THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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HOW VENEZUELA'S PREVIOUS OPENING BECAME AN EXIT FOR BP

Exploration Opportunities

Suriname's North West Sub-Basin: An extension to the Golden Lane

Most subsurface teams aren't making the most of their data

Moroccan Atlantic Margin: Where geological diversity meets outstanding exploration potential

GEO ExPro

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A fart in the wind

LAST YEAR, one of the most complex drilling projects in the world was (partially) completed in Geretsried, southern Germany. Eavor put into production what is supposed to be the first of four deep geothermal closed-loop systems. The remaining three will be drilled at the same location in the years to come. At least, that is the plan.

As can be expected, there was some attention from the press when the "radiator", because that is how it can be looked at, was switched on.

> **"Let's put our public money to work for other renewable baseload solutions"**

However, the most important bit of information was lacking from the press release. How much energy was this first system, which consists of six loops connected to two vertical boreholes, actually producing? It took some digging, but we got where we wanted. The output is a staggering 0,5 MWe, significantly lower than the pre-drill estimate.

What to make of this? Well, considering the huge costs of more than €350 M and the scientific evidence that closed-loop systems are poor performers in the first place, it is not too difficult to conclude that the economics of this project were questionable from the start.

A single offshore wind turbine already generates up to 15 MWe at capacity. The effort and investment required to generate 0.5 MWe of baseload energy is not worth it, in my view. My conclusion is that the Geretsried project is a fart in the wind. Let's put our public money to work for other renewable baseload solutions.

Henk Kombrink

BEHIND THE COVER

The year started with a flurry of news in which the subsurface played a prominent role. Greenland had been simmering for a while, but the lifting of Maduro from Venezuela came as a huge surprise to many. Immediately, questions around the rebuilding of oil infrastructure started circulating, which has been ongoing until today. But instead of putting in our two cents, we look back at the Apertura, the last time Venezuela opened its doors again to foreign oil companies. One of them was bp, and we tell the story of how they redeveloped Pedernales in the Orinoco delta. Not because it is THE example, but because it is AN example of how things can pan out. We talked to both local people and expats who worked on Pedernales and shared their fascinating stories. And thanks again to Lucía Pérez-Díaz for designing yet another beautiful and Venezuela-inspired front cover.

FIRSTS

"Game theory reminds us that in a connected subsurface, the smartest move is often the one that benefits everyone"

Rodney Garrard

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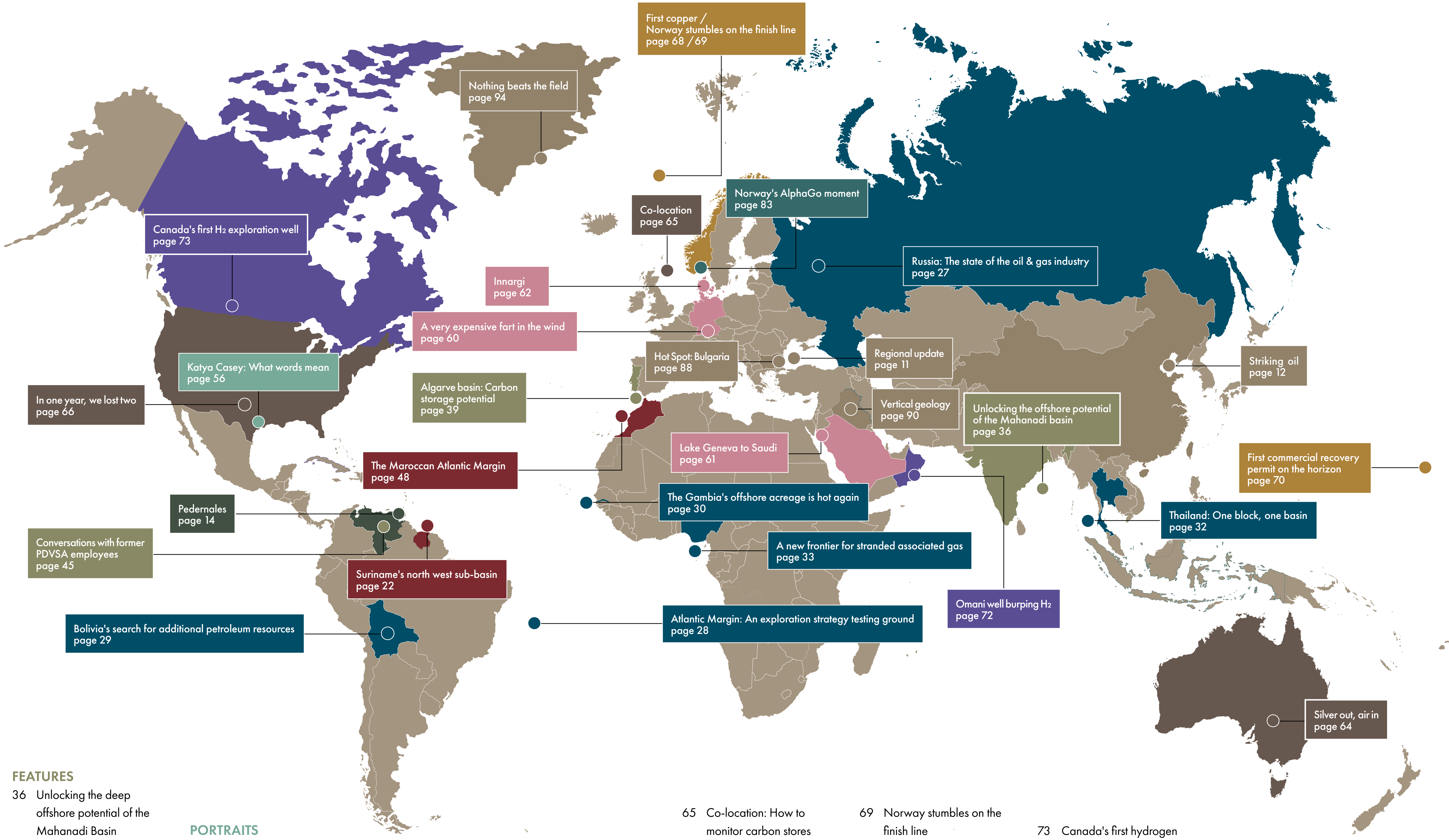

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CORING MUDSTONES

A wellsite geologist told me the other day that he was on one of the major oil platforms in the North Sea some years ago, drilling yet another development well. To his surprise, the operator had chosen to cut core, even though the reservoir was very well-known at that point in time, after decades of production. To make it even more interesting, coring was planned to take place in the immediate overburden. It turned out that the operator was carrying out a study to better understand the geomechanics of the overburden and how to land wells into the reservoir. Many holes turned out to have stability issues, and the direction of the wellbore could have something to do with that. It seems like the study paid off.

A BLOWOUT IN BANGLADESH

During a network session the other day, I met a driller who worked for a major operator in the 1980s. It was the time expats were sent from one place to another without much consideration for individual preferences. As such, the driller found himself assigned to a well in Bangladesh, in the southeast of the country. When he asked about the risk of shallow gas, his colleagues at headquarters told him there was no risk. He wasn't sure, though, and did some scouting around the place. By doing so, he soon found out that locals were using shallow gas for domestic purposes, clearly suggesting that his colleagues had missed something. And to make matters worse, a blowout even happened when drilling the well. Due to shallow gas. Fortunately, the well could be controlled with cement, and nothing serious happened. To the driller, it had not been too much of a surprise at least. The value of dipping into local knowledge.

DATA SHARING IS FINE, BUT COMES AT A PRICE

Last year, I asked Danish geothermal energy developer Innargi if it would be possible to get insight into the wells they drilled in Aarhus as part of a big geothermal project. At the time, they said the data package was possibly going to be released later. When I asked again at the start of this year, the reply was that the data can not be made available because of a potential sale to companies working in the CCS space in Denmark. That is an interesting development; at times when we hear that data needs to be shared more widely and openly, especially in the renewable energy sector, where margins are slim already, we see the opposite happening.

KUWAIT IS GOING FOR IT

A person with knowledge of the matter recently told me that KOC is very actively pursuing different opportunities to increase production. Why is this a key observation? It is a key observation because it shows that the country is trying hard to arrest the natural decline in production, and that there is no easy fix. Yet another example that easy oil is over.

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.

When carbon storage becomes a game

Lessons from the subsurface

IMAGINE PLAYING chess – but underground. Every move you make affects not only your own position, but also the stability of the entire board. Welcome to the world of carbon capture and storage (CCS), where injecting CO_2 into deep geological formations isn't just a technical challenge – it's a strategic one.

As CCS projects scale globally, a new layer of complexity is emerging: Multiple operators injecting CO_2 into hydrologically connected subsurface formations. These shared geological systems behave like a multiplayer game, where each player's decisions – how much to inject, where, and when – can influence the outcomes for everyone else.

This is where game theory comes in: The subsurface chessboard.

Operators aim to store CO_2 safely and permanently underground. But when formations are connected – through pressure regimes, fault systems, or fluid pathways – one operator's injection can change pore pressure and / or compromise the integrity of neighbouring sites.

ILLUSTRATION: RUDZHAN VIA ADOBE STOCK

STRATEGIC MOVES AND HIDDEN RISKS

Game theory helps us understand how operators behave when their actions are interdependent. In a non-cooperative game, each company tries to maximise its own benefit – injecting as much CO_2 as possible, as fast as possible. But this can lead to suboptimal outcomes: Increased risk of leakage, fault activation, or licence regulatory breaches.

In contrast, a cooperative game encourages shared monitoring, data transparency, and coordinated injection strategies. Everyone benefits from reduced risk and improved long-term viability. But cooperation requires trust, incentives, and often, external enforcement – especially when geology doesn't respect national boundaries. A good example is the North Sea, where multiple jurisdictions share subsurface formations.

Take the Utsira Formation, targeted by several CCS projects aiming to come online around the same time. The first injector may gain strategic advantages – access to optimal pore space, pressure control, and regulatory clarity. While Northern Lights is rightly celebrated as a pioneering success, it also represents only an opening move on the subsurface chessboard. The question remains: Is it scalable, and how will others play?

PLUME MANAGEMENT AND PRESSURE INTERFERENCE

At the heart of subsurface strategy lies plume and pressure management – the ability to predict, monitor, and control the migration of injected CO_2 and associated pressure changes. It is not often that well-reported. A well-managed plume remains confined within the intended storage zone, avoiding faults, legacy wells, or transmissive layers.

The associated pressure perturbation can be the silent killer in CO_2 storage. In the USA, decades of wastewater injection have shown how pressure plume interference can trigger unintended consequences. In regions like Oklahoma and Texas, high-volume injection into deep formations led to elevated pore pressures that migrated laterally – sometimes tens of kilometres – activating faults and inducing seismicity. These cases underscore that pressure effects can extend far beyond the injection site, especially in connected formations. For CCS, this means that even distant injectors must coordinate to avoid cumulative pressure buildup and cross-boundary risks.

CCS is not a solo sport. As we inject CO_2 into the earth to decarbonise the energy system, we must also inject with strategy, cooperation, and foresight. Game theory reminds us that in a connected subsurface, the smartest move is often the one that benefits everyone. ■

Rodney Garrard

The Black Sea is back

Interest in the Black Sea has been a slow burner compared to other oil and gas global provinces, despite a boom in licensing opportunities and block awards to international companies in the early 1990s after the breakup of the Soviet Union. The narrow Bosporus Strait in Turkey, with its limiting bridge height, did not help

THE REGION took a huge leap forward in 2020 when the Turkish state energy company Türkiye Petrolleri Anonim Ortaklığı (TPAO) announced the giant Tuna-1 gas discovery in the western basin deepwater. The field was subsequently named Sakarya, and further drilling on the structure confirmed it as the biggest field in the Black Sea. Phase 1 of gas production started in 2023 and is forecast to peak in 2028. More good news was announced in April 2025 with a second deepwater gas discovery at Göktepe-3 in the same area as Sakarya. TPAO is moving quickly to appraise the discovery and has deployed three drillships. TPAO is also reported to be drilling up to six exploration wells in the Black Sea basins in 2026.

In March 2025, OMV Petrom and partner Romgaz started development drilling on the shallower water Pelican South and deeper water Domino gas fields in the Neptun Deep Block in Romania. First gas from the project is expected in 2027 from a range of water depths between 120 m and 1,000 m. The strategic implications for the development of the fields are significant, marking a structural shift from Romania as a net importer to a net exporter of natural gas.

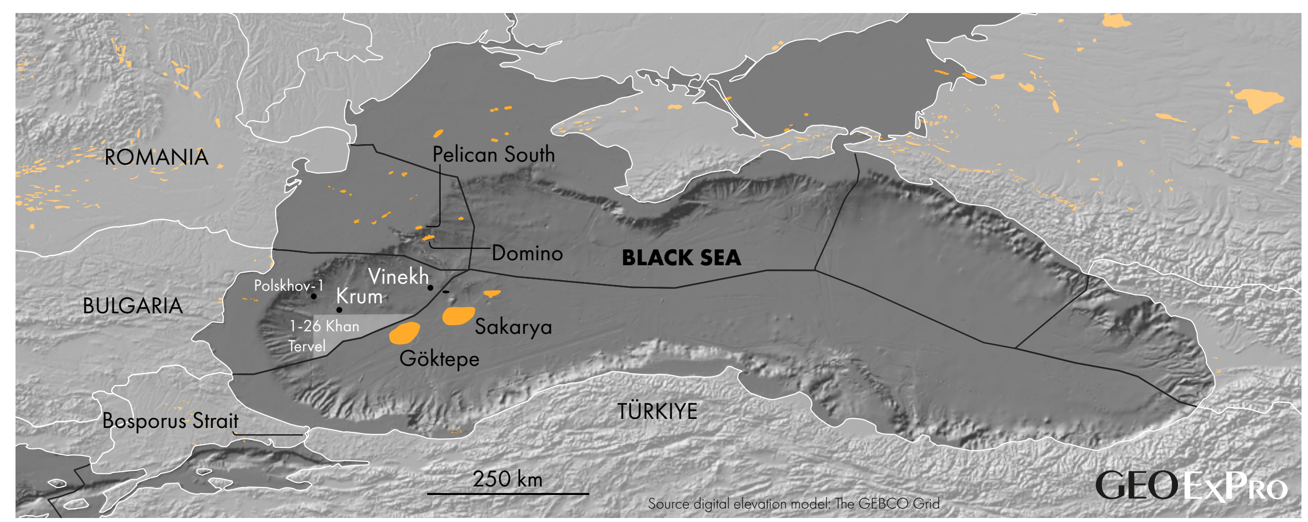
In Bulgaria, there is significant industry interest in the Vinekh-1 and the Krum-1 exploration wells operated by OMV with its new partner, NewMed Energy. The deepwater wells are located in Block 1-21 Khan Asparuh, situated south of the Neptun Deep Block. Both wells in a back-to-back programme will be drilled in the first half of 2026.

Adding to the interest in the Bulgaria offshore, Shell signed an agreement for deepwater Block 1-26 Khan Tervel in April 2025. This represents a return to offshore Bulgaria for Shell who exited the country in 2021. The initial work programme will likely focus on acquiring seismic in the area adjacent to the TPAO Göktepe discovery.

The Black Sea hydrocarbons are important for regional energy security, with the recent successes in the deepwater offering Europe alternative sources of gas. This was again reinforced in January 2026 when ExxonMobil and TPAO signed a Memorandum of Understanding (MOU) covering exploration and development opportunities in the Black Sea.

The post-rift basins offer much running room for exploration with the current focus on the Pliocene-Miocene biogenic gas plays, and in the future, we may see follow-up exploration on the Bulgarian Oligocene to Miocene clastic oil play opened up by Polskhov-1. Further romance exists in under-explored oil exploration targets in the syn-rift and pre-rift plays. In the coming years, the industry may shift more investment from the North West Europe offshore to this growing regional gas hub, where currently state-backed companies tend to dominate. ■

Ian Cross - Moyes & Co



A big new discovery or a confirmation of what was already known

CNOOC announced a big heavy oil discovery in the Bohai Basin, in an area that is already well-known for its hydrocarbon resources

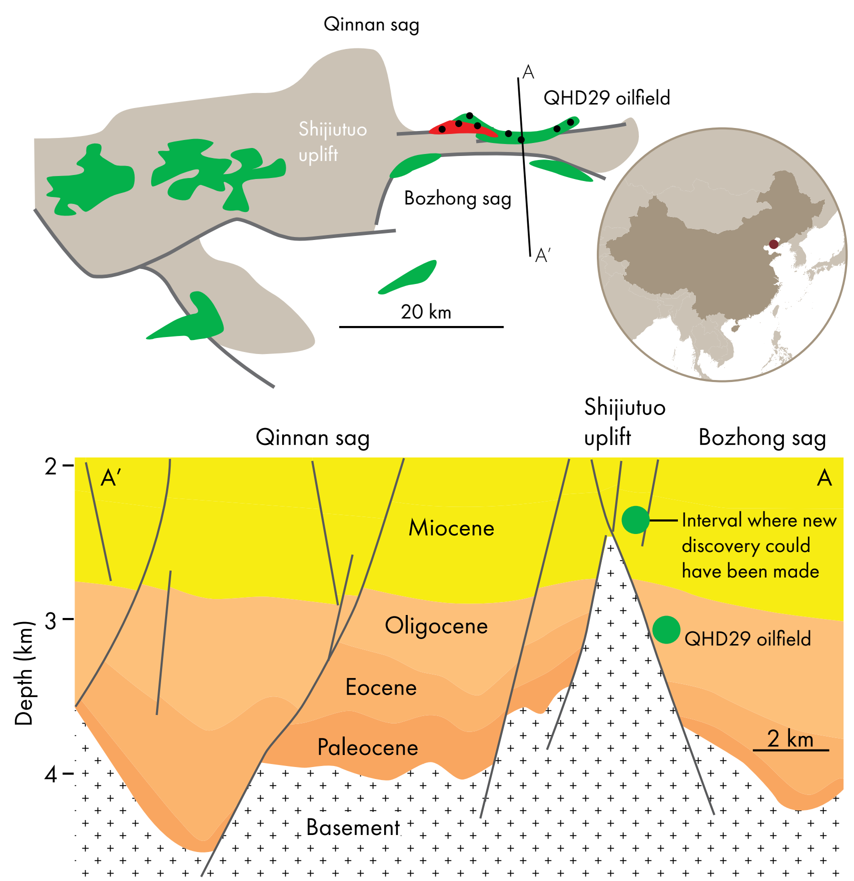
THE CHINESE are quite good at issuing press releases at interesting moments, and the one announcing the discovery of 100 M t (around 720 MMbbl) of oil in the Bohai Basin is yet another good example. Published on the 24th of December, Christmas Day, CNOOC made public the results of the Qinhuangdao 29-6 well, which reportedly tested at 2,560 barrels of oil per day.

The press release was copied by numerous outlets, without any attempt to put this discovery in context. As such, the reader is left to believe that around 720 MMbbl of newly discovered oil is now ready for development. Quite a large find.

However, a quick look at some published data reveals a different and more complicated picture. And even when these publications predate the completion of the Qinhuangdao 29-6 well, it still forms a very good basis to make some inferences as to what this discovery is really about. As well as the challenges it may face before it's put into production.

First of all, the well name already suggests that this is not the first well drilled on the Qinhuangdao structure. In fact, Qinhuangdao 29 is the name of a field that already exists, on the flanks of the Shijiutuo uplift. The most important reservoir in this field seems to be Paleogene sands, slightly deeper than the Neogene intervals mentioned as being the main reservoir in the press release.

So, with wells already present in the area, would it be possible that the Neogene oil was already known prior to drilling Qinhuangdao 29-6 well? Quite likely, and that is no miracle; rather the contrary.



Map and cross-section showing the Shijiutuo Uplift and the associated fields in the Bohai Basin, China. We speculate that the newly reported discovery is situated in Miocene sands draping the Shijiutuo Uplift, in contrast to the QHD29 field that is sealed against one of the bounding faults.

IMAGES REDRAWN AFTER WANG ET AL. (2016) – AAPG BULLETIN

Then, there is another interesting aspect to this discovery, and that is the observation made in this paper about the CO_2 contents of the hydrocarbons found in this area. Migrating upwards through deep-seated faults, this gas must pose a challenge to the economics of the development, if not to the CO_2 footprint of the project.

In other words, a ten-minute search is enough to find out that this discovery is not unexpected – it could even be that the heavy oil was already known before drilling the well. In addition, potentially high-CO_2 contents may pose a risk to the development. All in all, this "discovery" fits the picture of a move towards more complicated hydrocarbon accumulations as the easier once deplete. Something that we see all over the place.

CNOOC was approached to clarify the comment quoted in the press release: "This achievement challenges the conventional understanding that slope areas merely serve as pathways for hydrocarbons rather than sites for substantial accumulation." A reply was not received. ■

Henk Kombrink

COVER STORY

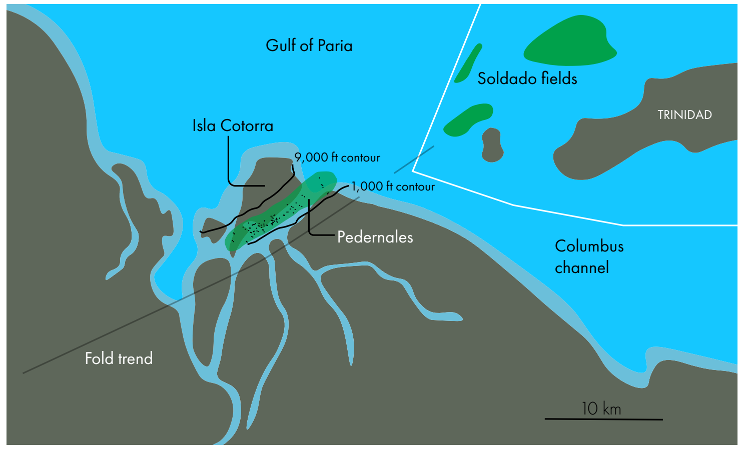
"You can't get blood out of a turnip, you know. If the earth is configured in a certain way, it will only give so much"

Dirk Bodnar – Geological Consultant

GRAND PLANS, CHALLENGING GEOLOGY

How the opening of Venezuela panned out for bp

HENK KOMBRINK



An impression of the Orinoco delta, and the Pedernales infrastructure on the banks of one of the tributaries.

TWO THINGS came together for bp in the late 1980s and the early 1990s. First, there were significant oil discoveries in Colombia. Then came the Apertura in Venezuela in the early 1990s, a government drive to bring in international oil companies to revive oil production following a period of nationalisation. “What if we can replicate the success in Venezuela?” bp executives must have asked themselves at the time.

It led to a hopeful entry into a country known for its ubiquitous hydrocarbon resources. bp was awarded exploration acreage in the eastern part of the Orinoco Delta, as well as a field that had been in production but had significant redevelopment potential – Pedernales. But did it become the success that was hoped for? No. As one of the people I spoke to for this story, “it was a great time for all who were involved, but a disaster for the business.”

In this article, the story of bp’s redevelopment of Pedernales is told through the experience of some of the people who were directly involved: Graeme Bagley, Dirk Bodnar, David Latin, Oscar Miron and Juan Oropeza. ▸

THE HISTORY OF PEDERNALES

The Orinoco Delta has long been known for its oil slicks. The story goes that even Columbus, on his travels to discover the Americas, had the hull of his ship tarred using oil that could be found locally.

It may have been the same slicks that ultimately led explorers to discover Pedernales. This took place in the year 1933 by Creole, Exxon’s affiliate in Venezuela. Remote as it is, at least the explorers did not need to venture into the delta far; the field is located just at the coastline of the Gulf of Paria on the island of Cotorra in the mouth of one of the Orinoco tributaries.

To facilitate drilling wells, Creole used an effective and inventive technology; they put a drilling rig on a railroad track that allowed quick movement from one drill location to another. Remains of this track can be seen in one of the photos included in this article.

With a pause in production during the Second World War, German U-Boats were seen in the area. Creole produced oil from Pedernales from 1935 to the early 1960s, using 44 producers in total. Once the field was nationalised in the early 1970s, Lagoven, one of PDVSA’s affiliates, operated the field for about five years using 17 producers in the early 1980s. When bp came along in 1993, the field had been shut in for around ten years.

An interesting story about Pedernales is that Shell also had a look at the opportunity when the Apertura was announced. But they apparently dropped the idea once they had looked at legacy production figures. Did they already see that there were issues to be expected?

COVER STORY

"THE NEXT BIG THING"

"The big next thing." That is what Venezuela was going to be for bp when the country opened up in the early 1990s – the so-called Apertura. Tony Hayward, who had overseen the exploration successes in Colombia with the discovery of the Cusiana and Cupiagua fields in the Eastern Cordillera foothills, saw the potential. He believed that South America was going to be the next big thing. As such, he was a driving force behind securing acreage in a similar structural setting to what he had been exploring in Colombia: The fold and thrust belt of Serrania del Interior, and the northern Orinoco delta in the eastern part of Venezuela.

And bp succeeded; the company was awarded two licences: One big exploration block called Guarapiche, and a licence that covered the abandoned Pedernales field in the northeastern part of the Orinoco delta. This story is mainly about how the redevelopment of Pedernales unfolded, seen from multiple perspectives.

The second phase of the Pedernales development came with costly jack-up rigs. A solution that proved to be too costly for what the wells could deliver.

PHOTOGRAPHY: IAN MACKLEY

A RUSH DEVELOPMENT

"The first phase of the Pedernales development was a success," says David Latin, who was in Venezuela to lead the reservoir engineering part of the second development phase for bp. "The first wells twinned the best of the past and were drilled at high angles from mobile drilling units. These wells were tied to a simple production barge with a total 20,000 bbls/day capacity. This initial success created a template for how things can subsequently derail."

Followed by the first production success, there seemed to have been a rush to proceed to a more full-scale development. However, data to support this decision were not even ready yet; seismic had been acquired, but no drilling targets had been identified.

Still, the decision was made to progress with the second phase of the development, which was also going to be much more expensive: Jack-ups were towed to the field, with day-rates that did not justify the later output of the wells.

"And whilst I was playing catch-up to match old wells with the new seismic, the new wells were already being drilled," remembers Graeme Bagley, who worked on Pedernales as a geophysicist from 1996 to 1999. "Which means that most of them were actually being drilled blind."

In addition, production histories of wells from previous developments seem to have been ignored, too. In other words, the second phase of the development was too rushed, and probably more driven by an expectation that things were going to be big than by a solid understanding of how this would actually be realised.

Then, the first well results that came in as part of the Phase 2 development suggested that the field was heavily compartmentalised. This led to some eyebrows being raised for sure. It was the time when production geologist Dirk Bodnar joined the team.

FROM ALASKA TO CARACAS

"I was working on Alaska's North Slope as a production engineer fixing wells for bp," Dirk says. "Wireline, slickline and coiled tubing jobs. Then, I got a call from a colleague in Venezuela, when it was -45° C outside."

THE PEDERNALES FIELD

Oil in Pedernales is reservoired in Pliocene paralic sandstones deposited by the paleo Orinoco Delta. The field is situated in the northern limb of a steeply dipping (45°) and decapitated anticline, which trends in a WSW-ENE direction. The steep fold may have a mud diapir core, but a deep-seated thrust fault might also explain the structural style.

"One of the questions we had," said Graeme Bagley, "was about the topseal. We could not really identify it, the more so because the top of the anticline was eroded. But in some ways, that question became less relevant because we saw that the slumping of the reservoir had created a lot of intermediate seals on the flanks. It didn't need an ultimate topseal."

A report from 1999 estimated that Pedernales had an OOIP of almost 1,000 MMbls, of which around 60 MMbls had been produced by the end of the 1990s. The oil has an average gravity of 21.5.

His colleague gave Dirk a rundown of the average weather in Venezuela. "Oh, and by the way, we need a production geologist too," he added. "But I have to warn you, the Pedernales field is known as the graveyard for production geologists…" "I'm always up for a challenge," Dirk said, so he decided to pack his bags in Alaska and move to warmer climes.

Was it a graveyard job? Unfortunately, it was…

"We P&A'd all the old well heads from the Creole development," said Dirk, "whilst drilling new development wells in the old Creole area at the same time. But when the new well data came in, the RFT data suggested that the pressures were way different, and the fluids were way different too. "We've got a bit of an issue here," he said. "It's not a good sign."

In order to find out more about what was happening in this field, Dirk got an idea. "From the Pedernales area, we could see lights in Trinidad and wondered what was there. It turned out to be the Soldado field that was operated by Trinmar at the time. We flew over one day to visit the company and learn about their experience operating the field, as we expected it to be the same reservoir. When I was reading through the reports they allowed us look into, I quickly realised that they were having the same challenges. We should have come over a lot sooner."

What was the issue?

Compartmentalisation. "The reservoir of the Pedernales field is a Pliocene paralic interval," explains Dirk, "deposited by the paleo Orinoco Delta. And while the delta was prograding, there was a constant formation of little growth faults. It is all those little growth faults that separate the sands of the field into the compartments that we know exist through our production and RFT data. The seismic only revealed so much of this architecture, unfortunately."

Graeme Bagley adds that it is not only the depositional growth faulting that proved detrimental to reservoir connectedness, it is also the faults that developed as the anticline formed. "As such, the reservoir is like a chessboard," he says.

"We tried many different solutions to get more oil out of the wells, such as gas injection and huff and puff," says Dirk. "But it didn't work. You've got billions of barrels in place, but it is not economic to recover."

"Years later," continues Dirk, "I drove in the Henry Mountains in Utah, looking at the Upper Cretaceous Ferron Sandstone Formation and saw immediately that this was an analogue for Pedernales; mouthbars, all river-dominated sands, and a lot of small growth faults."

Dirk used his experience on Pedernales a lot in subsequent training courses he gave for bp. And it was in there as an example of what you should not do.

> "You can't get blood out of a turnip, you know. If the earth is configured in a certain way, it will only give so much"
> – Dirk Bodnar

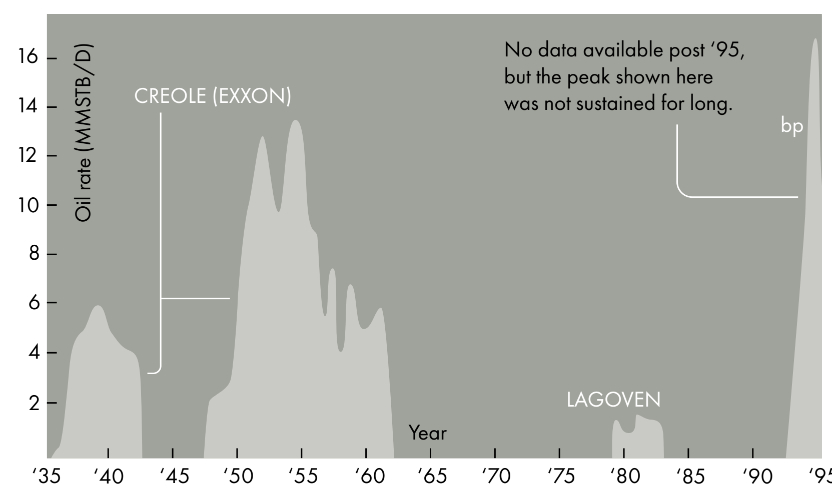
THE PEDERNALES STORY FROM A VENEZUELAN PERSPECTIVE

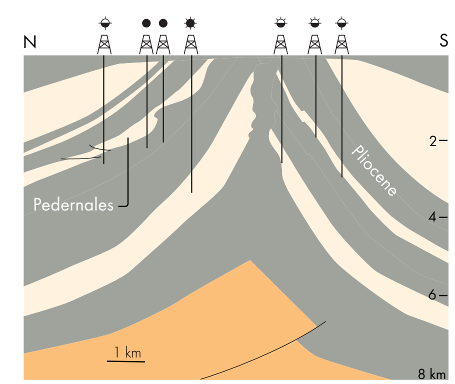
Pedernales was not the success that bp hoped for, but that doesn't mean it had no impact whatsoever. It surely had an impact on the many locals who were hired by bp. I spoke to two of them, Juan Oropeza, who currently lives in Portugal, and Oscar Miron, who has been based in Edinburgh for a long time. Both joined bp in their early careers.

"It was amazing to join an international operator like bp," says Juan when we meet on Teams. With a background in mathematics, Juan initially joined PDVSA in 1995. "I was hired by Lagoven," Juan says, "which was one of the three PDVSA operating companies."

At Lagoven, Juan took part in a two-year training programme for new entrants, with mentoring from the company's top specialists, reviving an idea pioneered by the former Creole Oil Company of Venezuela. "In other parts of the business, we were jokingly called "La Escuelita de Lagoven", or "The Little School of Lagoven." But it was great," he says. "It was an intense but meaningful programme, with the additional ►

SOURCE: SCHLUMBERGER WELL EVALUATION CONFERENCE, CARACAS, 1997 / REDRAFTED AFTER ILLUSTRATION SUPPLIED BY DAVID LATIN





Cross-section: N-S schematic cross-section through the Pedernales structure, showing the decapitated anticline and some of the wells drilled. The exact location of the cross-section is unknown.

benefit that we were submerged in an English-speaking environment."

With that in mind, when bp came to the country and started advertising for jobs, Juan didn't need to think long. "Everything aligned," he says, "as they were specifically asking for people with some experience but not too much. So, I applied and got the role."

"One of the main reasons why it was so insightful," he says, "was the fact that I became part of an international operator rather than a national one. That meant that I was suddenly exposed to people who had experience in the North Sea, in Canada and in the Middle East, and to hear these stories was just brilliant. In addition, information was very openly shared. In PDVSA, economic data were not really shared."

"In international companies," Juan adds, "there is more of a portfolio that is competing against each other." He particularly remembered the system of peer reviews in bp. "When you present something about the field you are working on as part of a peer review meeting, they don't only check your technical capabilities, but also how it compares to other assets around the world. That is an insight that you didn't have in PDVSA, because everything was local. Your biggest hurdle was the minister."

"It was not easy to make the Pedernales field economic," Juan continues. "Whilst we were familiarising ourselves with new tools and new ways of drilling, I knew that the bosses were getting headaches around the question of how to make this field work."

"Until you have your first measurements, you just have an aspiration. And that became a challenge when people started to realise that the wells did not sustain the initial production rates very long at all, with some dying in a couple of years."

"The idea of drilling long deviated wells to tap into multiple compartments at the same time was good on paper, but the reality was different," adds Juan. "Lots of things happened that compromised the wells, such as tool failure and fishing, water breakthrough, gas, and hole instability, with costs escalating with each intervention that was needed. There was the technological promise, but it was beaten up by reality."

