back on its feet after putting the pandemic in the rear-view mirror and witnessing oil prices exceeding $70 since mid-2021, combined with increasing world energy demands the need to provide the world with clean, affordable energy is more critical than ever.

As the recovery of shale plays and unconventional development continues to grow on both domestic and international levels, URTeC presents an opportunity for the world's leading professional geoscientists and engineers to discuss and connect on ways of sustaining and propelling our industry.

Experts from around the globe will gather on the collaboration and integration between the subsurface G&G disciplines, geomechanics, formation evaluation, wellhead design, completion design, enhanced recovery, production forecasting and the environmental, social, and corporate governance factors that will help you achieve long-term success. These topics, and more, will be discussed elaborately at the conference.

Further information at: URTeC.org


The 2023 Unconventional Resources Technology Conference (URTeC), 13–15 June 2023 at the Colorado Convention Center in Denver, Colorado, will be the best chance you'll have to exchange information, formulate strategic ideas, and solve problems to manage and optimise your unconventional resource plays.

SOURCE: CAIRN INVESTOR PRESENTATION, 2017

Devex – 20 years young

Aberdeen's most important upstream E&P conference takes place again in June.

TWENTY YEARS AGO, DEVEX was born! Since then, the conference has grown from strength to strength and continues to educate the industry and inspire the next generation.

Energy Security and Sustainability is one of the key challenges facing society today. DEVEX 2023 will focus on this and will ask the industry: "What are we doing to accelerate projects, reduce costs, increase production and reduce emissions?"

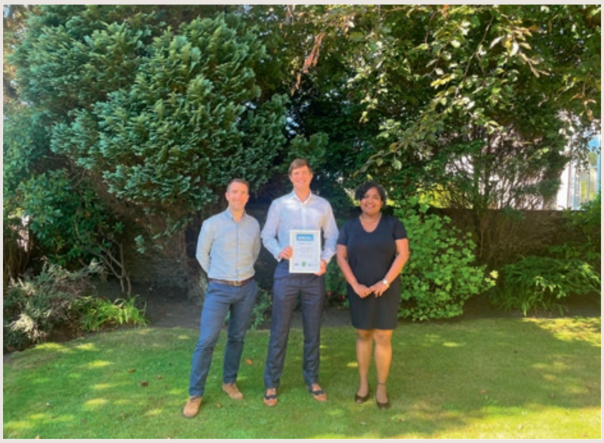
DEVEX's expert technical committee, led entirely by volunteers, work tirelessly to bring the audience the best technical content from a wide range of operators and service companies. This year's Chair, Grant Kelly, Petrophysicist at Equinor, is encouraging everyone to check out the technical programme and book early:

"This year's conference will look to build on the fantastic achievements of the previous 19 years and showcase all that's great about the energy industry in the North Sea.

Our keynotes, technical talks, masterclasses and techbytes will demonstrate what we are doing to accelerate projects, reduce costs, increase production and reduce emissions. It's a great opportunity for us all to share lessons learned, network and collaborate on the future of the basin.

Not only that, we have a fantastic field trip planned on the Angus coast and a YP mentoring event! I encourage you to check out our technical program and look forward to seeing you all in June!"

Further information at spe-aberdeen.org/events/devex-2023



DEVEX 2023 Chair Grant Kelly (l), pictured with 2022 Chair Andrea DSilva and 2022 Best Paper Winner, Matthew Macgregor.

Is artificial intelligence truly intelligent?

The future is Artificial Intelligence (AI) and Machine Learning (ML). The energy industry is eager to use these technologies to increase energy production in all regions. However, is this all we need?

DIGITALISATION IS A KEYWORD in the subsurface community when talking about the future and progressing to a cleaner energy world. For example, the recent DIGEX conference was full of interesting and clever ways in which AI and ML can be applied. Though, one thing everyone agreed upon, was the quality of data being used is pivotal to any AI model producing trustworthy results.

Quality checked, measurable data is essential for training and developing a trustworthy system. "Rubbish in, rubbish out," we all know and understand. The models are only as good as the hard data used. But what about the 'soft' knowledge?

AI can be used to check data coverage and retrieve information, but does it really understand geology or the subsurface? Enter the geoscientist with 2D evaluation and visualisation tools to add "experience and understanding".

Context is essential in any process, including machine learning and artificial intelligence. As a result, we must not lose sight of the importance of leveraging the expertise we have accumulated over decades in the energy industry. This is where Geoactive's integration, interrogation, visualisation and interpretation applications can help.

Further information at geoactive.com

Geoactive exhibition and demos during SPWLA in Stavanger 2022.

Sea-level curves: Assuming simplicity does not correctly predict complexity

In a comment to a recently published new sea-level curve, Peter Burgess discusses the complexities related to reconstructing facies.

PRE-DRILL PREDICTIONS of basin-fill strata, in the absence of substantial supporting data, have been a key objective of seismic and sequence stratigraphic methods. Despite much hyperbole, it is doubtful this objective has yet been achieved, for two key reasons.

Firstly, stacking patterns and spatial distribution of strata are most likely controlled by multiple complex factors, not just accommodation variations. This evidence for multiple controls means the assumption of dominant accommodation control underpinning the prediction of strata based on a eustatic of even a relative sea-level curve is unlikely to be reliable.

Secondly, it is very unlikely, based on currently available evidence, that any published sea-level curves are sufficiently accurate models of eustatic sea-level history to reliably constrain even part of the accommodation control that forms one single element of the multiple controls on any basin-fill. This is because a comparison of the various published sea-level curves shows very clearly that they all differ, and quite possibly none of them are correct.

A conclusion that none of them are likely to be correct is also supported by consideration of the methods used to construct the curves, all of which contain substantial uncertainty. Given all these challenges, how can we make progress predicting basin fill in a useful way? The simplest answer is, of course, acquire sufficient data to reduce uncertainty to the required level; robust prediction is worth the hard work.

Peter Burgess, University of Liverpool

Further information at geoexpro.com

PHOTOGRAPHY: DAN MEYERS/UNSPLASH; SOURCED FROM NOBEL HELIUM AND HELIUM ONE

Green helium exploration set for a breakthrough

Two helium explorers have agreed to source and secure a suitable drill rig together to use for dedicated helium exploration in Tanzania.

UP TO RECENTLY, helium was not actively explored for, but was mainly found by accident while drilling for hydrocarbons. Concentrations as low as 0.3% helium in the gas stream already make separation economic.

However, global helium shortages have now paved the way for dedicated helium exploration. As this exploration is taking place in basins unprospective for hydrocarbons, this has the added advantage of finding 'green helium'. Green helium has nitrogen as the dominant carrier gas which can be vented safely without carbon emission.

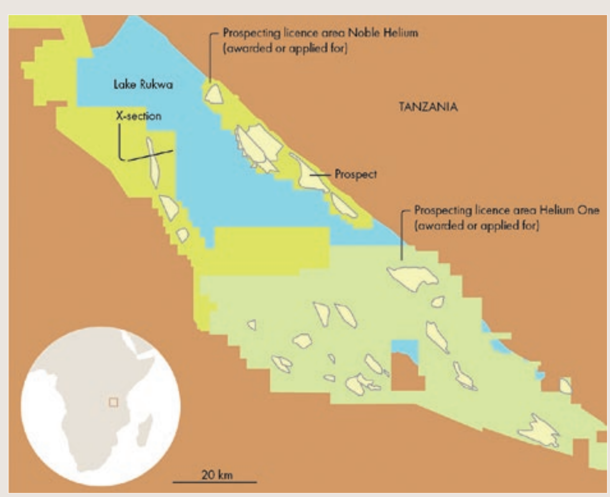
The Tanzanian section of the East African rift system is a place that meets these criteria, providing the source and heat flow needed. The rift basins are filled with sand- and claystones that serve as reservoirs and seals that trap the migrating helium.

At present, the Rukwa basin in the southwest of the country is the epicentre of exploration activities because several surface seeps containing up to 10.6% Helium have been detected. For this reason, not one, but two companies, Noble Helium and Helium One Global Ltd, are exploring for green helium along the lake's shores.

To prove and produce these reserves, Helium One and Noble Helium have now agreed to source and secure a suitable drill rig together to use for each of their operations. Both companies will drill exploration wells this year.

Mariël Reitsma – HRH Geology

Further information at geoexpro.com



Map of the Rukwa Lake area in Tanzania, showing the areas licensed and applied for by Noble Helium and Helium One.

THE CORE

COVER STORY

NORTH WEST EUROPE

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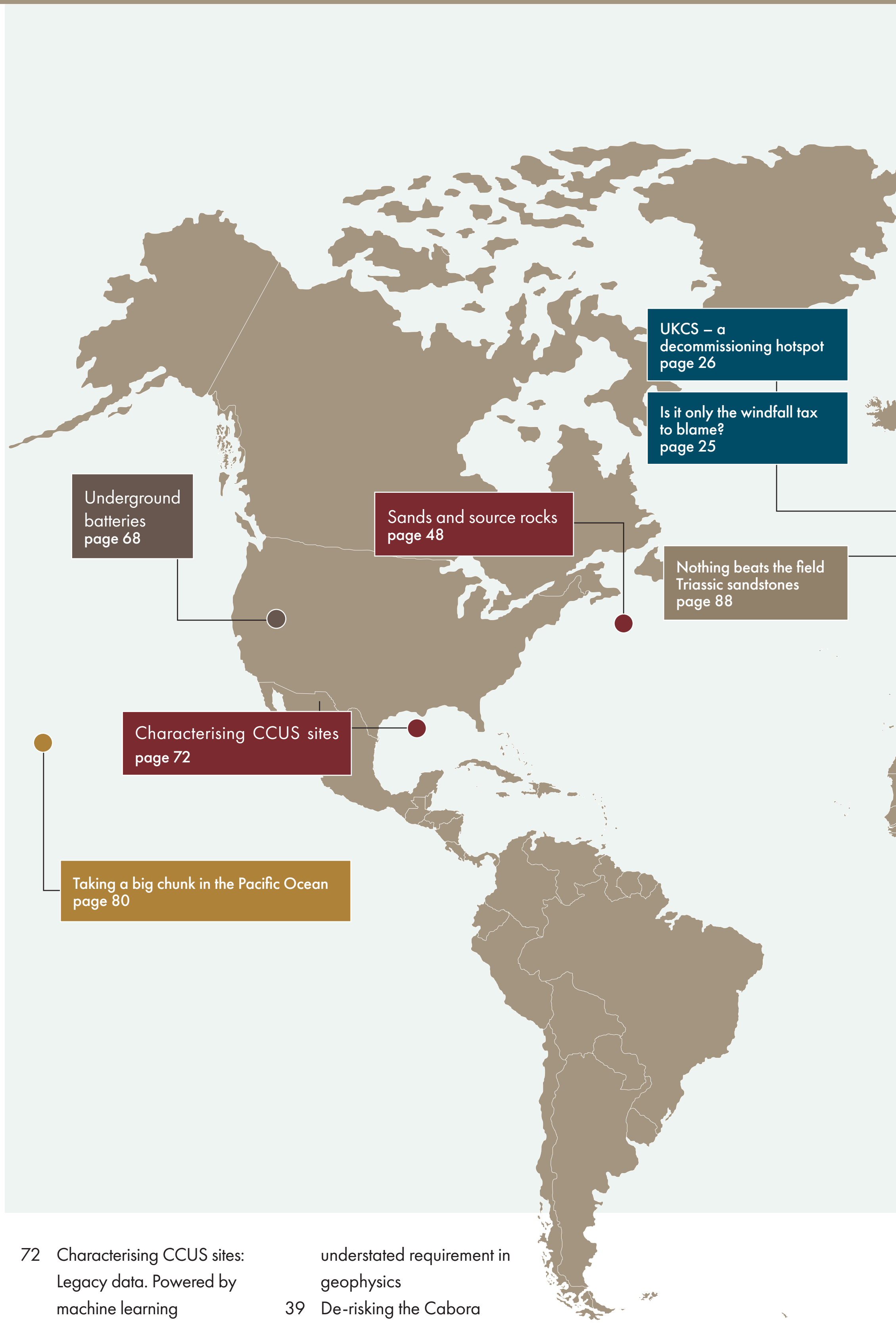

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The heartbeat of Europe

Ever since the discovery of Ekofisk in 1969, Norway has proven to be an important supplier of oil and gas to Europe, with discoveries still being made today.

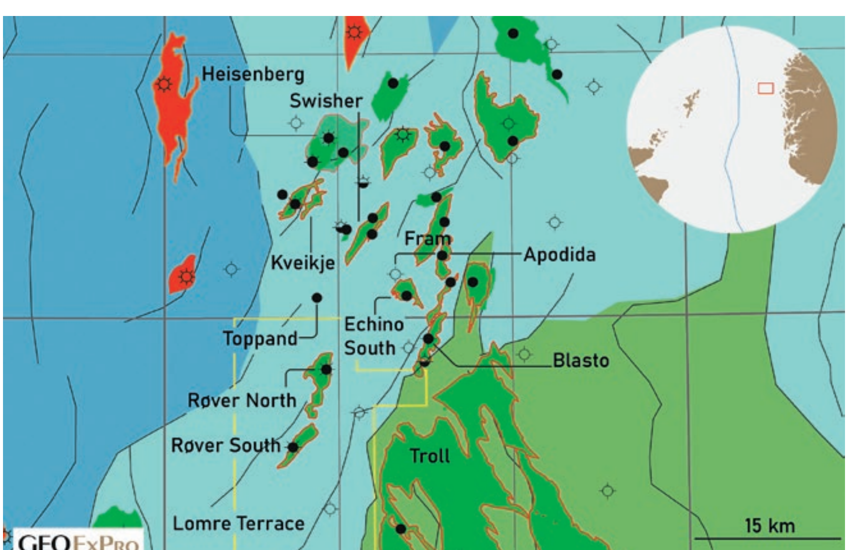
NORWAY REMAINS THE HEARTBEAT ACTIVITY in Northwest Europe, and is the gift that keeps on giving to use the well-known phrase. The country has had successful bid rounds, regular deal flow, exploration successes and continued its impressive hydrocarbon production to fuel Europe. Offshore Norway has considerable upside and room for surprises both in the mature areas and the frontier basins.

The history of exploration on the Norwegian Continental Shelf (NCS) was kick-started in response to the super-giant onshore Groningen gas discovery in the Netherlands in 1959. In 1962, Phillips Petroleum applied for a licence through its then Paris office to explore large parts of the central North Sea portion of the NCS, offering the government a work programme of just US$1 million to carry out seismic work. At the time, clarity was still needed on the offshore boundaries with the UK and Denmark, and subsequently Norway's first licensing round was opened in April 1965 with the Danish boundary still temporary.

The first major discovery on the NCS was the Ekofisk field in Block 2/4 made by Phillips in 1969. The well was designated 2/4-1AX and was the final well in the Phillips programme. In a twist of fate, the US operator had actually requested to pay a penalty and not drill this last commitment well after a series of failures but it turned out that drilling a wildcat was cheaper than walking away. The main Paleocene sandstone objective was however not present, and drilling continued into the hydrocarbon bearing Danian-aged chalk, and the rest is monumental history.

NORTH OF TROLL

Moving forward, Equinor has already made two oil discoveries this year near the Troll Field in the northern North Sea, which it operates. This makes it an impressive eight discoveries out of nine in the area since 2019 and more wells are planned. Volumes in this hub could exceed 400 Mmboe and can be brought on stream using the existing infrastructure. The discoveries are Echino South, Swisher, Røver North, Blasto, Toppand, Kveikje, Røver South and the latest success announced in March 2023 is Heisenberg. Equinor has also strengthened its position in licences in the area by acquiring Wellesley Petroleum AS interests in five discoveries.



North of Troll area showing recent wells drilled and discoveries made by Equinor and partners.

OBELIX

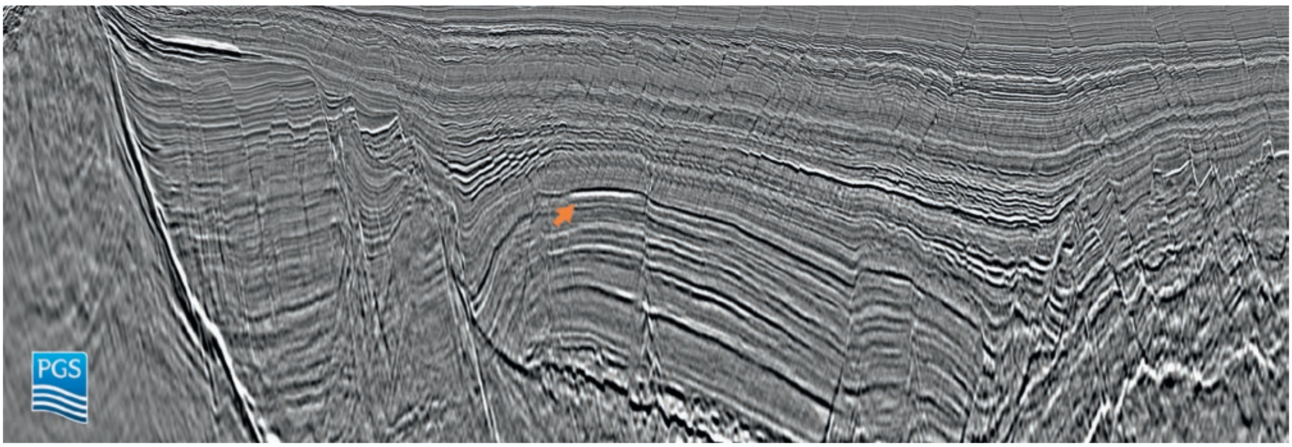
On other parts of the NCS, Equinor announced a commercial gas discovery at Obelix Upflank in the Norwegian Sea in January 2023. This well is some 23 km south of the Irpa (formerly Asterix) gas discovery, which is to be tied into the deepwater Aasta Hansteen gas and condensate field. Meanwhile, in the Barents Sea, Vår Energi disclosed that it made an oil and gas discovery at 7122/8-1 S (Countach Prospect) in February 2023. This is once again located in a favourable location for development near the Goliat field, which it operates.

Interest in the NCS is still buoyant and in January 2023 the Norwegian Petroleum Directorate (NPD) announced that 25 companies had been offered interests in a total of 47 licenses following the annual bid round known as Awards in Predefined Areas (APA) 2022. The excellent NPD website gives full details on the results of the bid round. Details on the forthcoming APA 2023 are awaited following the NPD's submittal for public consultation on blocks proposed. The round is expected to be greeted enthusiastically by the industry. ■

Ian Cross – Moyes & Co

“It’s the amplitude anomalies that brought us back”

When looking at a seismic line from the Andaman II Block in Indonesian waters, it is easy to understand why Harbour decided to drill the Timpan exploration well.

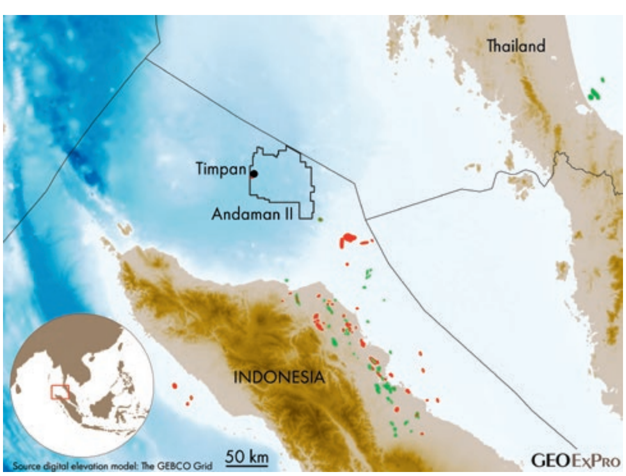


Seismic line through the Andaman II Block in Indonesian waters, clearly illustrating the Timpan flat spot.

“WHEN I PREPARED THE SLIDES for this talk”, said Nick Comrie-Smith from Harbour Energy during his presentation at the Seapex Conference in Singapore early March, “I considered the title “Shooting a fish in a barrel.” However, knowing that geology can always bite back in a surprising way, I decided not to.”

In the case of Timpan, the title would have been appropriate though, as the well did find gas, as expected. “Because of the prominent flat spot, Harbour even carried Timpan as an appraisal well”, added Comrie-Smith. The company assigned a 70% chance of success to the well pre-drill.

"Because of the prominent flat spot, Harbour even carried Timpan as an appraisal well."



Exploration drilling in this part of the Indonesian sector is not new, but what has changed is the quality of the seismic. BP drilled several wells in adjacent Thai waters in the 1980’s, and ENI walked away from the area as recently as 2010. If these companies would have had the seismic data Harbour currently has, Timpan would probably have been discovered much earlier.

The reservoir in Timpan, which is characterised by a net-to-gross of 90%, is of Oligocene age (Bampo Fm). “Porosity was lower than expected, which is partly because of chlorite occluding the pore space”, said Comrie-Smith. It goes against the commonly held belief that chlorite coatings are good for the preservation of porosity.

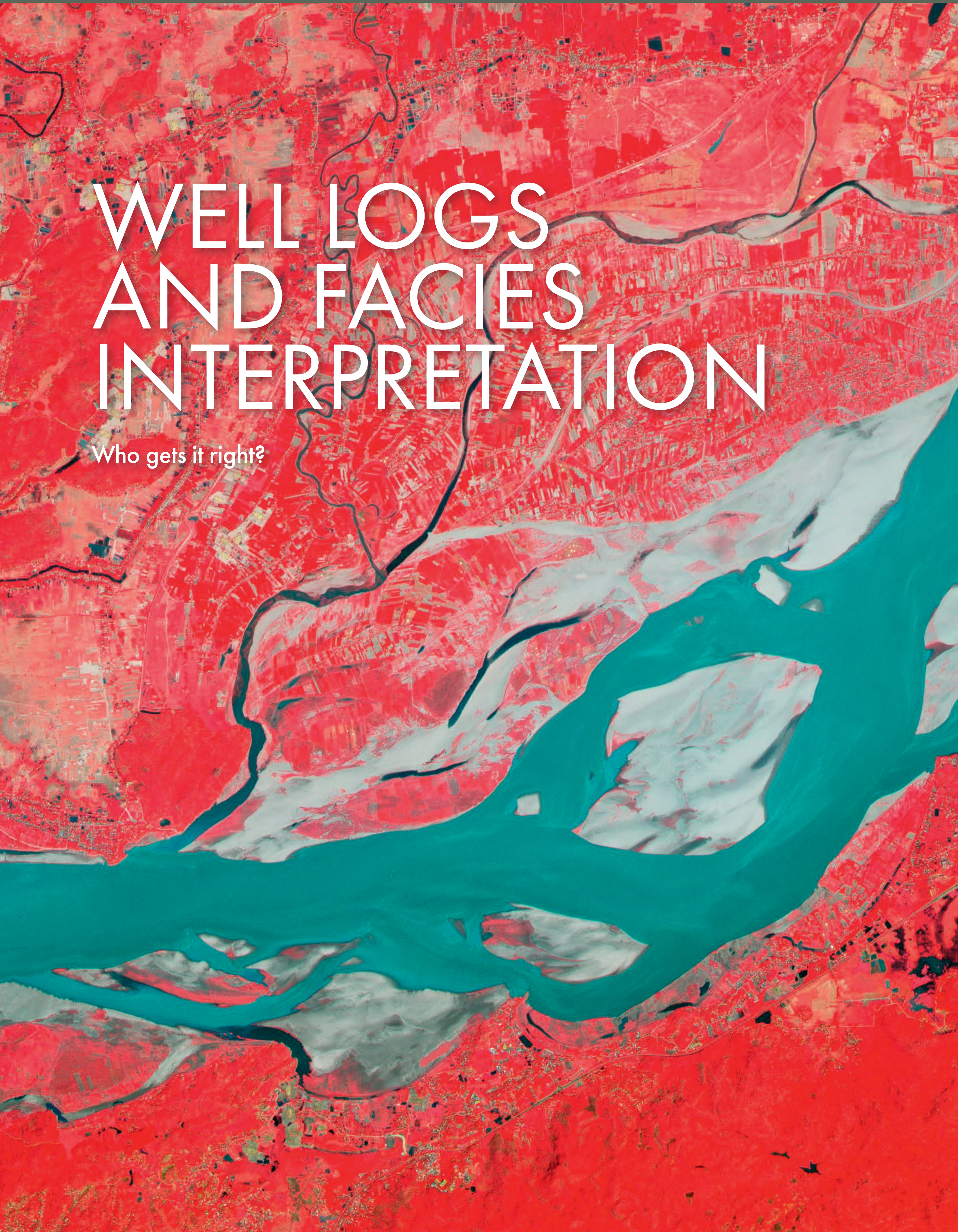
A commonly perceived risk in this area is high CO_2 contents, and one person from the audience in Singapore asked Comrie-Smith about it. “We were concerned about the presence of deeply buried carbonates and anhydrites”, the geologist said, “but we now think that not too many of these carbonates are present in this part of the basin that is characterised by a high heat flow.”

Based on the positive results obtained at Timpan, the company now aims to drill two more exploration wells – Halwa-1 and Gayo-1. These prospects are also clearly visible on the seismic but are slightly shallower than Timpan. Harbour and partners are considering exporting gas from Timpan to Thailand or Malaysia. ■

SEISMIC LINE: KINDLY PROVIDED BY PGS

COVER STORY

"Based on the outcomes of the polls, it can be concluded that they form a great tool to investigate the current status of thinking in the subsurface community."



WELL LOGS AND FACIES INTERPRETATION

Who gets it right?

A braided river pattern in the Brahmaputra river, India.

TEXT: HENK KOMBRINK

FOR MOST PEOPLE working in subsurface teams, discussions related to the interpretation of depositional facies on the basis of well logs are part of the daily routine. The more geologists in the room, the more ideas and interpretations. We decided to add some spice to these discussions and ran three polls on LinkedIn and Twitter. Each poll asked a simple question related to an important depositional environment; fluvial, carbonates and deep water.

The questions were:

- Do you interpret a blocky gamma-ray pattern as a braided river deposit and a fining upward trend as a meandering river?
- Should Maximum Flooding Surfaces in carbonate sequences always be interpreted at a peak in thorium and potassium?
- Using GR and dipmeter, is it possible to differentiate between proximal and distal settings (parallel to flow) in a deep-water environment?

Based on the outcomes of the polls, it can be concluded that they form a great tool to investigate the current status of thinking in the subsurface community. None of the polls was 100% in favour of one answer, which shows that there is considerable diversity in views. Especially the question around braided versus meandering river deposits generated an almost 50-50 split in answers, from a group of almost 100 voters.

This article presents the outcomes of the polls. We also spoke to several experts to put more context and ideas behind the topics discussed. It will hopefully add some information behind a topic that will probably never cease to generate plenty of discussions.

■

The meanders of the Kokolik River in Alaska, North Slope.

SOURCE: PLANET.COM

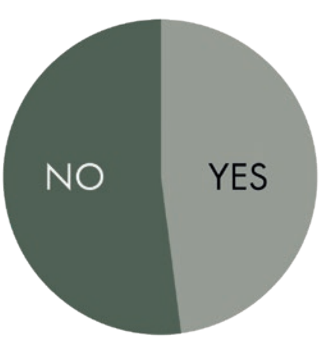
Fluvial deposits

Do you interpret a blocky gamma-ray pattern as a braided river deposit and a fining upward trend as a meandering river?

OUT OF THE THREE QUESTIONS we polled, the one on the distinction between braided and meandering river deposits resulted in the most engagement and the highest degree of "division". Out of the 98 people who voted, 47 are of the opinion that it is possible to make a call on river patterns based on a gamma-ray response, while an ever so slight majority of 51 think the other way.

In a comment on the poll on LinkedIn, Adam Goss from CNOOC responded in a way that is probably a good representation of how the "yes" voters approach the question. He writes: "If I a priori knew that the succession was 100 % fluvial and there was a blocky sand with no fining upward, I would call that a high-discharge braided fluvial deposit. However, I would look to justify my interpretation with other evidence of braided

> "Point bars and mid-channel bars cannot be distinguished. Likewise, sandy systems with little mud will be blocky, regardless of geometry."



VOTES: 98 (47 Y - 51 N)

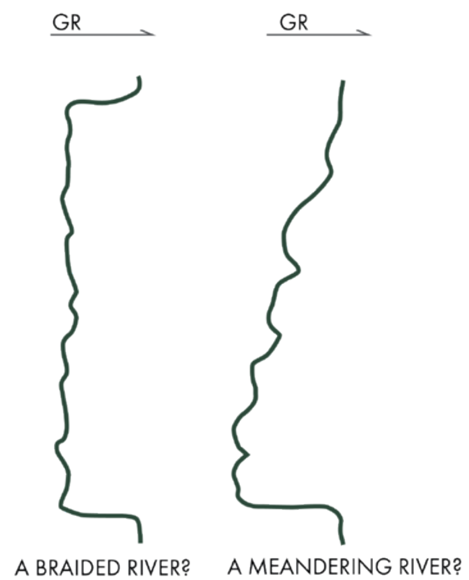
fluvial deposits and lack of evidence supporting a meandering river."

