THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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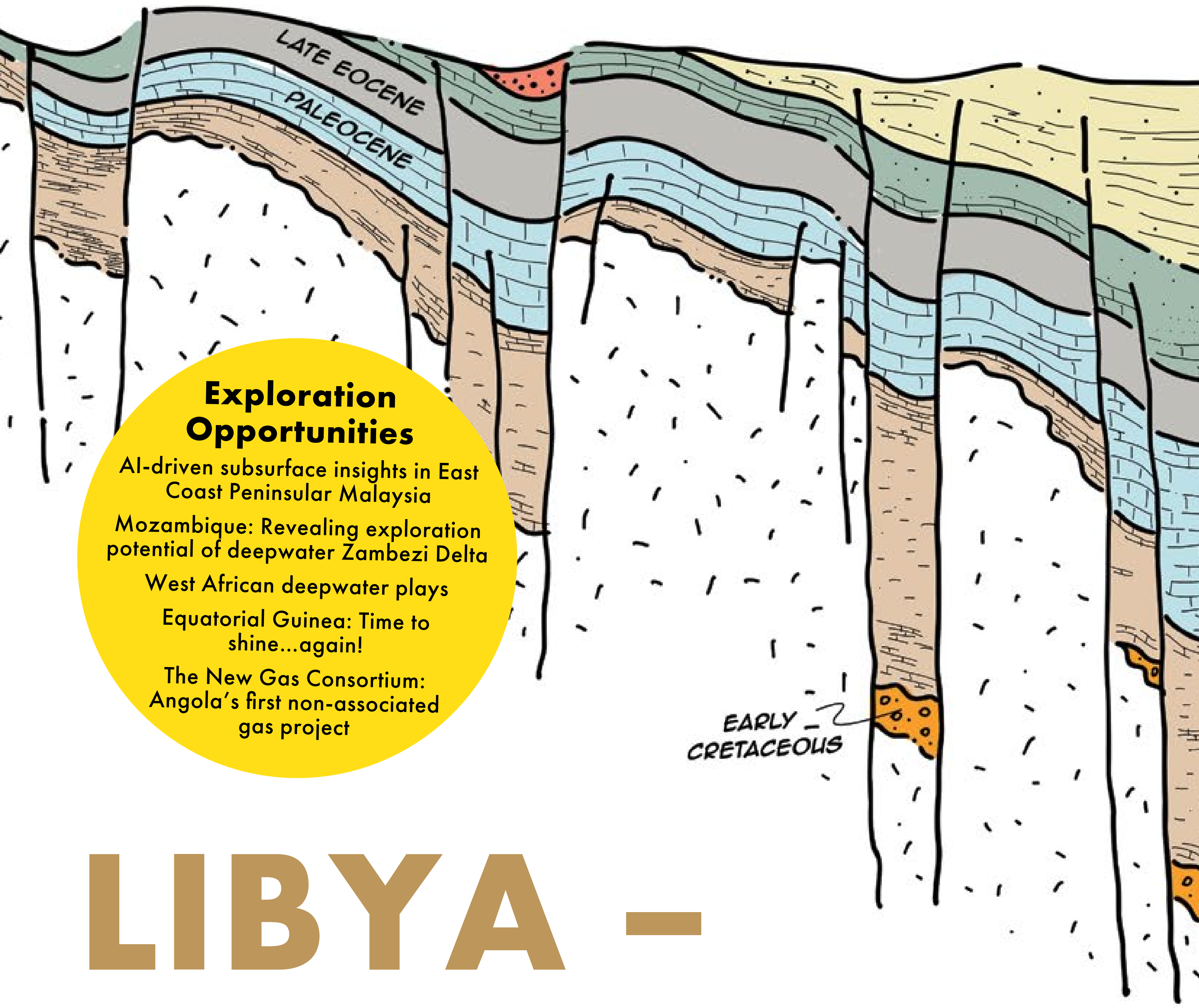

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LIBYA – EXPLORATION STORIES

GEO ExPro

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COVER ILLUSTRATION: MARCOS ASENSIO

Europe's schizophrenic attitude towards energy

ONE OF THE MOST insightful articles in this magazine – at least that's my take – is the one you'll find in the Seabed Minerals Section – page 72. Here, we describe how delegations from various countries in Europe are pushing the International Seabed Authority (ISA) to tighten rules towards the extraction of seabed minerals. To such an extent that it becomes almost impossible to go ahead and get going with it. All with the agenda that it should not happen, for environmental reasons.

But at the same time, the very same countries, Germany and France in particular, are the owners of seabed minerals exploration licences in international waters, governed by the same ISA. And with ownership of these licences comes the obligation to move forward to the point where extraction actually happens.

"It is proof that there are two parallel universes in these countries, two universes that probably ignore one another completely"

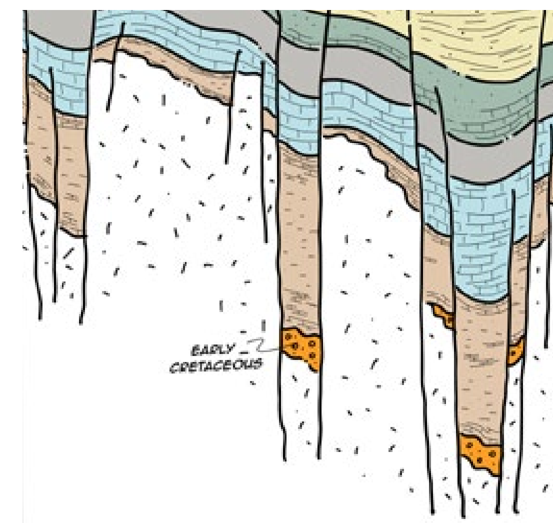
How can we possibly explain a situation like this? It is proof that there are two parallel universes in these countries, two universes that probably ignore one another completely. But this situation cannot continue, and I believe it will ultimately collapse as security of supply issues will become more and more prominent. And that's maybe not a bad thing, because I believe that it is possible to extract seabed minerals in a way that doesn't generate a complete breakdown of deep sea habitats.

It's just the same story as we've seen with oil. Some European countries are banning oil exploration, whilst happily consuming it to keep the economy moving. It is a testament to a detachment from reality, grounded in an ability to act like the environmental police from a position of I-have-it-all.

Henk Kombrink

BEHIND THE COVER

Libya is in the spotlight again when it comes to exploration. For the cover story, we talked to people who had worked directly in exploration in the country before the 2011 power struggle emerged. We hear about opportunities and we hear about failures, all painting a more colourful picture of how previous attempts to prove additional volumes have either failed or succeeded. The Sirt Basin plays a pivotal role in this story because it is the most prominent basin in the country. But also because there might still be untapped potential, especially in the deeper parts of the grabens. That is what yet another illustration from Marcos Asensio aims to portray.



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FIRSTS

"The idea that we can replace fossil fuels with some kind of improvised piecemeal energy system is misleading"

Rodney Garrard

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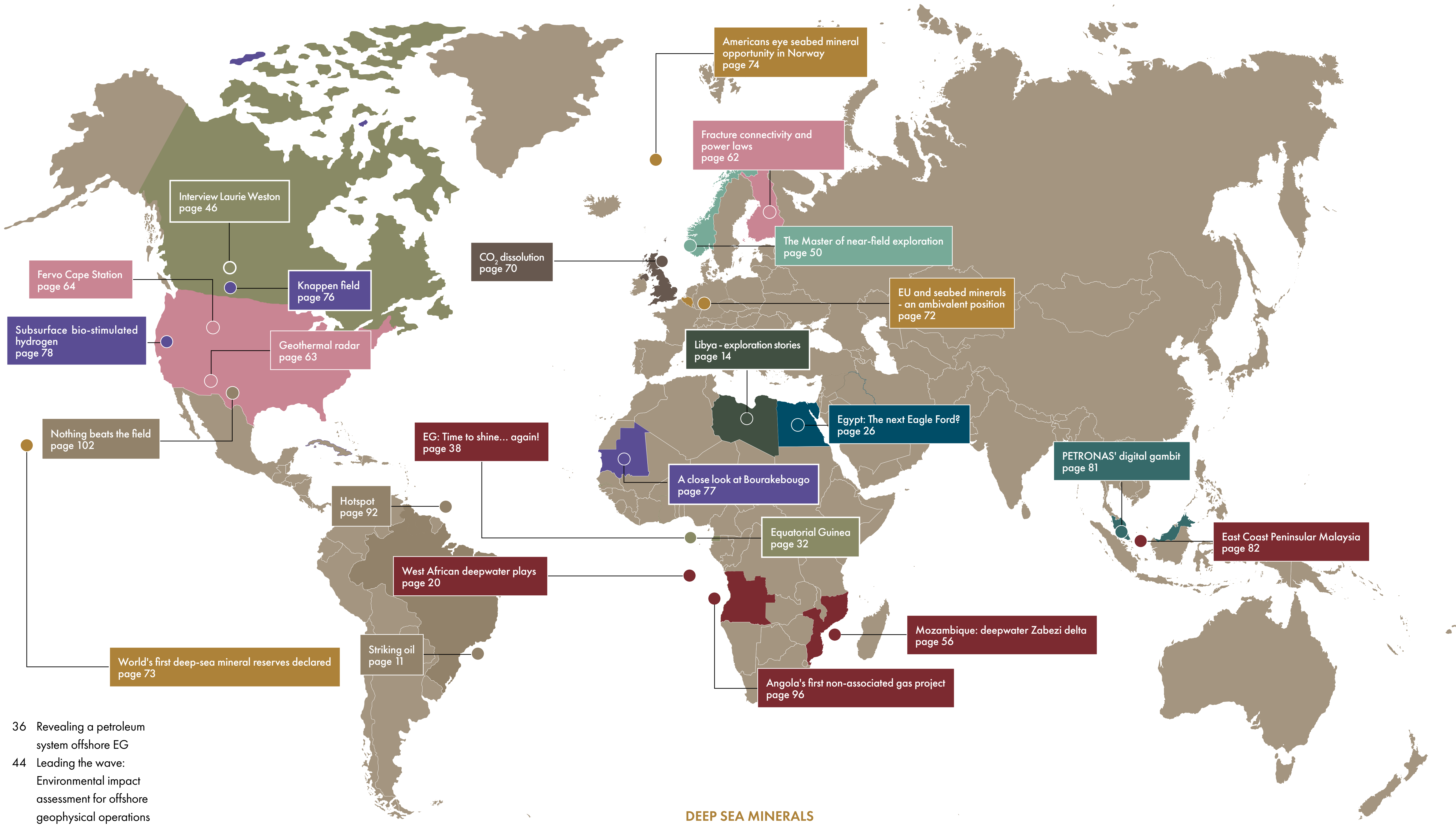

GEOTHERMAL ENERGY

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NEW GAS

TECHNOLOGY

WILL DENMARK OPEN ITS DOORS TO EXPLORATION AGAIN?

As the world entered lockdown in 2020, so was oil and gas exploration put into lockdown in Denmark during the same year. Denmark was not the only country making this call; Spain, New Zealand and France made the same decision to halt drilling for hydrocarbons. Only five years later, the tide had already turned for New Zealand, with exploration being on the cards again. Will Denmark follow? According to a Dane I spoke to recently, who has good connections in the sector, it may happen. "Our government takes a more pragmatic approach," he said, "and some people even claim that Denmark is not as explored as some may think."

MOPANE DOES NOT GIVE AWAY ITS SECRETS

Namibia is an exploration hotspot, and for that reason, many people flocked to the presentation that GALP was delivering about the Mopane discovery at the recent IMAGE Conference in Houston. But for those who now regret not having bought a ticket, rest assured, the talk was not what many had hoped it would be. A very generic workflow was presented, with no further details on the tests done, nor any well logs. We may need to wait until a farm-out deal announcement before hearing something about this supposedly sizeable discovery.

BACK TO WORK AS A MUDLOGGER

Many have already complained about the lack of drilling activity in the UK North Sea, first and foremost caused by the tax hike imposed by the British government. The effects of this can be traced back across the whole industry, with companies laying off personnel, and skilled people trying to find work elsewhere. An obvious consequence of the lack of work in the UK is the fact that people who had been promoted to well site and operations geologists now find themselves accepting mudlogger jobs in Norway, the next-door neighbour, where drilling is more buoyant. "It is a sad state of affairs," someone with knowledge of the matter told me.

BEING A NUMBER

I attended a talk the other day during which I had difficulties following what the presenter said. So, I decided to ask him for an email address. Similar to a lot of people at the conference, he had no business cards – something I do not understand, even in this day and age – so he showed me his email address on his phone. I should have taken a photo of it, but I foolishly decided to write it down in my little notebook instead. Where you can sometimes guess people's email once you know their name, this will be impossible in Chinese academia; the email address is nothing more than a long number. I now understand why this person didn't fancy having business cards printed.

A REFLECTION ON SOURCE ROCKS

"Most geologists tend to think that deep-marine environments are good for source rock deposition, but I see that most source rocks go away in these settings" – Andrew Pepper (ThisIsPetroleumSystem) during a presentation at IMAGE in Houston.

ILLUSTRATION: PCR.VECTOR / FREEPIK.COM

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

The age of snake oil

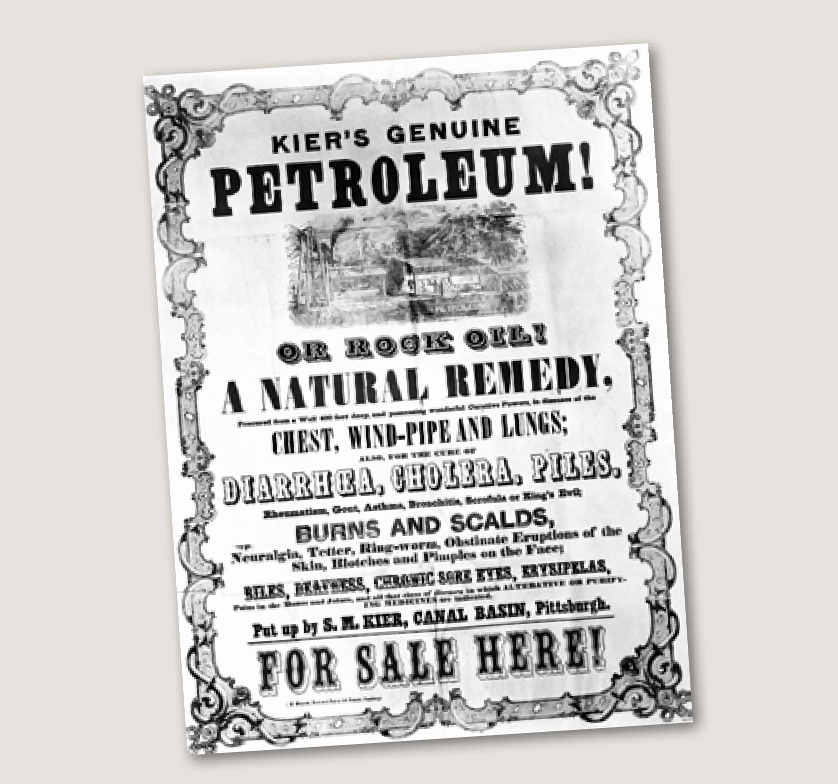
Samuel Keir's tactics of an old-timey snake oil salesman back in 1850 are similar to the hype currently characterising the energy sector

KEIR'S FAMOUS poster portrays petroleum as an effective remedy for every conceivable want, highlighting how any product may be marketed with absurd false promises. For hype to be a successful sales technique, the salesman cannot be held accountable for his / her claims; vague yet effusive promise takes the place of specificity. In this way, hyping a product to success is all about proxy and allowing the targeted customers to assume the most desirable outcomes.

Even once acquired, the average customer would not have been able to accurately discern whether the product was actually involved in their recovery – they may have incidentally recovered on their own while happening to use the product. But the consummate hype seller must immediately leap upon such examples as validation.

The poster is also interesting because it looks back to the time the oil industry began its domination of society, which should prompt us to ask the same questions of the vaunted "new" energies of today. This piece, therefore, not only sheds light on Keir's portrayal as a snake oil salesman but also on the mindset of consumers seeking simplistic panacea energy solutions.

"The idea that we can replace fossil fuels with some kind of improvised piecemeal energy system is misleading"



SOURCE: ALAMY

Note that the use of rock oil as an energy source is not mentioned on this poster.

Today, we find ourselves subjected to messaging that we no longer require fossil fuels and that modern intermittent renewables, principally solar and wind, will effortlessly usher us into a new utopian clean energy future. We love the trace scent of snake oil, the possible glint of silver on a bullet, we still want to believe in magic, a god.

Humans, likely both modern and ancient, identify ideas that suit their existing interests and ideals and will fiercely defend them rather than truly critically evaluate them. Furthermore, we tend to use that desired solution until something forces us to change. Nuclear energy, for example, comes with an undeniable "tomorrow's problem", and so we mostly cower from it.

The reason why this is important goes back to one of my earlier columns (GEO EXPRO Vol. 22, Issue 1, 2025) that stated: "Supplying 8+ billion people with energy security while minimising harm to the environment is a big and complex problem, and that energy density matters." The idea that we can replace fossil fuels with some kind of improvised piecemeal energy system is misleading. As a geoscience community, there is a need to critically assess the narratives surrounding certain "clean" energy solutions that claim to address all our energy requirements.

In energy, there is utility and there is hype. Where that line crosses requires an informed consumer to be able to separate the wheat from the chaff of hype and marketing. Thus, there is an opportunity for geoscientists to ground-truth the quality of such energy entities and, in a way, reclaim the narrative by encouraging a nuanced perspective without delving into overly polarising debates. ■

Rodney Garrard

Looking at the regional geology of the Wolin-East discovery in Poland

Positive well results expected to boost the wider Zechstein play in Europe

IN JULY, Central European Petroleum (CEP) announced that its Wolin East-1 (WE1) well in the Baltic Sea in Poland was a significant oil discovery, having been designed to target primarily gas. The Calgary-based company spudded WE1 in November 2024 using the Noble Resolve jack-up in just 9.5 m of water, reaching a total depth of 2,715 m. The well is reported to have encountered a 62 m hydrocarbon column in the Zechstein Main Dolomite of the Upper Permian – referred to as Ca2, or Haupt Dolomite.

CEP added in a press release that the Wolin East discovery is estimated to contain 200 mmboe mean recoverable, somewhat exceeding expectations, likely due to more favourable reservoir properties. If further appraisal work, including testing, confirms this volume, then it will represent one of Europe's largest discoveries in recent years.

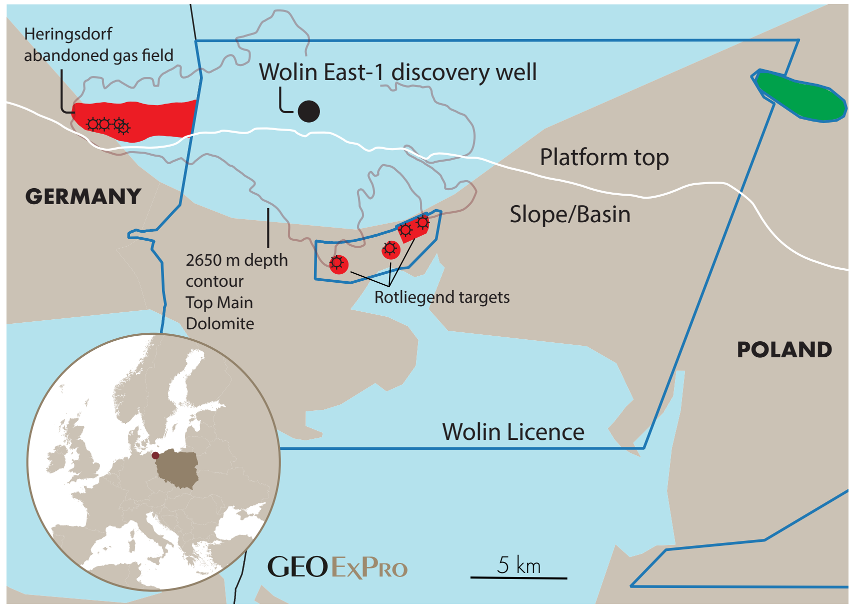
The Main Dolomite is not new to Poland, though. It is the main reservoir in Poland's largest onshore fields, such as the BMB Complex on the prolific Wielkopolska Platform, and the play also extends all the way to the east coast of the United Kingdom and the Mid North Sea High. Historically overlooked, this play has had recent success in UK waters at the Crosgan and the Pensacola discoveries, now operated by One-Dyas and Shell. Clearly, this demonstrates the regional potential of the Main Dolomite play.

Oil and gas exploration in the Polish part of the Baltic Sea began in 1975 by the Joint Exploration Organisation (established by East Germany, Poland and the Soviet Union), which was later renamed Petrobaltic. This organisation is now part of the Polish state-controlled energy giant Orlen. CEP was awarded the onshore and offshore Wolin Concession in northwest Poland in December 2017 with a 100 % working interest. The concession is adjacent to the Polish-German border and was granted for an initial ten-year term.

Mapping by CEP using legacy Petrobaltic 2D data and data from the abandoned Heringsdorf gas / condensate field across the border in Germany confirmed an extension of the Main Dolomite play into Polish waters. CEP mapped locations at Wolin West, Wolin East and Wolin Southwest in the concession and had run a farmout process ahead of drilling. The Wolin West feature had been identified as gas / condensate bearing in the Main Dolomite, and the WE1 well was designed to evaluate its extension eastward. The Rotliegend sandstones represented a secondary objective, which is gas-bearing immediately to the south in a series of Polskie Górnictwo Naftowe i Gazownictwo (PGNiG) onshore wells.

CEP reported that WE1 had encountered 33.4° C API oil in an excellent reservoir, likely afforded by the well's location targeting the platform top, an area of well proven high-quality reservoir development. With the Main Dolomite extending across its licence, it could prove up an exciting play fairway in shallow waters. A number of 400 mmboe recoverable within the licence has been quoted by the operator. With continued success in the play, it will be interesting to see how operators in surrounding areas and even countries can learn from this discovery. ■

Ian Cross - Moyes & Co



Wolin East-1 discovered oil on trend with the abandoned Heringsdorf gas field, highlighting potential correlations in the deeper Main Dolomite.

Bumerangue; what are the implications of drilling into one of the most structurally complex areas of the Santos Basin?

The potential volume in bp's latest oil discovery is there, but will it be economic to produce? Experts share their insights

BP ANNOUNCED what was hailed as its biggest discovery in 25 years – Bumerangue, located in the Santos Basin. The pre-salt discovery certainly looks promising when taking into account that the operator, being the sole owner of the licence, reported a 500 m oil column whilst it hit the reservoir 500 m below the crest of the structure at the same time. Combined with an aerial extent of the discovery of about 300 km², and a high-quality carbonate reservoir, there are even more ingredients as to why this discovery is looking particularly good.

However, there are some other factors to consider regarding this find as well.

As somebody with knowledge on the matter told me, the licence, when it was up for grabs, did not receive a lot of interest from many majors. And that does not only relate to the potentially high CO_2 contents, but also to the reportedly compartmentalised nature of the field. This must have been mapped on the available seismic pre-drill - both Viridien and TGS have acquired seismic data across the prospect, which might be a reason why bp did not have much competition when bidding for the block. Developing a compartmentalised deep-water field will require more wells, having a detrimental effect on CAPEX.

bp did report that elevated but yet undetermined levels of CO_2 were found in the well, which is not unexpected given the fact that surrounding discoveries have the same issue. The Libra field has a 40 % CO_2 content in its associated gas, which still allowed the field to be developed, but Jupiter, which is even closer to Bumerangue than Libra, has a prohibitive 80 % CO_2 in the associated gas. The Brazilian authorities do not allow venting of CO_2, so that is not an option. EOR might be an alternative in this case.

So the big question is, how much CO_2 is in the associated gas of Bumerange?

"I would not be surprised at all if there are significant levels of CO_2 in the associated gas of the Bumerange discovery," says Natasha Stanton in a recent conversation. Natasha has been studying the Brazilian margin for many years and is considered an expert in its tectonic history. "The Santos Basin overall is one of the most complex basins I have seen in my career," she continues, as it forms a transitional area between a volcanically active part of the South Atlantic rift, the Pelotas Basin, and a less volcanically active part, the Espirito Santo Basin.

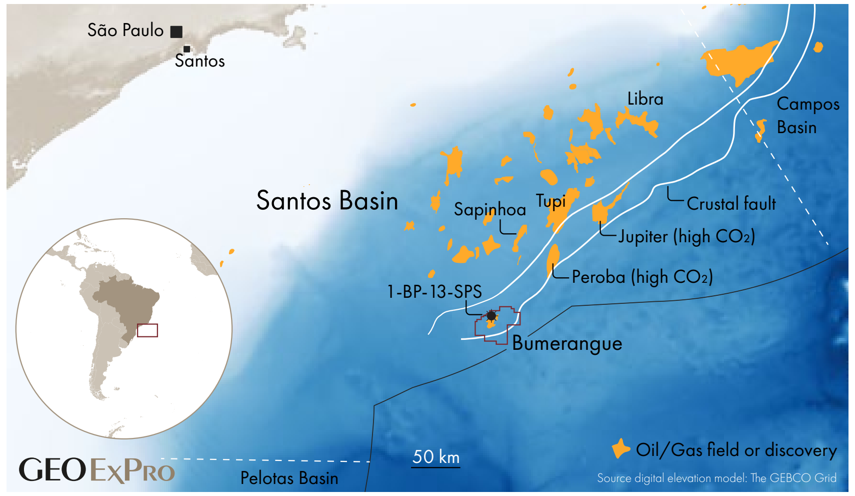
"Looking within the Santos Basin itself," Natasha continues, "it is the Bumerangue area that represents one of the most complex areas. This is because it is this area that experienced a change in direction of extension, causing the crustal block's rotation of about 90° C during the Lower Cretaceous, resulting in a very fragmented and faulted subsurface. And it is the faults that developed at the time that form the conduits for the CO_2 that is mostly derived from mantle sources."

Bill Dickson, in a post on LinkedIn, seems to verge into the opposite direction: "My thinking is that Bumerangue's CO_2 percentage is much less than Jupiter or Peroba, more similar to Sapinhoa at about 20 - 30 %... Bumerangue is uniquely positioned away from the deep CO_2 conduits while surrounded by what looks to be source-rich flows. The block holds multiple prospects within the ring of lows, explaining the need for multiple appraisals."

Finally, the timing of the announcement, two days before the publication of bp's second quarter results, also leaves some room for the idea that a positive story was needed, and to round off an apparently very successful string of ten discoveries this year.

Will the enthusiasm last, or will we see Bumerangue boomerang back? ■

Henk Kombrink



COVER STORY

"You don't discover gas by just dreaming about discovering gas"

Bashir Elmejrab – Tripoli University

COVER STORY

LIBYA – EXPLORATION STORIES

Through conversations with direct witnesses, we look at how exploration in Libya fared in the years before the 2011 uprising, providing more context for the current bidding round

HENK KOMBRINK

PHOTOGRAPHY: HENRY WILLIAMS

Mesozoic clastics and carbonates, Jabal Nefusa south of Tripoli.

In his book "The Prize", Daniel Yergin describes how Libya's entry on the global oil stage in the 1950s was spectacular and engineered wisely. Yergin quotes the Libyan petroleum minister: "I didn't want my country to be in the hands of one oil company." Rather than giving out large concessions to only a few companies, he awarded smaller blocks to a range of operators.

It took a bit of time for the first discovery to be made, and bp was already clearing its warehouse when Standard Oil of New Jersey made the first strike at Zelten in 1959. This led to the discovery of another ten fields during the next two years.

One company in particular deserves a special mention here, before we move on to the main topic of this article. It was in 1966 when Occidental struck oil in Block 103. Testing at an incredible rate of 75,000 barrels per day, this discovery is interesting because it was found at the site of a former Mobil camp. It was the use of seismic data that had allowed the identification of the prospect, beautifully illustrating how technology enabled the finding of previously unidentified resources.

This article is not about Libya's initial oil exploration boom in the 1950s and 1960s. Much has been written about that already. Instead, we take a look at more "recent" developments, which are worth knowing more about, given the country's current efforts to revitalise exploration.

I talked to three people who were there during those years: Bashir Elmejrab worked for Lasmo and Shell at the time, Bas van der Es explored with a Wintershall team, and Henry Williams spent a few years in Libya for Suncor. All three share some of their experiences. As such, this article is not an exhaustive overview of events, but rather sheds some interesting insights and thoughts on the exploration landscape at the time, told by people who were there, on the ground.

NEW HOPES

Bas van der Es spent five years in Libya from 2001 to 2005. During those years, he witnessed the first part of the EPSA 4 licensing round, which consisted of four different stages. It was initiated by a government keen to welcome back new international investment in the country.

Whilst exploration and development activity had not ceased completely in the decades before, the (partial) nationalisation of oil and gas assets by Mu'ammar Ghadafi in 1972-73 did herald a long phase of reduced activity from an international operator perspective.

"You can imagine that there were high expectations as soon as the EPSA 4 (Exploration and Production Sharing Agreement) rounds were announced in 2004," says Bas. "Many of the major international companies were there, and they were all bidding against each other."

Woodside was one of the big and unexpected winners at the time, probably helped by a key person from the Australian company who was rumoured to have good connections. "However," says Bas, "Woodside's Libya adventure did not go entirely to plan. I believe they drilled about 10 dry or sub-commercial wells in a period of only two years and then left. Quick entry, play hard, and quick exit."

In turn, Exxon played the bidding game in an interesting way. ►

COVER STORY

They had taken a detailed look at everything, both onshore as well as offshore, but only went for offshore acreage in the end. “We thought they offered a lot of money for it,” recalls Bas. “However, with the 2011 uprising, I realised it was a safer investment than onshore.”

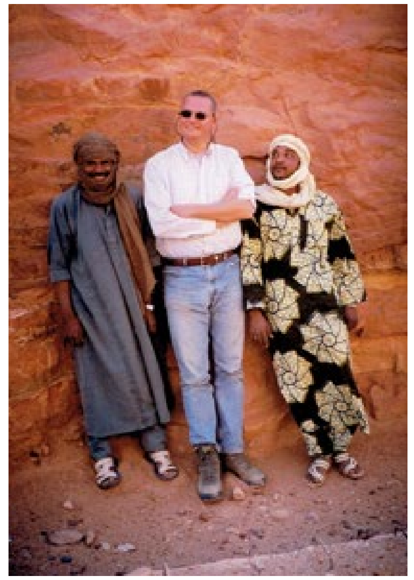
The work programs of the newly awarded licences were quite extensive, which means that there was a fair bit of drilling taking place between 2005 and 2011. “But, at the end of the day, discoveries were either small or lacking altogether,” says Bas. “In my view,” he continues, “the geologists working in Libya in the 1960s and 1970s were all quite well aware of where the main plays started and ended. Therefore, the existing licences were already situated in the best areas. Once drilling was done outside these main fairways, exploration success collapsed.”

This observation of the quality of work done by the earlier generation of explorers is backed up by Henry Williams, who worked for Suncor in Libya during the years before the country’s power struggle. “In the mid sixties, when Mobil was still in Libya, they must have had a team of excellent geoscientists,” Henry said. “We often referred to their earlier work, which, even after 30 years, was a valuable source of data and interpretations.”

Yet, there was room for discoveries to be made. “We drilled a string of successful wells in those years,” says Bas, “which may have actually fuelled some of the expectation that companies had for the EPSA 4 rounds. Based on a new concept, which relied on successful trapping in hanging wall closures next to basement highs, the company found a series of fields in concessions NC97 and NC98, each of them in the order of 100 to 200 million barrels in size.

THREE TIMES UNLUCKY

The history of Shell in Libya is a fascinating account of how companies perform exploration in the same country over multiple decades, under different circumstances and driven by different leadership teams. Here, the story is told by Bashir Elmejrab, who currently teaches petroleum geology and seismic processing and interpretation at the University of Tripoli. In 2017, he retired from Shell after spending two long periods with the major in Libya.



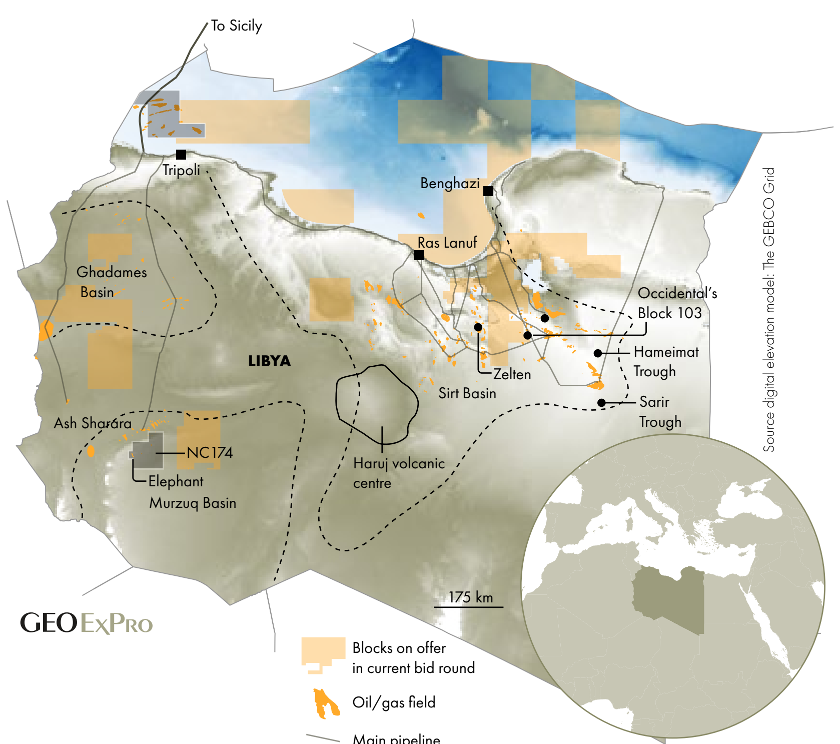
Bas van der Es (in the middle).

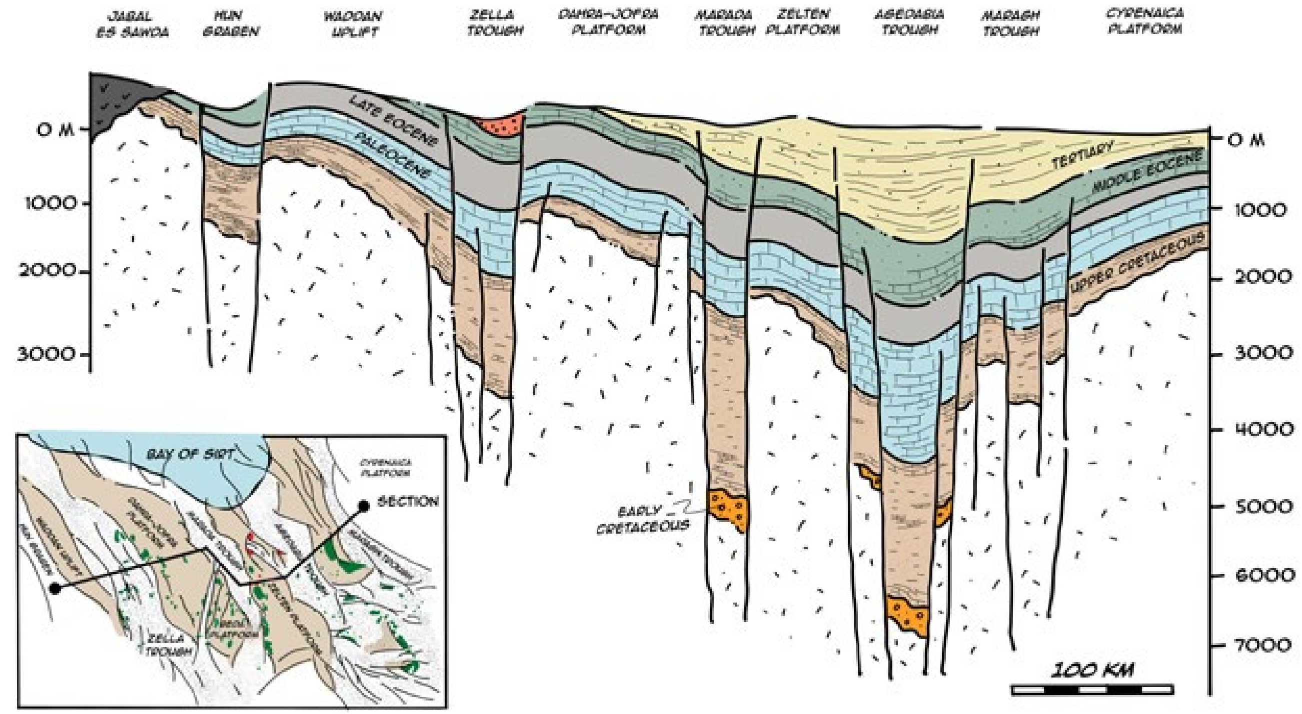
PHOTOGRAPHY: BAS VAN DER ES PRIVATE ARCHIVE

“After graduating in 1981, I joined Shell’s Libya team as a junior seismologist, working on the Sirt Basin,” Bashir says. “This basin has always been the most important oil and gas province in Libya.”

Within the Sirt Basin, which accounts for 80 % of Libya's reserves, most hydrocarbons are found in Tertiary carbonate reservoirs deposited on intra-basinal horst blocks and platform edges. About another quarter of the discovered volumes are trapped in the Lower Cretaceous – Nubian / Sarir play. This play has been extensively and successfully explored in the south-eastern sub-basins, within the Hameimat and Sarir Troughs. The deeper troughs of the central Sirt Basin, however, are still an underexplored domain in this mature hydrocarbon province.