Oscar Miron joined the Pedernales team almost straight from university. "I worked as a wellsite geologist for PDVSA for three months," says Oscar, but when I saw bp was recruiting it seemed a really good opportunity, as I found the corporate speed at PDVSA quite slow."

Oscar was thrown in at the deep end and started interpreting the seismic data that had just been acquired. "It was a challenging dataset to interpret," he says. "Land data is always tricky, but in this case, the way the data had been acquired didn't add to that. Instead of cutting straight lines through the forested island, it was somehow decided to do it in a stepwise manner, such that you wouldn't see a long line cut through the forest and potentially damage the fragile environment. Maybe with the best intentions," says Oscar, "but when you know how quickly vegetation re-establishes itself in that part of the world, it is a bit silly to try and make your path less visible. The more so because this way of acquisition had a detrimental effect on the quality of the seismic processing." Graeme adds to this that much longer offsets would have been required to image the steep limbs of the Pedernales anticline better.

Oscar had to plan the locations of new wells to be drilled based on the seismic data he was looking at. But because the imaging was simply not good enough to map the individual sands, drilling a new well could be considered a blind test," he says. "Sometimes we found sands, sometimes we didn't."

"VENEZUELA HAS SHAPED ME"

Below are a few excerpts from a short impression David Latin wrote following his experience in Venezuela.

Caracas, back in the mid 1990s, was a very exotic, chaotic, exciting place to be. A delightful mix of massive old American cars, new Toyotas and multi-coloured buses. A real melting pot of indigenous Amazonian and Caribbean, deep-seated European and more recent North American influences, which spread to clothing, music, cuisine and sports – everything..

The bp office was in El Rosal, on the large street Francisco de Miranda. A pack of us used to go and get coffee and empanadas every morning from "The Miserable Git" and at the end of the day wind up quite often in one of the local tavernas for a Polar beer or two. Just along from the office was a highly fashionable and expensive Lido shopping centre, which contained the Lido Day Spar, a fitness gym. It was here that we used to go at lunchtimes to stay fit for our regular excesses and enjoy mixing with the locals and aspiring Miss Venezuelas. It was here that I met my wife and mother of three daughters, in an aerobics class!

The weekends and holidays were marvellous. Trips to the nearby village of El Hatillo, with its sloths, small shops and pizzerias. Adventures further afield included going to the German-influenced Colonia Tovar, or seeing the Andes in Merida or the beautiful white-sanded islands of Los Roques, or Morrocoy to drink Cuba Libre (Rum and Coke) and eat arepas filled with shredded shark or "reina pepiada" – chicken with avocado.

For me, working on Pedernales reminds me of river banks and mangrove swamps, filled with scarlet Ibis, huge flying and crawling insects and giant snakes and where the waters hide sting ray, electric eel and pirañas. I felt like some sort of Indiana Jones when I used to go down there to visit "The Orgullo" (translated as "The Pride"), bp's production barge. The first time I went, much to my embarrassment and the amusement of others, my mobile phone was lost in the swirling and murky currents below.

This photo shows the abandoned "rail track" that was used by Creole (Exxon) to move the rig from one location to another.

PHOTOGRAPHY: IAN MACKLEY

EXPLORATION

As most of bp's work was being absorbed by Pedernales, the company also had an exploration licence that covered the area immediately west of the field; the Guarapiche Licence. This area, which is just as wet and inaccessible as the area around Pedernales, was mostly selected because it also forms part of the Venezuelan fold and thrust belt, where bp had been so successful in Colombia. However, the terrain prevented drilling at any random location. "It was so difficult that the terrain more or less determined where a well could be drilled, rather than solely driven by subsurface data," says Graeme. "I believe that there is still a hoover craft stuck in the delta somewhere, which was used to get bp executives to the rig site at some point."

THE END, OR NOT?

In 2000, about six years after the start-up of production from Pedernales, bp sold its share in the field to Perenco. "Looking back," David Latin said, "it would have been better to drill vertical wells and small bird-feeder style production facilities, instead of getting expensive rigs in."

The timing of the sale to Perenco may have been a blessing in disguise. It was a year after Hugo Chavez came to power, which was the starting shot for most Western companies to ultimately leave the country anyway.

Most of the expats were sent to other parts of the world as bp ceased operations in Venezuela, but sadly, the majority of local hires were made redundant, including Juan and Oscar. Juan joined ConocoPhillips, the company that was one of the few that developed a new field from scratch, with good reserves and good production. "That's why the company is still fighting in International Courts," Juan says, "because it was all nationalised when the field was about to start production. It was one of the most controversial aspects of the nationalisation."

"I hope that when companies return to Venezuela," Juan concludes, "this collaboration will have a longer lifespan, allowing for the flourishing of a strong ecosystem of national entrepreneurs with talented people, providing services and innovation within the country. A local ecosystem that would serve as a breeding ground for future Venezuelan champions on the international stage. Unfortunately, this process was interrupted the first time around, and many didn't survive the accumulation of unpaid debts with the new operators."

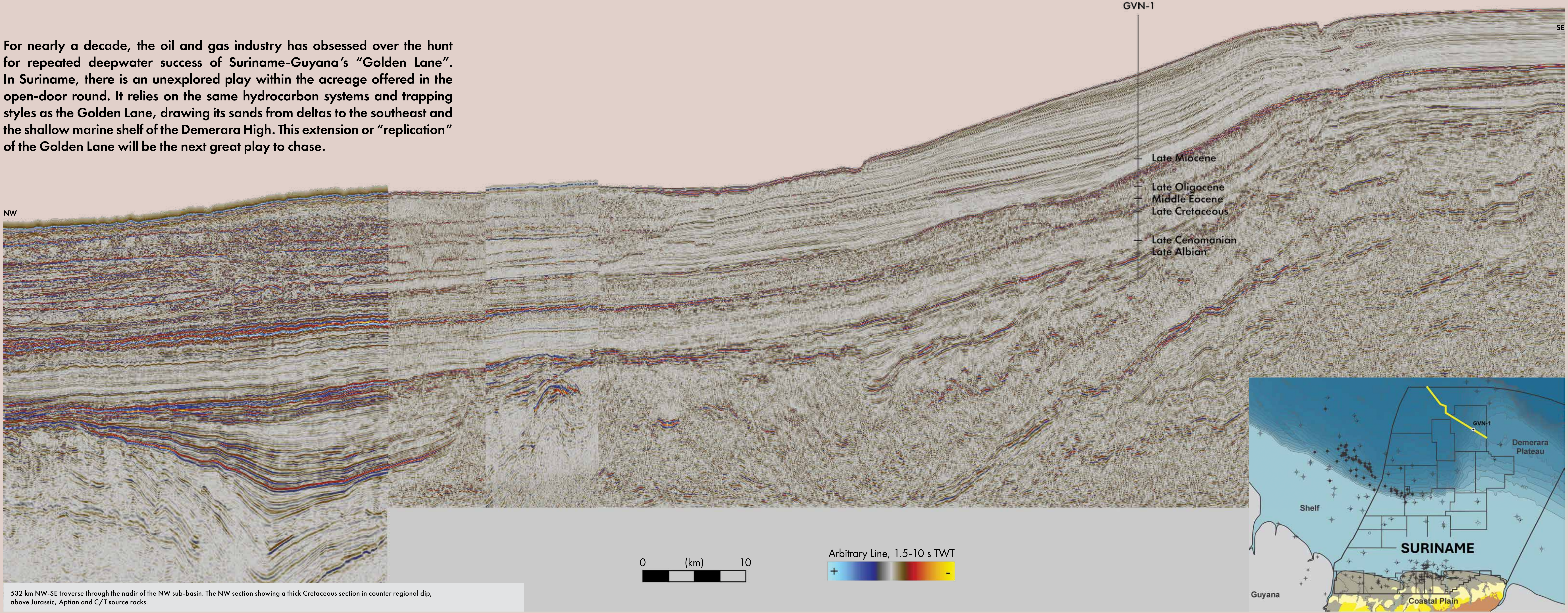
But what happened to Pedernales following Perenco's purchase? That part of the field's recent history is actually not well-known. One website writes the following: "The Pedernales oil field is run by Petrowarao, a company which was created in 2006 with 60 % capital investment and ownership by Venezuela's PDVSA and 40 % by the British-French oil firm Perenco. The field has 26 active wells and is largely based on floating platforms. In 2010 and before the recent collapse in oil production, Pedernales produced around 5,000 bbls/day."

And when looking at recent Google satellite imagery, it even seems as if some of the Pedernales infrastructure is still there, and it doesn't look as rusty as it might be. Maybe there is still some production ongoing? It could be the topic of another story. ■

Inside every Basin you know is another Basin you haven't met

Searcher STAATSOLIE

For nearly a decade, the oil and gas industry has obsessed over the hunt for repeated deepwater success of Suriname-Guyana's "Golden Lane". In Suriname, there is an unexplored play within the acreage offered in the open-door round. It relies on the same hydrocarbon systems and trapping styles as the Golden Lane, drawing its sands from deltas to the southeast and the shallow marine shelf of the Demerara High. This extension or "replication" of the Golden Lane will be the next great play to chase.



532 km NW-SE traverse through the nadir of the NW sub-basin. The NW section showing a thick Cretaceous section in counter regional dip, above Jurassic, Aptian and C/T source rocks.

Suriname's north west sub-basin: An extension to the Golden Lane

NEIL HODGSON, KARYNA RODRIGUEZ AND LAUREN FOUND, SEARCHER

GENEVIEVE HIRCHFELD, DHEERAJ BIHARIE, MITCH JIE A LOOI, VANISHA CHEDI, SHARISTA KISOENSINGH AND NOHAR POEKETI, STAATSOLIE

"Trendology" is often derided as an exploration strategy until it is apparent that a trap style in a regionally working play system is in fact repeating, and then everyone jumps in. Stepping out from success, though, where key risk elements may be subtly yet crucially changing, is still uncomfortable, and only a seismically de-riskable play can be followed comfortably until the play stops, or, more crucially, until the seismic stops.

After the unassuming discovery of Liza-1 in Guyana in 2015, the Guyanan "Golden Lane" was quickly extended with many other discoveries, all within the same Upper Cretaceous slope fan system. Exploration momentum continued into Suriname, where multiple successes again followed.

This was remarkable, with repeatable success coming from the seismic response to rock physics. 3D seismic showed negative amplitude reflectors at the top of the reservoir, bright amplitudes at near offset, and a strong amplitude increase with offset (Class III AVO anomaly). In addition, a hydrocarbon water-contact indicator – a flat spot, or polarity change at OWC can often be seen. The 3D seismic over the Golden Lane is good enough to reduce false positives, making this a seismically de-riskable play. Yet, although the seismic squiggles are the symptom we diagnose for rapid repeatable success, they don't make the play work. The geology makes the play work.

The "Golden Lane" trend is a 250 km long by 50 km wide NW-SE oriented stratigraphically trapped multi-channel play that has been explored extensively from Guyana into Suriname to the point where the Guyana escarpment meets the North-South edge of the Demerara Plateau. Down- and up-dip tests (Joe and Jethro (2019), Tanager, Carapa and Bulletwood (2020-21)) have not been proven to work commercially yet, though we all travel hopefully. So, why does the Golden Lane specifically work? Stratigraphic channel plays are notoriously risky, requiring each channel to have an up-dip barrier to oil migration, and this barrier – a fault or gap in sand connectivity is often desperate to image on seismic. So, how has something subtle occurred repeatedly along a 250 km long margin?

In 2021, Bryan Cronin proposed that the Golden Lane deposystem can be interpreted to be controlled by steep bypass channels on structural ramps with intervening lower relief terraces. Sands were not deposited on the steep ramps, and sand deposition only took place at the break of slope onto the terraces where poorly confined amalgamated beltway frontal splay systems and ponded intra-slope lobes accumulated in either levee or erosionally confined canyons. Further out, large-scale frontal splay complexes with MTD (Mass Transport Deposit) controlled stratigraphic or combination traps characterise the basin floor. The stratigraphic repeatability of the Golden Lane then is a function of the geometry of the slope: The steep ramp and flatter terrace geometry.

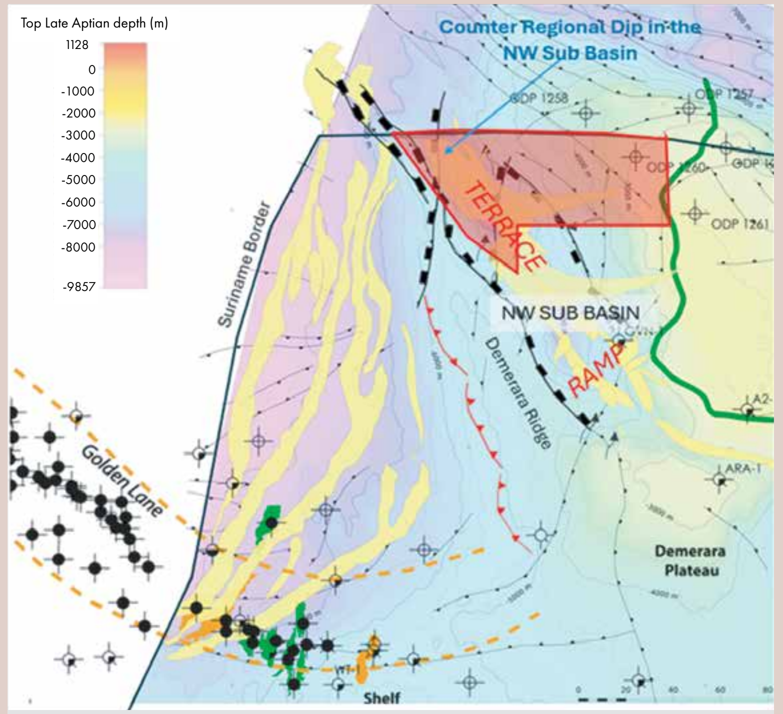


Figure 1: NW Sub-Basin Top Aptian Depth map and sand distribution (after Staatsolie GeoAtlas), Red Polygon is Searchers' proposed 3D area. Green line: Eastern edge of Aptian Source Maturity.

Following the Golden Lane into Suriname, where it converges with the Demerara Plateau, might have seemed like the final chapter for this prolific trend. But in reality, the Golden Lane story is far from complete.

Offshore Suriname presents a geological 'game of two halves' – a western, deep basinal half (Suriname-Guyana Basin) and an eastern half (Demerara Plateau) where basement is much shallower with thick Jurassic-Lower Cretaceous sections and thin Upper Cretaceous sections. What divides these two is the north-south trending western flank of the Demerara Plateau.

To understand these basins, we can lean on the insights from current explorers on the margin, particularly from Staatsolie, the State Oil company of Suriname who have heroically provided the industry with an insightful summary of the Suriname hydrocarbon system for all to use, accessible (QR 1). Figures 1 and 2 give examples of regional depth structure mapping and reservoir facies distribution from the GeoAtlas.

About 250 km offshore along the west Demerara Plateau lineament lies the "Demerara Ridge" – a steep, internally complex ridge verging NE. On the SW side of this ridge is the Suriname-Guyana Basin in all its golden-lane glory, yet on the NE side of this ridge is the "NW Sub-Basin" – as yet an unexplored ramp-terrace.

The ridge itself is often described as an olistostrome-type gravity slump, yet from its similarity to Eastern Tano or Western Ceara transform margins, this may represent an Albian strike-slip "Demerara Fracture Zone", deforming thick Aptian sediments during late syn-rift and drift separation from Africa. Regardless of its precise origin, the ridge has played a critical role in shaping regional sedimentation and from the Albian through the Late Cretaceous,

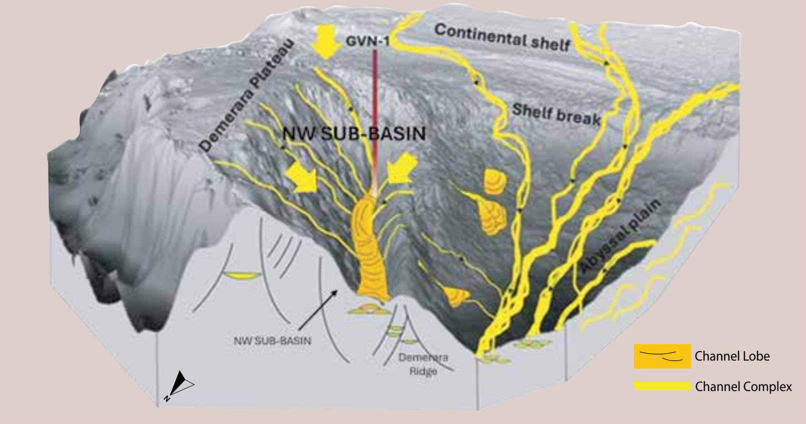


Figure 2: 3D illustration of Late Cretaceous Sands pouring off the Demerara High, down into the NW Sub-Basin, where they now reside in counter-regional dip configuration.

sand systems coming over and off the Demerara high were consistently funnelled into the NW Sub-Basin.

The NW Sub-Basin has a steep SE Ramp, where the GVN-1 well was drilled (oil and gas shows in Albian sandstones), leading NW to a terrace, i.e. precisely the depositional geometry of the Golden Lane. According to the Staatsolie GeoAtlas, this setting has repeatedly acted as a conduit for sand delivery, not just since the Late Jurassic but crucially throughout the Late Cretaceous as well.

Sands sourced from the SE, or derived from the sand-rich Demerara Shelf, were transported down the steep bypass ramp past the GVN-1 location before being deposited on an as-yet unexplored terrace at the slope break, as also documented by and pre-imagined by Max Casson and co-workers in their fascinating 2021 study (QR 2). At the far NW end of the Sub-Basin there is structural and depositional dip reversal in the Upper Cretaceous – a perfect complement to the Golden Lane depositional geometry.

The Staatsolie GeoAtlas demonstrates that the source rocks evaluated for the rest of the Golden Lane are present and oil generative under/in the NW Sub-Basin. Aptian and Cenomanian Turonian (ACT) source rocks, among others, are present at depths exceeding 3 km and are oil-generative within this basin. In the northern part of the NW Sub-Basin, we find 1-2 km of stacked Tertiary MTDs, the tail end of the gravity systems pouring from the Guyana-Suriname Shelf to the SW, related to the dynamic topography or simply the rise of the Andes above subduction. This is the cherry on the hydrocarbon system cake, as rapid thermal blanketing from MTD's help keep the NW Sub-Basin warm, and this is responsible for making the NW Sub-Basin such a prime target.

All key exploration ingredients for a Golden Lane extension appear present in the NW Sub-Basin, with one notable exception: the absence of 3D seismic coverage across the northern terrace, particularly over Block 59 (currently open acreage in the 2025 licensing round). In response, Searcher proposes to acquire Multi-Client 3D here in 2026 on a very simple premise: To demonstrate that the geology supports an extension of the Golden Lane to the north in the NW Sub-Basin, by verifying the seismic signature of oil in Upper Cretaceous sands. So, is this Golden Lane extension or replication a perfect seismically driven play that needs to be drilled? – In 2026, we intend to acquire the 3D and find out.

QR 1

QR 2

It doesn’t need to be clay mineral diagenesis

Colin Percival makes a case for paleogeography and sand connectedness being the main drivers for the observation of fresh water in deep-marine sands

LAST YEAR, we published an article (GEO EXPRO Vol. 22, Issue 2, 2025) about the presence of freshwater signals in deep-marine sandstones. It was an observation made by an explorer in the Pomboo well drilled in deepwater Kenya, where some people initially did not believe the lab outcomes, arguing that it was impossible to find fresh water in such a place. Yet, it was true.

This led to a follow-up post on LinkedIn that triggered a fair amount of feedback from our readers. One of the main reasons that came up to explain the presence of fresh water in such a setting was diagenesis, or illitisation. This process releases water, which then subsequently migrates to nearby reservoirs.

Then, a few months ago, Colin Percival told me during a conversation in Aberdeen that he didn’t buy the diagenesis story, based on his observations in the Faroe Shetland Basin (FSB), UK. I was intrigued; Colin has a wealth of experience as a geologist, and as such, we organised a meeting to further discuss.

OVERPRESSURED SANDS

“We’re talking about the Paleocene Vaila Formation,” says Colin as he kicks off the conversation. “In the FSB, the Vaila Fm sits beneath a regional seal, the Kettla Tuff. For that reason, it is slightly overpressured in many parts of the basin. Salinities range from 3,000 ppm to around 15,000 ppm, so well below the value of normal marine waters (35,000 ppm). In addition, we also see the presence of lots of wood fragments in the sands.”

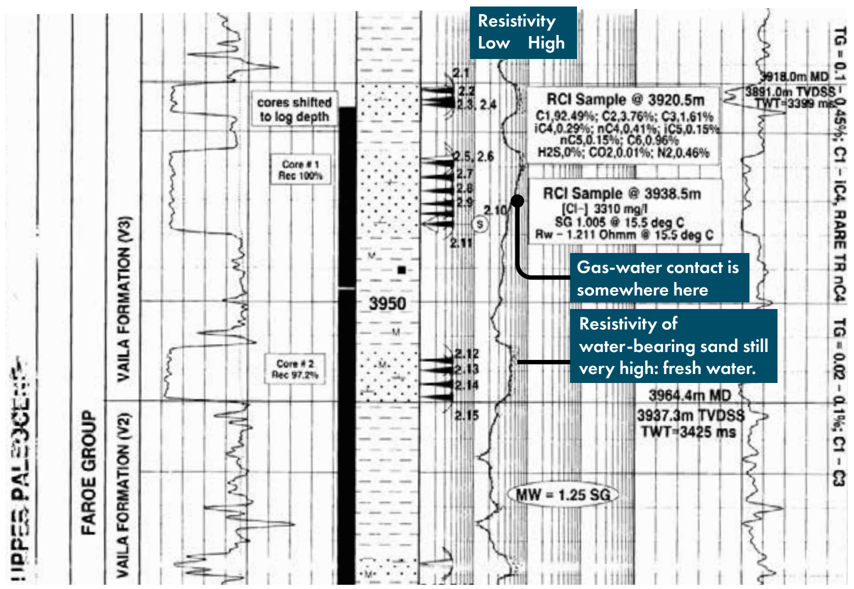
“Let’s take a look at the paleogeography,” Colin says. “In Paleocene times, the FSB was a relatively narrow embayment, with lots of fluvial input, especially during the lowstands when the Vaila sands were deposited by hyperpycnal flows.” In other words, the basin may not have been fully marine at the time. “As such,” concludes Colin, “I think that the salinity of the waters we currently observe in these overpressured Vaila sands is a sign of the salinity of the basin at the time. In the North Sea, we don’t see these lower salinities in equivalent sands at all, which should be explained by the fact that the basin was much wider than the FSB.”

“In those areas of the FSB where the sands are more normally pressured and better connected, we see a higher salinity in general. I explain that by later fluid migration and mixing,” says Colin. “This mixing was more challenging in the less well-connected Vaila sands.”

“I did not study this phenomenon in great detail,” admits Colin, “but I just feel like you need a lot of clay transformation to freshen the pore water signal in deep-marine sands if you only rely on that mechanism.” In addition, in further support of his theory, he argues that there has not been a lot of diagenesis in the Vaila succession in the FSB yet; the depth of burial is only about 7,000 ft below mud line in general.

So, it sounds like we have another factor explaining a freshwater signal in deep-marine sands. ■

Henk Kombrink



Composite well log from well 206/1-3 into the Laggan field, West of Shetland. Using the resistivity log alone and without the presence of pressure points, it would be difficult to see where the gas-water contact is.

An impression of the state of the industry in Russia

Based on a conversation with someone with knowledge of the matter, we provide some high-level observations from the country that does not feature in the oil and gas news frequently, but is an important exporter nonetheless

FOLLOWING the onset of the war in Ukraine, news about the E&P business in Russia seems to have become even more scarce than it already was. For this article, I spoke to someone from Russia who was willing to provide me with a few interesting insights that are worth sharing. That being said, this article does not claim to be the result of an exhaustive piece of research, but rather forms an impression from someone with direct exposure to what is happening in the country.

First of all, it is worth noting that the dynamics of the exploration business are different in Russia compared to other places. That is because during Soviet Union times, before the 1990s, a lot of drilling took place that proved up many discoveries, of which many have not made it to development yet. That’s not to say that all of these will ultimately progress, but there may be more of a backlog than in other hydrocarbon provinces.

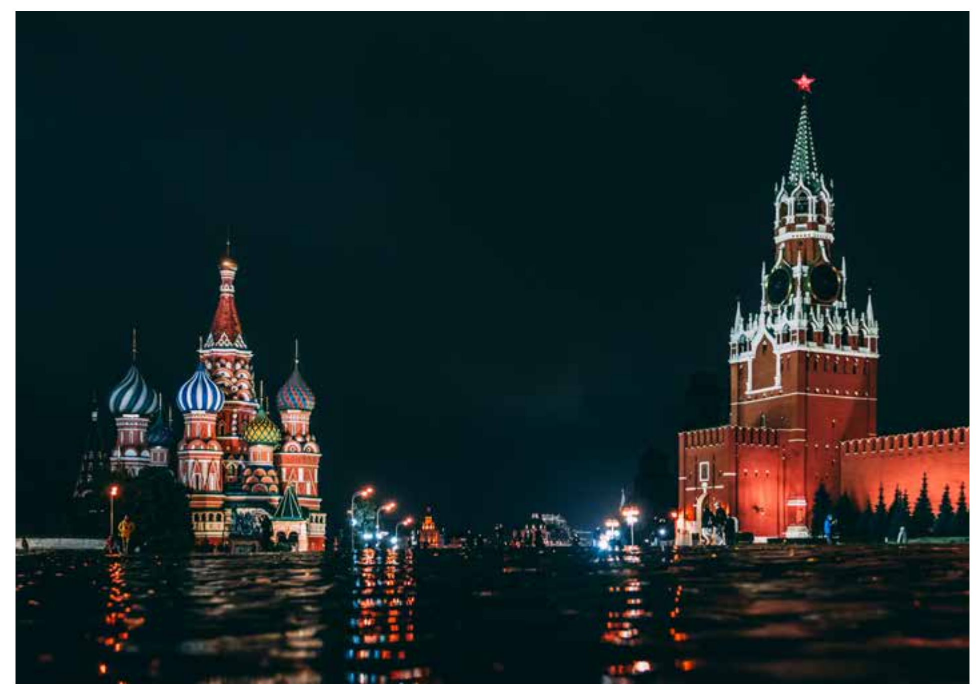
As an example, there is a 500 MMboe discovery now being developed in the High North that was found in the 1980s already. Drilling technology had to advance further to make it worthwhile. All of this doesn’t mean the quality of the reserve base is declining, but there seem to be many smaller satellites out there waiting for development. Based on this observation, it is likely that Russia will be able to maintain its current production level for some years to come.

Export of oil and gas is key. As my contact expressed it, “there is no internal market for all the hydrocarbons we produce.” That is a very different scenario in places like the Permian Basin, where large cities and an existing pipeline network provide at least an important customer base.

As much as Russia was benefiting from high oil prices before 2014, the subsequent crash has put the brakes on further spending. Rosneft has seen a 30 % reduction in drilling, for example. Western sanctions have also put pressure on access to technology, but that is now being replaced by products from China. It is an interesting question whether Western companies will ever be able to regain market share should the country open up again in the future.

As the Welligence article (GEO EXPRO Vol. 22, Issue 6, 2025) already points out, the area that holds most promise in Russia is Western Siberia. But will unconventionals be part of that? My contact is not convinced and mentions that he has not seen any meaningful production results as of yet. He also mentions that one company has tried it, but that high water cuts were observed and that the whole exercise was uneconomic. On that basis, he thinks unconventionals will not become an important part of the Russian energy mix for some time to come. ■

Henk Kombrink



Moscow.

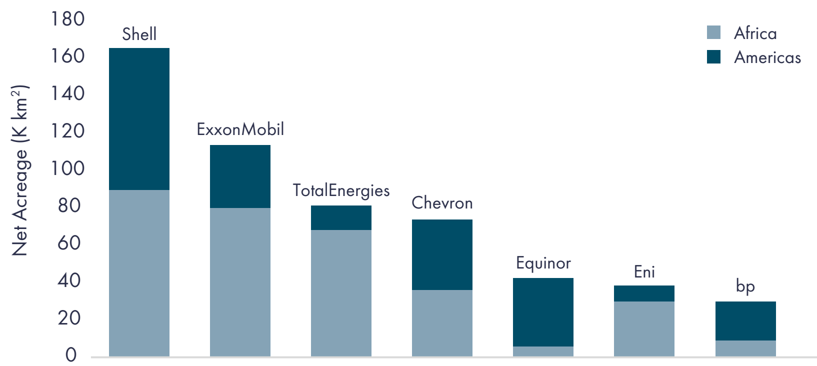
PHOTOGRAPHY: НИКОЛАЙ ВОРОБЬЕВ VIA ADOBE STOCK

A key testing ground for exploration strategies

How the Atlantic Margin continues to attract interest from the majors

JAMIE MCGREEVY, WELLIGENCE

THE ATLANTIC Margin is one of the most consistently successful exploration provinces globally, delivering material discoveries across multiple basins and exploration cycles. Since 2010, more than 70 Bnboe has been discovered along the margin, underlining its ability to generate sustained success across both frontier and mature basins. This performance has kept the region firmly in focus for the industry, particularly the majors who are in search of scale and the next frontier.



Atlantic Margin: Net Acreage.

HOW ARE THE MAJORS POSITIONED?

This exploration push is evident in how some of the majors have positioned their acreage. More than 540,000 km² of net acreage along the Atlantic Margin is currently held by the majors alone, with 2025 having been the most active year for licence awards and farm-in activity since 2020 in Sub-Saharan Africa.

Shell and Chevron have been on the front foot in loading Atlantic Margin acreage, building scale across both Africa and the Americas. Both have leaned into a conjugate-margin exploration strategy, maintaining deliberate exposure across key frontier basins, including the Orange and the Pelotas basins. In contrast, companies like TotalEnergies and Eni maintain more regionally concentrated portfolios, focusing their exposure on core areas in Africa.

WHAT IS THE DRILLING OUTLOOK?

Over the next 12-18 months, more than 45 exploration wells are expected to be drilled across the Atlantic Margin, with around 30 drilled by majors and large NOCs, highlighting the region's continued strategic significance. Activity is largely centred on emerging and frontier basins, most notably the Orange Basin, the Pelotas Basin, and the Foz do Amazonas.

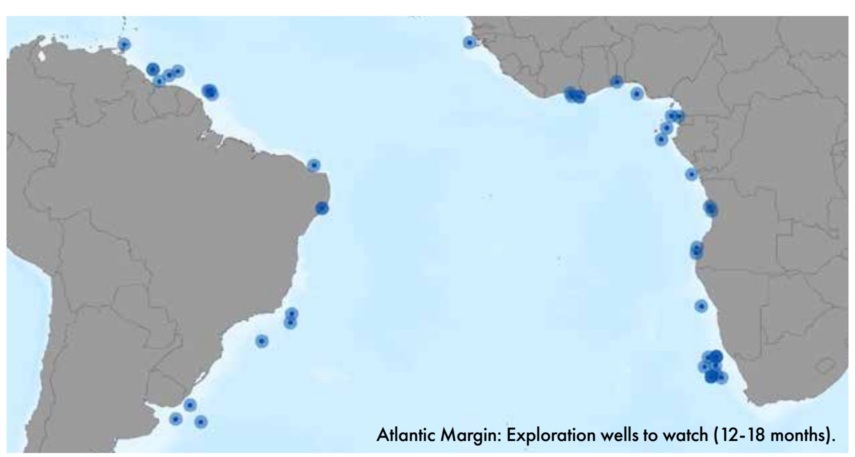
WHAT'S NEXT FOR THE ATLANTIC MARGIN

Looking ahead, several clear signposts will determine whether the Atlantic Margin's current momentum translates into tangible exploration success.

In Africa, commercial follow-through in the Orange Basin through project sanctioning is an important step in demonstrating that recent technical success can translate into real value. A final investment decision (FID) on TotalEnergies' Venus discovery is expected later this year.

On the frontier side, a basin-opening discovery on the South American conjugate margin, particularly in Uruguay or southern Brazil, would validate conjugate margin acreage captured by Shell and Chevron and refocus industry attention.

While commercial outcomes will continue to vary by basin, the Atlantic Margin remains one of the few regions capable of delivering material, high-impact discoveries at scale. As a result, it is likely to remain a key testing ground for exploration strategies over the coming decade. ■

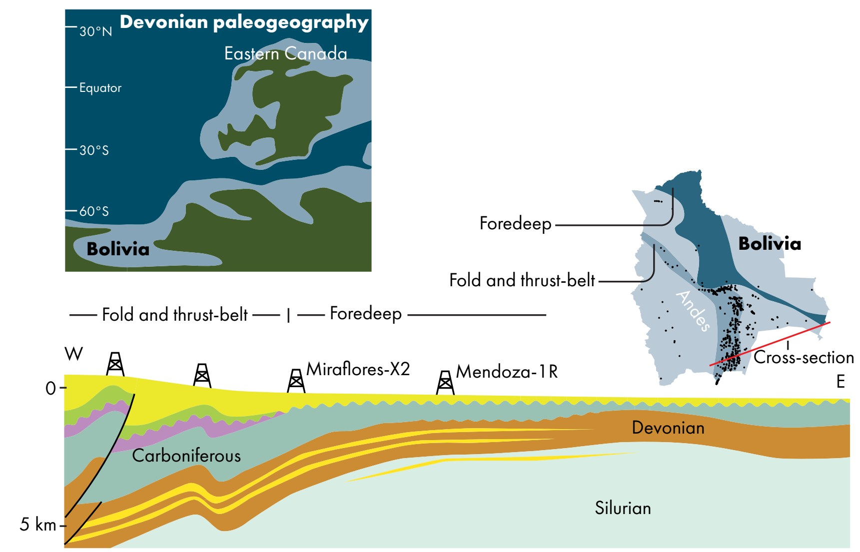

Atlantic Margin: Exploration wells to watch (12-18 months).

SOURCE: WELLIGENCE ENERGY ANALYTICS

How Bolivia's search for additional petroleum resources relates to Devonian paleogeography and paleolatitude

For years, Bolivia's oil and gas sector has seen underinvestment. Now that the country has become an importer rather than an exporter of gas, and with a more welcoming government in place when it comes to foreign investment, the challenge is to find the new resources that could reverse the trend of declining production in the fold and thrust-belt region. But that requires a new perspective on source rocks. Devonian source rocks

OIL AND mostly gas exploration in Bolivia has always focused on structural traps in the Andes fold and thrust-belt. Not that it was easy to drill there; overpressure, hard-to-interpret land seismic, and difficult terrain don't make up for ideal exploration conditions. However, successes were achieved, and for a long time, the country even functioned as an exporter of gas to Brazil. That, however, has now completely reversed, both due to natural decline from existing fields as well as a lack of foreign investment.