Not everybody agrees with Adam though. Consultant sedimentologist Jon Noad says on Twitter: "Some meandering river deposits have a thick package of trough cross-bedded sands at the base, giving a thick, blocky signature in an overall meandering setting. The overlying point bar deposits may be sand dominated, also giving a blocky signature."

Anton Wroblewski from Applied Stratigraphix is the most prominent advocate against determining channel geometries from log profiles. In a LinkedIn comment, he said: "Point bars and mid-channel bars cannot be distinguished. Likewise, sandy systems with little mud will be blocky, regardless of geometry. Also, braided bars can be heterolithic in a wide variety of situations. People forget that gamma-ray logs record composition and not grain size. If there is clay and organic material in the channel scour (rip-up clasts or fluid mud), it will appear "fine" to uncritical interpreters. I've seen this happen in wells that could be ground-truthed with core."

DOES IT MATTER?

More importantly, asked Anton Wroblewski, it's worth asking: does it matter if the system was braided or meandering? Both can leave a sand-rich belt as bars amalgamate and stack. In some situations, it matters, in others, it probably does not. Also, streams evolve from braided to meandering over the course of their lifetimes, so the emphasis placed on identifying their patterns in the subsurface is probably better spent addressing other, more important aspects of the channel belt deposits. At least, that's been my experience over the years."



A typical blocky (l) and "fining upward" gamma-ray pattern are sometimes associated with braided and meandering river deposits respectively.

Where it matters

By Anton Wroblewski, Applied Stratigraphix

THE CRETACEOUS MCMURRAY Formation in Alberta, Canada, represents a large fluvial system the same size and general morphology as the modern Mississippi River. The reservoir bodies are fluvial and estuarine point bars 5-10 km long (across channel), 1-5 km wide (parallel to channel), and up to 55 m thick that display predictable facies distributions such as increased volume of fine-grained deposits on the downstream side and coarser-grained material on the upstream side.

The bars are heterolithic, with very fine to fine-grained sand constituting the reservoir facies and forming lateral accretion sets that are interlaminated with clay, claystone breccia, and organic-rich shale beds, which form baffles and barriers to fluid flow.

Upstream parts of bars also tend to have more interrupted flow barriers because erosion and redeposition increased the occurrence of sand-on-sand bed contacts. The downstream parts are more heterolithic and potentially more compartmentalised.

The bitumen itself is extremely viscous - about the same consistency as peanut butter - so it does not flow unless it is heated up with steam from horizontally-directed wells. These wells are paired with producers and use steam-assisted gravity drainage (SAGD) to produce the mobilised oil.

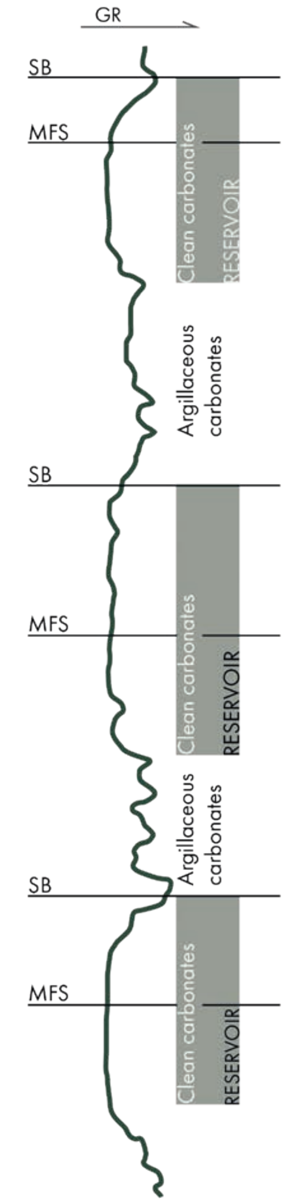
The heterogeneity of the meander bars is critical to planning the design for the steam chamber because the orientation, size, and facies distribution within the individual bars have a major impact on chamber size, reach, rate of growth, and bitumen recovery volumes.

In terms of fluvial reservoirs, the McMurray is unique because of its size, abundance of fine-grained material and viscosity of the bitumen. In fluvial systems where the reservoir facies were coarser, the mudstone beds and breccias less common, or the hydrocarbon less viscous, there would not be a need to so meticulously map out individual bars and potential steam chambers.

I don't think meandering versus braided counts for anything unless it's a system that has lots of very heterolithic bars that affected diagenesis or reservoir distribution and/or viscous fluid like the McMurray. ■

Carbonates

Should Maximum Flooding Surfaces in carbonate sequences always be interpreted at a peak in thorium and potassium?



Typical gamma-ray log pattern of Lower Lekhwair Formation in Abu Dhabi, and the associated sequence stratigraphic framework.

ESTABLISHING THE SEQUENCE stratigraphic framework of a succession is a fundamental step to providing the building framework for the understanding of the depositional architecture and its impact on the vertical and lateral facies variations in a reservoir.

I spoke to two carbonate experts for this poll; independent petrophysicist Jan van der Wal and carbonate geologist Laura Galluccio from Badley Ashton. Both have extensive experience working on a wide variety of carbonate reservoirs, primarily in the Middle East.

In an email exchange, Laura commented: “Many times, peaks in gamma-ray are automatically taken for maximum flooding surfaces. Nonetheless, the reality is more complex. Depending on the type of carbonate platform or ramp, the maximum flooding surfaces may well be within the most energetic and therefore cleanest facies. For this reason, maximum flooding surfaces will not correspond to a gamma-ray high, but rather a gamma-ray low in some cases.”

Jan remembers similar discussions whilst at meetings in the Middle East. “Some aspects of carbonate facies interpretation always crop up and the one on recognising maximum flooding surfaces based on logs is certainly something I remember and where there are always different points of view.”

The outcome of the poll reflects well what Laura and Jan said; the majority of the voters are of the opinion that maximum flooding surfaces should not always be interpreted at gamma-ray highs. However, a minority of 11 people indicate that it should, demonstrating that there are different points of view on this.

The carbonate island of Cayo Largo del Sur, Cuba. The cloudy appearance of the waters north of the island indicates reworking.

A SHALLOW RAMP

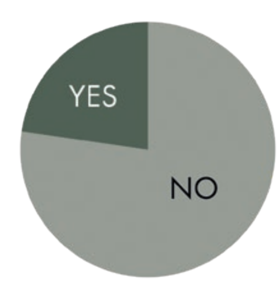
Laura recalls a paper she published recently based on work Badley Ashton performed together with ADNOC on the Lower Cretaceous, Lower Lekhwair Formation in Abu Dhabi. This is one of the most prolific oil reservoirs onshore and offshore UAE.

The study shows a depositional system characterised by the alternation of clean and argillaceous carbonates (see figure). The argillaceous facies reflected deposition within a very shallow water setting affected by continental runoff, whilst the clean carbonates reflected shallow water sedimentation away from the source of clays and therefore in a relatively deeper setting.

In this context, the sequence boundaries were placed at the base of the shallowest argillaceous intervals, characterised by the highest gamma-ray, where prominent hardground surfaces were also seen in the core.

In contrast, the maximum flooding surfaces were picked within the clean carbonates showing the highest accumulation of Lithocodium/Bacinella floatstones, having a relatively clean gamma-ray signature.

This example is an indication that maximum flooding surfaces do not necessarily correspond to highs in gamma-ray. Their positioning strongly depends on the specific depositional context. ■



VOTES: 59 (11 Y - 48 N)

PHOTOGRAPHY: NASA; ILLUSTRATION ADAPTED FROM: TENDIL ET AL. (2021), SPE-207692-MS

Deep-water sedimentation

Using GR and dipmeter, it is possible to differentiate between proximal and distal settings (parallel to flow) in deep-water environments?

DEEP-WATER depositional environments add another level of complexity compared to many other environments", says expert Bryan Cronin when I visit him in his sea-front cottage in Aberdeen. Bryan has been studying deep-water sediments for decades and is well-known for his beautiful drawings of the broad range of depositional settings associated with deep-water sedimentation.

"Deltas prograde, and topsets or shelfal paralic units form clear sequence stratigraphic packages, but turbiditic successions just switch course", Bryan explains. "There is no real progradational element in these systems."

A BLOCKY GAMMA-RAY PATTERN

"There have been attempts to use gamma-ray and other logs to predict where in the depositional system one would be, but the basic challenge is that a blocky gamma-ray can be found in both the proximal as well as in the distal domain", Bryan adds.

For that reason, he notes that there are always discussions about which part of a deep-water system was drilled. It is a sign that, when the seismic data is not conclusive, there is room for interpretation.

"Drilling a well into the axial part of a distal lobe can result in the discovery of a series of stacked sandstones that have the same appearance in logs as when this well was drilled into a proximal canyon system, and dipmeter logs do not necessarily help either", he continues.

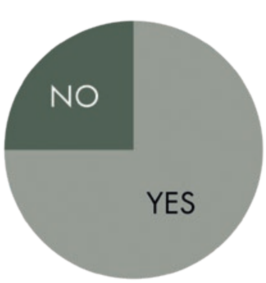
"The problem is the lateral component in these systems", Bryan explains. "In that sense, thin beds are more important than the sands in distinguishing in which part of the system one is looking."

Bryan has also observed that there is a tendency to drill for the updip parts of the succession when it comes to planning wells. "That does not necessarily mean that better-quality reservoirs can be expected in the updip domain", he adds. "It is not uncommon to see more reservoir pinch-outs for instance, which means poor lateral connectivity."

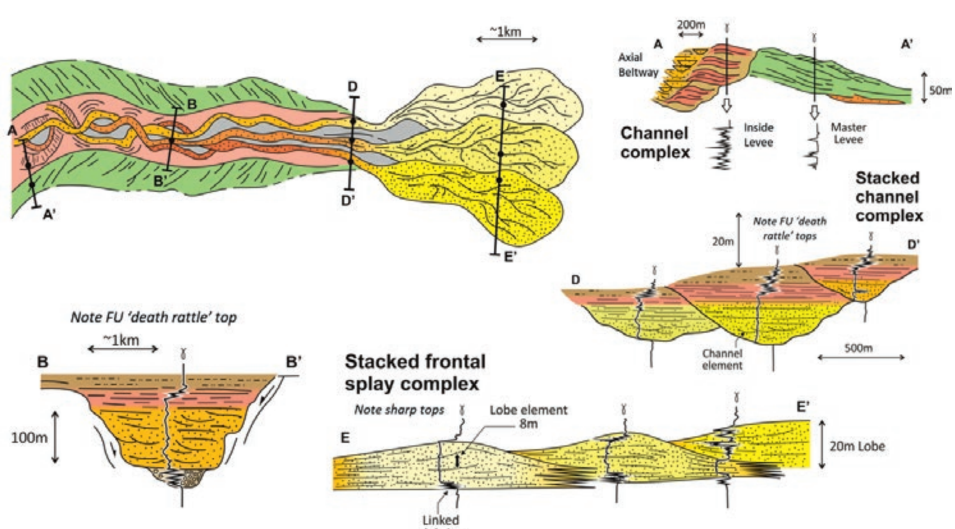
> "There have been attempts to use gamma-ray and other logs to predict where in the depositional system one would be, but the basic challenge is that a blocky gamma-ray can be found in both the proximal as well as in the distal domain."

POLL OUTCOME

Bryan Cronin says it is difficult to distinguish between different parts of a deep-water sedimentary system based on gamma-ray and dipmeter logs alone: "It takes considerable experience to be able to do this and I will challenge everyone to interpret sub-environments from ratty profiles alone." Yet, 75% of the 48 voters are of the opinion that it is possible. ■



VOTES: 48 (36 Y - 12 N)



Typical log patterns from different parts of a deep-water sedimentary system.

ADAPTED FROM: CRONIN, 2021

NORTHWEST EUROPE

"it is the age of UK offshore wells and the maturity of the basin that cause this country to be such an active player in the field of decommissioning these days"

More wells should be drilled with water-based mud

It is better for the environment and results in better data acquisition, argues operations geologist Anita Hansen.

ALL CUTTINGS BROUGHT to surface need to be shipped ashore when they are contaminated with oil-based mud (OBM)", says Anita Hansen in a recent conversation. Anita has decades' worth of well-site and operational experience and has seen supply vessels leave the rig loaded with containers stocked with cuttings to be processed and cleaned onshore.

"If a well is drilled using water-based mud (WBM), the cuttings can be disposed of directly into the sea, thereby reducing the amount of fuel needed to transport the cuttings by supply vessels", argues Anita.

And that is not the only advantage of using WBM. Anita continues: "Because drilling is usually a little bit slower when using WBM, data acquisition is more exhaustive and tools achieve a higher resolution. This should not just be seen as a bonus; in some cases, it can provide critical information about the subsurface that is relevant for why the well was drilled in the first place.

Anita Hansen

MORE DATA

"Drilling a well should not be seen as a race to terminal depth but as a possibility to uncover the subsurface secrets that cannot be seen on seismic alone", Anita continues. "One of the reasons I joined the oil industry as a relative outsider," says Anita, "was to cause changes from within the organisation, instead of just screaming from the outside." With a degree in environmental protection, she was seen by some as joining the enemy when she embarked on her upstream career.

> "...it is the mindset that is the problem, not the mud."

Asked if she was successfully pursuing change, she answers: "Yes, I hope so! It is probably thanks to my lobbying that Lundin drilled all its Utsira High exploration wells with WBM. At least up to 2018 when my involvement came to an end. And I was not alone; Hans Christen Rønnevik (exploration manager), Terje Kollien (petrophysicist) and our drilling manager Johan Bysveen all understood the benefits of using WBM.

The claim that WBM is problematic when swelling clays are encountered is not true according to Anita. "With focus on hole cleaning and maintaining good mud properties, the experience from the Utsira High wells shows that in vertical and sub-vertical wells it is the mindset that is the problem, not the mud", she says.

RECYCLING

Since OBM is more expensive than WBM, there is a tendency to re-use OBM more than WBM – even though recycling of the latter also takes place. "We were drilling a well in the Barents Sea", Anita says, "and found bugs in the samples that were typically found in the Viking Graben. These must have travelled to the Barents Sea in the mud." Even formation fluids can transfer from one well to the other. "We saw false shows of condensate that had made its way from one borehole into the next", Anita further explains.

In a way, it is understandable why there is still a tendency to drill wells using OBM. The main reason is that drillers are not the biggest fans of WBM. It slows the drilling process because of a lower rate of penetration and requires a little more maintenance.

However, given that Lundin drilled all their Utsira High exploration wells using WBM shows that it is possible to do and that in certain cases, with the right mindset, a change to a more environmentally conscious way of drilling is certainly possible.

"I am the last one to say that OBM is a thing of the past", Anita continues. "When a well is deviated, for instance a high angle side-track or a development well, OBM is still required to get the cuttings out in an efficient way, but as long as a well is vertical, there are so many advantages to using WBM!"

And with such a strong focus on data when it comes to drilling exploration wells, using WBM should really be a no-brainer", Anita concludes. ■

PHOTOGRAPHY: PRIVATE

Dunnottar Castle, near Stonehaven (Scotland) gave its name to a prospect recently drilled by Harbour in the UK North Sea.

Is it only the windfall tax to blame?

Whilst it may be tempting to say that UK exploration will be badly hit by the windfall tax, the reality is that some companies may never have had the drive to explore much beyond their core areas anyway.

THE RECENTLY IMPOSED windfall tax by the UK Government has made many oil and gas players decide to postpone, cancel or reroute investments elsewhere. For instance, Total UK announced that it would cut £100 m of spending on new wells in the area and Shell is weighing up UK investment plans too. And it is not only the big players with international portfolios having made that decision. Serica Energy stated that it will look for overseas opportunities if the situation does not improve.

EnergyVoice also reported that Apache North Sea cancelled a rig contract for the UK business, citing the newly imposed windfall tax as the main driver for the decision. Similarly, Harbour Energy recently announced that it would not participate in the 33rd Licensing Round, making a stand against the increased financial intake of the UK government following record-high profits.

In short, there is little doubt that the windfall tax has a detrimental effect on near-term activity in the UK North Sea. But would it be the only factor explaining a drop in exploration drilling? If that were true, one would expect a sudden decline in activity and a drying up of new finds. That is not the case. Instead, activity has been subdued for a number of years already. Also, the 33rd Licensing Round did attract a stronger response from industry than previous rounds, as announced by the NSTA.

> "...there is little doubt that the windfall tax has a detrimental effect on near-term activity in the UK North Sea. But would it be the only factor explaining a drop in exploration drilling?"

STAY LOCAL

Let us take a look at Harbour and Apache in particular, two important players in the UK North Sea. When looking at recent exploration drilling activity of these companies, there has not been much activity in the first place and the success rates of those wells that were drilled have not been high either. The wells drilled were all located in their core areas too.

It paints a picture of companies with a strategy that is focused on producing most from existing assets without too much of an interest to look beyond the licence boundaries. In that sense, the windfall tax is unlikely to have caused a major shift in strategy, because the strategy to go out there and grow the portfolio through the drill bit was probably never a prominent one to start with.

This is not to say that it's a bad strategy. As EnergyVoice reported, for Apache the North Sea business is still "by far the most profitable in its portfolio, generating pre-tax margins of $68 per barrel of oil equivalent (boe) last quarter – trumping results in both Egypt ($48) and the US ($31)."

J-AREA

Harbour, being the amalgamation of companies Chrysaor, Premier and ConocoPhillips, is the biggest player in terms of production on the UK Continental Shelf. However, being a big ▸

PHOTOGRAPHY: CONNOR MOLLISON/UNSPLASH

player does not equate to being bold when it comes to exploration drilling. All exploration wells since 2018 were drilled in the mature J area, being either step-outs from existing platforms (Jade South) or near-infrastructure targets (Dunnottar). The fact that Harbour decided to drill yet another appraisal well on the very old and relatively small Talbot (stranded) discovery is – in a way – enough to know that the company is prioritising developing smaller near-field volumes that carry lower risk than drilling exploration wells further afield.

Against that backdrop, which already shows that exploration is not very much part of the business strategy, is it a surprise that Harbour did not decide to participate in the 33rd Round? Maybe not so much anymore. The company, with a strong focus on short-term shareholder value, may not be too interested in risky exploration drilling to start with. On the other hand, it could also be a sign that the people with a proper regional understanding in the company know that in fact there is not so much left to explore for.

BACCHUS

Apache North Sea is known to be an active driller in the North Sea, especially when it comes to development wells on existing assets such as Forties and Beryl. The American company has had success tying back near-infrastructure discoveries to their core assets, such as Garten near Beryl and Aviat near Forties.

But again, looking at more recent exploration drilling, Apache has not had the success it must have hoped for. Near Forties, a new Bacchus compartment turned out dry and the well targeting the nearby Bacchus East prospect has also been decommissioned. Please note that the limits of what can be called exploration are being pushed here as Bacchus is already an existing field. In the Beryl area, Apache most recently drilled some of the injectite prospects near the boundary with Norwegian waters. Not much news has been released since the completion of these wells, which is most likely indicative of limited economic value in these Eocene sands.

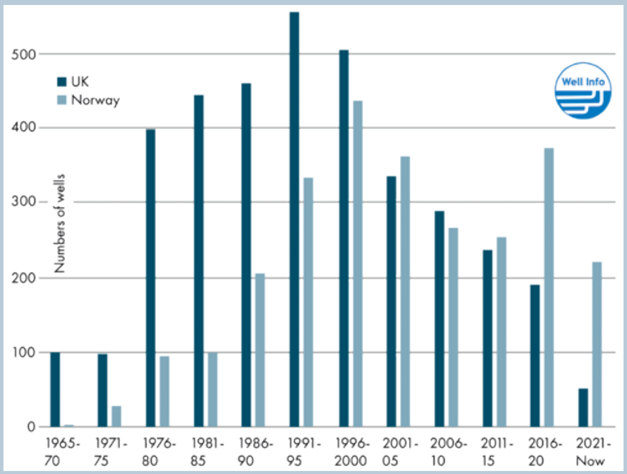
On top of all this, it also needs to be mentioned that both Apache and Harbour did not drill a single exploration well in 2022.

In conclusion, whilst at first glance it may look as if exploration activity will take a serious hit after the announcement of the windfall tax, the reality is that some companies may never have had the drive to explore much beyond their core areas anyway. ■

UKCS – a decommissioning hotspot

The number of wells in which decommissioning work was carried out across the UKCS in recent months greatly exceeds new wells being drilled.

IN TWO RECENT social media posts, Tom Morgan from Well Info nicely showed why the UKCS is such an active player when it comes to decommissioning wells in the North Sea. So far in 2023, only 5 new wells were drilled in the basin, but 46 wells underwent decommissioning operations. It illustrates a trend that is not frequently highlighted: the UKCS has become a centre of decommissioning activity rather than drilling new wells.



Age distribution of wells in the Norwegian and UK sectors that require decommissioning.

Since the late 1960's, the UK offshore saw around 12,000 offshore exploration, appraisal and development wells drilled, about twice as many as the Norwegian sector. In addition, it is also the age of these UK wells and the maturity of the basin when it comes to fields ceasing production that cause this country to be such an active player in the field of decommissioning these days.

As Well Info further showed, a total of around 6,390 wells require decommissioning activity in the UK and Norwegian sectors together. 58% of these wells reside in UK waters, whilst 42% of the wells are in Norwegian waters.

The average age of a UK well that requires decommissioning is 29 years, whilst the average age of a similar well in Norway is 21 years. This is further illustrated in the graph below. It also nicely demonstrates that levels of drilling activity on the UKCS peaked earlier than in Norway. ■

SOURCE: WELL INFO

Nature's microplastics

Robert Williams from the NPD tells the story of how scanning technology initially applied in aerospace and pathology has now made its way to geosciences.

PALYNOLOGISTS are palaeontologists who specialise in microfossils composed of acid-resistant carbon-hydrogen-oxygen biopolymer. In other words, their fossils are nature's microplastics. Resistant to almost anything diagenesis can throw at them, fossil microplankton, pollen and spores from the Earth's deep past are sometimes more abundant and better preserved than their descendants deposited on the seabed today. These resilient fossils are therefore a major part of biostratigraphic analysis in petroleum exploration.

Like all fields of palaeontology, palynology is grounded on taxonomy – identifying tiny fossils to the species level based on differences in both gross and fine structure at sub-micron resolution. This science appeals to geologists who are skilled in recognising visual patterns and morphological minutiae among copious numbers of complex forms.

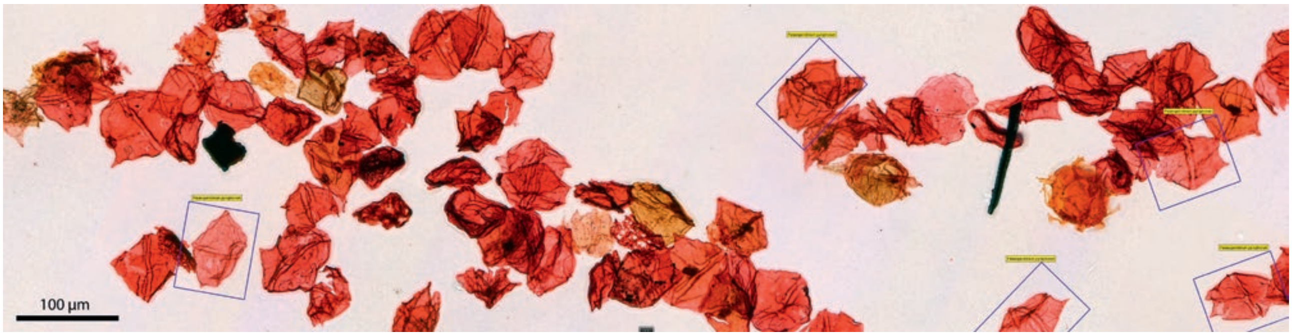
Palynological analysis is slow. Optical design and imaging technology have greatly improved, but microscopy has remained essentially unchanged for four centuries. Microscopists in a biostratigraphy laboratory are limited to examining one slide at a time. Other users may have to wait for weeks or months for access to a set of released slides from one or more wells.

Because glass slides are thin and fragile, hundreds of NPD slides have been fractured or lost during shipment. Contrast this with seismic data or wireline logs which lend themselves well to simultaneous interpretation in different locations, simply because they are digital.

What an advantage it would be to have digital microscope slides in sub-micron resolution, instantly accessible by palynologists the world over!

AEROSPACE AND PATHOLOGY

Unknown to me thirty years ago was that pathologists had already taken their first steps into the realm of digital whole slide imaging. Called telepathology, early trials of analogue electronic transmission of microscope slides were already improving diagnoses through interprofessional communication since the 1960s. In 1998, pathologists entered the digital realm with the advent of the first high-resolution whole slide scanners. ▸



Detail of a digital palynology slide. The marine dinoflagellate Palaeoperidinium pyrophorum dominates Late Paleocene deposition of submarine fan systems connected with the deltaic Moray Group to the west. This marine microplankton comprises most of the acid-resistant organic contents of the upper Hermod Formation on Balder Field in the North Sea. This image is only 0.13 % of the entire scan of 7 giga-pixels.

However, as late as 2011, whole slide scanners still did not attain sufficient speed and image resolution suitable for palynology. Perhaps this reflected the lesser optical resolution demands for pathology analysis, since pathology was the economic driver behind scanner technology.

After attending a slide scanner presentation in 2017, I and my palynology colleagues in Stavanger realised that whole slide scanners had finally achieved our required four pixel per micron resolution.

Fortunately, around the same time, the concept of digitalisation became prioritised in resource management at the NPD. Instead of simply making analogue data digital, digitalisation aimed to transform inefficient analogue processes into faster, automated digital processes.

With this goal in mind for palynology, the NPD sent me to The 14th European Congress on Digital Pathology, held in Helsinki in 2018. Every paper at this conference dealt with procedures, case histories and technology for the application of whole slide tissue scanning. Through machine learning and digital slide analysis among networks of medical specialists across national boundaries, the digital pathologists' goal was to improve diagnosis of diseased tissue. Replacing the words pathology with palynology, and tissue with palynomorphs, diagnosis with interpretation, every presentation was relevant for palynology's digital future.

This pathology conference made clear that we had to set in motion the digitisation of NPD's 120 thousand palynology slides as soon as possible. In addition to NPD slides, there exists at least as many slides stored in companies' and consultant laboratories' slide archives. All must be digitised.

AVATARA-P AND DISKOS

Within eight months after the Helsinki pathology conference, the NPD became the second institution in Europe to acquire the highest capacity, highest resolution whole slide scanner available, the 3DHistech P1000. The NPD's scanner was the second P1000 in the production queue after 3DHistech delivered the first one to the General Hospital of Vienna, Austria in 2019.

The NPD's digitalisation project Avatara-p – Advanced Augmented Analysis Robot for Palynology – had become a reality.

In spite of an eleven-month scanner shutdown and maintenance delays during the Covid-19 pandemic, Avatara-p has now produced almost forty thousand digital palynology slides from approximately 300 exploration and development wells. Currently, at 57 terabytes, the NPD is steadily expanding this dataset.