In the 1980s, during the second EPSA round, Shell was interested in exploring the flanks of those basins more,” Bashir says. However, the company was not very successful; it drilled four unsuccessful wells, three in the Sirt basin and one in the Ghadames Basin.





A cross-section through the Sirt Basin, showing the intra-basinal platforms, where most of the basin’s hydrocarbon resources have been found, and the deeper troughs that formed the target for Shell’s third Libyan exploration campaign.

ILLUSTRATION: REDRAFTED BY MARCOS ASENSIO AFTER GUIRAUD ET AL. (2005)

The 1980s round of drilling can be seen as the second phase of exploration by Shell to prove additional volumes in Libya. In the 1960s and early 1970s, before they left the country temporarily, the company already had licences in the northern and central part of the Sirt Basin. “It resulted in one big discovery in the northeastern corner of Sirt Basin, in a very tight Eocene carbonates,” says Bashir. “This discovery is still undeveloped, though.” In the same period, Shell also explored the Ghadames Basin in the west of the country, but only found gas. “Unfortunately, there was no appetite for gas at the time,” adds Bashir.

In May 2005, Shell returned to Libya for the third time and secured a large acreage position in the northern and central part of Sirt Basin, with favourable EPSA 3 terms. It was the same areas they had explored twice before. However, a large tract (approximately 19,000 km^2) of newly processed seismic data had improved imaging significantly, providing more confidence in mapping deeper parts of the basin. Further helped by gravimagnetic surveys, which suggested that there was some structuration, it was decided to go deeper than the basin flanks this time and explore the grabens instead.

“The company applied for some big blocks, as Shell did in those years,” says Bashir, who had returned to Shell as an exploration geologist in 2005 following a long international posting with another explorer and a stint with the NOC.

“We were clearly going for the deep plays, aiming to find large gas volumes,” he says, “including the Nubian sandstone that was found prospective further to the southeast in the Sirt Basin, where bp had made some big finds in the 1960s. However, there were no wells in the deeper parts of the basin in Shell’s concessions at the time.

Another thing that had changed was the increased appetite for gas in the early 2000s. Whilst oil had always been the main target, in those years Libya had realised that gas could be an important export product as well, especially now that Europe proved to be an eager customer in the light of declining domestic production. As such, there were big plans to expand the already existing LNG plant that Exxon built in the 1970s. But first, this gas needed to be found.

In the end, Shell drilled five exploration wells, with the first being a deep HPHT well (20,300 ft – deepest well in Sirt basin) and four shallower wells.

When the first deep well reached 20,000 ft, overcoming many technical problems, the primary target, the Nubian sandstone, turned out to be water-wet and of poor reservoir quality. The second well also targeted the Nubian Sandstone, but it proved to be absent. Instead, a small gas column was tested in a shallower Eocene carbonate reservoir. Gas was encountered in the third well, but unfortunately, a sudden and unexpected overpressure event led to a well shut-in, resulting in costly well control remedial operations and a final abandonment. The fourth well proved gas again, but in tight Paleocene carbonate reservoirs, and testing operations failed on the second attempt. In early 2011, while the fifth well was progressing, operations were suddenly halted when ▸

Wintershall field trip to Murzuq Basin.

the uprising against the Gaddafi regime had started in Benghazi, spreading fast towards Tripoli.

By mid-February 2011, Shell and other IOCs commenced the evacuation of the expat staff from Libya. "Shell used the force majeure to leave the country," says Bas, "and the exit was not entirely against their desire, probably."

WISHFULL THINKING

"You don't discover gas by just dreaming about discovering gas," adds Bashir, "but that is what seemed to have happened in those years. There was something wrong with the expectations."

Shell was aiming to be a major gas networking leader in a strategic geographic area, but this was all dependent on exploration success in a harsh and hazardous subsurface environment. "The hopes were dashed soon after drilling the first and second wells, which were anticipated to tap into substantial gas volumes," says Bashir. Until the results came in.

Altogether, Shell has never been lucky in Libya. Was going back to the same basin twice a smart move? As the technology had progressed, every time the company came back, and with that the focus onto other parts of the basins, it is too easy to say that it wasn't smart to do so. But especially during the third exploration phase, it was the expectation pre-drill that had a detrimental effect on how the poor drilling outcomes were perceived.

MURZUQ BASIN

The Murzuq Basin in the southwest of Libya may not be the most important source of oil in the country, but it does host a number of particularly big finds that were made not too long ago.

The first one of those is the Ash Shararah discovery, made by Rompetrol from Romania in 1985. "Rompetrol didn't have the required funds to progress the development of the giant discovery with the NOC, also due to imposed sanctions," says Bashir. "However, a deal with the Prime Minister of Spain turned Repsol into the new operator of the field, and soon after, its development went ahead. It was then realised that the field contained much more oil than Rompetrol had claimed, reaching more than a billion barrels in recoverable resources."

A few years later, during the second half of the nineties, UK-based company Lasmo became the main player in yet another big discovery (Elephant field, approximately 1.4 billion barrels OIIP) in the Murzuq Basin. By that time, Bashir had joined the company following his first stint with Shell.

"Before we made the Elephant discovery," Bashir says, "we drilled three wells in block NC174 with Lasmo, partnered with a consortium of Korean companies under the name of Pedco, before Eni joined. One of these wells was a discovery, another a minor find and one was a failure. All in all, this caused the company to be in choppy financial waters, and talks started to sell the company. However, it was chief geologist Jonathan Craig who managed to convince management to drill the Elephant prospect before giving up."

That took quite a bit of effort, though, because another company under the name BrasPetro had just drilled nine wells in the area that all failed. And one of those wells was very similar to the Elephant prospect; it had a large reverse throw, with a similar Ordovician glacio-marine sandstone target.

However, the Elephant trap was giant, and ultimately, management was convinced to get it drilled. And so it did, with a major discovery as a result. "It was a big event, and it was mentioned in a lot of newspapers in 1997," says Bashir, who emphasises that the name Elephant was not because of the size of the discovery, but rather because of large elephant rock engravings in the area.

"Charge was the critical risk for Elephant," explains Bashir. "We had no clear idea from which direction it came, which had a detrimental effect on our probability of success. But they took the risk."

Bashir Elmejrab wearing a Lasmo coverall in the Murzuq Basin close to the Elephant field.

WHAT ABOUT THE CURRENT EXPLORATION OUTLOOK?

Earlier this year, a new bid round was announced by the Libyan NOC, underscored by an international road trip to promote the available acreage.

I spoke to an exploration manager from a company that is currently active in the country. "I don't know how successful it will be," he said. "A lot of companies are worried about the fiscal terms, even though they are supposed to be better now. Contractually, the country can also be quite tough. However, near-field exploration potential is surely there," he added. "Also, some big fields are just sitting at a 10 % recovery factor, so imagine the potential for enhanced recovery. Hence, there is a lot to be gained from existing fields, even before you would consider exploration."

Bashir is not very upbeat about the country's exploration prospects either. "Our challenge is that we have two governments," he says, "one in the east and the other in the west, and that is not the ingredient for a stable country. Exploration was almost always done by the international partners, but I fear that these companies will not be coming back to Libya soon. It is just not stable enough."

Taking all this in, it is clear that exploration efforts during the years prior to the 2011 uprising had mixed results at best, especially onshore, where the established plays have been mapped out well. To me, listening to what I heard during the conversations I had, it may be the (re)development of existing discoveries and fields that has the most potential in Libya, with recovery factors lagging behind from what should be achievable these days. However, that doesn't mean that there is no potential for exploration at all, as someone reiterated: "Libya is where the North Sea was a few decades ago." Whether these resources will be proven tomorrow is another matter. ■

A CORE STORE IN A WAR ZONE

If reports are correct, a big core store in Libya became the victim of the 2011 power conflict. Being located in Ras Lanuf, which became a hotspot of fighting, it was apparently damaged by bombings.

Henry Williams made several visits to the Ras Lanuf core thanks to the cooperation of Harouge management and geologists before it was damaged. He remembers it hosted numerous exploration and development cores from the Sirt Basin, ranging from the 1960s to the present day. "It was a big warehouse, and because it had no air conditioning, we normally went there in November," he says.

"The boxes were stacked on high shelving," he describes, "and because there was no forklift, it was almost impossible to get your cores down when they were at the top of the pile, especially if they were not slabbed. Also, many boxes did not have lids on them, meaning that over time, sand would have blown into them and needed a good dusting before core examination. I did, however, find the visits provided invaluable insight into understanding the depositional environment and diagenetic reservoir development of many diverse clastic and carbonate reservoirs. One core included a granite basement overlain by talus debris with granite blocks up to a metre in diameter interbedded with fluvial sediments. You could never have interpreted that correctly based on wireline logs!"

PHOTOGRAPHY: BAS VAN DER ES PRIVATE ARCHIVE

PHOTOGRAPHY: BASHIR ELMEJRAB PRIVATE ARCHIVE

EXPLORATION AND VOLCANICS

An interesting exploration story from Libya comes from near the large Haruj volcanic centre in the Sirt Basin. It is mostly Pleistocene in age and reaches up to 1,200 m above sea level. "Some of the lava flows extend close to producing oil fields and could potentially be hiding other undiscovered hydrocarbon deposits," Henry Williams says. However, CO_2 might be a risk there. "A few wells drilled some distance from the volcanic outcrops encountered CO_2 rather than oil in prospective reservoirs," he says. Based on Henry's subsequent experience in Canadian helium exploration and production, he considers that this may have been caused by secondary flushing during Haruj magmatic activity.

West African deepwater plays

Tracking the Cretaceous mega-clastic systems

Mauritania and Senegal have jointly been producing gas, with the first shipments occurring during the first half of 2025, while Senegal has produced oil independently for a year. Despite this success, the deepwater basin domain remains underexplored, highlighting the importance of more robust de-risking of open acreage. The extent of hydrocarbon maturation along the margin and the degree of reservoir charging are still not fully understood. With a vast 3D data coverage having recently been added to the multiclient data library offshore Mauritania, play extents and prospects can be mapped over a greater area, inferring untapped subsurface potential. However, there is a need to better calibrate the subsurface evaluation with well data to entice re-investment. Similar trends are seen elsewhere along the West African margin, where exploration is moving into increasingly frontier areas. In Côte d'Ivoire, for example, extensive multiclient seismic coverage and recent exploration successes have broadened the scope of opportunities. Much of the Côte d'Ivoire basin remains underexplored, but recoverable reserves totaling 4.5 billion barrels of oil and 13 Tcf of gas from 82 fields underscores the potential yet to be realised.

This article highlights how extensive coverage of high-quality multiclient 3D enables more effective tracking of reservoirs already tested by exploration wells. The source-to-sink story becomes more concrete when fairways are mapped on mega-regional 3D data compared to hypotheses generated from regional 2D or patchy 3D survey coverage, as demonstrated by examples offshore Mauritania (Figure 1). Data quality also plays a crucial role in upstream ventures, as an example from offshore Côte d'Ivoire will show. In deepwater exploration, where higher risks are balanced by the potential for higher rewards, both data quality and coverage are especially vital, which we observe along the West African margin. As exploration continues to advance into greater water depths, modern multiclient 3D data proves essential in identifying and de-risking the next generation of targets prior to drilling.

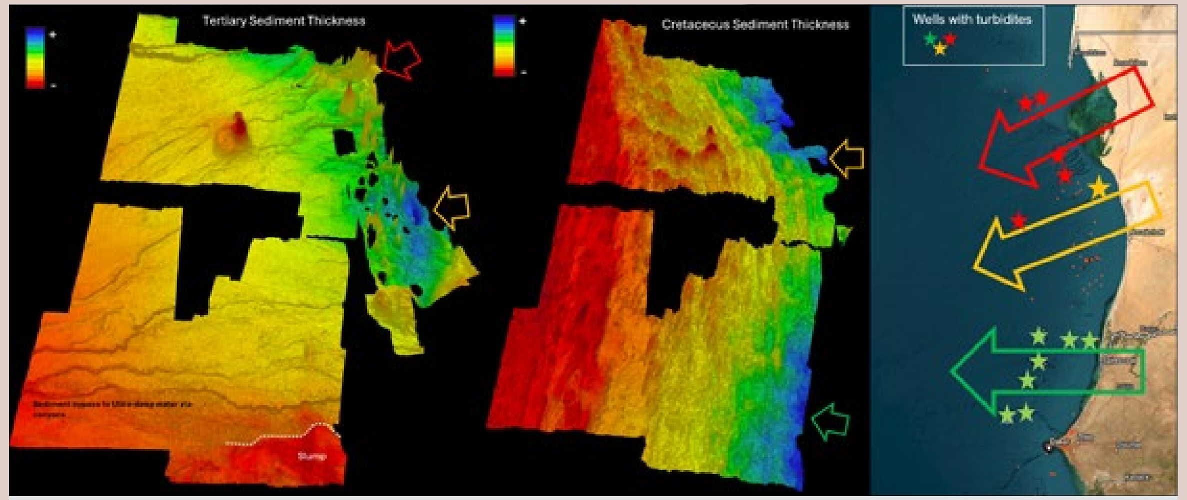


Figure 2: Sediment thickness map for Cretaceous and Cenozoic sequences.

TGS

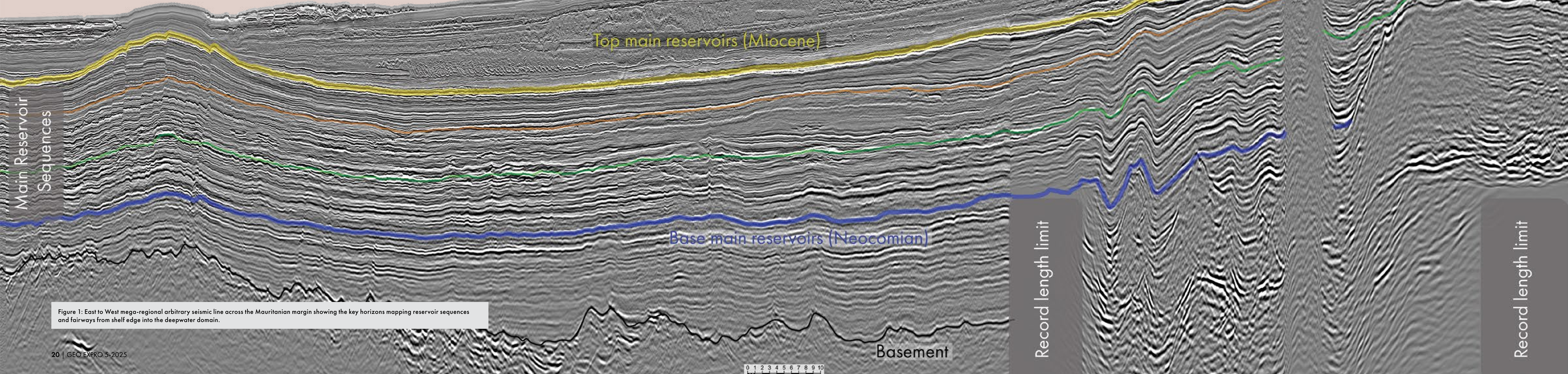


Figure 1: East to West mega-regional arbitrary seismic line across the Mauritanian margin showing the key horizons mapping reservoir sequences and fairways from shelf edge into the deepwater domain.

Unlocking deepwater potential

FELICIA WINTER, THOMAS HANSEN AND EMILY KAY, TGS

EXPLORATION in the Mauritanian coastal basin has historically focused on the Cenozoic salt-draped channel plays, as proven by the discovery of the Chinguetti Field in 2001. Since this time, nearly 80% of exploration wells has targeted this play. Neighbouring Senegal has traditionally targeted clastics trapped over the carbonate shelf (edge), an example being the Sangomar field, which is in production. Whilst untested potential also exists in the deeper Jurassic-Lower Cretaceous carbonate platform and underlying syn-rift section, the most prolific of these hydrocarbon finds along the joint Mauritania and Senegal margin have been in Mid to Upper Cretaceous mixed turbidite-contourite deposits of the post-rift and drift sequences. For example, in the Greater Tortue Ahmeyim (GTA) wells, the Fan discovery with 950 mmbbl and the latest discovery, Orca, with 13 Tcf (2019).

In contrast to Mauritania, the prolific hydrocarbon province of offshore Côte d'Ivoire, further south along West Africa's coastline, has yielded several producing fields.

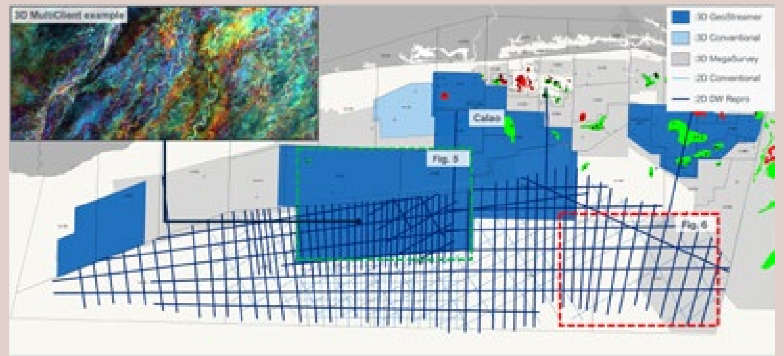


Figure 4: TGS data library coverage with Upper Cretaceous spectral decomposition surface, detailing a series of channels which extend beyond the 3D coverage, further outboard to the area covered by depth reprocessed 2D seismic (KPSDM). The location of the following 3D lead (Figure 5) and 2D lead (Figure 6) are highlighted by the dashed outline on the basemap, with Calao discovery labelled as a reference point.

Historically, exploration focused on structural traps on the shallow water shelf of Côte d'Ivoire. However, in recent years, similar to Mauritania, exploration activity has branched out into the deepwater domain, targeting deepwater Upper Cretaceous turbidite reservoirs, following analogues of Jubilee and Tweneboa fields. In 2024, the discovery of the Calao field was recorded as the second-largest discovery offshore Côte d'Ivoire. This expanded the geographical distribution of commercial hydrocarbon discoveries to the central deepwater basin domain, where previously discoveries had been concentrated in the eastern part of the basin.

NORTHWEST AFRICA MARGIN - MAURITANIA

Previous studies have identified several major clastic systems entering the Mauritania offshore Basin, depositing deltaic facies and associated down-slope channel and fan systems since the carbonate platform was drowned during the Early Cretaceous. The switch in major depo-centre from south to north is evident in Figure 2, and the main bypass routes are shown in Figure 3.

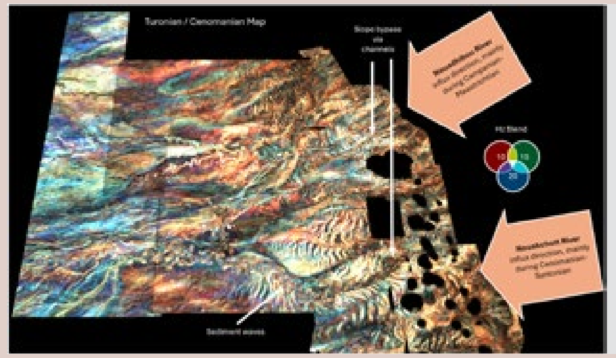


Figure 3: Slope bypass routes in the Late Cretaceous are showcased with a frequency blend map.

Upslope on the platform, sand facies have been penetrated at multiple stratigraphic levels, but often without significant thickness or net-to-gross (e.g., Courbine, Chinguetti 6-1 wells). Early wells targeted the continental shelf and were successful in Early Miocene channelized turbidites draped over salt structures (e.g. Chinguetti, Tiof, Tevet, Banda). In contrast, the Upper Cretaceous system has proven well-developed reservoir sands both on and off the shelf from the Coniacian to the Maastrichtian (e.g., Pelican, Aigrette, Lamatin, Fregate wells). The discovery of Pelican in 2003, an Upper Cretaceous turbidite channel play, unlocked the potential for Cretaceous clastics within the basin. This was soon followed by Faucon-1, Aigrette-1 and Cormoran-1, all of which discovered hydrocarbons in structurally closed Upper Cretaceous sand fairways. The lower to mid-Cretaceous system focused primarily on the southern and central parts of the basin and was fed by the Senegal River with a maximum deposition during the Apto-Albian. Significant bypass of the shelf is known to have occurred during this period, with large sand deposition downslope as proven in several deepwater wells (e.g., Tortue, Hippocampe, Marsouin). The Marsouin-1 well in 2015 and the Orca-1 well in 2019 discovered net pay in Cenomanian channel systems and previously untested Albian sands. Orca-1, was the largest discovery of 2019 with 13 Tcf directly after Zohr and reported excellent reservoir porosity (Kosmos Energy, Businesswire, 28 October 2019).

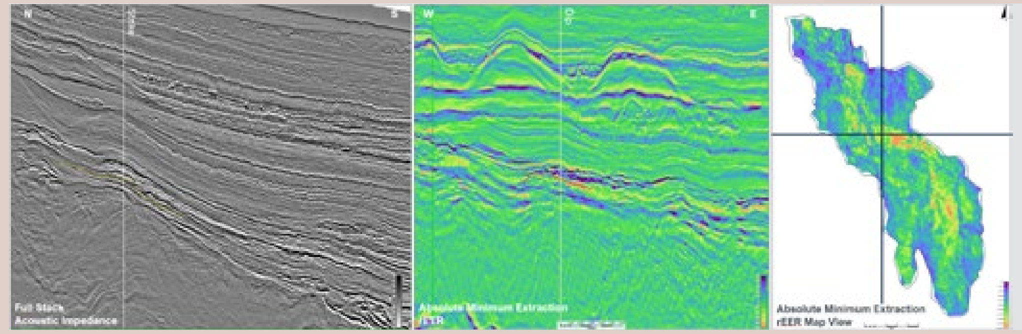


Figure 5: Shows an example of an undrilled Cenomanian turbidite fan lead, located west of Calao within open acreage. The rEER volume shows a clear anomaly indicating potential hydrocarbon saturation within the reservoir sand, adding to the detail observed in full-stack acoustic impedance.

WEST AFRICA TRANSFORM MARGIN - CÔTE D'IVOIRE

Transform fault segmentation along the Côte d'Ivoire – Ghana margin is a key control on sediment transport, source rock distribution, and trap development. Recent analysis using TGS's extensive 3D seismic coverage has revealed multiple terrace-margin systems, settings where reservoir sands tend to pond. The Murene-1X well (Calao discovery) encountered oil, condensate and gas within several sandstone intervals in the Cenomanian, reporting good to excellent permeability. The reservoir unit ponded and is stratigraphically trapped against the faulted terrace structure. Potential resources (assumed in place) were announced between 1 and 1.5 billion barrels of oil equivalent. The magnitude of this recent success provides a valuable perspective on exploration trends, as operators branch out into more frontier acreage to the west and into deeper water with a focus on Upper Cretaceous clastic reservoirs.

Several Upper Cretaceous clastic systems have been identified to the west of Calao, within 3D GeoStreamer coverage (Figure 4), and further south, into the ultra-deep water covered by newly depth-reprocessed 2D seismic. Here, sediments ponded in topographic lows and pinched out against structural highs, forming stratigraphic traps. These units are interbedded by layers of shales and mudstones. Including the main source intervals Apto-Albian, Cenomanian and Turonian shales.

High-quality data is needed in deepwater environments due to the more subtle nature of stratigraphic traps in a conformable basin infill environment. Reservoir quality lithologies and potentially charged targets are easier to differentiate on a high-resolution suite of attributes, allowing the broadband frequency content and VpVs relationship to highlight undrilled targets. The detailed analysis of rock physics on seismic attributes by proxy offshore Côte d'Ivoire is especially crucial for another reason. The recent Calao discovery shows a subtle response on full and angle stack data, but can be mapped on relative impedance. A Relative Extended Elastic Reflectivity (rEER) workflow was carried out on Côte d'Ivoire GeoStreamer seismic to help distinguish sands and shales and highlight hydrocarbon saturation anomalies. Several leads have been identified within the GeoStreamer seismic coverage (Figure 5).

Côte d'Ivoire demonstrates further potential in its ultra-deep water setting. The Upper Cretaceous turbidites are extensive, reaching outboard of the 3D coverage, captured by the depth reprocessed 2D seismic (Figure 6). Within this basin setting, the change between continental, transitional, and oceanic crust occurs. In the past, this has had negative connotations for source maturity and the ability to charge nearby reservoir units. However, discoveries offshore Guyana (Liza, Ranger) have demonstrated that source maturity can be achieved over transitional and oceanic crust. More recently, Namibia (Venus discovery) has proven source maturity and migration in a similar setting with significantly less overburden. This helps de-risk exploration in the deepwater area offshore Côte d'Ivoire, opening up an exciting frontier part of the basin.

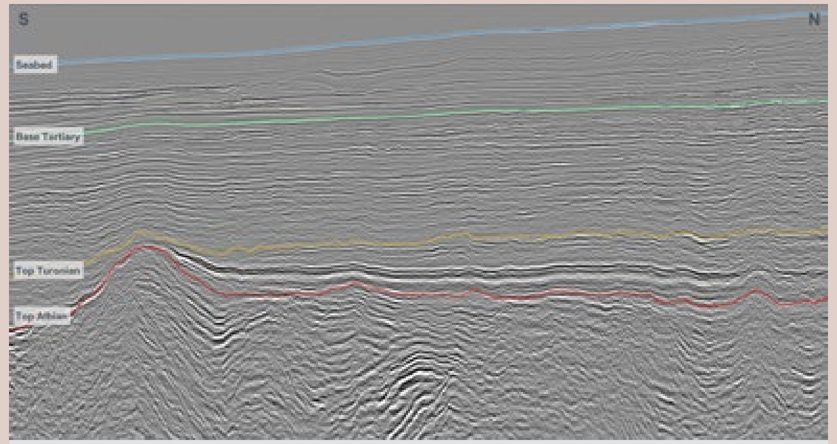


Figure 6: 2D depth reprocessed line (KPSDM) displaying stratigraphically trapped Upper Cretaceous fan lead in ultra deepwater basin setting.

Unlocking Egypt's Western Desert: The next Eagle Ford?

Canadian player TAG Oil aims to open up a new unconventional oil play in a country that is looking to arrest domestic production

When people think of unconventional oil, their minds probably go straight to North America, where long horizontals and multilaterals drilled in heavily faulted plays have unlocked massive gas, liquids, and heavy oil reserves. But there is similar geological potential stirring in unexpected corners of the world. It is therefore not a surprise that there are companies from both the USA and Canada exporting the technology and know-how built up in their backyard to new places.

ExxonMobil's recently announced agreement with Azerbaijan's SOCAR to pursue unconventional oil is an example of that trend. On a smaller scale, Canada-based Alvopetro acquired acreage in Saskatchewan, where it plans to develop a discovery using horizontal drilling technology to subsequently export it to Brazil. Similarly, TAG Oil, also rooted in Canada, has its eyes on Egypt's Western Desert.

Building on Egypt's long history of conventional oil, TAG has now proven the potential of the Upper Cretaceous Abu Roash "F" Formation with a horizontal test well – despite the well being shorter than planned. Apache and other operators have seen similar encouraging results here, signalling that a field once conventionally tapped by Shell may hold a far richer unconventional promise.

Nathan Kneisel, a consulting geologist working for TAG, logged much of the exploratory geology on this project in Egypt. Having Geosteered 20 years of exploration and production wells in heavily faulted strata across the Canadian oil patch in the Peace Arch, Deep Basin and many more, Kneisel was struck by the parallels he saw in Egypt.

"This was a fascinating project for me, seeing the potential that can be unlocked with the Geosteering skills and tools we've honed," he explained. "Like the trial and error that uncovered Egypt's first tombs, the Geosteering secrets the rock revealed in this first well are the key to unlocking this and many more fields across the Middle East."

And the rocks themselves tell an enticing story. The Abu Roash Formation – sometimes called the Eagle Ford of Egypt – are outcropping just 10 km south of Cairo near an ancient pyramid site closed to the public. The dark limestones, deposited in a shallow marine setting, have also been used as building stones. Subdivided into seven units, it has long been known as a conventional reservoir, but with a pay zone of over 20 m thick and an areal extent that far exceeds the size of most conventional oil fields, this naturally fractured and faulted interval is now ready to be navigated with modern directional drilling and geosteering tools. ■

Henk Kombrink

PHOTOGRAPHY: NATHAN KNEISEL

TAG Oil rig in Western Desert, Egypt

Does oil really stop diagenesis?

It is a phenomenon that is often mentioned in discussions about the difference in reservoir quality between water-saturated and oil-saturated reservoirs; hydrocarbons inhibit the growth of diagenetic cement. But the reality seems more complicated than that, as experts from Equinor show

It is all about timing. That is the main conclusion when reading a new paper recently published by Olav Walderhaug and Kristin Porten from Equinor.

The paper is mostly about the timing of albitization of plagioclase feldspars in sandstones, and the observation of oil inclusions within the newly formed minerals. However, the conclusions the authors draw also have interesting implications for the widely-held belief that oil charge stops further cementation of sandstones altogether. And it is the timing element that raises questions about this idea.

Through extensive analysis of thousands of samples, the authors have been able to show that albitization of plagioclase feldspars occurs in many reservoirs at a temperature of around 88° C. The fact that oil inclusions can be observed in these newly formed minerals also means that oil was already around in the reservoir when it reached this critical temperature, which is lower than many models predict.

In turn, when we assume that oil is indeed already in the reservoir when albitization is kicking off, we also know that quartz cementation is still in its initial stage at this temperature. Quartz overgrowth is generally assumed to reach its peak at temperatures of around 150° C, and quartz cement volumes rarely exceed 5 – 10 % at 100° C.

On that basis, if oil emplacement would indeed completely shut off all diagenetic reactions, it could be argued that one would not expect a significant level of quartz cementation in reservoirs with oil inclusions within diagenetically formed albite.

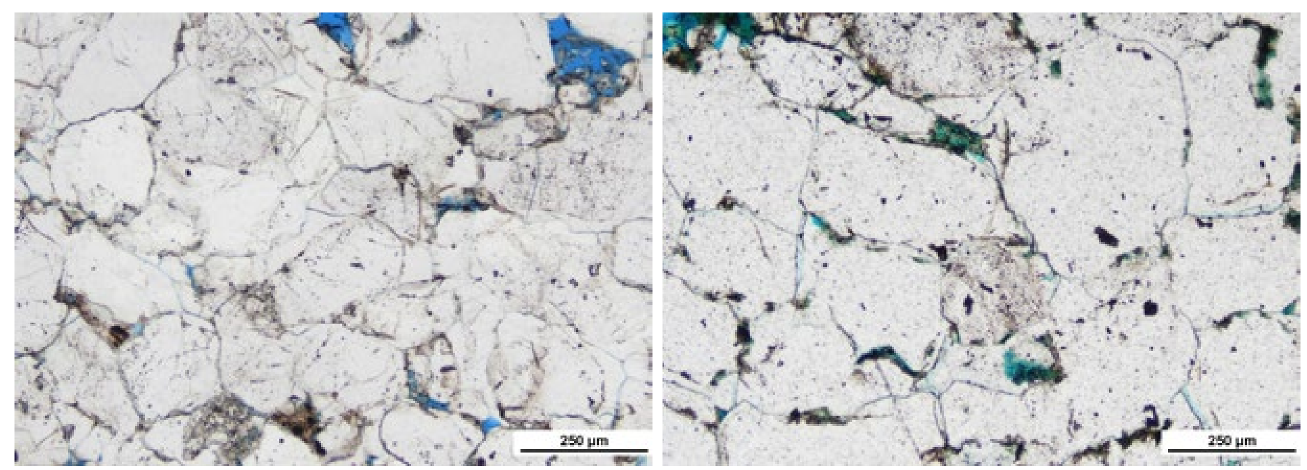
However, that is not what Walderhaug and Porten found. Instead, they describe deeply buried reservoirs with oil inclusions in albitized plagioclase to be just as quartz cemented as their water-saturated equivalents. It is therefore concluded that at least quartz cementation is a process that can still continue in reservoirs even when they are hydrocarbon-filled, challenging the concept that diagenesis is halted once oil enters a reservoir.

This is really not all that surprising as the reservoirs are still water-wet after oil filling with a water film covering the mineral grains. Assuming that early oil filling has prevented quartz cementation and preserved reservoir quality in very deep prospects therefore seems to be a rather optimistic approach.

But what about other diagenetic cements such as carbonates and illite, does oil-filling of the reservoir stop them as well? Regarding carbonate cements, they are mostly precipitated rather early in the burial history before quartz cementation starts, suggesting that they will mostly be in place before oil arrives. Illitization of kaolin, on the other hand, typically takes place at around 130° C, i.e., a long time after oil emplacement.

So, the conclusion appears to be that preservation of acceptable reservoir quality in very deeply buried sandstones will have to depend upon other factors than oil-filling. Factors such as grain coats on the quartz grains, lack of K-feldspar to avoid illitization, and large grain size to boost permeability are amongst the candidates. ■

Henk Kombrink



SOURCE: OLAV WALDERHAUG

Two micrographs of pervasively quartz cemented sandstone with hardly any pores preserved. The rare pores present are filled by blue epoxy, white is quartz grains and quartz overgrowths. The micrograph (right) from the Ness Formation (well 34/11-1, Kvitebjørn Field) showing oil inclusions in albitized feldspar and quartz dust rims in the wet gas zone. Kvitebjørn used to be oil-filled before the oil was displaced by gas. The micrograph on the left is from the Hugin Formation in 25/10-6 S is from an interval where there are no oil inclusions at all, no hydrocarbon column was found, and only some possible shows were reported.

Finding the right needle in the haystack

When multiple factors – and not only subsurface factors - determine how well a certain field forms an analogue for another, AI is the way to go

THE ULTIMATE question every operator faces is whether there is room to arrest the decline of their producing field by investing to increase the recovery factor. One of the most common ways to find out if there is potential to do so is by looking at field analogues: Is there an operator somewhere in the world that manages to squeeze more out of field X than we anticipate doing? There is an answer to that question for sure, but how to start and where to look?

This is where data from subsurface intelligence companies comes in, as it is only by having large global databases that enable someone to perform the screening required to answer this question satisfactorily.

"But it is not only reservoir characteristics such as porosity, permeability and oil viscosity that define whether a field is a good analogue," says Andrew Latham from Wood Mackenzie. "The performance of the same field may be vastly different depending on which country it is in. In other words, some places promote the application of technology more, or have tax incentives in place to do drill more development wells. That is a very important element to include in your analysis."

"And customers are aware of this," Andrew continues. "I recently talked to an operator in the Middle East who only looked at their own country to find good analogues for that very reason."

"The news is swamped with exploration drilling in new frontier areas, but the biggest investments in the upstream oil and gas sector are made towards improving the recovery of existing fields. As such, we want to offer a toolkit that provides our clients the confidence that there is room to make this investment"

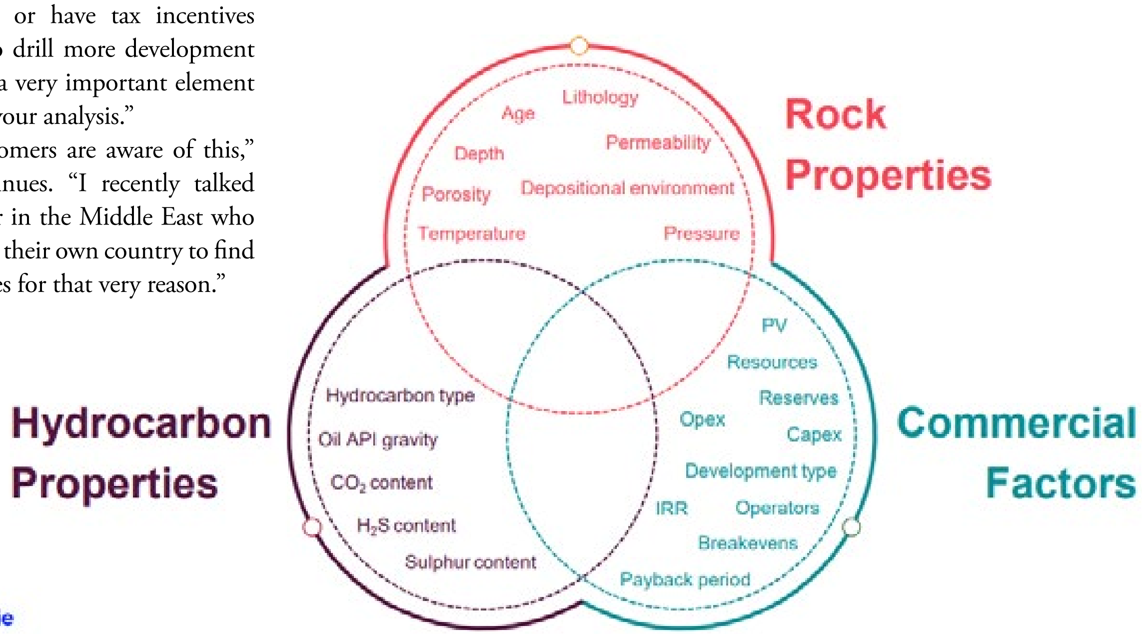
Andrew Latham

However, by doing so, you ignore a large swath of data that will potentially allow you to find an analogue in another location that may be a much better fit. An analogue that may even trigger an investment decision that would otherwise not be made.

"The simple filtering approach that we applied to interrogate our database thus far has proven to return data with insufficient granularity, especially when you include the commercial side of things," explains Andrew. "The selection that would be returned when applying a specific filter is often too narrow, and, more importantly, there is no ranking provided either."

"That is where our new AI approach comes in," he says. "Using AI, we can now sample our database more dynamically, including commercial variables, and return a ranked list of analogues that fulfil the criteria set at the start of the process. Much better than a list of candidates that all fulfil the same criteria without any ranking at all." ■

Henk Kombrink



The shrinking pool of large international E&P companies

What will be the impact on exploration?