Paleogeographic map showing how the area that is now Bolivia was situated at high southern latitudes during the Devonian, in climates less warm than what Eastern Canada and the rest of North America enjoyed. The cross-section shows the foreland basin in Bolivia and Paraguay. It is especially the fold and thrust-belt that has thus far been explored and developed, but potential for tight gas exists in more distal areas of the basin too, as wells Miraflores-X2 and Mendoza-1R have demonstrated.

SOURCE CROSS-SECTION: CORNELIUS (2019) – BOLIVIA 2018 – AAPG GEOSCIENCES TECHNOLOGY WORKSHOP / SOURCE MAP: SCOTESE.COM

The petroleum system in the Bolivian fold and thrust-belt relies to a large extent on Devonian source rocks, deposited in a seaway that opened up in a northerly direction 400 million years ago. And it is this Devonian source rock that is the key when exploration shifts towards the more distal places of the present-day foreland, where subtle, tight, and unconventional resources may exist.

There are places in the world where the distal parts of foreland basins are very important when it comes to hydrocarbons. Devonian marine source rocks and associated oil and gas play types are well known in North American foreland basins, for example.

So, why is there no current production associated with Devonian source rocks in the more distal parts of the Bolivian foreland? This might be related to its paleo-latitude position. The area was situated at around 60 degrees southern latitude in Devonian times, and it could be the location in a cooler environment that might have prevented the deposition of oil-prone source rocks similar to the ones in Canada and the USA.

Does the challenge of the presence of an oil-prone source rock exclude the possibility of success? No, as more distal wells such as Miraflores and Mendoza already demonstrated, there is potential for the production of gas from Devonian and Silurian sandstones. But due to the more dispersed nature of the TOC in the Devonian source rock in Bolivia, as well as its type, oil plays may be challenging to find. Paleogeography and paleolatitude are key. ■

Henk Kombrink

The Gambia's offshore acreage is hot again

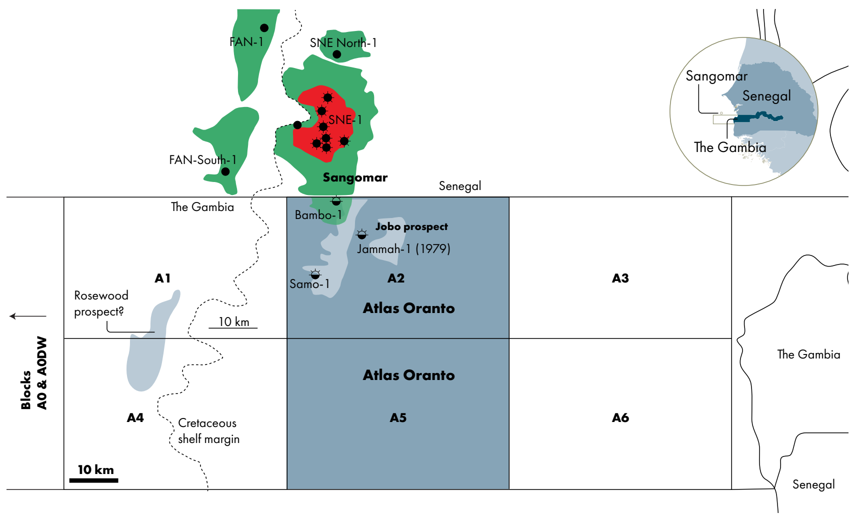
With two blocks recently awarded and more apparently underway, The Gambia is seeing renewed interest in its offshore sector following a few years of limited activity

THE WEST-AFRICAN margin is back in the exploration spotlight, not only because of the recent announcement by Shell to drill more wells on their PEL-39 licence in Namibia, but also because of acreage snapped up in countries that had only limited activity until recently.

In this case, we're talking about The Gambia, where seven of the eight offshore blocks that make up the offshore were all up for grabs after Far from Australia relinquished A2 and A5 early in 2024, following their campaign that saw two wells drilled (Samo-1 and Bambo-1) without apparent success. The only block that was under licence until recently was A4, but PetroNor relinquished it in November after failing to find a drilling partner. That left the offshore without any licences for a few weeks.

But it did not take long for this downward trend to be reversed.

A source close to the matter shared that from the end of November, the A2 and A5 blocks are under licence again, for a notable period of 30 years. The new owner is Atlas Oranto, the company run by Arthur Eze from Nigeria. The same company also took hold of some blocks in Liberia recently.



Blocks A2 and A5 have now reportedly been awarded to Atlas Oranto for 30 years. The location of the Rosewood prospect in blocks A1 and A4 was taken from a GNPC presentation at the African Energy Week in Cape Town in 2025 – available on YouTube. Blocks A1 and A4 are therefore likely candidates to be licensed next.

And that's not the only thing happening. Another industry source shared that a government official had announced that ENI and Ratio Petroleum are close to signing a licence deal as well. Whilst it is not clear yet which blocks this is about, looking at the map and the fields in Senegalese waters further north, one might think it is blocks A1 and A4 that are on the radar. Here, the companies might expect to find lateral equivalents of the Albian base-of-slope turbidite fans or contourites that form the reservoirs in the FAN discovery, or, east of the Cretaceous shelf margin, equivalent structures to Sangomar.

At the recent Africa Energy Week in Cape Town in October, the Petroleum Commission from The Gambia included an informative slide in their talk, showing how the prospects in blocks A1 and A4 match what can be seen in Senegal. In fact, the Rosewood prospect might even be more attractive than FAN, as it experienced less burial, which is known to be a detrimental factor in Senegalese waters.

Block A1 was previously held by bp, but was relinquished in 2021 as the pandemic unfolded and the company decided to move beyond petroleum. It paid a hefty fine for this move, as it had an exploration well commitment on the block. ■

Henk Kombrink

Ratio Petroleum is an Israeli company that was established in 2011 by geologist Eitan Aizenberg following the discovery of the Leviathan gas field. Aizenberg is the acclaimed prospect generator for Leviathan. He is currently the SVP Exploration and Production at Ratio, which already has acreage in the Guyana Basin, the Moroccan Atlantic Basin and the Philippines.

Why post well analysis matters

Discoveries are easy. That's because a discovery proves that all four key elements work: Reservoir, seal, trap and charge. In contrast, in the case of a dry well, the situation gets more complex: Not one, but more elements might have failed. Time for a proper post well analysis – using maps

MOST COMPANIES are aware of the value of doing post well analysis (PWA). But it is often done in spreadsheets. In that case, there is a high risk for myths to propagate, especially when it comes to charge and the presence or absence of a source rock.

The reason for that is simple. With each well, we have a test of reservoir and seal presence and quality, in addition to the trap configuration. However, just looking at a single well, it becomes much harder to make claims about charge and source rock presence, because that requires more of a regional overview and even the construction of a burial history model. In other words, the charge element is an interpretative step and is not only data-driven.

And will you get this sort of information from press releases? No. Press releases always carefully avoid any statements on the regional petroleum system because it could downgrade their wider licence, which investors don't like. On that basis, any post well analysis that is based on scouting information should be taken with a pinch of salt.

The only way to do it properly is to look at the observations, without making inferences about source rock presence or migration pathways. In addition, the results always need to be plotted spatially, which allows users to high-grade areas for exploration much more easily, and done in software rather than spreadsheets because the input data can change all the time. It is a dynamic exercise.

What PWA is especially useful for is the ability to tell us quickly where to focus our exploration efforts. And when doing so, just by plotting results on a map, we can very quickly highlight areas where it would be interesting to have another look, which is something you would not be able to do when only doing regional mapping alone, or by having spreadsheets only.

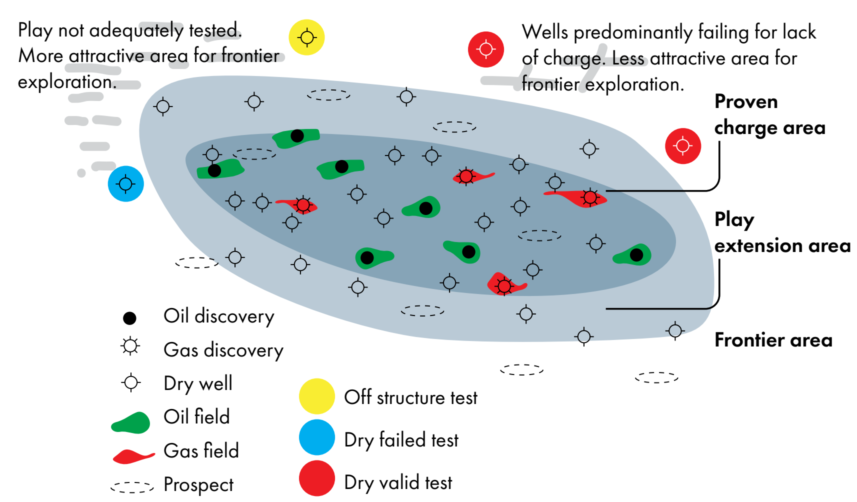
Another very important reason to do PWA is to identify areas of a certain play where the source rock interval is definitely at the right depth and temperature to generate hydrocarbons, but the quality of the source rock is too poor to be effective in expelling any hydrocarbons. That's not something a basin model will predict, since these models often infer source rock quality because of a lack of well evidence. Yet, identifying these areas early can save a lot of money.

That is why a rigorous, spatial and dynamic post well analysis is a lot more significant than what people often realise. ■

Henk Kombrink

GIS PAX PLAYER

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



Example using post-well analysis results to rank the more frontier areas of a basin beyond the proven and potential play extension areas.

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

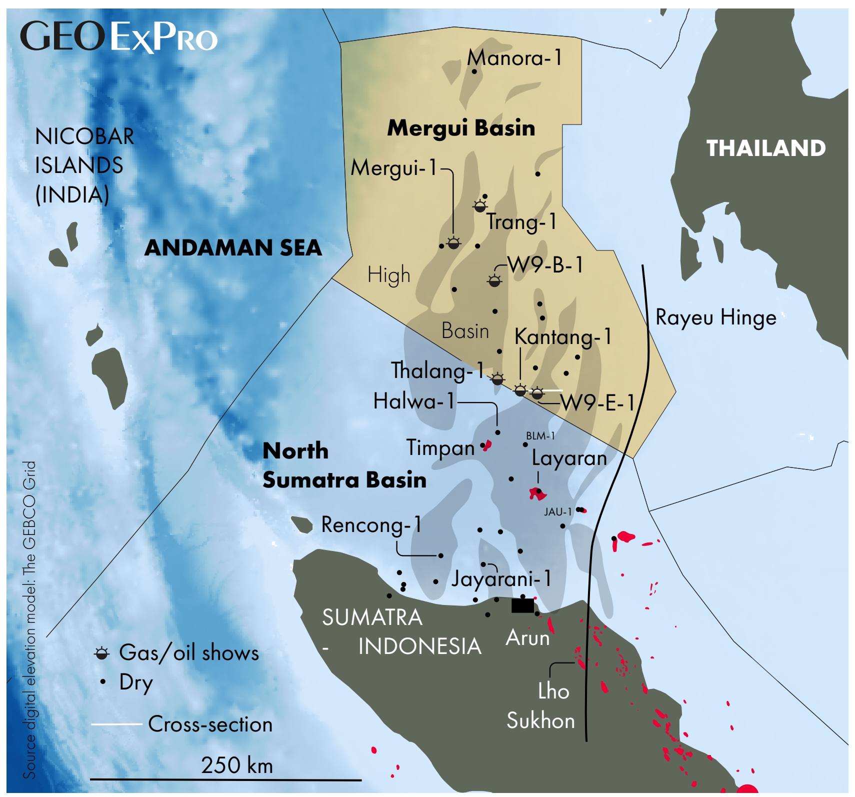
One block, one basin

Thai authorities are inviting bidders for an extensive exploration block that covers most of the Mergui Basin

ANDY RACEY AND ANDY TAYLOR

THE THAILAND Department of Mineral Fuels has just announced a licence round in the Mergui Basin, Andaman Sea. Interestingly, they have decided to license the area as a single massive block covering 60,288 km^2 in water depths that range from 400 m to around 2,000 m. The block encompasses all nineteen of the exploration wells drilled to date. Three of these wells were drilled in water depths of around 1,000 m, four in 750-1,000 m and the remaining eleven in 400-750 m of water. This is largely a frontier region, and its licensing has been much anticipated following the recent large gas discoveries at Timpan, Layaran & Tangkulo to the south in deep-water offshore North Sumatra.

A successful licensee would secure a large tract of acreage covering an entire basin in a country where gas discoveries would have a significant value to help counteract the need for increasing LNG imports and declining domestic gas production. Work commitments and commercial terms have yet to be announced, and it will be interesting to see how they differ from the terms previously applied to the Gulf of Thailand, where water is much shallower and there is existing infrastructure.



The block that is now available for bidding is indicated by the yellow / orange overlay. Please note, only the Mergui Basin wells have been classified as dry or having shows – wells in Indonesian waters have not.

Exploration in the Mergui Basin has been intermittent, starting in 1976 when twelve wells were drilled. This was followed by a second phase of drilling in 1997, during which a further five wells were completed. A single well was drilled in 1987, and the last well drilled was 25 years ago, and it was in the far north of the basin, close to the Myanmar border. The basin is currently covered by around 45,000 km of 2D seismic.

Four of the 19 Mergui wells had significant untested gas columns; three in Upper Oligocene sandstones (W9-B1, W9-E1 and Mergui-1) and one in Lower Miocene carbonates (Kantang-1). These were all drilled in 1976 during the first phase of exploration, when the main focus was finding oil. These are the same ages as the North Sumatra discoveries further south in Upper Oligocene turbidites in Timpan, Layaran and Tangkulo in the deep-water offshore and Lower Miocene carbonates in the Arun and Lho Sukhon fields onshore.

Oil and gas shows were also recorded in the Middle Miocene and Oligocene in the Thalang-1 well, and possible oil shows in the Oligocene in the Trang-1 well. None of the Mergui Basin wells reported any CO_2 or H_2S associated with the gas. Many of the dry wells were drilled to target Lower Miocene carbonate build-ups of similar age to those of the large Arun and Lho Sukhon fields, discovered in 1971 and 1972, respectively, onshore North Sumatra.

The deeper water western areas in Thai territory are therefore unexplored and hold potential to test the successful plays recently drilled to the south in Indonesia. ■

OIL & GAS

A new frontier for Nigeria's stranded associated gas

Underground gas storage in the Niger Delta

CHIMEZIE UDUBA, BARIKORNDUM NEEDAM, ADEDOTUN OLALERE, CHINWEIKE OKEKE, TEMIM YUSUF, RASAK SUNMONU, KAZEEM A. LAWAL AND SEGUN OWOLABI, FIRST E&P

NIGERIA'S Niger Delta remains one of the world's most prolific hydrocarbon provinces. Yet, the region continues to grapple with the challenge of managing and monetising associated gas (AG) in oil fields developed ahead of gashandling infrastructure. In many offshore developments, early oil production proceeds long before gas export routes are ready, leaving operators with few options beyond routine flaring.

A pioneering shallow-offshore project by FIRST E&P is now demonstrating a pragmatic, geoscience and engineering-driven alternative: Temporary underground storage of stranded AG in a virgin gas reservoir. This approach enables cleaner early-phase oil production while preserving gas for future monetisation once downstream infrastructure comes online.

A FIRST IN OFFSHORE NIGERIA

In this case, two shallow-water fields – Anyala (PML 53) and Madu (PML 54) – producing to a shared FPSO – lacked immediate access to a gas-export system. Rather than flare 30-35 MMSCF/d of separated AG, FIRST routed the gas through a 23 km subsea pipeline into a dedicated virgin reservoir (M-8000) via a newly drilled well (M-8), designed to operate initially as an injector and later as a producer.

The results have been striking. In 18 months, the project successfully stored more than 10 BSCF of AG, with flaring intensity dropping from nearly 80 % at project start to below 5 %. These achievements position the development firmly within the category of "advantaged oil".

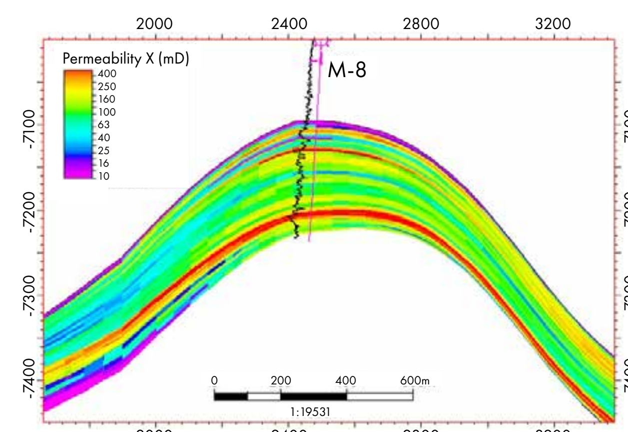
The reservoir's response has been exemplary. Bottomhole and wellhead pressures remained stable, indicating a laterally extensive permeable reservoir capable of sustained injection without adverse pressure buildup. Injectivity transitioned seamlessly from early transient behaviour to a stable pseudosteady state, with rates reaching 30-39 MMSCF/d.

Three pressure fall-off tests confirmed no induced fracturing, validating that injection remained well below fracture-initiation thresholds. Skin factor reductions reflected progressive near-wellbore cleanup, and benchmark analyses placed well M8 in the top decile of global open-hole gravelpack gas injectors.

Our dynamic reservoir simulation model, updated with 18 months of surveillance data, predicts minimal aquifer movement – only about 5 ft – even after more than two years of continuous injection. This indicates strong containment and a low risk of early water encroachment during future production of both stored and native gas.

A blueprint for emission reduction and effective resource management

Beyond its technical significance, the project offers a compelling model for emissions reduction and responsible resource management. For Nigeria, this storage solution provides a scalable, sustainable and economically sound approach. It enables early oil revenues without compromising environmental performance and safeguards molecules essential to the country's long-term gas utilisation strategy. To that effect, surveying has already started to build a short pipeline required to connect the gas storage site with the existing Eastern Offshore Gas Gathering line that connects to an onshore LNG plant. Once this is all in place, FIRST plans to produce 70 MMSCF/d initially, ramping up to 100 MMSCF/d. It will be a good moment to start reaping the benefits of the investments made. ■



Cross-section showing the well M-8 and permeability distribution in reservoir M-8000.

FEATURES

"If you grow up in an oil country, it is your dream to work in the oil and gas industry"

Anonymous interviewee

FEATURES

Unlocking the deep offshore potential of the Mahanadi Basin

New clues from Paleogene isolated carbonate banks and turbidite deposits

SRINIVASAN KRISHNAN, MICHAEL CASTELE, AND DAVID HUME, UNIVERSITY OF HOUSTON / DGH COLLABORATION

THE EASTERN Continental Margin of India (ECMI) is a 2,500 km long passive margin that comprises the following peri-cratonic basins from south to north, the Cauvery, Krishna-Godavari, Mahanadi, and Bengal Basins, of which the deeper parts remain largely underexplored. Currently, exploration operations are conducted in onshore and shallow water zones of peripheral basins. Oil and gas discoveries in the Krishna Godavari and Cauvery peri-cratonic basins demonstrate the potential for a functioning petroleum system in shallow- and deepwater settings. In contrast, in the Mahanadi Basin, discoveries are limited to biogenic gas within Neogene reservoirs. However, its deeper Eocene succession remains untapped, mainly offering substantial promise for thermogenic hydrocarbon exploration.

Source rocks along India's East Coast Margin, linked to existing hydrocarbon finds, span the Early Cretaceous, Paleocene, and Eocene periods. Regionally, the Cauvery, Krishna Godavari, and Bengal Basins provide potent analogs, with well-established Cretaceous, Paleocene, and Eocene source intervals. These intervals are expected to be even more prominent in the deep offshore regions of the Mahanadi Basin. Given the shared geological evolution and depositional history across the eastern offshore basins, the presence of similar Paleocene and Eocene source facies in the Mahanadi Basin is highly plausible, reinforcing its potential as a future exploration hotspot. The basin features extensive carbonate platforms, including both shelf-attached platforms and isolated deepwater banks, reflecting a complex depositional setting. Most drill wells are in shallow offshore waters, and a few extend into the deep offshore. However, none of the wells have penetrated the Paleogene isolated carbonate banks and the low stand turbidite deposits.

Structurally, it is divided into sub-basins bounded by the volcanic highs of the 85° E Ridge, further complicating its tectonic and stratigraphic architecture. Together, these geological attributes and regional parallels position the Mahanadi Basin as a compelling candidate for deeper, thermogenic hydrocarbon exploration. This article aims to highlight the deep offshore potential through an integrated analysis consisting of detailed seismic interpretation, well log analysis, detailed lead and prospect mapping, basin modeling, and volumetrics.

The passive continental margin of East Coast India developed following India's breakup from Antarctica. The breakup occurred around 136-132 Ma

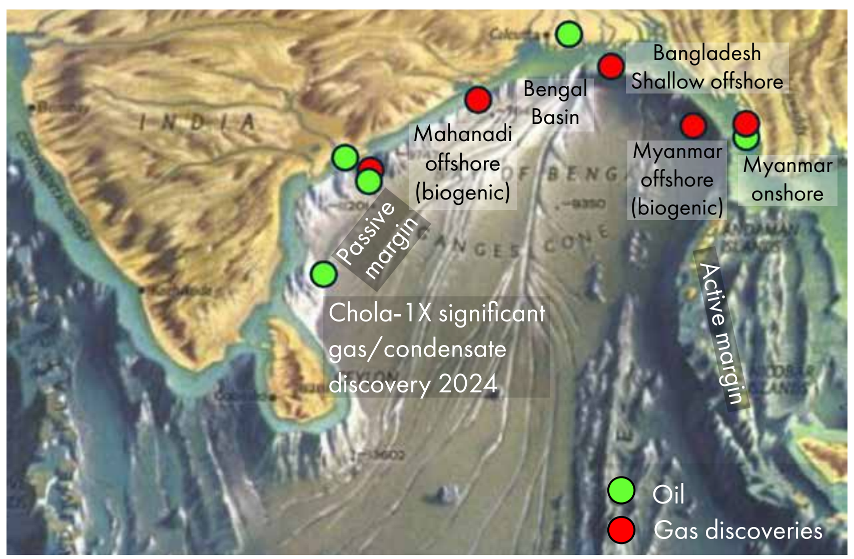


Figure 1: Oil and gas discoveries ECMI.

Well	Bathy (m)	Drilled Depth (m)	Potential Source Rock Interval (m)	Age	TOC (%)	S_2 (mgHC/g)	VRo (%)
K	776	3,545	1,990 - 2,025	Early Oligocene	1.01 - 1.39	2.42 - 3.86	0.4 - 0.47
L	778	3,779	2,780 - 2,850 3,330 - 3,510 3,720 - 3,730	Cretaceous	1.85 - 2.96 1.42 - 2.47 1.33	2.5 - 2.6 2.8 - 6.4 4.9	-
M	2,552	2,767	Absent	Cretaceous	<0.5	<2	-
N	608	2,416	Absent	Cretaceous	<0.5	<2	-
O	2,678	7,084	3,500 - 3,520 4,860 - 4,880 5,050 - 5,060 6,010 - 6,040	Paleocene Cretaceous Cretaceous Cretaceous	3.99 1.07 2.06 2.0-2.2	3.7 - 4.17 2.6 3.61 2.5 - 3	- 0.46 - 0.5 0.46 - 0.5 0.6 - 0.66
P	1,500	2,425	Absent	Pliocene	<0.5	<2	-
Good to excellent source rocks are observed in Paleocene and Cretaceous sediments in two wells of the Krishna Godavari deep water in the Eastern deep offshore.							

Table 1: Summarizes the source rocks deep offshore (Pande et al., 2008).

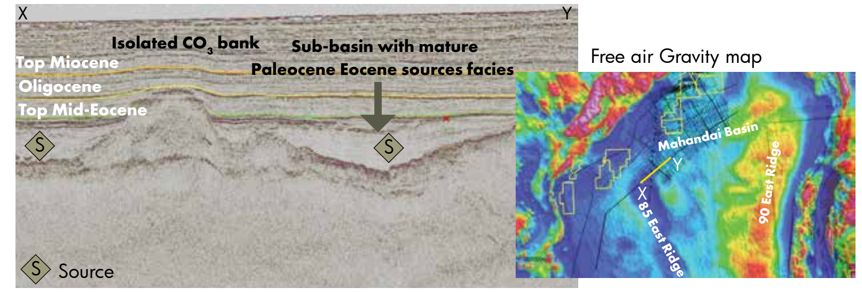


Figure 2: Free air gravity map and seismic line illustrate restricted basin conditions for the Mahanadi Basin to the emplacement of the 85 East Ridge and 90 East Ridge volcanic highs. Both ridges were from a hotspot that was emplaced during the upper Cretaceous.

(Rao, 2001). Three distinct phases of evolution marked this passive-margin continental margin: An intracratonic rift, post-rift thermal subsidence, and a passive continental margin. From north to south, the four important basins are the Bengal, the Mahanadi, the Krishna-Godavari, and the Cauvery. Oil and gas discoveries occur onshore and shallow offshore within these basins (Figure 1). Recently, a few biogenic gas discoveries have been made in both the shallow and deep offshore Mahanadi Basin. Biogenic gas discoveries are limited to Neogene reservoirs. However, much of the deep offshore and the Paleogene and Cretaceous successions are largely unexplored (Srinivasan et al., 2023). The key to unlocking the potential lies in a strong understanding of the petroleum system elements, which we believe exist in this vast, underexplored area. The University of Houston / Directorate of Hydrocarbons India collaboration, through an integrated state-of-the-art analysis, has unlocked the potential in the deep offshore.

SOURCE ROCKS

Fundamental to a working petroleum system and basin-opening discoveries is the presence of robust source rock intervals. Rifting history and regional geological understanding indicate the presence of multiple source rock intervals, including the lower Cretaceous Aptian.

The Mahanadi Basin is straddled between the Krishna Godavari, Bengal Basin, and the Assam shelf, where oil and gas discoveries are linked to the Paleocene / Eocene: The Ravva oil field and deepwater oil and gas discoveries in the Godavari Basin. Similarly, onshore oil and gas discoveries in the Bengal Basin and the Assam Shelf are associated with Paleo-Eocene source facies. Given the similarities in the stratigraphic succession, we anticipate the existence of Paleocene / Eocene source rocks deep offshore the Mahanadi Basin. Pande et al (2008) provide supporting evidence for the existence of Paleocene-Eocene source facies with excellent TOC content deep offshore. The Paleocene-Eocene epochs are known for two significant hyperthermals: The Paleocene-Eocene Thermal Maximum (PETM) and the Eocene Thermal Maximum 2 (ETM2). While these events are not formally classified as Oceanic Anoxic Events (OAEs) in the same way as those of the Cretaceous period, they did feature ocean deoxygenation and black shale deposition, which are characteristic of OAEs. The oil and gas discoveries in the greater ECMI region, linked to Paleocene-Eocene source rocks, support the presence of Paleocene-Eocene in the deep offshore. Restricted-basin conditions facilitate the deposition of source facies. The Mahanadi Basin in the Paleocene-Eocene likely experienced restricted basin conditions (Figure 2) in response to the emplacement of the 85 East Ridge and 90 East Ridge volcanic highs. Both ridges were from a hotspot that was emplaced during the upper Cretaceous.

A 1D basin model wherein we simulated two pseudo-wells deep offshore beyond the OCB. Three scenarios – low (0.5 %), medium (1.5 %), and high (5 %) – were modeled for TOC. All the cases ▸

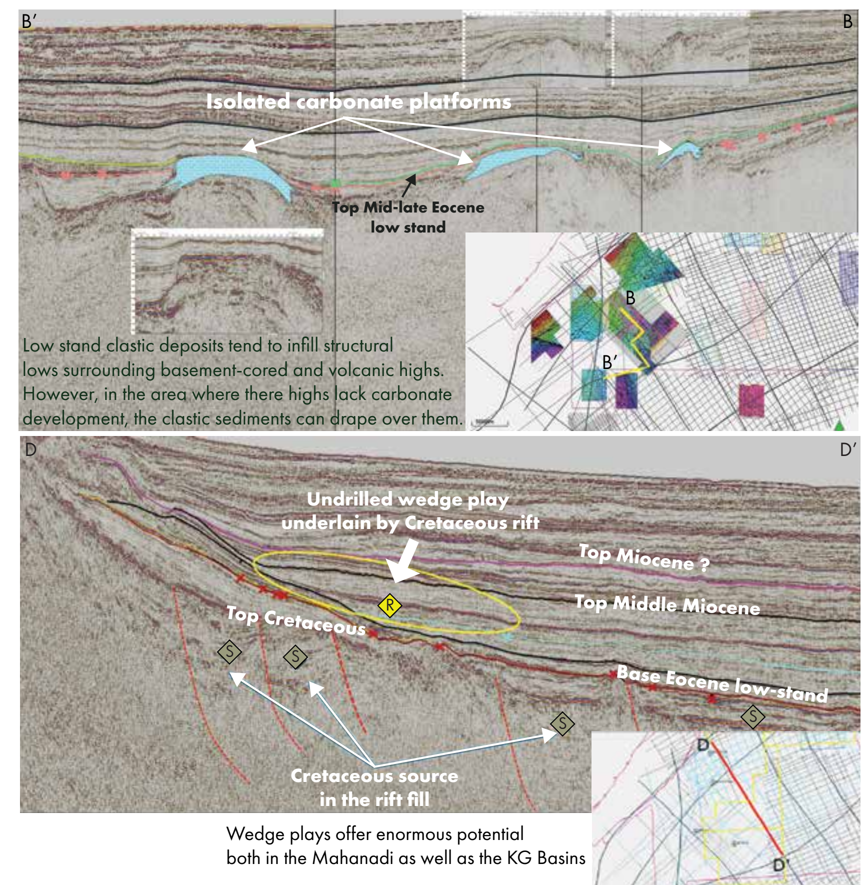


Figure 3: Seismic lines illustrating the play types and leads/prospects.

highlighted an active petroleum system in the deep offshore areas. In cooled oceanic basement, the maturity of organic-rich intervals occurs at burial depths > 3 km (Cunha et al., 2018). Our detailed mapping and depth conversion reveals that we have the necessary sedimentary thickness (~5 km) to drive maturity deep offshore in the Mahanadi Basin.

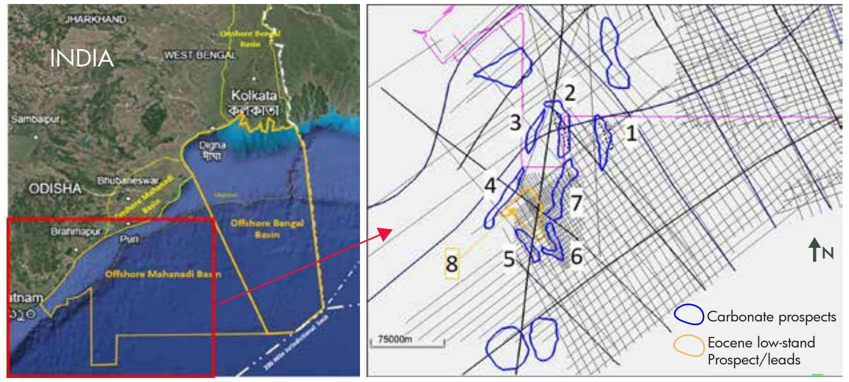


Figure 4: Mapped prospects and leads.

ISOLATED CARBONATE BANKS AND LOW-STAND TURBIDITE DEPOSITS

Much of the deep offshore Cretaceous succession is dominated by low-stand deposits derived from the hinterland drainage systems, including those of the Krishna-Godavari, Cauvery, and Mahanadi rivers (Bastia, 2007). However, in contrast, the early Paleogene highlights fundamental stratigraphic differences: The Mahanadi Basin was dominated by widespread carbonate deposition. The shelf setting was marked by the development of a ramp to a rimmed shelf carbonate platform. The deep offshore was characterized by isolated carbonate banks that nucleated on basement-cored highs and volcanic mounds associated with the 85 East Ridge. Detailed interpretation of 2D and 3D datasets has enabled us to characterize the early Paleogene carbonate deposits of the Mahanadi Basin. The Middle Eocene was marked by an influx of coarse clastics as indicated by incised valleys and slope channels. Our interpretation reveals that the low stand turbidites were funneled deep offshore. This low stand likely coincides with the late Middle Eocene global relative sea-level fall.

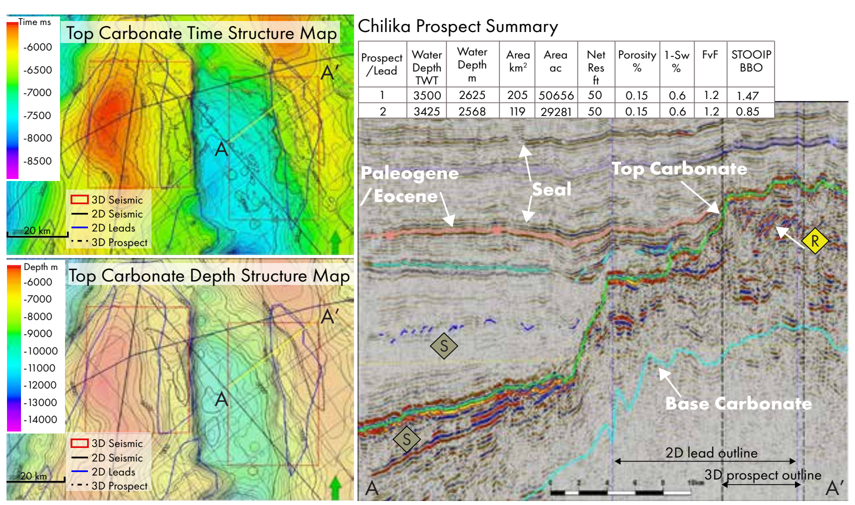
The depositional motif changed in the early Neogene. The prograding Bengal Fan from the north dominates the depositional systems. Broad, deep-water distributary systems likely constitute reservoirs for the Neogene succession across all the basins of the east coast margin. The biogenic gas discoveries of the Mahanadi Basin are within the Neogene reservoirs.

