THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

VOL. 21

GEO ExPro

5 2024

CHLORITE - A HELPER OR A HURDLE?

Exploration opportunities

CÔTE D'IVOIRE
The new West African exploration hotspot

SOUTH ATLANTIC
A raging bonfire of memes

GEO ExPro

geoexpro.com

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

Editor in Chief
Henk Kombrink

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

Sales Manager
Pia Himberg
+47 996 43042
pia@salgsfabrikken.no

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

Creative Direction
Ariane Busch

Layout and Design
XRB Media Limited, London, UK

Print
United Press, Latvia

GxP PUBLISHING

COVER ILLUSTRATION: NANO CREATIVE / SCIENCE SOUCE

No rush

LAST MONTH, I visited the site where the Texas oil industry kicked off: Spindletop. Here, a bit more than an hour's drive east of Houston, the first gusher well was drilled in 1901 on top of a salt dome. Overnight, the nearby village of Beaumont transformed into a buzzing town full of fortune seekers. It also heralded the birth of major companies such as Texaco, whose director built a large office tower in Houston to host all the oil companies that were founded in those years. The interesting thing is that this so-called Petroleum Building is now a hotel I stayed during my visit to Houston – the Cambria Hotel on Texas Avenue.

Following the remarkable oil find at Spindletop, international oil companies also came in to secure contracts to export the crude. One of these was Shell, and in contrast to what is common practice these days, no subsurface due diligence was carried out before a 20-year contract was signed, writes Daniel Yergin in his book The Prize. Spindletop production started to decline after 18 months, and Shell had to find other suppliers as a result.

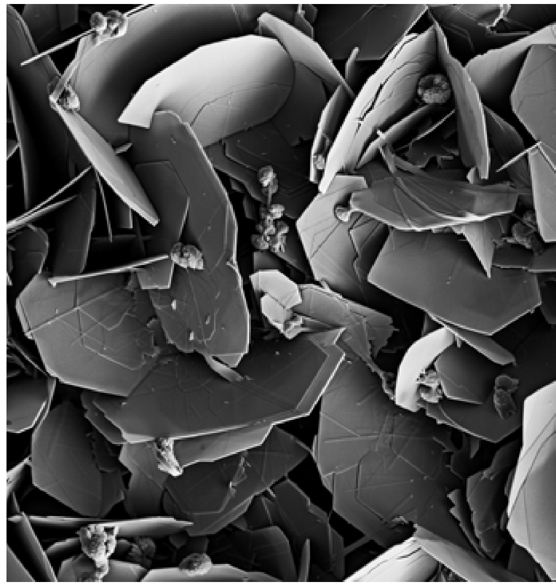
> "…in contrast to what is common practice these days, no subsurface due diligence was carried out before a 20-year export contract was signed"

Times have changed since, and Shell is more careful these days. The current Namibia deepwater bonanza is a good example of this. Although early reports of major finds suggested quick monetization, subsurface data has put a brake on moving towards a quick FID, as voiced by CEO Wael Sawan. In the cover story, we explore some of the factors that have emerged as the main contributors to this.

Henk Kombrink

BEHIND THE COVER

One of the factors behind the careful approach companies seem to take when it comes to developing deepwater discoveries in Namibia is the presence of chlorite in the reservoir. In contrast to many other cases where chlorite represents good news – chlorite coating of quartz grains is often reported as a way to arrest further diagenesis and, therefore, preservation of reservoir quality, the situation in Namibia seems different. In the cover story, we explore this further. The front cover shows an SEM microscopic image of chlorite minerals, which are a family of the phyllosilicates or clay minerals.



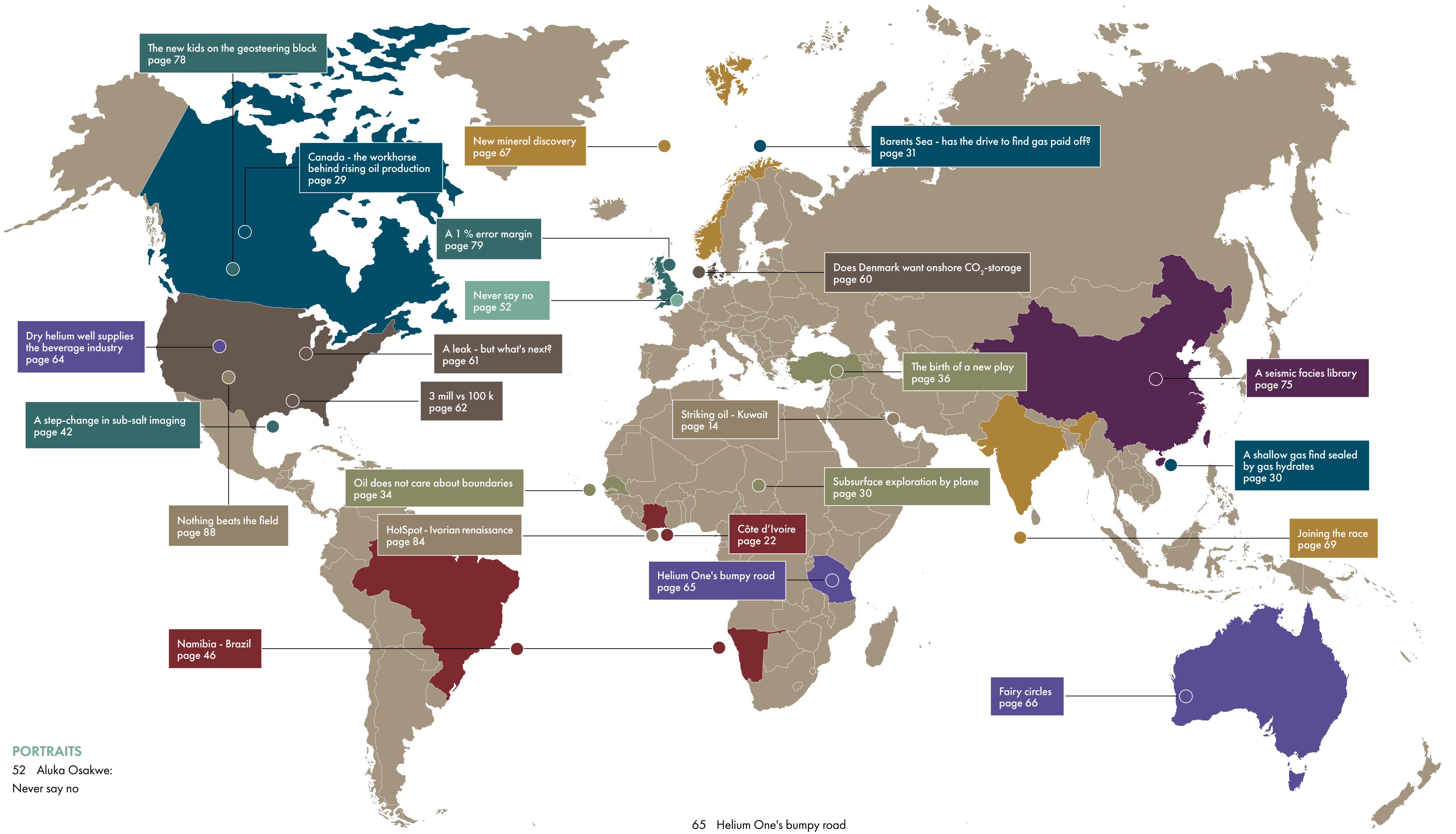
Comments: henk.kombrink@geoexpro.com
LinkedIn: geo-expro-magazine
Website: geoexpro.com

FIRSTS

"... we have forgotten what energy poverty means, with many of the last two generations not having experienced it in their lifetimes"

Rodney Garrard - Arch Insurance

CONTENT



The new kids on the geosteering block page 78
Canada - the workhorse behind rising oil production page 29
New mineral discovery page 67
Barents Sea - has the drive to find gas paid off? page 31
A 1 % error margin page 79
Does Denmark want onshore CO_2-storage page 60
Never say no page 52
Dry helium well supplies the beverage industry page 64
A leak - but what's next? page 61
The birth of a new play page 36
A seismic facies library page 75
3 mill vs 100 k page 62
A step-change in sub-salt imaging page 42
Striking oil - Kuwait page 14
A shallow gas find sealed by gas hydrates page 30
Oil does not care about boundaries page 34
Subsurface exploration by plane page 30
Nothing beats the field page 88
HotSpot - Ivorian renaissance page 84
Côte d'Ivoire page 22
Joining the race page 69
Helium One's bumpy road page 65
Namibia - Brazil page 46
Fairy circles page 66

AS TIGHT AS A DUCK'S ARSE

A wellsite geologist once sat a well in Saudi Arabia, a long time ago. It was a hot and long spell in the desert. When the drillers reached the prognosed reservoir, it was decided to cut the core. As usual, there was a lot of anticipation when the core arrived at the surface, but an experienced member of the team was convinced: "This rock is as tight as a duck's arse", he said. OK, some gas bubbles could be seen popping up, but nothing to get too excited about, was his firm opinion. Years later, the wellsite geologist decided to take a look at a map of fields in Saudi Arabia, and to his surprise, he saw that the area where he sat the well is now part of a major gas field. Not as tight as a duck's arse!

EXPLORATION IN TIMES OF SOCIAL MEDIA

When ExxonMobil had completed the discovery well on Liza, opening up the Golden Lane in Guyana and Suriname, representatives from the company went to visit the authorities in Guyana to inform them of what was found. To illustrate the message further, a well log was printed on paper, clearly demonstrating the discovery of oil in a few discrete sand packages. Someone in the group it was shown to was so excited that he or she took a picture of the print and posted it on Facebook. It took about a day before Exxon realized what happened, but in that timeframe some of the other companies operating in Guyana had already taken hold of the photo, creating a CPI log from what they could gather from the photo. Exploration in the times of social media....

"DO YOU REALLY HAVE A DISCOVERY?"

Scott MacMillian from Invictus Energy gave a presentation on his company's discovery in Zimbabwe at the Discovery Thinking session during the latest IMAGE conference in Houston. He argued that the Mukuyu field is a basin-opening multi-TCF gas-condensate find. At the end of the talk, one of the chairs asked Scott: "Do you really have a gas discovery here?" The background for this question is probably the lack of data to once and for all demonstrate that the gas find is real. Scott replied to the question by saying: "Well, we had moveable gas." Is this enough to claim a multi-TCF discovery? Time will tell...

WHEN WILL KOMODO BE DRILLED

According to someone with knowledge on the matter, the environmental permit for drilling of the ultra-deep water Komodo well in Colombia has been pulled. It is now a waiting game when the permit shall be re-issued. The Colombian government is known for its critical stance towards new oil and gas exploration, which may be a reason for this to have happened.

ILLUSTRATION: PCH.VECTOR

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

Let's not play Russian roulette with our energy system

The risk of an industry exodus increases as long as no new large-scale baseload or storage option arises for a continent that is running out of hydrocarbons

I AM NOT a pessimist, and I don't like using terms like "energy crisis", but if we do not start to take our energy system seriously, many industries will leave much of Europe in the next 10 - 15 years, at a huge socio-economic cost. The problem stems from the fact that we have forgotten what energy poverty means, with many of the last two generations not having experienced it in their lifetimes.

The theme of my columns is that modern societies are completely dependent on reliable energy production. And this dependency was and has been accommodated by hydrocarbons from the start of the 19th century onwards. However, the oil crises in the 1970s caused a big rethink. Therefore, from the mid - 70s to the mid - 80s Europe, embarked on the world's most extensive nuclear power build-out, which led to affordable fossil-free energy and resulted in accelerated industrial growth.

A reliable energy system depends on baseload energy sources. These currently consist of the three fossil sources coal, gas, and oil as well as hydro and nuclear power. Geothermal energy is another potential baseload energy source but has not yet been built at scale. Baseload energy sources help stabilize the electricity grid. Electricity must be consumed at the time of production; no current technology enables storage at grid scale.

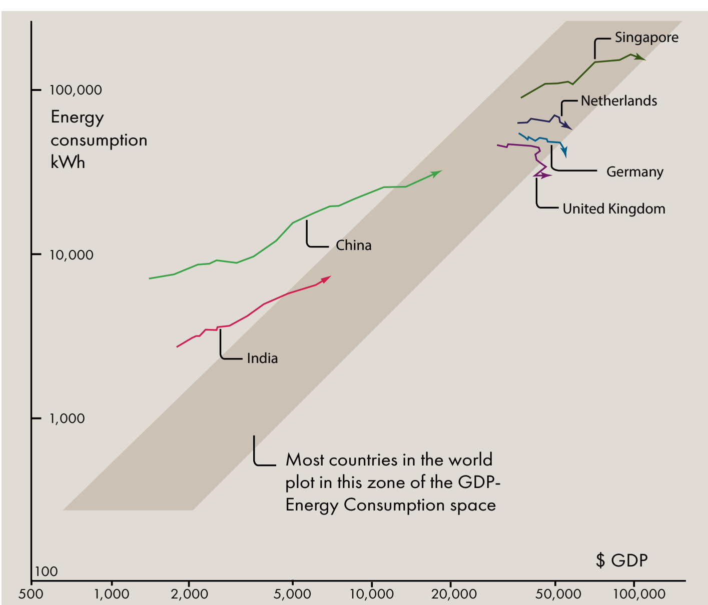
Currently, there is a lot of discussion on how to generate electricity but hardly anything on how the electricity should get from the producer to the user. That part of the energy transition discussion has largely been missed.

The very reason for today's high electricity prices in Europe was the choice of gas as a baseload energy, without sufficient internal supply. This causes high prices because the energy market is priced where the demand is. If Germany, with eighty million people and a large industrial base has too little baseload electricity production and is prepared to import electricity, this impacts other European consumers.

Today's situation was a choice of gas over nuclear. Partly through the closure of fully functioning nuclear reactors and a reluctance for new investments with high upfront costs. For example, prior to Fukushima, Germany received 30 % of its electricity from nuclear energy. If Germany had invested in nuclear energy to phase out coal and avoid gas dependence, that construction would be online today. Instead, Germany has one of the dirtiest electricity productions in Europe.

In the end, what matters most for a sustainable energy system going forward is the ability to have baseload options at the core to provide reliable, affordable power for households and industry, which is then complemented by wind and solar at the periphery. ■

Rodney Garrard – Arch Insurance



Even though some of the richest countries in the world have in recent years bucked the trend of increasing energy consumption as GDP rises, many countries are not at the stage yet - see China and India. Higher income means more energy consumption, and therefore means a need of a much higher baseload that is available 24 / 7 to run these advanced economies.

SOURCE: OURWORLDINDATA.COM

Bid rounds – is it time to consider another model?

Despite the mixed results of many global bid rounds in recent years, some National Oil Companies and government bodies continue to push the same concept

SOURCE: SYLVERARTS VIA ISTOCK

Against a backdrop of civil unrest, political uncertainty and unattractive fiscal regimes, it is no surprise that there is limited interest from international investors to embark on an exploration adventure in Africa.

Those that are, are mostly focused on redevelopment of old discoveries and fields. These assets often remain locked in local companies, with close connections to the government.

But how to attract the companies that are able to explore new frontiers? Only a few key players, likely less than five as operator, are able to take on deepwater exploration in Africa.

As a result, there is only limited competition for open acreage and multiple comparable opportunities exist in several countries at the same time.

So, why would a country exert pressure on this limited pool of potential bidders by introducing hard deadlines for putting in a bid? Other well-known drawbacks of recent bid rounds include the poor-quality data rooms, delays, cancellations and long negotiation processes, coupled with rigid and often non-negotiable terms that do not match the asset value.

PATIENT NEGOTIATION

Instead, there are well-founded arguments in both government and industry that an open-door policy, in combination with a well-prepared data room and the opportunity to negotiate directly with authorities, is a preferred model. In this quiet operator landscape, it is much more preferable to arrive at the award of one or two blocks with patient negotiation than pretending multinationals are fighting for the same acreage.

Let's take a look at some of the recent and current licensing rounds across Africa.

LOCAL COMPANIES

One of the more successful rounds has been the Angolan round which closed in January 2024, receiving over 50 bids. However, these were principally submitted by small and mostly local companies for the 12 onshore blocks on offer.

The Nigerian Upstream Petroleum Regulatory Commission opened a bid round offering 12 onshore and deepwater blocks in April 2024 and this was subsequently increased to 29 with the addition of 17 more deepwater tracts. There is however limited interest in Nigeria except from local companies reflecting global perceived political risk and other surface risks.

Zanzibar, a semi-autonomous region of Tanzania, has made eight offshore blocks available in the Pemba-Zanzibar sub-basin. This is frontier acreage for which demand has been extremely limited except for players already in-country.

CONTRACT SANCTITY PERCEPTIONS

In August, the Egyptian Natural Gas Holding Company launched its 2024 bid round for 10 offshore and two onshore blocks in the Mediterranean and the Nile Delta with a bid deadline on 25 February 2025. Egypt is in a serious gas supply crisis, which has affected perception of the contract sanctity for offshore investment.

OPEN DOORS

In conclusion, the recent and current bid rounds in Africa seem to confirm there is very limited uptake by international players able to open up new frontiers. Maybe it is time to revise the rigid bid round concept and permanently open the doors for those keen to explore. ■

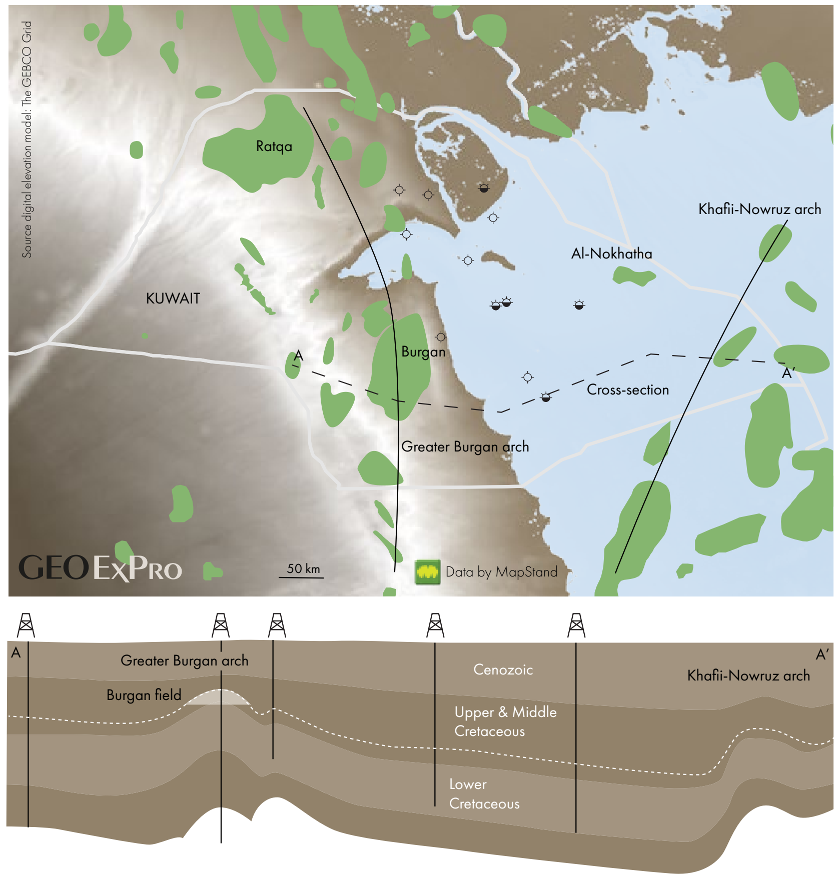
Ian Cross - Moyes & Co

A major and not-on-trend discovery in Kuwait

With a clear need to maintain its ability as a swing producer, Kuwait has now started to seriously explore its offshore acreage

KUWAIT IS not the first country one would associate with places ramping up efforts to discover more oil. At the end of the day, the small Gulf country is home to one of the biggest onshore oil fields in the world – the giant Burgan field. However, Burgan and its smaller equivalents across the desert have started a more mature phase of production and the times of easy oil from these fields seem to be over.

In that light, it is no surprise to see news items along the lines of "Kuwait Oil To Wrap Initial Offshore Drilling Campaign in 3 Years", as reported by the Journal of Petroleum Technology in October last year. The article describes that Kuwait received its first offshore rig in 2022, which is also a clear sign of the shift in focus towards the slightly more complicated and economically less favourable places in the country – its shallow waters in the Gulf. In some ways, one might be surprised it is only happening now.



The map shows the two major structural trends most fields in Kuwait are lining up with. The newly reported Al-Nokhatha discovery is clearly outside these trends, which suggests that another trapping mechanism would be required to explain the presence of hydrocarbons. That is why this is an interesting discovery.

SOURCE CROSS-SECTION: A. AZIZ AL-FARES (1998) GEOARABIA

NEW DISCOVERIES AND THEIR IMPLICATIONS

With the arrival of the offshore rig, KOC embarked on a six-well offshore exploration campaign, according to JPT. It may very well be that the announcement of a major gas and oil discovery earlier this summer is part of this campaign. According to KOC, 2.1 billion barrels of light oil and 5.1 trillion cubic feet of gas, equal to around 3.2 billion barrels of oil equivalent, were found in the Al-Nokhatha prospect. This volume represents about three years of the countries oil output, said KPC's CEO, Sheikh Nawaf Saud Nasir Al-Sabah.

The location of the new discovery is interesting, too. Even though one could argue that oil is present in any closure in this part of the world, it is clearly out of trend with respect to the Burgan-Ratqa cluster on the Greater Burgan arch trend and the group of fields lining up with the Khafii-Nowruz arch. This then begs the question, is the new discovery a stratigraphically trapped accumulation? If the cross-section is anything to go by, a simple anticlinal closure seems unlikely for Al-Nokhatha.

FUTURE PRODUCTION CAPACITY

The country really needs additional production capacity, as a report from S&P Global concluded in 2022. At the time, there may only have been about 30,000 b/d of upside left, given a daily output that swings around 2.8 million barrels per day. That equals around 1 % of spare capacity. S&P also wrote that it is KOC's plan to raise production to 4.75 million b/d in 2024, but this was seen as highly ambitious at the time. ■

Henk Kombrink

COVER STORY

"What is the reason why the discoveries offshore Africa are not advancing to FID yet? The answer may be in subsurface complexities..."

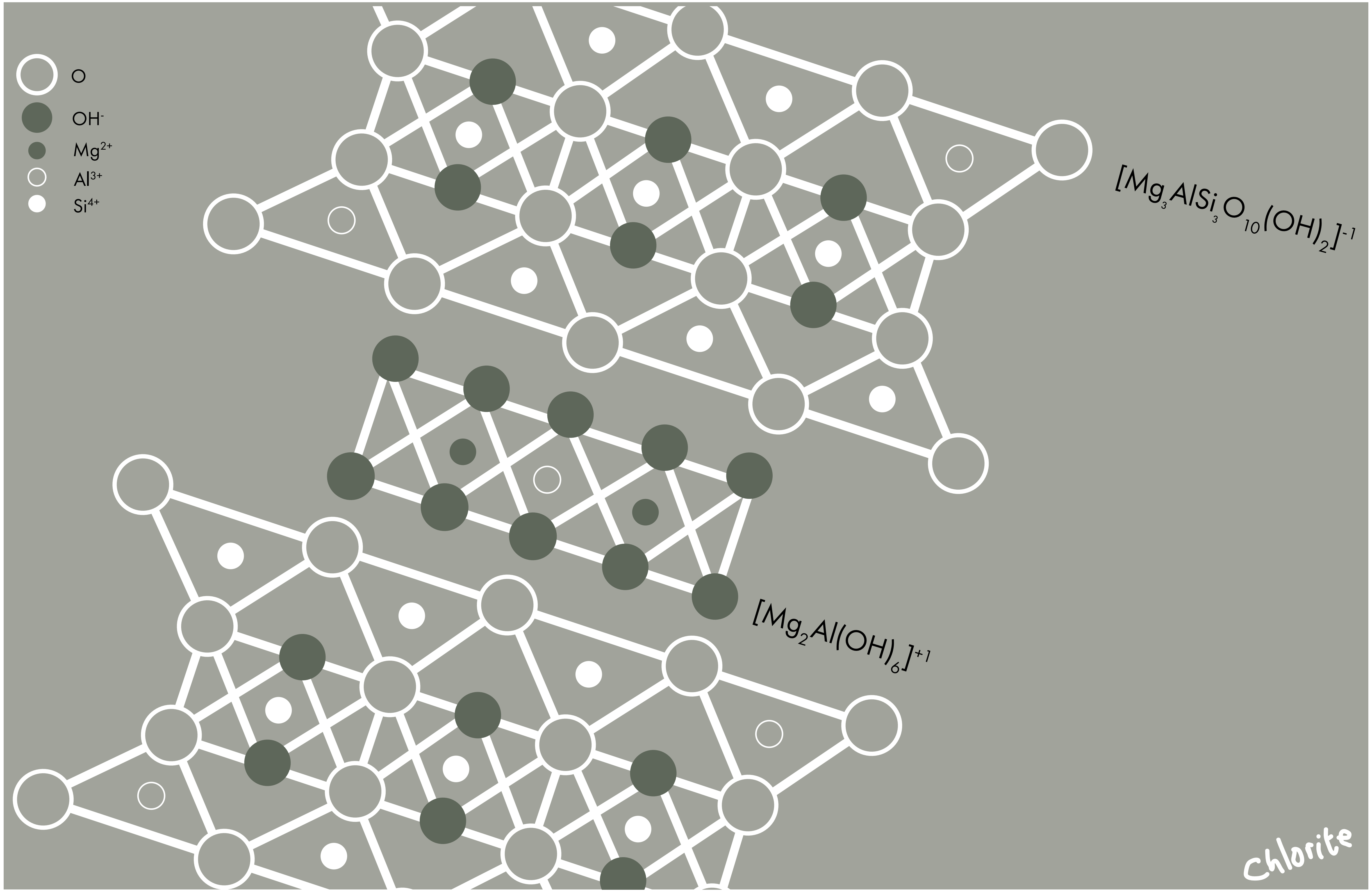
Wael Sawan - CEO at Shell

COVER STORY

CHLORITE - HELPER OR HURDLE?

And more about today's exploration hotspot in the Orange Basin

HENK KOMBRINK



"PEOPLE DON'T dream anymore", said Marcio Mello when he started his talk about Namibia's deep-water petroleum plays at the IMAGE conference in Houston in August, referring to the dreaming that is required to come up with new exploration ideas.

I had never heard from Marcio Mello before, but he made sure that his talk was delivered in such a way that it became an event to remember. It was a show, something I had not experienced before at a conference. Most people present were standing behind a lectern; some went a bit further and walked across the stage, but Marcio walked towards the audience, and he looked people straight in the eye. He was on a mission.

In 2010, credited as the geological mastermind behind Brazil's pre-salt success, he and his company, HRT, acquired three licenses offshore Namibia, primarily to explore for similar pre-salt resources. "It is all very simple", he continued his talk. Yet, he resigned from HRT in 2013 before it even spudded the first of three dry or uncommercial wells.

Were the three unsuccessful HRT wells drilled in Namibian waters the reason for stopping dreaming? Of course not, as we will see a little further down this article.

And now we are where we are today, with eight sizeable discoveries made in the Orange Basin. There is no need to spell them all out because everybody is aware of these major finds.

But, there is a but. As Graeme Bagley from Westwood Global Energy Group put it in an interview with us the other day: "If the Namibian discoveries were on the same timeline as the Liza discovery in the Stabroek licence offshore Guyana, the Venus and Graff discoveries would have received FID already". Tako Koning wrote in his long but very readable overview of the state of play in deep-water Namibia for the Africa Oil and Gas Report; "both Shell and TotalEnergies are distinguished ▸

COVER STORY

"Reduced permeability due to impurities can lead to lower recovery rates. Given that approximately 3.6 billion barrels of oil equivalent have been discovered since 2022, any hindrance due to permeability could significantly impact the overall production efficiency and economic viability of these fields"

Masum Akter, Rystad Energy

"THEY WERE CLOSE"

"They were close", I overheard someone saying during a conversation about Namibia's Orange Basin exploration history. We are not talking about the discovery of the Kudu gas field, which took place in 1974 already, but the subsequent phase of exploration in the Orange Basin that was ignited when Brazilian company HRT applied and was awarded a block in 2010.

Led and founded by geologist Marcio Mello, who had played an important role in discovering Brazilian's pre-salt play, HRT drilled a total of three wells in Namibian waters, Wingat-1 and Murombe-1 in the Walvis Basin and Moosehead-1 in the Orange Basin. With Moosehead being almost on trend with Mopane, it is justified to say that the Orange Basin could equally have been opened up some years earlier.

The main objective of the Moosehead-1 well was to test the resource potential of Barremian-aged carbonate reservoirs, which were expected to be equivalent to the 'pre-salt' reservoirs of Brazil and Angola. The Moosehead-1 well encountered about 100 meters of carbonates at the primary target, but the reservoir was less developed than expected at this location, and it was therefore classified as a dry hole.

The prize was ultimately found even further out into the deep, in sediments overlying the oceanic crust, as TotalEnergies and Shell were going to demonstrate in 2022. Twelve years after HRT sniffed around.

