

GEO ExPro 2026

THE AMERICAN SMALL INDEPENDENT OPERATOR – A UNIQUE BLEND OF GEOLOGY AND ENTREPRENEURSHIP

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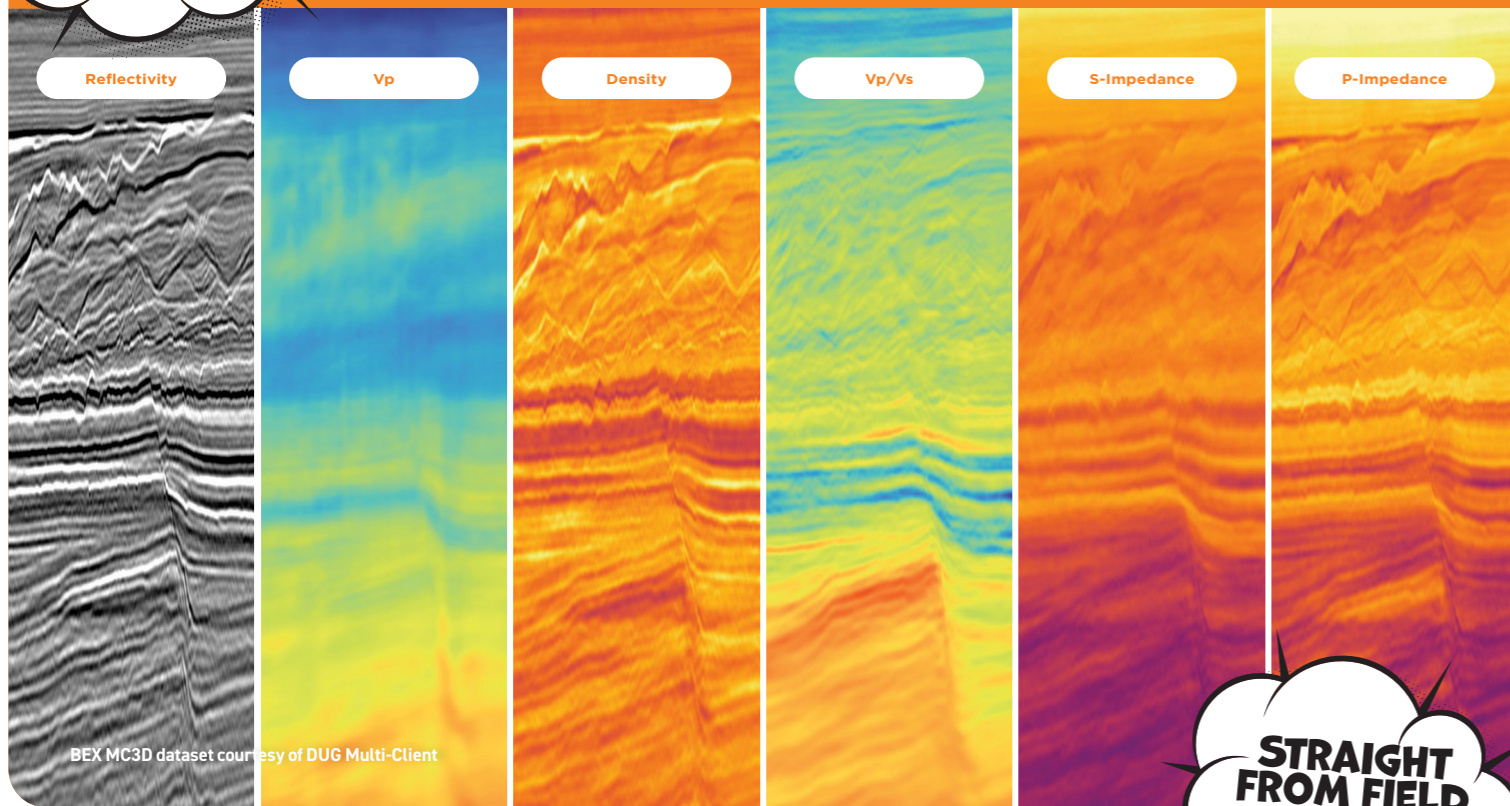
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Hunting rabbits in a different field

IN HIS BOOK *The Prize*, Daniel Yergin writes: “In any event, exploration in most of the OPEC countries was foreclosed because of nationalisation, and there was a rather strong presupposition that, if an E&P company had success in other developing countries, the fruits would be seized before they could be ingested. So the majors redirected their exploration spending to the industrial countries of the Western world. By 1976, Royal Dutch Shell directed 80 % of its non-US production expenditure to the North Sea.”

That was 50 years ago.

We are now at the end of that cycle. There are no big rabbits in the North Sea anymore, possibly not even in the USA. For that reason, there is nowhere else to go than going back to the unstable realms that they fled 50 years ago. I believe that Maduro’s lifting in January is an expression of that.

“...there is nowhere else to go than going back to the unstable realms they fled 50 years ago”

BEHIND THE COVER

America hosts a group of entrepreneurs that has no equivalent in any other country in the world: the geologists and engineers who run their own small onshore production companies. What is so fascinating about this group, who were present at the recent NAPE show marketing their prospects, is that they are mostly geologists and entrepreneurs at the same time. They represent a group of people who are a great example of not only knowing how to “do” geology, but also how to make it work financially. Very all-round. The front cover photo illustrates this; it is capturing operations at Christian Dohse’s Waxwing



Another expression of the scarcity of opportunities is that a company like Shell is getting smaller and smaller. This is not only apparent because of the drop in oil production that has seen a decline since 2019; it is also apparent when talking to people who have first-hand experience. The options for explorationists to move from one place to the other are getting more and more restricted.

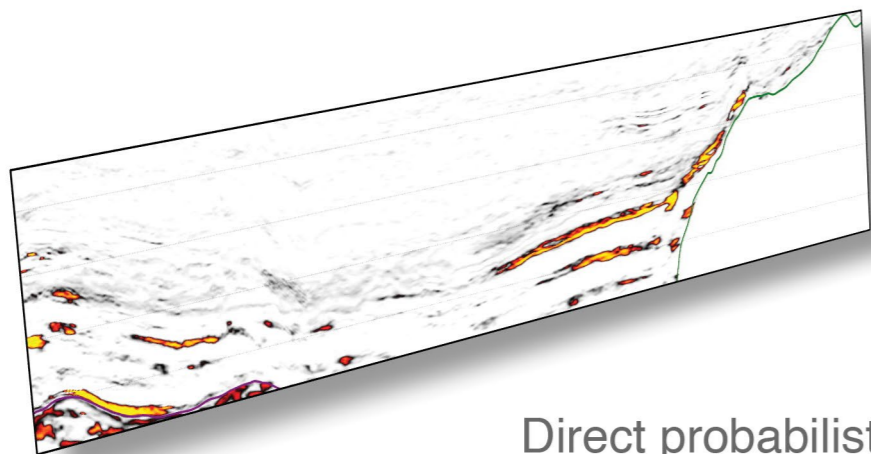
We are seeing the repeat of a cycle that started 50 years ago. But the cards have shifted. The international oil companies do not have a huge new exploration ground to go to anymore. Oil will concentrate more and more in the hands of the NOC’s. It will undoubtedly result in a few more “unexpected” moves as we have seen in Venezuela. Is Iran an expression of this, too?

The rabbits are increasingly harder to find.

Henk Kombrink



Energy prospect during the drilling of a new well down in the South Texas brush country. Read Christian’s story on page 17/18.



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FIRSTS

“European oil majors face a structural dilemma:
How to balance near-term hydrocarbon revenue
with long-term renewable ambitions under
relentless shareholder and public scrutiny”