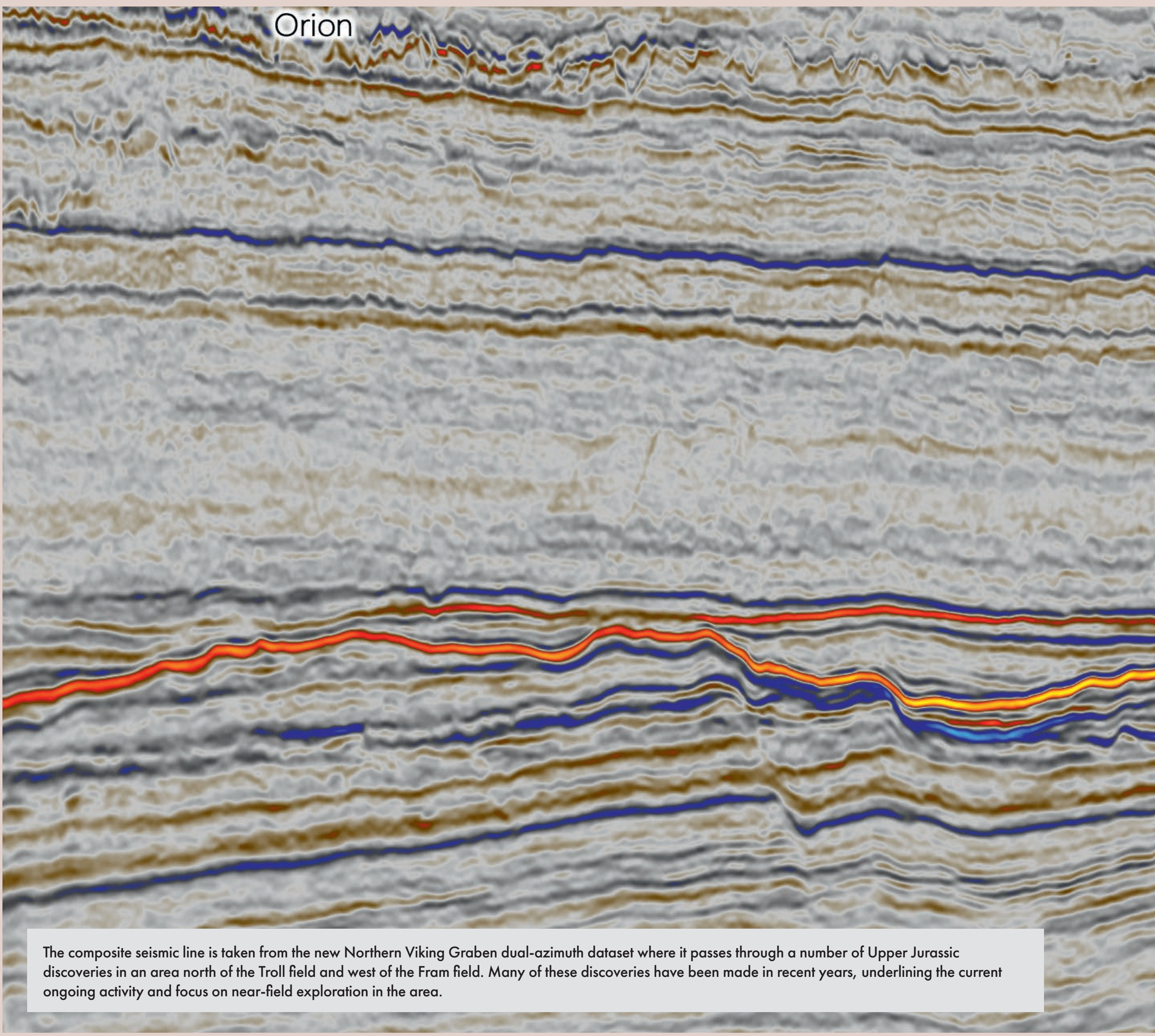
The entire dataset is now available on Diskos. By interrogating these digital slides with machine learning applications trained and quality-controlled by palynology teams and laboratories, the re-analysis of microplankton, pollen and spores may reduce complexity even more.

Palynologists have increased our knowledge of great swaths of Norway's deep history through fifty years of thorough analysis of uncounted numbers of palynology slides. Augmented analysis through machine-learning will potentially unearth even more unknown vistas in Norway's deep history. ■

The author at the controls of the Norwegian Petroleum Directorate's 3DHistech P1000. This scanner has a capacity of 1000 standard microscope slides, and scans at 0.25 µm per pixel at a numerical aperture of 0.95. Scan time for each focal layer of 330 square millimetres is two minutes.

PHOTOGRAPHY: NPD

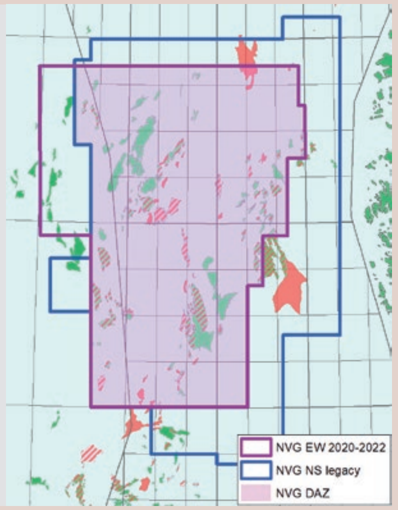
Northern Viking Graben – Chasing the Upper Jurassic Play



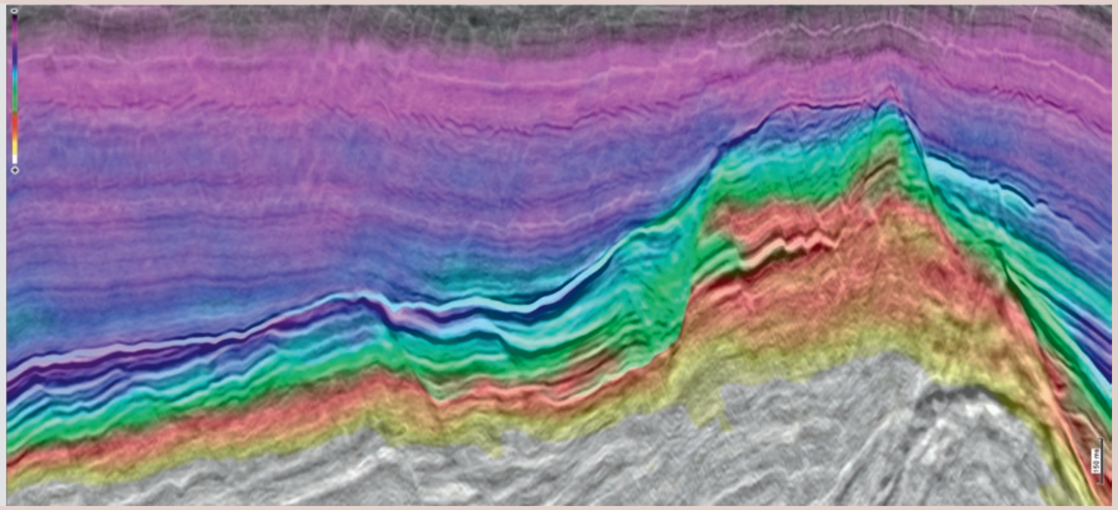
The composite seismic line is taken from the new Northern Viking Graben dual-azimuth dataset where it passes through a number of Upper Jurassic discoveries in an area north of the Troll field and west of the Fram field. Many of these discoveries have been made in recent years, underlining the current ongoing activity and focus on near-field exploration in the area.

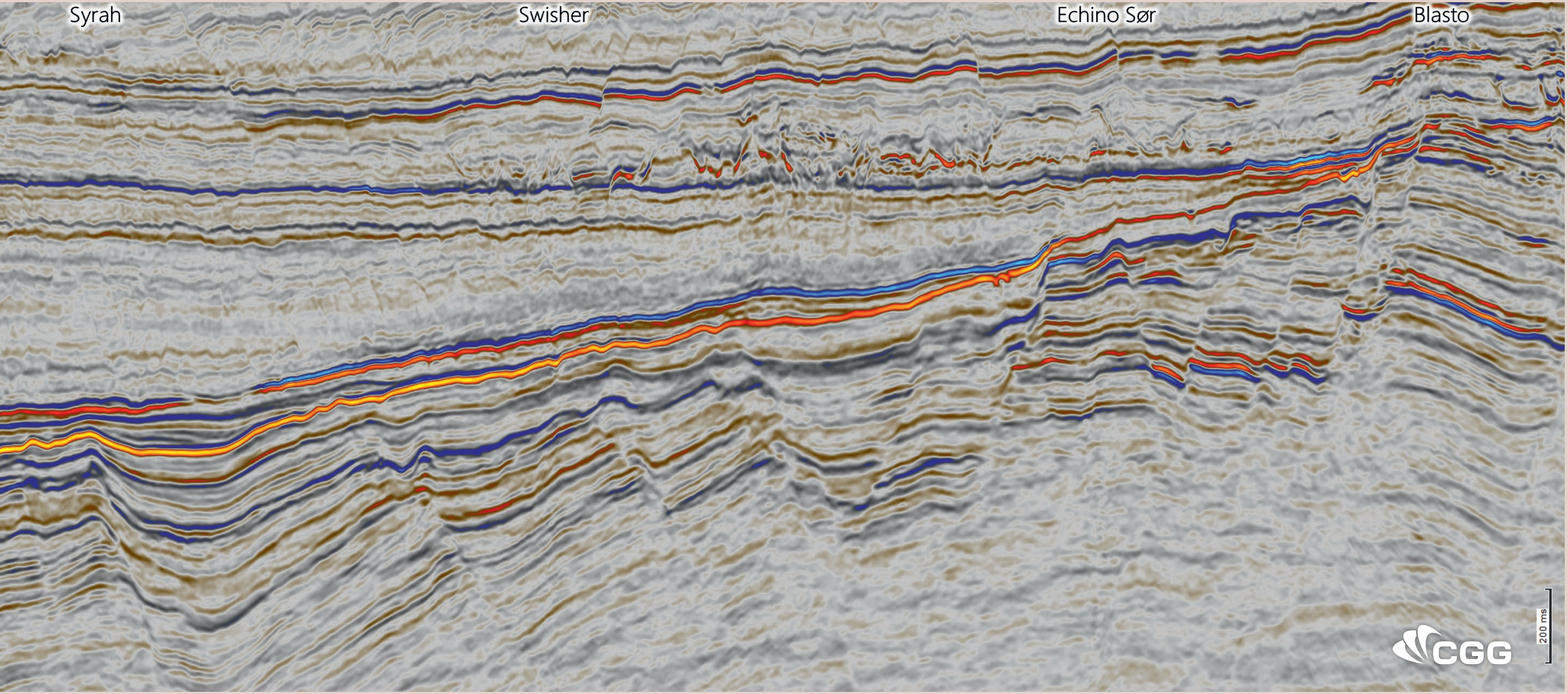
The northern North Sea is a very active oil and gas exploration region, where several commercial discoveries have been made over recent years. Upper Jurassic sands are one of the major reservoirs in the Northern Viking Graben. In recent years, the Upper Jurassic Intra-Heather Formation sands (Sognefjord, Fensfjord formations and equivalents) have been re-explored over the Horda Platform. Wells targeting these sands have resulted in new discoveries such as Swisher, Echino Sør and Blasto as shown in the seismic foldout.

Location map showing CGG's legacy north-south, new east-west and dual-azimuth seismic coverage in the Northern Viking Graben.



TL-FWI velocities with frequencies up to 14 Hz, draped over dual-azimuth seismic data. Velocity variations and details can be seen in the sub-BCU with particular attention paid to the variations identified in the Upper Jurassic between the erosional slump interval and the canyon-fed deposits down-flank.





Northern North Sea – dual-azimuth data brings new insights into the Upper Jurassic play

Enhanced imaging is achieved in recently processed dual-azimuth 3D seismic data, a combination of legacy north-south acquired data and new east-west acquisition, enabling illumination of prospective Upper Jurassic play targets.

JASWINDER MANN-KALIL, ANNA RUMYANTSEVA AND IDAR KJØRLAUG - CGG

Gravity-driven systems in the Northern North Sea are a major process for the transfer of Upper Jurassic sands into deep-water environments. Active rifting during the Permo-Triassic, and later in the Jurassic – Late Cretaceous, resulted in a series of regional fault terraces thought to be a major influence on gravity-driven pathways and reservoir sand deposition.

The importance of these systems for hydrocarbon exploration can be seen in the Northern North Sea where several discoveries have been made. Fields developed with reservoirs in this succession, such as the Nova Field on the Ryggsteinen Ridge, saw production start from intra-Heather Formation sub-marine sands in July 2022.

Looking at more recent exploration on the Horda Platform, persistent efforts have resulted in new discoveries such as Swisher (35/11-24) in 2020 and Blasto (31/2-22) in 2021, marked in the foldout section. In addition, the Dugong and Sjøpølse discoveries (34/4-15S), drilled on the Tampen Spur in 2020, both proved hydrocarbon-bearing Jurassic sub-marine and slumped sands.

Enhanced imaging of these Upper Jurassic systems has been achieved in recently processed dual-azimuth (DAZ) 3D seismic data over the Northern North Sea. This data set consists of a combination of reprocessed legacy north-south (N-S) acquired seismic (2014-2016) and new east-west (E-W) acquisition (2020-present), where the additional E-W azimuth reveals new details at depth.

The examples presented below bring insight into the subtle features at reservoir level, through spectral decomposition and inversion studies. We demonstrate the extent to which new regional seismic data and sedimentary mapping are integral to understanding Upper Jurassic gravity-driven sediment distribution in a mature hydrocarbon basin.

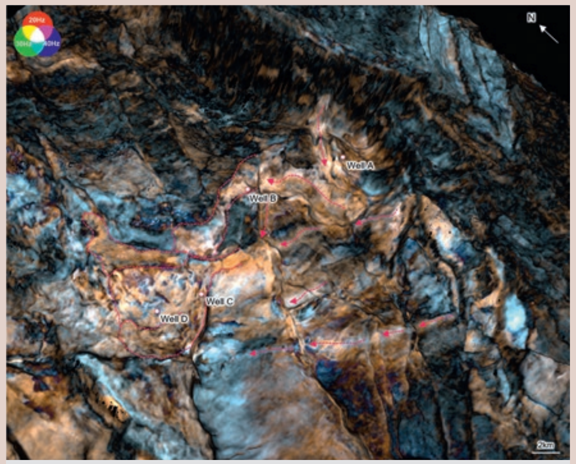


Figure 1. Spectral decomposition RGB-blend on a Upper Jurassic surface. Sediment-routing systems are shown by the magenta dashed arrows and submarine lobe systems are shown within dashed magenta lines.

IDENTIFYING DEPOSITIONAL SAND SYSTEMS

Spectral decomposition has become a vital part of the analysis of stratigraphic formations within 3D seismic data. This attribute has been used to further understand these gravity-driven systems, shown in Figure 1, where an extraction for a single horizon within the Upper Jurassic has been made over an area of ~500 sq km on the Horda Platform.

Bright amplitude anomalies from the colour blending are identified as feeding canyons where sediment-routing systems are interpreted across the closely spaced down-stepping fault terraces, as seen in the Swisher and Echino Sør discoveries. The sinuous transport channels seem to be largely controlled by topography but also influenced by fault geometries. At the base of these systems, we identify deposits fanning out into sand lobe complexes as seen to hold hydrocarbons in discoveries such as Gnomoria and Syrah.

To better understand potential reservoir sand deposition along these systems, Figure 2 shows a composite line taken through Wells A, B, C and D with the relative gamma-ray (GR) logs. Reviewing the GR log responses at the depth of the Upper Jurassic surface seen in Figure 1 (highlighted by a yellow dashed line in Figure 2) we can begin to correlate lithology with the seismic, along the depositional pathways as previously described.

In Wells A and B - Well A is drilled near to the source input and Well B on the inner flank of the canyon system - we can interpret silty sand deposits. As we move further down the system, Wells C and D have been drilled into the end of the depositional system identified as lobe complexes, where log results show clean, thinly stacked sand sequences at this level.

All these wells encountered petroleum within the Upper Jurassic units, indicating a good correlation with the features seen in the spectral decomposition with regard to the deposition of reservoir sands. The depositional pathways as described have been recognised and interpreted on a regional scale using new DAZ data with increased resolution and improved continuity of reflectors, allowing for analogous reservoir sands to be mapped.

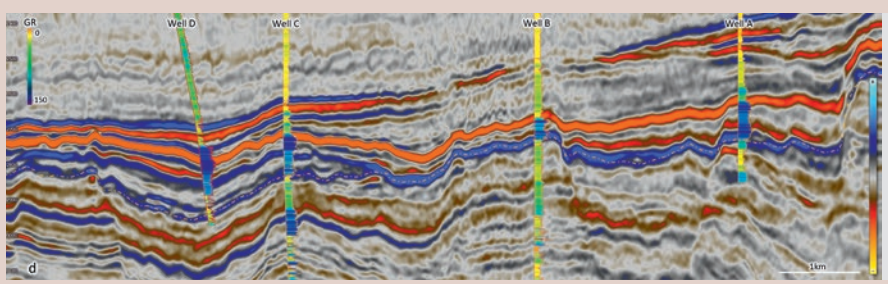


Figure 2. A composite line intersecting Wells A, B, C, and D highlighting gamma ray log responses to the Upper Jurassic depositional systems. The yellow dashed interpretation indicates the depth of the horizon surface shown in Figure 1. The locations of the wells are shown in Figure 1.

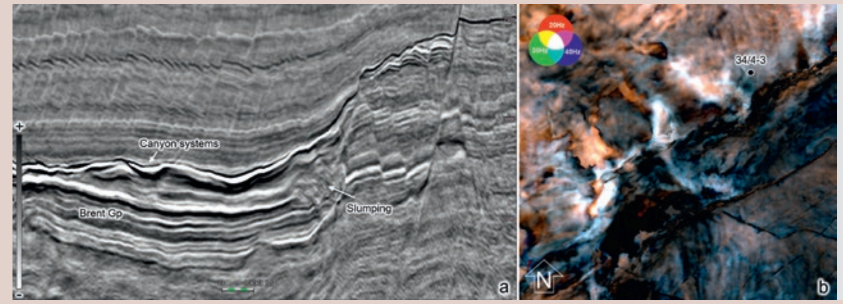


Figure 3 (a). A composite DAZ seismic line highlighting deposition of Upper Jurassic slumping and canyon-fed deposits. (b) RGB frequency colour blending showing Upper Jurassic deep-water sediment routing systems.

SEISMIC RESERVOIR MAPPING

Moving west onto the Tampen Spur, we observe different modes of gravity-driven deposition in the Upper Jurassic succession; these consist of canyon-fed sedimentation, as seen on the Horda Platform, and slumping due to erosion of rotated, steeply dipping fault blocks (Figure 3a). Canyon-driven deposition and interbedded hemipelagic sediments are observed above the shallow marine Brent Group. These are stratified and conformable in contrast to the slumped deposits which are chaotic and deformed (Figure 3a). Examples of both deposits can be seen in the hanging wall of a large fault in an area north of the Dugong discovery (Figure 3b). Results from a recent inversion study conducted over the area allow further evaluation of these reservoir targets through P-impedance and probability of sand extractions.

Seismic inversion studies are particularly beneficial for investigating uncertainties and mapping the probabilities of different lithofacies from seismic amplitudes. Upper Jurassic slumped deposits are identified as dense high-impedance bodies as seen in Figure 4a, where the P-impedance is superimposed on the DAZ seismic section. Likely controlled by erosion, with collapse from structural highs and deposited through a fast-paced system, this would imply the deposits are reworked and lithified, therefore identifying with a dense high-impedance response. In contrast, the hemipelagic, canyon-led deposits show a low-impedance response, conforming to the seismic response of these deposits in seismic.

Through a facies classification process, the elastic inversion results can provide the probability of different facies and we can evaluate these details from the most probable sand analysis (Figure 4b). These results correlate well with the gamma-ray log responses in well 34/4-3, which clearly define sand-rich layers at both intervals of the Upper Jurassic as well as the deeper Brent Group (Figure 4b).

By correlating results from the most probable sands away from well 34/4-3, we see a high probability of sand both in the chaotic slump interval and in the more conformable deposits in the canyons. This indicates potential reservoir intervals in both types of deposits and further de-risks exploration opportunities in the Upper Jurassic as seen from the Sjøpølse discovery in the area.

The availability of a regional dataset, acquired and processed with the latest seismic imaging technologies, is imperative to better understanding the depositional environments of one of the main hydrocarbon plays in the northern North Sea – the Upper Jurassic sandstones, as exemplified in the foldout line and examples above. Using recent discoveries, attribute analysis, and elastic inversion results, we can identify different Upper Jurassic sediment systems. Owing to the complexity of many depositional fairways, these studies show the great need for modern high-quality 3D datasets to better understand how we can identify remaining hydrocarbon potential in the region. ■

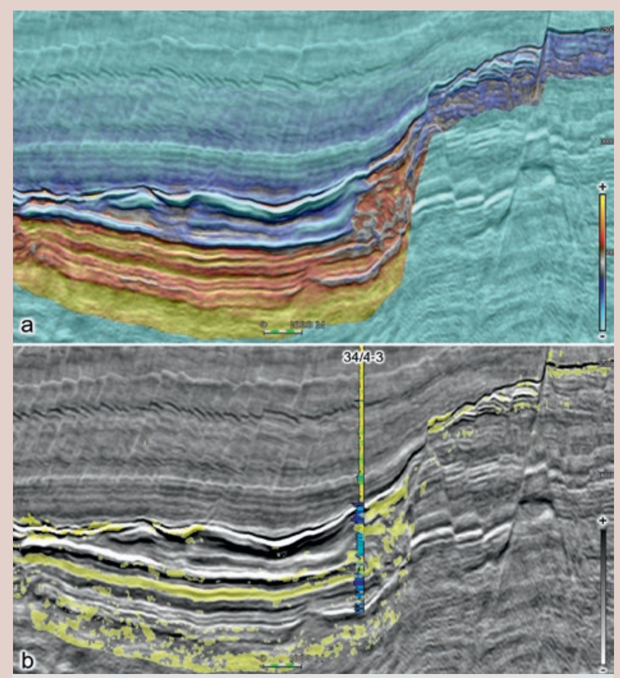


Figure 4. A composite DAZ seismic line highlighting deposition of Upper Jurassic slump and canyon-fed deposits. (a) Seismic line overlain with P-impedance (b) Seismic line overlain with the probability of sand.

FEATURES

"When drilling a new well based on machine learning results, the final cost of inadequate prior well sampling or mixing the training and validation datasets could run into the tens of millions of dollars."

Charles Puryear - Spectral Geosolutions

MACHINE LEARNING VALIDATION: AN OFTEN UNDERSTATED REQUIREMENT IN GEOPHYSICS

In the past decade, machine learning and deep learning have become buzzwords throughout the tech sectors, including geology and geophysics. While these technologies have proven useful for a variety of purposes, caution is still warranted, and validation of results is important.

CHARLES PURYEAR, SPECTRAL GEOSOLUTIONS

DEEP LEARNING IS A SUBSET of machine learning, which entails a neural network with three or more layers. It is thanks to deep learning that applications from fault picking to prediction of log properties have proliferated. However, as set out in this article, it is important to always validate results before drawing conclusions.

There are two primary validation methods that can be used for machine learning applied to geophysical data and seismic data in particular: 1) geological confirmation by a human interpreter and 2) out-of- sample well validation.

Are the marbles we see representative of the entire population?

IMAGE CREATED BY DALL-E

THE INTERPRETER'S CALL

Geological confirmation by an interpreter is relatively straightforward. If a fault detection algorithm is applied, the interpreter can simply check whether the faults appear on the input data and validate them, as a senior interpreter would be working with a junior interpreter. In supervised learning, corrections can be made from which the algorithm can "learn" and improve its future performance in fault picking. This type of automated interpretation generally entails low risk since the output can be checked directly by the interpreter.

Similarly, with rock properties prediction or resolution enhancement for the purpose of stratigraphic interpretation, the interpreter should confirm the geological character of the results and that there is correspondence between the events in the input seismic data and the output prediction or enhancement.

To enable this, the interpreter can familiarize himself/herself with the change in response between low frequency events and high frequency (resolution enhanced) events using a set of modeled reflectivity configurations. Resolution enhancement should not create new events, although exceptionally thin low impedance sands will become more evident. Figure 1 shows the Widess tuning curve with thin low

"...if out-of-sample validation is neglected, the predicted data result could be synthetic "high resolution" data..."

impedance/low amplitude sands on the left.

Events should never disappear or get "wiped out" with resolution enhancement - although they can bifurcate. If the output appears inconsistent with the input or contains artifacts, out-of-sample validation should be applied.

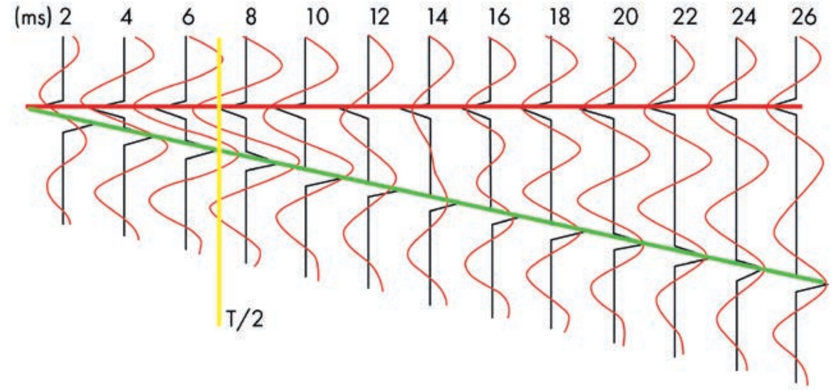


Figure 1: Wedge model where red is the top reflector and green is the base reflector. Amplitudes increase as the layer thins to tuning T/2, where T is the dominant period of the wavelet. Below the tuning thickness, amplitude decreases approximately linearly with thickness.

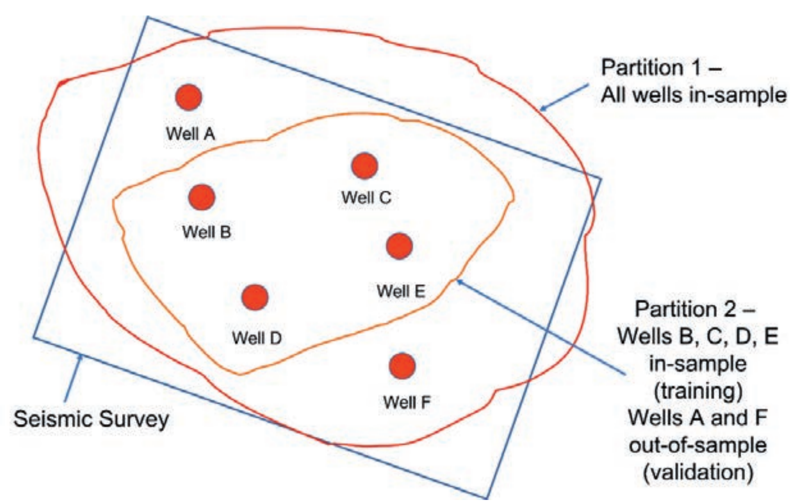


Figure 2: Examples of training/validation data partition for machine/deep learning.

OUT-OF-SAMPLE VALIDATION

There are two types of validation using a set of logs for 3D properties prediction: in-sample validation and out-of-sample validation (Figure 2).

In-sample validation simply means using the training data for validation; it is a trivial QC on the machine learning model and does not provide any meaningful indication of its predictive power. On the other hand, out-of-sample validation entails removing part of the dataset - for example, one or more wells - for validation. While it is generally desirable to partition the data at 80% training/ 20% validation, this is often not possible at the oil and gas exploration stage. Thus, we frequently suffer from a shortage of training data. Once the model is defined using the training data, it can be applied to the validation data in order to evaluate its performance.

Using in-sample validation only, nearly perfect well ties are achievable with machine learning properties prediction or resolution enhancement. However, if out-of-sample validation is neglected, the predicted data result could be synthetic "high resolution" data that deviate significantly from test wells drilled after the analysis; strictly speaking, out-of-sample validation does not guarantee that this will not happen either.

Consider a target unit with different rock properties that pinches out without being sampled by any wells; this unit cannot be used at all in the training process and the application of machine learning to predict its rock properties would be unreliable. These techniques are also sensitive to the input well tie quality and prone to artifacts if not properly parameterized.

"When drilling a new well based on machine learning results, the final cost of inadequate prior well sampling or mixing the training and validation datasets could run into the tens of millions of dollars."

In commercial settings, we recommend a "trust but verify" approach; at least one validation well should always be withheld from the vendor doing the machine learning or resolution enhancement analysis. If no wells, few wells or only low quality well curves are available, we recommend a signal processing approach such as Spectral Extrapolation for resolution enhancement, which does not require well information but can be used for phase calibration.

When drilling a new well based on machine learning prediction results, the final cost of inadequate prior well sampling or mixing the training and validation datasets could run into the tens of millions of dollars.

■

FIGURE 1: MODIFIED FROM WIDESS (1982)

DE-RISKING THE CABORA BASSA BASIN

Early January 2023, the Australian junior oil company Invictus Energy completed the drilling of the Mukuyu 1 well, and subsequent sidetrack, in the Cabora Bassa Basin of Northern Zimbabwe. Jamie Vinnels discusses the geological outcomes of the well.

JAMIE VINNELS, INDEPENDENT GEOLOGICAL ADVISOR

PHOTOGRAPHY: BIRGER STRAHL/UNSPLASH

Sunset in Zimbabwe.

