THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

VOL. 22

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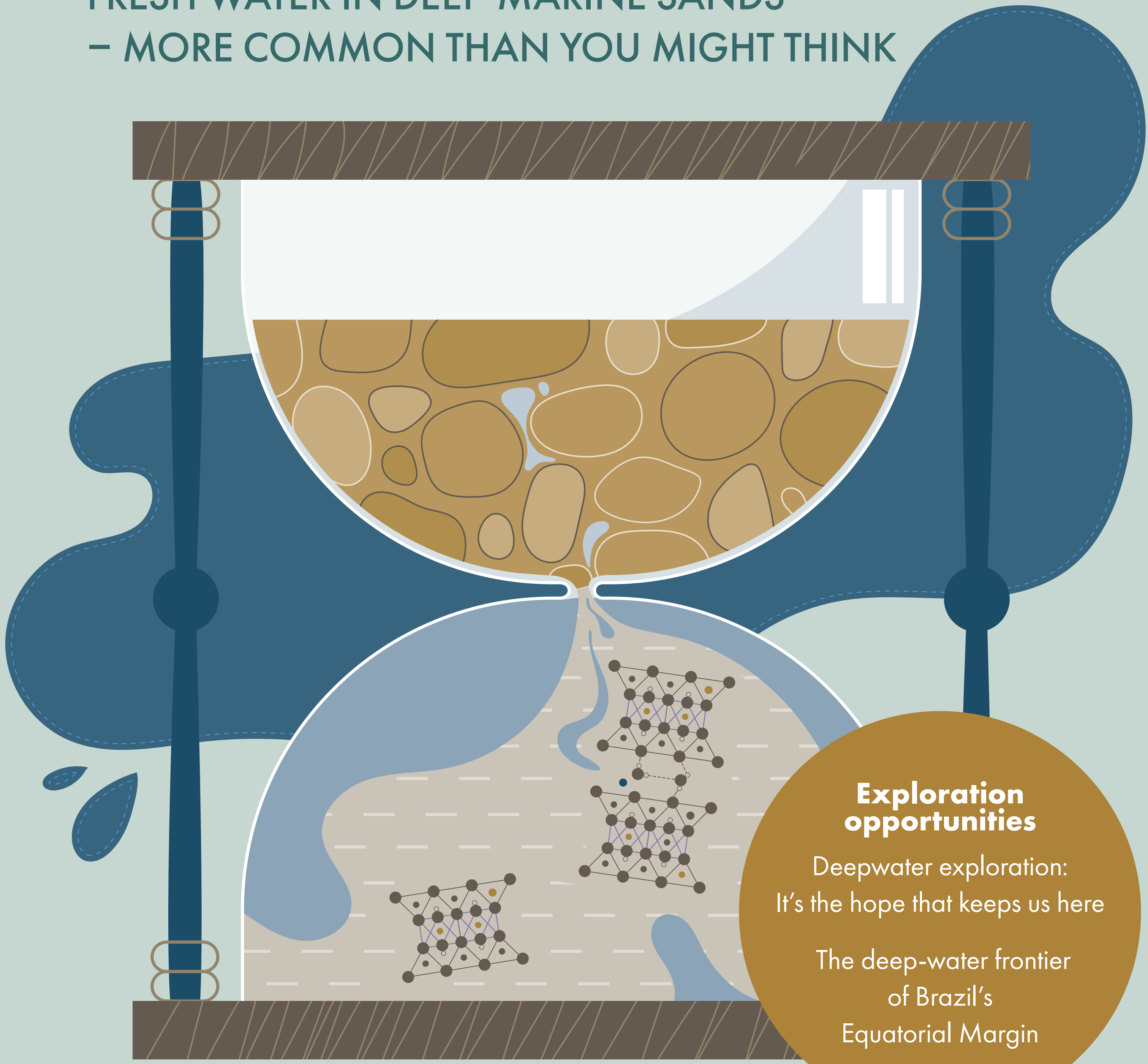
FRESH WATER IN DEEP-MARINE SANDS – MORE COMMON THAN YOU MIGHT THINK



Exploration opportunities

Deepwater exploration: It's the hope that keeps us here

The deep-water frontier of Brazil's Equatorial Margin

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Deeper and deeper

ONE OF THE great aspects of being an editor is seeing how a magazine takes shape as we gradually move toward the print deadline. And how individual articles – even when there was no masterplan behind it – all of a sudden seem very linked. That is surely the case in this issue.

Neil Hodgson and Karyna Rodriguez from Searcher write: "The deep-water sedimentation world we thought we had conquered is receiving a new approach. The effect of contourites on sedimentation that we can see on modern seismic is very hard to observe in core and logs – it's a matter of scale, but we are learning right now that they can dramatically influence the architecture of clastic turbidite deposits on both slope and basin floor."

All the while, in the portrait interview, we hear from one of the best-known academic deep-water experts himself, Javier Hernández-Molina, how he has managed to study contourites and thus shed more light on the often underestimated effect these systems have had on the deep-water geological record.

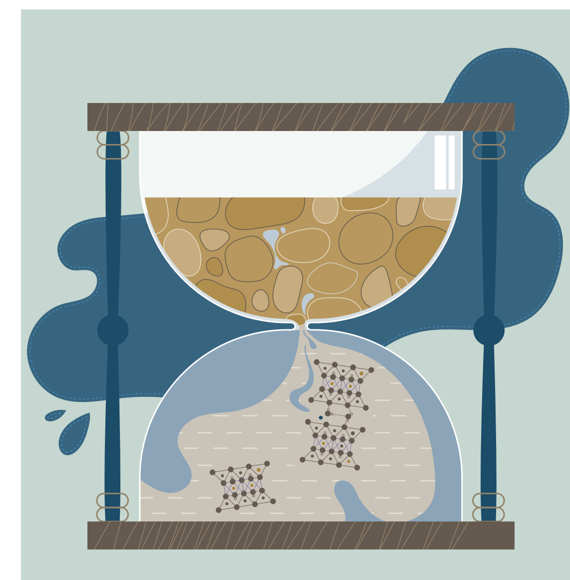
> "...the move towards deeper offshore regions is also very much marked by very personal and unique careers"

I warmly recommend you read both the Searcher foldout and the Portrait to see how – on the back of major technological advances – the move towards deeper offshore regions is also very much marked by very personal and unique careers. Enjoy the read.

Henk Kombrink

BEHIND THE COVER

As much as drilling and testing deep-water exploration wells can result in surprises, so do the front cover designs from Lucia Perez-Diaz. In a positive way. How to illustrate a phenomenon such as fresh water in deep-water sands, released through the diagenetic transformation of clay minerals? Not an easy task for sure. But she did an excellent job again, and through the introduction of the hourglass, she also managed to weave another critical element into what the cover story is about: Time. As that is an essential element required to arrive at a situation that many geologists left amazed: The observation of fresh water in the world's deepest wells that could never have had a direct input from meteoric water.



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FIRSTS

"With the sorrowful winddown of the UK oil and gas industry, luckily, sense still prevails in the Netherlands, and the offshore represents an attractive option for disillusioned companies on the other side of the median line"

Ian Cross – Moyes & Co

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

MOVING ACROSS THE WORLD FOR A DEGREE IN GEOPHYSICS

I had just arrived at an evening talk in Aberdeen when a student from the local university introduced himself to me. The reason for him to move to Aberdeen and enroll in a master's course in geophysics was that in his home country, Australia, there wasn't something available along those lines. The reason for that is as follows. In mining, which is the most important employer for geoscience graduates, seismic acquisition has traditionally not been an important aid for exploration. But that situation is changing according to the student. In pursuit for more mineral riches, against a backdrop of the easy ones being found already, companies are now looking deeper and are planning to use seismic data to find additional resources.

THE EARLY DAYS OF SUBSURFACE MODELS

I recently spoke to a geologist who was heavily involved with the introduction of the first generations of reservoir modelling software. He told me how maps from static reservoir models were printed and subsequently digitalized by the reservoir engineers in order to "import" them into their dynamic modelling software. It took a while before some code was developed to convert the static modelling output files directly into a dynamic modelling input file. It beautifully illustrates the incremental steps taken to arrive at the fully linked and integrated modelling software we have today.

"I'M NOT ALLOWED TO TALK TO YOU"

It was a first for me. Attending the GeoTHERM conference in February, I visited the Eavor stand in an attempt to hear more about the Geretsried project in southern Germany. An employee with a prominent Eavor sweater approached me, and we shook hands. Then he asked about my affiliation, upon which I told him about the GEO EXPRO magazine. He then replied swiftly, saying that he was not allowed to talk to me, and referred to a colleague from communication. Strict instructions, he said. I have been at many stands at many conferences, but this never occurred to me before. What is the point of being there when you can't talk to the press? I found it all a bit odd, and it makes you wonder if the company is hiding something.

SHALLOW GEOTHERMAL IS BOOMING IN ICELAND

In contrast to drilling deep for geothermal energy, the geological risks for shallow geothermal are minor or even non-existent, as loops are based on conductive heat transfer and do not draw fluids from the subsurface. In Iceland, where even shallow geothermal projects tap into >100° C formations, the drilling of closed loops for single house developments is, therefore, a no-brainer. The demand for these loops is now such that drillers are booked up for more than two years in advance.

ILLUSTRATION: PCR.VECTOR / FREEPIK.COM

Taking a seat on the 4-legged stool of honest energy policy

A physics teacher will tell you that energy is the ability to do work. An economics professor will say that it is the prime mover of human progress. A general will see it as the key to national security, and many environmentalists will see it as the root of many of our problems. As a geoscience community, our role should be to unite these perspectives into a solid foundation for the prosperity of future generations

It's time to start being honest to ourselves regarding the suitability of an ambitious, high-profile goal such as "net zero". The unpopular truth is that it has long been evident that Net Zero is incompatible with our current lifestyles. The fact is that, globally speaking, global carbon emissions are actually increasing. So why is it that we are moving further from our stated goal, and why do we struggle to frame our ambitions honestly?

THE FOUR-LEGGED ENERGY POLICY STOOL

It comes down to a 4-legged energy policy stool.

Leg 1 - Energy Security: Approximately 2 billion people have energy access like those of us in the West enjoy every day - the majority don't. For the remaining 6 billion people, coal is the preferred energy source because it's an accessible, secure means of baseload power available in high supply with straightforward logistics.

ILLUSTRATION: DZMITRY VIA ADOBE STOCK

Leg 2 - Energy Access: As developing economies modernize, their people gain access to energy services like a well-functioning grid and consume at rates closer to what we do in the EU. Energy access will be an issue for most of this century because it comes with trade-offs between trying to mitigate climate impacts and providing prosperity for all.

Leg 3 - Energy Economics: People want energy, but they don't want it to cost too much. This is glaringly obvious in global politics now. To pay a "duty" on energy for climate policy is not popular anywhere, despite general support for fighting climate change. Therefore, energy prices have to remain affordable.

Leg 4 - Energy Impact: All forms of energy have an impact, not only intensity of CO_2 emissions. Currently, there is too much single-issue climate action while downplaying the other 3 legs of the bar stool. Any discussion of climate issues that does not consider the other 3 legs of the bar stool will surely fail.

A REALISTIC APPROACH TO ENERGY TRANSITION

As a geoscience community, we tend to identify with specific energy technologies as we do with our favourite sports team. The reality is that we are going to need an "all of the above energy source" approach. This also requires being honest about what certain energy technologies can AND cannot do.

Reducing energy impacts from a world economy that has >80 % fossil emissions at the start of 2025 to a world my grandkids inhabit long after 2050 where the world economy has ~30-40 % fossil emissions is going to involve lots of incremental changes in order to make observable progress.

Currently, we seem to think we can sleep tight because we signed up to net zero by 2050. So, is a target and timeframe that is not achievable useful? Instead, we might be better off if we align with the Paris Agreement and prioritize the replacement of coal with nuclear and natural gas as a first step. ■

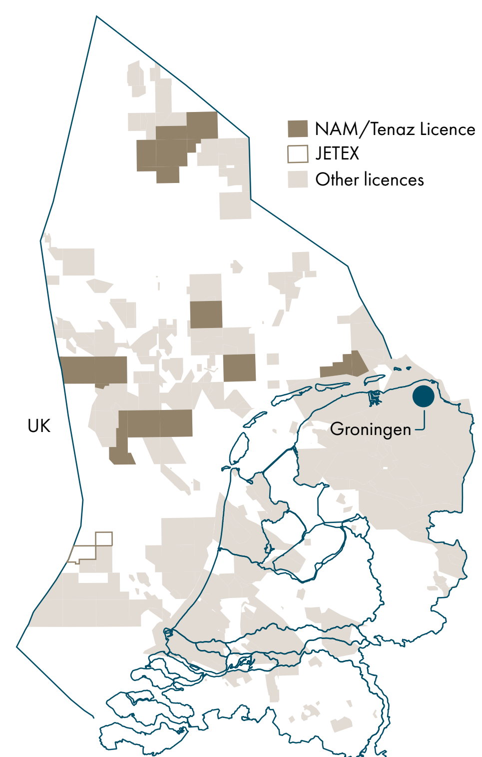
Rodney Garrard

Can the Netherlands be an attractive option for disillusioned companies on the other side of the median line?

Even when highly mature, a sense of urgency and a pragmatic government approach might put the Dutch offshore in a favourable investment light

The 1959 giant Groningen gas discovery made by NAM, the joint venture between Shell and ExxonMobil, transformed the energy landscape of Western Europe. It also formed the starting shot of a highly successful exploration bonanza across the North Sea that led to huge Rotliegend gas discoveries, especially in UK waters.

Groningen production started in 1963, but following reports of small earthquakes caused by pressure depletion, the Dutch Minister of Economic Affairs and Climate put the break on production in recent years, ultimately leading to full closure of the field last year. There is still gas production from nearby smaller fields to heat local homes, keep industry running, and lessen dependence on foreign gas supplies.



The rapidly falling production from these smaller fields, in addition to the early closure of the Groningen field, has now turned the Netherlands from an exporter to a net gas importer. However, the Minister of Economic Affairs and Climate still supports the exploration and development of gas from its North Sea sector, stating this is preferred over imports. There is still running room left in the county's offshore, and with its shallow waters, infrastructure and, of course, a hungry energy market, it makes small accumulations commercial with fast returns on investment.

OPPORTUNITIES

Energie Beheer Nederland B.V. (EBN), representing the government's interests in the extraction of energy resources, has outlined in an excellent publication the concepts and scope for exploration in the mature Dutch offshore province, including several overlooked plays. One such company that is active in exploring innovative ideas is UK-registered JETEX Petroleum. Operating Blocks P8b and P10c with partner EBN, JETEX is targeting the Carboniferous Namurian sands and Dinantian carbonates near the international border with the UK within the prolific Southern Gas Basin. Several seismic amplitude-supported prospects have been mapped.

DEALS TO BE DONE

On the deal side, the industry is still very much alive in the Netherlands. None more so than the announcement in July 2024 that Tenaz Energy from Canada had entered into an agreement with NAM to purchase its offshore exploration and production businesses, associated pipeline infrastructure, and onshore processing facilities, excluding assets in the Ameland area. The US$180 million deal is expected to close by mid-2025. The deal will make Tenaz the second-largest operator in the Dutch North Sea. Tenaz is familiar with the Netherlands already, holding both upstream and midstream assets. Tenaz entered the country through its purchase of a private company in 2022 and XTO Netherlands in 2023.

With the sorrowful winddown of the UK oil and gas industry, luckily, sense still prevails in the Netherlands, and the offshore represents an attractive option for disillusioned companies on the other side of the median line. ■

Ian Cross - Moyes & Co

The discovery that was supposed to be made last year

A second attempt to drill the Sockeye prospect along Alaska's North Slope has been successful, a year after the first well failed to hit the target

"THE GUYANA of Alaska's North Slope." Bill Armstrong, CEO of the exploration company that carries his own name, has been quite bullish about the potential of the Brookian delta-top play in Alaska. And when reading the press release related to the Sockeye discovery issued last week, one would think it is not unfounded either.

However, there are still a few things to iron out. Here is a short reflection on the Sockeye discovery.

The oil find is the easternmost of the Willow-Pikka-Sockeye trend, where reservoirs are mostly found in the topsets of west-to-east prograding Upper Cretaceous to Paleocene deltas. Therefore, the announced Sockeye discovery is the youngest of the three, given its location in the east.

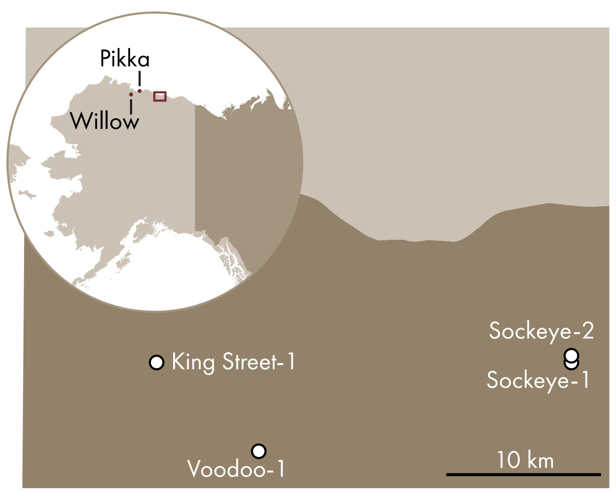
When looking at the map, it can be seen that it took two wells to discover Sockeye. Why is that? That is where the title of the article comes in. It was actually last year that Armstrong Oil and Gas, as the operator, was planning on drilling three wells in the area, namely King Street-1, Voodoo-1 and Sockeye-1. All three wells were spudded, each with a separate rig because of the limited time of the drilling season.

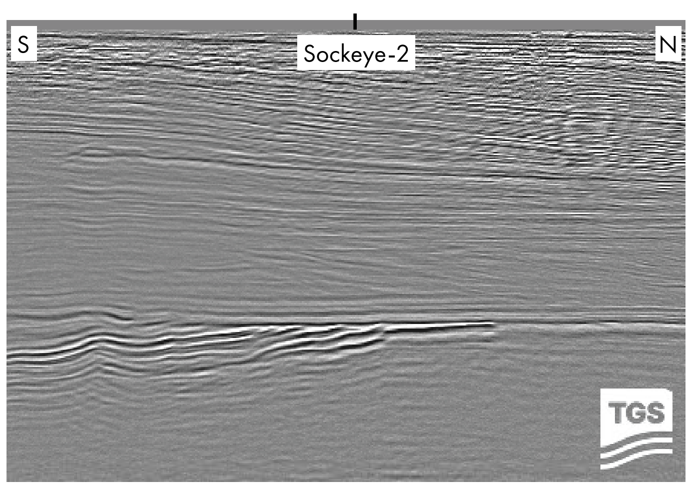
However, only one well reached TD, King Street-1, whilst the other two remained stuck in the overburden, due to drilling issues. Kingstreet-1 tested both topset (delta) and bottomset (basinfloor fan) plays, and although some oil pockets were observed, it is believed that the commerciality is limited.

As Sockeye-1 failed, and the drilling season came to a close because of the tundra melting, drilling had to be delayed to this year. Rather than returning to Voodoo-1 as well, the decision must have been made to only focus on Sockeye, and drill a completely new hole, number 2. According to someone with knowledge of the matter, the amplitude anomaly at Sockeye was the best of the three well locations anyway, because it had the most convincing geological reservoir and trap constraints.

Drilling Sockeye-2 paid off this time around, with TD at 10,500 ft and a net pay thickness of 25 feet. But even though porosities are presumably better than expected, it needs to be seen how easy it is to successfully develop the field. First of all, the in-place volumes still need to be determined across the heterogeneous topset geology. In addition, the resource density is low because of the lack of relief across the reservoir, which may require horizontal drilling and completion techniques. And finally, the remoteness of the area, albeit onshore rather than in deep-water such as in Guyana, will put this project to the test too. ■

Henk Kombrink





N-S trending seismic line across the Sockeye discovery, kindly provided by TGS. The reservoir section is probably somewhere in the middle of the section, above the unconformity that can be seen at about 1/3 from the base.

COVER STORY

"The formation water in the turbidites in the Pomboo well was indeed fresh enough to bottle for drinking water"

Brian Frost - Explorer

COVER STORY

FRESH WATER IN DEEP-MARINE SANDSTONES - HOW COME?

COMPILED AND EDITED BY HENK KOMBRINK, WITH CONTRIBUTIONS FROM BRIAN FROST, JUAN SOTO, NEIL HODGSON, DUNCAN WALLACE, BENOÎT HAUVILLE AND JOHN CATER

The formation water in the turbidites in the Pomboo well was indeed fresh enough to bottle for drinking water

"A FAMOUS example of anchoring is finding a high resistivity anomaly on a structure in a deep-water turbidite play and assuming it can only be petroleum related," wrote exploration geologist Brian Frost as a comment to a LinkedIn post last year. He was talking about the Pomboo well, drilled in deep-water Kenya.

"It did not occur to the exploration company in question that deep-water marine turbidites could also contain fresh water," he continued. "But it is a very common phenomenon in deep-water East Africa and is also known to occur in deep-water turbidite reservoirs in West Africa and the Niger Delta."

"Exploration is full of surprises and explorers must always consider what are facts and what are assumptions," Brian concluded.

This intriguing observation made me write a short story for the magazine, which was published late last year in Issue 6. In the article, we only put forward Brian's observation, and asked our readers if they had seen similar examples.

And so it happened that we received quite a few interesting comments from geologists all over the world, confirming that fresh water, or less saline than expected formation water, is actually more common than some may have thought. It also happens to be a phenomenon that has a fairly straightforward explanation; the dehydration of smectite and the transformation to illite. Eric Gaucher and his colleagues published about it a few years ago.

But even though there is a logical explanation for the presence of fresh water in deep-marine reservoirs, places that have never witnessed any substantial fresh water input at the time of deposition, it seems as if the exploration community is not very well informed about it yet. ►

COVER STORY

Fresh or brackish water has been DST'd in many deep wells offshore Norway.

A fresh water signal was observed in some legacy wells in deep-water offshore Brazil. In this case it was Cretaceous deep-water turbidites.....

It was very strange to observe this and we developed a few theories, but we couldn't find any global examples or consensus on what causes it.

Raya-1 well - Uruguay

Raya-1, drilled offshore Uruguay in the Peolotas Basin in 2016, broke a record for being the deepest water well at the time; 3,400 m. "However, rather than finding hydrocarbons, it encountered nice and blocky water-bearing basin floor fans instead," wrote Benoit Hauville.

"The water from the reservoir was sampled though, and the salinity turned out to be quite low, about 20,000 ppm NaCl equivalent, which is significantly less than seawater salinity (34,000 ppm). The team seeing the results were quite surprised, expecting a much higher salinity."

As these sands were clearly deposited in a marine setting and have never been exposed to continental conditions and meteoric waters after deposition either, it makes a strong case for the influx of fresh water at a later stage through clay mineral diagenesis.

Niger delta

The Niger delta has numerous examples of a fresh water signal in deeply buried sands. Given the extensive succession of mudstones in the sedimentary pile, plus the presence of shale diapirs, there is a mechanism to explain this phenomenon.

Lacustrine water?

"If lacustrine water was trapped during rifting and sealed during continental breakup and marine transition, perhaps it is possible to keep pockets of fresh water? Deep pre-Gamba sands offshore Gabon could have a high Rw this way," wrote Neil Hodgson.

The outboard of the Nile Delta is another good example of freshwater in a deep water basin.

Freshwater can be tricky for formation evaluation, as it is resistive in logs, so it can be challenging to pick apart from weak shows.

The formation water in the turbidites in the Pomboo well was indeed fresh enough to bottle for drinking water. An unnamed consulting company could not believe the water saturation used was correct until it was pointed out that it matched the water recovered from the DST. - Brian Frost

It's a very common phenomenon in deep-water East Africa and is also known to occur in deepwater turbidite reservoirs in West Africa and the Niger Delta.

Brian Frost

COVER STORY

For some of those who got in touch, the observation of a fresh water signal was as much a surprise as to the people involved in the Pomboo well. In other words, despite the literature on the matter, it does not seem to be common knowledge amongst geologists working in deep-water environments yet.

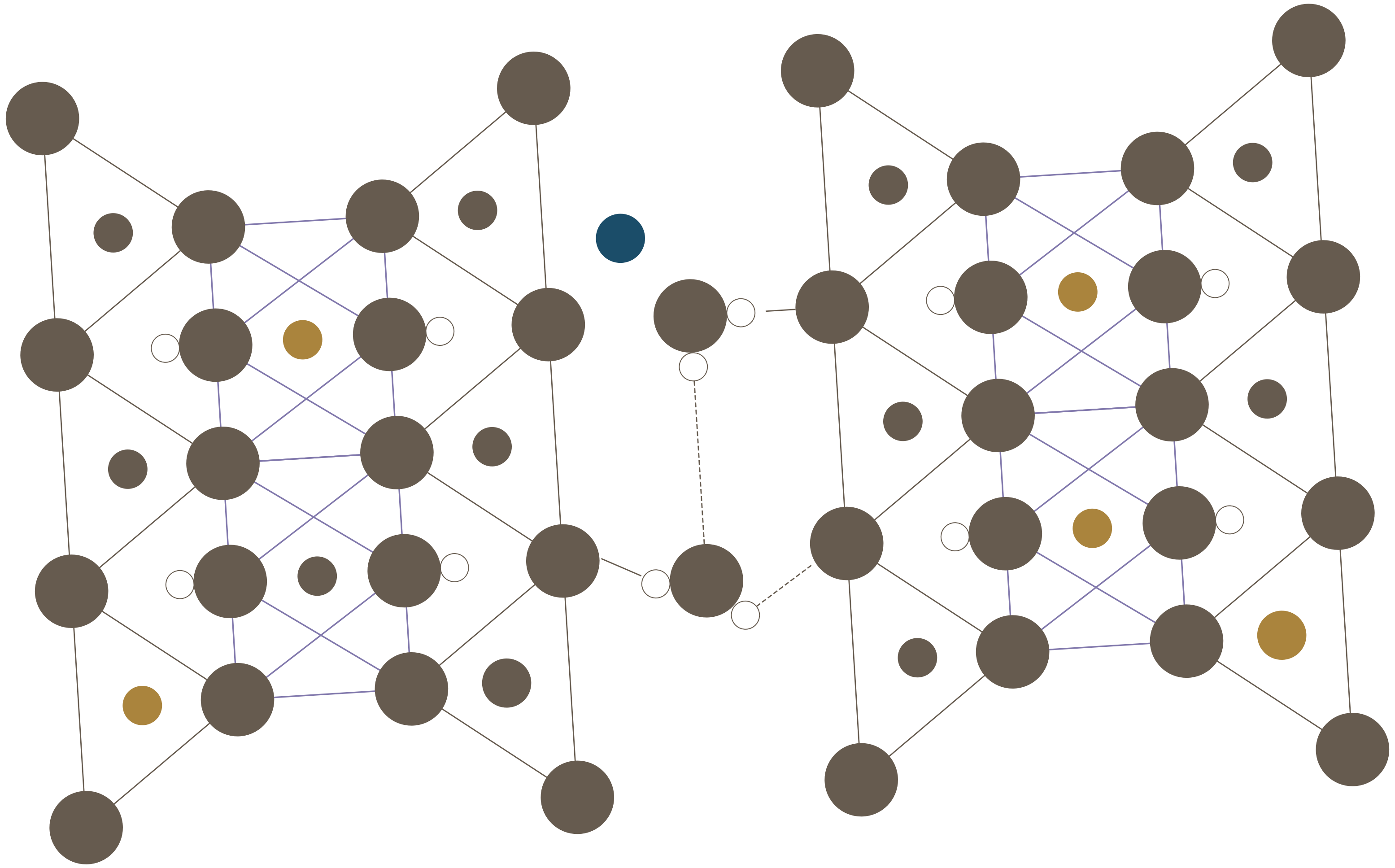
On that basis, we decided to bring together the observations people shared with us, together with a brief summary of the smectite to illite diagenetic transformation that seems to be at the basis of all this.