But as far as Venus is concerned, the original idea to go for a deep-water play rather than a Brazilian pre-salt analogue did not stem from TotalEnergies. It was the late Dave Roads from Impact Oil and Gas, who interpreted the Venus prospect and came up with the idea to start looking at the sands that could have been deposited by Cretaceous river and delta systems, shifting away from the focus on Tertiary targets such as the Niger Delta. At the end of the day, Jubilee had shown the potential of Cretaceous systems, and why could that not be replicated somewhere else?

"The biggest risk at the time of mapping Venus was the charge model", as Phil Birch from Impact said during a talk about the Venus discovery in August 2022 in London. Many thought it was impossible to cook a source rock overlying oceanic crust. That model has been clearly revised.

by their lack of information on the quantities of oil and gas to date."

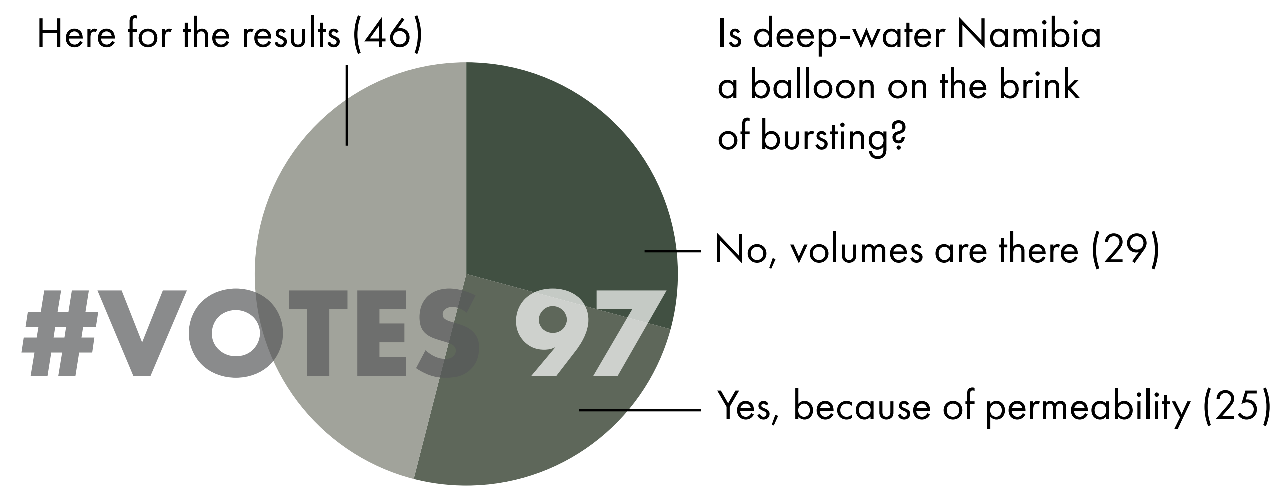
What is going on? That's what this article is about. Not because we claim to have the answers, but to explore what is supposed to be the issue a little more. We will approach it in three different ways. First, we held a poll amongst our readers and put the question to them: What do you think the future for Namibia holds? Then, we look in a bit more detail at one of the issues that has been rumoured to be a key problem – chlorite cementation. We talked to Professor Richard Worden from Liverpool University to learn about chlorite. Finally, we briefly touch on another aspect that may prevent a quick FID, which is the supposedly high gas content of the discoveries.

All of this is illustrated by a new diagram by Marcos Asensio from Argentina, who shows the main elements of the Namibian petroleum system as they have been unearthed over the past few years. Neil Hodgson from Searcher, who also likes to dream as he writes his epic foldout articles, greatly helped put all the elements shown in the diagram in place.

THE POLL

"ExxonMobil withdraws from race to buy a stake in Namibia oil block from Galp", wrote Namibia Mining and Energy recently. "It may not be long before one of the majors pull out of Namibia", someone with knowledge on the matter told me the other day. It paints a picture, combined with what we wrote in the introduction, of a situation that is not as booming as it was two years ago.

What is the reason why the discoveries offshore Africa are not advancing to FID yet? The answer may be in subsurface complexities, as Wael Sawan, Shell's CEO, recently hinted. Combined with an earlier insight that permeabilities may be problematic due to a diagenetic mineral – probably chlorite, we put up a poll to ask the readership about their point of view.



The question was: "Is deep-water Namibia a balloon on the brink of bursting?" People were able to vote for "No, volumes are there", "Yes, because of permeability", and "Here for the results."

The outcome of the poll, for which 97 people cast their vote, was interesting. It ended in an almost 50/50 split when it comes to people believing in the future of deep-water Namibia and those who are still holding their breath. However, the poll also attracted lots of people keen to see what their peers voted, as the number of "viewers" turned out to be almost 50 % of those interacting with the poll. Probably the highest percentage of the polls we have organised so far. Amongst the "No" voters, it is interesting to note that there were people from Shell and TotalEnergies, so people who may have some insight on the matter. We did approach some voters for comments, but it is always a challenge to get people to elaborate.

A POINTLESS POLL

Some people were not impressed with the way the poll was worded. Mike Hubbard argued that there are many more factors at play that could prevent the Namibian discoveries from becoming a success story, such as low reservoir pressure or high viscosity oil, which led him to conclude the poll was pointless. Of course, he is right in saying that there are other factors at play, but the spirit of the poll was intended to test the thinking of people around the future of the basin, added by the fact that we had heard a mineral is the factor that is causing reservoir issues.

WHERE IS THE EXTENDED WELL TEST?

An interesting conversation we had after the poll was around testing the discoveries. One petroleum geologist mentioned that extended well testing has not yet been performed because of the costs being prohibitive. Alan Foum, however, commented on the lack of an extended well test, as it is seen as a way to have a better understanding of well behaviour. Nick Madden replied to that, saying that the reservoirs should be world-class, so why would you bother? Maybe we should bother, in the light of Sawan's comments.

CHLORITE

There have been hints in the public domain that chlorite cementation has had a detrimental effect on the reservoir properties of the deep-water finds in Namibian waters. Is that a surprise?

For many working in oil and gas, the presence of chlorite may initially sound as good news, given the well-reported phenomenon of chlorite coatings forming around quartz minerals and the resulting quartz growth inhibition.

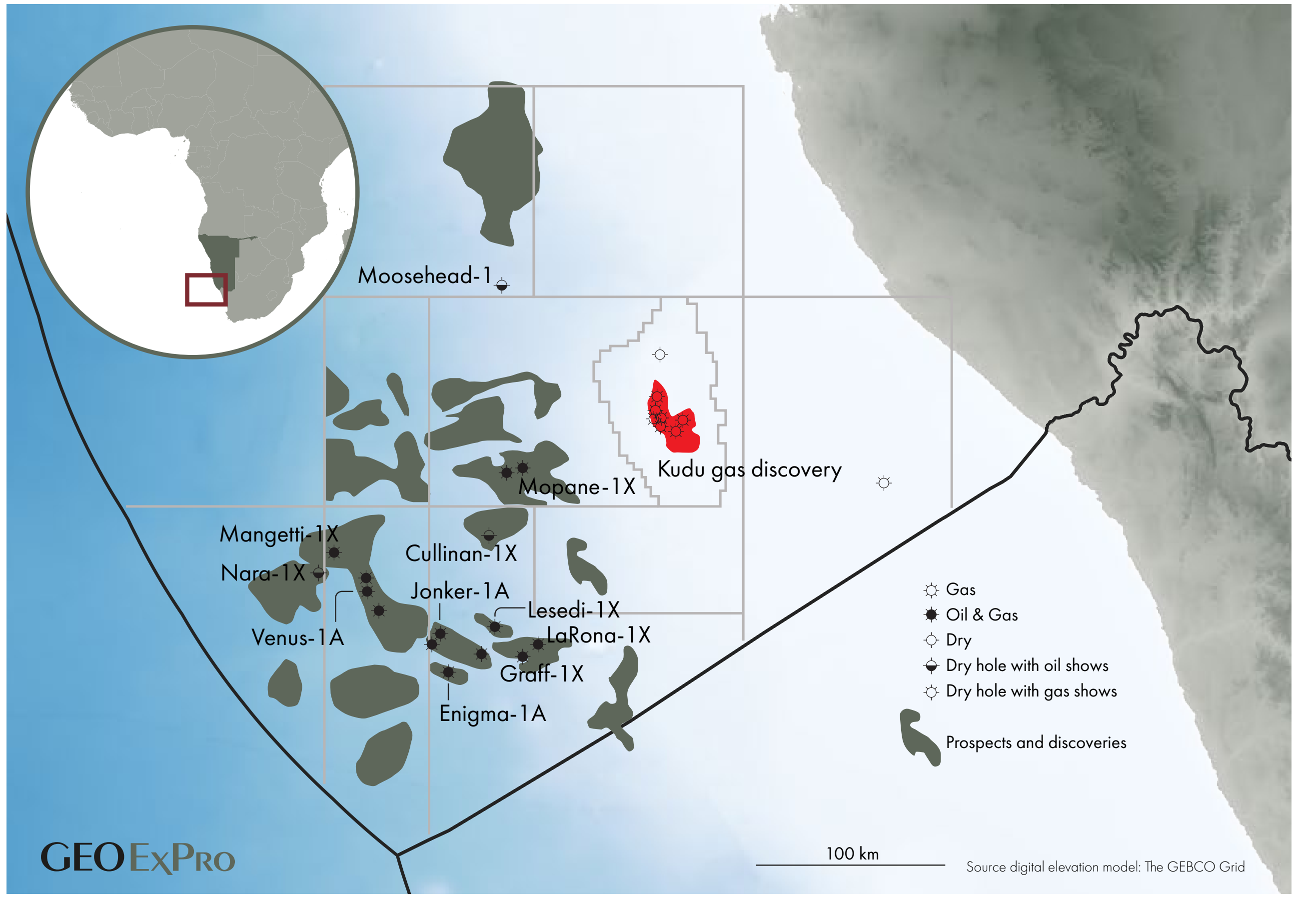
But can chlorite be detrimental to reservoirs as well? "Very much so", said Professor Richard Worden from Liverpool University in England, who has studied chlorite formation in sedimentary systems for many years.

"We are looking at a sliding scale", Richard explains. "No chlorite in a deeply buried reservoir usually means terrible porosity / permeability because of quartz cementation. At the other extreme, too much chlorite means the same thing, but now the pore-filling agent is chlorite itself. We need just the right amount, between 3 and 13 %, to be in the sweet spot, or what I would call the Goldilocks zone."

That's not to say that a particular sandstone is in one of the there above-mentioned categories. "It is quite common to see all three cases because chlorite or its precursor minerals are never evenly distributed across the sandstone to start with", Richard adds.

What are the most common sandstones to chlorite in? "If someone comes to me saying that they have a chlorite-cemented sandstone, my first guess would be that this person has an estuarine or shallow marine sandstone. A deep-marine sandstone, such as the reservoirs in ►

COVER STORY



Wells, discoveries and prospects in the Namibian Orange Basin.

SOURCE: SINTANA ENERGY COMPANY PRESENTATION

Namibia, would not be my first call", says Richard. "Saying that, there are other marine fan sandstone examples containing chlorite, for instance the Forties reservoir in the North Sea. There are bits of reports and hints in the literature that suggest this is the case. The big difference between Forties sandstones and the Namibian equivalents is that the former are not really benefitting from the presence of chlorite yet because they haven't been buried deeply enough, and quartz overgrowth has not really been an issue."

How does chlorite form? Chlorite, an iron / magnesium phyllosilicate or clay mineral, is mostly made up of iron, aluminum and silicon, with a little bit of magnesium, oxygen and hydrogen. "Magnesium is very mobile in the subsurface, so we don't worry about that one", says Richard. "But aluminum, iron and silicon are not, meaning that they tend to stay where they were deposited initially. And of those three, aluminum (feldspars) and silicon (quartz) are generally not the limiting factor; that is the role iron tends to play."

> "The Orange River was a dirty river. But further north, reservoir quality should improve"
>
> *Marcio Mello, BPS*

"In the Namibia case", concludes Richard, "where we are probably dealing with well-sorted deep-water sandstones, the "best" way to introduce the elements needed for the formation of chlorite are rock fragments, and in this case probably volcanic rock fragments. It may not have been chlorite when it was deposited; it could have hornblende or pyroxene at the time of deposition, but the building blocks were there, and all you need is some cooking."

BUBBLE POINT

Besides chlorite being a potential issue in the Namibian deep-water discoveries, there are also reports that a high gas content is a problem. Why is that? The risk is that the reservoirs are close to the bubble point, which means that as soon as production starts and pressure drops, gas will come out of the solution and make its way into the wellbore, inhibiting the production of oil.

Dealing with this right from the start is a big difference, for instance, compared to Guyana, where oil could be produced first before a gas solution is now being worked on. The same holds for Baleine in Côte d'Ivoire, where the GOR is supposedly low, enabling the operator to first focus on oil production. This may be one of the reasons, in addition to the chlorite problem, that has thus far prevented companies from giving the go-ahead because the engineering solution is more costly, especially given that this is deep water.

In fact, the presence of chlorite could be an intricate part of the bubble point problem because it may have resulted in a reservoir that is characterised by sections that are completely clogged up, in combination with intervals that still have good reservoir potential. These high-permeability streaks will be the "highways" along which gas will enter the wellbore once pressure starts dropping.

Why would the oil be gas-rich? Looking at the cross-section, it is not so hard to imagine why this is the case – the Venus reservoir is thought to be directly sitting on top of the source rock. For Graff and equivalent finds, the gas problem may be a bit less serious, as these are a little further away from the source rock.

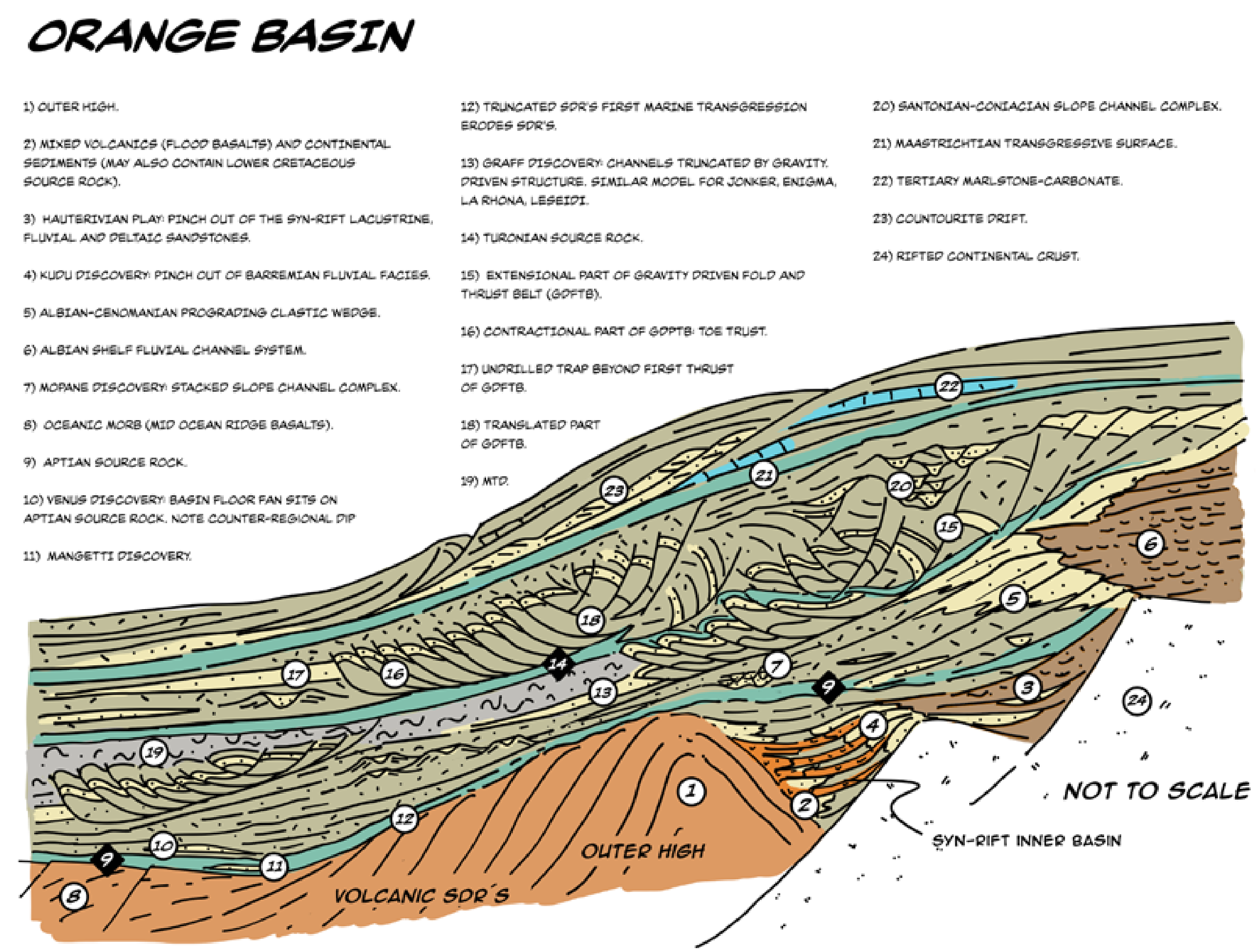
> "As Namibia seeks to enhance its oil recovery through techniques such as water flooding, impurities can migrate and accumulate in pore throats during these processes. This accumulation can lead to further reductions in permeability, complicating recovery efforts and potentially hindering production efficiency"
>
> *Masum Akter, Rystad Energy*

THE WAY FORWARD

Namibia and the E&P companies trying to firm up the juicy deep-water resource base seem to have woken up from a dream. In the present day, it is more likely that engineers and geoscientists are hard at work coming up with practical solutions to make their discoveries work.

For the explorationists, the next frontier already looms. Marcio Mello dreamt when he brought his ideas across from Brazil to Namibia in the early 2010s. Now it is time to continue dreaming and bring the experiences from Namibia back to Brazil, as Neil Hodgson, Karyna Rodriguez, and Lauren Found does on page 46 of this magazine. ■

ILLUSTRATION: MARCOS ASENSIO

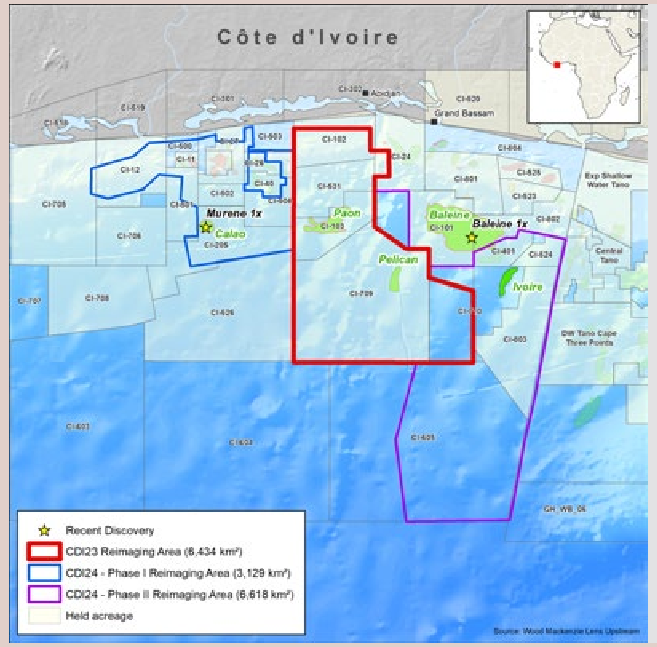


Schematic cross-section throughout the Orange Basin showing the main elements of the petroleum play, as well as the relative stratigraphic position of the recent discoveries.

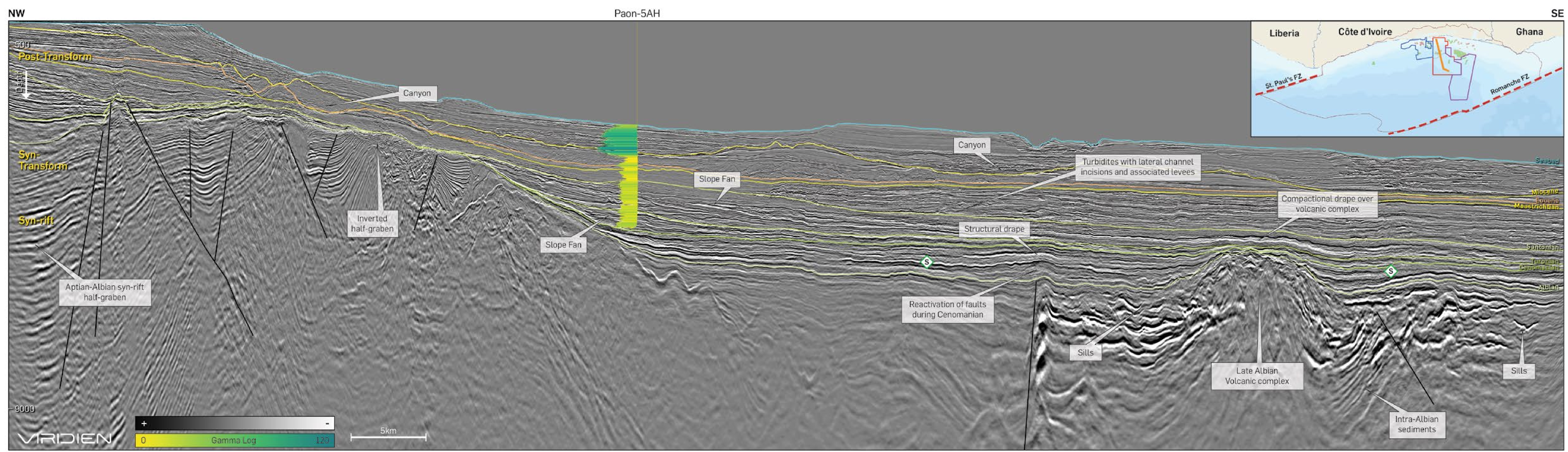
Côte d'Ivoire - The new West African exploration hotspot

The play-opening giant discoveries of Baleine and Murene-1 (Calao) offshore Tano Basin have reinvigorated exploration in the equatorial margin of Africa. The basin is geologically complex and has proven its unparalleled hydrocarbon potential. To further explore this basin, there is a need for high-end imaging to enhance the regional understanding and de-risk the full play potential.

In 2024, Viridien merged and re-imaged a seamless and contiguous volume of 6,434 km^2 of 3D PSDM multi-client seismic data (CDI-23) in the offshore Tano Basin, Côte d'Ivoire. This will soon be added to another 9,747 km^2 of data from the CDI-24 Phase I and Phase II multi-client re-imaging programs. Here we take a quick look at the fast-track imaging of the CDI-23 survey extending over the shelf to the outer slope domain, enhancing our understanding of the basin.



Location and coverage map of Viridien's 16,000 km^2 multi-client PSDM re-imaging program along the Côte d'Ivoire margin showing current held acreage, fields and recent discoveries.



Tano Basin, offshore Côte d'Ivoire: Fast-track results from the 2024 multi-client re-imaging CDI-23 program show a NW - SE 115 km profile giving remarkable insight into the basin architecture and key stratigraphy of a highly prospective basin. The inset map shows the key structural elements of the basin along with the line location.

A new regional framework for exploration offshore Côte d'Ivoire

State-of-the-art re-imaging provides fresh insights into the prospectivity of the Tano Basin

MADHURIMA BHATTACHARYA, MISHA ISAKOV, PAOLO GABRIELLI, CARL WATKINS AND DAN CARRUTHERS, VIRIDIEN

THE TANO BASIN along the Côte d'Ivoire and Ghana shelf has been well explored with various phases of seismic data acquisition and drilling activity since the 1970s. Oil production began in the early 2000s with the Espoir field, followed by further field developments in Côte d'Ivoire. The discovery of the Jubilee field in Ghana in 2007 kick-started an intense exploration campaign across the Equatorial margin of Africa. Exploration beyond 2,000 m water depths offshore Côte d'Ivoire began in 2011, with discoveries such as Paon and Pelican proving the extension of the Late Cretaceous plays into the distal parts of the Tano Basin. The play-opening 2021 Baleine discovery (a carbonate shelf edge play) – the largest discovery made to date along the Ivorian margin – transformed the country's production outlook with estimated volumes of 2.5 BBO of oil and 3.3 Tcf of associated gas. This was followed by the second largest discovery, Calao (Murene-1X), in 2024. These discoveries have attracted renewed exploration interest in the offshore of Côte d'Ivoire, with recent exploration acreage awarded to several IOCs, making it a current exploration hotspot.

Viridien, in association with Direction Générale des Hydrocarbures (DGH) and PETROCI Holding, is re-imaging a significant portion (up to 16,000 km^2) of the Ivorian margin to provide the industry with a solid foundation to build a regional understanding and de-risk the play potential of the Tano Basin. The program overlaps with the recent Calao discovery (Murene-1X) and is adjacent to the world-class Baleine field.

CUTTING-EDGE TECHNOLOGY BRINGS IMAGING UPLIFT

This article presents Viridien's fast-track results from the CDI-23 multi-client 3D PSDM re-imaging project (6,434 km^2) which consists of four separate surveys acquired over multiple blocks between 2000 and 2014 from the shelf to the outer slope domain. These four surveys were merged to create a contiguous seismic volume that had differing cable depths and streamer profiles, along with significant variations in legacy processing workflows. The new re-imaging was undertaken from field tapes using proprietary state-of-the-art technologies such as ghost wavefield elimination (GWE), advanced demultiple, and time-lag full waveform inversion (TL-FWI) velocity model building.

The fast-track 3D volume shows a significant imaging uplift compared to the legacy data (Figure 1). This is due to greater bandwidth and a more detailed velocity model, enabling better imaging of the basin architecture, enhanced resolution and delineation of faults, as seen in the foldout section, and improved imaging of Cretaceous reservoir intervals.

TANO BASIN AT A GLANCE

The CDI-23 re-imaging program is located on the transform margin of the Tano Basin between the Romanche Fracture Zone in the west and the St Paul's Fracture Zone to the east. The basin formed due to dextral-oblique divergence between Africa and South America. During the Aptian - early Albian, pull-apart rifting formed rotated fault blocks and individual grabens and half-grabens filled with various continental and marginal marine sediments as observed in wells such as Baobab-1. From the mid-Albian, the basin entered a transform phase with formation of crustal, oblique-slip faults and en-echelon folds (Scarselli et al., 2018). Crustal weakening along these large faults controlled the emplacement of the mid-to-late Albian volcanic centres and sub-volcanic sill complexes. Further strike-slip movement in the Cenomanian resulted in the inversion of existing structures. This had an important control on the deposition and trapping of the lower Late Cretaceous turbidite reservoirs but also created migration pathways for hydrocarbons. Carbonate deposition also occurred over crests of fault blocks as seen in the world-class Baleine Field. The upper Late Cretaceous-to-present, post-transform phase sediments were deposited in a deep marine setting with ponded and channelised turbidite systems, basin floor fans, contourites or off-axis hemipelagites, all of which are imaged exceptionally well in the fast-track seismic data (Figure 2).

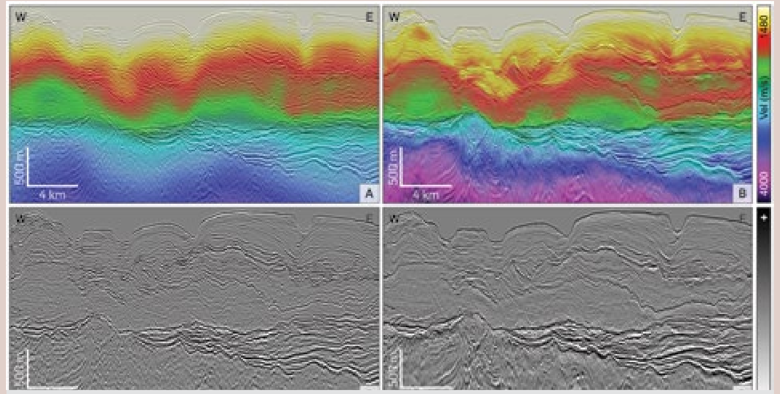


Figure 1: Legacy stack section with (A) and without (C) velocity overlay and newly re-imaged data (B, D). The newly reimaged data shows improved imaging of the sub-Albian section and higher resolution thanks to de-ghosting, de-multiple and time-lag full-waveform inversion.

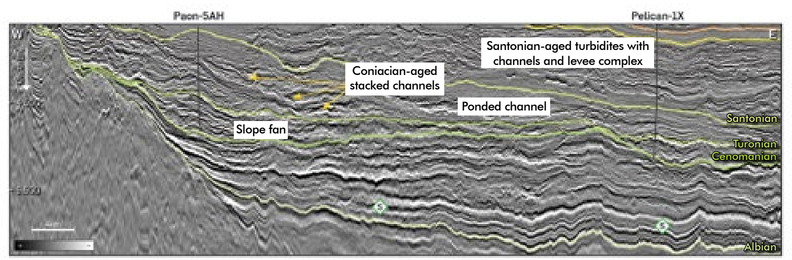


Figure 2: W-E line through the Paon field and Pelican-1X oil discovery showing key reservoir facies within the Late Cretaceous.