PLAY TYPES & PROSPECTS

We have identified several carbonate prospects and leads, as well as turbidite leads. The carbonate leads are isolated carbonate banks that grew on basement-cored highs and volcanic highs. Typically, these isolated carbonate banks form four-way closures with the source facies in the adjacent deeper parts of the basin. We have identified middle Eocene (?) incised valleys that serve as conduits for the delivery of coarse clastics into the deep offshore. These coarse clastic intervals have been mapped deep offshore. Drill well, MDW10 found thermogenic pay in a 2-meter clastic interval within the interpreted Eocene incised valleys (Das et al., 2012). Trap types include both structural and stratigraphic traps, including large four-way closures, low-stand wedge pinch-outs, and strati-structural entrapments (Figures 3, 4 and 5). Hydrocarbon migration occurred from mature Paleo-Eocene source rocks along faults and carrier beds, forming significant accumulations. Volumetric analysis illustrates a resource of 22 BBO distributed across multiple prospects and leads.

SUMMARY

Robust play elements likely characterize the deep offshore Mahanadi Basin. Our integrated analysis highlights new insights into the deep offshore succession. We have identified and mapped eight distinct carbonate prospects and leads deep offshore. These isolated carbonate banks typically form four-way structural closures, with source facies located in adjacent deeper basin areas. Based on preliminary estimates, these features may hold volumetrically significant potential. In addition, we have delineated several turbidite leads associated with middle Eocene low stand deposits in the deep offshore. These features represent additional exploration targets with potential for hydrocarbon accumulation. Our volumetric analysis reveals an in-place resource of 22 BBO distributed across multiple carbonates and turbidite prospects and leads. ■



Chilika Prospect Summary

Prospect /Lead	Water Depth TWT	Water Depth m	Area km²	Area ac	Net Res ft	Porosity %	1-Sw %	FvF	STOOIP BBO
1	3500	2625	205	50656	50	0.15	0.6	1.2	1.47
2	3425	2568	119	29281	50	0.15	0.6	1.2	0.85

Figure 5: Carbonate prospect example.

Offshore Algarve Basin geological carbon storage potential

Portugal emits roughly 40 Mt of CO_2 each year (APA, 2025), with about a quarter (10 Mt) coming from the country's ten largest industrial point sources, including refineries, gas-fired power plants, and cement production. This study evaluates the geological carbon storage (GCS) potential of the offshore Algarve Basin, highlighting its capacity to support the decarbonization of Portugal's hard-to-abate industries and strengthen the national climate strategy

TIAGO CUNHA, IGI, HUGO MATIAS, NET4CO2, MARTIN NEUMAIER AND NICKY TESSEN, ARIANELOGIX

In the Algarve Basin, two late Miocene plays have been identified southeast of the Faro Peninsula using high-quality seismic and borehole data (Figure 1). These comprise of high-porosity turbiditic sands of Tortonian and upper Messinian age, overlain by regionally extensive, shale-dominated seals (Ng et al., 2022).

Their GCS potential reflects the interplay of stratigraphic architecture and structural closures. The stratigraphic features were recognised along sedimentary fairways interpreted from the morphology of the late Messinian and top Tortonian surfaces. The structural traps are predominantly salt-related, including reservoir pinch-outs against diapir flanks and four-way anticlines above diapirs (Matias, 2007). Five prospects have been identified, based on the lateral continuity of the Messinian (Prospects 1, 2 and 3) and Tortonian (Prospects 4 and 5) reservoirs.

PROSPECT ANALYSIS

Figure 2 illustrates the workflow for Prospect 5, showing the parameterisation of key Monte Carlo simulator inputs and predicted outputs. The analysis focuses on the theoretical storage resources, based on net pore volumes (NPV), which are dependent on the size of the trap and the proportion of reservoir rock and the porosity (Figure 2A). The thermal model uses a mean geothermal gradient of ~31° C km^{-1}, consistent with regional constraints (Muñoz-Cemillán et al., 2025), and a surface temperature of 11.8° C, averaged from the CTD data within the study area (EMODNet). Hydrostatic pressures at the crest of the prospects vary between 9 and 14 MPa. To account for potential overpressure fracturing, a fracture gradient is applied (Figure 2B). Figure 2C shows that Prospect 5 carries some risk of liquid CO_2 under lower than average geothermal gradients, a very small risk of top seal leakage, and substantial theoretical resources (p50 of ca. 2.3 Gt of CO_2).

Table 1 summarises the key aspects controlling the variations in NPV, theoretical resources and phase in the modelled prospects. Prospect 2 holds significant NPV, but a high risk of liquid CO_2, as a result of shallower burial, and will not be considered in the overall estimation of resources. Prospects 1, 3 and 4 show low to medium risk of liquid CO_2 and ►

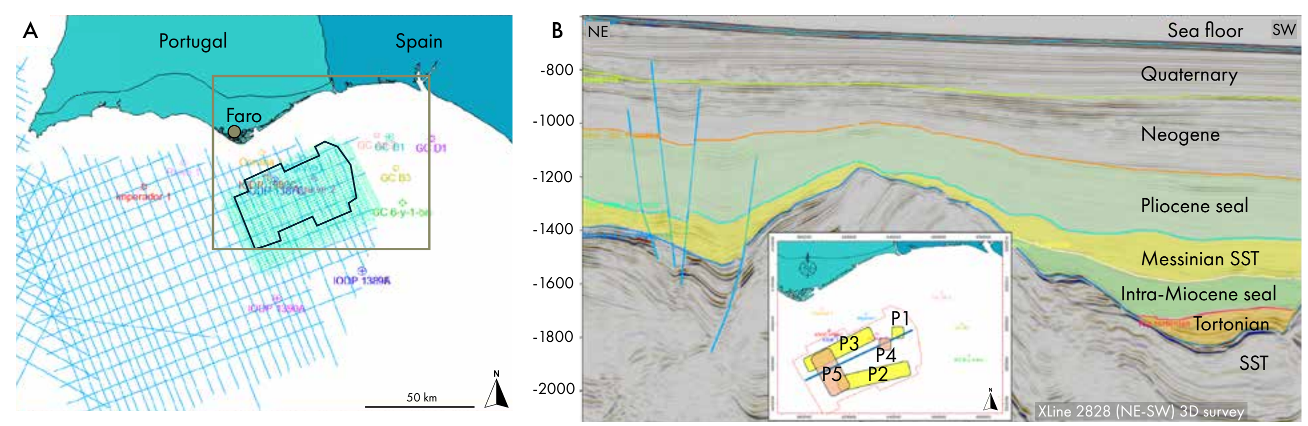


Figure 1A: 2D and 3D seismic data (TGS-001 survey) and location of commercial and IODP boreholes offshore Algarve (southern Portugal). 1B: Cross-section highlighting the late Miocene GCS plays. The inset shows the relative locations and sizes of the Messinian (yellow) and Tortonian (orange) prospects.

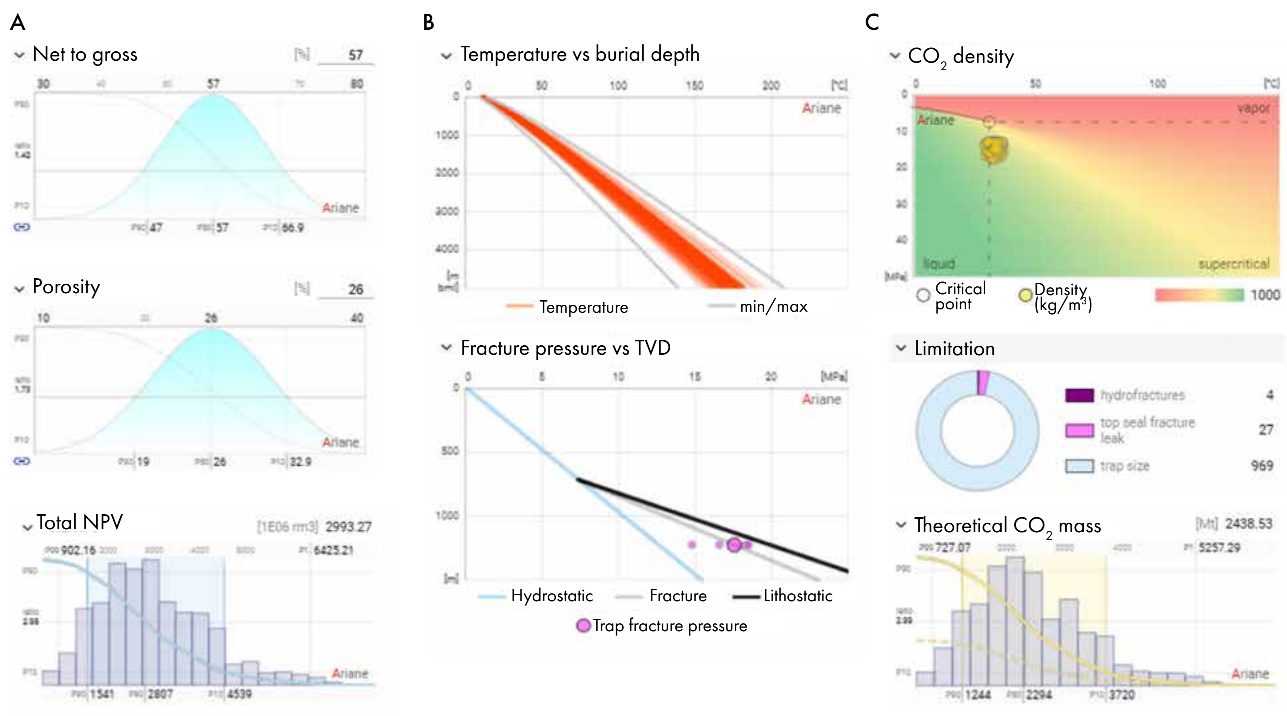


Figure 2: Monte Carlo simulator inputs and outputs for Prospect 5. A: Reservoir definition (top) and pore volumes (bottom); B: Thermal model (top), pressure and seal integrity (bottom); C: Predicted phase and density (PVT, top), limiting factor (middle), and theoretical storage capacity (bottom).

may also contribute to the GCS potential of the area.

GCS RESOURCES

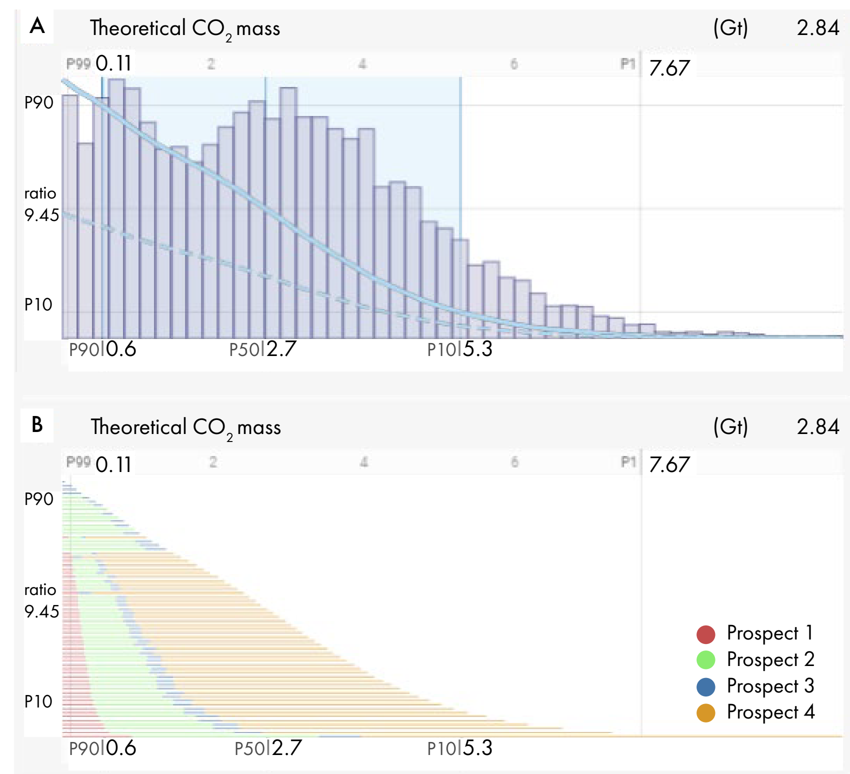
Prospects 1, 3, 4 and 5 have been combined to estimate the range of possible theoretical resources for the entire block. A probabilistic aggregation of multiple prospects consists of calculating both risk and success case CO_2 masses as part of an interdependent co-simulation of all individual prospects. These prospects can be related to each other via risk dependencies: If one prospect succeeds, other dependent prospects are also likely to succeed, and volume parameter correlation (e.g. porosity, NTG).

The likelihood that at least one prospect succeeds is 48 % (prospect cluster chance of success). In case of success, the theoretical resource range (Figure 3A) is very large – 116 Mt (p99) to 7.6 Gt (p01) – reflecting early exploration uncertainty. A more realistic conservative-to-optimistic range is 0.6 Gt (p90) to 5.3 Gt (p10). The mean theoretical resource is 2.8 Mt, with a median of 2.7 Mt (p50).

The most likely outcome is represented by the peaks in the resource distribution (either <200 Mt, 1 Gt or 3 Gt), dependent on the possible combinations of successful prospects. There are a few possible cases where either Prospect 3 or Prospect 4 are the only ones to succeed (<200 Mt scenarios). The 1Gt scenarios exclude Prospect 5, whereas Prospect 5 (chance of success 35 %) is needed for the cluster to exceed 2 Gt with a most likely of 3 Gt.

	Prospect 1 (Messinian)	Prospect 2 (Messinian)	Prospect 3 (Messinian)	Prospect 4 (Messinian)	Prospect 5 (Messinian)
Area (km²)	49	154	137	26	193
WD range (m)	438-510	522-860	484-744	515-558	558-858
Av. Burial (m)	715	600	822	1019	740
Av. Res. Thick (m)	60	160	50	70	110
P50 NPV (m³)	$390 \cdot 10^6$	$2702 \cdot 10^6$	$885 \cdot 10^6$	$231 \cdot 10^6$	$2806 \cdot 10^6$
P50 Theor res. (Mt)	276	2246	692	174	2294
CO_2 phase risk	Low-medium	High	Low	Very low	Low-medium

Table 1: Key features and predicted resources in modelled prospects.



C	Theoretical resource (Mt)	Target effective storage capacity (Mt)	Required storage efficiency (%)
P90	506	200	40
P50	2707	200	7
P10	5172	200	4
ML - small prospects only	200	200	100
ML - p5 not working	1000	200	20
ML - p5 working	3000	200	7

Figure 3: Aggregation of prospects 1, 3, 4 and 5: Histogram and cumulative distribution function of prospect cluster (A), contribution of each prospect to the cluster (B), and summary of theoretical resources versus target effective resources.

DISCUSSION

Meeting a 200 Mt storage target over 20 years requires converting theoretical resources into effective capacity, which depends on storage efficiency. This is still uncertain for the Algarve margin. Even so, the results indicate that conservative scenarios or those excluding Prospect 5 would require unrealistically high efficiencies (Figure 3c). Prospect 5 should therefore be the focus of further work, including pore volume refinement, dynamic simulation, and risk assessment, with other prospects providing supplementary capacity. ■

We acknowledge the funding program 01/C05-i02/2022, financed by PRR (Next Generation EU). The authors would like to thank DGEG (Portugal) for providing the data for this study.

Hunting for sands

How the depth accuracy of your formation tester is impacted by well design, tool-string configuration and mud rheology, and why this is more and more of an issue these days

If a school bus driver is instructed to stop the vehicle within a fraction of a meter, there needs to be systematic speed and brake control in place. Otherwise, the bus will likely overshoot or undershoot by several meters.

"The same is true for putting a formation tester at the right depth in a well," says Guy Wheater, R&D manager at Gaia Earth Group, "especially when it comes to present-day deep and tortuous wells."

The normal procedure for formation tester depth control is to tie it to a reference log from a previous logging run, carefully matching the gamma ray curves. In essence, it is a "dynamic correlation". However, once the winch speed changes, the tool depth may no longer agree with what the winch panel says; the tool may stop deeper or shallower than required, via anti-creep or creep, respectively.

Creep occurs in deeper wells when the winch is stopped: The tool will keep moving in the direction of travel (up or down) until the tension along the cable equalises. Anti-creep occurs when the tool is grabbed by sticky formation, usually at slower speeds, and although the cable continues to be spooled on the winch drum, the tool is not moving.

HOW TO MEASURE CREEP?

A common way to estimate creep is to come up-hole and stop the tool 3 ft below the top of a definitive sand, followed by observing the raw gamma ray signal. If the reading ends up low, we are still in the sand, and we need to try again with a smaller distance. If the creep is estimated to be 2 ft, the tool is stopped at 15,002 ft for a pretest at 15,000 ft. This is an erroneous assumption because other transients may greatly affect the tool position: Lag, creep-down, tool-grab, cable stretch, spring, bounce, and finally, creep-up. Most of the non-creep transients are not currently considered or evaluated for formation tester depth control. From a dynamics perspective, a logging tool is just a "dumb-weight on the end of a long elastic band in a tortuous pipe full of gooey fluid" – it is a deeply complex system: The well depth, tortuosity, rheology, temperature profile and tool-string weight all drive up the transients and depth uncertainties.

"In shallow vertical wells with ample fluid bypass, using a simple and short formation tester in a 12 ¼" hole of 5,000 ft deep, you can reliably put the probe at the desired depth and gain consistent data, well to well," Guy explains. "That's because the Coulomb drag, cable stretch and creep are minimal, and the tool and cable stictions are generally low."

When the cable stretch and stictions are high, the winch and tool movements may become decoupled. In fact, there may be periods when the cable and tools move in opposite directions along the wellbore. Furthermore, the tool acts as a piston in the mud column, damping and extending these decoupling events.

"The depth and complexity of wellbores and tool-string designs has progressed tremendously over time," continues Guy. "For instance, large formation testers can now weigh over 9,000 lbf in air, the wellbores may be deep and tortuous and have large temperature spans, which impacts the rheology and mud gelling forces."

Granted, in some places like the GOM, people do correct for tool-string creep, but downhole dynamics measurements over the last seven years have proven that creep is highly variable, and a uniform depth correction for each station is likely inaccurate.

In order to quantify creep, the team at Gaia used one of their own digital stand-off tools (WXSO®) that is fixed on the cable just 50 ft above the tool-string to better estimate tool-string and winch movements in a wellbore. When tool-string movement takes place, the WXSO® registers road noise via tri-axial accelerometers, which gradually fades when the winch is stopped. That gave the team an alternative method to compute creep time and distance.

"We wanted to offer better creep estimates for upcoming jobs, based on well depth, trajectory, mud weight and tool-string dimensions," explains Guy.

In order to pull together a database of measurements, the company collected data from eight wells drilled in the GOM, ranging in depth between 17-30,000 ft. "Intuitively, we expected more creep in deeper wells because of more stretch in the wire," says Guy.

MORE THAN PLANNED

Running the formation tester tool is usually the most time-consuming element of a logging programme. On a good day, with reasonable hole and permeability conditions, you can gain 5 to 6 pretests an hour, including a correlation pass. But because of winch-tool decoupling (off depth data) campaigns that have 40 tests planned can easily escalate to 60+.

"Instead, we found uncorrelatable sets of data, to a point where we could not offer anything meaningful for creep corrections. We needed to take two steps back and conclude that what we had measured was real, and that larger events were happening downhole. Other transients were at play, with the capacity to dwarf creep itself," says Guy.

"What most clients do," he continues, "is to make a U-turn (down-then-up) to arrive at the desired station depth. The reason clients like doing that is because dropping off each station is a good stick test and also correlating up to the station can be routinely monitored. But whilst doing this U-turn, especially in deep and tortuous wells, a lot of things can throw you off depth.

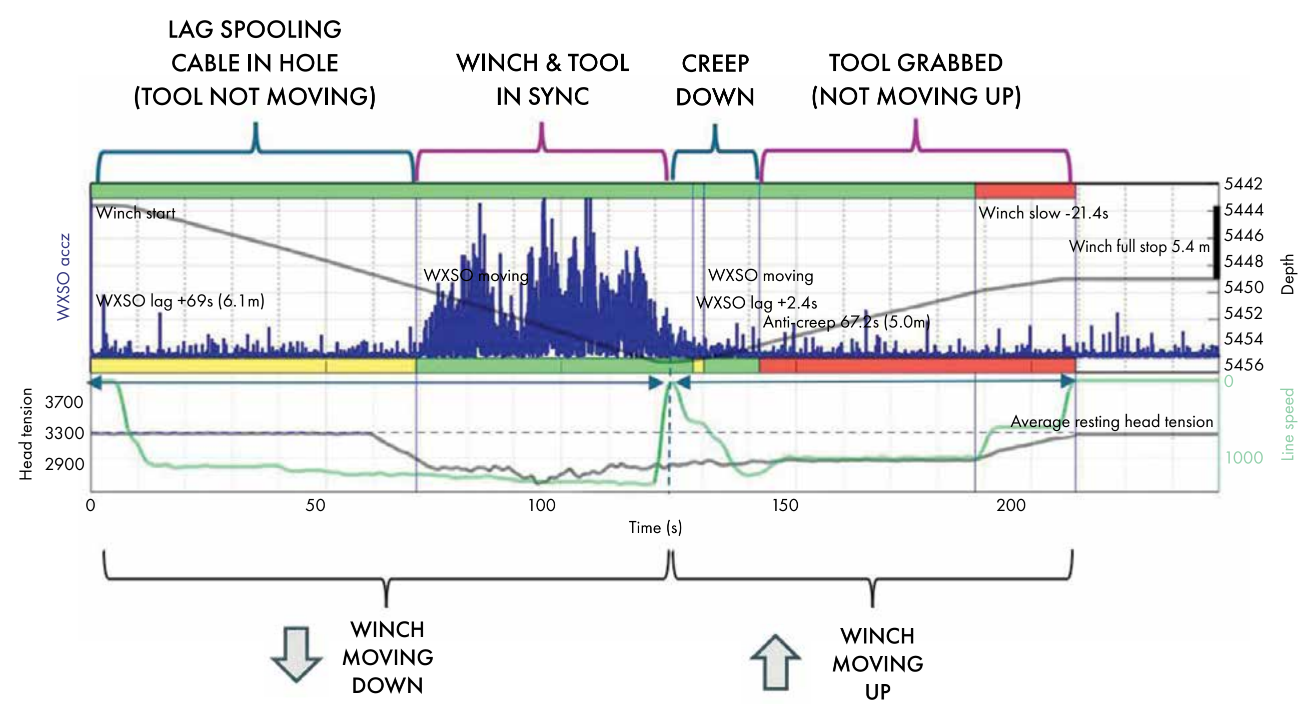
> **"There can be a large disconnect between people looking at NMR logs, doing very detailed sand and shale assessments and coming up with very specific depths for pressure measurements, versus the reality where targeting certain sands in a given environment may be infeasible due to unfavourable dynamics, leading to winch-tool decoupling and depth errors. Clients should be aware of their environment and capacity for test point targeting in advance, and adjust their work plans if necessary"**

Let's look at the plot below, demonstrating the conventional U-turn strategy, and how anti-creep can cause a major problem. First, we can see lag, then the tool and winch are in sync', moving downhole together before the tool is grabbed and the cable is just being stretched coming up to station. In the end, the probe may be set >5 m deeper than planned, approximately 10 times what the creep correction might have been.

"We also think it is preferable to travel just in one direction (no U-turns), staying in a lower tension regime and keeping on depth real-time," Guy says. "That way, you eliminate the majority of transients that may be induced from high-low-high tension cycling."

Guy and his team are now building an advanced modelling package to simulate wireline dynamics and devise optimal survey strategies with bespoke winch controls. "In logging programs," he says, "there is often talk about gauge stabilisation etc., but there is very little about depth control or winch driving. The potential savings in rig time and survey charges through detailed job planning and execution should be significant in deep or tortuous wells." ■

Henk Kombrink



From the moment the winch starts spooling in cable (left), we can first see a lag where the tool-string remains at a standstill. Then the tool-string starts moving downhole and is in sync' with the winch for a while. The winch then stops and changes direction to bring the tool-string up to the next station; in reality, it creeps down for a short while but becomes stuck and does not move up again. In this example, it is likely that the tool stops ~5 m deeper than planned.

Before the collapse in oil production, Venezuela saw another collapse – the mass firing of most of PDVSA's technical staff

Conversations with former PDVSA employees who share the story of how they experienced the destruction of the state oil company after the Chávez takeover

Many people on LinkedIn wrote about the dramatic decline in oil production in Venezuela from 3 MMbbl/day in 1998 to only a third of that twenty years later. How could this happen? Based on conversations with two people who worked for Petróleos de Venezuela S.A. (PDVSA) at the time Hugo Chávez took power in 1999, there is at least one factor that explains why this happened: the mass sacking of most of the technical staff. In one go.

Before going into this, it is important to stress that the names of the people quoted here are fictitious. That is to guarantee the safety not so much for themselves, as they are abroad already, but for any remaining family members living in Venezuela. Because the people who are there have not had a chance to celebrate the potential new chapter the country is entering now.

In contrast, there is a lockdown in place in Venezuela right now, and people who are found walking the streets without a good reason can be asked to show their mobile phones by the colectivos, a gang funded by the Maduro regime. If there is any negative commentary about the government in their chats, they are in serious trouble.

So, even though there are no celebrations in Venezuela at the moment, for many, there is a glimmer of hope that things will change. For the two people I spoke to, Susan and Jennifer, 26 years of oil industry destruction may have come to an end. The contrast with how the company looked when this all started in 1999, when they were both working for PDVSA, is stark.

"Let's start by saying that our country was not perfect in the late nineties," says Susan. "There was corruption, there was inequality and there were certainly aspects of ►

PHOTOGRAPHY: CARACASCHRONICLES.COM

Archivo Diario de Caracas, 2002: The firing of PDVSA's board triggers a national crisis and an opposition march to Miraflores demanding Chávez's resignation.

society that needed to be improved. But at the same time, we had opportunities to build a career, also for people from humble backgrounds."

"If you grow up in an oil country, it is your dream to work in the oil and gas industry"

What is really striking is that both Susan and Jennifer specifically mentioned the pride that came with working for PDVSA. It was a goal in life to get there, also because the recruitment process was very much based on merit and not on background.

"When I was in year 7, I knew that I wanted to be a geologist and work in the oil and gas industry," says Jennifer, "even though I lived in the mountains where there was no oil production whatsoever."

"In Britain, people speak about Henry VIII," she continued, "but in Venezuela, people talk about the times when the oil industry kicked off. It is a matter of pride. People know about the first well that started production in 1914, Zumaque-1, on the eastern border of Lake Maracaibo. We grew up with that."

Whilst she was still studying, Jennifer was offered a scholarship by PVDSA. "It was the sign that you were going to be offered a job after that," she says. The scholarship also came with six-week-long internships in the company; visiting the rigs, doing well correlation exercises, and looking at cores. "It was a taster," she says, "almost like *this is how it's going to be when you join us*, even before I had formally signed a contract."

"But from the moment I did join the company, I had the same experience as during my scholarship; having the chance to look at different divisions of the company and getting familiar with a diverse range of business lines, from upstream to midstream. In addition, you still had to study and get good grades."

Hugo Chavez blows the whistle, firing PDVSA leaders live on TV during "Aló Presidente."

PDVSA INTEVEP employees used to have a gas station on site.

After this first year, Jennifer was sent to a smaller subsidiary office along the shores of Lake Maracaibo. "I had to work hard, and the place wasn't very attractive, but hey, there was a lot of oil around. We also received a bonus twice a year, a Christmas bonus and a production bonus. Really, my only incentive to leave my job was to do a master's degree or PhD abroad, and then come back to the country."

Susan's experience is similar. "At the end of my studies," she says, "I was fortunate to get a six month internship with INTEVEP, the Research and Development Centre of PDVSA. It was a huge facility, almost a city, with world-class labs, just outside Caracas. It was a great working environment with lots of high-skilled and technical people. It became even better when I was offered a job before the end of my internship, in 1997. The atmosphere was very much like in the West," she continues. "Nobody cared about which politician you favoured; it was very much based on how you performed technically. As it should be."

But the working environment started to change quickly when Chávez took power in 1999.

"As expected," Susan said, "once Chávez started his presidency, the first thing he targeted was PDVSA. Before his time, it was a relatively independent company, even though it was owned by the state. The money that was made was paid to the government in the form of royalties and taxes, but a significant part of the profit was reinvested to improve equipment, technology and human resources."

The Chávez administration changed the game and started to use PDVSA as the cash cow to fund his Socialist Revolution, with no control whatsoever, leaving PDVSA without the means to reinvest and improve the main source of income for the country. "I personally saw politicians visiting our labs in PDVSA, not for ceremonial purposes, but to start gathering information on who was supporting the revolution and who was not," says Susan.

Chávez also started to replace managers at all levels with people from the military who had no clue about the industry.

For Susan herself, it was obvious that the new doctrine was a recipe for failure. "We had a couple of colleagues from Cuba in our team," she says, "both with PhD's from Russia. They fled the country in the mid-1990s, as there was a lack of everything, including essentials such as food and electricity. They had to create their own soap in the labs, using pig fats. One of them ate some much beef when he first arrived in Venezuela that he was sick for a month... And we all knew that Cuba formed a shining example for Chávez."

PHOTOGRAPHY: CARACASCHRONICLES.COM

As the situation in the country deteriorated, mass strikes started to take place in 2002. There was also pressure from outside for PDVSA-workers to join the strike. "We were seen as privileged," says Susan, "and to an extent, that was true. We had good and stable jobs with high incomes."

For Susan, it was very clear from the start that she was going to join the strike; she had been an avid opponent of the Chávez regime from the start. "I was probably on *the list* as soon as they started compiling it," she says.

For a little while, Jennifer was not sure what to do because she cared about the company and the foreseeable future. She felt intimidated. But when a peaceful protest ended up in a massacre, instigated by Chávez, she firmly decided to join the strike that started in December 2002.

But did the strikes have any effect? "No," says Susan, "rather the opposite."

Rather than listening to the demands and concerns of the workers, Chávez would hold speeches on TV, called "Aló Presidente" during which he would fire PVDSA managers on the spot, by blowing a whistle, naming someone and saying, "You're fired!"

Others were put on a list that was published in the national newspaper. Susan remembers the day in February 2003 when she found out about her redundancy. "They put me, and about 1,600 colleagues from INTEVEP, up for dismissal in one go."

It was bitter, obviously, also because there was no compensation paid, and people's pension contributions were also stolen. "For me," says Susan, "it was not too big a deal, as I was at the start of my career, but for others who were more senior, it was devastating."

"Ecopetrol in Colombia said thank you Chávez – we don't need to train these people who are now happily coming to work for us"

At the end of the day, 18,000 people were fired over a period of five months. Jennifer was part of that group, too. And who replaced all those people who were let go? Obviously, people who supported Chávez first of all, who supported "El Proceso", the process. "Not the brightest cookies in the jar," says Jennifer. "Many of them had been studying for 12 years and had never shown much ambition."

In parallel, managerial positions also went to people who were loyal to Chávez; having a background in the company did not matter anymore, as was the case before.

So, was PDVSA a company based on the values of working hard before, after the Chávez takeover, this philosophy went out of the window. "We used to be a company based on meritocratic values," said Susan.

Knowing that the company employed around 40,000 people at the time and knowing that it was mostly technical people who were made redundant, there is a very clear indication as to why oil production was to drop.

It is against this backdrop that it becomes easier to understand why so many people were happy with the events back in January 2026, even when there is absolutely no clear path to an immediate turn of the industry. "At the end of the day," Jennifer said, "it is the Chinese and the Russians who are now the owners of a lot of the oil-producing assets. They won't leave by the clip of a finger."

But regardless, there is a flicker of hope again. For some, there may be hopes of returning, but let's not forget how many saw their opportunities squashed and were unable to move abroad and start a new career. They not only lost their jobs, but their pension, savings and futures were stolen at the same time. ■

Henk Kombrink

Moroccan Atlantic Margin:

Where geological diversity meets outstanding exploration potential

As explorers continue to regard Morocco's offshore as an attractive area to invest in, this article provides a summary of the main plays and petroleum geology that are critical to its success

KARIM ATIKA, GUERNOUCHE KARIMA, MANAR MOHAMED AMINE, BENARCHID ASMAE AND DIDI SALWA, ONHYM

The Atlantic passive margin of Morocco is an emerging hydrocarbon province, offering a range of high-potential open acreage opportunities and presenting a unique first-mover advantage for exploration companies. These opportunities are supported by an extensive geological database and modern seismic data, of which a snapshot is shown here.

The margin extends over 3,000 km, from Tangier in the North to Lagouira in the South. It encompasses a significant salt province and holds one of the oldest stratigraphic records documenting the opening history of the Central Atlantic.

This diverse geological setting enabled the development of various exploration plays and targets. These are mainly related to nappe and salt tectonics in the northern segments, and to carbonate platforms, slope-related tectonics, and turbidite fans in the southern segments (Figure 1).

Despite its favorable geology for oil and gas exploration and production, the Atlantic offshore Morocco remains underexplored, with only 45 exploration wells drilled to date. However, extensive seismic acquisition has been carried out along the margin, yielding a considerable seismic coverage of approximately 176,623 km of 2D seismic and 67,888 km² of 3D seismic data.

WHO ARE WE?

ONHYM, the national agency for hydrocarbons and mining in Morocco, plays a central role in promoting and developing the country's energy resources. Through strategic partnerships, high-quality geoscientific data, and a reliable investment framework, ONHYM offers a stable and attractive environment for upstream exploration in Morocco and direct access to high-value subsurface data by organising free data rooms upon request. It contributes actively to strengthening national energy security and advancing regional energy cooperation. Through its sustained efforts, ONHYM is contributing to Morocco's emergence as a regional partner of choice in Africa's upstream sector, fostering South-South cooperation and energy integration.

From a hydrocarbon potential perspective, working and effective petroleum systems have been documented in both onshore and offshore basins through oil seeps and hydrocarbon shows and accumulations encountered in wells. In the northern offshore area, a Tertiary petroleum system was proven by the recent Anchois discovery. In the Tarfaya offshore area (southern offshore), the heavy oil discovery at Cap Juby in 1969 (CJ-1), although undeveloped, confirmed the presence of active Jurassic-Jurassic and Jurassic-Cretaceous petroleum systems. The main reservoir facies tested were carbonate build-ups from the Lower and Middle Jurassic, but oil and gas shows were also encountered in Lower Cretaceous and Cenozoic sandstones. Further to the southern part of offshore Morocco, the CB-1 well, drilled late 2014, encountered gas accumulation in Lower Cretaceous turbidite systems.

PALEOGEOGRAPHY AND RESERVOIRS

The early post-rift evolution of the Central Atlantic is recorded in the Lower and Middle Jurassic of the Moroccan Atlantic margin. Marine environments prevailed during this period, and a mixed carbonate ramp with siliciclastic shelf systems started to develop (Figure 2).

Local Reef buildups formed on the shelf edge as well as associated environments developed in the inner platform areas, with the narrow shelf acting as preferential entries of clastic sediments into the basin.