THE MECHANISM

It is well-known that fresh water can make it into marine realms, especially when aquifers extend from upland areas where they are filled by rainwater to places below sea level where the hydrostatic head of fresh water pushes the sea water down.

The Lebanese famously used water derived in this way to keep Alexander the Great at bay in the long siege of Tyre 332 BC. It made Alexander so cross that they could drink sea water that he killed them all when the town fell.

But in the cases shown on the previous page, this explanation cannot be used because the places where fresh or less saline water was found were simply too far away from shore or too deep to create a way for meteoric waters to reach the reservoirs. In other words, another explanation is required to explain the phenomena observed.



When sampling mudstones in outcrops, it can be hard to imagine these rocks allow any fluid migration, but they do. The photo shows Upper Carboniferous marine mudstones from the Peak District in England.

PHOTOGRAPHY: HENK KOMBRINK

PHOTOGRAPHY OPENING PAGE: CONGERDESIGN VIA PIXABAY

The interesting thing is that the people who shared their experience were all surprised to see the freshening effect in the wells they looked at, even though in some cases it wasn't that long ago and publications about it exist. It shows that new insights on burial diagenesis take a while to find its way into the E&P industry, as it is burial diagenesis that seems to be the most logical explanation for the observations made.

It was Eric Gaucher who got in touch to raise awareness of a paper he was involved with on the topic of smectite dehydration and illitisation (Tremosa et al., 2020, Marine and Petroleum Geology). Here are a few useful insights from the publication.

First of all, the release of fresh water through dehydration of smectite and the formation of illite are closely linked to the formation of overpressure. And it is not only the release of water causing this, it is also the formation of quartz in the illitisation process that causes an increase in overall rock volume, contributing to the overpressure generation.

The team of researchers Eric Gaucher was part of investigated and modelled these transformations for the Niger Delta, which is well-known for its thick succesions of mudstones. They found that dehydration of smectite is a much more important contributor to the formation of water than the smectite to illite transformation.

Together, both these process can account for about 30 % of the observed overpressure, the authors found.

MIGRATION

Now that a candidate for the generation of fresh water in the subsurface has been identied, there still needs to be a way to get it from the mudstone successions into the overlying or adjacent reservoir sands.

Juan Soto, a researcher from the University of Granada in Spain who has published extensively on this topic, has shared some thoughts with us on this.

He describes two possible ways for water generated in mudstones to make its way into neighbouring sands; through the loss of cohesion and the subsequent development of mud diapirs, or through the development of micro fractures in the mudstones through which the water can migrate.

WAIT A MINUTE

But is there another way of forming fresh water in the burial process? John Cater from Petrostrat got in touch and highlighted a phenomenon that can equally result in the formation of fresh water, at slightly shallower depths than the dehydration of smectite and the formation of illite, which takes place at depths between around 2 to 4 km.

"Fresh water is also expelled from siliceous sediments during the Opal A/Opal-CT transformation. That occurs at about 1500 m burial depth around a temperature of 50° C and will result in fresh water flow through interbedded sands."

John says this mechanism has been proposed to explain the mobilisation and injection of sands, resulting in the formation of sand injectite reservoirs. "I don't know the percentage change of volume, i.e. the amount of water liberated, but it is a serious contender for causing injectite formation in Palaeocene-Eocene strata in the North Sea area," he writes.

This is an interesting observation; could it be that in the shallow domain where the Opal A/CT transformation takes place, it is the sands that tend to become more mobile, whilst deeper down, where smectite dehydration and illitisation dominate, it is the mudstones that are more prone to becoming mobile?

I want to thank all the people who shared their insights with our followers on LinkedIn, and with me personally via email. It is fascinating to see how the subsurface can throw surprises at explorers, and how explorers therefore have to keep exploring to find explanations for newly observed phenomena. Maybe one day, when we have depleted our fresh water groundwater resources, there will be another well drilled on Pomboo to produce the ready-to-be-bottled water. From a deep marine sandstone. ■

The Equatorial Margin of Brazil is open for business

Recently, the Brazilian National Petroleum Agency (ANP) officially launched the 5th Concession Round of Brazil's Permanent Offer (OPC). This round provides explorers the opportunity to attain highly prospective concession blocks in Brazil's offshore Equatorial Margin Basins. Available blocks are located amongst oil and gas discoveries in the region and contain many of the same petroleum system elements that proved victorious in Guyana, Suriname, Ghana, Ivory Coast, Sergipe-Alagoas and Namibia. Extensive seismic data coverage in the region permits a detailed understanding of petroleum play to prospect-scale analysis.

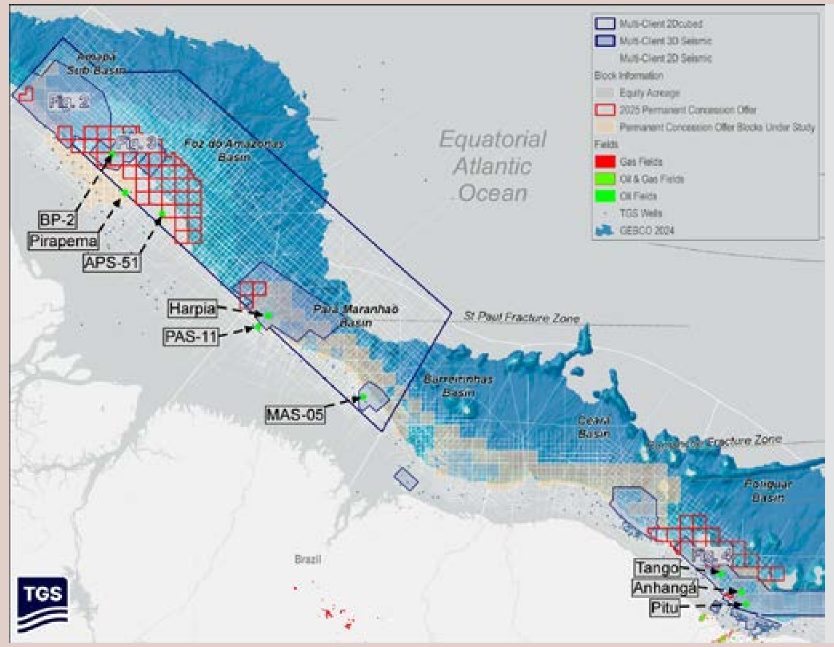
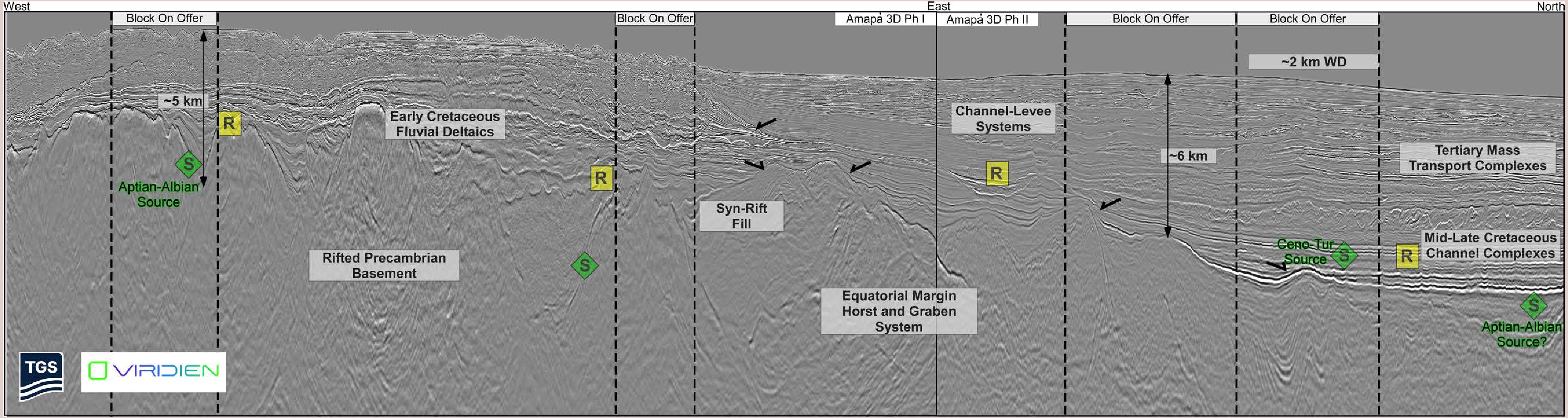


Figure 1: TGS data library map, basins, 2025 OPC Blocks, exploration wells and fields for the Equatorial Margin of Brazil. Key and recent discoveries marked with a green dot.



The deep-water frontier of Brazil's Equatorial Margin

On February 11, 2025, the ANP announced and launched the 5th Round of Permanent Offer Blocks in the Concession Regime sparking renewed interest in the Equatorial Margin Basins. Shallow water commercial fields and deepwater discoveries are limited but evidence of multiple deep- and ultra-deep water prospects and two proved petroleum systems are present.

KYLE REUBER, PEDRO ZALAN AND HENRI HOULLEVIGUE, TGS

THE EQUATORIAL Margin of Brazil (EMB) could be on the brink of an oil and gas exploration boom. A string of wildcat discoveries in the adjacent margin (Guyana / Suriname) and on the conjugate margin (Ghana / Ivory Coast) suggest a high probability for similar discoveries in the EMB. Last year's Potiguar Anhangá well and the 2011 French Guiana Zaedyus discoveries serve as "bookends" to a deep- and ultra-deep water frontier margin segment. These data points are important, as they point to a distal and deeper functioning petroleum system in the EMB. The 2024 Anhangá discovery in the Potiguar Basin was the first successful ultra-deep water well in the region. Prior to Anhangá, many of the previous exploration phases in the region had targets in the shallow and deep waters, aiming for rift-related units.

The 5th Concession Round of Brazil's Permanent Offer (OPC) contains 64 exploratory blocks in the region totaling over 58,000 km² (Figure 1). In the circa 600,000 km² equatorial margin forty-seven blocks are in the Foz do Amazonas (Amapá sub-basin) and Pará-Maranhão Basins with water depths ranging from 200 - 2,000 m. The remaining 17 blocks are in the Ceará and Potiguar Basins in water depths ranging from 1,000 - 3,000 m.

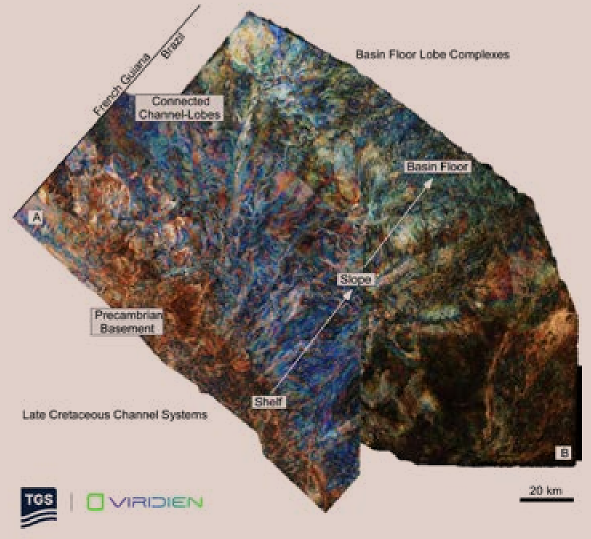


Figure 2: Calculated Spectral Decomposition attributes of Late Cretaceous fans and channels complexes from the Amapá 3D Phases I(A) & II(B). A special thanks to NKDeep for their contribution of these to attribute images.

Exploration in the Equatorial Margin of Brazil has ebbed and flowed over time with the earliest exploration activities starting in the 1960s. The 1970 - 1980s were periods of intense exploration in the EMB resulting in a small number of discoveries. In the last 15 years, the conjugate margins and nearby basins have emerged as prolific oil and gas provinces. Here we highlight prospective features within the newly offered blocks. It is expected that the move of exploration targets to deeper waters will net a higher commercial success rate, as has been the case in many other frontier basins. Vast amounts of 2D and 3D seismic data to support exploration have been acquired overtime in the EMB. The TGS seismic data library in the EMB is unmatched with >82,000 km² of 3D, >423,000 km of 2D and 270,000 km² of 2DCubed seismic products.

EQUATORIAL MARGIN OF BRAZIL

The Aptian / Albian opening of the Equatorial Atlantic Basin occurred along a series of pull-apart basins between South America and Africa. Oceanic spreading between these transform margins developed a deep-water domain and an open seaway between the Central and South Atlantic Oceans. The recently announced blocks of the OPC cover the slope-to-basin-floor setting of the passive margin phase units along the five distinct basins (Figure 1).

Blocks in the Foz do Amazonas and Pará-Maranhão Basins have a

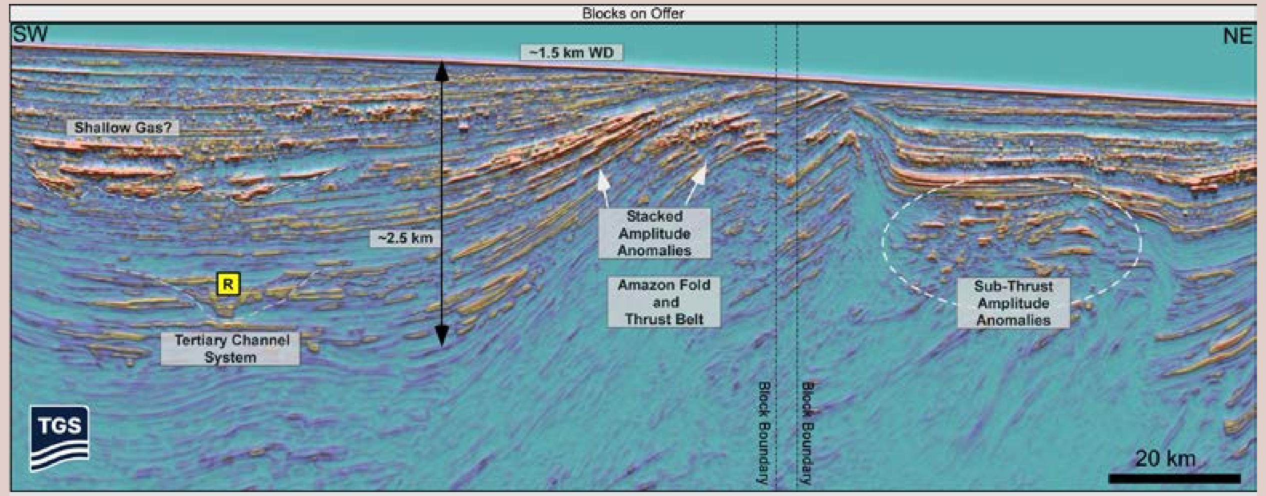


Figure 3: Calculated and co-blended pseudo-relief and trace envelope attributes from the Amazonas Vision 3D over the blocks offered in the 2025 OPC round of Brazil, highlighting prospective channels and DHIs. White arrows denote stacked amplitude anomalies on structure with a positive attribute response.

wide range of play types. Adjacent to the French Guiana border, spectral-decomposition attribute analysis reveals Mid-Late Cretaceous slope fans, stacked channel/levee complexes (Figure 2) that pre-dated the Amazonian drainage by >80 Ma. This depositional fairway is sourced from the Cretaceous drainage of the Oiapoque River. The Miocene-Present deposition of sediments from the Amazon River drainage has resulted in the accumulation of thick deltaic deposits. Due to the nature and magnitude of deposition, much of the deltaic cone has been structured in a fold and thrust belt (Figure 3). This deformation has led to the development of additional play types in the area. Within the offered block coverage, seismic amplitude anomalies are common and can be further assessed by using combined seismic tools such as Sweetness, Trace Envelope and Pseudo Relief attribute calculations (Figure 3). The thick deltaic sediments, although causing complexities, have insured the emplacement of petroleum system elements necessary for hydrocarbon generation along the margin segment. Notable well results in this area are Petrobras` PAS-11, Pirapema, APS-51A, Harpia and MAS-05 discoveries, plus the BP-02 well (Figure 1). All of which encountered oil and / or gas in clastic / carbonate reservoirs ranging from the Late Cretaceous to Miocene, proving at least two functioning petroleum systems offshore (one rift-related, the other drift-related). Of these, the Drift Stage Cretaceous Marine Anoxic Shales – Late Cretaceous turbidites petroleum system is promising, given its success in charging all the large recent discoveries in the Equatorial Atlantic Ocean.

The blocks for offer in the OPC in the Potiguar and Ceará Basins are located along-strike and outboard of the Tango and Anhangá discoveries (Figure 1). Within the offered areas, we observe depositional fairways in the Mid-Late Cretaceous intervals spanning the Syn- and Post-Rift phases. The Aquiraz 3D cross-section (Figure 4) is 34 km from the Tango discovery and highlights the various play targets covered by the blocks on offer. Here structured syn-rift units are overlain by early drift turbidites, channel complexes and amplitude anomalies at stratigraphic onlaps (Figure 4).

In the coming months, explorers will re-evaluate the EMB opportunities within the blocks of the OPC round. When framing the prospectivity of the region, the culmination of evidence will show viable petroleum systems and plays across the Equatorial Margin's basins. As has been demonstrated in other basins (i.e. Guyana, Suriname, Namibia), venturing into the deep-water domain can result in significant payoffs with commercial successes. Seismic data across the region show many prospective leads and untested play-types.

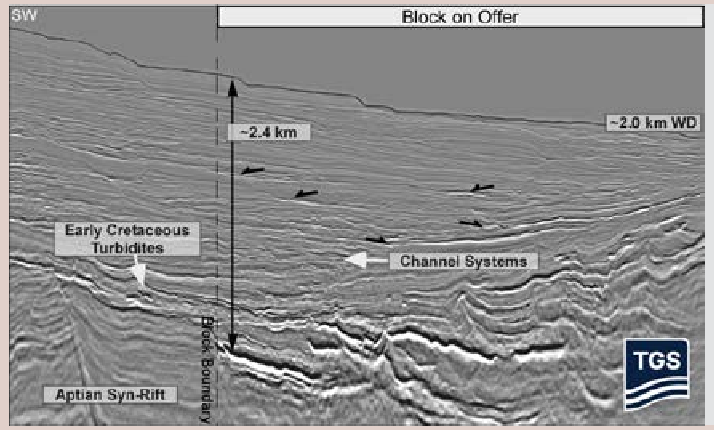


Figure 4: A representative depth migrated seismic section Aquiraz 3D volume showing analogous targets to nearby discoveries, channel complexes and amplitude anomalies within an OPC block on offer.

Why is the Orinoco Delta not known for its oil and gas?

As other major tropical deltas are associated with hydrocarbon production, the Orinoco Delta remains poorly explored. Why is that?

THE ORINOCO Delta in the east of Venezuela occupies a massive area that is virtually devoid of infrastructure and people. In order to reach the mouth of the most important tributary river, which flows along the southern part of the currently active delta system, it takes about six hours with a powerful speedboat from the nearest reasonably-sized town.

Given the sheer size of the Orinoco Delta system and the sediments it has carried over time, one wonders where the oil and gas fields are in the region. But apart from a few discoveries in the northern part of the delta, there are none. Why is that the case? Many of the major delta systems are well-known for their hydrocarbon riches, such as the Niger and Mahakam deltas, so why not the Orinoco?

However, before drawing any conclusions, it is too early to state that nothing was ever found in the Orinoco Delta and too early to claim that it has not been tried either.

For instance, in the tiny village of Curiapo, on the north bank of the river and not far from the Atlantic swell, a small pipe is sticking out of the ground. The villagers remember that the Americans were drilling for oil here a long time ago. The depth and the year remain unknown, but apparently, the well did find oil. Not enough, I suppose, to warrant further drilling, which is no surprise given the sheer remoteness of the area. But a petroleum system does seem to exist.

Finding out what else was done in the area remains a challenge. "Most studies on the Orinoco Delta are private", says Marel Sanchez from U3, a leading exploration consultancy based in Houston. "For instance, in the 2000s, the University of Texas at Austin - Bureau of Economy Geology performed satellite studies for PDVSA to identify significant features in the River. The study does not seem to be digitally available."

A small cluster of fields is known from the northwestern part of the delta, with Pedernales being discovered in 1933 and operated by bp in the 1990s. Deeper structures were explored, too, but these attempts remained largely unsuccessful. Border conflicts seem to have also taken their toll, with the Corocoro discovery by Conoco Phillips in 1999 being stuck in a legal battle that continues until today.

But apart from this corner of the delta, no other fields have been found. "The area remains largely underexplored," Marel Sanchez continues.

Would it be possible that Venezuela's abundant oil resources have so far discouraged exploring the Orinoco? Also, taking the risk of potential border disputes and the area's remoteness into account, there may be ample arguments for it. Food for thought when it comes to discussions about the limits of the world's oil and gas resources. ■

Henk Kombrink

Curiapo – a tiny village in the Orinoco Delta.

PHOTOGRAPHY: THIJS OOMEN

"Almost every foot of rock has oil in it"

Geologist John Sinclair reflects on why the Uinta Basin in northeastern Utah can be counted as the US's production hotspot

FOR THOSE people who don't work in the US onshore oil sector, names such as the Permian and the Appalachian may still sound familiar, as it is these basins that feature in the news so much. But what about the Uinta Basin? It was a new name for me, even though I must admit that I had visited some sites during a field trip to Utah more than 10 years ago. During the latest NAPE Conference, when asked about it, people were adamant, saying that the Uinta is the most prolific US onshore oil play at the moment.

So, why is the Uinta performing so well these days? The following things stand out.

"There is an extensive stratigraphic succession that has access to prolific and mature source rocks, ranging in age from the Cretaceous to the Tertiary Green River Formation. Basically, almost every foot of rock has got oil in it," says John Sinclair, a geologist who has worked in the basin for five years.

The Unita is not a classic structural play either, with the oil being produced from four-way closures of a limited geographic extent. Instead, the biggest fields in the basin, the Altamont and Bluebell fields, should be considered as basin-centre deposits. "It's not a big structure," says John. "When you look at the map, you might think it is a big anticline or something like that, but it is just the deeper part of the basin, only with a few structural perturbations. There are no closures."

The Uinta Basin also stands out for a very practical reason. "It is one of the few places I've seen where you can run a single-rig drilling programme and still ramp up production," John says. "In other basins, you will see that production declines more rapidly than new production coming online through the completion of a new well, which requires more rigs to be involved to ensure growth. That is not the case in the best parts of the Uinta Basin, where newly drilled wells can easily achieve up to 3,000 barrels a day."

Production in the Uinta started by drilling vertical wells into the deepest parts of the play. This has now evolved into operators drilling long horizontal wells that also require fracking. The water required for these operations is not of great abundance in Utah, but the flip-side is that most, if not all, the frack water is produced back so that it can be re-used.

And when it comes to water cut, that is also a factor that puts the Uinta in a good position. "Rather than in the Permian, where water cuts of 75 % are common, the Uinta hovers around 50 %. It is probably the high oil saturation and relative permeability to oil remaining quite high over time," John argues.

What limits the Uinta Basin to increase production even more is the nature of the oil, which is quite waxy and cannot be transported by pipeline. It, therefore, needs to be either trucked to local refineries with limited capacity or hauled to the Gulf coast by rail," says John, "which is not as cost-effective as local refining but still pays off." ■

Henk Kombrink

Oil production installation in the Uinta Basin.

PHOTOGRAPHY: HENK KOMBRINK

Why the term "fault block" is a useless way to describe a trap

In today's exploration arena, where smaller and more complex prospects are increasingly being targeted, traps need to be well-defined in order to capture the 3D architecture as well as ensure objective risking

In most prospective basins, the simpler and larger anticlines and high-side fault blocks have mostly been drilled. In order to find what is remaining, explorers can look for new trap types, such as low-side fault blocks and onlap or pinch-out traps.

