THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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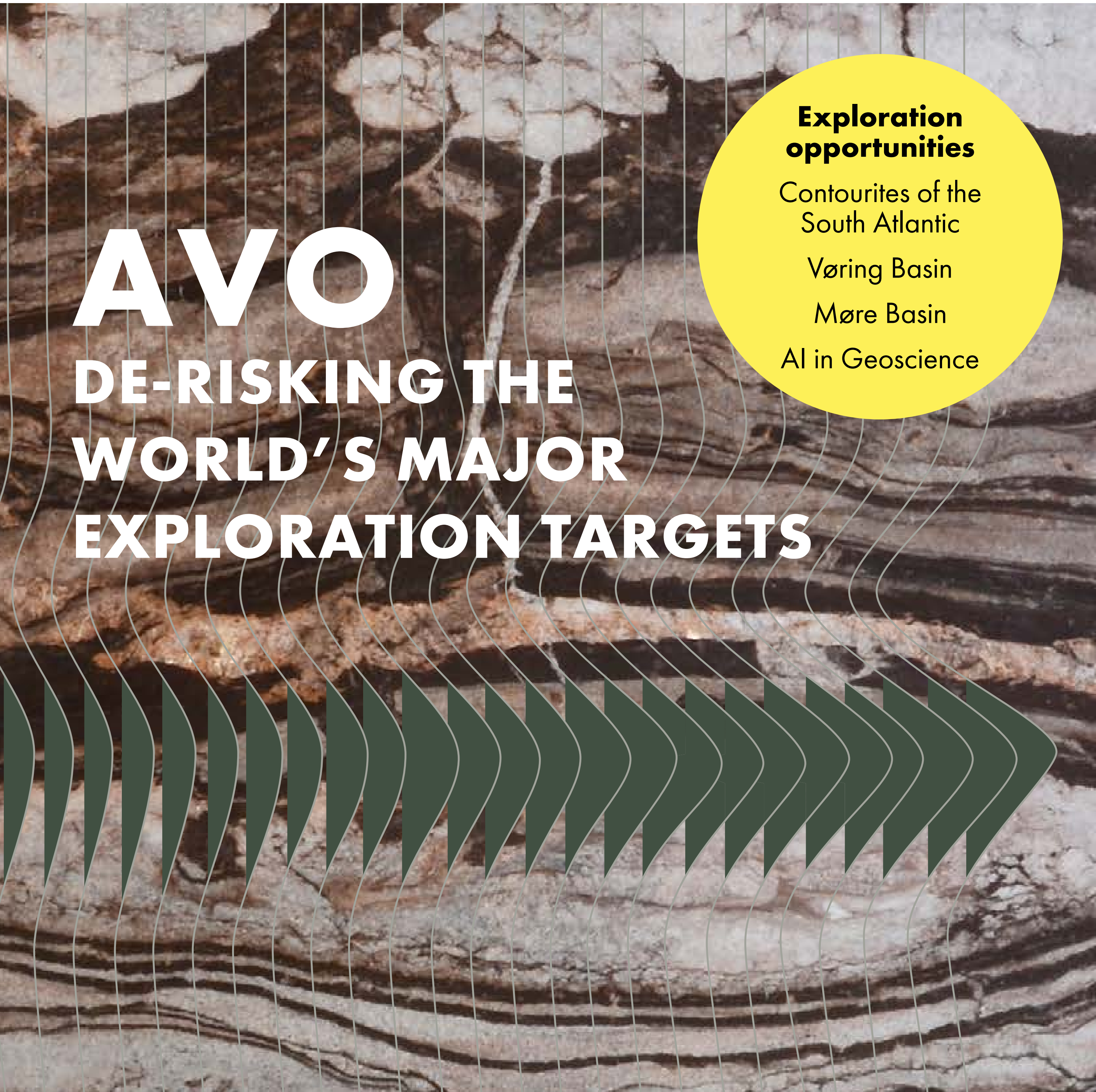


AVO

DE-RISKING THE WORLD'S MAJOR EXPLORATION TARGETS

Exploration opportunities

Contourites of the South Atlantic

Vøring Basin

Møre Basin

AI in Geoscience

GEO ExPro

geoexpro.com

Managing Director
Ingvild Ryggen Carstens
+47 974 69 090
ingvild.carstens@geoexpro.com

Editor in Chief
Henk Kombrink

Editorial enquiries
+44 7788 992374
henk.kombrink@geoexpro.com

Subscriptions
subscribe@geoexpro.com
GXP PUBLISHING AS
Trollkleiva 23
1389 Heggedal
Norway

Creative Direction
Ariane Busch

Layout and Design
XRB Media Limited, London, UK

Print
United Press, Latvia

GxP PUBLISHING

I'm all ears

WE HAND out our magazine at conferences. It is part of our business model – advertisers want exposure at the end of the day.

With the magazine being up for grabs at events, it also finds new readers. We don't know most of them, and in the majority of cases, we will not hear whether they like our content or not.

But sometimes people are more expressive about it. One of them, Wei Wei Jong from Fugro Marine, found the magazine at the recent Seismic Conference in Aberdeen, and was not only drawn by the front cover, but also by its diverse content. She even called it a highlight of the conference.

As an editor, that's the icing on the cake. It makes my day, and it provides me with new energy to continue my hunt for good stories to write and solicit.

I rely heavily on my network for input, and there are many people to thank for getting in touch with me with suggestions. Do you have an interesting learning to share, a new update on a subsurface project, or a personal work story, please do not hesitate to get in touch with me.

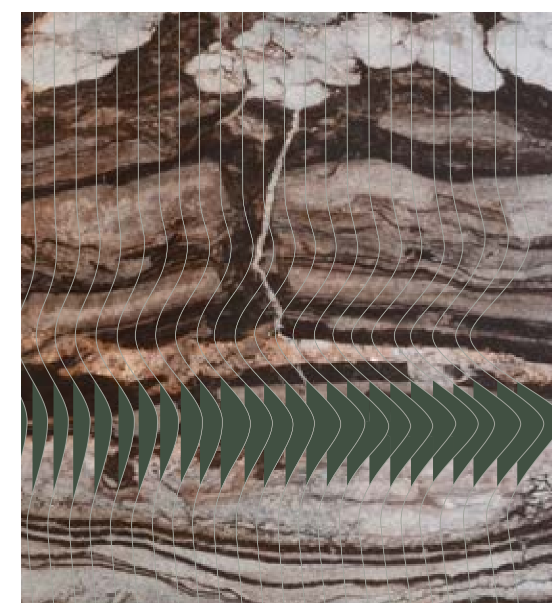
> "…it provides me with new energy to continue my hunt for good stories to write and solicit"

Our subsurface geoscience industry is a small world, but there are many stories yet to share! I'm all ears. In the meantime, enjoy this hefty issue!

Henk Kombrink

BEHIND THE COVER

GEO EXPRO's co-founder and first Editor in Chief, Halfdan Carstens, once told me to write articles not so much for the few specialists, but for those in the industry who are new to a certain discipline. I had that in mind when I talked to Henry Pettingill and Rocky Roden from the Rose DHI Consortium. For them, the story they shared with me about how AVO works, how it evolved, and how it's being used today is nothing new, but I do hope it will be very useful for geoscientists who don't work with AVO too often. The cover shows an AVO Class 2 anomaly against a backdrop of a beautiful Triassic core sample from borehole SM-14, kindly provided by CASP.



Comments: henk.kombrink@geoexpro.com
LinkedIn: geo-expro-magazine
Website: geoexpro.com

FIRSTS

"This may be the bottom of the E&P market in the UK as the government will have to realize the fiscal damage caused by the unbridled focus on renewables at any cost, particularly on its cash-starved constituents. The industry perception is that business can only get better"

Ian Cross – Moyes & Co

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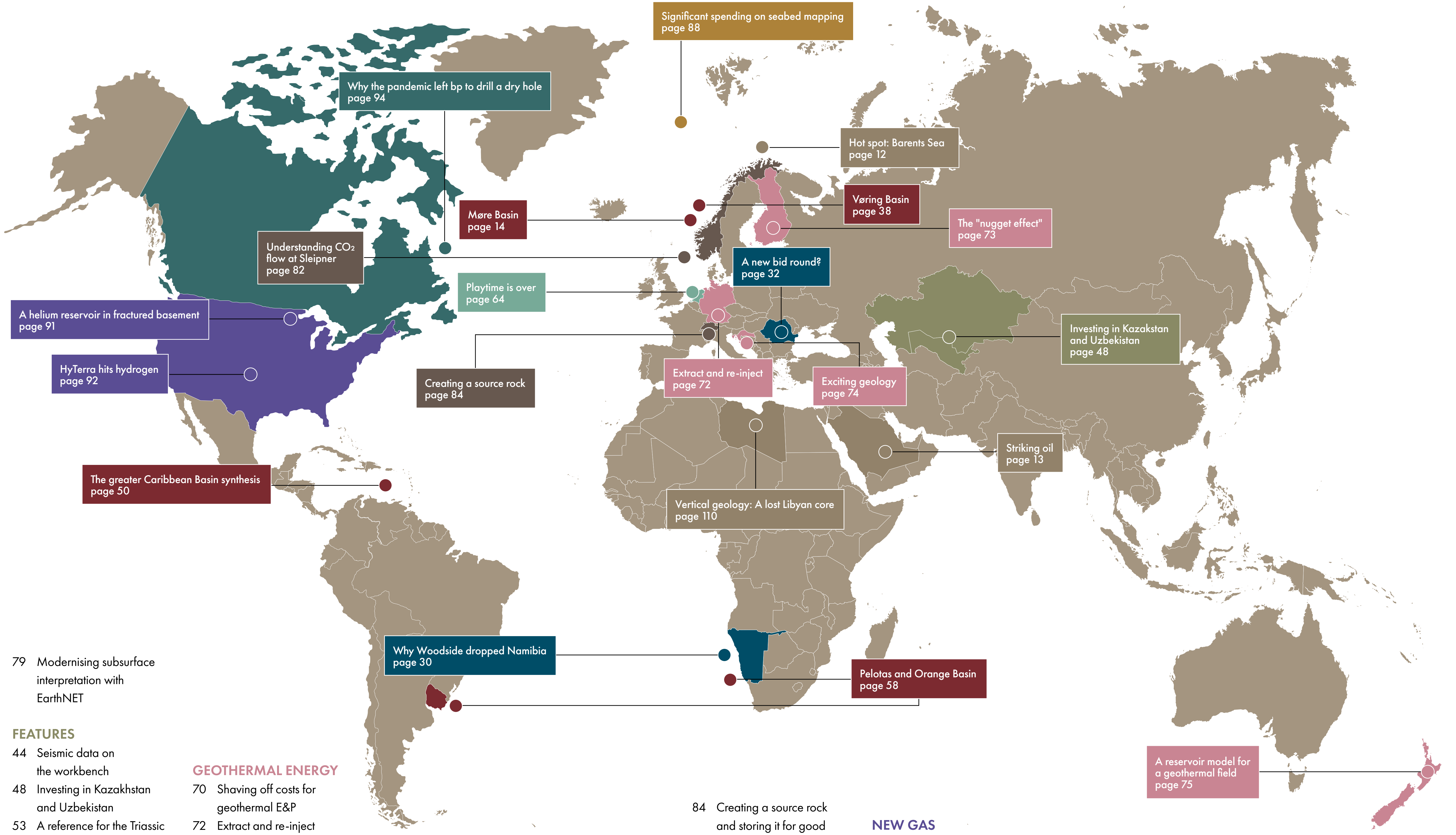

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A SEISMIC SURVEY IN THE MOST "VOCAL" PART OF THE COUNTRY

Knowing how challenging it can be to perform any "out of the ordinary" activity in densely populated areas these days without people getting up in arms, it is interesting to see that a 3D seismic survey will soon be carried out in the heart of Amsterdam in the Netherlands. Traditionally, the home of the wealthy and most vocal people in the country, let's see how the response will be. The survey aims to better map the subsurface for geothermal exploitation. Amsterdam is the only place in the Netherlands with an extensive district heating network, which offers a great opportunity for geothermal energy production.

CREATING A STICK

Newfoundland has consistently evaluated their offshore discovered gas resources for the first time, in an attempt to create more momentum behind possibly developing them. Currently, the licences in which these gas discoveries were made don't have an expiry date. The only way to create a stick to make the licence owners work up these finds is to demand a field development plan. If that does not happen, the authorities will have the right to make these companies relinquish the licence, and therefore create opportunities for others to come in. That is why an accurate volume assessment is now required.

THE NEXT WELL TO WATCH IN URUGUAY

Uruguay is being looked at again by the majors, following the success in deep-water Namibian waters. Apache is likely to drill the next high-impact exploration well late next year, targeting a supposedly Cretaceous reservoir unit. TotalEnergies drilled the Raya-1 well in the same block before, but this well TD'd in the Oligocene after finding water-wet sands. The Apache well will be a costly one, given the water depth of approximately 3 km and a depth below the mudline of another 4 km.

MISSING DOCUMENTS

In 2017, an exploration well, Nutmeg-2, was drilled offshore Grenada, the island that shares its continental shelf boundaries with Trinidad and Venezuela. The well supposedly found indications of gas, even though it was not tested at the time, and not much seemed to have happened since. But recently, the hopes for another look at possible continued exploration were revived as the new energy minister from Trinidad expressed a wish to embark on this together with her neighbours. However, a small problem has now emerged when it comes to further analysing the Nutmeg-2 well data; the documents cannot be found... What is going on?

The snippets of information shared here are based on conversations Editor in Chief, Henk Kombrink, has recently had. Sources are anonymous.

ILLUSTRATION: PCR.VECTOR / FREEPIK.COM

Storing radwaste: From academic pipe dreams to more practical ideas

Following decades of proposing a wide variety of ideas and the realisation of failed projects, a universally accepted subsurface design has emerged for storing radioactive waste. But will it be in time for the nuclear renaissance that is now coming?

THE HISTORY of radioactive waste disposal is probably one of the best examples of how subsurface projects evolve. Starting in the 1950s, the spectrum of project ideas was broad-ranging, from disposal of radioactive waste in the ocean subsurface, oceanic trenches, or later in subduction zones of oceanic plates, to below the ice caps of the poles or even in space. All these ideas, except for one, can be characterised as academic pipe dreams that could not be reconciled with practical reality.

The site of the Onkalo deep geological repository near Eurajoki, Finland, with the Olkiluoto nuclear power plant in the background.

Initially, the repurposing of old salt mines was pursued mainly in the USA and Germany. This led to projects at Lyons, Kansas in the USA and at Asse near Wolfenbüttel in Germany. Their difficulties and eventual failure required a rethinking of the path taken. Above all, the failure at the Lyons project was to prove extremely consequential as the site turned out to be punctured by old oil and gas wells, so scientists became worried that waste would leak out of similar, undetected wells. At the Asse site, problems related to water inflows were largely kept under wraps, further straining the public acceptance of nuclear waste disposal in Germany to this day.

Above all, it is important to note the changing social context regarding nuclear waste during the 1970s. The decade started with a strong expansion of nuclear energy, and ended with the emergence of a strong opposition that asked, "what about the waste". But rather than repurposing old salt mines, from the 1970's until now the state of the art has been to develop purpose-built subsurface facilities specifically designed for "permanent" disposal of radioactive waste.

The Swedes were really the pioneers in the efforts to find suitable solutions for radioactive waste repositories in the 1970s and 1980s, The central idea is to have a multi-barrier concept, which is ultimately designed to delay the dispersion of radioactive material so that any radiation dose for future generations will remain below legally defined limits. This concept has essentially been adopted by most countries using nuclear energy today and the differences between designs is limited to the choice of container material and host rock.

Recently, very encouraging steps have been taken when it comes to realizing repositories for spent fuel. The Finnish radwaste company Posiva will this year enter the operational phase of its Onkalo facility, and the Swedish radwaste company (SKB) received its construction license earlier this year. Other countries like France, Switzerland and Canada have submitted general licence applications for proposed sites for implementing subsurface repositories. However, many countries are not yet that far advanced, and significant work remains to be done especially if one is mindful about the global nuclear renaissance that is currently ongoing. It would be best to avoid the mistakes of the past and embrace "what about the waste" in a forward-looking manner. ■

Rodney Garrard

This is Part 1 of a two-part series. The next column will look at geological uncertainties.

PHOTOGRAPHY: POSIVA

Business can only get better

The mood of the UK oil and gas industry has reached rock bottom, which is reflected in the deals made

In anticipation of the tax changes announced by the UK government in October 2024, corporate merger and acquisition activity accelerated in 2024 and into 2025. These deals involved companies looking to acquire producing accretive cash assets that are non-core to the seller. Single exploration asset transactions stopped. The corporate deals include majors combining business units to create larger partnerships, taking advantage of synergies, including reduced costs, consolidating tax liabilities, and future profits.

The process started in early 2024 with the tie-up of ENI and Delek Group's subsidiary, Ithaca Energy. This briefly created the UK's second-largest operator after Harbour Energy. Then Equinor and Shell UK announced it was to combine their oil and gas assets in December 2024, thus creating the largest independent UK producer. This joint venture will include Equinor's interests in Mariner, Rosebank, and Buzzard, and Shell's interests in Shearwater, Penguins, Gannet, Nelson, Pierce, Jackdaw, Victory, Clair, and Schiehallion.

Private equity-backed Neo Energy and Repsol Resources announced the plan to merge their assets into a new UK entity, Neo Next. This will be 55 % owned by Neo and 45 % by Repsol. Repsol UK holds interests in some 48 oil and gas fields, while NEO UK operates several key assets in the Central North Sea, including interests in the major hubs of Shearwater, Britannia Area, and Elgin-Franklin.

Meanwhile, Viaro Energy, through its subsidiary RockRose Energy, has agreed to acquire the interests of both Shell and ExxonMobil in Shell's operated Southern North Sea portfolio, comprising a number of gas fields that make up the Leman and Clipper production hubs. Shell and ExxonMobil's interests in the Bacton gas processing terminal and Shell's operated 50 % interest in Block 48/8b, containing the Selene gas discovery, were also included in the deal.

On a smaller scale, Serica Energy and the Parkmead Group announced that it signed an agreement for Serica to acquire 100 % of the shares in Parkmead (E&P). This includes interests in a range of exploration and development assets in the UK offshore, but excluded its onshore Dutch gas production. The exploration assets include participation interests in Skerryvore Prospect in Block 30/13c, in which Serica already held 20 % working interest. On completion of the transaction, its interest will increase to 70 %, and it will become the operator. The development assets include a group of oil fields in the Moray Firth area with the heavy-oil Fynn-Beauly, considered one of the UK's largest undeveloped fields. It is worth noting that this is the first time that the 1970s Texaco-discovered field, estimated to contain oil in place of between 600 and 1.3 billion barrels, has almost wholly been held by a single licence partnership, which should bode well for a future development project. Orcadian Energy is Serica's joint venture partner in Fynn-Beauly.

With the timing of future bid rounds in the UK unclear, and the absence of exploration interest, we expect to see more transactions as companies seek to realign UK offshore assets and consolidating for efficiency.

This may be the bottom of the E&P market in the UK as the government will have to realize the fiscal damage caused by the unbridled focus on renewables at any cost, particularly on its cash-starved constituents. The industry perception is that business can only get better. At the same time, it is important to remember that there are more welcoming countries with better fiscal and regulatory terms actively competing for investment at the same time. ■

Ian Cross - Moyes & Co

Culzean, United Kingdom.

PHOTOGRAPHY: TOTALENERGIES.COM

Steadily, Saudi Arabia keeps finding more hydrocarbons

As announced the other day, Aramco found not one but 14 new hydrocarbon accumulations. In light of the ongoing seismic imaging campaigns in the country, it is expected that more of those announcements will follow

Volumes weren't mentioned in the press release that was issued early April, but the tone was clear nonetheless; Aramco is determined to find new volumes of oil and gas, and is also successful in doing so.

Fourteen new finds were announced, of which eight seem to be standalone discoveries, whilst the remaining six are more likely to be newly discovered reservoir intervals within existing fields. This suggests the nature of the exploration drive; it seems to be mostly driven by near-field and even in-field drilling.

The well test results provided in the article are quite varied, with the oil discoveries testing between 115 and 2,840 barrels per day and the gas finds between 1.5 and 32 MMscf/d.

LOTS OF ACTIVITY

We briefly spoke to Sean Siegfried, CEO of Saudi Geophysical, about the geophysical acquisition market in Saudi. He confirmed: "There is a remarkable drive to firm up more near-field volumes."

"About 30 to 40 % of the world's seismic acquisition crews are based in the Middle East at the moment," Sean explained. "In total, there are between 15 to 18 crews active at the moment, of which 90 % is about performing 3D acquisition of areas around perimeters of existing assets. Saudi has eight to nine crews, Kuwait has two and Bahrain is now embarking on a major project to map its shallow waters all around the island, amounting to around 5,000 km^2."

"These projects are not short-term either," Sean said. "Most of these projects will easily last for three to four years."

FROM STREAMER TO OBN

The way of seismic data acquisition has changed compared to how it was done before. First of all, the rapid commercialisation of nodes has resulted in a shift from streamer to node acquisition. Especially in the shallow waters of the Arabian Gulf, nodes are more flexible to put in place with light vessels.

Second, a country like Saudi is on a mission to prove all additional volumes they can get their hands on. Mohammed bin Salman Al Saud, Saudi's ruler, also known as MBS, has ambitious projects to pay for. At the end of the day, it is oil and the newly built Red Sea hotels that will ultimately need to generate the cash to sustain the public spending. But in the meantime, it looks as if oil will be the main cash generator, even at the depressed prices of the present day. Exploration does not seem to be affected by it either. The Saudis think longer term than most IOC's. ■

Henk Kombrink

Seismic acquisition in the desert.

PHOTOGRAPHY: ARAMCO

Discover more in Møre, Norway

Connecting the North and Norwegian Seas by extending proven and developing play models

As demonstrated by recent exploration success, Viridien's Northern Viking Graben (NVG) seismic survey in the Northern North Sea has already proven to be a valuable exploration tool. Thanks to the high-quality seismic data in this geologically challenging area, prospects are better defined, allowing for qualified drill decisions. In 2024, Viridien applied the latest seismic acquisition and imaging technology to add a northern extension, known as NVG24 (green polygon in Figures 2 and 3), to its current coverage over the NVG so that it now extends into the Møre Basin and Møre Platform in the Norwegian Sea. A glimpse of the early fast-track data from NVG24 is shown in the foldout juxtaposed with fully imaged data from the NVG East-West (EW) coverage (Figures 2 and 3). The upcoming NVG24 final data will be of the same high quality and reveal structural and stratigraphic details at the Manet Ridge, Marulk Basin, Gnausen High and the Møre Platform (Figure 3).

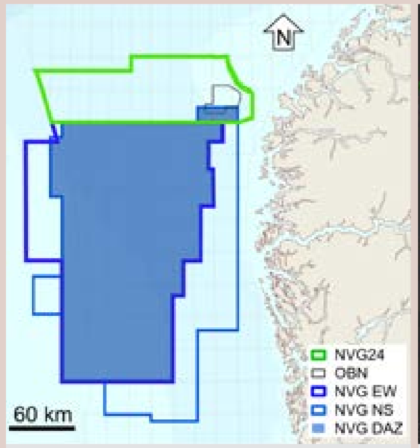


Figure 2. Overview map of the NVG survey (blue), NVG24 (green) and sparse OBN (black) coverage near the Norwegian coast.

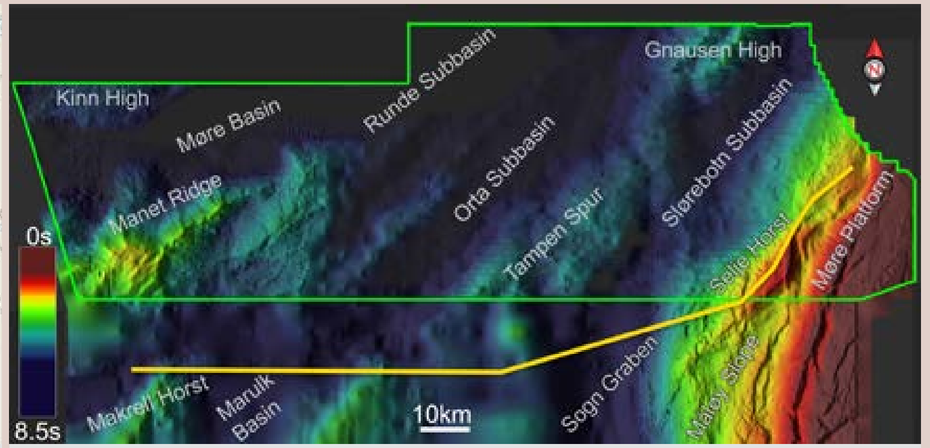


Figure 3. Time-structure map of the top acoustic basement in the Møre Basin, Sogn Graben, and Møre Platform. The green polygon is the NVG24 survey. The yellow line is the location of the seismic foldout line in Figure 1.

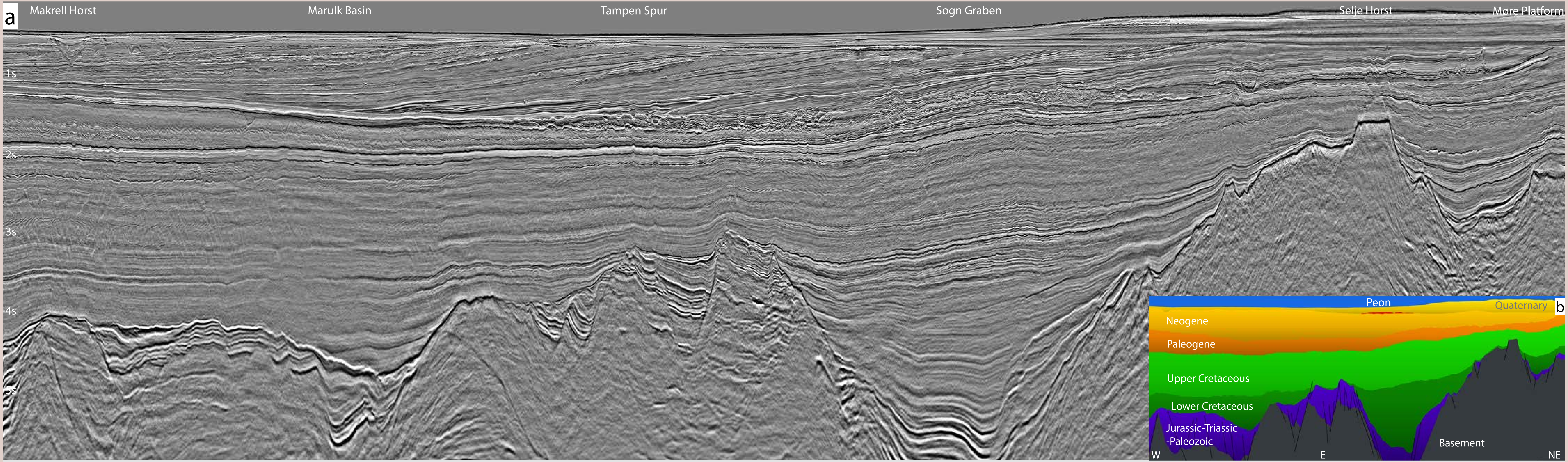


Figure 1: (a) Seismic section across the NVG final data and the recent NVG24. The vertical scale is in two-way traveltime.
(b) Coloured interpretation of the seismic foldout line. The line location is indicated in Figure 3.

New seismic data unlocks Møre Basin reservoirs

Do the Møre Basin and Platform hold the next hydrocarbon giants on the Norwegian Continental Shelf?

MARIT STOKKE BAUCK, ANNA RUMYANTSEVA AND IDAR KJØRLAUG, VIRIDIEN

VIRIDIEN'S Northern Viking Graben (NVG) seismic survey campaign in the North Sea recently celebrated 10 years of acquisition and imaging (Figures 1 and 2). Since its commencement in 2014, the survey has played a significant role in exploration in the Norwegian North Sea area. With the latest survey extension northwards, known as the NVG24 dataset, the NVG survey now covers parts of the Møre Basin and its bounding structures, the Marflo Spur, Kinn High, and the Møre Platform in the Norwegian Sea. The regional foldout line from the NVG survey intersects some of these structures (Figures 1 and 3). The first phase of exploration activity on the Møre margin was driven by the desire to investigate the possible extension of the Jurassic-rotated fault blocks already successfully targeted in the North Sea. So far, the wells drilled have found only minor amounts of oil and gas in Jurassic and Cretaceous reservoirs. However, it was the presence of hydrocarbons and reservoirs on the Manet Ridge and Møre Platform that encouraged Viridien to extend the NVG survey northward into the less explored Norwegian Sea and acquire the NVG24 data set (Figures 2 and 3). The streamer survey was acquired in an east-west direction with a broadband configuration. In the east, a grid of sparse ocean bottom nodes (OBN) was deployed; these results will be available later in 2025. This article outlines potential reservoirs that can be mapped with the new NVG24 imaging.

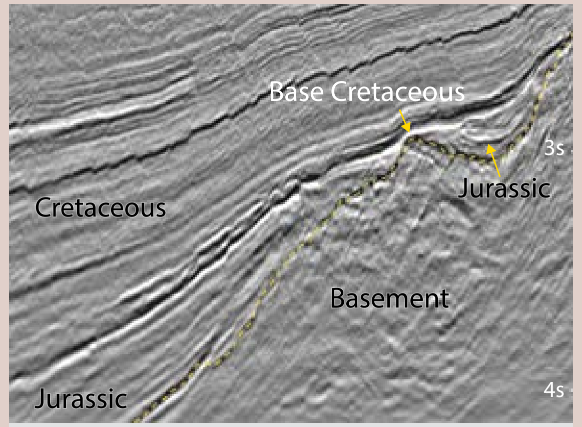


Figure 4: E-W seismic section across the Møre Platform and Slørebotn Subbasin. The yellow dashed line represents the top Basement, which is covered in Triassic and Jurassic deposits.

RESERVOIRS AND PLAY MODELS

MESOZOIC RESERVOIRS

Classic Mesozoic plays are seen both near the Manet Ridge in the west, extending north toward the Møre Basin, and in the near-shore structures on the Møre Platform in the east. These hold the potential reservoirs of Triassic and Jurassic sands. A three-way closure prospect in the Marulk Basin, toward the Manet Ridge, has possible reservoirs which are time-equivalent to Triassic-Jurassic Lunde and Statfjord formations (Figure 1).

The early NVG seismic survey vintages revealed half grabens with Jurassic deposits within the Måløy Slope. Similar half-grabens are found within the Møre Platform, which can be seen as a continuation of the Måløy Slope structure. Wells on the Møre Platform have proven both Triassic and Jurassic reservoirs in these half-grabens (Jongepier et al., 1996). On the inner part of the Møre Platform and the Måløy Slope, fault block crests were eroded to the basement level during the late Jurassic and Early Cretaceous (Figure 4). The redeposition of the erosional products are potential good reservoirs in the basins.

CRETACEOUS RESERVOIRS

Cretaceous submarine sand reservoirs are identified on the Måløy Slope, Møre Platform, and in the Slørebotn Subbasin (Figure 3). Locally, the Cretaceous unit is dominated by mud-rich, deep-water slope-to-basin-floor deposits interbedded with coarse-grained clastic sediments (Sømme et al., 2019). The unit has proven prospectivity with hydrocarbon discoveries in Lower Cretaceous (Albian-Aptian) and Upper Cretaceous (Turonian, and Campanian) sand reservoirs near the Måløy Slope and Møre Platform (Figures 4 and 5).

Sandstone units were identified in well 6204/11-1 in a thick Upper Cretaceous section, with debrites and slump deposits of Turonian and Coniacian age (Figures 5a, c). A time-equivalent good-quality sandstone section has been interpreted to be stacked submarine channel complexes in well 6204/10-1, 17 km to the southwest (Prélat et al., 2015; Figure 5c). Toward the Slørebotn Subbasin, the submarine channels eroded into the underlying strata in which sediments were transported further into the basin and deposited in

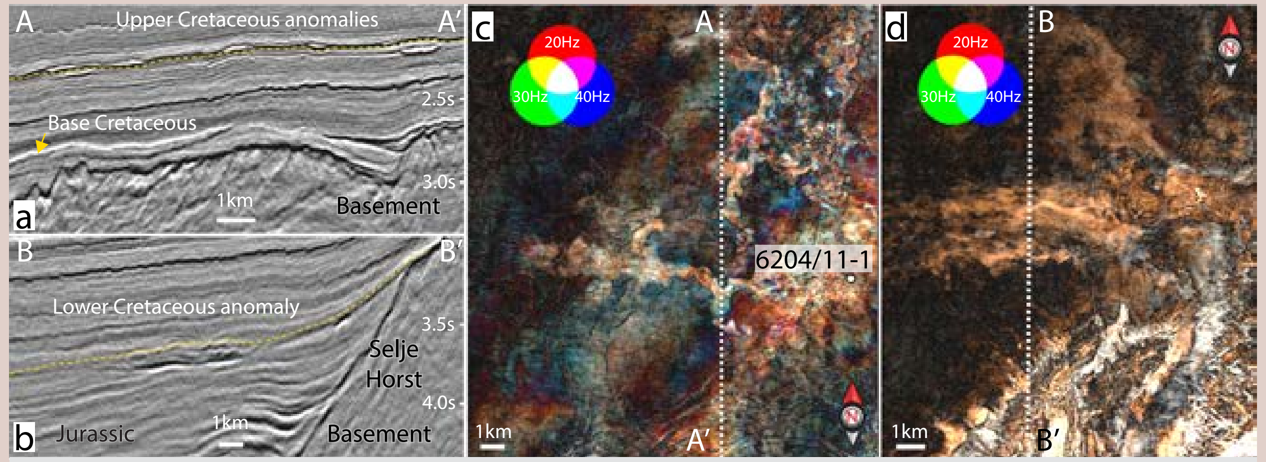


Figure 5: a) Seismic N-S section intersecting Upper Cretaceous anomalies in the Møre Platform. The yellow dashed line represents the base of the anomalies shown in (c), interpreted to be channels). b) Seismic N-S section intersecting lower Cretaceous anomalies in the Slørebotn Subbasin. The yellow dashed line represents a Lower Cretaceous surface shown in (d), interpreted to be channels with overbank deposits. c) RGB frequency blending from spectral decomposition analysis of the Upper Cretaceous (Kyrre Formation) sand. d) RGB frequency blending from spectral decomposition analysis of the Lower Cretaceous (Agat Formation) sand.

lobes. The north-south seismic sections and RGB frequency blending from spectral decomposition analysis show the confined channels and associated lobes (Figures 5a-d).

CENOZOIC RESERVOIRS

Various geologic details are revealed in the high-quality seismic dataset. Among these are proximal, thick basin-fill, polygonal faults, and an area with mounds and channels appear in the isochron of the Hordaland Group (Figure 6a). Above the polygonal fault systems, potential sand accumulations (residual sands, Utsira Formation) are observed as bright amplitudes (Figure 6b). The mounded structures can be interpreted to be the result of sinkites, where late Miocene-Pliocene sands have sunk into the polygonal faults, displacing highly porous diatomaceous ooze upwards (Rudjord and Huuse, 2024; Figures 6c, d). Bright-amplitude discordant reflections, interpreted as sand injections, are revealed in the Hordaland Group (Figure 6d).

REGIONAL 3D SEISMIC - A POWERFUL TOOL

The regional knowledge Viridien has gained in the North Sea through its NVG imaging and velocity model building work over the last decade has been applied to the new NVG24 dataset. Additional sparse OBN coverage acquired but not yet fully processed in the Slørebotn Subbasin and Møre Platform will also further enhance the velocity model used in the processing. Fast-track results from NVG24 are promising and already significantly better than existing public vintage data. The final data, processed with the latest seismic imaging technology, including advances in pre-processing, noise mitigation, and velocity model building, will benefit prospect evaluation in this area. The various prospective reservoirs described in the above sections demonstrate the variety of potential exploration models. With a high-quality modern seismic dataset, other play elements, such as trap and charge, can be evaluated and renewed exploration in this region can take place. Analog prospectivity extends further north and east, suggesting that acquisition should continue northward in this underexplored area of the Norwegian Continental Shelf. The potential to unlock the next giant hydrocarbon discovery may lie within the NVG24 or even further into the Norwegian Sea.