Rodney Garrard

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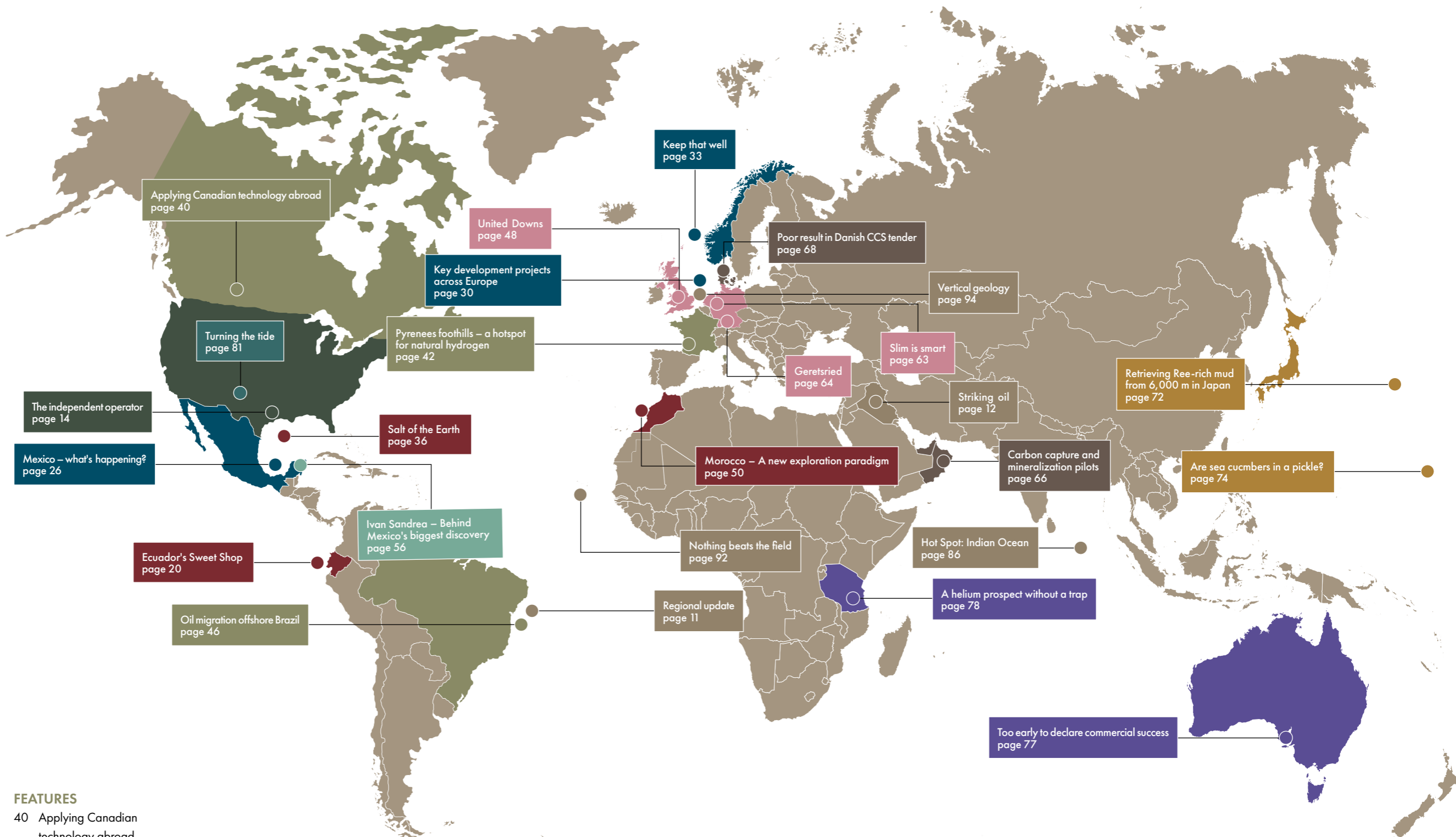
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THE FIRST PERSON I TALKED TO

At the most recent NAPE Conference in Houston, as I walked into the room for the icebreaker party, I decided to introduce myself to the first person I spotted who didn't have a conversation partner yet. That person turned out to be a geoscience graduate who was looking for a job. He told me that the market was not good at the moment, and because of that, he had decided to just walk into offices and introduce himself in the hope it would result in a job offer. It shows that despite the apparent slump in people graduating with a geoscience degree, there is still no skills gap. It looks like the opposite is true instead.

WHEN 'DRILL READY' DID NOT EXIST

"Back in the days," someone told me the other day, "the term 'Drill Ready' did not exist. You could start drilling anytime you wanted if the finances were in place. But nowadays, the term has become very relevant because of all the permitting that is required to make drilling happen. It is a testament to how times have changed.

THE REALITY BEHIND FLASHY JOB TITLES

I recently spoke with someone who works for a large international operator. To me, as a representative of a very small company, the job titles these people have always sounded very impressive. Exploration manager, this or that, it all suggests major responsibility and momentum. But when I bluntly asked the person how he found his job, he said: "I hate every single day of it." It's one of those rare moments when you get an honest insight into how people really experience their jobs, and it forms a reminder of the reality behind those flashy titles.

A PERMANENT EMERGENCY

In February, I visited the Mexican town that is sometimes called the Aberdeen of Mexico, Villahermosa, in the province of Tabasco. From the hotel window, I could see two flares lighting up the sky at night. When I mentioned that to some locals, they told me that flaring is prohibited in Mexico. Except when there is an emergency. It seems like there is a permanent emergency at some production locations...

SEISMIC ACQUISITION WITHOUT OFFICIAL PERMISSION IN PLACE

I recently caught the story of a UK town where the university wanted to acquire passive seismic data for a potential geothermal project. And there was some time pressure as well. Rather than waiting for official permits, which would have taken a long time, the team just decided to ask local residents if they could put a seismometer in their gardens for a while. People overwhelmingly said yes, which made the project fly very quickly. A great example of getting on with things in a creative way.

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

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Europe versus US oil majors

Why economics, not ethics, drives the energy divide



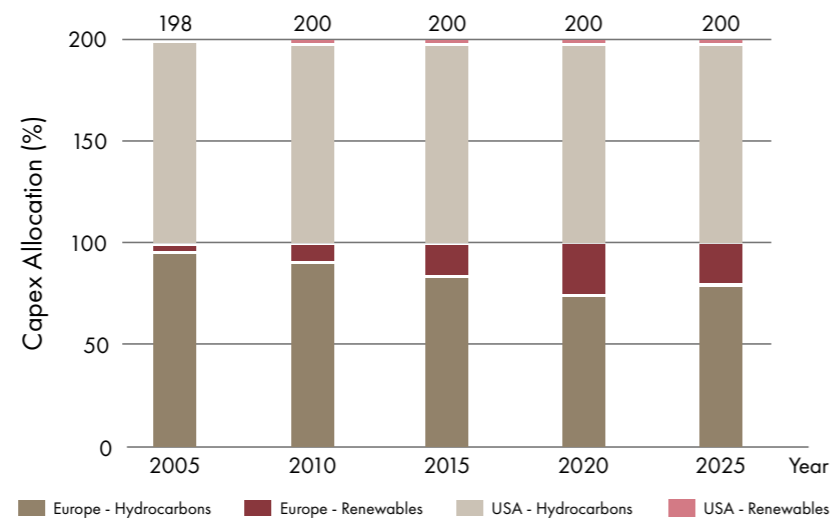
EUROPEAN OIL majors face a structural dilemma: How to balance near-term hydrocarbon revenue with long-term renewable ambitions under relentless shareholder and public scrutiny. While USA peers largely doubled down on hydrocarbons, European companies spent two decades allocating billions to offshore wind, hydrogen, and other low-carbon ventures. This divergence created a widening performance gap and exposed a business model under stress as macroeconomic conditions shifted.

By 2020, European majors directed roughly 25 % of capex toward renewables, compared to near-zero for US firms. Policy pressure and ESG mandates drove this divergence, while US companies maintained a value-first approach. However, cracks emerged as renewable projects failed to deliver competitive returns, highlighting a strong financial and operational divide.

ECONOMICS UNDER STRAIN

Offshore wind economics have deteriorated sharply. Rising interest rates, inflation, and supply-chain disruptions inflated costs and eroded margins. High-profile cancellations signalled further distress, making financing unpredictable. Hydrogen faces similar headwinds: Weak unit economics and uncertain policy frameworks have stalled projects on both sides of the Atlantic. These setbacks underscore the vulnerability of capital-intensive technologies to macro shocks.

Renewables often appear cheaper based on Levelized Cost of Energy, but this metric excludes critical system-level costs like grid integration, storage, and backup capacity. When these are factored in, the economics shift dramatically. Financing dynamics compound the challenge – renewables



Capex allocation: European vs US oil majors (2005–2025). S&P Global Financial Metrics.

require heavy upfront capital, making them highly sensitive to interest rates. Recent hikes disproportionately hurt offshore wind and hydrogen compared to hydrocarbons, which offer faster breakeven payback cycles. It should also be noted that costs are just half of the revenue calculation. The other half is the value of fossil fuels, nuclear and other dispatchable energy sources is greater than that of intermittent renewable energy. Therefore, the former can generate more revenue, even if they have greater production costs.

SHAREHOLDER VALUE DYNAMICS

Cancelled projects aren't necessarily unprofitable – they are simply less profitable than hydrocarbons under current conditions. Boards under pressure to maintain dividends and credit ratings prioritise projects with the highest risk-adjusted returns. This pivot reflects a mandate to maximise shareholder value rather than a wholesale rejection of renewables.

Most European majors have reintroduced upstream drilling programs to arrest declining production and stabilise reserve replacement ratios. This turn reflects a recognition that without hydrocarbons, providing the required capital for the energy transition becomes increasingly constrained.

Even with the best intentions, incumbent energy firms face competing interests between transition goals and profitability. New capital structures may be required, including creating daughter companies with separate governance that are insulated from short-term profitability pressures.