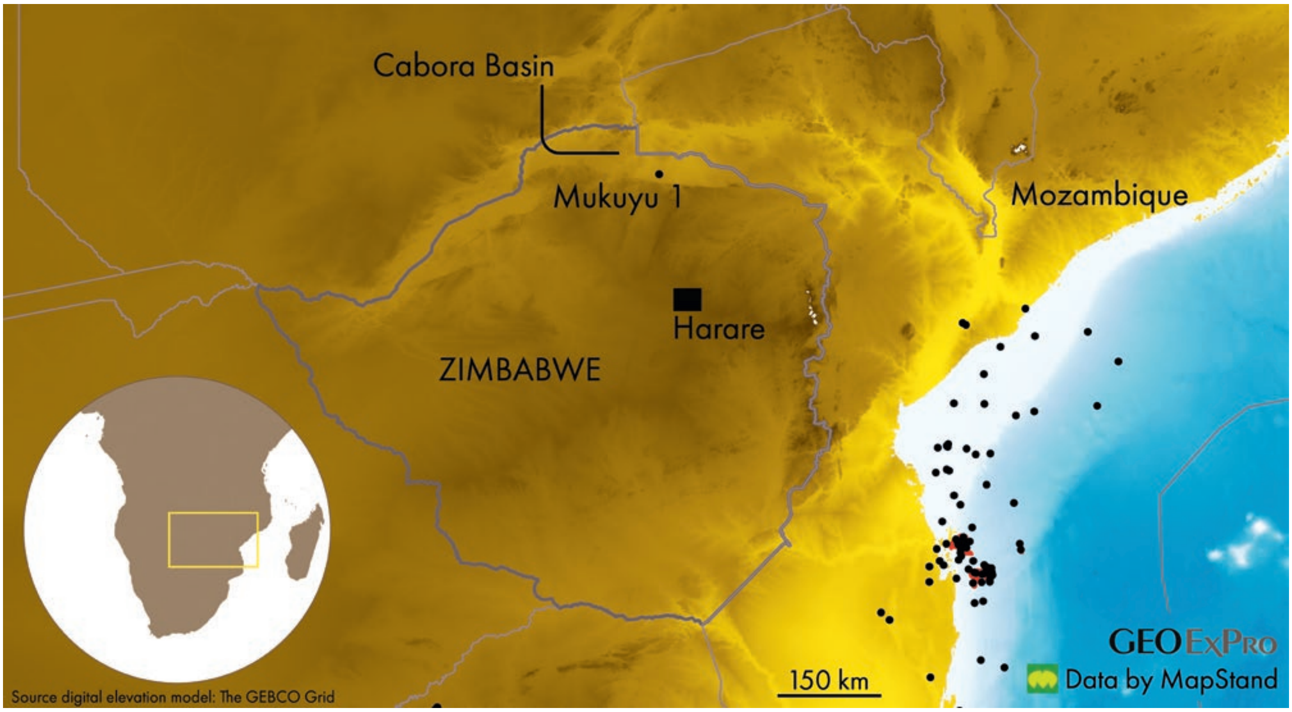


Figure 1: Map showing the location of the Mukuyu well in northern Zimbabwe. The topography nicely reveals the basin outlines. Note the remote location of the drilling site with respect to other wells completed in the area (black dots).

INVICTUS ENERGY consider drilling Mukuyu 1 a geological success. The well encountered gas and oil in multiple reservoir zones in Triassic Karoo Supergroup sediments, proving a working petroleum system along with potentially opening a new play in the region. However, due to repeated equipment failures that hindered the acquisition and retrieval of fluid samples, the Australian Securities Exchange Ltd (ASX) prevent declaration of a formal discovery.

Based on the current data, independent resource estimates suggest the Cabora Bassa Basin (Figure 1) may hold in excess of 5.5 billion barrels of oil equivalent across several prospects (Figure 2). Invictus Energy plans to integrate their findings from the well to develop a more refined understanding of the basin, along with updated resource estimates, intending to spud Mukuyu 2 in Q3 2023, along with potentially attracting partners to continue the exploration effort across the licence.

Landscape of the Cabora Basin, Zimbabwe.

SOURCE: SCREENSHOT OF VIDEO RELEASED BY INVICTUS

"Invictus Energy consider drilling Mukuyu 1 a geological success. The well encountered gas and oil in multiple reservoir zones in Triassic Karoo Supergroup sediments, proving a working petroleum system."

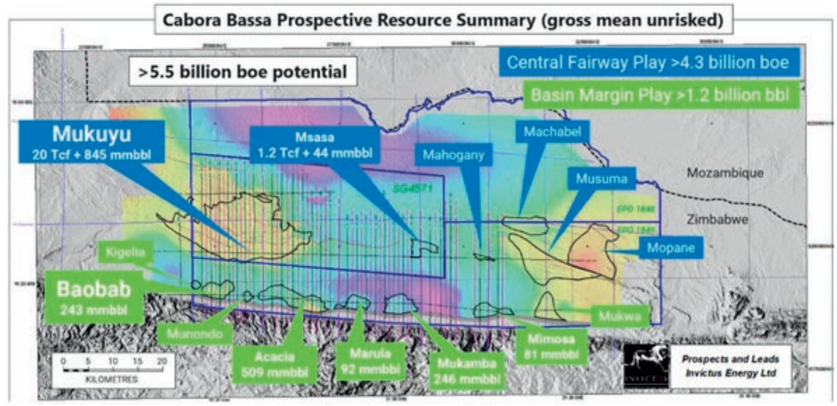


Figure 2: Overview of the Invictus Energy leasehold and prospect inventory. The basin is broadly subdivided into a Central Fairway Play (targeted by Mukuyu 1 and 1ST1) and a Basin Margin Play.

CONTEXT

The Cabora Bassa Basin is one of several rift basins found across Southern Africa. These formed during a series of tectonic events along the margins of Gondwana from the Late Carboniferous to Jurassic, within which a mixture of marine, marginal marine, to continental sediments were deposited as part of the Karoo Supergroup. Part of this succession was subsequently uplifted.

Outcrop and shallow borehole studies elsewhere in the region have indicated the key elements of a working petroleum system, including the presence of well-developed Permo-Triassic Karoo Group sandstones and organic-rich shales 40-60 km to the west of the licence area.

Based upon these analogues, predrill estimates were that the Mukuyu targets may be relatively sand-prone, with possible sealing and trap containment issues. A database consisting of legacy 2D seismic from earlier exploration by Mobil in the 1990's was supplemented by a new survey acquired by Polaris Natural Resources in 2021.

This revealed a series of 3- and 4-way closures across the licence area. Quantitative analysis also suggests the presence of flat spots and other direct hydrocarbon indicators. The Mukuyu 1 well spudded on the 26th of September 2022, and was targeting a series of stacked reservoir units in various Formations of the Karoo Supergroup (Figure 3).

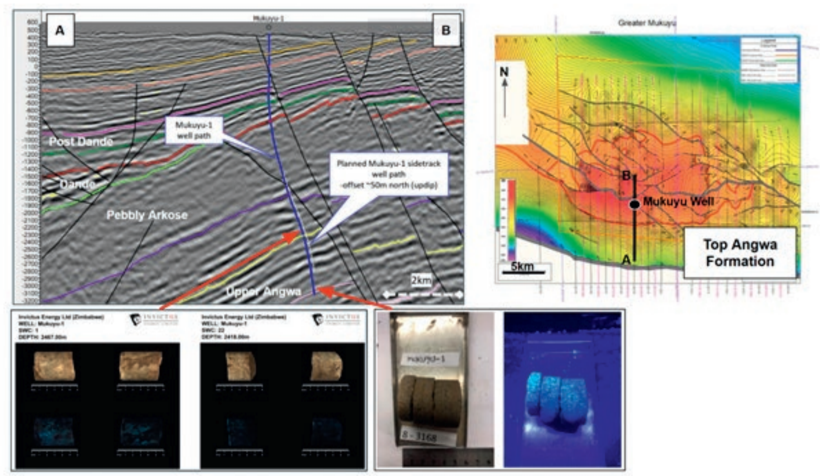


Figure 3: Mukuyu-1/ST1 well trajectories and targets. Sidewall cores showing fluorescence in the Pebbly Arkose and Upper Angwa Formation sandstones.

WELL RESULTS

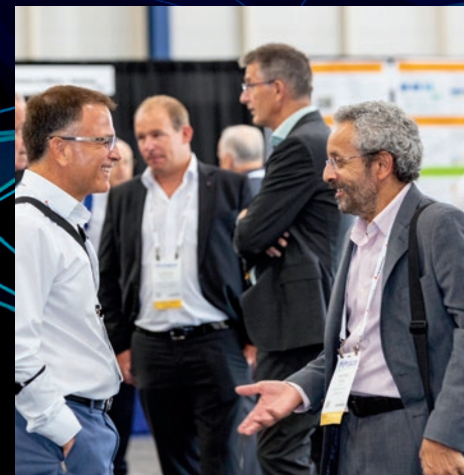
The drilling was dogged by adverse hole conditions, repeated equipment failures, and logistical issues, but was completed without any safety incidents. Despite this, Invictus Energy believes it has strong petrophysical evidence, and supporting data, to suggest multiple pay zones were encountered during drilling. Mukuyu 1 ST 1 identified at least 13 potential hydrocarbon bearing sandstone zones, with porosities of up to 15% and gas saturations of up to 90% in the Triassic Upper Angwa Formation, the primary target (Figure 3).

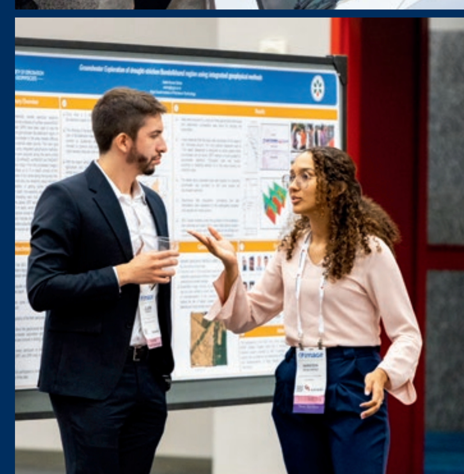
A shallower 10-15 m sandstone unit with complex mineralogy and gas indications was encountered in the shallower Post Dande Formation (Figure 3). Repeated reservoir, seal, and source packages with hydrocarbons were encountered until total depth of the well at 3603 m MD in the Upper Angwa Formation (Figure 3). The Lower Angwa Formation remains untested.

The well encountered a series of Triassic-aged non-marine, fluvial, fluvio-deltaic, pluvial, and lacustrine clastic sediments. Further palynological analysis will be undertaken to refine the age and environments of deposition. Invictus Energy liken these to the Karoo Supergroup strata found in the Ambilobe, Sakamena, and Majunga Basins of Madagascar.

The wells encountered considerably thicker shale sequences in the Upper Angwa Formation than predicted predrill, which has in turn decreased seal risk within these units. Overall, these units were thicker and therefore deeper than prognosed. Further analysis

SOURCE: INVICTUS ENERGY 2022/2023 INVESTOR UPDATES





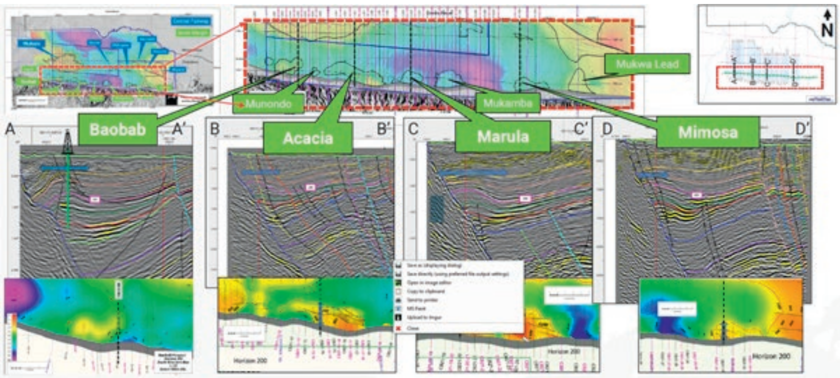


Figure 4: The Basin margin play consists of a series of 3- and 4-way dip closures against basin bounding faults, setting up traps at multiple stratigraphic levels. Current basin modelling suggests that these may be potentially more liquid prone.

SOURCE: 2022 INVICTUS ENERGY INVESTOR PRESENTATION

is pending the analysis of core data, where a total of 24 cores were taken in the reservoir, source, and seal intervals.

Larger sidewall cores were taken, which may allow the retrieval of native fluids from the reservoir units to better calibrate petrophysical models and highlight potential pay characteristics. Initial core analysis has revealed strong fluorescence in sidewall cores taken from 2407 m MD onwards in the Pebbly Arkose Formation.

Lower fluorescence and higher gas concentrations were noted in Mukuyu 1 ST1 compared to Mukuyu 1, which the company interprets may relate to a paleo-fluid contact, or that there is possibly considerable variation in reservoir and fluid properties across the broader Mukuyu structure. Post-well pressure analysis of pressure data suggests the potential for significant gas columns in the Pebbly Arkose and Upper Angwa Formations.

WAY FORWARD

The next phase of the exploration of the Cabora Bassa Basin will build upon the integration of the well and seismic data to refine the geological structure of the licence, refine basin modelling, updated resource estimates, and allow the high-grading and ranking of prospects.

Invictus Energy is uniquely positioned in owning the licence across the geological limits of the Cabora Bassa Basin. They interpret a "string of pearls' along the basin margin, analogous to the Lokichar Basin in Kenya, and the Albertine Graben in Uganda, themselves proving multi-billion barrel potential in East African Rift systems (Figure 4).

In a recent podcast, Invictus Energy Managing Director Scott Macmillan noted that the emphasis of the next exploration phase will be upon data gathering, cost consciousness, reducing uncertainty, gaining new information, extending and drilling play fairways and unlocking the prospectivity of the basin. In the same interview, he suggests acquiring infill 2D surveys across other parts of the basin, which is anticipated to start in Q2 2023 (Figure 4).

In the longer term, a 3D seismic survey could be used to conduct seismic geomorphology studies to delimit fluvial channel bodies and aid exploration and development well placement. Upgrades will also be made to the mud gas system and other equipment on the Exalo 1 rig, which Invictus Energy have retained for 12 months following the TD of the Mukuyu 1 and ST1 wells.

Invictus Energy intends to spud Mukuyu 2 in Q3 2023, along with potentially attracting partners to continue the exploration effort across the licence. The exact location is yet to be determined, pending further subsurface work and permitting.

Thanks to Scott Macmillan, Managing Director of Invictus Energy, for their input and permission to publish this article. ■

References provided online.

THE KAVANGO ONSHORE NAMIBIA – RECONAFRICA'S EXPLORATION PROGRAM IN ONE OF THE MOST UNDEREXPLORED BASINS

ReconAfrica's frontier exploration program in the Kavango area, east of the Owambo-Etosha Basin in Namibia continues to yield both surprises and encouragement.

ANSGAR WANKE & JIM GRANATH, RECONAFRICA

IT IS A RARE OPPORTUNITY in the twenty-first century to explore an untouched basin for hydrocarbons, but this is the position ReconAfrica finds itself in exploring the Kavango area, east of the Owambo-Etosha Basin in Namibia. Regional studies of Karoo tectonics in East Africa had hinted at the existence of a linked belt of rift-like structures across the African continent, with a Southern Trans -African Rift and Shear System (STARSS) stretching from the East African Rift to the Namibian Coast.

The impetus to license the NE Namibia area was driven by depth-to-basement inversions of high-resolution aeromagnetic data that were carried out by Earthfield Technology at ReconAfrica's behest in 2014. At that time, the Kavango-area geophysical database was sparse and seismic data were non-existent; only this high-resolution aeromagnetic imaging gave an idea of the deeper subsurface in the area that became the 25,341 km^2 large PEL 73 licence acreage (dashed green outline in Figure 1). The closest legacy well to ReconAfrica's block is well over 200 km away, in the Owambo-Etosha basin, which has long demonstrated the presence of Karoo lying on Neoproterozoic sediments.

In Kavango, no wells other than water wells were present, and from our review only the deepest of them ended in the uppermost Karoo unit, the Jurassic Etjo Sandstone. However, the aeromagnetic data suggested extensional features that could harbour a full Karoo sequence (Late Palaeozoic to Jurassic) rocks occupying grabens associated with the Africa-wide belt. This became termed the 'Kavango Sedimentary Basin' to distinguish it from the long-recognised Owambo-Etosha Basin to the west.

ReconAfrica subsequently commissioned a Karoo paleogeographic study for southern Africa that outlined how all these basins might tie together in a model of Karoo depositional systems. Together, these studies formed the conceptual foundation for ReconAfrica's play in both the Namibian licence and in neighbouring PEL 1 in Botswana.

Jarvie 1 – ReconAfrica-owned rig operating on a full-moon lit night in Kavango.

PHOTOGRAPHY: RECONAFRICA

THE FIRST WELL

Interpretation of the potential field data looked promising for the presence of a previously unidentified deep basin, and in 2020 ReconAfrica decided to drill its first stratigraphic test well. A rig was purchased, transported from Houston to a remote location in the Kavango region, and all efforts were made to ensure the success of drilling operations. Challenges associated with the COVID19 lockdowns, travel restrictions, goods transportation, and supply chain disrup-

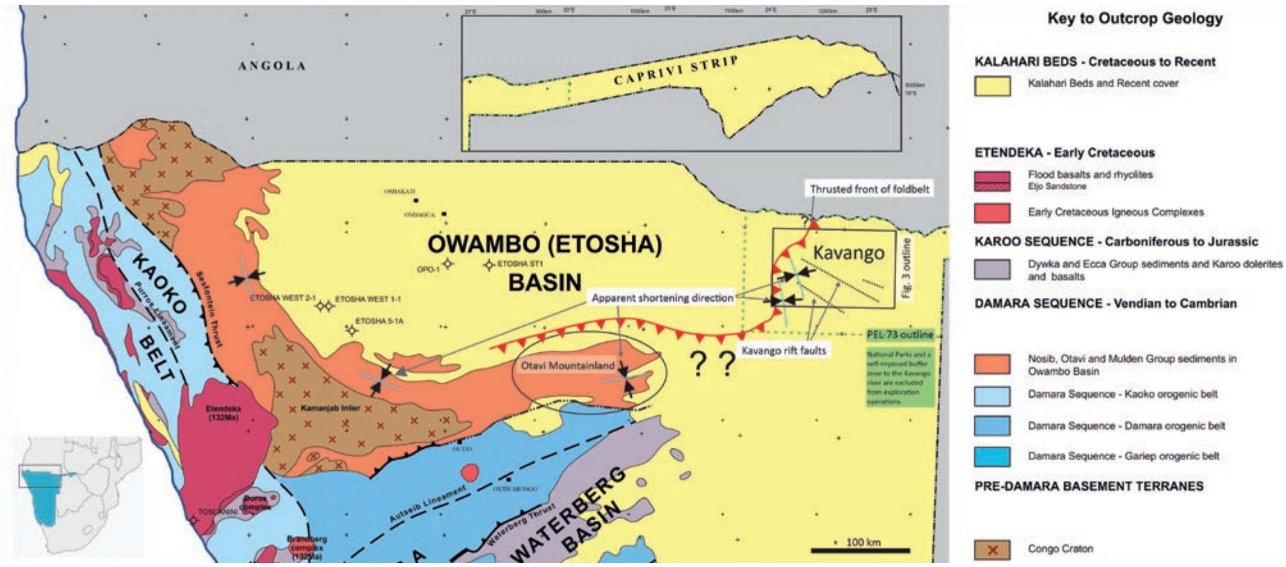


Figure 1: Map of northern Namibia showing the outcrop geology. The Owambo-Etosha and Kavango are largely covered by Cainozoic sediments. The converging arrows indicate the apparent shortening direction of the Cambrian orogen flanking the Owambo basin: the Damara belt undergoes a distinct oroclinal bend between outcrop in Otavi Mountainland and the Kavango area.

tions were eventually mastered, and the rig arrived on site in late 2020. Drilling of the first well, the Kawe well, commenced in January 2021.

The location for the first well (Kawe) was chosen on an intermediate high within the deep part of the basin based on aeromagnetic-derived depth-to-basement maps (Figure 2). This first deep well in the basin was a stratigraphic test designed to reveal the nature and the dimensions of the stratigraphy below what was known from the water wells and to potentially establish whether a petroleum system might be present.

No other data nearby gave any definitive indication of the age of any basin fill that might be present. The Etjo Formation could be on top of a more extensive Karoo section as in the neighbouring Waterberg Basin, or it could just form a thin veneer resting on the Precambrian Mulden Group, which is the case to the west in the Owambo-Etosha Basin proper.

HYDROCARBON SHOWS

The Kawe well intersected the Upper Karoo stratigraphy as expected, and from about 740 m below surface hydrocarbon shows were reported as the drill bit made its way into the Lower Permian Karoo sandstones and shales. Interestingly, light hydrocarbon fluid indicators were stronger than associated gases, and hydrocarbon shows continued into the pre-Karoo stratigraphy. Flow test and downhole fluid sampling tools were not on location as the well was permitted and planned only as a stratigraphic test. Fortunately, the wireline logs, closely spaced cuttings samples and over 180 rotary sidewall cores provided a wealth of information to better understand the newly discovered rift basin with an associated petroleum system.

A second Kavango well (Mbambi) was drilled in the same year. Mbambi also encountered strong gas and fluid indicators over long intervals, but it intersected only 630 m of Mesozoic-Cenozoic basin fill resting on deformed pre-Karoo carbonate and evaporite lithologies. In parallel, surface analyses indicated geochemical anomalies at both well locations, and an active hydrocarbon seep was discovered in the western portion of the licence block.

SEISMIC ACQUISITION

Following the two wells, an initial loose network of about 500 km of 2D seismic data were acquired across most of ▶

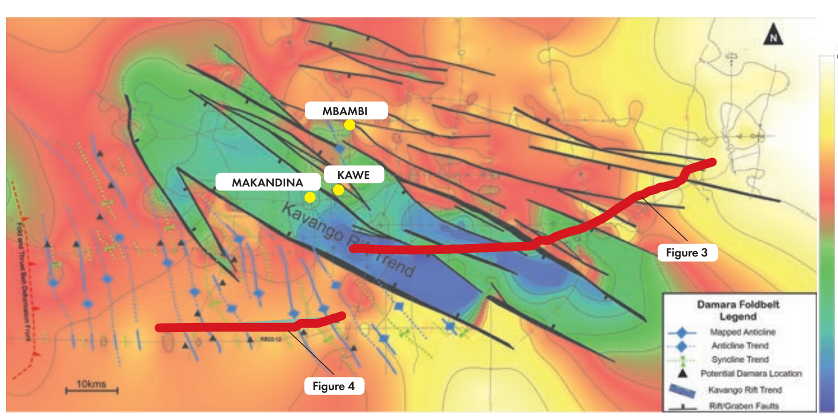


Figure 2: Time structural map on the base of the Karoo system, showing the main Karoo graben faults and the graben floor in greens and blues. Pre-Karoo axial fold trends west and south of the main graben, include anticlinal axial trends in blue with thrusted forelimbs in black, and synclines in green. The red dotted line at the western edge of the figure is the tipline of the thrust belt. The seismic colour bar represents two-way travel time (s).

Accelerated weight-drop seismic source – the Polaris Explorer 860. This source is highly manoeuvrable and requires only 3 metres wide access tracks. The receivers being used are wireless Stryde Nodes (insert image), which are small and compact even by the standards of modern nodes.

the northern part of the block (rectangle in Figure 1). This Phase 1 seismic campaign established the initial inventory of leads, 3rd party prospective resource estimates, and a framework for the second phase of seismic acquisition. The third Kavango well (Makandina) followed the completion of another 761 km 2D seismic acquisition.

THIRD WELL

Makandina was drilled between the end of June and mid-August 2022. As predicted by a nearby seismic line, this third well penetrated an expanded Permian Karoo section, and it encountered light hydrocarbons including gas liquids. It provided crucial stratigraphic and structural information, but the well was not deemed to be commercial. The seismic interpretation had located the Makandina well on a locally defined structure within a Karoo graben, only 6 km west of the first well.

A RIFT OVERLYING A FOLDBELT

At present, it is clear that indeed there is a Karoo Rift Basin lying over the easternmost edge of the Owambo-Etosha basin, and that this rift is filled with Karoo Supergroup deposits. An example seismic line (Figure 3) across the Karoo Rift Basin shows the graben structure and growth faults typical of an extensional basin. In addition, seismic data have shown that the rift straddles the frontal fold and thrust belt of the late Precambrian-Cambrian Damara Orogenic Belt. The term 'Karoo Rift Basin' is now the preferred terminology within ReconAfrica to describe this rift overlying older rocks.

Surprisingly, the deformed strata in the foldbelt also image well with the weight-drop source. With a flat unconformity developed on top of that folded system, unlike data in other more complex thrust belts around the world, the ray path assumptions and subsequent pre-stack time migration in processing is holding up very well. The result is the good seismic imaging shown in Figure 4. Imaging of these older structures, however, is degraded under the Karoo graben itself.

A NEWLY MAPPED OROCLINAL BEND

The Damara orogenic belt is a prominent feature of Namibia, stretching from the coast eastwards across the country to eventually disappear as it trends under the same Cenozoic Kalahari cover that hides the Karoo Rift Basin.

The seismic data revealed not only that the width of the Damara-age frontal fold belt is larger than was suspected, but also that the fold assemblages undergo a major northward deflection to become north-northwest trending in the licence area. This change in orientation from the west-east oriented structures in Otavi Mountainland, which is the only exposure of the frontal fold belt as developed in sedimentary rocks, is supported by FMI analysis of the bedding data sets from the three wells. They all show strong SSE-trending plunges of pre-Karoo Damara folds.

Thus, the system undergoes a 90-degrees swing, an 'oroclinal bend,' in the structural grain between PEL 73

THE MOST RECENT SEISMIC SURVEY

ReconAfrica extended its seismic acquisition program with the goal of acquiring a total of over 2,600 km in late 2022 and the first half of 2023. With acquisition limited at this stage to 2D seismic on existing roads, tracks, and fence lines, an enhanced Full Tensor Gravimetry (eFTG) survey has been permitted to compliment the seismic data. This high-resolution gravity information is expected to improve the interpolation between 2D seismic lines.

ReconAfrica chose to maintain the delicate balance between environmental footprint, sub-surface energy penetration and lateral interpolation with limited seismic control. Therefore, an accelerated weight drop, the Polaris Explorer 860, was used as seismic source. This source is highly manoeuvrable and requires only 3-metre-wide access tracks. In most cases, the existing tracks with minor scrub clearance is sufficient. In contrast, the standard large vibrators would provide a larger energy input but would require somewhat greater clearances than the Explorer and potentially greater noise and vibration.

Following modern trends in seismic acquisition, the project uses Stryde nodes, eliminating all the extra effort for deploying the cables of a conventional recording system and thereby reducing the logistical load associated with moving receivers. Stryde Nodes are small and light weight even by the standards of modern nodes enabling very quick deployment even by crews with limited experience.

Adjustments in acquisition and processing parameters compensate well for the lower energy and noise of the weight-drop source, and the structure within the graben and its base are clearly imaged.

PHOTOGRAPHY: RECONAFRICA

and the Otavi Mountainland (Figure 1). These folds occur from some 40 km or more east of the thrust front, a relationship that is not apparent to the west in front of the exposed Damara belt but should persist in one form or another all the way westward to the Kaoko Belt on the west side of the Owambo-Etosha Basin. Subcrop maps in Botswana suggest that the crystalline core of the Damara belt follows suit with this bend. These relationships clarify that the pre-Karoo Owambo-Etosha Basin is the Damara foreland basin and that it may not extend eastward from the easternmost Kavango region all the way to Botswana as is commonly portrayed on tectonic maps. The Kavango (Karoo-aged) rift system directly overlies this fold belt and more internal parts of the orogen.

PRE-KAROO POTENTIAL

Stratigraphically, the pre-Karoo in the Kavango resembles the Cryogenian-Ediacaran Otavi and Mulden Groups, likely extending into the Palaeozoic, as supported by palynology and Sr isotope ratio data as well as unique lithologies that were recovered from the wells. This stratigraphic framework could provide multiple source intervals associated with post-glacial anoxic events, as well as carbonate reservoir intervals. In fact, dolomitic shales with over 2% TOC have been sampled in the latest well, and carbonates with good dolomitic matrix and fracture porosity are present. Seismic data reveal trains of large thrust anticlines in the fold belt, which could provide large four-way dip closures each of tens of km^{2}s in size (Figure 3), analogous to some world class hydrocarbon provinces. These analogies make those large structures in Kavango attractive for exploration, especially as the pre-Karoo strata include potential source, reservoir and seal rocks. The pre-Karoo has been an exploration target further west in the Owambo-Etosha basin, so far only five stratigraphic/exploration wells were drilled between 1964 and 1986 there. Currently, Monitor Exploration is planning their exploration program in the eastern portion of the Owambo-Etosha basin, west of ReconAfrica's licence acreage.