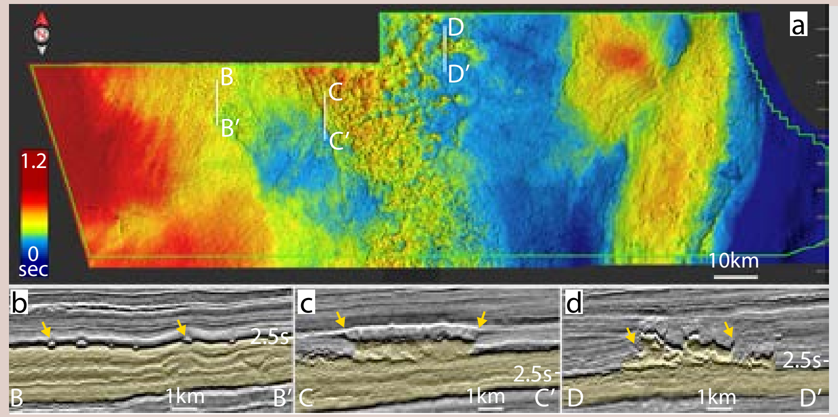


Figure 6: a) Isochron map of the Hordaland Group across the NVG24 area, revealing both subtle and significant thickness variations, as seen in seismic sections b-d. This map enhances differences across the survey area, as shown in the seismic sections. b) Polygonal-patterned ground in the west, with bright amplitude infill marked with yellow arrows in the figure. c) Mounded and elongated features occur in the central part. d) Discordant, bright amplitudes may represent sand injectites. These are found in the east and toward the Sogn Graben. Yellow colouring in the seismic sections indicates the thickness incorporated in the isochron map.

COVER STORY

"To me, it is extremely exciting to follow these developments, as it has the potential to produce phenomenal results once the quantum computing code is cracked. Imagine a future where elastic FWI is routine and DHI analysis, including AVO evaluation, incorporates data far superior to anything we have today"

Rocky Roden – Geophysicist, DHI Consortium

COVER STORY

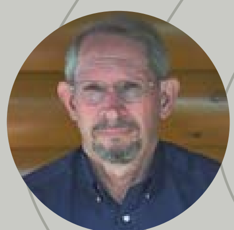
HOW AVO HAS BEEN AND CONTINUES TO BE AN ESSENTIAL TOOL IN DE-RISKING THE WORLD'S HIGH-IMPACT EXPLORATION WELLS

People tend to say that a good geologist has seen many rocks. But does the same apply to geophysicists? Is a geophysicist more knowledgeable when he or she has seen more seismic data? I'm not aware of that same principle being used. What I do know, however, is that the two people I spoke to for this article have seen a lot of seismic activity from all over the world.

A conversation with two world-leading experts - Henry Pettingill and Rocky Roden from the Rose DHI Consortium

HENK KOMBRINK

Henry Pettingill



Rocky Roden

Henry Pettingill, who is a geologist by training, became the head of the Rose DHI Consortium after having been a member for eighteen years. Geophysicist Rocky Roden has been a principal in the DHI Consortium for 25 years. Together with their colleagues Mike Forrest and Roger Holeywell, they have seen an unparalleled number of exploration programmes and discussed the subsequent drilling results that have all been thoroughly assessed for DHI's. This happens at regular meetings of the consortium members from over 30 companies, during which the work done on de-risking prospects is discussed privately, such that learnings can be shared.

Rocky and Henry tap into this experience when informing me about the basic principles of AVO, followed by a discussion on the most common pitfalls, how prospect risking is done in practice, and what the future of AVO-driven exploration entails. But let's start with the basics first.

THE 1950'S AND BEYOND

Our understanding of DHI's has evolved from Gassman's fluid replacement modelling in 1951, to the recognition of the relationship of bright spots and hydrocarbons, and subsequently to AVO changes with offset due to gas observed by Ostrander in 1984.

Nowadays, AVO is a standard tool in the exploration toolkit. That is not a coincidence, as the geological success rate of AVO-supported wells has been significantly higher than that of wells drilled without.

"It is also good to mention that AVO is only one of the geophysical methodologies that fall under the Direct Hydrocarbon Indicator umbrella. Some people think that every DHI has a strong AVO effect, but DHI's from stacked data, such as flat spots and edge effects are often more diagnostic. AVO is just one of the tools in the DHI toolbox," says Rocky.

Figure 1 shows the classification scheme on how amplitudes change with offset at the top of gas sands. Nowadays, typically five classes are distinguished, but when Steven Rutherford and Robert Williams came up with the first proper classification of AVO classes in 1989, only Classes 1, 2 and 3 were defined. "There was quite some discussion on how to name or number them," says Rocky. "We had Steven Rutherford present at our DHI consortium a few years ago, and he recalled the story of the discussion they had whether to call them 1, 2, 3; A, B, C or X, Y, Z. Only at the last minute, they went for 1, 2, and 3."

That was fortunate, as in subsequent years, Class 4 was added to the mix through the work of John Castagna and Herbert Swan in 1997. John Castagna has made numerous contributions to the Consortium through the years. In addition, a subdivision of Class 2 into two sub-classes was introduced through the work of Chris Ross and Daniel Kinman in 1995, where Class 2P includes a phase reversal with offset, whereas Class 2 does not.

CAREFUL CLASSIFICATION

"The five Classes provide a framework for interpreting AVO, but ►

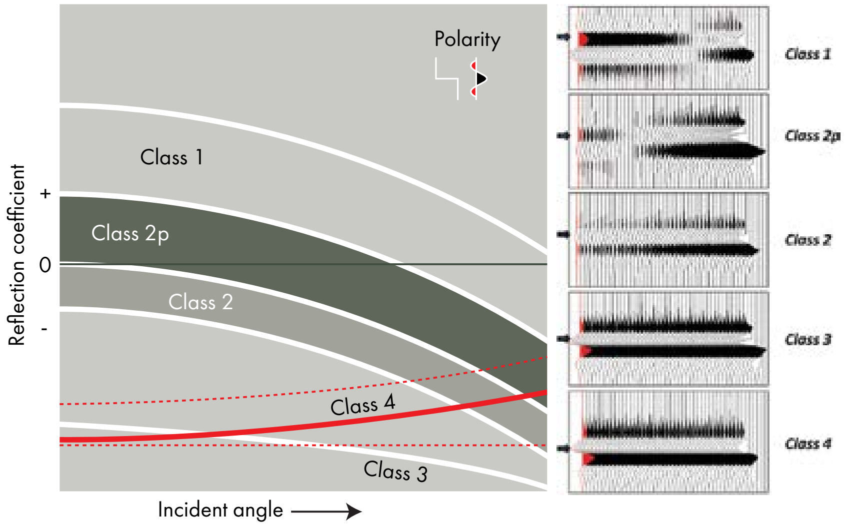


Figure 1: Classification scheme for the five different AVO Classes, showing how amplitudes change with offset at the top gas sands. Source: modified from Rutherford and Williams (1989); Castagna and Swan (1997); and Ross and Kinman (1995).

Low Impedance	High Impedance Gas Sand	Class 1
Slightly Lower Impedance	Slightly Higher Impedance Gas Sand	Class 2p
Slightly Higher Impedance	Slightly Higher Impedance Gas Sand	Class 2
High Impedance	Low Impedance Gas Sand	Class 3
High Impedance Hard Lithology	Low Impedance Gas Sand	Class 4

Figure 2: Note that it is the relative impedance contrast between the overlying seal and the gas sand below that ultimately determines the AVO Class. Source: DHI Consortium

what really determines the AVO Class for prospects is the following," says Rocky. "Look at the relative acoustic impedance contrast between hydrocarbon reservoirs and the overlying lithology (shale) in Figure 2; in some cases, a gas sand is low impedance, in others it is high. Basically, all combinations between seal and reservoir are possible, and therefore we have to be careful in assigning an AVO class before we have done an integration with other geological data."

"An example is a well in the Barents Sea we had the privilege to review. We had a 20 % porosity reservoir, typically a Class 2 AVO, but it also had a source rock sitting on top of it. And because that source rock had such low impedance, it looked like a Class 1 AVO. There are several places around the world where we can observe this, and it shows that it's not only the reservoir that determines the Class, but the combination with what sits above it."

AVO PITFALLS

"For me," says Henry, "the very reason why we have pitfalls in the first place is because of the non-unique nature of geophysical solutions and therefore AVO. Multiple scenarios can explain the same geophysical expression. That's why we always walk through a list of potential pitfalls, asking ourselves what might be other explanations to explain the amplitude response we see." This list of potential pitfalls is briefly summarised in Figure 6.

"If the contribution to the DHI-uplifted chance of success associated with AVO gets too high, compared to the other DHI characteristics, we see a decrease in prospect success rates," adds Rocky. "Uncalibrated AVO is the main reason for this. Most high-quality DHI prospects have numerous DHI characteristics, and a dominantly AVO-driven prospect therefore increases the risks." The drop in success rate is illustrated in Figure 7; when the AVO part of the DHI Index is more than 60 %, the chance of success is greatly reduced.

Below are a few of the more important pitfalls interpreters have to be mindful of.

AVO TUNING

"If you look at a gather," starts Rocky, "and it is not spectrally balanced, you often encounter Normal Moveout Out stretch as you get to the far offsets. This subsequently causes a lower frequency on the far offsets."

"So, if you have an uncalibrated thick wet sand, and it starts to tune right at the associated frequency, typically at the mid to far offsets, it blossoms because of the tuning effect. In turn, this looks like a hydrocarbon effect. It's a difficult thing to get your head around unless you do a lot of modelling. However, it is very resolvable; all you have to do is spectrally balance your gathers, such that you don't have any frequency changes across the gathers. Some companies will do this routinely, some of them will not."

"We know at least two to three cases in the DHI Consortium where AVO tuning effects produced inaccurate interpretations that led to failed drilling attempts. There are probably more in our database, but detailed modelling was not performed on these dry holes to confirm AVO tuning," concludes Rocky.

ASH BEDS AND OTHER SOFT NON-RESERVOIR LITHOLOGIES

About 20 % of failed DHIs are caused by non-reservoir lithologies – soft shales, marls, silts and ash. "We have seen the latter in the Gulf of Mexico, but also in the West of Shetlands," says Henry, "and it has been a thing that has hit me at regular intervals throughout my career."

"The first time was with Shell when we drilled Natasha in the Gulf of Mexico in the early 1980's, where we thought we had a good downdip conformance with structure, but we drilled a Pleistocene ash turbidite instead. It was the first time we hit such an ash bed in the area, but many more have been drilled since, in many levels ranging from Lower Miocene to Pleistocene."

"Twenty years later, when I was with Noble, we were going to drill the Stone's River prospect in the Mississippi Canyon, far away from Natasha. What happened? The beautiful Class 2 AVO turned out to be yet another sand containing 30 % ash."

"And that was not all. Twenty years later, at a company's office in Houston, we were discussing a prospect that had some sub-salt issues, and we were going down the road of discussing everything that could have gone wrong with this prospect, except what? A forty-year career, and being burnt at 20-year increments by the same pitfalls," Henry laughs. ▸

AVO EXAMPLES

Class 1: The Tanin gas discovery in the Eastern Mediterranean (Egypt) is a great example of a Class 1 AVO response, with amplitudes dimming at top reservoir level when moving from the water-wet to gas-bearing in the Tamar Sand A sand. A Class 1 AVO usually occurs in consolidated reservoirs, where porosity tends to be reduced at deeper levels. Because of the compacted nature of Class 1 sands, and the impedance difference between the sands and seals becoming smaller, the number of Class 1 AVO prospects in the DHI Consortium database of 415 wells is very limited.

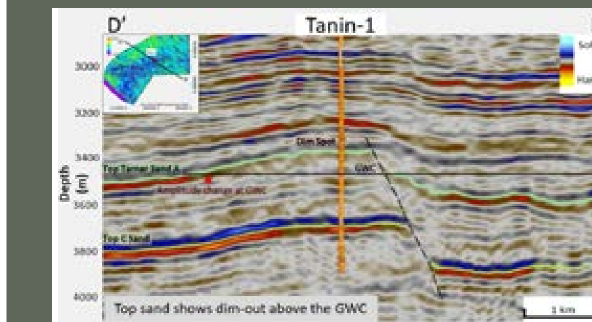


Figure 3: A Class 1 AVO response, showing a dimming of the top reservoir reflector at the Tanin gas discovery, offshore Egypt. Source: El-Ata et al. (2023),Sci Rep 13, 8897.

Class 2: AVO's tend to develop in slightly less compacted and consolidated sands than the Class 1 examples. The difference between a Class 2 and 2P AVO response is that the latter shows a polarity reversal whilst the former doesn't. Both AVO classes experience a negative gradient (slope) as the offset increases. An example of a Class 2 AVO response can be seen in the Tamar gas discovery offshore Israel, where a series of Miocene sands proved to be gas-bearing. As can be seen in Figure 4, the top sand (A) shows a Class 3 response from slightly negative to a more negative response with offset.

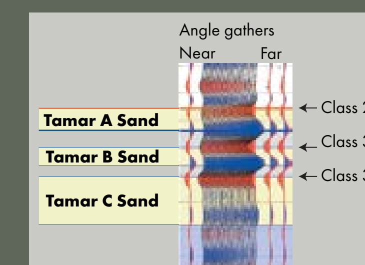


Figure 4: The Tamar gas discovery offshore Israel shows both Class 2 as well as Class 3 AVO responses, as shown here. Adapted from: Needham et al. (2017), AAPG Memoir 113.

Class 3: Because of the strongly negative response Class 3 AVO shows at the whole range of offsets, this class is also known as the Bright Spot AVO. With increasing offset, the amplitudes become even slightly more negative than they already are at near-offset. The Tamar B and C sands are examples of Class 3 AVO responses (Figure 4).

Class 4: Many Class 4 AVO's occur in unconsolidated sands, similar to Class 3 AVO's. But as Figure 1 already shows, the change of amplitude over offset is small, which means that the identification of a Class 4 AVO can be tricky. The example shown here corresponds with that observation, with a Class 4 from Hoover Field, Gulf of Mexico, where the Far-angle stack shows a slightly more subtle amplitude response than the Near-angle stack.

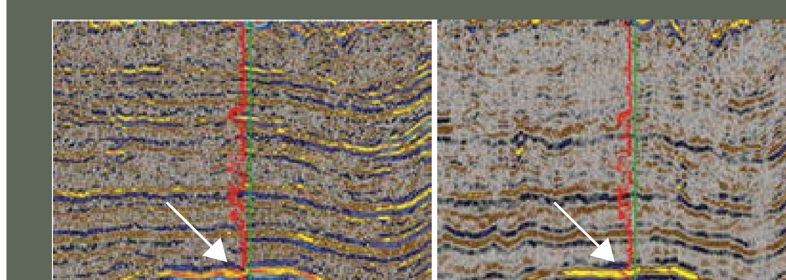


Figure 5: Near-angle stacked seismic data (left) and Far-angle stacked seismic data for the Hoover field, Gulf of Mexico, showing a gentle dimming from Near to Far. Source: Inyang (2009), Master Thesis University of Houston.

- Soft shales, siltstones, marls, ash or coal beds could produce this anomaly
- High porosity, clean, wet sands
- LSG - Wet reservoir with low saturation gas (1-30 % gas) in porous and permeable reservoir sands. Excludes gas charged shales and tight sands
- Hard streak above or within wet sands
- Amplitude caused by sharp onset or increase in overpressure
- Salt, volcanics, or carbonates (polarity or convolution issue)
- Diagenetic boundary or unconformity
- CO_2 or nitrogen
- Tuning effects
- Lateral change in lithology, rock properties or thickness
- Imaging complications - focusing and defocusing
- Unexpected change in properties of the bounding lithology (top or bottom) that affects the amplitude response

Figure 6: Checklist of most common pitfalls for interpreting DHI's and associated AVO effects. Can these pitfalls cause amplitude and AVO features that can be misinterpreted to be DHI's? Note: LSG does produce a hydrocarbon effect, but usually indicative of a seal or trap failure.

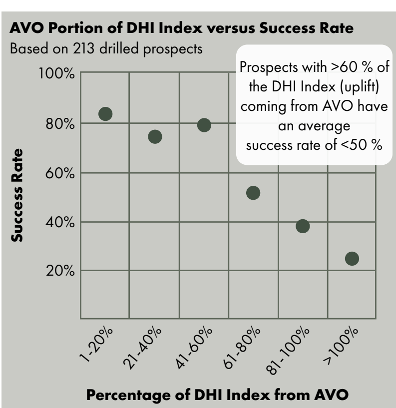


Figure 7: The AVO portion of the overall DHI Index should not be too high, as an analysis based on 213 drillled prospects has shown. A significant drop in success rate takes place when prospects rely on AVO for more than 60 % of the DHI Index. Source: DHI Consortium.

WET SANDS

"Half of the number of the dry holes in our database are wet sands," says Henry, "and most of those, when looking back, had a decent AVO response." See Figure 8 for an overview of the share of other factors contributing to drilling dry holes.

"You can get a response from a wet sand," continues Rocky, "but if you don't know anything else, and it is a Class 3 AVO with a small gradient in a frontier area without any calibration points, it will be hard to make a differentiation between a gas or water-bearing sand. Sometimes you are just in the margin of error bars. That's why we always try to look at as many characteristics as we can to find further evidence of hydrocarbons."

"Once we drilled four thick wet sands in a row with Noble," says Henry, "which obviously raised some eyebrows in the company. So, I called Rocky in as a consultant at the time to have a more detailed look at it. We had a discovery called Isabela, with another prospect on the flank of the same four-way structure. It looked all good, with an element of stratigraphic trapping that we were confident about, and a similar AVO response as the Isabela find. However, this prospect came in dry. It was Rocky who then identified that the rock properties of the topseal changed from one well to the other, and this is what caused the AVO response in the downflank prospect, rather than a gas-filled sand. It opened my eyes, as it was such a good example of non-uniqueness and simply how the rocks determine it all."

"Mind you, a few years later in Australia, something similar happened but, in this case, with a more positive outcome. It was the Enfield area, where the discovered field had a nice bright amplitude, but the nearby prospect that they were looking at didn't have nearly as good an AVO response as the discovery, despite the geology being similar. So the first thing that popped into my mind after seeing the variable top-bounding shales in the wells was, maybe there is a bounding lithology change. And sure enough, there was, and it was a discovery despite having a weaker AVO signature."

CHANGING DATA QUALITY

The DHI consortium keeps an impressive database (The Seismic Amplitude Analysis Module, SAAM) of 415 wells that have all been assessed and risked in the same way. Not only for AVO, but also for other DHI Characteristics such as brights spots, flat spots, downdip conformance and phase reversal amongst others. A geological chance of success is also assessed to ultimately determine the final calibrated chance of geological success for the prospect.

The database is a powerful tool to review, rank and evaluate the world's most important exploration wells, but in order to properly compare them, one must be mindful of the change in data quality that has taken place over the years.

"The gathers and overall data quality we see today are superior to what we saw at the start of our consortium 25 years ago. During the first five years, we hardly saw any gathers at all, because they were too expensive to generate," says Rocky. "If you don't correct for data quality somehow, you can have a good prospect with bad data having a poor ranking compared to a bad prospect with good quality data. That's why we introduced the data quality score, which aims to account for variations in data quality, especially when risking prospects of different seismic vintages."

"But at the same time, even with the advancements of better data, a lot of prospects today can be more complicated," says Rocky. "Things don't stand out anymore as they used to. We have got sub-salt prospects, stratigraphic prospects, all sorts of geological challenges that we were not looking for 25 years ago." "And to that I can add that gathers are still not perfect," says Henry. "Things can look good, but that doesn't necessarily mean they are correct."

Henry then pulls up a prospect drilled in the Gulf of Mexico not too long ago. The overall DHI Index of the prospect came out at 22 %, with the AVO part being 13 %. That's on the edge of being too AVO driven," explains Henry. "We want a prospect to have a healthy mix of DHI factors."

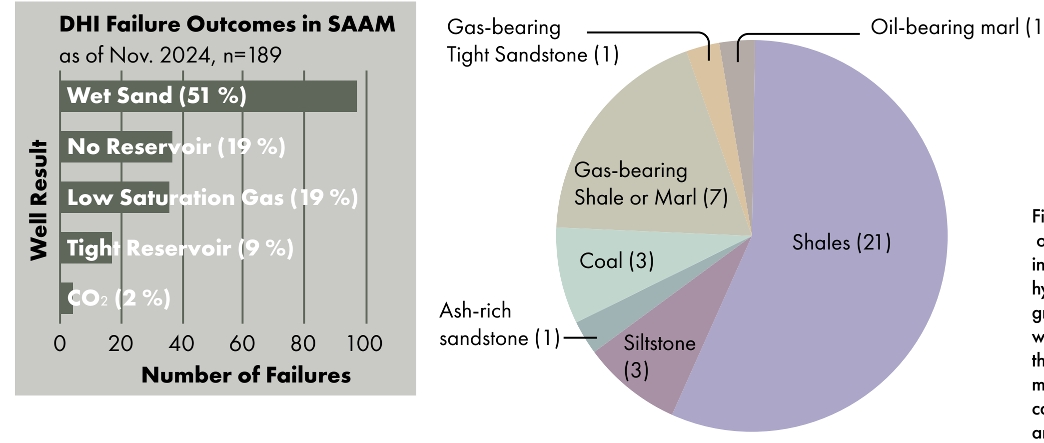


Figure 8: Wet sands form 51 % of the cases where a DHI was incorrectly interpreted as a hydrocarbon indication (left graph). Looking at the failures where a lack of reservoir formed the root cause, it is shales that are most frequently found in those cases (right). Data based on analysis by the DHI Consortium.

WHERE ARE WE GOING?

Kenny Goh, a geophysicist who recently commented on one of our LinkedIn posts, wrote: "ExxonMobil geophysicists mentioned to me that they do not believe that AVO responses at 2,200 m below mudline and 2,400 m water depth in Jubilee are correct or real."

So, I asked Rocky what his take on it is. "As rocks get buried deeper and deeper," Rocky explains, "they will become harder and as such, the impedance contrasts between them will gradually decrease. So the presence of hydrocarbons may not produce an anomaly. That's where the Class 1 AVO response comes in, where the reservoir is very compacted and as a result, the fluid effect on the AVO response is very small. For that reason, we have only seven Class 1 prospects in our database."

"So when it comes to defining the DHI floor these days, as the depth limit of direct hydrocarbon indicators is sometimes called, it really depends on the basin you are in," explains Rocky.

"Subsalt makes that even more complicated. Up to a few years ago, there was a general consensus that you couldn't believe DHIs subsalt," says Rocky. "Maybe you could map a structure, but surely you wouldn't believe the amplitudes. But it is thanks to new technology, primarily FWI and the application of ocean bottom nodes, that we are slowly getting more confidence in the quality of sub-salt seismic imaging for amplitudes. Maybe, in a few years time, we will be just as confident risking prospects sub-salt as we are post-salt."

"Computing power is still the challenge to make incremental improvements to the seismic though, especially sub-salt" adds Rocky. "FWI is an optimisation process that is computationally expensive, and processing for sub-salt imaging routinely takes months and months to complete."

"But quantum computing is maybe coming to the rescue. Last year alone, I saw four papers being published on the use of quantum computing in geophysics. The use of quantum computing for seismic imaging and modelling is in its infancy, but the largest technology companies and governments are committing billions of dollars to resolve the issues to make it work."

"To me, it is extremely exciting to follow these developments," concludes Rocky, "as it has the potential to produce phenomenal results once the quantum computing code is cracked. Imagine a future where elastic FWI is routine and DHI analysis, including AVO evaluation, incorporates data far superior to anything we have today." ■

AVO IN CARBONATES – AN INDIRECT HYDROCARBON INDICATOR

"You're opening up a whole different subtopic here," says Henry when I ask him about the role of DHIs and AVO in carbonates. "However, we always get asked about it during presentations, and we will present on the topic at the upcoming IMAGE Conference in Houston, so it is definitely a hot topic."

At the basis of it all, the AVO classification for sands simply does not apply to carbonates. The complex pore structure of carbonates tends to cause a scatter of velocities, complicating the seismic quantification of the parameters. In addition, carbonates often have a higher velocity heterogeneity and anisotropy than sands, which does not facilitate interpretation either.

"Against that backdrop," Henry adds, "when people say that they found oil in Paleozoic carbonates based on AVO, as that is what happened with quite some Midcontinent discoveries in the past, I tend to believe that the AVO effect was due to enhanced porosity development in the carbonates rather than the fluid fill itself. So in these cases, AVO should probably be seen as an indirect hydrocarbon indicator in carbonates at best, and no universal AVO classification scheme can simply be applied to carbonates at the moment."

"It is also telling that we only have five carbonate DHI examples in our database that consists of 415 wells."

OIL & GAS

"Traffic light exploration maps are useless"

Ian Longley – GIS Pax

And all the while, hydrocarbons are transitioning away from us

There is hope for frontier discoveries and hope for a reversal of declining production trends in mature basins. But how realistic is it?

"IT'S THE hope that keeps us here," wrote Neil Hodgson and the Searcher team the other day. He alluded to promising ultra-deepwater fields that are about to be discovered.

Hope also filtered through in the words of people as they commented on the news of an agreement reached in the Netherlands between the government, state oil and gas company EBN and the Dutch industry association Element NL to produce more gas from the offshore. Graham Goffey worded it as follows: "This is what pragmatic climate leadership looks like… trust the sensible Dutch."

Hope is also what keeps the Norwegians drilling around 40 exploration wells per year.

But why is Norway also keen on developing a seabed minerals industry at the same time? They see that peak oil and gas production is near, and without a Johan Sverdrup-sized discovery, the trend is clear.

"Hydrocarbons are transitioning away from us." It is what Rodney Garrard wrote in one of his columns for us last year. And I believe he has a good point.

It is also the basis for the situation the Netherlands finds itself in. The agreement will not materially change that. Because it is not a government policy or tighter EU rules that have resulted in the dramatic decline in offshore gas production – like it was for Groningen. It is the natural decline of the fields themselves. So, when people anticipate that gas production is going to ramp up significantly as a result, it is a disappointment in the making.

That is what I miss in the public debate that results from events like this. There is never any mention that the big boys started selling assets years ago for a reason; the volumes were simply not there anymore. Anything that will be done to facilitate more exploration is rather to manage the decline better.

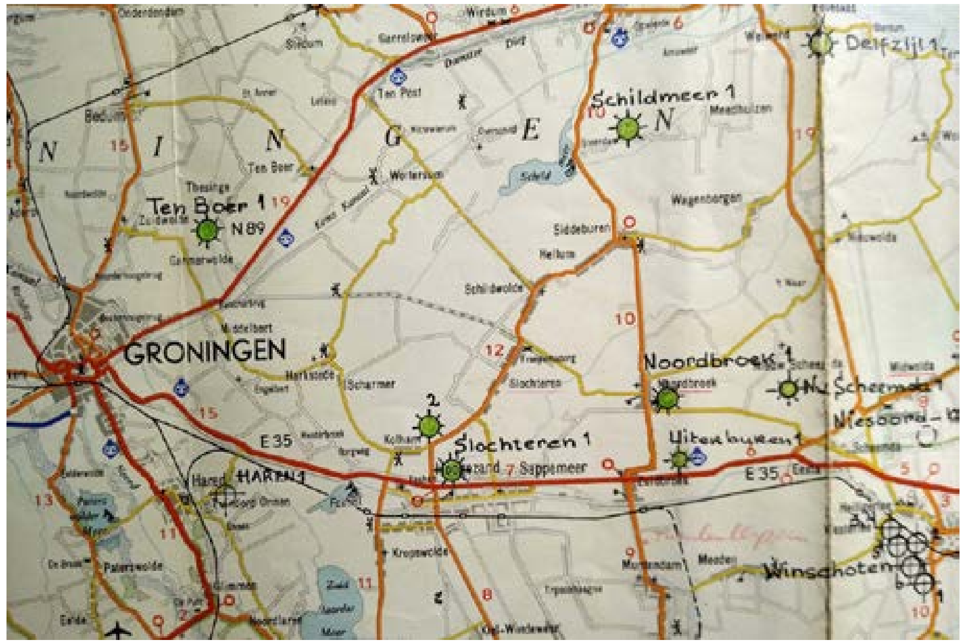
The big volumes ain't there anymore.

Yes, of course, there is always something to be found. That's in fact what the Norwegians prove through their near-field drilling that has dominated the exploration landscape for quite a few years now. But these additional resources are small.

What petroleum geologists also need to communicate to the public is the fact that it is not only accelerated climate change that forms a stick to move away from hydrocarbons; the hydrocarbons are indeed transitioning away from us. It is a hard reality, and any agreements to ramp up exploration in very mature areas will very unlikely reverse that trend. It is that observation that should, in fact, be a main driver for the energy transition, especially in light of the much-discussed security of supply.

That's not to say the agreement reached in the Netherlands is useless. It hopefully allows the current offshore players to finally get on with their plans more efficiently, which is needed and welcomed. That's where its power really lies. ■

Henk Kombrink



In the early days of exploration, geologists just put the wells they drilled on road maps. Quite an elegant way of working!

PHOTOGRAPHY: HENK KOMBRINK

Why traffic light play maps are useless

De-risking one, or multiple play element(s) can have a big positive effect on a series of initially high-risk prospects. This may lead to a situation where the most attractive prospect to drill is in an area that would have been red in a traffic light map. Here is why

WHEN exploring a new area, it is common for E&P companies to produce traffic light maps, with red areas being the ones where one of the key play elements is missing, orange where one is uncertain, and green where all elements are thought to be present.

However, the fundamental flaw of working with this methodology is that a traffic light map only considers risk. No exploration decisions are made on risk alone, it is always the combination of risk and reward (volumes). Only focusing on risk can lead to situations where the best prospects are, in fact, ignored.

What should be done instead, is to link risk and a reward in all polygons in a play map and perform a ranking in that way. It is called split risk play mapping, and it is the only play-based exploration methodology that fully integrates both risk and reward and has been around for a long time. That doesn't mean it is a widely-recognised methodology, though.

The outcome of using the split risking approach (where each polygon includes a shared play risk and a non-shared 'prospect' risk) can be widely different from using a traffic light approach. The main reason is that if one well demonstrates a play element to work in what would be a red area, it can impact multiple other prospects in that same red polygon. Notably, this only applies if the risk for one prospect also applies to the others in the same red polygon.

The example shows a map of three zones, which could have been interpreted as green, orange and red from south to north. However, look at the risked volumes, and what happens when a well proves prospect C to work? This then subsequently de-risks seven other prospects within the same polygon, which means that the combined risked upside of this cluster of small prospects amounts to 115 MMboe. That is a lot more than the risked potential of prospect B (12 MMboe and the only prospect where a success would deliver a commercial volume), which is the one that most people would have chosen if relying on a traffic light approach.

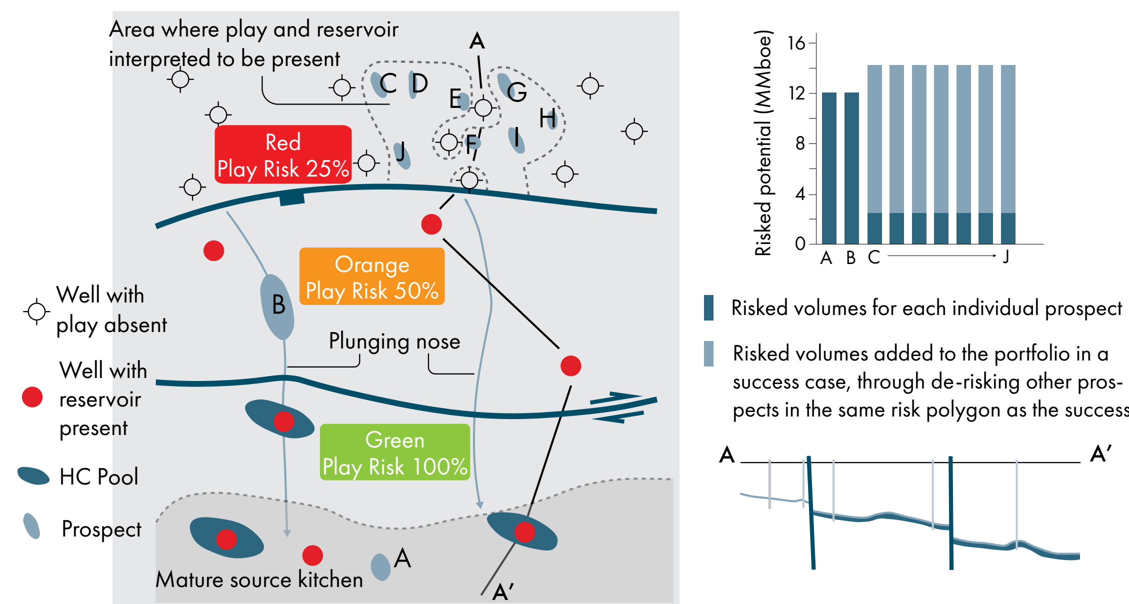
This clearly shows the value of properly risking prospects, even in what would be a red area when using a traffic light approach. If anything, this example shows that using a traffic light approach is dangerous and unjustified. ■

Henk Kombrink

GIS PAX PLAYER

This is the third of a series of articles based on work and experience from the GIS-Pax team in Australia, as presented by Ian Longley in a series of videos on LinkedIn.

More detail on this approach can be seen in the accompanying video of the GIS-pax LinkedIn Site:

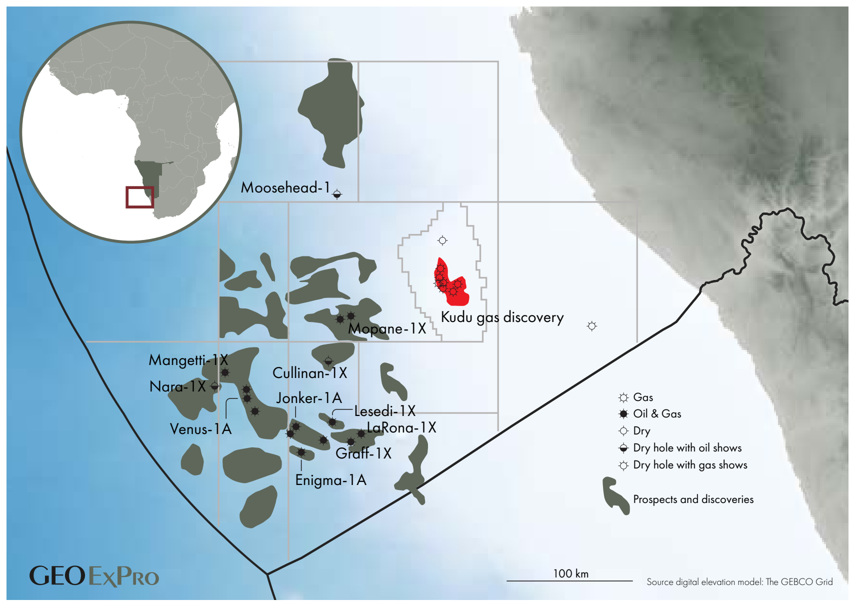


OIL & GAS

This may be a reason why Woodside decided not to farm in to PEL 87 in Namibia

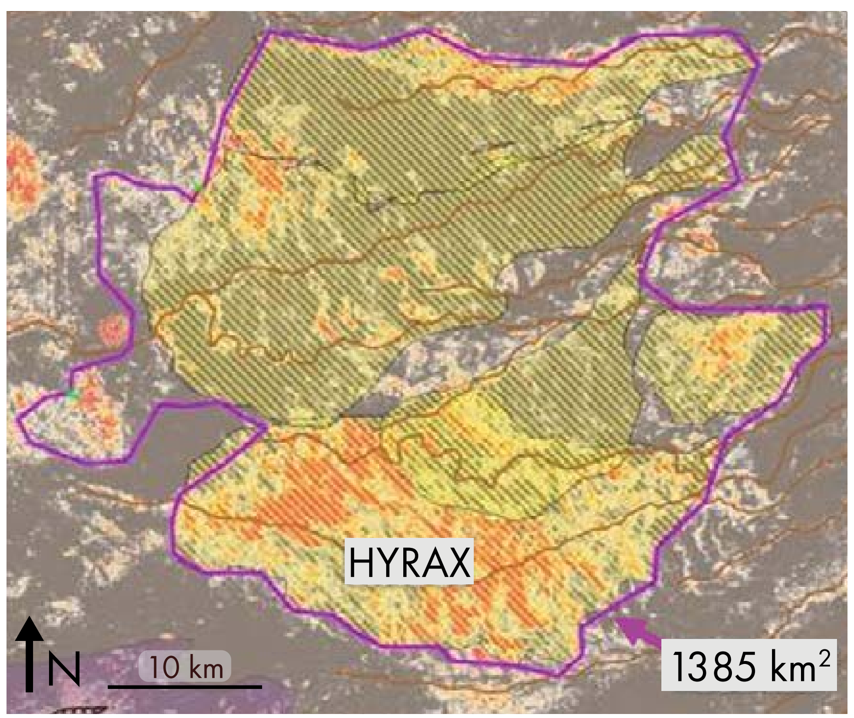
Seismic data suggest a more complex depositional architecture in the Saturn Complex than what could have initially been foreseen

IN MARCH 2025, Sintana Energy "broke" the news that Australian major Woodside decided not to exercise its right to farm into Licence PEL 87 in Namibian waters, north of the Mopane discovery. The decision did not cause a lot of stir, possibly because it was not a relinquishment as such. Still, it is not a good sign to see a major company decide not to move ahead after spending a significant amount on a high-spec 3D seismic survey across PEL 87, in which Pancontinental is the main operator (75 %), partnered by Custos (15 %, in which Sintana has a 49 % direct interest) and Namcor (10 %).