This is not about ethics but economics. Until offshore wind and hydrogen regain predictable economics, hydrocarbons remain the most reliable source of cash flow to fund future transition projects. The key question going forward is: Will we see larger energy corporations deploying significant capital into renewables within the current or five-year outlook?

Rodney Garrard

SOURCE: SPGLOBAL.COM

bp and Brazil

A relationship that can still go both ways



IN AUGUST 2025, bp announced the much-needed news that its exploration well designated 1-BP-13-SPS in the Bumerangue Production Sharing Contract block, located in the prolific Santos Basin, was a significant oil and gas discovery. The discovery represents bp's largest discovery since Shah Daniz in the Azerbaijan sector of the Caspian Sea in 1999. Planning of appraisal activities is reported to be ongoing, with drilling expected to commence in early 2027.

Development of the field, with its estimated resources in the billion barrels of oil equivalent range, will be a challenging project. This includes the technical difficulties of managing higher levels of CO₂ typical in the pre-salt reservoirs in the Santos Basin, such as Jupiter. bp has experience in developing fields with high CO₂, though, including the Tangguh-operated complex in West Papua, Indonesia.

bp's big move into the Brazil upstream space occurred in 2010 when it acquired Devon Energy's assets. Devon's Brazil package comprised eight licence blocks in the Campos and Camamu-Almada Basins, as well as two onshore licences in the Parnaíba Basin. The Campos Basin blocks included three discoveries at Xerelete, pre-salt Wahoo and Itaipu, and the producing Polvo field.

In 2013, bp strengthens its position further when it completed a deal with Petrobras to farm-in to five deep-water exploration and production concessions in the Potiguar Basin, and was awarded blocks in the 11th Bid Round. However, ahead of the success in the Bumerangue block bp had relinquished acreage in the Pau Brasil PSC block in the Santos Basin after the disappointing 2024 deepwater 1-BP-12D-RJS wildcat, and the BAR-M-346 concession, located in the Barreirinhas Basin, due to difficulties in the environmental licensing process.

bp currently holds interests in eight offshore blocks across three basins in Brazil, with four as operator. Interestingly, as part of its portfolio realignment in recent years, the major no longer holds any of the Devon assets it acquired in 2010 to give the company a foothold in the country. The Devon assets were either sold or handed back to the Agência Nacional do Petróleo, the government regulator. In the case of the producing Polvo oil field, it was divested in 2013 to HRT Oil & Gas due to disappointing production results.

In addition to appraisal drilling in the Bumerangue block, a much-anticipated exploration well is planned by bp on the contiguous Tupinambá PSC block in 2026. Contingent on results, two more wells might be drilled



thereafter, with one possibly testing an extension of Bumerangue into the block. The Tupinambá play type is thought to be the same as Bumerangue, and the Tupinambá High is considered one of the highest structural features within the Outer High of Santos Basin.

It is worth mentioning that bp was awarded both the Bumerangue and Tupinambá PSCs at 100 % equity. Companies ignoring the offering for these two blocks will therefore watch results closely.

Ian Cross - Moyes & Co

New oil in an old field

The biggest discovery of 2025 took place in a field that was found in 1976, illustrating how existing assets remain an attractive target for adding new volumes

WHILST attending a webinar the other day, Andrew Latham from WoodMac presented an overview of the largest discoveries of 2025.

This was a new name to me, but I'm sure that in Iraq's capital, the field name did not appear in the news for the first time last year. The East Baghdad field has been in production for decades, since 1989 to be precise, and has also been published about, including in this magazine. The main field is currently operated by Zhenhua Oil from China.

For that reason, the mention of East Baghdad in WoodMac's list of 2025 discoveries was a bit of a surprise. At the same time, it is also a confirmation of what the people from GIS-Pax talk about in their communique; most of the future discoveries that will be made are located in areas close to existing assets. I think the East Baghdad discovery is the perfect example of that.

The operator of the new discovery is not Zhenhua, but the Midland Oil Company, a state-owned oil company that is responsible for the development of recently auctioned fields in the middle of the country.

Munim Al-Rawi, in his article (GEO EXPRO Vol. 13, Issue 3, 2016) about the East Baghdad Super-Giant field, wrote that it remained very underdeveloped, mainly due to the issues related to the densely populated areas being situated where the field is. Extending over a distance of more than 100 km in a northwest to southeast direction, the field lines up with a central fault trending in the same direction, with smaller secondary faults branching off. For that reason, the field, which hosts around 90 % of its oil in Upper Cretaceous reservoirs, is characterised by many individual compartments showing different contacts.

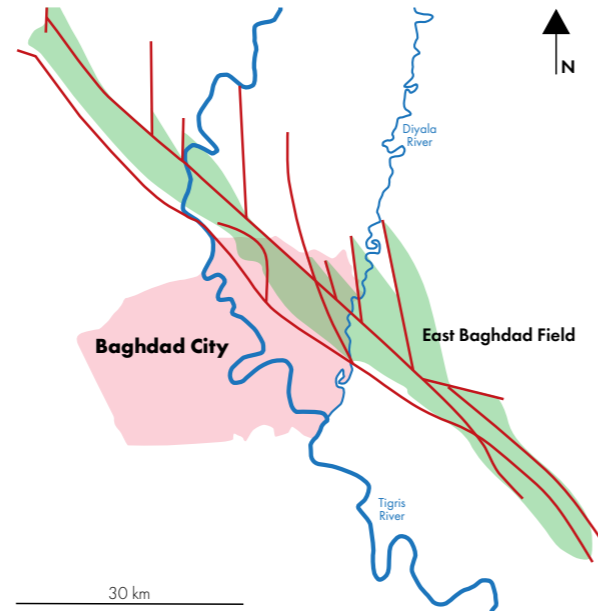
Against that backdrop, it may not be too much of a surprise to see that new drilling has resulted in a better delineation of the part of the field. Through a contact in Iraq, I learned that the increase in reserves is probably due to a better evaluation of the Upper Cretaceous Hartha Formation, in what looks like the youngest reservoirs in the field.

The discovery was probably made close to the southern tip of the field. A recent well drilled in that area reportedly showed strong oil indications in the Upper Cretaceous Hartha Formation reservoir rocks. A new seismic survey has also been acquired in this part of the field, aiding in the identification of the new drilling targets. For these reasons, the updated estimate appears to reflect both an improved reservoir understanding of the existing field area as well as the expansion of the field southwards.

All in all, the East Baghdad discovery, which went a little unnoticed in the media last year, is a clear example of the sheer potential that still exists in the giant fields of the Middle East.

Henk Kombrink ■

AGE	FORMATION	LITHO	H/C
Upper Cretaceous	Shiranish		●
	Hartha		
	Sa'di		
	Tanuma		
	Khasib		
Middle Cretaceous	Rumaila	●	
	Ahmadi	●	
	Mauddud	●	
	Nahr Umr Shuaiba	●	
Lower Cretaceous	Zubair	●	
	Ratawi	●	
	Chia Gara	●	



SOURCE: FIGURES ADAPTED FROM MUNIM AL RAWI, MARK FITZPATRICK, BRUCE WINSLADE - GEO EXPRO 2016

Capex allocation: European vs US oil majors (2005–2025). S&P Global Financial Metrics.

COVER STORY

“Having a little oil production ticking away in the background is a great way to generate some income”

Thom Davis

THE AMERICAN SMALL INDEPENDENT OPERATOR – A UNIQUE BLEND OF GEOLOGY AND ENTREPRENEURSHIP

HENK KOMBRINK

THIS YEAR, I went to the NAPE Exhibition in Houston for the first time. NAPE stands for North American Prospect Expo, and has served as a platform for American operators to market their prospects and find investors since 1992. NAPE is different from other industry events because the majority of stands on the exhibition floor are taken up by small operators showcasing their drilling opportunities. In many cases, you will be able to negotiate on the spot and buy yourself an interest in a drilling project. What makes this event so fascinating is that many of the people on these stands are the geologists who worked up these prospects themselves, and also organise everything else required to make drilling and production happen. It is a genuine mix of geoscience and entrepreneurship that is so unique to America. This article introduces you to a few of these entrepreneurs I met in Houston in February, telling their stories of how they ended up doing what they do.

**“AS MANY PEOPLE
IN THIS BUSINESS,
I’M A RISK-TAKER”**

– Jeff Swanson

Jeff is a striking figure. “I played basketball when I was young,” he says. After completing a business degree at Southern Methodist University, Jeff didn’t really know what to do first, so he initially continued his basketball career in Europe. Then his dad called for help. He was a geologist working for a big corporation – the family had moved fourteen times as Jeff grew up.

When his dad decided to start working for himself, he asked Jeff if he wanted to join. “Playing basketball was more fun, but I realised that I needed to change careers and become a bit more serious,” says Jeff.