CARLOS BELLORIN AND RUARAIDH MONTGOMERY, WELLIGENCE

THE GROUP of large international E&Ps has been steadily shrinking. Over the past five years, companies in the peer group, including Noble Energy, Marathon, and Hess, have been acquired. These companies were active explorers and were responsible for some high-profile discoveries. Others in the group, such as ConocoPhillips, Occidental, OMV, and Repsol, scaled back on high-impact exploration. This has raised concerns about a growing lack of technically capable E&Ps with exploration expertise, particularly in the deepwater space.

At the same time, the exploration outlook for the peer group is beginning to shift with acreage reloading taking place amongst some in response to the pipeline of projects becoming weak. But will the exploration reloading translate to an uptick in exploration by the peer group in the coming years?

GROWTH HOPPERS GETTING WEAK

Most in the peer group now lack strong international growth hoppers, which limits the scope for further acquisitions or broader consolidation. For those looking to remain in the E&P business, the return to exploration is therefore increasingly inevitable. Inorganic growth will still be pursued, but the acquisition options are increasingly few and far between, particularly for those looking to grow in the gas and deepwater space.

WHO IS ON THE FRONT FOOT WITH EXPLORATION RELOADING?

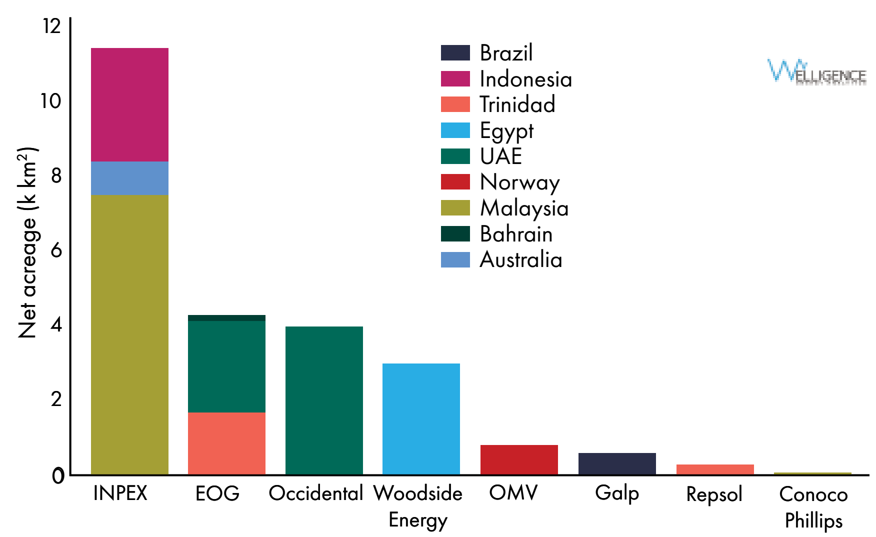
The good news is that some of the large international E&Ps are beginning to rethink their exploration strategies. INPEX, the Japanese E&P company, has been the most active in Southeast Asia. US shale specialist EOG is continuing to explore international expansion opportunities, picking up acreage this year in Bahrain and UAE. Galp from Portugal picked up acreage in the recent licensing round in Brazil. In addition, the energy transition narrative of the other European internationals is also changing when it comes to doing exploration.

WHAT IS THE DRILLING OUTLOOK?

Despite the increased appetite of some companies to do exploration, we believe drilling in the next 18 months by the peer group will remain measured. Prospect inventories need to be worked up, and, for some, exploration and new ventures teams will need to be grown first. But some in the group have high-profile wells to watch in the next 24 months, most notably Galp and INPEX.

Galp has been the most successful in the peer group with its drilling campaign offshore Namibia. Its Mopane find is estimated to hold around a billion boe of recoverable resources, and the Portuguese E&P company will be looking to replicate this success with its planned campaign offshore São Tomé next year.

Regardless of the near-term outlook for the peer group, the industry consensus is that exploration is still required to meet long-term oil demand, and we believe the large internationals are the key group outside the majors that can move the needle with high-impact exploration. ■



Exploration acreage reloading by the peer group since 2020.

Why P10/P90 prospect ratios are meaningless without involving the geology

In well-understood petroleum provinces, the risk profile for certain prospects can be calculated differently if the geology allows, changing the way P10 and P90 volumes are calculated

In many exploration departments, the ratio between the low-case P90 volume and the high-case P10 volume of a prospect is used to assess the distribution of its volume estimates.

Frontier prospects are thereby thought to have a P10/P90 ratio between 40 and 50, whilst near-field exploration targets are expected to have a value between 5 and 10, reflecting the higher uncertainty and therefore higher spread in possible volumes for more frontier prospects.

But does it make sense to create these buckets in which prospects need to fall? No!

The main reason is that the P99 and P90 are often chosen at too low a value, pinned at the "smallest identifiable hydrocarbon volume", typically in the order of 0.1 to 1 MMb (million barrels) recoverable. However, when looking at the geology, it is often justifiable to assume a higher P99/P90, related to the first likely spill or leak point of the structure. That is further illustrated in the example below.

Let's say we have a closure that is partly 4-way dip-controlled and partly fault-controlled. Also, it is situated in a basin where the sealing unit is proven, and fields have been found in similar settings nearby.

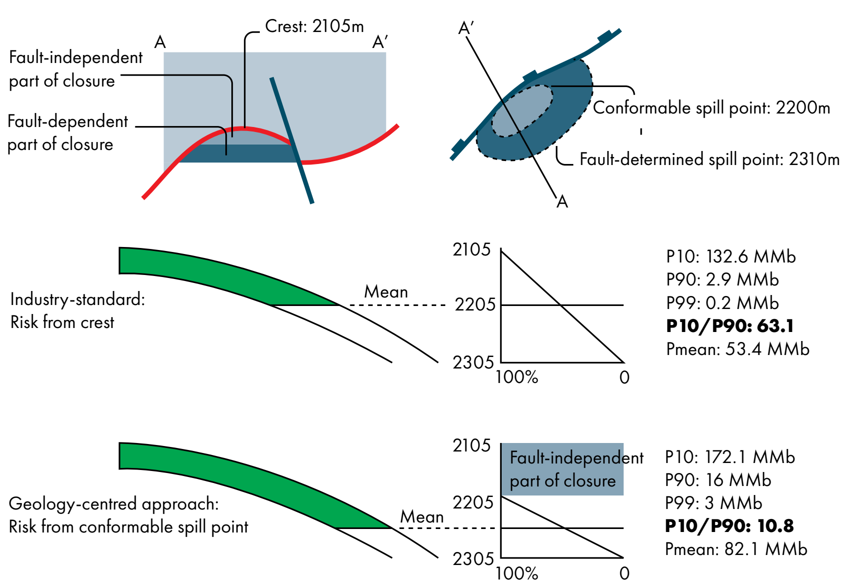
In the "conventional" way, geologists would start risking this prospect from very near the top of the crest, resulting in a Pmean volume in this case of 53.4 MMb and a P10/P90 ratio of 63.1. However, given the evidence from pools nearby, it can be argued that the risk element should only start at the "conformable" spill point where fault sealing becomes a factor at play. In that case, the P90 increases to 16 MMb, and the Pmean to 82.1 MMb. As such, the P10/P90 ratio changes to 10.8, so a lot less "frontier" than the initial value. And that is justifiable, given the evidence of a working petroleum system in nearby pools as well as the observation of a small but still important non-fault controlled closure.

Based on this, it can be concluded that the P10/P90 ratio should not be used to force prospects in a maturity bucket. Instead, prospects should be evaluated based on the geology you see in each individual case. The P10/P90 ratio might be handled in a more generic way; however, a too low ratio – often below 10 – is mostly caused by assuming too high a P90 and P100 volume. ■

Henk Kombrink

GIS PAX PLAYER

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



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

FEATURES

"A technical specialist may see the value of something you do, but that's only the start of a long chain of hurdles before having a signature on the dotted line. If one thing is needed in the service sector, it is resilience"

Laurie Weston – Sound QI

FEATURES

Imaging prospective sedimentary strata offshore Equatorial Guinea

Understanding deep-water sedimentary systems for exploration

LISA FULLARTON, NICK LEE, CHRIS JOHNSTON, MEREN ENERGY AND ALEX CLARK, ELIIS

THE OFFSHORE basins of Equatorial Guinea and its neighbouring countries host exceptional examples of paleo deep-water siliciclastic systems preserved within Cretaceous and Tertiary stratigraphy. These successions have proven to be prolific hydrocarbon exploration targets across West Africa, particularly within the Miocene.

> "Meren, views Equatorial Guinea as an underexplored province, strategically located adjacent to the world-class Niger Delta and along the prolific West African margin"

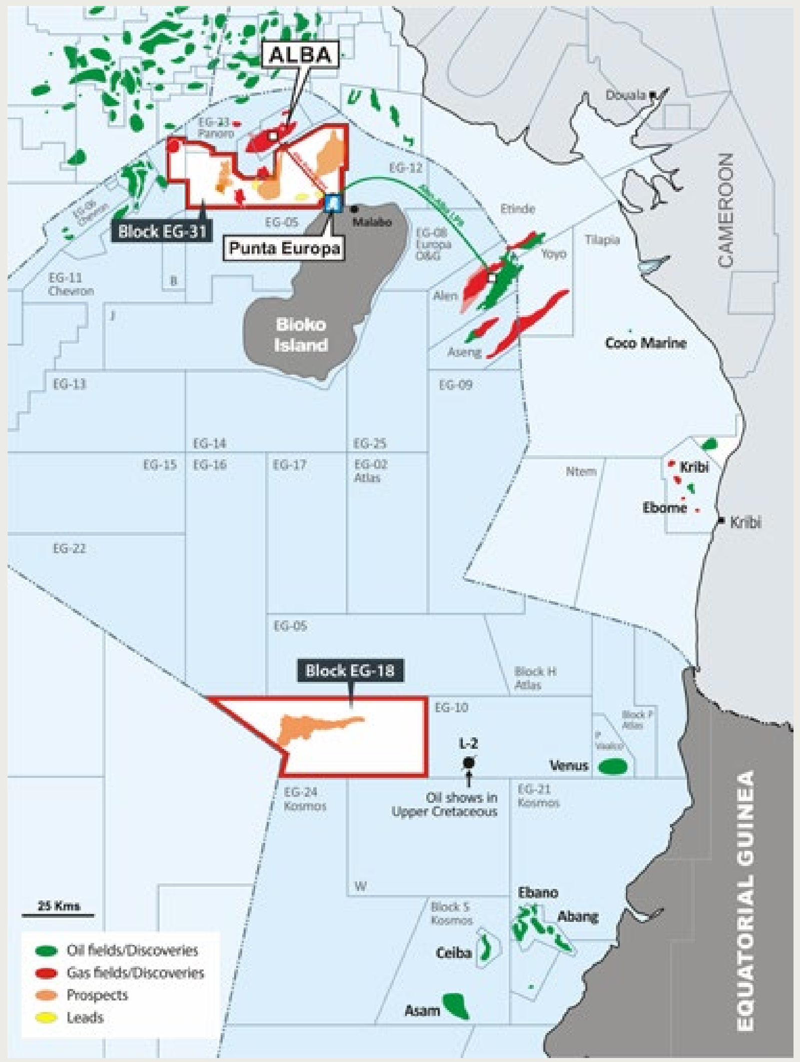


Figure 1: Location map of the Meren assets in Equatorial Guinea

In recent years, exploration has increasingly shifted toward Cretaceous deep-water sandstones across the broader Atlantic Basin, resulting in a series of major discoveries over the past 15 years. Considerable potential remains in both systems, and this article highlights illustrative examples from the relatively mature and well-understood Miocene systems in West Africa as well as the less differentiated Cretaceous marine systems, which are extensively developed around the South Atlantic Basin.

The Miocene deep-water systems are well established as highly productive reservoir targets, particularly in the Niger Delta. Similar success has been realised in the adjacent Equatorial Guinea basins, exemplified by the Alba Field in the Rio Del Rey basin. Meanwhile, Cretaceous systems remain at the forefront of active exploration across the South Atlantic margins, with landmark discoveries including ExxonMobil's Stabroek Block projects in Guyana to TotalEnergies' pioneering Venus project in Namibia.

Since 2023, in partnership with GEPetrol, Meren has focused its exploration efforts on both Miocene and Cretaceous depositional systems offshore Equatorial Guinea. The company has taken a leading role in the renewed interest in this region, acquiring an 80 % interest in two offshore exploration blocks in 2023. These blocks provide a balanced portfolio, combining near-field, infrastructure-led appraisal and exploration within the established Miocene Isongo play (EG-31) with frontier opportunities in the emerging outboard deepwater Upper Cretaceous play (EG-18).

Despite notable discoveries in Equatorial Guinea, including Zafiro, Alba, Alen, Aseng, and the Okume Complex, only 60 wells have been drilled across its vast offshore acreage, of which only a few are in the deep to ultra-deep water areas. Meren, therefore, views Equatorial Guinea as an underexplored province, strategically located adjacent to the world-class Niger Delta and along the prolific West African margin. Unlocking these opportunities depends on the identification of paleo–deepwater siliciclastic systems, a challenge that requires advanced geophysical interpretation tools capable of illuminating sedimentary architectures that are only subtly imaged in existing offshore data.

In this article, we will show examples of both Miocene and Cretaceous deep-water systems that have been mapped out using Paleoscan from Eliis to support the identification of large-scale multi-billion barrel and multi-TCF targets.

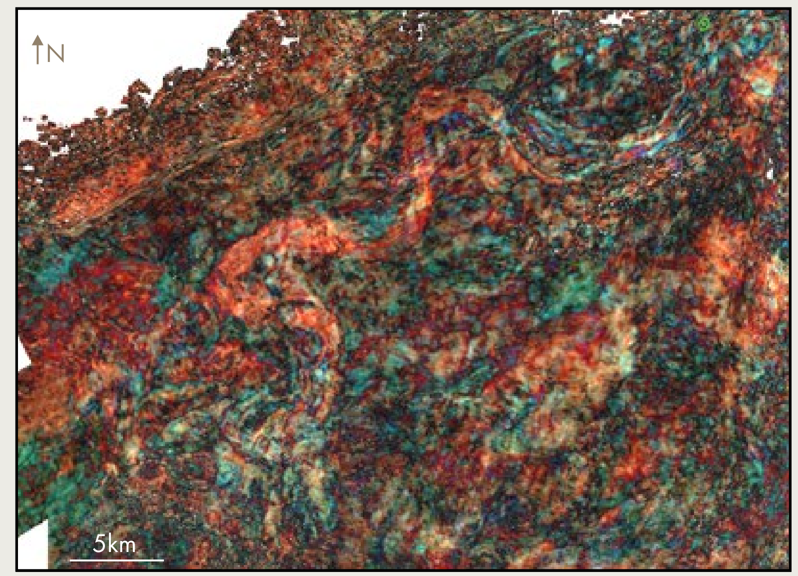


Figure 2: Spectral Decomposition (Full Stack volume from Perceptum) from the Miocene Sequence around EG-31 showing meandering channel (70km length) and submarine fan reservoir complex (Red 9hz, Green 20Hz, Blue 31Hz)

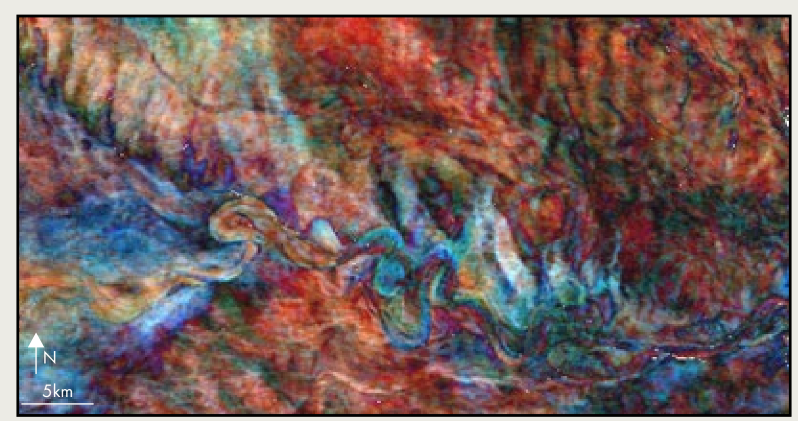


Figure 3: Spectral Decomposition (Near Stack volume from Geoex MCG) from the Cretaceous Sequence around EG-18 showing meandering, avulsing channels (70 km length) and submarine fan complexes (Red 10 Hz, Green 20 Hz, Blue 31Hz).

MAPPING BOUNDARIES

Following regional screening to identify the presence of potential viable 'source to sink' reservoir systems, alongside screening the other elements of the petroleum system, specific targets in both intervals are usually first observed as seismic amplitude anomalies. To develop the relevant exploration concepts, a strong stratigraphic component must be identified and mapped to develop a clear understanding of the potential trap geometry and the extent of the reservoir distribution in the case of structural traps. Consequently, the process to mature them into viable exploration and drilling targets leans very heavily on geophysical methods. Detailed AVO analysis forms a key component in the exploration workflows to evaluate the targets and assess the expected lithology and fluid responses. The other key element requires the application of advanced geophysical interpretation tools to develop a deep understanding of architectural elements within the systems and to enable the potential trapping geometry to be understood. In particular, the use of spectral decomposition is a hugely powerful tool to utilise alongside AVO and other attribute analysis of the target levels.

EVALUATION IN EQUATORIAL GUINEA

The shallow water EG-31 block contains infrastructure-led opportunities close to the Punta Europe LNG facility and adjacent to the world-class Za- ▸

firo and Alba fields. Meren has an extensive merged seismic dataset of 5,800 km^2 with vintages from 1994 to 2014. The older, more regional, mid-90s data was used for the Paleoscan work.

The Miocene Isongo system prospectivity in EG-31 is focused on large-scale, low-relief structural traps with high-quality sandstones comprising the reservoir. These are on-trend with the Alba gas field. The main challenge was unravelling the complexity of relationships between multiple stacked lobe/channel complexes and the relationship with structural development (Figure 3). Identifying and mapping key architectural elements is critical to prospect definition.

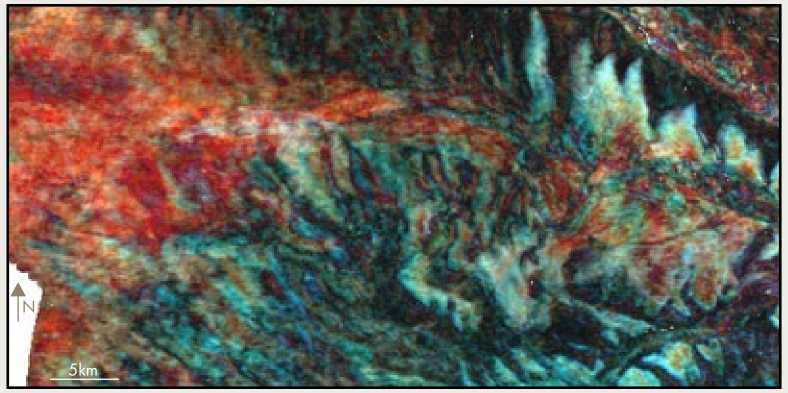


Figure 4: Spectral Decomposition of the Extended Elastic Impedance Volume from the Cretaceous Sequence around EG-18 showing lithology distribution in channel (70 km length) and submarine fan complex (Red 10 Hz, Green 20 Hz, Blue 31Hz).

Meren's EG-18 block is a frontier exploration opportunity down-dip from the major Alen and Aseng fields. The block is covered by 1 536 km^2 of 3D seismic data acquired in 2014. The main targets comprise largely stratigraphic traps developed within the undifferentiated sandstone-bearing marine Cretaceous section.

The spectral decomposition work (Figures 4 and 5) permitted critical aspects of the prospect definition to be mapped in crucial areas, e.g. channel-lobe transitions and the presence of shale-plugs to form up-dip seals to large stratigraphic targets. ■

A special thank you to our partner GEPetrol and to Perceptum and Geoex MCG for permission to publish images and derivatives from their seismic data.

FEATURES

New modelling study reveals a petroleum system overlying oceanic crust offshore Equatorial Guinea

New insights into a frontier basin: Douala-Rio Muni Basin

JOSÉ MIGUEL GOROSABEL-ARAUS AND PAUL MANN, DEPARTMENT OF EARTH AND ATMOSPHERIC SCIENCES, UNIVERSITY OF HOUSTON, ANDREW PEPPER, THIS IS PETROLEUM SYSTEMS

THE DEEPWATER Douala-Rio Muni Basin (DRMB) is a non-volcanic, Mesozoic-Cenozoic rifted passive margin located offshore in Equatorial Guinea (EG), West Africa. Commercial oil and gas fields have been discovered on the shelf and slope of EG include the Ceiba and Okume fields, charged by Lower Cretaceous source rocks on thinned, continental crust, or the Zafiro and Alen-Aseng fields, which are charged by Paleogene source rocks that overlie oceanic crust of Aptian age. In comparison, the deepwater region of the DRMB east of the Cameroon Volcanic Line (CVL) has yet to yield any major discoveries.

Our analysis of seismic, gravity, magnetic, and geochemical data, was integrated in a full-lithosphere 3D basin model, revealing a mature, potentially prolific Cretaceous petroleum system extending across oceanic crust, with its potential influenced but not handicapped by the higher thermal history of the adjacent CVL.

FULL LITHOSPHERE MODELS TO PREDICT THE HEAT FLOW

Our study area is located east of the CVL, a 1,700 km long linear chain of volcanic origin ranging in age from the Eocene to the present. The CVL has influenced the crustal, stratigraphic, and thermal structure of the Gulf of Guinea since its origin in the Paleogene. We combine five 3D seismic surveys covering approximately 7,600 km² (provided by Geoex MCG, along with 2D seismic lines, regional well data provided by Viridien Group), and gravity and magnetic surveys to create a full-lithosphere model. A newly developed gravity inversion technique enabled us to improve the accuracy of the depth to the Moho and the Lithosphere – Asthenosphere Boundary (LAB), revealing zones of mantle upwelling and increased thermal gradients beneath the deepwater region. These thermal anomalies closely align with the elongated, deep-rooted magmatic activity along the CVL and are a critical factor in assessing hydrocarbon generation in the deepwater area.

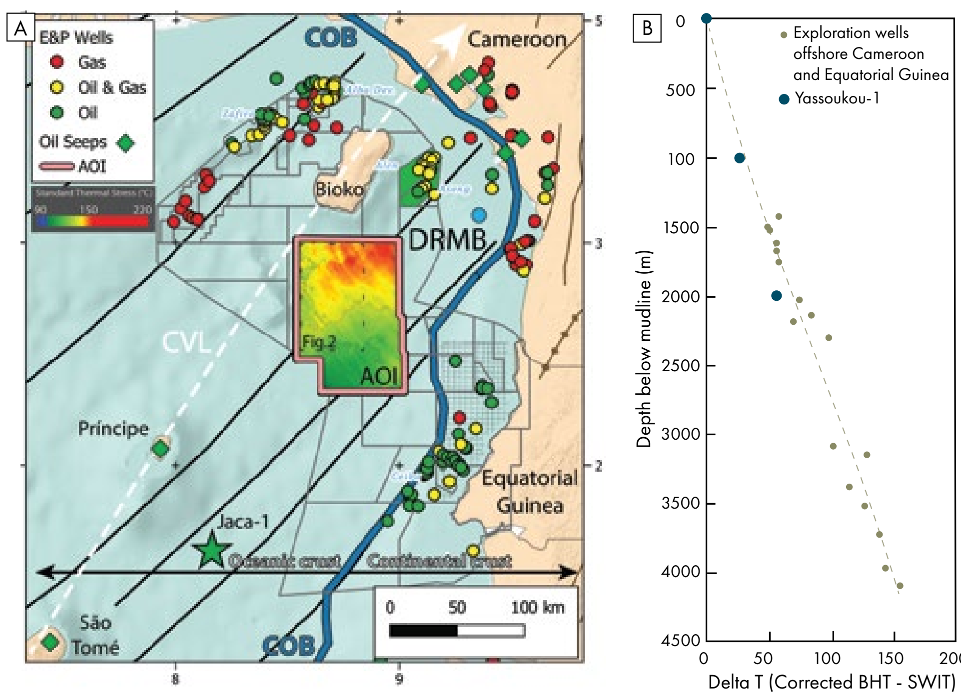


Figure 1A: Detailed map of the study area showing exploration and production blocks, exploration wells, and the distribution of oil and gas seeps in the deepwater Douala–Rio Muni Basin (DRMB). 3D models completed using the software ExCaliber are shown for the area of interest (AOI). COB, Continental-oceanic boundary. B: Corrected bottom hole temperatures (BHTs) plotted as ΔT versus depth below mudline, illustrating regional geothermal gradient trends. Well data shown in Figure 1 were provided courtesy of CGG Services (UK) Ltd (part of the Viridien Group). For data access and licensing of the Viridien GeoVerseTM database, contact GeoVerse.Support@viridiengroup.com.

SEISMIC CLUES TO RESERVOIR AND SEAL POTENTIAL

Seismic interpretation allowed the extraction of key attributes (RMS, sweetness) to identify deepwater fans and play fairways within the Albian-Campanian interval. In particular, the Santonian-Campanian channelized turbidites and basin-floor fans capped by thick mudstone packages form stacked reservoir-seal pairs. In several areas, these systems are folded or uplifted as a result of volcanic doming along the CVL. Such structural overprints also create combination traps as a potential drilling target.

SOURCE ROCK POTENTIAL OF THE REGION

Rock-Eval pyrolysis data from exploration wells on the shelf and upper slope of Cameroon and Equatorial Guinea (e.g., Campo R-1, Kribi E-1), combined with deepwater reference sites (e.g., DSDP 530A), allowed us to characterise and model source rock potential and compare it with the conjugate rifted margin in the Sergipe area of northeastern Brazil. The resulting source rock characterisation indicates that the Albian and Cenomanian-Turonian intervals are the primary Cretaceous source rocks in the deepwater area of the DRMB.

These organic-rich, marine clay-rich mudrocks typically contain over 2 % total organic carbon, with Hydrogen Index values between 200 and 400 mg HC/g TOC. Thermal restoration indicates original HI values in the 300 – 600 range, as observed for prolific conjugate analogues in the Sergipe Basin of Brazil. Seismic data show stratigraphic continuity between drilled source rocks on the shelf and slope to predicted source rocks in the deepwater area of the DRMB.

HYDROCARBON GENERATION ON OCEANIC CRUST

Our basin models were calibrated using corrected bottom-hole temperatures (BHTs) from regional wells and 1D pseudowells, which constrained the burial history, maturation, and oil and gas expulsion of the area. The results indicate a consistent southwest-to-northeast increase in the thermal stress gradient, aligning with the lithospheric structure of the CVL and a larger sedimentary input entering the basin along a NE - SW trend. This northeastward rise in the thermal gradient is supported by exploration data from the Jaca-1, Ceiba, Zafiro, and Alen-Aseng fields over a distance of 600 km.

The deepwater source rock intervals are present within the transitional zone from oil to gas-condensate expulsion windows across the study area. 3D models confirm significant oil and gas generation, with the northeastern sectors exhibiting more advanced maturation and potentially higher gas-oil ratio (GOR) accumulations. This proposed directional trend to the northeast of higher gas-oil ratios fits with the production at the Zafiro and Alen-Aseng fields.

SIGNIFICANCE OF THE EG PETROLEUM SYSTEM

By integrating seismic, geophysical, geochemical, and thermal modeling, this study proposes a working Cretaceous petroleum system developed above oceanic crust of Aptian age.

Given the presence of hydrocarbon seeps on São Tomé and Príncipe and shows in the Jaca-1 well drilled in 2023, the DRMB's deepwater sector east of the CVL provides a promising exploration target. The next steps include constraining the thermal and crustal framework and identifying the optimal trap and migration pathways.

The implications of this study go beyond Equatorial Guinea. The DRMB shares a similar history of rifting and depositional history with its conjugate in the Sergipe-Pernambuco Basin of northeast Brazil. Insights from our research can guide deepwater exploration approaches in both regions of the South Atlantic, especially in frontier oceanic areas that are often overlooked. ■

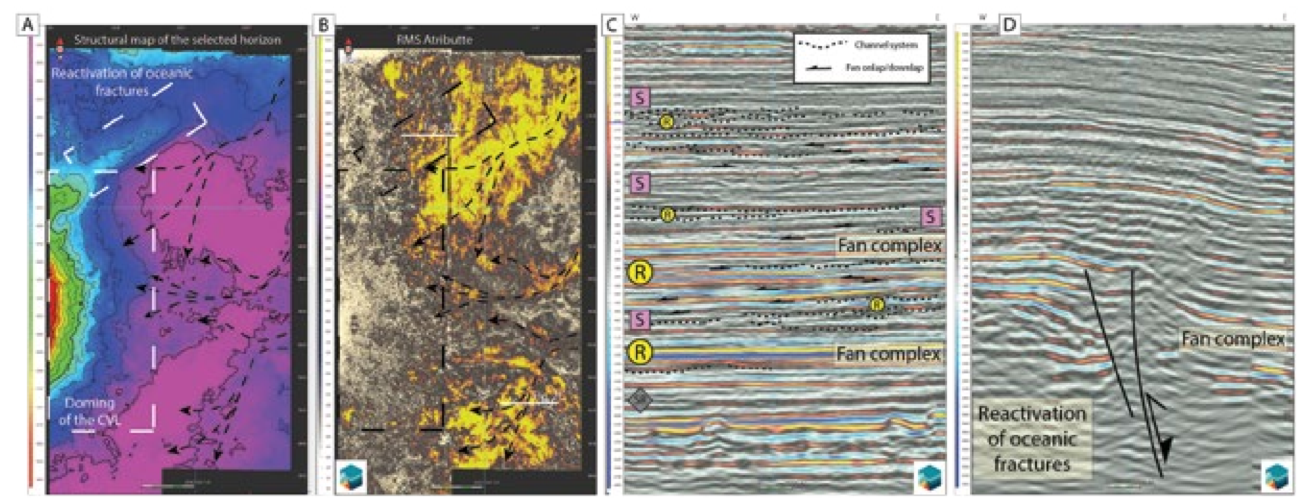
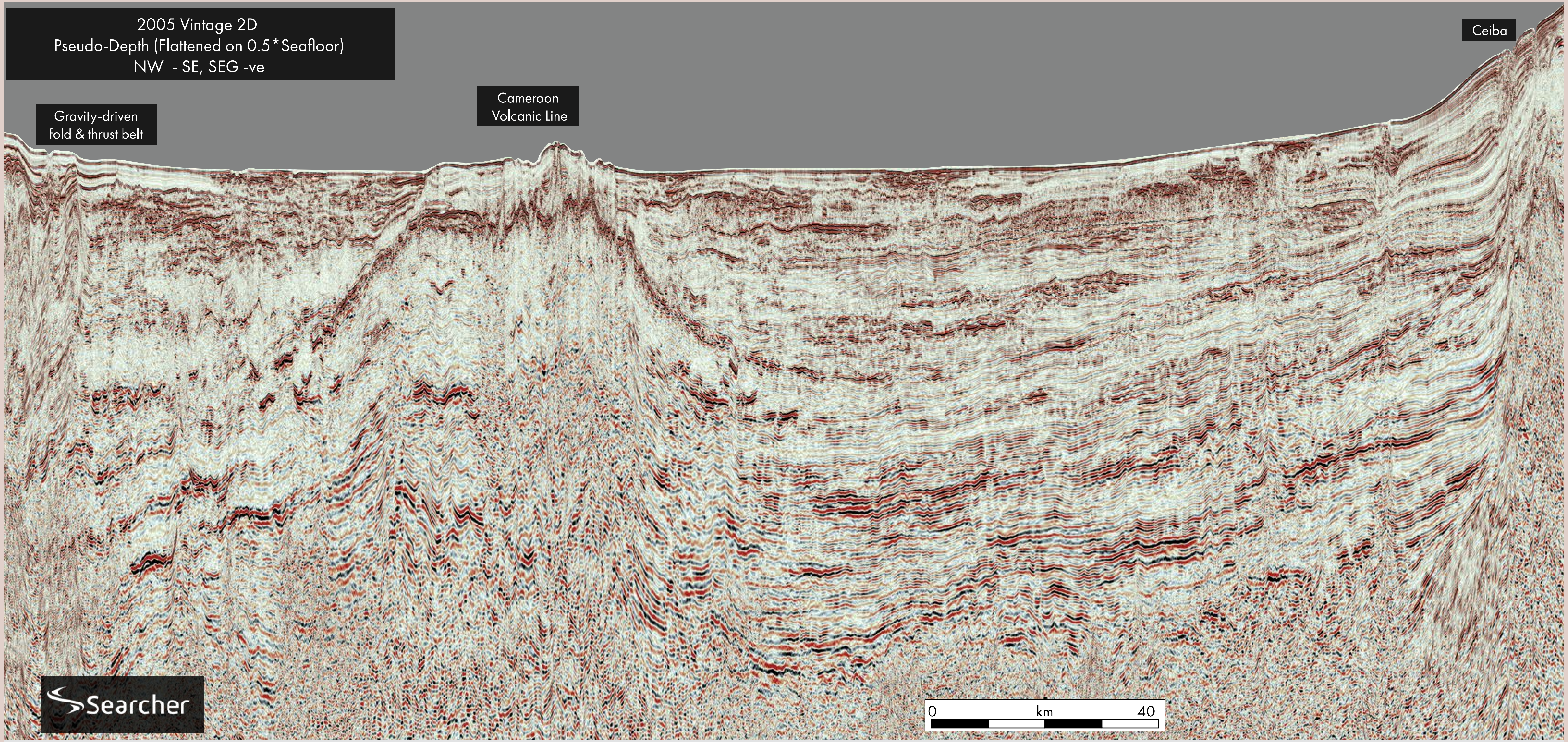


Figure 2: Seismic interpretation of potential reservoir intervals in the Albian–Cenomanian section. A: Structural map of a surface interpreted at the base of the Santonian-Campanian turbidite complex. B: RMS attribute map extracted along the Albian–Cenomanian surface, highlighting localized high-amplitude anomalies interpreted as potential sand-rich turbidite systems within a predominantly fine-grained, deepwater setting. C-D: Seismic interpretation of potential reservoir intervals within the Albian–Cenomanian section. A: Dip and strike seismic lines showing attribute responses (e.g., RMS) and highlighting depositional geometries of turbidite systems within the interval. Seismic data courtesy of Geoex MCG. For data access and licensing, please contact Geoex MCG at www.geoexmcg.com.

Equatorial Guinea: Time to shine...again!



2005 2D line spanning from the NW GDFTB to the SE Ceiba area mainland margin crossing the CVL.

Searcher

As geoscientists we walk through the dark eons of deep time, and we know that things happen only when the time is right. In the last 20 years of quiet exploration for Equatorial Guinea, science and technology have moved on. But the time is now right, new science breathes a new wind into EG, yielding an extraordinary opportunity.

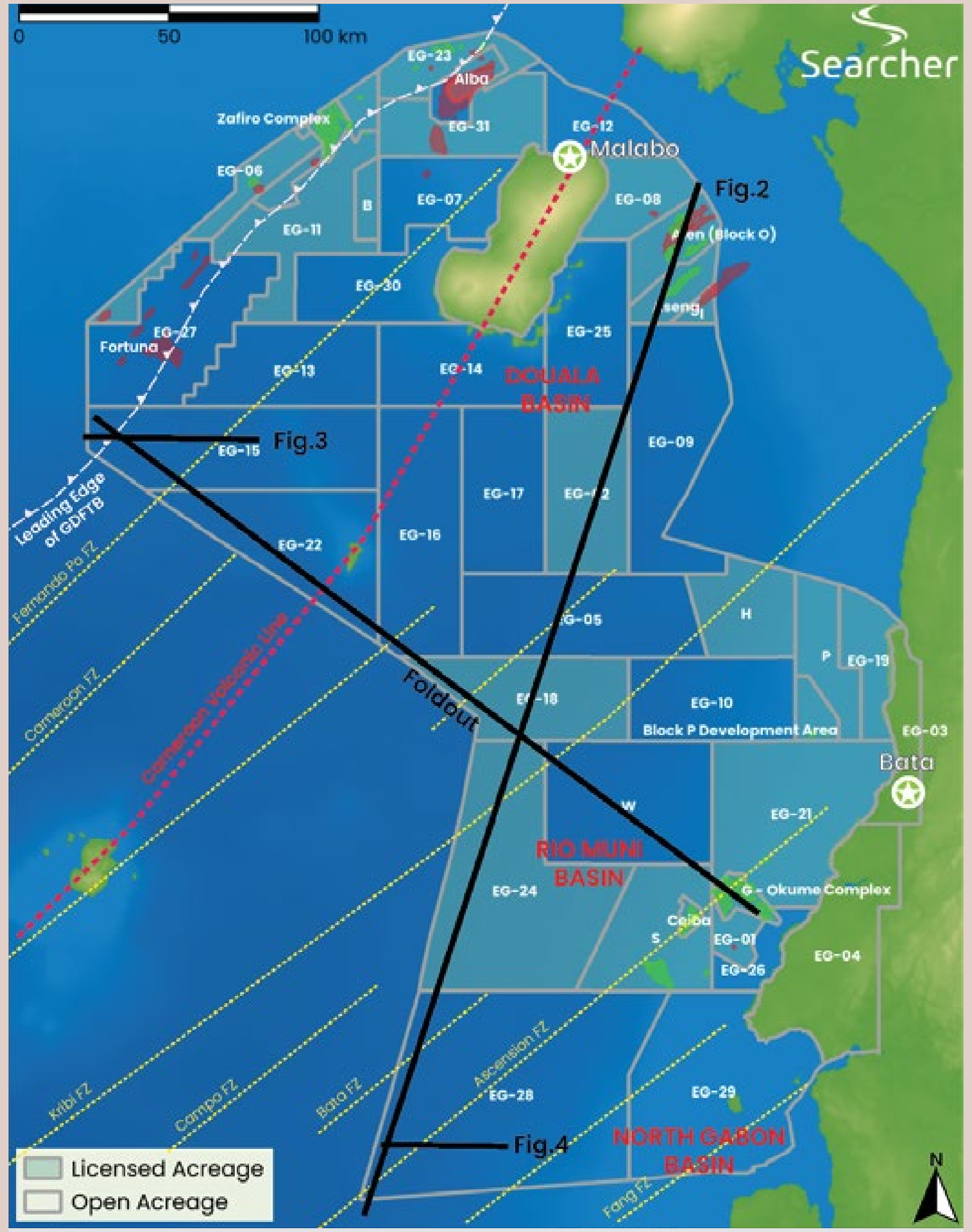


Figure 1: License blocks in EG.