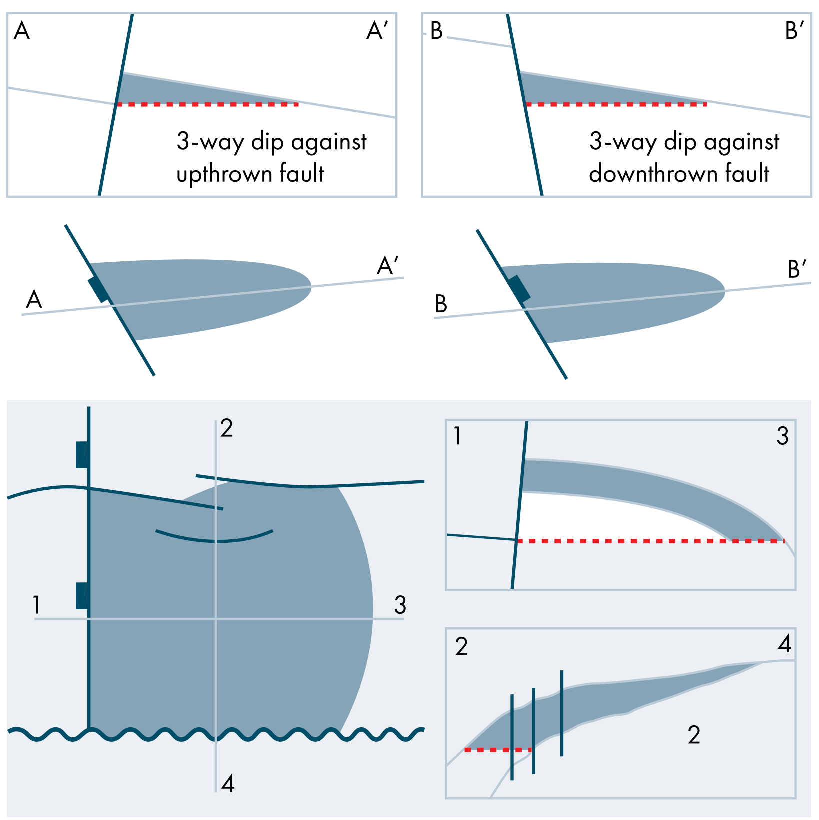
The key questions in that case are how many different trap types may exist beyond the already existing ones, have they already been drilled before, and why were these unsuccessful. This requires an accurate definition of trap types.

However, in order to precisely define what a new trap type is, we need to look at the 3D picture. This immediately exposes the shortcomings of most trap schemes, as they are often a series of 2D cross-sections. In addition, different teams within the same company sometimes use different schemes, further adding to the potential for miscommunication.

So, let's take a look at an example here. Both examples in the top part of the figure are fault blocks, but they have a different risk profile altogether. The low-side example needs either the fault plane to seal or for the juxtaposed section in the footwall to be sealing, while the one on the left does not. In addition, we would also like to know how many other faults are involved since, intuitively, the more trap flanks that are faulted, the more risky the trap will be. On that basis, the term "Fault Block" for a trap type is useless; the complete 3D picture needs to be taken into account.

GIS PAX PLAYER

This is the second 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.



The second example shows how each prospect should ideally be evaluated, looking at all four sides, assisted by a map and two cross-sections. These are still generalised but do provide a much better assessment of the trap style by looking in all directions.

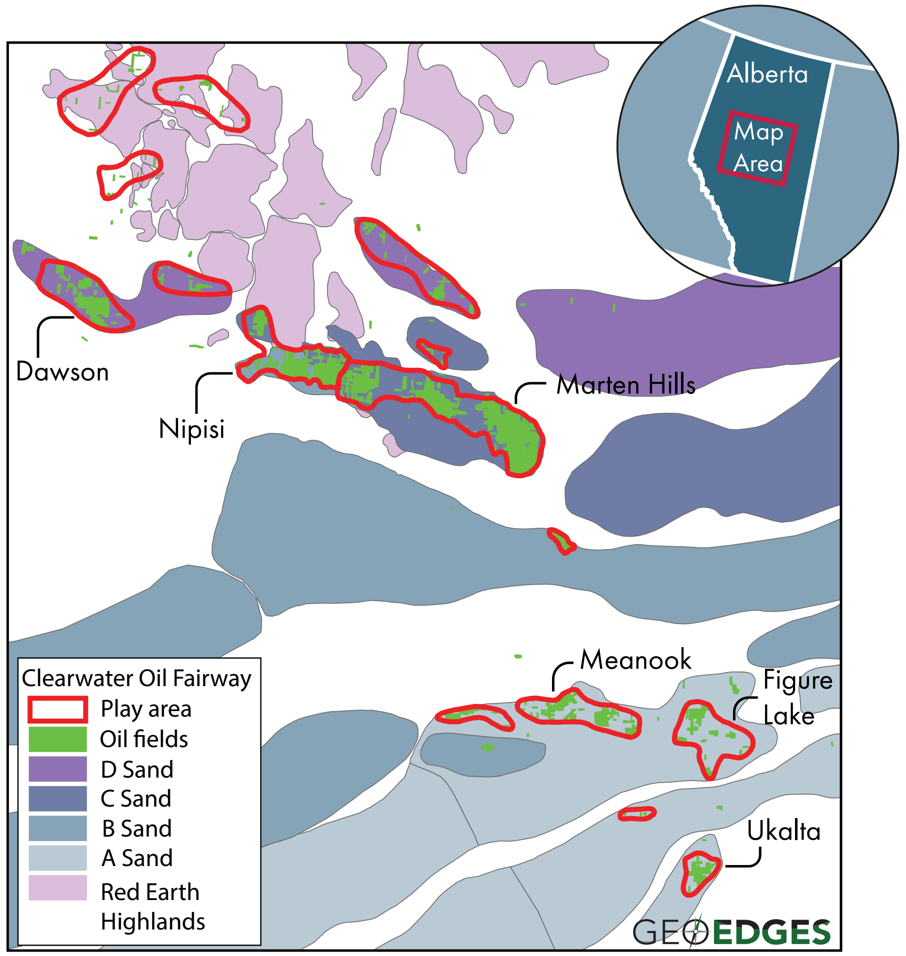
A solution to this problem is a systematic trap description scheme that can unambiguously define any conventional trap in 3 dimensions. One key aspect of the scheme is to classify the defined (4 flank) traps using the unofficial industry "Way Schemer" which has always been used. It has been expanded to include two types of 2-way traps, a 1-way trap and 0-way trap styles. This simple classification system, defined for the first time, helps better indicate risk and charge profiles, plus it helps find real analogues to the undrilled traps being evaluated. ■

Henk Kombrink

The full video and description of this method can be viewed here:

The hottest play in Canada

Even during the downturn and the pandemic, when drilling slowed dramatically across North America, one play continued to be developed at pace – the Clearwater. What makes it so special?



Clearwater Formation: Canada's hottest oil play – key reservoirs.

SOURCE: REDRAWN AFTER GEOEDGES

At the Image Conference in August last year, I met some wellsite geologists from Calgary. They were the first to tell me about the Clearwater Formation and that drilling has been steady in this play despite the various downturns we have seen over the past ten years. Then, my colleague Ingvild attended the NAPE Conference in Houston last February, where she did some scouting around exhibitors, asking what the most important play in North America is at the moment. The Clearwater was mentioned many times.

So, what is the Clearwater all about? We asked Mike Sherwin from GeoEdges. His company maps petroleum plays and reservoirs across the North American continent for explorers to use in a GIS environment.

"The oil in the Clearwater had been known for a while already," said Mike when we spoke on Teams in March. "In that sense, it is not a newly discovered reservoir. However, it was uneconomic to produce the fairly low API oil with the vertical wells that were commonplace at the time when the oil was first proven. It took a breakthrough horizontal drilling technology to make the Clearwater oil economically attractive. And it did, big time."

According to this website, the payback time for a horizontal production well drilled in the Clearwater is about half a year, which is the best amongst a range of other North American plays. The wells are completed open hole and don't need fraccing either, adding to the favourable economics. The spacing between the wells is very tight too, often less than 100 m, which means that rigs don't need to be moved far and can drill many miles from the same pad. Drilling rates of up to 400 m per hour are quite common in the Clearwater, which is extremely fast. The depth of burial of the reservoirs is around 700 m at the present day, so there is not a long overburden section to be drilled.

The Clearwater reservoirs are part of a series of Lower Cretaceous shoreface sands that prograded into the Western Canadian foreland basin. The extent and thickness of these shoreface sands, which are separated by shallow marine mudstones, are, therefore, an important controlling factor in determining where drilling takes place. The Marten Hills development of the Clearwater play shows the best thickness

The source of the oil in the Clearwater sands is similar to the oil mined further to the northeast in Alberta – the Devonian marine shales of the Duvernay and Muskwa formations. The kitchen is situated to the southwest of the Clearwater play, where the Devonian is buried more deeply in the foreland basin. The Clearwater oil can, therefore, be regarded as being trapped at an earlier stage in the migration process, with the open pit oil sands being at the more distal and shallow end. ■

Henk Kombrink

FEATURES

"One of the main things that my profession is experiencing when it comes to seismic processing is the difficulty of having access to new technology"

Geophysicist - Iran

FEATURES

Drilling around mud diapirs

Production geologist Peter Henneberg tells the story of how better seismic imaging, an improved subsurface understanding, and a healthy dose of perseverance led to the drilling of a successful well that tapped into a multi-million barrel resource that had been left stranded for a long time

Mud diapirs have long been enigmatic structures in the subsurface. With older seismic data being of insufficient resolution to properly map them, companies often took a careful approach when it comes to drilling close. This is primarily related to the observation that the mud diapirs are often associated with overpressures.

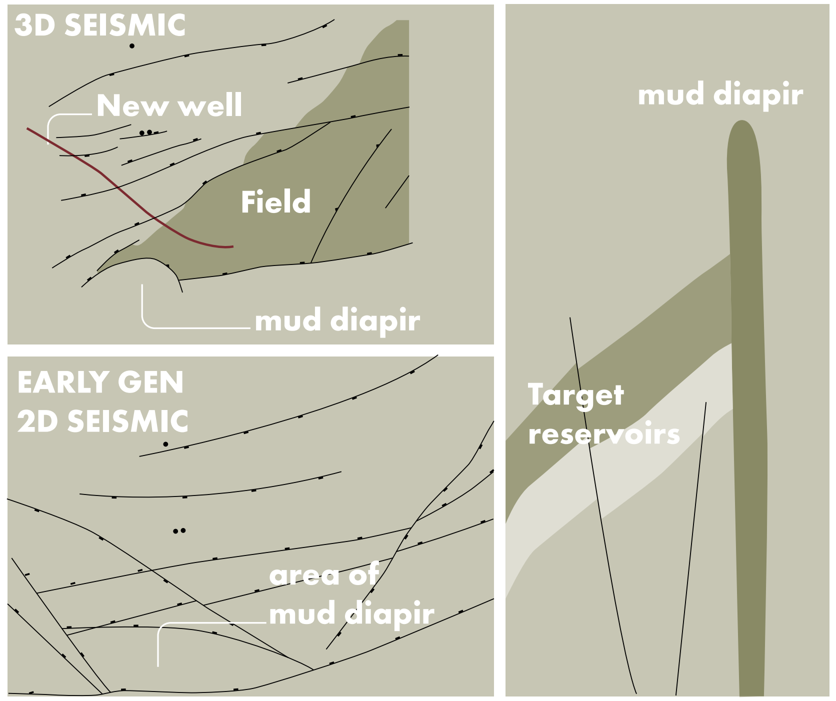
The Tertiary basin in Brunei is a good example of this phenomenon.

Peter Henneberg, who worked in the country for seven years, was involved in drilling a well that took him a lot of convincing of management, because it was getting close to what was just before mapped as a mud diapir. For a long time though, it wasn't even known that it was. But it was considered a no-go zone anyway, because a well had been drilled into it had experienced overpressures and was rather shaly.

"Early maps of the field based on 2D seismic data showed a zone that was surrounded by a series of faults, as if it was an isolated fault block," says Peter. It shows how geologists tried to solve the pressure difference between the main field and in the well that drilled the diapir.

Only when 3D seismic volumes became available, the contours of the mud diapirs became more obvious. In time slices, circular zones can be seen, which are mostly transparent, but with clear higher impedance slivers in it, interpreted as isolated overpressured sands.

"It is these sands that are the problem," says Peter. "They have kept the pressures from deeper down, and due to their isolated nature, they still record higher pressures than the sands in the reservoirs juxtaposed against the diapir at the same depth. However, we did observe that some pressure dissipation must have occurred though."



The two maps on the left show the difference in structural interpretation of the section of the field where the mud diapir was found. The early generation interpretation based on 2D seismic lines shows the area of the mud diapir being surrounded by a set of faults, without necessarily having the right concept in mind what this area represented. All the team had available at the time was the observation of higher-than-normal pressures in the area, which had to be somehow isolated from the remaining part of the field where "normal" pressures dominated. The new well that Peter Henneberg suggested to drill, and which was ultimately drilled as planned, is indicated in red in the upper left map, coming closer to the mud diapir than any of the previously drilled wells had done and thereby tapping into a new resource base even though the same reservoir had already been drilled further to the east. Please note that not all wells drilled in the area are indicated on the maps; only three wells (black dots) have been included to help compare the two maps.

THE EASY BITS FIRST

The oilfield Peter worked on was large, and because there were plenty of areas to go after for oil production first, the "difficult" high-pressure zone was avoided for a long time. Until the moment that even this area appeared on the radar, invariably driven by the depletion of the easy parts of the field. But it was only the radar of the production geologist the area appeared at, not so much on the management's radar because of the cloud of overpressure issues hanging over the area. It took some convincing, or maybe to word it differently: Education.

As with so many things, once it is possible to explain why it happens, it becomes much more feasible to find ways to mitigate against the potential issue. And the mud diapirs were a classic example of that.

Peter took the matter to heart and, having studied similar structures elsewhere, was clearly being able to show that the zones of overpressure tend to be confined to the diapir itself. This meant that the extent of overpressure could be mapped, which de-risked the areas immediately around it. That was the area Peter had in mind targeting, because he saw that a significant undrained compartment must be present there. The existing production wells in the field were simply too far away to have properly done that.

PHOTOGRAPHY: LEONID ANDRONOV VIA ADOBE STOCK

Traditional stilt village Kampong Ayer on the Brunei River in Bandar Seri Begawan, the capital of Brunei Darussalam.

INTO THE FIELD

In order to make things easier to understand, Peter even organized a field trip for management to show how a diapir looks like in outcrop and that the sands intercalated tend to be isolated and unconnected to the main reservoirs outside the diapir. This helped, and slowly the idea to drill a new well became more concrete. The continued depletion of the main field helped make the case as well.

Then came the question how to drill the well, what trajectory it should have?

It was decided to drill the well parallel to the sides of the diapir, in an attempt to tap into as many compartments that may have arisen due to faults radiating away from the diapir. These faults are commonly found around these structures, and have a tendency to create compartmentalization of individual fault blocks.

After all, the well was drilled successfully, and a 2 million barrel resource could be produced safely. No overpressures were observed, and all the reservoirs known from the wells at a distance were found. This clearly demonstrated the value of the seismic data and the value of applying a valid model to explain overpressures observed at times when it all seemed so obscure. ■

Henk Kombrink

The well listeners

Why real-time pore pressure and geomechanics monitoring is still essential

"I RECENTLY gave a talk in Kuala Lumpur," says geologist and pore pressure specialist Karol Jewuła, "for which I made an overview of drilling-related issues with wells drilled from 2014 to 2021. What turned out to be the case? Most problems are still related to pore pressure and geomechanical issues. To me, it illustrates that despite all the technology we have these days, we are still unable to mitigate all risks pre-drill. The Earth is a pretty nasty partner to work with, and that's why we need to monitor things closely when drilling."

"The basic thing we try to do as real-time pore pressure and geomechanics engineers is to minimise uncertainty when it comes to staying in a safe drilling window," says Karol. "We use all the parameters we've got to see if there are indications that mud weight is too low, leading to formation collapse and possibly an influx of formation fluids, or mud weight being too high, which means that we can frac the formation and experience mud losses."

But, at the end of the day, it's easier to control kicks than losses. "That's why it is very important to stay away from the fracture pressure, maybe even more so than staying away from the formation pressure," explains Karol. "The complicating factor here is that there is not always agreement on the definition of the fracture gradient, with each company using their own or even multiple scenarios. That's why we often define the minimum fracture pressure of the ones that have been calculated, to stay on the safe side."

FRONTIER WELLS

Karol and his colleagues Łukasz Karda and Tim Sheehy at Bizon are mostly called in for frontier exploration wells, where there is not enough offset data to develop a sound understanding of the expected pressure regimes.

"We can make a nice pre-drill well design with casing points, but in my experience, nature always throws a curveball and we are the ones who are tasked with picking that up and communicating that," says Karol. As an example, he recalls a recent project in South America where everyone thought pre-drill that pressure would be quite low, but as soon as operations started, pressures were significantly higher than expected.

"The most important parameter we use as we continuously monitor drilling is gas data," says Karol. "This is the most crucial set of data. And not only total gas but also its composition. This can tell us more about whether it is connection gas we are dealing with, or whether there is more to it."

"As soon as we start a job, we try not to look at the predicted gradients all the time, as that leads to anchoring and a tendency to confirm the predictions made by our client. It is the data we acquire during drilling that should be leading and if necessary, we need to revise the pre-drill model, even if the client may not be too happy with that."

NOT SOMETHING NEW

Real-time monitoring is not just something of the recent past. Back in the 1970s, even though LWD did not exist yet, inferences on pressure regimes were made real-time using drilling data. For instance, when drilling rates increase significantly, this is often a sign of reducing overbalance. Without having access to any other type of information, it was always known that higher formation pressures could be behind this.

"A lot has changed in the way we handle our data, the ease with which we can now work from home, and the much wider range we've got available. But at the same time," says Karol, "we still have to rely on the basics to do the job properly."

Karol Jewuła.

PHOTOGRAPHY: KAROL JEWULA PRIVATE ARCHIVE

DRILLERS WANT JUST A NUMBER

"Communication is the most important aspect of our job," says Karol. "It is our routine to report to the operations geologist and drilling superintendent, and not to the rig straight away. Ultimately, the power sits in town and that's where our information is required first."

"I do adapt my style of reporting to the people I report to, with very short reports to the drilling engineers who are not interested in a scientific justification of my decision. The more elaborate reports are for the geology nerds like me," he jokes.

Karol is now used to do his job from home. "I have worked on the rig, I have worked in the client office, but these days I do really prefer to work from home, because it feels more independent. And that is exactly what our role should be. We have to be independent and let the incoming data inform us about any potential intervention. There is no real advantage to being on the rig nowadays, apart from the possibility to examine and evaluate cavings personally versus looking at pictures."

And then, at the end of some of our jobs, when the well is drilled successfully, Karol is sometimes questioned by the drillers: " Why were you needed? We haven't experienced any issues." "That is precisely why we were there!"

GOING DEEPER

Karol is excited to see how wells are being drilled deeper and deeper these days. "Managed Pressure Drilling (MPD) has been an instrumental technology in that sense," he says, "because it allows us to drill through very narrow pressure windows and control mud weight at surface directly through pressuring up the return mud line. This results in a much more instant response, and I believe that without this technology some of the deeper targets these days could not have been drilled."

Is real-time monitoring still required in that case? "Yes, I'd surely say so," says Karol, "because you can better define the limits of the system and make a more informed decision as to how far you can go."

"How does the future project pipeline look?", I ask at the end of our conversation. "I have a bit of a funny feeling about it," says Karol. "There are quite some factors that put pressure on continued exploration drilling, even when we hear "Drill, baby, drill" all the time. But this mostly applies to development drilling, for which our service is generally not required. It's the exploration wells we need, and that's a place where I don't really see a major uptick at the moment." But is it reason to be concerned? "No," Karol concludes, "being independent always comes with ups and downs, and if there is one certainty, it is that the demand for oil is not going to slip away tomorrow." ■

Henk Kombrink

GOING INDEPENDENT

Karol started working for IKON Science in 2014, where he learned the ropes of pore pressure prediction from people such as Eamonn Doyle, who gained decades of experience monitoring wells in the Norwegian sector. "He was the best teacher I've ever had," he says.

But the oil crisis and the big wave of redundancies led Karol and his business partners to become consultants soon after. However, it was the busiest time he and his colleagues ever had, mainly because wells committed to during the good times were still being drilled in the first few years of the downturn. This enabled him to work on many wells all over the world, from Brunei, Suriname and West Africa, to the Falklands.

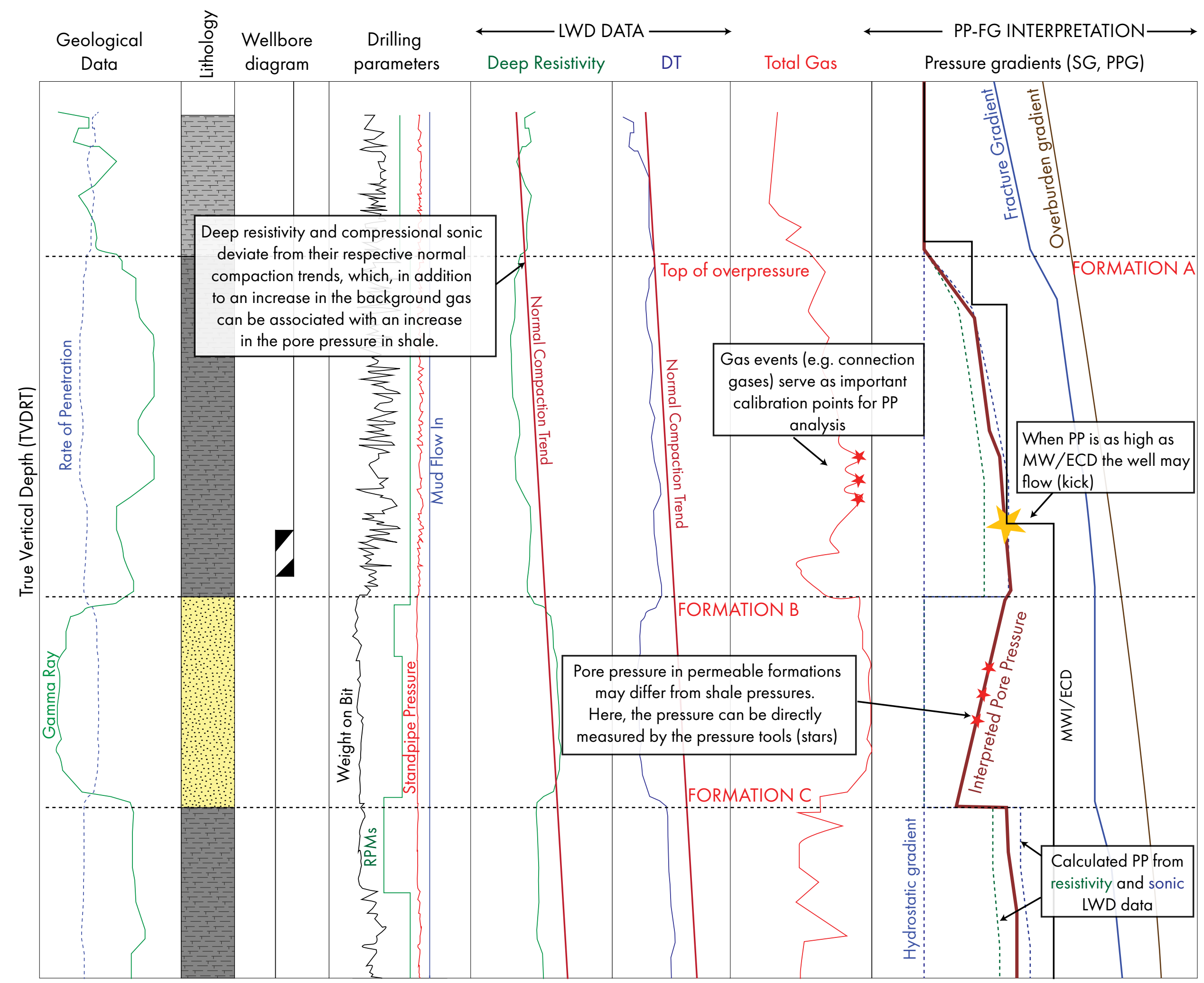


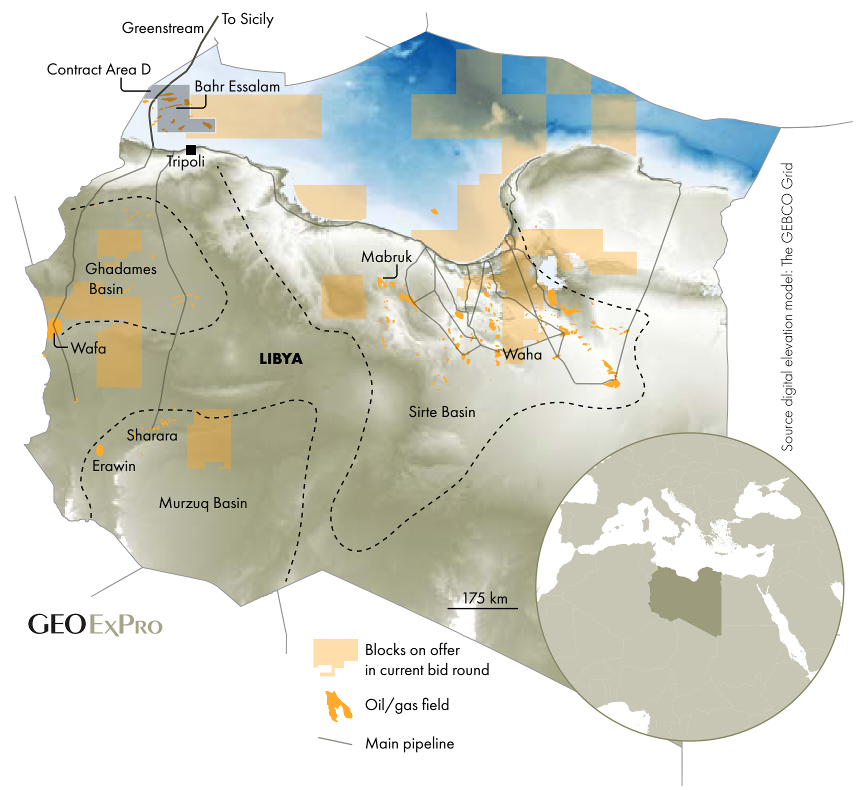
ILLUSTRATION: KAROL JEWULA

Simplified example of PPFG analysis plot.