So, he joined his dad’s start-up reservoir description company, which took them to Venezuela for four years, principally consulting for PDVSA and its affiliates. ▶



Open-hole logging in action: Waxwing Energy's rigging up to log a newly drilled shallow oil well.

But it was not only reservoir description work that Jeff and his dad were offering as a service. They were also instrumental in developing software that enabled users to build what is now known as 3D geocellular models.

Under the name Stratamodel, the team built the software from first principles, also patenting the workflows along the way. It caught the attention of the major oil and gas service providers, ultimately leading to a merger with interpretation platform Landmark. And with Landmark being acquired by Halliburton less than a year following the merger, the software is still being used today.

Whilst the people who had developed the software joined Landmark, Jeff decided to move on. It was in those years that he decided to set up his own oil and gas producing company, Durango Resources. “We focus on acquiring producing assets and try to optimise production through workovers and infill drilling.

“As many people in this business, I’m a risk-taker,” he says. “I’ve made a lot of money, but I’ve lost a lot too.”

Investing in new wells is obviously the most expensive part of the business, and if these wells don’t work, they become a burden to a project. “We had two expensive horizontal wells drilled on one

of our assets,” says Jeff, “and neither of them produced as much as we expected. We spent years investigating what could have gone wrong, but we never fully got to the bottom of it.”

Jeff is at NAPE to find investors for a new prospect on one of his leases. It is a small but typical old-school, structural Gulf Coast prospect at a depth of around 5,000 ft. “We identified it because our neighbours to the south perforated the same target sand and achieved an unexpectedly good result,” says Jeff.

“We never paid too much attention to this interval because old log data from the area suggested that the quality of the reservoir wouldn’t be that great,” he continues. “Then it turned out that another company operating to the west of where we are also found the same reservoir, being more productive than anticipated, so it became quite obvious to us that there was something to be tested. That led us to identify a prospect in time-equivalent strata in our lease as well.”

“It’s a fairly low-risk prospect,” continues Jeff, “but obviously, there is always a chance that the trap has been breached by some of the numerous faults – some of which are sub-seismic – or that a legacy well produced from the reservoir without there being a report about it. That happens in an area with a long history of

oil production; there is always the chance that things go unreported.”

With drilling costs under \$1 M, Jeff’s prospect has an estimated return of 5:1. Even though he did not sell an interest on the spot, the conversations he had at the event have already led to some follow-ups. He is therefore hopeful of progressing the project soon.

“YOU MIGHT NOT THINK THERE IS LAND SOUTH OF NEW ORLEANS, BUT THERE IS”

– Bo Sibley

Bo Sibley worked in Southern Louisiana during his entire career. “I would not be comfortable drilling a well in Western Texas,” he says.

When he retired from his corporate job as a petroleum engineer, he felt he wasn’t done yet and found a broker offering a producing asset in the area he is so familiar with.

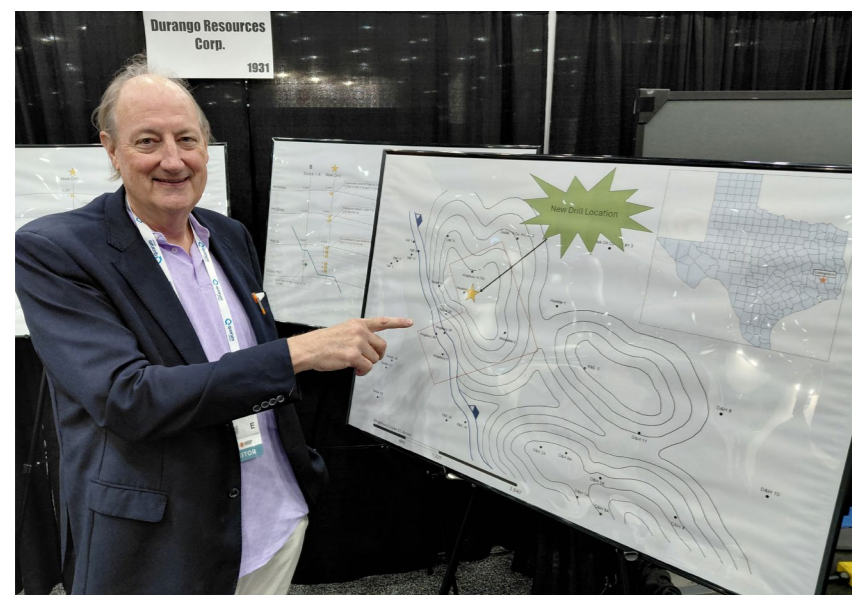
“It is south of New Orleans, Bo says. “You might not think there is land south of New Orleans, but there is.” The area where his asset is situated is surrounded by levees of the Mississippi River, in a green and lush environment.

The lease consists of six wells, of which only one was producing at the time Bo made his purchase. But still, it meant that he was generating income straight away.

Then it turned out that the producing well experienced sanding issues. “We had to do a workover and install a sand screen to get rid of the issue,” says Bo. “So, we went in, but then it turned out that the casing had collapsed, preventing us from installing the screen.”

The well is now shut in, and a decision has been made to side-track the parent well and penetrate the reservoir with a new hole. It is the financing of the side-track that Bo is finding investors for at the NAPE conference. “It is worth drilling the side-track, Bo says, “as I expect there to be around 200,000 bbl of oil left to be produced.”

PHOTOGRAPHY PREVIOUS PAGE: CHRISTIAN DOHSE / PHOTOGRAPHY: HENK KOMBRINK



Jeff Swanson shows his prospect that he helped identify through learning what his neighbours were up to in their leases.



An impression of the asset Bo Sibley now owns south of New Orleans, with the wells in the foreground and facilities in the background.

HOW NAPE EVOLVED

The NAPE show has evolved a lot over the years. “Thirty years ago, it was a room full of tables in what is now the Galleria area of Houston,” says Tom Armstrong, who was there from the very start. “A prominent feature of the room was the line of cell phones that potential buyers could use to discuss matters with the head office before making a deal.”

Someone else told me that NAPE used to be much bigger than it is today, up to three times as big. That’s incredible, because I found the size impressive even this year. The number of attendees has also come down, I was told. Nowadays, it is around 6,000 people, whilst it was around three times as many years ago. “You couldn’t walk through the aisles quickly,” someone said.

Most people agree that an important factor explaining why NAPE has become smaller is the arrival of unconventional players. They had big stands, surrounded by financial firms. That seems to have calmed down now, as people have figured out that even when there is less geological risk in unconvensionals, there is still a financial risk.

Today, NAPE is more than a prospect show, with many service companies exhibiting as well. But there is no way to escape the trend that the number of people representing the small players, something the conference was always intended for, has come down over the years. That’s what almost everybody tells me. And it is visible from a demographic point of view too; most exhibitors promoting their prospects are men who are either retired from their corporate jobs or are close to doing so altogether.

Is the end of the small independent near? From what I have seen and heard, it looks like the independent American producer is indeed a slowly disappearing species. I would say the shale boom is an important factor there. Geologists who have worked their careers in shale are not familiar with the type of risk-taking that comes with drilling conventional wells, which means that there is a major gap in the influx of people wanting to get their hands dirty. On top of that, there is the increasing pressure of permitting, which is slowing processes down.

It is a shame, because from what I have seen, these small independents, even when they don’t produce so much when added up, this group of people harnesses so much practical experience that they also transfer to the people they work with. In that sense, they are still a foundation of what the American oil and gas industry represents: Entrepreneurship, willingness to take risks, and a willingness to get your hands dirty at the same time.

PHOTOGRAPHY: BO SIBLEY PRIVATE ARCHIVE

Bo obviously hopes to find investors at the conference, but he also reiterates that you don’t want to have too many stakeholders in a single project. “Three or four partners is a good number,” he says, “otherwise it will get too crowded with too many cooks.”

“I WAS YOUNG AND HAD TOO MUCH ENERGY TO SIT AT A DESK IN DOWNTOWN HOUSTON THE WHOLE DAY”

– Christian Dohse

“I grew up in the Corpus Christi area and was fascinated by the pump-jacks I saw in the landscape from a very young age,” says Christian Dohse when I meet him at his stand in the George R. Brown Convention Center. “It triggered my interest in geology, wanting to know what happened in the subsurface.”

As such, Christian went to study geology when he left secondary school, and was lucky enough to land a job with Hess in Houston. However, it didn’t suit him as much as he had thought. “I was young and had too much energy to sit at a desk the whole day in downtown Houston,” he says.

He was lucky enough to find part-time roles with two small companies in the Corpus Christi area, which meant a lot more hands-on work and a much more flexible schedule. One of the jobs was with a gas producer, whilst the other company produced oil. However, as time moved on, and the shale gas boom started to manifest itself, the gas operator was pushed out of the market, so Christian had just one employer left. However, that also came to an end when the pandemic hit, and Christian decided to venture into something different for a while.