Exploration of the Tano Basin has proven a highly effective working petroleum system (Paon, Pelican and Baleine wells). Regional primary source rocks include the Albian, Cenomanian and Turonian shales with present-day optimal maturity across the basin.

NEW GEOLOGICAL INSIGHTS

This regional fast-track PSDM dataset is a valuable tool for seismic interpretation and attribute analysis of the highly complex and variable Cretaceous section. The features of the depositional architecture can be identified and mapped, including the presence of leveed channel complexes, slope and basin floor fans and a series of sediment waves. Root mean square (RMS) amplitude extraction along stratigraphic slices through the Late Cretaceous interval are particularly revealing as seen in Figure 3. Figure 3a shows an Early Turonian stratal slice with a high sinuosity channel system that fully traverses the survey and crosses an area with well-defined sediment waves that may represent contourites, whilst Figure 3b shows a Late Turonian stratal slice with three distinct sediment transport pathways with channels widening into fans to the southwest. Additionally, multiple sediment transport pathways and deepwater sediment dispersal systems are identified that extend through the entire AOI and into the deeper basin.

The variability in depositional elements and their organisation is merely a snapshot of the complex stratigraphic evolution during the Late Cretaceous, with offset stacking and routing around structural highs meaning the reservoir is widely distributed across the area.

WHAT'S NEXT?

The CDI-23 re-imaging project will be completed by Q4 2024 and soon be added to an additional 9,747 km^2 of data from the CDI-24 Phase I and Phase II multi-client programs. The final re-imaging results of the CDI-23 survey will provide interpreters with a state-of-the-art seismic volume to explore even the subtle stratigraphic and / or combination trap prospects. This will allow for further work entailing AVO analysis to delineate anomalies and amplitude signatures that could be consistent with direct hydrocarbon indicators, followed by rock physics work to calibrate these anomalies to further de-risk the basin.

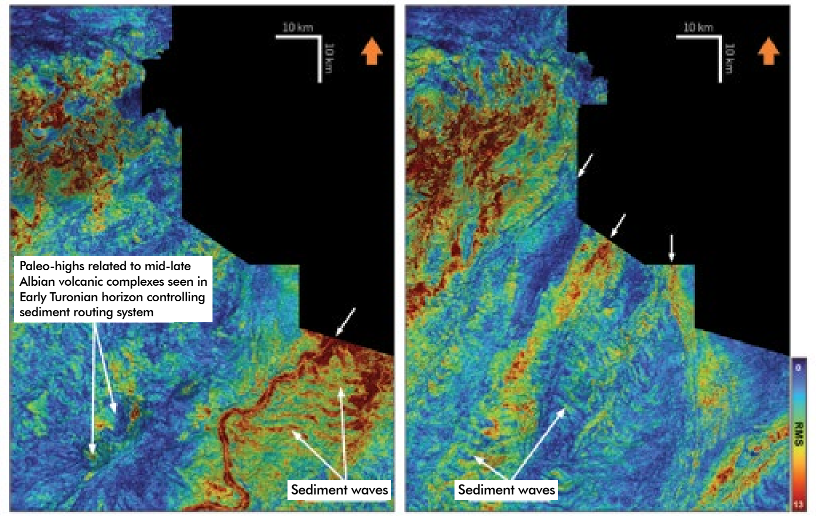


Figure 3a (left) and 3b (right): RMS amplitude extraction for two stratigraphic slices through Turonian channels and turbidites.

OIL & GAS

"Combined with the commercial success rate for the wells drilled so far being better than 50 %, this year is looking promising for hydrocarbon exploration across the African continent"

Jamie Collard - Westwood

Canada – and the workhorse behind its continued rise in oil production

For offshore explorers, recent drilling results from Canada have not been too upbeat, but in the meantime, oil production continues to grow year on year

With Equinor breaking the news last month that its Sitka prospect only contained non-commercial amounts of oil, another disappointing drilling result hit the exploration community in Canada. Sitka was supposed to have been completed in 2022, but Equinor was forced to end drilling operations before it made it to the target, citing operational challenges at the time. The Sitka prospect is located close to the Equinor-operated Bay du Nord project, the development of which was postponed last year due to cost concerns but has since moved forward with the choice of contractor announcements for the project.

Sitka is not the only disappointing offshore drilling news as of late. Last year, bp drilled the much-anticipated Ephesus well in the Orphan Basin further to the northwest. A genuine wildcat considering its location, the well targeted a Paleocene low-relief closure that was hoped to be a major gas field. But Ephesus did not live up to expectations.

And as we go to press, the news is about the break whether or not the Persephone well drilled by ExxonMobil, also in a frontier part of the Orphan Basin, has hit the 3 billion barrel jackpot.

In the light of these developments, one would almost conclude that Canada's ability to sustain production is at risk, but when looking at production overall, there is no sign of that. In contrast, and despite a government that has demonstrated not to be overly pro-oil, the facts leave little room for discussion. Since 2010, Canada's crude oil production has been on the rise from less than 3 million barrels per day in 2010 to more 5 million b/d this year. This is an incredible rise and is mostly thanks to the country's oil workhorse.

THE OIL SANDS

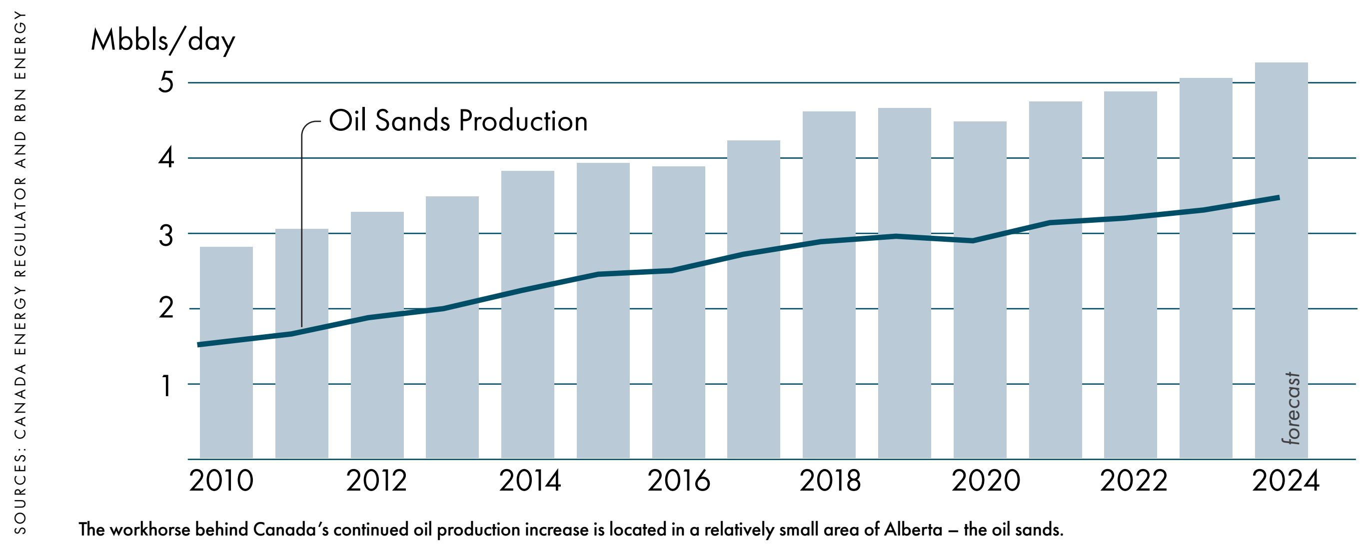
"Most of the production increase comes from oil sands, mines and in-situ development with thermal methods", explained Calin Dragoie, who works for Chinook Consulting Services, when I asked him the question about what is behind this production increase. "And this has happened despite there being a serious egress issue, with producers competing for pipeline space and resorting to rail and barge transport."

But that issue has now been resolved thanks to a project to twin the already existing Trans Mountain pipeline (TMX) that now allows the export from land-locked Alberta of almost three times as much crude as was possible before – 890,000 b/d.

Taking the investment decision to build this second pipeline is based on an important observation: Oil sand projects are large and have a low decline rate. They also have long-term offtake contracts, with lots of smaller producers on top of that who play the market and drill or pause development based on small fluctuations in oil price and differential.

In other words, whilst the explorers keep a close eye on offshore drilling results from ExxonMobil in the Orphan Basin, it is important not to lose sight of what is happening onshore. ■

Henk Kombrink



The workhorse behind Canada's continued oil production increase is located in a relatively small area of Alberta – the oil sands.

A shallow gas find sealed by gas hydrates

Even though it is not a very recent discovery, shallow gas in deep-water is still a very interesting play the Chinese now seem to pursuit

When I was a PhD student, 20 years ago, a seasoned geologist told me that the energy transition was not so much a transition, but a shift towards tapping into all possible sources of energy in the light of oil and gas becoming more difficult to produce. The Chinese took to heart what my manager said at the time.

They are clearly at it. Whilst building new coal power plants all the time, the country also champions the solar, wind and hydro sectors. Nuclear energy has also seen a spectacular rise, especially between 2010 and 2020, with 30 more power plants under construction.

That is not enough, though. If any nation is pushing the frontiers of oil and gas exploration, it is China. Abroad, they are present in an increasing number of places, with Suriname being one of the latest countries to sign a Production Sharing Agreement. In the meantime, they keep on drilling away in many other areas, amongst others in the Congo, where I heard it is not uncommon to see the completion of 200 wells within a year.

And then on home turf, the quest for new hydrocarbon resources continues, with ultra-deep exploration in the Tarim Basin, development of basement reservoirs in the Bohai Sea, and now the reported find of ultra-shallow gas in ultra-deep waters. So, what is this about?

The discovery was announced by CNOOC in June and says that the Lingshui 36-1 gas field – situated in the South China Sea – is in approximately 1,500 m of water but only 210 m below the seabed. The reservoir is of Quaternary age, and it seems to have a gas-in-place volume in excess of 100 billion cubic meters.

In contrast to the West, where one won't find any literature on a new discovery in the public domain, this is different in China. The Journal of Marine and Petroleum Geology already published a paper last year on what is supposed to be the area where the discovery was made, clearly suggesting that the timing of the press release does not line up with the moment the well reached TD.

One of the main conclusions of the paper is that the gas could be trapped at such a shallow depth below the seafloor because of the high water depth, the resulting pressure exerted by the water column, and the presence of gas hydrates. That is a very interesting observation, as it deviates from the commonly held view that most shallow gas in marine environments is sub-economic because of a lack of effective trapping. Have the Chinese hereby unlocked a new type of play? As they report in the paper, this model of shallow gas in deep waters may be a play worth looking at in other parts of the world too. ■

Henk Kombrink

The interesting thing about this map is that we published it in 2022 already, be it in a slightly different format. The bottom line is, the Lingshui 36-1 field was already known by then. But that does not make it less interesting.

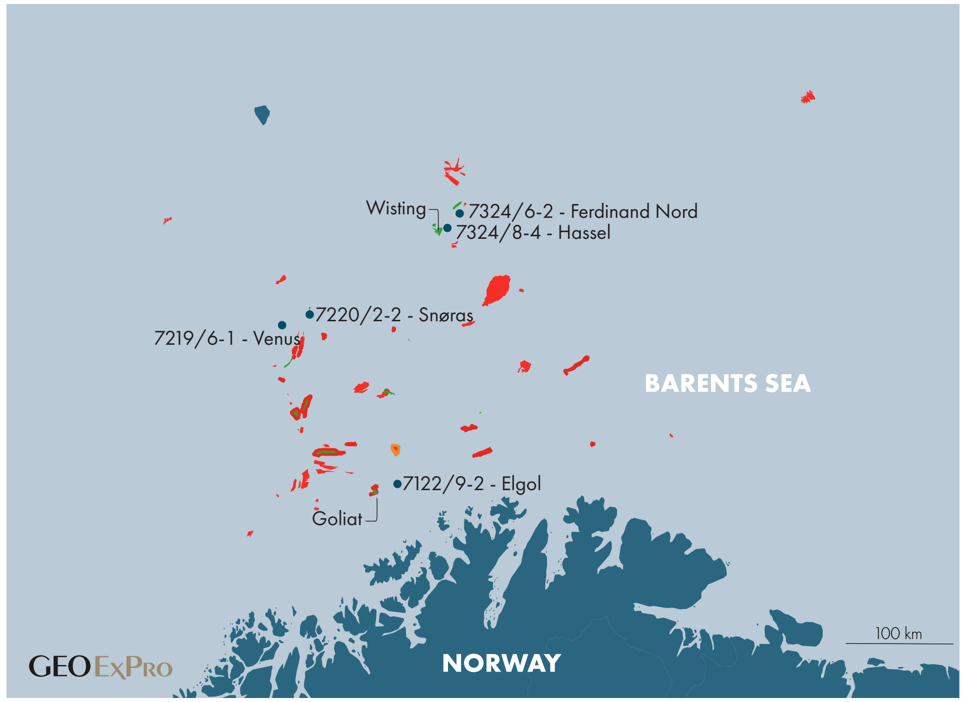
Has Norway's drive to find more gas in the Barents Sea paid off yet?

Looking at the activity so far, only one well can be seen as a play-opener, with one more to go this year

Fuelled by the gas crisis that unfolded in Europe following the Russia's invasion of Ukraine, the Norwegians voiced hopes that the Barents Sea was the place where additional gas resources were waiting to be discovered. When successful, this could be a reason to build additional pipeline infrastructure, which would be needed to export the newly discovered volumes quickly. The gas currently produced from the Barents Sea is all going through an LNG terminal, and this terminal will be at capacity for the next few years.

But has this drive to renew exploration in the Barents Sea paid off yet?

"I think the expectations of finding more gas have not been met to date", said Alyson Harding from Westwood Global Energy Group in a recent webinar.



Location map of Barents Sea drilling projects in 2024.

LIMITED UPTAKE

So far this year, four wells have been completed in the Barents Sea. It must be said that not all four of these were drilled to target new gas resources. In fact, only one of those four can be properly attributed to being a relatively prominent frontier gas exploration well. In that sense, the push to discover more methane has had quite a limited uptake thus far.

Two of those wells, 7324/8-4 (Hassel) and 7324/6-2 (Ferdinand Nord) were drilled close to the Wisting oil discovery. The third well, 7220/2-2, was targeting the Snøras prospect and is close to the Johan Castberg development.

The fourth well is 7219/6-1 (Venus) by Vår Energi, and this one drew attention because of its frontier nature, prospective size and the chances of encountering gas. However, rather than finding gas in a high-quality Paleocene Torsk Formation reservoir, the well only encountered traces of gas in a poorly developed and tight section.

WHAT REMAINS

Next month will probably see the 7122/9-2 Elgol well spudded: This is also a relatively frontier well, targeting Permian Røye Formation carbonates in a pinch-out trap. It has pre-drill resources of 265 MMboe according to operator Vår Energi, with an expected gas phase and associated condensate. This well will be batch-drilled along with other wells in the Goliat field area.

Although no plans have been announced to date to drill wells in the Barents Sea in 2025, it is hoped that the recently awarded APA 2023 will result in more exploration drilling in the next few years. There was a renewed interest in the area, with eight licences awarded to Equinor, Aker BP, Vår Energi, and Petoro. Six of these are considered frontier, with the others in sparsely drilled areas, many with the potential to discover gas. ■

Henk Kombrink

Africa on course for busiest year since 2020

If all plans materialise, about twenty high-impact wells are to be completed in Africa this year, according to Westwood Global Energy

"COMBINED WITH the commercial success rate for the wells drilled so far being better than 50 %, this year is looking promising for hydrocarbon exploration across the African continent", said Jamie Collard from Westwood.

"At the same time", he added, "we should be mindful that in 2014, more than sixty high-impact wells were drilled in Africa. But, since an incredible low in 2020, when only four high-impact wells were drilled, it can't be denied that Africa is on its way up."

FROM GAS TO OIL

Another factor that will please most explorers is that since 2018, it's oil that was predominantly discovered rather than gas. The years 2015 - 2017 were exceptionally rich in gas discoveries, with more than 6 billion barrels of oil equivalent discovered mostly as gas, primarily driven by successes in Mauritania, Senegal and Egypt. But the tide has turned in favour of oil since, with Namibia taking the biggest share in this.

"Unless there is a well-developed local market for gas, or a readily available export route, gas is still seen as a difficult product to get to market", said Graeme Bagley, who also works for Westwood. "The Eastern Mediterranean is a hotspot for gas exploration, with Egypt contributing significantly to success in the region", he says, "which is no surprise given domestic demand and geographical position relatively close to the network of European pipelines."

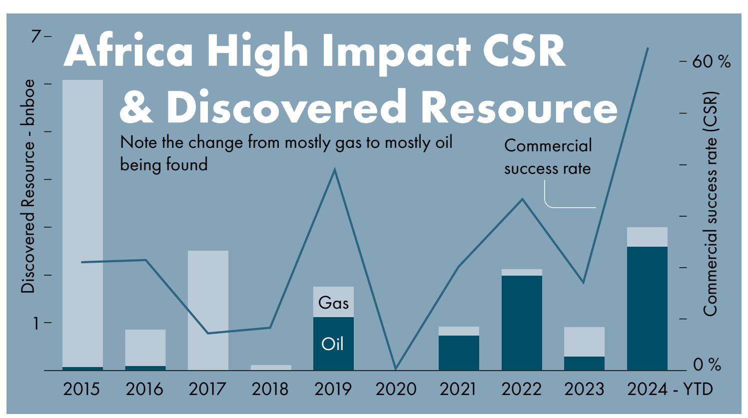
Of the 32 African basins where high-impact drilling took place over the past 10 years, only 10 delivered commercial success and only in five basins more than 1 billion barrels of oil equivalent was found: The MSGBC, the Orange, Nile Delta, Tano and Congo.

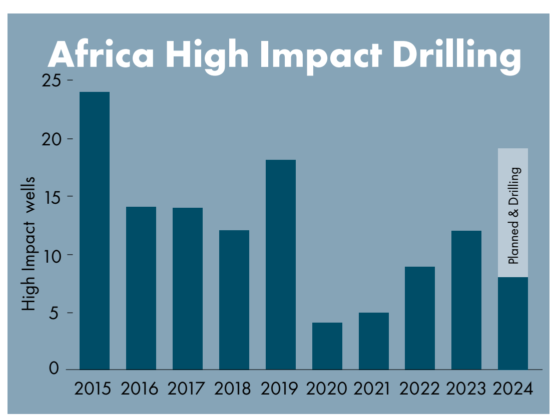
IF NAMIBIA WAS GUYANA…

"What is subsequently happening in these hotspots is not the same", said Jamie. "In the Nile delta, commercialization of discovered volumes is happening fast, because of the presence of infrastructure and a local market. In contrast, despite the gas discoveries in the MSGBC, most majors have since left the basin because of disappointing exploration results, the absence of a local market and the investment required to build (floating) LNG terminals." And the Orange Basin? "If the Namibian discoveries were on the same timeline as the Liza discovery in the Stabroek licence offshore Guyana, the Venus and Graff discoveries would have received FID already", added Graeme. If anything, it shows the more complex nature of the Namibian finds, which was recently confirmed by Shell's CEO Wael Sawan when he said that the major needed more time to further address subsurface complexities before being able to take FID.

"Despite these uncertainties, the Orange Basin will remain active in 2024, with at least three more wells expected to spud in Namibia before the end of the year", said Jamie. The timing for exploration drilling is less clear offshore South Africa, and is likely to commence from 2025. Elsewhere in South Africa, the recent Brulpadda and Luiperd gas discoveries were left in an uncertain future with TotalEnergies recently exiting Block 11b/12b. "Once more, it shows that making a discovery does not always lead to commercial success." ■

Henk Kombrink





SOURCE: WESTWOOD GLOBAL ENERGY

FEATURES

"Many colleagues at the time agreed that petroleum geology was more art than science"

Jan De Jager

SANGOMAR FEATURES

Oil does not care about boundaries

The southern margin of the Sangomar field perfectly lines up with the offshore boundary between Senegal and The Gambia. How credible is that?

In the early decades of oil exploration and production, from the 1860s to the early 1900s, the concept of an oil field having clear boundaries was not given much thought. Drilling just radiated away from where the discovery was made to a point where water was the only thing that was found.

Production was, therefore, very chaotic and fast; it was a matter of who pumped hardest. There was no consideration at all of extending licence boundaries vertically down to where the field was, implying how much one could produce. If you didn't produce it yourself, your neighbour would, so you'd better get on with it. This strategy led to a mad rush once a field was discovered, seriously supporting the boom and bust cycles of the oil industry.

EARLY OIL EXPLORATION AND PRODUCTION

The first "reservoir engineer" who recognized the need to properly map a field outline with the idea to unitize the volumes of oil allocated to each licence owner was Henry Doherty. He argued that it would enable producers to pump at much more modest rates, which would in turn increase recovery factors and thereby guarantee a much longer economic life of a field.

His peers ridiculed him for a long time. This is more so because he suggested that the state should have ultimate control over this. In the USA, this was very badly received, especially by the smaller explorers, because they just wanted their opportunity to get rich.

But he did ultimately get his way, and today, the first thing geoscientists do when exploring or drilling for oil is to map the outline of a prospect or discovery to calculate volumes and perform an economic analysis.

This was a long introduction to the main topic of this article, Sangomar, but it fits the narrative of what follows.

SANGOMAR DISCOVERY AND ITS IMPLICATIONS

Sangomar was discovered in 2014 in Senegalese waters through well SNE-1, drilled by Cairn Energy (40 %) and partners ConocoPhillips (35 %), FAR (15 %) and Petrosen (10 %). The oil – and gas – are hosted in Lower Cretaceous Albian sandstones in a closure on the Lower Cretaceous shelf edge. Subsequent appraisal wells confirmed the presence of oil and gas and contingent recoverable resources which are now estimated to be around 560 MMboe (2C). The field celebrated its first oil in June this year, and the operator is now Woodside (82 %), partnered by Petrosen.

Being close to the median line with neighbouring The Gambia, it is no surprise that following the discovery of Sangomar, people in The Gambia also started to be excited about their oil potential.

FAR'S EXPLORATION AND DRY WELLS

FAR, the Australian company that already had a 15 % stake in Sangomar, saw the potential in The Gambia too, and acquired an 80 % stake in blocks A2 and A5 in 2017. There is little doubt what FAR was after, as in a predrill presentation, Ms. Norman from FAR commented: "You can see clearly that the Sangomar oil fields extend south into The Gambia. In fact, the location of the (planned) Bambo-1 well is 500 meters from the border to the south, drilling into the extension of the Sangomar field that we call the Soloo prospect."

In fact, the company even seemed to be of the opinion that the Sangomar and Samo structures might share the same contact, potentially increasing the size of the field significantly. It is probably this concept that determined the order in which the two wells that FAR and Petronas subsequently planned in The Gambia were drilled. First, the Samo-1 well testing the potentially biggest price, and subsequently, the Bambo-1 well either to confirm the connection or to test a more modest extension into The Gambia in case the Samo-1 would turn out dry.

However, disappointingly, both wells came in "dry", with only some shows reported.

The Samo-1 well did find the Upper and Lower Albian reservoir, but deeper than predicted and it also confirmed seal breach as the main factor as to why only some shows were encountered. The same seal breach explanation was subsequently presented to explain a failure at Bambo-1. Even worse, in this case, the reservoir quality turned out to be very poor, in contrast to Samo-1, where it exceeded expectations.

LACK OF TRANSPARENCY AND SPECULATION ON FAR'S DECISIONS

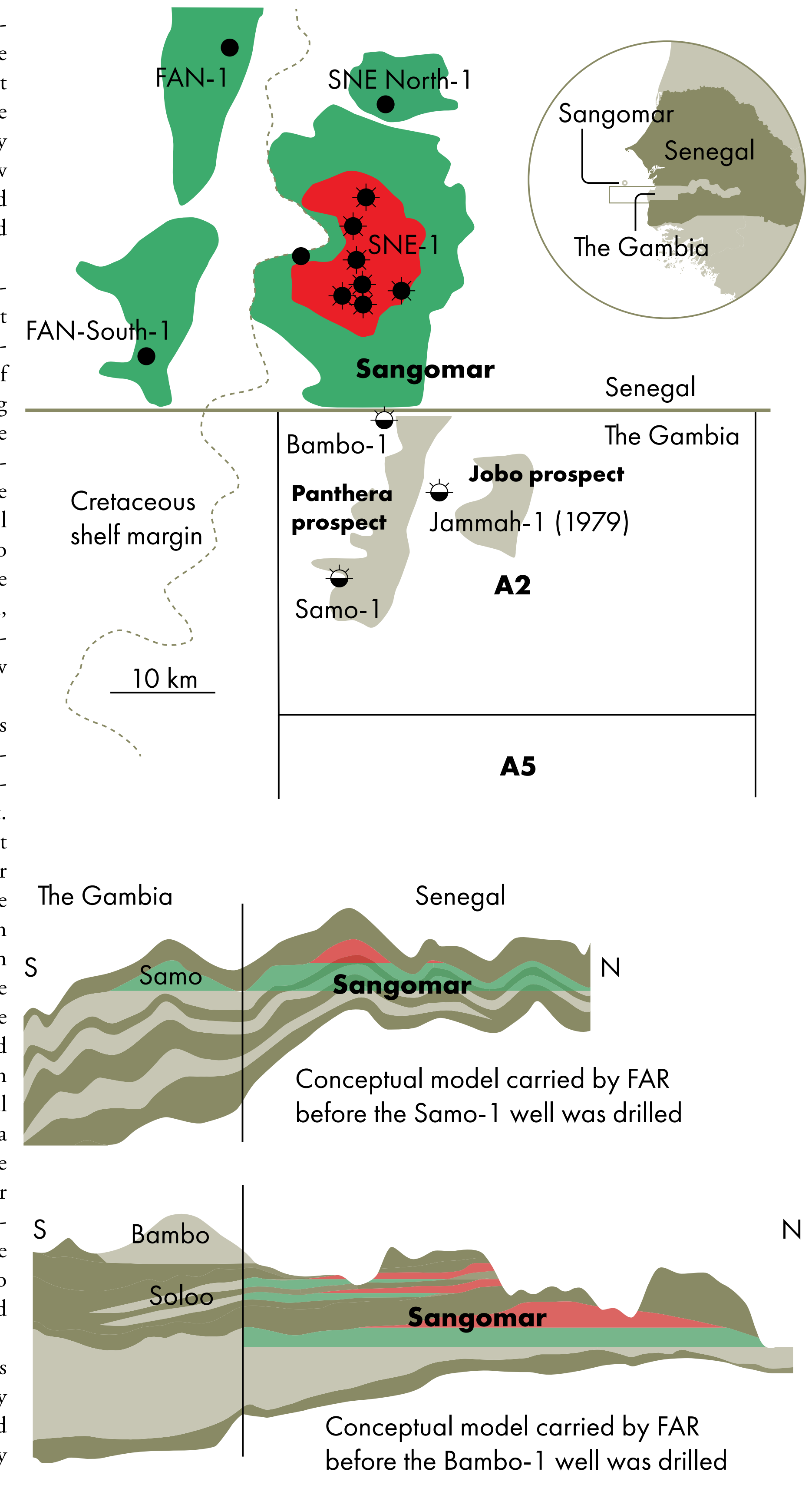
What stands out is the lack of data from the press releases. No well logs are presented, no porosity nor permeabilities given, no pressure points are being mentioned, and the wells were wrapped up very soon after drilling was completed. Seismic data are missing in company updates too; it is only cartoon-like drawings that are being presented. This renders it very challenging for outsiders to see how FAR arrived at this conclusion and whether the right data were obtained to support these claims.

But let us assume that the information shared is correct and that Bambo-1 especially found a poor reservoir with a breached seal. First of all, it would then still be surprising to keep the southern boundary of the field exactly lined up with the median line. Secondly, why would one conclude only on the basis of one well that Sangomar does not extend into The Gambia at all? The depth of the top reservoir has not been presented, and therefore, no map can be produced showing the extent of the now "discounted" area.

There may be more at stake, as Ousman F. M'Bai argues in a reconstruction of the Sangomar exploration history he published in August. In this long read, he points out that FAR sold its 15 % stake in Sangomar in 2020. He also points out that the company has done very little to firm up any of the identified potential in The Gambia in recent years, despite claims that there remains a lot to be found. Combined with the likelihood that none of the current partners in the field were keen on the potential of lengthy negotiations to arrive at a unitization deal, would it be possible that FAR got a good deal for their Senegalese stake in Sangomar in return for keeping a low profile in The Gambia? Ousman has attempted to seek answers from FAR, but has had no response so FAR.

This brings us back to where this story started – the need to properly unitize discoveries. But we can add an element to what Henry Doherty argued for at the time. Making absolutely sure that each country gets its fair share. ■

Henk Kombrink



Map showing the Sangomar field and the FAN discoveries in Senegalese waters, and the wells drilled in The Gambia. The Panthera and Jobo prospects were defined by FAR after drilling the Samo-1 and Bambo-1 exploration wells. The two cross-sections show the subsurface models presented by FAR in the context of drilling the Samo-1 well and the Bambo-1 well.