Libya's oil and gas renaissance

Promise and prudence amidst a strategic licensing round

SCOTT PARKER, CORE LABORATORIES



Libya, long regarded as one of Africa's most geologically rich petroleum provinces, is re-emerging with renewed focus and ambition. After years of underinvestment, geopolitical instability, and widespread field shut-ins, the National Oil Corporation (NOC) is actively working to reposition the country as a key energy partner on the global stage, underpinned by ambitious production growth targets.

A major area of focus has been the optimisation and redevelopment of mature fields experiencing natural decline, with the NOC, its subsidiaries and existing IOC partners engaged in reactivation and workover campaigns. Complementing these efforts, the recently launched and long-anticipated licensing round underscores Libya's intent to attract new international oil companies (IOCs) into its prolific basins, offering significant upside opportunities alongside inherent challenges and considerations.

Looking ahead, attention is also turning to the potential contribution of the country's unconventional and untapped shale oil and gas resources as part of Libya's broader production strategy.

A TIMELY BID ROUND

The new block licensing round announced by the NOC comes at a time of geopolitical significance. With Europe continuing to seek improved energy security, Libya offers both geographic proximity and untapped resource potential. The country's location on the southern edge of the Mediterranean, combined with its substantial oil and gas reserves, positions it as a natural supply partner for European markets, as well as interest from the US, Asia and the Far East.

This licensing round, currently being promoted through a global roadshow by the NOC, opens the door to both established operators in Libya and new entrants. However, its success will depend on Libya's ability to reassure potential investors regarding its fiscal regime, political stability, and the technical challenges associated with its upstream sector.

A 2 MILLION BARREL PER DAY TARGET

Oil production in Libya currently averages around 1.4 million barrels per day (bpd), a sharp recovery from previous lows. The NOC has outlined a national objective to increase production to 2 million bpd within the next three years. This will be dependent on several key enablers: International investment and exploration activity; the restoration of infrastructure following extended periods of field inactivity; continued political and security improvements; and revisions to the IPSA IV fiscal framework to reflect an increasingly more competitive, investor-friendly landscape in Africa.

LEGACY AND MOMENTUM - CURRENT IOC ACTIVITY

Despite Libya's past challenges, several major IOCs remain active or have resumed operations, contributing significantly to production and field development:

- **Eni,** in partnership with NOC, operates the Greenstream pipeline, transporting gas from the Wafa and Bahr Essalam fields directly to Sicily. Eni's recent offshore discovery in Contract Area D (Sirte Basin) signals a strategic push towards developing LNG exports. While their current focus is offshore, ENI also holds significant positions in onshore Ghadames and onshore Sirte Basin assets. ▸

- **bp,** a joint partner with Eni in Libya, is also exploring further involvement in LNG developments.
- **Repsol,** through Akakus Oil Operations, has drilled and completed multiple wells in the Sharara field, making gains aiming to sustain production and offset natural decline.
- **OMV** has resumed exploration in the Sirte Basin with NOC via Zueitina Oil Operations, marking a return after a hiatus since 2011.
- **TotalEnergies** has revived activity in the Mabruk Oil Field and increased its stake in Waha Oil Company, targeting the development of previously shut-in assets, including NC-98, NC-170, and NC-129.
- **PGNiG** lifted its force majeure in early 2023 after a decade, resuming exploration activities in Libya.

In parallel, state-owned NOC subsidiaries are making notable contributions including but not limited to:

- **WAHA Oil Company** reported producing over 350,000 bpd in November 2024, the highest in over 11 years.
- **Zallaf Libya Oil & Gas** announced a new discovery in the Erawin Field (Murzuq Basin) in 2023 as part of a strategy to tap smaller, underutilized fields.
- **Arabian Gulf Oil Company (AGOCO)** confirmed new onshore discoveries in the Sirte Basin, furthering NOC's aim to boost domestic output.
- **Sirte Oil and Gas Company** reached a crude output of 103,000 bpd in December 2024 and over 100 million cubic feet of gas per day in the Al-Hatiba field, a notable achievement since 2007.

TECHNICAL CHALLENGES - TURNING TO GLOBAL EXPERTISE

Libya's geologically diverse subsurface, combined with the legacy of prolonged shut-ins, presents a number of technical challenges in field development and production optimisation. Addressing these challenges has drawn upon international expertise. Core Laboratories, for example, has played an important role through its delivery of specialised technical workshops, application of advanced regional subsurface knowledge, and ongoing collaboration with local institutions such as the Petroleum Research Centre, a subsidiary of the NOC.

PHOTOGRAPHY: HUSSEIN EDDEB VIA ADOBE STOCK

Capital of Libya, Tripoli seafront.

OPPORTUNITIES VERSUS RISKS

For international oil companies (IOCs) looking for value proposition, Libya offers a compelling blend of strategic location, proven reserves, and new frontier potential.

High-quality hydrocarbons, favourable reservoir characteristics, low development costs, and underexplored acreage all contribute to its appeal. Existing infrastructure, including pipelines like Greenstream with direct links to Europe, adds to the country's logistical advantages. The political will and renewed leadership focus to revitalise the sector, most notably through the NOC's active licensing campaign, has not gone unnoticed by industry observers.

While the fundamentals are attractive, several considerations remain top of mind for operators evaluating entry or re-engagement. While stability in key producing areas has improved, evolving security conditions and international travel advisories will remain a point of continued monitoring and consideration, particularly in more remote interior regions.

On the fiscal side, the government has taken steps to modernise the IPSA IV framework. Updates include a profitability-based sliding scale (R-factor), the removal of the daily production base (B-factor), and the NOC's commitment to cover contractor income tax, reforms designed to enhance returns and shorten project payback timelines. Infrastructure renewal, meanwhile, continues across the country through joint NOC-IOC initiatives aimed at production recovery and field optimisation.

A REGION WORTH WATCHING

With shifting global energy dynamics, Libya's re-emergence could prove pivotal, not only in supplying Europe but in re-establishing its position as an international regional hub for investment. For companies seeking scalable, early-mover opportunities, Libya presents a uniquely attractive prospect. Recent policy changes, improving infrastructure, and growing openness to collaboration indicate a sector in transformation.

If the licensing round proves successful, it will mark not only a technical and commercial milestone but also a broader signal that Libya is once again a serious player on the energy map. Momentum will be closely observed at the upcoming stops on the NOC's roadshow, including visits to London in April and Frontier's Africa Energies Summit in May.

The coming months will be decisive, not just for the NOC's licensing efforts, but for the broader redefinition of Libya's role in the global energy landscape. ■

Evaluating the uncertainty in a Saturation Height model

Uncertainty is present in everything we do with subsurface data, so trying to understand the impact of that uncertainty in our interpretations and models, both static and dynamic, is essential

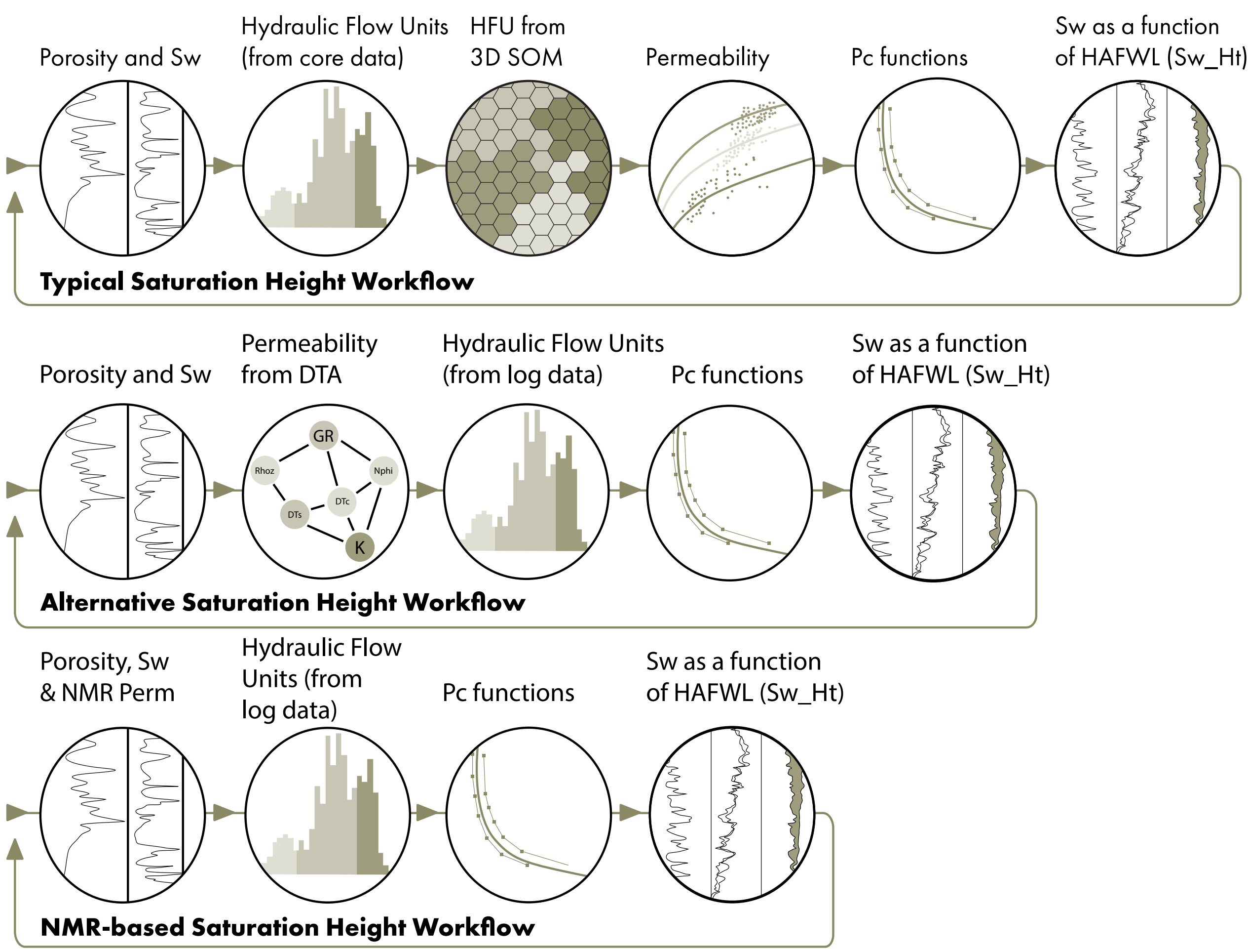
PAUL SPOONER, GEOACTIVE

EVEN THE 'ground truth' of core data is uncertain when you really think about it. There is nothing better than a lump of rock to look at, touch, smell, or even lick (if you are so inclined) to provide some certainty about the rocks. Some data is very subjective, like facies description, but what about the hard data, the 'facts', that we calibrate our models to? Every core measurement, including depth, porosity, permeability and capillary pressure (Pc), has uncertainty, even cutting the core and recovering it to surface alters it from the in-situ condition. When you consider all the uncertainties in the data used to build a saturation height model, then it can feel like quantum mechanics, a bit fuzzy, and very often a lot fuzzy.

A typical workflow to develop a saturation height model makes use of a variety of data and interpretations, from log and core.

This may include the following steps:

1. An interpretation of the logs to determine porosity and water saturation (Sw) in the wells
2. An interpretation of the core data to determine the hydraulic flow units (HFUs)
3. Extend the HFU model from core to the wells, with a predictive model using the log data, trained on the core derived HFUs, e.g. with a 3D Self Organising Map (SOM)
4. Use the HFU por-perm relationships, with the porosity and predicted HFU, to determine permeability in the wells
5. Fit functions to the core Pc data, for each HFU
6. Apply those functions in the wells to determine water saturation from the model (Sw_Ht)
7. Compare Sw_Ht to the Sw from step 1 and adjust the model to get the 'best' fit



This last step is where most of the hard work is, because every step could be adjusted or completely changed. It's not just about the R2 in fitting the function to the Pc, it's about everything. Is the log-derived porosity correct? What about the Sw? Have we identified the correct number of HFUs in the core? Do we have the right boundaries? Can we robustly predict the HFUs in the wells? This is a complex task, and why many petrophysicists and reservoir engineers often dedicate so much time to it.

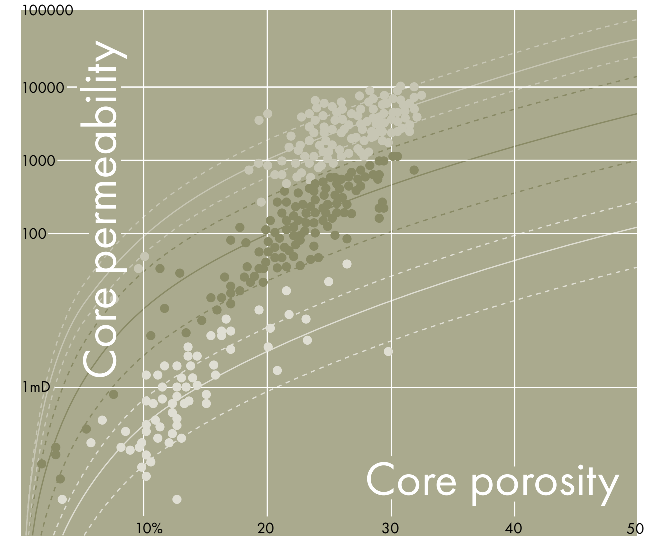
There are many choices to be made at every step, such as which volumetric methodology to use and which predictive model to use, but even the number and order of these steps is a choice that depends on data availability and preference. One alternative approach is to use a predictive model for permeability instead of the HFU, e.g. using Domain Transfer Analysis (DTA), and then use that permeability with the porosity in the HFU model. That reduces the number of steps to 5.

Another alternative is to use NMR log permeability, removing the need for a predictive model and reducing the number of steps to 4.

These different workflows all contain uncertainty, so how do we decide on the 'best' model, the most fit-for-purpose model? We can, of course, just pick the workflow that gives the closest match to the log-derived Sw, but there are other aspects to consider, such as how this model will be implemented in the dynamic model.

If the permeability used in the model came from the HFU por-perm relationships, they can be applied directly in the dynamic model. This means that both static and dynamic models are consistent, using exactly the same relationships, removing a common source of uncertainty. If a predictive model was used for the permeability in the static model, you may get a better fit to Sw, and you have reduced the number of steps in the workflow, but that predictive model cannot be implemented in the dynamic model. Typically, a separate HFU por-perm model will be used for that, meaning there is a disconnect between the static and dynamic models, re-introducing uncertainty. Its swings and roundabouts.

Ideally, we would quantify the uncertainty in these models, to help decide which is the 'best', and this can be done with a Monte Carlo uncertainty analysis on the entire workflow. We cannot Monte Carlo all of the choices in the workflow, there are too many possibilities and it becomes an infinite problem, but we can run the numbers on the entire workflow, end-to-end. For example, in a Monte Carlo run, we can numerically quantify the uncertainties in the following steps:



Por-Perm relationships for three hydraulic flow units, with P10 and P90 percentiles.

1. The inputs logs: Every log has a published tolerance, e.g. RHOB +/- 0.02 g/cc, so we can use that, and in a rugose borehole it will be even more uncertain
2. The interpreted results: Every numeric parameter affecting every result, such as porosity, mineral volumes and Sw, has uncertainty, even those we may think we know, e.g. Rw. Did it come from produced water? Was it picked in a clean wet zone? Or based on an assumption?
3. The HFUs: We consider the HFU model 'fixed', meaning the number of flow units and their boundaries, and the predictive model 'fixed', having been trained on the HFU data, but running the predictive model will yield varying distributions of HFUs across the wells as we are capturing the uncertainties in the inputs, whether they are logs or interpreted results
4. The permeability: We can use the P10, P50 and P90 of the por-perm relationship for each HFU
5. The Sw_Ht results: We consider the functions 'fixed', as Sw_Ht will change with changes in porosity and permeability, but we can also apply uncertainty to the FWL, GOC, fluid densities and IFT correction factors

By applying all these uncertainties together, in each Monte Carlo iteration, and running the entire workflow hundreds or thousands of times, each with slightly different parameters, we can quantify the impact of the different porosity, flow unit, permeability, and function on the final Sw_Ht. If we include a calculation of hydrocarbon-pore-feet (PhiSoH) for the interval in question, for each iteration, then the P10, P50 and P90 of the PhiSoH shows the overall uncertainty in the entire workflow. That way different workflows can be quantitively compared, rather than the subjective "I like that one as it looks better." ■

Iran – not at a standstill

It is easy to focus on the oil and gas exploration hotspots of the world, where news around discoveries or the completion of a dry hole is guaranteed for attention from those following the industry. But what about areas that do not feature in the news that much?

IRAN IS one of those countries you normally don't hear a lot from. This is obviously exacerbated by the USA sanctions that are still in place and prevent the exchange of Western goods and services.

For this article, I wanted to hear from people who are currently based in Iran to hear what is going on. Initially, I asked someone I knew from the past, but she told me most people from her network now live and work abroad. Then, I approached two people from my LinkedIn network who work in Iran, and both responded positively to my request even though we never met in person.

When reading through the reports I was subsequently provided with, it is clear that Iran is not sitting idle – see also Mariël Reitsma's article in this magazine about Iran starting helium production. The tone is very much one of self-sufficiency in developing the tech and hardware required to beat the sanctions and get going with the work at hand.

Source digital elevation model: The GEBCO Grid

Working in the seismic imaging sector in Iran

A processing geophysicist tells us about access to technology and the current state of exploration in her country

You don't often hear about subsurface news in Iran, as the country is still gripped by US sanctions. That is why I contacted someone who currently lives and works in Iran, to hear a bit more about the current situation. She has been part of the geophysical processing community for quite a few years and was willing to give me a flavour of how it is to work in the petroleum sector and how the sanctions affect her daily routine. However, she preferred to stay anonymous for various reasons.

"One of the main things that my profession is experiencing when it comes to seismic processing is the difficulty of having access to new technology," she says. "For instance, many international companies are now using Full Waveform Inversion (FWI) technology, developed by the global players in the seismic acquisition business. We don't have direct access to it, and that is frustrating. Of course, we are developing similar technology in-country through academic research and collaborations, but it is not the same as what is developed elsewhere." This creates an overall feeling of "why do we need to reinvent the wheel when we know the technology is available so close to us?"

It is an aspect of the sanctions that is easily forgotten about when these measures don't affect you, but it is a reality that many working in Iran face daily.

Despite these difficulties, it does not mean the country is at a standstill at all. "Exploration activities are ongoing at a rapid pace," she says. "We are carrying out seismic surveys across the entire country, both 2D and 3D, meaning that there is a drive to explore for more. And even though travelling abroad is not easy these days, we still gather as a geophysical community to hear the latest from colleagues working in the country, in addition to hearing what happens elsewhere through people visiting."

But is the current situation something she is happy with? "I personally think it would be much better to exchange knowledge more freely and make travelling easier," she adds. She has a lot of family members already living abroad. "Surely, there are plenty of people who are ok with the current situation, it is not like we all crave this change, but for me, it would be a big advancement, and I think it would also be of benefit to the profession given that access to the latest technology would be so much easier."

Another interesting observation is that exploration activities in Iran have focused around the country's borders in recent years, something I am not entirely sure about why. At the same time, exploration is also taking place in parts of the country where this wasn't done previously, which is a testament to a drive to find new resources wherever possible.

In the section below are some observations to illustrate how the country remains an active player in the oil and gas exploration arena. What follows is a more personal account of someone I met on Teams for a conversation about life and work in Iran.

It seems like exploration has recently ramped up in Iran. A website article from May 2024 quotes the head of exploration of the National Iranian Oil Company, saying that the number of rigs involved in exploration drilling would have reached ten last year, where it was only two rigs in 2021. The same article also mentions that the replacement rate of oil and gas in the last few years has been 100 %, in contrast to many other basins in the world. And apparently, the success rate is high too; the article suggests that 100 % of the exploration wells drilled have been successful in finding hydrocarbons, which is an impressive statistic if true. Another website notes that since the Islamic Revolution in 1979, when recoverable liquids stood at 88 billion barrels and gas at 8 trillion m^3, these numbers have grown to 156 and 32, respectively, last year. In other words, in contrast to so many places around the world, where petroleum reserves are steadily declining, Iran clearly sits on a very large and seemingly still growing reserve base. ■

Henk Kombrink

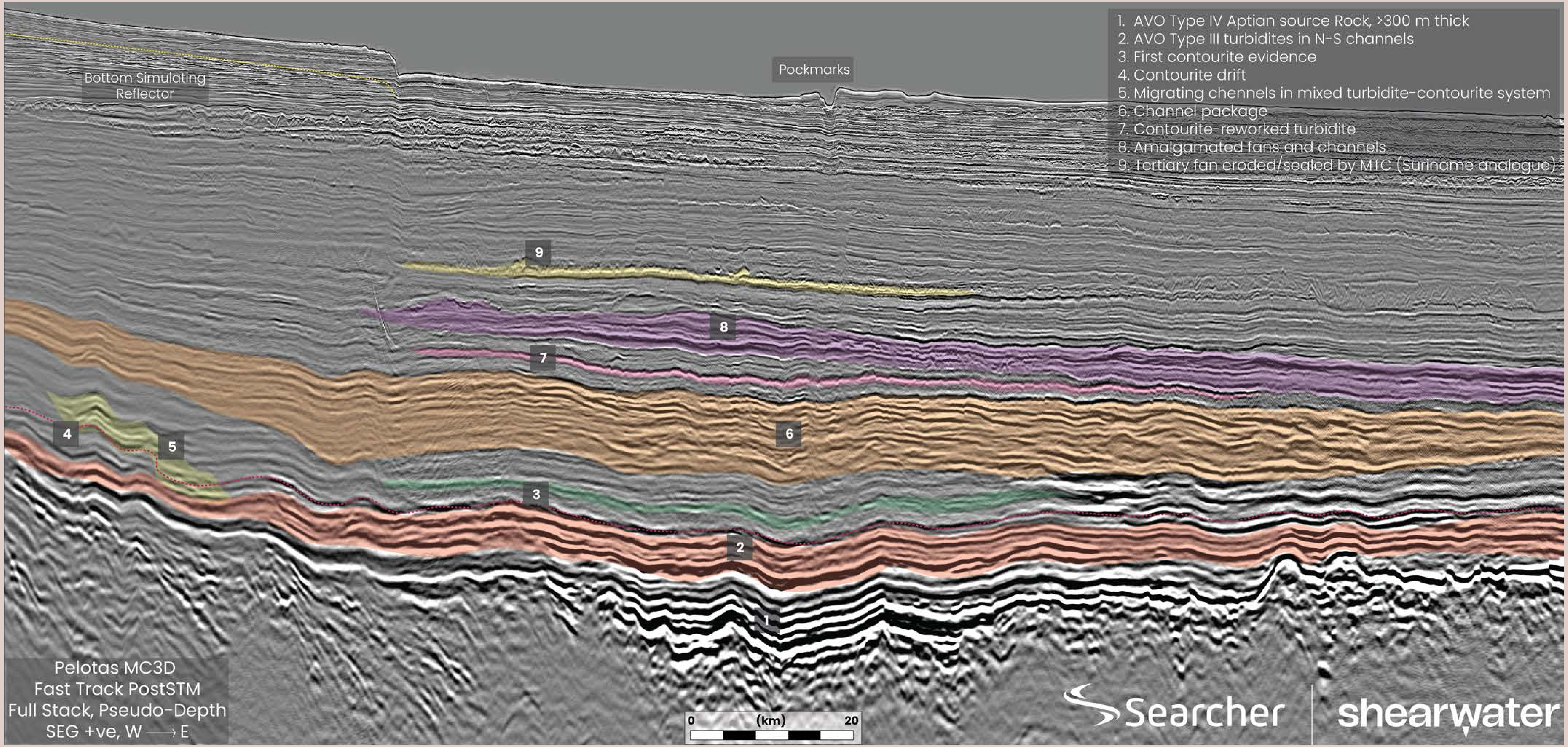
NOT ONLY SOUTH PARS

It is well-known how important the discovery of South Pars has been for Iran. It represents around 8 % of the world's gas reserves on its own. But other (gas) discoveries have more recently been made as well, with volumes that nobody would sniff at either. For instance, in 2019, the discovery of the Eram gas field was announced in the southern province of Fars, not far from South Pars. The reservoir is cited to be 50 km in length and holds over 13 Tcf in gas reserves, with 19 Tcf in place. But because of the presence of South Pars, the discovery of a field like this does not result in a stir in Iran: "Such a discovery would be taken seriously were it made in other countries," said Reza Dehqan, deputy CEO of NIOC in 2019.

Deepwater exploration: It's the hope that keeps us here

You are reading this at both the end and the beginning of extraordinary Eras. Humanity is engaged in a desperate mission to search for the carbon-based energy resources that will "fill the gap" between the depletion of existing fields and the inexorable demands for future production required whilst we transition to low-carbon energy for all. All hopes lie in the hands of the explorers who have systematically scoured the accessible world for over seventy years and who know their only chance to find new resources in quantity is to look somewhere they haven't looked before. That new arena has been unexplorable until now. It lies on a part of the Earth that has geologies we are only just beginning to understand, indeed a part of the Earth that is so inaccessible it is almost beyond our comprehension.

The hope that keeps us here is that the oil and gas needed to fuel the transition will be found in the world's deepwater basins on passive continental margins, such as the Pelotas Basin of Brazil, shown in the foldout line here. Fortunately, this existential search could not have come at a better time as this new responsibility for our industry has come exactly at the moment when we have developed the new technologies to achieve it.



New technologies for deepwater

So where do you look for billions of barrels of oil and gas equivalent, after really smart and determined humans built a civilization out of looking really hard, everywhere they could reach for a hundred years? Not onshore and not in shallow water offshore either. The only place to look now is somewhere you couldn't access before – the deepwater basin floors of the world's passive margins

NEIL HODGSON, KARYNA RODRIGUEZ AND LAUREN FOUND, SEARCHER

OUR INDUSTRY has recently developed a number of tools with specific applications in deepwater that will help us survive this challenge. Firstly, we all have the optional use of the most complicated machine in the universe – our human brains, which will provide the imagination and the curiosity to adapt to the new play environment in deepwater. It may be hip to augment this tool with thinking machines but the organics will lead the way.