But the industry still appealed to him, and at some point a few years ago, Christian started looking at obtaining a lease in the South Texas area. He started pulling together well and seismic data to look for a prospect that he could get his hands on. ▶

“I mapped a prospect on a plot of land that wasn’t under lease yet,” he says. “The landowner, a rancher who is into bird watching, was happy to lease me the mineral rights and because it was my first lease, I decided to name my new company after one of the local birds that would frequently visit my yard – Waxwing Energy.”

Christian drilled his first well, and now has production from the field he discovered.

He is at NAPE to find investors for another conventional oil prospect he wants to drill. Looking at the map he’s got at his booth, it is clear that this on-shore trend of the South Texas Gulf Coast has seen a lot of drilling before. The petroleum system is therefore proven; it is a matter of testing valid traps in up-thrown fault blocks. The closure Christian has identified is in Eocene sands of the Yegua Fm, and could hold up to 441,000 bbls of oil and 250 M ft³ of gas if the prospective reservoirs are present and hydrocarbon-bearing.

In an email conversation following the conference Christian shared that he has now placed all the interest in the prospect and that he will be drilling the well later in spring or summer.

“HAVING A LITTLE OIL PRODUCTION TICKING AWAY IN THE BACKGROUND IS A GREAT WAY TO GENERATE SOME INCOME”

– Thom Davis

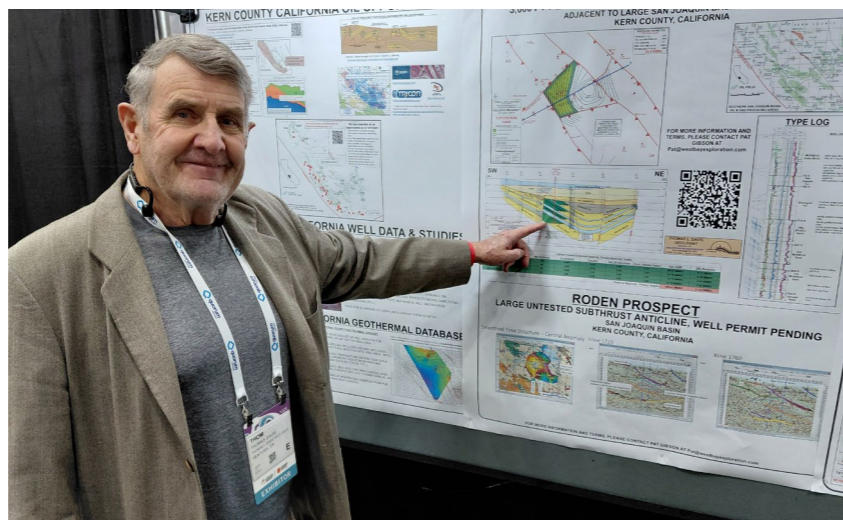
“I don’t want to live from project to project all the time, as so many consultants do,” Thom Davis tells me when we meet on the NAPE exhibition floor, where we both have a little stand in the same aisle. “Instead,” he says, “having some oil production ticking away in the background is a great way to generate some ‘passive’ income to cushion the periods when there is little project work around.”



Christian Dohse was successful in closing interest in his prospect and will drill it in spring or summer this year.

Passive is a relative term here, as it takes considerable effort to get a new drilling project up and running, especially in California, where Thom works and lives. “The state has not been easy about permitting,” he says, “for reasons we all know. But the mood is changing, and we believe a more welcoming regime may be returning.” he says.

It took around four years to get the regulatory approvals for the Callisto prospect that West Bay Exploration Company and Thom want to drill. It is also a project that Thom is trying to find investors for in Houston. “Geoff Gallant, a geologist on my team, and I have eyed this opportunity for nearly 20 years,” Thom says.



California seems to be more welcoming to new oil and gas drilling applications now. Thom waited for four years to get his application approved.

When we are in between consultancy jobs, Thom and Geoff have the habit of going through old wells drilled in the San Joaquin Basin, and by doing so, they have found several opportunities, especially when combined with reprocessed legacy seismic.

“The San Joaquin Basin is considered a Super Basin, with 5 Bbbl still to recover,” says Thom. He also leads field trips and Geo-hikes in southern California, which is a fold and thrust belt bisected by the San Andreas fault, with many good outcrops and panoramas. His Geologic Maps Foundation digitises legacy geological maps from the region and makes them freely available to the public.



Tom Armstrong pointing at his prospect, showing the importance of seismic mapping in identifying the thickness not only of the reservoir unit, but also of the overburden.

The estimated dry hole costs are just less than \$1 M plus \$300,000 to complete for the 3,000 ft well that Thom aims to drill on the Callisto prospect. If all four individual sandstone reservoirs come in, the prospect might contain 20-25 MMbbl of oil. The prospect relies on an element of trapping against a fault, well known for trapping several hundred million barrels just to the south, as well as truncation trapping.

The cross-section Thom is pointing at in the photo illustrates the trap configuration of the Callisto prospect. It is also interesting to see the number of wells that were used to put the cross-section together; it clearly shows that the basin has already been extensively explored, with dry wells located on either side of the prospect.

But nevertheless, it is great to see that there are still people who are chasing the opportunities that no doubt remain. 25 MMbbl is not a volume to sniff at if you realise that some prospects being marketed at NAPE are only a few hundred thousand barrels large. If successful, Thom might even need more than just one well on Callisto, and maybe he can also take a longer break from his consultancy work and preserve more legacy maps.

“CONVENTIONAL OIL PRODUCTION LIKE THIS IS MUCH LESS SENSITIVE TO FLUCTUATIONS IN OIL PRICE THAN UNCONVENTIONAL OIL PRODUCTION”

– Tom Armstrong

“I sat my first well as a well-site geologist in 1978,” Tom Armstrong of Armstrong Oil & Gas says. “And it was a two-million-barrel discovery straight away.”

Ever since, he has worked in the same area that straddles the boundary between Texas and Oklahoma, a place that is part of the Hardeman Basin. Here, Lower Carboniferous mud mounds form the target for most wells. Tom has an interest in 24 wells in the basin at the moment.

“It is a seismic play,” says Tom. “We analysed a large group of wells drilled in this play before and found that the most successful wells were the ones that had the most condensed unit directly overlying the reservoir. I don’t have a direct explanation for this, but the statistics clearly point this out,” he says. “As such, mapping prospects using seismic data is key.”

The areas of elevated porosity and permeability are also hard to predict in these carbonate mud mounds. “We are currently reprocessing seismic for that reason,” says Tom, “but it remains a risk for all wells we drill; a ‘dry’ hole in one position on the structure may be a successful one a little further away on the same closure. That’s the risk of the game.”

The prospects in the area are mostly small, with volumes less than 1 MMbbl being the rule rather than the exception. For that reason, the Hardeman Basin is a good place for small operators. “We pay around \$200 per acre,” Tom says, “which is a price that works.”

Some years ago, Apache picked up acreage in the area and offered land owners a lot more per acre, remembers Tom. “It ruined the stability we had in the area, but they drilled a dry hole and left again after, so that was only a brief period after all,” he says.

“I have sold a 20 % share in the prospect already, but I’ve had cases where someone came to me and said, *take the posters down, this prospect is mine.*” That may not happen this time around, but there has been decent interest so far, and Tom shared later that he had a list of eleven companies wanting to meet up with him after NAPE to discuss his prospect.