SOURCE: FAR.COM.AU

The birth of a new play

Where platform carbonates were the main candidate for exploration and production in southeast Türkiye for a long time, a renewed look at subsurface data highlighted a related oil play in its seal unit

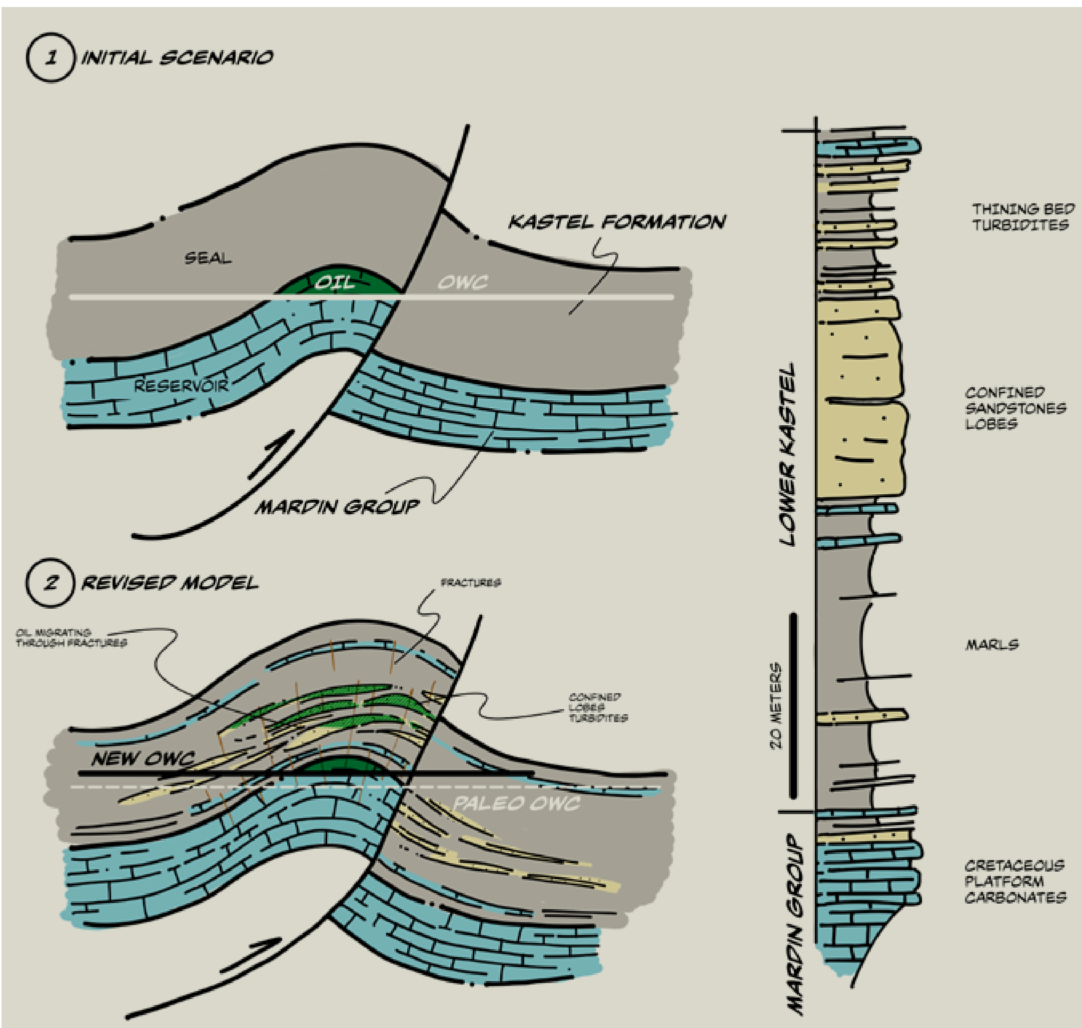
THIS IS A story of how subsurface data was used in the way it should be – to incrementally gain a better understanding of how a petroleum system works. And whilst doing so, a much more subtle picture of a play emerged – from a binary situation of having just a reservoir and a seal to a situation where the latter is also recognized as being able to host oil.

This can either be considered a complicating factor, with oil being "lost" in thin sands within the overburden, or it can be seen as an opportunity. Geologists from the Turkish Petroleum Corporation (Türkiye Petrolleri Anonim Ortaklığı, TPAO) did the latter, successfully, and are now producing oil from what was previously considered a unit that had to be drilled through as quickly as possible. It took 70 years of initially bypassing this interval with hundreds of wells.

IDENTIFYING THE ISSUE

But how did this all happen?

It started with the observation that development wells drilled into the platform carbonate reservoir of the Cretaceous Mardin Group sometimes had much earlier water breakthroughs than anticipated. It led to the conclusion that the oil-water contact was, in fact, at a shallower level than previously thought and that the closures were not filled-to-spill. ▸



These cross-sections illustrate the evolution of thinking about the petroleum plays of southeast Türkiye. Where the initial model was simple and based on the expectation that oil was mainly to be found in Upper Cretaceous platform carbonates, analysis of well and production data and outcrop analogues gradually gave way to a more subtle model that includes secondary oil migration from the carbonate reservoir into the overlying sealing unit.

ILLUSTRATION: MARCOS ASENSIO

Oil-charged submarine fan channelized lobes and amalgamated channels in the Maastrichtian-aged upper Kastel Formation.

PHOTOGRAPHY: GOKTURK MEHMET DILCI

This was an unexpected conclusion, as the source rock in the area is regarded as prolific.

Could this be driven by oil having leaked into the overburden instead? This triggered a study to better understand the overburden.

The first thing to note here is the lithological variation within the overburden. Gokturk Mehmet Dilci, an exploration geologist from TPAO who is behind initiating this study, noted that moving further away from the axis of the foreland basin that developed in southeast Türkiye in Late Cretaceous times, the percentage of calcite increases. This increase in calcite content subsequently promoted a more brittle style of deformation as compressional stresses folded and faulted the succession. It is the fractures that were generated in the overburden that compromised the seal to the underlying carbonates, promoting the secondary migration of oil.

DISCOVERING THE MIGRATION PATH

But where did the oil migrate to? Gokturk made another observation in the field, where he studied outcrops of lateral equivalents of the sealing units belonging to the Kastel Formation in the Afiyaman Province, Southeast Türkiye. And some of these sands, deposited as turbidites in the foredeep at the time, were oil-stained. It is the same sands that were drilled by wells targeting the deeper carbonate reservoir for about 70 years without much consideration of their reservoir potential until Gokturk and his colleagues started to join the dots that the "missing" oil in the carbonate closures could, in fact, be lurking in the turbidite sands above.

THE KASTEL PROJECT – ANALYSIS AND DEVELOPMENT

This subsequently initiated a research project to better understand and map the Kastel Formation to see if economic quantities of oil could be produced from these turbidite beds. Could this be a hint of what is happening in the subsurface? he thought. He then embarked on a detailed study of the potential of the Kastel Formation to host economic quantities of hydrocarbons. Until that time, no or very little data acquisition had been done on the Kastel Formation, driven by the prevailing concept that it was just the seal that had to be drilled through as soon as possible. In some wells, only Gamma Ray and Sonic Slowness logs were available; in many wells, logs were missing altogether.

Under the umbrella of the "The Kastel Project" the team from TPOA performed detailed microscopic analysis of cuttings and, where available, core samples, focusing on oil indications. This information was integrated with the limited existing petrophysical data to determine perforation interval, which led to the assessment of re-entry potential for old, abandoned wells that were originally drilled with the deeper Cretaceous carbonate targets in mind.

To optimize the reservoir stimulation approach, XRD mineralogical analysis of the turbidite sands was carried out in order to better understand the response to various acidization techniques. Finally, a development design had to be put in place to isolate the perforations in the turbiditic sands of the Kastel Formation from the deeper carbonate units, which had long been invaded by water cones.

RESULTS AND IMPACT

Out of approximately 500 wells initially screened based on sparse petrophysical logs, around 50 candidate wells were selected after detailed analysis of archived drill cuttings, resulting in nearly 30 successful discoveries through perforation and acidization.

This project led to the first-ever oil production from the Kastel Formation sandstones in 2019; 65 years after the founding of TPAO and 86 years after the establishment of the initial petroleum exploration division in Türkiye. The play is still being actively explored and drilled, demonstrating the big shift in thinking of how this petroleum system works. It is a good example of how a second look at subsurface data can result in the extension of oil production in an area beyond the boundaries of the initially defined play. In this case, by looking up. ■

Henk Kombrink

Subsurface exploration by plane

In regions where well and seismic data are scarce, such as is the case for large areas in Africa, one of the best ways to do a quick initial mapping exercise is airborne geophysics

JONATHAN WATSON, METATEK

Data, particularly information about subsurface geology, is key to successfully exploiting natural resources, be they mineral, hydrocarbon or renewables such as geothermal and natural hydrogen. Especially in Africa, where large swaths of the continent have not been mapped in detail, surveying large areas to produce nationwide subsurface resource maps would be a significant step forward and key to achieving a unified, cohesive understanding of subsurface geology and resource potential.

There have been some notable initiatives by organizations such as the National Geoscience Data Centre (NGDC), Operated by the British Geological Survey (BGS) and the U.S. GeoFramework Initiative (USGI), but national scale subsurface mapping projects in Africa remain elusive. The African Magnetic Mapping Project (AMMP) is one example which includes 1:2,000,000 and 1:5,000,000 shaded relief total field magnetic maps, as well as country digital grids with 1 km x 1 km resolution draped on topography. There have been other commercial geological mapping projects, in some cases funded by African governments or via agencies such as the World Bank, which have contributed to geological mapping across the continent. These projects help the understanding of Africa's geology and natural resources but are often at insufficient resolution, sometimes based on satellite-derived data or older geophysical airborne techniques. ▸

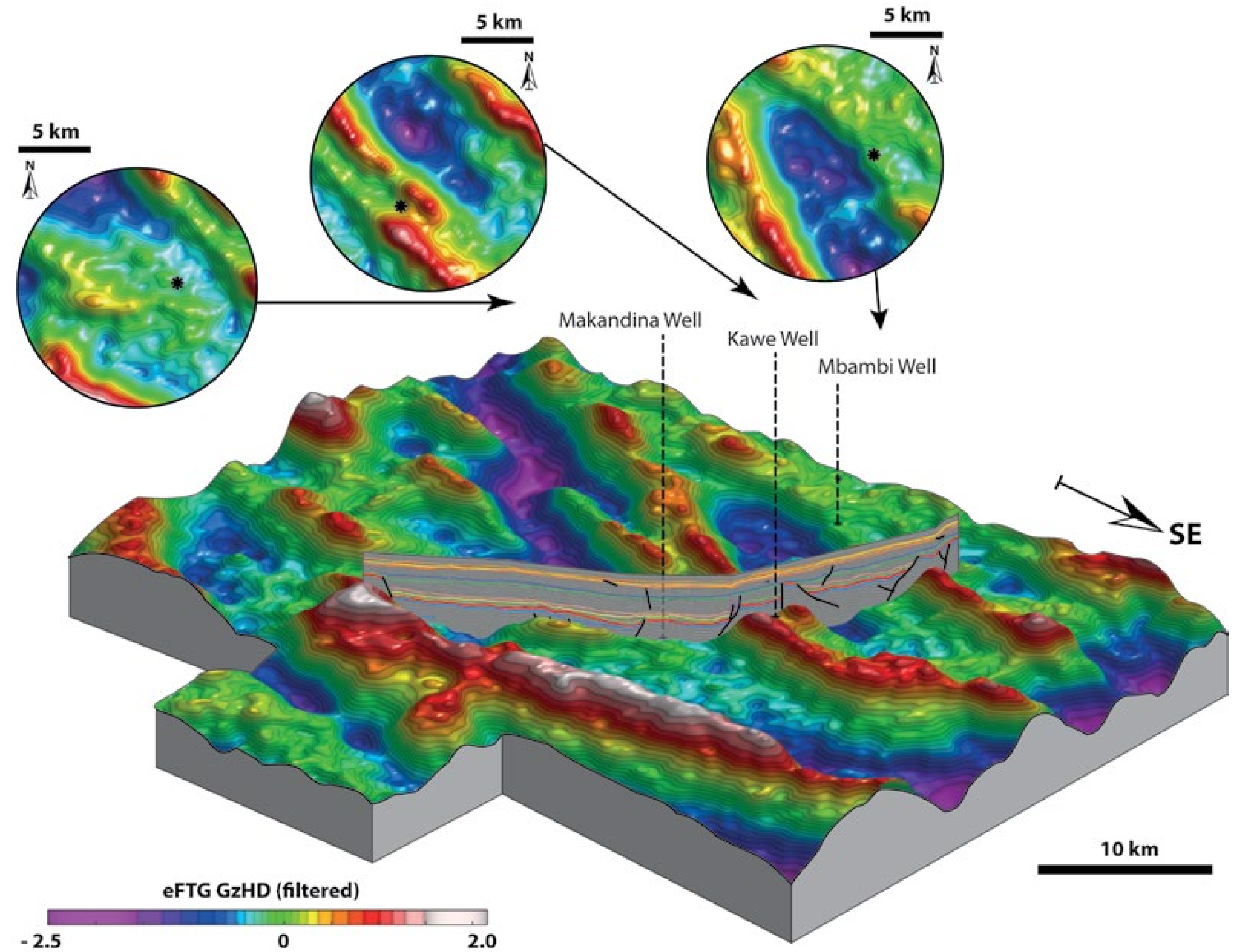


IMAGE COURTESY OF RECONAFRICA

Image showing eFTG dataset and 2D seismic line. Taken from 2023 Namibia survey. The hot colours (red and white) show structural highs, cool colours (blue and purple) show structural lows. Note the insets showing three stratigraphic wells drilled to date, and the strong correlation of the 2D seismic line to the eFTG data.

WHY AIRBORNE FULL TENSOR GRAVITY GRADIOMETRY SURVEYS AT SCALE MAKE SENSE

Innovative technologies can enable accelerated development of natural resources, especially when the technology in question can be deployed quickly and efficiently and with minimal environmental footprint. This is one of the key advantages of the deployment of the latest version of Full Tensor Gravity Gradiometry (FTG).

FTG is a way of measuring changes in the density of the subsurface caused by subsurface geology. It is used by natural resource and mineral prospectors to measure and map changes in the density of the subsurface.

Just as seismic geophysics has evolved over recent decades, the development of gravity gradiometry, when compared to conventional scalar gravity, can be likened to the jump in resolution from 2D to 3D seismic, and the latest advanced Enhanced Full Tensor Gravity Gradiometry (eFTG) can be further compared to the development of ultra high-resolution 3D seismic.

This information is used to construct a picture of subsurface faults, structures and lineaments, which can then be used to accurately identify a variety of oil, gas, groundwater and mineral targets.

Because FTG and other geophysical instruments such as magnetometers and LiDAR can be deployed at the same time in an aircraft, large areas can be surveyed rapidly with different and complementary techniques.

LARGE AREAS SURVEYED RAPIDLY

For example, in late August 2024 the commencement of airborne acquisition of eFTG, gravity, magnetic and LiDAR data began. Covering over ~28,000 km^2 of the Kwanza Basin, onshore Angola, 38,000 + line kilometers of data will be flown by the end of September. Coverage includes 23 onshore exploration blocks with limited legacy geophysical data coverage.

This survey was conducted in conjunction with the Agencia Nacional de Petroleo, Gas e Biocombustiveis to provide data on the geological structures, sedimentary basins and salt tectonics in the Kwanza Basin to enable the participating operators to fast-track their exploration effort and to provide a basin-wide dataset to launch new international onshore bid rounds for the region.

The eFTG datasets will allow detailed information to be gleaned in terms of the structural composition, subsurface trends and lineaments and impact of the broader regional geology over the survey area, as well as highly-detailed information, achieved by infill over individual licence blocks. The magnetic data acquired at the same time is crucial to understanding the distribution and variation of volcanic rocks. Of particular interest is the identification of sedimentary basins and basement structures and specifically, the new eFTG data prepares the groundwork for challenging seismic imaging of the sub-salt structure.

COUNTRY-WIDE PERSPECTIVES ON RESOURCES

These larger scale 'national' surveys allow governments and agencies to have a country-wide geophysical dataset which can be used for multiple purposes such as mineral, hydrocarbon and renewables exploration as well as providing data that can be used for environmental and infrastructure planning purposes. The data also allows the unification of well data and numerous geophysical data sets, such as 2D and 3D seismic data, which is usually present over quite limited areas.

In many African countries where data coverage is sparse, such as Angola where only 10 percent of the country's land has been geophysically and geochemically surveyed, these larger surveys can be an extremely cost-effective way of kick-starting or rejuvenating much needed resource exploration.

It is quite common, especially in oil and gas exploration for companies to abandon exploration in a sedimentary basin after just a couple of unsuccessful wells and temporarily at least, assigning that area to 'barren status'. Early exploration in Namibia provides such an example with that country now a thriving production and exploration hotspot.

In such cases where there is a lack of early success, host governments often require new data to encourage entrants with a fresh approach to the area. Or if a new licensing round is initiated, an up-to-date, unifying geophysical dataset can be the catalyst to encourage new participants and fresh thinking to a basin with great potential but limited subsurface information. ■

PHOTOGRAPHY: METATEK

Death by 0.9

Is it sometimes safe to assume a probability of 1 for certain play elements in a risky exercise when any lower estimate will almost certainly kill the project?

During an evening lecture organized by the Geoscience Energy Society of Great Britain (GESGB) in Aberdeen the other day, a discussion unfolded about how to risk play elements in a mature and heavily-explored basin such as the North Sea. It followed on from a talk delivered by John Seedhouse from the North Sea Transition Authority, during which he presented an overview of exploration results over the course of the past few years.

It is the costly process of towing a rig to location and spudding a well right where the geologist pointed his or her finger at the map that might cause a little bit for cold sweat to those involved in the risking exercise. What if there is no reservoir at just this single spot?

PHOTOGRAPHY: DARREN CLARK

> "The element I feel always gets overlooked is that we rarely drill crests, which means that pre-drill 'Prospect GPOS' is not comparable to post-drill statistics. That bakes in a proportion of perceived under-achievement from management when looking at post-drill stats. If we drill prospects at 'economic threshold' depths, then strike rate can never match pre-drill POS for a portfolio."
> Bill Wilks – Merlin Energy Resources

RISK ALLOCATION CONCERNS

Stuart Archer from Harbour Energy commented that during his career, he had seen many cases where colleagues had been wary of allocating a probably of 1 to certain play elements in a risking exercise, even when there was overwhelming evidence from offset wells and fields that this could be done. He used the presence of the Kimmeridge Clay source rock as an example, which is by far the most prolific source across the Central and Northern North Sea. "If we know that the Kimmeridge Clay is present and we know that it is mature thanks to the production of oil from nearby fields, what is the rational behind introducing uncertainty when it comes to source rock presence?", he asked. "We are over-risking things and we understate the chance of success", he added.

EXPLORATION SUCCESS VS. VOLUME ESTIMATES

This is particularly interesting to conclude because the understating chance of exploration success seems to go hand in hand with overstating the volumes to be found. Of the twenty six discoveries presented by John Seedhouse, only four had a post-drill volume that was larger than the pre-drill estimate. This is another well-known issue in the industry. Convincing management to drill a well, especially in an international operating company where competition from exploration teams in other parts of the world is prevalent, one of the ways to get your well drilled is to be upbeat about its potential volumes.

POLL RESULTS

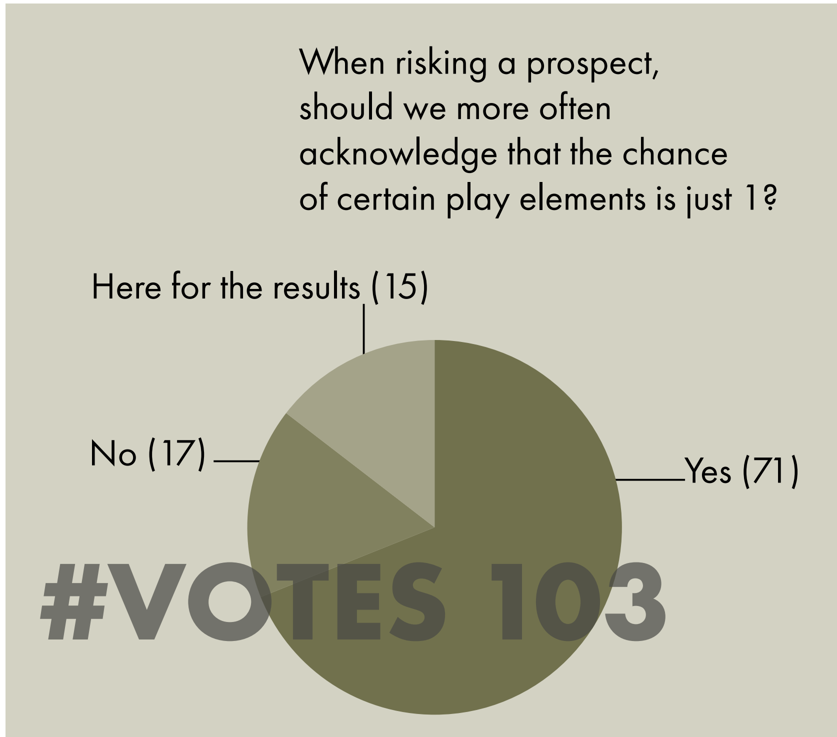
Back to the risking element of the exploration workflow. The discussion taking place during the lecture prompted us to organize a poll along similar lines. Of the 103 respondents, 71 voted "Yes", saying that it is justified to sometimes allocate 1 to an element in the play-risking exercise. Amongst the people who voted were many petroleum geologists as well as geophysicists, including a few from Harbour Energy. But interestingly and maybe not surprisingly either, there were also some who thought it is not done to allocate a probability of 1 in the risking process. ▸

Amongst this group were some seasoned explorers and university lecturers, so there is certainly a debate to be had still.

DEBATE AND PERSPECTIVES

And this debate unfolded in the post's comments section, for which all contributors are thoroughly thanked.

Jan de Jager, former explorationist with Shell and also the author of another article in this section, argued that a 100 % probability for some play elements can very well be reasonable. He cites charge in some Tertiary deltas and trapping geometry for a Miocene reef as two examples. He also mentions that the reason for the failure of unsuccessful exploration wells can tell you whether a 100 % chance factor may be justified. For example, if there are no wells within a sector of a basin that has failed for the absence of charge, why then go below 100 % for a new exploration well?



ARGUMENTS AGAINST 100 % PROBABILITY

"Some explorers still want to go for 99 %. After all, they then maintain, how can you ever be 100 % certain about the geology in an exploration environment?" "But that would be just a covering-your-back exercise that has virtually no effect on the final probability of success", he argues, adding that it is well known that the average rate of success in exploration is better than the average pre-drill Probability of Success. "It may well be that a reluctance to assign 100 % probabilities has something to do with that", he concludes.

INSIGHTS ON RISK PRECISION

Rene Jonk, who worked for ExxonMobil for a number of years, commented that "Death by 0.9" was a famous saying going around the workrooms at his company. "Especially when there was a 9-element risk matrix, it was very true...", he wrote.

"Some would argue that you can never be 100 % sure, but I think that speaks to a poor understanding of precision in risk. It's why I tend to suggest keeping your risk number to one decimal, and hence, the "I can never be one hundred percent sure" becomes a 1 for anything from 0.95-0.99!"

"In my experience, it is more important to articulate the main reason a well will fail and what observation in the well would support your main inclination for well failure. The false precision of a risk number becomes rather meaningless when you've put "some risk" on every possible element. It becomes a poor predictor of well outcome. Especially when we often fail to articulate what we are risking against."

TRIPLE VALUE LOGIC

Not everybody buys this, though. Martin Jagger argued that besides true and false, the result of logical expressions can also be 'unknown', citing Donald Rumsfeld when he said that there are always unknown unknowns in our attempts to understand and predict nature.

"Whilst there may be a large volume of information relating to the risk or decision in question, it may be partial information, incomplete, uncertain - even conflicting - in terms of support it provides for a given interpretation. Some practitioners - organizations or individuals - are sometimes biased by over-reliance on a particular source of evidence or "belief" when faced with contradictory or equivocal evidence from elsewhere."

He, therefore, makes a case for using evidence support logic - or Triple Value Logic – which breaks down the question into a logical hypothesis model, exposing opinions and judgements to the quality of evidence available.

Raffik Lazar from GeomodL International, with this discussion in mind, therefore argues to distinguish between exploration in frontier exploration, where a general lack of control of all play elements exists, and ILX-driven exploration whereby swathes of data are at the geologist's fingertips. Read more about that in his column in the Insights-section. ■

Henk Kombrink

Exploration geology - science or art?

Working up a prospect came with lots of arm-waving in the past. Now, we tend to calculate all risk elements, but that doesn't mean that the outcome is necessarily much better

JAN DE JAGER

During my career in the oil industry, exploration geology has changed enormously. Not long after I joined Shell in February 1979, my son, who was play school age, asked me what my job was. I replied that I was colouring most of my time. And that was, actually, a pretty accurate description of what I was doing.

It was not only colouring, though. Contouring was another major element of my daily routine, by reading off 2-way travel times at shot-points from interpreted seismic sections, noting the values down on maps, and then contouring them. A very time-consuming job.

In those days, there were a few very experienced colleagues in Shell's central office who we referred to as "gurus". They seemed to know almost everything there was to be known about exploration for oil and gas. They had seen a lot of geology and understood how basins develop, how sediments are laid down, when source rocks can be expected to have generated hydrocarbons, how structures form and which lithologies can be effective seals. They had opinions on prospects worth drilling and new basins we should enter. Their word was gospel.

> "Many colleagues at the time agreed that petroleum geology was more art than science."

Petroleum geology in those days was very qualitative and "arm-waving". Many colleagues at the time agreed that petroleum geology was more art than science.

Much has changed since those days. Virtually all technical disciplines that are part of the umbrella science that we call petroleum geology have become more quantitative. With deterministic and probabilistic computer applications, many aspects of geology are now being modelled. With that, data has become all important and, as a result, the need for it to be easily accessible.

Possibly as a result of this, the importance of our gurus has diminished… I haven't heard about gurus in our exploration departments for some time. It is probably the deepening and quantification of the science in areas like basin development, petroleum system analysis, structural geology, depositional system analysis, etc, that has resulted in the loss of the uomo universale in exploration geology.

Has exploration geology morphed from an art into a science?

GENERALIST AND INTEGRATOR

When, after my Shell career, I joined academia, I was asked what my area of expertise was. I struggled to find a good answer – nothing really, or maybe petroleum geology. As an exploration geologist in the oil and gas industry, I realised I have become a generalist and an integrator.

To understand a prospect, it is essential to understand its regional context: How did the basin in which we identified the prospect form, and how does the overall play work? On top of that, we need to understand the details of the trap, reservoir, charge and seal. That requires input from many different sub-disciplines - from colleagues with a deeper understanding of their areas of expertise. As an integrator, ▸

PHOTOGRAPHY: HENK KOMBRINK

it is then your task to use all the data, opinions, models, and what have you, to form an opinion about the subsurface, the hydrocarbon plays, and ultimately, the prospect and its chance of success.

At times, there is tension between the assumptions we make and the data supporting these. That is because data is often sparse and of limited resolution, prone to multiple interpretations, and diverse with input from multiple disciplines that may not always align with each other.

This requires us to make judgements about the weight of the evidence that is brought to the table. We must ask the right questions and listen to the experts; they know their stuff better than I do, as a generalist. At the same time, we cannot always take the expert's word as it may be in conflict with some evidence from another field of expertise. Experts, just like most of us, are human. This means that they can be biased just as easily as we can. Two examples illustrate that nicely.

Several decades ago, staff from Midland Valley in Glasgow showed an artificially-generated cross-section at their booth at conferences. The cross-section looked like a seismic section, and they asked people visiting their booth what they thought they were looking at. Is it a surprise that people who had worked most of their careers in salt basins thought that they were looking at salt tectonics? In fact, it was an inverted half-graben.

When the giant Groningen gas field was discovered in 1959, experts were flown in from the US to shed more light on the depositional setting of the cored reservoir sequence. After all, the Rotliegend was very new to most geologists at NAM because so far it was the overlying Permian Zechstein evaporites that formed the primary exploration target. The experts from the US had worked all their careers in the Gulf of Mexico and concluded that we were looking at a deltaic succession. It turned out to be desert sandstones.

If all you have is a hammer, everything looks like a nail.

THE ART REMAINS

Exploration geology has definitely changed. We have greater and deeper knowledge of many aspects of the exploration game, thanks to the more quantitative approach taken when de-risking a prospect. But just because we can calculate some seemingly very precise numbers, it does not mean that the outcomes are necessarily correct. The input for such calculations and modelling exercises always are, to a greater or lesser extent, uncertain.

"We always have to judge which information/data/model we give the most weight."