Blue skies over Malabo

Time for Equatorial Guinea's next day in the sun

NEIL HODGSON, LAUREN FOUND AND KARYNA RODRIGUEZ, SEARCHER

Equatorial Guinea, "EG", is a unique land in a myriad of ways, with the capital of Malabo on Bioko Island in the middle of the Gulf of Guinea, and an onshore region that lies on the West African coast to the southeast. Malabo lies at the feet of the Pico Basile, an active volcano on the Cameroon Volcanic Line (CVL), a relatively young linear array of volcanoes extending from onshore Cameroon into the Gulf of Guinea. Volcanoes and oil exploration don't always mix well, but EG is a country where the volcanoes have played a crucial role in creating opportunity.

In the 1980's exploration in EG was focusing on a Tertiary Gravity Driven Fold and Thrust Belt (GDFTB) that extends East-West near the northern border with Nigeria (Figures 2 and 3). Here, the heads of toe-thrusts form shallow, relatively clearly imaged antiforms in Pliocene to Miocene high-quality sands that were poured south from the Niger Delta. These targets were the low-hanging fruit of the 1980s and 1990s, the time when the giant Alba gas field was discovered. When Mobil discovered the giant Zafiro oil field in 1995, on-trend with Alba's high-quality Pliocene age sands, it transformed the nation's economy.

Shortly after the Zafiro discovery in 1999, Triton Energy discovered the Ceiba field in the south of EG's Duala Basin mainland slope. Again, like Zafiro, this discovery was considered to be in extraordinary water depths at the time for Africa, 600-800 m. As a bellwether of the shape of things to come, Ceiba was brought online incredibly quickly in 2000 by subsea tie-back to an FPSO. The Ceiba field and the adjacent Okume complex of fields, which followed in 2001/2 are mixed structural and stratigraphically trapped channel levee complexes consisting of turbidite and overbank splay sandstones of Campanian age in the upper slope within the Elon and Okume canyons.

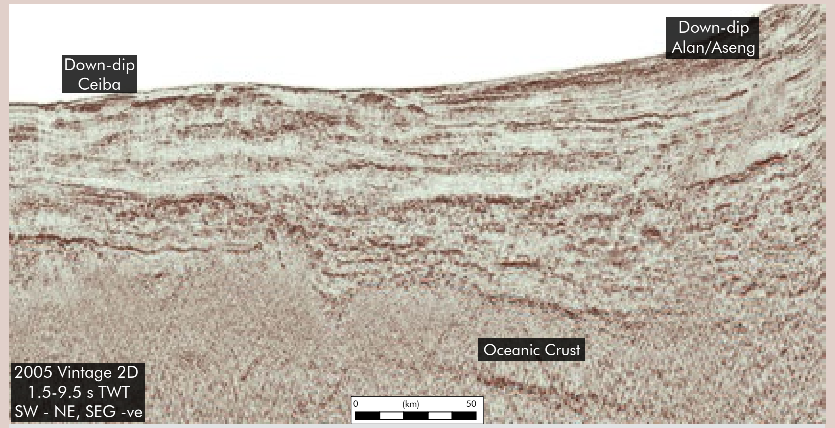


Figure 2: A 2005 2d TWT line traversing the main plays east of the CVL. The Late Aptian to Late Cretaceous section above Early Aptian Oceanic Crust is rich in onlapping sands being brought to the basin floor (visible as both soft and hard acoustic impedance contrast events).

Although stratigraphically deeper targets have now been identified, including Kosmos' non-commercial discovery in the Albian on the Ceiba block in 2024, in this southern basin, down where the channels meet the basin floor and its counter-regional dipping plays, these fans remain steadfastly untested. Cretaceous sands from the Eastern Duala basin running SW along oceanic fracture zones (just as they do in Benin on the transform margin), and sand coming from the Elon and Okume canyons to the east all end up on the basin floor, draped over oceanic crust blocks or in huge oceanic crust dip plays (Figure 4). This untested southern area is adjacent to where the Jaca well was drilled in 2022, on trend with the fracture zones. Jaca-1 has an additional later sand source from the Ogooue Delta of North Gabon, yet the big play is in the Cretaceous and due to see new exploration drilling Q3/4 2025.

Through the 2000s, some shallow water EG play concepts continued to be defined. The discoveries off the east coast of Bioko Island targeting Miocene sands coming from the northeast in Cameroon are testament to that. The Belinda Aseng, Diega, Felicia and Benita discoveries lie in shallow water (ca 75 m), but they demonstrate that Miocene sands coming into the basin were steered or directed by the ongoing volcanism of the CVL, deforming the basin floor to develop multiple parallel channel systems running NE-SW. However, the idea that the CVL had been there forever, controlling deposition into NW-SE striking depocentres, is unlikely to be correct. The CVL was only emplaced through the Tertiary – implying that Cretaceous turbidites coming from any direction into the basin could now be either side of CVL, where they were guided by topography related to fracture zones on the oceanic crust. This stopped when volcanism started initiating the northern GDFTB. The volcanoes generated basin floor topology or breaks of slope that constrained basin floor channels or moved the slope-breaks causing turbidite flows to drop their coarse clastic load (Figure 2 and foldout line).

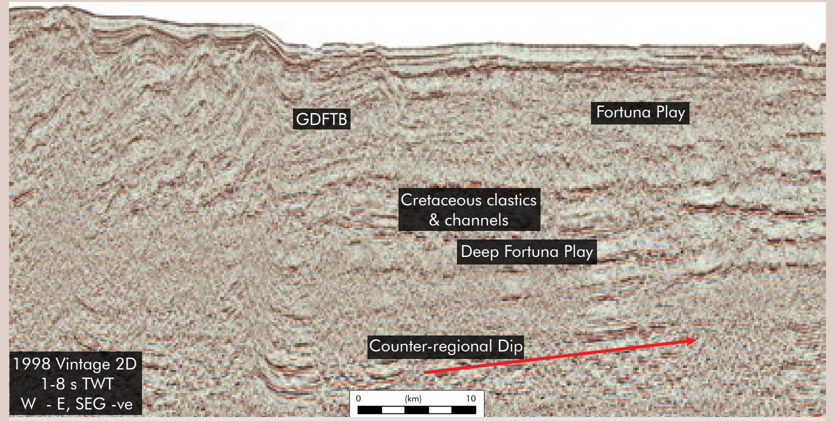


Figure 3: 1998 2D TWT line across the GDFTB showing the play elements of the deep Fortuna Play Area.

The thrust belt plays on the northern GDFTB border were found and mapped in the 1990. However, it would take another decade before wells were drilled in the GDFTB foreland to the east. In 2006, the chance of finding big oil in the foreland play enticed Ophir to explore the eastern end of the thrust trend. What excited Ophir was a Mid Miocene channel system winding and cutting through the then-growing GDFTB, depositing a large fan in the foredeep (Figure 3). When the Fortuna 1 well was drilled in 1,691 m of water in 2008, it actually encountered a 55 m dry gas column in high-permeability 30+ % porosity sands. The field was appraised, and another similar Mid-Miocene discovery, Viscata, was added to the discovered resource on the block. We understand that a total of ca 4 TCF is now proven, which is considered commercial.

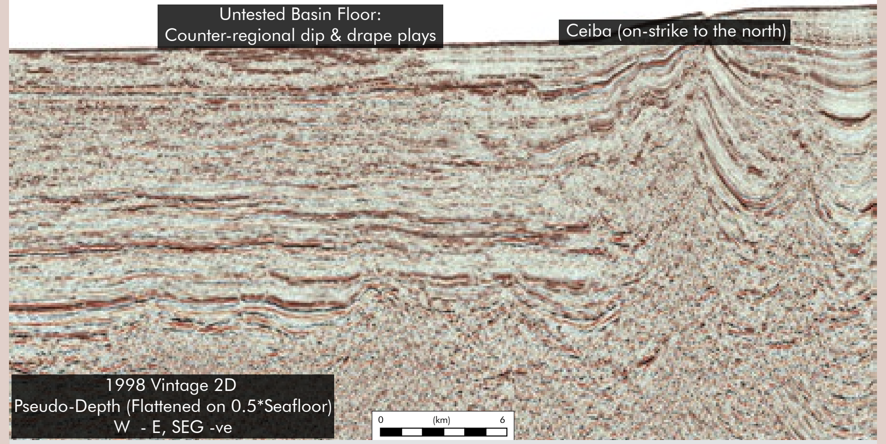


Figure 4: 1998 2D line pseudo depth to show basement Counter-Regional dip and drape over oceanic crust blocks south of, and down slope of Ceiba. In the Far East (left), the Salt play geometries of the northern Gabon salt basin.

However, Fortuna and the appraisal wells not only confirmed a syn-GDFTB Mid-Miocene play, but crucially also encountered underlying Upper Cretaceous sands that pre-dated the GDFTB. This is a significant observation as it proves that pre-GDFTB and pre-CVL intrusion, offshore EG was a deep basin floor, not only accumulating sands from the NE and SE but also accumulating Cretaceous basin floor fans and aggrading channel systems from the Niger Delta in the north. Don't doubt that sands can get this far – they are penetrated in the Fortuna wells and comparable to many other examples of sands travelling huge distances, for instance from Senegal to volcanically inverted Maio in the Cape Verde Islands. This is an incredibly important play as the basin's structural dip caused by the Tertiary CVL puts the Cretaceous basin floor fans into large and as yet untested counter-regional dip traps between the GDFTB and the CVL.

And this perhaps is where the excitement for explorers starts. This is where the time capsule opens. Whilst the industry has been accelerating into commercially challenging water depths off the continental shelf in multiple basins around the world, in EG the deepest water you can find is only 2,200 m, and yet here, the white hot cauldron of pushing the boundaries of exploration and development drilling depths 25-30 years ago, the focus has been mainly on development and not on exploration since 2007.

Equatorial Guinea is a unique country. Its people are unique, the geology is unique, and we can't think of anywhere with so much open acreage in moderate to shallow water, covered by 3D that is being reprocessed right now to PSDM. In addition, the area has many proven hydrocarbon systems for oil and gas, a sophisticated regulator and existing production. Furthermore, the EG Minister for Energy is reported to be preparing a new acreage access initiative for 2025/6 and this heralds the perfect time for explorers in EG to target big, simple, low-risk, oil and gas prospects using perfect data.

THE BIGGEST LEAP FOR MANKIND

The most rapid advance in geoscience, and our industry, and indeed the biggest technological leap for mankind since Neil Armstrong stepped on the moon in 1969, has been the development of seismic processing technologies over the last 10 years. And here's the fascinating thing – a lot (although crucially not all) of EG's open blocks are covered by 3D's (many post 2000). Yet virtually none of these datasets have been reprocessed since the ubiquitous adoption of de-ghosting and PSDM technologies about 7 years ago. Therefore, we can confidently expect astonishing uplift from these data in which companies like Searcher and GeoexMCG are currently reprocessing along with regional 2D datasets.

Leading the wave: Environmental impact assessment for offshore geophysical operations

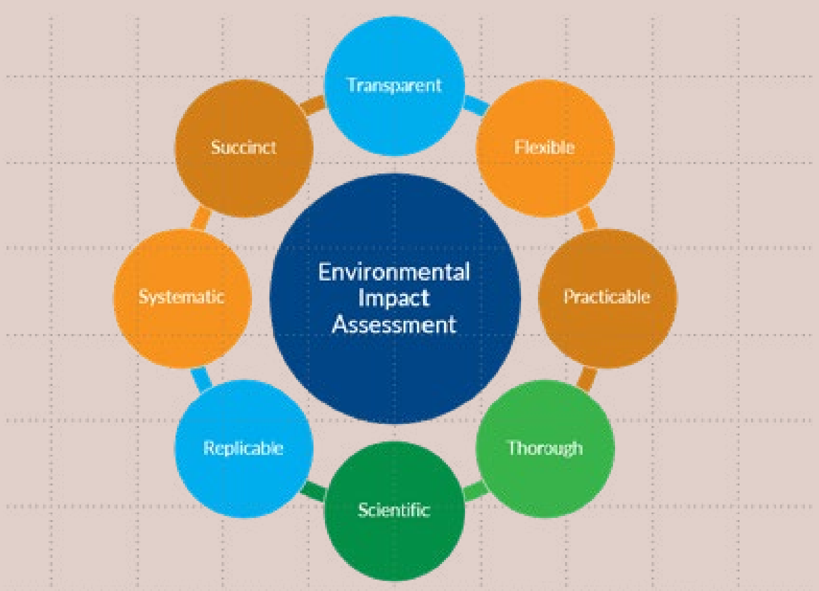
By offering a credible, science-based foundation for early planning and decision-making, EIAs help to differentiate between perceived impacts and genuine risks or conflicts that necessitate mitigation and management

ALEX LOUREIRO AND DAGMAR FERTL, ENERGEO ALLIANCE

ENVIRONMENTAL Impact Assessments, or EIAs, are a critical tool for evaluating the potential effects of human activities. As geoscience activities grow increasingly complex and expand into frontier regions, EIAs are essential to identify and mitigate possible risks to wildlife, ecosystems, and the human communities that depend on these resources for economic, social, and spiritual well-being. Industry bears the responsibility to ensure that these resources are safeguarded.

A well-structured EIA enables operators to manage and mitigate environmental risks, meet permitting expectations, and build trust with regulators, stakeholders, and the public. While EIA requirements vary dramatically across jurisdictions, the central aim – protecting the natural environment and the people who depend upon it – remains constant. For geoscience activities, these risks may include emissions, spatial use conflicts with other ocean users, underwater sound, and biological interactions, among others.

Many jurisdictions require some form of an EIA – sometimes referred to as Environmental and Social Impact Assessments (ESIA), Strategic Environmental Assessments (SEA), Environmental Impact Statements (EIS), Environmental Plans (EP), or other variations. With the variation in names, however, also comes variation in expectations for content and level of detail. This can create misalignments in expectations between project proponents, regulators, and stakeholder communities. When managing questions pertaining to underwater sound and the complex physical and biological factors with which it interacts – this balance becomes an even greater challenge.

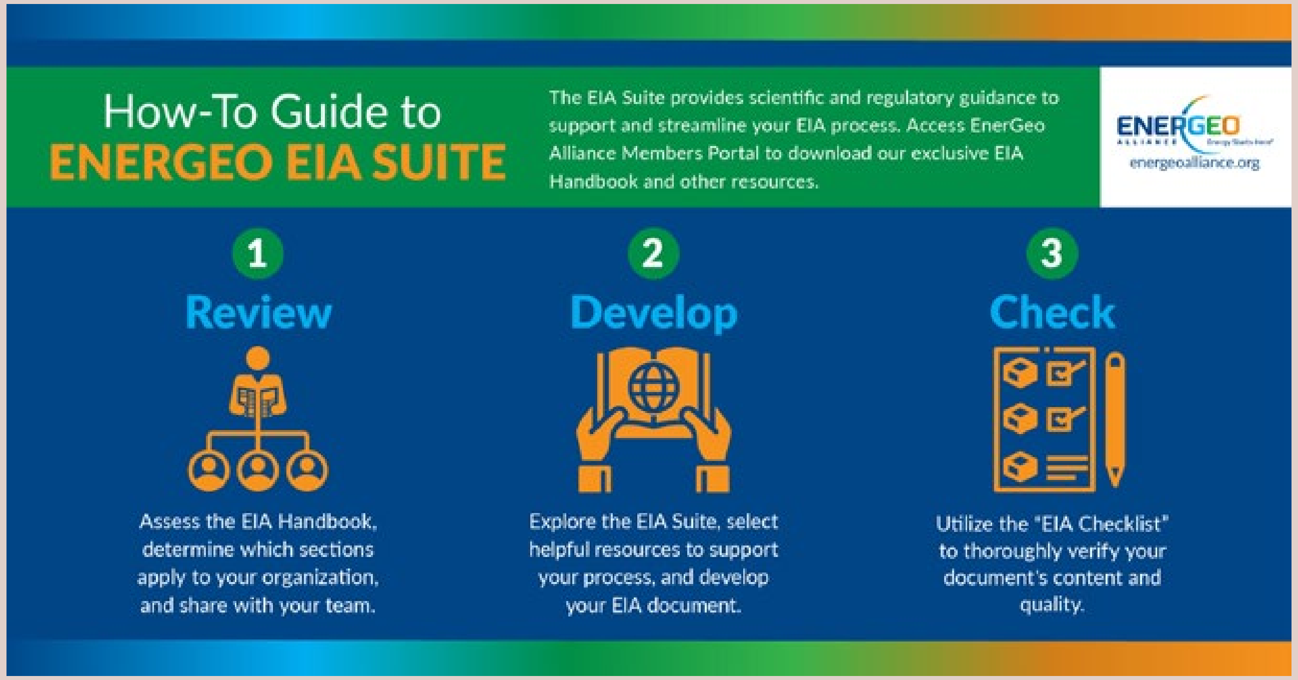


SOURCE: ENERGEO ALLIANCE

SUPPORTING EXPLORATION

Through reliable science- and data-based regulatory advocacy, credible resources and expertise, and future-focused leadership, EnerGeo Alliance (EnerGeo) continuously works to help shape informed government policies that advance responsible energy exploration, production, and operations. We provide our members with relevant and timely topical events, seminars, news, and a range of educational, scientific, and regulatory tools and information to support the exploration and development of mainstay, alternative, and low-carbon energy solutions. EnerGeo's vision is to be the most credible and effective voice for promoting and ensuring a safe, environmentally responsible and competitive energy geoscience industry. To support this vision, we have developed a comprehensive EIA Guidance Suite to help project proponents and regulators prepare EIAs that meet these essential objectives.

These member-exclusive resources are intended to support companies as they navigate complex and inconsistent regulatory landscapes globally. The EIA Suite consists of a number of resources for members and their supporting contractors, including: Our flagship EIA Handbook; Stakeholder Engagement Guidance; Global Seismic Regulations Summary Spreadsheet; a curated set of EIA Resources; an EIA Preparation Checklist; and various fact sheets and literature summaries covering a diverse array of technical topics.



The EIA Handbook offers step-by-step guidance tailored to the unique risks and requirements of geophysical surveys. Updated regularly and available in English, Spanish and Portuguese, the EIA Handbook addresses all aspects of the EIA process from preparation through stakeholder engagement, prompting best practices and scientific rigor while discouraging impractical requirements or requirements that are not supported by evidence. This includes template language intended to clearly convey the complexities of geophysical equipment, operations, and underwater sound.

Preparation resources – including a Global Regulations Summary Spreadsheet, a list of EIA Resources, and fact sheets – facilitate an efficient development process. The EIA Checklist covers each step of the process comprehensively, allowing companies to either develop EIA documents internally or share these resources with their contractors. EnerGeo's EIA Suite promotes industry-wide alignment and ensures the use of the best available scientific information in EIA development worldwide.

CONTACT WITH COMMUNITIES

Preparing a document, however, is rarely adequate to satisfy obligations with local communities. Stakeholder engagement may be required in certain areas, or it may be in a project proponent's best interest to engage with the relevant communities. Particularly in frontier areas, geoscience operations are generally the first contact communities have with the energy industry, and creating an open dialogue early in the process is generally beneficial as exploration and production proceed. EnerGeo's Stakeholder Engagement Guidance is intended to shape a mutually beneficial process for working with diverse stakeholder groups.

A VALUABLE RESOURCE FOR REGULATORS

While developed for EnerGeo members, the EIA Suite also serves as a valuable resource for regulators. EnerGeo's government affairs and scientific subject matter experts often engage with regulatory agencies to share these tools. By providing a neutral, science-based benchmark for EIA preparation, regulators can more efficiently determine whether submitted documents satisfy their environmental evaluation requirements. Clear, consistent standards for EIA documents also streamline the process for industry—both during the development phase and throughout regulatory review.

EnerGeo's extensive government affairs and scientific expertise have generated valuable lessons for ensuring an EIA process that benefits industry, regulators, and community stakeholders alike. Members are encouraged to engage early and consistently with regulators and stakeholders, presenting technical information in clear, accessible terms. Integrating both local and global expertise is essential to developing a robust and context-appropriate evaluation. Project proponents are encouraged to allow sufficient time for scoping, data collection, and analysis, while proactively proposing mitigation measures that are effective, operationally feasible, and aligned with real risk.

NOT A CHECKBOX EXERCISE

As expectations for environmental performance evolve, the EIA Suite will continue to be updated to reflect new scientific insights and regulatory requirements. It embodies the industry's shared commitment to minimising impacts, enhancing transparency, and driving continuous improvement. Above all, EIAs should never be viewed as a mere checkbox exercise. When applied thoughtfully, they provide a meaningful framework to reduce risk, build trust with regulators and stakeholders, and support safe, successful operations. By promoting sustainable geoscience practices, EnerGeo members will continue advancing our mission for years to come – together, we are Making Energy Possible®.

For more information, contact info@energeoalliance.org

The value of seismic attributes and the value of having your own business

A candid conversation with Laurie Weston, founder of Sound QI

"WE NEED THIS," said a geoscientist from a major operator in Houston once Laurie Weston had finished one of her presentations as part of the Canadian SEG distinguished lecturer tour.

It was in 2017, ten years after she had launched her own business in Calgary. "It's always a great feeling to get attention from a major, she says. "It's one of the drivers behind doing it all."

This initial conversation led to many follow-up meetings with the operator, but it didn't result in a contract at the time. "Things do not always go the way you want them to go," Laurie says. "A technical specialist may see the value of something you do, but that's only the start of a long chain of hurdles before having a signature on the dotted line. If one thing is needed in the service sector, it is resilience".

"Onshore Canada, seismic data is relatively costly, and that's why I felt the need to get the maximum value out of it."

We meet in an Indian café in Houston and enjoy a coffee and a tasty late breakfast. It is yet another warm and humid day in August, straight after the IMAGE Conference. We are both tired from three days of conferencing, so it is nice to sit together for a bit without the interruptions big events tend to bring.

I am going to hear what Laurie learned along the way from establishing her company to where she is today, what drove her to do it and the sacrifices it sometimes requires.

"WHAT KIND OF GAMES ARE YOU PLAYING?"

The first time Laurie's desire to go for it herself surfaced was when she worked at Nexen in Calgary in 2007, where she arrived after years working for Shell Canada and Lasmo in London.

"I worked two days a week, as a mother of three daughters," she says. "And as I worked only two days a week, I was given the crappiest computers they had. I tried to run my seismic inversion algorithms overnight, given the time it took to complete these exercises. But then, overnight system updates imposed by IT would often terminate the process prematurely."

Celebration of the move into our first Sound QI office at the base of the Calgary Tower in 2018.

PHOTOGRAPHY: LAURIE WESTON PRIVATE ARCHIVE

Laurie was convinced of extracting more value out of the seismic though, and was determined to perform the process of running the memory-demanding exercises successfully. "Onshore Canada, seismic data is relatively costly to acquire compared to drilling wells," she explains, "and that's why I felt the need to get the maximum value out of it."

But given the challenging corporate circumstances she had to deal with, she decided to take her fate into her own hands. Laurie was going to buy the hardware out of her own pocket and offer the service herself, unknowingly initiating a whole different set of challenges.

It turned out to be a great idea. Even before purchasing the computing power, she already had three clients lined up, with projects worth a considerable amount. She could definitely afford a new work-station.

And so it happened. Rolling up to the computer hardware store in her minivan, accompanied by three little girls in princess dresses, Laurie started a conversation with the store manager about the kit she required. The store manager looked surprised at her and the kids: "What kind of games are you playing?"

A ROLLERCOASTER

Laurie soon started hiring people for the company that she named Oil Sands Imaging. Times were good, and with that came more responsibility, and also, delegation of tasks.

But larger teams also come with challenges. "I made many mistakes," she admits. "Hiring people without knowing what I was doing was one of those mistakes. It caused a situation whereby we were losing resilience rather than gaining it."

Faced with a downturn taking its toll on her project portfolio from 2014, Laurie made the call that it was better to join a bigger organisation, and Oil Sands Imaging became part of Canadian Discovery, a local consultancy. However, with that, she lost the capacity to continue developing the fledgling tools she had started at Oil Sands Imaging, and then: "My developer was made redundant when I was on holiday," she says.

The tide turned again in 2017, when Laurie was on the distinguished lecturer tour described at the start of this article. "From one day to the next, whilst being in Houston, I changed the logo on my slides because we were going independent again," she says. It was the start of Sound QI.

THE START OF SOMETHING NEW

The 2017 distinguished lecture tour came at the right time. Initially, a little nervous to present in Houston and having to answer questions from geophysical gurus such as John Castagna, Laurie overcame her impostor syndrome. After her talk, John even came to her and said, "You have taught this old dog some new tricks." It was the start of a new friendship that has lasted until today, with Laurie using John's office when she was in Houston on business in the years that followed.

Back home in Calgary, Sound QI started simple. "As with so many companies, Canadian Discovery had taken a hit during the oil price crash, leaving plenty of open office space, so we could stay there behind a pile of Canadian Discovery's storage boxes," Laurie continues. "And one of the first things I did," she says, "is re-hire my software developer, because I had plenty of new ideas to build into the software."

One of the things Laurie had observed during her career was that inversion results and seismic attributes were not being utilised to their maximum potential. This led to the idea of building software that enables geophysicists to interactively filter the entire spectrum of attributes in 3D space such that areas of potential interest can be quickly highlighted. The tool she imagined is now commercial and known as Maestro™.

"Compare it to finding the best place to catch lobster," Laurie explains. "Finding this sweet spot in a swath of sea is not only dependent on water depth, but also on salinity, current movement, availability of food, and several other factors. The same holds for identifying a prospect to drill; it may have a certain Vp/Vs ratio, but it could also require constraints imposed from other attributes at the same time. "I believe that this interactive way of filtering all the attributes offers a great way of using seismic data in the best possible way," she says. Incidentally, John Castagna called the idea "game-changing".

"I'M NOT GOING TO LET IT PASS BY"

Our late breakfast meeting is coming to an end, and it is time for me to order my Uber to make my way to the airport again. Our conversation comes back to where we started, to that moment during her distinguished lecturer tour when a geophysicist from a major operator wrote his email address on a napkin. The opportunity that did not materialise in the end. Now, eight years later, this person has retired, but he told his successor to reignite the conversation with Laurie because he still sees the potential. "Who knows what it will bring, she says. "But one thing is for sure, I am not going to give up on this, because, among other things, I have learned how to be so much more resilient in the intervening years. I'd surely be willing to give it another go. I believe in the value of our offering, and I'm never going to let these opportunities pass by!" ■

Henk Kombrink

Laurie Weston and Kevin Lee manning the booth at a geoscience conference, 2022.

PORTRAITS

"I had no interest in exploration at all, and was very happy to go very deep into understanding the sedimentary record instead"

Tom Dreyer – Recently retired from Equinor

THE MASTER OF NEAR-FIELD EXPLORATION

Tom Dreyer is the mastermind behind several successful near-field exploration campaigns in the Norwegian sector. As he recently retired from Equinor, it is time to learn how this all unfolded

HENK KOMBRINK

When thinking about exploration geology in the oil and gas sector, most people will envisage going to places unknown, map the big bumps, and get them drilled. That's not how Tom Dreyer's career in exploration went. "I have never been a man for frontier exploration," he tells me when we meet on a warm day in August. Instead, Tom made a career doing rather the opposite; near-field exploration. "It suited me more," he says, "given my background in sedimentology and reservoir studies."

Tom Dreyer, ready to explore new locations. Verbier, Swiss Alps.

PHOTOGRAPHY: TOM DREYER PRIVATE ARCHIVE

INSPIRED BY A NEW INDUSTRY

Growing up in Norway in the 1970s and 1980s, there was no escape from what was happening in Norwegian waters. "The news about the discoveries inspired me," says Tom. "Yet, I wasn't particularly interested in geology as a child, but I rather had a broad fascination for science and the natural world."

However, once he started studying geology at university, it quickly got him hooked. "The thought of being able to reconstruct ancient landscapes by studying rocks fascinated me," he says. He quickly became very studious, and an academic career seemed to lie ahead for him.

After doing a PhD on "poorly exposed" rocks in eastern Norway, Tom contemplated doing a postdoc on well-exposed outcrops in Egypt. But then, Statoil called in 1985, asking him to perform a study on the major Statfjord field for about a year. He decided to do it, thinking that the path to becoming a sedimentology professor was still wide open anyway.

Statoil had just taken over operatorship of the Statfjord field from Mobil at the time. "I joined a very enthusiastic team," says Tom, "Statfjord was the first field that Statoil was going to operate. You can imagine the excitement that brought."

For the first nine months, he worked on describing Triassic and Lower Jurassic cores of the Statfjord Formation, the secondary reservoir unit in the field, and correlating these to well logs. "I had never seen a well log before," he laughs.

GOODBYE STATOIL, GOODBYE ACADEMIA

Whilst Tom was working on Statfjord in Stavanger, he received a call from the research centre of Norsk Hydro in Bergen, his hometown, asking if he wanted to join the team as a sedimentologist.

It was the time when sequence stratigraphy was emerging, as well as the development of large-scale depositional models. In other words, an exciting time to join a company that was at the forefront of the discovery of what the North Sea subsurface was about.

The working conditions were excellent. "We were allowed to spend a lot of our time on field work and looking at cores, to create depositional models for fields Norsk Hydro was operating. All in all, I think I did about a full year of field work between 1987 and 1994," Tom adds. "It was a great learning experience. I must have visited the Spanish Pyrenees more than 50 times in total."

And whilst in the Norsk Hydro research centre, Tom did not entirely forget about his academic interests. He kept publishing papers in scientific journals, which also allowed him to obtain a Doctoral Philosophy degree in 1995. "That degree doesn't exist anymore," Tom says, "but given that I had published more than ten papers, I qualified for it."

"Looking back at those years from joining Norsk Hydro in 1986 to receiving my final degree in 1995, I was a total sedimentology freak," laughs Tom. "I had no interest in exploration at all, and was very happy to go very deep into understanding the sedimentary record instead. And in a way, the environment at Norsk Hydro was superior to academia; there were always funds to do fieldwork, whilst I could still publish my work."

READY FOR THE BIGGER PICTURE

During those ten years at Norsk Hydro, Tom very much focused on reservoir characterisation at an outcrop analogue scale. "But then," he says, "I started wondering how all these architectural elements were organised at a larger scale, and I began to look more into seismic data."

This led to a number of years of doing seismic geomorphology, in combination with field work that also focused on larger-scale organisation of facies associations and sequence stratigraphy.

> **"I started wondering how all these architectural elements were organised at a larger scale, and I began to look more into seismic data"**

It was in that period that Tom also made his first moves into exploration. "I was tasked with developing facies models, not for existing fields, but for undrilled prospects," he says. "It was the first time I looked at prospectivity, trying to come up with a model without having any control points other than some seismic lines and a few nearby wells."

THINKING ABOUT PEOPLE SKILLS

The work by Tom did not go unnoticed at Norsk Hydro, and management wanted him to switch to exploration entirely. "I wasn't convinced," he says, "but I agreed on a trial period for a few months in Oslo, where the company had its exploration department."

It turned out to be a success. "I found it interesting," says Tom, "and therefore I was happy to accept a permanent position as exploration manager in Oslo in 2004. I had the benefit of having a very enthusiastic manager, Bjørn Rasmussen, who believed in me and made the transition to exploration quite smooth."

Yet, it didn't feel like the most natural match. "I'm a bit of an introvert and a thinker," Tom continues, "so I did wonder how I could make people thrive in my team."

But he succeeded through the ability to spot what people are good at. "I strongly believe that everybody has something to bring to the table, and I've always tried to channel that positively. This came with taking the time to get to know people and talk to them about what they were keen to do. Ultimately, I wanted a collective that worked together rather than a group of individuals protecting their own data. At the same time, I also tried to protect the people in my team from "noise" coming from the higher echelons in management that can sometimes cause unnecessary stress," he adds.

Tom's solid background in geoscience also presented him with the ability to technically steer people when needed. "I had done all these geoscience ▸

A SAD STORY WITH A POSITIVE OUTCOME

In 1987, Hydro told people in the exploration department, which had a branch in Bergen at the time, to pack up their bags and relocate to Oslo. "I had just joined the company at the time, and seeing grown-ups cry made a bit of an impression on me," Tom says. "It took almost 20 years before I was able to move this team back to Bergen, where it belonged. The reason for that was simple; the research centre was still in Bergen, as well as the production geologists. By moving the team back to Bergen, we had better access to the people running the fields as well as those doing the research. I still regard that as a big achievement of my career."

things myself and was therefore able to sit next to someone to discuss the technicalities and provide feedback and recommendations. I believe that this has saved the group a lot of time in some cases."

A STRING OF DISCOVERIES

Tom's career got a further boost in 2007, after the Norsk Hydro and Statoil merger. Following an interview with Tim Dodson, he became VP of Exploration and started managing teams in Stavanger and Bergen tasked with finding new volumes close to existing fields.

Whilst some people may think near-field exploration on the Norwegian Shelf is something of recent years, it was already in the 2000s that the first deliberate push was made to prove additional near-field volumes, driven by the fact that some of the big fields had come off plateau around that time.

"Near-field exploration suited me," Tom says. "I have always been interested in better understanding what happens between producing fields. It's probably driven by my background in reservoir geology and outcrop studies; it was that scale of geology that really intrigued me. More than doing the frontier work."

And Tom proved that he had a talent for finding sweet spots close to existing assets. Between 2007 and 2009, driven by combining the best blocks of both the Statoil and Norsk Hydro portfolios, his team made 15 commercial discoveries. "It was a very hectic time," he says, "it was almost like every second well we drilled during those years was a discovery."

But the hectic nature of the job was partly self-inflicted. "My remit was to look for volumes around the Gullfaks, Oseberg and Sleipner fields, but I also took the liberty to explore other areas in the North Sea," Tom laughs.

EXPLORATION IN SYN-RIFT DEPOSITS

Tom's first exploration success was an excellent example of how attractive near-field exploration can be. We are in the Fram area, where the Upper Jurassic Sognefjord Formation is the reservoir for the Fram field, discovered in 1990. Within Fram, the Sognefjord sands have a shallow marine origin, but it was known that immediately west of Fram, the basin deepened at the time, forming an important depocenter.

"We expected deep-marine sands in that area," says Tom, "and we planned a well to drill a prospect in there, H-north." Initially, the results did not look great. Less than 10 m of pay in the main sand, in addition to a thin 1 m oil column in a secondary and unprognosed sand. All in all, it didn't look too attractive.

"However, in the seismic we could demonstrate that the thin sand with 1 m pay was thickening towards the west, to an extent that within 200 m from the well, we were predicting more than 50 m of sand. I then asked the drillers if they could prepare a sidetrack and test the area to the west," Tom continues.

Within three days, the drillers put together a plan to complete the sidetrack, and it was quickly approved by management. The sidetrack (35/11-15S) was drilled and indeed found a sizeable oil column in the predicted 50 m sand, 200 m away from the well that initially found the same sand to be 1 m in thickness.

A REAL SUPPORTER OF DOING THE GROUNDWORK FIRST

Even though Tom spent significant parts of his exploration budgets on acquiring new seismic data, realising its potential to unlock subtle traps, he is also well-known for being a healthy sceptic towards putting too much focus on DHI's. Instead, Tom has always been an advocate of doing a full-scale geological prospect assessment using all available data. "I have always tried to prevent geophysicists from taking over the show completely through only focusing on prospects with a clear DHI," he says. "Look at the giant Johan Sverdrup discovery; it had no DHI whatsoever. Of course, DHI's should not be ignored, they are part of our toolkit, as is EM, but not more than that."

"This clearly demonstrated the lateral variability in these syn-rift deposits," says Tom. "It is the area where we found the thickest accumulation of Upper Jurassic sands altogether, in the region of 180 m of stacked turbiditic sands."

A TRIASSIC SWEET SPOT

"One of my most fascinating exploration wells was the one we drilled just west of the giant Oseberg field in the North Sea in 2009," says Tom. "From Oseberg going westwards, a complex of terraces rapidly plunges into the deeper parts of the Viking Graben. It is one of those terraces that were on the radar for drilling, even though the quality of our seismic data we had at the time did not allow us to make a proper inference on what the likely target age would be."

The team expected the Statfjord Formation to be the main reservoir here, but it turned out that it was missing altogether due to erosion. The slightly older Lunde and Lomvi formations were found in 30/5-3S instead. Initially, that did not seem good news, because these formations had never been proven to hold commercial quantities of hydrocarbons so far. However, and here is the interesting part of the story, gas was found at a depth of around 4,000 m, in a good-quality reservoir.