The most important prospective area within PEL 87 is the Saturn Complex, the size of which matches or even supersedes the extent of the discoveries a little further south. This then begs the question: What made Woodside decide not to embark on a Namibian adventure?

There is likely a subsurface element at play that caused the company to make this call, even though it cannot be ruled out that it was simply a matter of reduced appetite to go for something frontier and enter a new country. But let's focus on the subsurface here. There are some seismic sections available from PEL 87 that may actually hint at a more complex subsurface setting than what might initially be assumed. This was flagged to me by geologist Jamie Vinnels last month.



Hyrax leads in the Saturn Complex, showing ultra-far seismic offset AVO response.

SOURCE: PANCONTINENTAL HALF YEAR REPORT 2024

In the latest Pancon (Pancontinental) Half Year report, some interpreted seismic lines and time slices were published that show the Saturn Complex. These images allow for making some inferences about the reservoir architecture of the sediments in the Saturn Complex.

Looking at the time slice from the Pancon report, which shows lead within the Saturn Complex - Hyrax, one might at first think that it represents channel-lobes complexes. However, two observations complicate this observation. First of all, the position of these prospects is only a few km from the shelf edge, which is usually the steeper part of the slope. This is the area that is often prone to sediment bypass, leading to the deposition of thin discontinuous sands on the slope, while delivering more substantial reservoir sands further into the basin.

Second, when taking a closer look at the amplitude responses within the mapped prospects, there is something else going on. Namely, some elongate ridges can be observed that run parallel to the paleo-shelf break – this can particularly be seen to the south of the "Hyrax" label in the image (left). Considering the position of the Saturn Complex, these ridges could be interpreted as slumps that formed as a result of the shelf edge failing, which is not unthinkable given the position of this prospect with respect to the shelf edge. In addition, the failure scarp can in fact be seen in the seismic line that was also published by Pancon (see below).

If these prospects are in fact slumped units rather than an undisturbed reservoir section, there is much more of a risk of compartmentalisation, which has detrimental effects on reservoir connectedness. This is not what companies will want to see in a deep-water frontier environment like Namibia, and might therefore have been a reason for Woodside to leave the area for what it is. ■

Henk Kombrink

Romania – will there finally be a new bid round?

With the last bid round ages ago, it will be about time for another one to be held, with recent rumours pointing in that direction. But will this turn the tide of overall inertia in the country?

ROMANIA used to be Europe's stronghold when it comes to oil production. But it's not anymore today. That's not because the country has run out of oil or gas - see the important Neptun gas field development offshore; it also has something to do with the lack of activity regarding further drilling or development. "Romania is the sad part of Europe's oil and gas story," said someone I spoke to at the BEOS Conference in London the other day.

The most telling statistic when it comes to inactivity is the fact that the last onshore bid round took place in 2011. If you compare that to countries like Hungary and Ukraine, where there are two licensing rounds per year, and with other neighbouring countries having open-door policies, the conclusion is obvious.

There are two main petroleum provinces in Romania – the southern and eastern Carpathians. In the south, exploration potential seems quite limited and is mostly focused on undrilled compartments close to existing fields, but in the east, there is more potential, also when it comes to exploring new plays. However, it was only a few years ago that the first 3D seismic survey was acquired in that region, which suggests that the arrival of this technology is late in that part of the world and another sign that progress has been slow. And this is against a backdrop of a complex foreland compressional regime, requiring 3D for better prospect mapping and exploration.

So, will there be another bid round soon? According to a person I spoke to on the matter, it is not the first time that these rumours have circulated, and many people don't count on it at all. "No one will believe until it is published in the official gazette," he concluded. ■

Henk Kombrink

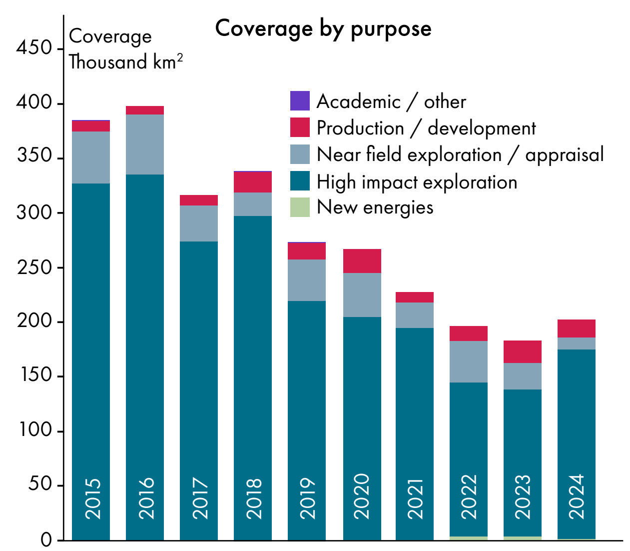
At the start of the next super-cycle or halfway to rock-bottom?

The total annual areal extent of seismic surveys has rapidly declined over the past ten years

APART FROM Norway, the UK Continental Shelf saw the highest number of seismic surveys acquired when looking at a global overview over the past ten years. Is that something to cherish as a UK exploration community and use as proof that there is actually a lot going on?

Maybe not so much, when listening to Graeme Bagley's presentation at the Seismic Conference in Aberdeen the other day. "Most of these surveys were postage stamps," he said when I spoke to him afterwards.

This observation seems to correspond with a global trend when looking at overall seismic acquisition activity over the past ten years, as Graeme illustrated in several ways through the work performed by his colleagues from Westwood Global Energy Group and Seisintel.



REDRAWN AFTER WESTWOOD GLOBAL ENERGY GROUP AND SEISINTEL

In 2015, about 400,000 km² was surveyed; in 2024, it stood at slightly north of 200,000 km².

"It is a tough game the industry is in," said Graeme at the start, "and these numbers are probably the reason why the business is tough."

Then the question can be asked, are we now at a turning point towards an increase in surveying activity in the years to come, or is it a matter of continued decline?

When looking at high-impact exploration drilling activity over the same period, it is very hard to see a trend. Where trends in oil price and the number of exploration wells drilled was nicely coupled, despite there being a small time-lag, that relationship broke down around 2020. Oil prices rose again after the Covid slump, but the number of wells drilled has not and stabilised at most. "Capital discipline at times of enhanced volatility" is how Graeme called it.

So, I guess it will be difficult to predict the future, but what is more certain is that the global prospect portfolio is drying up this way. In support of that, Graeme showed that from the moment a survey is acquired, the success rate of wells drilled on that survey drops off after five years. This probably relates to the observation that a good prospect will stand out on a new acquisition, forming an immediate momentum to drill and not wait. If there is no obvious candidate, there is more of a chance for the data to be "forgotten" for a little while.

It will be really interesting to see how the industry is developing over the next few years, but if there is a trend that provides ammunition to those wanting to see the end of high-impact exploration, at least by the IOC's, it is the graph shown here. ■

Henk Kombrink

S&P Global
Commodity Insights

The E&P industry of the future

The global energy landscape is undergoing profound transformation, shaped by shifting market dynamics, technological advancements, and the accelerating need for sustainable energy solutions. The Exploration & Production (E&P) sector stands at the forefront of this evolution, navigating the complex interplay between operational efficiency, resource optimization, and the broader energy transition. This brief, produced by S&P Global Commodity Insights in collaboration with the European Association of Geoscientists and Engineers (EAGE), explores the immediate opportunities in 2025 and the long-term transformations that will define the industry over the next five to ten years.

RACHAEL MORELAND, VP GLOBAL ENERGY SOFTWARE & INNOVATION LEAD

AN INDUSTRY IN TRANSITION OR TRANSFORMATION?

The upstream E&P sector has faced challenges over the last decade, including a downturn, the energy transition, and COVID-19. The industry is resilient but must address questions about its future shape and size as it considers factors such as expected continued demand beyond 2050, workforce demographics and capabilities by 2035, and the role of technology in achieving returns on investments. Figure 1 shows the S&P Global Energy Scenarios liquids demand up to 2050, highlighting the "Inflections" scenario with peak demand around 2029 followed by a gentle decline.

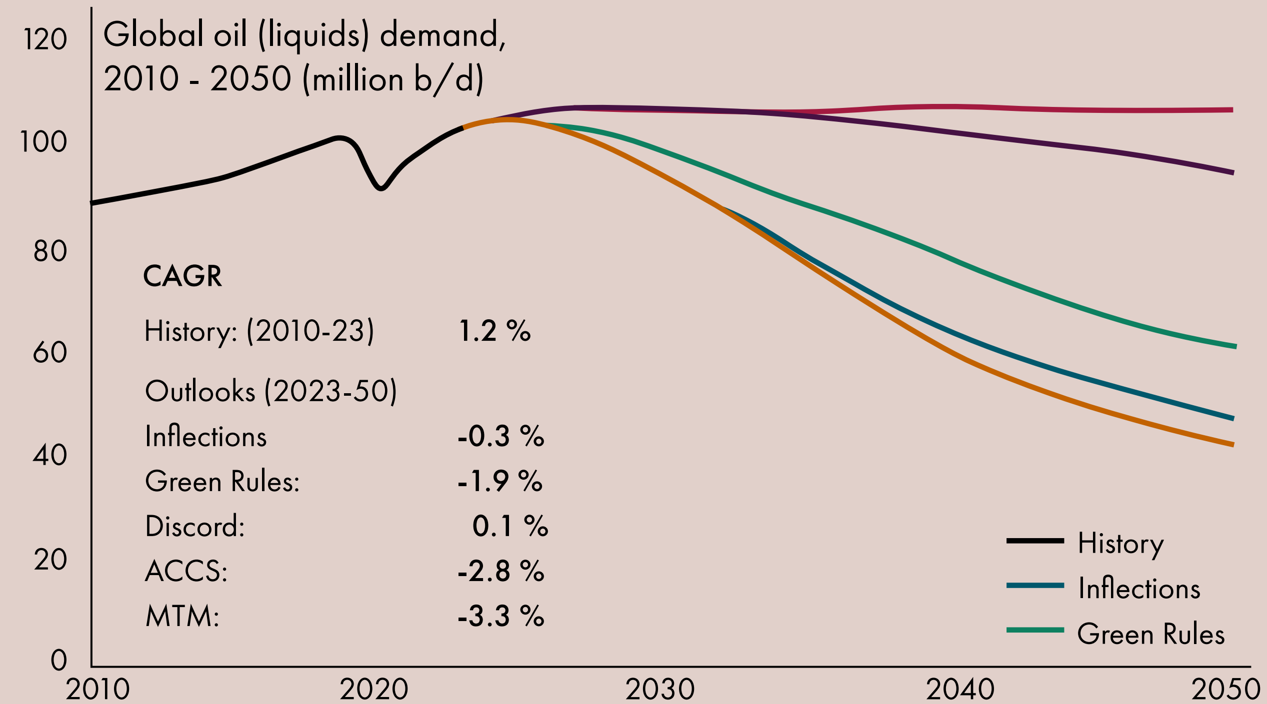


Figure 1: S&P Global Commodity Insights Scenarios, July 2024.

GLOBAL GEOSCIENCE OUTLOOK FOR 2025: SETTING THE STAGE FOR YEARS TO COME

The energy industry is shifting in how it works, manages data, and makes operational decisions. Key themes for 2025 include emerging technologies, sustainability, decarbonization, evolving workforce skillsets, and global challenges in the geopolitical landscape. Opportunities will center around new job roles in Carbon Capture and Storage (CCS), Geothermal, and Digital Transformation within the E&P sector. Several factors will influence how this landscape evolves in 2025:

- The continued drive to harness the potential of data-driven decision-making, including the testing and scaling of autonomous systems already in development
- Evolution of the geoscience workforce as the sector adapts to career development and skills evolution in order to create business advantage through technologies such as AI
- Maximizing recovery through relentless focus on excellence in reservoir optimisation
- Continued innovation in subsurface data (e.g. seismic) and technologies

AI, automation, and digitalization are transforming the E&P industry. It is being tested and applied in many workflows, from strategic settings such as portfolio management through to technical applications such as predictive analytics, seismic interpretation, reservoir modelling, and production optimization. Over the next five years, AI-driven geoscience models will improve subsurface imaging, reduce exploration risks, and enhance resource identification. AI-powered automation will optimize drilling parameters, and AI will play a crucial role in emissions monitoring and carbon capture initiatives.

Exploration drilling and resource discovery potentially hit record lows in 2024, and whilst an uptick is possible in 2025, there is a real risk that secure, diverse production at the required levels might be difficult by the late 2030s. This is a combination of stranded resources (transition regulation, cost, GHG intensity) and low discovery rates allied with reducing returns from established technical reserves replacement approaches such as enhanced oil recovery or infrastructure-led exploration. If the industry accepts that exploration is needed to add material reserves back into market, then it might struggle to do so through highly mature basins, meaning that risks associated with finding new reserves increase. The jury is still out on the return of exploration, but it is becoming increasingly apparent that new strategies and approaches are needed.

This is a sector and workforce that continues to innovate and evolve commercially and technically against a backdrop of reduced budgets for exploration, increased regulation, a push to shorten times (e.g. the typical 8-10 years of an offshore cycle from licensing to production) against an uncertain monetization pathway and continued M&A activity. It's fine to ask or encourage geoscience to evolve faster but good leadership is needed to really enable this.

E&P WORKFORCE OF THE FUTURE: THE DILEMMA

The demand for hydrocarbons will continue, requiring skilled professionals to find and produce resources. The industry faces challenges in attracting new talent due to declining enrolments in petroleum engineering programs and societal pressure against working in the industry. Retaining existing staff, ensuring they are up to speed with new technology, and attracting bright new staff with new skills and capabilities are essential steps. Where will these staff come from? There seems to be convergence in key areas:

- Providing routes into industry without pure geoscience degrees
- Recruiting from regions that have increased their geoscience academic offerings and working with those institutions to help them deliver the best courses possible
- Building bigger teams local to resources where education can be supported and there are additional benefits such as meeting local content requirements
- Understanding the demographics of teams a decade from now and maximising knowledge retention in E&P organisations through both technology and people before the opportunity is lost

E&P TECHNOLOGY INNOVATION

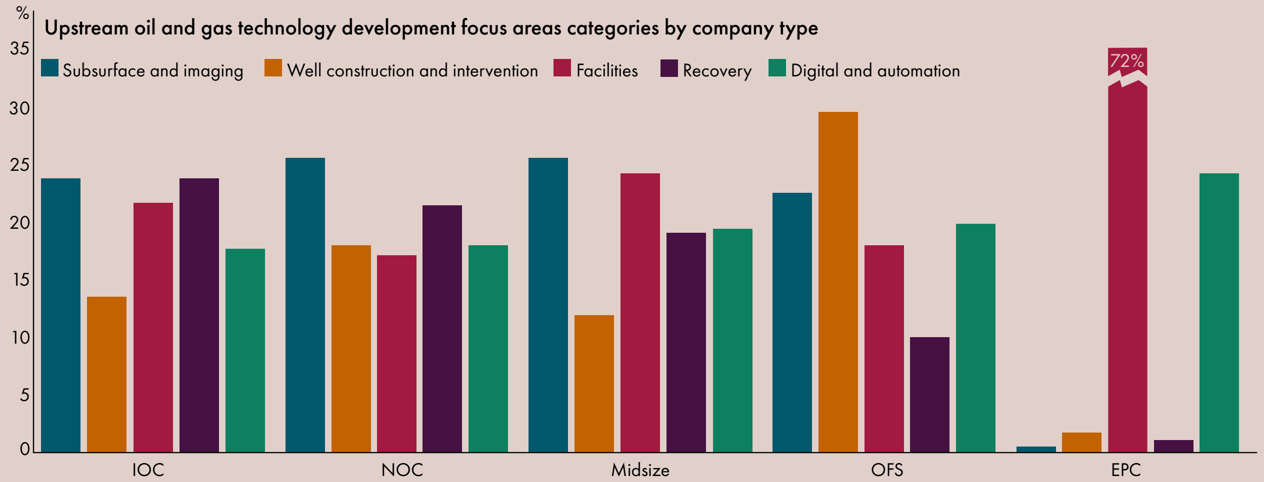
Technological innovations have significantly impacted the E&P industry, focusing on enhancing efficiency and developing new capabilities. Recent improvements include seismic acquisition, wellbore, and reservoir technologies. Digital transformation has also led to advancements in exploration and production workflows, data retrieval and processing, and increased innovation cycles.

Different types of companies across the Upstream space vary on their technology development strategies. Figure 2 shows OFS companies have shifted focus to wells and subsurface, while IOC operators align strategy with development, and NOCs emphasize subsurface and enhanced recovery. Digitalization and automation remain consistent priorities across the industry.

The exploration and production (E&P) industry is undergoing a profound transformation, driven by advancements in artificial intelligence (AI), automation, and digitalization. Technology innovation and areas of investment will rapidly change with the next few years being pivotal in defining areas of rapid AI development and adoption. As operators and service companies strive to enhance efficiency, optimize reservoir management, and reduce operational costs, AI is increasingly becoming a core enabler of technological evolution in this space.

ENERGY DIVERSIFICATION FOR A PROFITABLE ENERGY TRANSITION

Energy companies are diversifying their portfolios beyond traditional oil and gas as part of broader energy transition strategies. This includes investments in CCS technology, renewable energy, and green hydrogen. The out- ▸



Data compiled September 19, 2024.
Based on 576 discrete technology records of 8 IOCs, 1,061 records of 21 NOCs, 472 records of 17 Midsize companies, 794 records of 17 OFSs and 177 records of 6 EPCs.
Source: S&P Global Commodity Insights.

Figure 2: Upstream oil and gas technology development focus areas. S&P Global Commodity Insights, September 2019.

look for carbon sequestration projects is optimistic, with significant growth expected in regional hubs like the Gulf Coast, Permian Basin, and Midwest. These hubs are being scrutinized to see if they really work and can be replicated elsewhere in the world. Renewable energy investments are also robust, with North America, Europe, and Asia-Pacific leading the transition to a low-carbon energy system.

SUMMARY

The E&P industry is at a pivotal moment, navigating the complexities of the energy transition while striving for operational efficiency and sustainability. This brief highlights the key trends, challenges, and strategic imperatives that will shape the future of energy. As we look ahead to 2025 and beyond, it is crucial for industry professionals to embrace innovation, digitalization, and collaboration to drive the evolution of E&P in a changing world.

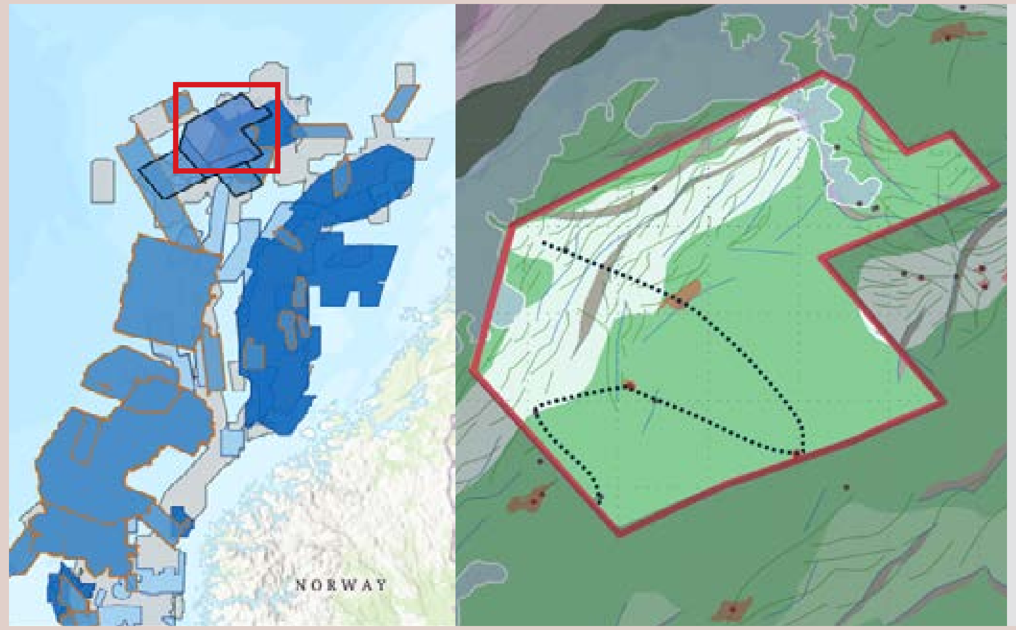
Explore how S&P Global equips geoscientists with tools and data for future E&P decision-making.

Geological understanding based on new data is required to unlock potential in the Vøring Basin

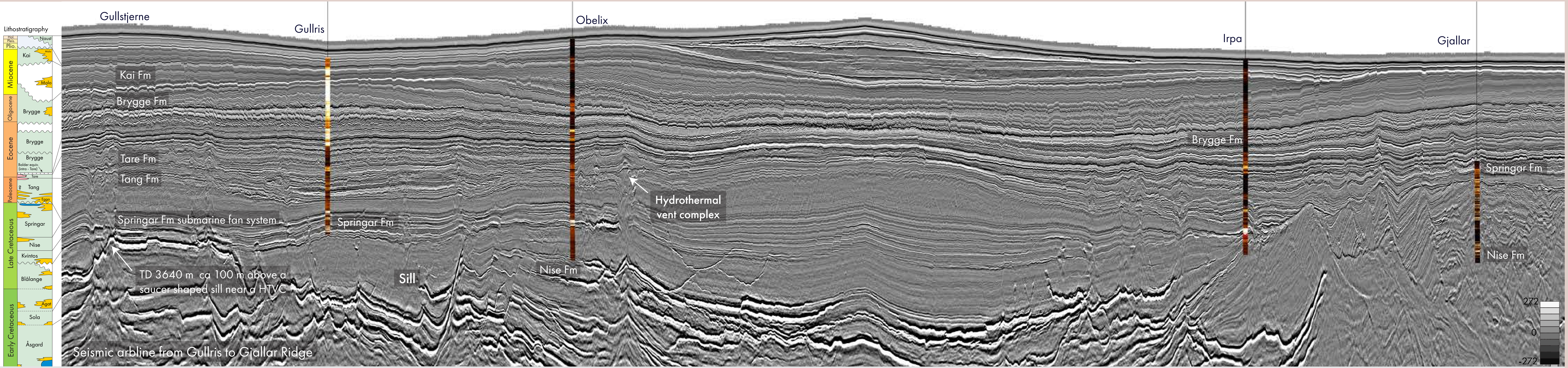
TGS has taken another step forward for new exploration in the frontier Vøring Basin acquiring 10,000 km^2 GeoStreamer 3D seismic using state-of-the-art broadband processing and imaging technology.

Highlights:

- New high-quality seismic and FWI velocity attributes to identify petroleum plays and prospects
- Refinement of sedimentary systems and sand deposits in regions with complex geology
- Identification and mapping of deep-water Paleogene source-to-sink sedimentary systems
- New understanding of volcanic basin processes and deposits
    - Interaction between volcanic rocks / sill intrusions and sediments
    - Maturation and focused migration of hydrocarbons from deeper structures to shallow reservoirs in hydrothermal vent complexes (HTVC)
- Tie to industry and scientific boreholes and seabed sampling locations



TGS 3D seismic data coverage in the Norwegian Sea. PGS23M02NWS GeoStreamer 3D seismic and location of composite foldout line.



The composite line is from the newly acquired PGS23M02NWS 3D survey. The line passes near five wells in the Vøring Basin, from Gullstjerne 14 km east of the Balderbrå discovery to 6704/12-1 on the Gjallar Ridge. The primary drilling targets were sand units in Springar Formation. Gullstjerne and Gullris were both associated with a class III AVO anomaly believed to be related to gas bearing turbidites, but the wells were dry. Obelix was a gas discovery estimated to contain 12.6-69.2 million barrels of oil equivalent. The Irpa gas field was discovered in 2009. Production is planned to start in 2026, and the field may extend the life of Aasta Hansteen until 2039.

Outer Vøring Basin - what is required?

JENS BENFEELDT AND REIDUN MYKLEBUST, TGS

TO UNLOCK the prospectivity of the Outer Vøring Basin, TGS has acquired ~10,000 km^2 of GeoStreamer multisensory broadband data using a wide-tow triple source configuration and two long tails for FWI (full-waveform inversion) processing. This new dataset is the latest piece of the comprehensive TGS Atlantic Margin data library, covering the Faroe Shetland Basin to the Norwegian Sea.

During the last decade, there has been a shift to larger 3D surveys, which is important for the new geological understanding. From 2017 to 2020, TGS acquired more than 55,000 km^2 in the Møre and Vøring basins, providing new insight and knowledge of the prospectivity along the whole mid-Norwegian continental shelf.

The PGS23M02NWS addition to the Atlantic Margin is a high-quality GeoStreamer volume which combines multisensory broadband and wide-tow triple source efficiency with the latest processing technology and velocity model building to improve the subsurface imaging, its complexities and potential. Pre-stack depth migration (PSDM) combined with full-waveform inversion (FWI) makes a major difference for the interpretation and mapping of hydrocarbon deposits and for discrimination between volcanic rocks and sediments.

GEOLOGICAL SETTING AND OPPORTUNITIES

For more than three decades the Outer Vøring Basin has been explored, experiencing increasing or decreasing industry interest depending on recent well results and resource estimates. The area was without infrastructure, and it took 21 years before the 1997 Luva discovery, now a part of the Aasta Hansteen Field, to come online in 2018 after the construction of the Polarled pipeline. Recent discoveries such as the Obelix Upflank (2023) and Haydn (2024) have again spurred interest in the area potentially extending the life of Aasta Hansteen by seven years. Besides the infrastructure in place, what other factors have changed to renew the industry interest?

"Norwegian gas is in high demand and is crucial to Europe's energy security. That's why it's important for us to continue exploring and making new discoveries so we can maintain a high level of deliveries" (ref: Equinor).

Another important factor contributing to the change of exploration interest in the area could be the cooperation between academia, petroleum companies, and the government in joint research projects, leading to the publication to new geological models and research results. The Paleogene continental breakup and ocean formation is an important event in this geologically complex area, as it impacted the sedimentary systems going from shallow to deep marine environments with bottom currents and sedimentary drift deposits. To further improve the exploration success in the Vøring Basin, an understanding of the volcanic margin deposits and processes is essential. Short-term effects of the magma emplacement included deformation, uplift, heating of host rock, petroleum maturation and differential compaction. The recent results from the IODP Expedition 396 drilling campaign in 2021 may provide new documentation and constrain on the Paleogene breakup magmatism which should be beneficial for the explorationists working in this area.

The Gjallar Ridge, covered by the PGS23M02NWS, was a large pre-breakup structure. Sand sourced from Greenland may have crossed the Vøring transform margin to the Vigrid Syncline and Fenris Graben.

With new high-resolution seismic data, interpreters will be able to map and explore in detail the deep-water source-to-sink sedimentary systems related to the Paleocene-Eocene Thermal Maximum.

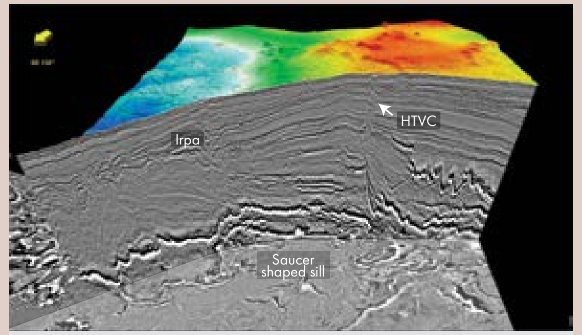


Figure 1a: Irpa gas discovery (proven in 2009) is located above a deep saucer-shaped sill connected to a HTVC less than 2 km from the well. Obelix Upflank discovery is located 20 km further south, and is situated in a similar geological setting close to sill intrusions and hydrothermal vent complexes.

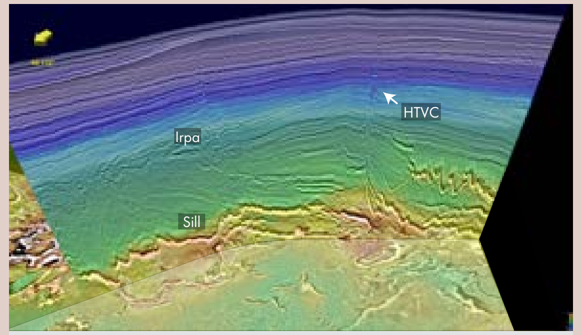


Figure 1b: The sill complex correlates with high seismic velocity, whereas the HTVC is associated with lower seismic velocities in the dome structure. Low velocity might be an indication of gas and thus a good guide for mapping fluid migration not clearly visible on the seismic profile.

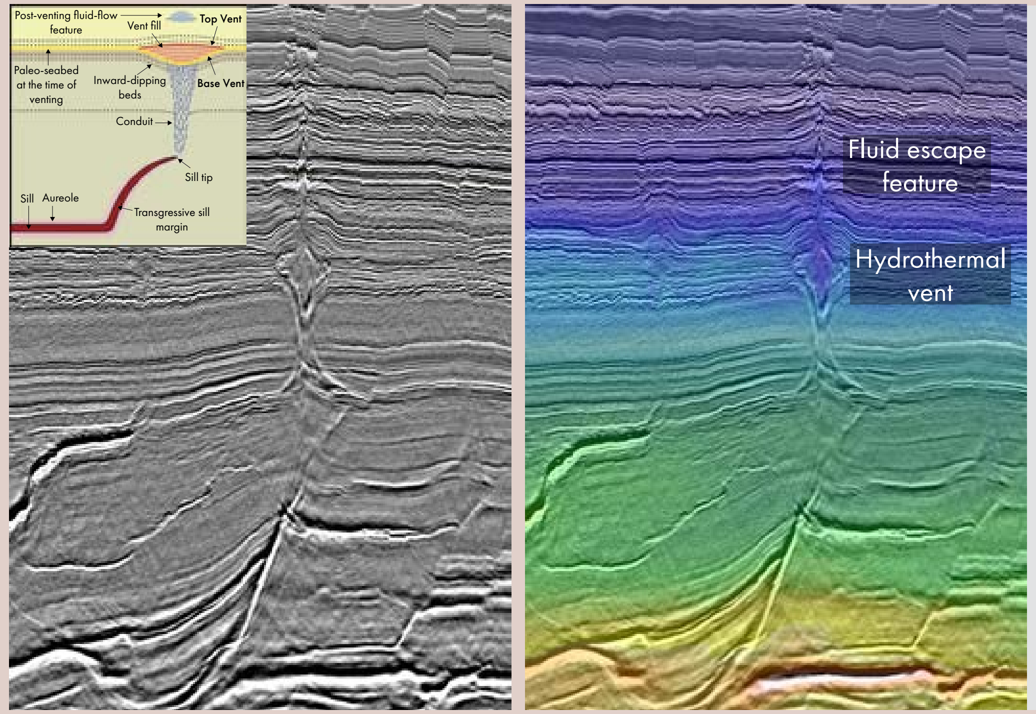


Figure 2: Seismic characteristics of hydrothermal vent complex (HTVC). Inset fig from Manton et al., 2022. Vent conduit with a conical geometry has disrupted reflections of variable amplitude. Post-venting fluid-flow features are image in the velocities. Gas leakage may correlate with velocity inversion. Schematic figure: Manton et al., 2022.

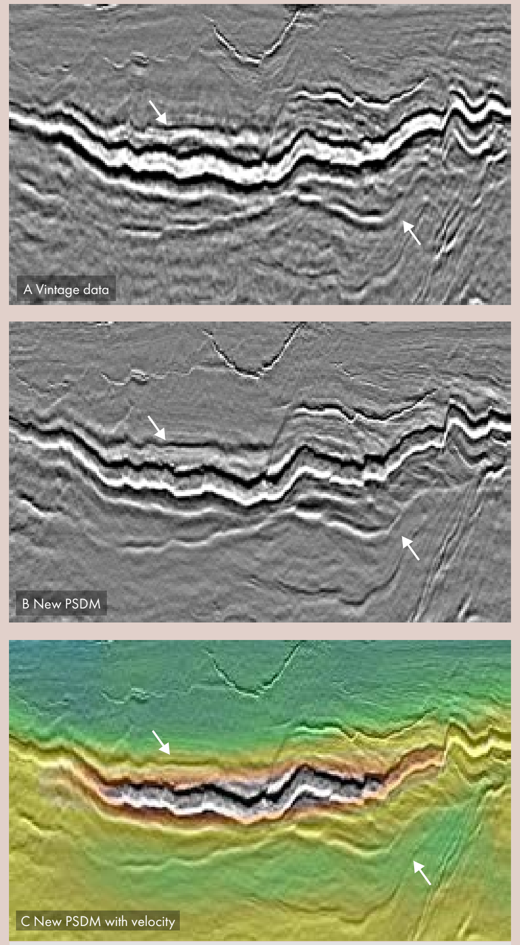


Figure 3: New PSDM (B,C) showing improved sub-sill imaging. Top and bottom of a 100 - 200 m thick sill ("Vivel Sill") can be interpreted with higher confidence and is also supported by high FWI velocities. Sub-sill structures and faulting have better definition compared to vintage data (A).

Over the last decade, more than 800 hydrothermal vent complexes (HTVC) have been identified in the Vøring Basin, and some of them studied in great detail. A schematic from Manton et al. (2022) is shown in Figure 2. These studies have led to a better understanding of their formation and long-term impact on fluid migration and petroleum systems. The vent complexes were formed due to pressure build-up in metamorphic aureoles around the hot magma intrusions.
56 millions years ago, mainly by explosive eruption of gases, liquids and sediments, forming craters at the seafloor. Most of them are located at the Top Paleocene level (Planke et al., 2004). The conduits between the sills and the vents are important for fluid-migration and potential for hydrocarbon migration from deep structures to shallower reservoirs. Mounds and seismic seep anomalies located above the hydrothermal vent complexes suggest that they have been re-used for fluid migration long after their formation. (Manton, et.al., 2019). Internal structures of the vent complexes are now possible to interpret in detail on the new data and will contribute further to the knowledge of these.