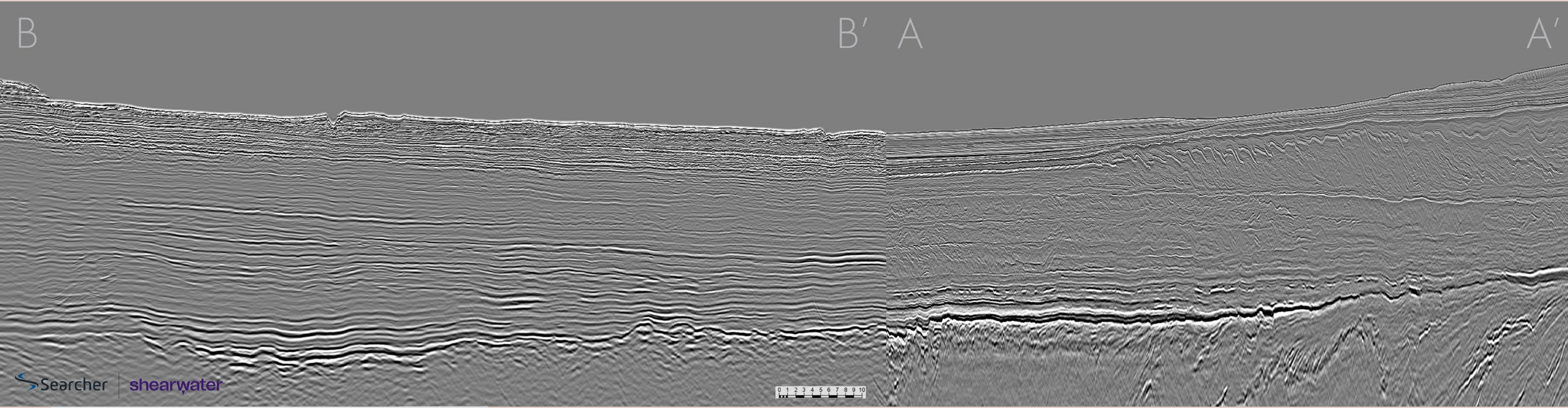
Most of the time, the uncertainties in exploration geology are enormous and are seriously underestimated. And on top of that, the subsurface is incredibly diverse. There may be similarities between two prospects within a certain play, but no two prospects are the same. We always have to judge which information / data / model we give the most weight.

It is, therefore, still true, just as it was when I joined the industry in 1979, that the more geology you have seen, the better a geologist you are. Exploration geology has become more of a science, but at the same time, it still has many characteristics of an art. And I am still keeping a box of colour pencils in the upper drawer of my desk. ■

South Atlantic – a raging bonfire of memes

In the words of Fat Boy Slim, the best time in the history of our industry to be an explorer is "right here, right now". In the South Atlantic, the deepwater plays are now low risk and huge as the biassed memes of the past are incinerated by exploration drilling success, and modern exploration 3D.

Searcher



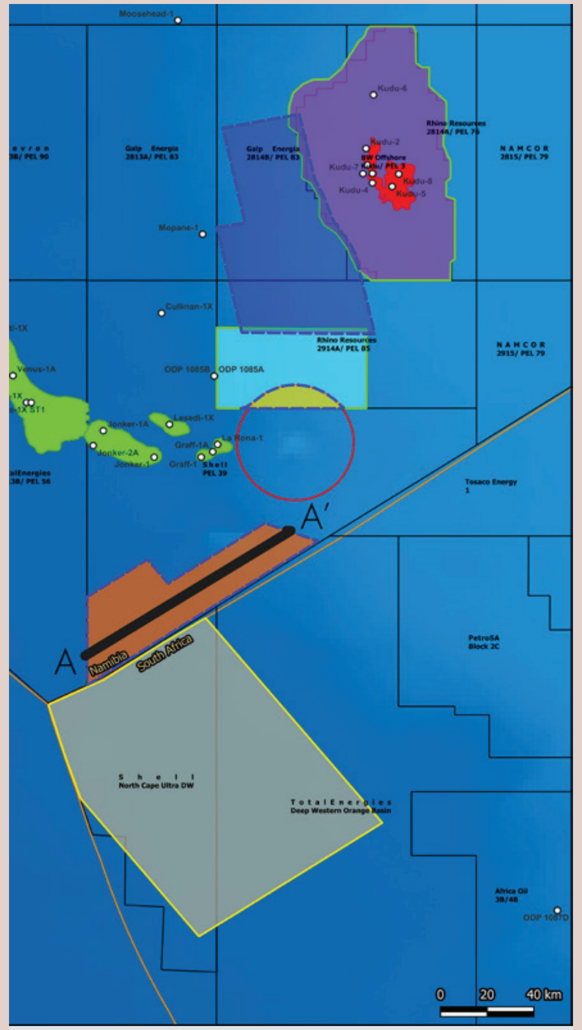
Left hand side: 2024 Pelotas Basin, Brazil Quick Look 2.5 D Post-STM depth converted
Right hand side: 2023 Orange Basin, Namibia, GAP Fast Track Pre-STM depth converted. Both sections are at the same horizontal and vertical scale – neither are depth-shifted to achieve the tie.

Namibia - Brazil: Where memes collide and where we go next

From outdated to new memes: How recent discoveries in Namibia's Orange Basin are shaping exploration strategies for Brazil's Pelotas Basin

NEIL HODGSON, KARYNA RODRIGUEZ AND LAUREN FOUND, SEARCHER

THE FATHER of modern macroeconomics John Maynard Keynes wrote that "the difficulty lies not so much in developing new ideas as in escaping from old ones". This issue is the beating heart of exploration, which is built upon both confounding the expectations of our predecessors and doing it before the competitors. The received wisdom of memes are the ideas that explorers use as the glue to hold disparate or uncertain data together in a framework required to define risk and value. But as the statistician George Box almost said; all memes are wrong. And although some may be useful, they can equally be disastrously misleading.



Orange Basin, Namibia.

THE EVOLUTION OF EXPLORATION MEMES

In Namibia's Orange Basin, the understanding of the deepwater hydrocarbon system had become wrapped in a cluster of ideas that led most of the industry astray until Shell and TotalEnergies drilled Graff and Venus respectively in 2022. The memes had evolved in the data-poor atmosphere of uncertainty where the absence of evidence was all one had, so it stood for evidence of absence. Yet, these have now been passed through the excoriating fire of an extraordinarily successful drilling campaign and many pre-existing models have been eviscerated in the process. New memes have evolved, becoming fitter in the process to deep water passive margin exploration in general, so these are the new exploration memes that will take us forward to the next frontier – the Pelotas Basin of Brazil.

Hydrocarbon systems have never been so vulnerable to critical thinking-driven analysis – not because we have particularly new ideas about how the key risk elements combine or interact, but because recent deepwater drilling experience and 2024 technology have crushed the uncertainties in our exploration models, letting the memes evolve and become fitter.

When Richard Dawkins coined the term "meme" to mirror "gene", he was representing a cultural idea, like geologic models – earth visions in our imaginations that are capable of replicating and evolving to better fit or mitigate increasingly available data. Models of deepwater gravity-driven clastic sedimentation, such as "turbidite depositional systems", adapting through observation and experience.

Such as embracing the "contourite" meme – becoming mixed systems and changing the way turbidite flows are understood to deposit sediments in deep water settings. See, for instance, Bryan Cronin's brilliant recent work in the Ghanaian margin.

IMPACT OF EXPLORATION DISCOVERIES

In the Orange Basin, a number of exploration memes of received "truths" had grown over the decades of exploration, evolving in a survival of the fittest sense to work around the available data. However, these had conflated with each other to cast a negative light on all aspects of the hydrocarbon system off the shelf. Some of these memes included that the inner basin had no source rock, had no sand, had poor quality sand, was gas prone, and further outboard the outer basin had no sand, no source rock, immature source rock, no migration, no traps, no seals and was too deep water. These had become the received wisdom, with no evidence that this was or wasn't the case. Or even against the evidence such as the thick source rock on the oceanic crust in DSDP361 drilled in 1974.

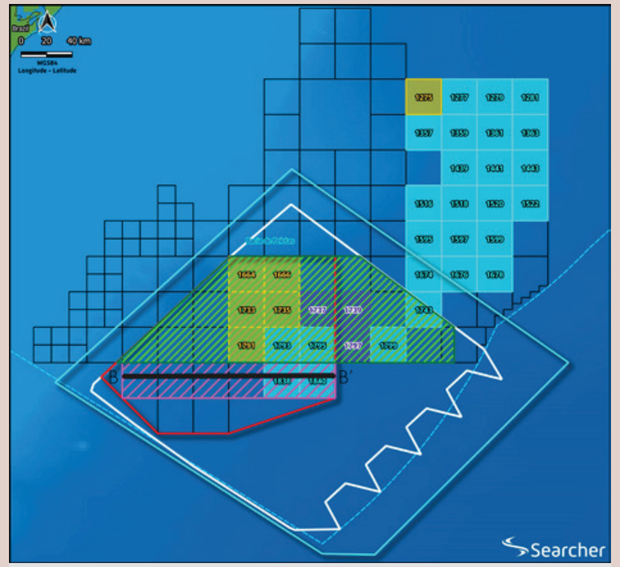
LESSONS FROM VENUS AND GRAFF

Total Energies' drilling of Venus and Shell's drilling of Graff in 2022 represented a Chicxulub evolution event to deepwater exploration memes, as the historically negative models in Orange went to the flames, and sneaky preadapted memes became better fit to the new data. To be fair, the dying memes were not built of unwarranted concerns, quite the reverse, but the negative baggage they brought was not supported by any data, only the absence of evidence. These memes were self-replicating received biases, and not the useful kind. For an excellent series on biases in exploration analysis, a great starting place is Marc Bond's LinkedIn posts.

Post the Venus and Graff oil discoveries, we appreciate that the clastic sediments are mixed systems, have re-thought their water depth of deposition, rethought the thermal history and thermal blanketing that supports the results of Seismic Thermometry and generates oil in the Aptian, confirmed the trapping potential created during syn-drift SDR to MORB transitions and counter regional dip mega-trap creation, and re-imagined the potential for innovative mixed system slope traps. These plays are no longer high-risk, because the technology we have, when applied in the right meme framework, solves the problem for you, alchemically turning the old high risk "frontier well" terror meme into the low-risk quiet confidence of the future.

FUTURE DIRECTIONS AND OPPORTUNITIES

In the foldout presented here, a "quick look" data post-stack time migrated (in 2.5 D mode) and depth converted line that was available for interpretation before the last shot of the 2024 Pelotas MC 3D programme, is compared at the same depth and horizontal scale to its near conjugate margin, a 2023 MC 3D pre-stack time migrated and depth converted section from beyond the outer high in Namibia. Pelotas, like Orange, had acquired a number of hydrocarbon system memes that were not helpful: Mud rich delta, Aptian source not present, source too deep, gas prone, too hot, too cold, no structure, and too deep water. This foldout lights the blue touch paper that will immolate those memes and allow fitter memes, evolved in the data-rich Orange Basin, to supersede them.



Pelotas Basin, Brazil.

MOVING BEYOND OLD MEMES

The meme that the Pelotas and Orange Basins are "not at all similar" is the first dinosaur on the Barbie as the transition from SDR to oceanic crust is present on both sections in mirror order. The Aptian source rock is visible on either margin as is the outboard counter regionally dipping overlying soft clastic fan of Aptian / Albian age – the amplitude on the foldout is just a function of processing maturity in these two examples. The Venus play in Orange = Venus play in Pelotas. That sections above the Lower Cretaceous are different is obvious and thanks to dynamic topography. The Namibian section comprises 3 km of Upper Cretaceous instability-induced mass transport deposits, whilst the Brazilian margin comprises a well-bedded Cretaceous and Tertiary sequence. Yet, this is of secondary importance as both isopach's over the Aptian are the same, in the same water depth and possessing the same crustal structure, illustrating that the proven Aptian hydrocarbon maturity in Orange is quite reasonably exactly that in Pelotas, and Pelotas is therefore an oil play too. That the overlying Upper Cretaceous confined channel system in Pelotas is also still present and clearly imaged on fast-track data is one would imagine, a bonus.

Between 2022 and 2024, Searcher has been blessed by being able to play a role in the collection of six huge multi-client 3D datasets across the new play fairways in the South Atlantic – five with our amazing partner Shearwater. Sharing observations from these datasets as soon as we can with the industry via our weapon of choice; GEO EXPRO Magazine, has been a joy. Now it's time to review the exploration memes that collided in the Orange Basin, find the evidence-rooted ideas that actually work, and take them across the Atlantic.

PORTRAITS

"I am not someone who likes to play the shaming game when it comes to working in oil and gas. No, it's a shame to do that actually"

Aluka Osakwe

NEVER SAY NO

Aluka Osakwe represents a new generation of oil and gas entrepreneurs, who is not afraid of speaking up for the industry. Here, she shares how she arrived at the point where she is now – managing field studies in Africa, being part of an organisation advising tech start-ups, and being an associate for various consultancy firms. And for those who think it is down to having a big profile on social media, no, it is down to building a good old network. Here's Aluka's story.

HENK KOMBRINK

"I WAS BORN disciplined", says Aluka at the start of the interview. "With my parents both being academics, it was no surprise that I wanted to learn", she continues, "but I was so determined that they never needed to chase me for any school-related work."

Aluka grew up in Abraka, a small town in Nigeria's Delta State, which gets its name from the fact that it is situated in the larger Niger Delta in the south of the country. Her parents both taught at Delta State University.

Aluka did not stay in Abraka for long, though. When she turned eleven and had finished primary school, she went to boarding school. "Looking back, says Aluka, I think my parents were very brave to let me go at that age." But she made it her new home straight away. "I saw kids arriving and burst out crying once their parents were about to leave. The only thing I thought was, what is wrong with you? It wasn't because I lack emotions; it was because I was so focused on what I was going to do there", she says.

Aluka stayed at the boarding school for six years, after which she went to the Obafemi Awolowo University in Lagos. That meant she also left Delta State for the first time, not knowing that she would not come back, at least until today.

"I loved numbers, which is why I decided to study computer engineering", Aluka continues. It was supposed to be a five-year course, but because of the frequent strikes from university personnel, it took her a bit longer. "It's there where I met my best friends, and we still stay in touch", she says.

PHOTOGRAPHY: DAVID WOOLFAL

After university, Aluka spent a year in mandatory military country service. "I liked it though", she says, "especially because I was sent to a completely different part of the country. I was transferred to the north. It was a great year if only to be exposed to yet again a completely new language and a different culture."

Military camp service may sound harsh, it was actually much more civilized than that. Following the intensive camp drills, I was lecturing at the local university as an assistant to the professor and also at local elementary schools", she says. "And it was really nice to do that, and see the curiosity of the kids, especially the girls who tended to be the quiet ones."

After her service, Aluka moved to Abuja, the capital of Nigeria in the middle of the country. "It was the best city that I had lived in thus far, she says. "It's new, it's big, and there is a lot of business and tech whilst it still felt homely at the same time." She worked there as a network engineer in a telecom startup, until a friend asked what she wanted to do next...

SAVING FOR A MASTERS

And this friend happened to work for Schlumberger….

"I must be honest about this", continues Aluka, "I didn't join Schlumberger because I was so interested in the oil and gas industry. My main driver was to be able to complete a master's course. And there was the prospect of travelling as well!"

So, in 2007 Aluka joined the drilling team at Schlumberger and moved to Port Harcourt. "Well, I spent more time working offshore than being in town", she laughs. "Unlike the North Sea, where it is a matter of two weeks on and two weeks off, I had times when I spent 47 days offshore in one go."

"Working for Schlumberger was quite exceptional", Aluka continues. "They did not wait for you to get ready. You get ready. I was given responsibility for running tools within six months after starting, and was supervising teams soon after. Combined with the travelling opportunities I was offered, I must say that whilst my parents were instrumental in making me independent by sending me to boarding school, Schlumberger added the next step through their company and can-do attitude."

It was working with these downhole tools that Aluka got the idea of what the master's course she was saving up for needed to be; something related to better understanding the subsurface. "I ran all these logging tools for two and half years, including a phase at Addax Petroleum in Lagos as the company representative, but I was not well aware of what was actually happening down there", she admits. "That's how I stumbled across Heriot-Watt University in Edinburgh, as they offered a Reservoir Evaluation and Management course."

"The group of students in Edinburgh was very diverse and from all over the world", says Aluka. "One of the best parts of the course was to go to Spain and visit outcrops to learn about the architecture of reservoirs. I learned so much more about geology, it became a little less abstract to me."

I WASN'T HERE FOR SIGHT-SEEING

But then, after finishing her course, the oil price had just dipped in response to the 2008 financial crisis and jobs were not easy to find. Yet, Aluka was keen to stay in the UK.

"It's nice to be in Edinburgh, I thought, but that's not where my future job is, as that is in Aberdeen. So I moved to the granite city without having any concrete job offer yet, and without knowing anyone", she explains.

But it paid off. Aluka found a job as a support geoscientist with the petrophysical software team at Senergy. She subsequently spent about eight years with the company, moving up from the software team to being a petrophysicist in the consultancy group.

Even though the oil price dipped in 2009, the major slide took place in 2014. Along with so many companies in the oil and gas sector, Senergy went through multiple redundancy rounds. Not an easy time for anyone.

Having a job is important, but Aluka also relied on Senergy as a sponsor of her UK visa. "Finding another job is one thing", she says, but finding another company wanting to sponsor your visa is another matter." Being so dependent on your employer to be able to stay in a country is something that is probably hard to imagine for people who have never been in such a situation.

> **"I am not someone who likes to play the shaming game when it comes to working in oil and gas. No, it's a shame to do that actually."**

"So, I had a backup plan", Aluka says. "Whilst in Aberdeen, I applied and was granted a permanent residency from Canada. Don't get me wrong, I could have gone back to Nigeria, and I have many friends who work there, but I wanted an international career."

Fortunately, though, Aluka never needed her Canadian visa and managed to keep her job at Senergy.

However, after eight years in Aberdeen, Scotland had become too small for Aluka, and she asked her employer if it was ok to be transferred to London where the company had another office. Astute as she is, she told management that the London team needed at least one petrophysicist to be physically there.

FROM LINKEDIN TO LYTT

"After two years working in the London team, which I enjoyed fully, I started to look around", says Aluka, "and came across Lytt, a technology spin-off from bp."

It turned out to be a good fit, as Lytt was all about processing data ▸


Field trip in Spain.

derived from a relatively new technology used in downhole logging, DTS and DAS. Distributed Temperature and Distributed Acoustic Sensing technology is based on fibre optic cables fitted in the wellbore, deployed either permanently or as part of a well intervention to monitor inflow, well integrity or perform borehole seismic acquisition.

"Amongst other things, I was tasked to come up with new ways to process and filter the data such that the trials bp was carrying out in the North Sea and in Azerbaijan were meaningful", Aluka says.

"YOU'RE SLEEPING IT AND WAKING IT"

After two years at Lytt, something started nagging with Aluka. Even though she began at the company thinking to make it to retirement, over time this completely turned into a desire to be independent and set up her own business.

"What it was going to be, I had no concrete idea yet, but it was consistent and I trusted that something good was going to happen", says Aluka. "Maybe other entrepreneurs recognize it, but it was literally on my mind 24 / 7, and I almost had to do it to set myself free!"

So, she left Lytt and entered the dark hole.

And where are we now, more than a year later? "Well, things have started to come together", Aluka laughs.

"Quite soon after I had left, I was contacted by a company that connects entrepreneurs with tech companies to provide advise on a board level. I had to think about it for a while, but I made that step and now I meet fantastic people in the tech community, who I try and help navigate the hurdles of growing a business."

But she is still very much present in the oil and gas industry. "It's a long story, but I now manage a project in Ghana, looking at three different fields and coming up with plans to drill infill wells", Aluka says. "I was responsible for finding the people to carry out the work, so in some ways, I'm back to my Senergy days, but now it's me having to manage it all", she laughs.

And it suits her, the combination of integrating the input from the various technical experts to communicating the results to the client. On top of that, Aluka has also become an associate petrophysicist for consultancy firms Tracs and ERCE, so it is easy to see how busy her days are.

And the little secret is, all this happened only to a limited extent through social media. "I am not on X, not on Facebook, I only do LinkedIn really", says Aluka. "I prefer that other people speak about me rather than speak about myself."

Instead, it is the network of established contacts that has helped her most of all to get where she now is. "Authentic relationships are ones that you don't necessarily build on social media, and it's those that have brought me so much over the past year."

"And do you look ahead at what's coming next?", I asked. "No", Aluka concludes, "because I am doing things I like. The only thing that is in my head is expansion and never say NO to upcoming opportunities. How I will blend a new project in is a worry for tomorrow!"

For very good reasons, Aluka takes pride in what she has achieved so far. "And let's be honest about this, it is the oil and gas industry that has given me all these opportunities. I am not someone who likes to play the shaming game when it comes to working in oil and gas. No, it's a shame to do that actually", she says. "We must not forget how essential oil and gas still are for society, and how essential it was for me to do all the things I've done. Let's please not forget that!" ■

PHOTOGRAPHY: PRIVATE

GEOTHERMAL ENERGY

"I would not be in this business if we would not think we can produce competitively priced energy"

Mike Eros - Sage Geosystems

A huff-and-puff reservoir

Sage Geosystems is working on a subsurface energy storage project that could ultimately replace peak gas systems

"I WOULD NOT be in this business if we would not think we can produce competitively priced energy", said Mike Eros from Sage Geosystems during his talk in the Geothermal Hub at the IMAGE conference in August. The challenge? Provide base-load carbon-free energy as and when required, compensating for intermittency that comes with wind and solar.

In order to do that, the company is testing a new development concept within the family of deep geothermal solutions. And in contrast to what initiatives like Fervo and FORGE are testing, with the completion of two wells and circulating water from one to the other, the Sage system is dependent on just one.

The basic concept includes the creation of vertical fracs in a sufficiently deep and low-permeability succession in the deep subsurface. Water is subsequently injected into these fractures to "inflate" the system, to be released when there is a need for power for the grid. In order to do this successfully, the minimum depth of drilling and generating the fractures is 7,000 ft, whilst the maximum permeability is 1 mD to guarantee that the system remains under pressure without fluids leaking away. The pressure window the company aims to adhere to will be between the fracture opening and the fracture propagation pressures.

In order to test this new concept, the company will soon start drilling a well near a lignite coal power plant operated by San Miguel near Christine in Texas. The idea is to generate 3 MW when the system is being depressurized over a period of around 6 - 10 hours.

UNCERTAINTIES

A project of this kind will have some related subsurface uncertainties. First of all, it is key to create enough fracture space to enable the storage of a sufficient volume of water in order to sustain energy production for the desired number of hours. Then, there is the concern about pressure dissipation and leak-off through naturally existing fracture systems, something that will be hard to completely avoid, according to experts. In that regard, the company says that 2 % of leakage is acceptable. Finally, it is not unthinkable that fractures will close over time, requiring the need to perform re-fracs during the course of the lifetime of the well.

COMPETITION

Another thing that I found interesting whilst listening to Mike's talk was the way he seemed to present his company's geothermal solution as being superior to alternative projects such as Fervo and FORGE. To me, the geothermal operating space should not be an arena of competition but rather a collaboration space... The race to secure investment from a limited pool of candidates seems to be the most plausible explanation for this sense of competition between different geothermal solutions. ■

Henk Kombrink

The drilling site is being prepared near the San Miguel lignite power plant. Once realized, it will be the first time geothermal power will be integrated into the ERCOT grid in Texas.

SOURCE: SAGE GEOSYSTEMS

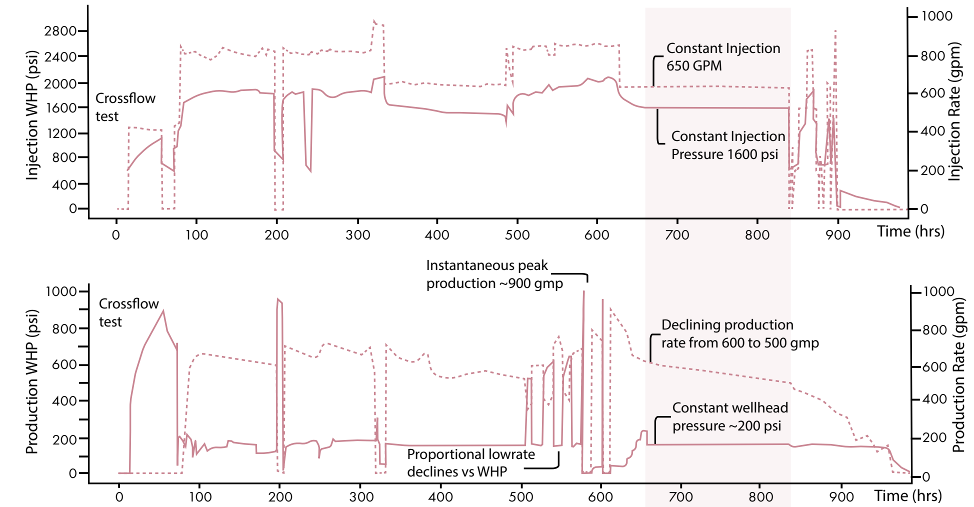
A critical look at Fervo dataset suggests lower output

Net power of enhanced geothermal project may be only a third of the number that is generally quoted

ELLIOT YEARSLEY AND HENK KOMBRINK

IN JULY 2023, Fervo made public a pre-print containing plots and analyses of a well test in Nevada, related to their project Red. This allows for a more detailed analysis of the results, independent of what press releases say.

The project, on the periphery of the Blue Mountain geothermal field, entailed the drilling of a horizontal producer and injector pair into basement rocks, after which a fracking job was performed on the production well to create a connection between the two.



Flow rate and wellhead pressure recordings during the 37-day circulation text for injection well 34A-22 (top) and production well 34-22 (bottom).

SOURCE: FERVO ENERGY

PRODUCTION TEST RESULTS

The data presented by Fervo following an injection and production test provide sufficient information to critically verify the statements made about the project in most of the press releases.

First of all, it is true that the Fervo test in Nevada yielded higher production flow rates compared to previous EGS attempts. However, the consistency of these flow rates has not been demonstrated. A decline in production rate is observed during a period of constant injection, which may have implications for achieving stable round-the-clock production. A similar observation was made whilst analysing the Forge project, indicating that fluid is being lost to the formation.

In addition, the Fervo paper for Project Red uses "crossflow" data to arrive at an estimate of the "Transmissibility" (in units of bbl per minute / psi - essentially the Productivity Index) while the production well is shut-in. However, a similar analysis can be derived from the flow data, which is a more direct measurement of this parameter.

Using the data presented by the Fervo project, an estimated flow rate per unit pressure differential (Productivity Index) during flowing conditions of 0.4 gpm / psi can be calculated. This compares to Fervo's estimate of 3 gmp / psi derived from the crossflow test, suggesting that the flowing pressure drop between the production and injection well is much higher than indicated by Fervo.

NET POWER GENERATION

Finally, the stable net power generation of the Fervo project is lower than what the press releases often quote. The gross power shown for the constant injection and constant pressure period between 660 - 830 hours during the test starts at about 2.1 MW at 600 gmp and declines to 1.8 MW at 500 gmp. Using a reasonable estimate of pump power being close to 0.5 MW, a net power of around 1.3 MW is achieved at the end of the most stable portion of the test (at 830 hours). This would generally be considered marginal or non-commercial in the geothermal industry.

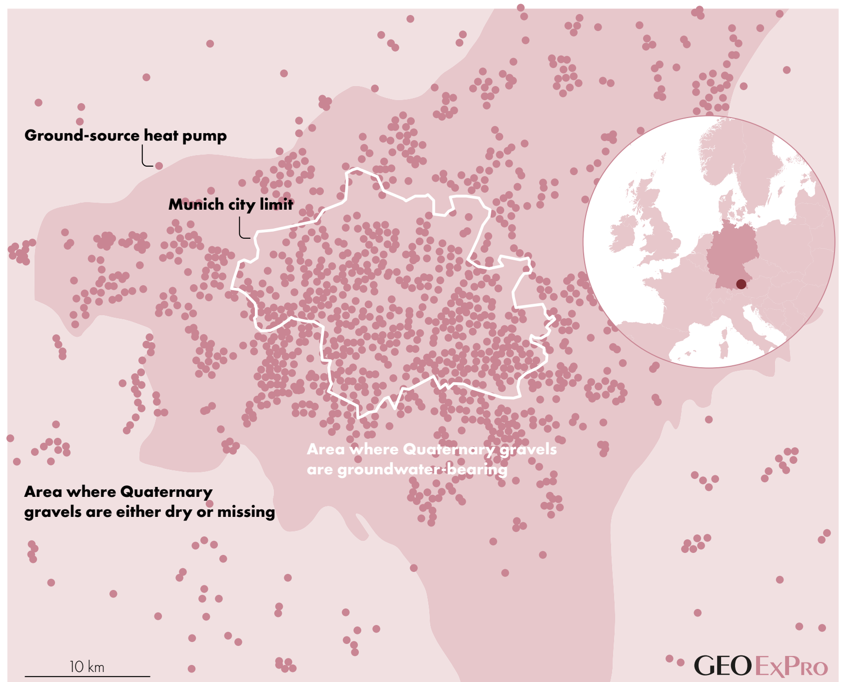
Based on the analyses presented here, it may be too early to conclude that the Fervo Enhanced Geothermal Systems design is ready to be scaled up to a commercial development. More work will be required to order champagne. ■

Gravel and geothermal energy

The city of Munich is built on a Quaternary gravel plain, which has become a drilling target for shallow geothermal projects in recent years. But even though it is shallow, careful mapping and planning is still required to de-risk new projects

It is well-known that Munich is benefiting from a favourable setting in terms of deep geothermal energy production. It is a little less well-known that Munich also sits on a much shallower geothermal reservoir, and that is the Quaternary gravel plain that underlies the entire city and its surroundings.