"It was a good old facies change that was responsible for the better-than-expected reservoir quality," explains Tom. "In most of the Northern North Sea, the Triassic is in a continental facies, but in the area west of Oseberg, a deep lake existed at the time. Clean lacustrine mouth bar sands were deposited here, and these sands have better reservoir quality than their continental equivalents."

Because of these exploration successes, by 2010, Tom had established a strong reputation within the company. The Norwegian North Sea clearly had proven to be a worthwhile hunting ground. A year later, in 2011, Tom was asked to go somewhere else and try the same thing. And that place was not far away.

PHOTOGRAPHY: TOM DREYER PRIVATE ARCHIVE

Tom spent large parts of the early phase of his career mapping reservoir analogues in outcrop. Here from the Cretaceous shallow-marine section in the Roussillon area (southern France). Red pigmentation probably due to hematitic clays leached into the shallow-marine sediments during weathering processes.

LONDON CALLING

In 2011, Tim Dodson asked Tom to lead the UK exploration team in London. "Well, it was only Ireland and the Faroese Islands initially," he says, "but we also entered the UK soon after my move. In a way, it was surprising that Equinor had not entered the UK before, given the successes in Norway."

Tom and his team started at the very beginning and built up a portfolio of licences, whilst also engaging with the regulator and other companies operating in the basin. "The main area we identified for drilling was a long-distance migration play from the Central Graben onto the platform in the west. Remember, it was the time of the Catcher discovery, which proved that long-distance migration was certainly possible."

"However, the well we drilled turned out to be a false DHI. It would have been a bit more of a frontier discovery," says Tom. "But as you now know, I'm not made for those!"

In the meantime, following drilling in the Faroese offshore was fascinating too. "I was most impressed by the drillers," says Tom, "and how they managed to knock the bit through these thick basalts. The problem in the Faroese sector, at least that's my intuition, is that a working source is lacking in that region."

When Tom moved back to Norway in 2016, it must be concluded that he had not been able to replicate the success of his string of discoveries in Norway. The starting point had obviously been very different, with Equinor having no acreage at all in the UK in 2011. This meant that many near-field opportunities were located in acreage that was already taken. Another factor that probably plays a role as well is that the UK North Sea reached a mature drilling status earlier than it did in Norway. This means that many near-field opportunities had been drilled already by the time Equinor entered the basin.

HOW A HEALTH ISSUE WAS INSTRUMENTAL IN FINDING 100 MILLION BARRELS

When Tom returned to Norway after his five-year stint in the UK, he resumed his role as VP of Exploration, again travelling back and forth between Bergen and Stavanger. Until a health issue stopped him from doing so for a few months.

It made him reflect on his job, and he asked Tim Dodson if he could take a step back and become exploration manager again, permanently based in Bergen with fewer commutes. Unintentionally, this heralded a second three-year phase of near-field exploration success, starting in 2019.

It was in those years that Equinor made yet another string of discoveries in the Troll-Fram area, of which the Blasto find was the biggest one. Developed as a tie-back to the nearby Fram field, it ranks as its biggest satellite. And as had been the case during the 2007 – 2009 campaign, Tom and his team were the driver behind all this activity.

BRENT REVIVED

"This year, after a spell of intense drilling activity in the Northern North Sea, Equinor has drilled fewer exploration wells in this region," says Tom. "In addition to this being a reflection of increasing maturity of the area, it must also be seen as a result of pressure from the green lobby to restrict exploration."

"But there are still quite a few prospects to go after," says Tom, who also admits that the golden age of exploration is now behind us. "The evolution of our understanding of the Brent depositional systems is one of the drivers for that.

Many people will be familiar with the Brent depositional system. Sourced from the Central North Sea and the Norwegian mainland, this Middle Jurassic prograding shallow marine to deltaic system formed the exploration focus in the Northern North Sea during the first years of drilling activity. Almost all big oil fields that were found in that region in those days, both in the UK and Norway, were reservoired in Brent sands.

In the 1980s, the question came up about how far the Brent would extend in a northerly direction. Tom remembers that as being a main issue when well 35/4-1 was drilled, being located much further north than the existing Brent discoveries. "In that sense," he says, "it was not too much of a surprise to see that the Brent wasn't properly developed there, despite all the excitement." ▸

Tom spent the majority of his outcrop analogue studies in the Spanish Pyrenees, studying mainly fluvial and shallow-marine sediments. This example is from the Ametlla Formation in the Ager Basin.

"Guided by sequence stratigraphic studies on the Brent that were published in those years, we put together a model that helped explain our exploration results quite well," Tom says. Combined with the creaming of the Brent play, this meant that scientific work on the Brent came to a bit of a standstill from the mid-1990s onwards, until recently.

"Our understanding of the Brent system has changed thanks to the advances in seismic imaging and the integration with in-depth sedimentological work," Tom continues. "Newly acquired or newly processed seismic has brought out subtleties that weren't visible before. And the northern boundary of the Brent depositional system is one of those subtleties that can now be much better assessed."

"Fifteen years ago, the Brent pinch-out line was drawn as a relatively straight boundary between the area north of the Snorre field towards Fram. Today, however, we realise that this line is not a straight line at all, but a much more convoluted boundary instead. This has made it possible for Equinor to identify a selection of exciting new prospects, some of which may be drilled as early as next year," Tom says.

ONE NORTH SEA

Tom Dreyer officially retired from Equinor in the first week of August. With that, he left behind a remarkable legacy of over 30 discoveries, many of which were found during two highly successful near-field exploration campaigns over the course of about six years.

But even though he will not call himself a frontier guy, and even though he has not made a major play-opening discovery in the great unknown, it is too easy to conclude that Tom's exploration success is just based on projecting reservoir properties away from existing fields into nearby areas, as the term near-field exploration seems to suggest.

In contrast, behind successful near-field exploration ultimately lies a strong regional understanding of sedimentary systems, a similar type of understanding that is required for more frontier work, but with more control points. Looking back at his style of exploration, it is this drive towards understanding the regional picture that has always been key during his career.

This is also reflected in Tom's initiative to initiate the One North Sea project when he came to London in 2011. "Only by understanding the basin in its entirety, and without looking at national boundaries," he says, "is it possible to map prospectivity in a sound way."

In that sense, it should be concluded that Tom Dreyer is not only the master of near-field exploration but also of regional geological integration. ■

PHOTOGRAPHY: TOM DREYER PRIVATE ARCHIVE

Mozambique: Revealing exploration potential of deepwater Zambezi Delta

As global energy demand continues to rise, continued investment in oil and gas will be critical to keep pace. Recent frontier basin exploration, particularly in deepwater basins in Namibia, Côte d'Ivoire, Guyana and Brazil, have yielded high-impact discoveries. However, these settings demand identification of large prospects to justify high drilling and development costs. In such cases, quantitative interpretation techniques play a critical role in de-risking prospects and reducing exploration risks.

The deepwater Zambezi Delta Basin in central Mozambique remains largely under-explored with historical exploration focus limited to onshore fields (e.g. Pande and Temane) and the shallow shelf. In 2017, Viridien acquired over 15,000 km^2 of 3D multi-client broadband seismic data (Figure 2) imaged with advanced pre-stack depth migration (PSDM) using full-waveform inversion (FWI) for velocity model building to de-risk exploration and provide high-resolution subsurface imaging in the basin (Figure 1). Emphasis was placed on preserving amplitude-versus-offset (AVO) behaviour to support attribute analysis. Key plays include the Upper Cretaceous basin floor fans, Paleocene hybrid channel systems and the Tertiary channel systems related to the Zambezi Delta system. Here, we look at how we can assess prospectivity in a frontier basin using AVO screening techniques.

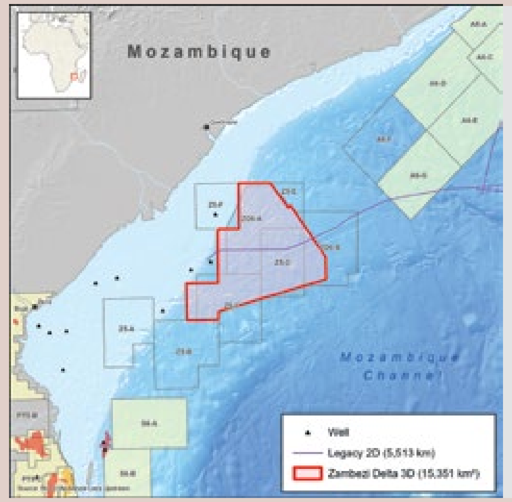


Figure 2: Location and coverage map of Viridien's 15,000 km^2 multi-client PSDM seismic survey in the deepwater Zambezi Delta Basin, Mozambique showing current held acreage, fields and wells.

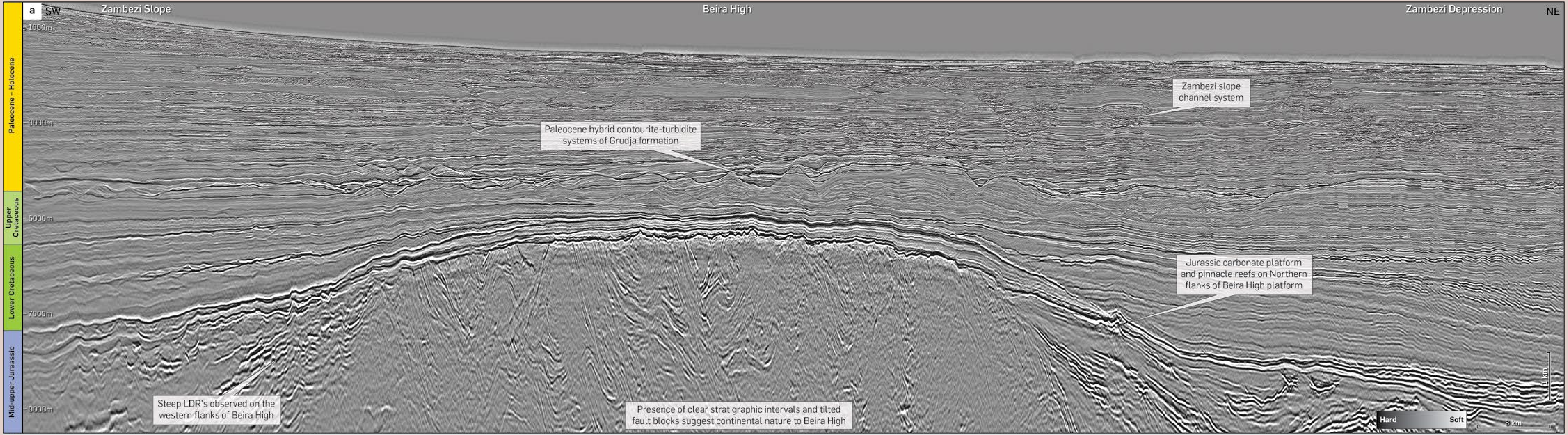


Figure 1: The southwest-northeast full-stack Kirchhoff PSDM (prestack depth-migrated) seismic line taken from the southern area of the Zambezi 3D survey shows transition of the deepwater system from the proximal slope to distal slope (Zambezi Depression).

Mozambique's deepwater Zambezi Basin: Where AVO meets untapped opportunity

Integrating AVO analysis into frontier workflows to identify exploration opportunities

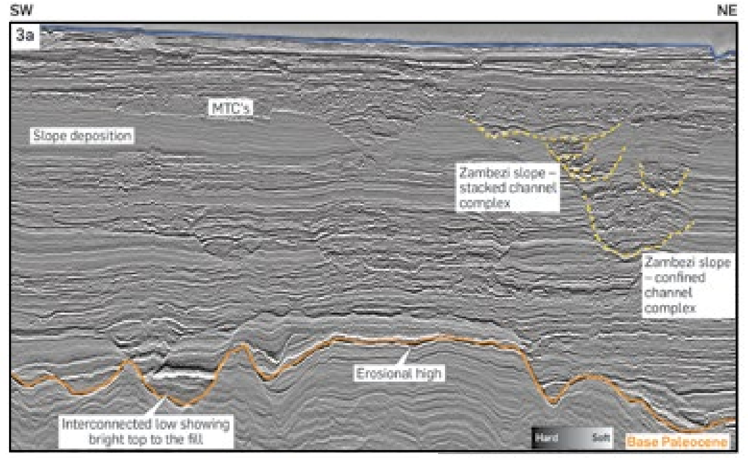
MADHURIMA BHATTACHARYA, ANDY HOLMAN, PAOLO GABRIELLI AND DIEGO LOPEZ, VIRIDIEN

ASSESSING frontier basin prospectivity with limited subsurface data presents significant challenges in evaluating its petroleum potential. As well data is often sparse or absent, it becomes essential to acquire and interpret high-resolution 3D seismic data to build knowledge of petroleum systems and plays.

To further enhance our understanding of the Zambezi Basin, Viridien recently conducted a regional AVO screening study on its 15,000 km^2 3D seismic survey. Several plays have been identified in the post-rift sequences of the deepwater Zambezi Basin ranging from Upper Jurassic to the Oligocene-Holocene play. The study focused on hybrid turbiditic-contourite channels of the Paleocene Upper Grudja formation with an aim to assess fluid characterisation and better understand rock physics to delineate zones of prospectivity within this interval.

PALEOCENE RESERVOIRS

The Paleocene Upper Grudja formation is considered to have reservoir potential with sedimentation occurring largely within a slope setting. The Upper Grudja formation within the southern part of the survey area is characterised by migrating channel levee complexes indicating synchronous interaction of downslope-flowing turbidity currents and along-slope contour currents (hybrid channel systems). These hybrid channel systems were strongly controlled by the position of the pre-existing Upper Cretaceous contourite drifts and moats. The reservoirs consist of thick channel deposits (Figure 3a) with potential vertical connectivity. An RMS map of the Base Paleocene (Figure 3b) shows the distribution of potential reservoir sands, some of which exhibit a high-amplitude response within the connected lows of the hybrid channel systems in the south of the survey. These reservoirs are sealed by fine-grained clastic slope deposits. Hydrocarbon charge is likely to be from Early Cretaceous (Aptian-Albian) and Late Cretaceous (Turonian-Coniacian) source rocks. Traps are stratigraphic and consist of truncations, onlap and ponding within the lows of the channel systems.



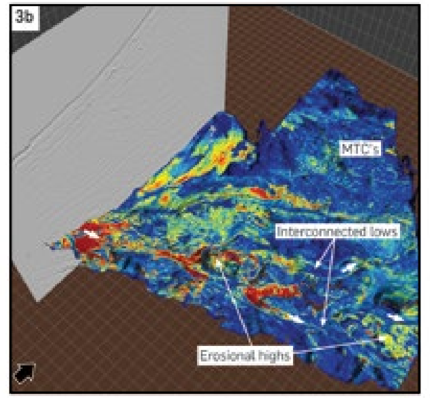


Figure **3a** and **3b**: **3a** Seismic section illustrating hybrid channels (turbidite contourite systems) of the Paleocene Upper Grudja formation and stacked channels and confined channel complexes of the Tertiary Zambezi Delta system. **3b** RMS amplitude extraction highlighting areas of sand deposition within the Grudja formation hybrid channel systems. White arrows indicate sediment transport direction.

FROM INSIGHT TO OUTCOME

For the AVO screening, our rigorous workflow included data QC on gathers to assess and condition data for AVO attribute generation, AVO class screening, generation of additional attribute volumes and, finally, geobody picking.

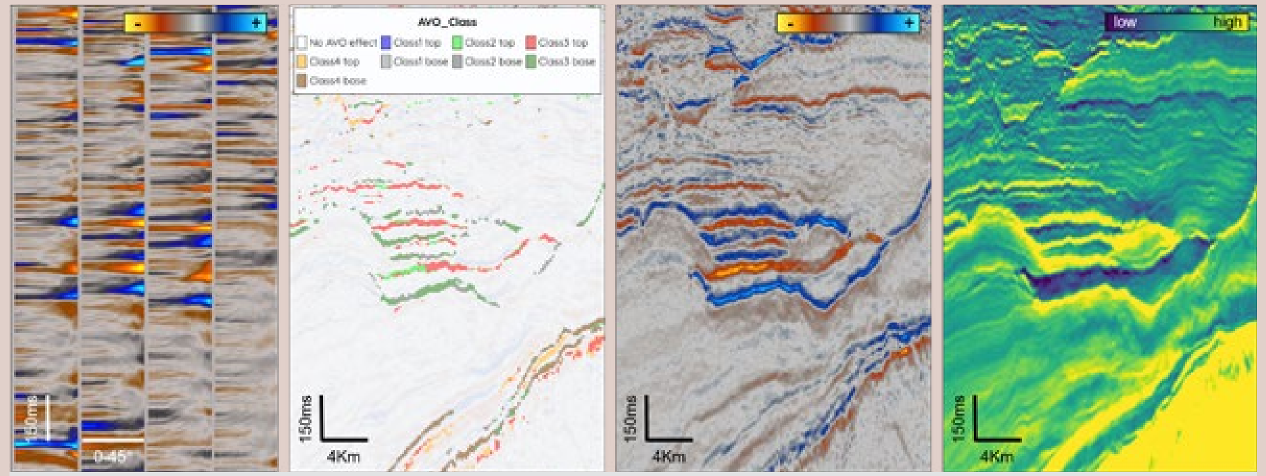


Figure 4: Left to right, CDP gathers, AVO class, fluid factor and fluid indicator where low values indicate higher chances of hydrocarbon presence.

First, a seismic velocity field was required to convert horizons from depth to time. This volume provided a low-frequency trend for impedance estimation. Four angle stacks – near, mid, far and ultra-far – and offset gathers were available for this screening. The data quality of angle stacks was observed to be good with noise well suppressed.

The basic screening attributes were generated from AVO fitting of the data using Shuey and Fatti approximations. Further attributes such as AVO class and chi rotations were generated from the Shuey-derived intercept and gradient, whilst Fatti provided P and S reflectivity. The P and S reflectivity allowed us to generate the fluid factor attribute, and after inverting for P and S impedances, we obtained Lambda-rho/Mu-rho and fluid indicator, any of which can be used as potential hydrocarbon indicators (Figure 4).

KEY LEARNINGS

The Fatti-derived fluid factor and Shuey-derived chi rotation (20° works best) both identify the same anomalous features, whilst the AVO class display provides further information about the position of the data in the familiar R0/G crossplot space. For this project, we required data that was appropriate for AVO analysis. The data was made more robust using volume-based attributes, preferable to the interface properties provided by the reflectivity attributes. The reflectivity volumes from Fatti were therefore inverted to provide P and S impedances and, from there, the fluid indicator attribute was generated. Rocks containing hydrocarbons instead of brine will tend to exhibit reduced P impedance values and hence low or negative fluid indicator values (Figure 5a).

We then further high-graded the fluid indicator attribute using a selection criterion in the fluid indicator/S impedance space and picked geobodies from the result. By mapping out the geobodies, we can visualize areas where the seismic data indicate potential sweet spots for hydrocarbon prospectivity (Figure 5b). The geobodies vary in extent, reaching up to 90 ms two-way time in thickness; when coupled with their positions within the channel systems, some will be more attractive or plausible than others. By linking this information with our understanding of the lithology, paleogeography, and geological timeline, we can determine which of these areas are likely to have reservoir potential.

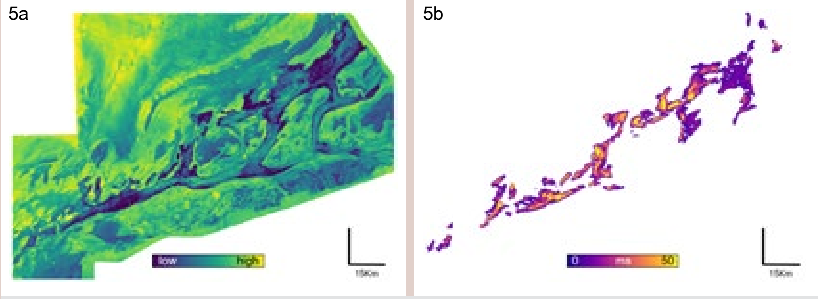


Figure **5a** and **5b**: **5a** Fluid indicator at Paleocene channel level. Darker colours indicate geobodies with greater hydrocarbon potential. **5b** Zoomed in view of geobody thickness. Lighter colours indicate thicker sections.

FOUNDATION FOR INFORMED ACTION

Our AVO screening indicated several potential hydrocarbon leads within the Paleocene hybrid channel systems seen in this seismic volume. These channels are observed to exhibit Class II/III AVO. The fluid indicator attribute allowed us to identify areas with potential fluid effects and, when combined with S impedance, isolate and capture the most anomalous features. The integrated methodology successfully demonstrates how advanced seismic attributes can help unlock prospectivity in frontier basins.

GEOTHERMAL ENERGY

"Ultimately, we're not just providing another mapping tool, we're giving companies the confidence to make better exploration and drilling decisions by quantifying uncertainty"

Philip Ball – Geothermal Radar

Fracture connectivity and power laws

Why deep geothermal open-loop systems need to take into account the density of natural fractures

IT WAS ABOUT a year ago that I heard about a deep geothermal drilling project in Finland (St1 Deep Heat Project), during which a couple of 6 km deep wells were completed in basement rocks. The ultimate aim was to establish connectivity between the wells to create an enhanced geothermal system (EGS).

The person I spoke to at the time was Signhild Gehlin from Sweden, who told me that the project was not a big success because no connection had been established between the two wells, despite stimulation. Conductivity did increase slightly after stimulation, but turned out to be pressure-dependent; lowering the pressure made any induced fractures close again.

Then, a few months ago, I entered into a conversation with Graeme Saunders from New Zealand, who is currently developing a new methodology to better map natural fracture systems in the subsurface before geothermal wells are drilled. The idea behind this is that the trajectory of these boreholes can be planned in such a way that they benefit areas of natural permeability.

In turn, Graeme recommended speaking with Peter Malin from Duke University in Durham, USA, whom he has been working with for a while and who is a specialist on passive seismic monitoring. Then, it turned out that Peter worked on the Finnish geothermal project and had ideas about why establishing a connection between the wells had failed.

"I recommended the project managers to have a well separation at depth of about 40 m," Peter told me, "but it was ultimately decided to go for around 400 m instead." Was this too big a distance? It probably was, and Peter has an explanation for that.

"Fracture connectivity may be good at the well location," Peter explains, "but as you move further out, the connectivity is diminishing. Therefore, net permeability at a large scale is falling as you move away from the well."

Peter then explains that you need some sense of calibration around the well as to where the fractures are, and that you can't exceed that distance and expect to have a permeable system. "The connection of fractures follows a power law, and the distance between the injection and production well needs to obey that power law in order to maintain permeability," he argues.

Using fracture density data, Peter arrived at the above-mentioned well separation of around 40 m. Is it, therefore, a surprise that the wells turned out to be unconnected? Probably not. As Peter further explains, stimulation will only do so much because a frac fluid will always tend to stimulate already existing fracture systems first.

For that very reason, Peter sees merit in passive seismic monitoring. This technology has already proven that it is possible to map natural fracture systems in the subsurface. He is embarking on another big research project of that kind just this month (September). If wells can be planned knowing where areas of natural connectivity are, there is a much higher chance that a connection between an injector and producer can be established. ■

Henk Kombrink

Basement rocks.

PHOTOGRAPHY: HENK KOMBRINK

Embracing uncertainty in geothermal exploration

New geothermal start-up better maps subsurface temperature distribution

"IF WE CAN'T discuss uncertainty, we won't go anywhere." Geothermal Radar's co-founder, Philip Ball, is adamant about what is currently lacking in the planning of new geothermal exploration wells. "Where oil charge, migration and trapping are key factors in hydrocarbon exploration, the temperature at target depth is one of the most important drivers for the success of a geothermal project," he says.

"However, from what I have seen, often there is no proper uncertainty assessment when it comes to the expected temperature range," says Philip when we meet on Teams. "And that is odd, because there is a lot of uncertainty and there is always a significant financial investment at stake when drilling a new well!"

The EAVOR deep drilling rig in 2022 at lightning dock geothermal, New Mexico. Philip Ball predicted 257° C at 5.5 km. The well found 257° C at that very depth.

PHOTOGRAPHY: PHILIP BALL PRIVATE ARCHIVE

Philip shows me a location somewhere on the globe in his newly launched Geothermal Radar platform from which he's got a range of temperature models predicting what the likely subsurface temperature profile will be. "As you can see," he adds, "each of these models predicts a slightly different outcome, which is testament to the various input parameters used for each individual model. Having a better understanding of the range in outcomes will improve our ability to plan for a drilling project."

Philip is not new to subsurface models. He worked in oil and gas for a good number of years, where he was widely known as a rifted margin and plate tectonic specialist, looking at large-scale basin models. Temperature data were part and parcel of those basin models, but in those cases, more from a hydrocarbon maturation point of view. "When I saw a new seismic line," Philip says, "I always checked for the Moho first!"

During those years, Philip's hobby was to seek out published lithospheric and isotherm models, even without a plan in place with what to do with it. This changed when he started doing an MBA, during which he chose to do his topic on geothermal energy.

"I decided to bite the bullet and started to integrate the temperature models and data in a global platform, with the vision that individuals and companies can quickly assess the range of temperature predictions for the areas they are interested in. Ultimately, we want people to produce a P10 - P90 range of expected temperatures," he adds.

With his co-founder, Vladimir Stroganov, they are optimising Geothermal Radar to be a single platform for energy companies, investors, the industry and even national authorities. "We are already engaging with quite a few oil and gas majors interested in geothermal energy," says Philip, "with the aim to integrate our techno-economic and temperature models with their proprietary data and 3D basin model outputs."

And while Geothermal Radar is now live, Philip keeps on adding new data and cutting-edge models all the time, working with researchers at Twente University in the Netherlands and Keele University in England. "I'm also very much into continuing research, such as the question of where we can find those temperature nuggets that are normally only in our P10 range," Philip explains.

"Ultimately," he concludes, "we're not just providing another mapping tool, we're giving companies the confidence to make better exploration and drilling decisions by quantifying uncertainty. As such, the analysis isn't just academic – it is essential for commercial success." ■

Henk Kombrink

Critical look at Fervo Cape Station data raises questions over sustainability

Similar to Blue Mountain, Cape Station production rate declines rapidly

ELLIOT YEARSLEY AND HENK KOMBRINK

IN SEPTEMBER 2024, Fervo made public a preprint containing plots and analyses for their Cape Station project in Utah. Although not nearly as detailed as the Blue Mountain dataset released in 2023, this Cape Station data allows for a critical look at the results.

The Fervo project in Utah, on the periphery of the Roosevelt Springs geothermal field, entails the drilling of multiple horizontal producer and injector wells into basement rocks, after which the rock is hydraulically fractured to create flow paths between the injectors and producers. In this case, the test results are from a "Triplet" – two injection wells and one production well.

Fervo states that the production rate was "levelling out at approximately 93 kg/s after the first day of production". However, a close look at the plot suggests that this is not the case; the rate declines from about 97 to 93 kg/s over the last 12 hours shown. Importantly, this declining trend is continuing at the end of the plot.

This has obvious implications for the consistency and sustainability of production, the bread and butter of geothermal projects. If the production rate levels out at 93 kg/s as stated, why not show this? The Cape station paper presents only 24 hours of data, versus 37 days for the test in Blue Mountain, Nevada.

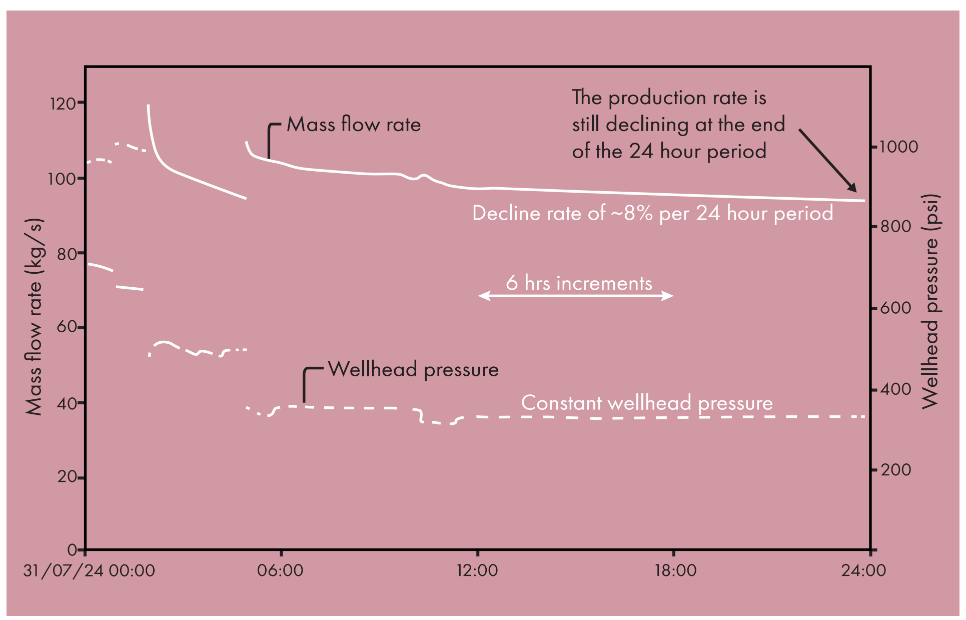
Also, no injection rate data is presented, so it is difficult to judge if the higher production rates at Cape Station were a result of more efficient fracking or a higher injection/production ratio.

GROSS AND NET POWER

Fervo states that the first Cape Station production well "sustained an output of 8-10 MW". However, net power should take into account the power required for the injection pumps. This is a function of the pressure differential between production and injection and the injection rate. We are told that the injection pressure is between 2,000 and 2,300 psi, and the wellhead pressure at the end of the 24-hour period looks to be about 350 psi.

The injection rate is not given, but if we assume 120 % of the production rate, the pump power can be estimated at about 2.5 MW, making the net power 6.2 MW at the end of the 24-hour period. If the production decline continues at a rate observed in the Blue Mountain test during its longest period of constant injection – an average of 2.5 % per 24-hour period – the net power at the end of 7 days would be 4.8 MW. Net power of 4.8 MW is a fair way off from the "sustained 8-10 MW" stated by Fervo in their white paper.

As for Blue Mountain, it has been almost two years since the pilot production well has been "flowing to the plant", so there has been ample opportunity to document the sustainability of EGS injection / production rates. In an earlier article, we raised questions for Blue Mountain that have not yet been answered. For Cape Station, the stakes are much higher, but the questions are still the same. ■



24 hours of production data provided by Fervo.

The tech powering the future of geothermal energy

How advanced 3D modelling and innovative drilling techniques from the oil and gas industry are positioning geothermal energy as a pivotal player in the future of clean energy

JOCELYN BROWN, SEEQUENT

Geothermal energy, once overshadowed by other renewables, is entering a new era. Historically, its use depended on rare geological conditions: Underground heat, permeable rock, and natural water supplies — usually found near plate boundaries or volcanic regions. These limitations kept geothermal on the fringes of global power supply.

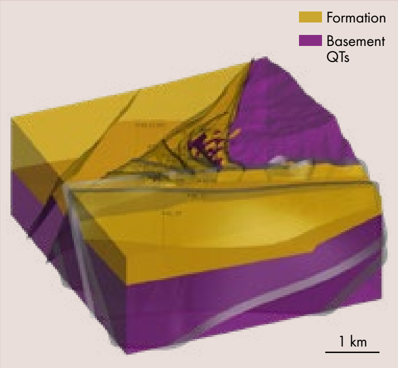
Now, Enhanced Geothermal Systems (EGS) are changing the landscape, making it possible to tap into Earth's heat in areas without natural reservoirs. With recent advances in drilling and modelling, and steadily decreasing costs, geothermal could supply as much as 15 % of global electricity demand by 2050 (source: IEA report: The Future of Geothermal Energy).

EGS expands the reach of geothermal energy to high-temperature regions that lack sufficient fluid volumes or natural permeability — areas once dismissed as "hot, dry rock" zones. Two such major projects breaking this new ground are the Utah FORGE initiative and Fervo Energy's Project Red in the USA.

Steve Fercho, the Exploration Geoscience Lead at Fervo Energy, says these Enhanced Geothermal Systems (EGS) could be the answer. Co-developed by Fervo and Google under a partnership in 2021, Project Red is 'the world's first corporate agreement to develop an enhanced geothermal power project.'

With Project Red, Fervo has achieved a lot of firsts: The first commercial EGS project, the first known geothermal project that uses fully horizontal wells, and likely the hottest horizontal wells ever drilled in the world.

"Our number one goal for Project Red was to prove that using horizontal drilling and multistage stimulation treatment technology is viable for geothermal. It's hugely validating to show that impermeable rock, previously considered too hard, too deep, and too hot for tech to handle, can be successfully drilled," says Fercho.



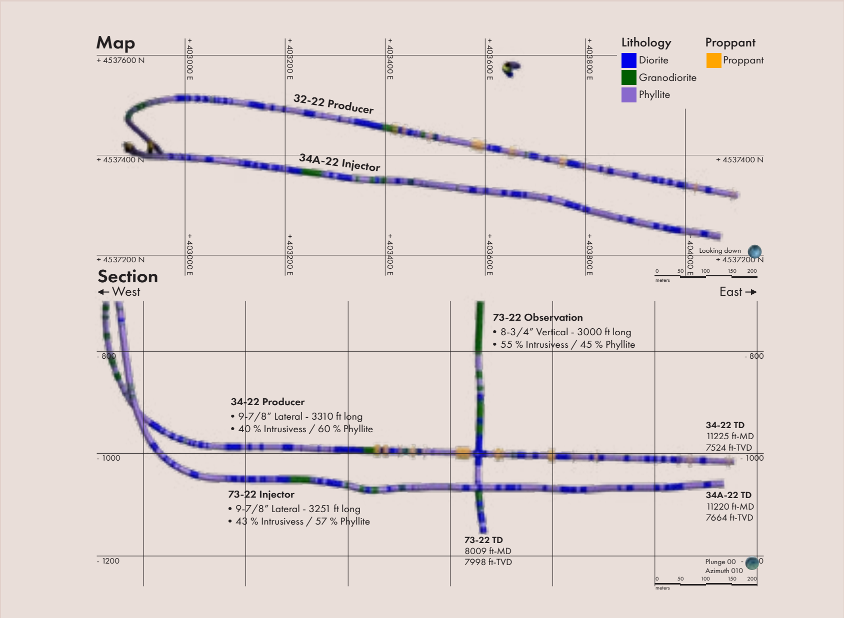
Seequent's digital workflows enable 3D models of complex subsurface environments, to help assess stimulated rock volumes and target wells.

Alongside horizontal drilling, the Fervo team uses Seequent connected software: Oasis montaj for their geophysical modelling, Leapfrog Energy 3D ground modelling software and Seequent Central to visualise, track and manage their large geological datasets from a centralised, auditable environment.

Fercho says of Leapfrog, "It's our most important tool to characterise the subsurface to determine the best location of the wells before we drill. And, as we drill, we can update our models for continuous planning."

With global investments in geothermal technologies increasing, Enhanced Geothermal Systems (EGS) are overcoming geographical and geological barriers, enabling energy production in regions previously considered unsuitable for geothermal. Unlike wind and solar, geothermal energy is not intermittent; it provides constant, around-the-clock power, making it a true baseload renewable resource.

As both private and public sectors continue to support innovation, further breakthroughs in technologies and research could continue to help geothermal energy assume a more central role in helping the delivery of global clean energy.



The Leapfrog Energy model shows a horizontal well pair with 3,250-foot laterals reaching 376° F (191° C).

SUBSURFACE STORAGE

"This way, we can go much deeper than any 'conventional' subsurface storage facility will ever be able to achieve"

Rod Baltzer – Deep Isolation

New study on global CO_2 storage capacity met with fierce criticism

Authors of Nature publication apply too restrictive boundary conditions

"OH NO! I'd better call the Porthos office to stop construction (of our CO_2 injection project)! Apparently, we are injecting in unviable depths!", wrote Joop de Kok from EBN in the Netherlands as a comment to a LinkedIn post from Rachael Moore (CarbStrat) the other day.

In her post, Rachael criticises the decisions made by the authors of a newly published Nature paper, in which they present a reassessment of the total global CO_2 storage capacity. The authors conclude that the current total CO_2 storage capacity is about an order of magnitude less than what was previously assumed, from around 11,800 to 1,460 Gt CO_2.

News outlets picked up on this. For instance, the Financial Times came up with the following title: "Carbon capture set to be less useful in tackling climate change, scientists warn". Rachael suggested a new title: "Sufficient carbon storage resources to meet next 100 – 200 years of CCS needs".

As the reaction from Joop de Kok already alludes to, it is the deviation from otherwise widely accepted depth criteria for successful CO_2 storage projects that has not only surprised Rachael Moore, but also the Global CCS Institute. In an official release, they state: "For example, their depth limits of 2,500 m for subsurface storage ignore successful projects like Northern Lights operating at 2,600 m, while their 300 m ocean depth restriction overlooks Brazil's decade-long experience with CO_2 injection at 2,000 m water depths."

And it is not only the maximum depth limit that the authors are restrictive about, but also the minimum depth. Rather than using the conventional and widely accepted 800 m mark, the team of researchers applied a 1,000 m minimum depth. By using a more restricted depth window, it is no surprise that the estimated storage capacity is smaller than what was previously thought.

The authors also applied a very conservative spatial buffer of 25 km between densely populated areas and new injection projects. The Global CCS Institute adds: "The study's 25 km buffer zone around populated areas also appears conservative when compared to operational experience and discordant with the typical approach to permitting. CarbFix operates at 8 km from populated areas and Shell Quest at 15 km. Existing projects demonstrate through rigorous permitting and risk assessments that high safety standards can be met in practice."

What is very important to stress is that, despite this "downgrade" and whatever you think of its assumptions, there is still plenty of storage space available. Rachael writes in her post: "We need 3 – 12 Gt/yr of CO_2 storage by 2050, depending on how long we continue to use fossil emissions." We have plenty of space to fill.