Sills display a large variation in geometries and sizes and the emplacement processes lead to complex geometries in the Vøring Basin. Sills can vary from a few meters in thickness to a couple of hundred meters and they are observed to merge into one or split into several sheets. They may clearly impact both seismic imaging and potential hydrocarbon reservoirs, The intrusive sill complexes can more easily be recognized and risk-evaluated on the new seismic data. Deep sills which were poorly imaged on vintage data can now be mapped with high confidence and supported by velocity contrast as seen in Figure 3. The new data are crucial input for basin and reservoir modelling and can facilitate de-risking of prospects.

FEATURES

"The new zonation I have been able to define is therefore a great addition to our knowledge of the Triassic in the Southern North Sea..."

Niall Paterson – CASP

FEATURES

Seismic data on the workbench

As the oil and gas industry is slowly shifting from acquiring lots of seismic surveys to making the most of what currently exists, so are companies moving into the domain of enhancing the quality and facilitating the handling of these datasets. Anders Kihlberg, one of the people behind the development of the Petrel software, is now working on a new generation of tools under the umbrella of the OpenMind platform to do exactly that. Here, Anders and his colleague Brit Sauar explain what the company's plans are and what they have been able to realise thus far

"MY GOAL is to equip explorationists with a toolbox containing all relevant algorithms to efficiently create optimal seismic volumes for interpretation and stratigraphical analysis," says Anders, who hails from Sweden but has been part of the Norwegian generation of successful entrepreneurs in the energy service sector over the past decades. "We want to simplify complex geophysics by making seismic post-stack data improvement and optimalization easily accessible to all interpreters."

Brit Sauar.

Anders Kihlberg.

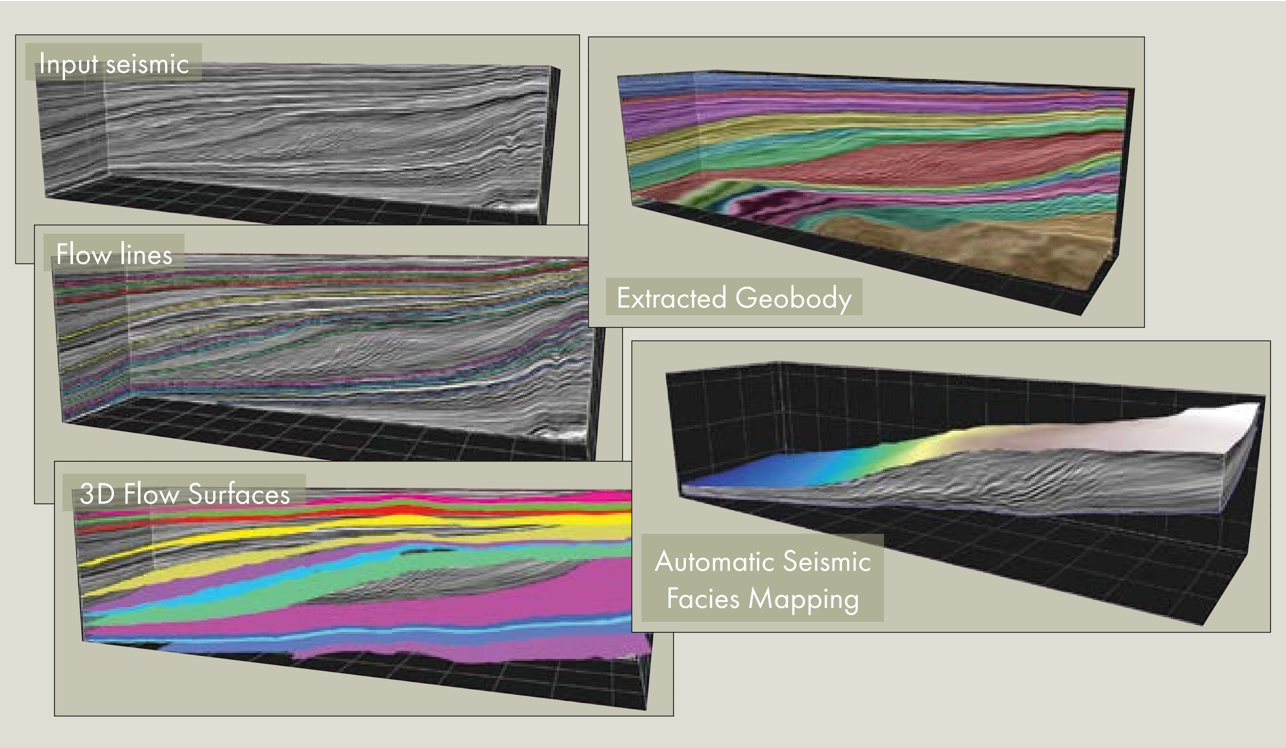


Figure 1. Series of steps in the StratCracker process. A single zone is filtered out and displayed in the upper right corner.

PHOTOGRAPHY: BRIT SAUAR PRIVATE ARCHIVE

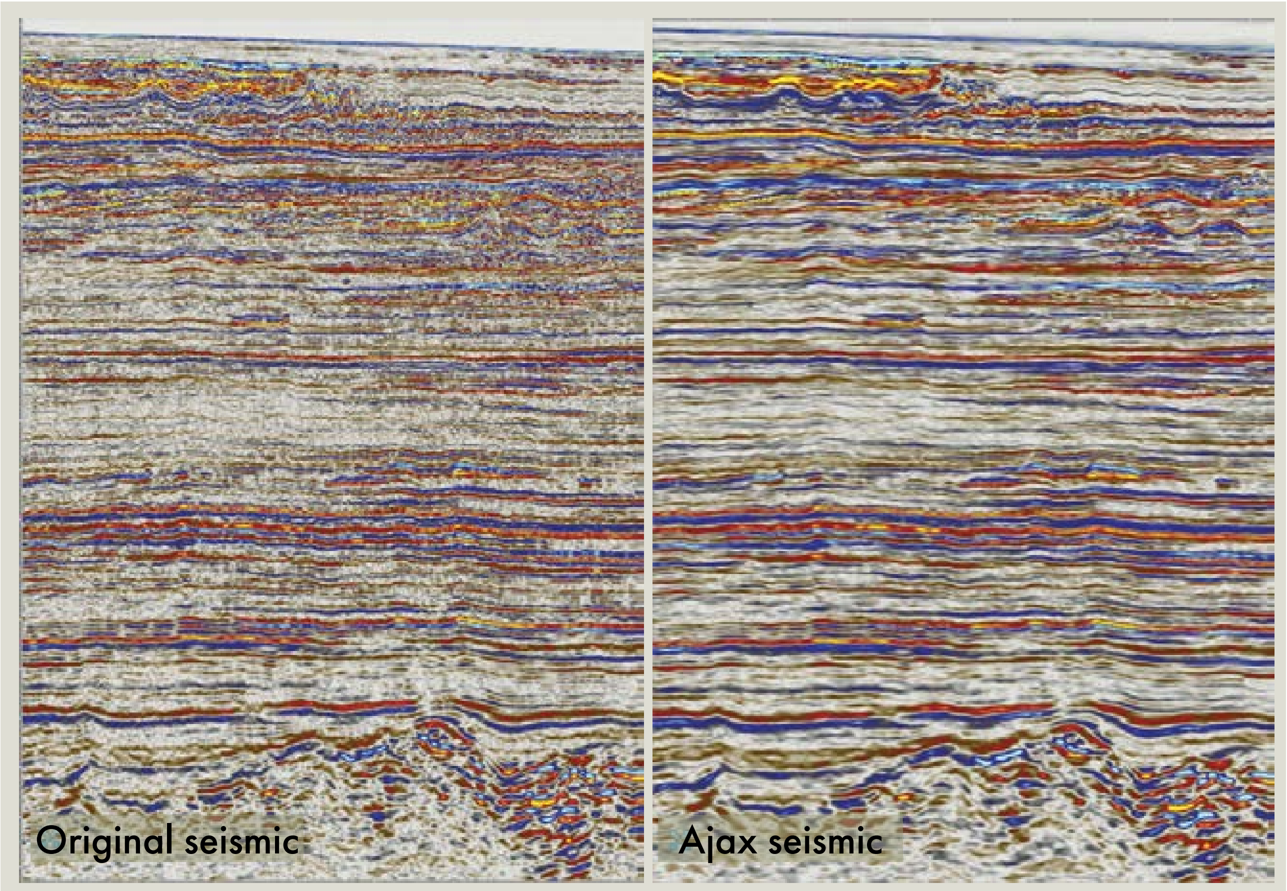


Figure 2. Seismic from a project offshore Namibia, showing improvement of the seismic after running the Ajax AI one-click function.

Anders continues to explain that the majority of seismic volumes have undergone mainstream pre-processing. "The seismic character and quality vary and in many cases are sub-optimal for structural and stratigraphic interpretation," he says.

"We are therefore building an AI interactive and stepwise process wherein the interpreter experiments with various seismic attributes, visual blends or physical blends, until a combination that gives the best result for efficient seismic interpretation. We will introduce a multi-attribute physical blend function, accompanied by a copilot designed to guide and assist the interpreter in determining the most suitable seismic volume," continues Anders.

"Presently, many interpreters accept the provided seismic volume without scrutinizing its data quality and usability, mostly due to limited project time. We provide the interpreter with all the necessary post-processing imaging tools, enabling users to interactively, easily and efficiently extract all available deterministic information from the valuable seismic volume," adds Brit.

EXTRACTING GEOLOGICALLY MEANINGFUL STRUCTURES

Anders and Brit have observed that despite all the conversations around AI and machine learning, which certainly dominates much of the subsurface geoscience narrative, challenges remain when applying deep learning to large-scale seismic interpretation.

"Neural networks are typically constrained by memory limitations, requiring seismic 3D volumes to be subdivided into smaller sub-cubes for training and inference," says Anders. "These sub-volumes must then be stitched together, often introducing discontinuities and mismatches. More critically, this subdivision can obscure important geological context, especially for large-scale stratigraphic patterns that span the full extent of a volume."

"These limitations have motivated us to rethink our approach to multi-horizon and multi-zone interpretation. When interpreters examine a seismic section, their eyes are naturally drawn to broad, low-frequency features - coherent reflections and first-order stratigraphic units that represent depositional cycles bounded by maximum flooding surfaces, unconformities, or other major geological events. These features are intuitive for humans to trace, yet they remain difficult for automated methods to extract consistently.

To address this, we introduce a framework designed to automatically extract first-order sequences from a seismic volume. Our approach begins with spectral decomposition, emphasizing low-frequency components to enhance the visibility of large-scale stratigraphic units. These enhanced features are then interpreted ►

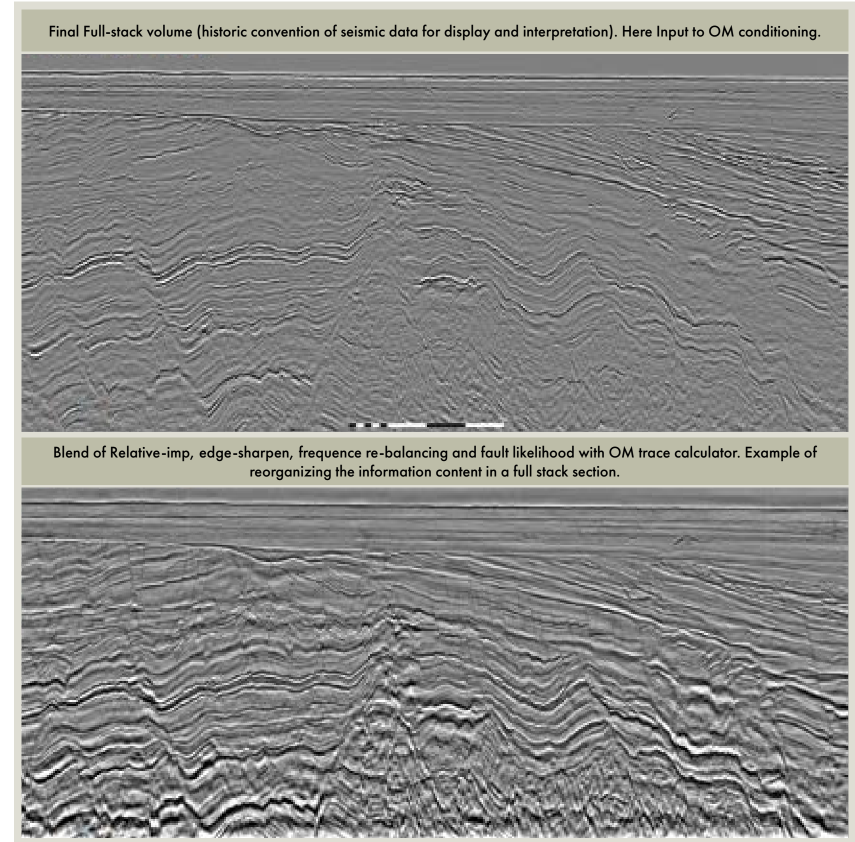


Figure 3. Blend of Relative impedance, edge-sharpening, frequency re-balancing and fault likelihood using the OpenMind trace calculator.

through the reflection dip field, which we treat like a fluid velocity field, generating seismic flowlines that follow the underlying structural geometry of the seismic volumes.

Flowlines capture the geometry of seismic reflectors by integrating along the local dip, yielding dense networks of trajectories. However, not all flowlines correspond to significant geological features. To isolate those of interest, we apply a targeted "smart selection" strategy based on seismic attribute analysis along the flowlines themselves.

This workflow begins by computing seismic attributes along each flowline in a 2D seismic section. These attributes capture changes in reflection character and, when evaluated along geologically meaningful paths, reveal lateral continuity and context that is often missed in traditional, seismic amplitude analysis.

We then identify breaks or contrasts in these attribute profiles to select the most geologically relevant flowlines. These selected trajectories serve as seed lines for extension into 3D, allowing us to automatically generate a multi-zone probability volume that reflects the underlying first-order seismic stratigraphy. Each zone can be visualized independently, colored, or filtered to support focused interpretation of specific intervals (Figure 1).

With this approach, we emphasize the goal of identifying and extracting geologically meaningful structures, advancing toward a more consistent and automated interpretation framework that also can be used for meaningful seismic attribute extraction and analysis."

THE WORKBENCH

Another thing the GeoMind team has in the pipeline relates to further enhancement of seismic imaging quality. "Post-stack seismic volumes often contain valuable geological information that remains obscured due to noise, amplitude imbalance, or limited frequency content - making image enhancement an important step for maximizing interpretability," says Anders. "One-click AI functions such as Ajax, are already available in OpenMind and prove to be very successful."

"We are currently working on a so-called processing workbench designed to support both expert users and non-experts to simplify and streamline seismic image enhancement and multi-attribute volume creation, ultimately improving geological interpretation."

To ensure scalability and performance, the system supports batch job scheduling in the background, allowing users to launch and queue processes without interrupting interpretation work.

"A key capability of the workbench will be multi-attribute volume blending, where several attributes such as relative acoustic impedance, edge sharpening, frequency rebalancing, and fault likelihood, combined into a single enhanced output," adds Brit. "We can build these volumes today through a bit of a cumbersome process in the OpenMind trace calculator, whilst we aim to streamline this functionality. This will produce volumes that better highlight stratigraphic and structural features than conventional full-stack displays."

Figure 3 demonstrates how such blending enhances interpretation: Clearer reflector terminations, improved fault visibility, and more balanced amplitude distributions. While this specific attribute combination produced optimal results for one project, every seismic volume is unique, and the ability to experiment and tailor blends is essential. The final output of the workbench is a high-quality ZGY volume, fully compatible with platforms like Petrel."

This enables interpreters to seamlessly transition from enhancement to interpretation, leveraging the improved data quality directly within their existing workflows. ■

Henk Kombrink

Investing in Kazakhstan and Uzbekistan

Using western technology to arrest production decline

TAKO KONING, GEOLOGICAL CONSULTANT

Condor Energies ("Condor") is a Canadian, Calgary-based, publicly listed (Toronto Stock Exchange) energy transition company focused on Central Asia. The company has distinguished itself by building significant operations in Kazakhstan and Uzbekistan. Condor has over eighteen years of experience operating in Central Asia.

Central Asia includes the resource-rich nations of Kazakhstan, Uzbekistan, Kyrgyzstan, Tajikistan, and Turkmenistan, and the region has some of the largest oil and gas fields in the world. In Kazakhstan, this includes giant oil and gas fields such as Tengiz, Kashagan, and Karachaganak. These fields all have Western oil majors as partners, including Chevron, Eni, Shell, TotalEnergies and ExxonMobil. In Uzbekistan, this includes the giant Gazli gas-condensate field. Turkmenistan holds the giant Yolotan gas field. Central Asia lies in an optimum location with energy-hungry markets such as Europe to the west and China, India and Pakistan to the east.

In 1991, both Kazakhstan and Uzbekistan gained independence from the Soviet Union. Kazakhstan has a population of 20 million and is producing oil at a rate of 1.8 million barrels per day. In 2024, Kazakhstan produced 60 billion cubic meters of gas. Uzbekistan, with a population of 36 million, in 2024 produced 50 billion cubic meters of gas and minimal volumes of oil. Uzbekistan is planning to produce more gas but will keep most of it at home due to increasing domestic consumption including power generation, industrial uses and household heating.

LNG IN KAZAKHSTAN

Condor will be the first company to deliver Liquified Natural Gas (LNG) in Kazakhstan. In 2024, the company received two natural gas allocations to be used as feed gas for the company's modular LNG production facilities. The company is planning to construct Kazakhstan's first LNG facilities and produce, distribute, and sell LNG to offset industrial diesel usage in the country. LNG applications include rail locomotives, long-haul truck fleets, marine vessels, mining equipment, and municipal bus fleets. The total LNG fuel produced will have an energy-equivalent volume of over one million liters of diesel daily, while reducing CO_2 emissions equivalent to removing more than 38,000 cars from the road annually. These applications have all successfully used LNG fuel in other countries.

Construction of this facility is ongoing, and fabrication works are expected to be completed in the fourth quarter of 2025, with LNG production expected in the first half of 2026.

CRITICAL MINERALS LICENSES IN KAZAKHSTAN

In 2023, Kazakhstan awarded Condor with its first critical minerals license covering 37,000 hectares. In February 2025, a second contiguous license covering 6,800 hectares was awarded to Condor. The Company holds a 100 % working interest in both licenses. These licenses are in a heavily faulted geothermally active region, allowing migration of mineralized brines into Carboniferous-age subsurface reservoirs. The licenses offer a significant opportunity to recover lithium, cesium, manganese, rubidium and strontium, minerals of critical importance in the energy transition.

Shoreline view of Aktau city, nestled along the Caspian Sea, Kazakhstan.

PHOTOGRAPHY: ELEONZEBON VIA ADOBE STOCK

CONDOR IN UZBEKISTAN

In January 2024, Condor signed a production enhancement services contract with JSC Uzbekneftegaz to increase the production, ultimate recovery and overall system efficiency from an integrated cluster of eight conventional natural gas-condensate fields in Uzbekistan. Giant-size gas fields surround Condor's operations, including the Gazli field with gas reserves of 190 Bcm (23 TCF). Condor was the first Western strategic operating partner of the national holding company.

Prior to Condor's participation in the Uz field, production was averaging 10,000 boepd (barrels of oil equivalent per day) from the eight fields with approximately 80 active producing wells and 40 shut-in wells. Production is from Upper Jurassic shelf carbonates. The Uz reservoirs are larger analogues of Western Canada's prolific Triassic-age Charlie Lake and Mississippian-age Midale Formation platform carbonates. Condor's strategy is to apply proven Western Canadian technology to abundant workover opportunities in order to grow production.

In June 2024, the company commenced with a multi-well workover campaign for the eight fields, including installing proven artificial lift equipment, perforating newly identified pay intervals, and installing new production tubing. Currently, two workover rigs are being utilized. Production averaged 11,175 boepd in the first quarter of 2025, resulting in Canadian $22.2 million sales (Q1 2025). A very successful recent workover increased overall production to 12,300 boepd in mid-March. At least six additional well candidates have been identified with similar geological characteristics using a combination of legacy data and reprocessed 3D seismic data.

On March 20, 2025, Condor announced its 2024 Year-end Results. Don Streu, President and CEO commented "For Condor 2024 was a transformational year. Our strategy to implement multiple proven Western technologies in Uzbekistan on eight existing gas fields has not only mitigated a 20 % annual natural decline but yielded material production gains from the ongoing workover program and facilities upgrades. As a result, production volumes and revenues continue to increase quarter-on-quarter, which is generating positive netbacks. Results from our recently reprocessed 3D seismic data is providing higher resolutions that should assist with more accurately characterizing the reservoirs and identifying new targets in preparation for a 2025 infill vertical and horizontal drilling program."

More recently, using advanced cased-hole logging tools and the 3D seismic data, Condor identified a Cretaceous channel sand which flowed at 1,300 boepd on test. The company will further evaluate these channel sands as part of its 2025 infill drilling campaign. Condor Energies is expected to continue to grow in Central Asia due to its effective working relationships with the governments and national oil companies of Kazakhstan and Uzbekistan and application of proven and new technologies to produce LNG and hydrocarbons, all at the doorstep of numerous energy-hungry markets. ■

CONTENT MARKETING

The greater Caribbean Basin synthesis: Exploring the bigger picture using modern reprocessed data

The Caribbean has always presented explorers with the challenging task of understanding the complex regional tectonics and the associated relationships with source and reservoir deposition. Geoex MCG are currently utilising their unique position of having data throughout the Caribbean by reprocessing existing legacy data to elucidate the subsurface in this region. Several volumes from producing areas are now finished, with additional data ready to be added to this library in the coming months. Geoex MCG intend to leverage this understanding to encourage exploration in one of the world's truly last remaining frontiers

MIKE POWNEY, GEOEX MCG, JULIAN SHERRIFF AND STEPHEN DOYLE, DUG

UNDERSTANDING THE CARIBBEAN - DISCOVERIES CONFIRMED, POTENTIAL GROWING

The Caribbean has a long-standing history of hydrocarbon exploration, with most activity occuring within the region of Trinidad. Here, numerous gas fields have been discovered, including the prolific fields of Chaconia, Hibiscus, Poinsettia, etc. Despite this success, the rest of the Greater Caribbean has seen much less activity in the offshore domain in comparison. There are several reasons why this may be the case, one of which is the complex geological landscape facing explorers and the lack of modern data.

To truly understand the prospectivity of a region, explorers must first understand the geological history and how this has altered through time. This is particularly important in an area such as the Caribbean, where a series of unanswered questions remain regarding the formation of the basins. It is largely accepted that the Caribbean plate formed during the Late Cretaceous in the eastern Pacific region and then migrated eastwards relative to the North and South American plates behind an east-facing Great Arc of the Caribbean to its present position, but in order to constrain the timing of the collision across the northern area of South America new seismic is required. Geoex MCG have therefore embarked on an ambitious reprocessing campaign of a series of surveys in these key locations to better evaluate the regional tectonics and the subsequential link to subsurface prospectivity. This has been integrated into a wider portfolio of data (Figure 1) throughout the Caribbean, which has provided a deeper and clearer understanding of the various impactful events in this emerging frontier.

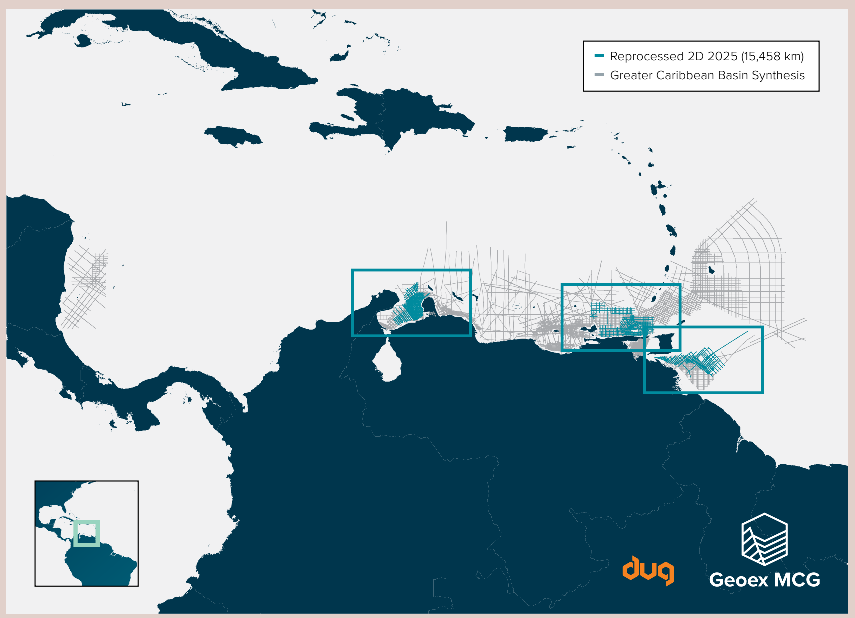


Figure 1: Map of the Greater Caribbean Basin Synthesis.

MAXIMISING LEGACY DATA – BESPOKE REPROCESSING TO FORM THE REGIONAL UNDERSTANDING

The surveys have followed an extensive reprocessing workflow, undertaken by DUG Technology, which has been adapted in a bespoke manner to deal with the various vintages (1980 - 1989) and associated targets within the various geographies. The surveys in question are now processed in both time and depth, with all associated products available, including gathers and angle stacks. Modern reprocessing has involved the creation of an accurate velocity model undergoing three iterations to ensure that the relative geological changes have been accounted for and captured efficiently. This has significantly improved the migration of key structures, which will develop the current view of the prospectivity in these regions. Further uplifts include undertaking a thorough SWSRME process to improve the shallow section as well as Q amplitude to ensure the vintage data quality is best maximised for reprocessing.

PERLA DISCOVERY AND FURTHER INSIGHTS

The first of such surveys that has been reprocessed, shot in 1980, is located north of Lake Maracaibo overlying the Perla discovery. This area is renowned for large oil discoveries, which have produced in the order of 30 billion bbls. However, Perla is particularly unique in that it relies on a secondary source rock which is alternate to the La Luna interval associated with the Maracaibo discoveries. Oligo-Miocene carbonates are invoked to provide the 17 TCF, which was discovered in 2009 by Repsol. The survey has been reviewed following the completion of reprocessing and has revealed additional Oligo-Miocene type structures in close proximity, whereby the amplitude response associated with these alternate intervals has been directly compared, with similarities evident. Furthermore, the imaging (Figure 2) has provided further clarity on the relationships between the Dabajuro Platform to the Urumaco Trough, which provides more insight into the locations of the largest sedimentary accumulation. From a structural viewpoint, a large-scale unconformity can be seen throughout the line, which is likely to mark the interactions of the regional tectonics, providing a more precise timing constraint.

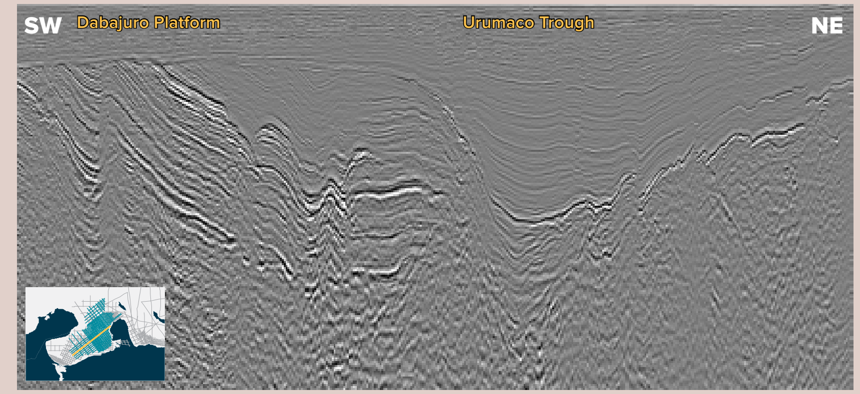


Figure 2: Reprocessed seismic line over Perla Discovery highlighting Oligo-Miocene structures and regional unconformities.

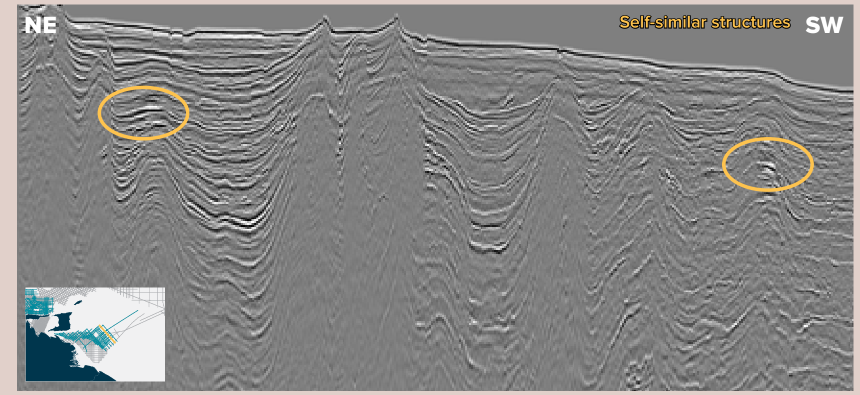


Figure 3: Reprocessed seismic line revealing self-similar structures in the offshore Orinoco Delta South of existing discoveries.

IMPROVING THE UNDERSTANDING OF THE OFFSHORE ORINOCO DELTA

A secondary area of significance to the prospectivity story of the Greater Caribbean is the SE of Trinidad. The offshore Orinoco Delta / Colombus basin region has been characterised by a series of discoveries. Similarly to the previous area, the tectonics are complex in the region, which is subsequently juxtaposed by a prograding system. Understanding this system with the reprocessed data will develop new insights and prove the prospectivity of the distal Orinoco delta system. Here, the source rock invoked is the 'Querecual' of Late Cretaceous age, which is the time equivalent of the infamous La Luna source rock responsible for the aforementioned Maracaibo discoveries.

This area, as well as being topical of late following bp's FID on the Manakin-Cocuina fields, has been selected for reprocessing to better evaluate the wider potential of these fields in a more regional context. Having evaluated numerous lines on the survey, self-similar structures (Figure 3) similar to the discoveries have been encountered, showing that the prospectivity in this area continues to the South of the existing drilling. These are seen to have similar amplitude responses that require further evaluation using the full suite of angle stacks and gathers available to Geoex MCG, intimating that the Orinoco Delta offshore region does, in fact, have excellent prospectivity.

CONCLUSIONS

Seismic data is knowledge. This is especially the case in areas of more frontier exploration where reprocessed data can shed light into the potential implications of the tectonic history on the prospectivity. Having recently finished the reprocessing of these volumes, Geoex MCG intend to integrate this data into their already regional portfolio to further evaluate and constrain the tectonic history with the view of developing areas that are likely to show improved prospectivity. From the areas that have been reprocessed so far, significant insights have been generated regarding the timing of tectonic events and the associated prospectivity, with areas such as the Delta Amacuro region & Northern Maracaibo showing excellent prospectivity. As this project develops, more data across the North of Southern America will be reprocessed, providing valuable insights that will contribute to this ever-evolving story.

How a recently acquired mining core became a new reference section for the Triassic of the North Sea

And the timing is right, because the Triassic is a key reservoir target for various carbon storage projects in the same area

In North Yorkshire, United Kingdom, a huge mine is being constructed by AngloAmerican to produce polyhalite from an Upper Permian evaporite succession. In order to design the shafts, a borehole was drilled to better understand the overburden, which includes Triassic and Lower Jurassic rocks. The section was entirely cored along its full 900 m length. This provides a unique dataset to understand the Triassic depositional system of the North Sea, even though it was not intended for that purpose.

Although the mine facilities are obviously onshore, the Jurassic, Triassic and Zechstein successions in the area are very much the equivalents of what is commonly found offshore. For that reason, it was recognised by geologists from CASP that the core of the so-called SM14 borehole offered a great opportunity to better characterize not only the Bunter reservoir, but also its sealing units. It is especially the seals that have hardly been cored offshore, for obvious reasons, but even cores from Triassic reservoirs are rare, because the interval has never been a major target in the UK North Sea.

"We're extremely grateful to AngloAmerican for granting permission to access the SM14 core," says Steve Vincent, CASP's Chief Geologist, "it really was a unique opportunity."

It resulted in the collection of about 600 samples, a detailed logging exercise of the core, and a hand-held XRF scanning project to have a better grip on the bulk chemistry of the rocks.

A BETTER GRIP ON TIME

"The Triassic succession in the North Sea, especially the continental Bunter Sandstone and its more distal playa lake equivalents, have been mostly considered barren in terms of the microfossil content," says Niall Paterson, who has been working on a new palyno-zonation of the Triassic based on the data from the SM14 core. Another advantage of the core is that we don't suffer from the ▸

PHOTOGRAPHY: CASP


Logging of core SM14 in AngloAmerican's core store in North Yorkshire.

effects of caving, which happens a lot when relying on cutting material for doing palynological research. The new zonation we have been able to define is therefore a great addition to our knowledge of the Triassic in the Southern North Sea, and rather than conventional wisdom that the Triassic is all barren, actually some of these formations are full of palynomorphs; not only the mudstones but also the evaporitic intervals."

CEMENT

Where Niall was mainly focused on the finer-grained lithologies in the SM14 core because of their microfossil recovery, sedimentologist Michelle Shiers mainly looked at the sandstone itself. Using whatever material there was available from offshore cores as well, she focused particularly on the distribution of cement in the sandstones, as this is a main driver for the ultimate storage and injection potential. "Some people may think that the top of the Bunter is always cemented by halite because of the overlying Röt evaporites," says Michelle. "We saw that the opposite is true in some cases, revealing a more complex diagenetic history than expected."

54 plugs from the Haisborough Group of core SM14, prior to porosity-permeability testing.

CASP

The organisation now known as CASP originated in 1948, when Brian Harland, also known for his work on the Geological Timescale and the Snowball Earth Concept, began the Cambridge Spitsbergen Expeditions (CSE). Many senior figures in academia and industry gained early field experience on these expeditions. CSE gave rise to the Cambridge Arctic Shelf Programme in 1975. Subsequently, CASP greatly increased its regional scope, diversifying its research to areas outside the Arctic for conducting field-based geological research in frontier and under-explored basins. This has led to the accumulation of about 46,000 samples from all over the world and a large analytical database. In more recent times, the organisation has pivoted towards geological carbon storage research.

THE SEAL

Going back to SM14, and it may sound counterintuitive, but it is the sealing units overlying the Bunter sandstone that formed the real boon in this project. "Combined with the wireline logs that were available from the borehole and the strength testing results, we have a unique dataset covering the equivalent of the sealing units of some of the future carbon stores in the UK Southern North Sea," says Simon Schneider, who has been involved with this part of the project.

A SECONDARY SEAL

The sealing unit that sits on top of the Bunter reservoir is generally considered as just Triassic in age, but there is a Lower Jurassic fine-grained succession that also forms part of the storage complex, as well as being a primary seal elsewhere. This Lower Jurassic interval is not only present in the SM14 core, but also in coastal outcrops not too far away from where the core was cut. That presented the CASP team with the opportunity to both study the core as well as the cliffs, such that a regional element could be introduced to the overall seal assessment. "It allowed us to provide more tangible data when it comes to the heterogeneities that characterise the Lower Jurassic succession," says Colm Pierce, who worked on the outcrops and core, "which are ultimately helpful to upscale into storage complex performance models."

Should you be interested in knowing more about the study, please get in touch with the team at CASP. ■

Henk Kombrink

PHOTOGRAPHY: CASP

Crafting a software that is ready for the future

Herman Nieuwoudt and Bill Shea give an honest account of how to manoeuvre in a changing subsurface software market and how being part of CMG fits into that narrative

As much as there is a consolidation happening in the large operator landscape and the seismic acquisition space, the same applies to the subsurface software business.

"Let's face it," says Bill Shea from Sharp Reflections, "in a market where there is not an awful lot of natural expansion, creating room for newcomers, only the strongest will win."

"A consolidation such as what we have now seen with CMG, makes sense in such a market."