There are some very clear exploration advantages to the geologies encountered in the deep and ultra-deep of passive margins. Every ocean plate will shallow as one moves from older to younger parts, i.e. further offshore from the base of slope. Sands that get to the basin floor are draped onto the crust and pinch out offshore; therefore, with time, the counter regional dip creates a zero-risk trapping configuration (Figure 1 and foldout). Prior to that, when the margins start to drift, they do so in narrow restricted basins ideal for depositing restricted marine source rocks directly onto the new crust. If above upwelling mantle, the rift is initially sub-areal, so flood basalts (and SDR's) are generated; if above colder downwelling depleted mantle, the margin stretches rather than melts, creating a hyperextended margin or initial drift volcanism is submarine. The former is a "magma rich" margin where the basement nadirs (with the source rocks and basin floor fans) have a good chance of being loaded with enough sediment to generate oil. Such a play is the Venus-1x discovery of Namibia (Figure 1) – soon to be emulated both in the South African extension of the Orange basin and in the Pelotas basin (foldout) in south Brazil.

The "magma poor" margins (such as Gabon's Southern basin, Espirito Santos in Brazil or Kwanza in Angola) are just as common and the same principles of source will apply – the exhumed mantle is submarine, and source rock and basin floor fans will still deposit on top of it (Figure 1). Where allochthonous salt basins form inboard – reservoir must come into the basin laterally (i.e. from the Congo in South Gabon, Kwanza and Espirito Santos) and / or post the deposition of the salt basin despite halokinesis (Kwanza). In some cases, the salt basins slide under gravity creating a canopy of salt out over the crustal transition (i.e. all the above mentioned basins) the play still exists below and outboard of the canopy, and has not been tested in the Atlantic with the possible exception of the Ondjaba-1 well drilled out-board of the allochthonous salt in Angola in 2022.

Our second suite of technologies is the constantly evolving seismic acquisition, processing and imaging technologies to see and derisk new plays. Regional scale 3Ds are more common, often made affordable by being multi-client in nature. Ten to twelve long offset 8 – 10 km streamers in wide-tow configuration 150 m apart captures the full scale of opportunities – and whether conventional or multi-component streamer,

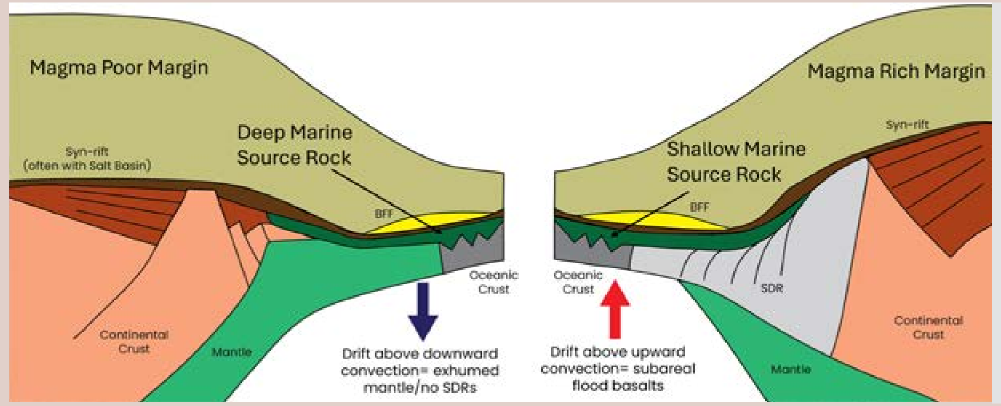


Figure 1. Conceptual magma rich and magma poor margins.

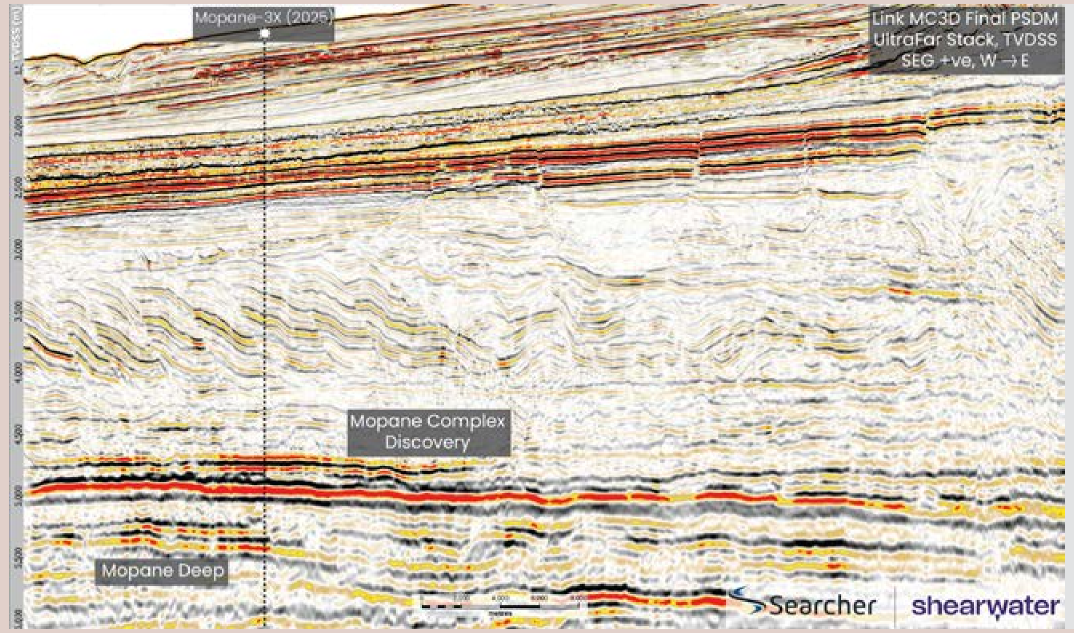


Figure 2. Ulta-far angle stack through Mopane 3X.

these data will reveal the subtle detail of the sedimentology as well and give justifiable confidence in drill-ready prospects. It is in seismic processing that the constant progress occurs on a rolling 10 year basis, where the arcane cutting edge becomes the affordable normal deliverable in this timeframe. Availability of compute, refinement of algorithm and demands of the consumer drive the constant turnover of capability, so that it's unthinkable that a new seismic product will not be de-ghosted, SRME'd, FWI'd where possible and pre-stack processed through PSDM today. This is changing both what we see and how we use this data.

Concentrating processing on deducing the correct seismic velocity field lets us use the far angles better than we have ever been able to. Discoveries relying on ultra-far angles to show amplitude variation with offset where far offsets show little effect are becoming legion (Figure 2). Risk reduction by detecting increases in amplitude with angle or offset has long been thought to be essential, but modern seismic can also attack source presence and effectiveness by revealing reduced amplitudes with offset. This is a major addition to just being able to image the source rocks better with de-ghosted, denoised data stacked accurately.

Modern seismic is also changing the way we think about deepwater sedimentation. Hand in hand with the development of deepwater-clastic fields, the new seismic is changing our understanding of the influence and impact of hitherto cryptic contourite currents on deposition of turbidite deposits. The deepwater sedimentation world we thought we had conquered is receiving a new approach. The effect of contourites on sedimentation that we can see on modern seismic, are very hard to observe in core and logs – it's a matter of scale, but we are learning right now that they can dramatically influence the architecture of clastic turbidite deposits on both slope and basin floor.

Our last key technology to win the day is "engineering". So far, the engineers have never let explorers down, and over the last 70 years have steadily progressed in exploration drilling water depths from (almost 0 m to 3,600 m of water at a rate of ca 500 m per decade (Figure 3). This year a well may be drilled in 3,900 m of water (offshore Colombia) so that in ten years time it is perhaps unambitious to assume we will be drilling in 4,900 m of water.

It's an exciting time to be a human. It's also an exciting time to be an explorer as we transition from "easy" shallow water into exploring a part of the Earth that until recently was so inaccessible and is still being understood. We can marvel at the simplicity and elegance of this low-risk exploration play in deepwater – and hope that the counter regional dipping clastic fan is where the world will find the oil and gas it needs to fuel the transition into a better world.

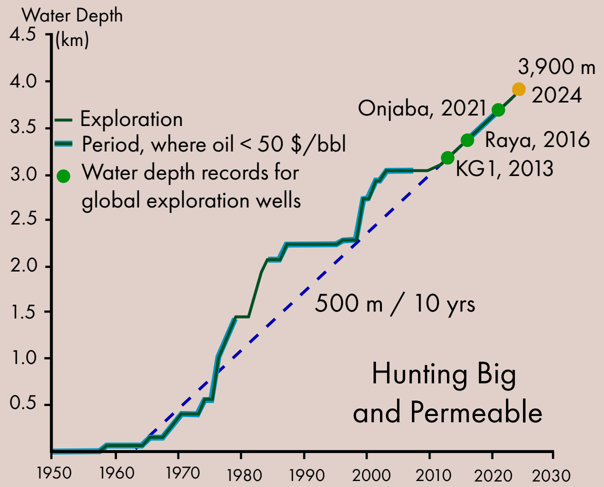


Figure 3. Engineers driving exploration to deeper water to find "Big, Simple and Permeable" – the future of exploration.

PORTRAITS

"Many geologists are nowadays working on 3D seismic datasets that may reveal a lot on the area imaged, but the bigger picture is sometimes obscured this way. Regional 2D seismic lines still have a significant benefit in that regard"

F. Javier Hernández-Molina -
Researcher Andalusian Earth Science Institute

PORTRAITS

ON DRIFT

F. Javier Hernández-Molina reflects on several decades of researching sediment transport in the deep sea

HENK KOMBRINK

Javier onboard the JOIDES Resolution, crossing the Strait of Gibraltar during IODP Expedition 401, "Mediterranean-Atlantic Gateway Exchange." (December 10, 2023 – February 9, 2024).

When we meet on Teams on a morning in March, F. Javier Hernández-Molina is calling in from his office in Granada, Spain, where he works at the Andalusian Earth Science Institute (IACT-CSIC). In the background is a picture that fits the main topic of the conversation that we will have quite well - a large sailing boat navigating icy waters, probably somewhere around the poles. It reminds me of Shackleton's expeditions to the Antarctic.

Looking at a map that is included in Javier's CV, showing the projects he has been involved with over the years, it is not unlikely that around 100 years later, he explored the very same area at some point more recently. But where Shackleton was primarily interested in reaching the South Pole and doing some research on the side, Javier's primary drive during all of the expeditions, field works and cruises he participated in was to better understand what happens beneath the surface of the sea, sometimes at great depths, unravelling the deep-water sedimentary systems that characterize these places.

And where some will intuitively argue that there is not much activity there, the sediments often tell another story. It is a story that Javier and his research team are trying to resolve, with the help of boreholes drilled through the International Ocean Drilling Programme, the energy industry, but also with seismic data and outcrop analogues.

Javier has long been interested in basin analysis and sedimentary geology. Though initially focused on continental shelves, since 1996, he has been working on integrated studies of continental margins where his current research focuses on deep-water sedimentation, including the influence of bottom-current / oceanic circulation in marine basins. Bottom currents and a series of secondary oceanographic processes interact at different scales to form sedimentary deposits referred to as contourites and mixed (turbidite-contourite) depositional systems. They can be found across major swaths of the continental margins and the adjacent abyssal plains in many of the world's oceans.

Explorers in the energy sector have also cottoned on to the relevance of the work done by Javier and his co-workers. With the move to explore deeper parts of the world's continental shelves, so has the industry shifted its attention to better understand the sedimentary environments of these places. This has put him in pole position to become one of the world's best-known experts on deep-sea sedimentary systems with a strong link to the industry, as the lead of the successful "The Drifters" research group.

HOW IT STARTED

"Is it a coincidence that I ended up as a marine geologist? Maybe not so much, as I grew up in Cádiz, a beautiful town in the far south of Spain surrounded by the sea," says Javier at the start of our conversation. "Also, once I began my university degree, I was very inspired by a lecturer who had a keen interest in stratigraphy and marine geology. It convinced me even more to go in this direction."

It was the deep seas that most attracted Javier, following a PhD in shallow marine sedimentary systems in the Alboran Sea at the Spanish Oceanographic Institute (IEO). This was again triggered by the special location of the Gulf of Cádiz, near the mouth of the Mediterranean Sea into the Atlantic, where the mixing of Mediterranean and Atlantic waters takes place.

In those years, we're talking the early 2000s, the Gulf of Cádiz appeared on the radar of the Integrated Ocean Drilling Program (IODP) as a candidate to better understand the effects of the Mediterranean Outflow Water (MOW) waters into the Atlantic circulation and how paleoclimatic variations affected those fluxes.

The cores that were retrieved from IODP expedition 339 not only resulted in increased knowledge about cli- ▸

PORTRAITS

matic variations but also revealed stunning examples of contourites and reworked turbidites by bottom currents. Or should they rather be interpreted just as turbidites? "That was the question we had many debates about when studying these cores in those years," says Javier. In order to try to answer that question, the research group started to look for analogues in the ancient sedimentary record.

The timing of all this, and the realisation not only by Javier's team but also by other different research groups that a lot of deep-water sediments are being affected and reworked by the circulation of water masses and by the bottom currents, sparked the interest of several industries. Not only were energy explorers interested in the results, telecoms companies having cables on the seafloor were also keen to learn more.

"The first companies that took an interest in the research we were doing were BG and Spectrum," says Javier. "They identified some deposits in the seismic data they acquired offshore in the South Atlantic and involved us in having a closer look because they were different to other well-known deep-water sedimentary systems."

"Over time, this resulted in more and more companies approaching us for input on deep-water sedimentary environments, which led me to start the first official Joint Industry Project (JIP#1) in 2017," continues Javier. A few years before, he had moved from Spain to London to work at Royal Holloway University of London (RHUL).

MORE THAN GRAVITATIONAL SYSTEMS

One of the main outcomes of the first phase of the research project was the realisation of how common contourites and mixed / hybrid systems are, and their importance in terms of the total amount of sediment moved within the ocean system. "That's critical to be aware of, as some people may initially think that it is the gravitational systems such as turbidites, mass-transport systems (or complexes) that cause the bulk of sedimentation. However, it is the transport and deposition capabilities of water masses and bottom current by the oceanic circulation that should not be underestimated. These oceanographic processes are eventually able to transport major amounts of sediment," Javier reiterates, "to a point where they can cause large depositional or erosional features themselves."

"Many geologists are nowadays working on 3D seismic datasets that may reveal a lot on the area imaged, but the bigger picture is sometimes obscured this way. Regional 2D seismic lines still have a significant benefit in that regard"

"Another important thing that we found is that through the actions of bottom currents, especially in relationship to the opening of ocean gateways as the modern oceans started to form during the Mesozoic and Cenozoic, is that most of the sediments shed into the oceans over time did not find its way directly into the abyssal plains. Instead, they were transported laterally by bottom current to different parts along the continental slopes. This means that there is a lateral transport factor involved at the end of the source-to-sink chain that caused a significant part of bulk of the sediments to be stored on slopes lateral from where they were dropped by gravitational force, rather than all straight into the abyssal plains."

THE BIGGER PICTURE

"When it comes to identifying contourite deposits, normally they are not difficult to interpret based on seismic data, because they are so prominent and large-scale and different from other deep-water systems," explains Javier. "The problem arises when you are looking at more detail or using outcrop or core data where the "bigger picture" is missing and you rely on just making observations on a little postage stamp area."

THE DRIFTERS

"The Drifters" Research Group, led by F. Javier Hernández-Molina, studies deep-marine sedimentation and investigates the influence of bottom-current circulation along continental margins and adjacent abyssal plains. The group members routinely collaborate with high-profile industry partners and is developing successful research partnerships with other top-ranked research centers in the field. It also has a sustained impact on knowledge transfer in the discipline both through research projects and public engagements.

The group is sponsored by a wide variety of research projects and companies interested in energy geosciences, with whom results are shared on an annual basis. The group is currently in its second Joint Industry Project (JIP#2, 2024-2027), following a successful first one that ran from 2017 to 2022.

The group is currently looking for new partners and if you are interested in joining the JIP and / or would like details about the activities of this consortium, please contact Javier (fj.h@csic.es).

"The Drifters" also organise regular online talks (Virtual Get-Together (VGT) sharing series) that are open to those interested in deep-water sedimentary systems to share the latest research or hear from other experts in the field for provoking discussions and promote a network between academia and the industry. As such, the group has established itself as the global centre of expertise when it comes to deep-water sedimentation and deposits.

THE DRIFTERS RESEARCH GROUP
BOTTOM CURRENTS & DEEP-WATER SEDIMENTATION

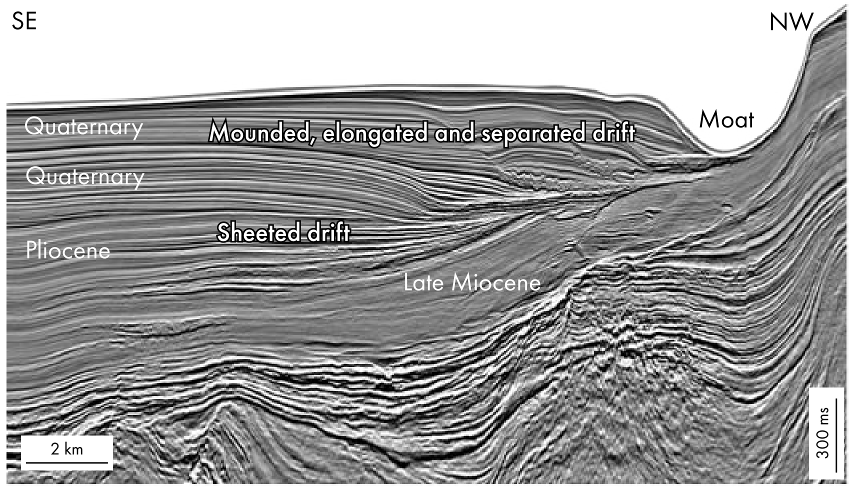
Javier on fieldtrip in California searching for late Cretaceous sandy contourites. (September, 2023).

PHOTOGRAPHY: F. JAVIER HERNÁNDEZ-MOLINA PRIVATE ARCHIVE

"During the first part of the Joint Industry Project, we specifically developed criteria to better distinguish between contourites, turbidites and hemipelagic deposits. First of all, evidence of sedimentary condensation, reworking, reactivation surfaces, smaller grain-size variations, small-scale hiatuses, and omission surfaces are some of the criteria in identifying contourite deposits. All of these vary depending on paleoenvironmental conditions, especially current velocity and sedimentation rate. Turbidites, on the other hand, are sometimes reworked by bottom currents. But at the end of the day, we do need to look at a multidisciplinary approach, to allow the discrimination between deep-water facies." Javier also highlights the importance of primary sedimentary structures, microfacies and ichnological features, often complemented by geochemical proxies, as the best diagnostic criteria to distinguish reworked turbidites and contourites at the sedimentary facies scale.

What do you recommend someone who is new to the industry to do when it comes to becoming more familiar with contourite deposits? "There are key areas, such as Brazil, Mozambique and the Gulf of Cádiz where researchers and explorers identified good examples of cored contourite or mixed deposits if you'd like to have a look at these things yourself. But in a way, there are many parts of global continental margins and abyssal plains, as we discussed earlier, where these deposits can be found at different scales, from the seismic to sedimentary facies," says Javier.

"The first thing I would always recommend people to do is to familiarise themselves with the regional setting of an area, both the geological features as well as the (paleo)oceanographic characteristics; look at the bigger picture before zooming in on your field area. There is a risk these days of immediately zooming in on a newly acquired 3D volume, without having a look at the broader area first. It may be very helpful to look at some regional 2D lines initially, and then dive into the 3D, also because the contourite depositional systems are commonly developed at a basin scale." ▸



Example of a ContouriteDepositional DSystem. Pliocene and Quaternary deposits in the Faro Drift, Gulf of Cádiz (figure from Watcharapong Phothadee adapted from Hernández-Molina et al., 2016. Marine Geology. Courtesy of TGS).

IMPLICATIONS FOR ENERGY GEOSCIENCE

"One of our current lines of research, as part of the JIP#2, is to look at a larger scale than we did during the first project when the focus was more on differentiating deep-water deposits. Knowing that contourites are so common in recent sedimentary systems, we now try to better understand when contourite and mixed depositional systems formed at various stages of the geological record during the Mesozoic and the Cenozoic. We also try to better quantify their stratigraphic significance within the paleoceanographic framework that we've built during the last decade. Since we know that fine-grained contourites can act as a seal while the coarser-grained equivalents can be potential reservoirs, there is potential to discover new plays in areas where no one has looked before. It is an exciting thought that has also triggered significant interest from the energy industry."

THE POWER OF COLLABORATION BETWEEN ACADEMIC AND INDUSTRIAL PARTNERS

Javier lived and worked in London for 11 years, where he taught and performed research at Royal Holloway University of London. "Before I moved to the UK," Javier recalls, "my thinking was that academia and industry were very separate entities that did not interact with each other very much."

"However, UK universities took this to another level. They turned out to be really adept in setting up Joint Industry Projects, and I realized that collaboration between academia and industry was normal," Javier says. "It was a new thing to me at the time, and it gave me the inspiration to start up the first consortium back in 2017, which was sponsored by seven companies."

"To me, it shows how beneficial this type of research collaboration can be," Javier says, whilst he reiterates that he and his colleagues can still perform the research they want. "There is no overall steer from the industry in which direction we need to go, they are just interested in being part of the team that does the work and hear directly from the researchers what the latest results are."

ACADEMIC RESEARCH AND THE ENERGY SECTOR

Despite the academic value that the research into contourite depositional systems has achieved over the past 10 years, it is well known that universities are experiencing pressure not to work with companies operating in the energy sector anymore. "It is certainly an issue these days," Javier admits.

"It is clear that in the face of global climate change, we must change the way we use energy resources, and therefore a transition towards clean energy is essential. However, I don't think it's positive to stigmatize the industry. Not only is the energy transition a gradual process, but the collaborative efforts by many research groups and companies also focus on aspects of interest to the energy transition, such as gas, CO_2 capture and storage (CCS), and perhaps, hydrogen in the future."

THE FUTURE

"What is the future of your research," I ask Javier near the end of our conversation.

"The growing interest in and implications of contourite and mixed depositional systems demonstrates that there is a demand for the work we do. At the start of our second phase in 2022, I wasn't so sure about the appetite for research collaborations, as the energy sector was very much hit by the pandemic and the loss of hydrocarbon demand. However, looking at the current situation, we have eight companies involved in our programme and we keep on talking to new ones frequently as well. It definitely seems that there is a strong industry interest in deep-water research."

And what are those lines of research going to be? "The link between tectonics and sedimentation, timing of ocean gateway opening and the dynamics this resulted in when it comes to bottom-water currents is something that will keep us going for quite some time," says Javier. "There is the numerical modelling aspect of oceanographic processes and sedimentation as well that we will further develop over the next few years. In short, there is enough to do and I see plenty of room to continue this collaborative work." ■

GEOTHERMAL ENERGY

"It will be very hard, if not impossible, to claim that a geothermal system will be devoid of bacterial life"

Elsemiek Croese – Microbial Analysis

Every site is different

Thermal response tests for shallow closed loop projects show how important both lithology and groundwater flow are on energy transfer

SHALLOW closed loop boreholes (150-300 m deep) for ground source heat pumps (GSHP) are increasingly popular as a solution for individual or small clusters of housing projects, even though the cost of drilling a hole and placing the loop are still not to be sniffed at.

That is why it is sensible to perform a thermal response test in the borehole, especially if a campaign of multiple boreholes is planned at the same site. If the thermal conductivity is better than expected, it might be possible to drop a borehole from the programme, which means quite a significant saving. But even if the project is just about one hole, knowing the thermal conductivity allows the end-user to make better predictions of expected energy extraction.

I came across a series of LI posts from geologist James Horton the other day. He works for Qvantum Solution Design, a company involved in performing system design and thermal response tests across the UK. Some interesting insights can be taken from these posts; here are two examples.

QUARTZ AND GROUNDWATER

In November last year, James posted about a thermal response test project carried out in a borehole drilled in a sandstone formation. The outcome of the 48-hour test resulted in a conductivity of 3.06 W / m·K, which is impressive, as he mentions in the post. Why is the conductivity so good? It is down to quartz, which is a good conductor? As a result of the higher-than-expected conductivity, the planned 12 boreholes for the project could be reduced to 11, shaving off a significant part of the projected cost.

Another observation James made was that the conductivity curve showed a minor step, as indicted in the figure here. This could be explained by a small groundwater disturbance, such as active drilling operations installing at the opposite end of the borefield.

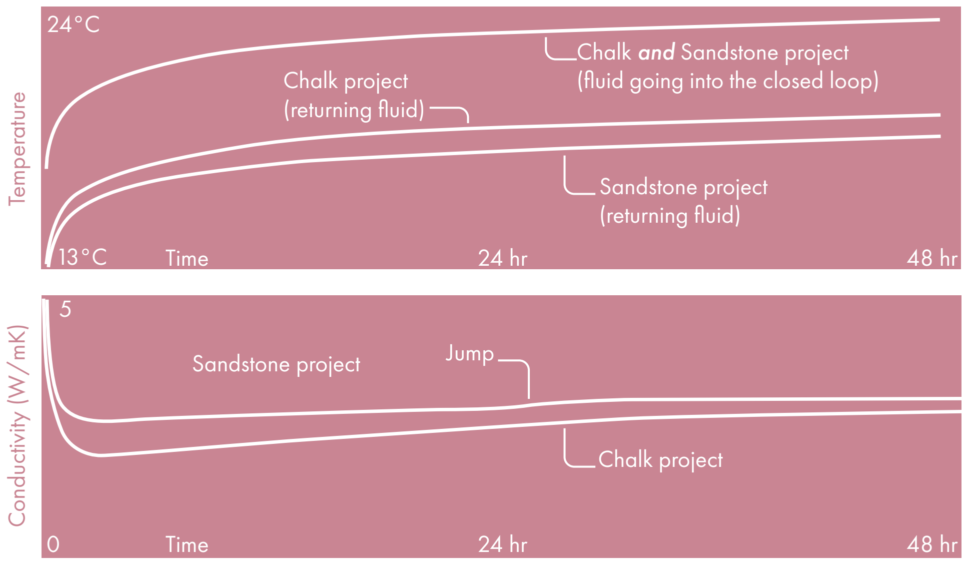
The influence of groundwater flow in these sandstones can be much larger, especially at sites close to rivers and on hillsides where gradients are larger, resulting in more flow. “We have also seen massive short-lived spikes in conductivity during rainfall events, in cases where the sandstones are directly exposed to the surface,” said James.