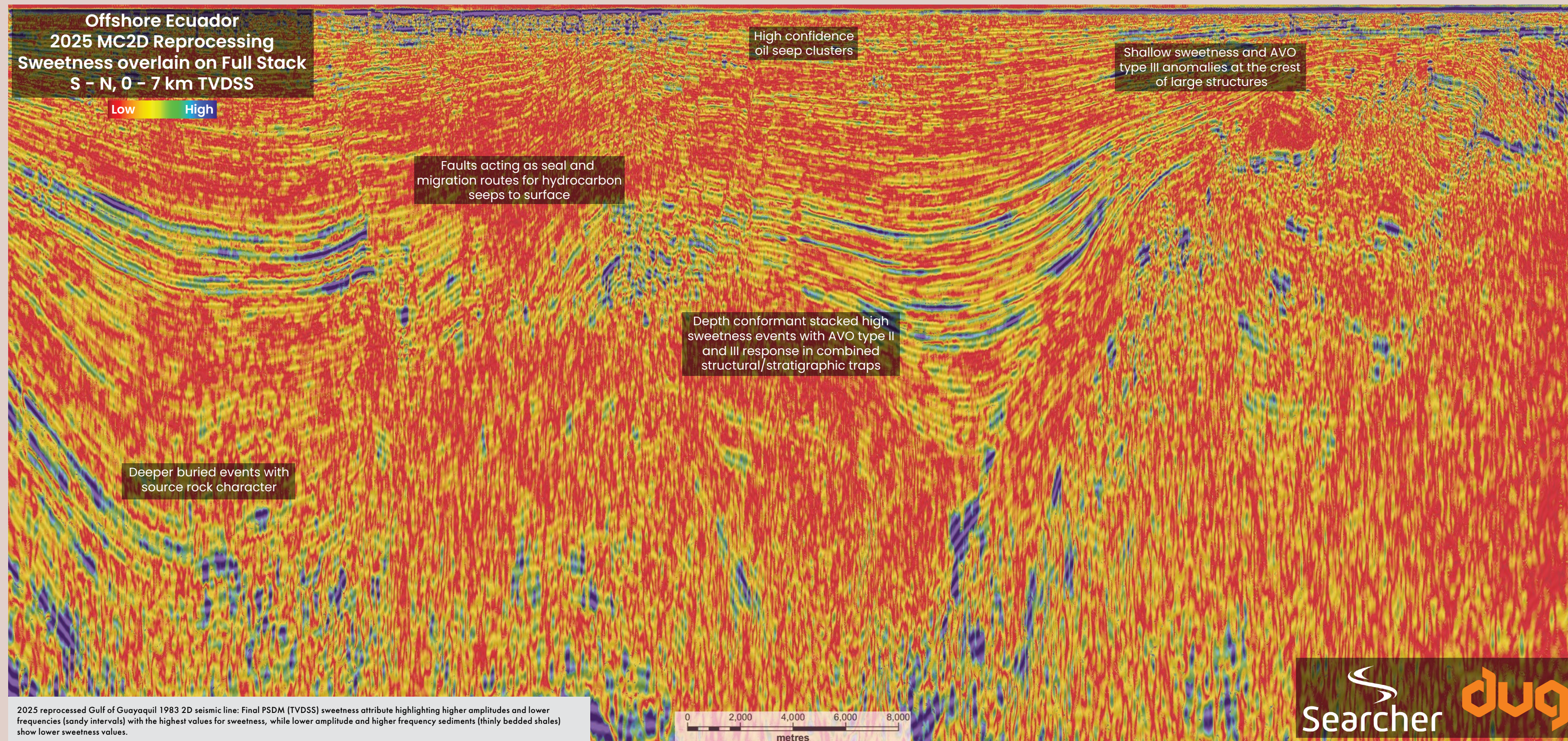
The estimated cost of drilling the well on Tom’s West #1-18 prospect in the north of the Hardeman Basin is around \$1.5 M. If the well turns out to be a success, and the volumes come in as expected, the rate of return could be as high as 25:1 when assuming an average oil price of \$60.

“Conventional oil production like this is much less sensitive to fluctuations in oil price than unconventional wells,” says Tom. “I return a profit at \$20 oil, whilst the main unconventional players in the Permian Basin will struggle to make money at \$55 oil. That’s why there is still music in this type of work, even when the risk profile is different from the shale gas sector.”

PHOTOGRAPHY: HENK KOMBRINK

PHOTOGRAPHY: HENK KOMBRINK

“Seeking the Sweet Spot in offshore Ecuador’s Sweet Shop”



Ecuador has an estimated 8.3 Bbbl of oil reserves and a rich history of oil exploration and production within the Amazon Basin east of the Andes. To the west of the Andes, early onshore exploration resulted in a number of onshore oil discoveries, which provided much of Ecuador’s oil exports from 1920 to 1960. Taking this oil province offshore with the rudimentary seismic available in the 1960s and 1970s led to a hit-or-miss exploration affair, and despite oil, condensate and gas discoveries, the offshore sweet spot remained illusive. Until now. Reprocessing of the legacy seismic dataset, using 2026 technologies, is generating new confidence in offshore exploration. It is clear now that this offshore margin, with its large prospects (that we can now image), in shallow water, is so prospective, it’s like looking for a candy in a sweetshop.

Indeed, seismic reprocessing follows much the same path as extracting sugar from sugar cane. Raw materials – the legacy offshore Ecuador datasets – are carefully pounded by modern algorithms until the sweet primary signal is distilled from the chaff of noise and multiples that made working the data so difficult for the early explorers.

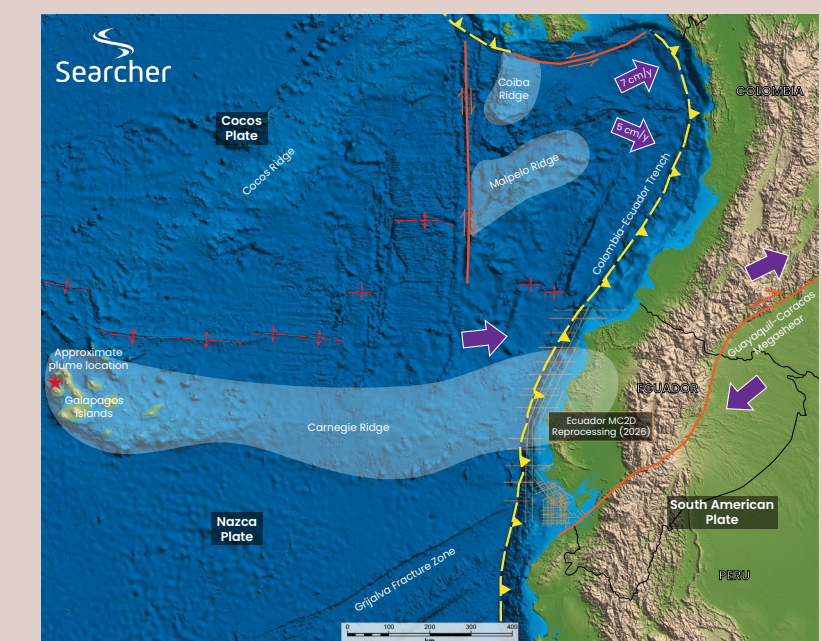


Figure 1: Offshore Ecuador main tectonic elements.

Searcher use of modern processing algorithms to unleash the hidden sweetness in Ecuador's legacy offshore seismic

KARYNA RODRIGUEZ, NEIL HODGSON AND LAUREN FOUND, SEARCHER

SETTING THE SCENE

The destructive margin setting for Ecuador's northern offshore margin has its own complexity in this region, as the oceanic crust being subducted includes a spreading centre, multiple fracture zones and the consumed oceanic crust carries the sunken remnant of the Galapagos plume trail (Figure 1). The Gulf of Guayaquil Basin, however, comprises a strike-slip related pull-apart basin, formed at the junction between the continent-spanning Guyaquil-Caracas Mega-shear and the obliquely subducting Nazca Plate. Into this basin, the erosional derivatives of the local Andean Granitic mountains have been constantly pouring, providing abundant quartz-rich coarse sandstone reservoirs.

The Ecuadorean offshore basins have also been considered complex structurally; however, this is due partly to the woeful imaging of legacy seismic. What these legacy 2D and 3D datasets, recently made available by Searcher, do reveal is a very thick Tertiary clastic sedimentary package and an array of time variant structural styles from compressional thrusts and folds to extensional half grabens, with many, potentially huge, traps which were not optimally imaged with the legacy seismic data, and so to address this, Searcher, in collaboration with the Ministry of Energy and Mines (MEM), have reprocessed 5,000 km of 2D seismic data on this margin (Figure 2).

SEISMIC REPROCESSING

Searcher's reprocessing has enhanced the seismic imaging along this margin, allowing the structuration to be imaged, the prospects to be mapped and offering accurate far-angle stacks and flat gathers to address the distribution of reservoir, fluid, and source rocks in the Ecuadorean Basins. The regional subset of lines selected to be reprocessed was based on several criteria including available and usable field data, lines with the best well ties; making sure to capture interesting structures and features with potential for image enhancement; providing sufficient coverage over offshore blocks and under clusters of high confidence oil slicks; including lines covering previously identified prospects which, when reviewed by the Searcher team,

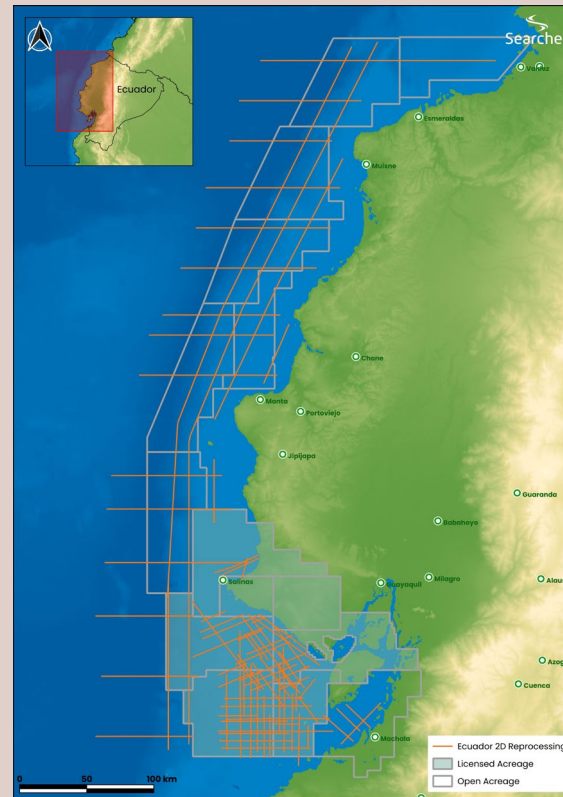


Figure 2: Offshore Ecuador seismic lines reprocessed in 2025.

still seemed viable. Outboard and to the north, over the Esmeraldas / Manabi offshore sub-basins, long strike lines were included as well as dip lines showing indications of deep reflectivity and clear BSRs (Bottom Simulating Reflectors at the base of gas hydrate zones). To the south, lines were selected to tie with Searcher's available dataset in Peru.