Thanks to the combination of high porosity and permeability and the presence of fast-flowing groundwater, this shallow succession has been and continues to be the target of ground-source heat pumps. The map shown here nicely illustrates the close relationship between the density of ground source heat pumps in the Munich area and the presence of groundwater in the Quaternary gravels.



This map from the greater Munich area in southern Germany nicely illustrates the relationship between a favourable subsurface setting – in this case, a permeable Quaternary gravel bed – and the number of ground source heat pumps and associated boreholes that have been drilled to tap into this resource.

SOURCE DATA: UMWELTATLAS.BAYERN.DE AND CEE.ED.TUM.DE/HYDRO/PROJECTS/GEOTHERMAL-ENERGY-GROUP

But that doesn't mean a borehole can just be drilled anywhere. Careful site investigation is still required – the thickness of the Quaternary gravel succession can change quickly, and this can impact the design of a borehole.

In order to perform an informed site investigation, authorities in the Munich area have therefore launched several initiatives to make subsurface data publicly available. In analogy to deep exploration projects, offset data provides more security when planning new projects. The data density varies, especially in the outer city areas, so the risk profile changes per location. And, on top of that, there is always the odd surprise.

This was the case in a recent project where Stadtwerke Munich explored the subsurface before starting a project in order to see if the data were reliable and if there was enough groundwater. The exploration phase suggested favourable conditions, so the well was planned, and the project was started.

Even though the production well was positioned only 5 m away from the exploration borehole, it showed a 2 m vertical offset of the aquifer basis. Luckily, the project was still successful, but the pipes had to be re-ordered again so they fit the subsurface conditions.

For that reason, Stadtwerke Munich now drills its exploration boreholes in exactly the same location as where the future planned well is to be drilled in order to prevent these situations.

Because of the data density now available and the experience gained through offset studies, smaller projects do not necessarily need an exploration borehole drilled first. Yet, sometimes, the predicted depths match the drilled depth with an accuracy of a centimetre.

The hydraulic conductivity of the gravels has turned out to be harder to predict, as it ranges from around kf = 0.0001 to 0.01 m/s and has a high impact on the productivity of a well. But, with cumulative experience on projects in the gravel plain predictive power has also increased in this regard. ■

Henk Kombrink with input of Ayla Hernández, SWM

SUBSURFACE STORAGE

"If we want geological CO_2 storage to become a major element in mitigating anthropogenically induced climate change, let's not use this project as a tool to shut down projects but rather focus on improving both materials and monitoring techniques"

Henk Kombrink

Does Denmark really want onshore CO_2 storage?

With the most advanced onshore storage project missing out on being awarded a licence, it feels as if Denmark is back to square one when it comes to storing its carbon

IN OCTOBER 2023, less than a year ago, we published an article about what was supposed to be Europe's first full-scale and commercial onshore CO_2 storage project, aimed to be operational next year.

But, a couple of months ago, the future of the Stenlille project in Denmark looks a lot less rosy. As part of a round of licence awards towards future carbon storage projects onshore Denmark, the Stenlille project did not receive a storage licence. It has not been in the news often, but we stumbled over it when reading a post by Danish company CCUS Partners on LinkedIn (LI).

The Stenlille gas storage facility, Denmark. Gas is stored in the Gassum reservoir in the crest of a domal structure, and CO_2 was planned to be injected in the flank of the structure in the northeast.

SOURCE: BUSINESSWIRE.COM

WHAT IS GOING ON?

It has turned out difficult to get some more information about the reasons why the licence was not granted, which leaves us to pull together the few things we do know and draw up some hypotheses.

First of all, what is Stenlille? It was quite a particular storage project all along, because the site is also used as a gas storage project in the crest of a domal structure. The CO_2 was supposed to be injected into the Jurassic Gassum Formation in the N / E flank of this dome, with reservoir simulations predicting that it would take more than 50 years before the CO_2 would ultimately migrate towards and "meet" with the gas storage area. At the same time, because the site has been used to store gas for so many years already, the sealing capacity of the overlying Jurassic Fjerritslev Formation can be seen as tested and confirmed.

The project was not in an initial phase anymore. As said above, the first injection was planned for next year or 2026, with two suppliers of CO_2 lined up, and detailed engineering studies had already started.

So, how is it possible that the licence was not awarded? Is the regulator to blame for a change of mind, or did the companies and institutes behind the project move too fast? There is a case to make for both.

If the most recent reservoir modelling work performed by Gas Storage Denmark had not changed any of its inferences with regard to CO_2 migration towards the gas storage site, it is possible that the authorities ultimately took a more stringent stance than what the stakeholders might have expected. There is a comment on LI that suggests something along these lines.

At the same time, it could also be that further study by the future operators changed the scenarios. In the article we published GEO EXPRO Issue No. 6 2023, the authors state that new seismic had been acquired, which should shed more light on the Gassum Formation reservoir in the N / E flank because existing 3D data only partly covered the area of interest. If that is the case, it is odd that the project seemed to be moving ahead even without the latest data being available to confirm that the N / E flank was indeed the best candidate.

In conclusion, it is difficult to point a finger at the party most responsible for this change of plan. However, the question can nevertheless be asked: How serious is Denmark about getting CO_2 into the ground? This project was clearly the most advanced in the country, and even though three new exploration licences have now been awarded, it nevertheless feels like back to square one. ■

Henk Kombrink

SUBSURFACE STORAGE

A leak – but what next?

It is not a good sign that CO_2 has been able to leak into the overburden of a US carbon storage project, but let's focus on improving materials and monitoring rather than halting projects

THE E&E NEWS website, part of Politico, recently published the news that the US Environmental Protection Agency (EPA) issued a violation notice to the operator of the Decatur CCS project in Illinois, USA. A leak related to a monitoring well has caused around 8,000 tonnes of CO_2 to migrate up in the overburden, but it is not thought to have threatened groundwater resources.

The leak was detected in March this year at one of the two monitoring wells at a depth of around 5,000 ft, but the corrosion had been known since about October 2023. The operator of the plant is Archer-Daniels-Midland.

It is important to note that this project is a saline aquifer injection scheme, with wells drilled to contain and inject / monitor CO_2. The injection permit for this project specifically states that "casing and cement or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may be expected to come into contact." It is, therefore, a concern that corrosion has taken place to the extent that CO_2 has been able to leak.

The incident also sparked discussion on social media about monitoring these things more efficiently and promptly. Andres Chavarria from LUNA OptaSense, commented that more and more CCS facilities are starting to be instrumented with fibre optic sensors in order to monitor plumes, induced seismicity and wellbore integrity.

NO STOP

It is of concern that wells drilled with a carbon storage project in mind corrode to a point where leakage occurs. However, if we want geological CO_2 storage to become a major element in mitigating anthropogenically induced climate change, let's not use this project as a tool to shut down projects but rather focus on improving both materials and monitoring techniques. ■

Henk Kombrink

4.5 MILLION TONNES

The Decatur CCS project has been running on and off since 2011, when the first 3-year CO_2 injection phase started. The objectives at the time were to validate the capacity, injectivity, and containment of the Cambrian-aged Mount Simon reservoir while almost 1 million tonnes of CO_2 were injected. The top of the reservoir is at approximately 1,670 m, and its thickness is 450 m. The sealing unit is the Eau Claire Shale, which attains a thickness of around 130 m. So far, a total of 4.5 million tonnes of CO_2 have been injected, and the project is thought to run for a few more years.

A core of the Mount Simon reservoir in which CO_2 is being injected.

PHOTOGRAPHY: ILLINOIS STATE GEOLOGICAL SURVEY

3 million versus 100 k

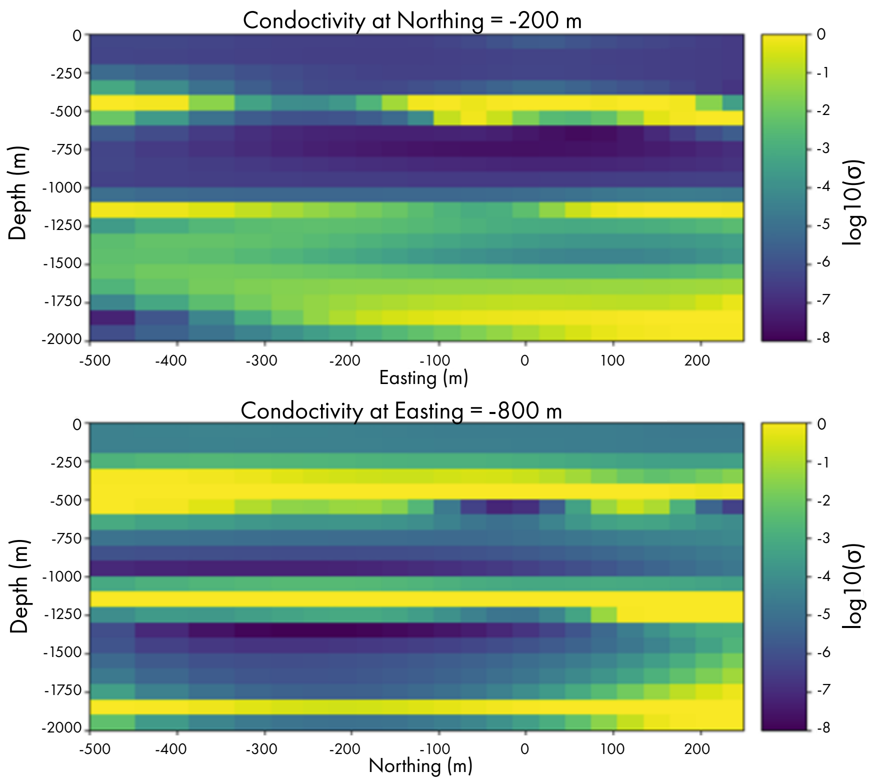
Electromagnetic surveys using airborne methods may be a cost-effective way to monitor CO_2 injection and migration, study suggests

ONCE large-scale CO_2 injection projects will hopefully ramp up, monitoring injection will be an essential part of the workflow. And because the carbon storage business will never be a commercial exercise, there is pressure to come up with monitoring technology that is fast and affordable.

During the recent IMAGE conference in Houston, Colton Kohnke from the National Energy Technology Laboratory presented a study that involved electromagnetic surveys as a means to monitor CO_2 injection. He and his colleagues performed a field test at Kemper CarbonSAFE in Mississippi, USA, whereby electromagnetic measurements were carried out by flying a helicopter across the site.

The financial savings that could be realized using this technology are substantial. Colton said during his presentation that a conventional seismic survey would cost around 3 million dollars, compared to around 100 k for an airborne survey.

In order to map the subsurface, dipole transmitters were put in place along both a north-south oriented as well as an east-west oriented road in the area of the future injection site. The magnetometer was subsequently flown in north-south oriented lines at a distance of 75 m.



Conductivity profiles at two transects across the future injection site. The planned CO_2 injection will take place in the reservoir (yellow band) at 1000 m depth.

SOURCE: KOHNKE ET AL. (2024) - IMAGE 2024 CONFERENCE ABSTRACT 4093586

CONDUCTIVITY

The resulting data were inverted to obtain conductivity profiles in depth, as shown in the figure. It is clear that the top of the top of the saline aquifer earmarked for injection at around 1000 m depth is delineated by a higher conductive interval. However, a second interval of higher conductivity at 300 m was not present on logs of a nearby well, even though literature had suggested its presence.

CO_2 injection is expected to result in a lowering of the conductivity in the reservoir, but the question is whether this signal will be strong enough to be picked up by the tools – at the end of the day, the experiments performed so far are only a baseline survey and actual CO_2 injection is not foreseen for at least two more years.

To estimate the depth of investigation using electromagnetics, the skin depth can be taken as a good approximation. Using a bulk conductivity of 0.25 S/m and frequencies of 0.1 – 10 Hz, the skin depth for a frequency of 10 Hz is 0.3 km, and 3.1 km for 0.1 Hz, meaning these frequencies should be able to detect conductivity changes at the reservoir depth. The biggest uncertainties when it comes to using this technology successfully are cultural noise and the CO_2 saturation in the reservoir. The modelling exercise used a constant saturation of 80 %, which obviously is a simplification and will depend on the distance from the well and the reservoir quality.

But for now, let's hope the injection of CO_2 can soon begin. ■

Henk Kombrink

NEW GAS

"CO_2 produced directly from the subsurface is a more reliable source for the food industry"

Mariël Reitsma - HRH Geology

Dry helium well supplies the beverage industry

With carbon capture and storage high on many an agenda, it seems contradictory that geological CO_2 is still actively produced

THE USA is by far the world's largest geological CO_2 producer, extracted from a small number of high - CO_2 reservoirs. The vast majority of this CO_2, 97 %, is immediately reinjected into the ground to facilitate enhanced oil recovery. The other 3 % is traded on the merchant CO_2 market and bought first and foremost by the food and beverage industry. In the US, geological CO_2 makes up about a quarter of merchant CO_2 but it is a growing segment.

RELIABLE SOURCE

Ethanol refining and ammonia production are large industrial sources. However, CO_2 is only a by-product and hence its production is dependent on the alcohol and fertiliser markets as well as any issues within their supply chain. For example, the UK's food-grade carbon dioxide supply was cut by 60 % in 2021 when two fertiliser plants halted work due to a rise in gas prices.

CO_2 produced directly from the subsurface is a more reliable source for the food industry, bypassing these issues. That does not mean it is not without potential issues though; in 2022 the Jackson Dome reservoir in Mississippi was contaminated when gas from a nearby mine seeped in. The Jackson Dome is a 98 % pure CO_2 reservoir that supplied about 35 million MCF merchant CO_2 per year until problems arose. The resulting shortages and resulting CO_2 price hike triggered several North American operators to start profiting from the CO_2 that has been present in their hydrocarbon and / or helium reservoirs all along.

For example, Royal Helium built a processing and purification facility at its Steveville project in Alberta, Canada. The production plant produces pure helium and food-grade CO_2. The limited ancillary methane produced from the wells is recycled back into the facility to power its operations and only nitrogen is vented to the atmosphere.

EXPLOITING CO_2 DISCOVERY

Blue Star Helium's Galactica/Pegasus prospect in Colorado contains 2 – 6 % helium in the Lyons Formation. However, once its chilled distillation facility will be completed, it will start capitalising on the 40 – 70 % CO_2 that is present in the gas stream as well. Yet, the company's main CO_2 production will come from the nearby Serenity field, where exploration drilling in 2022 did not result in the discovery of helium but >98 % CO_2 instead. Blue Star quickly pivoted into this sector and will now supply the beverage industry from its 'dry' well. ■

Mariël Reitsma, HRH Geology

GEOLOGICAL CO_2

There are several ways in which CO_2 is generated in the subsurface. At depths up to ~2 km, it can be formed by biogenic activity through the bacterial decay of organic material. At greater depths, CO_2 can be the product of late-stage thermal maturation of kerogen. However, CO_2 is also found in metamorphic settings in the absence of organic material. In this case, CO_2 results from metamorphism of impure carbonate rocks. CO_2 in reservoirs that lack methane or other hydrocarbons most likely has a metamorphic origin. This could well be the case for Blue Star's acreage in Colorado.

Lyons Formation outcropping in Roxborough State Park, Colorado. Blue Star produces helium and CO_2 from the Lyons sandstones in Las Animas county.

PHOTOGRAPHY: TILTEDFRAMEPHOTOGRAPHY VIA PIXABAY

Helium One's bumpy road to success

Exploring helium in the Rukwa basin of Tanzania has been a steep learning curve for Helium One. Here, we summarise the trajectory that led to the discovery of very promising helium concentrations this year. It took a few wells, rigs, and various conceptual models to get there

FIRST OF ALL, the rig. Helium One used a slimline mining rig during the initial exploration campaign that started in 2021. This is probably a contributing factor to a range of hole stability and data acquisition issues in the Tai-1 well. A sidetrack had to be drilled, but yet again, wireline logging could not be run. However, thanks to cuttings and mud gas data, helium shows were still confirmed in the deeper Red Sandstone and Karoo Group.

After operations at Tai-1/1A came to an end, it was concluded that the largest helium show of 2.2 % was detected at a relatively shallow depth of 70.5 m in the Lake Beds. This subsequently became the main target in the next well, Tai-2.

The location of Tai-2 was probably chosen for logistical reasons as well, as the well was drilled from the same pad. Despite the tiny offset distance of 20 m, the geology played hide and seek, and the sand that had been found in Tai-1 had pinched out at Tai-2. No helium show, and back to the drawing board.

For the phase II drilling campaign in 2023/24, the company must have decided to go deeper again, but better equipment was needed. Therefore, a proper oil rig was bought with the ability to reach a depth of 2 km. At that time, the play concept was probably to drill into a deeper reservoir, and major faults were avoided.

The Tai-3 well finally enabled the Karoo Group to be fully assessed, but a continuous helium-bearing reservoir was not found. Instead, a fracture zone yielded the maximum concentration of 0.8 %, and helium was also detected at top basement but could not be accurately measured.

That is why it was decided to test the basement connection with the next well, Itumbula West-1, and target two major fault zones, both in the Karoo Group as well as in the fractured basement itself.

GREEN HELIUM

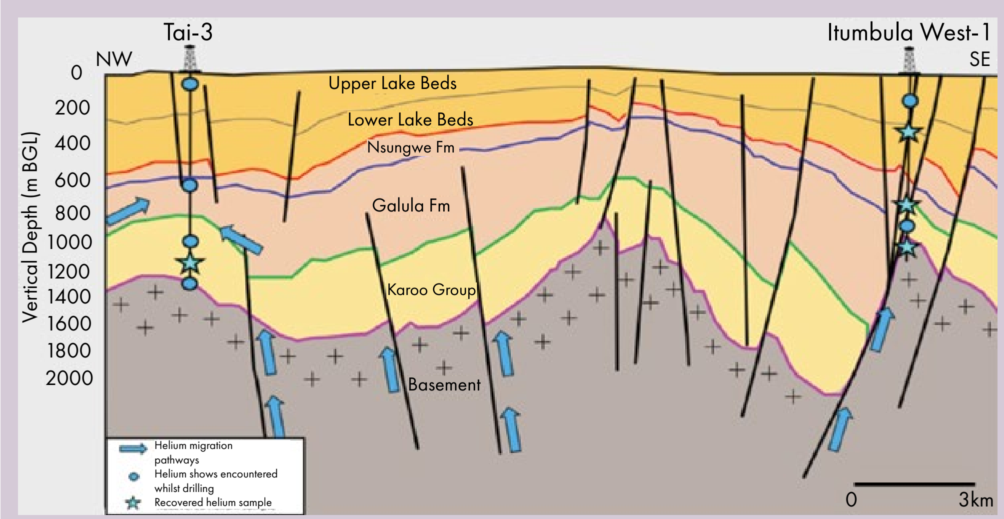
The helium being tapped into is not present as a free gas but dissolved in hot fluids. As the fluids rise to the surface, the gas comes out of the solution. The gas is a pure helium and N_2 mixture, making it a 'green' helium accumulation.

This change of concept paid off, with an extended well test on ITW-1 flowing a sustained average of 5.2 % helium from the faulted Karoo Group and 5.5 % helium from the fractured basement.

It took some perseverance and changing strategies, but now Helium One seems to be on to something and has filed a commercial development licence. This is not for a "classic" reservoir but for a dynamic fault-related resource instead. ■

Mariël Reitsma, HRH Geology

SOURCE: HELIUM-ONE.COM



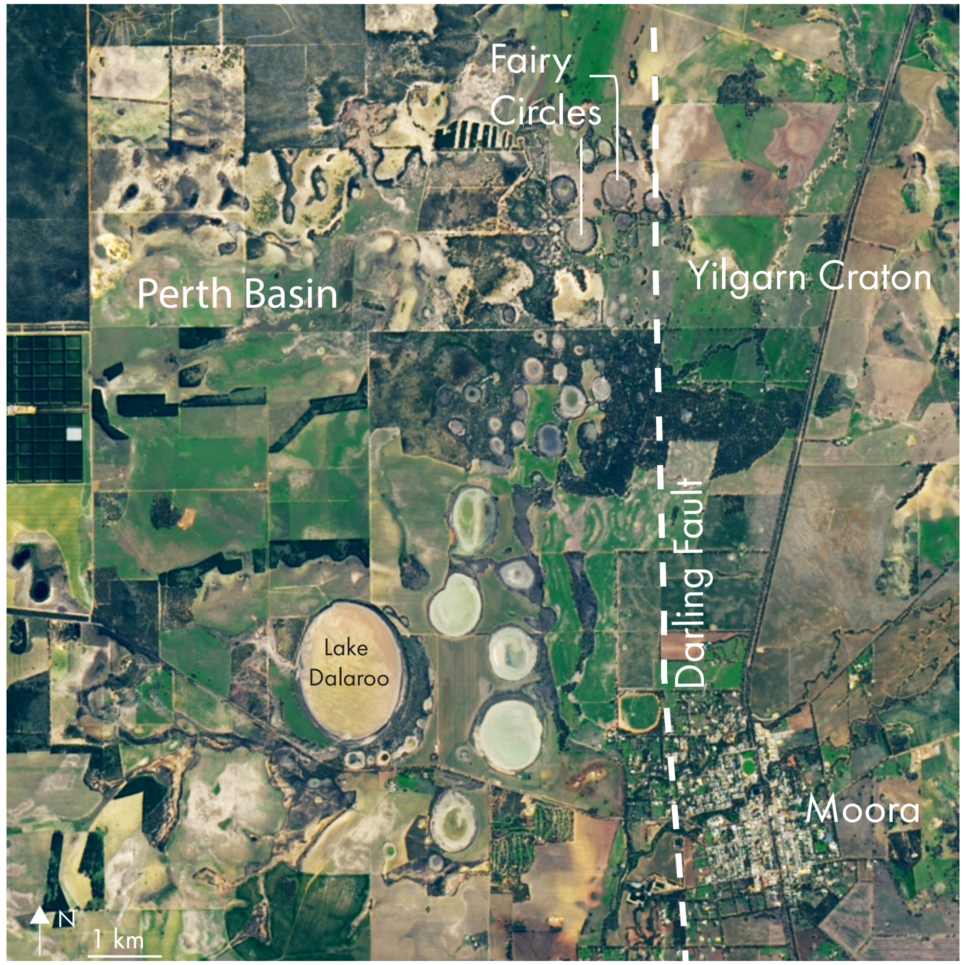
Compare the setting of the Tai-3 and Itumbula West-1 wells – a non-faulted versus faulted penetration. The highest helium concentrations were found in the latter.

Fairy circles

Rather than looking for hydrogen in legacy wells, let's go and ask the fairies

Companies exploring for natural hydrogen are rapidly popping up everywhere, but how do the geologists decide where to start prospecting? Many of them look at historical data from "dry" hydrocarbon wells to see whether they accidentally found hydrogen instead. However, subsurface H_2 is formed by processes different from hydrocarbons, and hence, locations that were never on the radar for oil exploration might well be a good prospect for hydrogen.

So, rather than looking at legacy wells, exploring areas with known H_2 surface seeps is also a good place to start. It has been found that H_2 surface seeps regularly create easy-to-spot pockmarks at the surface, often called 'fairy circles'. These semi-circular depressions are frequently filled with water and have vegetation growing around the edges. Fairy circles have been found all around the world, with examples in Russia, Mali, Brazil, the United States and Australia.



Satellite image showing the fairy circles near the town of Moora, Western Australia. The circular depressions are aligned along the Darling Fault, a major crustal boundary between the granitic and (ultra)mafic rocks of the Yilgarn Craton to the East and the sedimentary rocks of the Perth Basin to the West.

SOURCE: NASA

In the satellite image shown here, we see the many fairy circles near the town of Moora, located 150 km north of Perth in Western Australia. The fairy circles, locally known as salt lakes, vary in size from tens of meters to over a kilometre in diameter. They form a band along the eastern edge of the North Perth Basin, separated from the Yilgarn Carton by the Darling fault.

HYDROGEN GENERATION AND CHALLENGES

The hydrogen is thought to be generated via serpentinization processes in deep aquifers that are in contact with Archean iron-rich basement. The gas subsequently migrates to the surface via the extensional fault network. Soil samples show that the fairy circles mainly seep H_2 around their perimeters.

Yet, the discovery of H_2 surface seeps does not automatically pave the way to announcing a commercial find. In contrast, the fact that seepage occurs can equally be an indication that the gas is not efficiently trapped in the subsurface. Therefore, additional work is required to firm this up.

The H_2 seeps near Moora are all closely aligned with the Darling fault zone, which most likely acts as a conduit for the upward-migrating H_2. Towards the centre of the Perth Basin, where fewer faults transect the overburden, it may be more likely that an H_2 reservoir can be found if the play conditions of source, reservoir, and trap all prevail. ■

Mariël Reitsma, HRH Geology

DEEP SEA MINERALS

"Our decisions must be made on knowledge – if we fail to produce enough electricity in the years to come, we will take many steps backwards as a society"

Terje Aasland – Minister of Energy, Norway

New mineral discovery in the Norwegian Sea

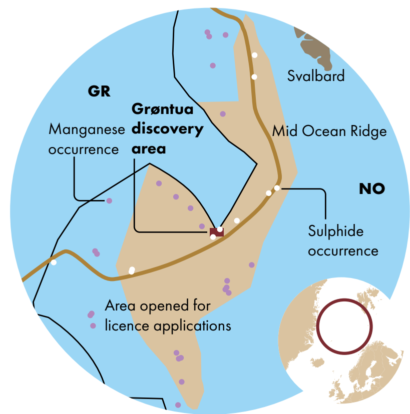
The Center for Deep Sea Research discovered a new sulphide deposit on the Mohns Ridge. The discovery was made close to last year's major discovery, Deep Insight

GRØNTUA IS the name of the new sulphide deposit that was found during a trip under the auspices of the Center for Deep Sea Research at the University of Bergen (UiB) this summer.

The voyage, which took place in the Norwegian Sea and the Greenland Sea from 24 June to 12 July, aimed to increase knowledge of the deep sea, where both environmental and geological data were collected. It is the Norwegian Offshore Directorate (NOD) that reported the discovery.

Grøntua is located at a depth of 1,175 m on the Mohns ridge, has a diameter of 150 m and extends 60 m above the seabed. The deposit has not been drilled, but seven samples of the deposit were collected using the grab arm of UiB's remotely operated underwater vehicle (ROV) Ægir 6000. The samples have not yet been analysed, but the NOD writes that the presence of the mineral atacamite indicates that the deposit may have a high content of copper.

The inactive sulphide deposit was found on a hill where the EMINENT research project discovered the Deep Insight deposit last year. Deep Insight was discovered by chance when the partners in the research project were testing drilling equipment. Grøntua is located approximately 1 km west of Deep Insight. The voyage in 2024 was carried out with the research ship G.O. Sars.



MODIFIED MAP BASED ON THE CENTER FOR DEEP SEA RESEARCH

FAR MORE TO FIND

The number of known active and inactive hydrothermal deposits increases from year to year. At the time of writing, ten active deposits and four inactive deposits have been found.

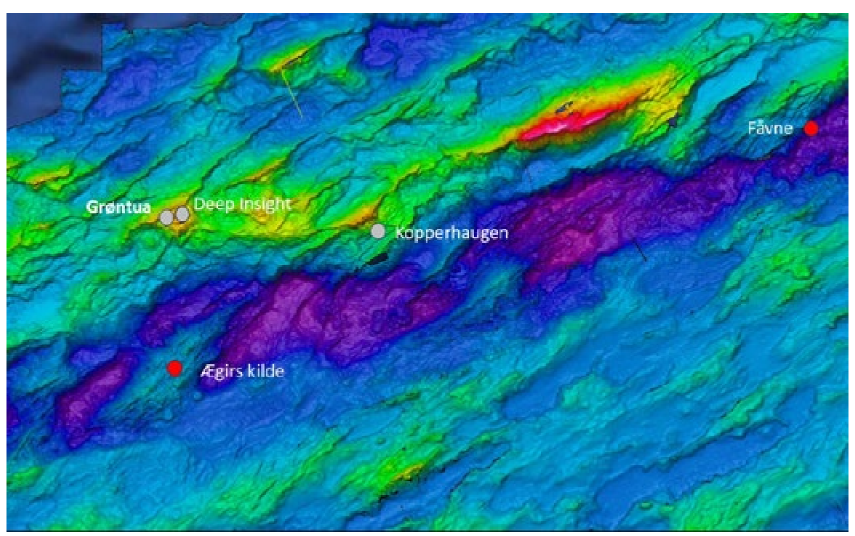
From a resource perspective, it is the inactive, extinct fields that are of interest. According to the Seabed Minerals Act, active deposits are protected because they create the basis for unique ecosystems. It is also more technically demanding to operate in the extreme temperatures that occur where boiling water flows out from the seabed.

The Center for Deep Sea Research, led by Rolf Birger Pedersen, has been central to the exploration of the deep sea for a number of years and is behind many of the discoveries of active and inactive sulphide deposits that have been made so far.