THE NEXT STEP

In summary, the ReconAfrica exploration program has confirmed the initial play concept of a Permian rift basin in northeast Namibia, with indicators of migrated petroleum. It has also identified a Damara Fold and Thrust Belt play. The company is now completing its regional seismic program alongside the start of acquisition of the eFTG survey and the next well. All will add to the data required to further advance our knowledge of this newly explored basin, and hopefully identify commercial hydrocarbon accumulations. ■

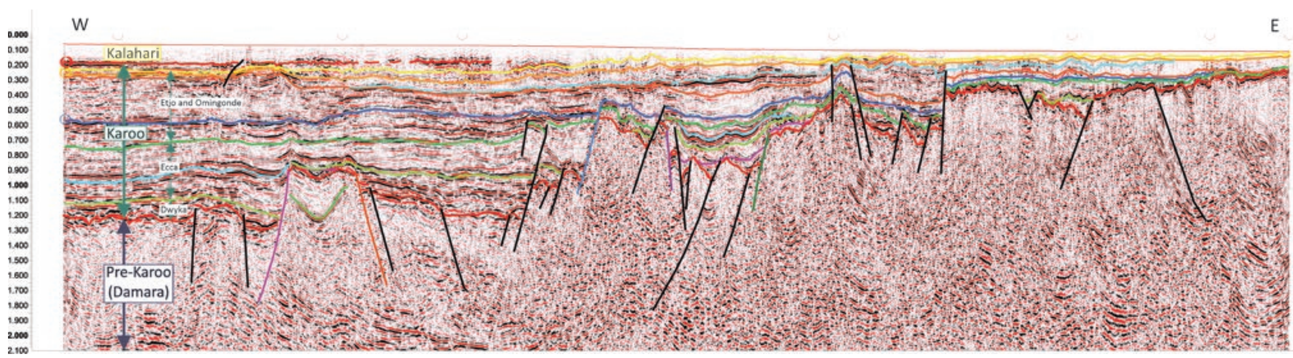


Figure 3: W-E seismic line showing Karoo Graben and growth in the Karoo section. The Karoo section includes the Etjo Sandstone (yellow to orange), Omingonde Formation (orange to green), Ecca Group (green to pea green), and Dwyka Group (pea green to red). The red horizon is the base of the Karoo lying over Pre-Karoo (Damara belt) rocks. The line is 86 km long.

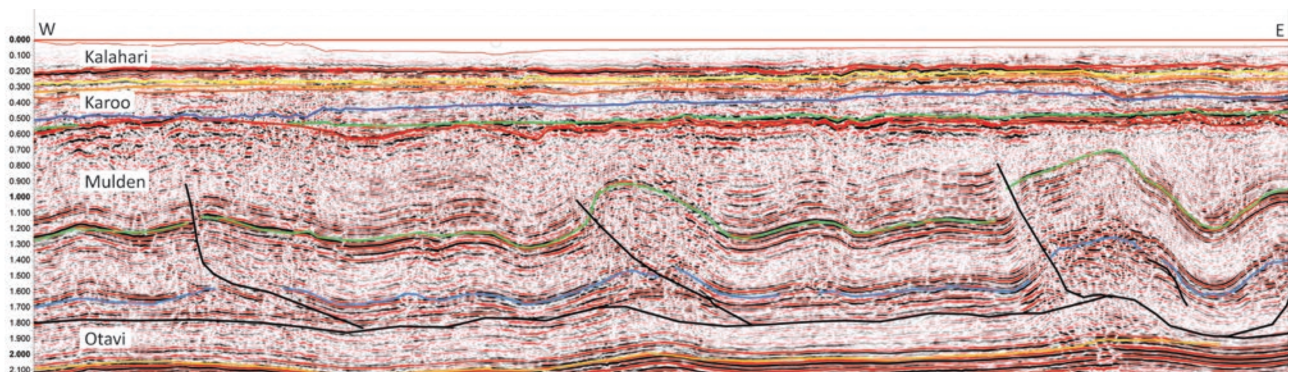
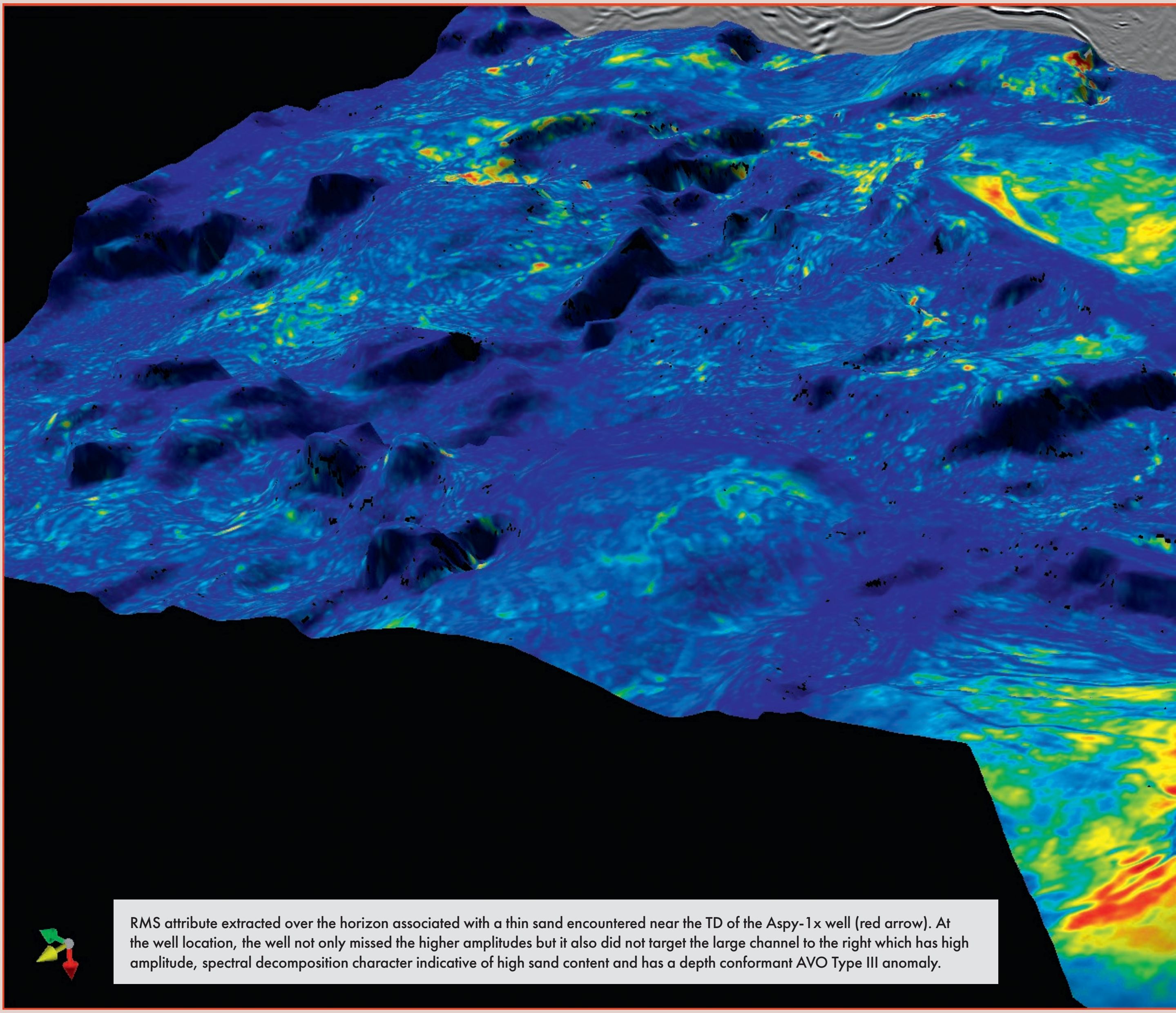


Figure 4: W-E seismic line showing a train of detachment folds with large whaleback anticlines, some with frontal thrusts that diverge from the basal detachment. A thin Kalahari cover and a Karoo platform section follow above the red unconformity. Green, blue, and yellow horizons are inferred to represent the Mulden and Otavi groups of the Precambrian pre-Karoo section. The line lies south of the graben shown in Figure 5. The displayed section is 45 km long.

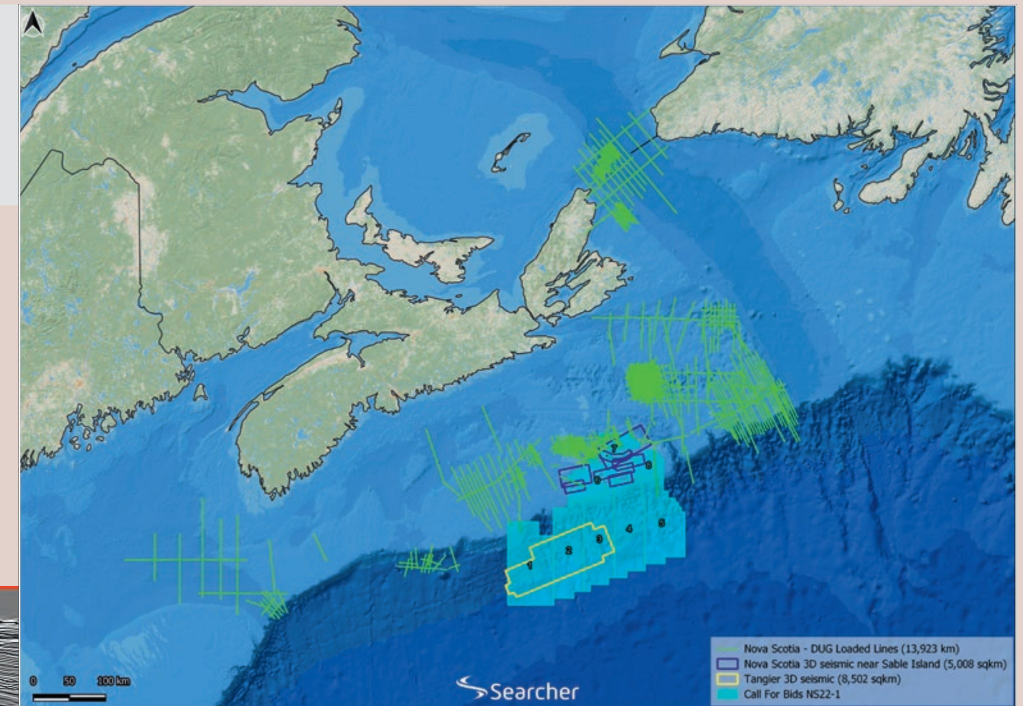
Sands and source rock delivered by the Tangier WAZ3D in the current Nova Scotia Licence Round

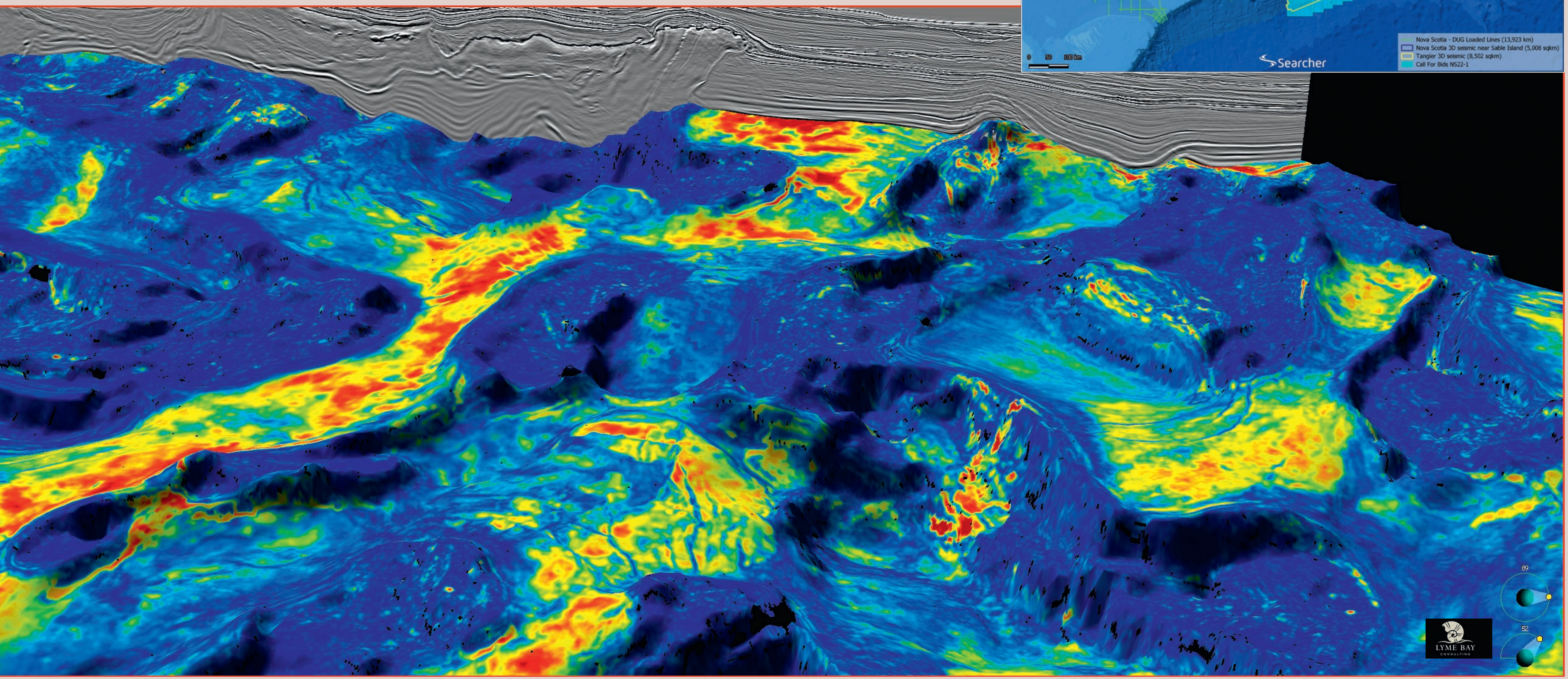


RMS attribute extracted over the horizon associated with a thin sand encountered near the TD of the Aspy-1x well (red arrow). At the well location, the well not only missed the higher amplitudes but it also did not target the large channel to the right which has high amplitude, spectral decomposition character indicative of high sand content and has a depth conformant AVO Type III anomaly.

The story of exploration off the shelf of Nova Scotia has been written by the courageous achievements of exploration giants equipped with only 2D data to locate their wells, creating a narrative of information gaps rather than hydrocarbon negatives. Examination of one of the world's most technologically advanced 3D surveys allows us to re-write this story, revealing evidence for the trapping of material oil reserves in a deeply analytical forensic thriller.

Map showing Blocks available in the 2022-2023 Bid Round and available seismic data from Searcher.





Evidence-based exploration on the slope of Nova Scotia

In his definitive book on the form, Robert McKee writes that a "story" tells how characters navigate the restoration of balance to the world, when that balance has been disturbed. Similarly, imperfect and incomplete subsurface data can leave explorers perceiving source, seal and reservoir are also out of balance until new imaging, models and analysis arrive and our roles in these stories play out when we grasp, absorb and use the new data to construct a new order.

KARYNA RODRIGUEZ AND NEIL HODGSON, SEARCHER

In the slope of the passive Nova Scotian margin lies some of the most interesting geology in the world, that we are only now beginning to image. Beneath a thick Cretaceous and Tertiary clastic sequence lies a Triassic and Jurassic syn-rift on extended continental crust that grades out-board to variable magma-rich and magma-poor transitional oceanic crust. Out of that syn-rift, a huge volume of mobile salt has flowed reactively creating salt walls and diapirs, and in the early Tertiary this salt even spilled out on to the slope seabed creating a glacier of salt. Later, this salt itself got swamped and covered by large volumes of clastic deposits pouring off the Nova Scotian shelf.

Gas and oil have been discovered and produced on the shelf, yet on the slope, in the salt province, exploration has barely begun. It is here, where a series of open blocks are being offered in the current licence round, that an epic battle between evidence and misconceptions is being fought.

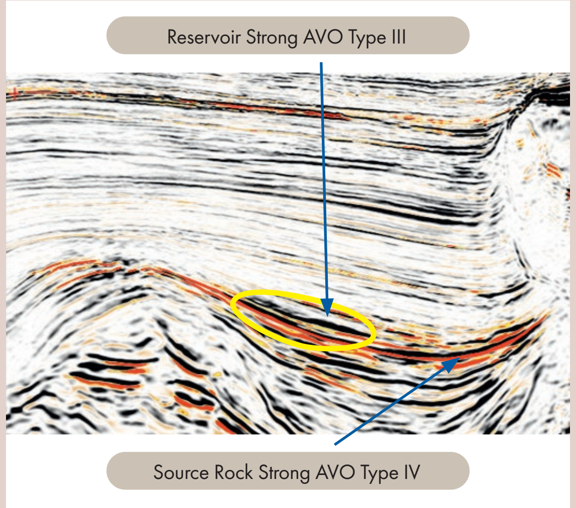


Figure 1: Seismic section from Tangier 3D displaying (Far Angle Stack- Near Angle Stack)*Far Angle Stack attribute. Red indicates a high-amplitude event associated with a decrease in acoustic impedance with amplitude dimming in the far angle stack (AVO Type IV). The black event inside the yellow polygon is a high amplitude event associated with a decrease in acoustic impedance but with amplitude brightening in the far angle stack (AVO Type III).

ABSENCE OF EVIDENCE

It is a commonly held belief that two of the principal players in hydrocarbon exploration off the shelf of Nova Scotia - source and reservoir, are profoundly challenged. It is true that the few exploration wells drilled do leave some elements unproven, but these are knowledge gaps, not negative evidence. Absence of evidence is not evidence of absence, and as Christopher Hitchens has written "what can be asserted without evidence can also be refuted without evidence." In our industry, the perception of a flaw or an "issue", let alone two, to a hydrocarbon system in glorious duality is both a huge obstacle and a huge opportunity.

THE VISIONARY ASPY WELL

New scenery on this particular stage: The discovery, in the visionary Aspy-1X sub-canopy well, of a section below the salt where silts and sand cuttings were oil-stained and fluoresced. Were this not evidence of source presence and effectiveness, then let this be conflated with the occurrence of multiple natural slicks and oil in sea bottom cores and the penetration of Middle Jurassic source rock in the along-strike Monterey Jack-1 and Cheshire-1 wells.

Additionally – one of the world's most rigorously acquired and processed wide Azimuth (WAZ) 3D datasets lies on this slope – the Tangier 3D. This dataset acquired in 2014 offers a cornicopia of fluid flow and direct hydrocarbon indicators, and Late and Middle Jurassic sections with strong type IV AVO anomalies that scream source rock. The lack of commercial success of Aspy-1X well can be ascribed to a lack of seal in the post-canopy pod/pre-canopy trap configuration, and the scarcity of reservoir rather than a lack of source.

NO SANDS?

The second conceit of the story concerns the lack of reservoirs in the few wells drilled into the Cretaceous on the slope, which showed limited development of Cretaceous sands. This led to the perception that there is no sand in the deep basin – despite its abundance on the sand rich shelf. In order to fully believe that, we would have to imagine that this huge sedimentary section, perhaps 0.5 trillion m3 of sediment, would be comprised only of muds and silts, and salt – no coarse-grained clastics at all. If that were the bet, the Tangier 3D is the weapon of choice to resolve this issue.

MEANDERING TURBIDITES

In a collaboration with Lyme Bay Geophysical, we have extracted attributes from the 3D that indicate huge turbidite channel belts flowing down the slope. Without the Tangier 3D though, such fairways would be desperately hard to identify – which, we believe has led to reservoir results in wells drilled to-date. Spectral decomposition along these channels demonstrates the internal character of meandering turbidite flow deposits, bright thalweg channels and lateral accretion packages deposited in channel systems that are limited by levees.

In places, these sand-rich channels have been caught by post-depositional salt movement and now lie in salt wall/salt diapir structural traps, with reservoir stacking similar to the significant recent discoveries in the Campeche Salt Basin offshore Mexico, such as the ENI Yatzil-1 2023 discovery. Elsewhere, channels are seen to run into salt evacuation derived mini-basins where the sands are deposited in fan-like bodies.

RE-WRITING THE NARRATIVE

The acquisition and thorough processing of the Tangier WAZ 3D has been the key to re-writing the narrative for the Nova Scotian slope basin. The imbalance in prospectivity analysis that relied on imperfect imaging and limited well data can be re-ordered by imaging of source and reservoir systems on this majestic dataset. The juxtaposition of reservoirs in mini-basin fans and structural traps in the Upper Jurassic and Cretaceous located on or directly above seismically identified Middle Jurassic source rock suggest uniquely low risk plays, where source and reservoir sat in perfect equipoise.

Searcher have mapped and evaluated a number of such targets, which are associated with positive AVO anomalies (Type 3) and structure conformable amplitude brightening (Figure 2). Taking conservative estimates of net thickness, porosity, oil saturation, Bo and recovery factors suggest individually that the prospects that we have identified routinely have **resource potential for 2 to 4 billion barrels of oil or oil equivalent.**

Our detective story on the Nova Scotian slope standing on the shoulders of exploration giants equipped with only 2D data to locate their wells, was set in a stage full of information gaps rather than hydrocarbon negatives. With the help of observations and analysis of one the world's most technologically advanced and beautiful 3D surveys, we can fill the gaps and reveal enough evidence for the trapping of material oil reserves in deepwater Nova Scotia to create a deeply analytical forensic thriller. Evidence from the Tangier 3D urges us to rise up and apply for acreage in the current Nova Scotian Licence round, "or at least look at the Tangier 3D - you have nothing to lose but your misconceptions." ■

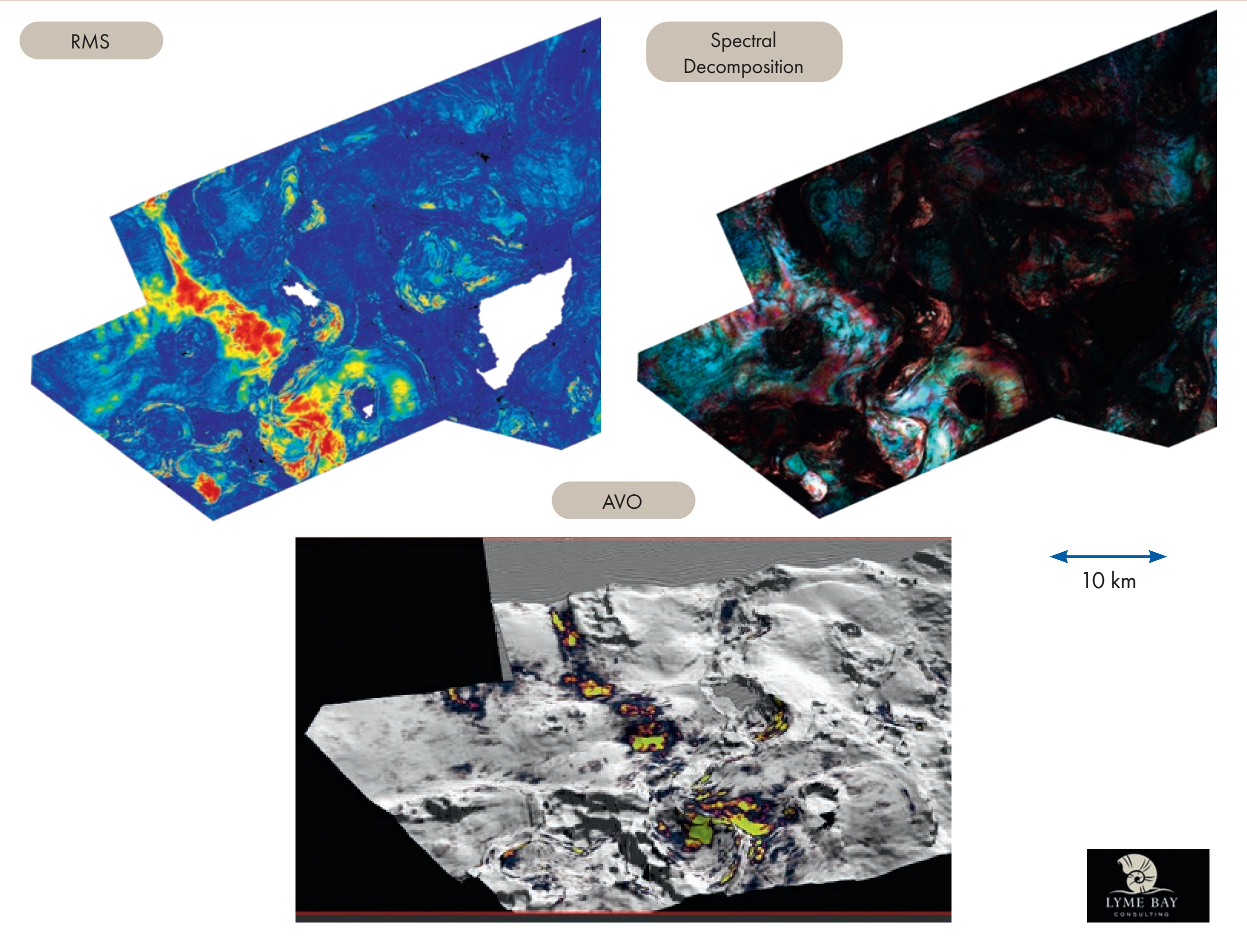


Figure 2: RMS Amplitude, Spectral Decomposition and AVO attributes extracted over an AVO Type III event directly overlying the Middle Jurassic source rock, in turn associated with an AVO Type IV event and oil seeps on the sea surface.

PORTRAITS AND INTERVIEWS

"Little did I know how this "decision" determined the rest of my career, as I took up natural sciences instead. And now, looking back, I think that the regime did me a favour!"

Helena Dobrova

A KEY MEMBER IN EUROPE'S UPSTREAM NETWORK

Born in Prague, Helena Dobrova witnessed how Europe became one as she gradually built up a network of upstream professionals that continues coming together until today.

I'M SO PLEASED to be able to organise in-person meetings again", says Helena Dobrova. "Soon, we will host our 56th event in Poland." Helena can easily be ranked as one of the best networkers in the European upstream energy business. She is the Executive Chairwoman of the Continental Europe Energy Council (CEEC) and has a long history in the European energy intelligence sector too.

Here, she talks about her academic career in Prague, how she scouted for subsurface data in Central and Eastern Europe for Geneva-based intelligence business Petroconsultants, and finally how she established the CEEC in 1994.

LIFE ON THE OTHER SIDE

"Our lives were good, but within strict limits", says Helena when we start our conversation about her life in Prague where she was born and raised. It was the time of the great divide in Europe, with the Central and Eastern European countries locked behind the Iron Curtain. "Probably the worst for us as young students was that we couldn't travel freely", she adds.

The communist party exerted strong control over decisions in people's lives. "For instance, I was told to give up my ambition to study languages, what I had preferred at the time", Helena says. "Knowing foreign languages was considered a threat to the regime. Little did I know how this "decision" would determine the rest of my career, as I took up natural sciences instead. And now, looking back, I think that the regime did me a favour! My interest in languages; I now speak seven and understand another seven, has been of great advantage for my future job in the oil business", she adds.

"Little did I know how this "decision" determined the rest of my career, as I took up natural sciences instead. And now, looking back, I think that the regime did me a favour!"

Helena studied engineering geology, hydrogeology and applied geophysics at Charles University in Prague, where she also got her Doctorate in natural sciences. Afterwards, she worked on hydrogeological and geotechnical projects for the local industry until the fall of the Iron Curtain in 1989, when everything changed.

SHEER COINCIDENCE

"After the political changes, companies, universities and institutions in the West were offering grants and work opportunities to people in the "liberated" Central European countries", Helena continues. Initially, her plan was to move to Spain, where she did a part of her Doctorate at the Universidad Politécnica de Minas in Madrid. However, things then took a different turn.

"It was a sheer coincidence that I ended up in Geneva", she continues. "A university friend had a connection in Geneva who wanted to speak to him about a position. But, as he already had another job in the US, he asked me to meet that person. This person turned out to be Bogdan Popescu, an executive of Petroconsultants who was responsible for foreign scouting. Shortly after, another Petroconsultants VP, Hans Oesterle, visited me in Prague and the rest is history. I was initially planning to stay for only a couple of years, but now here I am in Geneva, many years later!"

Why was a subsurface intelligence company like Petroconsultants interested in hiring someone from Prague? Simple, because the business needed ▸

PHOTOGRAPHY: AMAURY CHAMPION

Helena Dobrova
in Geneva.

Helena Dobrova in Geneva.

someone, preferably a geologist speaking languages and able to easily make contacts, to start scouting for data in an area nobody had been able to look at for decades. "I was from that region and understood the culture. It was certainly a special time", Helena recalls. "There was no data available from Central and Eastern Europe. We started from scratch."

"Throughout the years, we created a pretty good database and maps that, as we were told, were better than those issued by the countries themselves. Some people may still remember that Petroconsultants maps were highly appreciated in the oil industry all over the world."

From her early days at Petroconsultants, Helena remembers with a certain nostalgia her discussions with Harry Wassall, who founded the company back in 1956 in Cuba while he was working there as an oil geologist for Gulf Oil. "I actually spent a few years in Cuba when I was a kid, so we had something to talk about. It was thanks to my Spanish that I was also responsible for some Latin American countries for a couple of years too."

A GROWING NETWORK

Helena slowly built up a network of contacts and correspondents in the various countries in Central and Eastern Europe. "It was quite laborious, as any information related to the petroleum industry was regarded as highly confidential by the national oil companies. And the landscape was heavily dominated by national oil companies at the time", she explains.

"It took a lot of effort and time to sign DEAs (data exchange agreements) and generally we had to wait until the NOCs were privatised", Helena continues. "Important sources of information were government authorities responsible for licensing and data. But again, getting a cooperation agreement with them was particularly tough. On top of that, it is important to remember that all these relationships required careful maintenance and could also cease to exist at any given time", Helena explains. "With a change of a government or of a company management, which happened frequently, the negotiation started all over again", she adds.