CHALK AND FRACTURES

The second example James published about was a project in London, where the Upper Cretaceous Chalk was subjected to a 48-hour thermal response test. In this case, the resulting conductivity was lower than in the first example mentioned above, but it was still higher than for most of the Chalk conductivities, he wrote. The reason for this “anomalously” high conductivity of 2,85 W / m·K might be the presence of a fracture system through which groundwater flow takes place, enhancing the heat transfer properties.

These two examples nicely illustrate how local geological conditions can influence the performance of a shallow geothermal loop and that it makes sense to quantify this prior to project completion so that a better estimate of energy deliverability can be made. ■

Henk Kombrink



Two superimposed thermal response test results, showing the temperatures of the fluids run through the system in the top graph and the resulting thermal conductivity at the bottom. Because the chalk has a lower conductivity than the sandstone, the returning fluid temperature is higher than in the sandstone project – less energy could be transferred into the formation.

SOURCE: JAMES HORTON (LINKEDIN)

Bacterial life is everywhere in the subsurface

And so is the risk of finding bacterial growth in unwanted places

“LET’S PUT it this way,” says Elsemiek Croese from Microbial Analysis, “one of the key ingredients of life is water. In that light, it is no surprise to see that geothermal projects are sensitive to developing issues like biological clogging or microbial induced corrosion (MIC) when it comes to bacterial growth. Maybe even more so than in oil and gas.”

That’s not to say the issue doesn’t exist in oil and gas. Especially in projects that experience an increase in water cuts or where water injection is taking place, the same issues related to biofilms or MIC can occur. “We have seen oil and gas projects where no bacterial problems existed, but when water injection starts or water-cut ramps up, the first problems arise,” explains Elsemiek.

Elsemiek Croese, who is a senior project manager with Microbial Analysis in Groningen, the Netherlands, is a microbiologist with a passion for everything that comes with bacterial life and how they work under stressed conditions. In her day job, she is involved with many geothermal but also oil and gas projects that experience challenges due to bacterial activity. Based on her eleven years with the company, she has some more interesting insights to share, for instance about the presence of bacterial life in the subsurface.

Elsemiek Croese

PHOTOGRAPHY: ELSEMIEK CROESE PRIVATE ARCHIVE

“It will be very hard, if not impossible, to claim that a geothermal system will be devoid of bacterial life,” Elsemiek says, “unless you operate at temperatures exceeding 121° C, beyond which very little survives. But when you look at the low enthalpy geothermal projects that are characteristic of Western Europe, with temperatures often below 100° C, we have found that bacteria or their spores are consistently present in produced water. It’s true, the optimum temperature for most bacteria is 20 - 37° C, but certain species tolerate higher ranges, and we also see that there is an element of adaptation when exposed to higher ranges.”

And the challenge with geothermal systems is that the temperature of the produced fluid decreases as it makes its way through the network. That means bacteria have an opportunity to grow or settle in the temperature zone where they thrive best. “That is a challenge geothermal developers need to be aware of,” says Elsemiek. Especially when a project is at a standstill for a while, this creates even better conditions for biofilms to grow. “Luckily,” Elsemiek adds, “to avoid microbial related problems, there are more solutions than killing all microbes present in the system.”

When it comes to taking lessons from the oil and gas industry and applying these to geothermal, Elsemiek sees that there are still some barriers in place. “I have seen some examples where geothermal projects would clearly have benefitted from taking oil and gas guidelines into account when designing their infrastructure. I believe that there is more scope for cross-fertilisation in that respect,” she concludes. ■

Henk Kombrink

ADDING WATER

Unrelated to geothermal, Elsemiek has direct experience with another example of adding water in a fossil fuel environment. “Diesel is required to have a percentage of bio-diesel mixed in these days,” she explains. “This bio-diesel contains more water, which in turn leads to more bacterial-induced corrosion in storage tanks.” It is a clear example of how the energy transition comes with challenges in unexpected ways. Nobody wants leaking diesel tanks, but this has become more of a risk due to the addition of a more sustainable product.

The dominance of oil and gas at a geothermal conference

On the face of it, the GeoTHERM conference is about geothermal energy, but when you look closer, there is a lot of oil and gas business behind it

"I WORK on gas installations, but I have come to this conference to network, as so many people from the sector are here," somebody tells me at the lunch table when I get into a conversation.

A company I speak to sells technology in the oil and gas sector, with their main market being the Middle East. They also try to break into the geothermal market, which is why they are present at the GeoTHERM conference in Offenburg. But have they sold anything yet? No, is the answer. The technology is not cheap. In addition, creating the opportunity to sell it also requires being aware of drilling plans right from when they are being made, otherwise there is certainly no budget for it. And that is not an easy thing to achieve.

These two examples already provide a good illustration of the interesting nature of this event. On the face of it, it is about one thing: Geothermal energy. And certainly, that is made even more tangible through the presence of multiple shallow drilling rigs both at the entrance and in the exhibition space. These companies have not come to drill for oil or talk about oil, that's for sure.

But when it comes to deep geothermal drilling, the presence of the oil industry is very evident. Again, if you did not know what these companies do, you might initially think that they solely work in geothermal, but in many cases the opposite is true. What to make of the presence of Baker Hughes, for instance? Well, they are actually drilling a well near Celle, a historic oil and gas hub in the north of the country, where the Rhaetian sand is being targeted for geothermal energy production. But still, Baker has yet to prove that geothermal will be able to be a sizeable part of their portfolio.

I am not writing this to criticise the oil industry for being at a geothermal event. The cross-over is natural. And because domestic hydrocarbon production is only going one way, the geothermal sector must be viewed by many companies in the service sector as a potential candidate to make up for the loss of work in oil and gas. And for some, it is, surely.

It is that drive, that hope, which is one of the reasons behind the growth of the conference, I think. Everybody told me how the event has gained momentum over the years, with two impressive exhibition halls filled with stalls.

But is this hope of the oil and gas service sector to really shift from oil and gas to geothermal and make the latter the money-maker oil and gas has been for so long? I am not sure yet. As someone else told me at the very start of the event, "This all looks very impressive, but the reality is that progress is, in fact, very slow when it comes to actual projects in this part of the world." Others I spoke to echoed this, and it makes you think, given the much lower margins in the geothermal industry, how long can this be sustained? ■

Henk Kombrink

Not-so-hot volcanic rocks in Saudi Arabia

Drilling of three wells in a young succession of lava flows shows that the heat has gone, limiting the application for geothermal energy production

THAT IS what a team of researchers concluded in a paper published in the journal Geothermics this year. It must have been a bit of a surprise to find very modest heat flows and no sign of an active geothermal system at all, despite a thick succession of basalts. It wasn't the oldest basalts either.

ANOMALIES

The team drilled a total of three wells to a depth of 1,000 m. The locations of the wells was chosen in such a way to increase the probability to tap into faults and fracture zones that could provide a pathway for convection of geothermal fluids. The presence of a series of high-conductivity magnetotelluric anomalies was also instrumental in locating the wells. Either the presence of a clay cap or the upwelling of hot fluids from deeper strata was seen as an explanation for the anomalies.

MODEST RESULTS

All three wells fully penetrated the volcanic interval, beneath which a thin Cenozoic sedimentary succession was found before basement was hit. The Cenozoic succession is dominated by fine-grained rocks, overlain by a few tens of meters of coarsed-grained alluvial deposits.

In contrast to what one might expect from a young volcanic system though, the average geothermal gradient found in the wells is low; approximately 22.3° C / km when considering the whole drilled interval, and 20.3° C / km based on data from the basement section only. Higher conductivity of the basement rocks is a possible explanation for this.

The geothermal gradients already provided a hint to the main conclusion of the study; no active geothermal reservoir has been identified in the wells, even though porous and fractured rocks were observed. Normal groundwater conditions prevail, with evidence of an older hydrothermal system given hydraulic brecciation observed in the cores.

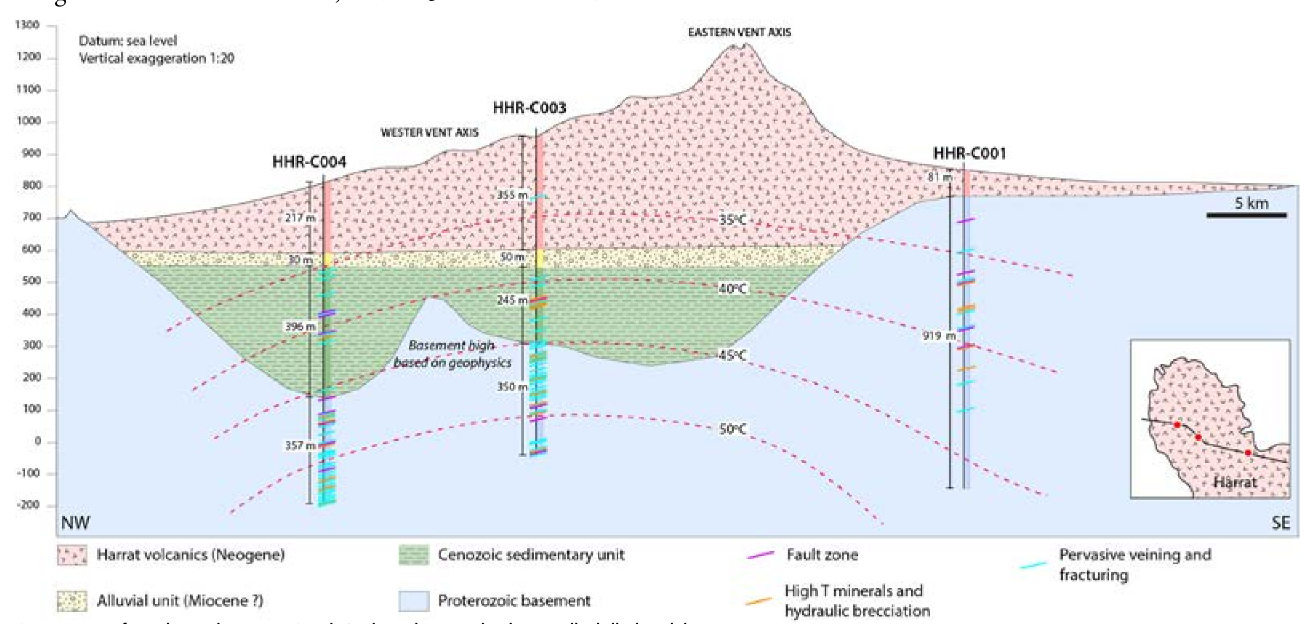
The conductive layers observed in the magnetotelluric data probably represent the mudstone rocks concealed beneath the Rahat lavas rather than from clay caps that can sometimes be found above geothermal reservoirs.

The authors conclude that there may still be potential for deeper geothermal projects, but it all seems a little like trying to finish off with some promise whilst the data have clearly suggested that this area does not offer the best geothermal ticket in the country. ■

Henk Kombrink

THE NORTHERN RAHAT VOLCANIC FIELD

The lava field of northern Rahat is the most extensive of the Arabian Plate, and developed from the Miocene to around 10,000 years ago. Decompression melting associated with the Red Sea spreading centre or upwelling related to a plume have been put forward as explanations for its formation.



SOURCE: BISCHOFF ET AL. (2025) – GEOTHERMICS

Cross-section from the study area in Saudi Arabia, showing the three wells drilled and the temperature contours.

SUBSURFACE STORAGE

"In some ways, knowing the reservoir storage capacity of a CCS project is even more critical than knowing the size of the same reservoir prior to gas production"

Alan Johnson - Petrophysicist

SUBSURFACE STORAGE

CCS – a roller coaster ride from an oil crisis to a climate change solution

To understand why the public might be sceptical of CCS is to understand that for most of its history, CCS has generally been regarded as a way of overcoming a shortage of oil and gas

RODNEY GARRARD

INITIALLY, at the time of the 1970s oil crisis, Carbon Capture and Storage (CCS) was proposed as a way of getting more oil out of the ground through enhanced oil recovery (EOR), culminating in the introduction of the U (utilisation) into CCUS in 2012. Then, in the mid-2000s, after rising natural gas prices spooked utilities on both sides of the Atlantic, CCS was seen as a way of getting new coal plants built in the face of major environmentalist opposition. Such opposition was generally informed by the oil crisis / peak oil / peak gas mind-set of the time, with oil production thought to cease earlier than coal production. Of course, what this opposition failed to understand at the time was that in mass terms, we will never run out of hydrocarbons, but they will remain in the ground after we end their use because it will be too expensive to extract them.

E&P COMPANIES NOT IN THE STORAGE GAME YET

In the UK, bp announced in 2005 a CCS project at Peterhead based on pre-combustion capture of CO_2 in a newly built power plant to back up a UK government initiative that took CCS to the forefront of international climate change policy. In addition, the hydrogen it generated fitted well with the “Beyond Petroleum” motto of the company at the time. However, shortly afterwards, UK power utilities made a ‘dash for coal’, with plans to build around ten new 800MW power plants. These plans were soon besieged by major Greenpeace-organised protests extended to Westminster and other power plant sites. As a result, pre-combustion capture on natural gas became completely irrelevant, both technically and politically.

What was needed was a post-combustion capture solution for the new coal plants, which was started in 2007.

Peterhead gas power station.

PHOTOGRAPHY: ISTOCK

Then, the recession came along, UK electricity demand dropped rapidly by over 5 % and global gas prices fell on weak demand. UK utilities subsequently abandoned all plans to build new coal power plants and the competition for new coal plants with CCS therefore became unnecessary.

CCS, however, was still recognised by the UK government as important, if no longer urgent, to help achieve an 80 % reduction in emissions by 2050, and a project to demonstrate full-chain CCS at a small scale was launched. This resulted in a post-combustion capture retrofit project, largely run by Shell, on the existing natural gas power plant at Peterhead and a new-build coal oxyfuel project at Drax that included industrial partners with capture and onshore CO_2 transport expertise. But, importantly, no E&P company was involved in handling the geological storage.

LIMITLESS GAS

In the meantime, across the Atlantic, shale gas expanded rapidly. This led to a situation that continues today, where it appears that global natural gas supplies are unlikely to be commercially constrained for the foreseeable future, with major exports from the USA via LNG. This made coal CCS projects less popular in the USA.

Instead, it spurred oil field CO_2 injection pilots utilizing EOR to successfully increase recovery rates as high as 25 % of Original Oil in Place (OOIP). Pennzoil’s SACROC (Scurry Area Canyon Reef Operators Committee) Unit, initiated in 1972, stands as the world’s largest CO_2 flood within the Permian Basin's depleted Kelly-Snyder oil field. This 205 km^2 project, targeting a depleted carbonate reservoir, has a long history of CO_2 EOR. Initially, CO_2 came from nearby gas plants, but inconsistent supply led to a 1996 switch to natural CO_2 from Colorado. While early estimations placed recovery at 8 % of OOIP, Kinder Morgan's operations have driven cumulative CO_2 injection past 7 trillion ft3 (TCF), yielding over 180 million barrels of EOR. These long-term projects are the unsung heroes of CCS and provide invaluable data on CO_2 trapping.

IN THE MEANTIME, IN CANADA

In Canada, significant early advancements in CO_2 storage monitoring began in 2000 with the Weyburn CO_2 Storage and Monitoring Project. This international collaborative scientific study aimed to evaluate the technical feasibility of storing CO_2 in geological formations, particularly focusing on oil reservoirs, while also developing world-class best practices for project execution. Recognizing that large-scale CO_2 storage in saline aquifers was likely the most viable option for CCS, Shell launched the Quest project in 2015, successfully sequestering over 1 MT annually in a deep sandstone saline reservoir.

SaskPower's Boundary Dam project, the first commercial-scale post-combustion CCS initiative at a coal-fired power plant, began capturing CO_2 in 2014. Since then, it has captured over 6.5 MT of CO_2, which has been used for sequestration at the Aquistore project and for EOR at Whitecap Resources' Weyburn CO_2-EOR field.

E&P COMPANIES IN THE STORAGE GAME

Back in the UK, a natural gas and CCS project might have succeeded, but the first-of-a kind small-scale unit costs were too high, and there was little prospect of larger amounts of fossil-fuelled power generation being built in Scotland in the longer term. In turn, this was mainly driven by the extensive wind power construction north of the Border. To cap it off, in early 2015 the

PHOTOGRAPHY: CATAZUL VIA PIXABAY

Coal fired power station Neurath in Grevenbroich North Germany.

”… as industry veterans will tell you, CCS has been a roller coaster ride from an oil crisis to one of a range of potential low-carbon technologies that surely needs to be addressed at scale now”

Department of Energy and Climate Change (DECC) effectively gave away the low-carbon electricity support funding it had reserved to cover CCS running costs to fund extra intermittent forms of renewables instead.

Nonetheless, following the Paris Agreement in 2016, the UK and many other countries began a journey to transition to net-zero. Prior to this, E&P companies were not under pressure to deliver on CCS as it was mainly for coal facilities, who were mainly not up to the task. It is only really at this point that E&P companies really began to engage and find technical solutions to deliver CCS across all aspects of hydrocarbon use and in varying geologic areas, especially in areas like the North Sea and the USA that have a wide range of storage sites. This movement is still valid today.

A TRUE ROLLER COASTER

In summary, as industry veterans will tell you, CCS has been a roller coaster ride from an oil crisis to one of a range of potential low-carbon technologies that surely needs to be addressed at scale now. And whilst doing so, the nascent CCS industry would be wise to not discount the know-how of the long running EOR projects in a bid to achieve the long-term objective of decarbonising the energy system. However, this conceptual realisation can only be translated into the necessary large-scale deployment if the various countries signed up to the Paris Agreement invest a significant fraction of the money devoted to infrastructure to fund CCS technologies that are critical for delivering it. Currently, planned CCS capacity is 2.0 - 2.5 % of current emissions in the USA and UK/EU, with high project cancellation rates observed as the CCS value chain becomes more complex to achieve economies of scale. So, it has to be concluded that any pipeline of projects is speculative at best. Just as it always was.

This article draws on Gibbins, Chapter 17: 'CCS – From an Oil Crisis to a Climate Crisis Response' in Carbon Capture and Storage, Edited by Mai Bui; Niall Mac Dowell, Royal Society of Chemistry, 2019, with added material from experience in the USA and Canada. All of the assertions and conclusions are, however, solely the responsibility of the author. ■

The benefits of being an oil veteran when assessing depleted fields for carbon storage

Making sense of old core analysis data certainly helps when you have worked with it at an earlier stage of your career

Rotliegend sandstones from the UK Southern North Sea, well 48/11b-A5. The parallel-laminated sands represent aeolian deposits, and it is not difficult to imagine that these are low in clay content.

PHOTOGRAPHY: NORTH SEA CORE

"IN SOME ways, knowing the reservoir storage capacity of a CCS project is even more critical than knowing the size of the same reservoir prior to gas production," said Alan Johnson at the start of his presentation at the Aberdeen Formation Evaluation Society the other day.

This is mainly because storage contracts will often need to be signed before FID for a CO_2 capture project is considered. Of course, this is all still a bit theoretical, as there are not that many examples of CO_2 storage projects that have experienced FID, but the reasoning makes sense. At the end of the day, a chain of investments on the capture side is heavily dependent on the ability to store the CO_2 at the downstream end of the line.

For that reason, Harbour UK asked Alan to carefully assess the subsurface data of the Viking A depleted Rotliegend reservoir in the UK Southern North Sea, with the main underlying question of how reliable the core and wireline data are as input to calculating its ultimate storage capacity. The Viking A field is one of the earliest discoveries made in the UK North Sea, 1969 to be precise.

Having started his career in petrophysics in 1974, just a few years after the first major gas discoveries were announced, it is easy to see why Harbour asked Alan to carry out this job. He worked with the data types used back then and knew about the uncertainties, which is surely an advantage when revisiting it 50 years later.

One of the main questions centred around the reliability of porosity data from core measurements carried out in those early years. Often, core reports from back then do not accurately describe the ways the cores were dried, which might have had implications for the amount of water still in the core at the moment a porosity calculation is made. For instance, statements such as "Thoroughly dried" are a common occurrence, which clearly leaves room for speculation at which temperature the cores were actually dried.

However, despite these uncertainties, a careful analysis of various ways in which cores were prepared for analysis indicated that the drying methodology was not of detrimental effect on the reliability of the data. Why is that?

"The Rotliegend reservoir sands are quite forgiving," concluded Alan at the end of his presentation. As the sands are often quite well sorted and without significant clay content, he concluded that the drying method has ultimately had little effect on the reliability of the porosity data. This is good news when it comes to using old data to calculate storage space in this area. However, if it would have been another reservoir with more of a mix of lithologies, this certainly would have been a little harder to conclude. ■

Henk Kombrink

DEEP SEA MINERALS

"There has been a lot of focus on the fact that mineral deposits may eventually be buried by sediments, but for those located in the rift valley, it is just as likely that they may be covered by lava flows. This of course has an impact on the availability of the resources – we may not be able to detect the deposits that are covered by lava, and they may be difficult to exploit"

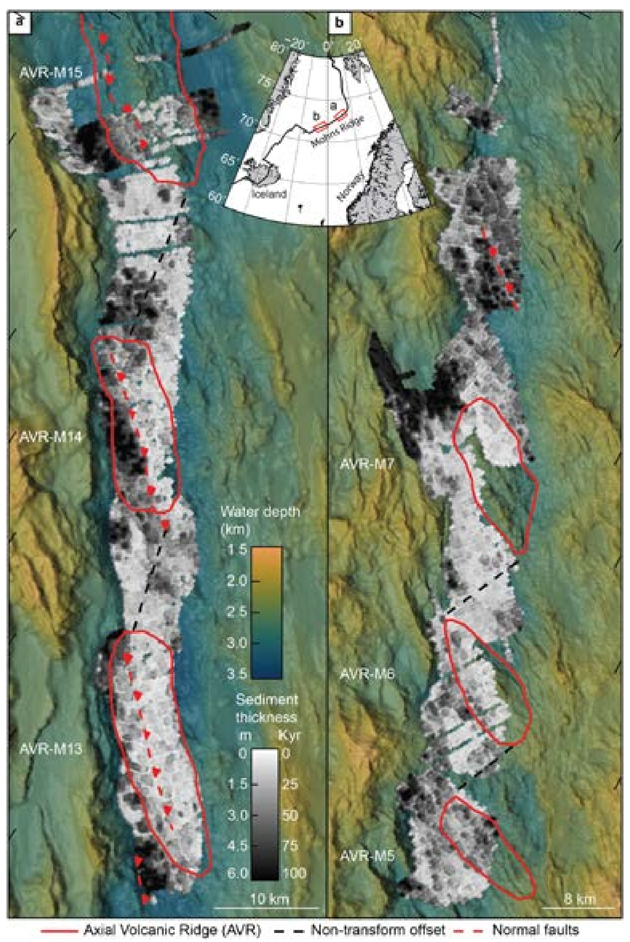
Håvard Hallås Stubseid - University of Bergen

How spreading rates determine your exploration strategy

Harvesting minerals from slow-spreading mid-oceanic ridges will have an additional complicating factor compared to doing it at faster-spreading ones

The terrain along the ultra-slow-spreading Mohns Ridge in the Norwegian Sea is continuously renewing itself with frequent volcanic eruptions across a wide zone in the rift valley, a new doctoral thesis shows. The knowledge is useful, among other things, for companies that want to explore marine mineral deposits.

"Ultra-slow spreading ridges (<15 mm/year) have quite different characteristics than faster (25-150 mm/year) spreading ridges," says Håvard Hallås Stubseid, researcher at the Center for Deep Sea Research at the University of Bergen (UiB).



Mapped sediment thicknesses at two segments along the Mohns Ridge. Sediment thickness serves as an indicator of the age of the underlying lava flows.

He explains that the most obvious difference is the topography. Slow spreading is the key to forming a rift valley along the plate boundary. "Along a fast-spreading ridge, the volumes of magma that flow up from the depths are significant so that a thick volcanic crust is built. At lower spreading speeds, the spreading is less magmatic, and more tectonically influenced," he explains.

Along the Mohns Ridge, the rift valley is of considerable extent: About 10 – 15 km wide and 1 – 1.5 km deep. The flanks of the rift valley are marked by major faults, and along the valley floor a number of volcanoes protrude.

ACROSS THE ENTIRE WIDTH

One of the main findings of the study is that volcanic activity occurs across the entire width of the rift valley. In comparison, a fast-spreading ridge will only have volcanic activity within a very narrow belt of around a couple of hundred meters.

The Mohns Ridge is, therefore, far more volcanically dynamic than previously thought. This means that the seafloor in this terrain is constantly renewing itself and remains relatively young.

"There has been a lot of focus on the fact that mineral deposits may eventually be buried by sediments, but for those located in the rift valley, it is just as likely that they may be covered by lava flows. This, of course, has an impact on the availability of the resources – we may not be able to detect the deposits that are covered by lava, and they may be difficult to exploit," says Håvard.

He mentions the discoveries Ægirs kilde and Lokeslottet (both active springs) as examples of deposits that are at risk of being buried by new lava flows. Håvard is more optimistic about the preservation potential of the deposits that are located along faults on the flanks of the rift valley.