Several challenges are faced during the reprocessing of such old, vintage datasets. However, deghosting (removal of source and receiver ghosts) is key to improving the bandwidth of the data. By paying careful attention to maintaining data consistency over such a large area and a wide range of water depths, Zero Phasing and noise and multiple removal challenges could be overcome allowing careful velocity model building. With the final PSDM imaging uplift, structural and stratigraphic definition is greatly improved across the entire Ecuadorean margin (Figure 3).

EXTRACTING THE SWEETNESS

The reprocessed regional 2D seismic dataset has provided exciting insights into what was already suspected to be a prospective forearc basin (Pacific oil rush: The sequel – and this time it's Ecuador, GEO EXPRO Vol. 21, Issue 6, 2024). In the Gulf of Guayaquil, where the producing Amistad Field has proven a working gas and condensate petroleum system, there is also a working oil generative system, and the light oil production has been successfully tested in the Golfo de Guayaquil-1 well to the south, near the border with Peru. Various other wells have reported fluorescence and oil shows, and many natural high-confidence oil slicks have been identified with satellite data.

Using the reprocessed data, a set of very large prospective and undrilled structures has been imaged, based on seismic horizons that are more continuous, with higher resolution and better amplitude content. The sweetness attribute is a very useful tool for delineation and identification of the depositional environment of a sequence, distribution of reservoir facies and source rock. In the sweetness attribute display used in the Foldout image here, we are combining instantaneous amplitude (reflection strength) and instantaneous frequency (calculated by dividing the amplitude envelope by the square root of the instantaneous frequency). Use of this attribute in hydrocarbon exploration, both defining sedimentology (channel detection, lithology discrimination) and hydrocarbon detection (both in reservoirs and source rocks), has been well documented since its discovery in the 1990s. The value in the sweetness display is that it reduces the contribution of high-frequency events to the display. Areas containing higher amplitudes and lower frequencies (sandy intervals) will display the highest values for sweetness, while lower

amplitude and higher frequency sediments (thinly bedded shales) will show lower values for sweetness. A first pass evaluation using the sweetness attribute (Foldout) shows events with anomalously high values (high amplitudes with low frequencies), pointing out potential source rocks of Eocene to Oligocene age.

We observe that when these events are more deeply buried, strong shallow anomalies are observed above them, connected by faults acting as hydrocarbon migration conduits. The data have revealed large structures, acting as natural foci for hydrocarbon migration.

Most importantly in this reprocessing project, Searcher has generated a unique set of angle stacks (near-ultra far up to 44°) which is aiding in the identification of Avo Type II, Type III and Type IV anomalies.

Traps are imaged onlapping onto these large structures and / or terminating at major faults, where a series of events with strong sweetness and AVO Type II and III response have been mapped. Natural Oil slicks and seeps have been reported directly above the same areas with deeply buried source rock (Type IV anomalies) and above some of the large structures. A stacked set of potential accumulations in combined structural and stratigraphic traps of between 50 and 150 km² has been mapped on the Far Angle Stack.

Despite the hiatus of exploration in the offshore, as the early explorers suspected that the play elements were all there, and yet for the first time, the seismic imaging can keep up. Only now, offshore Ecuador, we can seek the sweet spot in the sweet shop.

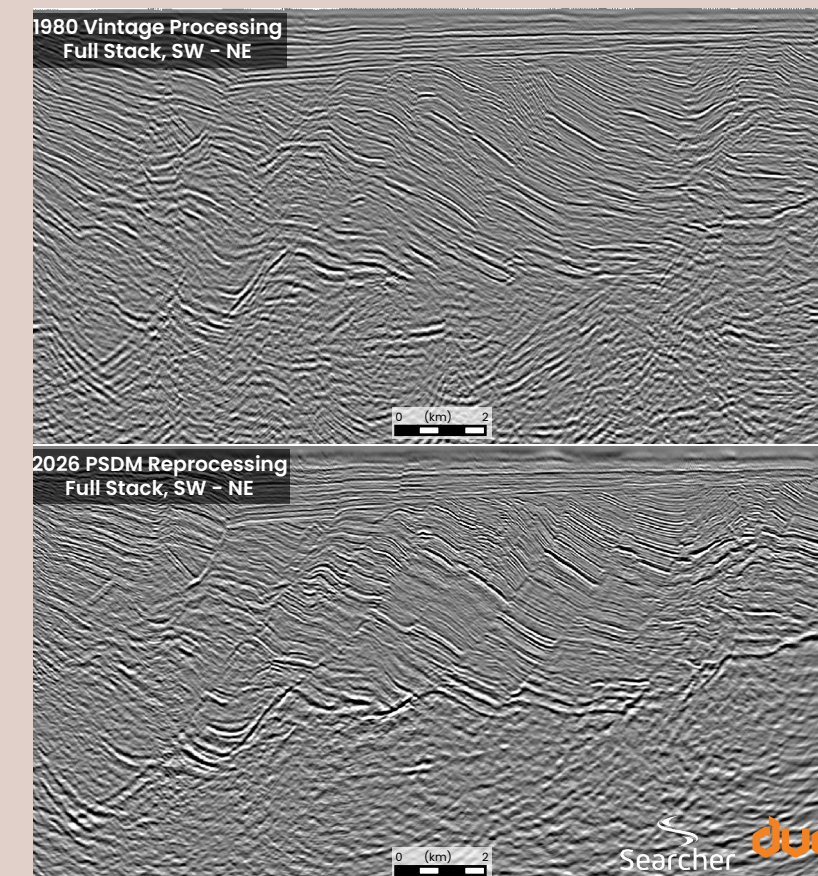


Figure 3: Example of imaging uplift resulting from Searcher's 2025 reprocessing of 2D seismic data offshore Ecuador. The top is legacy 1980 seismic data, and the bottom is the 2025 PSDM reprocessed line. In TWT for easier comparison.

OIL & GAS

"... 21 new fields, each with reserves of >50 MMboe, are set to be developed across Europe, with start-up expected by the end of 2030"

David Moseley – Welligence Energy Analytics

Mexico – what’s happening

The state of Pemex and the state of exploration

ONE OF THE best ways to learn how an industry is doing is to talk to people when you are actually around. That’s what happened to me in February, when I was in Mexico for a week. Through the conversations and chats I had during that week, a picture started to emerge of how the oil industry is doing in this big country.

PAYMENT DELAYS

One of the most pressing issues in Mexico’s oil and gas industry – this was a recurring theme during the conversations I had – was the challenges that Pemex is facing. The state-owned company has apparently been unable to pay contractors for a long time, to the extent that many are facing serious financial trouble and are running the risk of going out of business.

I spoke to one service company director who was very serious in his attempt to drum up business abroad to become less dependent on work coming in from Pemex. But he also admitted that it will be very difficult to do

so in the current environment, where drilling is not at a global high.

What is the explanation for Pemex’s inability to pay its contractors? I guess there are multiple reasons for that, but what I heard was that the government takes too much of a cut, and that Pemex has been ignored since the country opened up to foreign investment in 2016. At the time, the hope was that the newcomers would take care of finding the new volumes the government was craving for, leaving Pemex in the shadows. I think this is not necessarily how the situation has unfolded, with companies slowly turning their backs on Mexico again recently.

STILL AN IMPORTANT PLAYER

At the same time, Pemex is still by far the most important player in the country. Many people, especially in the Villahermosa area in the south of the country, have family members who either work for the company or did so in the past. The perks of working for Pemex were very good; going back some years, it was even possible

to nominate a family member as a successor to your role if you retired from the company. Things have become less attractive over the years, on the back of the situation sketched above, but it is clear that Pemex is still a major force.

As such, it is also Pemex that is currently exploring for additional resources. Commissioned by Pemex, Sinopec is in the process of acquiring a large 3D seismic survey onshore Tabasco – in the Villahermosa area – to map deeper prospects beneath the main oil and gas fairway in Miocene deep-water sands. There is hope that deeper Cretaceous and Jurassic strata at depths of 3-6 km may hold further potential. The acquisition is not an easy task; the lowlands of Tabasco are characterised by wet and swampy areas where access is problematic.