"…the business needed someone, preferably a geologist speaking languages and able to easily make contacts, to start scouting for data in an area nobody had been able to look at for decades."

"The mood in energy companies in this part of Europe is a bit more upbeat than what I see elsewhere."

"When it comes to getting hold of data, Romania was probably the biggest challenge of all the countries in Europe", Helena continues, "even though all the countries in the region had their issues in terms of confidentiality. Sometimes it happened that the authorities were not even sure where the original data resided."

However, there were challenges to get hold of data in Western Europe too. "Accessing subsurface data in a country like Germany is still very difficult, mainly due to the fact that it is held by the individual states but also because of the complex licensing system."

BOOMS AND LULLS

When Central and Eastern Europe opened up in the early 1990's, oil companies from the West hoped that there were reserves left that could be discovered with modern technology. Many big companies including majors applied for acreage in countries such as Albania, Bulgaria, Hungary and Romania, only to find out a few years later, after a lot of exploration money was spent, that this was not the case. "This led to an exodus of foreign companies from Central Europe for quite a while", Helena recalls.

The shale gas boom that started here in the mid 2000's led to another huge wave of interest from international players, but now looking for unconventional formations. Especially Poland saw a swath of big companies coming in such as ExxonMobil, Chevron, Marathon, ConocoPhillips and also Talisman, BNK and San Leon. However, similar to the rush in the early 1990s, the initial interest in shale gas soon dissipated.

PHOTOGRAPHY: AMAURY CHAMPION

"This was partly because of serious civil unrest against shale gas operations in many Central European countries", Helena says. "And there was of course another good reason; the expected resources were not there or were not as big as initially anticipated", she adds.

STILL A PLACE FOR THE INDUSTRY

"That's not to say that there is nothing left to be found in Central and Eastern Europe", Helena stresses. "There was a lot of licensing and E&P activity in Ukraine before the start of the war. It is a matter of time until that resumes", she says. "The Black Sea is another example of an area of activity, with discoveries not only in Turkish waters but also in the Romanian sector."

"The mood in energy companies in this part of Europe is a bit more upbeat than what I see elsewhere", adds Helena. "The general feeling is that oil and gas will be part of the energy mix for the foreseeable future, as there will not be a good transition without energy security."

"And, even though the dependency on oil and gas imports to Europe as a whole will unlikely disappear as a result of major discoveries, for smaller and mid-size independents, niche as well as regional players, Central and Eastern Europe is still an attractive place to invest", continues Helena. "Favourable legislation, good infrastructure, a big market on the doorstep and a relatively safe environment are the reasons why this area is still attractive for many companies."

It was not easy at the beginning, as communication was very limited because of the completely different approach to data exchange. Instead of networking, the "Easterners" went shopping and the "Westerners" went to drink beer.

CEEC SCOUT GROUP

"In my early Petroconsultants days", remembers Helena, "when we had almost no information from the Central European region, my VP Bogdan Popescu had the bright idea to set up a local scout group that would bring Central European and Western companies together. And so we did, back in 1994, with eight founding members."

Until today, it is mainly the people working for the oil and gas operating companies and the associated upstream service sector who form the backbone of the scout group, which changed its name from Central Eastern Europe and Caspian Scout Group to the Continental Europe Energy Council. "But we also welcome representatives from NOCs, licensing authorities, investors and academia, gathering the entire energy-related "society" in Central Europe in one place", Helena stresses.

"It was not easy at the beginning, as communication was very limited because of the completely different approach to data exchange. Instead of networking, the "Easterners" went shopping and the "Westerners" went to drink beer", says Helena with a smile.

"Over the years, we have developed into a solid group that has clearly demonstrated its importance for the energy industry in Europe. We have expanded regionally to cover all of continental Europe and the scope of our activities now also includes geothermal energy, hydrogen and CCS."

"It was not easy at the beginning, as communication was very limited because of the completely different approach to data exchange. Instead of networking, the "Easterners" went shopping and the "Westerners" went to drink beer."

In 1998 and 1999, when the oil price fell dramatically, Helena feared that the group might cease to exist. Now, almost 25 years later, the organisation she is heading is preparing its 56th event in Torun, Poland in May.

Helena fully admits that the CEEC is an important part of her life. "Building relationships, facilitating networking and business discussions, and bringing all kinds of professionals in the energy business together continue to drive her. "When an executive of a US company once told me that he had never seen so many deals sealed at the bar, I knew that what I was doing made sense!" ■

Helena in the field with colleagues from Georgia Oil & Gas.

PHOTOGRAPHY: PRIVATE

GEOTHERMAL ENERGY

"Geothermal exploration is more like mining than oil and gas."

Elliot Yearsley

Geothermal energy production can be profitable

At the recent Seapex Conference in Singapore, reservoir engineer Elliot Yearsley gave an interesting account on geothermal energy production from volcanically active regions.

"IT KEPT ME IN THE JOB", said Eliott Yearsley when asked about scale and corrosion in geothermal wells by a participant of the Seapex Conference in Singapore.

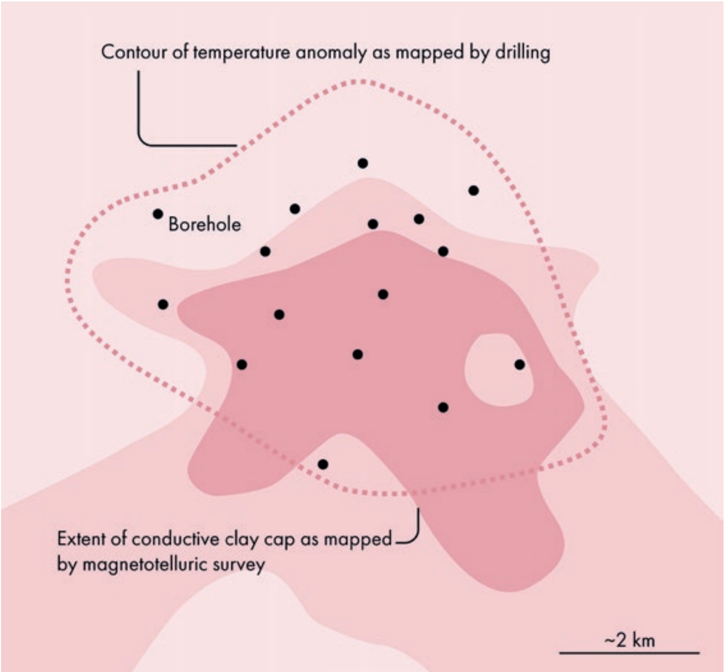
Yearsley had just given a presentation on geothermal energy production and the various projects he worked on in the past. "Scale is certainly an issue, to an extent that it was common practice to have two rigs continuously in operation doing workovers", Yearsley added as a reply to the question from the audience.

Despite this challenge related to scale and workovers required to keep geothermal wells flowing, Yearsley delivered a positive message to the audience in Singapore. "Geothermal is economic", he said on multiple occasions, "and can really make significant money." To illustrate this, he showed a basic calculation on the value of some geothermal fields.

In 2019, the Awibengkok field in Java (Indonesia) had a capacity of 377 MW and a total reserve base of around 67,000 GWh. Using his 1.5 barrels per MWh rule of thumb, Yearsley calculates that this geothermal "field" hosts an equivalent of 100 MMboe. A 100 MMboe field is certainly a reasonably sized oil accumulation.

> "Geothermal is economic and can really make significant money."

Extent of conductive clay cap superimposed on the field limits of Awibengkok, later proven by drilling (dashed line).



REDRAWN FROM: ACUNA ET AL. (1997)

ANOTHER WAY OF DOING EXPLORATION

Yearsley's talk addressed geothermal from a different angle compared to what is commonly done in low heat flow regions such as Northwest Europe. While geothermal exploration in Europe often comes with 2D or 3D seismic interpretation to map a potential reservoir, followed by drilling a single exploration well, the process to locate the highest temperatures in volcanically active areas works differently.

As Yearsley explained in his talk, there is often a conductive clay layer present on top of the geothermal reservoir. Magnetotelluric surveys are able to detect this clay layer, which can subsequently be used to map the geothermal "field". The map shown here provides an example of this from the Awibengkok field.

Unlike oil and gas traps, that are often clearly identified on seismic, the outline of a geothermal reservoir in a volcanically active area needs to be further constrained through drilling. "Rather than using expensive deep boreholes, small diameter (4 inch) holes are often sufficient to map the temperature anomalies", explained Yearsley during his talk. This does not implicate that these small diameter boreholes don't go deep; exploration drilling into the Awibengkok field reached depths of around 2,500 m. ■

A NEW SERIES

In the months to come, we will publish a series of articles from Eliott Yearsley, in which he will address key aspects of geothermal pumped wells such as subsurface characteristics, economics and energy calculations.

A potential depth record?

Geothermal well may be drilled to a depth of 7 km in the south of Poland.

THE WEBSITE THINKGEOENERGY reported in February that preparations were ongoing for drilling a geothermal well in the south of Poland, with a potential terminal depth of 7 km. Reaching this depth would be a global record for a geothermal well, according to the website.

What is the geological setting in which this well is being drilled? And how much is known of the geology at these depths?

FOREDEEP

When looking at the cross-section below, it is clear that the Podhale Basin, in which the well is being drilled, is a foredeep of the Carpathian Mountains in the south of Poland.

An overview paper, published by Wiesław Bujakowski and co-authors in 2020 in Geothermal Energy, deals with geothermal boreholes drilled in Poland and describes the Podhale Basin as a prospective region for geothermal energy production.

The authors also write that the most important geothermal aquifer constitutes Triassic limestones and dolomites, which tend to have low porosity. For that reason, flow is primarily dependent on natural fractures and faults.

TWICE AS DEEP

By 2020, a total of 15 geothermal wells had been drilled in the Podhale Basin, with the maximum depth reached being 3,600 m at the time. The authors further mention that the Triassic attains a thickness of around 700 m in the central part of the basin, which means that the succession marked as "Triassic?" in the cross-section below must also contain younger or older strata.

Regardless, drilling of a well twice as deep as the deepest well in the basin is not a trivial thing. Even though the location of the well has not been projected onto the cross-section, it is likely that it is targeting a more central location within the Podhale Basin where the Paleogene overburden reaches maximum thickness.

> "The Podhale basin already hosts the largest geothermal heating plant in Poland."

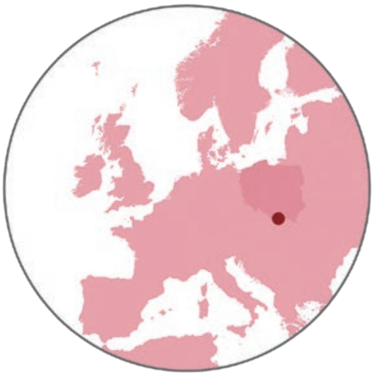
HIGH PRESSURE

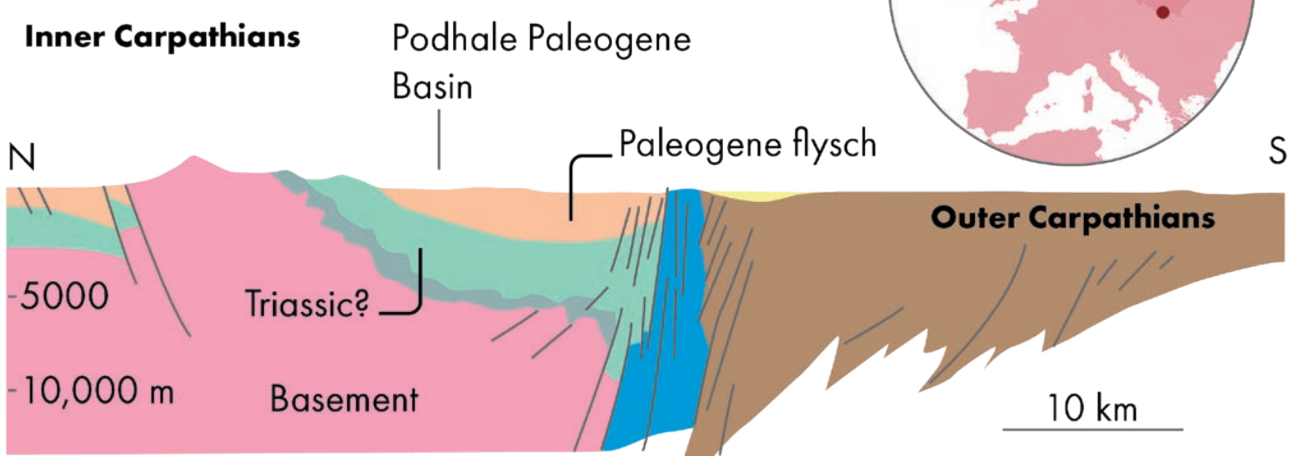
The authors of the paper also note that most wells drilled in the basin to date do not need any pumps because of high reservoir pressures (up to 27 bar).

Wellhead temperature of produced water in the basin varies from 20°C in the southern part of the system up to 90 °C in the central and western part. However, the authors note that temperatures of up to 120°C were recorded in deeper parts of the basin at a depth of 4,800 m, even though geothermal energy production never took place from that particular well.

The Podhale basin hosts the largest geothermal heating plant in Poland (40.7 MW of geothermal installed capacity, 82.6 MW total) as it produces water from the Podhale 1 mining area located in the central part of the Podhale geothermal system.

The ThinkGeoenergy website further mentions that the newly drilled well will provide heat to the village of Szaflary and its neighbouring places. Given the targeted depth and the expected temperatures, one would think that electricity generation is also part of the mix. ■





REDRAFTED AFTER BIRKENMAJER (1985)

North-south cross-section through the Carpathian Mountains in Poland, showing the Podhale foredeep where drilling of the deep geothermal well is planned.

The production chemistry challenges of geothermal energy

Production chemistry challenges in geothermal systems require high investments in materials to cope with corrosive fluids and high fluid flow.

THE GEOTHERMAL INDUSTRY requires a much tighter control on scale formation than the oil and gas industry", said Peter Wilkie from Roemex in a talk delivered during SPE's online Geothermal conference earlier this year.

"While hydrocarbons are non-corrosive, gases such as CO2 dissolved in formation water are", added Peter. Combined with much higher flow rates in geothermal wells – rates of 75,000 barrels a day are common – it is easy to see why there is so much more pressure on geothermal systems when it comes to materials used. In addition, it is also important to remember that geothermal doublets require the produced fluids to be re-injected into the same formation where mineral scale, accumulation of corrosion products and bacterial biofilms can cause issues.

Another major difference between oil and gas and geothermal is that in the latter, production of brines takes place directly through the casing, without a production tubing in place in a large part of the well. That has implications for the costs of maintenance if integrity issues arise in a geothermal well. If a casing is compromised, it is much more expensive to replace than part of a production tube.

EXPERIENCE IN THE NETHERLANDS

Wilkie spoke about his experience in the Dutch geothermal sector, where his company has worked on various geothermal projects. "The oilfield corrosion inhibitors used in the hydrocarbon industry have proven to pose challenges in a water-dominated system", he said. "It may lead to greasy residues that cause problems in injection wells. There are solutions for this, but we are now also using more water-soluble corrosion inhibitors that have shown to avoid these problems", he added.

North-south cross-section through the Carpathian Mountains in Poland, showing the Podhale foredeep where drilling of the deep geothermal well is planned.

Another challenge geothermal energy production is facing is radioactive lead (210Pb) deposition, both in the casing as well as in the heat exchanger. Even though it is also a known issue from the oil and gas sector, it is now also seen in many geothermal systems producing from the Jurassic Delft sandstone and the Permian Slochteren sandstone in particular, two of the most important geothermal targets in the Dutch sector.

The use of inhibitors has been shown to reduce the volume of lead deposition, "but the remaining issue with lead deposition is that the problem can only be relocated to another part of the system, but not entirely solved", said Wilkie. Glass Reinfored Epoxy (GRE) lining in the casing can prevent Pb to contact iron downhole, but this may then lead to problems at surface. "Very little technology is available to prevent elemental lead formation, which is key to achieving optimal production rates", Wilkie concluded.

SCALING IN HEAT EXCHANGERS

Scaling, or the precipitation of minerals from the produced brines, is very well known in the oil and gas sector. It is a challenge in geothermal systems too. Even though no incompatible brine mixing occurs as it is the formation fluids themselves that are being re-injected, the temperature drop in the heat exchanger at surface can cause mineral precipitation. "A thin layer of scale in a heat exchanger has an immediate effect on its efficiency", Wilkie said, "and can be observed in real time."

Unlike the oil and gas industry, where fluid re-routing is possible, geothermal sites have to inject all the fluids produced. "It is therefore key to ensure that injectivity of the reservoir is maintained", said Wilkie. A particular challenge observed is the formation of biofilms in the injection wells, which can reduce injectivity. Periodic biocide treatments can prevent and overcome downhole pressure increases.

Based on the findings presented above, it is not a surprise that Wilkie concluded his talk by saying that significant production chemistry challenges exist in the geothermal sector. It reinforces the need to use the best casing materials as possible, using corrosion-resistive alloys for example. Although this will have a knock-on effect on project economics, preventing issues is always better than curing. ■

PHOTOGRAPHY: GEERT-JAN VIS, TNO

The hurdles for deep closed-loop geothermal systems

In a recent blog post, Mark McClure from ResFrac discusses the challenges related to drilling complex wells to harvest energy through conductive energy transfer.

THE ECONOMICS for closed-loop geothermal systems are worse than for open-loop systems because of the much slower energy transfer", writes Mark McClure in an extensive blog post he published on LinkedIn in March.

Whilst a single vertical conventional geothermal well, which relies on pumping up hot water from a depth of around 1 to 4 km, generally produces around 4 to 6 MWe, a 7.5 km deep closed-loop system that includes 90 km of laterals all connected up to a single producer will yield between 2.2 and 8.6 MWe. It is not difficult to see how big the challenge is.

"In comparison, a conventional geothermal well drilled to these depths will produce 10 times more energy for 10 times less drilling."

At the same time, writes McClure, the temperatures at which multi-lateral drilling will need to take place greatly exceeds the temperatures seen in the oil and gas industry today. In O&G, a downhole temperature exceeding 150°C is already regarded as HPHT; the closed-loop multi-laterals will need to be drilled at temperatures of more than 200°C.

"In comparison, a conventional geothermal well drilled to these depths will produce 10 times more energy for 10 times less drilling", he concludes.

SEALING FORMATIONS

Another challenge that these closed-loop systems face is how the many horizontal sections or laterals will ensure that no leakage of fluids occurs – both into the wellbore as well as into the formation.

The many kilometres of drilled section cannot be cased, so will rely on another treatment to make the formation seal. Then there is the temperature drop that is to be expected when colder fluids are injected into the system, which may result in fracturing of the formation.

FRACTURES

Another solution proposed is to create hydraulic fractures around the well and fill those with a highly conductive material. However, as McClure argues based on published research, the contribution of thermally conductive fractures to the total amount of energy supplied to the wellbore is small. A thermal conductivity of at least an order of magnitude than any known substance would be required to make this solution work.

Lots of tubes will be required for the energy transition.

SOURCE: DALL-E

USING OLD WELLS

McClure concludes that retrofitting oil and gas wells with heat exchangers is basically not worth it at the present day, even though he does not write it in that way. Given all the work that needs to be carried out, which includes installing insulated tubing, a treatment to seal perforations and install surface facilities, a back-of-the-envelope calculation using a US shale well as an example results in an estimated 20 kWe. This translates to $17,500 a year. Will that pay for the work required?

It reminds me of Andy Wood's phrase "one megawatt at a time" when he speaks about the role of geothermal in the energy transition. Applying that to their closed-loop systems being fitted to old wells, it may rather be "one kilowatt at a time." ■

SUBSURFACE STORAGE

"When we can make it work,
it would be a very large deal."

Jack Norbeck, Fervo Energy

A typical Nevada landscape.

PHOTOGRAPHY: JAHONGIR ISMOILOV/UNSPLASH

"When we can make it work, it would be a very large deal"

A report written by specialists from industry and academia states that more than Houston-based Fervo Energy experiments using geothermal systems as batteries.

IN AN ARTICLE that appeared on the MIT Technology Review website in March, a summary of findings was presented on a new type of geothermal production test. Fervo Energy aims to pump fluids into a previously fracced reservoir that are subsequently produced at times of energy demand, in an attempt to counterbalance the fluctuations in energy supply from solar and The company has run field trials in Nevada, US, where it drilled an injector and a producer well into granitic and metasedimentary basement rocks with an elevated geothermal gradient. The wells reached a depth of around 2,500 m and both had a horizontal step-out of more than a kilometre.

Not only did Fervo Energy select the geological sites because of their geothermal gradient, but also because they are characterised by very low or no matrix porosities and permeabilities. The rationale behind this is that the fractures created during the fraccing operation generate a closed network that ensures pressures can be built up without dissipation.

> **FERVO ENERGY** was founded in 2017 by former drilling engineer Tim Latimer and Jack Norback. The company has since raised nearly $180 million in venture capital from Bill Gates' Breakthrough Energy Ventures amongst others. It has already announced several commercial power agreements for future geothermal projects, which include powering Google's operations in Nevada.

> "The fractures are able to dilate and change shape, almost like balloons."
> *Jack Norbeck, Fervo Energy*

Several tests have already been carried out where pressure was allowed to build for 8 to 10 hours, followed by the opening of the valves for an equivalent amount of time. The idea is to generate electricity from the heat that is produced. The article does not mention the amount of energy produced by the tests.

NOT WITHOUT RISK

Fraccing basement rocks is not without risk, as the article mentions too. Induced seismicity in a similar geological setting in Basel, Switzerland, resulted in a series of small earthquakes and termination of the project.

It is also the question of how many cycles of injection and production can take place before the produced water has cooled to such an extent that the operation becomes uneconomic. As we discuss on page 63 of this magazine, systems that rely on conduction are much less efficient than systems relying on convection. And the way the injected fluids are heated up in this project is through conduction.

Another risk to this type of project is the discovery of a natural zone of fractures that prevents the build-up of pressure. As we reported on in the previous issue (page 60), drilling in a similar setting in Australia resulted in the discovery of a thrust fault in basement rocks. Upon testing, it was only this thrust zone that accommodated the injected fluids, as evidenced by monitoring the multiple induced seismic events. ■

The challenge at Gorgon

During the recent SEAPEX Conference in Singapore, Chris Stavinoha from Chevron shared insights on the issues the company experiences with its flagship Gorgon CO_2 injection project.

EVERY CO_2 PROJECT will have its unique challenges", said Chris Stavinoha from Chevron during his presentation at SEAPEX last month. And as he explained during his talk, Chevron's Gorgon CO_2 injection project in Australia has got its own share of issues too.

The site is located on a small island (Barrow Island) just off the northwest coast. The CO_2 that is being injected is derived from a very local source; the Jansz gas field close by.

Chevron operates three drill centres, consisting of four wells each, from which CO_2 is being injected into the Lower Dupuy reservoir. Around three kilometres away from the injection site, Chevron operates a pressure management site, consisting of six wells in total, from which water is being produced from the reservoir where CO_2 is injected in. This water is subsequently re-injected into a shallower reservoir. Why was it required to drill production wells? That is very much related to the geological setting.

Stavinoha concluded his talk by emphasising that "We need to tell the story of carbon storage better." That is for sure, because people should be made more aware that the (hydro)geology plays an important role in the success of a project.

As Stavinoha put it during his talk, the carbon storage reservoir is confined when it comes to aquifer connectedness. He did not give a number on the exact size of the reservoir unit, but it was clear that in order to accommodate the injected CO_2 and the related pressure build-up, a way had to be found to release pressure in the reservoir. Stavinoha reiterated: "We have always operated under the fracture pressure, and we monitor this closely all the time."

The issue that the company has been experiencing relates to production of water from the reservoir, not to the injection of CO_2. Namely, the production wells have faced sand issues, to the extent that the formation around the wellbore gets clogged up and sand is also being produced together with the water. As Stavinoha put it in Singapore: "These wells make a lot of sand."

For that reason, Chevron is now working on a project that includes drilling two new water production wells and also side-tracking the existing producers, aiming to better manage sand production.

"These wells make a lot of sand."

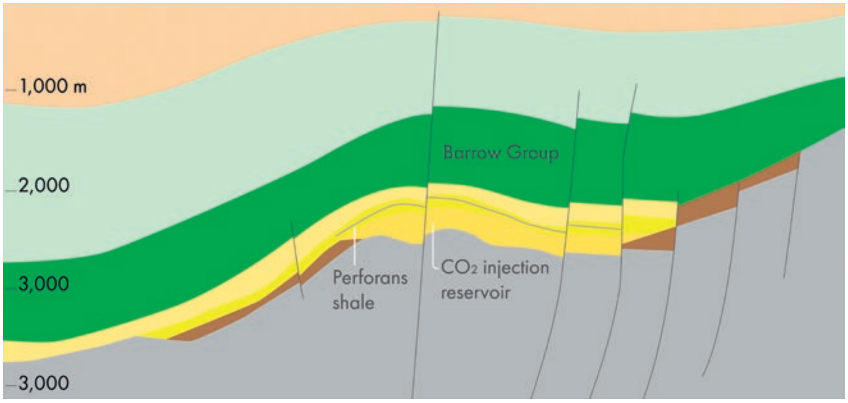
MONITORING

Apart from drilling new wells, Chevron also monitors the CO_2 plume regularly, every one to two years. "So far", said Stavinoha, "we have obtained an excellent match between the predicted CO_2 plume growth and what we observed on our surveys." He showed a map of the extent of the reservoir extent, with the injection wells indicated. The CO_2 plumes showed up as nice circular blobs around the wells, with a diameter of around 500 m.

"With a projected life-span of 40 years, it is good to see that injectivity is above expectations and that the plumes behave in a way as predicted," Stavinoha added. ■

PROJECT TIMELINE

FID on Gorgon was taken in 2009, but it lasted until 2019 until the first CO_2 was injected. The plan was to inject up to 4 million tonnes of CO_2 a year, but due to the pressure and sand production issues, the current rate of injection is limited to 1.6 million tonnes a year. So far, around 7 million tonnes have been injected, which still classifies Gorgon as one of the biggest CO_2 storage projects globally.



Schematic cross-section through the Gorgon CO2 injection site.

REDRAWN AFTER FUNNELL ET AL. (2023)

Irina Gaus and Michael Köbberich at DIGEX 2023.

Spotted at...

Geologists from Swiss Nagra visit DIGEX 2023 to hear more about subsurface modelling.

A CONFERENCE ABOUT DIGITALISATION and subsurface data in Norway – it is a platform where one would mainly expect people from energy companies and the related service sector. But the theme of the recent DIGEX conference also reached beyond the "usual suspects".

During the evening drinks, we met geologists Irina Gaus and Michael Köbberich from Nagra, the Cooperative that is currently working on plans to construct a geological disposal site for nuclear waste in Switzerland.

In recent years, Nagra collected a vast amount of geological data, mainly from an area in the north of the country where conditions for building a site looked promising. Several boreholes were drilled and completely cored to gain a comprehensive understanding of the Middle Jurassic Opalinus Clay and its over- and underburden. In addition, a 3D seismic survey was acquired to better map the subsurface.

The Opalinus Clay is the main candidate for construction of the facility, thanks to its favourable thickness and fine-grained lithology. Following the analysis of the data acquired, Nagra has recently selected a smaller sub-area that will now be subjected to an even more detailed subsurface study.

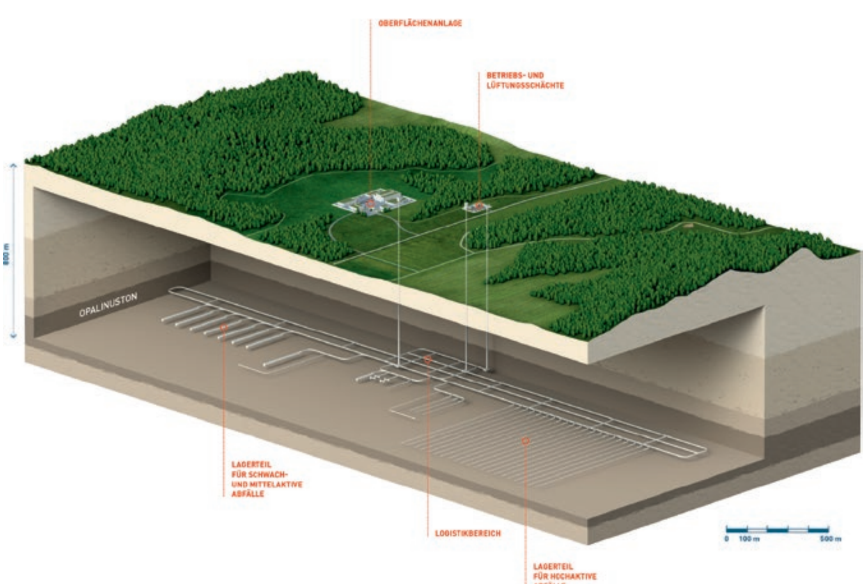
"As we have narrowed down on a site for further study, the next step in our project is to build a detailed subsurface model of the area. We are at this conference to hear what the current state of knowledge and development in the field of subsurface modelling and digitalisation is", said Irina.