The Lower Cretaceous is marked by relatively rapid thermal subsidence, followed by the progradation of mega deltaic systems across the shelf (Figure 2). Further west, Lower Cretaceous distal sandy turbidites are either exposed in outcrops on Fuerteventura Island or were penetrated by DSDP wells.

In addition, deep-water turbidite sequences are present at Jurassic, Cretaceous, and Tertiary intervals in the Atlantic passive margin. Seismic attributes and reflector patterns support the existence of these deep marine turbidite successions.

SOURCE ROCKS

Five potential type II/III source rock intervals have been identified in the Eocene/Miocene, Cenomanian-Turonian, Aptian-Albian, Callovian-Oxfordian and Pliensbachian-Toarcian. Geochemical modelling indicates that the Jurassic source rocks are in the wet to dry gas window, those of the Aptian-Albian are in the oil window while the Cenomanian-Turonian SRs are marginally mature to immature depending on the subsidence of the area. The Eocene ones are regionally immature, however the Miocene could potentially have reached the oil window in the north through burial below the melange complexes "nappe" (Figure 3).

The growth of salt diapirs and the emplacement of the Rifan nappe had an impact on source rock maturities in the northern segments of the margin. In the southern offshore, deposition of the Boujdour delta system has particularly affected Callovian-Oxfordian and Pliensbachian-Toarcian source rocks through increased burial.

Furthermore, the Berriasian has recorded a maximum flooding surface, providing the ideal boundary conditions for the deposition of a potential source rock with good maturity at the platform, outboard settings, and in the oceanic domain.

For discussions related to the country's legal, fiscal and investment framework, as well as asset promotion and management, connect with:
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For data access, technical exchanges and exploration-related discussions, connect with:
Ms. Benarchid - Petroleum Exploration Director benarchid@onhym.com

ONHYM

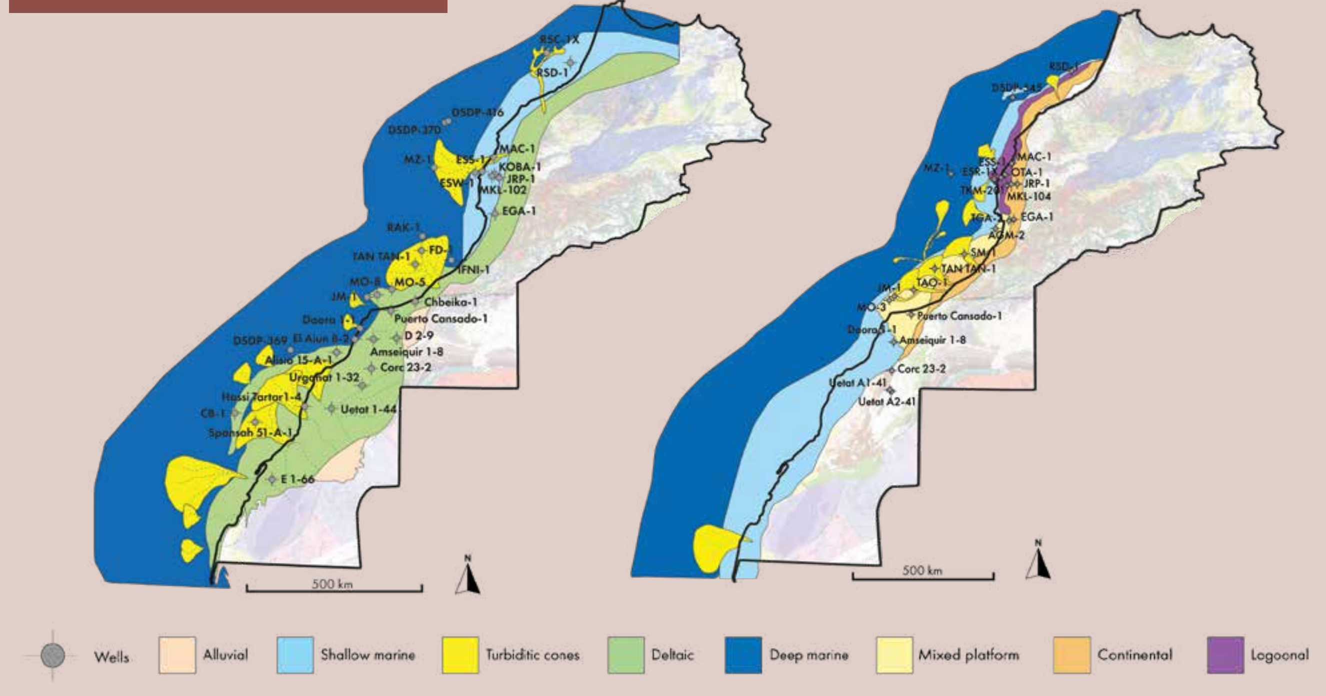


Figure 2 left: Berriasian-Barremian Paleogeographic map, right: Lower and Mid Jurassic Paleogeographic map.

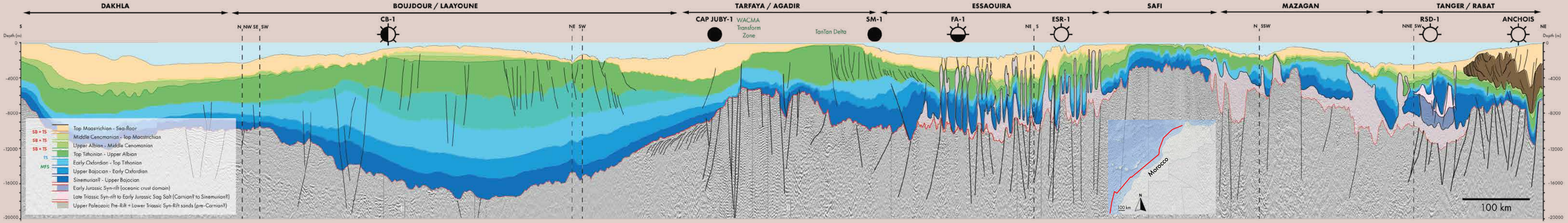


Figure 1: North – South regional transect (from GeoEx multiclient seismic lines) showing the main structural domains along the Moroccan Atlantic Margin.

PLAYS

Various exploration plays have been identified along the offshore Atlantic margin. These plays have been developed thanks to intensive 2D and 3D seismic acquisition, processing and reprocessing over the past two decades. They are mainly associated with turbidite systems, carbonate platforms, thrust belt movements (nappe), and salt tectonics. The latter has also led to the formation of a large salt province (Figure 4).

The thrust-related play is identified in the northern part of the Atlantic margin, where the dominant structural traps are related to the Alpine Orogeny. In fact, RMS amplitude anomalies extracted from seismic data within the nappe highlight channelised features and sand fairways indicative of potential hydrocarbon reservoirs. These anomalies, along with structural features such as thrust-bound traps and imbricate thrust sheets, suggest favourable conditions for hydrocarbon entrapment. The observed patterns support the presence of reservoir deposition in a deep-marine setting, further substantiated by petrophysical data from surrounding areas such as the Gharb Basin, which demonstrate high porosity and permeability in Miocene sands.

Post-nappe targets were successfully tested by the Anchois discovery.

The main targets in the Pre-salt play are folded Paleozoic and faulted Triassic deposits. This play represents an extension of the onshore basins, where Triassic and Jurassic fields are producing oil and gas.

The salt-related play is well developed, particularly in the Safi – Agadir segment, where several salt-related structures have been positively tested by previous wells, indicating oil and gas shows. The salt features include salt diapirs, canopies and toe thrusts.

The deepwater turbidite systems, mainly of Tertiary and Cretaceous age, have also been successfully tested by the CB-1 well in deeper settings in the southern offshore. This well encountered 14 meters of gas net pay in the Valanginian-Berriasian interval.

The carbonate platform play, where the primary target is of Jurassic age, has been positively tested by several wells along the Atlantic Margin. A secondary objective of Hauterivian age, consisting of reef build-ups, has been identified in the Boujdour offshore area.

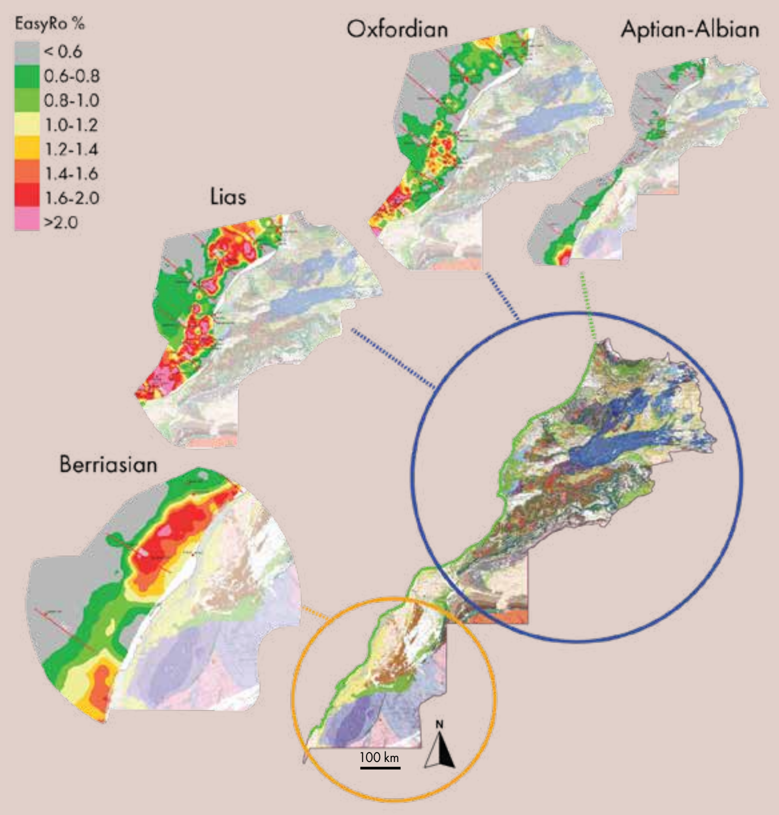


Figure 3: Lower Jurassic and Lower Cretaceous potential source rocks along the Moroccan Atlantic Margin.

MOROCCO'S GEOLOGICAL HISTORY IN A SNAPSHOT

During Triassic times, a series of extensional basins developed along the future continental margin and in the Atlas rift system. In the Jurassic, the basin evolved into a passive margin, marked by the development of a widespread carbonate platform. During the Early Cretaceous, the margin witnessed a major sea level fall with the uplift of the hinterland, which led to the formation of major river systems and development of basin-floor fans in the deep-water domain. A major transgression occurred during the Cenomanian-Turonian, followed by Atlantic compression as a result of the Alpine inversion from the Late Cretaceous onwards.

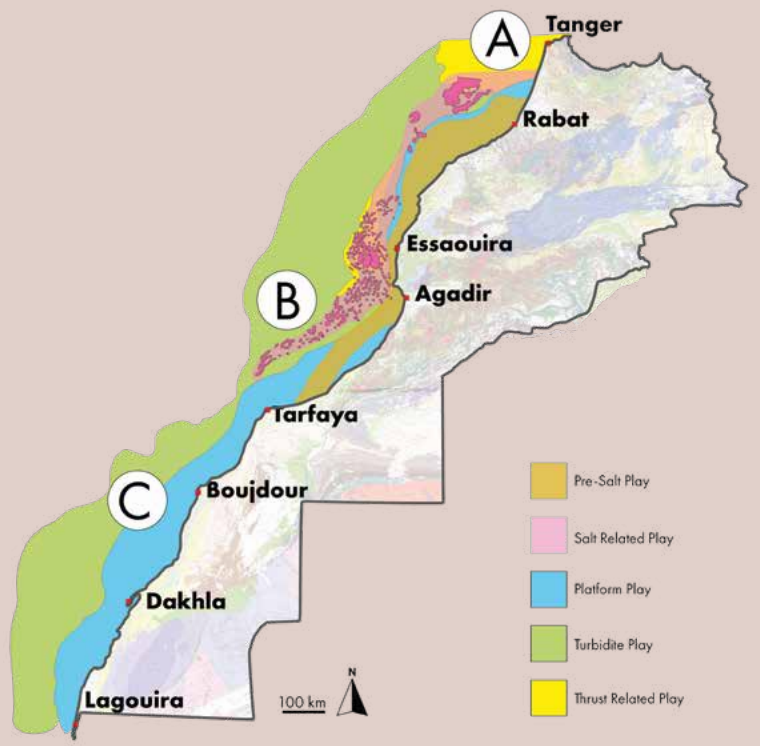
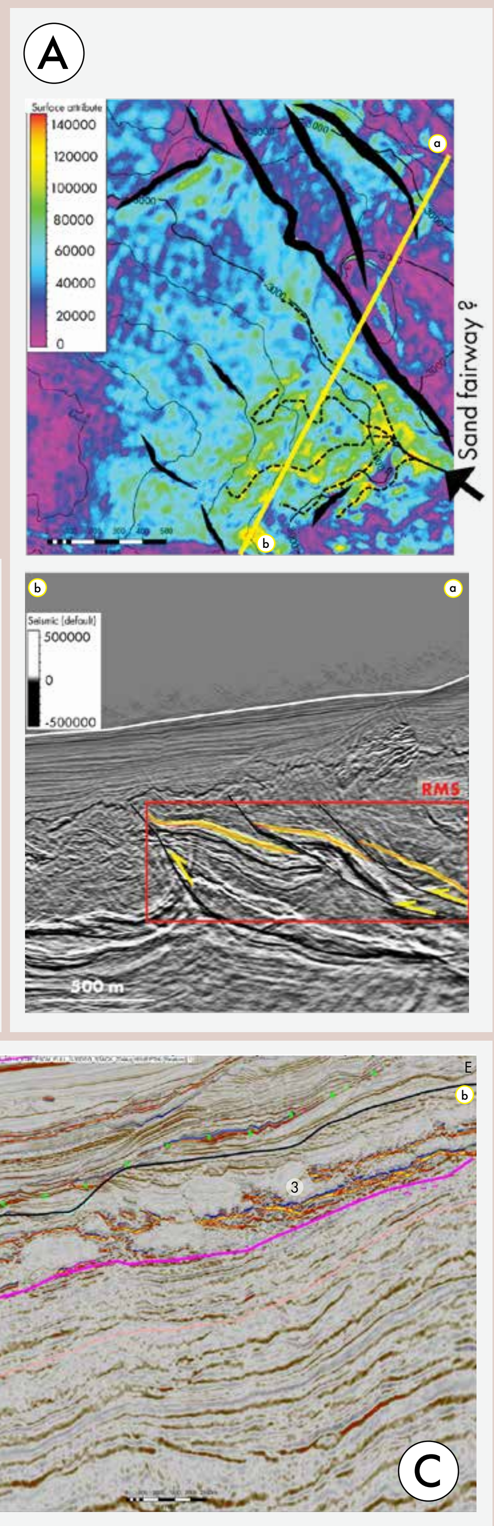


Figure 4: Play types identified along the Moroccan Atlantic Margin with examples from the north, central and south segments.
A: RMS map and seismic section showing the Tertiary structures in the north segment (Gharb offshore).
B: Paleoscan maps and seismic section showing Lower and Middle Jurassic canyons and channels in the central part (Agadir offshore).
C: RMS map and seismic section showing the Albian channels in the south segment (Boujdour offshore).

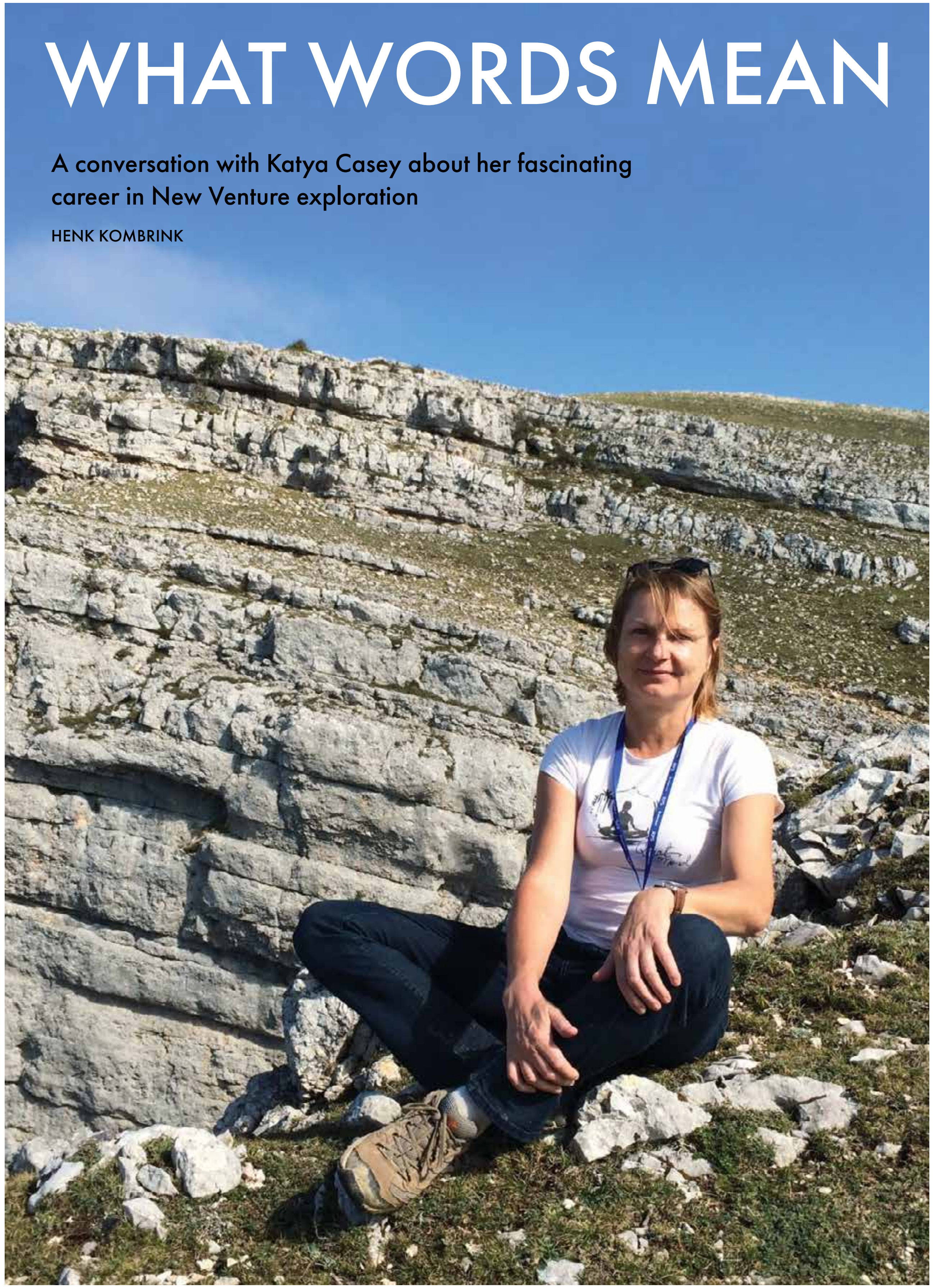


PORTRAITS

"...everyone has a different appreciation of what words mean to them, based on their experience. That became an important reference for me. I wanted to make clear that we are all on the same page"

Katya Casey – U3 Energy

WHAT WORDS MEAN



A conversation with Katya Casey about her fascinating career in New Venture exploration

HENK KOMBRINK

At the top of the outcrop during the field trip, Pyrenees, Spain.

PHOTOGRAPHY: KATYA CASEY PRIVATE ARCHIVE

DO WE BOTH have the same concept in mind when we talk about a 3D model? "No," says Katya Casey, "surely not." That notion shaped her career and the style in which she works. "It is important to be sure that there is a shared understanding, otherwise there is the danger that conversations derail, and nothing gets done."

It paints Katya's desire to be an integrator, bringing together specialists from different disciplines. It is something she excelled at while working for a variety of explorers, and something she still does today in her role as co-owner of U3 Explore.

Here, Katya talks about her career, which took her from Moscow to Houston, where she joined an industry that explored the same seas she had explored in Russia, but for different reasons. And how in both worlds, she was driven to bring technology to the table, being able to identify early the benefits it offers.

GROWING UP IN THE SOVIET UNION

Katya grew up in Moscow, Russia, surrounded by well-educated people devoted to science and exploration. Their interests and respect for everyone were evident in everyday life: "I never heard a curse word until I went to university," she laughs.

Her decision to study geology and geophysics was not driven by oil and gas. "My father was a sea captain who was on scientific cruises a lot. The stories he brought home, many of which were shared by his friends who worked on the ships, fascinated me; I wanted to know more about the deep oceans and the world," says Katya.

"I did some things backwards during my life," she continues. "When I graduated from university in Moscow, I married straight away and had two children while working at the Academy of Science."

In that position, she was part of a large research project called InterRidge, where scientists from the program's founding countries worked together to better map and explore the world's oceans. Having the ability to map the ocean floor during these cruises already sparked her interest in basin formation and tectonics.

"Mind you," Katya says, "it was the time when plate tectonics came up. Since then, this concept has always been of interest to me, and I always try to put things into a platetectonic setting. It was not at the forefront of everyone's mind who worked in oil and gas. For that reason, one of my coworkers called the concept 'Katya's religion,' she laughs.

It was during one of the cruises that Katya met Jack, a professor from the University of Houston who actively invited people to come to the USA to join their graduate program.

This happened at a time when the Soviet Union was falling apart. "I was experiencing the same thing in my private life," says Katya, "and combined with my observation that the value of education had diminished in those transition years in the early 1990s, I decided to pack my bags and take my two children to Houston to start a new life."

"It was the most difficult thing I have done," she says. "I made a decision not only for me but also for my two daughters, and I went to graduate school in Houston while caring for two kids at the same time. I financed our simple life by working as a teaching assistant at first. I was in the first group of students from the Soviet Union; everyone at the university helped us, and we found a routine."

AMOCO

Later in her graduate studies, Katya also worked at Amoco during the summer. "American companies were actively looking at acreage in the former Soviet Union states, and they needed help translating technical documents that were obviously all written in Russian," she says.

"I was not only a translator but also populated a database with geological information. It was a fascinating period of brain development, which you only see when you look back after a number of years."

After finishing graduate school, Katya joined Amoco as an exploration geophysicist, working on projects in Kazakhstan and Azerbaijan.

She felt welcomed and appreciated in a great group of exploration professionals. With a nose for technology, she was motivated to implement new ways of working. "Digital technology was in the early days of development, with a lot of promise, but it was met with resistance from some people," she says. "Yet I did have support from most of my colleagues and my management."

It was during those years that Katya first encountered GIS. She quickly realised it was a great analytical tool for geologists. GIS technology was developing rapidly, but companies were organised in such a way that technicians operated the GIS software. It is still considered a secondary skill by some managers today.

"I feel that is wrong," says Katya. "Software enables people to conduct real-time analysis themselves, rather than having someone else do it for them. I believe, especially when interpretation is involved, that it is important for people to do it themselves. That's when you have to start thinking, and that's where the power of using software comes to fruition."

DID YOU EVER ASK THE QUESTION "WHAT IS A GRID?"

When Amoco merged with bp, it led to a big round of redundancies, of which Katya was part as well. Four months later, when she found a job with Vastar, a subsidiary of ARCO that operated in the Gulf of Mexico, it marked a sharp new turn in her career. Here, she was designing new digital workflows and deploying emerging technologies. This required many discussions with colleagues that opened her eyes to how important a common understanding of technical definitions is.

"I worked with a geophysicist who was supposed to hand over a grid to the basin modellers. While discussing ▸

it, it dawned on me that he thought he needed to hand over the picture of the grid as he saw it on the screen. Without realising that it was not the picture itself the basin modellers were interested in, but the set of xyz coordinates behind it."

"Of course, I did not want to talk to him as if he were in kindergarten, but you do need to explain that a grid is not a picture but rather a spatial dataset of which we see an expression on the screen. If you are so misaligned during a conversation, there is nothing but to try to land on the same page."

Katya's time at Vastar did not last long in the end, as bp came knocking on the door again. "This time, I was not going to stick around," she says, "despite many people telling me that Vastar was doing so much good work in the GOM. I was determined not to go through a second merger with bp."

WHAT IS THE BEST OPTION TO MOVE FORWARD?

After only a year with Vastar, Katya received an offer from BHP through a headhunter. "It was a headhunter I developed a good relationship with," says Katya. "It was the same person who got me the position at Vastar, too."

"Looking back now," she says, "it reminds me of how times have changed. Because I knew this headhunter, she was able to really help me with specific opportunities. Do you think you will achieve something like that with LinkedIn these days? I don't believe so."

But times were different in the early 2000s. "Over a period of around ten years, from 2005 to the crash in 2014, I received calls from headhunters all the time," says Katya. "When I changed my job title on LinkedIn to reflect a change in position within the company, I immediately got a flood of calls, and I had to tell them that I was quite happy in the role. It was a clear sign of how deepwater experience for the Atlantic, which was my speciality at the time, was valued."

Yet, Katya stayed with BHP for almost 13 years. "It was amazing to be part of their growth, and I could apply my creativity," she says. "Until we got a new CEO who was a micromanager."

At BHP, Katya saw the same things she had seen throughout her career. She saw how new technologies became available to the market, but how slow the uptake was internally. Through her natural interest in these matters, she soon rose to the Global Geocomputing Manager level, until she realized that she also needed to demonstrate the benefits of the technologies she was promoting.

"You have to lead by example," she says. "That's an important reason why I went back to a technical position in a newly reopened New Ventures team. Of course, money is nice, but it is not the ultimate driver for me."

In addition to GIS, Katya promoted 3D seismic interpretation methodologies. "At the time, we did not call it AI, but auto-picker," she says. "But hey, it was the same thing with a different label. This technology came with some shocks, and some people didn't like it at all. Because it increased the resolution with which you can interpret things."

"It reminded me of my early days at the Academy of Sciences in Russia, where we used to hand-contour maps based on ship tracks," says Katya. "When I produced my first computerised map, my boss said that it was not smooth enough, it didn't look good. But what if there is more data behind the new map, data that would be hard to ignore?"

ON THE SAME PAGE

"Now I see how you work!" a colleague told Katya when he saw how she prepared for a meeting by talking to all participants beforehand to ensure they were aware of the topic. "Of course," she said, "if I don't do that, it will only lead to participants making their points without listening to each other very well. The preparation is key to making sure that we are all on the same page."

> **"...everyone has a different appreciation of what words mean to them, based on their experience. That became an important reference for me. I wanted to make clear that we are all on the same page"**

"It might not look good, but it tells us something we don't yet know," says Katya. "The same applies to the auto-tracker. Only when you see a surface appear, and the mudcracks jump out at you in map view, do you see that it actually interpreted something that made sense. Except that it might look very wiggly when looking at it on a single in- or cross-line!"

During her time at BHP, Katya had another insightful experience regarding the meaning of words. "On one occasion," she says, "I was describing a regional 3D model we built using 2D seismic data. But as the conversation evolved, it dawned on me that my colleague had a different model in mind. We were not talking about the same thing at all. He was alluding to voxels in 3D seismic cubes, while I was talking about a stack of 2D grids that make up a 3D volume in GIS."

"Based on that conversation, I concluded that the words grid and map are the most difficult in our geoscience domain, as everyone has a different appreciation of what these words mean to them, based on their experience. That became an important reference for me. I wanted to make clear that we are all on the same page," she says.

"Explaining things off the cuff is not enough," says Katya. "If people don't really understand what you are talking about, they will not listen to you. They will share value only when they see that something really matters. That's the shared value that companies always talk about."

"In my view, alignment in company values comes with having lots of conversations, because only in geoscience already, there are so many different disciplines, you can't have the overview and understanding of the entire spectrum."

"That's what I think is the risk with the current rounds of layoffs and the desire to keep only an organisation with people who are specialists in their own small domain," she adds. "The risk of ending up in a very siloed organisation is high because these specialists are not the best candidates to scout around and find out what their peers in other disciplines do."

RIDING THE WAVES OF NEW VENTURE EXPLORATION

The timing of Katya joining BHP was right. In many ways, the skills she learned in the past and what was now needed came together. It was the time of yet another attempt to have a New Ventures team in the company, and Katya was going to be part of it.

"Our focus was the entire Southern Atlantic," says Katya. "In this area, ION had just begun acquiring deep lines as part of the SPAN project, and together with gravity and plate tectonic reconstructions, we were tasked with finding the regions that could be most prospective."

For an integrator like Katya, it was a great time. Because now, seismic data wasn't only used to find traps, it was used to map basement, major lineaments and volcanic strata, all to better understand where a petroleum system could potentially exist, with a valid source rock. But it came with risks too, such as the Falklands, where the company drilled a dry hole.

Regional exploration skills in the Deepwater Atlantic were in high demand, and Katya joined Apache Corporation in Houston to grow the company's exploration portfolio. The company wasn't particularly known for frontier exploration, but during those years of high oil prices, even Apache's of this world were looking more frontier. One of those areas was the Suriname-Guyana Basin.

"I never drilled my own well," Katya says, "but I did help choose the blocks where others drilled a discovery." The Suriname-Guyana Basin is an example of that, where Apache made the first deepwater discovery in Block 58 after Katya had already left the company. When Katya started working in the basin, people said the Guyana Basin was just like the Tano Basin in West Africa. But that wasn't the case, as we have Jurassic sediments in the Guyana Basin, whereas in the Tano Basin, it is only Cretaceous, associated with the Atlantic opening.

"That's a starting point for building your regional understanding, which led us to point to Block 58, where the reservoir and petroleum charge came together. And let's be clear, this was all done based on 2D seismic data at the time," Katya reiterates. "I did not map the prospects themselves; others did that after I had already left Apache."

Following her time at Apache, Katya joined Murphy for a few years. The company had its eyes on the Southern Atlantic too, with the Falklands coming into focus. "The company was interested in the area south of the Walvis Ridge," she says, "and when you want to understand this region, you have to understand the Falklands, because the area from the Walvis Ridge to the ►

2008 Leadership in Technology Award, Houston, USA.

PHOTOGRAPHY: KATYA CASEY PRIVATE ARCHIVE

Falklands is different, with salt basins to the north of the Walvis Ridge and no salt to the south. It made me aware that you always have to expand your understanding of basin evolution," she says.

Katya's time at Murphy came to an end in 2016, two years following the oil price crash. "There is only so much you can do," she says. "Decisions are made at a level I would not be able to influence. The only thing I could influence was that I did not want to be unhappy in my job, so I moved from one company to another. As soon as the global appetite for New Venture exploration dried up, people with big-picture thinking were made redundant.

Representing Actus Veritas Geoscience at the World Energy Summit in 2025, London UK.

GOING INDEPENDENT

After her redundancy from Murphy, Katya needed to reinvent herself. "I did not want to become the sour person in the corner of the room," she says. But becoming an entrepreneur is not for everybody. "You have to be able to weather it emotionally, especially if you look at the financial side of things."

"Looking back, I prepared myself for that moment since I was made redundant from Amoco at the start of my career. It was a great lesson in that sense."

Together with Marel Sanchez, a former colleague at Murphy, Katya founded Actus Veritas Geoscience, a consulting firm in the exploration space. In addition, they also run U3 Explore, an initiative that focuses on collecting exploration knowledge and stories for places where significant potential remains, such as Venezuela.

"Our patience was tested to the limit," Katya explains. "Around 2017, geoscientists were going out of fashion, in favour of data scientists. Then came the movement toward companies going green and not needing exploration. Then came Covid, and projects with delayed payments. At each of these points, you can give up. But I'm still a firm believer that things will get going at some point. It is just very difficult to predict. You have to be very resilient and accept that nothing goes to plan."

"Looking back over the past fifteen years of my life," says Katya, "it makes me realise how good it was. As you progress through your career, the frequency of your activities decreases. Where you jump from one thing to the other in your 30 and 40's, it will slow down in later years. And that is a good thing, as you can reflect on things better and assess the decisions you made in the past. Because in many cases, you don't know if a certain decision is the right one or not when you take it. You only see that when you are ten years down the line."

"I also feel like my actions have had much more meaning," Katya says as our conversation comes to an end. "Simply because nobody tells you what to do, nobody tells you to do something that you may not agree with. You have to do it all yourself. But luckily, at a certain age, you lose the fear of being judged all the time. That is something I'm not worried about anymore, which is liberating. It is freedom." ■

THE LITTLE PLANET

On the very first research cruise Katya joined while still working for the Russian Academy of Sciences, she had a bit of an epiphany. "We sailed from Kaliningrad through the Baltic Sea to the Atlantic," she says, "and by doing so in less than a week, I suddenly realised how small our planet actually is and that we need to take care of it. The waters in the Atlantic were pristine, but as we came back into "civilisation," more and more debris was floating around at sea. It made me aware that we need to take care of this small place better."

PHOTOGRAPHY: KATYA CASEY PRIVATE ARCHIVE

GEOTHERMAL ENERGY

"Nature and the earth give us multiple energy sources year-round. We just need to gather the possibilities and assemble them the right way for each specific situation"

Nicolas de Varreux

A very expensive fart in the wind

That's a way to look at Eavor's energy output from the Geretsried project

EARLY DECEMBER last year, Eavor announced the start of electricity production from their Geretsried deep closed-loop project in the south of Germany, near the village of Geretsried. As expected, it led to a flurry of thumbs up. But how much energy it was actually producing was not mentioned in the press release, nor in subsequent articles written about how successful the project was.

Fortunately, the Germany-based "Informationsportal Tiefe Geothermie" hosts an article that mentions the electricity output; between 0.5 and 1 MWe. Through a contact of mine in Germany, who is well connected, I subsequently learned that the output is sitting at 0.5 MW at the moment, so at the bottom end of the range quoted in the article.

Granted, the energy being produced now is coming from just one loop. The plan is to drill three more, with the combined output anticipated to be 8.2 MWe. But given the results of the first loop being in now, the big question is how the output per loop will be 2 MWe where the first one suggests that it is more like 25 % of that.

Jeanine Vany, co-founder and executive vice president of corporate affairs at Eavor, is quoted in this article, saying: "The advancements and lessons learned at Geretsried are translating into a competitive Levelized Cost of Heat (LCOH) along with a significant increase in energy output potential for future projects." But she did not say how exactly.

So, looking at what we know now, it must be concluded that the energy output is very low indeed, especially when considering the sheer amount of work involved getting to this point; more than two years of drilling using two of the heaviest-duty onshore drilling rigs in Europe.

But working with the numbers we've got now, do the costs of drilling and completing these loops justify the output? In the article mentioned above, company spokesperson Alexander Land admitted that the costs of the project had already exceeded €350 M. As we don't know by how much, let's work with €350 M for four loops anyway. It means that if the 8.2 MWe will be achieved, which also sounds increasingly unlikely, the costs per MWe of this project is €42.7 M.