I'd say geological storage space is a rather uninteresting factor in the whole debate of getting CO_2 injection projects over the line. The limiting issue at the moment is not related to subsurface factors, but rather the financial side of it. That's where the challenges lie. ■

Henk Kombrink

Power plant.

PHOTOGRAPHY: CATAZUL VIA PIXABAY

Using horizontal drilling technology to permanently store radioactive waste

An American company will soon embark on a full-scale test to drill a borehole to store canisters of rad waste deep underground

"WE GET THAT question a lot," says Rod Baltzer, CEO of Deep Isolation, when he calls in from Dallas. "But no, oil and gas wells cannot be easily converted to store spent radioactive waste."

> **"This way, we can go much deeper than any 'conventional' subsurface storage facility will ever be able to achieve"**

"The reason is simple," he continues, "the canisters we developed in which we store the waste are about 15 inches wide. That's about three to five times the diameter of most oil and gas wells near terminal depth."

The idea of storing radioactive waste in boreholes sounds quite simple and elegant, using the space at the toe of drilled wells. "This way, we can go much deeper than any 'conventional' subsurface storage facility will ever be able to achieve," says Rod.

"As we saw the advances made in horizontal drilling in the oil and gas sector, we thought why not use this technology for rad waste as well? Previously, plans had always centred around drilling deep vertical boreholes into granite, but the ability to drill long horizontals in shale formations opened up the opportunity to apply that technology in our domain," he explains.

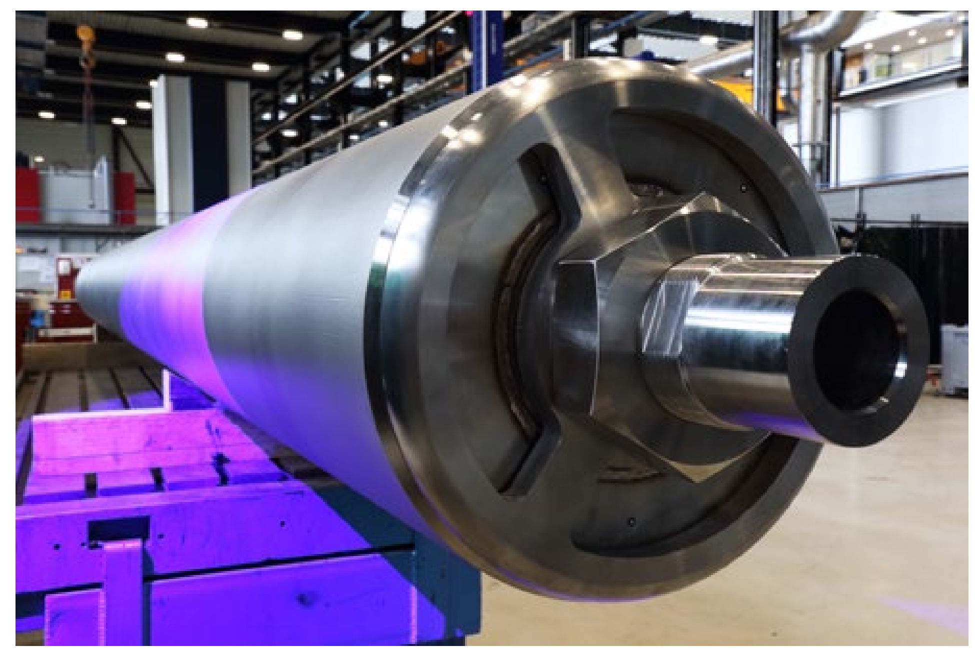
The timing is right. So far, permanent subsurface storage of nuclear waste, despite a few attempts, has never been successful. Finland is getting close, with their newly built facility ready and available for receiving the first batches next year, but that's about it. And that in a time when nuclear is on the table again as a reliable and low-carbon energy source.

And there are other advantages too: "The cost of drilling twenty wells with a 1 km horizontal section in which the canisters will be stored – enough to accommodate the waste one nuclear power station produces in about 60 years – can be up to 70 % less than building a full-scale underground storage facility."

It is the combination of costs and safe storage that formed the reason for Deep Isolation to test the concept better. "We will soon start a full-scale test of our technology at a test site near Cameron, Texas," continues Rod. "That means we will drill a borehole to a target depth of about 1,500 m with a diameter downhole of 21 inches. That should be sufficient to get the 15 inch canisters in. It is crucial in the well design to prevent sudden changes in inclination, otherwise the canisters may get stuck whilst lowering them into the hole."

"We have already tested this during two previous tests at intermediate depths," says Rod, "to great hilarity from the drillers. Successfully lowering a canister into a borehole and getting it back up again did not sound like rocket science to these guys at all, but it was an exciting step in the radwaste disposal community at the same time. It shows how different perceptions are in individual communities when it comes to how "cutting-edge" new technology is." ■

Henk Kombrink



A canister developed by Deep Isolation to store rad waste in.

PHOTOGRAPHY: DEEP ISOLATION

How a sandbox model caused an epiphany

Only when Sean Kelly saw how CO_2 behaves in an analogue model, he realised that the results of the detailed reservoir models he had been building made sense

"I THINK I watched it about 50 times," Sean tells me when we meet online on a rainy morning. He refers to a video published by the FluidFlower research team in Bergen, Norway. In the 4-minute movie, we see what can be described as a narrow fishtank filled with different types of sand, simulating a range of porosities and permeabilities.

"The purpose of this analogue model," Sean continues, "was to inform the public about how CO_2 moves around in the subsurface once it is injected. This was all done in the framework of the Northern Lights CCS project that has just seen its first batch of CO_2 injected into its reservoir.

Sean, who works as a geomodelling researcher at Aberdeen University in Scotland, describes the things we observe in the video: "During the first few minutes, nothing happens that would overly surprise a geoscientist working on subsurface fluid flow. But then, after a couple of minutes, we see "fingers" of CO_2 starting to migrate downwards to the base of the reservoir," he explains. "It is CO_2 that enters into solution, making the brine heavier than the surrounding fluids."

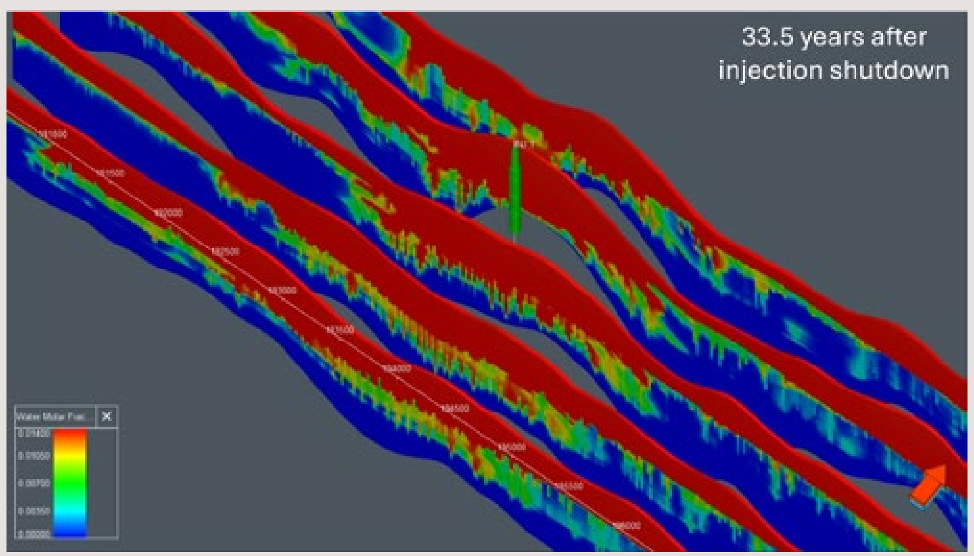
"I had seen this in my models," he said, "but until then I had not properly understood what they were."

Sean started looking into it more and found out that what the analogue model and his reservoir models had shown was no surprise at all to those who worked on the physical principles of what happened. But somehow, this was not on Sean's radar. And that is odd, because the notion that CO_2 is moving down in the reservoir is great news for the integrity of potential storage sites.

"I think many previous modelling exercises had not captured this phenomenon properly," Sean says in an attempt to explain why he and people around him were unaware of this downward migration. This is where new technology comes in. "Using tNavigator from RFD, I was able to build a reservoir grid fine enough to replicate exactly what I saw in the video," he says. "This would not have been possible a few years ago at all, but now we can. This is why the process has not really been picked up on by geoscientists and reservoir engineers; the models were simply not detailed enough to accurately represent what happens in the subsurface."

The implications of this work are potentially far-reaching. "We can more confidently say that seal integrity of a CO_2 store will become less of an issue over time as more CO_2 will go into solution," explains Sean. "In fact, we see that the process kicks in within years of the start of injection, all adding gravitas to getting more CO_2 projects over the line." ■

Henk Kombrink



Timestep (33.5 years post-injection) from a large-scale CCS simulation showing CO_2 water molar fraction (i.e., the proportion of CO_2 dissolved in formation water). At the top of the storage unit the buoyant supercritical CO_2 plume is visible with a relatively flat base. Beneath it, downward-moving convective "fingers" of CO_2-rich brine can be seen, formed by early diffusion and dissolution at the plume-aquifer boundary.

SOURCE: ABERDEEN UNIVERSITY

SEABED MINERALS

"With rapid global population growth, geopolitical tensions and a strong belief that everybody has the right to the same level of development as we do, additional primary metal sources are a necessity"

Annemiek Vink – BGR

The ambivalent position some European countries find themselves in when it comes to seabed mineral extraction

On the one hand, countries with seabed mineral exploration licences must be seen as progressing towards harvesting, but at the same time, their own governments are pushing back against it, creating a complex standoff situation

When the convention of the sea was adopted in 1994, the newly formed International Seabed Authority (ISA) started to award licences for the exploration of seabed minerals. Now, in 2025, these licences have caused a particular situation for some countries. Two of these stand out, Germany and France.

Especially the German delegation to the ISA is pushing for extremely high and costly environmental standards, and is slowing down the ISA's attempts to develop a reasonable and adaptive mining code to progress to seabed mineral extraction. But at the same time, Germany owns two licences that should progress towards the ultimate goal of extraction, according to ISA contractual obligation. France also has two exploration contracts in international waters, is exploring for seabed minerals in national waters around its southern Pacific territories, but has officially proclaimed a moratorium on seabed mineral extraction at the same time. Why then, are these countries holding on to their exploration licences?

A similar situation applies to the Netherlands, even though the country does not have mineral exploration licences. Whilst the members of the Dutch delegation at the ISA Council are very much in line with Germany's approach, Delft-based Allseas has converted a former drill ship to a nodule-harvesting vessel. Equally, Royal IHC developed a prototype nodule collector that was tested in the Mediterranean.

"It's a difficult situation we find ourselves in," says Annemiek Vink from the BGR in Germany. "We cannot consider seabed minerals without looking at the consequences of land mining; you have to see the complete picture. With rapid global population growth, geopolitical tensions and a strong belief that everybody has the right to the same level of development as we do, additional primary metal sources are a necessity. I think seabed minerals form a reasonable alternative to opening new land mines with high social and environmental costs, provided that the right management systems are in place."

"With Germany calling for a precautionary pause in seabed mineral extraction, the main focus of our exploration work at the moment is on the environmental side of things," says Annemiek. "Rather than working directly towards seabed extraction, we collaborate loosely with companies wanting to test their equipment and focus on aspects of environmental monitoring and impact analysis. But it is clear that we are walking on eggshells."

However, in the light of what is currently being discussed around security of supply and the US' move to bypass the ISA, this whole situation might change. It might just be a matter of time until these countries will make a turn. ■

Henk Kombrink

PHOTOGRAPHY: THE METALS COMMAPNY

Essential part of the CCZ pilot collection trial.

World's first deep-sea mineral reserves declared

The Metals Company's long-awaited pre-feasibility study for the NORI-D nodule project declares the world's first deep-sea mineral reserves, citing a $5.5B net present value – but critics question optimistic assumptions

The Metals Company's (TMC) August release marks a milestone in its history, as well as for the global marine minerals industry. The technical summary of the pre-feasibility study (PFS) for its NORI-D nodule project includes the declaration of mineral reserves, which is a first in the deep marine realm.

Located in the Clarion-Clipperton Zone (CCZ), the world's largest known nodule field in the Pacific Ocean, NORI-D is a cornerstone of TMC's ambitions. The company is targeting commercial production by late 2027, reaching 10.8 of wet nodules annually by 2031. The expected production timespan is 18 years.

The technical report declares 51 Mt of probable reserves. Additionally, 274 Mt are pegged in the "measured, indicated and inferred" mineral resource categories, with 113 Mt potentially recoverable beyond this. Annually, NORI-D is expected to produce approximately 97 kt of nickel, 2.4 Mt of manganese, 70 kt of copper, and 7.4 kt of cobalt, comparable to a medium-to-large land-based mine.

TMC's lean, capital-light strategy with initial capital outlays of less than $550 M, should appeal to investors. The PFS outlines a phased approach, leveraging vessels and offshore operations by partner Allseas and initial onshore processing by Pacific Metals Company (PAMCO). The PFS projects an after-tax net present value (NPV, estimated future cash flow value today) of $5.5 B for NORI-D, with a 27 % internal rate of return.

ROSY PRICE ASSUMPTIONS

However, the metal price estimates stand out as rather optimistic, with cobalt prices well above current levels. While TMC states that the price assumptions are provided by third parties, mining companies typically use more conservative commodity price assumptions in technical reports.

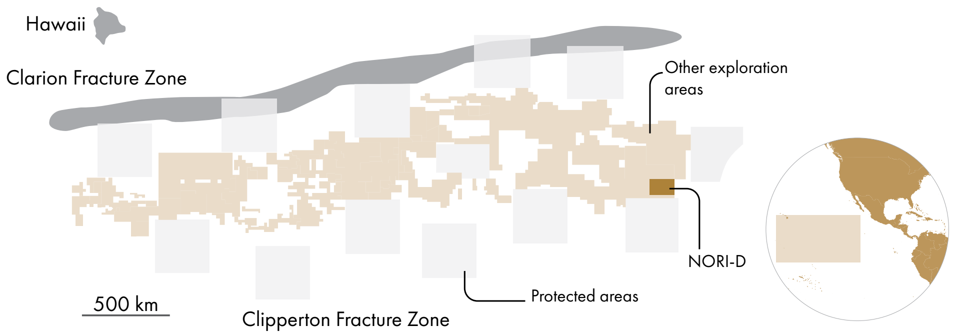
In TMC's defence, a price sensitivity analysis shows NORI-D retains a solid NPV of around $4.9 B, even with a 20 % decline in the price of either nickel sulphate and manganese, the two most sensitive metals in the NPV analysis. Still, a corporate practice of using buoyant prices may leave some investors to question whether other aspects of the PFS are overly optimistic.

ICEBERGS AHEAD

Critics share these concerns. Iceberg Research, known for its activist approach and short-selling reports, sharply criticizes the PFS's validity in its latest report. The research firm highlights a 152 % surge in offshore costs and a 35 % cut in nodule production due to complex seabed terrain. Iceberg also criticises TMC's above-market metal price assumptions, noting that its manganese output (13 % of global supply) could flood the market and depress prices. Iceberg's recalculated NPV, with conservative assumptions, yields a negative $1.5 B, concluding: "The economics simply do not work".

However, despite widespread scepticism over TMC's daring sidestep of the ISA, a recent $85 M strategic investment from metals refiner Korea Zinc signals a vote of confidence. Furthermore, TMC's stock price has soared in 2025, suggesting market belief in the company's future.

Ronny Setså ■



Location of the NORI-D licence in the Clarion-Clipperton Zone.

American company eyes seabed mineral opportunities in Norway

WetStone considers Norway attractive in terms of developing a value chain around seabed minerals. The company invests in and collaborates with exploration companies and host countries to build a new marine industry

"EARLIER IN my career, I have had the privilege of working in Norway, which is a leading example of how industry, trade, and the public and private sectors collaborate. And you have a fantastic resource base," boasted Graham Talbot, CEO of WetStone.

He gave a lecture at the major shipping conference Nor-Shipping in Lillestrøm in June this year, where a half-day event was dedicated to deep-sea minerals.

WetStone is an American company that wants to develop robust value chains for seabed minerals. They invest in and collaborate with operators across jurisdictions, and develop the necessary infrastructure and technology to mature the industry. The New York and London-based company is already involved in more than ten countries, and Graham did not hide that Norway is an attractive investment destination.

WetStone focuses exclusively on the seabed minerals sector. The director explained that a growing global demand for critical minerals, such as nickel and cobalt, is driving the need. He expressed doubts about whether land-based mines can cover this in a sustainable way, as ore quality declines, and new projects become more expensive and time-consuming to develop.

LOW-HANGING FRUIT HAS BEEN PICKED

Graham drew parallels to his background in the oil and gas industry: Once the simple resources are extracted, you are left with the more demanding ones. And he believes that is also the situation for the mining industry today.

Graham Talbot, CEO of WetStone, at the Deep Sea Minerals 2025 conference in Bergen, Norway, in April 2025.

WetStone focuses exclusively on national jurisdictions (exclusive economic zones), and steers clear of international waters, where other players are investing. The reason is, among other things, uncertainty related to when the International Seabed Authority (ISA) will be able to finalise regulations for mineral extraction in such areas.

Regarding technology, Graham pointed out that the industry can benefit from experiences from sectors such as oil and gas and defence. Exploration has so far been expensive, unreliable and difficult to scale, but WetStone is working to develop a scalable, global exploration platform to meet these challenges.

The director repeatedly boasted of Norway's strong position in the global race for seabed minerals and shared the US perspective: "It is clearly possible to invest and develop partnerships here, and look at opportunities for how we can get involved in developing the sector."

He pointed to clear opportunities for the Norwegian seabed community to attract US capital, both through direct investments and so-called offtake agreements, where future deliveries of metals can secure financing, potentially via US state or semi-state institutions.

In light of Graham's glowing review of Norway's potential for developing marine mineral resources, and WetStone's active search for partnerships, it will hardly come as a surprise to hear about an agreement between the US and Norway at some point soon. ■

Ronny Setså

PHOTOGRAPHY: GEOPUBLISHING

NEW GAS

"A closer examination of field data, however, raises doubts about how much free hydrogen gas has actually been proven to exist"

Arnout Everts – Aegeo

Sometimes an old well is better than a fancy new one

Henry Williams explains how various issues with a newly drilled helium producer led to the decision to focus on a 65-year-old well instead

WHILE THERE is always press around helium discoveries, companies that are actually producing it often go unnoticed. That doesn't mean they don't have interesting stories to tell. Canadian-based Thor Helium, which has been steadily producing from the Knappen field in south-east Alberta since 2020, is an example.

In 2015, Thor and its partners acquired a 55-year-old well, which had previously produced methane from Carboniferous and Jurassic reservoirs. After the acquisition, the focus shifted to other reservoir zones that were previously recorded to flow non-flammable gas.

The team recompleted the Cambrian sandstone resting on basement, and dolomites belonging to the Devonian Beaverhill Lake Group. Henry Williams, VP Geosciences at Thor, says: "It's crazy. If I had been in the company at the time the decision was made to recomplete the well, I'd have argued not to touch it. Especially a well that had so much work done to it."

However, rather than the old well, a strongly deviated well drilled by Thor itself in 2019, near the edge of the Knappen Field, has caused the issues.

The Devonian reservoir in the Knappen Field consists of multiple dolomite-anhydrite cycles. This has created a compartmentalised reservoir where each dolomite interval contains gas with a unique signature. The deepest compartment contains 1.5 % helium, 89 % N_2 and 5 % CO_2, while the top compartment contains 0.3 – 0.8 % helium and up to 85 % CO_2. Helium and nitrogen are likely basement-derived, while Henry believes that the CO_2 is linked to local Eocene magmatism that has flushed the top reservoir compartment but left the other intervals relatively untouched.

Only the helium-rich intervals were produced. However, after several years, CO_2 concentrations in the gas started creeping up. Following plant shutdowns, excess CO_2 had to be briefly vented before helium production could resume. "The tighter CO_2 zones are held back from flow during production, but as soon as you shut the well in, it appears to enter the producing reservoirs," explains Henry.

Thor Helium was concerned that the whole field would get contaminated with CO_2 and decided to cement squeeze all perforated intervals from the 2019 well to prevent cross flow. During the operation, they pulled the tubing and found that it was severely corroded. CO_2 had come into contact with water and formed carbonic acid.

"I didn't think carbonic acid was strong, but it is; it can eat through 3/8 inch steel tubing in three to four years," says Henry. "Apart from corrosion, cross flow also took place behind the casing due to poor cement. The high angle of the well and poor cement bond allowed gas flow between the high CO_2 intervals and the reservoir."

Thor Helium has now abandoned their 2019 well and is considering a replacement, whilst the now 65-year-old original well continues to produce. ■

Mariël Reitsma, HRH Geology

Severely corroded tubing from the 2019 Knappen well.

PHOTOGRAPHY: THOR HELIUM

A large natural hydrogen gas accumulation or an aqueous hydrogen seepage with localised gas pockets?

A closer look at the Bourakebougou field in Mali

ARNOUT EVERTS, AEGEO

THE BOURAKEBOUGOU (Bougou) field in Mali has made headlines as the "world's first producing hydrogen field". It has been described as a "large accumulation of hydrogen gas in carbonate and sandstone reservoirs ranging from 30 to 1,500 m depth, with volcanics sills (dolerites) acting as caprocks".

A closer examination of field data, however, raises doubts about how much free hydrogen gas has actually been proven to exist. Other than the flow of relatively small amounts (between 150 and 1,500 m^3/day) from Bougou-1, producing from the shallowest reservoir zone in the field, no other industry-standard evidence of free gas in the reservoir, such as downhole gas samples or pressure points demonstrating gas gradients, has been publicly released.

In the International Journal of Hydrogen Energy, Jos Bonnie, Ramon Loosveld, and I offer an alternative interpretation of Bougou as a seepage system of hydrogen dissolved in formation water with only small, localised gas pockets. Here is the supporting evidence for this alternative interpretation:

First, there is no link between the occurrence of mud gas shows in wells and structural elevation, despite some 80 m of vertical relief on the structure. No base-of-shows can be defined. A continuous hydrogen gas cap across all wells on the structure of at least 80 m high would result in crestal reservoir pressure close to or in excess of lithostatic pressure.

Second, using pressure data from the Bougou-1 well, notably the 60 psi Shut-In Tubing-Head Pressure (SITHP), and intercepting this with an aquifer-pressure-gradient based on regional groundwater data, indicates that most of the reservoir must be in the water leg.

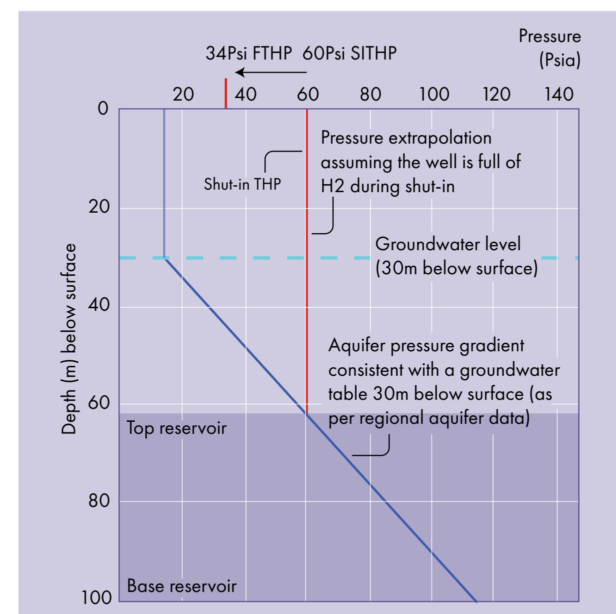
Finally, across the prospective reservoirs, including the intervals with mud gas shows, the neutron log deflects towards higher porosities whilst the density log also reads high. This log response is suggestive of water rather than gas-filled pore space. If pores had been filled with hydrogen gas, it would result in exactly the opposite effect: A lower neutron porosity due to the low Hydrogen Index of gaseous hydrogen, especially at low pressure and a lower density due to the low apparent density of hydrogen gas.

Whilst most of the hydrogen gas shows appear to come from reservoirs with an aqueous pore fill, some small crestal hydrogen gas caps or pockets may locally exist. The accidental Bougou-1 producer may have intercepted one of these pockets. Gas caps of a few meters high and 1 to 2 km in radius would contain enough volume to sustain the small Bougou-1 hydrogen production for several years.

Reportedly, the shallowest reservoir zone in Bougou, where the field's only hydrogen well is producing from, is an important regional aquifer in which, over the years, hundreds of water wells may have been drilled. These wells may have subsequently lowered the groundwater table and, hence, depleted aquifer pressures significantly. I speculate that this pressure depletion may have triggered the formation of small, localised gas pockets by releasing hydrogen from aqueous solution.

The "emblematic case of Bourakebougou" is often quoted as key evidence that natural hydrogen gas can be trapped in significant quantities in the subsurface, and for that reason, it is important to get clarity on the nature of hydrogen in Bougou. We urge the operator of Bourakebougou to provide full disclosure of all key subsurface data required to determine pressure and phase of hydrogen in the various reservoir layers within the field. ■

SOURCE: REDRAWN AFTER EVERTS, A.J.W., BONNIE, J., & LOOSVELD, R.



Pressure evidence: The low shut-in pressure of Bougou-1 (60 psi) is not compatible with a hydrogen gas cap connected to the regional aquifer.

Subsurface bio-stimulated hydrogen

Has the hydrogen holy grail been found?

The quest for affordable, low-carbon hydrogen is far from over. While well-established techniques such as steam reforming and electrolysis exist, they come with significant drawbacks in terms of cost and infrastructure. Hydrogen generated from organic waste in bioreactors presents a sustainable option, but scaling this process is challenging. Additionally, exploration for naturally occurring hydrogen is in full swing; however, economic reserves have yet to be proven.

As the search for the hydrogen holy grail continues, US-based company Gold H_2 is innovating and combining known processes in a new way. They aim to create an anaerobic bioreactor within a depleted oil reservoir. This approach has several advantages: It reuses existing infrastructure, has ample feedstock at its disposal in the form of unproducible oil, requires minimal to no energy input for hydrogen generation, and avoids the need for water addition.

What does this process entail? Anaerobic digestion involves the breakdown of organic material by microbes in an oxygen-free environment. This process occurs naturally in many shallow oil fields (T <80° C) and is known as biodegradation. During biodegradation, microorganisms feed on hydrocarbon molecules, producing methane and acids while leaving behind a heavy oil residue. It is during the intermediate 'dark fermentation' phase that hydrogen and CO_2 are formed, only to be subsequently reduced to methane. The key challenge is to create conditions that prevent this reduction, allowing the capture of hydrogen instead.

Another challenge is that fermentation rates in oil fields are typically low. Biodegradation occurs at the oil-water contact interface, where microbes are limited by the nutrients present in the water. They must constantly wait for fresh nutrients to diffuse toward them. Therefore, to stimulate hydrogen production, additional nutrients need to be introduced into the reservoir to accelerate fermentation.

Gold H_2 tested this approach in the San Joaquin Basin in California. The climate tech company identified a legacy oilfield that showed no signs of biodegradation and introduced their proprietary blend of microbes and nutrients. As this mixture migrated through the reservoir, microbial activity was stimulated, leading to the conversion of residual oil. The produced gas contained 40 % hydrogen. While this appears to be a promising outcome, questions arise about the remaining 60 % of the gas composition. Hydrocarbons serve as feedstock; the hydrogen atoms are released as gas, but where does the carbon go? Is it transformed into carbon dioxide and / or methane? Or does the carbon remain fixed in the reservoir, and is most of the gas H_2S?

The gas stream may also contain methane and other light hydrocarbons that exsolved from the residual oil. Without clarity on the remaining 60 % of the gas's composition, it's difficult to conclude that the hydrogen holy grail has been achieved. While the question was posed to Gold H_2, it went unanswered. The company chose to remove the question and close the comment section instead. ■

Mariël Reitsma, HRH Geology

Nodding Donkey in San Joaquin Basin, USA.

PHOTOGTAPHY: ZENSTRATUS VIA ADOBE STOCK

TECHNOLOGY

"The seismic velocities that can now be calculated through FWI are really at the basis of our workflow. Now that we are there, we have expanded our toolbox to such an extent that we will be able to use the data itself rather than analogues to inform ourselves about the field-wide variation in porosity, permeability and water-saturation"

Rafael Sandrea – ExploroilgasAI

"FWI has changed the game"

A conversation with Rafael Sandrea, who has co-developed a new tool to obtain porosity, permeability and water saturation directly from seismic data

"I'M A PETROLEUM ENGINEER, but I've been in the exploration and seismic business since the 1970s," says Rafael when we meet on Teams a week before the IMAGE Conference in Houston.

"We were one of the first to digitise analogue seismic, not by tracing the reflections, but by using a military fax – a game-changing device at the time. Then I was involved in setting up a seismic processing centre with Shell in Venezuela, which took up a few years of my career. However, when 3D seismic arrived, the computer power to process the data increased so dramatically that I could not afford the workstations required for it."

"I had seen so many reports from investors marketing a prospect, but hardly ever was there any technical detail on the three parameters that ultimately determine the economic value of a discovery: porosity, permeability and water saturation"

Then, Rafael got more involved with investing in oil and gas exploration, which ultimately triggered the idea that led to the business venture he is now part of: XploroilgasAI.

"I had seen so many reports from investors marketing a prospect, but hardly ever was there any technical detail on the three parameters that ultimately determine the economic value of a discovery: Porosity, permeability and water saturation," Rafael says. "These are the parameters that determine the size, production potential and production (income) profile of the prospect."

"The seismic velocities that can now be calculated through FWI are really at the basis of our workflow. Now that we are there, we have expanded our toolbox to such an extent that we will be able to use the data itself rather than analogues to inform ourselves about the field-wide variation in porosity, permeability and water-saturation"

Rafael Sandrea

"The industry is used to AVO analysis," continues Rafael, "but the problem with AVO is that it is mostly used for gas in siliciclastic reservoirs. The methodology has not proven to be very effective when it comes to oil, and neither for carbonates." Rafael adds that their technology, which relies on seismic velocities, can be applied across the spectrum of different reservoirs and applies to both oil and gas.

Then, I ask Rafael about the aspect of non-uniqueness – alluding to the observation that the same AVO signal can be explained by different combinations of porosity and gas saturation. How does the same phenomenon impact the results of his analysis? "We've got solid correlations between Vp and porosity for oil, which we have obtained by looking at more than 150 fields and over 140 of lab-generated cores," says Rafael. "Vp values below 10,000 f/s are a strong indicator of gas accumulations. Other fluids like unconventional heavy oils also have low Vp values but geologic logic clarifies this duality."

"We are currently working on the Wilcox play in the Gulf of Mexico, where we can now extract porosity, permeability and water saturation from any location in the dataset we've got," continues Rafael.

"The seismic velocities that can now be calculated through FWI are really at the basis of our workflow," Rafael concludes. "The maths have been around for decades, but we simply lacked the computing power to come up with satisfying results. Now that we are there, we have expanded our toolbox to such an extent that we will be able to use the data itself rather than analogues to inform ourselves about the field-wide variation in porosity, permeability and water-saturation. In turn, this will translate into a much better handle in the investment risk that comes with putting your money on the table for an exploration well." ■

Henk Kombrink

PHOTOGRAPHY: RAFAEL SANDREA PRIVATE ARCHIVE

PETRONAS's digital gambit: Architecting an AI-powered E&P ecosystem

Turning data into energy with the power of AI

DAN AUSTIN, SEKAL

IN A STRATEGIC pivot that extends far beyond typical corporate upgrades, PETRONAS is executing a national data strategy designed to redefine Malaysia's position in the global energy landscape. The company is making a calculated, multi-billion-dollar bet that in the 21st century, digital supremacy is as valuable as geological assets. This ambitious strategy hinges on transforming the nation's vast hydrocarbon data into an intelligent, predictive, and monetizable asset through the aggressive application of Artificial Intelligence.

The strategic imperative is clear and has been articulated by the highest levels of leadership. President and Group CEO, Tan Sri Tengku Muhammad Taufik, has framed AI as an "indispensable foundational technology" necessary to navigate the complexities of the energy trilemma – the simultaneous challenge of ensuring security, affordability, and sustainability. This executive mandate provides the thrust for what is arguably one of the most comprehensive digital transformations in the industry today.

At the heart of this strategy lies the myPROdata platform, the digital gateway to Malaysia's upstream sector. PETRONAS is systematically evolving this platform from a conventional data repository into a sophisticated, AI-powered engine designed to de-risk investment and accelerate discovery. The roadmap is clear: MyPROdata 2.0, targeted for 2025, will feature Generative AI-powered semantic search for the Malaysia Bid Round, with the ultimate goal of an integrated database powered by "Agentic AI" capable of autonomously performing complex tasks like seismic interpretation and reservoir simulation by 2026.

To bring this vision to life, PETRONAS has assembled a formidable ecosystem of partners, each chosen to fulfill a specific role. Global tech giants like AWS and SLB are providing the foundational cloud and Generative AI infrastructure. On top of this sit domain specialists like Earth Science Analytics (ESA) and the "TriCipta AI" venture with Beicip-Franlab and AFED Digital, who are deploying targeted AI applications to solve high-value E&P problems. This digital layer is then connected to the physical world through automation partnerships with Velesto Drilling and NOV, aiming to translate digital insights into safer, more efficient drilling operations.

Underpinning this entire structure is a crucial investment in human capital through an alliance with FPT Corporation and Universiti Teknologi PETRONAS, ensuring a sustainable pipeline of local talent to power this digital future

This intricate ecosystem serves two primary strategic goals. First, to achieve "internal supremacy" by creating "advantaged barrels" – resources found faster and produced more economically and sustainably, and second, driving "external growth" through a transformative partnership with industrial software leaders.

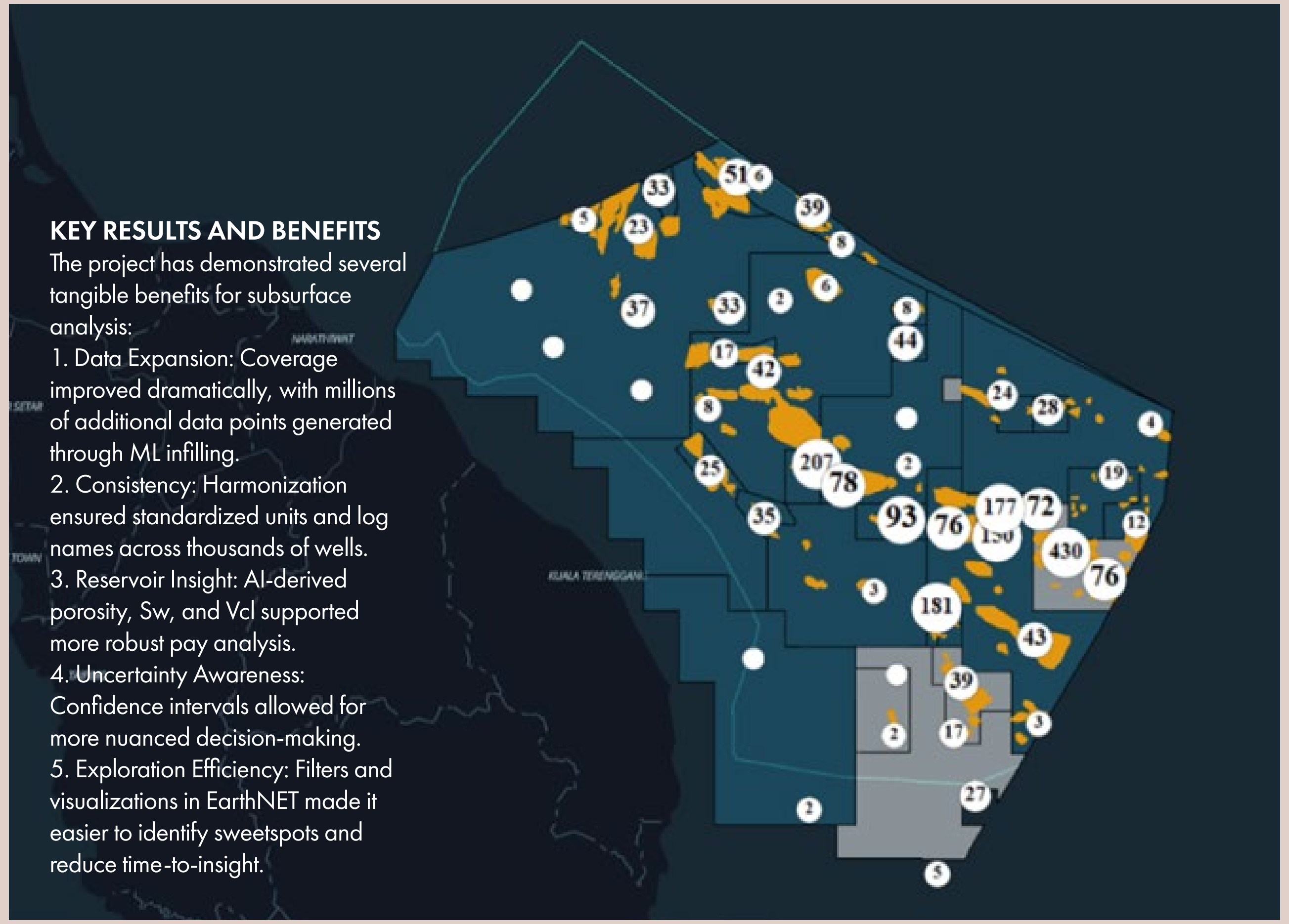
PETRONAS's strategy is a clear-eyed declaration that the future of energy will be won by those who can most effectively turn data into barrels. By building a competitive moat based on data, algorithms, and a world-class partner ecosystem, the company is not just securing its own future; it is aiming to redefine the technological benchmark for the entire region. ■

PETRONAS Twin Towers skyscrapers.