"Whether we will ever be able to knock Petrel out of the park is another question," he laughs. "Ultimately, they have got resources we certainly don't, but yeah, we are here to join the battle."

Let me introduce Bill and Herman very briefly. Bill is the founder of Sharp Reflections, the company that has earned its mark in the time-efficient analysis of pre-stack and 4D seismic data. Herman is the President of Bluware, the company that is on the frontline when it comes to developing tools for seismic interpretation supported by AI. Both companies were recently acquired by CMG, which has a long tradition in reservoir simulation development.

Bill Shea.

A PLATFORM OR NOT A PLATFORM

"Will this combination of companies lead to the establishment of a new platform that facilitates the workflow from seismic processing all the way to reservoir simulation?" I asked Herman. His response is probably very different from what people would have said ten years ago.

"We don't believe in locking people into a platform, because there will then be compromises along the way. You will never be the best of everything," Herman says.

"Instead, people should have the ability to do something else in another software, and seamlessly bring it back into our workflow again. That's where CMG wants to go. It started with the acquisition of Bluware, then Sharp Reflections came in, and there will be others in the future. But we will not become that single platform that people will not be able to work with flexibly."

Looking at the subsurface tech industry as it is today, nobody wants to be locked into a single platform anymore. This trend can be seen everywhere.

"Let's look at the Apple iMessage debacle as an example," explains Herman. "Initially, the company attempted to lock its users in by having blue bubbles for messages only if it was received from other users of the iMessage software. This created a backlash soon after, to the extent that Apple opened up iMessenger to other non-Apple product users such that all messages are now shown in blue. Even Apple had to admit that an open architecture is the way forward."

"Without pretending we are as big as Apple, there is a parallel with the story nonetheless. We know that in order to stay competitive and attractive for companies and people to buy our software, we need to be open. That's why one of my main concrete targets when it comes to the development of our software is to make it even easier to dip in and dip out of it in a seamless manner. If you don't implement that, people will just not do it and strike a compromise towards something that just produces a good enough result."

That's why Herman has spent quite some time lately with customers and prospective customers to identify where friction exists when it comes to creating seamless workflows. "I thought it is interesting to see that in an industry that produces most of the lubricants in the world, there is so much friction," Herman says. "I see people working too hard for what their output is."

Herman van Nieuwoudt.

THE LOWER THE OIL PRICE, THE BETTER

"Believe me, I know what a 60 dollar oil price means," continues Herman, who worked for Baker Hughes for many years. "But when looking at our niche in the market, the workload doesn't tend to decrease; it is the number of people who have to perform those tasks. So these people have to find ways to become more efficient instead, which is where our software offering comes in. In addition, change usually happens in wartime, not at peacetime. In that sense, we are prepared for some things to happen, as operational departments start to feel the squeeze from dipping oil prices. We see it as an opportunity for the industry to adopt new tech."

NEW TECH IN A FAST-MOVING SPACE

But how does the development of new tech work after an acquisition of this kind? I asked Bill.

"I feel that we have been running a three-lap race," he says, "with the first one being the establishment of the company as a start-up. Then, Equinor Ventures came on board, which changed the game completely and shifted our concern from "do I have something the market wants, to how can I get more eyes on it." The third lap, and that's the one where we are in now, is the one in which we have the challenge of how to capitalize on the customer-base that CMG already has."

"I'll be the first to admit that our technology, which is very much based on CPU and memory, may not have the future some of the GPU-based technologies have. There is a reason why NVDIA is one of the richest companies out there."

"But, at the same time, I am not worried about use cases that suit our solution," continues Bill. "Last week, I visited a client who wanted us to put every frequency iteration into our 4D software to understand what they are getting from a full-scope FWI exercise, with the simple reason that such a project costs more than six times what used to be a reverse time migration cost four years ago. Each iteration costs huge sums of money, and we can help show what it's delivering".

"What concerns me more is the question of whether we've got the creativity, listening bandwidth and development resources to meet the demands of an industry that is moving ahead so fast."

Bill is still very driven to help shape Sharp Reflections' future under the CMG umbrella. "A lot of companies discard founders straight away," he says, but I saw a differentiating element in CMG's offer for me to stay on for a while. "We benefit a lot from the insights he brings to the table; not only when it comes to his own company, but also the wider perspective," says Herman.

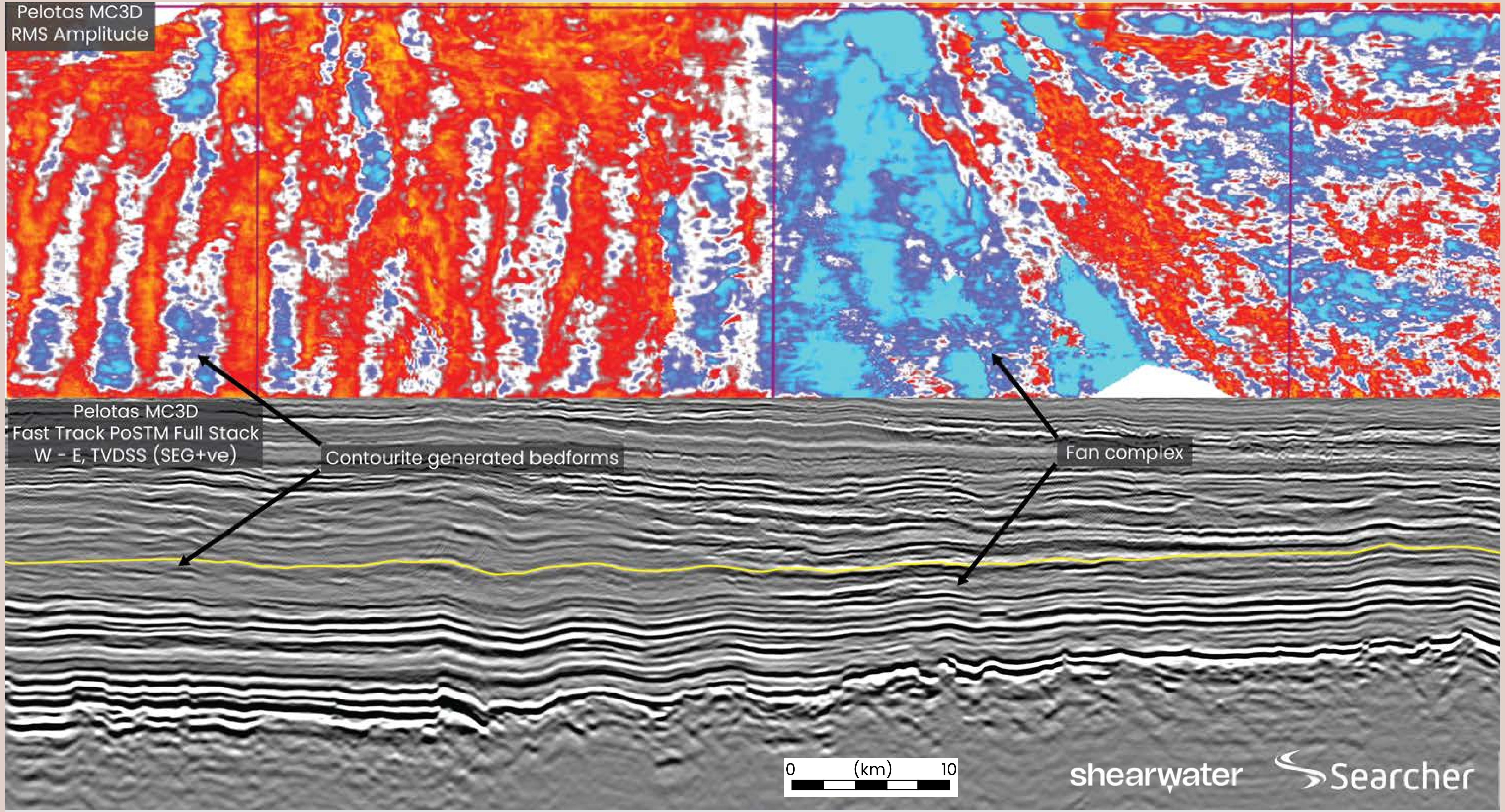
A BET

"It is good to stay around, as it creates some continuity for the business, and I value the confidence management has in me to be around for a little longer."

"We don't overlap much, and although we don't connect like a glove, there is a lot of potential there." ■

Henk Kombrink

The future has arrived



Depth converted East-West line from the Pelotas 2024 3D fast track seismic dataset. RMS extraction in a window below the regional pink horizon shows the contourite dominated sand wave-like bedforms to the west and the turbidite dominated fan complexes to the east.

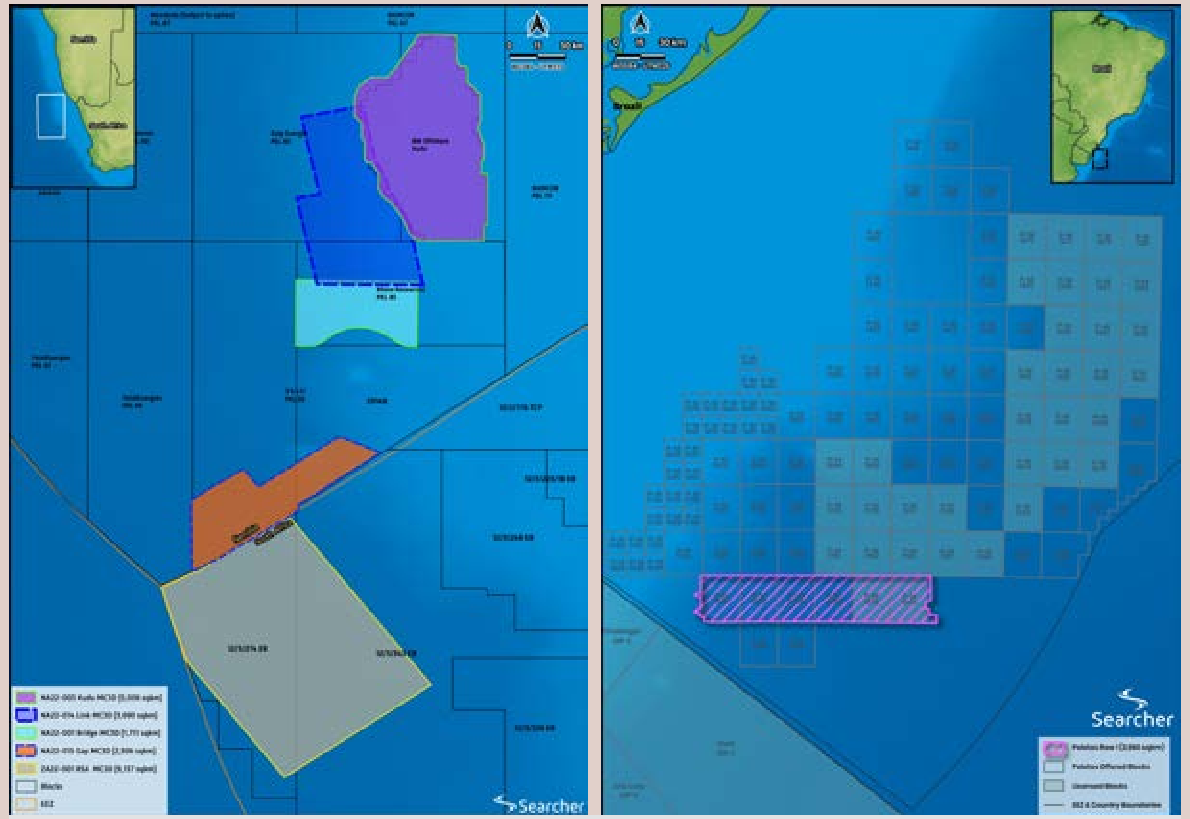


Figure 1: Location of the 3D seismic datasets acquired between 2022 and 2024 in the Orange and Pelotas Basins

Cyber Punk's visionary pioneer William Gibson wrote, "The future has arrived. It's just not evenly distributed yet". And certainly the future on the Atlantic's passive margins is not evenly distributed because the future there lies in hybrid systems; gravity-driven clastic turbidite flows that have been modified during and after deposition by coast-parallel contourite currents.

Gravity-driven turbidites were once assumed to be the dominant (even the "only") process controlling deep water sediment deposition, but in a remarkable metaphor for modern life, it turns out that its the actions of unseen cross-currents that gives shape to what is created. Indeed, contourites rarely leave clear fingerprints on the deepwater sediments we see at outcrop, yet they may have significantly altered the composition of the flow such that classic turbidite Boumer sequences are not deposited at all. Removal of the fine sediment fraction of a turbulent flow thereby increasing net sand of subsequently deposited sediment (building mud and silt drifts at the same time), creation of asymmetric levees in slope systems that lead to channel migration, evolution of depositional topology on the slope and basin floor, and reworking, redistribution laterally of basin floor sediments are all products of the interactions between gravity driven turbidite flows and contour following currents.

Contourites: When everything going sideways saves the day

Though complex in detail, hybrid systems become clearer at scale - modern 2D and 3D deepwater data is reshaping how we interpret and pursue deepwater reservoirs

NEIL HODGSON, KARYNA RODRIGUEZ AND LAUREN FOUND, SEARCHER

SINCE 2022, all of the Multi-client 3D seismic acquired in the Orange Basin of Namibia and the Southern Pelotas Basins of Brazil (> 20,000 km^2, Figure 1) have been acquired by Searcher, mostly with partner Shearwater, in response to recent exploration success in deeper water settings. This has revealed for the first time the seismic character and prospectivity of the different depositional systems generated by the interaction between turbidite and contourite current-related processes in these basins.

SEISMIC IDENTIFICATION AND EVALUATION OF HYBRID DEPOSITIONAL SYSTEMS

With the Charge and Trap petroleum system on both margins largely de-risked by 3D imaging, offset wells, basin modelling and most compellingly the large number of commercial discoveries being made, then the main added value from modern 3D seismic is to analyse reservoir presence and effectiveness risk. Two key frameworks are available for the analysis of the dominant process in deposition: The relation between contourite current velocity and depositional grain size (Hernandez Molina et al., 2011) and the three main types of interaction in mixed systems (Fonnesu et al., 2020).

In the Late Early to Early Late Cretaceous of the south Atlantic, contourite currents have alternated in strength, direction and influence through time and with position on the slope. The oceans then were just as layered, divided vertically into slabs of equal density (isopycnals), as the modern Atlantic is, with limited interaction between these layers, which can move separately. So, a given position on a slope at a given time may have been sculpted by contourites flowing north, and other places on the slope either experience no contourite influence or a southward-moving current.

ORANGE BASIN ONSET OF CONTOURITE CURRENTS AND ASSOCIATED BEDFORMS

As can be seen in Figure 2, the Venus Basin Floor Play Fairway (yellow dashed polygon) extends into the Gap and ZA22 3D datasets acquired in 2023/24. Venus reservoir analogues and the unexpected identification of contourite influence, immediately above the Aptian source rock, have both been observed (Figure 3).

In South Africa, the RMS amplitude distribution resembles a bedform between undulatory ripples and sand dunes generated by medium velocity contourite currents and medium grain size sands. In contrast, to the north in Namibia, the amplitude distribution is more chaotic and irregular and resembles bedforms formed by higher velocity currents and associated with coarser grain size. These observations have raised questions regarding the timing of the onset of contourite currents in the basin as well as the process triggering them. The early onset could explain the outline of the Venus discovery, with sediment sourced from the east and yet the polygon aligned in a NE-SW direction (Figure 2) as if the turbidite sand had been redistributed by contourite currents, potentially leaving coarser material to the SE and finer sands to the NW.

Another bedform feature generated by contourite currents is the sediment waves generated by contourite currents. These can resemble progrades (see Figure 4) and be on a colossal scale (>500 m high in Uruguay's Pelotas basin) and have been interpreted as aggrading slump units (ref. The PEL97 discussion in GEO EXPRO Vol. 22, Issue 2, 2025).

Searcher and Shearwater are in the second season of acquisition of the only multi-client 3D in the Southern Pelotas Basin. The first events overlying the source rock are characterized by continuous and extensive amplitude anomalies with AVO Type III response. RMS extractions over these events show North-South trending amalgamated channels fan complexes (see Foldout image). The North-South trend is intriguing as sediment should be sourced from the North-west. It's possible that the turbidites have been redeposited by contourite currents, in a similar way to the Venus discovery.

Higher up in the sequence, sand wave-like bedforms (see Foldout again) are interpreted to be associated with medium velocity contourite currents and medium grain size sands. While to the east an older fan complex seems to be unaffected by such a current.

Contourite thinking in exploration is an on-trend geoscience innovation for hipsters. If you still feel the future is far away, then as Slaughterhouse-Fives's visionary author Kurt Vonnegut wrote, "be patient, your future will come to you and lie down at your feet like a dog who knows and loves you". With huge mixed system fan complexes with AVO Type III response being mapped on Multi-client 3D, the future of exploration has already been written in unevenly distributed hybrid systems in both the Orange and the Pelotas Basins.

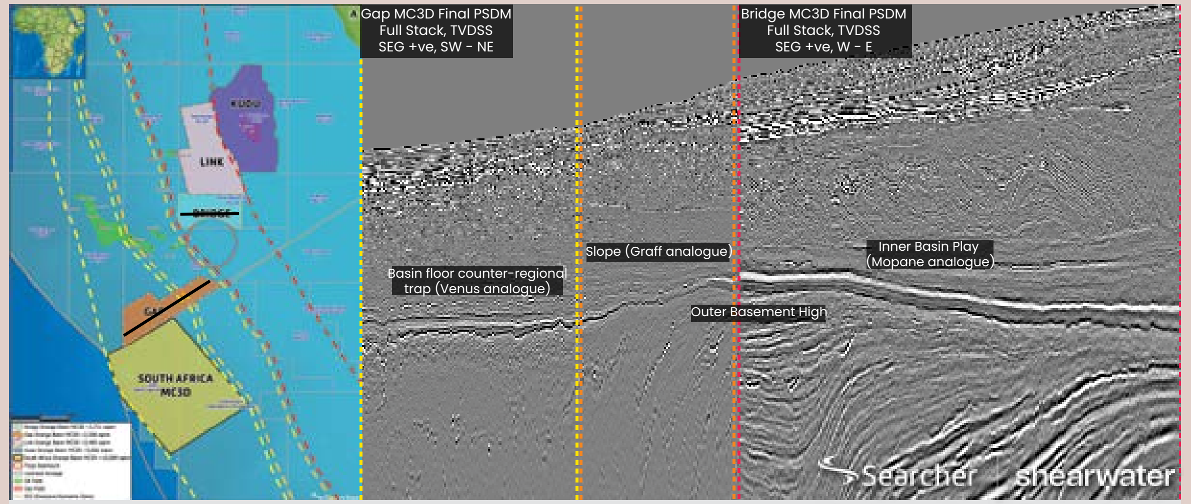


Figure 2: Right: Map showing recent discoveries in the Orange Basin (green polygons), approximate outline of the three main play fairways recently discovered (dashed outlines), and 3D datasets used in this study. Left: Composite seismic line across Bridge and Gap 3D datasets showing the character of the Aptian source rock and the seismic expression of the extension of the discovered plays. Note Rhino's recent Capricornus discovery is located within the red dashed polygon, in a similar setting to the Mopane discovery.

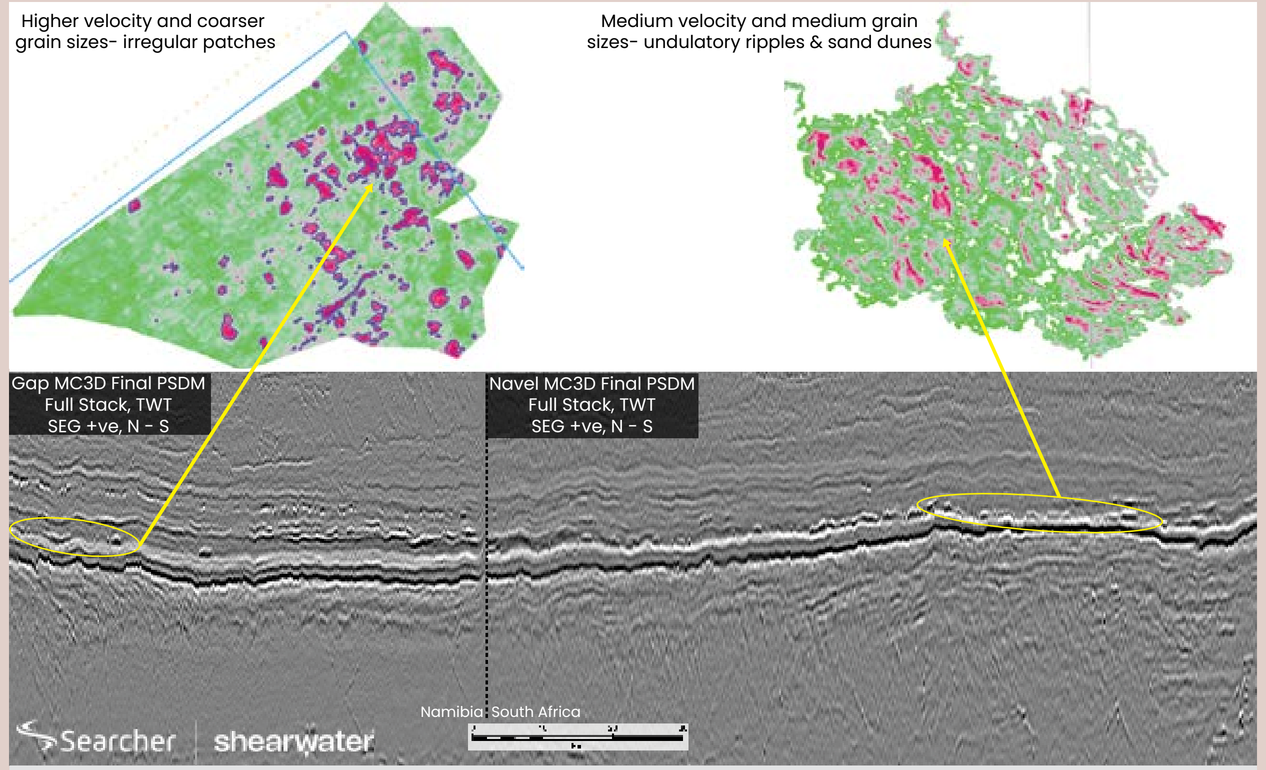


Figure 3: Depth converted arbitrary line from ZA22 to Gap survey, approximately NW-SE oriented. Note the high amplitude, discontinuous event above the Aptian source rock (brown horizon). The inset maps represent the RMS amplitude extraction over the blue horizon within the yellow polygons. Note the similar seismic character between the surveys but a very different aerial distribution of high amplitudes (red). The graph published in Hernandez Molina et al., 2011 was used to infer the possible process generating the bedforms.

PORTRAITS

"... the only reason why China is growing so rapidly when it comes to geothermal energy is that there is the political will to do it and make it happen"

Marit Brommer – International Geothermal Association (IGA)

"PLAYTIME IS OVER"

As one of the most-travelled geothermal ambassadors of the world, Marit Brommer has seen many geothermal projects and maintains a remarkable network in the community. She has now been at the helm of the International Geothermal Association (IGA) for more than eight years, which puts her in a great position to reflect on what has happened, what has not happened, and how the industry has to scale up. Reflecting is what she is doing in this interview, openly and honestly.

HENK KOMBRINK

PHOTOGRAPHY: MARIT BROMMER PRIVATE ARCHIVE

"A LOVELY little department dedicated to geothermal energy. That's what I found when I started at the International Geothermal Association (IGA) in 2017," says Marit Brommer, who had left a demanding role working on challenging subsurface projects at Shell.

But it wasn't exactly what she had expected.

"Even though I knew that IGA was obviously very small compared to an oil major, I did think I was joining another efficient global organisation. But even though it had already existed for almost 30 years at the time, it was still quite fragmented and funding solely relied on a single EU grant," says Marit.

"I had no history in geothermal energy, and all of a sudden, I was the Executive Director, changing the way we worked"

"When looking back now, I understand much better that I actually had a mandate to implement change rather than a remit to continue as usual. This mandate included turning the IGA into a more visible organisation; larger, more independent, and a global go-to vehicle for geothermal best practices, knowledge sharing and advocacy."

It meant a radical change, which did not always come easily. "I had no history in geothermal energy, and all of a sudden, I was the Executive Director, changing the way we worked. I would be lying if I said everybody welcomed that," Marit says.

"But maybe my lack of expertise was an advantage at the same time," she continues. "It allowed me to restructure in a way that allowed the new model to work."

What was this new model all about?

"First of all," Marit says, "we needed to move away from the academic outpost of Bochum, and become a fully independent organisation with our own base." How to make that happen, though, and where to go?

To become more financially independent, Marit soon realised that the funding model needed to change, with more buy-in from the industry. She started making the case to companies active in the energy sector. "If you want to see geothermal grow, facilitate learning and have a platform that acts as an incubator for the international geothermal sector, you have to support us," she wrote in letters and emails to potential partners.

It worked.

Marit secured more than 25 companies to underwrite the goals of the organisation, supported by 30 member countries. "Let's face it," says Marit, "during those years, there was increasing public and governmental pressure on energy companies to diversify their energy mix. It helped get companies like Shell on board as sponsors, but also service companies such as Baker and Halliburton."

Then, the location. It became the city of Bonn, where many UN organisations, also in the energy and climate space, are based, and which seemed a good fit for her organisation at the time.

"No matter your cultural background, diplomacy only works when meeting people face to face"

"When the move to Bonn was completed, and our funding model was completely overhauled, I looked back with satisfaction," said Marit. But soon she was about to find out that it wasn't all plain sailing.

DIPLOMACY DOES NOT WORK VIA TEAMS

"The pandemic was detrimental to our goals to continue our mission," Marit says. "No matter your cultural background, diplomacy only works when meeting people face to face. Doing business might work that way," she adds, "but diplomacy relies on real human interactions." ▸

WHERE THINGS ARE HAPPENING TODAY

"It is great to see how the USA is a hotbed of new technology, both in the realms of drilling and reservoir stimulation," says Marit when we get to speak about ways to accelerate the pace with which geothermal wells can be completed. "It is a major pillar on which future project decisions will hinge."

"As a global organisation, it is very important to closely follow developments in these domains, she says, but I also feel that we need to pay attention to the areas where things are happening today, as that is currently where our growth takes place. R&D projects are great ways to gain exposure, but it is important to realise that they do not yet contribute to our baseline."

"The places where recent growth in electricity production has concentrated are all in areas where geothermal already was an established player; New Zealand, Kenya and Indonesia. This is not so much in the news, but it is something we have to be mindful of and also share better, as it is in these areas where the action happens."

Marit also stresses that there are tens of thousands of volcanically active islands, most with only small populations, that would greatly benefit from having a small conventional geothermal system, which would make them completely independent of diesel imports for electricity generation. It is those sort of opportunities we also need to pay attention to, as it is low-hanging and tangible fruit."

Site visit in the Kingdom of Saudi Arabia courtesy by Saudi Geological Survey and STEP.

"At the start of the pandemic, people were still up for having calls early in the morning or late at night to accommodate time zones, but that energy soon dissipated. Also, the World Geothermal Congress, which was about to happen in spring 2020 in Reykjavik, was postponed. Even though it did ultimately take place in October 2021, I feel that by that time we had already lost a bit of our momentum," says Marit.

There is another factor at play, too. "To be brutally honest," she continues, "over the past five years, our message got more and more diluted by the advance of the (green) hydrogen hype. Everybody started to do hydrogen. How many posts have I seen claiming that solving the storage issue that comes with intermittent sun and wind is now behind us? It did not help putting geothermal centre stage, as strange as it sounds, that there is competition when it comes to pushing different renewable energy solutions."

And, on the back of that, it also turned out that Bonn was not the best place to be. "As an organisation like ours, you not only need an international audience, you also need a local audience that is keen to hear from you and develop initiatives with. It did not materialise in Bonn to the extent I had foreseen," admits Marit.

> "…geothermal is becoming more visible again…"

For that reason, it became clear that the organisation would benefit from another home, yet again. It became Den Haag in the Netherlands. "Certainly not because I am Dutch myself," laughs Marit, "there were many other good reasons for this. In 2021, there was a big drive to expand geothermal in the Netherlands, both from a governmental and private sector perspective. There was a geothermal master plan, a road map, and a great network of embassies and organisations supporting the Sustainable Development Goals. All in all, the perfect place for an organisation like ours. And judging by the number of events we had and hosted in those first two years, it surely was a good move."

Fast forward to 2025, the overall picture has changed yet again for Marit and her organisation. Let's now take a look at how bursting bubbles and China play a key role in the narrative today.

PHOTOGRAPHY: MARIT BROMMER PRIVATE ARCHIVE

A NEW REALITY

"We are back in the spotlights," says Marit after a short break. "There is a more nuanced view coming through on what hydrogen can and cannot do for the energy transition, which means that geothermal is becoming more visible again as a result. In the way we want it to be, as a solution to provide baseload energy round the clock."

"However, that doesn't mean we are back to where we were in 2020," she says, "because we also see that the E&P industry looks at their commitment to geothermal in different ways than before, with Shell being a prime example. "The company recently decided to divest its interests in geothermal energy projects in the Netherlands, but decided to invest in the geothermal power business in the USA at the same time," Marit says. "It demonstrates that the company is not yet convinced of low-enthalpy geothermal in their project portfolio."

> "… the only reason why China is growing so rapidly when it comes to geothermal energy is that there is the political will to do it and make it happen."

Is that a wake-up call? Yes, it is, and it fits into the overall change of the energy debate towards security of supply and the continued focus of majors to look at shareholders' returns.

This has exposed an important difference between geothermal energy versus oil and gas production.

"We can not see geothermal energy as a vehicle on the same footing as oil and gas," says Marit. "Oil and gas as a business model works. Otherwise, we would not have a society that is so dependent on it. But where oil and gas is a commercially viable venture, the geothermal sector, wherever you look, is dependent on subsidies. There is not a single geothermal project across the globe that runs entirely on commercial principles. Money needs to be injected first to make it happen."

"Let's accept this," says Marit, "and regard geothermal as a utility, not as a commodity. If we do that, I'm convinced that we can work towards an energy system that still includes geothermal."

That's where the public sector comes in.

"As long as there is no public mandate and political backing to implement geothermal energy at scale, in collaboration with private parties carrying out the work, you will always keep on having one-off projects such as the ones we are seeing around us too often. It is not what we need. We need more examples like Munich, Paris, and more… China's!"

In fact, it is China where things have really taken off.

CHINA AS A ROLE MODEL

"Let's not sugarcoat it," says Marit, "the only reason why China is growing so rapidly when it comes to geothermal energy is that there is the political will to do it and make it happen."

"A lot can be said about the country, but it is remarkable to see how a mandate turns into action on a grand scale, something we cannot replicate in Europe by any stretch of the imagination," she says. "An example is the master plan to clean the air in the inner cities, which means that heating and cooling need to decarbonise. In turn, this has resulted in the phasing out of coal used for that purpose. Combined with the fact that China does not have ample gas supplies and is reluctant to become even more dependent on imports, geothermal presented itself as a viable alternative."

And where Shell has shown to be lukewarm to the geothermal business case, Sinopec has turned into an important water driller. The combination of geothermal expertise brought in from Iceland, Sinopec's drilling experience, and access to manpower and rigs has resulted in the completion of more than 1,000 deep geothermal wells over the past decade. ▸

Speaking at Geolac El Salvador 2024.

"This is how to upscale conventional geothermal – because that is what it really is – drilling to 2 to 3 km to tap into 80-90° C brines. It has led to the realisation of around 40 GWth. In addition, more than 8,000 shallow geothermal boreholes were added to that at the same time," Marit explains. "It is a school example of how broad government support can result in the large-scale implementation of a geothermal action plan."

WHAT IS HAPPENING IN THE WEST?

We come back to speak about Europe. "When looking at what China can pull off, I think that we have to conclude that despite all the road maps, master plans, and one-off projects, Europe is lagging behind," says Marit. "To put it even more bluntly, I feel that in some ways Europe does not seem to want geothermal to grow significantly. At the moment, I see more stall than speed," she says, "with processes and procedures causing long delays."

And what is the reason for this delay? "We experienced dilution of our message when the hydrogen hype started to develop around 2020, but what I increasingly see now is that despite all the promises and plans, the reality is that our biggest competitor is not hydrogen, but oil and gas," Marit says. "At the end of the day, 90 % of heating and cooling is still supplied by hydrocarbons, and trust me, there is an efficient network of people behind the scenes talking to individual governments to make a case for that."

"And this is all happening when we see another country growing geothermal at scale. If anything, it proves that it can be done, with the right political momentum in place. Europeans need to be careful not to become fence sitters."

THE WAY FORWARD

"Playtime is over," Marit concludes as we near the end of this interview. After eight years at the helm of the IGA, she is still incredibly passionate about the role geothermal can play in the world's energy mix. Especially now, as security of supply concerns only form another reason to get serious about geothermal. What is better than produce the energy required for domestic heating from your own back yard?

"That's why I am not giving up," she adds, "but rather feel empowered now that we have gone through this cycle of maturation as an organisation." "Will the centre of gravity in the near future move to China then?," I ask at the very end. "Well, given what is happening there, it does make sense in some ways," concludes Marit. ■

THE BIGGEST GEOTHERMAL CONFERENCE EVER

"The World Geothermal Congress, which took place in Beijing in 2023, was the biggest one we have ever had," says Marit. "It is another sign of how serious the country is about the role of geothermal in the overall energy mix. Sure, it is run in a typically Chinese way, being a little bit stiff and very protocolised. In that sense, the field trips and dinners are essential to talk to people and get a better impression of what is really happening. Also, I don't know how many business deals are done, and there are fewer press releases compared to what we are used to in the West. But, let's be clear, I do have a lot of respect for China, and the action they take."

PHOTOGRAPHY: MARIT BROMMER PRIVATE ARCHIVE

GEOTHERMAL ENERGY

"We can't just afford drilling exploration wells, they will surely be converted to producers if the potential is proven"

Marijan Krpan – President of the Management Board of the Croatian Hydrocarbon Agency

Shaving off costs for geothermal exploration and production

To make geothermal energy production more efficient, the FindHeat project develops a series of tools that help streamline both subsurface as well as above-ground processes

"LET'S face it," says Arndt Peterhaensel from TRACS, "with the energy density of geothermal energy being so much lower than from hydrocarbons, the service sector around this resource has to operate at slimmer margins than in oil and gas."

"The EU recognises that," continues Sebastian Geiger, who oversees the consortium on behalf of Delft University of Technology in the Netherlands, "and with that in mind, the FindHeat project was funded for a period of four years."

"Our goal is to create a public online space, the FindHeat platform, that hosts a range of essential tools that will facilitate geothermal energy producers or potential developers with the essentials to make decisions faster and more efficiently."

Geothermal energy producers do not tend to have large geoscience departments such as oil and gas companies, if they employ them in the first place, so there needs to be a port of call that fills that gap. "That's not to say we want to eliminate the service sector by implementing this, we do recognise that services will always be required for individual projects to get them off the ground," adds Sebastian.

To make things more concrete, eight geothermal projects that are currently ongoing in the Europe region are part of the consortium; each with its own challenges, be it from a subsurface or a societal perspective.

For instance, a project in Iceland takes part with the specific challenge in mind to expand its operations into deeper horizons. This kind of near-field exploration is an aspect that can be translated to many other existing projects where there is an additional need for energy or where the current source is getting close to maturation.

"For this type of work, we don't necessarily need the most advanced reservoir modelling software," says Sebastian. "As part of the project, we are preparing an existing open-source and easy-to-use software called Rapid Reservoir Modelling for use within the portal," he says.

It is a good example of the cross-fertilization between the oil and gas and geothermal sector; the software was originally developed for E&P but is now finding its way towards geothermal. "It has the right scale of granularity to do a rapid assessment of remaining nearby geothermal resources that can also be handled by people who are not working with this on a daily basis."

Geothermal drilling at the campus of Delft University of Technology.