Let's compare that against offshore wind. This website, https://guidetoanoffshorewindfarm.com/wind-farm-costs/, provides a detailed price breakdown for offshore wind projects in 2025. Since then, prices may have risen, as might be expected given the well-known commodity crunch, but the number quoted by the website amounts to €4M / MW. In other words, offshore wind is about ten times cheaper than the deep Eavor geothermal closed-loop energy.

If we would, however, assume that the energy production from the currently operating loop is representative of what is

The Geretsried geothermal drilling site.

to come, so 0,5 MWe, the price per MW rises to €175 M as a minimum. That means offshore wind is more than 40 times more affordable.

Sure, offshore wind does not guarantee the same constant energy production as geothermal does. That is certainly a drawback. But an investment that is between 10 and 40 times more expensive, for an output that can be produced by a fraction of just one single offshore wind turbine, I very much doubt if this is the way to go. Imagine, one single offshore wind turbine already generates between 8 and 15 MWe.

And even when looking at the net annual average energy production for an offshore wind turbine, which stands at around 4,200 MWh/year per MW, the current Geretsried loop only just exceeds that number when assuming the current power production (4 380 MWh / year).

The "Informationsportal Tiefe Geothermie" article also mentions that the expected start date for drilling the second loop is in March this year. Based on the observations pointed out here, I am curious to see if this will actually go ahead. For now, my conclusion is that this project is a very expensive fart in the wind.

Note: Two emails were sent to Eavor to enquire about the energy output of the first loop. No response was received.

Update based on new information received early January 2026:

Some people argued that I was wrong by focusing on electricity production only. They said that the project is supposed to deliver 64 MWth as well, once the district heating network is in place. However, as it turns out, it is more likely to be either/or, and not in addition. So Geretsried will produce either 8,2 MWe in electricity, or it can switch to delivering the equivalent in heat: Around 64 MWth. The conversion factor to go from thermal to electricity is around 0.13 (13 %), which is a fairly common number.

It is still unconfirmed if the 0.5 MWe now reported is gross or net. If it is the latter, we need to subtract the energy required by the plant before we know how much electricity is genuinely delivered to the grid. One person I was in touch with, who is well-connected, claims that it is a gross number, which means that even less is available to the public. ■

Henk Kombrink

PHOTOGRAPHY: EAVOR

From the shores of Lake Geneva to NEOM in Saudi

Nicolas de Varreux stumbled into the shallow geothermal business in Switzerland, but it has taken him on a mission to the Arabian desert

"WHAT ARE you doing?" Nicolas de Varreux asked his neighbour in Switzerland when a drilling rig rolled into his garden back in the summer of 2005. He had never seen such a machine before and became even more intrigued when his neighbour explained this was to drill a shallow geothermal borehole for a heat pump…

It was at that point that Nick got hooked and it was the start of a 20-year-long deep dive into the shallow geothermal and geoenergy world. One that continues today.

In 2007, Nick and two associates bought a drilling rig, which ultimately led him to become the head of regional operations for the once-largest European geothermal probe installer, running 22 geothermal rigs.

"We were installing over 10,000 m per month and with such a fleet, fine-tuning drilling techniques was paramount. Because in the end, it all boils down to how quickly you can install the ground heat exchanger," Nick explains.

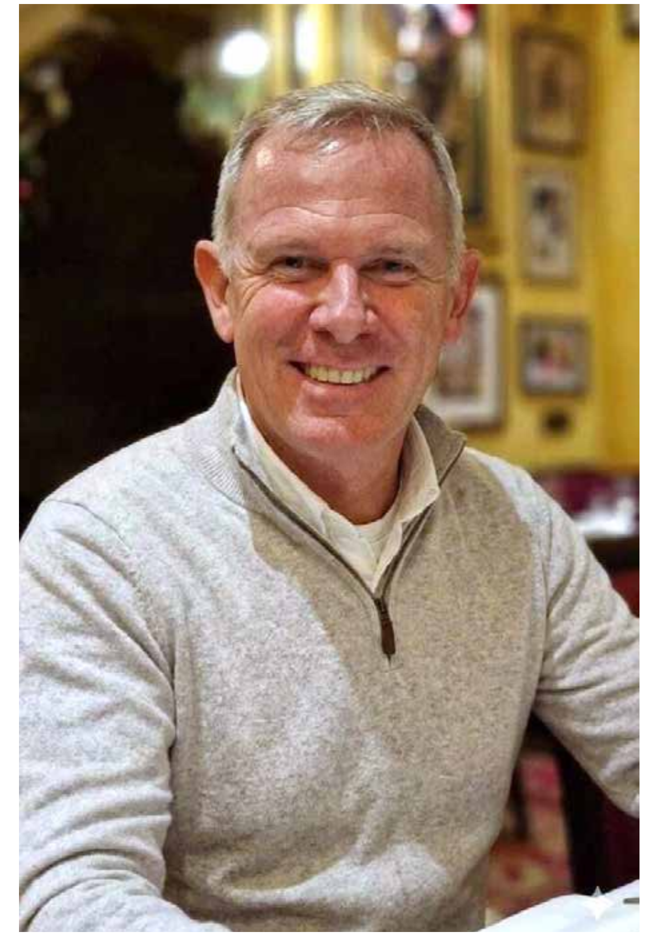
"Early on, I remember that some rigs were only installing 50 m per day. Now, it is more like 300 m, with peaks close to 1,000 m per day in ideal conditions. What a difference that makes when you realise that drilling time is the most important variable influencing CAPEX in a shallow geothermal loop installation."

SHALLOW VERSUS DEEP

"Compared to other renewables, shallow geothermal is hidden," Nick continues, "once the rig has gone and the system is connected, you don't see anything. In a way, that's wonderful, but it also means that this fantastic technology gets very little public exposure."

"The shallow subsurface is akin to one big battery, and our job is to tap into this enormous and practically unlimited resource that actually exists and can be exploited almost everywhere. An important contrast to deep geothermal," Nick argues, "which is completely dependent on local geological conditions."

In the deep geothermal world, it is a fact that the real profitable projects are still in the sweet spots where thermal gradients are at their highest, or like in the Paris Basin, where a prolific reservoir occurs at the right depth. "But every single deep geothermal project starts with a very expensive exploration phase," Nick explains, and if that fails, which is unfortunately often the case, millions are wasted."



Nicolas de Varreux.

IN THE DESERT

Now, with all the experience he has accumulated over the years, Nick finds himself in Saudi Arabia, helping to design a sustainable energy system for the NEOM project underway in the northwest of the country. It is a project on a scale that has rarely been seen before, with multiple different geological settings and challenges.

"In the end, it's all about thinking out of the box, being a little ingenious and having smart economic sense," concludes Nick. "Nature and the earth give us multiple energy sources year-round. We just need to gather the possibilities and assemble them the right way for each specific situation." ■

Henk Kombrink

PHOTOGRAPHY: NICOLAS DE VARREUX PRIVATE ARCHIVE

If plans come to fruition, the Aarhus geothermal project in Denmark may almost deliver what was promised

Innargi's flagship geothermal project reports energy output from its first operational doublet, with a possible five more to be completed. We look at the numbers in a little more detail following a request for information

THE AARHUS geothermal project in Denmark, developed by Innargi, has been a flagship project since it was announced in 2022. One of the most differentiating things Innargi did in order to revitalise geothermal development in Denmark, where district heating systems already exist in many places, was to take on the subsurface risk that comes with drilling deep wells. This risk can be seen as one of the main drivers behind the several geothermal projects in Denmark that failed prior to commissioning the Aarhus project.

The original plan in Aarhus was to drill up to 17 wells, producing 110 MWth for the local district heating network – 20 % of total demand.

Fast forward to the start of 2026, the initial results are in after the first months of commercial heat production from the first doublet have passed. What is the verdict? Has the project met expectations? Of course, my view on the project is limited, but Innargi has been answering some of my questions properly and seriously, which is something that needs to be emphasised.

The site now produces a total of 17.5 MWth from a single doublet, a company spokesperson shared. One of the main questions related to this output, as expressed, was how much of this number is actually heat or energy coming from the Triassic Gassum sands. Innargi did install a series of heatpumps at the production site, which are being used to bring the fluids to a certain spec temperature. Innargi shared that more than 85 % of the thermal power delivered to the heating network comes from geothermal energy, so that means we have a doublet that produces around 15 MWth in geothermal energy.

That is a good start, but still quite far off the target of 110 MWth. What will be done next?

Innargi now plans to drill more wells as part of the Phase 2 development, the company shared. Two more wells – an injector and producer – will be drilled at the current production site at Skejby, and two doublets (four wells) at the Halmstadgade site, where a new geothermal facility will be built. The drilling campaign is planned to start in the first half of 2027. A subsequent Phase 3 includes another two doublets at the Bautavej site.

If all of this comes to fruition, and we can use the energy production from the Skejby site as an indication in terms of what is to come, we could expect the project as a whole, when six doublets are in operation, to deliver 105 MWth (gross) and 90 MWth (net). That is not too far off the initial target of 110 MWth. However, we have to be a bit patient, as Phase 2 is not even commencing this year. ■

Henk Kombrink


The Skejby production site, Aarhus, Denmark.

PHOTOGRAPHY: INNARGI

SUBSURFACE STORAGE

"Everybody expected that 2025 would be a turning point in the CCS market, with many projects coming online. But unfortunately, that did not happen. And if you ask me when it will, I'm now inclined to say that it will rather be 2027 instead of this year"

Habib Al Khatib – Spotlight

Silver out, air in

How disused mine shafts in Australia facilitate the construction of a subsurface compressed air battery

Just as Aberdeen in Scotland – where this article was written – is sometimes referred to as the “Silver City”, the village of Broken Hill in southeastern Australia is described in the same way. But where in Aberdeen this nickname comes from the shiny character of the locally mined white granite, in Broken Hill, it is thanks to the massive silver ore bodies that have been mined for a long time. And still are.

Now, one of the mines in the area, Perilya’s Potosi Mine, located to the northeast of Broken Hill, will also be used for a purpose one would not quickly think of: Compressed air storage. Or better: Advanced Compressed Air Energy Storage (A-CAES). At a depth of around 500 m, the mine infrastructure provides access to a type of rock that lends itself well for air storage, because it is very tight: The Potosi Gneiss.

“The target geology was selected since it has extremely low permeability,” a spokesperson from Hydrostor in Canada, the developer of the project, said to us. There are sparsely spaced fractures, but these are very tight and part of the rock mass. “Combined with a very high rock strength, this lithology formed an attractive target for this project.”

To better investigate the local rock properties, extensive in-situ permeability testing has been performed on the host rock geology through the cavern location to confirm that the formation has suitable containment for A-CAES use. These tests showed that the geology has extremely low permeability indeed, and subsequent leakage modelling has demonstrated that the cavern will have negligible air loss over time.

It is the existing mining infrastructure that forms the cost-saving; work on constructing the cavern in which the air will be stored in, can begin much faster this way. And once construction has finished, the cavern will be sealed off from the mine access using a massive monolithic concrete bulkhead. A monitoring system will also be put in place to support cavern operations, including ongoing measurement of the level of air within the cavern.

ROUND AND ROUND
The principle behind compressed air storage starts with excess electricity being used to compress air and pump it into the cavern. When the energy is needed, a connected water reservoir is opened up, allowing water to move into the cavern as the air makes its way to a turbine at surface where the electricity is generated. The process is reversed when the cavern is full of water.

Once in operation, the project will provide crucial long-duration energy storage capacity and stability to the Broken Hill region and the wider network, with a total capacity of 200 MW and 1,600 MWh (8 hours of storage duration at full output). As such, the new energy storage facility will replace ageing diesel generators, nearing their end-of-life, and will also form a useful buffer for excess electricity generated during peak times. ■

Henk Kombrink

Gneiss is gneiss. This is an example from Iona, Scotland.

PHOTOGRAPHY: SHEELAGH DONNELLY VIA PIXABAY

How can we monitor North Sea carbon stores under wind farms and production platforms?

The UK North Sea is now a multi-energy basin, with carbon capture and storage (CCS), offshore wind, and oil and gas facilities increasingly competing for geographical and seafloor space

NIGEL PLATT, SAM HEAD AND JOHN UNDERHILL, UNIVERSITY OF ABERDEEN

Repeat time-lapse seismic surveys can track CO_2 plume migration, but where the seabed is obstructed by wind turbines or oil and gas platforms, access by vessels towing long multi-streamer arrays is impractical.

Research in the Centre for Energy Transition, part of the University of Aberdeen's Interdisciplinary Institute, has sought solutions allowing wind and carbon storage projects to co-exist. Sponsored by The Crown Estate (TCE) and Crown Estate Scotland (CES), Project Colocate focused on areas of potential cross-sector overlap in the Outer Moray Firth (OMF) and East Irish Sea (EIS), reviewing the operational and depth limitations of alternative monitoring technologies and the adaptation of Measurement, Monitoring and Verification (MMV) plans to specific store characteristics.

For example, gravity monitoring may offer partial assurance in an area of wind farm and CCS overlap at Morecambe Net Zero (EIS; Sherwood Sandstone reservoir, 700-1,100 m), but exponential decay of signals with depth sees gravity as unsuitable for the deeper Cretaceous Captain and Cenozoic Mey sandstone reservoirs at 2,200-2,500 m in the Acorn and East Mey stores of the OMF. Similarly, microseismic surveys may identify and locate seal failures but cannot adequately image CO_2 migration in typical reservoirs.

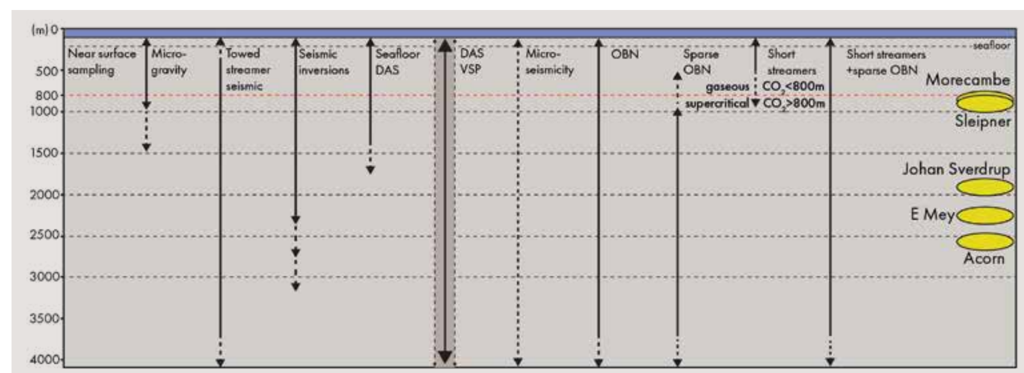
Amongst alternative seismic methods, single-source (‘spot’) seismic has allowed point calibrations for the Southern North Sea Poseidon project, but recent modelling at Acorn shows that aquifer displacement following CO_2 injection should be imageable across the wider store, with repeat time-lapse 3D (4D) seismic coverage therefore preferred.

Smaller vessels towing short streamers are more manoeuvrable but offer limited imaging below 1 km, while access to may still present collision risks. High-density Ocean Bottom Node (OBN) seismic is expensive, and sparse OBN lacks the short offsets needed for accurate shallow velocity fields. Promising tests of fibre-optic seafloor arrays (DAS, Distributed Acoustic Sensing) at Norway's Johan Sverdrup oilfield, now support future application to MMV, but the technology is as yet immature.

Adapting workflows tested by Equinor at Sleipner in Norway, our study proposes a hybrid solution with short streamer seismic acquired prior to construction, complemented by initial baseline and later time-lapse sparse OBN.

Processing these datasets together through Full Waveform Inversion captures both long and short offsets. Re-using the short streamer data assures shallow velocities, with reservoir fluid changes at depth then imaged via merged repeat sparse OBN, which can be acquired with obstructions in place.

Project Colocate highlights the technical and commercial compromises arising from the co-location of CCS with offshore wind and oil and gas, concluding that coordinated multi-sector licensing should avoid creating new co-location scenarios wherever possible. Nevertheless, a bespoke and hybrid MMV approach, combining short streamer data with time-lapse sparse OBN, may offer a solution for carbon stores where wind farms or other obstructions are already built or planned. ■



Effective investigation range of CCS MMV technologies, showing depth comparison of the OMF Acorn and East Mey CCS stores with Morecambe, Sleipner and Johan Sverdrup.

"In one year, we lost two years"

Habib Al Khatib talks openly about the current global CCS landscape and how his monitoring company Spotlight navigates this space

Habib Al Khatib.

"LAST YEAR was not a very good one," Habib admits when we meet on Teams on a Monday afternoon. "Everybody expected that 2025 would be a turning point in the market, with many projects coming online. But unfortunately, that did not happen. And if you ask me when it will, I'm now inclined to say that it will rather be 2027 instead of this year. Hence, my statement that we lost two years in one."

"Let's face it," says Habib, "there is pushback on the energy transition."

But did he lose hope? Surely not. For two reasons. First of all, projects are moving ahead, and secondly, Spotlight has adapted to this new situation and has established a pre-FID service. For good reasons.

"Absolutely," says Habib, "January last year – when the new US administration took seat – was a turning point in the CCS space, especially knowing that the USA was and still continues to be the biggest market of all. But at the same time, there is more clarity now, and there is still commitment. Projects such as Oxy's Stratus and Exxon Mobil's Rose are still going ahead."

Habib also mentions datacentres and how these have very quickly become an attractive target for small-scale CCS projects. "We know that power is one of the main limiting factors for this rapidly increasing sector, and we also know that gas is still one of the most common energy sources. One and one is two."

Similarly, Canada has reconfirmed its commitment to CO_2 storage on the back of a drive to increase it's exports of oil and gas. Europe is also moving forward, albeit slowly. Especially in the UK, where the government has made the commitment to guarantee a minimum CO_2 price for the two Track 1 projects. "That is unrivalled," says Habib.

OK, but given the project delays that we are still seeing, how does a company like Spotlight position itself in this market? At the end of the day, monitoring only takes place after project initiation. "We have now moved into the pre-FID space," explains Habib. "If we can show, with the assistance of our flow modelling approach, how a plume of CO_2 will move in the reservoir, we can build a strategy for phased plugging of legacy wells in the area, together with a robust monitoring system in place. That means a phased investment rather than a front-loaded one. That has big advantages."

The big question obviously was how regulators respond to that. "Well," says Habib, "we actually had one regulator telling us that they like this, because it allows more time to benefit from experience elsewhere on how to best plug these legacy wells. There is not a lot of experience in this field yet, and technology is advancing rapidly, so it may be good to wait a little longer."

"I believe that we now have a service that is light and agile enough for what the market is asking for," concludes Habib at the end of our conversation. "Combined with a series of recent successful projects, and what is in the pipeline, I believe that we are in pole position." ■

Henk Kombrink

Static shooting on a calm day at sea – monitoring Perenco's Leman CO_2 injection test.

PHOTOGRAPHY: SPOTLIGHT

SEABED MINERALS

"Given the promising results of project EMINENT, it is all the more surprising that the Norwegian government has put the first seabed mineral licence round on hold for at least the next four years"

Ronny Setså – GeoPublishing

First seabed copper from Norway

Research expeditions in the Norwegian Sea have shown that the Mid-Ocean Ridge has high prospectivity for metal ore. The list of known deposits is growing steadily, and for the deposits that have been sampled, the metal grades are often higher than what is typically seen in deposits mined on land

OVER THE PAST three years, academia and industry joined forces in the project EMINENT to increase knowledge of the deep sea and demonstrate a full value chain for sustainable extraction of seabed minerals. Now the results are on the table, and they include the first copper extracted from mineral deposits in Norwegian waters. It is tangible proof that the project has succeeded in demonstrating a complete value chain for the exploitation of seabed minerals.

Much of EMINENT's research, environmental monitoring and technology testing concentrated on the Mohns Ridge. During the project's first expedition, in May 2023, the project participants drilled directly and completely unintentionally into a previously unknown inactive sulfide deposit. They named the deposit after the expedition: Deep Insight.

The expedition's purpose was to investigate water circulation in the subsurface by drilling into a fault, as well as to test FlexiCore – a cost-effective concept for core drilling in difficult deep-sea terrains. Further mapping has shown that Deep Insight, situated 8 km from the political border with Greenland, may be among the largest sulfide deposits so far discovered in the Norwegian Sea. The ore formed when boiling hot mineral-rich water percolated to the seabed and quickly cooled.

The EMINENT project was also involved in finding the Grøntua and Gygra inactive sulfide deposits. From a resource perspective, it is inactive, extinct fields that are of interest. Active deposits are protected by the Seabed Minerals Act because they form the basis for unique ecosystems. It is also more technically demanding to operate in the extreme temperature conditions that occur where boiling water flows out from the seabed.

BIOLEACHING

EMINENT has also investigated how copper, zinc and cobalt can be extracted from sulfide deposits under the seabed without breaking up the ore body. The method is based on principles from two established technologies: in-situ leaching and bioleaching.

In-situ leaching involves adding liquid, often acidic, directly to the deposit to dissolve the metals, while bioleaching uses bacteria to selectively break down the metals in the ore. The researchers believe this could be achieved by injecting a bacterial solution into the deposit through one well and retrieving metal-rich water via other wells.

Laboratory tests have shown that the method can provide high recovery rates. If in-situ bioleaching can be realised, it could significantly reduce energy consumption, environmental footprint and costs. In other words, a more sustainable alternative.

Given the promising results of project EMINENT, it is all the more surprising that the Norwegian government has put the first seabed mineral licence round on hold for at least the next four years. ■

Ronny Setså

PHOTOGRAPHY: RONNY SETSÅ

The first Norwegian copper of marine origin. The greenish rock is a sample of metal ore, taken from the Gygra sulfide deposit west of Svalbard.

SEABED MINERALS

Norway stumbles at the finish line

Just as the first refined metals appear, and companies prepare themselves for further growth and innovation, the Norwegian government pulls the plug from seabed mineral activities

ON THE NIGHT of December 3, Norwegian parliament reached an agreement on the state budget for 2026. One point in the budget agreement reads as follows: *The parliament asks the government not to announce the 1st licensing round for seabed minerals during this parliamentary term.* Four years' postponement, at least. For an industry in its early stages, this is dramatic.

FIRST COPPER

Over the past three years, academia and industry joined forces in the project EMINENT. The project's aim was to increase knowledge of the deep sea and demonstrate a functioning value chain for seabed minerals in Norway. The 15 project partners have provided new insights into the environment, ecosystems, geology and resource potential of seabed minerals, and developed technology for exploration, production, processing and monitoring. At the project's closing seminar on December 9, 2025, the tangible result was presented: The first refined copper extracted from Norwegian sulfide deposits.

This result should have been a springboard to continue data collection and further develop expertise throughout the first licence round for seabed minerals. "The political decision to postpone the licensing round puts both knowledge building and Norway's position at risk," says Anette Broch Mathisen Tvedt, CEO of Adepth Minerals and project manager for EMINENT.

> "Norway possesses some of the world's most attractive deep-sea mineral resources"

GREEN MINERALS

The first licensing round had already been halted indefinitely in late 2024. The consequences have been clear: Loke Marine Minerals went bankrupt, Green Minerals had to cut staff significantly, and political unpredictability may have caused both Norwegian and international players to refrain from investing.

Green Minerals states that Norway "possesses some of the world's most attractive deep-sea mineral resources," and that the company has worked purposefully on plans for "environmentally responsible and profitable extraction." As a result of the political uncertainty, Green Minerals has now announced that it will turn its attention to other regions. The company has signed a Memorandum of Understanding (MoU) for a license in the Clarion-Clipperton Zone (CCZ) in the Pacific Ocean – one of the world's most promising areas for polymetallic nodules. The license is estimated to encompass 200 million tonnes of nodules, containing metals such as copper, nickel and cobalt.

There are still a few bright spots for Norway. Although the budget agreement pulled the Norwegian Offshore Directorate's funding for mineral mapping, the organisation confirmed that it is still planning expeditions in 2026 and will present an updated resource assessment for the Norwegian Sea in the first half of the year. ■

Ronny Setså

PHOTOGRAPHY: NORWEGIAN OFFSHORE DIRECTORATE

Resinated cores collected from a drilling campaign managed by the Norwegian Offshore Directorate at the Mohns Ridge in 2020. Darker areas are sulphide materials, while the lighter grey areas are basaltic rocks.

First commercial recovery permit for seabed mining on the horizon

The US government has streamlined exploration and exploitation licence applications for seabed mining in international waters. This bypasses the International Seabed Authority (ISA), which has been slow in establishing a governance structure for commercial mineral recovery

The National Oceanic and Atmospheric Administration (NOAA), an agency within the US Department of Commerce, recently updated regulations regarding seabed mineral exploration and commercial recovery. The updated framework allows US companies not only to apply for a permit to explore for seabed minerals in areas beyond national jurisdiction, but also to commercially recover them.

In other words, qualified applicants can now submit exploration and commercial recovery information together, and may incorporate environmental, geological, and engineering data collected during exploration activities directly into commercial recovery permit applications.

One company responded to that change in regulation immediately. A day after the framework update came into effect, the US subsidiary of The Metals Company (TMC) submitted a consolidated application for an exploration licence and a commercial recovery permit for polymetallic nodules in international waters of the Clarion Clipperton Zone (CCZ) in the Pacific Ocean.

The Metals Company has already explored the CCZ thanks to its partnership with the Pacific Island countries of Nauru and Tonga, holding exploration licences issued by the ISA under UN law. But apart from a production test, these licences do not allow commercial production.

And to date, the ISA has not managed to come up with an agreed framework that offers guidelines on how companies can be awarded a production licence, much to the frustration of the industry. So, if NOAA grants its first commercial recovery permit to The Metals Company, it could mark the inauguration of commercial seabed mining in international waters.

In a 35-page response to these developments, the ISA stated: "Any commercial exploitation outside of national jurisdiction carried out without the authorisation of ISA would constitute a violation of international law." ■

Mariël Reitsma

The CCZ is located between Hawaii and Mexico, and includes the Clarion fracture zone in the north, the Clipperton fracture zone in the south and the adjoining abyssal plain. It is rich in polymetallic nodules, loosely scattered on the seabed, that contain four base metals: cobalt, nickel, copper and manganese, in a single ore.

TMC designed a nodule collection system that creates a suction force to coax the nodules into the collector without digging or dredging. The sediment is then washed off the nodules and deposited back on the sea floor before the nodules travel 4,200 m up the riser to the production vessel.

Once aboard, nodules are dewatered and residual water, sediment and nodule fines are sent back to a depth of 2,000 m via the return pipe. This is a strategically chosen depth, well below the productive upper ocean layers and bypassing 95 % of marine life. The polymetallic nodules will subsequently be processed onshore, leaving minimal tailings behind because most of the ore can be used.

Ferromanganese nodules collected from seamounts in the Pacific Ocean.

PHOTOGRAPHY: US GEOLOGICAL SURVEY

NEW GAS

"With a bit of geological knowledge and a play concept in mind, hydrogen can be found in many favourable places"

Jürgen Grötsch – Tellus Energy Solutions

Omani research well burping hydrogen

Hydrogen gas forms naturally when water and iron-rich rocks react. What if we stimulate and accelerate this process to produce low-carbon hydrogen as an energy resource?

When professor Alexis Templeton from the University of Colorado conducted a techno-economic analysis on stimulated hydrogen, the results suggested that generating profitable volumes of gas is nearly impossible. Still, she pushed for a pilot well to be drilled to compare theoretical calculations and lab experiments with reality. The field results exceeded everyone's expectations, not in the least Alexis' own; stimulated hydrogen is within closer reach than anticipated.

The pilot well is located in Oman, a country with an ophiolite belt as its backbone. Serpentinisation reactions between water, olivine and pyroxene within the peridotite generate large volumes of hydrogen. Local hydrothermal springs degassing hydrogen prove that this process is naturally occurring.

The Rock-Hydrogen pilot well was drilled in early 2024 to a depth of 1,050 m. The top 900 m were cased off, leaving 150 m of relatively fresh peridotite exposed in the well bore. The project team, headed by Alexis, pumped >4,800 m^3 of water downhole and shut the well in. The formation was left to soak and iron-rich minerals reacted to serpentine. When flow testing began after a year, to everyone's surprise, the well did not produce sparkling water but burped gas instead. Alexis: "We weren't prepared for the volumes of both water or gas that we were going to see, we were extremely excited!" The well produced, without decline, equal amounts of gas and water over the multiple-day flow test. The vast majority of gas is hydrogen, complemented by nitrogen and methane.

This result exceeded expectations, because neither the formation nor the injected water had been primed to enhance serpentinization. For example, lab experiments at the University of Colorado show that the ideal temperature for hydrogen formation is 150° C, while the bottom hole temperature in Oman is only 55° C.

The Rock-Hydrogen Project was also restricted to use municipally treated water for injection, while their research shows this is the least favourable composition due to the high concentration of nutrients. In other words, these preliminary results provide a baseline for stimulated hydrogen, leaving room for many improvements to be made.

Additional options are fracking the peridotite to increase the reaction surface and / or adding catalysts to the water. One thing we do not have to fear, according to Alexis, is microbes consuming the hydrogen: "Microbes seem unhappy under the well conditions, the rate of hydrogen production far outstrips the rate of consumption."

The next step in the Rock-Hydrogen Project is to drill an injection and production well array, reaching to greater depth than the pilot well. Alexis is content to have demonstrated that peridotite can be effectively stimulated: "The question is now how much more hydrogen can we make? How much can we scale this and what is the most appropriate way to do it?" ■

Mariël Reitsma

Professor Alexis Templeton in conversation at the 2025 H-NAT Summit.

PHOTOGRAPHY: H-NAT

Canada's first hydrogen exploration well

Mining companies are entering natural hydrogen territory by force

In certain coal mines, it is already common practice to use vented mine gas, predominantly methane, to power operations. The same principle can be applied to ore mines where hydrogen makes up a good proportion of the mine gas. Mining is very energy-intensive, and mines are often situated in remote locations, so readily available gas as a free energy source is a win-win. In addition, it also reduces the operations' carbon footprint.

Canada-based Max Power Mining Corp is one of the companies that adds hydrogen to its repertoire. Originally a critical mineral explorer, mainly focused on lithium, it has now drilled Canada's first-ever natural hydrogen well. The 2,278 m deep Lawson well was drilled in November 2025, near Central Butte, Saskatchewan.

Members of the Max Power team got their first lead in 2022 when they provided geological and operational support for a non-hydrogen exploration well. The company has since identified a multitude of early prospects based on aeromagnetic basement anomalies and legacy seismic data. Most of these are located along the so called 'Genesis Trend': A 475 km basement structure extending northwest-southeast through Saskatchewan and into the USA. The eastern boundary of the Genesis Trend is nestled against the Prairie Evaporite, which functions as a regional barrier and potentially acts as a seal that traps hydrogen.

The Lawson well targeted a Precambrian basement structural high. Natural hydrogen shows were detected in multiple horizons ranging from the shallow Cretaceous strata to the basement complex. An inflow test was performed on an 8 m thick, fractured interval within the uppermost portion of the basement complex. After casing perforation, the well quickly achieved free gas flow to surface before being overtaken by a powerful influx of formation brine. The initial gas flow is due to the pressure differential between the borehole and the formation. Like opening a fizzy drink, excess gas escapes first. In other words, this is an aqueous hydrogen reservoir, not a worthwhile free gas reservoir. Yet, Max Power holds out hope that free gas might be encountered at the apex of the structure.

The hydrogen concentrations from the flow test range from 16.8 % to 19.1 %, with the remainder of the gas being predominantly nitrogen. In the basal Cambrian, immediately above the basement, helium concentrations up to 8.7 % were extracted from core samples.

Max Power has three more high-level prospects; Lucky Lake and Radville, both situated on the Genesis Trend, and Bracken, part of its Grasslands acreage. The Grasslands project is situated along the Saskatchewan-Montana border and is surrounded on the Canadian site by producing helium wells owned by North American Helium. Max Power hopes to spud the Bracken well in February 2026.

It does make one wonder why the company is so set on finding hydrogen when helium is a much more lucrative business. ■

Mariël Reitsma

Did the people from Central Butte realise that a century after this photo was taken in 1914, their village would be the place of the first hydrogen exploration well in Canada?

PHOTOGRAPHY: PRAIRIE-TOWNS.COM

Finding hydrogen is not the problem; producing it is...

But that is what Tellus Energy Solutions is trying to tackle

THE NATURAL hydrogen community is coming to the realisation that finding large free gas, hydrogen reservoirs might be rare, or might not be on the cards at all.

Instead, consensus is growing that 'aqueous hydrogen', hydrogen dissolved in aquifer water, is a more natural state for subsurface hydrogen to occur in. Both HyTerra in the USA and Gold Hydrogen in Australia, two of the most active hydrogen exploration companies, have only found aqueous hydrogen reservoirs to date. Like opening a bottle of soda, these wells may release gas when the reservoir is first exposed, but go flat soon after. Hence, large volumes of water need to be produced, gas separated, and wastewater reinjected, a process that reduces the production rate and drives up the costs.

Sample of Bunter sandstone.

However, with the acceptance that aqueous hydrogen reservoirs are most common, one can turn this challenge into an opportunity. Tellus Energy Solutions is the frontrunner and has come up with a simple yet innovative idea. "Don't go for high-risk, high-reward prospects like free gas accumulations, which are not supported by data like pressure measurements or reliable production tests, but develop a production mechanism which lowers the subsurface risks dramatically," says Jürgen Grötsch, co-founder and CEO at Tellus.

Rather than only focusing on separating hydrogen from aquifer water, Tellus aims to produce geothermal energy in addition. According to Jürgen, this does not complicate exploration: "With a bit of geological knowledge and a play concept in mind, hydrogen can be found in many favourable places."

By combining play concept with regional geology, Tellus landed on Northern Bavaria in Germany for its demonstrator project. The region is underlain by Bunter Sandstone, an up to 550 m thick, lower Triassic fluvial succession. In Bavaria, the Bunter serves as an aquifer, where the favourable porosity and permeability make it an ideal low-temperature geothermal reservoir.

As for hydrogen, a large set of soil gas samples collected over thousands of square kilometers reveal high concentrations in the region. Jürgen: "Aquifers act as baffles for hydrogen; they are not complete barriers." Hydrogen is generated in the ultramafic basement underlying the basin and partially trapped by the aquifer as it migrates to the surface.

Dr Jürgen Grötsch, CEO at Tellus Energy Solutions.