PHOTOGRAPHY: DAN AUSTIN

Harnessing AI-driven analytics for subsurface insights in East Coast Peninsular Malaysia

EARTH SCIENCE ANALYTICS



KEY RESULTS AND BENEFITS
The project has demonstrated several tangible benefits for subsurface analysis:
1. Data Expansion: Coverage improved dramatically, with millions of additional data points generated through ML infilling.
2. Consistency: Harmonization ensured standardized units and log names across thousands of wells.
3. Reservoir Insight: AI-derived porosity, Sw, and Vcl supported more robust pay analysis.
4. Uncertainty Awareness: Confidence intervals allowed for more nuanced decision-making.
5. Exploration Efficiency: Filters and visualizations in EarthNET made it easier to identify sweetspots and reduce time-to-insight.

The oil and gas industry is undergoing rapid digital transformation, and nowhere is this more apparent than in subsurface analysis. With the increasing complexity of geological data and the need for faster, more accurate decision-making, artificial intelligence (AI) and machine learning (ML) are becoming indispensable tools.

This article provides a comprehensive overview of a pioneering project conducted in collaboration with PETRONAS MPM, focusing on the integration of PETRONAS myPROdata with EarthNET for AI-powered geoscience and subsurface reservoir characterization. The project, executed in two tasks and multiple phases, demonstrates how digital technologies can expand data coverage, reduce uncertainty, and unlock new hydrocarbon opportunities in East Coast Peninsular Malaysia

THERESIA MARIA CITRANINGTYAS AND WILLIAM REID, EARTH SCIENCE ANALYTICS

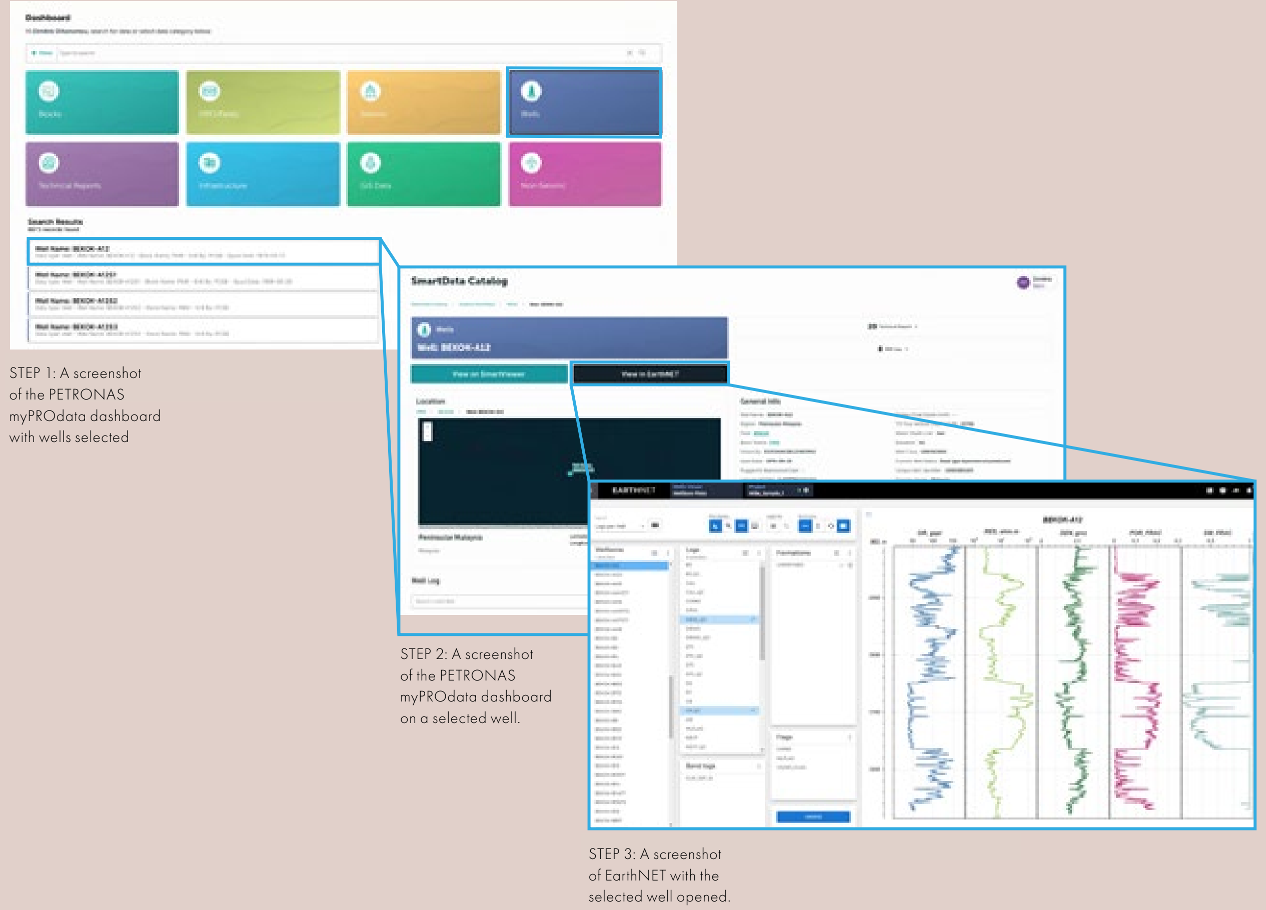


Figure 1: The 3-step process to visualize Logs on the fly directly in the PETRONAS myPROdata dashboard and visualized in EarthNET.

PROJECT STRUCTURE AND OBJECTIVES
The initiative was divided into two major tasks:

Task One – Integration of PETRONAS myPROdata with EarthNET
The objective was to enable seamless data integration and transfer between PETRONAS myPROdata repositories and EarthNET, ensuring that geoscientists could visualize, analyze, and interpret well and seismic data efficiently.

Task Two – Subsurface Analysis Using Machine Learning
This task focused on applying modern data management and AI-driven data analytics methods for well data harmonization, log infilling, and reservoir property prediction.
Phase One: Well-based analysis including ingestion, quality control, harmonization, and reservoir characterization of more than 2,000 wells.
Phase Two: Expansion from well-scale to seismic-scale interpretation, with AI-powered quantitative interpretation for elastic and reservoir properties.

PETRONAS MYPRODATA AND EARTHNET INTEGRATION
One of the primary challenges in subsurface exploration is ensuring that well and seismic data can be accessed, visualized, and analyzed in a seamless workflow. The integration between PETRONAS myPROdata dashboards and EarthNET addresses this by allowing geoscientists to select wells and seismic surveys within myPROdata, and then instantly visualize them in EarthNET's browser-based environment.

- **Well Data Access:** Wells can be selected directly in the PETRONAS myPROdata dashboard and visualized in EarthNET, with logs displayed on the fly (Figure 1).
- **Seismic Data Access:** Users can select seismic surveys from available datasets or through EarthNET's smart viewer, enabling quick visualization of seismic sections.
- **Pre-trained ML Models:** EarthNET provides results such as fault prediction using machine learning models, offering geoscientists immediate insights into structural interpretations.
- This streamlined workflow reduces the time between data selection and interpretation, ensuring that large datasets can be efficiently analyzed.

MACHINE LEARNING FOR SUBSURFACE ANALYSIS
PHASE ONE: WELL DATA INGESTION AND HARMONIZATION
The project began with the ingestion and harmonization of 2,200 wells, comprising ~1,600 development wells and ~550 exploration wells. Because the data originated from multiple sources with varying formats and units, significant effort was devoted to:

- **Data Harmonization:** Standardizing units, curve names, and metadata.
- **Quality Control (QC):** Identifying errors, cleaning logs, flagging inconsistent values, and removing duplicates.
- **Gap Identification:** Recognizing missing log intervals in key measurements such as sonic (DTC, DTS), density, neutron porosity, and reservoir properties (porosity, water saturation, and clay volume).

Once cleaned and standardized, the dataset was prepared for machine learning workflows to expand coverage.

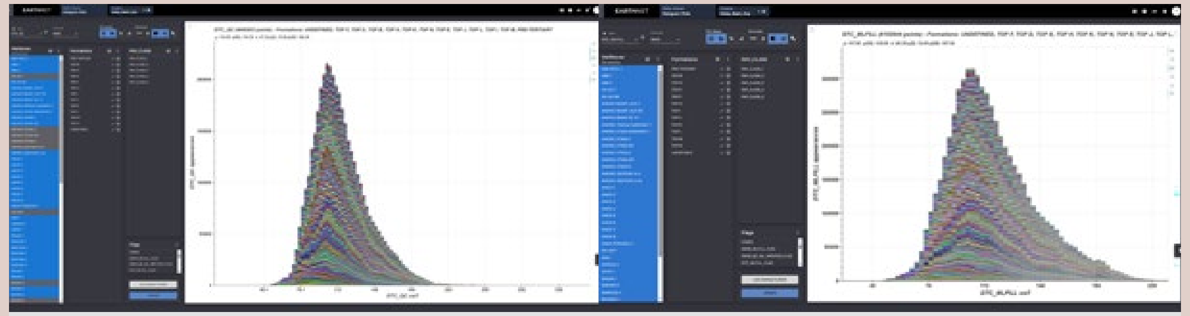


Figure 2: Histogram comparing initial (left) vs. post-cleaning (right) data availability.

LOG INFILLING USING MACHINE LEARNING

A central component of Phase One was supervised machine learning for log infilling. The goal was to fill gaps in well logs to increase coverage and reliability, enabling consistent reservoir characterization. The methodology involved:

- Training ML models on available logs using combinations of input features.
- Blind testing to select the best-performing models.
- Applying a prioritization framework (Figure 3).
- QCed measured logs were given the highest priority.
- Predictions from models using fewer features were of lower priority.
- Predictions from models with more features and better performance were of a higher priority.
- Generating infilled logs with traceability and uncertainty quantification.

This approach significantly expanded data coverage — for example, DTC (Figure 4) coverage improved from 57 % to 87 %, and density logs expanded from 4 million to 6 million data points.

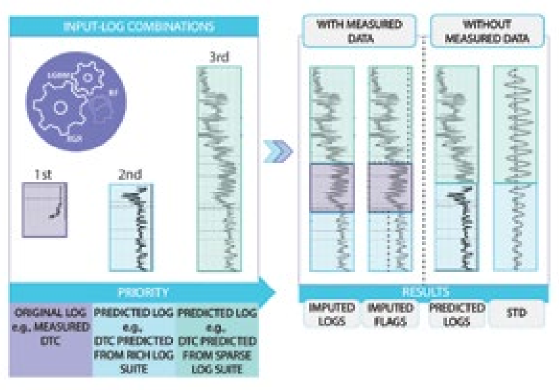


Figure 3: Example of prioritization hierarchy for log infilling.

RESERVOIR CHARACTERIZATION

With expanded log coverage, the project advanced into reservoir property prediction. ML models were used to derive key properties (Figures 5 and 6) such as:

- Porosity
- Water Saturation (Sw)
- Clay Volume (Vcl)

These properties enabled one-dimensional pay analysis and the classification of wells based on reservoir quality. Importantly, uncertainty quantification allowed geoscientists to differentiate between predictions with high confidence versus those requiring caution (Figures 5 and 6).

VISUALIZATION AND ANALYSIS IN EARTHNET

EarthNET provided powerful tools to visualize both measured and ML-predicted datasets:

1. Well Viewer (myPROdata module):
   - Bar plots showing cleaned vs. infilled logs.
   - Side-by-side comparison of wells.
2. Cross Plots:
   - Elastic property plots (e.g., AI vs. Vp/Vs).
   - Colored by uncertainty (standard deviation) or pay class, enabling quick identification of trends.

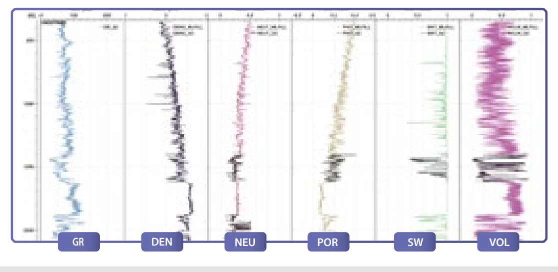


Figure 4: Before-and-after plots of DTC and density log coverage.

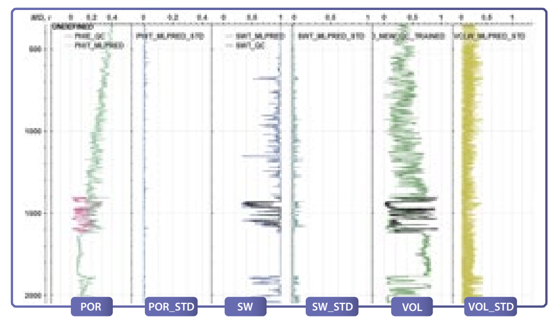


Figure 5: A standard deviation (uncertainty) curve illustrating confidence intervals.

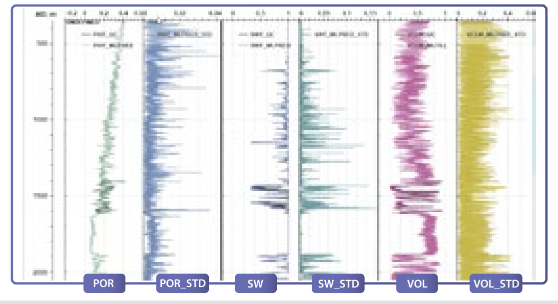


Figure 6: Well section plots showing measured vs. ML-predicted porosity and Sw.

3. Map Plots (Figure 8):
   - Spatial distribution of wells with filters applied (e.g., porosity >0.4, Sw <0.2, low uncertainty).
   - Ability to zoom into intervals of interest (e.g., 1,000–2,000 meters).
4. Pay Class Analysis (Figures 7 and 8):

These cut-offs were determined in close collaboration with PETRONAS MPM. Class 1 represents high-quality reservoirs (porosity > 0.4, Sw < 0.2), while subsequent classes represent progressively lower reservoir quality.

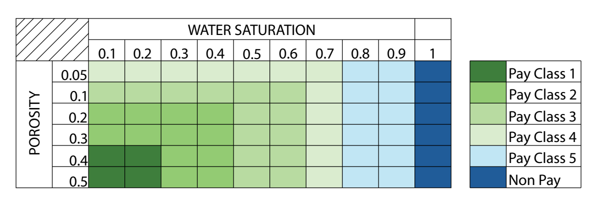


Figure 7: Reservoir properties predicted from the ML study were used to define five pay classes, based on different cut-offs.

This combination of predictive modelling and advanced visualization provides exploration teams with actionable insights at both well and basin scales.

TRACEABILITY AND UNCERTAINTY MANAGEMENT

One of the most critical outcomes of this project is the focus on traceability and uncertainty quantification. Each predicted interval can be traced back to:

- The machine learning model used.
- The features contributing to the prediction.
- The associated uncertainty (standard deviation).

This ensures that predictions are not "black boxes" but instead come with context, enabling geoscientists to judge their reliability. Such transparency is vital for building trust in AI-driven workflows in exploration and production.

Figure 8: Predicted hydrocarbon pay classes for a subset of exploration wells in the study area.

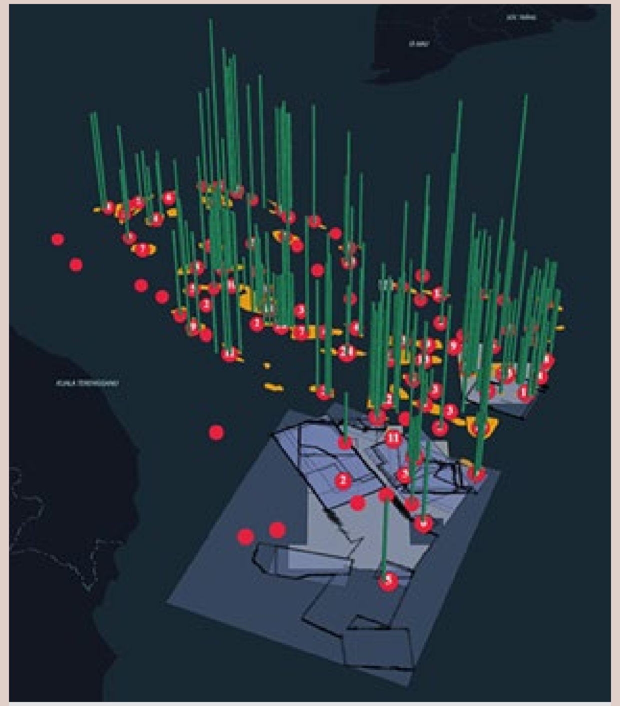


Figure 9: Example of a map of exploration wells filtered by porosity and water saturation. Bar chart of pay class distribution across wells.

TURNING DATA INTO DISCOVERY

By integrating PETRONAS myPROdata with EarthNET and applying AI-driven subsurface analysis, this project has shown how machine learning can transform traditional workflows. From harmonizing thousands of wells to predicting missing logs and quantifying reservoir properties, the approach significantly accelerates exploration while maintaining rigor and transparency. Ultimately, the initiative demonstrates that AI is not just a tool for automation, but a partner in discovery — helping turn well data into the next hydrocarbon opportunity in East Coast Peninsular Malaysia.

Interested in accessing our AI-powered East Coast Peninsular Malaysia results?
Contact us: contact@earthanalytics.no

Quantifying the hydrogen-generation potential of iron-bearing rocks

The makers of the Rock Eval machine have developed a first prototype of a device to analyse the hydrogen potential of basement rocks

EVERYONE working in basin modelling and geochemistry knows what Rock Eval machines do; they provide data on how much organic carbon is in a source rock sample, how much has already been generated, and what the remaining potential is.

But the world is moving beyond oil, at least that's the plan, and the developers of the Rock Eval machines are aware of that. For that reason, they have now built a machine that is capable of measuring the hydrogen-generating potential of iron-bearing minerals.

To achieve this, the team, which is deeply rooted in organic geochemistry, first developed a method to obtain hydrogen data from organic source rocks. I met with Nicolas Bouton from Vinci Technologies at the Image Conference in Houston to learn more.

"Our story starts in the south of France," says Nicolas, "at an old coal mine tailing."

PHOTOGRAPHY: ISABELLE MORETTI

Dan Levy measuring gases, among them hydrogen, on a burning old coal mine tailing in the south of France.

"Isabelle Moretti, who used to be ENGIE's Technical Officer and who started promoting hydrogen even before it became a hype, collected some coal fragments from the tailings, thinking that the maturation of coal should also generate hydrogen."

And she was right; the Vinci Technologies team managed to fit a hydrogen detector on one of their Rock Eval machines and was able to measure the hydrogen generated as the coal fragments were heated up.

> "Having a machine that helps calculate the generative potential of a mass of rock brings us closer to putting a number on a 'prospect', which is where we need to go"

"However," Nicolas added, "the temperatures at which the hydrogen is generated are very high, with a Tpeak around 800° C, at 25° C/min. If we would extrapolate that to the field, there are not that many places in the world where one could expect coal at reachable depths where these conditions are met."

"There are two places where this could be an option," he continues, "Australia and China, but even there, the economics are probably unfavourable for large-scale drilling that would be required to get the hydrogen out. If it hasn't migrated away."

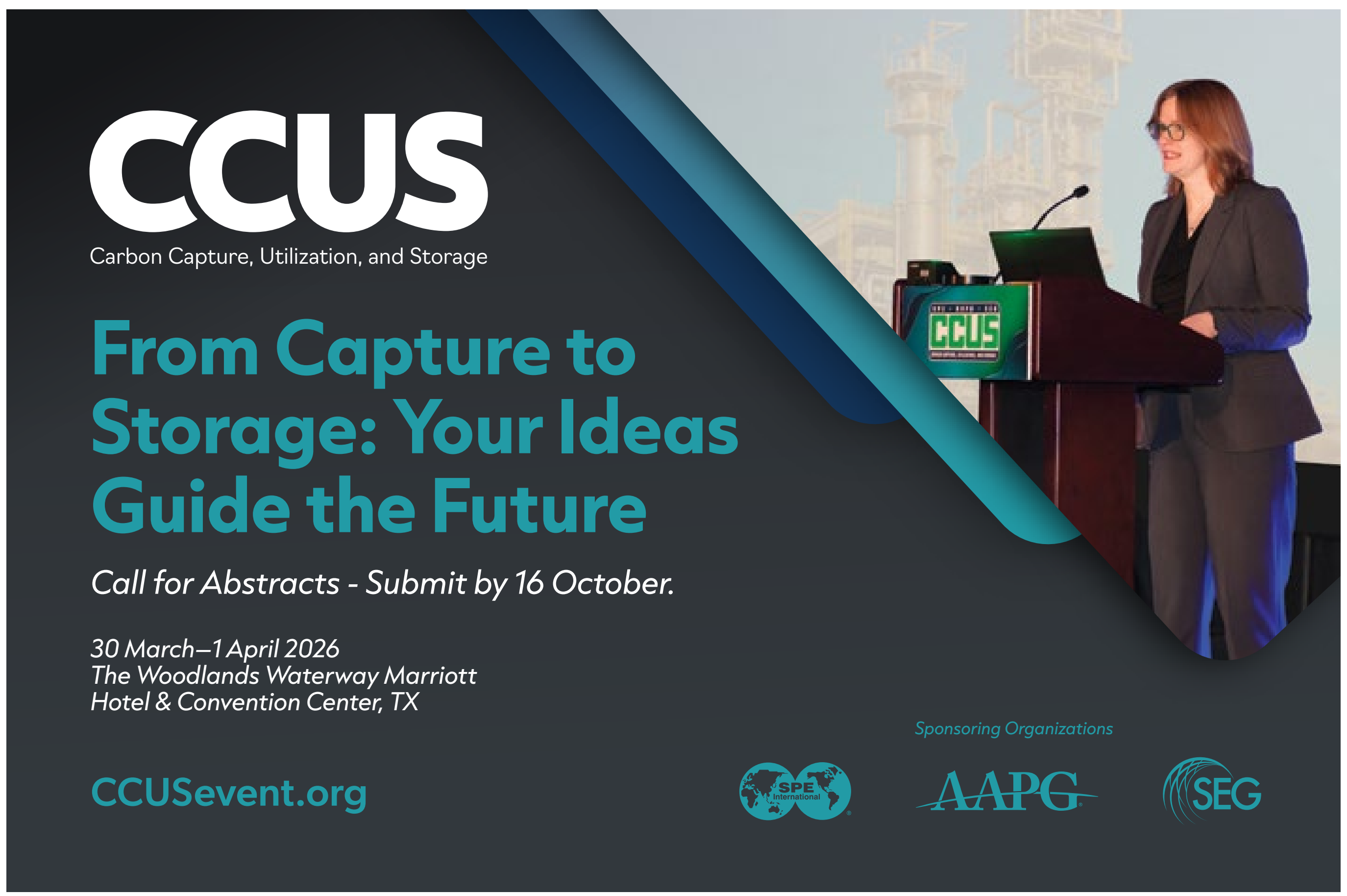
Then, the team realised that iron-bearing minerals, such as those found in ophiolites, are a better candidate for analysis. Interaction with groundwater makes these rocks produce hydrogen, which is currently being produced in places like Mali, and at relatively shallow depths of less than a kilometre.

"So, we started collecting samples and designed a machine that enables the throughflow of water," says Nicolas. "That was the biggest change we had to implement to set into motion the process that also happens in the subsurface. But we succeeded, we captured the hydrogen peak, and we patented the process," he says. "It was a great moment."

"We are not there yet," concludes Nicolas. "We are now entering into a Joint Industry project to translate the findings in the lab to what happens in the field, where these reactions take place at lower temperatures."

"And we need to deliver," he says, "because explorers are watching with interest. Having a machine that helps calculate the generative potential of a mass of rock brings us closer to putting a number on a 'prospect', which is where we need to go." ■

Henk Kombrink



INSIGHTS

"...it is the hydrocarbon properties or PVT data from already drilled exploration wells in a basin that form the critical piece of the puzzle"

Lukasz Krawczynski and Martin Neumaier

Pasties, piskies, pegmatites… and Pliny

A Prythian journey of Geo-energy and Geo-resources: Past and present

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

Britain has strong, quiet, ancient communities on its further reaches: Norse Shetland, Gaelic and Doric Scotland, Wales, the Isle of Man, and Cornwall at the southwest tip. All connected by primeval, migratory and trading routes, and then onwards to their Irish, Breton, and Basque brethren.

This July, I was invited to assist in a project in Cornwall, currently (forgive me here) the hotbed of UK geothermal energy: Various projects, companies and government support.

I've always been unashamedly pro–Oil & Gas, never tempted to intentionally "pivot" to the energy transition. Yet, in recent years, I have worked on hydrogen, helium, gas storage, CCS, and wind farms, and now geothermal and lithium.

I flew into tiny Newquay from Zurich, puzzled as to why such a flight existed: Cornish surfers requiring secretive banking? Cuckoo-clock artisans needing to de-stress on windy beaches? The approach across the Cornish peninsula revealed the swatch-chart of flooded pools of St Austell: Turquoise and teal, celadon and cornflower. Remnants of Cornwall's world-class geo-resource China-clay… or to you and me, kaolinite.

St Austell lies above the vast Upper Carboniferous (c. 280 Ma) Cornubian granite batholith. Biotite, tourmaline and lithium (zinnwaldite) rich compositions, fine-grained to pegmatitic. Hydrothermal greisenisation turning hard rock into a friable, easily quarried matrix containing the prized, fine-grained kaolinite.

Zinnwaldite takes its name from the German town Zinnwald-Georgenfeld: "Zinn" is German for tin. The adjacent Czech town is Cínovec: "Cín" is Czech for tin. Tin was the ore, and tin-mining the industry, that made Cornwall a global heavyweight in the 18th and 19th centuries.


Wheal Owles Mine, Botallack, near St Just on the Cornwall coast.

However, Cornish tin mining and trade reach back to the Bronze Age. Pliny the Elder (23–79 CE) refers to the *Cassiterides*, the "tin islands," from the Greek kassiteros. Previously, the Greek explorer Pytheas of Massalia (c. 350 BCE) had visited Britain and described its tin and lead trade. Those Celtic routes allowed Cornish tin to be traded right across Europe, and we may rightfully dream that it was used in the bronze armour of Perseus, Patroclus, Paris and Priam.

Each day, our lunch, as for bygone miners, was a Cornish pasty: Shortcrust pastry filled with diced beef, potatoes, swede, and onions. The characteristic crimp allowed miners to hold an entire meal – or Cornish *croust* – with hands ingrained with mud, filth, and metal ore.

We Celts are a superstitious bunch, embodying every aspect of nature with the supernatural, from anemones to zephyrs. A delightful folkloric extension to such lunchtime practicality was that miners, to ensure good luck, tossed the last piece to appease the *piskies*, or more specifically, in the mines, the *knockers* or *bucca-boos*. These small goblinesques lived underground and may benevolently warn or malevolently mislead the miners. Mythological good luck? Or was tossing the final contaminated corner simply a way of avoiding potential poisoning?

Today, lithium-rich mica, in pegmatites or brines, offers Cornwall a new geo-resource, a resource standing on the shoulders of kaolinite and tin. The question is, will the new wave of miners be wise enough to continue to respect eldritch and primeval traditions and offer tribute to the Cornish piskies? ■

PHOTOGRAPHY: HELEN HOTSON VIA ADOBE STOCK

The human touch in reservoir modelling

"In reservoir simulation, software runs the models — but people make the difference," says Bastian Steffens from RFD

As our 30-minute conversation took place on a Tuesday morning early September, three emails arrived in Bastian's inbox. Three separate and unrelated enquiries from customers in Switzerland, Germany, and the UK. "The way we deal with these questions determines how we as a company perform, says Bastian, Lead Engineer at Rock Flow Dynamics. At the end of the day, it is people operating our software, and we cannot expect them to be experts to such an extent that they don't need any help at all."

"After all, the word 'service' must stand for something," Bastian notes with a smile. He pauses, then adds: "It's the personal support that defines us. But joking aside, in today's fast-paced environment where AI drives the agenda of press releases, with every release promising better and faster output, it is tempting to think that soon anyone will be able to report a company's petroleum reserves without any personal assistance. In addition, with an increasing volume of code available for free via platforms such as GitHub, you might argue that there is no business case anymore for those companies that sell software licences and employ dedicated support staff."

"In my experience, that's not the case, and it is that human factor that is key," says Bastian. "At the end of the day, the human factor is often missing when you download from GitHub. Researchers move on, bugs don't get fixed, and support is intermittent if it exists at all. It is easily forgotten that a simple personal email, a video call or even a coffee is often the essential ingredient to move things forward," says Bastian.

Bastian knows how it is to produce tools that so many researchers produce these days. "I spent a significant part of my PhD connecting different software packages such that I could run a workflow with the click of one button. However, it came with a significant time investment to make things work properly, and all the while, I realised that as soon as one of the software packages I had linked in my workflow would undergo an update, my codes would need fixing."

This is where tNavigator makes the difference. "In my daily working environment, I have a platform that brings together all the elements of reservoir model creation and simulation, taking away the need to build an API to link different modules," explains Bastian.

And when integration with existing tools is required, flexibility is built in. With our API, customers can connect their tools seamlessly, without the effort of building new links from scratch. This flexibility is essential. And then we come back to the human touch: "It is the way you facilitate integration that creates the credibility and ultimately the drive to want to work with you," Bastian concludes. ■

Henk Kombrink

PHOTOGRAPHY: RFD

Bastian Steffens presenting at a conference in London.

HOT SPOT

Wildcat activity in the Latin American Atlantic Margin

NVENTURES

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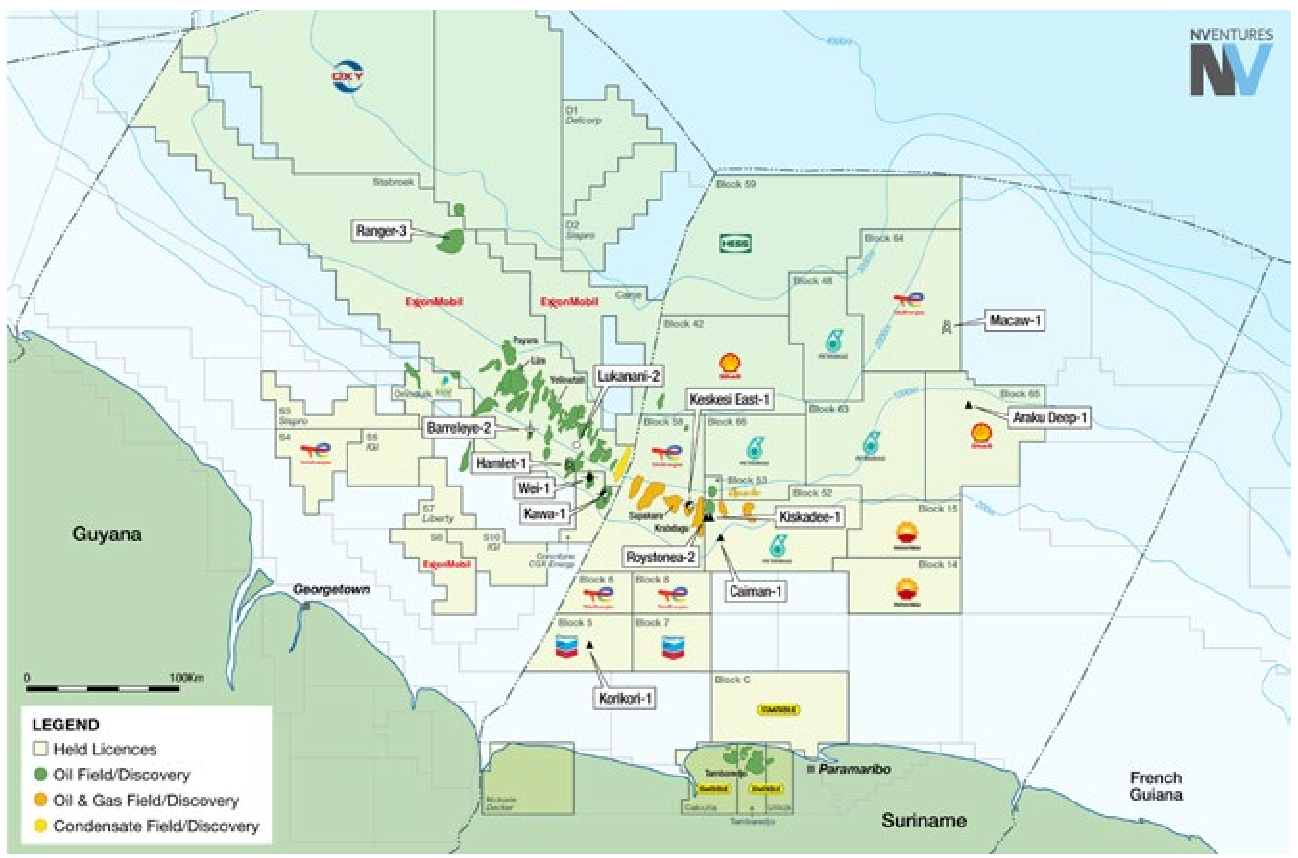
From updip the Golden Lane to Brazil's pre-salt, there is plenty of exploration activity to report on

ANDRES MESA, NVENTURES

ALL EYES are on the Stabroek Block, where ExxonMobil and its partners have embarked on a significant three-well drilling program. The campaign, which commenced in April 2025, includes the Hamlet-1, Barreleye-2, and Lukanani-2 wells. These targets are strategically positioned updip of the prolific "Golden Lane" trend, that is close to reaching 900 mbopd from 4 FPSOs. ExxonMobil appear to have started an appraisal campaign on Ranger, the deep-water Lower Cretaceous carbonate reservoir discovered in 2018.

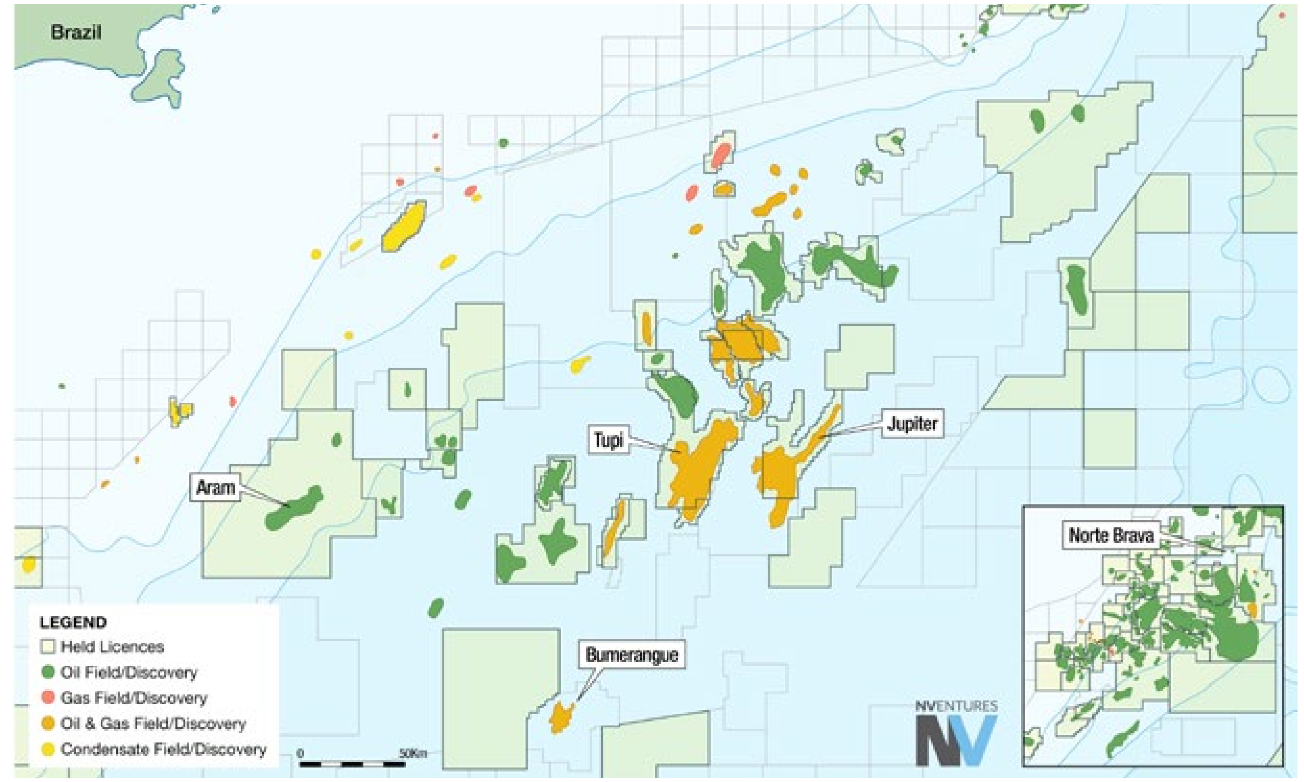
The Lukanani and Barreleye discoveries, announced in 2022, found 35 and 70 m of oil-bearing Maastrichtian sandstone, respectively, proving the presence of hydrocarbons in this structural position. The market awaits further data from the two appraisals, with no official information yet released, to gauge the full commercial potential of these updip accumulations. Ranger-1 reported 70 m net oil pay in Cretaceous carbonates, an ambitious target in these water depths (2,735 m).