PHOTOGRAPHY: GEOTHERMIE DELFT

At the other end of the spectrum are above-ground challenges such as how to communicate with local communities when a geothermal project will start in their area. "Even though it is a very low-carbon source, it is not always met with open arms," says Arndt. "We also aim to provide a set of documents that help people communicate new projects to local stakeholders, which will hopefully create more awareness of what a project entails and thereby reduce lengthy regulatory processes." ■

Henk Kombrink

Extract and re-inject water, from the same well

That's the solution the city of Munich, Germany, is working on to help install more systems in congested areas. A great way of spatial subsurface planning

THE CITY of Munich is blessed with a very permeable succession of Quaternary sediments that enables a high and consistent supply of groundwater flow. As such, there is great potential for renewable heat supply through thermal groundwater utilization. Currently, there are more than 3,000 such systems in Munich, with a total thermal output of approximately 300 GWh. The city is now looking to expand that further.

However, the required minimum distance between the extraction well and the discharge well must be observed to avoid thermal breakthrough. This minimum distance is usually estimated at 10 m. In addition, in order to drill a well, a certain distance must be maintained from the neighbouring property and the building itself. These conditions reduce the available space for duplicate wells in a groundwater heat pump system, which results in some houses being unable to meet the minimum distance needs. This is illustrated in the illustration here.

In order to increase the utilization of these systems, the Technical University of Munich, the Munich Public Utilities, and the City of Munich are now investigating the extent to which efficient use of the thermal groundwater resource is also possible via single-well systems. The single-well system is a groundwater heat pump that feeds groundwater into the same well from which it was previously extracted.

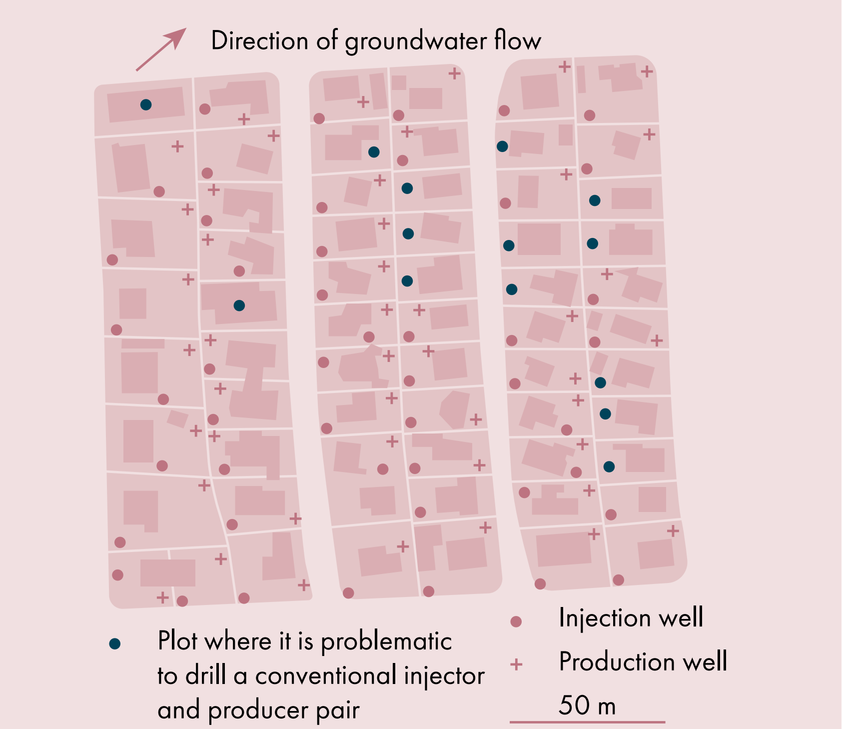


Illustration showing how some properties are unable to have a conventional groundwater system drilled because of the risk of interference when looking at the direction of groundwater flow.

SOURCE: ADAPTED FROM ZOSSEDER ET AL. (2024)

This solution eliminates the need for two wells and allows drilling in more confined spaces. It also saves investment costs during installation. However, it is important that the system's efficiency is still maintained and that the production temperature is not negatively affected by re-injection. For that reason, the vertical distance between the production and injection filters is usually chosen to be as large as possible.

In addition, in most cases, an impermeable layer needs to be in place between the production and injection intervals to prevent cross-flow. However, the hydrogeological conditions in Munich are characterized by very high hydraulic conductivity and flow velocities of 5-20 m/d, which means that the injected temperature anomaly near the well usually flows downstream without significant vertical mixing. In turn, this negates the need for a separating barrier.

It is anticipated that in large areas of the city, the heating needs of single-family homes can be met with single-well systems. In some particularly suitable areas, withdrawal rates greater than 10 l/s are probably possible.

Because of this, in collaboration with the municipal utilities, the city, and the Technical University of Munich, it was decided to implement a pilot plant in Munich as the next step in order to verify the numerical and basic data-based results achieved in reality. A site has already been selected for this purpose, and implementation of the project has begun. ■

This article is largely based on a publication in Technik Geothermie by Kai Zosseder et al. (11-2024).

Henk Kombrink

The "nugget effect" in geothermal exploration

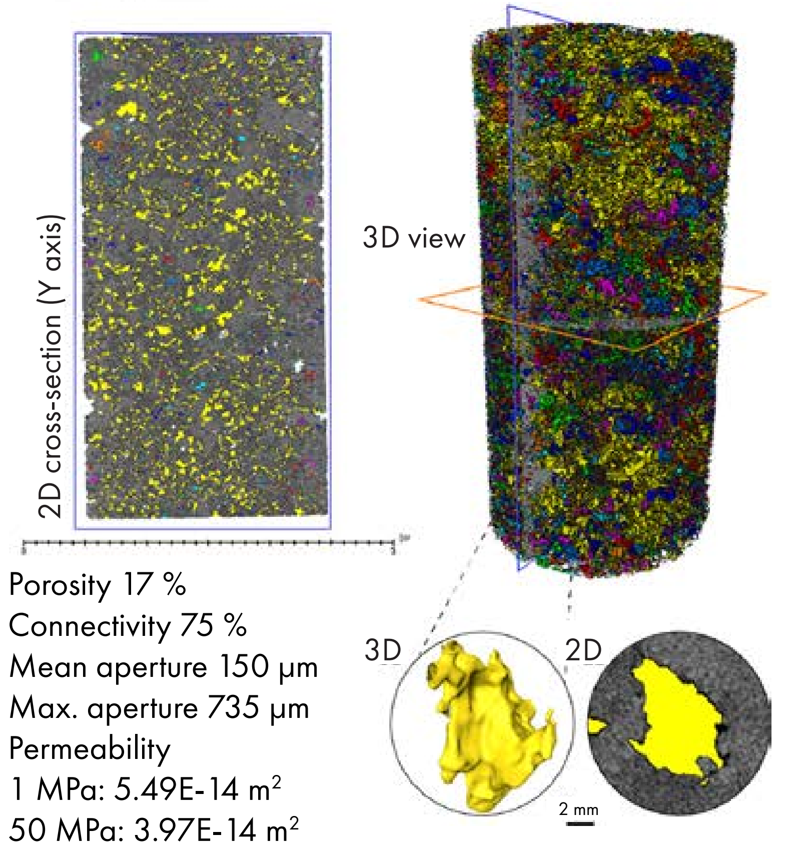
Finding a zone of high geothermal productivity may be tricky in fractured basement rocks, but it can surely pay off

"WE SEE permeabilities of 10 Darcy and above 15 % porosity, easily," says Alan Bischoff. Alan is associate professor of geoenergy at the University of Turku in Finland. In that capacity, he researches fault, fractures and the impact of mineral alteration in crystalline basement rocks.

"Finland ranks quite high in geothermal heat production, but that is all from shallow and mostly closed- loop systems," Alan says. "But what if we can find these subsurface nuggets where porosity and permeability are such that we can produce fluids at economic rates?"

"We are finding these nuggets," Alan says. He calls them nuggets because the challenge is that the location of high poro-perm zones is hard to predict. "That's where our research comes in," he adds. "We try to better understand how to predict these systems, how they formed and how large they are."

Finland is a good place to study faults and fractures in igneous rocks. "The glaciers of recent ice ages have scraped the bedrock surface to an extent that many fault zones are devoid of vegetation," says Alan. "This has led to great outcrops that allow inspection, mapping and sampling of fractures and faults."



CT scan images highlighting the pore morphology and connectivity of altered granite within a hydrothermally altered shear zone. Pores of the same colour are connected at a limit of 11 μm resolution.

SOURCE: WWW.SCIENCEDIRECT.COM/SCIENCE/ARTICLE/PII/S0375650523002493

SIZE IS KEY

Once found, the size of a network of high-permeable faults or fractures is the key question. Finding that out requires well tests, and fortunately Alan and his team of researchers have been able to do this using a close network of exploration wells drilled for Finland's nuclear waste storage facility. "It turned out that we could prove hydraulic connection between several boreholes, to lateral extents of at least 1.5 km," says Alan, "which is a very promising thing, also because these wells were not stimulated."

The geometry of the fractures is another key aspect that determines the deliverability of these zones. The team has used modern XCT imaging to determine the pore-scale connectivity of these crystalline reservoirs. When fractures are characterised by parallel planes, they tend to close as confining pressure increases, highlighting the challenges of deep geothermal production in crystalline cratons. However, the more irregularly shaped fracture planes and vuggy pores created by mineral dissolution are much less affected by this.

"Of course, it is true that there are uncertainties associated with drilling open-loop systems targeting fracture systems that may or may not be there, but it is also good to remember that if successful, the energy that can be produced exceeds by far what can be produced through closed-loops where the geological risk is much less. In addition, mineral alteration processes can enrich the geothermal brines with valuable elements such as lithium, which may add revenue to a geothermal prospect. So yes, targeting fault zones is open for problems, but open for opportunities at the same time!" ■

Henk Kombrink

GEOTHERMAL ENERGY

An exciting drilling campaign in exciting geology

Four geothermal exploration wells are drilled back to back in Croatia

DID EBN set a trend? That's to be seen, but the four-well geothermal drilling campaign the Croatian Hydrocarbon Agency recently embarked on to prove the potential of an equal number of towns has similarities to what EBN is doing in the Netherlands. Here, up to seven wells are being drilled back to back, also to prove the potential for geothermal energy production.

However, where the wells drilled in the Netherlands were chosen in underexplored areas first and foremost, the Croatian wells have been planned at sites as close to population centres as possible, and in places where district heating systems are in place already. "And, of course, areas that have the subsurface potential as well," says Martina Tuschl, who is overseeing the project on behalf of the Croatian Hydrocarbon Agency.

Another big difference between the two projects is that the wells drilled in Croatia will be completed with the idea to convert them into either a producer or an injection well. "We can't just afford drilling exploration wells," says Marijan Krpan, President of the Management Board of the Croatian Hydrocarbon Agency. "The wells will be completed with a 7" slotted liner at reservoir depth, and the well heads are prepared for ESP pumps as well," adds Martina.

The project in Croatia is exciting and must be seen as a serious attempt to de-risk four towns for the further development of their local geothermal resource. The first well is currently being drilled near the town of Velika Gorica, just south of Zagreb, the capital.

"The primary target of this well are the lithotamnic limestones of Middle Miocene age at a depth of around 2,100 m," says Martina, "with the second target are older Miocene rocks 700 m deeper. The expected temperatures are 90° C and 140° C, respectively.

"We plan to test the wells for a duration of around seven days following completion, and depending on the results, we will either plug or temporarily abandon them in order to come back later. The other wells are planned near the towns of Zaprešić (north of Zagreb), Osijek, in the far east of the country, and Vinkovci, just south of Osijek.

It is no surprise that the locations of all four planned wells are in the northern part of the country, which is part of the Pannonian Basin. Here, the geothermal gradient is close to 50° C / km, in contrast to the southern part, where it is only 18° C / km.

Seismic surveys were acquired in all areas to narrow down the best location for the wells, supplemented with magneto-telluric surveys.

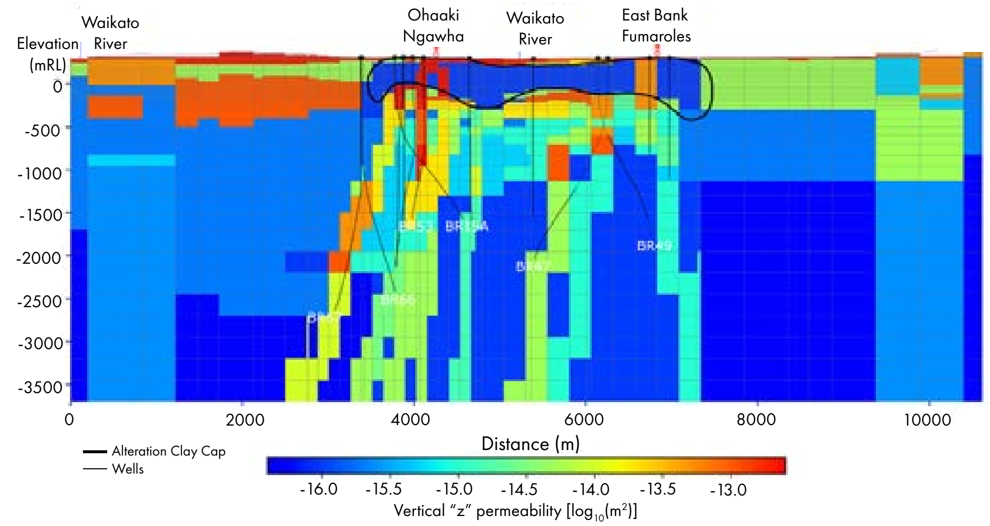
"There is potential for high-temperature geothermal in our country as well," says Marijan Krpan, "but the investment framework has to be established for that first. Hence, with this campaign, we are looking to tap into temperatures that lend themselves for use in district heating networks." ■

Henk Kombrink

Building a reservoir model for a geothermal field

A different kettle of fish compared to an oilfield model

THE FIRST well in the Ohaaki geothermal field in New Zealand was drilled in 1965. However, it lasted until 1989 before power production really started, even though large-scale testing of wells had taken place before the commissioning of the 116 MWe power plant.



Vertical permeability distribution across the Ohaaki geothermal field, clearly illustrating the faults.

SOURCE: O'SULLIVAN ET AL. (2025), GEOTHERMICS

Over time, different models have been built of the subsurface with the aim to better understand the decline in steam production, and therefore allowing a better forecast of what was still to be produced. This seems like a useful exercise, because the decline rates were quite high, immediately from the start of production, as a new paper published in Geothermics describes.

The first model of the Ohaaki field published in 1977 consisted of just one single reservoir block – or grid cell – that matched pressure drop by recharge flow. This also allowed making guided estimates of total reservoir volume. Subsequent models also included the CO_2 component, which is quite high in the field.

From 2001 onwards, the first more advanced 3D models started to make an appearance, culminating in a model consisting of 35,446 blocks in 2015. Soon after, though, it was realised that the model had to be deepened, as some of the more recent wells were getting too close to the base of the model that was used at the time. This added about 3,000 more blocks to it.

It is only in recent years that some geological features that have been known for a long time have been explicitly incorporated into the model of the geothermal field. The main features are the clay cap that is present at a shallow depth, forming an impermeable horizon for fluid migration from below, and the deep-seated faults that form important conduits for the heat. Combined with the porous nature in the shallow subsurface, another feature that was introduced is a dual porosity version that allows matrix and fault/fracture fluid flow.

The construction of the 3D model has been aided by magneto-telluric data, deeper wells, and the use of tracer technology to better understand fluid pathways.

It is interesting to see, when looking at the model cross-sections in the paper, how faults are represented. Rather than lines that offset reservoirs sections from each other, such as is the case in reservoir models in oil and gas, the faults are assigned grid blocks in this geothermal model too. It is no surprise, as it is the faults that support the fluid flow, much more than the surrounding rocks. The faults can nicely be recognised in the vertical permeability cross-section below.

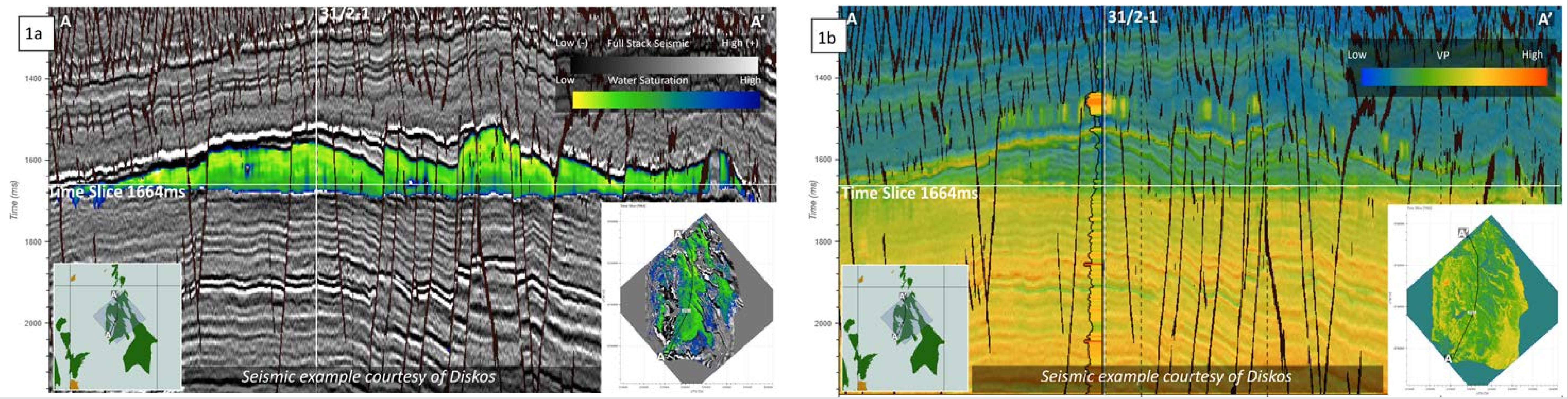
The authors conclude that their model fits field data better than previous models, so the mission is completed. However, they do describe a misfit between model results and observed data from some deep wells, which required input from reservoir engineers to learn that the contribution from the deeper section in these wells had deteriorated immediately from the start of production. A good example of the benefit of talking to each other. ■

Henk Kombrink

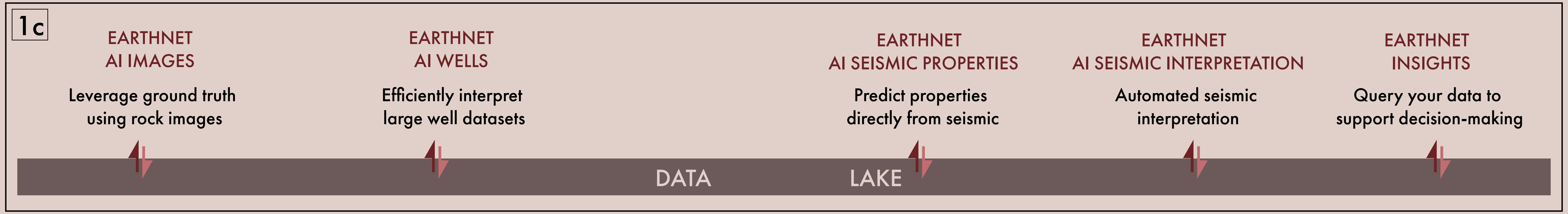
From data to discovery:
Applying AI in offshore geoscience

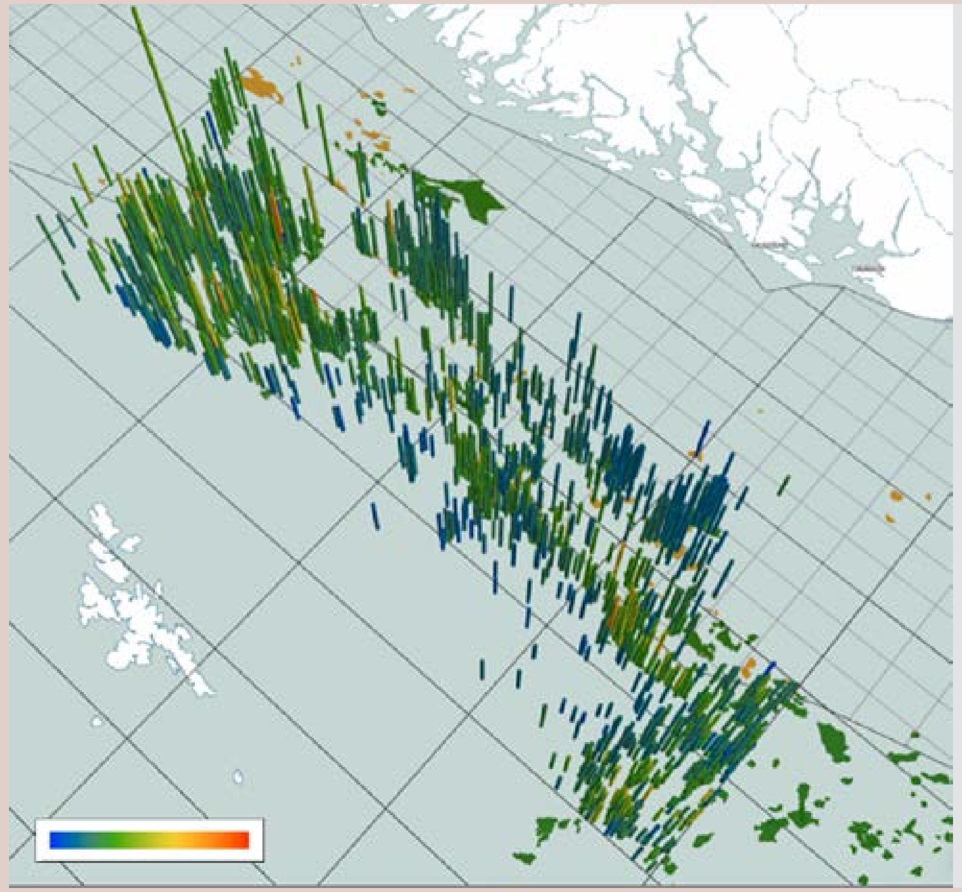
The North Sea continues to rank among the most prolific hydrocarbon regions globally, with abundant remaining resources in both barrels of oil equivalent and carbon capture and storage (CCS) potential. In this comprehensive study, we leveraged advanced AI workflows to interpret multiple seismic surveys and utilize a vast dataset of well information to unlock new opportunities for exploration and development.

Focusing on a large area of the UK and Norwegian continental shelf, the analysis covered nearly 5,000 wells, 643 of which are Norwegian exploration wells, encompassing around 70 unique data types. Additionally, the dataset included 2,924 UK development wells and a range of UK exploration wells. This project used the ESA EarthNET platform to ingest, process, and interpret the data over six months. What follows is a walkthrough of our full workflow - from raw data ingestion to final geological deliverables - demonstrating how EarthNET supports rapid, scalable interpretation in data-dense offshore regions.



A well-known example demonstrating the value of AI/ML-driven workflows in data-rich regions is the Troll Field, as illustrated here. This case demonstrates the precision and efficiency of automated interpretation techniques when applied at scale. Troll is visualized in time on section A-A' and the time slice 1,644 ms, displaying the water saturation (Figure 1a) and VP (Figure 1b) distribution across the reservoir, showcasing a clear, accurate Hydrocarbon pay indicator. This figures ware generated following the full AI / ML workflow using Earth NET applied to a dataset comprising over 5,000 wells from both the UK and Norwegian Continental Shelves.





Gamma ray log colored by averaged measured depth for 5,000 wells.

The EarthNET Data Lake is a platform for managing, contextualizing, and exploring subsurface data across the entire exploration and development workflow. Directly connecting EarthNET modules enables a seamless transition from raw data to actionable insight. As shown in Figure 1c, the Data Lake acts as the central hub of EarthNET's integrated, AI-powered subsurface ecosystem.

THE EARTHNET WORKFLOW

- **Import Your Data** - From files, databases, or directly from OSDU™.
- **Contextualise It** - Add metadata and indexing to make your data easily searchable and usable.
- **Explore It** - Use map-based and object-specific explorers to understand spatial and relational context.
- **Make It Analytics-Ready** - Use EarthNET's cleaning and alignment tools to prepare for AI/ML workflows.
- **Continuously Improve It** - Iterate on training data and model outputs with feedback loops and active learning.
- **Export & Share** - Push data back to the OSDU™ Data Platform to enable collaboration and third-party tool integration.

AI at Scale: Modernising subsurface interpretation with EarthNET

A machine learning-powered workflow enabling geoscientists to analyse and interpret large, complex subsurface datasets efficiently

Using AI-driven workflows, EarthNET reinterpreted nearly 5,000 North Sea wells, revealing over 450 missed hydrocarbon pay zones. This study shows how machine learning can unlock new value from legacy data in one of the world's most mature basins

WILLIAM REID, EARTH SCIENCE ANALYTICS

BUILDING THE DATA FOUNDATION: EARTHNET DATA LAKE

The project began by ingesting data into the EarthNET Data Lake, which served as the unified environment for managing and analysing the 5,000+ well dataset. Key inputs included:

- 30,000 km of basic logs (GR, RES, DEN, DT, NPHI)
- 995 formation tops, 155 km of labelled training data (porosity, Sw, lithology)
- Depth-indexed logs (~90 million measurements)

Before initiating machine learning workflows, comprehensive quality control and data-conditioning were carried out using EarthNET's automated and semi-automated tools. This process involved identifying and flagging bad hole conditions using caliper readings, borehole size, and density log mismatches. Non-physical values were removed, and anomalous zones were detected through domain-specific pattern recognition techniques (Figure 2).

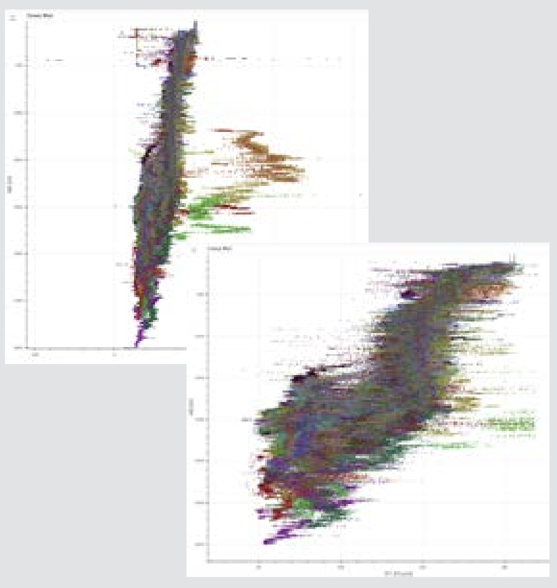


Figure 2: DT for the wells plotted against MD before (a) and after QC (b).

PREDICTING SUBSURFACE PROPERTIES: AI WELLS

With a cleaned and contextualized database, the EARTHNET AI Wells module was used to predict rock and fluid properties for each well. The ML model was trained to generate porosity, water saturation (Sw), lithology, and pay flag (based on both static and dynamic classification).

These predictions were validated with blind QC on multiple well examples, showcasing predicted porosity against original logs and ground-truth labels. Pay classes were visualized across stratigraphic intervals with net reservoir and pay intervals filtered for wellbore condition, highlighting potential pay zones even in wells previously classified as dry. Well 35/11-13 (Figure 3), made the Byrding discovery in 2005, in the Heather Formation, high porosity and low water saturation were recorded in the Heather Formation, but interestingly also in the Draupne Formation.

Our workflow revealed a significant and much thicker oil accumulation in the segment adjacent to the well location. This was verified after our workflow by the use of the 2017 sidetracked well, which proved a 20 m oil-filled intra Draupner Fm, demonstrating the value of the workflow in identifying missed pay opportunities.

SEISMIC-SCALE ANALYSIS: AI SEISMIC INTERPRETATION & PROPERTIES

Once well-scale predictions were complete, attention shifted to the seismic domain using AI Seismic Interpretation and AI Seismic Properties.

A prime example is the Troll Field (Figure 1a and Figure 1b), located in the Norwegian Continental Shelf, where EarthNET's seismic workflow demonstrated the full integration of AI-derived well and seismic

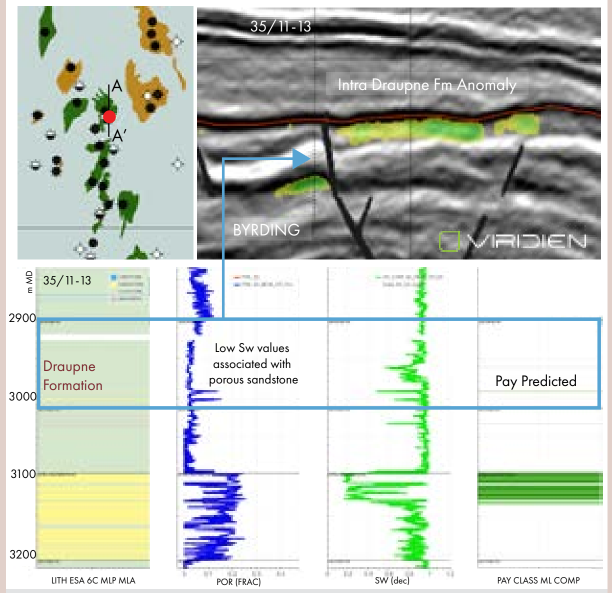


Figure 3: 35/11-13, originally drilled in 2005, targeting intra Header sandstone. Seismic example courtesy of Viridien.

data. This seismic-to-well integration showcases EarthNET's ability to move beyond simple structure mapping and into full reservoir property prediction across volumes, enabling better prospect identification and risk mitigation. This combined approach enables rapid evaluation of large datasets.

One of the most powerful applications of this workflow was the identification of missed pay in historically drilled wells, many of which had been classified as dry.

REAL-WORLD IMPACT: MISSED PAY ANALYSIS

EarthNET's ML models re-evaluated legacy logs and successfully identified 450+ new hydrocarbon pay intervals.

Application in mature fields: The Brent Field is characterized by a westerly dipping tilted fault block structure, forming a fault-controlled unconformity trap. The field comprises two primary reservoir units: Brent Group (Middle Jurassic) and Statfjord Formation (Lower Jurassic to Triassic). As expected, pay flags are observed (Figure 4) in the Brent and Statfjord groups. However, there is also a

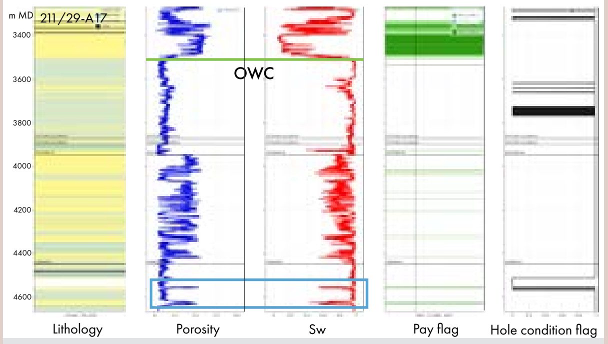


Figure 4: Well 211/29-A17 post-EarthNET analysis showing pay in commorant formation.

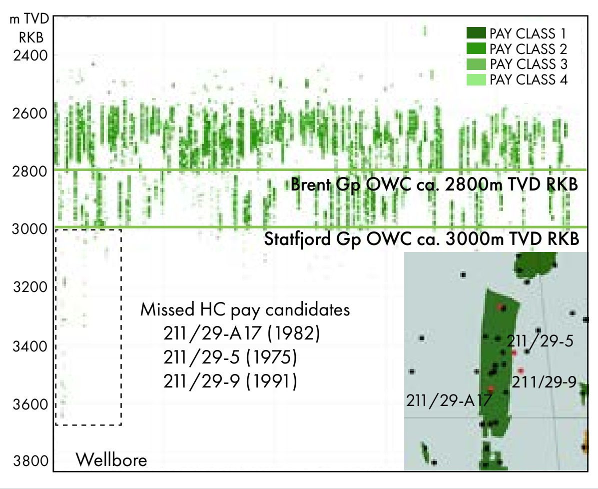


Figure 5: Selection of wells showing HC pay and OWC's highlighting opportunity deeper in the sections.

distinct drop in water saturation that aligns with a porosity spike within the Cormorant Formation, highlighted in the blue rectangle, suggesting a potential overlooked pay.

VIEWER AND INSIGHTS: FROM PREDICTION TO DECISION SUPPORT

Utilising EarthNet Insight, we conducted an evaluation of predictions and interpretations across the 5,000 wells, we interactively explored hydrocarbon pay by depth and formation, viewed lithology and porosity overlays, interpreted structural elements from seismic data, and analysed 3D reservoir property cubes.

This is illustrated in Figure 5, where true vertical depth (TVD) in meters is plotted against hydrocarbon pay across multiple wells. Notably, the oil-water contact (OWC) in the Brent Group is visible at approximately 2,800 m, while the Statfjord Group OWC appears around 3,000 m. When presented in this format, the observation from well 211/29-A17 stands out not just as an outlier, but as a potentially missed pay opportunity on a regional basis within the Commorant Formation. Additional candidate wells that show similar characteristics include 211/29-5 and 211/29-9.

CONCLUSION

This North Sea case study illustrates how EarthNET is not just a collection of tools, but a digital ecosystem for subsurface analysis. By fully integrating seismic and well data, applying AI/ML-driven predictions, and enabling exploration geoscientists to visualize and validate in real time, the platform unlocks overlooked value in one of the world's most data-rich basins. From missed pay reclassification to seismic-scale property prediction,

EarthNET has predicted pay intervales for ca 5,000 wells and identified more than 450 hydrocarbon pay intervals in wells registered as 'dry'. This is reshaping how we as geoscientists interpret the subsurface - turning legacy data into tomorrow's opportunities.

SUBSURFACE STORAGE

"We started as a project when Swiss supermarket concern Migros wanted to find a solution to process its food waste in a carbon-neutral way..."

Tim Baars – Recoal

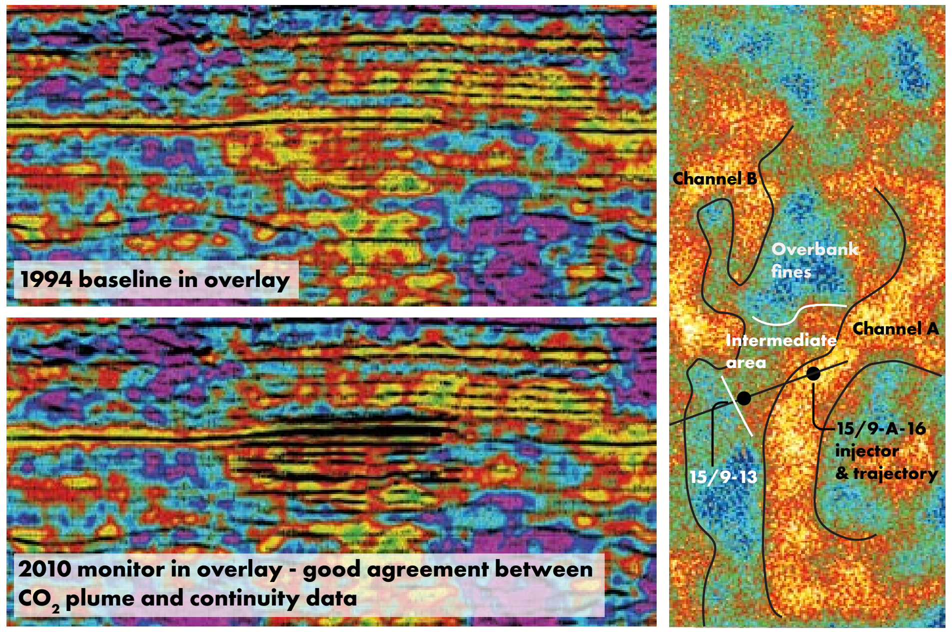
Understanding CO_2 flow at Sleipner using stratigraphic continuity

Seismic attribute shows good correspondence with plume migration

BASIL ONYEKAYAHWEH NWAFOR AND JOHN CASTAGNA, UNIVERSITY OF HOUSTON, ROBERT VAN EYKENHOF AND MARIANNE RAUCH, LUMINA GEOPHYSICAL

The Sleipner project, located offshore Norway, marks one of the first large-scale carbon capture and storage (CCS) initiatives. Since 1996, more than 18.5 million tons of CO_2 have been injected into the Utsira Formation. While time-lapse (4D) seismic data has helped track the CO_2 plume, early pre-injection seismic data lacked the resolution to fully understand the reservoir's geological structure. This limited our ability to predict how CO_2 would migrate underground.