Tellus Energy Solutions has coined its field development concept 'Triple H', pointing to the co-extraction of hydrogen, heat and potentially helium. The extent of the Bunter aquifer in Bavaria allows for a decentralised approach when selecting well locations, producing heat and hydrogen where it's most convenient for the market. By drilling open-loop systems, water is produced to the surface, where membrane technology separates geothermal energy and hydrogen before reinjecting the cool water back into the Bunter. Costs will be recovered by geothermal energy production, making even low hydrogen production rates profitable. Tellus is supported by regional government authorities, local utility companies and private investors. The demonstrator project is expected to start in the second half of 2026 with the acquisition of a 3D seismic survey. ■

Mariël Reitsma

PHOTOGRAPHY: NATURAL HISTORY MUSEUM, COBURG

NEW GAS

Most subsurface teams aren't making the most of their data

Is there still a first-mover advantage in digital subsurface workflows?

EARTH SCIENCE ANALYTICS

Energy companies have invested heavily in data over the past several decades. Seismic surveys, wells, petrophysical data, cores, cuttings, lab data, interpretations, and reports now exist in volumes that were unimaginable only a generation ago.

Yet despite this abundance of data, most decisions that are based on data leverage only a small fraction of the data that has been acquired, and that could be of relevance for the decisions at hand. Why is this the case, and does it need to stay this way?

The problem is not a lack of data, nor a lack of technical expertise. It is a lack of time and efficient tools that can enable large-scale integrated digital workflows. Traditional subsurface workflows are labour-intensive, highly manual and therefore time-consuming. Traditional software solutions are not designed to handle and integrate large, multi-disciplinary datasets. Energy companies, therefore, struggle to scale their data utilization so that more valuable insights can be extracted from existing datasets within the short timeframes that project execution requires. Data may be accessible through many domain-specific platforms and software packages, but access alone does not translate into insight. When core, well-logs, seismic, and other geological information remain siloed across databases, formats, software tools, and teams, the full value of the subsurface is never fully realized.

Figure 1: Using EarthNET and its Data Lake facilitates harmonization, indexing, and contextualization of the data, making it analytics-ready.

Using EarthNET and its Data Lake module, you can have all the data at your fingertips. Although the data available to subsurface teams is typically siloed and stored within multiple disparate databases, EartNET enables direct access to these data without duplication. The data can be visualized directly from where it is stored. The data can be accessed from legacy corporate datastores, file systems, as well as from OSDU™. Adopting OSDU™ standards brings obvious benefits when it comes to data discovery and data management, since OSDU™ is connecting rich metadata to the data. However, there are several reasons why we need to go beyond just data discovery and management. Modern large-scale integrated workflows require that we have access to harmonized, indexed and contextualized data. EarthNET facilitates the data ingestion and standardization that is required. Raw well data can be ingested at scale from disperate silioed legacy storages, harmonized, and validated to ensure consistency across thousands of wells. EarthNET also facilitates cleaning, indexing, and contextualization of the data making it analytics-ready so that it can feed into multi-disciplinary and highly automated workflows.

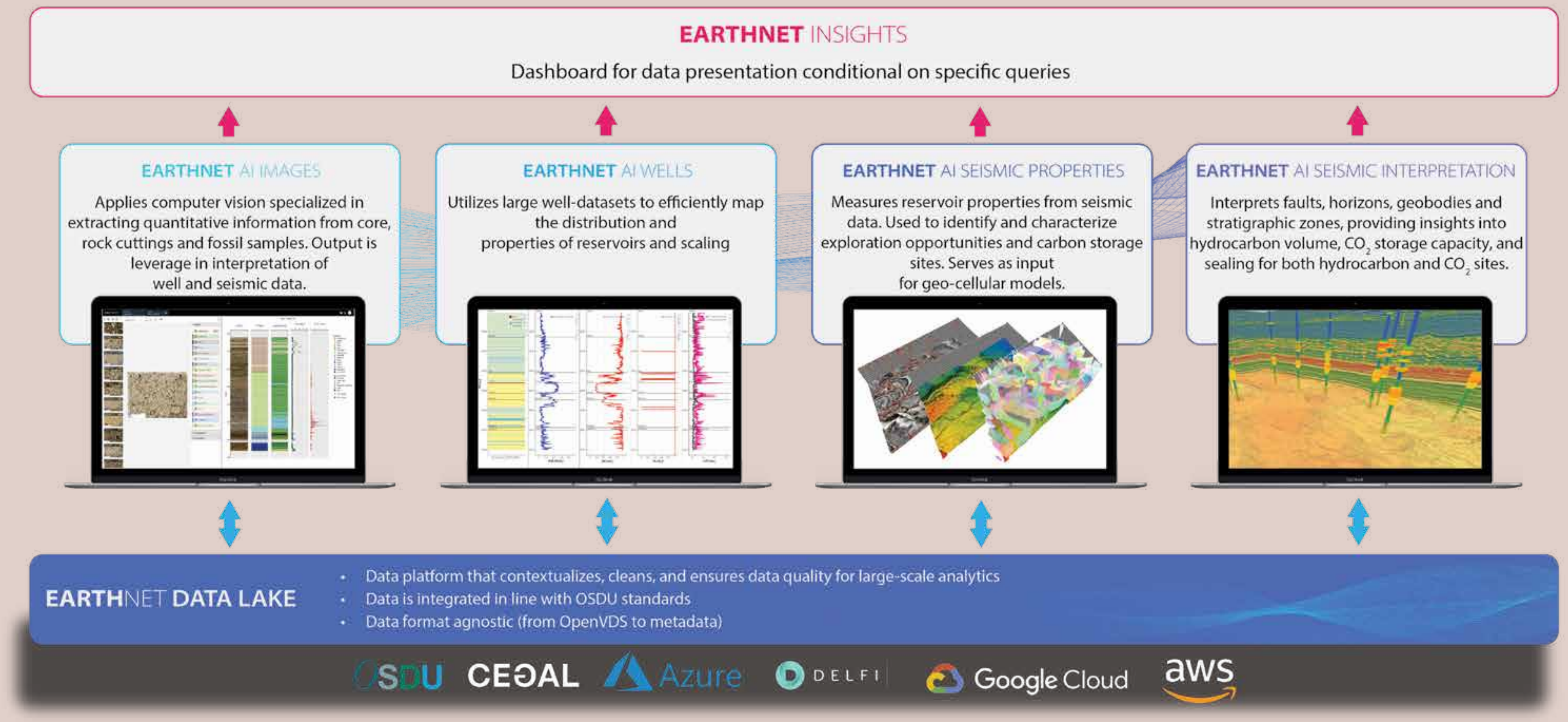


Figure 2: EarthNET is a central part of a modern connected data ecosystem. EarthNET Data Lake connects to external data storage as well as to EarthNET's AI applications and INSIGHS discovery module.

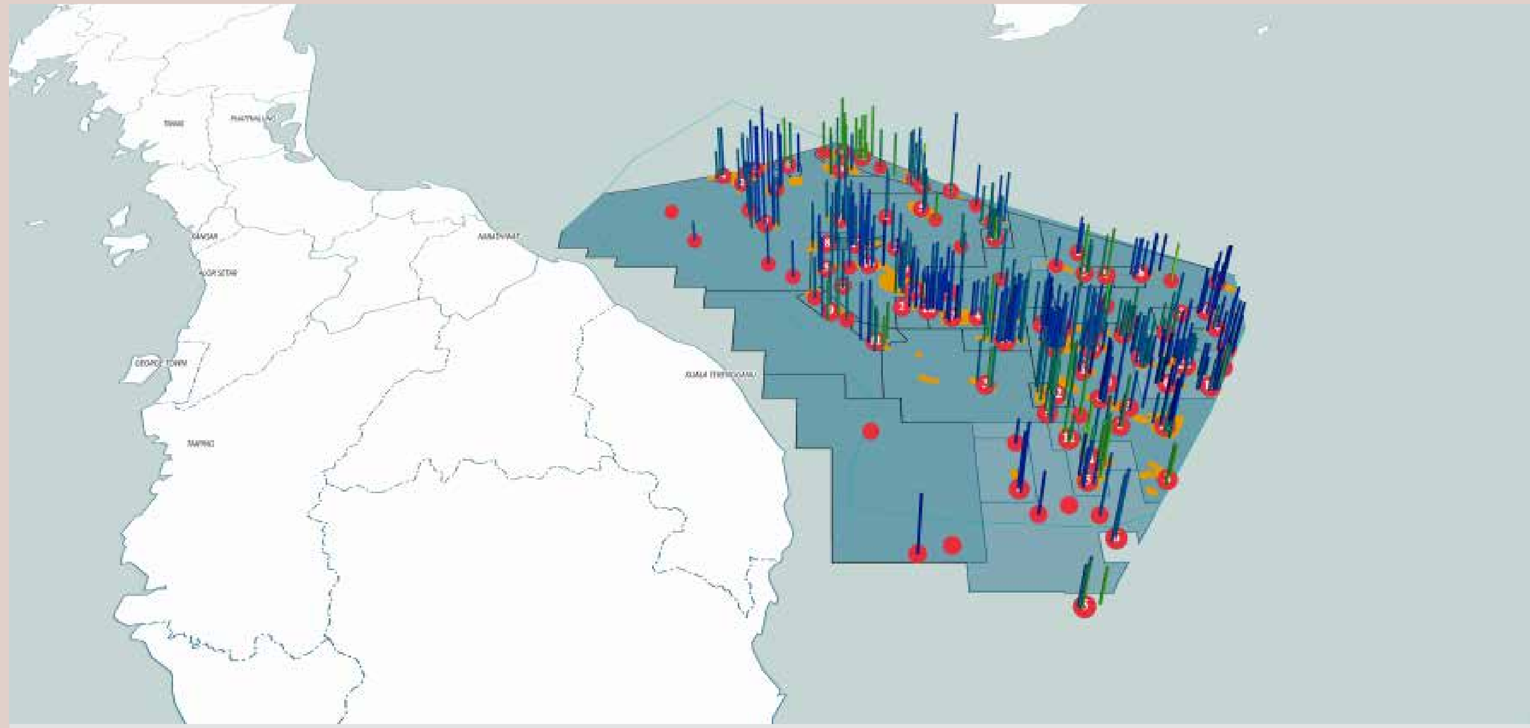


Figure 3: Large-scale study from Peninsula Malaysia. 2,200 wells are ingested, and lithology interpretation and property estimation are predicted across the whole basin.

EarthNET is being used by PETRONAS (MPM) as part of their myPROdata platform to give energy companies access to Malaysia's exploration and production (E&P) data. The purpose is to highlight exploration opportunities in the Malay Basin, as well as to enhance the insight into these opportunities using advanced Artificial Intelligence (AI) and Machine Learning (ML) technologies. The MBR 2025 WELL AND SEISMIC PACKAGE contains over 2,000 wells that have been ingested and gone through rigorous quality control. Missing log prediction, reservoir characterization, and pay analysis have been carried out for the wells. The analysis has then been taken further into the 3D domain with seismic property prediction, and automated fault and horizon interpretation for approximately 40,000 km^2 of 3D seismic data.

EARTH SCIENCE ANALYTICS
Leading Brand of IMDEX™

Over the past decade, digital subsurface workflows have begun to change this picture. Advances in data platforms, cloud infrastructure, and AI-enabled analytics now make it possible to connect subsurface data end to end – from ingestion and contextualisation (Figure 1), through interpretation and screening (Figure 2), to decision-making. This raises a critical question for organisations today: If digital subsurface workflows are becoming more widely available, is there still a first-mover advantage – and where does it come from?

FROM DATA ACCESS TO WORKFLOW EXECUTION

Modern exploration and production strategies increasingly rely on layered digital architectures. Enterprise data platforms – often implemented using OSDU™ standards – provide governance, accessibility, and interoperability. However, these platforms alone do not deliver geological understanding on their own.

Value is created in the layers on top of the data platforms, where data are contextualised, analysed, and interpreted. EarthNET Data Lake operates within this ecosystem by providing structured ingestion, indexing, and contextualisation of seismic, wells, core data, cuttings data, microscopy imagery and interpretations, creating a consistent foundation for downstream analytics.

Building on this foundation, EarthNET functions as the analytics and interpretation layer of the digital subsurface workflow, operating alongside enterprise platforms and enhancing them rather than replacing them (Figure 2).

UNLOCKING LEGACY SUBSURFACE DATA AT SCALE

A persistent challenge in subsurface geoscience is the underutilisation of legacy data. Historical wells, logs, and physical samples often exist in inconsistent formats, making data integration and basin-scale analysis difficult.

EarthNET AI Wells applies machine-learning models across large populations of historical well data to support automated interval identification, lithology interpretation, and property estimation at scale. (Figures 2 and 3).

In parallel with analysis of well logs, EarthNET AI Images (Figures 2 and 4) applies computer vision to geological cuttings and core imagery, enabling automated lithology classification, semantic segmentation, and object detection. Together, these capabilities transform archived offshore data into analytics-ready datasets that can be reused consistently across projects.

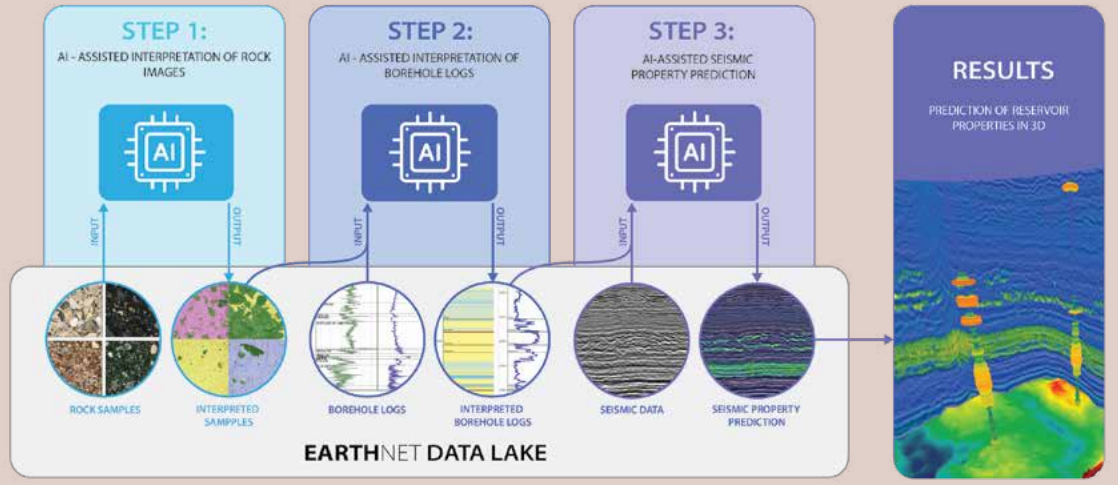


Figure 4 : EarthNET enables large-scale integrated workflows. This example illustrates a multi-model AI workflow for integrating subsurface data at scale, from rock samples to basin-scale seismic-based rock property prediction. Nguyen et al. (2023).

Subsurface data analysis in the energy industry is ultimately done to support decision-making related to exploration, field development or production. The decisions that we as subsurface domain experts are supporting need input from multiple datatypes and scientific disciplines. To support these decisions, we therefore need to interpret and analyse each relevant datatype, as well as integrate the analysis of each datatype and scientific discipline.

EarthNET offers applications for both manual, semi-automated and fully automated interpretation of individual datatypes using AI models. EarthNET also enables the concept of integration through the data layer, i.e. the EarthNET Data Lake. This enables propagation of information across datatypes and scientific disciplines.

In the example illustrated in Figure 4 the output derived from interpretation of core and cuttings data (Step 1) is used as input to the interpretation of well-log data (Step 2). The output from the interpretation of well-log data is used as input to the interpretation of seismic data (Step 3).

This example is only one of many examples of integrated workflow one can execute using EarthNET. The end result of this workflow is a set of regional facies or lithology volumes and associated confidence volumes that can be used in reservoir characterization. The high level of automation enables subsurface professionals to do this type of work with very little resource use, and can thus leverage the resulting insights early in the exploration and production value chain.

EXPLORING FOR OVERLOOKED OPPORTUNITIES – FROM MISSED PAY TO NEW DRILLING TARGETS

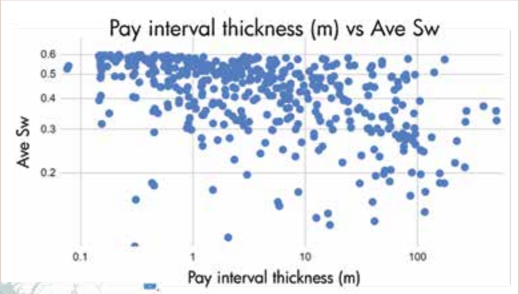
Open digital ecosystems and connected digital workflows (Figure 4) enable subsurface teams to rapidly screen large well-populations, compare stratigraphic intervals, and identify areas of interest early in the project lifecycle. Using EarthNET analytics and visualisation tools, outputs from AI wells, AI images and EarthNET AI seismic properties can be analysed together, supporting rapid offshore field screening and early-stage subsurface modelling based on integrated datasets rather than isolated studies (Figure 1 and 5).

Early adoption of AI for subsurface workflows has been focused on using a single datatype rather than on extracting insights by integrating multiple datatypes.

Examples of single datatype usecases include (i) fault-interpretation using deep-learning methodologies, (ii) filling of missing well logs using various machine-learning algorithms, and (iii) interpretation of facies from core imagery. Examples of integrated use cases include (i) from core and cuttings to petrophysics interpretation, (ii) from core to seismic, and (iii) PhysicsInformed Neural Networks for seismic property prediction that have learned both from sample data, well-log data and from established geophysical relationships and knowledge.

SCALABLE WORKFLOWS ACROSS OFFSHORE REGIONS

While early digital initiatives focused primarily on mature basins, the same workflows are now being applied across Europe , Asia-Pacific and the Middle East. Because EarthNET workflows are cloud-native and data-format-agnostic, Earth Science Analytics has applied the same AI-enabled approaches across regions with varying data density and subsurface maturity, supporting faster understanding and more consistent decision-making at portfolio scale (Figures 3, 4, 5 and 6).



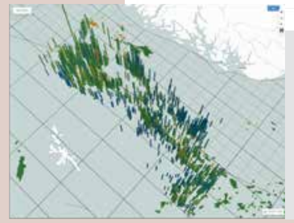
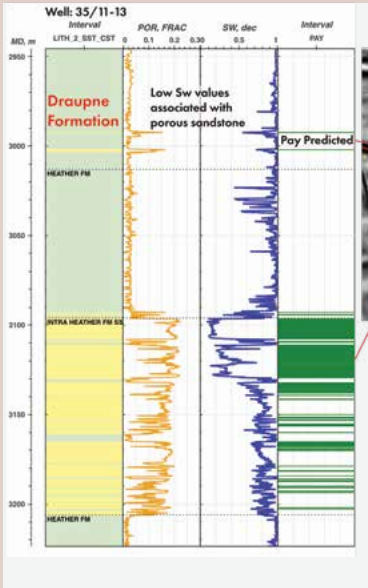


Figure 5: Large-scale missed pay studies. EarthNET's ability to analyse very large datasets with a high degree of automation enables the use of legacy data to identify overlooked exploration opportunities.

EarthNET is being used in the North Sea to identify overlooked pay intervals in legacy wells from both the Norwegian and UK sectors. These studies highlight exploration opportunities in a mature basin. Several hundred pay intervals have been identified in parts of wells that were previously thought to be dry. Energy companies are using this large database of overlooked pay intervals as a starting point for further evaluation of exploration opportunities. Some of the pay intervals are thick with significantly reduced water saturation and some thinner and more subtle. Also the subtle ones may be "smoking guns" that can lead to commercially attractive opportunities when pursuing them further using seismic data.

EarthNET enables integration across datatypes, and propoagation of information from the well domain to seismic domain. The example in Figure 6 illustrates two very thin pay intervals that were identified in the overburden (in the Draupne Formation) above a known accumulation (in the Heather Formation). The analysis was taken further from the initial well analysis into the 3D domain using EarthNET's 3D seismic property prediction module. The seismic property prediction delivered a facies volume, a porosity volume and a water saturation volume. Automatic fault and horizon interpretation was carried out to define the structural and stratigraphic framework.

The extended study revealed that there was a commercially viable exploration opportunity present in the Draupne Formation across the fault from the initially discovered accumulation. This example illustrated that although being thin, the missed pay interval that was revealed in the well lead to an attractive exploration opportunity laterally after integrating the well data with seismic data.



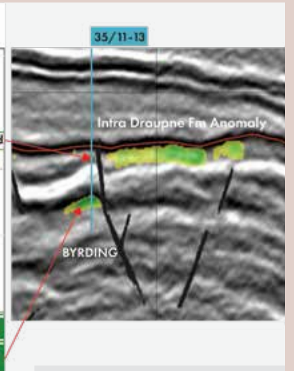


Figure 6: Mapping of exploration opportunities in 3D. EarthNET takes you from the identification of missed pay intervals in wells to mapping the exploration opportunities in 3D using seismic data.

WORKING ALONGSIDE OSDU™ IMPLEMENTERS

Interoperability remains a key requirement for enterprise digital strategies. EarthNET is designed to integrate with OSDU™-based data platforms, with EarthNET Data Lake supporting OSDU™-compatible ingestion and export (Figure 7). AI-derived interpretations from AI wells and AI images can be delivered back into enterprise environments, ensuring alignment with corporate data governance while enabling advanced subsurface analytics.

SO, IS THERE STILL A FIRST-MOVER ADVANTAGE IN DIGITAL SUBSURFACE WORKFLOWS?

The answer is yes – but it no longer comes from adopting technology first. The advantage lies in how effectively digital workflows are embedded into everyday subsurface work. Teams that connect dataplatforms, AI-enabled analytics, and geological expertise into operational workflows move faster, learn continuously, and reuse insight at scale.

EarthNET and Earth Science Analytics have led this digital transformation, delivering proven, actionable results across subsurface projects in Europe, the Middle East, and Asia. By applying AI within connected digital workflows – rather than as isolated tools – they enable organisations to unlock value from existing data, whether OSDU™ compliant or not, and whether working with wells, cores, cuttings, seismic, or integrated studies.

For energy companies ready to move from digital adoption to digital execution, the opportunity remains very real.

To learn how your subsurface data can deliver deeper insight and lasting value, contact Earth Science Analytics at contact@earthanalytics.no.

TECHNOLOGY

"The advancement of this technology helps enable Through Tubing Abandonment, which can save a lot of money, time and complexity"

Iain Whyte – Islay Subsurface

When the reliability of your project depends on a single tool at hundreds of meters depth

Electric Submersible Pumps (ESPs) form the lifeline of many geothermal projects where there is no natural flow to surface. Especially in the case of single doublets, the risk of pump breakdown and a forced standstill is real and continues to be hard to predict. Therefore, technology is needed to better understand when ESPs might fail

An ESP can fail at any time, even before geothermal projects officially start. We recently reported on such a special case of ESP failure in the southwest of England, where the United Downs project is hoping to start producing geothermal energy from a very deep borehole soon. But even before the system started operating, the ESP broke down.

Ryan Law, the founder and CEO of the United Downs project, was quite vocal on LinkedIn about where to put the blame for the ESP failure: Baker Hughes. He has now put his hopes on technology from SLB: “Unfortunately, the deep Electrical Submersible Pump from Baker Hughes stopped working and is being replaced. (…) Hopefully, the new ESP from SLB will finally enable us to start producing electricity early next year.”

It is quite rare to see an operator point fingers at hardware suppliers this way, but maybe he had a good reason to do so. Anyway, this example clearly shows how important ESPs are for the functioning of a geothermal system.

The critical nature of ESPs is not unique to the geothermal industry; they are also quite common in oil. But here, flow rates are often lower, there are fewer starts and stops, there is less variation in temperature, and corrosion and scaling are not as severe. In addition, many oil fields will have more than one producing well, which introduces contingency in case one needs to be shut in temporarily.

Example of scale development at an ESP in Southern Germany.

PHOTOGRAPHY: STADTWERKE MÜNCHEN

> The ESPs that are running in geothermal wells in the Netherlands have an average run time between one and two years. However, there is a reported case of tool failure after nine days, as well as an exceptional lifetime of more than five years. It demonstrates the variation of tool performance.

But what kind of technology is available to improve the reliability of ESPs? A workshop was held in the Netherlands to discuss what is happening in that domain.

Apart from better hardware, quality is a cost-reducer rather than a cost inflation – traditional monitoring of ESPs by looking at voltage and flow is now increasingly being supplemented by acoustic sensors and fibre-optic measurements to detect instability, wear or abnormal loads. This has enabled the prediction of failure days or weeks in advance, which allows the operator to prepare for an intervention while the ESP is still operational. This can minimise downtime significantly. Another aspect that was discussed in a presentation was the need for proper testing of new ESP prototypes under conditions that are representative of downhole conditions.

In the meantime, let’s hope that Ryan Law will soon be able to post about the successful startup of his geothermal project and that the SLB ESP will last longer than the one from the competitor. ■

Henk Kombrink

Have a look at the presentations that were given during the ESP workshop in the Netherlands:

Norway’s AlphaGo moment: Why 2025 changed the game

With 2025 clocking in as the second-best year for exploration in a decade for Norway, the industry is asking a critical question: Is this a final flush of luck in a mature basin, or have we finally cracked the code?

DAN AUSTIN, SEKAL

In 2016, Google’s AlphaGo played "Move 37" against Lee Sedol – a move that looked bafflingly wrong to human experts but ultimately secured the win. In 2025, the Norwegian Continental Shelf (NCS) experienced its own "Move 37." Just as AlphaGo proved that machines could "see" moves humans couldn't, we are finding more not because the geology changed, but because our ability to see it did.

Equinor has been vocal in attributing their recent success to AI. The operator reported that Artificial Intelligence contributed approximately $130 M in value creation and savings in 2025 alone.

In 2025, 2 M km² of seismic data were interpreted using AI tools, and geoscientists have increased their capacity to screen vast acreages of the mature shelf tenfold. Meanwhile, AI-driven well planning has saved $12 M on Johan Sverdrup Phase 3 alone through improved hit rates and optimised well placements.

Elsewhere on the shelf, Aker BP is fundamentally changing how an oil company thinks. Their latest strategy to become "AI-First" moves beyond simply buying new software tools. Instead, they are redesigning their workforce and daily operations around artificial intelligence. Aker BP is training its own staff to be the experts – they want their engineers and geologists to build and control their own digital tools. Before recruiting a person for a role, they now ask, "Could an AI do this?", ensuring that human talent is reserved for complex, creative problem-solving, while machines handle repetitive data work.

Aker BP also now treats AI models like standard industrial machinery – reliable, secure, and available to everyone in the company. By organizing their data in a central, secure library that anyone can access, they have turned AI from a novelty into a daily utility, as essential as a drill bit or a wrench.

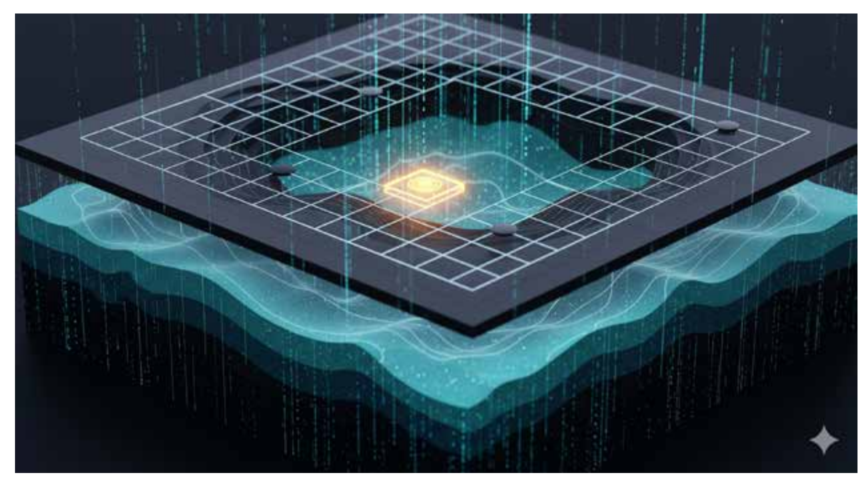


ILLUSTRATION: GEMINI GENERATED BY DAN AUSTIN

Their success in 2025 – headlined by discoveries like Lofn/Langemann and Omega Alfa (see cover story) would suggest that this is paying off.

2025 also marked the 30th anniversary of the creation of Diskos. Once a static library, Diskos has grown into a dynamic engine powering the industry's new foundation models. The sheer volume and quality of standardised data on the NCS have made it the perfect training ground for advanced machine learning. Reported data have increased by almost six petabytes, from 16 in 2023 to 22 in 2025.

Crucially, this software revolution is matched by a hardware one. The "full stack" includes the physical layer – modern rigs, automated drilling control, and Ocean Bottom Node (OBN) seismic acquisition. The ability to place sensors precisely and drill autonomously allows the digital models to be executed with unprecedented accuracy. The feedback loop between physical hardware and digital twins has closed, reducing execution risk and cost.

The digital assists from Aker BP and the AI-driven confidence of Equinor suggest that for the NCS, the best years of *efficiency* might still be ahead. The exploration success of 2025 wasn't driven by brute force or blind luck, but by a level of strategic intuition provided by AI that human teams alone could not achieve. ■

"It will make you look like a hero"

How new technology and a robust subsurface approach can drive down costs and complexity when decommissioning wells

"WHEN WE START shaving off millions of each well, then we are talking business," says Iain Whyte from Islay Subsurface. "That's the prize we're all after."

But how to win that prize? That's what Iain and his colleagues have looked into recently, through a collaboration with the Net Zero Technology Centre (NZTC) in Scotland.

"First of all," Iain says, "we need to be increasingly aware that a proper subsurface evaluation is key to making sure isolation plugs are set where they really should be. What I mean by that is that not all sands need to be isolated from one another. There has to be potential for sustained flow, and often stringers with little or no connected volumes can be shown to have limited potential in that regard. That is the first part of the abandonment puzzle; only emphasising the zones that really require isolation."

Then there is the technology part of well abandonment, which centres around the question if there is a tool that enables companies to look behind casing whilst running it through the production tubing. The prize? "If we can show that the cement is properly sealing the formation behind casing, we might be in a position where the plug can be set through the tubing itself," explains Iain. "That way, we eliminate the need to pull the tubing out of the hole."

And because of the implied cost savings for leaving the tubing in place, a range of companies have embarked on developing a tool that can do exactly this, from the established major service companies to new kids on the block.

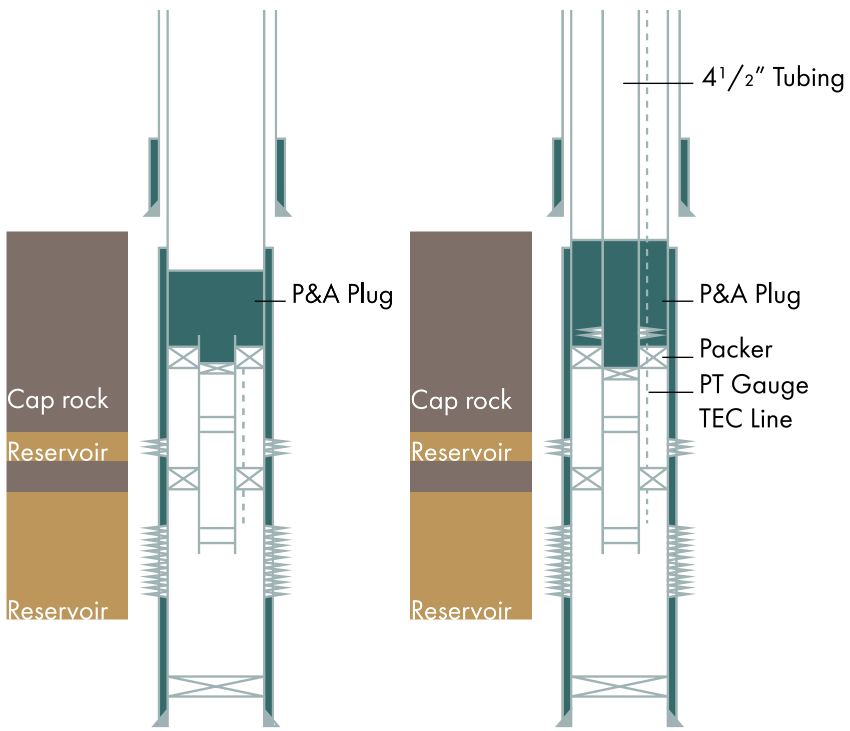
"We identified eleven companies that are active in this realm, even ones that had no previous downhole tool experience," Iain says. "The first phase of our project was to make a "Market Landscape" evaluation of the different technologies used by these manufacturers, varying from acoustic, nuclear, electromagnetics to X-ray, and how they process the data."

Then, a subset of the vendors was selected to be tested in a test well in Norway, where markers had been placed on the outside of the casing at unknown depths for the tools to pick up. "Some of the log responses are far superior to the conventional methodologies out there," says Iain, who is not yet in a position to share the results of the tests. The tools detected synthetic and natural defects behind the casing, and the Top of Cement. This was performed through both centralised and decentralised tubing strings in the test well.

"Let me put it this way," he says. "The advancement of this technology helps enable Through Tubing Abandonment, which can save a lot of money, time and complexity. Suddenly, not everything needs to be done through an offshore rig. Rather, a lighter intervention vessel can be used. In the case of a 84 wells decom project in West Africa, we went USD 492 M to USD 342 M as a result."

"Can you now imagine why I'm saying that this approach can make you look like a hero?" Iain asks rhetorically. ■

Henk Kombrink



The illustration on the right shows a "conventional" way of abandoning a well by pulling the production tubing and putting a cement plug in place just above the reservoir. The diagram on the left shows a situation in which Through-Tubing logging enables confirmation of good cement behind casing, which subsequently allows leaving the tubing in place.

INSIGHTS

"Understanding whether a basin has undergone multiple phases of extension and compression helps set realistic expectations and allows interpreters to either support or confidently rule out an inversion interpretation"

Molly Turko – Devon Energy

Love and sex and oil and passion

We never forget our first time. When we lose our virginity. When we pop our cherry. When we can consider ourselves a proper adult. It doesn't have to be love, though it may be. It shapes us. It stays with us

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

WE ALSO never forget those true loves. We carry them for life.

My first time and first love was Beatrice. I consider myself very lucky. I was young, and she was older, mature. She taught me to be attentive, to respect details. To never expect relationships to be easy. She taught me that youth and inexperience are not interesting, that age and history and stories and experiences are. She carried scars. She carried secrets. She rewarded persistence.

She was Scottish and the ex-wife of a well-known oil executive, and we were together for four years. Every day was a pleasure. Genuinely. That was three decades ago, and I still hold her dearly in my heart. I thank her for sharing and for teaching. She made me a better person. And then we had to go our separate ways. I never saw her again.