A NEW DEPARTMENT

The timing of attending the conference is good, as Irina is the head of a new department within the Nagra organisation called Optimisation from the 1st of April. "This is our first month as a new department within Nagra, and it is the members of this group who will be involved in the next step of the project, to bring all the data together", adds Irina.

Michael will be part of Irina's team. Having worked as a BIM manager at Nagra before, he brings the right skills to the team. BIM stands for Building Information Modelling, which is a method used in engineering that involves the digital representation of complex construction projects. "Having been exposed to the engineering side of things, we now want to ensure that our building and subsurface models are even better coordinated in the future", adds Michael.

"We have gained a good understanding of what is happening in the digital subsurface community", concludes Irina during one of the coffee breaks, and "we surely take a lot of new insights and new connections home to Switzerland." ■



Artist's impression of the geological storage site for waste disposal in Switzerland.

PHOTOGRAPHY: HENK KOMBRINK; SOURCE: NAGRA

Producing more from Norwegian oil fields without impacting the climate

Norway can significantly increase oil production from several fields and at the same time contribute to climate targets. But then we have to take action now.

THE ANSWER IS A DEFINITE YES", says Ole Gunnar Tveiten, geologist at AGR, regarding the possibility for Norway to maintain oil production in the years to come and at the same time reducing emissions of CO_2.

CO_2 DISPLACES THE OIL

"CO_2 for increased oil recovery - CO_2-EOR (Enhanced Oil Recovery) - is a method that can help us make better use of our producing fields, while at the same time removing CO_2 from the atmosphere", explains Tveiten.

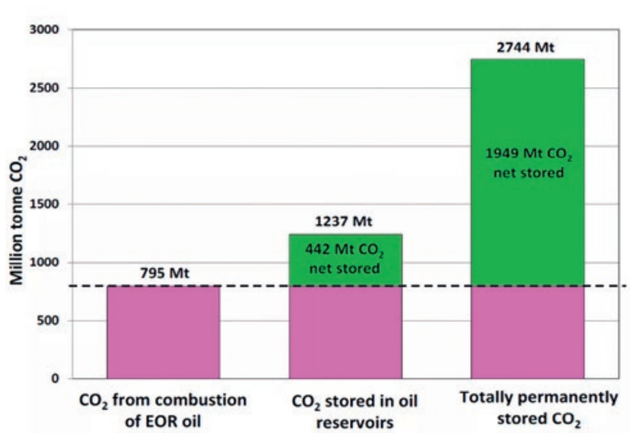
CO_2-EOR is well known, both in Norway and in a number of oil-producing countries such as the USA, Canada and China. The Norwegian Petroleum Directorate, Sintef and other Norwegian professional groups have been conducting research on CO_2-EOR for a number of years.

In short, the method involves injecting CO_2 into a producing oil field in order to increase the recovery rate. According to Tveiten, CO_2 is very suitable as a medium for this.

"When CO_2 gas is injected beyond at least 800 m depth, it is compressed into a liquid as a result of pressure. This liquid has similar flow properties to oil, and thus displaces the oil from the pores better than water does", Tveiten explains.

CLIMATE-FRIENDLY TAIL PRODUCTION

A report prepared by NTNU, based on 30 years of experience from dozens of other oil fields in the world, shows that the recovery rate can be increased by 7-15 percent relative to the oil originally in place.



This graph from a study carried out by Sintef (Lindeberg et al., 2017) shows that CO_2-EOR on the NCS can result in a net removal of CO_2 from the atmosphere. Purple columns show emissions of CO_2 from burning the extra volumes of produced oil. Green bars show net stored CO_2.

From a climate perspective, oil production is assessed based on kg CO_2 per barrel of oil produced, which also triggers a CO_2 tax. In certain mature fields on the NCS, emissions per barrel are increasing strongly as a result of high water cuts of up to 98%. The Johan Sverdrup field, however, pulls down the average for the NCS significantly.

"Increasing the oil output during the final years of production can therefore help reduce greenhouse gas emissions per barrel of oil produced. Injection of CO_2 that is permanently stored can be added to that", Tveiten argues.

The geologist also refers to a study carried out by Sintef in 2017 where the researchers identified 23 mature oil fields in the North Sea where CO_2-EOR could be suitable, including Ekofisk, Brage, Oseberg Sør, Troll, Gullfaks, Snorre and Statfjord.

In the study, it was simulated that if up to 70 million tonnes of CO_2 per year were injected into the 23 fields over 40 years, it would have led to the extraction of 1.8 to 2 .2 billion extra barrels of oil. This corresponds to the entire Snorre field. As a comparison, Norway's total emissions are approximately 50 million tonnes of CO_2 per year.

CO_2-EOR CAN BE PROFITABLE

Today, existing projects and ongoing developments are far from good enough to achieve climate goals. Longship – the most advanced CCS project in Norway - has cost NOK 27.6 billion, of which NOK 17.9 billion has been financed by the Norwegian state and taxpayers. However, the capacity is a fraction of the 300-600 million tonnes of CO_2 per year that the EU has set as a target to store by 2050.

"We would benefit from seeing concrete plans for large CO_2 storage sites, but that can be expensive. The degree of state funding in other countries is, to put it mildly, uncertain", Tveiten adds.

The geologist does not envisage that CCS as a climate measure will succeed unless the projects are profitable. In this context, CO_2-EOR scores well.

"EOR extends the life of fields, which means reusing existing infrastructure and providing funds to finance new CO_2 storage projects. It will also reduce the environmental and climate footprint", claims Tveiten.

WE ASK WHY CO_2-EOR HAS NOT BEEN ADOPTED IN NORWAY.

"We have not had CO_2 available for injection, as they have had in the USA and Canada. The research that has been performed in Norway on CO_2-EOR has been done under the assumption that the greenhouse gas will at some point become available in the North Sea", Tveiten says.

At this point in time though, it is unlikely that a CO_2-EOR project on the NCS could be realised through importing the gas. The explanation for this lies in the fact that in 2020 the EU launched a classification system (taxonomy) for sustainable activity.

"The European Commission's taxonomy for the phasing out of fossil energy lays down very strong guidelines for, among other things, the financing of projects. An EOR project cannot qualify for support from the EU, and will also have problems obtaining other funding from institutions and investors because it is not properly labelled as green", Tveiten adds.

The result is that oil companies in Norway, and in other oil-producing countries in Europe, will be reluctant to make such investments. Without external funding, they will carry all the risks themselves.

RESEARCH ON CO_2-EOR: POSITIVE FOR THE CLIMATE

Tveiten believes that CO_2-EOR can and should be accepted by the EU in light of the energy crisis and the important role Norway has gained as the largest and most stable supplier of gas to the continent.

Furthermore, the EU has very high ambitions for CCS – several hundred million tonnes of CO_2 are to be stored annually by 2050 – but very little has so far been realised.

"It has been documented in several reports that CO_2-EOR stores more of the greenhouse gas than is emitted through burning the extra oil we collect. The accounts are climate-positive and profitable", Tveiten argues.

One of these reports is the Sintef study from 2017 mentioned earlier in the article, which focused on the EOR potential for Norwegian oil fields. The diagram shown here clearly depicts that CO_2-EOR on the 23 Norwegian oil fields will store more CO_2 than what is released into the atmosphere by burning the extra volumes of oil.

IT'S URGENT

"If logic and common sense prevail, we should be able to expect good news from Brussels." Tveiten is cautiously optimistic, but stresses that it is urgent. "Time is running away from us."

"The method is time critical. On the NCS, we have many fields that are nearing the end of their lives, they are nearing shutdown, and when that first happens, the infrastructure is dismantled. In addition, it often takes two to three years to carry out the necessary CO_2-EOR studies for a given field, so if this is something we want to realise on the NCS on a larger scale, we must get started."

Tveiten believes that CO_2 for increased oil extraction is feasible in Norway even without "the green stamp", as long as the will is there. "However, at the Ministry of Petroleum and Energy, the Norwegian Petroleum Directorate and the largest players on the Norwegian continental shelf, it seems that the taxonomy dominates the decisions."

NOT FULLY DEPENDENT

Tveiten further points out that we are also not fully and completely dependent on deliveries of CO_2 from Europe to make this happen.

"A Norwegian offshore gas power plant, powered by Norwegian gas, and which captures and stores the CO_2 emissions through CO_2-EOR would be one way to do it."

But also in Norway, a gas power plant with capture and storage of CO_2 will be subject to the EU Commission's taxonomy system, which makes financing more demanding.

The geologist is an advocate for CO_2-EOR as one solution that can secure Norwegian supplies of low-emission oil in the coming years, which also means getting a step closer to zero-emission targets. "The method should be part of the energy transition", he says.

"CO_2 for increased oil extraction is certainly something that should be able to happen. It is a self-financing climate measure and should be able to fall under the EU's taxonomy as sustainable. I hope that politicians and governing authorities make arrangements for CO_2-EOR to be realised on the Norwegian continental shelf", concludes Ole Gunnar Tveiten. ■

Characterising CCUS sites: Legacy data. Powered by machine learning

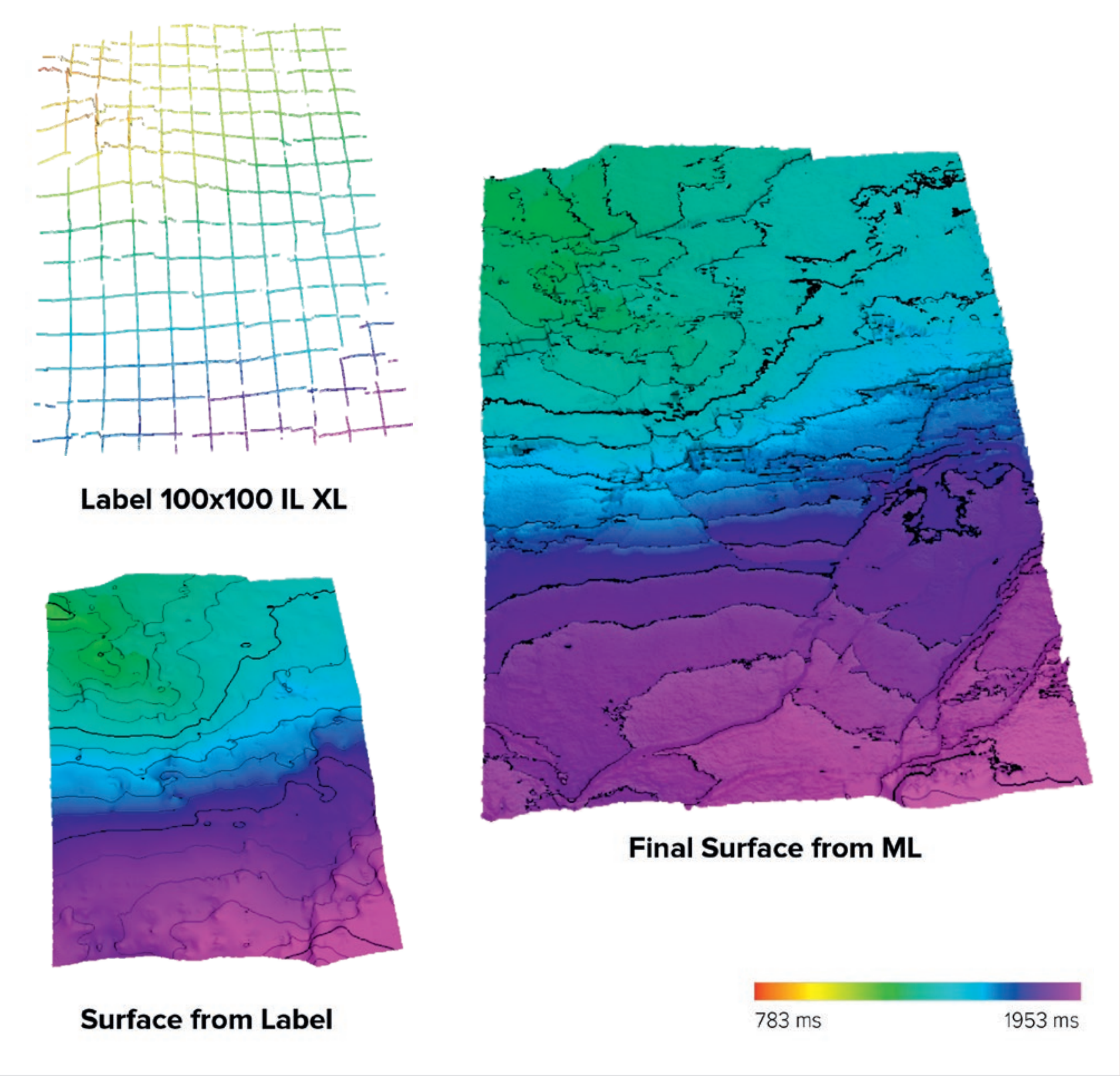


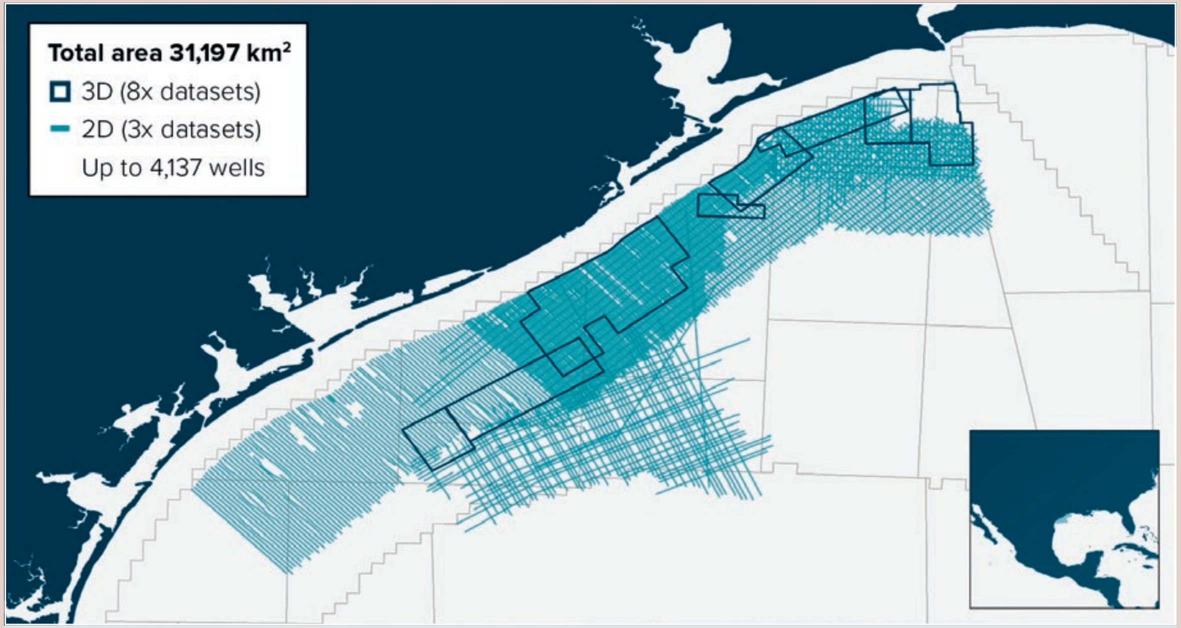
Figure 1. From labels to insight, ML has fast-tracked horizon identification

CCUS is widely accepted as a vital emissions reduction technology to mitigate the effects of climate change. The initial candidate locations to inject CO_2 into the subsurface are likely to be areas of prolific oil and gas exploration and in close proximity to anthropogenic sources of CO_2. Examples of this include areas with good infrastructure and favourable geology that have been well documented.

With many places worldwide fitting these criteria, shooting new seismic to cover each promising area is an unrealistic cost. Therefore, returning to legacy data and using a machine learning approach to rank areas is a cost-effective tool that can be deployed worldwide to provide insight into potential locations.

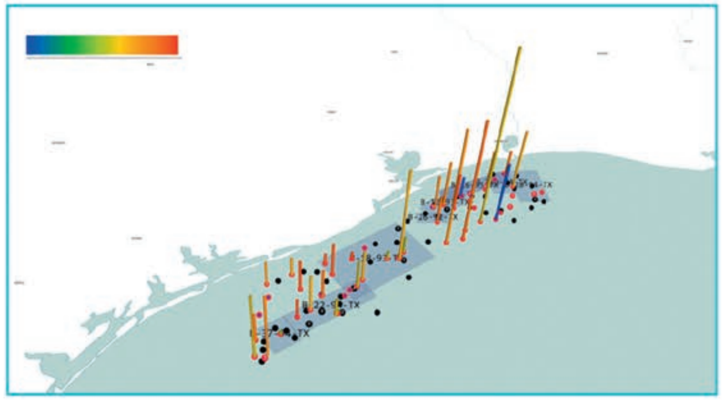
Geoex MCG

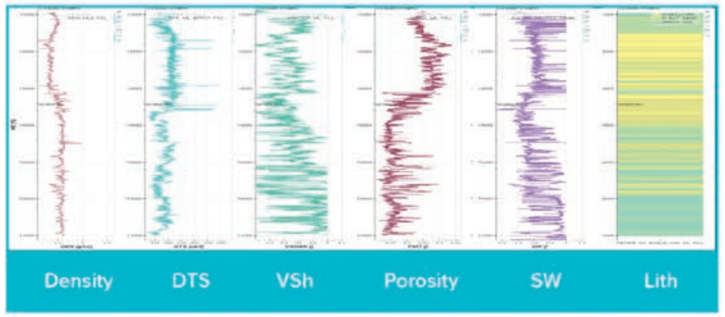
EARTH SCIENCE ANALYTICS



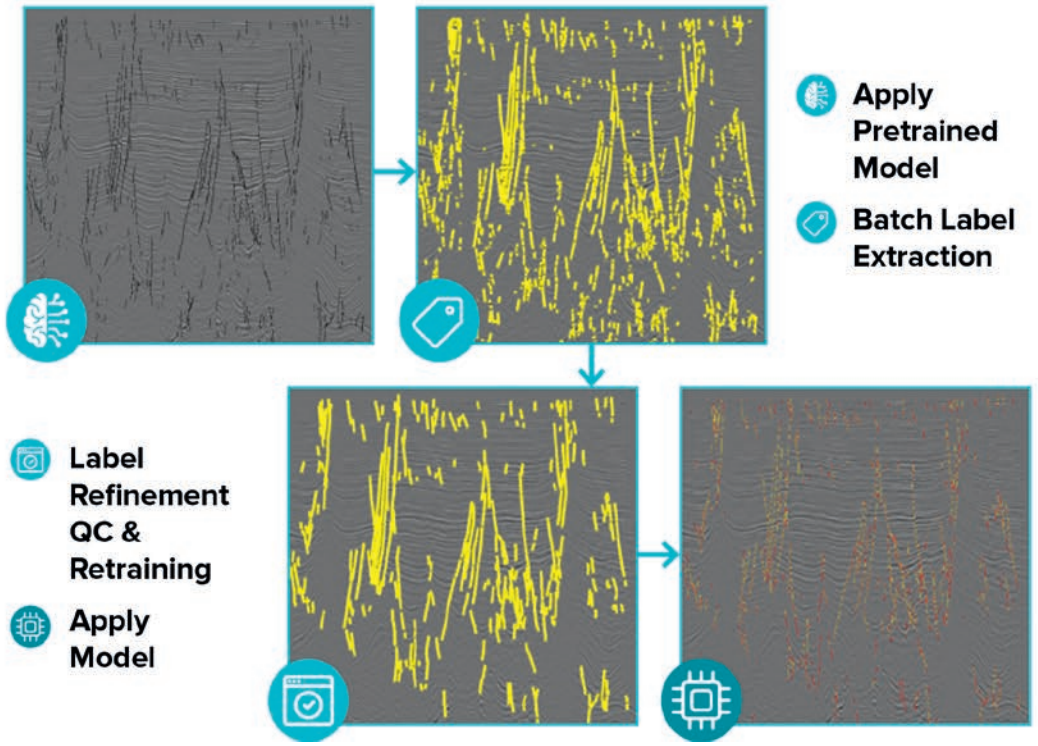
Map: AOI with conditioned, integrated data, extent ranges from High Island to Brazos.

BASINS SCALE PROPERTY QUERIES

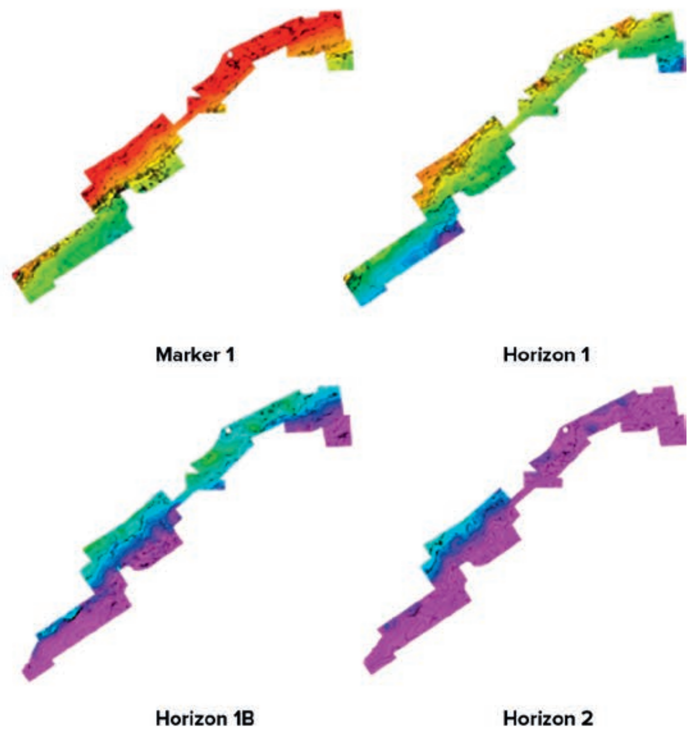




AUTOMATIC FAULT INTERPRETATION



ML DERIVED HORIZON PREDICTION



The US GoM and beyond

A clear candidate for CCUS is the US Gulf of Mexico (GoM). Exploration has been ongoing in the region since the late 1930's meaning there is a plethora of information about the offshore from many operators. As a result of this exploration, plentiful infrastructure already exists which would ease the transition from oil and gas exploration and production to CCUS injection.

MIKE POWNEY[1], JENIFFER MASI[1], DAN AUSTIN[2], THERESIA CITRANINGTYAS[2], MONIKA DYRENDAHL[2], BEHZAD ALAEI[2], ANASTASIIA JACOBSEN[2], SHARON CORNELIUS[3], FELIX DIAS[3] AND PETE EMMET[3]
GEOEX MCG[1], EARTH SCIENCE ANALYTICS[2], BVGS[3]

HISTORY OF THE GOM. CCUS POTENTIAL?

The geological history of the GoM is particularly favourable for injection. Characterised as having a two-phased opening, the first phase of rifting began in the Late Triassic to Early Jurassic with the separation between the South American and African plates. Subsidence followed during the Early to Middle Jurassic before the Yucatan block drifted in a counter-clockwise direction, initiating the second phase of rifting. From the Early Cretaceous through to the Paleocene, a significant sediment succession was deposited in the basin.

Deposition continued through to the Early Eocene, decreasing temporarily in the Late Eocene. The Miocene is a key interval for CCUS injection as it is at a significant depth to remain in a supercritical state, as well as having sufficient porosity to store CO_2. The Miocene is dominated by fluvial deltaics, but there is a significant migration of deposition eastwards from the Paleocene-Oligocene to the Mio-Pliocene.

The Miocene interval represents a sufficient reservoir for CO_2 storage as well as having thick seals above the reservoirs. Seismic data and detailed interpretation are instrumental to improving the understanding of the implications of injection.

LEGACY DATA, PREPPED FOR THE FUTURE

To screen potential locations for injection, publicly available legacy data from the BOEM website has been utilised. Eight 3D's and three 2D's, covering a total area of 31,197 km2 from 'High Island' to 'Brazos' have been analysed for this study (Figure 1). This AOI was selected following the analysis of areas with good seal and reservoir potential from available data.

The data in question vary in vintage from 1984-1996. Consequently, the image quality is highly varied. For Machine Learning processes to characterise sites effectively, conditioning was required to create useable volumes. Initially, the frequency spectra for each 3D were investigated to identify the most consistent survey.

Once selected, conditioning was completed in a radial pattern from the 'reference survey' until each survey had been conditioned. This conditioning workflow is summarised below:

- Ensuring that datasets were internally consistent
- Comparing the 3D frequency spectra to define reference survey
- Bulk scaling of amplitudes
- Completing mistie analysis of seismic volumes to reference survey
- Balancing vertical amplitudes
- True Amplitude Frequency Equalization (TAFE)
- Matching of phases and wavelets

Below is a before and after image of an arbitrary line through some of the volumes (Figure 3). The upper image shows the volumes at the same amplitude before any processing has taken place. The amplitudes here have the same range but vary drastically. Some of the amplitudes are far too strong, others are 'washed out' by the large range.

The final image is shown below, although some joins in the data can be seen. The overall amplitudes are now comparable and ready for Machine learning. Unfortunately, no information was provided on any of the volumes to understand processing sequences. Field tapes were inaccessible too, meaning inherent issues within the data could not be removed.

Better understanding lithologies was now the focus. Within this area, approximately 4,137 wells were available for use. To find the most appropriate wells in the context of CCUS site selection, a series of criteria were applied. Crucial elements in the selection of wells included: availability of paleo reports, check shots, digital well logs and areal distribution. The well data also varied in quality with vintage. From this process, 132 wells were selected in total. For direct comparison between wells, a standardized nomenclature of tops was created.

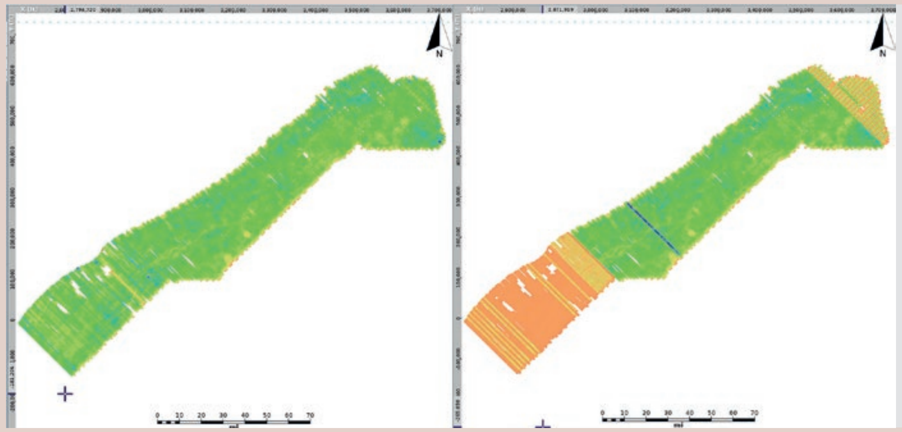


Figure 2. Inherent differences exist in the data; it is important to correct these differences before balancing.

REDUCING TIMESCALES, GENERATING VALUE

To interpret the seismic data, Earth Science Analytics' Data management and Machine Learning (ML) EarthNET software was used to create fault probability volumes. These volumes were subject to several iterations to remove 'false positives', improving the veracity of the results. Unassigned fault sticks were then deduced to give a good overview of the structural complexity of the AOI. The next step was horizon interpretation. For this process, a supervised learning approach was used. Labels of the various key horizons for reservoir and seal were picked and used to create accurate horizon interpretations. ML models were trained to predict the horizons from full-stack seismic data, which was then applied over the entire study area. This combined with the structural analysis allowed an initial ranking of key areas.

A further analysis was completed using the information from wells, where logs were compiled and conditioned to produce reservoir and seal properties including lithology predictions. EarthNET 1D workflow was used to build a contextualized and indexed dataset. The workflow includes comprehensive well log QC, completing missing log predictions and reservoir and seal property predictions. The conditioning of well logs involved removal of nonphysical values, interpolated zones, and flagging data of poor quality.

For missing log predictions, multiple models were trained with available logs at each depth. Models with a higher number of logs usually have a higher accuracy but often lower coverage. With fewer logs, the coverage is often better, but the accuracy is decreased. In this sense, a 'fill in' technique is required in areas with high coverage and less data to prioritise logs that are more reliable. The training process is supervised, ML metrics as well as blind testing are used to verify the performance of the models in addition to a geological sense check.