There is reason to believe that several of the companies - if or when they are awarded licenses - will concentrate their activities around the Mohns Ridge, which is the most prospective area with regard to sulfide deposits. The research can help exploration companies understand the preservation potential of the mineral deposits and which areas are most suitable. ■

Ronny Setså

ILLUSTRATION: STUBSEID ET AL. 2024, NATURE COMMUNICATIONS

DEEP SEA MINERALS

The world's largest SMS deposits

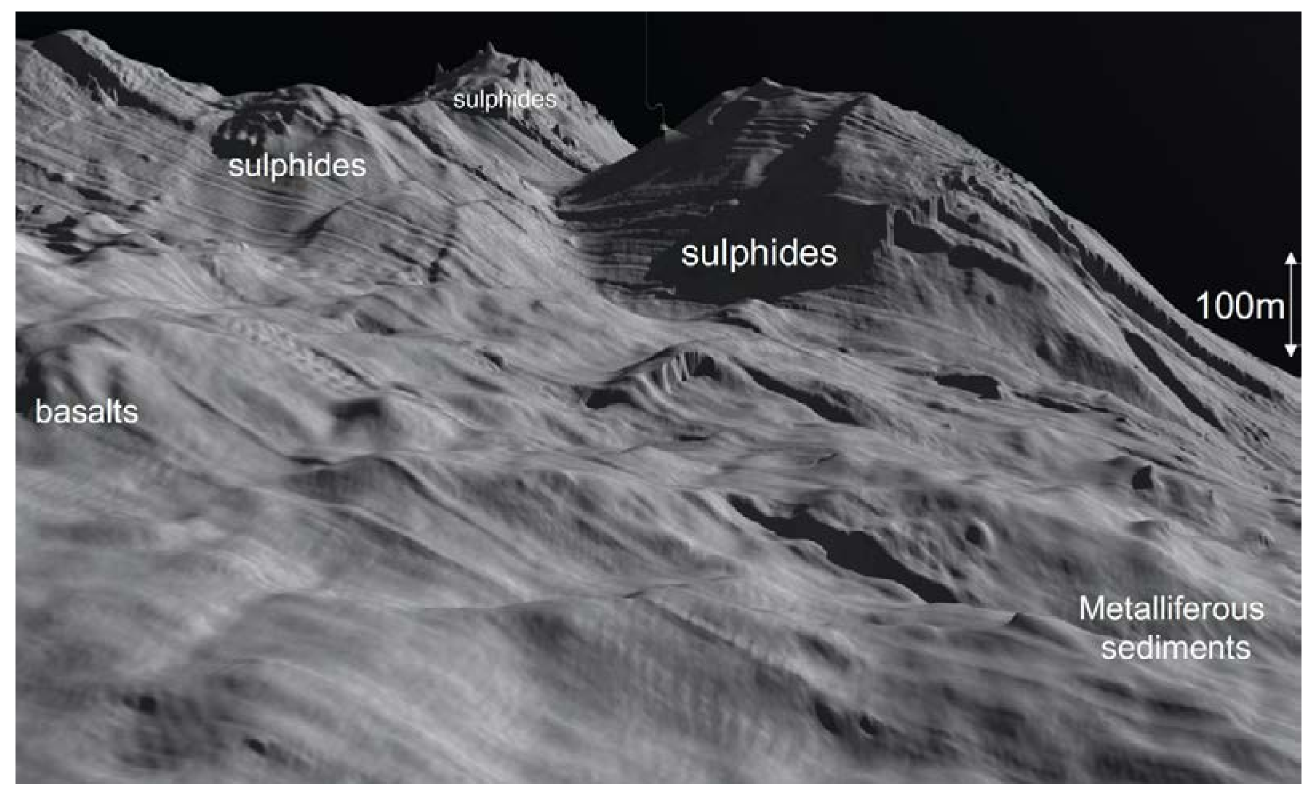
A team of scientists has discovered a cluster of large sulphide deposits along the Mid-Atlantic Ridge and offers insight into how they came to be and where else to look for them

The terrain along the ultra-slow-spreading Mohns Ridge in the Norwegian Sea is continuously renewing itself with frequent volcanic eruptions across a wide zone in the rift valley, a new doctoral thesis shows. The knowledge is useful, among other things, for companies that want to explore marine mineral deposits.

"Ultra-slow spreading ridges (<15 mm/year) have quite different characteristics than faster (25-150 mm/year) spreading ridges," says Håvard Hallås Stubseid, researcher at the Center for Deep Sea Research at the University of Bergen (UiB).

Researchers have identified several mounds on the seafloor at approximately 13° N along the Mid-Atlantic Ridge, which is at a latitude similar to that of Senegal. These mounds represent the largest known deposits of seafloor massive sulphides (SMS) found to date.

The mounds measure up to 300 m in height and almost half a kilometer in width. Initial estimates suggest ▸



Perspective view of the SMS mounds at Semenov 4 hydrothermal field, located on the Mid-Atlantic Ridge. The mounds are estimated to contain more than 100 million tonnes of sulphides.

SOURCE: MURTON ET AL., 2025 (CONFERENCE ABSTRACT)

DEEP SEA MINERALS

they contain at least 100 million tonnes of sulphide. For comparison, the SMS deposit Mohns Treasure, located on the Mohns Ridge, is believed to contain about 2.2 million tonnes of sulphide ore.

These mounds are part of the Semenov hydrothermal field cluster, which has been regularly visited by researchers involved in the ULTRA project. The project members have collected a variety of data from the sites, using high-resolution seafloor mapping, remotely operated vehicles, seafloor drilling, sediment coring, sub-seafloor imaging by seismic reflection and refraction, and sub-seafloor resistivity surveys using controlled source electromagnetics.

THE HYDROTHERMAL PARADOX

Hydrothermal seafloor massive sulphide (SMS) deposits are formed by seawater circulating through the hot rocks beneath the ocean floor at mid-ocean ridges, where they strip out various elements, particularly metals, which are then deposited at the seabed as they emerge and cool at hot water vent systems.

Most of these vent systems have been within the active volcanic zone at the ridge axis. Recently, though, vent systems have been found at large faults which expose rocks of the oceanic mantle at the seabed.

This presents a paradox: Most of the vents occur at very active ridges with fast spreading rates, but the largest hydrothermal SMS appear to occur on these detachment faults (also called oceanic core complexes), at "amagmatic" ridges with slower spreading rates, and very limited volcanic activity. Source: ULTRA

MANTLE EXPOSED AT THE SEABED

The researchers propose that the vast amounts of accumulated sulphide material can be explained by the presence of an oceanic core complex (OCC). OCCs form on the flanks of mid-ocean ridges where detachment faults exposes ultramafic rocks (mantle rocks) at the seabed.

The study suggests that detachment faults create ideal conditions for large SMS deposits by sustaining geothermal activity, maintaining high temperatures, and keeping fluid pathways open. These processes make OCCs promising targets for future deep-sea mineral exploration.

OCC formation is common at slow-spreading ridges, such as the Mohns Ridge, suggesting excellent potential for sulphide deposits in the Norwegian exclusive economic zone. ■

Ronny Setså

India to auction first offshore mineral blocks

India's Ministry of Mines has put 13 blocks in three areas in the India EEZ up for auction, with closures expected imminently. The areas contain lime mud, construction sand, and polymetallic nodules and crusts

India's Ministry of Mines has announced that the country is entering offshore mineral production for the first time in its nearly 75-year history. This initiative aligns with India's vision of becoming self-reliant and marks a new chapter in the country's mining sector.

During 2023 and 2024, India has advanced its offshore mineral policy, and the Ministry has now initiated its Tranche 1 auction for offshore blocks located within India's exclusive economic zone (EEZ), which spans 2.3 million km^2.

THE RESOURCES

According to the auction presentation material, the Geological Survey of India (GSI) has performed offshore mapping and exploration within the EEZ for decades. Within the seven blocks off the Great Nicobar Island in the Andaman Sea, GSI has demonstrated the presence of nodules and crusts through ROV visual inspections and chemical analysis of samples.

The resources found in these areas are expected to contain manganese, iron, nickel, cobalt, lead, and rare earth elements. The deposits occur at depths ranging from 500 to 1,500 m.

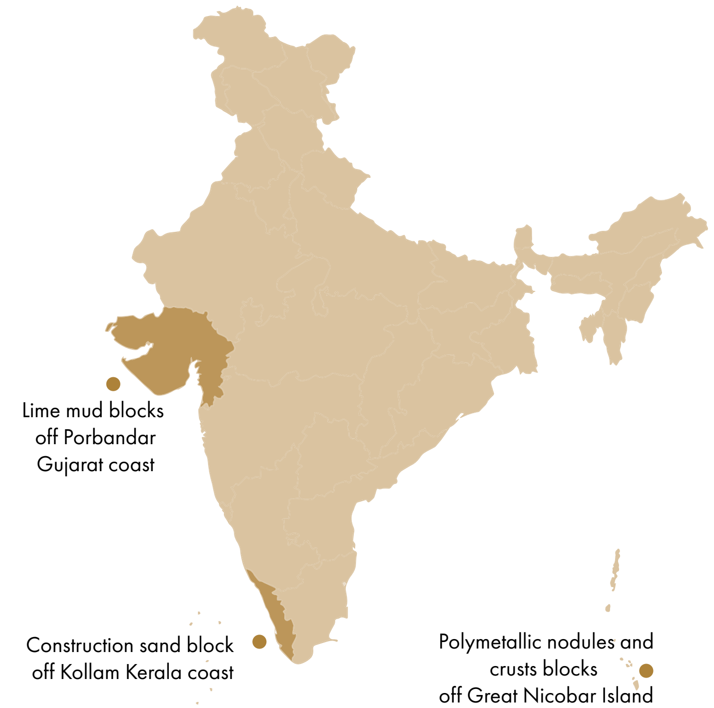
GSI emphasizes that nodules and crusts present a viable alternative to land-based mining, citing their high grades and the potential for reduced waste and environmental and human impact.

THE AUCTION PROCESS

Potential bidders must follow several steps during the auction process. In short, eligible bidders (only Indian nationals and registered Indian companies) will make technical bid submissions and an initial price offer, i.e. the percentage of mineral revenue they are willing to share with the government.

Next, a technical evaluation of the bids takes place. The top 50 % of the technically qualified bidders will then advance to the next stage. The highest initial price offer will establish the floor price for this next round, where selected bidders will participate in a live auction.

The bidder with the highest bid will be declared the preferred bidder. This bidder must then make upfront payments, secure environmental and regulatory clearances, and submit a production plan. Once these steps are completed, a development and production agreement will be signed, followed by the issuance of a production license.



Offshore mineral blocks map.

SOURCE: MINISTRY OF MINES

ACTIVITIES OUTSIDE THE EEZ

While large amounts of minerals can be expected to be found within India's EEZ, the Indian Ocean may contain a much larger inventory. The Indian Ocean covers approximately 70 million km^2, and areas outside of India's EEZ are regulated by the International Seabed Authority (ISA).

The Indian government is actively involved in mapping parts of this vast region through a five-year initiative known as the Deep Ocean Mission.

To date, the ISA has awarded exploration contracts for sulfides and nodules to four contractors: The Government of India, the Federal Institute of Geosciences and Natural Resources (BGR, Germany), the Government of the Republic of Korea, and the China Ocean Mineral Resources Research and Development Association. ■

Ronny Setså

NEW GAS

"...it does suggest that the Ellis and Gelman in-place hydrogen numbers have very little bearing on reality"

Arnout Everts - AEGeo

Estimates of trapped hydrogen globally – a reality check

If there should be a similar amount of hydrogen in sedimentary basins as there is oil, how come an accumulation has never been found?

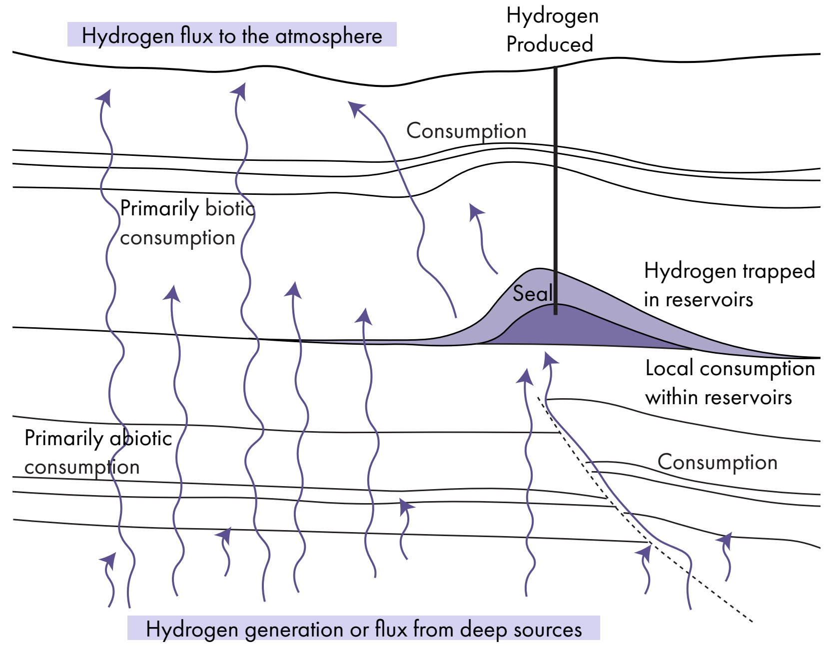
ARNOUT EVERTS, AEGEO

Over the last few years, there has been a continuous stream of news coverage on "ground-breaking natural-hydrogen discoveries." A paper by Ellis and Gelman, published late last year, very much fit that narrative and made furore in mainstream media and social media: "Model predictions of global geologic hydrogen resources."

Ellis and Gelman use a mathematical model to work out global hydrogen fluxes and trapping. They assume a "trapping efficiency fraction" of 0.01 (1 %), inspired by petroleum analogues, to arrive at a "most likely" (P50) estimate of "Hydrogen-In-Place" trapped in the subsurface globally, of ~5.6 million Mt.

However, the geological settings that comprise the "petroleum-analogue trapping efficiency" used in Ellis and Gelman's model are mostly limited to sedimentary basins, where the petroleum traps are. In other geological provinces, for example in cratonic shields or oceanic crust, hydrogen fluxes may still occur even though trapping – if any – would be in relatively small quantities and from rocks that are unfavourable to resource recovery. Therefore, it would have been much better to split Ellis and Gelman's "global fluxes" model into different crustal domains such as sedimentary basins, cratonic shields, and oceans.

Each crustal domain will then have its own range in hydrogen flux; low in sedimentary basins, high in oceanic crust, medium on cratonic shields. The chance of trapping can also be refined to high in sedimentary basins, low on cratons and medium in oceans. Model results would have been more realistic this way.



6.6 million Mt trapped hydrogen globally – a reality check...

Considering that sedimentary basins occupy about 17 % of the earth's surface, a reality check on Ellis and Gelman's model results can be performed. Assuming hydrogen fluxes are uniform across different settings, Ellis and Gelman's model implies that trapped hydrogen-in-place across the sedimentary basins globally may be around 17 % * 5.6 = 950 thousand Mt. In energy terms, 34 million TWh or 20 trillion barrels of oil equivalent.

This then allows a comparison with oil and gas resource quantities. Oil production to date and expected in the near future amounts to some 3.15 trillion BOE. Gas production historically and in the near future adds another 2 trillion boe. Assuming a recovery factor for oil of 10 % and for gas of 50 %, the in-place quantities of oil and gas consistent with all this historic production and reserves may amount to some 35 trillion BOE.

In other words, Ellis and Gelman's estimate of hydrogen-in-place, scaled to the sedimentary basins, is a similar order of magnitude as the hydrocarbon-in-place equivalent of all historic oil- and gas production and remaining reserves.

It then appears extremely odd that despite decades of exploration during which globally, tens of thousands of wells were sampled for detailed gas-composition analysis and millions of wells were logged with neutron-density tools capable of detecting hydrogen, no hydrogen gas fields were discovered. That is not to say such fields cannot exist. But it does suggest that the Ellis and Gelman in-place hydrogen numbers have very little bearing on reality. ■

ILLUSTRATION: REDRAWN AFTER ARNOUT EVERTS

NEW GAS

Iran to finally start producing helium

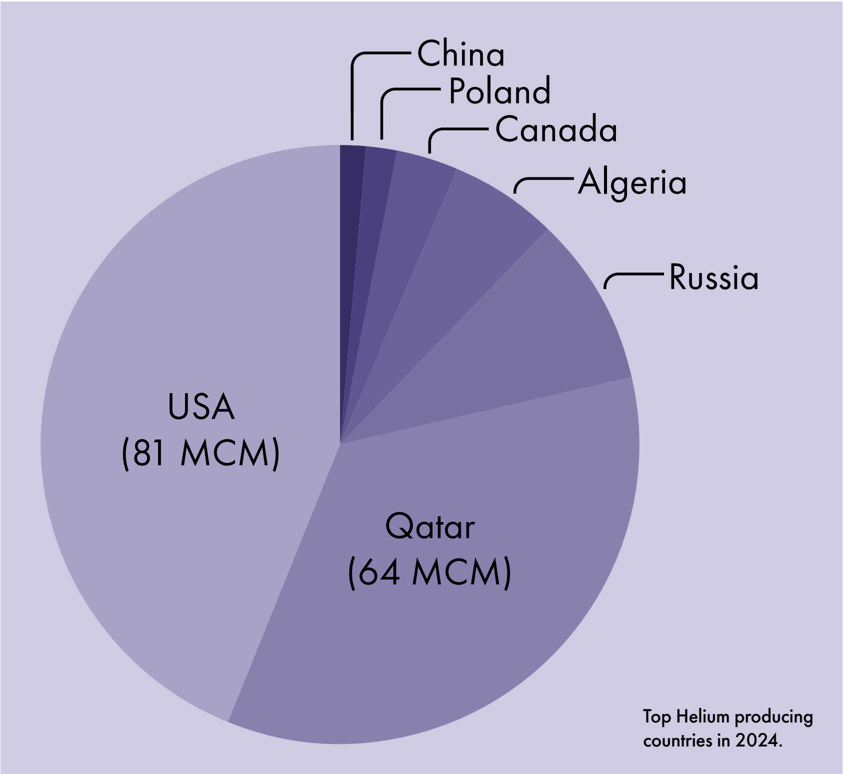
Estimated to possess about a third of the globe's noble gas, it was a matter of time before Iran capitalised on its reserves

Iran is set to join the exclusive group of helium-producing countries. With the launch of its pilot project to extract and purify helium from natural gas, it is on its way to becoming one of only ten global producers. Initially, the helium will supply the domestic market, but eventually, the intention is to export. While this might sound like Iran is ahead of the game, it is actually a delayed response to exploit its well-established helium reserves. This is largely due to the sanctions imposed on the country, meaning the project had to be entirely domestically engineered and manufactured.

In contrast, Qatar, located across the Persian Gulf from Iran, has been separating helium from natural gas for 20 years and is currently the second-largest helium producer in the world. Qatar's helium is extracted from the vast North Field, which extends across the maritime border into Iranian territory, where it is referred to as the South Pars Field.

The North Fields's reservoir section, within the Upper Khuff Formation, is characterised by five marine regression cycles. The youngest four cycles each consist of carbonate with good reservoir properties and sealing dolomite with interbedded anhydrite. The field is dome-shaped, with the apex located on the Qatari side of the border. The down-dip position of the Iranian part of the closure means that gas flows towards Qatar as the field depletes.

The United States, the world's largest helium producer, considers it economically viable to separate helium when the gas stream contains at least 0.3 %. In contrast, the North Field contains an order of magnitude less helium, about 0.04 %. Nevertheless, due to Qatar's high natural gas production rate, it still manages to account for 34 % of global helium production.



Top Helium producing countries in 2024.

SOURCE: STATISTA, MAP: REDRAWN AFTER IHS ENERGY AND GOOGLE EARTH

The trace amount of helium present in the North Field is generated by background levels of radioactive decay. Helium can be added to hydrocarbons at any stage in the play model: In the shales where the natural gas is generated, during its migration to the reservoir or within the reservoir itself.

The Atomic Energy Organisation of Iran, responsible for launching the helium pilot project, has not disclosed which gas field or fields will be utilised for helium extraction. Iran is currently producing natural gas from approximately 21 fields, situated both onshore and offshore. Although the helium concentration of these fields is not publicly available, estimates suggest that Iran may possess the third-largest helium reserves in the world.

If the construction of the pilot facility proceeds as planned, helium extraction and purification are set to start in March 2026. ■

Mariël Reitsma,
HRH Geology

Hydrogen exploration potential in Uruguay

Thanks to its diverse geology, the South American country has multiple opportunities to go after

JOSEFINA MARMISOLLE, CECILIA ROMEU, SANTIAGO FERRO, PABLO GRISTO, JUAN TOMASINI, RODRIGO NOVO AND NATALIA BLÁNQUEZ, ANCAP

Uruguay has completed the first phase of its energy transition; most electricity is now generated from renewable sources. For the second phase, the country has identified green hydrogen and its derivatives as a key component of its strategy. In this context, the National Oil Company of Uruguay (ANCAP) has initiated a research project to determine whether natural hydrogen should be part of the second phase of the energy transition too.

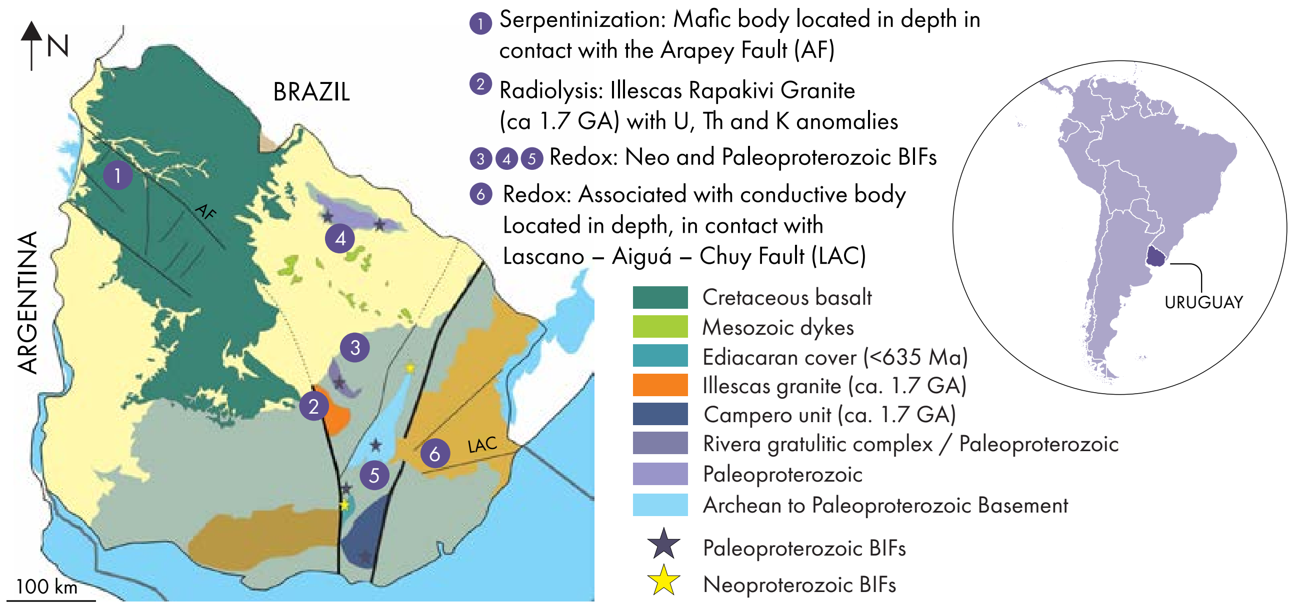
Hydrogen can form in the subsurface through more than 30 different processes. These processes range from biotic to abiotic and are associated with various rock types and geological settings. Given Uruguay's geological diversity, the likelihood that the different components of the natural hydrogen system come together in a single location increases significantly... As a first step, the ANCAP team has identified potential hydrogen source rocks and the chemical processes that could generate hydrogen. This effort has led to the identification of three distinct hydrogen-forming processes across six prospective exploration sites throughout the country.

The first location is in the northwest sector of the Norte Basin. Here, a mafic body, which could act as a hydrogen source rock, is located at approximately 1,500 m depth. When water reacts with olivine and / or pyroxene in the mafic body, serpentine and hydrogen gas are formed, a process called serpentinization. Normal faults dissecting the Norte Basin may serve as pathways for hydrogen migration, channelling the gas from its source to the sedimentary basin infill.

The next potential exploration site is the Illescas Granite, located over the Sarandí del Yí shear zone in central Uruguay. The granite is enriched in radioactive elements potassium (K), uranium (U) and thorium (Th). Hydrogen could be generated here via radiolysis, a process in which radiation emitted during radioactive decay splits water molecules.

Sites 3, 4, 5 and 6 are situated in the eastern half of Uruguay. The common denominator for these sites is the presence of iron-rich basement rocks. In these areas, magnetite in banded iron formations reacts with water to form hematite and hydrogen through a process known as hematization.

This study is the first step in natural hydrogen exploration in Uruguay. The identification of six sites of interest can now be followed up by an analytical campaign to determine whether hydrogen anomalies can be detected in the field. ■



Selected priority sites for natural hydrogen exploration onshore Uruguay.

ILLUSTRATION: ANCAP. MODIFIED FROM SEQUEIRA ET AL., (2024); OYHANTÇABAL ET AL., (2018); AND ORIOLO ET AL., (2018)

INSIGHTS

"Some geek at some point realised that graphics cards can be used to power workflows outside the gaming space. It was a game changer"

Vasilii Shelkov - Rock Flow Dynamics

How we become geologists

Looking around - Where all's to be

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

Q: How do you know if someone is from the Isle of Man?

A: Because they insist on telling you every five minutes!

Every geologist has a story as to why they are a geologist. I grew up in the Isle of Man, a small island that is neither England, Ireland, nor Scotland, and my story, though centred on an inspiring teacher, as so many life-changing stories are, is rooted deep in the Isle of Man.

In the first year of secondary school, our geography teacher, Mr Booth, took us out of the classroom (already exciting), across the playing fields, over a stone wall, down a rough gravel track to the low, flat, stepped cliffs and said: "What do you see?"