After that, as a young free guy, I drifted. Short-term liaisons in Scotland and London. Then I met Hope.

Hope had had a troubled past. From the Ivory Coast, she had been misunderstood, abandoned at a young age, and in desperate need of belief and revitalisation. I truly think I was able to do that, to help her to heal. Rediscover her confidence and fire. It was hard work. I'm not ashamed to say it. We invested everything together: Time, energy, discipline, commitment. We became a success. She became a success.

Others played their part, of course, but for me, Hope and I were the team. I visited the Ivory Coast and saw her beautiful, complex, damaged country. It helped me understand her better. She herself was staggeringly beautiful. And complex. And damaged.

PHOTOGRAPHY: KICHIGIN19 VIA ADOBE STOCK

Once again, life moved us on. I missed her desperately for many years. Good friends of mine have stayed with her, and so I know she thrived. That warms my heart.

I talk of these things to remind us of something fundamental: Loving matters. Committing is essential. Building success is a love affair. A mental, emotional, and carnal pleasure. Not for corporate loyalty. Not for supporting slogans. Not for parroting mission statements. Physically immersed, emotionally invested. The love affair geologists have with their rocks.

So stay alive. Stay physical. Stay curious. Stay in love.

Never forget the passion. ■

FOR THOSE WHO DIDN'T QUITE GET IT

Beatrice is the UK Inner Moray Firth oil field that produced from a Middle Jurassic shallow marine sandstone reservoir. It was discovered in 1976 by Mesa Petroleum and named after the wife of Mesa's founder T. Boone Pickens. The field was picked up by Talisman in the mid 1990s to rejuvenate.

Hope is the English translation of the French word Espoir and also an oil field of Middle Cretaceous deep-water sandstones. Discovered and developed in the 1980s by Phillips Petroleum, it was redeveloped by CNR and came onstream in 2002.

Diverting the flow: The hidden power of overburden barriers

And more insights from a conversation with Mark Lakos from Rock Flow Dynamics

Mark Lakos.

SINCE MARK Lakos joined RFD from Wintershall Dea a bit more than a year ago – a job that brought him to Russia and Egypt – Mark has been heavily involved with modelling of CO_2 injection and migration in the subsurface, using RFD's t-Nav software. As a reservoir engineer with a background in managing gas-condensate fields, he was up for that type of work.

"One of my key learnings was that our modelling suggests that the risk of CO_2 coming up all the way to surface is, in fact, negligible," Mark says. "Look at this cross-section," he continues, and he points to a model of just a single 100 m reservoir with a 900 m thick overburden consisting of a mix of lithologies that do not form a perfect seal. "Even in such an extreme case, where we don't have a perfect seal," he explains, "we don't see CO_2 migrating to surface in a matter of 100 years, as most of the CO_2 would have dissolved in the formation water by that time."

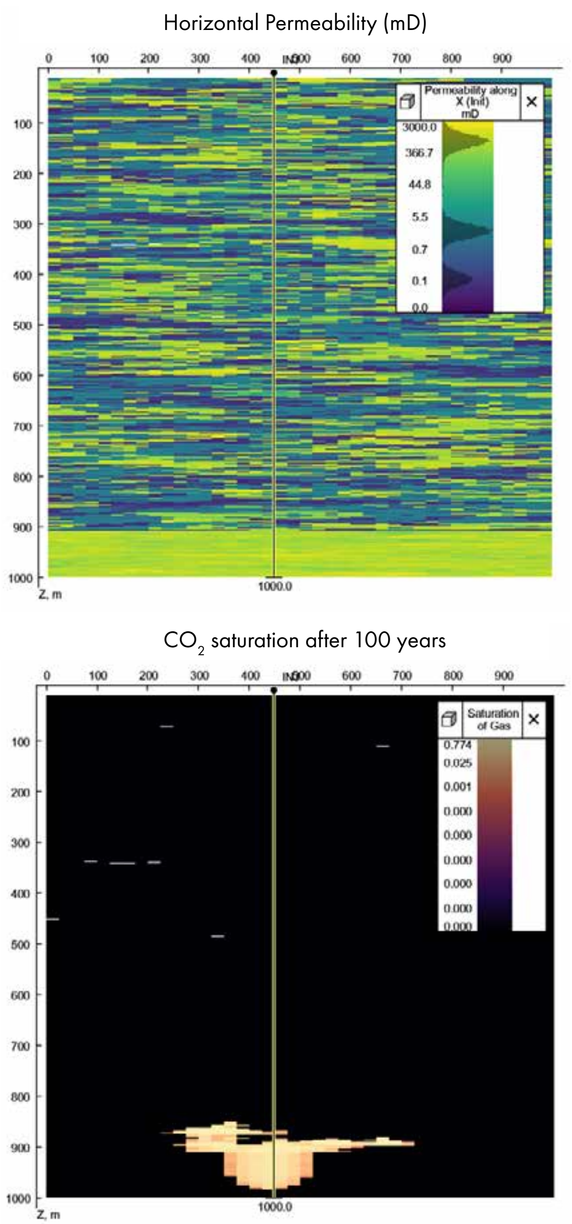
"Even better, the faster we inject the CO_2, the less the plume will have migrated up over time," Mark says. "This sounds counterintuitive, but there is an explanation for it. When we inject CO_2 at a higher rate, it will penetrate deeper into the reservoir than if we injected at lower rates, due to kinetic forces dominating over buoyancy. At low rates, buoyancy is the key driver of the migration, leading to more rapid vertical CO_2 movement."

This observation would lend support to the model of injecting CO_2 by offshore vessels, as the injection rates in that scenario are high.

"And then we haven't even introduced lateral barriers," Mark says. Following on from work published by Alexander Bump from the University of Texas at Austin, who has been saying that the subsurface is not the problem when it comes to CO_2 injection, Mark also ran models in which he introduced these barriers. "In that case," he says, "even when the barriers are discontinuous, we still see that they strongly inhibit vertical movement. To an extent that upward migration is even less of a concern."

In other words, based on the modelling he has performed, Mark thinks that the often-heard concern about CO_2 leakage has received too much negative press. "Some are usually sceptical about modelling work," he concludes, "and its capability of forecasting reliably hundreds or thousands of years into the future. But even if we are slightly wrong and some CO_2 does escape to the atmosphere, let us give it a thought: Is it better to store 99 % or nothing at all?" ■

Henk Kombrink



Discontinuous barriers in the overburden can effectively divert CO_2 flow.

What is the driver for drilling two costly exploration wells offshore Bulgaria?

NVENTURES

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It's the success that the neighbours reported in the Western Black Sea. Not once, but multiple times now

JON FORD, NVENTURES

The spudding of wildcat Vinekh-1 in the Han Asparuh block marks the entry of Bulgaria into high-impact deepwater biogenic gas exploration in the Western Black Sea. And that's not all, straight after completion of Vinekh-1, Krum-1 is expected to be drilled, also in Bulgarian waters. This is quite a step up in activity, but the explanation is straightforward: Exploration success in Türkiye and developments in Romania.

The exploration history of the Western Black Sea begins, as usual, with the proximal onshore and shallow water areas. Here, off Romania, Bulgaria and Türkiye, minor biogenic or perhaps mixed biogenic/thermogenic gas discoveries have been made, such as Ana-Doina, Galata-Kavarna-Kaliakra and South Akcakoca. But due to limitations in trap size and reservoir thickness, commerciality has proven to be an issue for these finds.

Then, the promise of thermogenic kitchens of the regional Paleogene "Maykop" rich source rock drove exploration to look for significant structural traps in deeper waters, resulting in Bulgaria's 2016 Polshkov sub-commercial oil discovery with potential reservoir sequences in the Oligocene and Lower Cretaceous. Follow-up wells Rubin-1 and Melnik-1 were dry.

The first large deepwater biogenic gas discoveries had already been made by this time, off Romania in the Neptun Deep licence, at Domino (2011) and Pelican South (2015) by OMV. To be simplistic, the exploration philosophy is straightforward: Look for deepwater reservoirs off a major delta, in this case the Donau, which has been delivering large sediment volumes since the Miocene.

Neptun Deep is expected to produce first gas from its 3.5 TCF resource in 2027. Plateau rate will be 775 MMscfpd delivered from ten wells, and it will make Romania the largest gas producer in the EU. Further exploration to extend field life is planned.

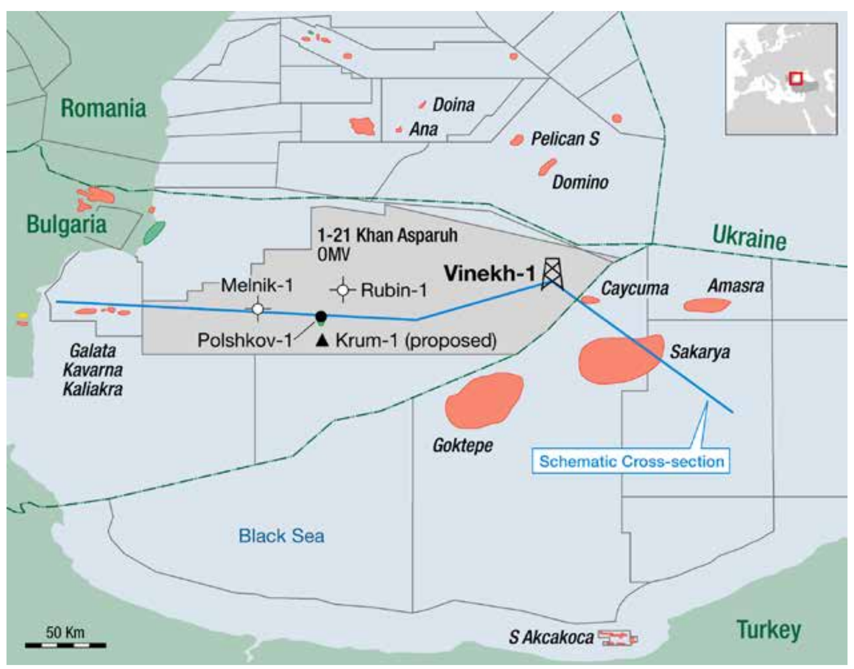


Figure 1: Western Black Sea location map showing fields and wells mentioned in the text.

The operator of the Han Aspurah licence is OMV, in a 50:50 partnership with NewMed. The latter is farming in by paying the premium of the first €50 M of both the Vinekh-1 and Krum-1 wells. The Vinekh-1 well is in 1,900 m of water, around 160 km offshore, and will be drilled by the Noble Globetrotter drillship. TD is estimated to be at 3,250 m, 1,350 m below the mudline. The dry hole Authorization for Expenditure cost is €89 M, with contingent testing a further €20 M. Immediately following Vinekh-1, the drillship will move to drill the partly analogous Krum prospect, at a gross estimated cost of €86 M, to a depth of 3,540 m in water depths of 1,760 m.

SOURCE: NVENTURES

Reservoirs are in a slope-to-basin-floor setting in the Plio-Miocene. Both Vinekh and Krum prospects are along trend from Neptun Deep.

How far across the Black Sea do distal Donau fan sandstones extend? The answer lies in Turkish waters, where TPAO announced the Tuna-1 gas discovery in 2020. Renamed the Sakarya field, initial resource estimates were reported to be 11 TCF, which seemed a lot following one exploration well. The next discovery, along trend from the Tuna-1 well, was Amasra, discovering reportedly 8 TCF. Any scepticism about the significance of these discoveries fell away with the successful Caycuma-1 well, adding a further 6 TCF and bringing the total discovered volume to 25 TCF. Water depths are around the 2 km mark with sub-seabed target depths ranging 1,800 to 2,800 m. Further exploration continued; in June 2025, TPAO announced the successful appraisal of the Goktepe discovery, adding a further 2-3 TCF.

TPAO moved swiftly to exploit the discovered resource; some 210 MMcfgpd now flows to Türkiye's domestic market in Phase 1 of the Sakarya project via a 155 km pipeline. Phase 2 is underway to deliver a total of 325 MMcfgpd by 2028. In addition, ExxonMobil have signed an "exploration pact" with TPAO for the Black Sea in early 2026.

STACKED SANDS

The reservoirs in the Black Sea biogenic petroleum play consist of multiple, sometimes stacked, fine-grained basin floor sands deposited in an overall mud-rich Plio-Miocene system. These muds both provide the seal and the biogenic gas source. Traps are simple four-way dip closures, possibly stratigraphically enhanced, draped over deeper structures. On seismic, the gas-charged reservoirs may provide simple direct hydrocarbon indicators, such as at Amasra; but there are imaging challenges at or near the seabed from canyons, shallow gas including hydrates, and complex stratigraphy including debris flows from the seismically active southern boundary of the basin. On well logs, there are challenges as well; a limited gamma-ray contrast between reservoir and non-reservoir, and a high level of bound water in the fine-grained sands, complicating the interpretation of the resistivity log. The gross reservoir interval is reported to be up to 130 m thick by TPAO. But the standard advantages of producing biogenic gas apply: Dry, so no liquids to process, and some 98 % methane that can go straight to market.

To circle back, the Turkish Caycuma discovery borders and may extend over the maritime boundary with Bulgaria. Figure 2 is a schematic cross-section illustrating the relationship between Sakarya and Bulgarian waters. Vinekh-1 lies less than 30 km from Caycuma and is reported to share as one of its targets an equivalent reservoir interval, "A1", with prospective resources according to a competent person's report of 2 TCF at a geological risk of 43 %. Secondary targets add a further 1.4 TCF at a risk of around 25 %. The follow-up Krum prospect, which lies further west away from the Turkish proven resources, has aggregate prospective resources of 7.5 TCF in three reservoir targets at risks between 16 and 32 %.

ESTABLISHMENT OF A BIOGENIC GAS PLAY

Success at the scales predicted in these two forthcoming Bulgarian wells will complete the establishment of a proper Western Black Sea biogenic gas province. It is a matter of time until the more northerly part, offshore Ukraine, will be tested too. ■

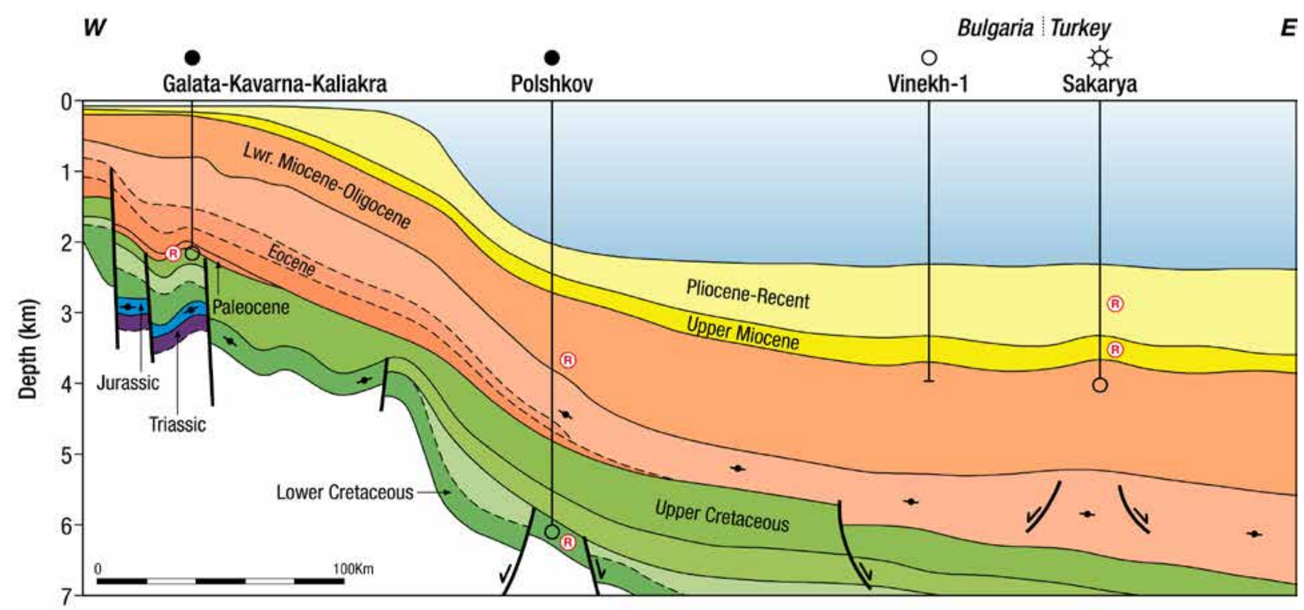


Figure 2: Schematic geological cross-section through offshore Bulgaria and Türkiye. The location of the cross-section is shown in Figure 1.

When the lithium cycle bites back

Why are prices rallying in China at the start of 2026?

ISTVÁN NAGY-KORODI, CONSULTING GEOLOGIST

Commodity cycles rarely announce their turning points. They emerge quietly, through inventory data, project pipelines, and subtle shifts in physical markets – long before consensus catches up. The lithium price rally unfolding in China in early 2026 fits this pattern. It's almost like a textbook.

What looks, at first glance, like a sudden spike in lithium carbonate and hydroxide prices is in fact the delayed response of a system that has been quietly tightening for more than a year.

Based on SCI (Figure 1) and Benchmark Intelligence data (Figure 2), the most important early warning came from project development information. During the 2021-2023 boom, more than 50 lithium projects globally progressed to feasibility studies. Following the sharp price correction of 2023-2024, that pipeline collapsed. By 2025, the number of feasibility studies and Final Investment Decisions had fallen to historic lows. Capital withdrew, boards delayed sanctioning, and the industry effectively chose to wait out the downturn.

For lithium, this decision carries structural consequences. Even the fastest lithium developments – brines, brownfield expansions, or DLE pilots – require several years to reach commercial scale. When feasibility work dries up, future supply is quietly removed from the system. The impact is not immediate, but it is inevitable.

While investment stalled, demand did not disappear. Battery-grade lithium carbonate and hydroxide continued to be consumed by electric vehicles, energy storage systems, and industrial users. According to market data, inventories in China have been steadily drawn down since September 2025 and entered 2026 at their lowest levels of the year. Once inventories thin, the market's behaviour changes. Prices no longer move gradually; they react sharply to even marginal shifts in sentiment or procurement.

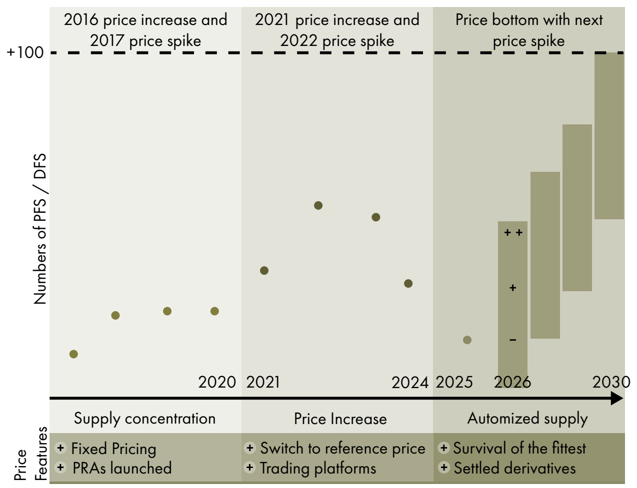


Figure 1: The number of feasibility studies and FIDs has dropped significantly in 2025.

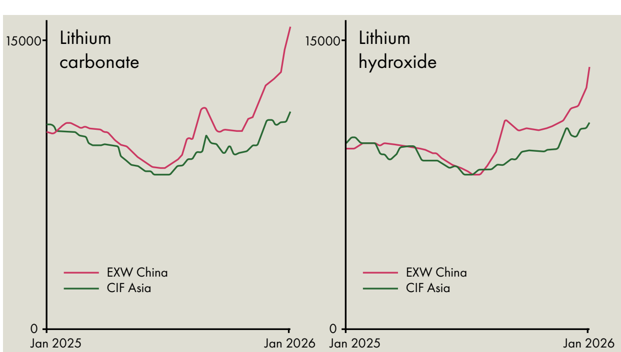


Figure 2: Increasing lithium price in beginning of 2026.

Crucially, the price recovery did not require a surge in demand. It only required the demand to stop falling. By late 2025, EV growth in China stabilised, energy storage deployments absorbed additional carbonate volumes, and downstream players shifted from destocking to cautious restocking. In a market already stripped of inventory buffers, that was enough to trigger a rapid repricing.

From an energy-geologist's perspective, the current lithium rally looks less like a surprise and more like a delayed inevitability. The industry responded rationally to low prices by cutting investment. The subsurface responded, as it always does, by refusing to accelerate on demand.

Lithium, like oil, copper, or uranium, are reminding markets of a fundamental rule: You cannot shortcut time in the subsurface / sanction supply retroactively. By the time prices signal scarcity, the development gap is already locked in, and when that reality finally shows up in inventories, prices move first and fast. Questions get asked later. ■

SOURCE FIG. 1: SC / FIG. 2: BENCHMARK LITHIUM PRICE ASSESSMENT

How to generate an oil accumulation in a gas-prone petroleum system?

The answer is in seal capacity and plenty of hydrocarbon charge

LUKASZ KRAWCZYNSKI AND MARTIN NEUMAIER

Australia's NW Shelf is characterised by a gas-dominated petroleum system, where Middle Jurassic deltaic coals of the Plover Formation make up the main source rocks. That is why oil occurrences along the NW Shelf tend to be the result of secondary alteration processes, ranging from water washing in the Bonaparte Basin, phase fractionation in the Vulcan Sub-Basin to biodegradation in the Carnarvon and Browse basins. In rare circumstances, oil accumulations are sourced from oil-prone Upper Jurassic marine source rocks and require shielding from the dominant Middle Jurassic gas source.

The Vulcan Sub-Basin is characterised by a whole-system gas-to-liquids ratio of approximately 20,000 scf/bbl (~50 bbl/MMscf). Early oil discoveries in the 1970s and 1980s, including the Jabiru and Challis fields, led to the interpretation of an oil-prone petroleum system sourced from Upper Jurassic marine source rocks, largely based on geochemical interpretations. However, subsequent exploration delivered underwhelming results, with discoveries commonly deemed sub-commercial due to limited oil volumes or the presence of significant gas phases, as observed in the multi-Tcf accumulations of the Cash / Maple and Bratwurst discoveries.

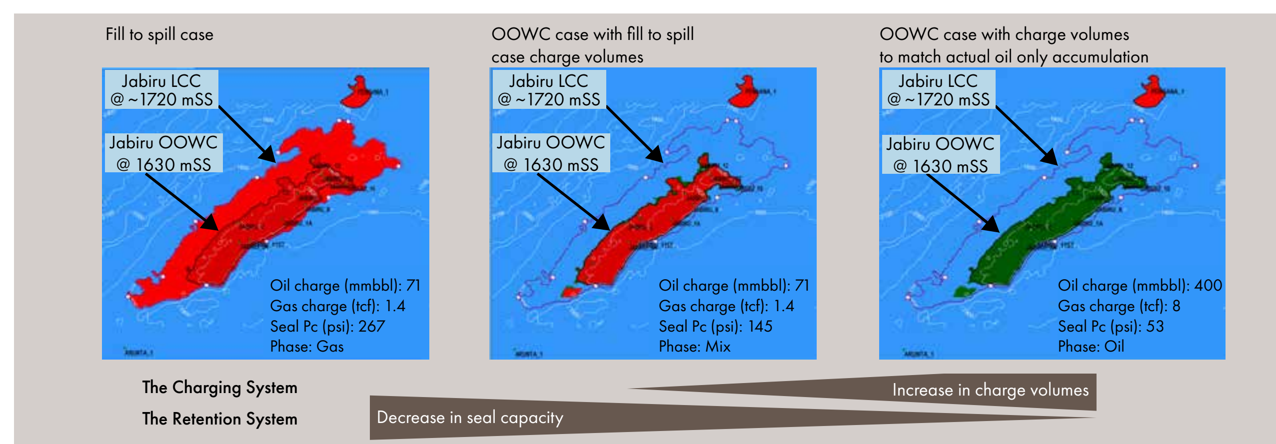
Integration of bulk fluid properties with modern geochemical analysis indicates that the discovered oils are best interpreted as products of phase fractionation from an originally gas-condensate-dominated charge. Consequently, the interaction between phase fractionation processes and seal integrity emerges as the primary control on hydrocarbon phase distribution and preserved oil volumes.

The Jabiru oil field was subjected to a charge–fill analysis to evaluate the impact of the relationship between phase fractionation and seal integrity. The image on the far right shows the Jabiru field outline and hydrocarbon phase at discovery. At that time, the oil–water contact (OWC) was interpreted at 1,630 m below sea level and the lowest closing contour (LCC) at 1,720 m, indicating an underfilled trap of approximately 90 m. Prior to production, Jabiru was estimated to contain approximately 220 MMbbl of oil originally in place (OOIP).

Fractionating 220 MMbbl of oil from a charge with a 20,000 scf/bbl GLR requires in the order of 8 Tcf of gas to transit through the trap, coupled with limited seal capacity to allow excess gas to leak.

If the seal at Jabiru had been robust, consistent with the underlying petroleum system, the accumulation would most likely have been a filled-to-spill gas accumulation of approximately 1.4 Tcf, as illustrated on the far left of the slide. Conversion of such an accumulation into an oil-only field requires both a reduction in seal capacity and an increase in charge volume, enabling continued phase fractionation of oil while excess gas is progressively leaked from the trap.

Hence, any prospect assessment requires integrating the underlying petroleum system to assess whether its fetch cell captures sufficient expelled gas volumes to fractionate the necessary commercial volumes of oil. ■



To arrive at an oil column of the extent found in the Jabiru discovery (right), a high petroleum charge and a relatively low seal capacity are required. If seal capacity would have been much better, the scenario on the left would have been more likely.

Recognising structural inversion

Three key rules serve as powerful and practical tools that every structural interpreter should keep readily available in their interpretation workflow

MOLLY TURKO, DEVON ENERGY

In structural geology, inversion describes a situation where a fault or structure is reactivated with the opposite sense of movement from its original displacement. The most common type is positive inversion, in which a normal fault is later reactivated as a reverse fault, although negative inversion, from reverse to normal, can also occur. Three practical rules help geoscientists recognise structural inversion when interpreting seismic sections or outcrop data.

The first rule involves looking for syn-tectonic thickness changes across faults. During an extensional phase, sedimentary packages typically thicken into the "down-dropped" hanging wall of a normal fault as syn-rift growth occurs (label 1a in the figure). Later, under compression, younger packages may thin toward the structure or onlap onto the crest of an anticline that has developed over the same fault (label 1b in the figure). This pattern of initial thickening followed by thinning or onlap strongly indicates that the fault first accommodated extension and then switched to contraction, which is the hallmark of classic positive inversion.

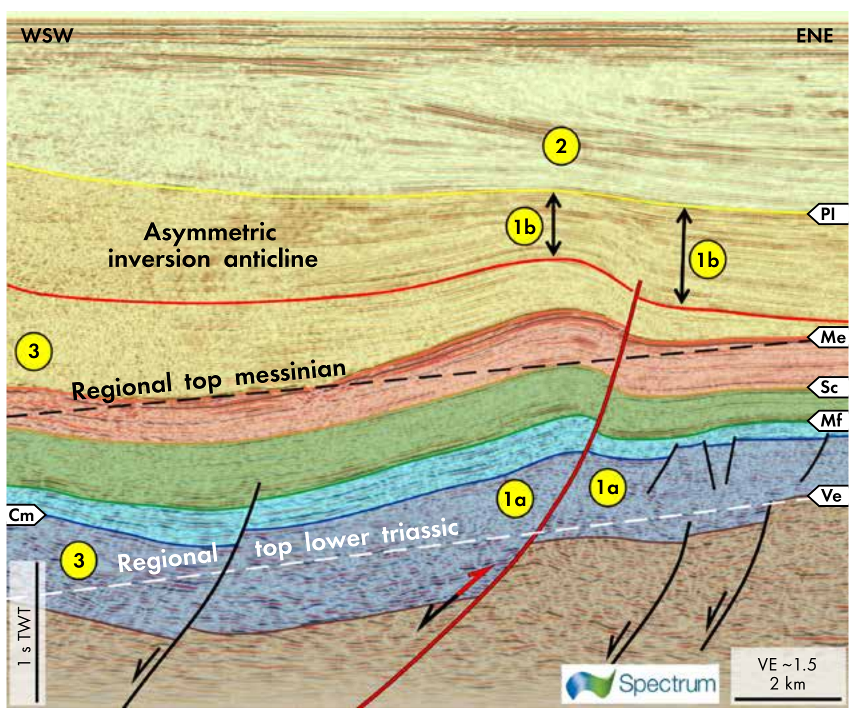


Image and interpreted seismic section courtesy of the Virtual Seismic Atlas, original author is Rob Butler. Inversion structure is from the Adriatic Sea.

The second rule focuses on the presence of folding above an older normal fault. An anticline that forms directly above the offset of a deeper normal fault serves as a reliable indicator of positive inversion (label 2 in the figure). At shallow levels, the structure might appear to be a simple reverse fault cutting through a fold, but deeper imaging often reveals the underlying normal fault geometry, confirming the earlier extensional history.

The third rule relies on deviations from the "return to regional" or "near-regional" datum line. By projecting an undeformed regional horizon across the section, interpreters can observe that older, deeper units lie below this datum, which is consistent with extension and subsidence, while younger, shallower units sit above it, indicating contraction and uplift. Finding both patterns along the same structure provides strong evidence of positive inversion (label 3 in the figure).

Finally, before drawing any conclusions, it is always essential to review the regional tectonic history. Understanding whether a basin has undergone multiple phases of extension and compression helps set realistic expectations and allows interpreters to either support or confidently rule out an inversion interpretation. Together, these three rules serve as powerful and practical tools that every structural interpreter should keep readily available in their interpretive toolkit. ■

NOTHING BEATS THE FIELD

Greenland's unconformity

This fantastic example of an unconformity, where steeply dipping Devonian strata meet Permian sediments, is exposed on the north side of Wegener Halvø in East Greenland (71° 44 ′ north). It is actually not far from this exposure where the equivalent Permian formations are being explored for oil.

What follows is a short description of the characteristics of the Permian formations we see in the outcrop here, with reference to how equivalent strata are developed "across the mid-ocean ridge" in Norway.

The Permian Karstyrggen Formation is the better reservoir unit in the area, and at outcrop has common bitumen staining and vuggy to cavernous macro porosity due to extensive evaporite dissolution and karstification – hence the name. This is also the same play that is working on the Loppa High and has been imaged along the Finnmark Platform. It also has potential in Mid Norway.

The Wegener Halvø Formation has super nice reefal build-ups, but generally lacks karstification and secondary porosity. It also seems quite tight due to early transgressive cements, as also seen in Permian wells in Mid Norway.

The Ravnefjell Formation is an excellent intrashelf basin type source/top seal horizon – and is quite extensive along East Greenland based on the scattered outcrop work. This is partly proven in Mid Norway in the Helgeland Basin and Nordland Ridge wells, but has not been drilled in an optimal location to prove up a good source section. It could be a good secondary source – it is essentially age-equivalent to the Kupferschiefer of the Zechstein Basin.

The Schuchert Dal Formation are nice by-pass clastics that seem to fill in the lows between remnant Wegener Halvø reefal highs. These have also been proven in Mid Norway and Barents Sea wells, and in the latter proven decent reservoir quality/discovery. They are quite similar to the Delaware Basin Permian by-pass sands in the USA.

Text: Ian Sharp (Equinor) and Steven Andrews (Leeds University)
Photography: Steven Andrews

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.

Not too many, not too few

A look at a cored section from the Shewashan oil field development wells in the Kurdistan region of northern Iraq

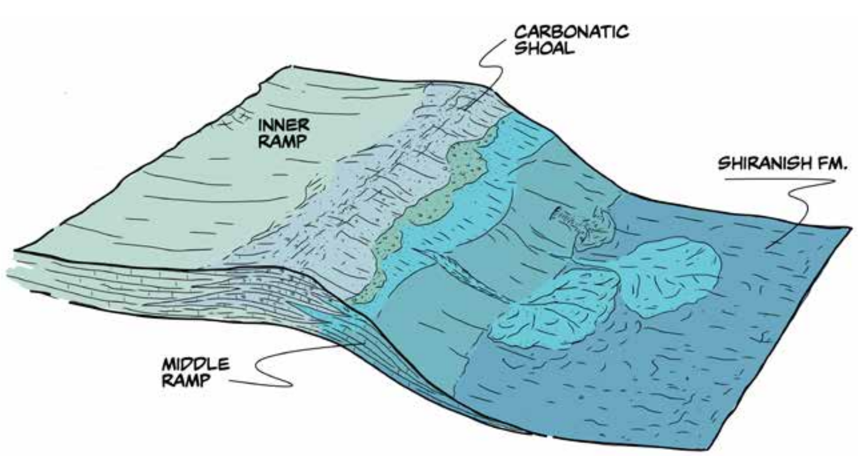
THE SHEWASHAN oil field is located in one of the world's most famous petroleum provinces – the Zagros fold and thrust belt – not far from the major Kirkuk field. Here, we show a bit of core from the Shewashan-4B well that was drilled by Gas Plus Khalakan in 2016. It formed part of a multi-well development of the oil field that took place around that time. Hopes were high that Shewashan was going to produce 10,000 bbls/day by the end of 2016. But was it?

As the keen observer can spot in the core photo, the limestone reservoir looks quite fine-grained. This core is part of the Shiranish Formation, which records distal pelagic sedimentation during the Late Cretaceous, relatively far away from the carbonate platforms that existed in the area around the same time. Is this one of the reservoirs that would contribute to the expected 10,000 bbls/day?

Early 2018, Gas Plus Khalakan issued an update on the Shewashan field. One of the main messages was that production from the field was significantly lower than anticipated. The deeper Qamchuga Formation reservoir of Aptian/Albian age turned out to be so heavily fractured that water breakthrough took place sooner than foreseen. In contrast, the statement also mentions that the Shiranish reservoir production had been limited because of a tight matrix, which the core photo indeed suggests. In addition, where the fracture matrix is too good in the underlying Qamchuga, it is poorly developed in the Shiranish Formation.

The Shewashan field was shut in later in 2018, and Gas Plus Khalakan reportedly walked away from the field in 2019. Breakeven field economics were estimated to be 2,152 bbls/day at a $50 USD oil price, but the field was producing only less than half of that. In a way, the core already gives away part of the challenge this field was facing. Fractures are great, but they mustn't be too extensive, nor too sparse either. Especially when the reservoir matrix is tight. ■

Henk Kombrink and Marcos Asensio



Upper Cretaceous depositional setting in the Kurdistan region of the Zagros fold and thrust belt.

Cored section of the Shiranish Formation limestone in well Shewashan-4B, a development well on the Shewashan oil field.

ILLUSTRATION: MARCOS ASENSIO

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