We performed a study to improve the resolution of pre-injection seismic data using a technique called Sparse Layer Spectral Inversion. This method enhances thin-layer imaging and produces new seismic attributes - most notably, stratigraphic continuity. This has the potential to reveal key geological features controlling CO_2 flow.



Comparison of the Stratigraphy Continuity Attribute (colours) computed from the baseline survey with the 1994 baseline and 2010 post-injection monitor data highlights laterally consistent geological layers in warm colors and areas with interruptions in cool colors. Black high-amplitude wiggles in the lower image are the plume imprint overlain on the 1994 continuity volume, matching well with the highlighted channel. The map also shows the channels with the same attribute, including a zone of intermediate connectivity where a more recent westward plume has been detected.

Sparse Layer Spectral Inversion, unlike conventional methods, doesn't rely on well data or assume continuity. Instead, it analyzes seismic reflections to better detect closely spaced layers, even those thinner than what traditional seismic can resolve. The technique uses high-resolution spectral decomposition to extend the bandwidth of the data, while reshaping the frequency spectrum to avoid artifacts like ringing.

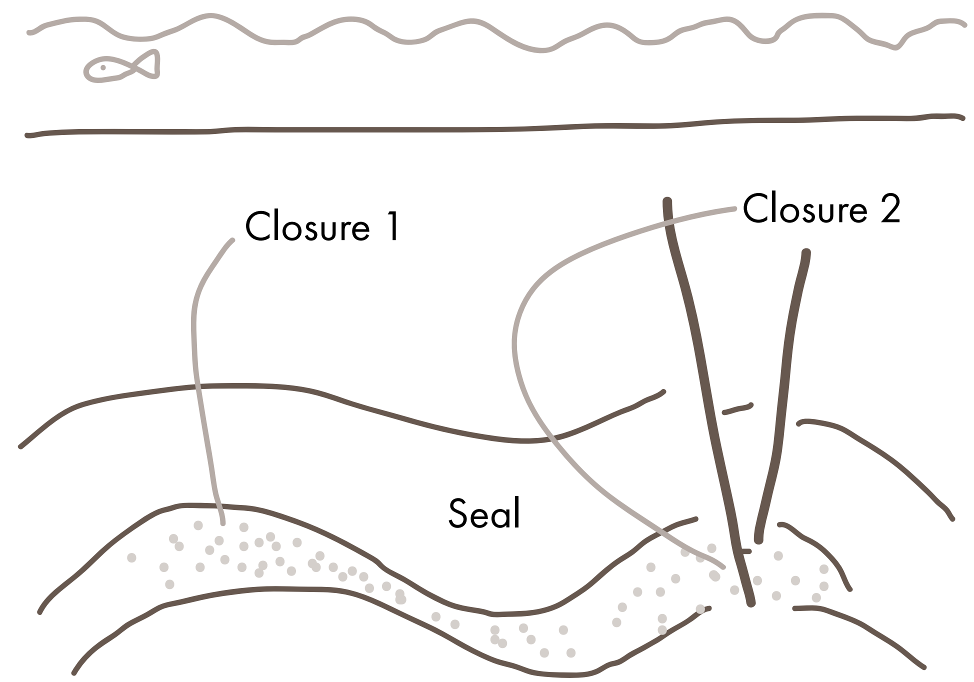
For the Sleipner project, the most impactful outcome is the creation of the Stratigraphic Continuity Attribute (SCA), a seismic attribute using the bandwidth extended data that highlights how continuous or disrupted subsurface layers are. It identifies areas where geological layers are laterally consistent, shown in warm colors like yellow, red, and green, versus areas with interruptions that are shown using cool colors like blue and pink. These latter ones may indicate faults, erosion, or depositional boundaries.

These insights are key in understanding how CO_2 will travel underground: Continuous sand channels act as flow paths, while disruptions may block movement. When plotted in map view, our results also support a more recently identified zone where westward CO_2 migration was observed. It corresponds to a zone of intermediate continuity, which might explain the delayed migration in that direction due to poorer reservoir quality.

By comparing the baseline (1994) and post-injection data, it is evident that stratigraphic continuity accurately predicts the CO_2 migration route. This approach can play a vital role in future CCS projects, helping identify ideal injection zones and anticipate plume behavior, especially in channel-rich formations like Sleipner. ■

Keeping geoscientists busy

A seismic acquisition and interpretation project in the UK North Sea was carried out to better assess a very small risk for leaking brines. Does that justify a project of that kind?



Closure 1 is the candidate for CO_2 storage; Closure 2 is deemed too risky, even though the faults are likely to be sealing.

> "Knowing that the study was done not even to de-risk leaking CO_2 but to de-risk a leaking brine, this project looks like people are desperately looking for potential problems to justify the mobilisation of kit"

Geoscientists can go too far in the relentless pursuit to de-risk all elements that could cause a CO_2 store to leak. At least, that is my take based on listening to a presentation by a member of the Endurance Partnership at the Seismic conference in Aberdeen.

What happened?

North of the Endurance CO_2 store, which is going to be the first Triassic saline aquifer in the UK North Sea that will be used as a site for CO_2 injection, is another cluster of potential sites that can be used for the same purpose. Two of those potential sites were the topic of a talk delivered by Adrian Merry from TotalEnergies, one of the three shareholders of the Northern Endurance Partnership.

One of those sites will probably lend itself for CO_2 storage, as it is a gentle anticlinal structure with a good seal on top. This one is marked Closure 1 in the sketch. However, the next-door anticline shows some major faults cross-cutting the crest of the structure, offsetting the reservoir. You don't need to be an expert to see that it would be risky to store CO_2 in there. That isn't the plan either.

Yet, a seismic acquisition was performed over this faulted structure in order to better assess how far the faults continued into the overburden. Why? Because there is a risk that CO_2 stored in Closure 1 would cause a pressure increase in the wider Triassic reservoir – there is a connection between the two sites – which may cause formation water to reach the seafloor via the above-described faults.

Is that a bad thing? The only rationale that was brought forward was something along the lines of "another composition" and "unwanted". But is that bad? I don't think it is necessarily so, especially because this is all happening in a shallow sea with a major tidal current.

And there is another reason why there was no need to mobilise a seismic acquisition vessel, even when knowing that the whole exercise only lasted a week. As was shown during the same talk, modelling demonstrated that the faults are likely sealing, and further geomechanical work also suggested that fault reactivation is unlikely. These studies alone should have been sufficient to not move ahead with the survey.

Overlooking all of this, and knowing that the study was done not even to de-risk leaking CO_2 but to de-risk a leaking brine, this project looks like people are desperately looking for potential problems to justify the mobilisation of kit and thus keep some geoscientists busy. I'd rather plan a development well. ■

Henk Kombrink

Creating a source rock and storing it for good

That is what Swiss start-up Recoal aims to do in an attempt to sequester carbon in a different way

"WE STARTED as a project when Swiss supermarket concern Migros wanted to find a solution to process its food waste in a carbon-neutral way," says geologist Tim Baars from Recoal. "The work we did for Migros ultimately led to the launch of our start-up in 2023."

The idea of Recoal centres around the BiCRS concept, which stands for Biomass Carbon Removal and Storage. Many different processes fall under the BiCRS umbrella, ranging from simply pumping sewage slush in a subsurface reservoir to creating Biochaa form of anthracite - through pyrolysis of organic waste and subsequently storing it on agricultural fields.

"What we do at Recoal is yet another process, called hydrochar, which is based on the concept of hydrothermal carbonisation," explains Tim. "The advantage of this methodology is that we can use wet-waste products as an input, saving energy in comparison to processes that need dried input products. Using a pressure vessel at high temperature, we arrive at a substance between lignite and bituminous coal when looking at the organic maturity."

The big advantage of using the hydrochar methodology is that the carbon concentration is much higher than when you would use unprocessed sewage sludge, and it is much more stable at the same time. In addition, it is an exothermal process, so once the pressure vessel is in operation, no more energy input is required to make sure the operation continues. If the installation is of a sufficient size, the heat generated during the process could even be used for other purposes.

Once the coal has been generated, the storage aspect kicks in.

"Abandoned mines or salt caverns are likely candidates," says Tim. "This already happens with fly ash, for instance. We also looked at the possibility of storing our coal in abandoned quarries or pits, even though some more remediation might be required in those cases because of the closer proximity of the material to groundwater and air. But regardless of where our coal ends up, monitoring will always be part of our strategy to ensure permanent storage. This will be done through gas or groundwater sampling."

A clear advantage of the hydrochar methodology is the storage efficiency. "We estimate that we can store up to a ton of CO_2 per cubic meter, whilst CO_2 storage ranges between 600 and 800 kg in the same volumetric unit. That means we need significantly less space to store the same amount of carbon," Tim concludes.

The company plans to order the first demonstration plant in the months to come, with first production of coal in 2026. With this installation, the aim is to process 1,000 tonnes of CO_2 per year, with further upscaling to 1 Mt/year per plant in the longer term. ■

Henk Kombrink

Hydrochar batches, each produced from manure feedstock.

PHOTOGRAPHY: TIM BAARS

SEABED MINERALS

"There are environmentalists who claim that if you remove all the nodules, an entire ecosystem will be lost. But that is impossible, because the areal extent of these nodule fields is so huge that it will never be possible to mine it all"

Annemiek Vink – Bundesanstalt für Geowissenschaften und Rohstoffe

A pragmatic approach to seabed mining

Biologist Annemiek Vink from German Research Institute BGR believes that seabed mining should be considered as an option given the circumstances we find ourselves in, adding a well-balanced view to a polarised debate

"I do obviously worry about the ecosystems down at the seafloor," says biologist Annemiek Vink from the Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) in Hannover when we meet on Teams. "On the other hand, I also appreciate the impressive size of the resource."

"There are environmentalists who claim that if you remove all the nodules, an entire ecosystem will be lost. But that is impossible," Annemiek says, "because the areal extent of these nodule fields is so huge that it will never be possible to mine it all. In fact, even if we were to aim to mine 20 % of it, it would still take us hundreds and hundreds of years to do it."

"If you see these nodules lying on the seafloor through the camera of an ROV, and you know that seascape continues on for hundreds of kilometers, it makes you more aware of the sheer scale of the area these nodules are covering," adds Annemiek. The Clarion Clipperton Zone (CCZ) alone is equal to the size of Europe.

However, it is only a smaller part of that total area that lends itself for seabed mining. There are mountainous areas where mining would be much more complicated, in addition to areas where the density of nodules does not make a mining exercise an economic exercise in the first place. "Taking these things into consideration, it is 20 % of the CCZ that is mineable at most," explains Annemiek.

TWO EXPLORATION CONTRACTS

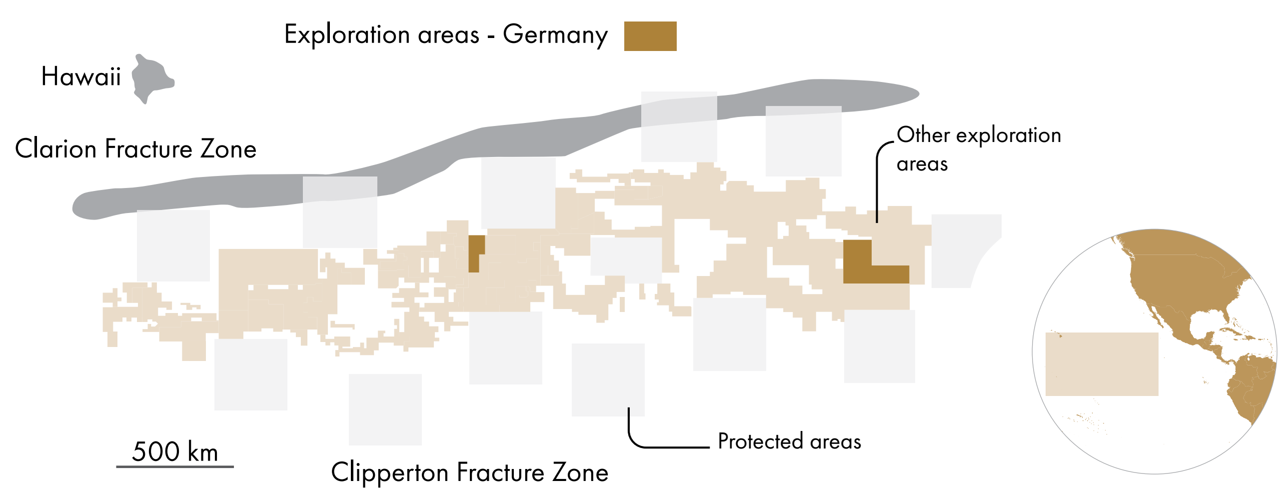
Germany has two contracts for the exploration of seabed minerals in international waters; one in the Indian Ocean for polymetallic massive sulphides and the other in the CCZ for polymetallic nodules. Annemiek coordinates the polymetallic nodules project in the CCZ, which started as far back as 2006. Meanwhile, about 80% of the work in the area relates to environmental baseline and impact studies.

UNIQUE ECOSYSTEMS

"Most of the species we find in this environment are rare; it's not like in forests where you see many common types of trees or birds across large regions with some rarer species alongside," says Annemiek. "That means diversity is high and difficult to quantify, with the implication that we will never be 100 % sure what species reside at every location. However, I feel that we should not even try to attempt to do that, simply because that would be an overly complicated and impossible task, also because we are not nearly close to having this information on land either."

"Instead, what we need is a pragmatic approach and a process that allows us to protect important parts of this ecosystem without the need to completely avoid other activities. In my view, that is possible. If we can have large and ecologically robust protected areas that are 80 % similar to the areas that will be mined, we are already in a good position. This will also help re-colonize mined areas." ■

Henk Kombrink



TMC's bold move

Frustrated by the International Seabed Authority's stalled progress on a deep-sea mining code, The Metals Company is turning to a 1980 US law to fast-track its ambitions

Frustrated by delays at the International Seabed Authority (ISA), the UN-affiliated body regulating mining in international waters, TMC is making a daring move. In Q2 2025, the Canadian company plans to instead apply for permits under the US Deep Seabed Hard Mineral Resources Act (DSHMRA) of 1980, side-stepping the ISA's stalled process.

This shift aims to accelerate commercial mining of polymetallic nodules in the Clarion-Clipperton Zone (CCZ) in the Pacific Ocean. The DSHMRA, passed by the US Congress in 1980 and regulated by the National Oceanic and Atmospheric Administration (NOAA), enables exploration and commercial recovery of deep-sea minerals in the high seas.

TMC's urgency isn't new. For years, the company has worked with the ISA, investing half a billion dollars and partnering with developing states like Nauru - the first to sponsor an ISA contract in 2011.

CEO Gerard Barron recently concluded that "After 16 years of engaging with the Authority in good faith, we are increasingly concerned that the ISA may not adopt the Exploitation Regulations in a timely manner."

Despite TMC's efforts - 22 environmental campaigns and successful nodule collection and processing tests - the ISA failed to deliver a Mining Code, even after Nauru's 2021 two-year notice. For Barron, this stalls not just the company, but the aspirations of sponsoring nations, including Tonga and Kiribati.

Under the United Nations Convention on the Law of the Sea (UNCLOS), the ISA governs the "Area" - the seabed beyond national jurisdiction. Most nations recognize its authority, but the US, a non-signatory, doesn't, creating a legal gray area TMC hopes to leverage.

This challenges the international framework, particularly ISA's role as the perceived sole regulator of the Area. Barron, however, argued: "The ISA does not have an exclusive mandate to regulate seabed mining activities in the Area", arguing it has drifted from its dual mission to both regulate and enable mining.

Before taking the helm in January, newly elected Secretary-General at ISA Leticia Carvalho, recognized that the work towards a mining code may still require years. Nevertheless, without ISA approval, mining could be seen as unregulated or even illegal by UNCLOS signatories. Enforcement, however, is weak, and US domestic law might shield the company.

Yet the risks are real. Environmentalists, already weary of deep-sea mining's potential impact on fragile ecosystems, may intensify opposition to this apparent bypass of ISA oversight. Global markets or governments could also reject TMC's metals as "illegally sourced," denting profitability despite US backing.

At the same time, success could set a precedent, tempting US-based firms or others frustrated by ISA delays, although most competitors are tied to UNCLOS nations.

TMC's manoeuvre highlights a tension between national interests and global governance. The US path offers speed, potentially bringing TMC to market in a couple of years. The ISA path, though slower, offers broader legitimacy, which could be vital for long-term acceptance of its metals.

What's TMC's true aim? Is this a hasty leap to kickstart mining or a calculated push to pressure the ISA? Its statements suggest the former, but one can't rule out that it is a bid to force the Authority into action to maintain its grip.

Either way, this dual-track approach could hasten TMC's path to production while shaking up international seabed governance. The future of deep-sea mining beyond national waters hangs in the balance.

It's your move, ISA. ■

Ronny Setså

PHOTOGRAPHY: TMC

A processing milestone: This high-grade nickel-copper alloy was recently produced by Japan's PAMCO using nodules collected by TMC as raw material.

Despite putting the brakes on seabed mineral licensing, the Norwegian government continues to spend ever-increasing amounts on seabed mapping

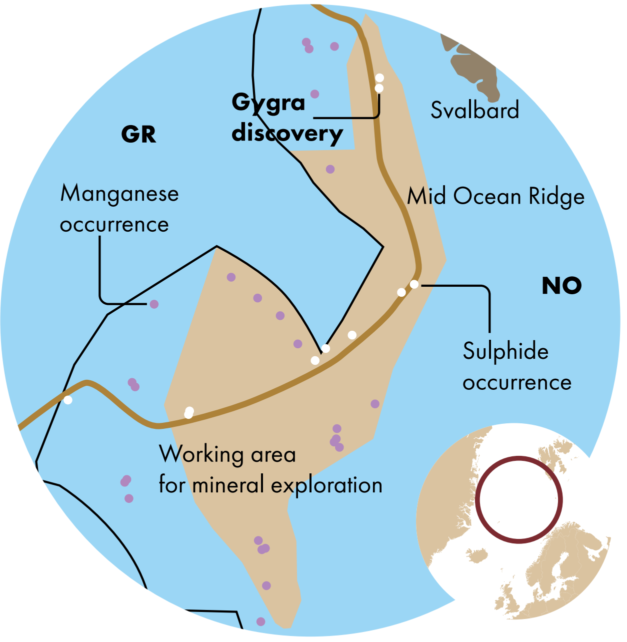
The Norwegian Offshore Directorate received a significant increase in funding in the 2025 state budget to continue mapping the deep sea

"WE HAVE been busy," confirmed Hilde Braut, Deputy Director for New Industries at the Norwegian Offshore Directorate (NOD), when she gave a lecture at the Deep Sea Minerals 2025 conference in Bergen in April.

Braut pointed out that the directorate, in collaboration with the universities of Bergen and Tromsø, conducted three expeditions in 2024, and so far in 2025, they have completed two more.

When so much mapping is carried out, it is no surprise to see that the odd discovery is made as well.

During the latest expedition in March, a new sulphide deposit was confirmed and sampled. The deposit, which is named Gygra, is located on the Knipovich Ridge about a kilometer southeast of Jøtul, an active hydrothermal spring that was discovered in 2022. A total of 53 samples were collected using the Ægir 6000 submersible's grapple arm.



A KEY MINERAL

Braut said that the samples have so far been analyzed using a measuring instrument (handheld XRF) on board the ship.

PROSPECTIVE, BUT REQUIRES MORE RESEARCH

Recent expeditions in the Norwegian Sea have clearly shown that the Norwegian part of the mid-ocean ridge is very prospective in terms of sulphide resources. The list of known deposits is growing steadily, and of the deposits that have been sampled, the metal contents are often higher than what we typically see in deposits that are mined on land. However, it is still an open question whether any of them will be viable. Single samples taken from the seabed are not sufficient to establish a resource estimate. Drill cores are also needed to provide a sufficient statistical basis for the ore bodies in three dimensions.

The preliminary results appear to be encouraging from an exploration and resource perspective.

"The analyses indicate that the material has a copper content of between 2 and 30 %, with an average of 5 %," said Braut.

She pointed out that the presence of the mineral atacamite is a confirmation of the high copper content in the deposit. The same mineral was also detected at the Grøntua sulphide deposit on the Mohns Ridge. Grøntua was found last year.

Braut was not the only speaker to highlight atacamite at the conference in Bergen. A research team at the University of Southampton has, in recent years, conducted research at the Semenov sulphide fields along the mid-ocean ridge in the Atlantic Ocean.

Their research so far has shown that atacamite in the upper, weathered part of the sulphides at the seafloor is a good indicator of the presence of copper in deeper layers. ■

Ronny Setså

NEW GAS

"Natural hydrogen exploration is currently a hot topic, but few companies have advanced from initial exploration to the drilling stage. HyTerra is one notable exception"

Mariël Reitsma – HRH Geology

If there was a hydrogen market, geological storage would not be the bottleneck

The Hydrogen Technology Collaboration Programme, established by the International Energy Agency, has released its final report on the feasibility of underground hydrogen storage

To balance intermittent renewable energy generation with grid demand, green hydrogen can be produced and stored in the subsurface at times of surplus energy generation, and subsequently used to supplement the grid during periods of high demand.

Underground hydrogen storage is not a novel concept; in the 1960s, 'town gas' was stored in salt caverns and depleted gas fields to ensure a reliable supply and manage fluctuating demand. Town gas, produced through coal gasification, contains up to 60 % hydrogen, along with methane and carbon monoxide. Countries like the UK, Germany and the USA utilised town gas before natural gas became widely available in the 1970s. The geological storage of town gas demonstrated that hydrogen-rich blends could be safely and successfully managed, with only minor issues reported.

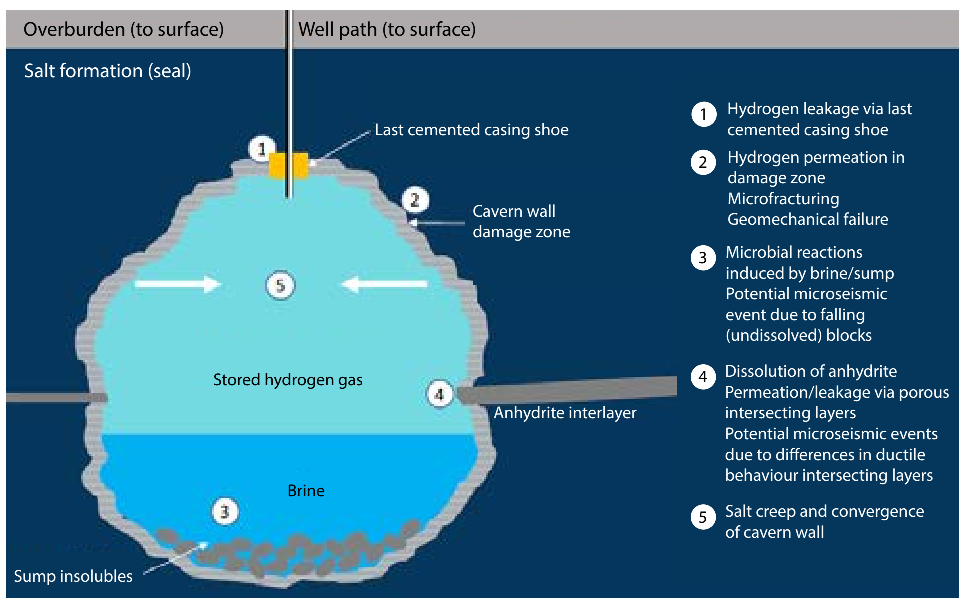
Nevertheless, the International Energy Agency was cautious and commissioned additional research to ensure safe and effective operations throughout the storage lifecycle, from initial construction to eventual decommissioning and abandonment.

Hydrogen behaves differently in the subsurface compared to natural gas; it is more mobile and reactive and serves as a feedstock for microorganisms. Therefore, before hydrogen is injected into a reservoir, it is crucial to identify potential issues. For instance, can the reservoir seal contain the small, mobile hydrogen molecules? Are there minerals present that could react with hydrogen and produce unwanted byproducts? Or will microbes feast on hydrogen, reducing its concentration and creating contaminants like hydrogen sulphide? The conclusion is that by selecting the right reservoir and implementing specific measures, these problems can be minimised for both salt cavern and porous reservoir storage sites.

The primary challenges arise during storage design and construction because depleted gas reservoirs and salt caverns cannot be directly repurposed for hydrogen storage. Hydrogen is corrosive and can embrittle steel, requiring specialised materials for hydrogen-related projects. Additionally, legacy wells in depleted gas fields are often unfavourably located, and hydrogen storage requires larger diameter wells to achieve the necessary flow rates. Ideally, storage sites should be located near or onshore, as fully offshore sites, including the surface processing facilities, would incur significantly higher development costs.

In conclusion, while geological hydrogen storage does not have major drawbacks, the associated costs and the current absence of a functioning hydrogen market mean large-scale underground storage remains a pipe dream for now. ■

Mariël Reitsma, HRH Geology



Overview of processes that may impact underground hydrogen storage in salt caverns.

IMAGE: REDRAWN FROM THE FINAL REPORT OF HYDROGEN TCP - TASK 42

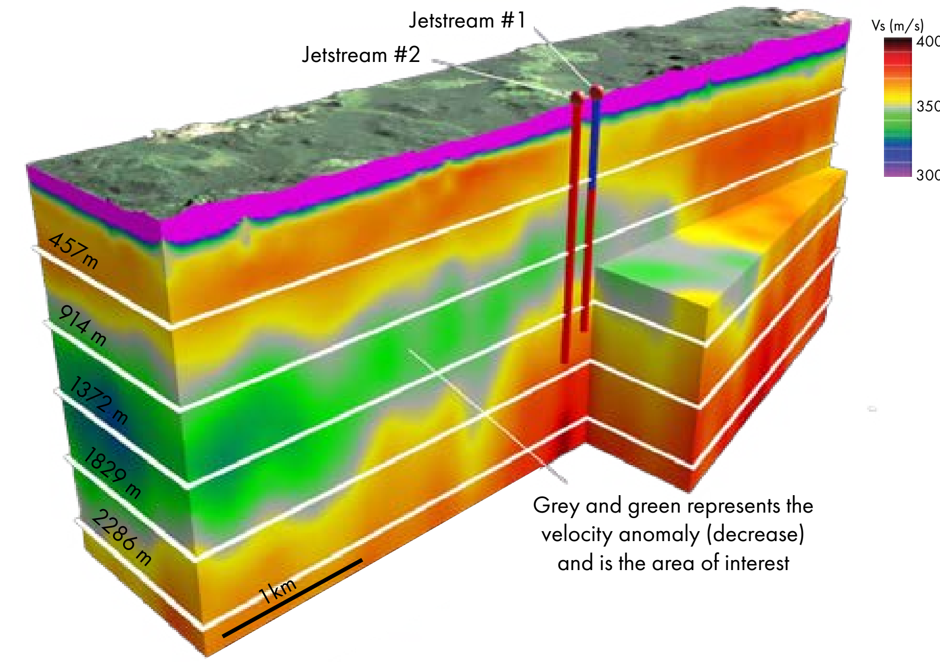
NEW GAS

A helium reservoir in fractured basement

Most of the world's helium is produced as a by-product of natural gas extraction or from geological settings similar to classic hydrocarbon plays. However, with the growing demand for helium and dwindling hydrocarbon reserves, helium explorers are expanding their search. One such company is Pulsar Helium, which acquired acreage in Lake County, northern Minnesota, a region historically known for metal ore mining

In 2011, a borehole targeting nickel unexpectedly discovered gas. The gas flowed from the hole with such force that it reportedly 'screamed like a jet engine' for four days until experts were able to seal the well. Analysis revealed that the gas contained over 10 % helium, along with CO_2 and nitrogen.

The targeted rock formations are part of the Duluth intrusive complex. The complex consists of layered mafic rocks emplaced 1.1 billion years ago when the Midcontinent Rift began to split apart the North American craton. The relatively stable tectonic conditions since then have allowed helium to slowly accumulate over time.



Ambient Noise Tomography (ANT) Shear Wave (Vs) Velocity Model for the Topaz prospect.

ILLUSTRATION: PULSAR HELIUM

WELL ABOVE THE CUT-OFF VALUE

In 2024, Pulsar Helium drilled the Jetstream #1 appraisal well, located 20 m from the discovery hole. Laboratory tests revealed up to 14.5 % helium and an average of 9.9 % helium over a 12-day flow test, well above the 0.3 % cut-off value for economic production. Wireline analysis identified discrete zones with productive permeability related to fracture porosity within the igneous rock. The well achieved a flow rate of 821,000 ft^3 per day under well-head compression.

The passive seismic model shows a significant velocity decrease in the zone that flows helium, while impermeable igneous rocks cap the helium-rich zone. The shear wave anomaly has a vertical thickness of approximately 610 m and covers an aerial extent of 7 km^2.

Initially, the Jetstream #1 well only reached the top of the low-velocity zone. Consequently, Pulsar Helium decided to deepen the well earlier this year, and it now transects the entire velocity anomaly. The company also drilled the Jetstream #2 appraisal well to further assess reservoir properties, such as porosity, permeability and well connectivity. Both wells successfully flowed helium to surface, confirming the geophysical interpretation of the shear wave anomaly corresponding to the helium-bearing zone.

ROCK DUST

Currently, the company is conducting pressure and flow tests. Wellhead pressures are encouraging for both wells, but drilling fines, rock dust generated during air drilling, are hindering the flow tests. Drilling fines partially coat the wellbore walls and limit gas flow. A preliminary clean-up of both wells has mobilised part of the drilling fines and resulted in improved flow; the wells flow naturally and on compression. Further flow testing will resume once clean-up is complete.

In addition to helium, Pulsar plans to capitalise on the approximately 62 % CO_2 present in the gas stream by constructing a dual helium-CO_2 production facility. ■

Mariël Reitsma, HRH Geology

HyTerra hits hydrogen – but will it be like a soda going flat?

Based on published results from the historic twin well, a proper gas accumulation is still far from proven

Natural hydrogen exploration is currently a hot topic, but few companies have advanced from initial exploration to the drilling stage. HyTerra is one notable exception.

Recently, the company drilled the Sue Duroche 3 exploration well in Kansas, USA, where they discovered concentrations up to 96.1 % hydrogen. This finding is not entirely surprising, as the well is located just 200 m north of the Sue Duroche 2 well, a hydrocarbon exploration well that found over 90 % hydrogen already in 2008.

The Sue Duroche wells are located above the buried crest of the Nemaha Ridge. The Ridge formed during Pennsylvanian reactivation of the 1.1 billion-year-old Mid-Continent rift. The basin is filled with Paleozoic sediments, primarily carbonates, along with mud- and sandstone. The Sue Duroche 3 well drilled through 335 m of sedimentary rock before reaching the Precambrian basement that constitutes the Nemaha Ridge, ultimately reaching a total depth of 1,052 m.

The gas sample with the highest hydrogen concentration was taken while drilling the Pennsylvanian carbonate that overlies the fractured basement. The sample contained 96.1 % hydrogen, 3.1 % CO_2 and 0.1 % methane. It is believed that the hydrogen originated from the basement, where it formed through serpentinisation of iron-rich minerals before migrating into the carbonates of the Lansing Formation.

Now, the big question is; has HyTerra found a reservoir with a hydrogen leg, or rather a dynamic system that is being fed hydrogen from the basement below. Published data form the previously drilled Sue Duroche 2 well provide a clue.

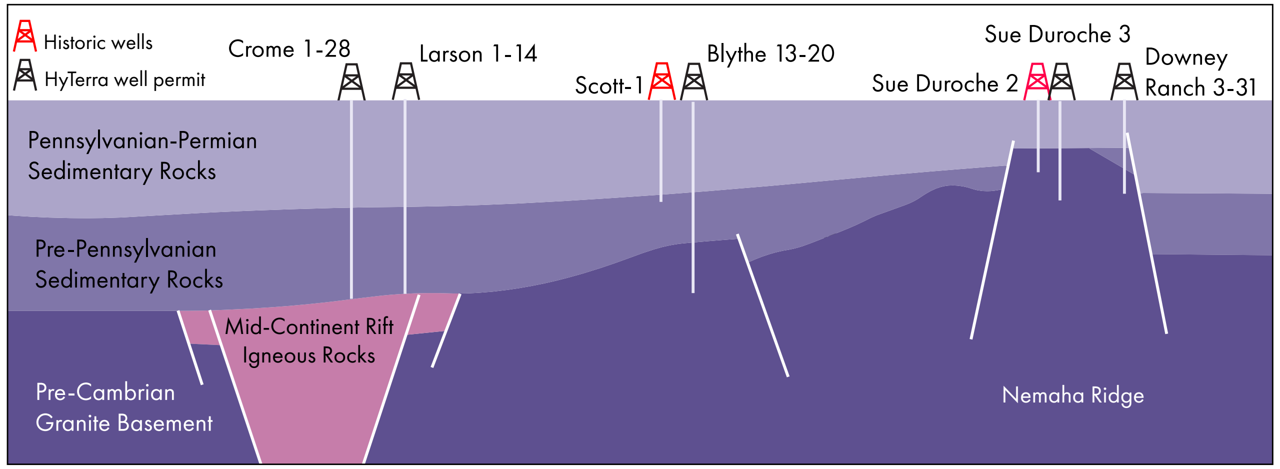
The Sue Duroche 2 well initially produced high hydrogen gas concentration (92 %) when the wellbore was open to fractured Precambrian basement. However, after a plug was placed at basement level, and flow was only dictated by the overlying Pennsylvanian aquifer, gas bubbling out of the aquifer only contained up to 3.1 % hydrogen.

This exposes an interesting difference between the Sue Duroche 2 and 3 wells. Where the results from the latest well suggest hydrogen concentrations to be highest in the carbonates overlying basement, data from Duroche 2 seem to hint towards the basement being the place to be; after plugging, there was not much more hydrogen left. We also have to bear in mind that chemical reactions with iron oxides in the sedimentary aquifer are suspected to consume the hydrogen, which also points to a dynamic system that includes hydrogen seepage from below.

This raises the question whether the hydrogen concentration at Sue Duroche 3 will decrease over time, similar to a carbonated beverage going flat, or if flow from the basement can be sustained. Extended well testing will have to prove this and the commercial viability of Sue Duroche 3.

First, however, HyTerra will drill a second exploration well, the Blythe13-20, located approximately 50 km southwest of the Sue Duroche wells and close to the historic Scott-1 well. The Scott-1 well, drilled in 1982, found around 56 % hydrogen rather than the anticipated hydrocarbons. ■

Mariël Reitsma, HRH Geology



SOURCE: HYTERRA

Projection of legacy, planned and recently drilled wells in north-east Kansas.