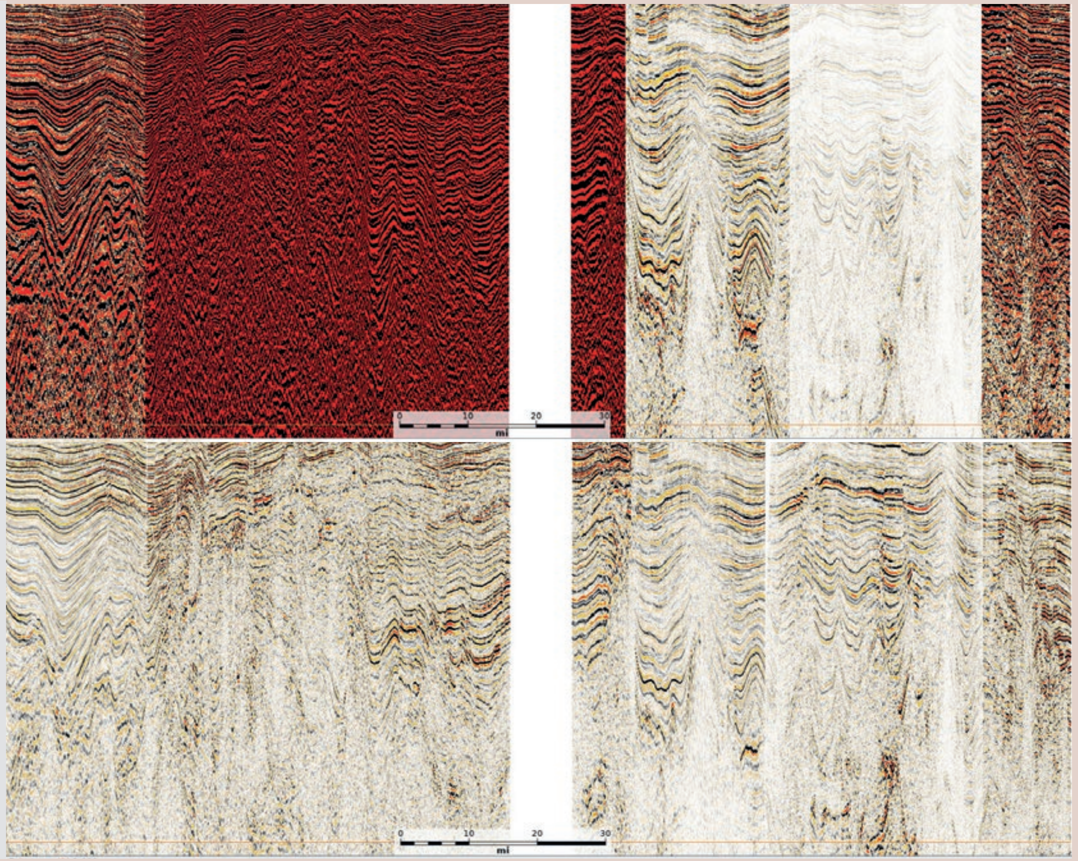
WORLDWIDE IMPLICATIONS

The culmination of this analysis allowed us to make informed choices regarding the most suitable sites for CO_2 injection. These locations were further screened for their viability to contain CO_2 by evaluating implications of the pressure environment and potential volumetrics.

Using ML techniques with legacy data, workflow timescales have been significantly reduced. The processes described above allow for legacy data to be repurposed, and when combined with ML, generate an incredibly powerful workflow to rank sites in large areas. Decision-making time is significantly condensed.

This process allows ranking of areas, reducing both cost and time, and can be developed for other regions in the world. For injection to take place, there may remain a need to shoot modern seismic to fully understand the nature of the subsurface, as there is a limited amount of conditioning that can be undertaken until a new shoot is required. ■

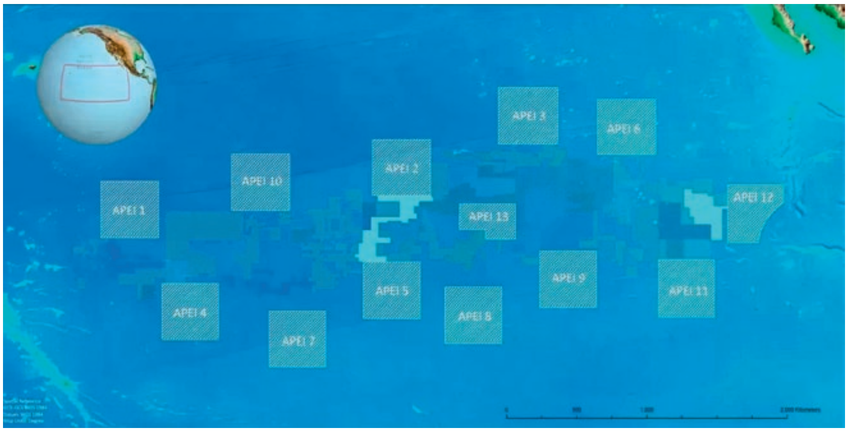
Figure 3. Conditioning workflow images – Before and After.



DEEP SEA MINERALS

"Intensification of public and private mapping is essential to ensure Norway a greater role as a producer of sustainable raw materials for the green industry of the future."

Torgeir Stordal – NPD and May Britt - NGU



Map of the polymetallic nodules licence area of the Clarion Clipperton Fracture Zone. The UKSR licence areas are shown in light blue.

Taking a big chunk in the Pacific Ocean

Loke Marine Minerals acquired two large seabed mineral licenses in the Pacific Ocean and is aiming for production in 2030.

NORWEGIAN LOKE MARINE MINERALS (Loke) aims high in international waters. In March, the company announced that it is acquiring UK Seabed Resources (UKSR), which fully owns two deep-sea mineral licences in the Pacific Ocean. UKSR also has a 19.9% stake in the Ocean Minerals Singapore ISA licence.

The licences cover areas in the Clarion-Clipperton Zone (CCZ), which is considered the world's largest field of nodules with the world's largest undeveloped deposits of the battery metals nickel and cobalt. The CCZ is located between the west coast of Mexico and Hawaii. Nodules are metal-rich tubers that grow on and in the sediments on the seabed.

The acquisition of UKSR from Lockheed Martin UK provides Loke with an exploration area of approximately 133,000 km2. This corresponds to roughly a third of Norway's area including Svalbard.

"The acquisition accelerates Loke's exploration plans and the ambition to deliver safe production of nodules with minimal environmental impact", says Walter Sognnes, managing director of Loke. Sognnes further said that the company aims to make an investment decision in 2027 and start the production of nodules in the CCZ in 2030.

TECHNOLOGY TRANSFER

Since its inception in 2019, the company has worked on technology development related to the exploration and extraction of deep-sea minerals. Both Sognnes and several of his colleagues have a background in the oil and gas, and service industry and know that there is great potential for technology and expertise transfer towards seabed minerals.

In connection with the acquisition, Loke brings in new capital by introducing the Kongsberg Group as a new industrial investor. The Kongsberg Group is a technological leader in maritime and petroleum activities, and through the agreement, the two parties have formed a closer collaboration.

NORWEGIAN WATERS

In Norwegian waters, Loke Marine Minerals has ambitions to extract manganese-rich crusts. However, this requires the government to go ahead with the ongoing opening process of the investigation and extraction of deep-sea minerals on the Norwegian continental shelf.

Last autumn, the Ministry of Petroleum and Energy published an impact assessment. They have subsequently received input from the consultation bodies and intend to submit a parliamentary proposal on the opening of the Norwegian continental shelf for mineral activities this spring.

At the end of January, the Norwegian Petroleum Directorate published the long-awaited resource assessment for minerals on the Norwegian continental shelf. They reported significant quantities of copper, cobalt, gold and several other metals.

Green Minerals has also shown an interest in the Pacific Ocean. In January, the company announced that it had issued a letter of intent regarding the acquisition of a licence. The Clarion-Clipperton Zone is located in international waters, and it is the International Seabed Authority (ISA) that manages the resources in these areas. ■

RESOURCES

The current resource estimate for the two licences is 750 million dry tonnes of polymetallic nodules. These numbers are expected to be revised upwards following new resource surveys planned for the coming years. The nodule resource estimate corresponds to:
Nickel resources – 10 million tonnes, Cobalt resources – 1.4 million tonnes, Copper resources – 8 million tonnes, Manganese resources – 210 million tonnes.

SOURCE: ISA

Positive to possible opening

Aker BP is positive about the opening of mineral exploration licences on the Norwegian continental shelf so that companies can carry out surveys. However, the operator will only consider mineral extraction if it is environmentally and economically sound.

THAT IS WHAT AKER BP wrote in a press release earlier this year. At the same time, the company stressed that it has not decided on whether it will apply for acreage once a bidding round would open. Regardless of the ultimate decision, it is clear that Aker BP is closely following developments in the deep-sea minerals space, given that it is involved in several projects to gain a better technical understanding of the matter.

This includes the project ***Seabed Minerals - Accelerating the energy transition***, in which 15 companies and specialist communities participate. The aim of the project, which secured funding in December last year, is to establish a basis for an integrated value chain for seabed minerals in Norway. The project has received financial support from the project partners to develop tools and technology that will minimize the footprint and reduce emissions at all stages of the mining process.

A HANDBOOK

It has also emerged that Aker BP, as part of an international consortium, is participating in the ESG Handbook project. The "Handbook" is intended to be established as a guide and common methodology for the industry that works with deep-sea minerals, stipulating which topics must be reported and how. The overall goal is a transparent and uniform way of reporting, which provides ESG improvements and ensures financing of the best projects. Equinor also participates in the project, even when the company recently stated that "seabed minerals are not part of Equinor's strategy or investment areas."

CONSULTATION

Aker BP further writes in the press release that they are awaiting the government's summary of the ongoing consultation round.

"If there is an opening for exploration licences, we will consider participation in order to obtain data on the resource potential, economic and environmental impact. In line with our strategy, we will contribute knowledge, data and experience to new industries, where, in addition to producing oil and gas, we can create significant income for owners and the state."

The current consultation round came in the wake of the impact assessment that the Ministry of Petroleum and Energy published last autumn. The intention is to put forward a parliamentary proposal on the opening of the Norwegian continental shelf for mineral activities this spring.

It is just a few months since the Norwegian Petroleum Directorate released the long-awaited resource assessment for minerals in the deep sea. Despite a sober presentation, the estimates show that the Norwegian continental shelf has great potential in terms of metal deposits, many of which will play an important role and will be in high demand in the energy transition (renewable energy production and electrification of mobility solutions). ■

"The search for seabed minerals requires Norwegian oil technology to be fully utilised, and to increase knowledge of the environment in the deep sea, it is absolutely necessary for the industry to invest."
Aker BP

Resinated cores collected from the NPDs drilling campaign at the Mohns Ridge in 2020. Darker areas are sulphide materials, while the lighter grey are basaltic rocks.

PHOTOGRAPHY: NPD

Directors with a shared goal

The Norwegian Petroleum Directorate and Norwegian Geological Survey do not disagree as much as the national broadcaster would have it regarding the knowledge base for marine mineral resources.

THE DIRECTORS BELIEVE that Norway must intensify seabed mapping and open up areas to concretise resource estimates and utilise these in the long term.

In a joint press release, the Norwegian Petroleum Directorate's (NPD) director Torgeir Stordal and director of the Norwegian Geological Survey (NGU) May Britt Myhr stated that the Norwegian National Broadcasting Corporation (NRK) has given an incorrect representation of NGU and NPD having different views on the facts related to deep-sea minerals.

Earlier this year, the NPD released the long-awaited resource assessment for minerals in the deep sea. Despite a sober presentation, the estimates show that the Norwegian continental shelf has great potential in terms of metal deposits, many of which will play an important role and are expected to be in high demand in the energy transition.

NGU has pointed out in its consultation response to the impact assessment that the NPD is not in the position to comment on everything mineral-related from exploration and environmental monitoring to preparation and production.

The disagreement was highlighted in several articles published by NRK. However, the two directors believe that NRK's coverage of the case does not give a complete picture.

"Intensification of public and private mapping is therefore essential to ensure Norway a greater role as a producer of sustainable raw materials for the green industry of the future."

Torgeir Stordal – NPD and May Britt - NGU.

NEEDED FOR THE ENERGY TRANSITION

"We need more metals and minerals to carry out the energy transition, and it is urgent. NGU and NPD, who carry out the public resource mapping on land and on the seabed, must intensify mapping and sharing of data to facilitate proper management of the resources."

Stordal and Myhr highlighted the energy transition and vulnerable value chains as good reasons why Norway must also invest in the development of mineral deposits. And they both agree that Norway's resource potential is significant and that the country is well equipped for it.

"... to take a greater role in sustainable mineral production based on a significant resource potential, both on land and on the seabed. More mapping and more research is necessary if the potential is to be concretised and exploited in the long term. On the seabed, it is necessary that private actors also take part in the surveys in the same way as they do on land. For that to happen, areas must be opened up."

In conclusion, the directors write that increased mineral production is a premise for the energy transition, and that Norway not only has resource potential, but also the tools needed to ensure that the extraction will take account of the environment and society.

"Intensification of public and private mapping is therefore essential to ensure Norway a greater role as a producer of sustainable raw materials for the green industry of the future." ■

What a meeting at a conference can do

Tore Karlsson tells the story of how he got involved with the GEO EXPRO Magazine.

AS MANY PEOPLE from my generation, I started my career with Saga Petroleum", says Tore Karlsson. Having graduated as a geophysicist from the University of Bergen, at Saga he was further trained into seismic acquisition, processing and interpretation for five years.

Whilst at Saga, Tore met geologist Halfdan Carstens, both not aware that their paths would cross again many years later when they decided to start GEO EXPRO Magazine.

"Then, I joined Geco, '*The*' Norwegian seismic company at the time. As Geco was subsequently acquired by Schlumberger, I continued in various roles as a geophysicist, but also in marketing and line management in different countries", Tore continues.

"Halfdan and I met again at a conference 20 years ago", Tore adds. "At the conference, Halfdan was promoting the idea for an international magazine with 'easy to read' informative articles for geologists, geophysicists and reservoir engineers involved in subsurface exploration and production of oil and gas."

"I liked the idea and this type of magazine seemed to be lacking in the industry", Tore continues. "Since Halfdan is a geologist and I am a geophysicist, and asset teams were considered important at that time with the need for cross-discipline understanding, we decided to go ahead with the project. We as a family had also just moved to London, which was a good location as a base for starting an international magazine."

"We launched GEO EXPRO at the EAGE Annual conference in Paris in 2004, which was just the starting point of being present at relevant subsurface conferences and exhibitions around the world, continuing until today."

"So, we started out publishing the printed magazine. One of Halfdan's creative ideas early on was the seismic foldout, providing the opportunity for geophysical companies to show mostly new or reprocessed seismic data. It was and still is a very successful development."

"We launched GEO EXPRO at the EAGE Annual conference in Paris in 2004, which was just the starting shot of being present at relevant subsurface conferences and exhibitions around the world. We have formed media partnerships with the main institutions in the industry, which has been beneficial for all parties", Tore adds.

In addition to working for GEO ExPro, Tore started his own consultancy business in 2002. "I worked in different partnerships, as a board member, and was also an associate professor in entrepreneurship at the University of Oslo", he says. "Combined with my role at the magazine, it has given me great exposure to the industry."

Last year, Tore formally ended his role with the magazine. "In the last few years, I have had the chance to attend a number of international conferences. These meetings are excellent opportunities to follow the development of subsurface technology. A good example is the development of seabed seismic over these 20 years. I have contributed with articles in the magazine myself, but more importantly, provided ideas picked up at conferences as input to the editors and other contributors for articles."

Planned for later this year is a feature on Tore's wife Kirsti Karlsson, who continues to be instrumental for the magazine in her role as Director of Sales. In other words, the magazine has got deep roots in the Karlsson family! ■

Tore Karlsson in France, where he spends a few months a year.

Mature basins still favoured for exploration dollars

Peter Elliott
peter.elliott@nventures.co.uk

The Tano Basin in West Africa provides a good example of this, as Peter Elliott from NVentures explains.

OLD BASINS STILL ATTRACT new exploration investment, with great success in the case of the Tano Basin in the transform margin of West Africa. Spanning the eastern Cote D'Ivoire and western Ghana offshore, the Tano Basin represents a large Mesozoic margin wedge, with a thick succession of Cretaceous clastics and localised carbonates, caught between the abrupt margin of the coast and the major transform faults sweeping west to east in the deep water.

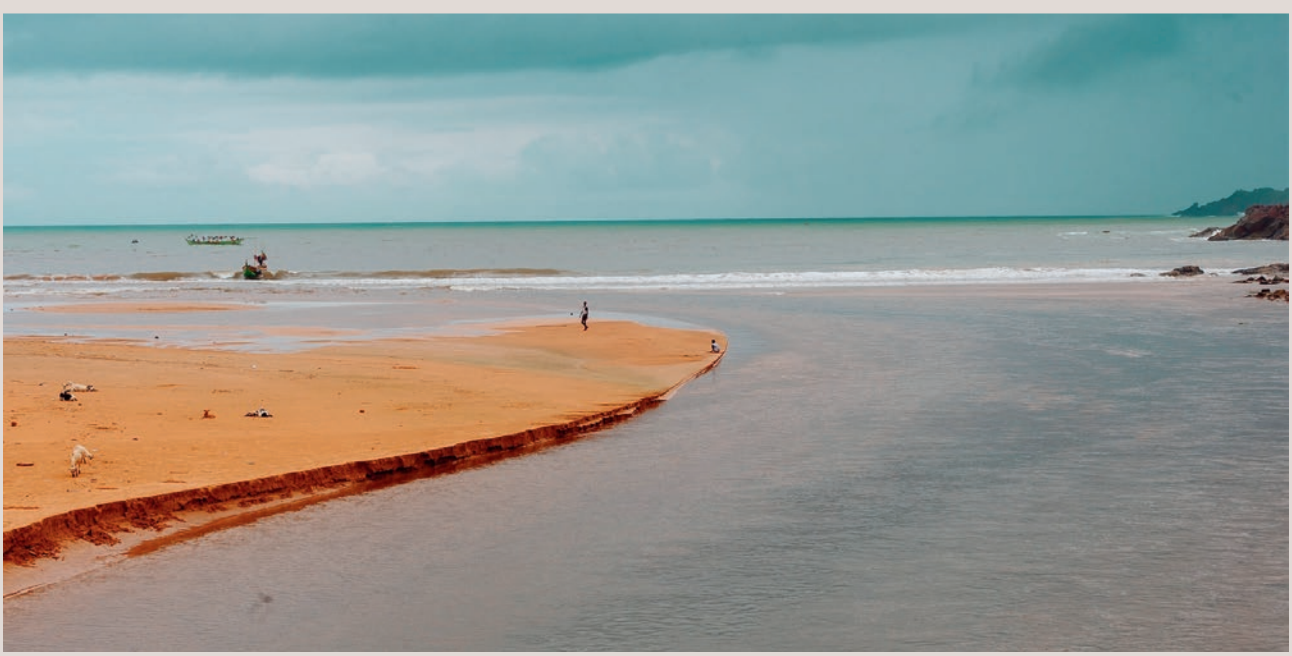
The resulting series of thick marine clastics and prolific source rocks have been clearly proven across the basin, from Gye Nyame in the east to Baleine in the west. A great number of opportunities still exist amongst these large discoveries, with farm-in opportunities and open acreage available.

GRABEN FAULT BLOCKS

The original focus in this area was on the shelf through the 1970's and 1980's, with companies testing the large broad pre-rift Albian graben fault blocks trapped against the syn-rift basin of the transform margin. This resulted in finds such as Espoir in Cote D'Ivoire and the shallow Tano fields in Ghana. Post-rift discoveries were made in these shallow and shelf environments, and operators only now are returning to smaller, mixed-phase fields such as at Ibex, Eland and Kudu in Cote D'Ivoire and North and South Tano and Ebony in Ghana. These represent excellent opportunities to monetise smaller fields in jack-up territory.

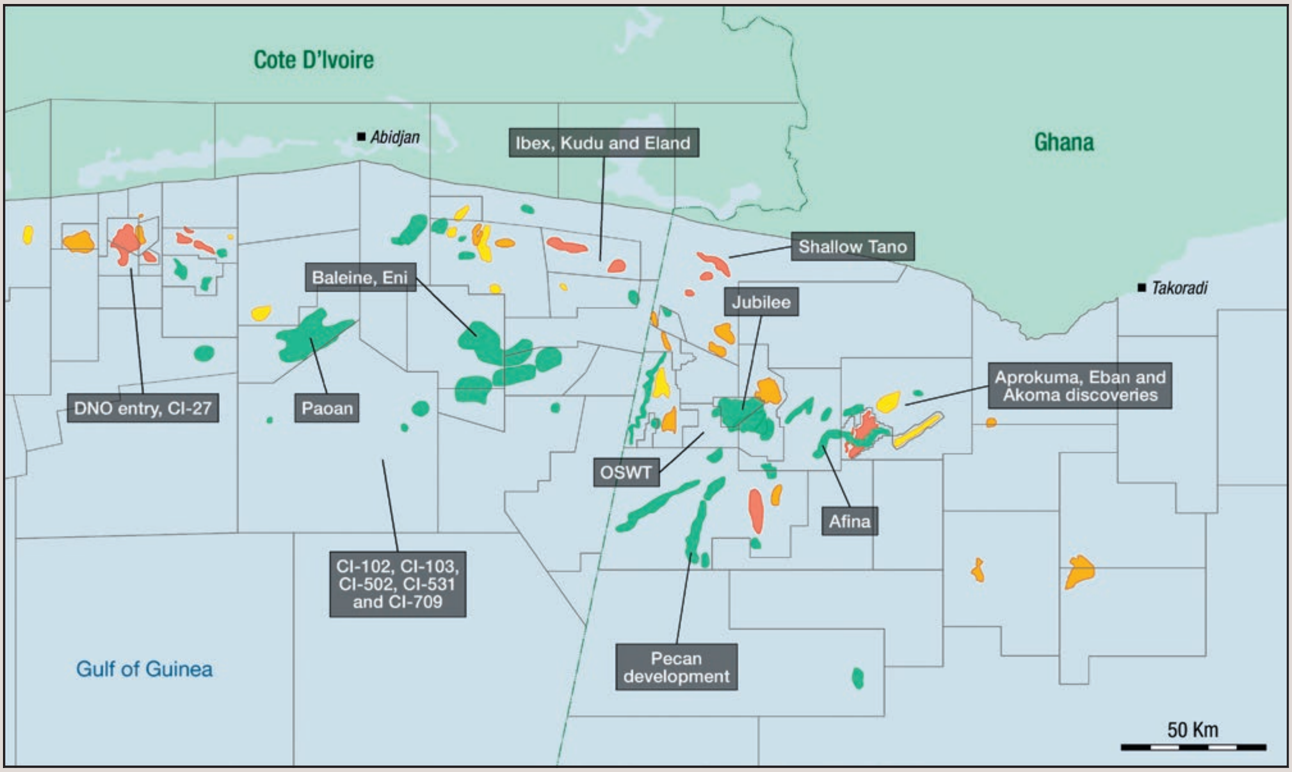
MOVING INTO DEEP-WATER

By the 2000s, deep-water exploration had taken off, and 2007 saw the discovery of Jubilee, a giant oil field with turbidite style reservoirs in the Turonian and world-class source rocks in the Cenomanian and Turonian. This so-called CT play has now been extended across both sides of the border. Whilst there was a noticeable gap in any major discoveries immediately on trend with Jubilee, with Tullow, Anadarko and



Akwidaa, Ghana.

PHOTOGRAPHY: KOBE SUBRAMANIAM/UNSPLASH



Lukoil amongst others drilling several dry and sub-commercial wells in that play, recent exploration has produced better results at Sankofa and Afina in the east and most recently Baleine in the west.

These latest discoveries have pushed the exploration model to include Cenomanian and Albian targets, leaving the Jubilee and TEN cluster of fields to sit in the sweet spot of the Upper Cretaceous fairway. Jubilee itself has recently been extended with drilling at the Jubilee Southeast extension. In the last 18 months Eni in particular has had great success extending these slightly deeper trends, through Aprokuma. Eban and Akoma, on trend with Gye Nyame and Sankofa, and at Baleine and Baleine East, setting the trend in Cote D'Ivoire.

Whilst these successes have been notched up, the industry is catching up and moving quickly to take advantage of experience and best practice learnt in this mature basin. The Petroleum Commission in Ghana has been around the world with a 6 Block roadshow, encouraging investment in shallow water marginal fields and deepwater exploration. Petroci likewise is heavily promoting their acreage, with new online data rooms available. Press reports recently suggest that Murphy, Petroci and Tullow have all been awarded new blocks in and around the Baleine discovery at CI 709 for example. DNO have made a significant entry to the west, joining Foxtrot and Heling in the CI 27 developments. Data rooms are busy, and further awards and applications are expected to be announced soon.

Farm-in opportunities are also grabbing serious attention, with firms looking to enter the basin with established and experienced players, laden with good data and mature prospects. Heritage Oil have a number of low-risk prospects in Offshore Southwest Tano (OSWT), adjacent to Jubilee and TEN. Amni, Eco, Springfield and Base Energy have opportunities in the area, while Aker and partners seek to develop the Pecan cluster of fields with new partners and investors.

"Whilst there was a noticeable gap in any major discoveries immediately on trend with Jubilee, with Tullow, Anadarko and Lukoil amongst others drilling several dry and sub-commercial wells in that play, recent exploration has produced better results at Sankofa and Afina in the east and most recently Baleine in the west."

There will always be mileage in the aphorism "the best place to find oil is to look where it has already been found", and this is fast becoming a call to arms across most of the exploration industry, as greenfield exploration struggles to find funding, and major basins like the Tano Basin deliver excellent lessons in perseverance and value creation. ■

Peter Elliott, NVentures Ltd

An analogue for carbon storage reservoirs

THE GERMAN EIFEL hosts some great outcrops of the Lower Triassic 'Buntsandstein', such as this one featured here near the village of Bitburg. These sandstones were deposited in an arid environment and consist of braided river, overbank sabkha and aeolian deposits. The Southern North Sea equivalents of these sandstones not only form (minor) gas reservoirs, but they also play an important role in the energy transition. Both the storage reservoirs of the Porthos CCS project in the Netherlands and the Endurance CCS project in the UK consist of these sandstones.

The Buntsandstein outcrops near the Bitburg reservoir offer the opportunity to study the sedimentary development of these deposits over tens of meters. The outcrop shown here consists of aeolian deposits sitting on top of a gravelly floor. The cross-bedding is fairly low-angle at the base, changing upwards to high(er)-angle cross-bedding. Cross-beds are present in sets with a bounding surface above and below. Several apparent wind directions can be seen, although it should be noted that the face of the outcrop is not flat and the cross-section is not necessarily perpendicular to prevailing wind direction. The measuring stick in the middle of the picture is 2 m long.

Text and photo: Allard van der Molen.

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.

The love of reducing complexity

The most beautiful core of the Norwegian Continental Shelf – art and science.

ROBERT W. WILLIAMS, NORWEGIAN PETROLEUM DIRECTORATE

Paleogeographic map showing the location of Devonian basins (orange) in the North Sea.

"The love of complexity without reductionism makes art; the love of complexity with reductionism makes science."

Edward O. Wilson,
Consilience: The Unity of Knowledge

DISPLAYED IN A CORRIDOR near the reception at the Norwegian Petroleum Directorate in Stavanger is a five meter long glass print of a Late Devonian core from the Embla field. Fifteen seamlessly overlapping images form a high-resolution mosaic of the most beautiful core ever recovered from the Norwegian continental shelf.

The core penetrated an amalgamation of rocks eroded from the Caledonian mountains to the west. Palaeomagnetically dated to 375 million years, this alluvium came to rest at approximately the same time as the evolution of the ancestor of all terrestrial vertebrates, be them parrots, pterosaurs, blue whales or humans.

We owe our existence to a strong-limbed, flat-headed, laboriously air-breathing fish slightly younger than that core. These rusty conglomerates were deposited during the Late Devonian, when northern Europe lay just south of the equator. The eroded pebbles are among the first sediments deposited on what later became the Norwegian continental shelf.

Conferences and seminars outside the petroleum sector sometimes use public meeting rooms located near the decorative core mosaic. During one such gathering, participants stood in a queue for the coffee machine. They could not avoid noticing the beautiful rusty red and green conglomerates, the eroded remains of the highest terrestrial mountain chain the Earth has ever known. One of them scowled at the bright quartz pebbles and red silt matrix and resolutely declared, “I cannot fathom what anyone sees in modern art!”

While this anecdote may raise a smile from geologists, it demonstrates that reducing complexity from an immensely convoluted set of information demands the consilience of a vast range of disciplines. To appreciate the core’s deep meaning, the observer would have to be versed in stratigraphy, sedimentology, geochronology, paleogeography, paleoenvironments and early tetrapod evolution. We deciphered our Devonian history through linking together principles from chemistry, physics, biology, geology, and amazingly, even orbital mechanics.

The information content of this image is indeed equivalent to “modern art” when input from these disciplines remain vague or isolated and when unity of knowledge is lacking. But, with only a basic geologic understanding, the image will be appreciated in all its dimensions. ■

PHOTO: ODD JØRGEN

The Embla core in NPD’s Stavanger office.