"What we saw," he explained to us, was that the cliffs were low and flat and stepped because they were bedded Carboniferous clean limestone with interbedded carbonate mud. In the midground between the cliffs and the crashing waves was a long, broad whale-back, explained as an anticline, and in the distance, rising out of the foam, was a raggedy, craggedy, nasty berg, explained as a basaltic volcanic plug. Criss-crossing everything were anthracite-grey rail tracks, explained as Tertiary dolerite dykes, swarming all the way from southwest Scotland.

That was me. Hooked.

Our home was 20 metres from the sea: We played on the beach, threw stones at each other, and laced herring heads with bicarb for the seagulls to vomit up. We sailed patched-up plywood dinghies when there was a breeze and dodged breakers when it was blowy-as.

The uppermost beach was cobbles, which graded down through pebbles, sand, and silt. Spring low tides exposed patches of fine clay, which we slathered ourselves. Storms threw pebbles and sand and salt into the gardens. My father struggled to grow anything in the coarse, free-draining sand other than potatoes and kale. I grew up in a paralic depositional system.

The broad bay had Carboniferous limestones at each end and Ordovician "slates" in the centre. The cobbles and pebbles on the beach reflected that. The local buildings also, with coarse stone-work using the abundant slates whilst quoins and details used the more easily worked limestone. The local farm had a huge gateway made of slate with an engraved limestone plaque at the apex. It read, "Judge Not Your Fellow Man's Condition Until You Be in His Position." Wise and thoughtful words.

My father, who is more pragmatic, would tell us: "Do not judge anyone until you have walked a mile in their shoes… then you can judge… because then you're a mile away… and you have their shoes." ■

PHOTOGRAPHY: JUAN COTTIER PRIVATE ARCHIVE

Why preserving a detailed facies reservoir model has everything to do with your graphics card

Developments in computer processing power have shown two very different trends over the past decades, with a big impact on how reservoir modelling and simulation are done

"IMAGINE a bulldozer," says Vasilii Shelkov, CEO of Rock Flow Dynamics, from his office in Houston. "That is how you need to envisage the power delivery of the Central Processing Unit of our computers. Or, in short, CPU. In the early days of reservoir modelling, it was the bulldozers doing all the hard work. But with rapidly increasing demands when it comes to grid size, cell size, and the parameters that people want to see modelled within the grid cells of their reservoir models, so have the demands from software companies to up their processing speed."

Vasilii and Eddy with a new graphics card in the Houston office.

This soon led to friction.

"The problem is," continues Vasilii, "the development of bulldozers has not been able to keep up the pace with the rising demand from the software. Something else had to be involved in being able to act as a workhorse in churning all these calculations." The answer is in GPU, or the Graphics Processing Unit.

"Some geek at some point realised that graphics cards can be used to power workflows outside the gaming space," Vasilii says. "It was a game changer. Not only because there was another vehicle available to take the load off the bulldozer (CPU), but also because the development in graphic card processing capability has advanced much more rapidly than in CPU."

"For that reason, we started to use GPU to perform our modelling workflows," says Vasilii, who can still be found under his desk installing the latest graphics card - constantly experimenting with configurations to maximise parallel throughput and extract every ounce of performance the hardware can deliver.

But, there is always a but. The way the calculations are made in CPU space is very different from GPU. In turn, that has a significant ramification on how the software is run, which implies changing the code. That is quite a time-consuming process. And that's where the challenge lies. How much do you invest in terms of converting code to run on GPU, versus leaving code to run on CPU?

But regardless, what has been instrumental is at least being able to harness the capability offered through GPU, where CPU has not been able to cope with developments.

And that is very important, for the following reason: There is now no need to upscale anymore, which means not losing the resolution in the translation from your static to your dynamic reservoir model. Which then comes back to the title of the article – if you don't need to upscale anymore, the business case for investing in yet another seismic survey is much better. Because the increased level of detail can now be preserved all the way throughout your modelling process. All thanks to your graphics card. ■

Henk Kombrink

PHOTOGRAPHY: RFD

Direct entry opportunities for every strategy across the Middle East and South Asia

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With significant levels of E&P activity across the Middle East and South Asia region it is timely to provide a round-up of government-sponsored entry opportunities in the form of licensing rounds

MADELEINE SLATFORD, NVENTURES

In recent years there has been a very low uptake by IOCs for opportunities offered in countries such as India, Pakistan, Bangladesh and Oman, while in Iraq, foreign entries via the licensing round process have been dominated by Chinese companies such as Geo-Jade and Sinopec. While there are undoubtedly valid reasons for the low interest, including above-ground considerations and often sub-industry benchmark commercial terms, it is difficult not to feel that these countries are possibly superficially overlooked by investors in search of more familiar options closer to home. This has historically led to firms underestimating the long-term merits of a new country entry and missing out on well-established oil and gas reserves and mature geological plays.

OPPORTUNITIES IN INDIAN AND BANGLADESHI EXPLORATION MARKETS

India opened OALP-X, its largest-ever exploration acreage offering, comprising 25 blocks covering a total of 191,986 km² in 13 basins, in February 2025. The round is open until the end of July. While all blocks offered in the previous OALP-IX round in 2024 received competing bids, no awards have been formalised, and it would presumably inspire investor confidence if the results of the prior round were determined before progressing too far with the current one. Meanwhile, bp, having generated significant publicity in February 2025 by back-tracking on its previously stated renewable energy targets, is courting India through signing a comprehensive MoU for exploration with state entity ONGC, a regular winning bidder in the OALP rounds.

Acreage on offer in OALP-X includes four deepwater blocks to the east of the offshore Andaman Islands, in the back-arc basin setting where there have been exploration successes in recent years to the south, in Myanmar and Indonesian waters. While state-backed company OIL's first well in a current campaign is to the west of the Andaman Island chain, in the forearc basin which has seen limited success to date, ONGC in March spudded an ultra-deepwater well, ANE-E, in the backarc basin to the east. If successful, this will be a play opener and highlight the attractiveness of the blocks on offer. Both OIL and ONGC have further drilling planned for the Andaman region. Bangladesh offered a comprehensive offering of offshore acreage in 2024, but despite numerous international companies subscribing to the seismic data package acquired by TGS specially for the round, there were no bids. Petrobangla is expected to re-launch the round in April 2025. TGS has indicated that the lack of bidding interest was due to above ground issues rather than the geology. While Bangladesh has in the past suffered due to perceived unfavourable commercial terms, the model PSC had been updated for the round, and it is possible that the political unrest of mid-2024 deterred bidders. Onshore blocks are also on offer, and Chevron is reported to have bid for an unspecified onshore block, possibly adjacent to its producing Surma Basin gas fields.

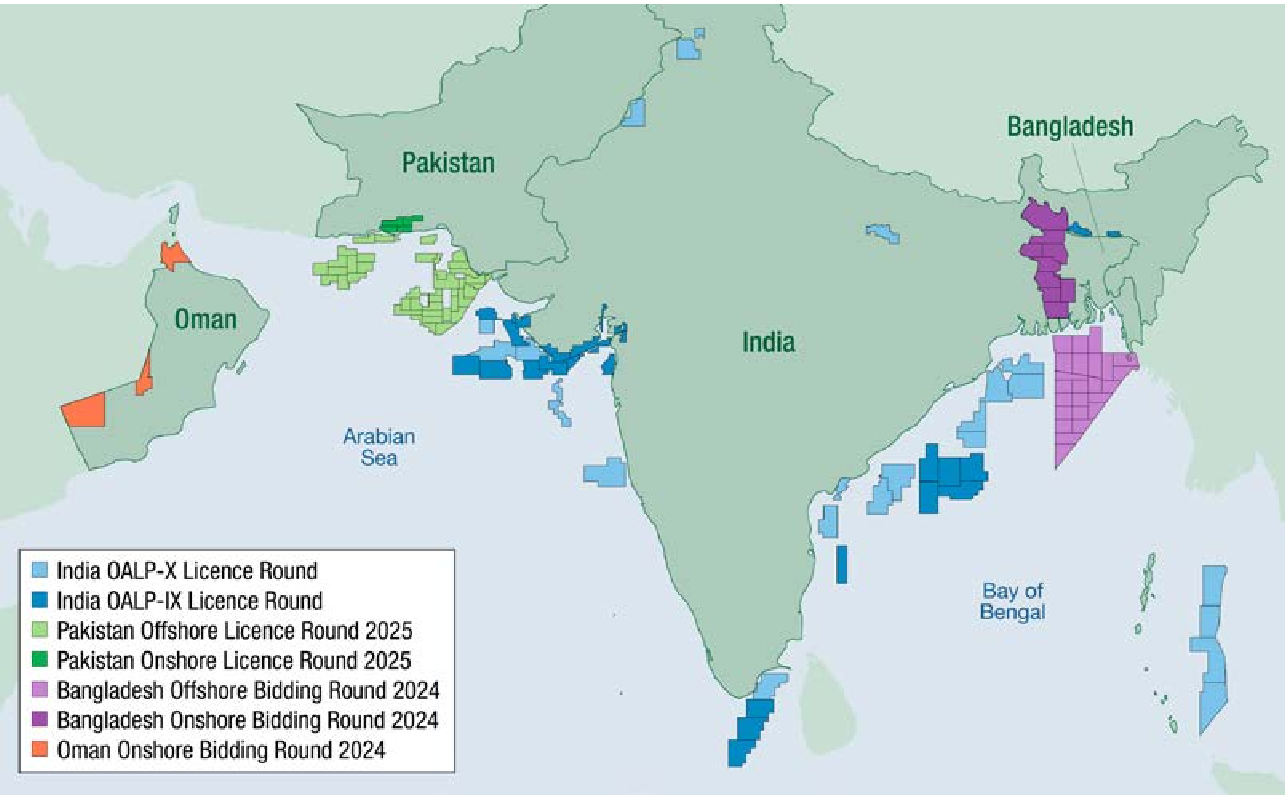
PAKISTAN AND OMAN: A SHIFT IN FOCUS FOR REGIONAL EXPLORATION

Pakistan has an offshore bid round currently active, offering significant tracts of the Indus Delta as well as the frontier offshore Makran area. The deadline for the round was recently extended from mid-March to end June 2025. Pakistan's previous round saw bids by the state-run and domestic entities and the Chinese-led UEP.

Across the Arabian Sea, Oman had been expected to offer offshore Block 18 which would offer geological contiguity with Pakistan's Makran coast. However, the blocks announced in early February 2025 as available in Oman are three onshore blocks (Blocks 36, 43A and 66) including recently relinquished acreage.

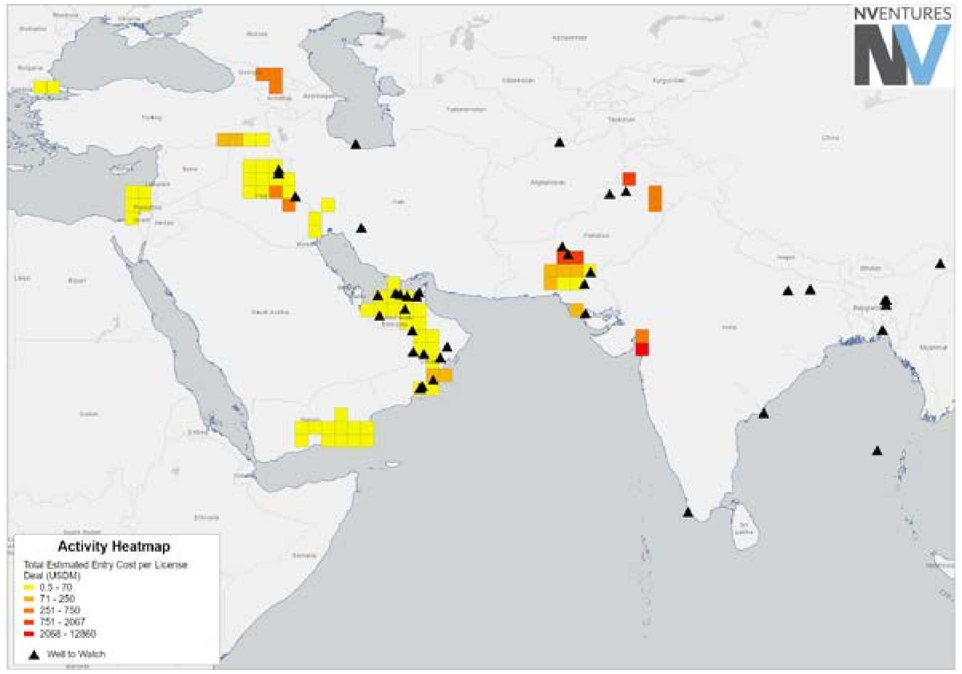
Delays and variations to expectations (in blocks, fiscal terms and timing) such as these may deter company confidence in the licensing round approach to gaining acreage in the region. However, the award of Block 54 (Karawan), ensuing from Oman's 2023 onshore bid round to new entrant Genel Energy, partnering with state-backed OQ as an operator, announced in March 2025, is encouraging from the bid round outcome perspective.

Considerable levels of current and forthcoming exploration activity in the region, highlighted by the NVentures Wells to Watch map, mean the significance of high-impact exploration successes, such as ONGC's play-opening Chola-1 in the deepwater Cauvery Basin, and Mari Energies' Spinwam-1 in the Bannu Basin onshore Pakistan, could be overlooked in the international E&P space. However, with the countries under discussion continuing to make significant strides ahead in the New Energy sector, in which Solar, Hydrogen, Wind and CCS projects are all gaining traction, seeking an exploration entry into one of the MESA countries by way of a bid round could be seen as a good way to ally with energy transition projects and thus enhance green credentials and deliverables. ■



SOURCE: NVENTURES

MESA Region Bid Rounds, March 2025.



SOURCE: NVENTURES

Total Estimated Entry Cost per Licence Deal (USDM).

A cool vitrinite reflectance model

Following decades of refinement, the current VRo model seems well-versed to reconstruct the timing of source rock maturation

DAVID RAJMON, GEOSOPHIX

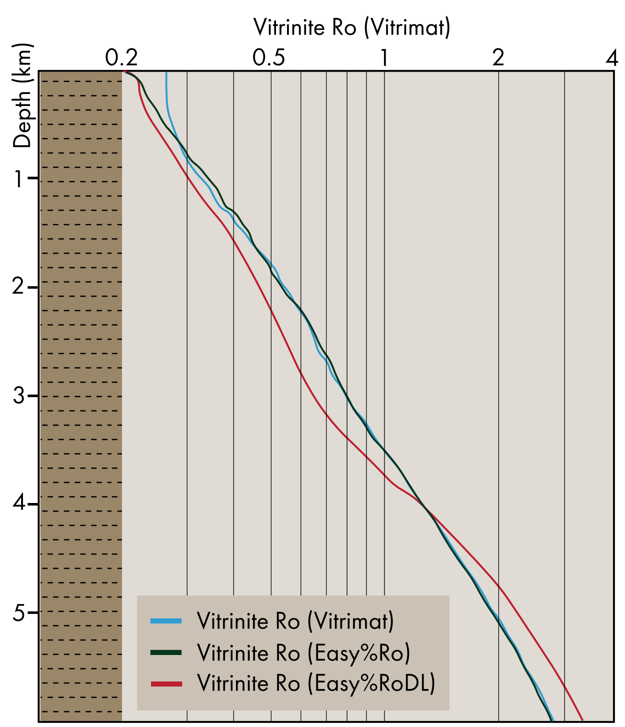
A BASIN model describes the thermal evolution of a basin to estimate when its source rocks expel hydrocarbons and of what type. Basin models do so by evaluating a number of relationships, such as heat flow from beneath the basin, heat generation, heat transfer through the sediments and the loss of heat at surface.

These relationships need to be anchored to provide somewhat accurate results for the unknown past. One obvious anchor is the present-day temperature measured at the surface and in wells. This fairly reliably anchors one end of the modelled history but leaves large uncertainty for the entire modelled history. We need other indirect thermal indicators informing us about the thermal conditions in the past. The most widely used one is the reflectance of light off the surface of woody particles, called vitrinite.

Vitrinite is the principal component of coal but is also present in trace amounts in other hydrocarbon source rocks. As vitrinite thermally matures, its internal structure rearranges, leading to an increase in its ability to reflect light. Pioneered by the coal industry, vitrinite reflectance (VRo) was eventually tied to time and temperature through lab heating experiments and field investigations. Initial VRo models relied on statistical correlations between VR and temperature-time exposure. By the 1980s and 1990s, models such as Sweeney & Burnham's VITRIMAT introduced kinetic reaction principles. These models treated vitrinite transformation as a series of temperature-dependent reactions, significantly improving predictions over simple empirical relationships. EASY%Ro, a simplified version of VITRIMAT, in particular, became widely adopted due to its ease of implementation and broad applicability.

The 2000s saw further refinements with models incorporating variable activation energies and detailed kinetic reaction schemes. These refinements were driven by growing computational speed, better calibration sample sets and the need to explain the mismatch of VRo models with some VRo data. More extensive calibration data proved an older idea that VRo evolution during burial is affected by the presence of liptinite organic matter. Vitrinite from woody coals increases its reflectance gradually with increasing temperature and time. Vitrinite from liptinite-rich samples (i.e. with high hydrogen index) display delayed reflectance at lower temperatures and faster reflectance increase at higher temperatures. This caused two phenomena observed in common VRo data: 1) the "dog leg" kink in the VRo trend at depth and 2) apparent "VRo suppression" in high-quality source rock samples (with high HI) relative to EASY%Ro model. This also means that basin models calibrated to the EASY%Ro model tend to overestimate the thermal history of a basin in order to fit the "suppressed" VRo calibration data.

An updated model, EASY%Ro-DL, solved this problem by calibrating its parameters to higher-HI samples and by adjusting the frequency factor of the reaction equations to yield more consistent results over a range of heating rates. Various uncertainties remain in VRo application for basin modelling, but I think that, at the very least, we now have a sufficiently accurate VRo model to interpret available VRo data. ■



Comparison of VRo models for a schematic basin model of 6 km of shale deposited over 50 million years.

Deciphering Earth's secrets

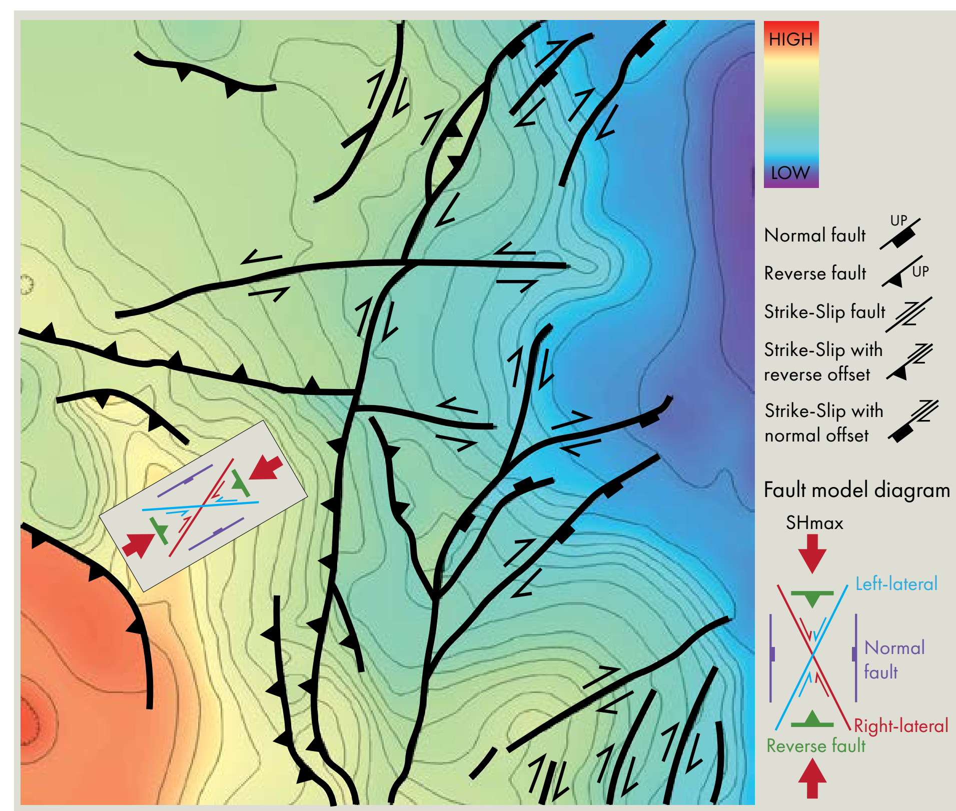
The vital role of fault symbols on geological maps

MOLLY TURKO, DEVON ENERGY

FAULTS ON geological maps are far more than just lines; they are a critical form of communication, conveying essential information about the Earth's subsurface structure and tectonic history. Central to this interpretive power are fault symbols, the shorthand of structural geology. These seemingly simple lines and annotations hold a wealth of information, and their accurate use is crucial for understanding our earth and making informed decisions about its resources and hazards.

Fault symbols provide a standardized visual language for geologists to communicate the characteristics and kinematics of faults, yet it is too common to find maps with faults portrayed as simple lines. Different symbols are used to distinguish between normal faults where the hanging wall moves down relative to the footwall, reverse faults where the hanging wall moves up, strike-slip faults where movement is primarily horizontal, and in some instances, structural inversion.

The figure shows a structure map where symbols are used to illustrate the slip sense along faults. By understanding the timing of fault movement, we can decipher the paleo - stresses and tectonic history. The fault model diagram shows expected orientations of three different fault types under a northeast - southwest directed maximum horizontal stress (SHmax). Aligning the diagram with the associated fault types on the map, helps us to decipher the paleo - stress field which has key implications to the tectonic history; a task that is only possible by reading fault symbols in the absence of other data. The absence of or inconsistencies in fault symbol conventions can lead to misinterpretations of geological structures, potentially impacting resource exploration, civil engineering projects, and hazard mitigation efforts.



But there is a disclaimer. Geoscientists may not always have the data to confidently determine the type of fault they are looking at and if this is the case, then some grace can be offered. Adding to the frustration, some mapping software applications either don't have an option for fault symbols, or they make the process of adding them very cumbersome. However, regardless of difficulty, geoscientists should always do their best to provide this crucial information to their maps. Fault symbols are the silent language of geological maps, conveying critical information about the dynamic forces that shape our planet. Their accurate and consistent use is essential for effective geological interpretation, resource exploration, hazard assessment, and a wide range of other applications. They are not merely decorative elements on a map; they are a fundamental tool for deciphering the Earth's secrets. ■

Carboniferous-Permian erosive contact, Kowala Quarry, Poland

A spectacular erosive contact between Permian continental conglomerates and Lower Carboniferous marine strata can be observed at the Kowala Quarry in the Świętokrzyskie Mountains, Poland, situated in the southeastern part of the Southern Permian Basin. The Lower Permian (Rotliegend) facies are considered one of the most significant oil and gas reservoirs in central and western Poland. In the marginal parts of the basin, coarse-grained deposits, including conglomerates, are prevalent, as depicted in the photograph. These conglomerates were deposited in dry alluvial fan settings, although some represent infills of dry river valleys (wadis) similar to those currently observed in the Arabian Peninsula. During the Early Permian, the climatic conditions in this part of Pangea were arid and hot, interrupted by short phases of humidification, which were responsible for the evolution of short-lived but powerful rivers. The presented erosive contact is evidence of such an event.

Such conditions facilitated the development of extensive intervals of conglomerates and sandstones with high porosity and good permeability. Consequently, climatostratigraphic studies can play a crucial role in identifying high-quality oil and gas reservoirs in these deposits.

Photography and text: Karol Jewuła, Bizon Geological Consulting

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.

On the HUNT for Somalian core

Decades before the internet connected us all, Graham Heard found a former well site and some cores in the north of Somalia through good old detective work

Graham Heard at the Daga Shabel-3 well site in northern Somalia, where he found that the cores had been abandoned straight after being cut.

PHOTOGRAPHY: GRAHAM HEARD PERSONAL ARCHIVE

"HAVING worked on the first-ever offshore seismic survey in South Yemen in 1976, and seen the results of the first offshore well drilled in Yemeni waters, south of Socotra Island, I thought there must be a failed rift succession on the southern side of the Gulf of Aden in Somalia" wrote geologist Graham Heard in a recent email to us. It resulted in a few intriguing visits to the country, including a search for old well data.

Graham's employer at the time, Quintana Petroleum, was supportive of his ideas and allowed him to travel to Mogadishu to discuss obtaining an exploration concession. It worked, and the company was soon awarded a 10 million-acre licence in the Guban Region in the north of the country.

The next step was to finance the acquisition of 2D seismic data, for which a partner was needed. Graham presented his play models to Ray Hunt of Hunt Oil, who liked the concept and the company farmed into the acreage to acquire 1,000 km of 2D seismic lines.

Besides the acquisition of seismic data, Graham was also aware that some wells had been drilled in the area in the past. Unable to find the locations initially, he later found a photo album at the Ministry of Mineral and Water Resource in Hargeisa that showed some leads. The album contained material of fieldwork done by hard rock geologist John Hunt for the British Protectorate of Somaliland in the 1940's and 50's, at the time when the wells were drilled. Graham thought it would be good to try and find John Hunt, then in his 70's and retired. Fortunately, he was still listed as a fellow of the Geological Society of London, which allowed him to get Hunt's address.

John Hunt, who was not related to Ray Hunt from Hunt Oil at all, told Graham of the person who assisted him with the fieldwork at the time and who lived in Hargeisa. He even remembered the house, and he suggested Graham find him on his next trip. He would know how to get to the well locations.

So, Graham travelled to Somalia again, where he found the house and the person John Hunt had described. They drove down the road that connects Hargeisa to Berbera and indeed found the dirt tracks to the well locations. At the location of the Daga Shabel-3 well, Graham also found something else. A pile of cores that were dumped right at the well site. He collected the cores, and with the help of the composite log, he was able to reconstruct how the various bits had to be put together. They even carried out geochemical and sedimentological analyses on the cores back in England.

However, despite all these efforts and data gathering, a new exploration well was never drilled on the Quintana-Hunt licence. Hunt struck oil on the opposite side of the rift in Yemen and ignored the Somalia licence for good. ■

Henk Kombrink