This theme of commercial uncertainty in the structurally higher play did not go well for CGX's operations on the Corentyne Block. The company's Kawa-1 (2022) and Wei-1 (2023) wells encountered 61 m and a combined 99 m of oil-bearing Upper Cretaceous sandstones, respectively. Despite these technically successful discoveries, CGX faced challenges in securing a development partner, with the market perceiving risks regarding its commercial viability. Both the government and the operator are vigorously pursuing further plans for this acreage in Q3 2025.



Guyana-Suriname wildcat map.

SOURCE: NVENTURES



Santos Basin wildcat map.

SURINAME: EXTENSION AND NEW PLAY OPENERS

Exploration activity in Suriname waters is equally dynamic, characterised by a mix of appraisal drilling and bold frontier tests. Following the November 2023 Roystonea-1 discovery in Block 52, which encountered pay in Campanian sandstones, operator PETRONAS is set to appraise it with the Roystonea-2 well in a campaign that has now started and will go until 2026 with two additional wildcat wells. One of those, Caiman-1, will be crucially drilled approximately 25 km to the south of Roystonea, targeting the updip extension of the Upper Cretaceous play.

Meanwhile, a highly anticipated frontier test is underway in deepwater on the Demerara high. The TotalEnergies-operated Macaw-1 well in Block 58, alongside Shell's Araku Deep-1 well, are targeting a new play concept for the region: Aptian carbonates on the Demerara Plateau. This daring move aims to test a northern migration pathway from the main kitchen, which would untap a whole new region to explore. Whilst the Lower Cretaceous has proven hydrocarbon bearing at the Keskesi East 1 well (APA, 2020), these targets are deep and challenging, and the Demerara carbonate play is a major new play test. Success may draw the explorer's eye across the Atlantic to the Guinea Plateau, once conjugate with this play.

BRAZILIAN PRE-SALT: DISCOVERIES AND LINGERING CHALLENGES

Shifting focus south, the Brazilian pre-salt continues to yield significant discoveries, though not without its challenges. bp announced a major find at the Bumerangue prospect in the Santos Basin, approximately 25 km south of the giant Tupi field (Petrobras). The well encountered an impressive column of around 500 m of oil-bearing carbonate reservoirs, with estimates suggesting an in-place volume of approximately 2.5 bboe.

However, the commerciality of such discoveries in this region of the basin remains a key question. The area is known for significant CO_2 content, which can complicate development and increase costs. The giant Jupiter field (Petrobras and Galp), holding an estimated 1.6 bboe and 17 TCF of gas, has remained undeveloped for precisely this reason. bp's assessment on the content of CO_2 will be crucial to unlocking the value of Bumerangue.

In other announcements, Petrobras reported discoveries at Norte Brava (1-BRSA-1394-SPS) in the Campos Basin and Aram (1-BRSA-1395-SPS) block in the Santos Basin. While both affirm the continued potential of the pre-salt, the state-owned operator has yet to release details on net pay or resource estimates.

A REGION FOR THE FUTURE

The Latin America Atlantic Margin remains a powerhouse of global exploration. From the meticulous updip appraisal in Guyana to the play-opening gambits in Suriname and the ongoing, complex evaluation of Brazil's pre-salt, the results from these campaigns will set the tone for investment and strategy in the region for years to come. ■

Porosity in compressional stress regimes

Why basin models sometimes overestimate porosity

DAVID RAJMON, GEOSOPHIX

POROSITY prediction sits at the heart of basin models and prospect evaluation. It underpins our understanding of reservoir quality, pore pressure, and thermal history. Traditionally, porosity has been modelled as a function of burial depth, using compaction curves and vertical effective stress (VES) derived from the overburden load minus pore pressure. This approach has proven reliable in passive margins and extensional settings.

But when explorers drill into fold and thrust belts or accretionary wedges, some may be surprised that sandstones show significantly lower porosities than predicted. The reason lies in lateral stress. In compressional and strike-slip tectonic regimes, lateral stresses rival or exceed vertical stress. Under such conditions, sediments do not just compact under the weight of the overburden – they are squeezed laterally and sheared as well.

A partial analogy illustrates this effect. Imagine filling a jar with flour. Under its own weight, the flour settles to a certain level. Now tap the jar sharply from the side: The grains rearrange, and the flour settles further. Similarly, laterally stressed and sheared sediments compact beyond what vertical loading alone would predict. In geological settings, grains may also fracture, leading to further compaction.

This has been observed in the Orange basin, Appalachian thrust and Nankai accretionary wedge. For instance, at the Nankai wedge, sediments above the basal detachment show 6 – 8 % lower porosity than equivalent normally compacted sediments ahead of the deformation front. Another example is fault rocks and compaction bands in the vicinity of reverse faults.

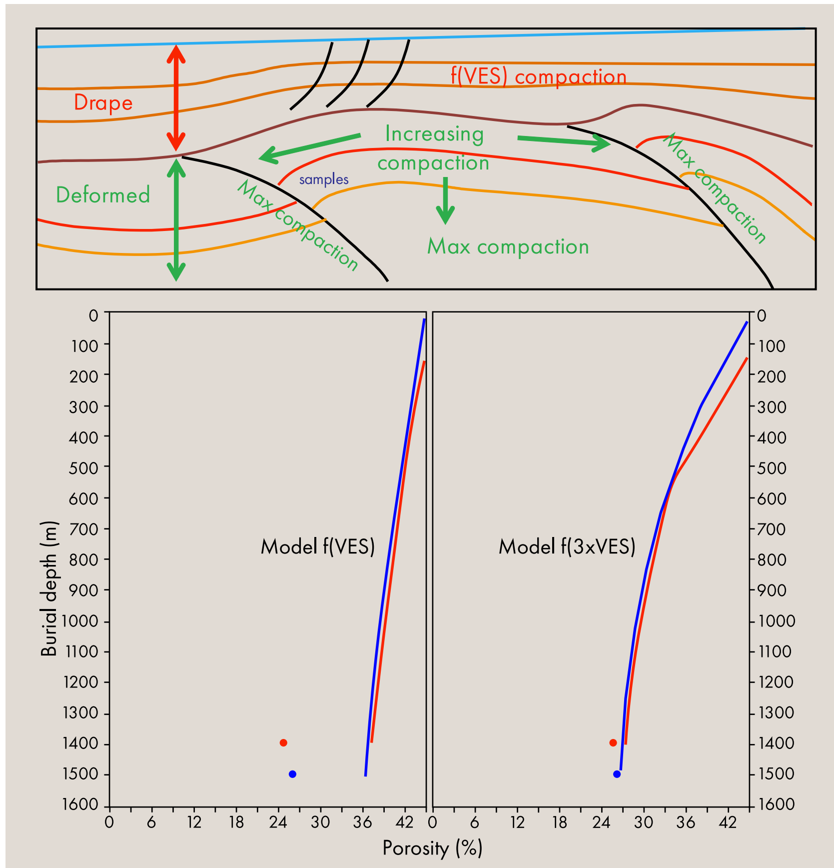


FIGURE: MODIFIED AFTER D. RAJMON AND L. HATHON, 2014

From a modelling perspective, this is a challenge. Basin models calculate compaction from VES alone. To bridge this gap, one has to consider an "equivalent mean effective stress" (EMES) that reflects all principal stress components. Applied to sandstones in NW Borneo, replacing VES with EMES, effectively increasing stress by a factor of 2 – 3, produced porosity predictions consistent with measured values.

This workaround has practical implications. While current basin modelling tools cannot explicitly simulate lateral shortening, explorationists can approximate the effect by adjusting lithology parameters or scaling VES in compressive and shear settings. The effect is strongest on the thrust fault and decreases with distance from the fault.

On a reservoir scale, properties of faulted rocks are routinely considered, but the fault effect in the adjacent rocks is also important. The compression/shear effect in the bulk rock volume is likely limited near regular reverse faults due to small fault movements (compared to thrust faults), but it can be localized in compaction bands where porosity can drop significantly.

The message is clear: When assessing prospects in compressional regimes, porosity predictions must account for lateral stress. Ignoring it leads to overestimating reservoir quality. ■

Hydrocarbon and seal properties are key

Better predicting the hydrocarbon phase of a prospect or in a basin as a whole requires more than knowing about the source rock and its maturity

LUKASZ KRAWCZYNSKI AND MARTIN NEUMAIER

MOST COMMONLY, Petroleum Systems Analysis (PSA) studies tend to focus on source rock distribution, its quality, and the thermal regime of the basin to then model migration pathways and the associated hydrocarbon phase. This is also sometimes referred to as "Bottom-up" PSA, which predominantly depends on large uncertainties in the basin centres, away from well and data control.

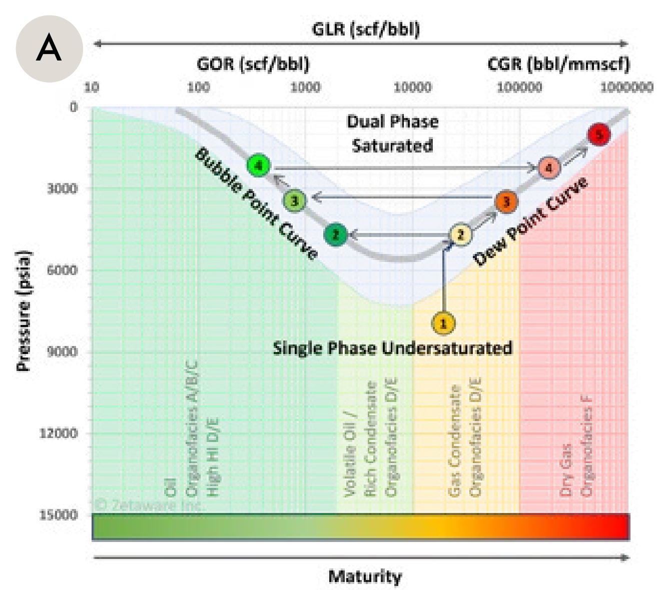
However, this methodology can fall short when it comes to predicting the hydrocarbon phase of prospects. As demonstrated by Zhiyong He, the variations in hydrocarbon properties such as phase, API and gas-to-liquids ratio (GLR) across a migration pathway are not necessarily related to maturity or local variations in source rock properties, but can be entirely explained by seal capacity.

In the example shown here, all the hydrocarbons of very different composition have originated from the same expelled gas condensate. As the gas condensate reaches saturation pressure, oil begins to fractionate out. If the seal is compromised, excess gas leaks off vertically, leaving behind an underfilled oil accumulation.

On the other hand, a competent seal allows for a gas column to accumulate, which displaces the oil leg updip, leaving behind a fill to spill gas accumulation. As such, the occurrence of a filled-to-spill oil field only or a mixed phase accumulation is very unlikely. At the same time, it is those overoptimistic scenarios that are often assumed in prospect assessments.

As this example shows, it is the hydrocarbon properties or PVT (pressure, volume, temperature) data from already drilled exploration wells in a basin that form the critical piece of the puzzle. This type of data tends to be neglected in "Bottom-up" studies, and we therefore make a case for what we call a "Top Down" approach to be applied in PSA at the same time as the study of source rock generation over time.

Both the "Bottom-up" as well as the "Top Down" approaches enrich the understanding from opposite directions, and ideally result in consistent predictions of the exploration risk. "Top-down" thinking must not only be integrated into any regional PSA study, but also into the prospect resource assessment, where a proper evaluation of the relationship between the PVT data and seal properties at the trap allows making probabilistic assumptions about the hydrocarbon phase and resource volume uncertainty ranges. ■



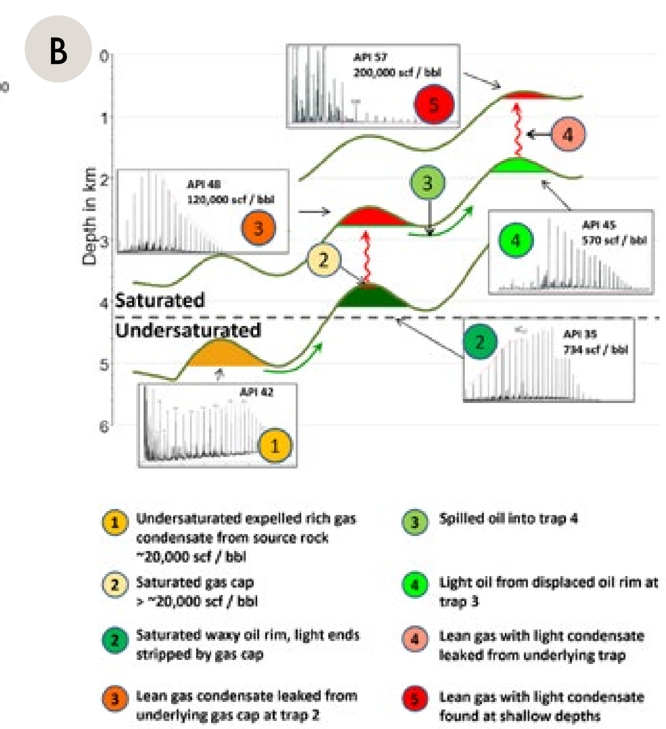


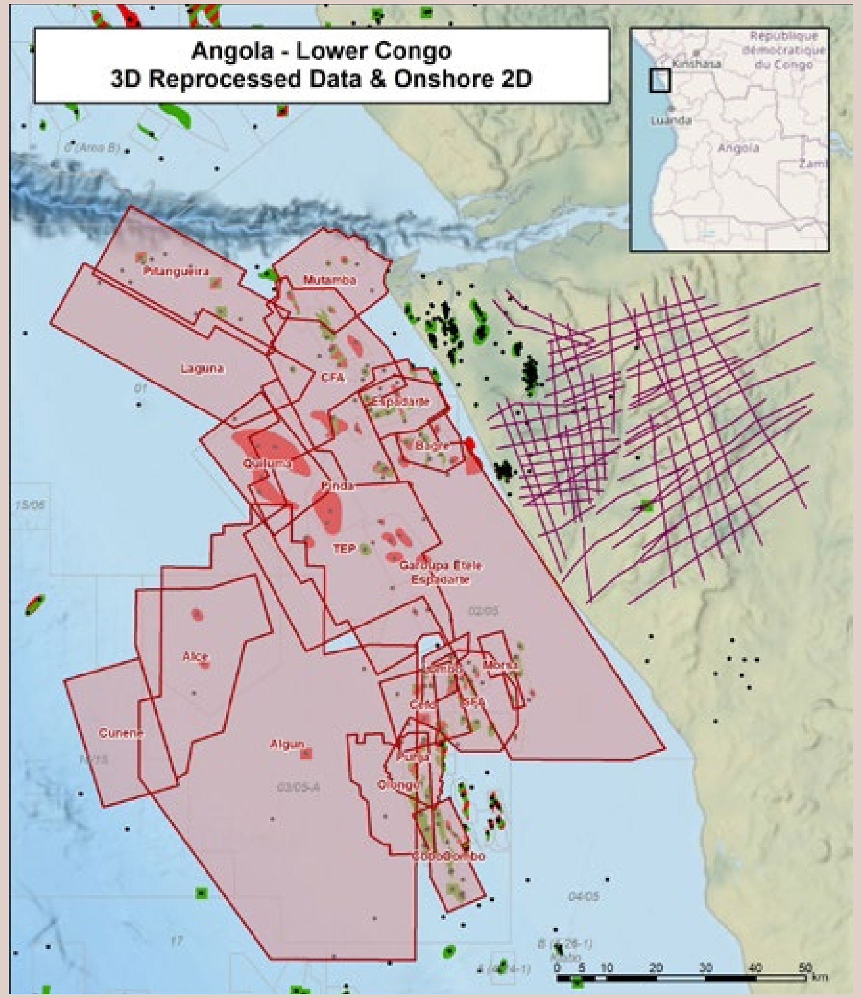
Figure 1: Impact of the relationship between PVT data and seal properties on the hydrocarbon phase at the trap. A) Phase diagram, B) Generic migration pathway.

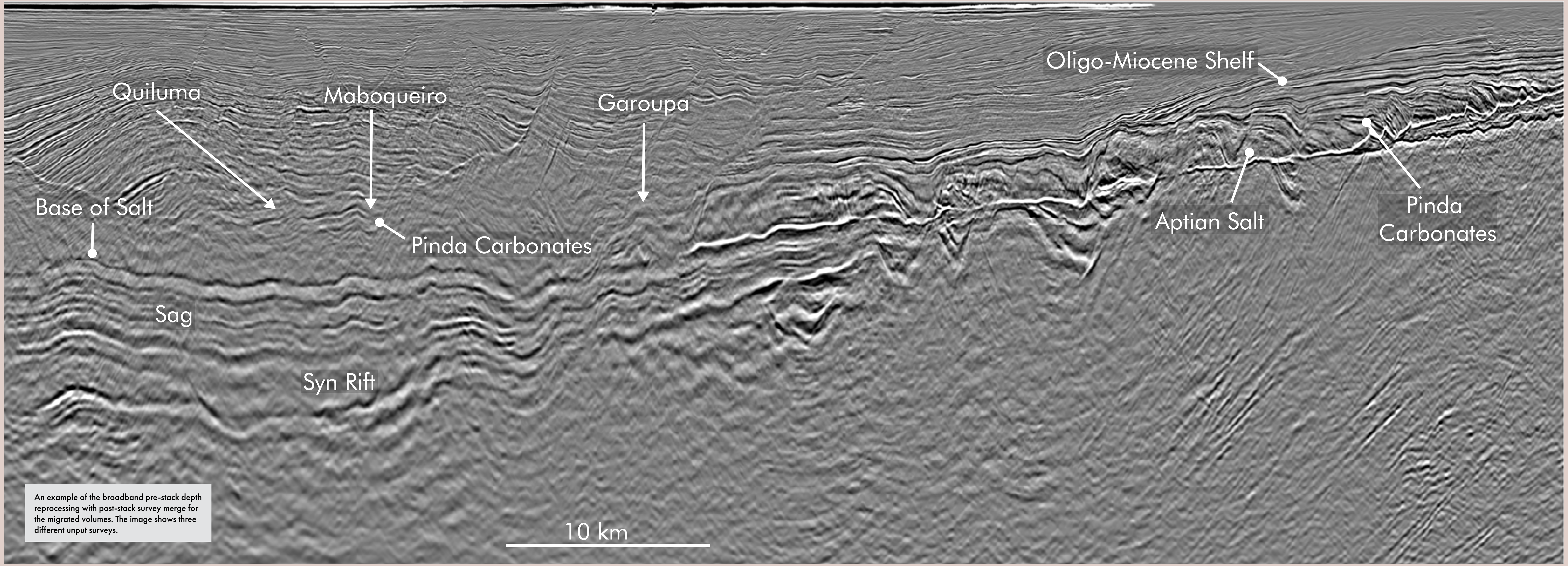
SOURCE: MODIFIED AFTER HE, Z., 2020

The New Gas Consortium: Angola's first non-associated gas project

The Lower Congo Basin of northern Angola currently produces a little over 1 MB of oil and 2,700 mmscf of gas per day; however, the gas produced is all associated gas, being the by-product of oil production. Despite a hydrocarbon industry with a 110-year history, none of the discovered gas fields have yet been developed.

That is set to change with imminent production from Angola's first non-associated gas project, the New Gas Consortium (known as the NGC). This project is set to develop gas fields discovered over 50 years ago, with production due to commence in early 2026, adding 350 mmscf/d to the country's gas production by 2028.





An example of the broadband pre-stack depth reprocessing with post-stack survey merge for the migrated volumes. The image shows three different unput surveys.

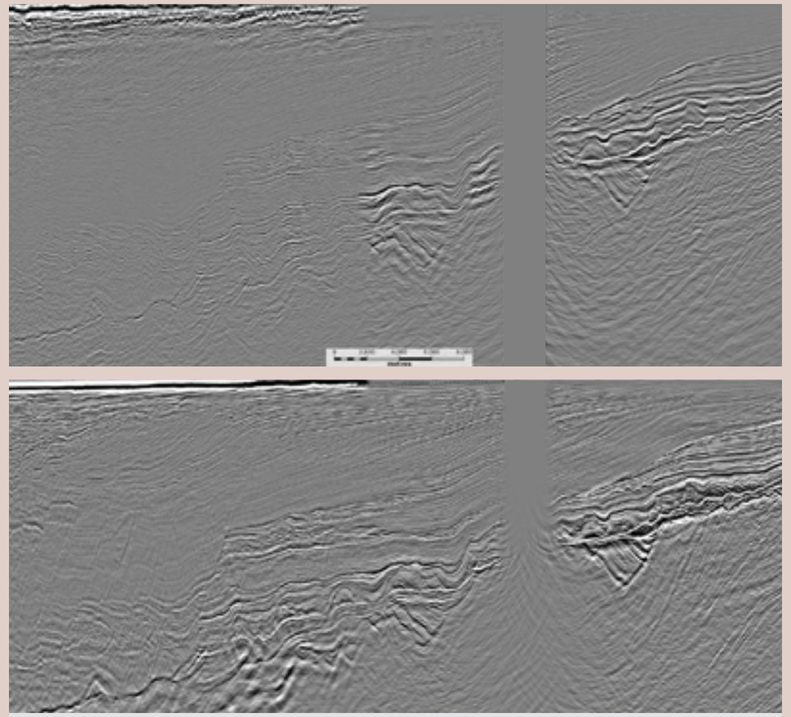
How broadband pre-stack depth reprocessing, with a post-stack survey merge for the migrated OBC and streamer volumes, has enabled the development of 50-year-old gas fields

Multiclient reprocessing of recovered legacy 3D seismic datasets has re-imaged historic gas fields, providing reliable attributes for reservoir modelling and the location of appraisal and production wells. Both OBC and streamer data was reprocessed, with workflows tailored to each dataset and a velocity model derived from processed well data.

MATT TYRRELL, DDMS & TROIS, JAMES DODSON, GEOPARTNERS, AND EUNICE OLIVEIRA, ANPG

Exploration on the shallow water shelf of the Lower Congo Basin during the 1970s and 1980s discovered numerous fields containing oil and gas within the post-salt succession. Although several of the oil fields were developed, with oil production from Block 2 set to reach 40,000 bopd, from 17 fields, the discovered gas fields have lain undeveloped.

The largest of the gas fields are Quiluma and Garoupa, discovered in 1970 and 1981, respectively, and Maboqueiro, discovered in 1995. Despite significant gas volumes in place (Quiluma and Maboqueiro are estimated at 2,551 BCF of gas), companies were historically unable to commercialize these resources due to regulatory limitations as well as challenges related to resource density and market access. Consequentially, these gas fields have lain undeveloped for over 50 years.



Comparison of vintage and reprocessed seismic data through the shelfal area.

WHY ARE THE GAS FIELDS, DISCOVERED OVER 50 YEARS AGO, BEING DEVELOPED NOW?

With a desire to increase the country's hydrocarbon production headline figure, ANPG (the state body in charge of hydrocarbon supervision, regulation and promotional activities) has, in recent years, introduced legislative decrees to incentivise gas production. The most notable of these, in relation to gas, is Presidential Decree No. 7/18 of May 18, 2018, which established the framework for the rights related to natural gas. This decree, which governs its exploration, production, and sale, aims to attract investment and promote the development of the natural gas sector.

An outcome of this legislative change has been the formation of the New Gas Consortium (NGC), a collaboration between Azule Energy (ENI & BP JV), Sonangol Pesquisa e Produção, TotalEnergies and Cabinda Gulf Oil Company (Chevron), covering Angola's Blocks 1, 2 and 3 (as well as a small deeper water area named Block 15/14). This $2.4 billion project aims to share knowledge and risks, reduce costs and pool resources in such a way as to develop and produce the non-associated gas in a profitable way.

The first gas field to be developed within this consortium will be Quiluma, followed by Maboqueiro and Garoupa, with considerable potential to appraise and develop smaller, neighbouring gas fields in the future.

SEISMIC IMAGE LIMITATIONS ASSOCIATED WITH RETURNING TO THE HISTORIC GAS FIELDS

With the NGC formed, and large historic gas fields identified for appraisal and development, a notable challenge has been the availability and image quality of the vintage seismic data. Oil companies acquired some 19 3D seismic surveys over the blocks in the period from 1989 to 1998 (with a following phase of 3D surveys focused only on oil field development). Consequently, the discovered gas fields that are now to be developed by the NGC are imaged by 35-year-old 3D seismic data, tempering confidence in reservoir models and drilling decisions.

To overcome these data limitations, a multiclient data collection and broadband depth reprocessing project was undertaken on the OBC and Towed Streamer seismic data. Locating the field data and navigation data for these surveys took several years, with visits to oil company and regulator archives, a close collaboration between oil companies and ANPG was required to retrieve and catalogue the data. With so many mergers and acquisitions between interested oil companies over the 35 years, this process involved a fascinating delve into oil companies' historical data archives, together with the handling of some very dusty boxes of data tapes!

BROADBAND REPROCESSING TO RE-IMAGE THE GAS FIELDS

With the original seismic data finally retrieved, all surveys were able to be reprocessed from field tapes using a full integrity VTI pre-stack time imaging sequence and TTI anisotropic pre-stack depth imaging sequence.

The reprocessing of the two OBC surveys, acquired in 2008, used the hydrophone and geophone recordings in a P-Z summation centred workflow to suppress the receiver side multiples. This was followed by source-side deghosting and source-side multiple attenuation using SRME and Shallow Water SRME. The data were 5D COV regularised to ensure azimuthal information was preserved through the migration.

Streamer data reprocessing incorporated bespoke noise attenuation workflows for each survey, deterministic source and receiver deghosting, plus extensive 3D SW-SRME, traditional 3D SRME and 3D muted SRME multiple modelling combined with adaptive subtraction techniques. Significant coverage gaps were recovered through 4D regularisation passes, and diverse azimuth imprints were suppressed by robust acquisition footprint removal.

The velocity model building sequence, which incorporated environmentally corrected, processed and interpreted well data, included several passes of anisotropic tomography update. They utilised both RMO and First Break picks from all surveys in order to update the model covering the surveys. This was followed by multi-survey diving wave FWI that was run up to 12 Hz (3 dB down). Recorded shots from all surveys together with corresponding source signatures were used to simultaneously update the model. Kirchhoff pre-stack depth migration was used to image the data.

The applied velocity model building workflow included D-FWI, resulting in a reliable, seamless model that accurately represents the subsurface, capturing intricate details such as low-velocity gas pockets, ultra-low velocity regions, and sharp unconformity edges. Integrating this improved model with advanced data reprocessing techniques yielded significant enhancements in the broadband seismic image, resulting in improved structural and fault definition, better focusing, and overall clearer and more reliable imaging.

FUTURE OUTLOOK

The development of the Quiluma and Maboqueiro fields, which constitutes the first phase of the NGC project, consists of two offshore wellhead platforms, the construction of a new onshore gas processing plant at Kivinca Nvemba and also an upgrade of the existing Angola LNG plant at Soyo. With the offshore platforms now in place, first gas is expected from Quiluma in early 2026, with production from Maboqueiro expected later that year.

These projects are expected to increase Angola's production rates by 350 mmscf of gas a day, directly increasing Angola's LNG production and the availability of domestic gas for the country's industrial development.

The broadband reprocessed 3D seismic data has guided the placement of the recent appraisal well, and will also support the location of any additional production wells. Furthermore, it will provide a robust AVO response to allow rock physics models to be extrapolated in the data and will also provide a baseline survey for any future 4D monitor surveys.

Despite taking 55 years to come to fruition, it seems that the country's first non-associated gas development will help fuel the country's growth and development into the future.

Decoding slip with tension gashes

How simple observations from the rock face can tell something about an entire rift system

MOLLY TURKO, DEVON ENERGY

Tension gashes are fractures in rocks formed under extensional stress, often filled with minerals like quartz or calcite. These features are key kinematic indicators in structural geology, revealing fault slip direction and tectonic processes. By analyzing their orientation, shape, and arrangement, geologists gain insights into past tectonic events.

Formed in brittle or semi-brittle rocks, tension gashes appear as planar or lens-shaped fractures when extensional stress exceeds the rock's tensile strength. Often arranged in an en echelon array, they open perpendicular to the least principal stress (σ3) and are filled by minerals from hydrothermal fluids. They are closely associated with faulting, particularly in shear zones, where localized stress causes deformation.

Tension gashes indicating right-lateral slip sense in Marble Canyon, Death Valley National Park, USA.

The geometry and orientation of tension gashes make them valuable kinematic indicators. In a shear zone, the long axes of tension gashes are typically oriented at an angle (often 45°) to the shear plane. For example, under right-lateral slip, en echelon tension gashes are rotated clockwise relative to the fault plane, while under left-lateral slip, they rotate counterclockwise. This systematic arrangement allows geologists to deduce the sense of slip. The angle between the gashes and the fault plane, along with their sigmoidal or straight shapes, helps deduce the shear direction and magnitude.

Tension gashes also provide clues about the stress regime. In extensional settings, such as rift zones, they form perpendicular to the regional extension direction. In compressional settings, like thrust faults, they may develop in the hanging wall, indicating localized extension amidst overall compression. By mapping their distribution and measuring their orientations, geologists can reconstruct paleo-stress fields and fault kinematics.

For instance, in a shear zone, en echelon tension gashes may show progressive deformation. Early gashes may rotate during ongoing shear, forming sigmoidal shapes that record cumulative strain. Cross-cutting vein sets can indicate multiple deformation phases, aiding in reconstructing tectonic history.

In summary, tension gashes are vital for understanding fault kinematics and tectonic evolution. Their orientation, shape, and arrangement in shear zones provide direct evidence of slip sense, enabling geologists to unravel Earth's crustal dynamics through field observations and analytical techniques. ■

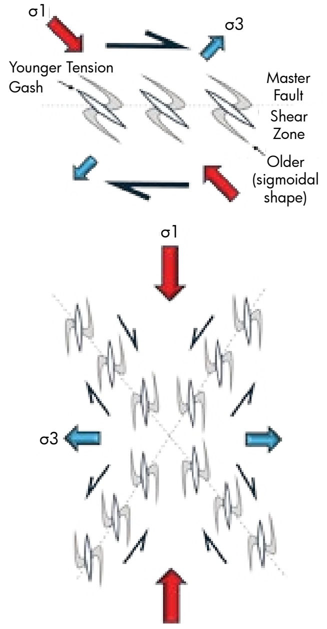


Diagram illustrating the relationship between tension gashes and principle stresses in a shear zone (top) and as conjugates (bottom).

Sponge clasts in calciturbidites

At the recent IMAGE Conference in Houston, somebody told me that the Permian Basin in Texas is not only famous for its hydrocarbon resources, but also because the uplifted areas surrounding it often allow detailed study of what is deeply buried a few miles further down the road. This photo from Guadalupe National Park shows an example of an outcrop that illustrates this beautifully. Here we see a small but neat section of the Capitan Formation, which is interpreted as an interval of lower slope calciturbidites shed off the rimmed carbonate platform that formed the shallow-marine margin of the basin in Permian times. The photo also shows that not every turbidite event resulted in a similar depositional sequence: Some are fine-grained throughout, such as the grey bed at the top of the photo, while others include a coarser fraction at their base, such as silicified sponge clasts mixed with shells.

Text : Henk Kombrink, Photography: Ali Jaffri, Applied Stratigraphix.

FEATURE YOUR OUTCROP

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

Dead oil traces in a lonely pebble bed

The beautiful core of well 73/14-1 documents a short spell of high-energy fluvial activity during a long period of calmer depositional settings

Where most exploration activity on the UK Continental Shelf took place in the North Sea, and later along the Atlantic Margin west of the Shetland Islands (WOS), it is good to remember that other areas also witnessed brief spells of drilling. The core featured here is from one of those "forgotten" areas that experienced a short period of rather intense activity; the Southwest Approaches, an area that aligns with the maritime boundary with France. In fact, the well is only located about 15 km from French waters.

According to the composite well log, the cores from this fairly coarse-grained interval belong to the so-called Bunter Pebble Bed. Very much resembling a fluvial depositional environment, given the organisation of (mud) clasts and trough cross-bedded sands, it is no surprise that the wellsite geologists named this interval after the well-known Bunter sands from the Southern North Sea, further to the east. But is it really the same as the Bunter?

Well, that will be difficult to prove based on a log signature alone, but the fact is that geologists have looked at this interval at a later stage and renamed it to the Sherwood Sandstone. This is a name that is frequently used for Lower Triassic sands in the Celtic Sea between the UK and Ireland, as well as onshore areas.

But regardless of the name of this coarse-grained thin unit, which is only about 25 m in thickness in this well, it makes you wonder what geological event caused the appearance of a coarse-grained fluvial system when the depositional environment both before and after is characterised by finer-grained floodplain and sabkha environments for such a long and seemingly uninterrupted time.

Then there is the dead oil comment in the margins of the composite well log. According to petroleum system analyses done in the area, it is the stratigraphically higher Lower Jurassic that is oil-prone in the area. It could be in a downfaulted position somewhere close to 73/14-1, possibly explaining some oil migration. But looking at the cores now, with no sign at all of any oil staining, the conclusion seems justified that this was a dry well.

Murphy Oil donated this core to North Sea Core, a small Community Interest Company I run in addition to editing this magazine. Murphy is one of the few names that were around in the UK in 1986, when 73/14-1 was drilled, and that is still around. Stan Stanbrook, who is a geologist at Murphy Oil and who has been instrumental in getting the core shipped back to the UK, wrote to me that he is currently looking at newly acquired core from a major discovery his company made in Vietnam. Core still rules. ■

Henk Kombrink

Cores from 73/14-1 in the SW Approaches.

PHOTOGRAPHY: HENK KOMBRINK

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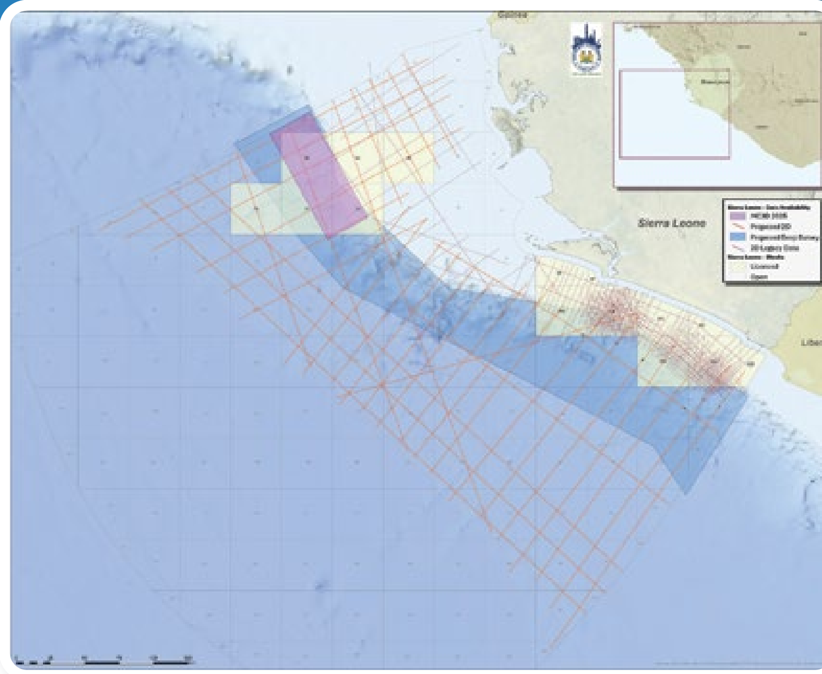
Offshore Sierra Leone

Geophysical Data



GeoPartners is proud to work in partnership with **the Petroleum Directorate of Sierra Leone (PDSL)** to promote the hydrocarbon prospectivity the country's offshore has to offer. Our surveys will comprise full coverage of the offshore area from shallow to ultradeep water, providing ties to all existing wells and allowing a complete evaluation of the available acreage. The existing and proposed data volumes comprise:

- A new 3D seismic survey of over 2800 sq. km targeting the prospects derived from regional interpretation in the northern offshore area. The survey completed acquisition in August 2025 and is currently being processed to provide high-resolution broadband imaging in both the time and depth domains. A fast-track volume will be ready by the end of September 2025.
- The brokerage of over 8000 km of legacy 2D data, covering the full extent of the offshore area and with particular emphasis on the prospective inshore areas in the south.
- A new 2D seismic campaign of over 7000 km targeting the deeper water shelf edge lays. Survey parameters will include using a single ultra-long cable, with a full suite of deliverables including PreSTM and PreSDM processed volumes.
- A new Seep Finding survey covering water depths between 750 and 3500m. This proposed survey of over 22,000 sq. km covers the entire deepwater area offshore and will involve the acquisition of Multi-Beam Echo Sounder data, selected piston cores and heat-flow measurements.

The continental margin of Sierra Leone developed during Cretaceous extension and early opening of the equatorial Atlantic. The shallow water shelf and deep-water basins define distinct hydrocarbon provinces, bisected by the Sierra Leone Transform Zone (SLTZ); a major strike-slip system associated with complex structures including rotated fault blocks and local inversion. Four out of five exploration wells drilled in the southern deep-water basin encountered light oil (34-42° API), condensate or gas in the Upper Cretaceous section. Reservoirs include stacked, high net / gross channelised turbidite sands, with good porosity, located in slope apron fan systems of the Cenomanian and Turonian. Interbedded marine shales are organic-rich, oil-prone and mature. Equivalent source / reservoir facies are prospective on the French Guiana conjugate margin (with the Zaedyus-1 well proving 72m net of oil pay in high quality Cenomanian and Turonian fan sands). Untested, large slope apron and basin floor fan plays are recognised on the Sierra Leone margin with potential mature sands sourced from the South American and West African margins. Thick sequences of Apto-Albian and Cenomanian fluvio-deltaic to marginal marine sandstones, proven by wells on the southern shelf, are interbedded with oil-prone lacustrine shales. This play could prove prospective on the broad, unexplored shelf north of the SLTZ.

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