TECHNOLOGY

"In the end, AI may draw the outlines faster. But it still takes a geologist to see the story the Earth is trying to tell"

Dan Austin – Sekal

Why the pandemic might have left bp drilling a dry well in Canada

That's at least what CSEM results from a neighbouring licence suggest

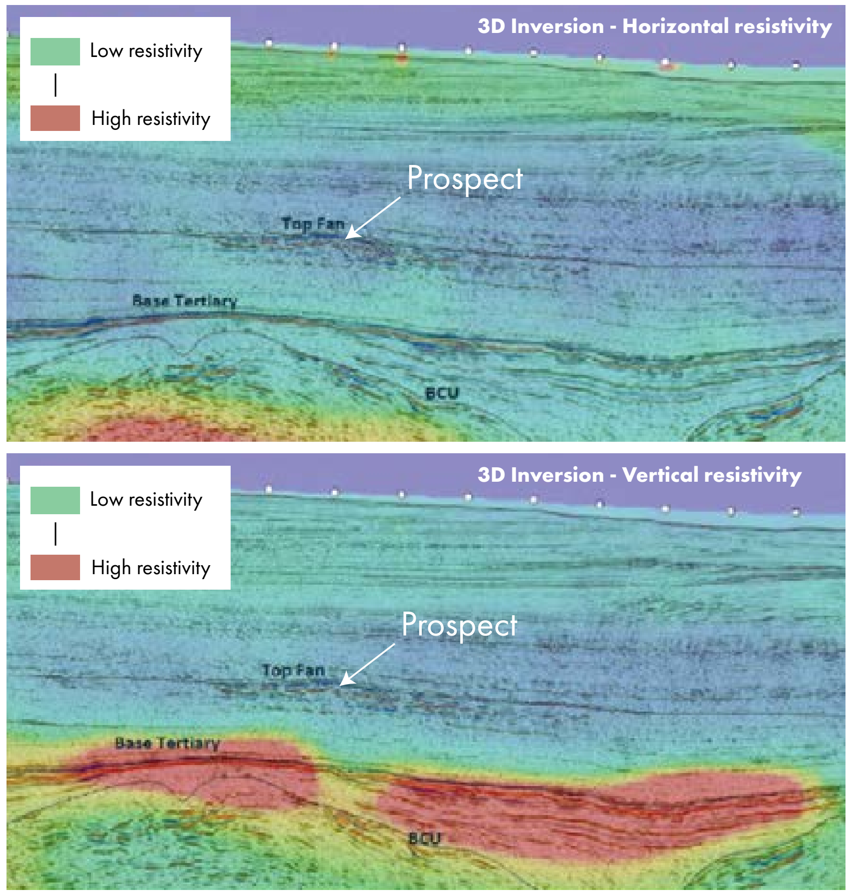
"WE HAD a very limited time window to operate in, in fact, it was too short to acquire 3D seismic data," says consultant geologist Peter Mikkelsen from Navitas Petroleum. Navitas had a licence next door to bp's licence 1,145, offshore Newfoundland, in which the major drilled what is generally assumed to be the dry Ephesus well.

"We were chasing a similar Eocene fan system in our block," says Peter. "But with the licence expiring soon, the time was not available to first wait on the results of the Ephesus well, which had experienced severe delays for various reasons, and then embark on a seismic survey."

The option then appeared on Navitas' radar to acquire a CSEM survey instead. "The survey was an order of magnitude cheaper than a conventional seismic survey and was easy to deploy," Peter adds. "In addition, the energy source was now ten times stronger than it used to be. That gave us the confidence to apply it in our acreage, where our prospect was at a depth of around 4,300 m below sea surface."

And there was another thing that worked in favour of using CSEM: the geology. "It was almost ideal for it," says Peter, "because we were dealing with a fairly simple and undeformed lithological mix of sands and muds, and the question of whether there are hydrocarbons in there, or water."

"The results were extremely clear," continues Peter. "We got a very good response from the base of the Tertiary, which is about 1,000 m below our target, going even deeper into the spectacular Mesozoic underburden. If even structures at depths of 5 to 6 km could be distinguished, it gave us the confidence that our Eocene prospect would have been picked up too if it had hydrocarbons in it."



CSEM results overlain on seismic dip line. The "Top Fan" label indicates the Navitas Eocene prospect. No resistivity can be seen at that level at all.

SEISMIC COURTESY OF TGS

But the prospect had no response whatsoever, not even a glimmer.

"We also had some modelling done for us by EMGS, who acquired the survey. Even when we only put around 200 million barrels equivalent of hydrocarbons in it, which is way smaller than the prospect might have been able to hold, we would have had a response from the survey. Going even lower than that, we would have been in the grey zone of picking up the signal or not, but in that volume range we would not have had an economic discovery anyway."

Is it too easy to claim that bp did not want a CSEM survey over Ephesus? "It is," says Peter. "We had plans to carry out a joint survey in 2020, but that was all canned by the pandemic. In the meantime, drilling plans progressed at bp to a point that they couldn't really go back. The result is that we spent less than 10 million on our licence, whilst bp spent an order of magnitude more." ■

Henk Kombrink

Thinking like a geologist in the age of AI

Geologists have long been doing, in an analogue way, the kind of inferential, cross-disciplinary, real-time reasoning that modern AI still struggles to replicate. Understanding this isn't just comforting - it may shape how we thrive as the landscape evolves

WE'RE ALL feeling a tension as geoscientists: Caught between an old way of working and a rapidly changing future dominated by Artificial Intelligence. As the dust starts to settle, another idea emerges: Perhaps geologists, more than many other professions, are uniquely suited for this moment, not because we code or because we operate new software tools, but because of how we think.

Field geologists move through complex, noisy environments, integrating information across multiple scales - from the grain size in a thin section, to the stacking patterns of outcrops, to the regional tectonic story visible on seismic. Every observation is provisional, every interpretation is open to revision.

In the field, we sketch, annotate, hypothesize, and cross-check. We think probabilistically, not deterministically. We recognize analogues but know where they fall short. This way of thinking - constantly synthesizing incomplete data, questioning early conclusions, refining models on the fly - is fundamentally different from how most machine learning models operate today.

While today's AI is powerful in recalling patterns and filling gaps from training data, it still struggles when asked to reason dynamically under uncertainty, to balance competing hypotheses, or to know when an observation "doesn't fit."

In that sense, geologists were "doing AI tasks" - inference from sparse data, model-building under ambiguity - long before AI was a household term.

GROUND TRUTH IN THE AGE OF SYNTHETIC REALITY

One lesson from field geology stands out: There is no substitute for ground truth.

We train our eyes and hands to spot subtle changes - a gritty texture, a faint color shift, a cementation style - that can change an entire depositional model. We know that laboratory measurements, log signatures, and even seismic amplitudes must be tied back to something physically real.

IMAGE: IPOPBA VIA ADOBE STOCK

In the emerging world of AI-generated outputs - synthetic logs, pseudo-realistic seismic sections, automatically generated interpretations - the temptation will be strong to accept digital results at face value. But synthetic realism isn't real realism. Without a human in the loop, evaluating the outputs against physical understanding and experience, we risk building castles on sand.

Working with AI tools will increasingly resemble doing fieldwork: Checking assumptions, testing interpretations, looking for inconsistencies, and maintaining a healthy skepticism about surface appearances.

THE ROAD AHEAD

We are still in that 'weird time' - the transition period where AI is neither fully mature nor easy to ignore. But for geologists, this isn't the first major shift we've weathered. From the days of hand-drawn maps to photogrammetry, from the first seismic sections to 3D visualization, we've adapted - because our core skills aren't tied to any one tool.

The best future workflows won't be about humans versus machines. They will be about human reasoning amplified by machine suggestion, and geoscientists, if we lean into our strengths, are remarkably well prepared to lead in this hybrid space.

In the end, AI may draw the outlines faster. But it still takes a geologist to see the story the Earth is trying to tell. ■

Dan Austin, Sekal

How advanced seismic inversion and a sound depositional model led to the successful appraisal of an initially uneconomic discovery

The Gnomoria discovery in the Norwegian North Sea is a great example of how seismic inversion helps to identify reservoir sweet spots

LET'S TAKE a step back and look at the structures targeted in the early days of North Sea exploration. It is no surprise that back then, the big fields were found first, as the seismic data was rudimentary and only really lent itself to identifying the major traps.

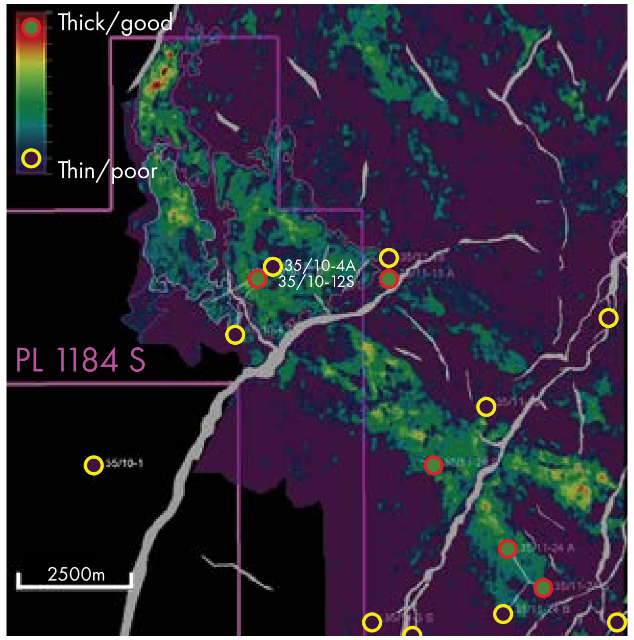
Fast forward to today, and the way seismic data is used to better understand the subsurface is remarkable. Subtle traps can now be explored and, even better, reservoir heterogeneity within the closure itself. It is that latter aspect that has allowed Wellesley and partner Equinor to turn an initially uneconomic discovery into an economic one. Here's how.

The Gnomoria discovery was made in 2018 through drilling well 35/10-4A. It found an Upper Jurassic succession of turbidite deposits associated with a delta system positioned to the southeast. However, the targeted sand proved too fine-grained and was cemented, even though oil shows were reported. The conclusion at the time was that if a more porous reservoir could be found, the discovery might work. That's where new seismic inversion data came in.

Aided by surrounding offset wells drilled since the initial Gnomoria discovery well, and using Viridien's latest shoot over the North of Troll area, a team from Qeye performed a full elastic and direct probabilistic inversion exercise across the discovery in an attempt to better predict the spatial distribution of the different facies in the interval of interest.

One of the main outcomes was that the 35/10-4A well was drilled in a location where the inversion predicted non-productive reservoir. However, all around the well, the probability of finding productive reservoir turned out to be greater than 60 %, making a clear case to drill an appraisal well.

Before making a call on that, the team first wanted to better understand why the reservoir in the discovery well was so fine-grained, also compared to offset wells. After a careful mapping exercise, the most logical explanation seemed to be compensational stacking, with the poor section in 35/10-4A being deposited in an area where the underlying turbidite sand was well developed, blocky and thick. This created a more unconfined environment for the subsequent sand input, resulting in a poorer and finer-grained nature than the surrounding and more confined areas of flow. This allowed the team, together with the seismic inversion results, to take the decision to appraise the discovery. The results confirmed predictions.



Probabilistic inversion result of the main reservoir interval in Gnomoria, showing the poor quality in the area of the discovery well and the predicted – and proven – enhanced quality a little further to the west.

SEISMIC DATA COURTESY OF VIRIDIEN, ANALYSIS PERFORMED BY QEYE

35/10-12S did indeed find more net reservoir than the discovery well, in line with a less well-developed underlying sand. A 21 m hydrocarbon column was proven, with an average porosity of around 13 %. The expected volume range for Gnomoria now stands between 5 and 25 MMboe. ■

Henk Kombrink

INSIGHTS

"The BGS is a British national treasure. At a time when certain government bodies are being mocked as wasteful and dismantled, I'd like to remind us all that the BGS, and the USGS, and every similar geoscience authority are the foundation to our national endeavours"

Juan Cottier – Geologist

I talk of dreams

Are they really the children of an idle brain?

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

Peel Castle, Isle of Man.

PHOTOGRAPHY: PHILIP VIA ADOBE STOCK

I AM A dreamer. I always have been. Though not on the scale of Alexander the Great or Martin Luther King, but I do dream every night, with complex narratives and full technicolour.

As a little kid, I had three recurring dreams: Firstly, fighting a Tyrannosaurus Rex; secondly, being chased by and chasing two rusty-armoured, ginger-bearded dwarfs around an island castle; and thirdly, possessing a handheld device that could answer any question I asked of it.

Forty years later, things have changed. Firstly, in the late 70s, there were only about 12 dinosaurs, all completely different, the evolutionary gaps were enormous, and the idea that dinosaurs and birds were linked was bonkers. Now, we can smoothly trace ourselves through geological time with barely perceptible changes in speciation.

Secondly, the idea of a handheld device that can tell you everything is now commonplace. Wikipedia on a smartphone was literally my dream come true. Now, given a dash of curiosity and a modicum of search skills, everything is available.

Which brings me seamlessly to natural gas processing and 14th-century English castles.

Recently, I was working on an asset in the Irish Sea feeding into the Rampside Gas Terminal in north-west England. I had assumed this landfall to be a remnant beach-bar with a back-lagoon, and I preferred the geomorphological terms of stoss and lee to "ramp". Immediate access to the British Geological Survey "Geology Viewer" showed me I was wrong, and the back-lagoon was where outcropping Triassic, Preesall Halite Member would be had it not enjoyed marine dissolution.

Rampside geology hosts the tiny Piel Island (0.1 km²), which has all the essentials: A pub and a castle. The castle was built by the Abbot of Furness in the early 14th Century to control the Abbey's significant Irish Sea trade, until becoming Crown Property in the 1530s. So, Henry VIII demonstrating a very different type of dissolution. Piel Castle is purported to be constructed from the island's beach material, which would be the Triassic orange St Bees Sandstone and grey Kirkham Mudstone Members, and utilises these different colours beautifully between sandstone quoins and window details versus mudstone rough wall fill.

The BGS is a British national treasure. At a time when certain government bodies are being mocked as wasteful and dismantled, I'd like to remind us all that the BGS, and the USGS, and every similar geoscience authority are the foundation to our national endeavours.

To close a circle, my dwarf chasing dream was set around my local childhood castle, the similarly named Peel Castle, situated on the boundary between grey Silurian metapelites and orange-brown Devonian sandstone and, again, beautifully built.

All that said, and praise aside, the BGS hasn't yet explained the dwarfs. ■

Some snakes don't bite

Learning Python is less scary than you think, and can be very useful in reservoir modelling

Everybody is talking about machine learning and big data these days, but what does it mean in reality, and how do geoscientists embrace it in their daily lives? To learn a bit more about that, I caught up with Tom Marsh and Elias Ortiz from Rock Flow Dynamics in their Aberdeen office. Both of them work with and develop reservoir modelling software, which is a discipline that lends itself well for elements of coding and machine learning applications.

The first thing that Elias told me immediately reminded me of something I had heard before. "The subsurface geoscience sector is not a big data environment. That's where the social media platforms operate in," he kicks off the conversation.

"Instead," he continues, "our geoscience niche is rather an environment where there is a lack of data, so machine learning algorithms taken from the big data realms are not necessarily useful in our case. In addition, we work with spatial and stratigraphic data, which is more complex in some ways."

"No generic data analysis code will be developed with superposition in mind," adds Tom. "For us, it makes sense, but it is important to be mindful when using off-the-shelf solutions."

But how does it work in practice?

"While our core software is developed in C++, we offer a native Python extension and API, allowing users to work and develop workflows in Python," Tom continues. "This is the environment that most developers use these days. Our clients can output the workflows they develop in our software as a Python script, and subsequently add their own twist to it. It's the new way of working when it comes to operating software and offers users the flexibility they need and more and more often require."

But that means users will need to have some Python skills too.

"Python is not as scary as you think," says Elias. "Admittedly, I started doing elements of coding when I attended university, and I have a natural interest in it, but the time of learning all the commands one by one is surely over. In the Python environment, Notebooks allow you to quickly test something for which code already exists," says Elias. "The tool I use a lot is called Jupyter Notebook, and it hosts a wide range of Python applications and libraries for interactive development. In addition, ChatGPT will also spit out some code for you when you ask."

"Are you afraid that all this will replace the geologist at some point soon?" I ask at the end of the conversation. "No, I'm not," says Tom. "The modules we develop all require an element of expert supervision to verify what the machine comes up with. I would rather say that we can do more and we can do it faster, but the geologist will always be an essential part of the process." ■

Henk Kombrink

Tom Marsh (left) and Elias Ortiz in front of Elias' workstation.

PHOTOGRAPHY: HENK KOMBRINK

Intense exploration and appraisal in the Norwegian Barents Sea

NVENTURES

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Wells recently drilled are a mixed bag of results, but reflect a strong desire to either extend the life of producing assets or improve the economics of undeveloped discoveries such that FID is more likely to be taken

JON FORD, NVENTURES

The Norwegian Barents Sea has been the venue for a continuous campaign of exploration and appraisal over the past year. As shown in Figure 1, to date, there have been six wildcats resulting in an oil discovery (Zagato), three gas discoveries (Elgol, Hassel and Ferdinand), and two dry holes (Venus and Snøras), plus two successful appraisal wells (Countach and Wisting). The commercial drivers are to extend the lives of existing fields, Goliat (operated by Vår Energi), Snøhvit (Equinor) and the recently

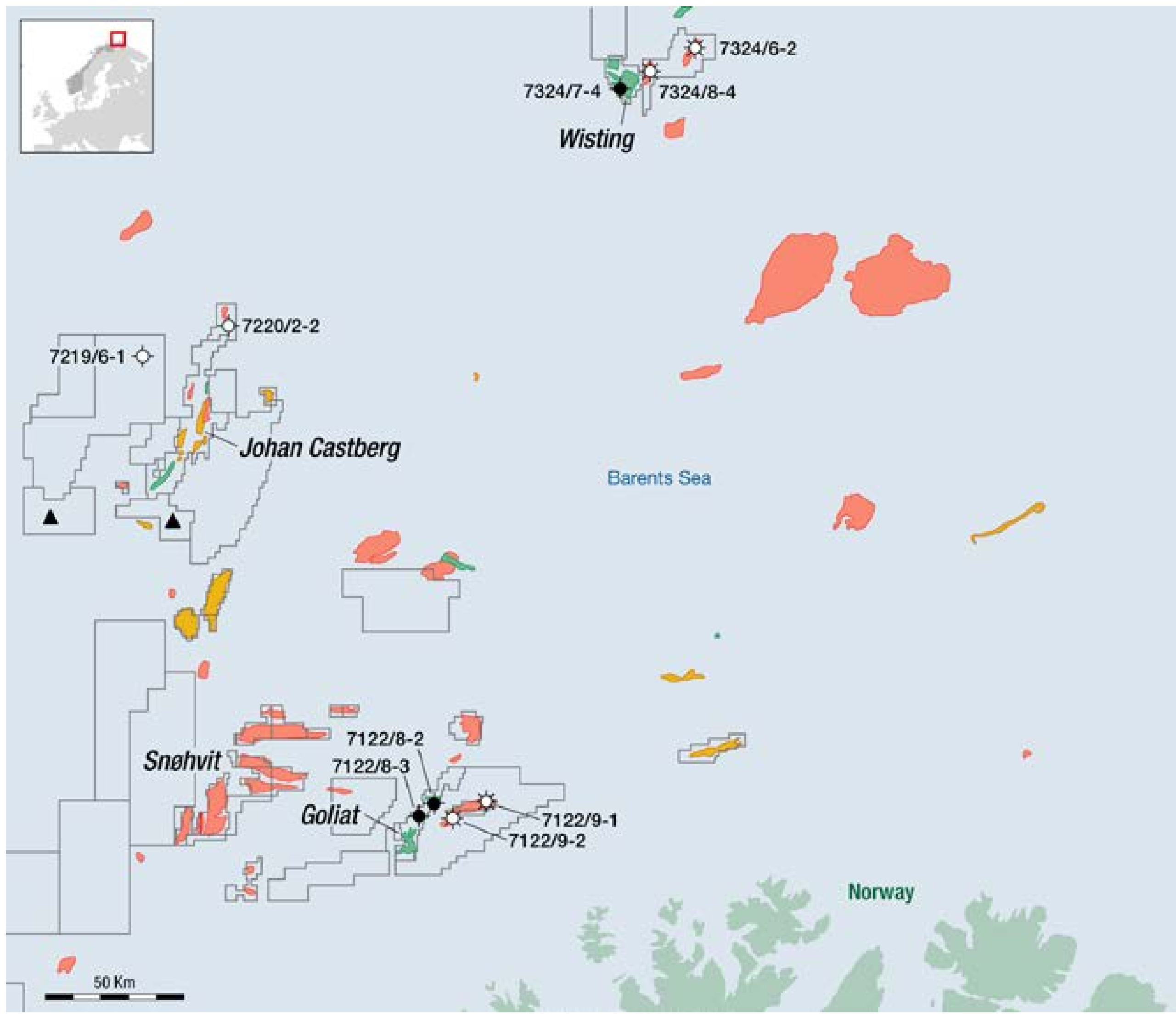


Figure 1: Barents Sea location map with producing fields and 2024-25 exploration and appraisal wells labelled.

SOURCE: NVENTURES

onstream Johan Castberg (also Equinor), and to determine a decision on the development of Wisting.

The Goliat field began production of an estimated original resource of around 200 mmbl via FPSO in 2016, of which some two-thirds are now exploited; rates have declined from nearly 100,000 bopd to 21,000 bopd, and the search is on for additional reserves for tie-back. Goliat reservoirs are Trias to Lower Jurassic sandstones trapped in a faulted complex at depths of 1,100 - 1,800 m. Well 7122/8-2 (Vår and Equinor, December 2024) successfully appraised the Countach discovery with estimated resources now up to 50 mmbbl contained in the same reservoir formations as Goliat and along strike on the same inverted fault block. The following well 7122/8-3 (December 2024) discovered some 40 mmbbl at Zagato lying between Goliat and Countach. Two further wells and two seismic campaigns are planned in 2025. Figure 2 illustrates the Goliat Ridge structure.

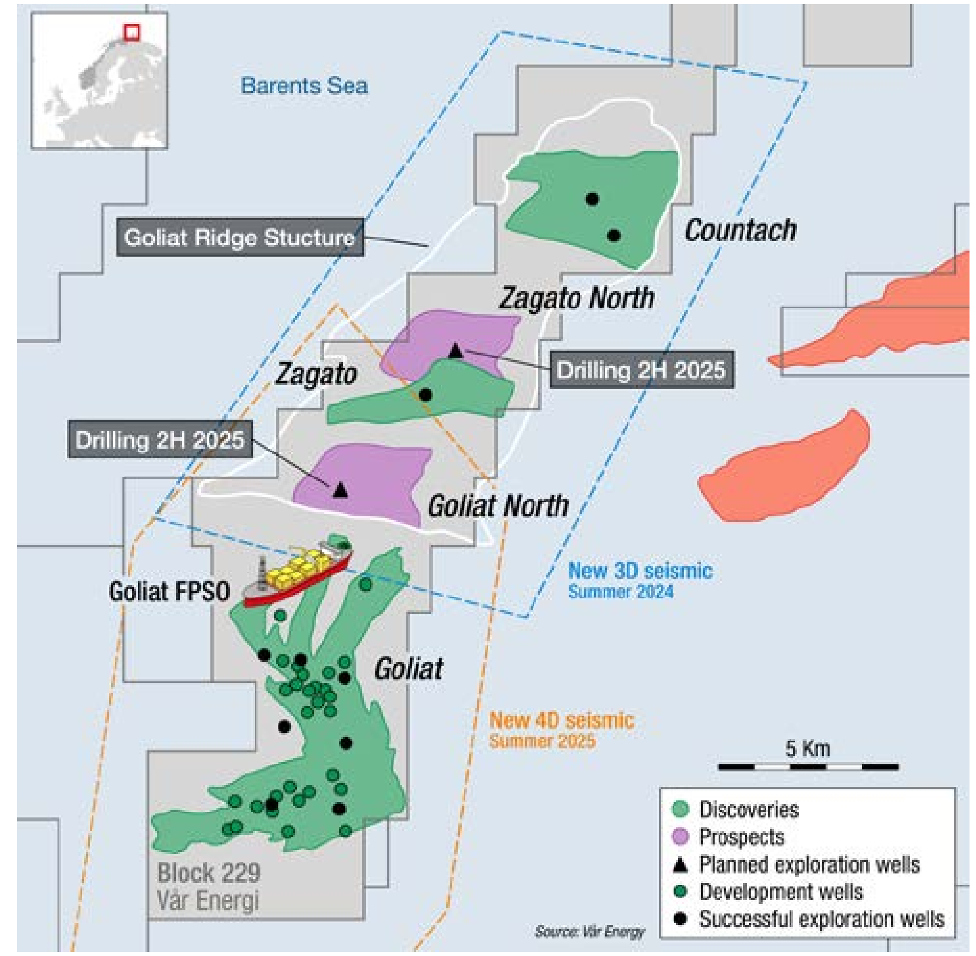


Figure 2: The Goliat Ridge.

Currently, produced gas at Goliat is reinjected, but long term, the plan is to export gas via the Snohvit facility and pipeline to shore. Following the December 2022 discovery of more than 600bcf in Triassic sandstones at Lupa with well 7122/9-1 (Aker BP and Var, licence 229), the Elgol prospect was drilled by 7122/9-2 in January 2025 (Vår, Petoro, Equinor and Aker BP, licence 1131) but reportedly is a technical discovery only with modest reserves (15-115bcf) and moderate to poor reservoir quality.

Following this partly successful start, the Goliat joint venture plans to continue a modest risk exploration and appraisal campaign of up to four years and 20 wells in total, with a stated aim to increase the gross production to more than 350,000 boepd.

The 560 mmbbl Johan Castberg discovery began production from Triassic and Jurassic sandstone reservoirs via FPSO in March 2025. Here, recent attempts to discover satellites for potential tie-back have failed, with Venus (well 7219/6-1, Vår, Equinor and Petoro, May 2024) and Snøras (7220/2-2, Equinor, Vår & Petoro, June 2024) both dry. The former's target was in the commercially unproven Palaeocene, with the latter targeting the more familiar Lower Jurassic.

Wisting discovered up to 500 mmbl in the Lower to Middle Jurassic in 2013. Four appraisal wells have now been drilled, including last year's 7324/7-4 (Equinor, Aker BP, Petoro & Inpex Idemitsu Norway, April 2024). Development plans remain in the balance due to the challenges of an extraordinarily shallow reservoir depth, just 237m below the seabed in water depths of some 400 m, despite which the oil quality shows only limited biodegradation. Interestingly, operator Equinor reported that the information gathered by the appraisal was not only for reservoir but also for the seal.

Close to Wisting there have been two wildcats, both modest gas discoveries of approximately 25bcf at shallow depths, at Hassel and Ferdinand (wells 7324/8-4 and 7324/6-2, Aker BP, Equinor, Petoro & Inpex Idemitsu Norway, May-June 2024). How such gas resources will contribute to the development decision at Wisting is unclear.

Intensive exploration drilling continues; NVentures is tracking a further eight "Wells to Watch" in the West Barents Sea, with a further five likely to mature. ■

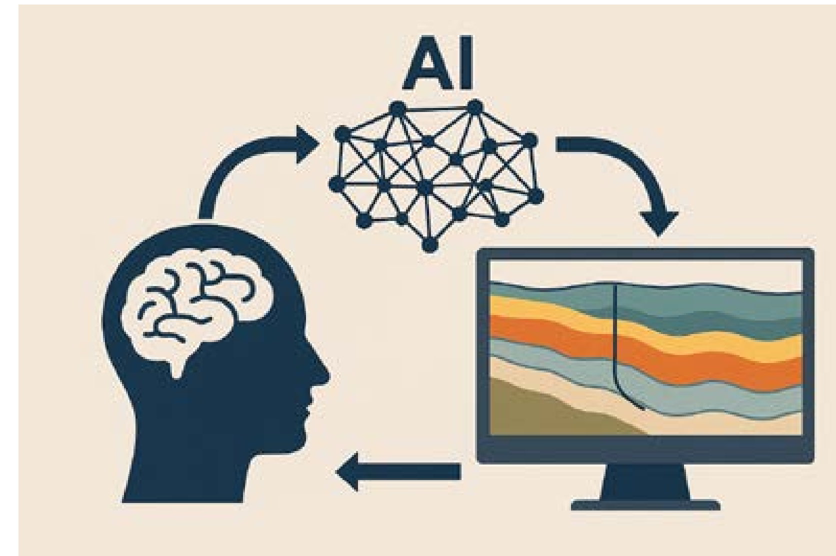
Basin modelling in the age of AI: A partnership, not a replacement

Whether in exploration, geothermal, or CO_2 storage, AI-supported models could become standard practice

DAVID RAJMON, GEOSOPHIX

Artificial Intelligence (AI) and Large Language Models (LLMs) are now part of many professional domains - from healthcare to engineering - and the subsurface is no exception. In basin and petroleum systems modelling, however, AI is not shaping up as a disruptive replacement. Instead, it offers a new layer of support: Accelerating workflows, helping identify patterns, and reducing the time needed to explore multiple scenarios.

This was a key theme in the recent EAGE webinar Introduction to Subsurface Systems Modelling. The tone was cautious, but forward-looking. Physics-based models remain central to understanding basin evolution and petroleum systems. AI's emerging role lies in improving, not replacing, those models.



An AI-generated figure supporting this article. Not bad... huh?

One of the most valuable contributions AI can make is in data assimilation and calibration. Traditionally, calibrating a basin model is a manual, iterative process dependent on expert judgment and sometimes influenced by personal bias. AI can help by scanning through large and diverse datasets, identifying optimal parameter spaces more efficiently. Done right, this improves objectivity and accelerates convergence on geologically plausible outcomes.

But this doesn't mean full automation. Experience still matters. AI tools work best in supervised workflows, where humans guide, evaluate, and adapt the results. AI can highlight inconsistencies or suggest alternatives, but geological understanding remains essential. Hybrid systems - combining physics-based modelling with AI/ML components - are emerging as a pragmatic path forward.

Another key takeaway was the importance of quality over quantity. AI must be trained on a few well-constructed, thoroughly vetted models, rather than on large volumes of inconsistent data. What AI learns must be geologically grounded to be useful.

A conversation with a friend who is a software developer in the manufacturing industry offered helpful analogies. This field is just beginning to utilize AI in their manufacturing models to search for similar solutions, products and models, which is speeding up model development and constraining parameters of the model. My friend is also using AI as a reasoning partner - providing reasons why something is in a certain way, why it cannot be otherwise, how to convince a manager/partner about a proposed solution.

AI could play a similar role in geoscience by searching for patterns and analogs, providing evidence, test assumptions, justify choices, and communicate more clearly with non-specialists and specialists across disciplines. This help in communication may seem subtle, but in my mind this is probably as important as building the model.

I do not expect to hand over the reins to machines any time soon. We should build systems where AI helps us think faster, test wider, and explain more clearly. Whether in exploration, geothermal, or CO_2 storage, AI-supported models could become standard practice - provided they remain rooted in geoscientific insight and guided by experienced hands.

Are you beginning to see these tools appear in your own modelling environment? ■

Unlocking fractured basement reservoirs

Geological controls and global success

MOLLY TURKO, DEVON ENERGY

Fractured basement reservoirs, often igneous or metamorphic rocks like granite or gneiss, contrast with conventional sedimentary reservoirs. Without primary porosity, they depend on fracture networks for hydrocarbon storage and flow. Effective oil and gas production requires understanding the fracture network and its controls, lithological and mineralogical influences, and the hydrocarbon system.

Fracture networks primarily govern reservoir performance, shaped by tectonic stress and varying in scale, density, and orientation. High-density fracture zones near faults boost permeability and connectivity, aiding hydrocarbon migration and accumulation. The structural setting is vital, with basement reservoirs often in uplifted or faulted blocks, where the tectonic history dictates fracture patterns. Pre-existing weaknesses, such as ancient shear zones, may reactivate, increasing fracture density. Multiple tectonic events may enhance fracturing, particularly along reactivated faults. Present-day stress fields affect fracture aperture, with open fractures aligned to maximum horizontal stress, improving flow rates. Essential datasets, which include borehole imaging, core samples, and 3D seismic, help distinguish open versus sealed fractures, as mineral infills like quartz or calcite can impair permeability.

Lithology and mineralogy significantly impact fracture development and reservoir quality. Hard, brittle rocks like granite fracture easily under stress, forming extensive networks, whereas ductile rocks deform plastically, reducing fracture formation. Mineral composition affects fracture toughness - quartz-rich rocks fracture more readily than those dominated by feldspar. Heterogeneities like dikes or veins can compartmentalize reservoirs or locally enhance fracturing. Petrographic analyses aid in identifying productive zones by clarifying these lithological controls. Additionally, alteration processes, such as weathering in granite, can increase brittleness and fracture density, making the study of erosional unconformities crucial.

Fractured basement reservoirs follow petroleum system principles, needing a trap, seal, source, migration, and reservoir. The trap is typically an uplift or fault block geometry. The source ideally lies directly above or beside the fractured basement for easy migration into fractures.

Diagram depicting a fractured basement structure beneath the sedimentary layer, with red and green colors highlighting oil and gas reservoirs, respectively.

IMAGE: JOHN PEREZ GRAPHIC DESIGN, GEOART.COM

Key factors also include the diagenetic history—burial and uplift - which impacts fracture preservation. Lastly, geochemical analyses of hydrocarbons and fluid inclusions may help reconstruct this history, verifying an effective petroleum system.

Successful production from fractured basement reservoirs depends on understanding their geological characteristics. Though relatively uncommon, these reservoirs achieve commercial success globally. Notable examples include Bach Ho Field (Vietnam), Renqiu Oil Field (China), Suban Gas Field (Indonesia), Mumbai High Field (India), La Paz Field (Venezuela), Edvard Grieg (Norway), Lancaster (UK), Wilmington and Edison fields in California (USA), and fields in the central Kansas uplift (USA). ■

Ripples and plane beds

The Cutoff Formation, currently exposed in the Guadalupe Mountains in Texas, USA, was deposited over a drowned shelf margin in Permian times. The name of the formation is derived from subsequent erosion of its strata, which left the shelf, shelf margin and basinal domains in isolated sections. The field photo shown here is from the basinal part of the formation, in which coarser-grained intervals can be found in the form of deepwater channel systems deposited by low-density turbidites. The aggrading ripples and plane beds that can be seen in this beautifully exposed section are interpreted as part of the levee system associated with one of those deepwater channel systems.

Photography and text: Ali Jaffri, Applied Stratigraphix

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.

A lost Libyan core

In Scotland, carbonates and anhydrites from the Sirte Basin are patiently waiting for a new home

We are very close to our print deadline for this issue, and I must say it was a marathon. Most people expect this magazine to appear at regular two-months intervals, but our agenda is very much governed by the events we attend, and these cluster in certain periods of the year. For that reason, we only had six weeks to put together this record-breaking edition, with more than 110 pages. And knowing that it sometimes takes a month to only arrange an interview, let alone waiting on approvals, it is easy to see why six weeks is not that long.

What does all of this have to do with our core feature? Well, I've got two jobs. I also collect core, mostly from the North Sea. It's core that is discarded by the industry as soon as fields are decommissioned, or from exploration wells that were cored but turned out dry.

In that capacity, I recently had the opportunity to take delivery of a core from Libya. That doesn't happen every day. The cores had been sent to Scotland for special core analysis, but were apparently never claimed back by the operator. As such, they were sitting in a warehouse for years, until the space was needed and the owners called me to come to the rescue. And that's why these cores are now ours.

And being an editor at the same time, knowing how difficult it can be to have some core images released from places that do not have a nice public repository, I grabbed this opportunity to feature some of our core by just driving to Reservoir Group, where we have some space to store this material. Yes, Reservoir Group, the company that cuts cores in many of the world's highly anticipated exploration wells. Our orphaned core sits in the same warehouse where the core barrels and core bits are waiting to be deployed, going all over the place. Isn't that nice?

Core 3, GG18-11, 3, 113-3, 122 ft, showing an undulating base of a shallow water carbonate succession overlying anhydrites.

And now we are back to the beginning; we are close to the print deadline, but I'm in the lucky position to just take a photo of a core that I would otherwise not have had access to by any stretch of the imagination. And in the meantime, I also had a nice chat again with Steve Rait, who so kindly offered us some storage room on his site about a year ago.

And finally, what is shown here? Eocene anhydrites and carbonates from the Hon Formation in the Ed Dib field in the western part of the Sirte Basin in Libya, probably drilled by Suncor. The best part of the succession is the undulating transition between gypsum – now anhydrite – deposited under hypersaline conditions, to an interval of carbonates, deposited during times of slight sea-level rise that allowed deposition mainly of micritic aragonite. ■

Henk Kombrink

PHOTOGRAPHY: HENK KOMBRINK