There is, nevertheless, good reason to believe that new discoveries will continue to be made in the years to come. In the first half of 2025, the Ministry of Energy will award the first licences so that commercial players can begin exploration activities. Mapping under state auspices will continue in parallel with this.

It is primarily the Mohns Ridge that is prospective with regard to sulphide deposits due to their location along the mid-ocean ridge. The NOD has estimated that - under certain conditions and assumptions - around 1,000 deposits can be found. ■

Ronny Setså



Terrain model over the central part of the Mohns Ridge. Grøntua and last year's discovery Deep Insight are located at the same height, 1 km apart. Gray circles indicate inactive deposits, red circles active ones.

Joining the race

India is working on its "Deep Ocean Mission" to further develop deep-sea mining technology

WHEN LOOKING at activities when it comes to the development of deep-sea mining technology and the licensing aspects of it, it is easy to be drawn to the news around the Pacific Ocean, where the Clarion-Clipperton zone is receiving a lot of interest, as well as Norway, where the first deep-sea minerals licensing round opened up this year. However, countries like Japan and also India are actively working to harvest metals from the deep sea. Here, we look at the program currently being developed in India, which is mostly based on an article that appeared in The Hindu in October last year.

India's efforts to explore and exploit the deep seas form part of the Deep Ocean Mission, which is a five-year program launched in 2021. As part of this, both unmanned and manned missions to the bottom of the deep sea have been planned and been carried out.

In 2022, India's underwater vehicle called "Varaha" was used to harvest polymetallic nodules, potentially providing a source for copper, manganese, nickel and cobalt, from a record depth of 5,270 m. Situated in the Indian Ocean, it travelled a distance of 120 m during a timespan of 2.5 hours. It operated with a flexible riser technique: The vehicle was lowered to the ocean floor from a vessel using a high-strength flexible cord system. Once in position, a pressure pump sucked up the polymetallic nodules and transported them to the surface.

The next step in the journey towards getting the nodules to surface on a larger scale is to crush them at depth and pump a slurry upward through the riser. As the article in The Hindu describes, a challenge with this system is to supply the power to the system at depth.

Rather than only using unmanned vehicles, India is also building the Matsya6000, a deep-ocean submersible designed to accommodate a crew of three members capable of going to a depth of 6,000 m. This vehicle will be used to carry out further research into the deep-sea environment. The Matsya6000 submersible has an operational endurance of 12 hours, which is extendable to 96 hours in the event of an emergency. The first journey to 6,000 m is expected to occur in the next two years. ■

Henk Kombrink

SOURCE: MILLER KA VIA OAEPUBLISH

Indian Ocean distribution of the four primary classes of metal-rich deep-ocean mineral deposits: polymetallic nodules, polymetallic or seafloor massive sulphides, cobalt-rich ferromanganese crusts, and REE-rich muds.

WHERE CAN DEEP-SEA MINERALS BE FOUND IN THE INDIAN OCEAN?

Deep-sea minerals are mostly associated with nodules, which form on abyssal plains only in areas where sedimentation rates are very slow, crusts forming on seamounts by the precipitation of colloidal components from seawater or sulfide vents that mainly occur at ocean spreading ridges. All three types are present in the Indian Ocean. At the same time, recent studies have also shown that pelagic muds may contain significant amounts of rare earth elements, as research carried out around Hawaii and Japan has demonstrated.

The polarising debate about seabed minerals

With the title "rescue or destruction", it was inevitable that the debate about Norway's next potential offshore industry would be filled with strong exchanges of opinion. However, the Minister of Energy gave a good account of the ongoing opening process

THIS YEAR, the Norwegian parliament opened up the continental shelf for mineral exploration activities. After a public consultation and tender process, the Department of Energy is scheduled to award companies the first exploration licences on the Norwegian continental shelf in 2025.

Anette Broch Mathisen Tvedt (Adepth Minerals), Jan Erik Saugestad (Storebrand) and Hildegunn Blindheim (Offshore Norway).

SOURCE: ARENDALSUKA (VIDEOSTREAM)

The opening process has been done step by step and has provided and will provide increased knowledge about the environmental and resource conditions in the deep sea, in parallel with the emergence of a new industry.

However, the discussion about whether Norway is ready to open up for exploration and possible future extraction of the marine mineral resources has at times been polarising. This was the case when industry, the authorities, the environmental movement and academia met during Arendal Week in August, Norway's annual conference where policymakers and the public meet.

The Ministry of Energy indicated that it would be a cautious opening process, with the objective of the opening being to assess whether marine mineral resources can be extracted economically and sustainably. It also emphasised the need for self-sufficiency in minerals due to the energy transition, for geopolitical reasons and in terms of how some mineral supply countries (e.g. China and Russia) relate to health, safety and the environment.

It also stated that the start of exploration will allow the acquisition of the knowledge required of the deep sea and its ecosystems and that this will happen under the auspices of the state. A license gives companies the right to explore but not to extract, and that experience in the oil and gas industry means that Norway is in a good position to obtain environmental knowledge and has the technology to do things properly.

OPPOSITION

The Green Party (MDG) and WWF stated that there is insufficient knowledge about the deep sea, that the opening was just an irresponsible experimental project, and that experts and the Norwegian Environment Agency have been sidelined. The WWF believes that the decision has been based on a flimsy and insufficient basis. As a result, the organisation is sueing the state. They also questioned whether there was actually a need for deep-sea minerals. They pointed out that 50 large companies have said no to such minerals in their value chains and that the EU also wants a moratorium.

THE INDUSTRY PERSPECTIVE

In addition to the environmental movements concerns, Storebrand Asset Management supports a delay in extraction of deep-sea minerals and is unwilling to invest until it is sure of the consequences. As a result of this, it has excluded companies that are planning such activities and has sold out of The Metals Company. Storebrand does, however, continue in dialogue with Kongsberg and Wilhelmsen.

A TRADE-OFF

At the end of the discussion, the Minister of Energy reminded all participants that the energy transition is marred with dilemmas and that difficult choices and trade-offs must be made. "Our decisions must be made on knowledge – if we fail to produce enough electricity in the years to come, we will take many steps backwards as a society." ■

Ronny Setså

DEEP SEA MINERALS

Deep Sea Minerals 2025 - Call for Papers

Critical knowledge – Critical technology – Critical minerals

We are pleased to announce that one of the leading international conferences on Deep Sea Minerals will be organized for the fourth time in 2025. The event will take place in Bergen, Norway from 01-03 April 2025.

The initial conferences attracted a large and diverse group of stakeholders from across the globe, including exploration companies, service providers, academic professionals, politicians, environmental advocates, regulatory bodies, and individuals with expertise in law and finance. With the industry's imperative to establish connections, exchange knowledge, and draw on each other's expertise, we are certain that another well-attended and stimulating conference lies ahead of us.

A MOMENTOUS YEAR AHEAD

As we approach 2025, a new global industry is emerging, with Norway being one of the deep-sea mineral hotspots. Since the Seabed Minerals Act was enacted in 2019, Norwegian authorities have been diligently advancing the opening process. The first permits are expected to be granted to exploration companies in the first half of 2025.

Internationally, many companies are positioning themselves in the Clarion-Clipperton Zone in the Pacific Ocean as the International Seabed Authority is working towards completing the exploitation regulations. State-sponsored institutes and commercial companies are conducting extensive surveys, leading to significant advancements in our understanding of the environment, operational challenges, and the resource itself – polymetallic nodules.

In another part of the Pacific Ocean, the Cook Islands authorities oversee the exploration efforts of three companies that were granted licenses around two and a half years ago.

There have also been notable developments in research and technological advancements in a number of other countries.

Globally, knowledge-building and technological advancements are progressing rapidly as the industry evaluates transitioning from exploration to exploitation. We invite companies, institutions, and academia developing new methods, workflows, and technology or showing outstanding results in deep-sea minerals research to submit an abstract.

WE INVITE CONTRIBUTIONS WITHIN THE FOLLOWING TOPICS:

- Advancements in understanding the deep-sea environment
- Strategies, challenges, and opportunities for effective environmental assessment and monitoring
- Exploration strategies and technology: Methodologies, workflows and technologies
- Data management and digital solutions: Case studies and evaluations of DSM data sets, best practices
- Innovations in deep sea mineral extraction – technologies and recent advancements
- Advancements in deep sea mineral processing
- Insights and synergies from land-based mining throughout the value chain
- Regulations and legal frameworks in deep-sea mineral resource management

The program committee welcomes contributions on the topics from all relevant regions across the globe. We encourage postgraduate students to submit their work.

Take the plunge and join us to share your knowledge at the upcoming conference by sending your abstract to events@geopublishing.no by 09 January 2025.

Abstract requirements
Word format
Font: Times New Roman, 12 pt.
Min. 500 words
Min. one figure

DIGITALISATION

"… before you conclude that gamification is a matter of adding points or badges to stimulate people from doing their jobs, that's a misconception"

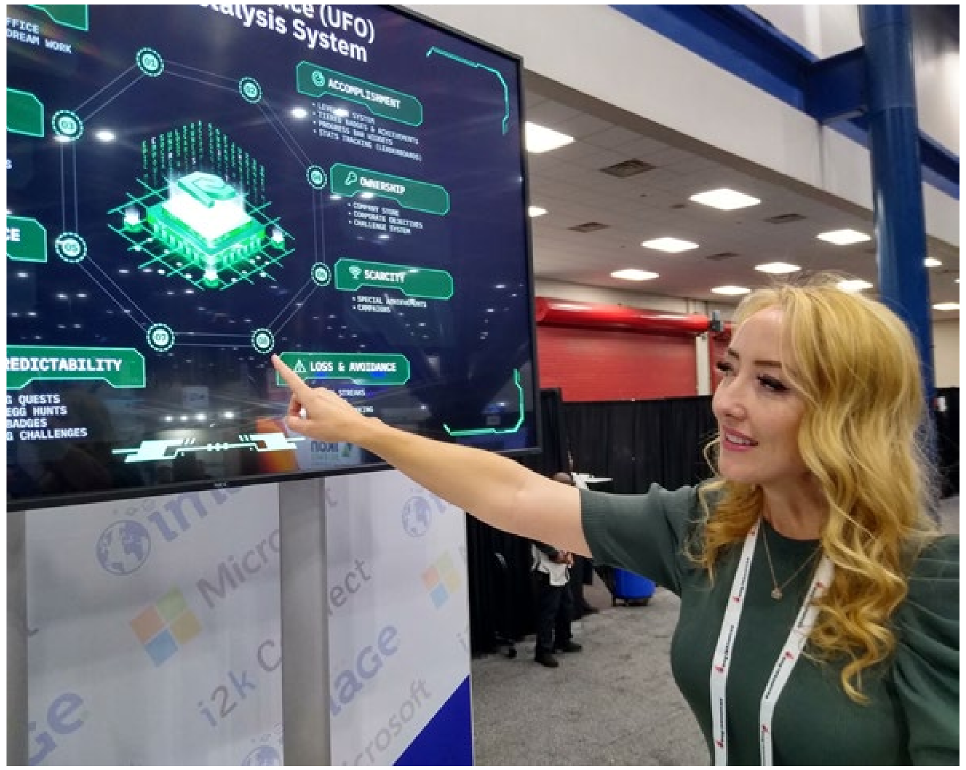
Yu-kai Chou – TED talk

The gamification of the oil and gas industry

Introducing a game element in routine workflows leads to higher productivity

"IMAGINE A WORLD where labour is obsolete", says Yu-kai Chou at the start of a TEDx Talk delivered for the University of Lausanne in Switzerland in 2014. "And I'm not talking about a world run by robots", he continues, "but a world that harnesses the power of play." That's what gamification is all about. It has been around for about four years already", says Yu-kai Chou in his talk.

"And before you conclude that gamification is a matter of adding points or badges to stimulate people from doing their jobs, that's a misconception", says Yu-kai. "The thing that really drives people to get on with something that may otherwise be boring is when it is challenging and motivates core drives."



Erin Fair showcases the software her company developed.

PHOTOGRAPHY: HENK KOMBRINK

BEHAVIORAL CHANGE

In his talk, Yu-kai provides eight examples of introducing a game element into a non-game environment to drive behavioral change. One deals with the question of how to make people more mindful of their energy consumption. One energy company came up with the idea to provide statistics not only of people's own use but also include figures on what the neighbours are doing, with the "best" neighbours and "average" neighbours' energy use provided as a benchmark. This subsequently caused a significant energy-saving drive across the entire client base - a very good example of how gamification drives behavioral change.

RESNET CASE STUDY

Gamification is now also making its way into the oil and gas industry. Yes, oil and gas has a record of being a little bit slow when it comes to the uptake of new ideas…

At the Digitalisation Pavilion during the recent IMAGE conference in Houston, Ryan Rice and Erin Fair from ResNet demonstrated a recent case study on the use of gamification in the production and operations software they developed.

In the case of Ryan and Erin's example, it is about operating and inspecting software for oil and gas infrastructure, where workers had to routinely input observations to check the integrity of pipes and valves. How to make sure that all elements are routinely inspected?

MOTIVATION

"We introduced gamified features that enable our users to see how they are fulfilling the tasks at hand", says Erin. "This way, it may either form a deeper motivation to do better or provide confirmation that the job is done well. It also forms a great and more objective basis for their annual review."

"Since the introduction of the new software, we have seen a clear uptick in data collection across the facilities where our software is being used", says Erin. This is a clear indication that a true behavioural change has taken place. ■

Henk Kombrink

DIGITALISATION

A seismic facies library

A new approach for generating a library of seismic facies patterns helps automate and speed up the interpretation process

SEISMIC facies classification can be a tedious process, especially in an exploration context where large areas need to be assessed. In order to speed up that process, using a library of seismic facies patterns from a benchmark dataset can help map the 3D distribution of seismic facies in an automated way.

Hui Gui, representing a group of researchers from the University of Science and Technology of China (Hefei), gave a talk at the recent IMAGE Conference in Houston, during which he illustrated how a large collection of benchmark seismic facies patterns was put together. Both the datasets and the codes have been made available online for anyone interested to know more.

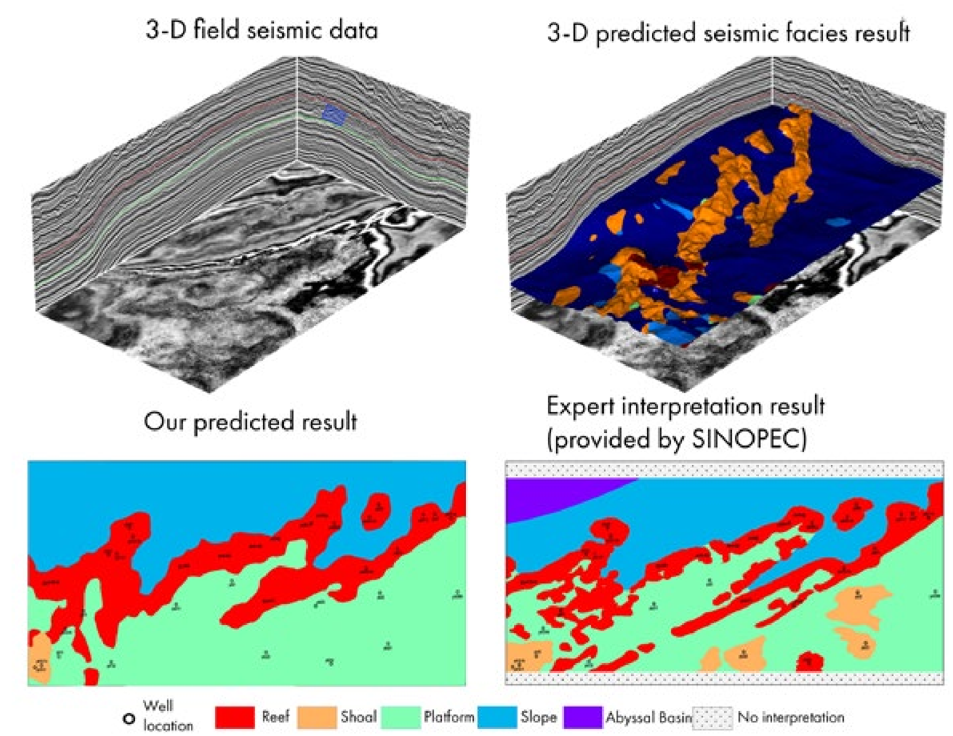
HOW TO BUILD IT?

But how to make sure that a library of seismic facies patterns covers the diversity observed in the real world? In order to do that, the team worked with a three-tier strategy.

First of all, they built a portfolio of characteristic seismic facies from public domain data. These datasets, being from different seismic vintages and areas, were standardized through a spectral analysis exercise.

Due to the lack of diversity in examples from public domain sources, as a second step the authors also generated synthetic facies samples based on prior knowledge of seismic facies. But even though a noise factor was introduced in this process to arrive at a more real-world representation, this dataset still suffered from a lack in diversity and realism.

To overcome the issue, as a final step, the team used the images generated in the first and second stages as training datasets to train a so-called GAN model. The progressive growing of a GAN model consists of a generator model (G) and a discriminator model (D), where G is used to capture the data distribution and generate fake images to resemble the training dataset, and D is used to assess the probability that images are real or fake. This training strategy allows the network to learn the features of the training dataset from large to small scales, resulting in faster training speed, higher stability, and better-quality images. After training the GAN model, the generator model (G) was used to automatically generate diverse samples.



The workflow includes a sliding window scanning the entire 3D target section, yielding the seismic facies classification results. Then the corresponding sedimentary facies is obtained based on the predicted seismic facies result, well log information, seismic data and geological and geophysical expertise. The predicted sedimentary facies result is consistent with the expert interpretation results.

SOURCE: HUI GAO ET AL. (2024)

THE TEST

The authors subsequently showed how the model was applied to a 3D seismic dataset using the Yuanba 3D as an example – shown here. They showed that an expert interpretation of a series of carbonate reefs and slope areas were correctly predicted by the model.

During the Q&A, someone from Chevron remarked that the benchmark dataset seemed to have been built using unfaulted seismic data, implying that faults may hinder the automatic interpretation process. The author replied that this will be part of future work. ■

Henk Kombrink

Data fabric architecture – the solution to explore better?

Making relationships between data visible in graphs helps expose trends that could otherwise be missed

Geologists like visuals. That is why Puneet Saraswat and his colleagues from Querent AI are a step ahead already, because they create visuals, out of large collections of reports. They don't call it visuals, though, but semantic knowledge graphs. Not as easy a word as a "visual", but the result is the same.

At the recent IMAGE conference in Houston in August, the Querent AI team presented about their latest technology: How semantic knowledge graphs provide a meaningful and searchable data representation, linking information that is present in disparate datasets. Relationships between entities such as geological structure, geological rock, geological periods, people, and events are thus made visible.

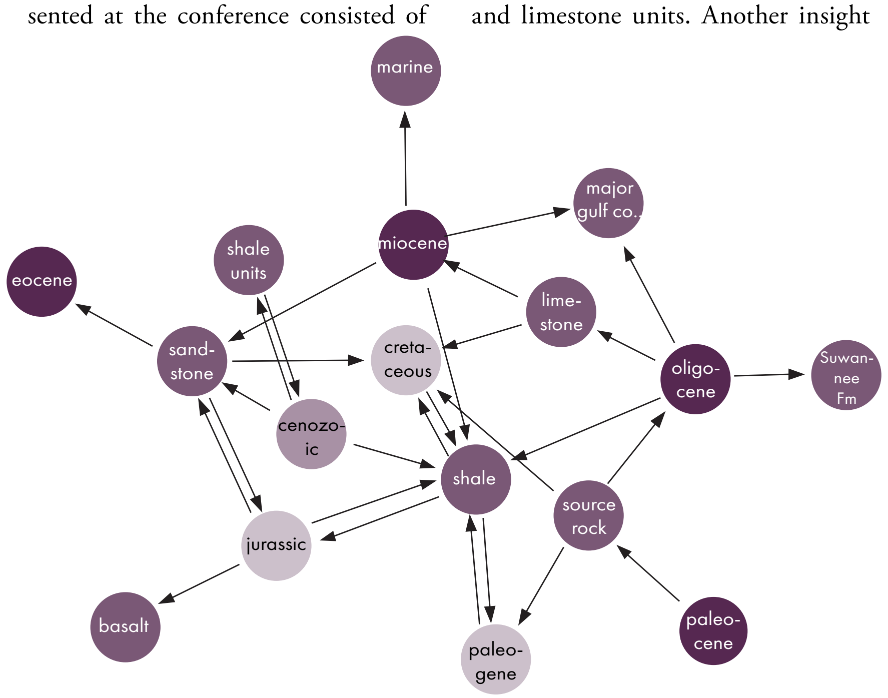
The dataset used in the work presented at the conference consisted of around 1,500 peer-reviewed scholarly publications on various major basins to demonstrate the capabilities of the proposed semantic graph computing method.

Here, an example output graph is presented highlighting the Gulf of Mexico (GOM) basin, one of the important petroleum basins in the world. Where traditional geological data analysis methods may struggle with information retrieval and interpretation spanning the entire dataset of literature, this methodology will cover it all.

The figure shows a semantic knowledge graph visualization of a query examining the GOM basin's stratigraphic record. It is clear that the basin underwent a transition from the Jurassic to the Cretaceous period, highlighted by the formation of basalts and sandstones that evolved into shale and limestone units. Another insight seen is the prevalence of shale units in the Cenozoic era, reflecting a time of intense sediment supply.

There is no doubt the Querent AI algorithm is able to troll through large datasets much more quickly than any human will ever be able to do, highlighting important geological trends. I do, however, feel that whilst it is efficient in extracting these trends, the thing about exploration is to spot something that has not been investigated very much yet, or challenge an idea that exists in the literature. In my view, that is an aspect of exploration that will still be hard to replace using AI. With that in mind, I would probably use this as a first step in getting more familiar with a basin before embarking on a more critical assessment of the individual petroleum play elements. ■

Henk Kombrink



Semantic knowledge graph showing the sedimentary and tectonic evolution of the Gulf of Mexico basin.

HOW IT WORKS

Before entering the semantic graph-building logic, the software operates with parallel workflows for asynchronous data ingestion and LLM (Large Language Model) processing. Following the identification of all references to entities, semantic relationships and associated metadata are extracted and stored in a graph database with structured ontologies. Ontologies are a blueprint for transforming data into meaningful categories and relationships that support more advanced analyses.

SOURCE: GUPTA ET AL. (2024) – IMAGE CONFERENCE ABSTRACT 4093638

TECHNOLOGY

"And that is because we speak the language of the people who work in the field"

Amoin Qaderi - BITCAP

The new kids on the geosteering block

Three wellsite geologists from Calgary decided to develop their own software following years of working on the rig site

FOR SOME people, the pandemic came at the right time. That certainly applies to wellsite geologists Amin, Ammar and Rafi representing BITCAP, a new start-up that released its first commercial version of geosteering software about eight months ago. Before Covid hit, they were simply too busy working in the Alberta oil patch, where they had been drilling wells since graduating from university in 2006.

"Only when our agendas were wiped and little new work came in, there was time for other things to do", says Ammar when I bumped into them at the IMAGE conference in Houston in August this year.

In the fast-paced drilling environment, these guys had numerous other responsibilities to manage. They were increasingly frustrated with the software they were using on the rig, especially the abundance of redundant operations and the unnecessarily complex steps for simple tasks. Visualizing that information in one view was an equal challenge.

On top of that, during the pandemic, there was one geological formation that became a drilling hotspot in Alberta – the Clearwater Formation. This Lower Cretaceous sandstone, which is not deeply buried and unconsolidated, became the center of activity because drilling it is relatively cheap, and fast. Penetration rates of up to 400 m per hour can easily be achieved in this formation, putting even more strain on the ability to do all the routine tasks of a wellsite geologist. At the same time, geosteering is important in this formation because of the presence of calcite stringers against which the drill bit tends to deflect.

So, Ammar, who has had a strong interest in software development from a very young age, met Ajaz Karim, BITCAP CEO and former geology and GIS professor. They decided it was time to develop something new, a geosteering software with GIS functionalities together with striplog features and they quickly came up with the first version of what is now Pathfinder.

But once they had the prototype, the job of getting the software to market began.

Earlier this year, the team went to their first conference, Geoconvention in Calgary. "We clearly experienced some skepticism, but it seems like we have overcome that hurdle in the Alberta community already, says Amin.

> "And that is because we speak the language of the people who work in the field."

As the company expands, both Amin and Rafi continue doing their roles as wellsite geologists, while Ammar and Ajaz have focused on software and business development. The drive, joy and energy of these guys is infectious, and I am looking forward to following their expansion into the upstream sector. ■

Henk Kombrink

Wellsite geologists and entrepreneurs Rafi, Ammar and Amin (from left to right) show their software at IMAGE, Houston.

PHOTOGRAPHY: HENK KOMBRINK

A 1 % error margin is not acceptable anymore

Anwar Sutan developed technology to make sure that the reported gas composition exported from a production platform matches exactly what came out of the wells

IT IS SOMETHING that many geoscientists may not think about daily, but there is a whole community in the upstream oil and gas sector that is working to make sure that the volume and composition of hydrocarbons exported through pipelines are properly measured or metered. At the end of the day, it determines how much companies are being paid.

Where simple analogue devices had to do the job years ago, with the ability to measure more accurately and having the data processed and transferred to the cloud straight away, the possibility has arisen to perform these measurements more precisely than ever. And that is exactly the opportunity Anwar Sutan saw after spending some years in the metering business. To realise this, something unexpected had to happen first.

"If my visa application had not been rejected in preparation for my next job in Singapore", Anwar tells me when we meet at his company's office near the airport in Aberdeen, "we would not be sitting here today." But his application was rejected, and it presented him with the spare time he needed to develop the first version of the software that is now known as GCAS.

Anwar is not a geologist, nor a geophysicist or reservoir engineer. He is an electrical engineer with a background in the metering business. He runs i-Vigilant, a small outfit that not only maintains gas chromatographs (GCs) that are fitted on production platforms, but also develops the software to make sure that these important devices run accurately. And it is the latter part that has made the company, no matter its modest size, to a global player with contracts to most of the majors.

"I was always thinking critically about the methodology", Anwar continues. Calibration of GCs is sometimes regarded as being sufficient to ensure accurate measurements are made, but who says that the calibration was done correctly? There are very small variations in the gas content of calibration gases, too, combined with non-linear behaviour of the machine, all contributing to a lack of accuracy.

"Our software continuously monitors these things", says Anwar, "and will ring alarm bells when something is not right. This can translate into a difference of a couple of hundreds of thousands of dollars on a monthly basis", Anwar concludes. ■

Henk Kombrink

Anwar Sutan in i-Vigilant's workshop in Dyce, Aberdeen, showing one of the gas chromatographs his company services.

PHOTOGRAPHY: HENK KOMBRINK

A GOOD BUSINESS ENVIRONMENT

Anwar, who is originally from Indonesia, has been in the UK for 15 years. He is very positive about doing business in the country he now lives in. "People tend to respect each other's time, the industry is eager and interested in improving business practices using new technology, and there is transparency. Anwar's company i-Vigilant currently employs eight people and operates from an office and linked warehouse near the airport in Aberdeen, Scotland.

A step-change in sub-salt imaging

One of the last remaining Gulf of Mexico frontiers can now be better de-risked than ever before

When Sid Kaufman, a geophysicist at Shell in Houston, performed the first offshore seismic survey in the Gulf of Mexico in 1937 using a few shrimp boats he used from a group of fishermen, a colleague told him that there was no point doing it because drilling in 64 ft of water was never going to happen. Equally, the reflections they saw at 9,000 ft were considered impossible to ever reach with the drill bit.

MAPPING SALT BODIES

Yet, here we are in 2024… During the Michel T. Halbouty lecture at the recent IMAGE conference, Bill Langin from Shell gave an interesting overview of the key figures in his company who drove seismic innovation and how thinking outside the box has contributed towards the landscape we look at today – mapping salt bodies at great depths in the deepwater Gulf of Mexico (GOM).

And with mobile salt being such a prohibitive feature when it comes to better imaging the subsurface, today's technological developments have focused on better mapping large velocity variations. "Exploration-based node acquisition is the next game-changer in that respect", concluded Bill during his talk.

This game-changer was needed. In the early 2000s, Shell's amplitude-driven portfolio of Miocene targets creamed after a few dry wells in the GOM. The only way to increase the drilling success rate was to get better data.

GARDEN BANKS

And better data is now available, as illustrated by Michael Merritt from Shell, who also presented during IMAGE before a standing-only audience at the very end of the last day. He discussed the Garden Banks protraction area in the GOM, which is known for its poor subsalt imaging.

In this area, a thick evaporite succession and multiple episodes of salt advancement resulted in a complex system of irregular salt canopy. Streamer data, even with increased offsets to around 15 km, has not been able to significantly improve the imaging of the subsalt geology.

LOW FREQUENCY IMAGE

In order to unlock prospects in the area, Shell commissioned the acquisition of a long offset (60 km) ocean bottom node (OBN) survey, in combination with a new marine source, to improve the low-frequency signal-to-noise ratio. Even though this was the first full-scale acquisition of this kind,

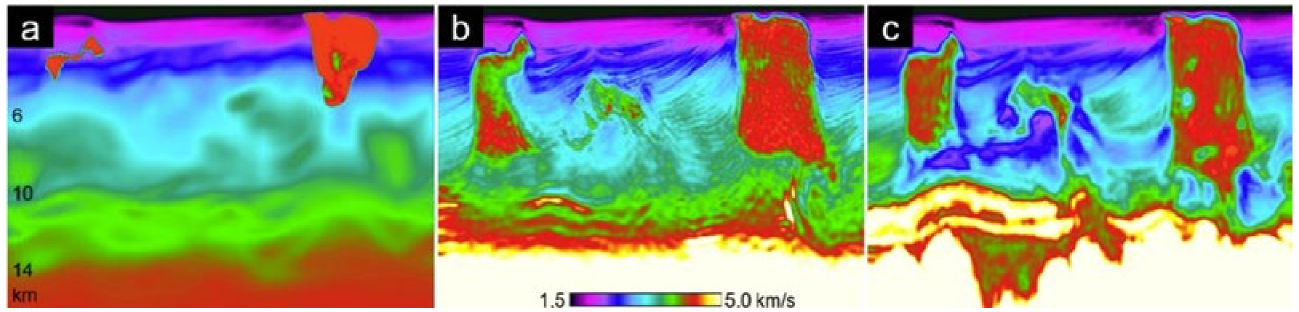
the results were much better than previous data, with rich low-frequency content down to around 1 Hz. This subsequently enabled FWI to correct for large velocity model errors, resulting in a low-frequency image of the subsurface all the way to basement.

HIGHER FREQUENCY CONTENT

However, despite these major improvements to subsalt imaging, there is still the need to better the higher frequency content to enable detailed mapping. For that, either a denser OBN acquisition will be required, or the utilization and integration of full-azimuth streamer data. That's what Shell is working on now.

In the meantime, hats off to Sid Kaufman for making the first move offshore! ■

Henk Kombrink



Velocity models of (a) legacy, (b) Phase 1 from streamer FWI at 6 Hz, and (c) Phase 2 from OBN FWI at 5 Hz. Compared to the legacy model, the Phase 1 model exhibits some improvements, while the Phase 2 model shows a substantial update with resolved complex velocity features.

SOURCE: MICHAEL MERRITT ET AL. 2024, IMAGE CONFERENCE ABSTRACT

INSIGHTS

"I prefer a simpler map-based approach, manually assigning properties to horizons based on geologic insight, openly admitting the uncertainty and using the resources to explore various scenarios that can be tested with data and lead to more accurate understanding of questions that matter"

David Rajmon - Geosophix

Static reservoir modelling to transition from POS to POM

At times of more near-field exploration, should the Probability of Success concept be retired?

RAFFIK LAZAR, GEOMODL INTERNATIONAL

PROBABILITY Of Success (POS) is the central concept for petroleum exploration. POS is used to predict dry well occurrence, risk an exploration portfolio of prospects and eventually decide what gets drilled (first). Currently, the chance of success for near-field exploration is still approached the same way as frontier exploration. However, in a mature basin with decades of development, what is the relevance of POS? Especially when most of the risking criteria are equal or near 100 %, because reservoir presence, source rock maturation and seal have all been de-risked.

Instead, Probability Of Maturation (POM) is a better approach to quantifying the likelihood of a discovery going into future commercial development. POM considers more criteria to assess the probability of developing hydrocarbons in the event of a commercial discovery. The criteria to compute POM can be summed into three groups:

Subsurface complexity - Hydrocarbon fluid types and contaminant content, reservoir pressure, compartmentalization;

- Surface complexity - Proximity to existing infrastructures;
- Commercial complexity - Fiscal terms, sales commitment.

This approach has already been implicitly adopted by most companies following an infrastructure-led exploration strategy, especially in the North Sea and offshore Malaysia.

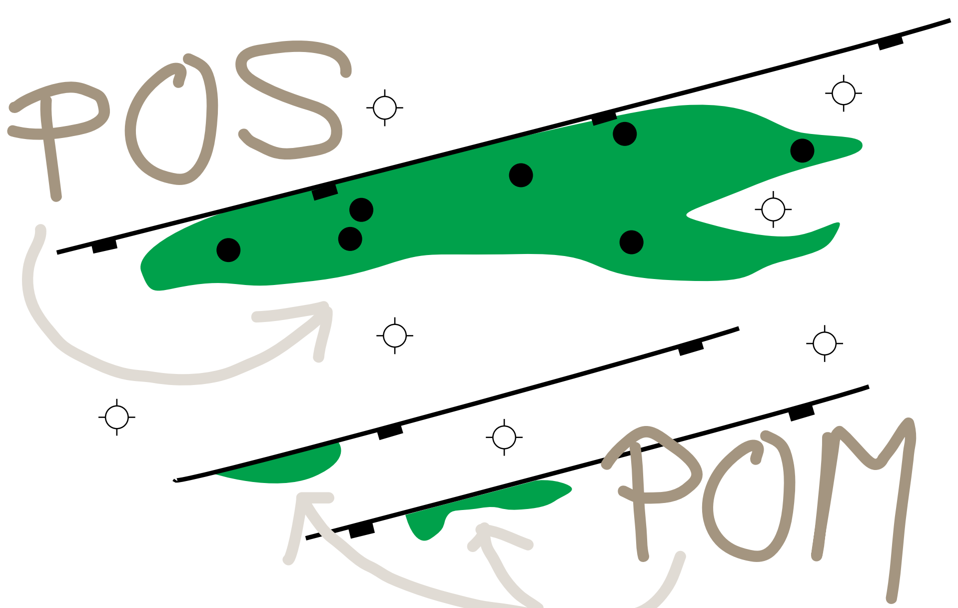
Building a static reservoir model during the exploration phase can support the transition from a POS to a POM approach by focusing on the subsurface element. Thinking with a development hat at the exploration stage helps fast-track the field development process in the event of a discovery.

For the GRV component, contact scenarios oscillate between fill to spill (structural closure) and some degree of underfill that can be captured by analyzing the nearby producing accumulations.

For NTG and Porosity, regional trends can be captured from seismic data and used at the prospect / field scale. Depth control on porosity for clastic reservoirs is a good example.

For fluid type and saturation modelling, nearby field datasets are a good starting point. Routine Core Analysis can give a solid control on the Porosity/Permeability relationships, while MICP data provides a robust understanding on the saturation height relationship. SCAL data sheds some light on the hydrocarbon flow dynamic with respect to water.

In our current era, where the non-technical risks are slowly becoming more dominant - a political decision to introduce additional taxes and ESG considerations, to name a few - POS is somewhat less relevant, and POM becomes the key decision-maker in exploration programs. Building a static model at the exploration stage might prove a game changer in our quest to develop the hydrocarbon resources to support the energy transition more efficiently. By front-end loading the subsurface challenges early in the game, the focus can be shifted to other non-technical complexities once a decision needs to be made whether to develop a near-field discovery or not. ■



Ivorian renaissance

Prizing open a new world-class play in the West African Transform Margin

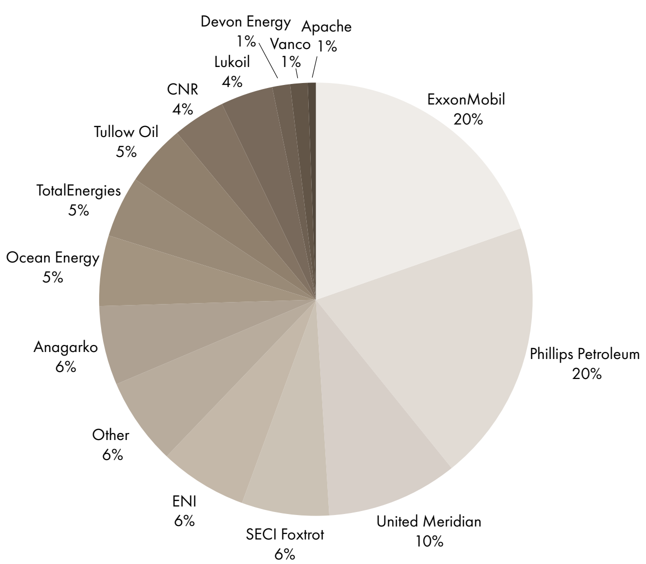
PETER ELLIOTT, NVENTURES

NVENTURES

Brought to you in association with NVentures www.nventures.co.uk

THE PETROLEUM provinces of Cote d'Ivoire are amongst the hottest properties in the exploration sector at the moment. While oil and gas regulators and operators work hard to stimulate investment in the Liberia, Harper and Tano basins across the Transform Margin, a hotspot has emerged around the Ivorian Basin on the back of some billion barrel discoveries by Eni and a reported land grab by the supermajors Chevron and Shell. In an industry reluctant to support frontier exploration, explorationists are revealing new world-class plays in West Africa.

Cote D'Ivoire has a long and successful history in E&P. Whist the "original" majors roamed around Africa looking for the Prize in the 1970s, ExxonMobil drilled a number of small gas and oil discoveries on the shallow water shelf in the east of the country, the "Ivco" wells. By the 1980s, a number of reasonable discoveries had been made, relatively deep water at the time, notably Espoir (Philips). Foxtrot and the associated partners and backers found gas at Foxtrot, and Agip tested gas at Eland. By the 1990s, United Meridian had made a concerted effort in the eastern shelf play, with small discoveries at Kudu, Lion, Ibex, and Panther. Most of these remain undeveloped, apart from Lion / Panther. Devon Energy drilled two shelf prospects in 1998, Hippo 1 and Crocodile 1, with a small discovery of gas condensate at Hippo. As technology improved in the early 2000s, Ranger / CNR took on the Espoir development. Spurred on with success they drilled the Baobab structure, and both fields remain in late-life production. The Canadian pioneers successfully drilled Kossipo soon after. By 2005, Foxtrot had stepped out of their comfort zone at the Foxtrot field and soon added Mahi and Manta.



Historical exploration drilling in Cote D'Ivoire by Operator.

TWO PLAYS

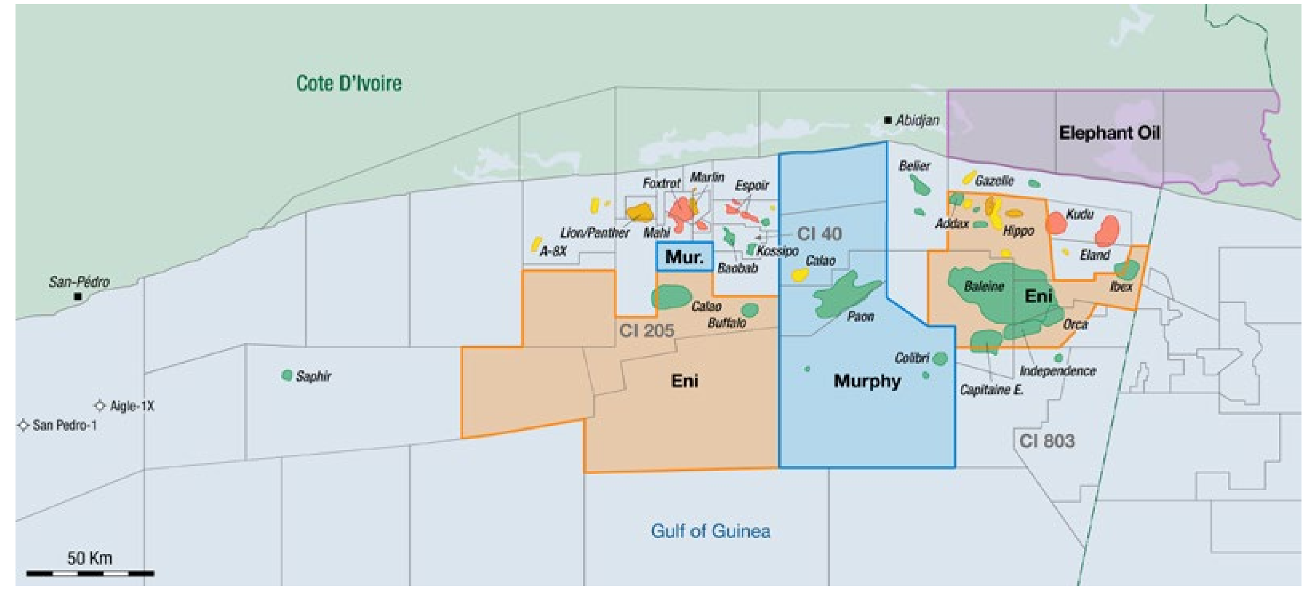
By this point in the story of Ivorian exploration, two main plays had been established; the deeper Lower Cretaceous (Albian) play at Espoir, a structural play usually trapped against the Mid- Cretaceous unconformity, and an Upper Cretaceous play comprising marine clastics from the Cenomanian to the Maastrichtian, usually stratigraphic in nature.

The discovery of Jubilee in Ghana in 2007 turned a lot of exploration ideas on their heads. With deep-water Upper Cretaceous turbidites sourced from world-class CT source rocks, and often with excellent reservoir quality, the Upper Cretaceous deep-water play became the talk of the town. However, the original pioneers at Jubilee proved hard to mimic. It would take until 2023 for a new play sitting right between the Lower and Upper Cretaceous to be finally tested, with great success, by Eni.

THE HUNT FOR A JUBILEE LOOKALIKE

The hunt for a Jubilee lookalike consumed vast energy and resources through the 2010s. By 2012, Lukoil had taken up the charge across the WATM, using state-of-the-art 3D seismic and Qualitative Interpretation techniques to identify deep-water fans and turbidite reservoirs. Wells at Independence, Capitaine and Orca successfully defined a series of high-quality turbidite reservoirs defining a trend along the southeastern edge of the Baleine High offshore Cote D'Ivoire, but none with commercial quantities of hydrocarbons.

It could be said Vanco lured Lukoil into deep waters, although their first well at Albacore was P&A'd dry. TotalEnergies tested the Ivoire 1X prospect in 2013 with no success. Not put off, operators continued to drill similar prospects. Immediately west of the Baleine "nose" or structural high, Tullow chased the Paon complex of turbidites and channels, whilst Lukoil drilled Buffalo 1X further west. Anadarko took control at Paon and by 2017 around 6 wells had been drilled in the Paon complex, with no sanctioned field development to show for it. Anadarko later became part of the new Occidental empire and the play was left fallow until Murphy took up the call in 2023. Immediately northwest of Paon is the most recent giant oil discovery, Calao, drilled into a deeper Cretaceous play by Eni in 2024 with the Murene 1X well.



Oil and gas fields in Cote D'Ivoire, with prominent operator positions.

SOURCE: NVENTURES

Further west still in 2014 and 2015, a number of wells were drilled into the San Pedro Basin. TotalEnergies drilled Saphir 1X (sub-commercial oil), while TotalEnergies and Anadarko tested the Saumon and Morue prospects, both P&A. Genel and Vitol drilled Agile 1X (P&A). Vanco had been the first to test this huge western offshore basin in 2005 with the San Pedro 1 well, funded by ONGC and OIL. The well appeared to top off an extinct volcano and the structure was dry. By 2017 major drilling campaigns had tailed off, although Africa Petroleum Corp and Ophir managed to drill the Ayame West prospect to mark the end of two prolific but unsuccessful West Africa drilling campaigns.

RETURNING ENTHUSIASM

By 2018, attention was returning to the central and eastern Ivorian basins. TotalEnergies continued to test the Upper Cretaceous play with the Barracuda 1X well and CNR successfully appraised Kossipo. Late 2021, saw Eni pick up a large Albian prospect mapped over the Baleine High by Vanco in 2007. Concentrating on the Albian to Cenomanian "in-between" play in this area, with an unambiguous four-way closure, gas cloud, and both carbonate and clastic reservoirs to target, Eni drilled one of the largest closures in the margin and hit the jackpot with Baleine 1X. Already in 2024, Eni and Petroci are planning Phase III of the Baleine development plan, with first oil achieved in August 2023.

THE ENI SUPERHIGHWAY

About this time (2021) Tullow and Cairn (now Capricorn) had joined forces onshore the Ivorian Basin, shooting Full Tensor Gravimetry and 2D. However, both firms dropped the acreage amidst zero investment sentiment for new frontier exploration. DNO saw the opportunity to participate in safe production and a thriving gas industry at Foxtrot and bought into CI 27 in 2022. Tullow entered CI 803 later in 2022, although more likely to secure acreage west of their struggling TEN field in Ghana. Svenska, partners in Baobab, had been on the market for a few years, and in 2022 Vaalco made the purchase, joining CNR in CI 40. Seeing the upside around Baleine and the under-evaluated plays north and south of Paon, Murphy made a strident entry into the basin in 2023, taking a wide strip of acreage (5 blocks) through the Paon trend between what would become the "Eni superhighway" with the 2024 Calao discovery to the west (approximately 1.5 Bbo recoverable) and Baleine to the east (3.5 Bboe). Eni themselves have since secured four concessions around the Calao CI 205 Block, further bolstering their hold on this fantastic play.

ALL ROADS LEAD TO ABIDJAN

Looking ahead, all roads lead to Abidjan, as for now, they are racing ahead of their neighbours.

Operators and contractors are busy working the frontier in Cote d'Ivoire. Shell is rumoured to be signing deep-water blocks in Cote D'Ivoire seaward of Baleine and Calao, while Chevron is strongly associated with two deep-water blocks south of Baleine. Murphy might be expected to find partners on very good terms in the near future, and Eni themselves are running a process to find partners with deep pockets and generous terms on their two discoveries and producing assets. ■

HOT SPOT

Less is more - uncertainty in rock properties

Why a paper drawing can be just as good as a complicated numerical mode

DAVID RAJMON, GEOSOPHIX

MY LAST article opened a topic of uncertainty in basin models. Discussion following its publication brought up an interesting research paper describing how increasing model complexity increases uncertainty in its results. It illustrates the issue with several examples spanning various fields of science…

"Our" field offers another example. Basin models involve the calculation of rock properties used to calculate heat and fluids transfer through a basin. These rock properties mutually control each other through a web of physical relationships. Some of these relationships are expressed in the model.

For example, porosity is a function of sediment mechanical compaction, cementation and dissolution. These processes are controlled by mineral composition, grain shape, effective stress, fluid chemistry and temperature. Each of these parameters needs to be calibrated with detailed petrographic data. Such calibration is only possible for selected siliciclastic reservoirs with drilled wells sampling key lithologies. Then, we are able to model porosities within +/- 1 % of rock volume.

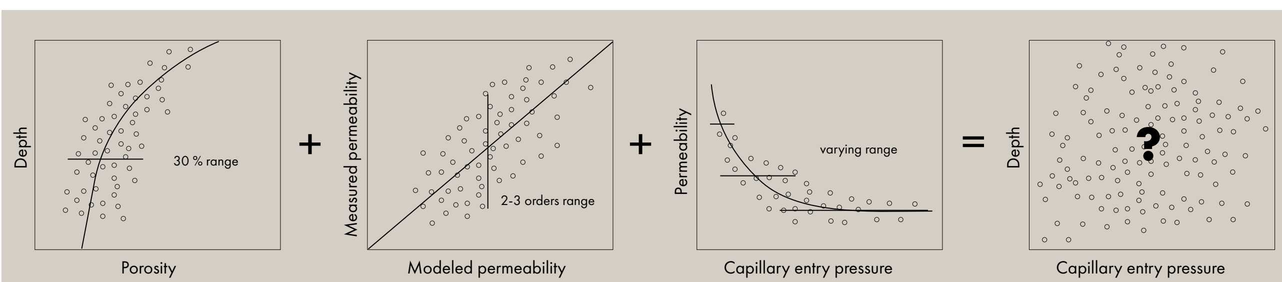
Such detailed calibration is not available for the vast majority of a basin fill. In fact, we do not even know the distribution of the basic lithology types for most of the basin. Thus, porosity is typically only calculated with an exponential function of vertical effective stress adjusted for general sediment type (sand, shale, limestone, etc.). The uncertainty in such calculated porosity is around +/- 5 - 15 % for a given lithology and a range of depth. This porosity is then used to calculate permeability using some function adjusted for general sediment type.

However, permeability is also controlled by multiple processes and parameters and so the calculated permeability is associated with an uncertainty of 2 - 3 orders of magnitude. Now, combine it with the porosity uncertainty and the permeability uncertainty easily becomes 3 - 4 orders of magnitude. But it doesn't end here. Finite element models go on and calculate capillary entry pressure (Pc) based on the permeability.

I remember a conference presentation on such a calculation, discussing minute details of Pc evolution through modeled geologic history. In reality, given the irreducible uncertainties, the magnitude of Pc remained largely unconstrained. The calculated Pc was no more accurate than a hand-drawn line on a graph basically saying that Pc tends to increase with sediment compaction.

So after all the time, IT and financial resources spent computing unconstrained details for millions of cells, we arrive at a model with some layers being flow barriers / seals and some being flow carriers… which is about as accurate as a hand-drawn sketch on a piece of paper. The complicated model creates an illusion of accuracy and barely allows time for the generation of a couple of scenarios.

I prefer a simpler map-based approach, manually assigning properties to horizons based on geologic insight, openly admitting the uncertainty and using the resources to explore various scenarios that can be tested with data and lead to more accurate understanding of questions that matter. ■



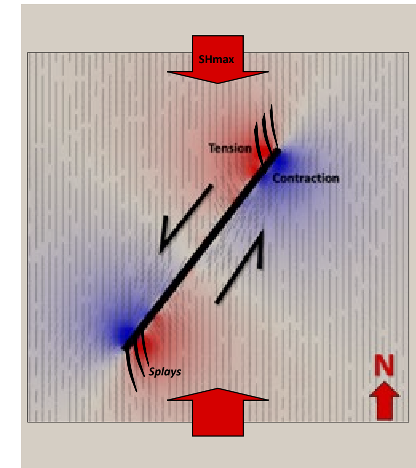
How detailed modelling work can still result in a fairly random estimate of the key parameter.

Horsetail splays, wing cracks, and splay faults

Important structures for modelling fluid flow in the context of mineral exploration, geothermal development and petroleum exploration

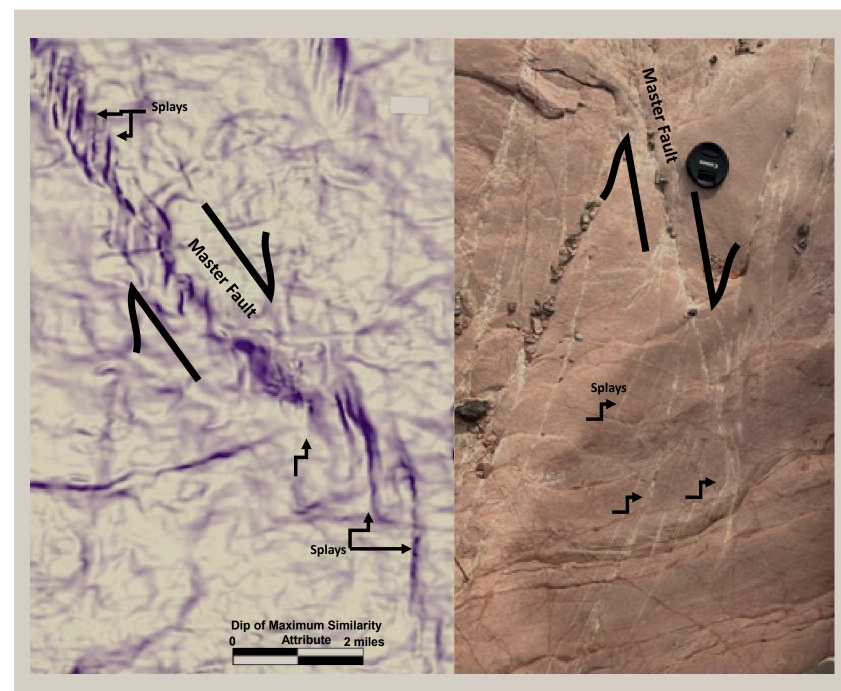
MOLLY TURKO, DEVON ENERGY

THESE FUNNY faults go by several names, but traditionally refer to the secondary faults and fractures that develop near the tips of a primary fault. Although these can occur on both normal and reverse faults, the terminology is commonly used when referring to strike-slip faulting. Horsetail splays often look like the hairs from a horse's tail near the tip of a fault. However, they are often limited to just one side of the fault representing a tensional quadrant. The opposite side of the fault would represent a contractional quadrant (figure on the right).



Horsetail splays occur as displacement dissipates near the end of a fault and slip is distributed through several smaller branching faults that curve away from the main fault - sub-parallel to the maximum horizontal stress, SHmax - in an imbricate pattern. They are great kinematic indicators for slip direction, and in the case of strike-slip faults, for determining left-lateral verse right-lateral slip. Horsetail splays occur as the rock is pulled away from the fault tip, forming an acute angle with the master fault "pointing" in the slip direction. The opposite side of the fault would be under more contraction / compression as the rock pushes towards the fault tip. Often, we can find dissolution (stylolites) or grain crushing (compaction bands) features in this quadrant.

The image below shows horsetail splays at two different scales, one in an outcrop occurring in Jurassic eolian sandstone, and one in 3D seismic enhanced by structural attributes. Larger horsetail splays can be resolvable in 3D seismic volumes due to the extensional component of slip that accommodates the strike-slip faulting in the tensional quadrant. These are helpful for determining slip sense along strike-slip faults in the subsurface where piercing points may be difficult to come by.



FLOW CONDUITS

Identifying and understanding the tensional regions around faults can be important for energy ventures. Horsetail splays often represent tensional deformation where the faults and fractures can act as conduits for fluid flow, making them critical for both mineral exploration and geothermal development. Additionally, horsetails splays may even host prospective sedimentary basins along the tips of major strike-slip faults, making them important for petroleum exploration. ■

NOTHING BEATS THE FIELD

The exposed Interior Seaway – Just layer cake geology?

If anything, long and continuous outcrops often suggest that geology is much more varied in a vertical than in a horizontal direction. This beautiful photo from the Bisti Badlands in New Mexico, US, nicely illustrates that. The boundary between the greyish-greenish fine-grained sediments at the bottom of the section and the overlying coarser-grained and lighter sandstones can be traced across the entire area captured by the photographer.

However, that does not mean the sandstone "hoodoos" capping the succession were once part of the very same continuous sandstone. Before that conclusion can be drawn, more information would need to be acquired through some detailed fieldwork; are these distributary channels, shoreface sands, or splay deposits? All of these options are possible within the overall shallow marine to coastal framework of these Upper Cretaceous rocks. Depending on what they represent, the sandstones may well be more isolated than one initially would think based on a first glance. That's why a more detailed inspection of outcrops – especially the sandstones – is always required before concluding it is all layer-cake geology.

Photography: Nina, via Adobe Stock
Text: Henk Kombrink

FEATURE YOUR OUTCROP

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

A mystery

How can cores of different diameters end up in the same box?

THE UPPER Permian Zechstein of the UK Southern North Sea is experiencing a little revival these days. The main reason is that gas and some oil were discovered last year in the Pensacola prospect drilled by Shell. Well 41/05a-2 found oil and gas in the Hauptdolomite, the main carbonate member in the second evaporitic Zechstein cycle. An appraisal well is planned to further test this exciting discovery that could host around 8.5 billion cubic feet of gas.

INCREASED DEMAND FOR CORE DATA

Because of this, core data from the Zechstein and the Hauptdolomite in particular has suddenly become more in demand. But there is not a lot of it. The reason is that the UK Southern North Sea has never seen production from Zechstein reservoirs take off. Instead, the underlying Permian Rotliegend sandstones were the main target for many years, resulting in many core cuts from eolian reservoir sands. The overburden was just drilled as quickly as possible.

Well 41/15-1, located not that far away from Pensacola, is one of those rare exceptions. Drilled in 1991, not even that early in the North Sea exploration bonanza, Conoco UK identified a prospect in the Carboniferous, below the Zechstein. Even though the Zechstein was regarded as a secondary target only, most of the cores cut in this well are from the Permian. These days, it would be unheard of to see a secondary target being so extensively cored even before the primary target has been reached, but rig rates probably were not so much of an issue those days.

CORE CHARACTERISTICS AND SEDIMENTOLOGY

Two intervals were cored in the Zechstein of 41/15-1; the Plattendolomite in the third evaporitic cycle, and the Hauptdolomite in the one below. One thing stands out when looking at a photo of cores from both formations. The Plattendolomite is much more laminated and finer-grained than the Hauptdolomite. The latter also has a lot of vuggy porosity. Just looking at this, anyone would probably argue that the Haupt has better reservoir potential, but it was the Plattendolomite that was tested using a DST based on the observation of shows. No fluids were produced to the surface, though.

Carbonate sedimentologists from Aberdeen University, who recently inspected the Zechstein cores, confirmed that the Plattendolomite has a more basinal depositional setting, whilst the Haupt has more of a platform top facies.

But there is one more question remaining. When looking through the boxes of cores, most have the same 5 inch diameter, as expected. But there is one smaller diameter bit as well. Looking very similar to the other cores, including a correct depth mark, what could be the origin of these smaller-sized parts? A few geologists visited the core store as well, and they were also puzzled. If you have ever come across this, please let us know! ■

Henk Kombrink

Two boxes of Zechstein dolomite – Hauptdolomite from 6647 ft on the left and Plattendolomite from 5608 ft on the right, both from well 41/15-1 in the UK North Sea.

PHOTOGRAPHY: HENK KOMBRINK