Pemex is also drilling exploration wells in the area already. Just recently, well Krem 1-XP experienced a blow-out whilst targeting Cretaceous reservoirs in the Las Choapas area in Tabasco. It is the first well of a four-well campaign in the area. ■

Henk Kombrink



The lowlands of Tabasco and Veracruz are characterised by lots of rivers, swamps and lushy green landscapes. Not the easiest environment to drill wells and acquire seismic.

PHOTOGRAPHY: HENK KOMBRINK

Venezuela, Greenland, Iran and oil

Against the backdrop of the US’s creaming shale plays, could recent geopolitical events be seen as a renewed quest for greater control over foreign oil resources by the USA?

JAVIER BLAS wrote in a recent post that “the US shale revolution hands the USA a much stronger hand in controlling prices.” But how long will production from shale in the USA remain key in determining the oil price when sudden global events unfold?

“Growth in the US shale market is undoubtedly slowing, and an overall decrease in oil production is forecast for 2026,” Eve Thomas wrote in Offshore Technology in late February. Shangyou Nie, in his latest AAPG Explorer column, included an item of the same nature in his top five news events for 2025.

Here, I’d like to add a few recent observations that, in my modest opinion, could link a creaming local shale resource with US actions abroad as they have unfolded in Venezuela, Greenland, and now in the Middle East.

It is very well-known that Venezuela has enormous oil and gas potential. Even though some of the majors already made it clear that the country is not investable yet, I caught someone in Houston the other day who said that a well-known geologist and his company are currently “mobilising” in Venezuela. The same geologist also formed part of a group of people who seemingly advised senior US leadership on Venezuela’s oil and gas potential.

Greenland is the other region that featured in the news, again in close relation to the USA. Instead of oil, the public narrative is largely focused on critical minerals that are supposed to be abundant. However, it should be noted that it is an American company planning to drill for oil in Greenland later this year. Even when most geologists argue that the chances of finding a new important play are

slim, it is nonetheless an interesting development.

Then we get to the Middle East. During a recent presentation by Wood Mackenzie, senior analyst Andrew Latham explained that the future of oil production is in the hands of the NOC’s. In turn, the bulk of future development will focus on onshore assets, and then mostly through gains in recovery factors from existing fields. The typical frontier exploration that features the headlines in the oil and gas news is not going to make a big difference.

The interesting thing is that Andrew mentioned that recovery factors to date have been very low in countries like Iraq and Iran. “There is an upside of 10’s of % in a country like

Iran,” he said. And similar to Venezuela, where interim president Delcy Rodríguez is supposed to be listening to what US leadership says, Trump also announced that he wants to be “involved” in the appointment of Iran’s next leader.

So, three countries feature heavily in the news this year because of actions instigated by the US, and all three have a prospect of producing lots of oil, be it from different starting positions. Has the creaming of US shale plays anything to do with this? I am not an expert enough to confidently make that claim, and there are surely other factors at play too, but it is worth a thought, I guess. At the end of the day, the economy is energy. ■

Henk Kombrink



PHOTOGRAPHY: LAURA UPSHAW VIA PIXABAY

Serendipity maximisation

Using historical exploration data in combination with known and postulated prospects, a new methodology developed by GIS-Pax aims to identify those areas where operators have the best chance of getting lucky

“WHEN PEOPLE make a creaming curve for a basin,” says Ian Longley from GIS-Pax, “they draw a line, and say *that’s going to be the future for the basin.*”

“The problem with that methodology is, when you predict to find, let’s say, 500 MMbbl in ten years, there is nothing to inform you about whether this yet-to-find resource will be found as a single 500 MMbbl discovery, or a string of 1 MMbbl finds. All the creaming says is that you end up at a certain point in time, but how you get there is entirely unknown.”

That’s why the team at GIS-Pax decided to approach this from a different viewpoint, all from a desire to make a more informed prediction on the potential size of the volumes to be found, and on a global scale to enable ranking different basins and countries.

“Let’s say the geological success rate is 50 %,” continues Ian, “and we are predicting ten fields of more than

20 MMbbl, there have to be twenty prospects of that minimum size. We distribute those prospects in an area, and subsequently run a stochastic model in which these wells are being “drilled”, let’s say a thousand times. In turn, that will result in a distribution of expected volumes given the number of wells drilled. This will also allow us to apply volume cut-offs, something that is not possible using the simple creaming curve methodology described at the start.”

But of course, rather than defining the prospects themselves, it would be better to use a set of prospects already defined and mapped for a certain country or basin. To tap into that source, the GIS-Pax team formed a partnership with S&P Global, which maintains a worldwide catalogue of prospects. “It is only in areas where there are no mapped prospects in the public domain, such as in Saudi Arabia, where

we use the approach of defining a set of prospect polygons ourselves,” says Ian. “At the end of the day, we want to achieve a global and complete overview of prospectivity, as only then can we claim that our approach enables a global screening exercise.”

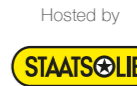
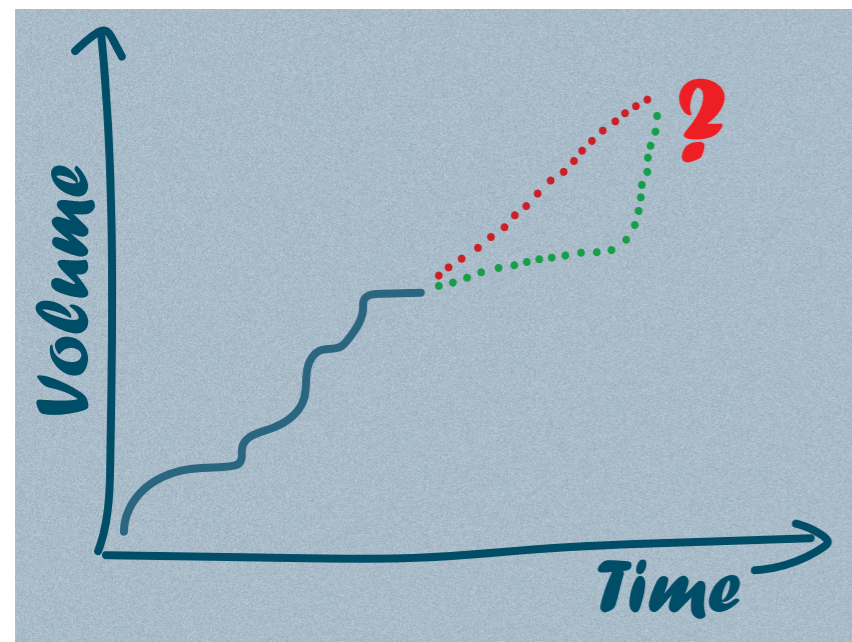
The global database now uses around 26,000 prospects from the S&P database, and the data gaps are filled with more than 100,000 postulated prospects. “There is a significant spatial and subsurface analysis that stands at the basis of this work,” continues Ian. “In a proven play, we use historical data to estimate the geological chance of success, but as we move deeper, shallower, or away from the source kitchens, we also change the success rates because we rely more on oil migration.”

The methodology also attempts to evaluate basin complexity. For example, if all of the large discoveries are made early and get progressively smaller over time, the basin may be quite simple and new big surprises are unlikely. This contrasts with basins where large discoveries continue to be made through the exploration cycle. It is these more complex basins that have a higher chance of future large discoveries.

“We know that our predictions will be wrong,” concludes Ian. “But what we try to achieve here is to have a consistent approach that can be applied globally, without there being a scatter of different techniques for different areas as we so often see. And through working with volumes, as well as historical performance data, we even try to predict where the next late-stage large discoveries, like Buzzard in the North Sea, might be made. We believe that is predicting the impossible!” ■

Henk Kombrink

ILLUSTRATION: GEO EXPRO



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A round-up of key development projects across Europe – a subsurface summary

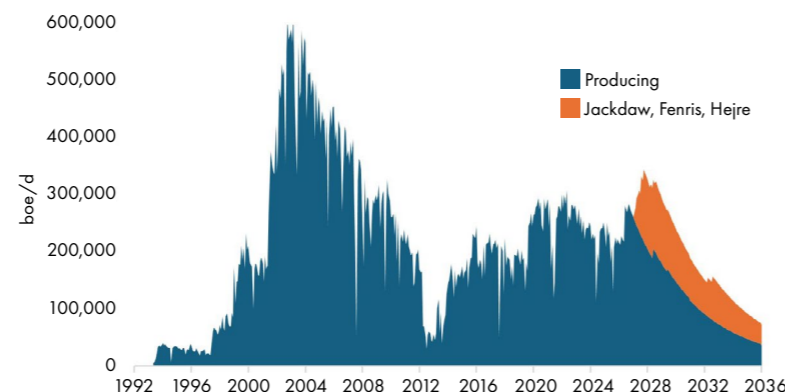
A wave of new large oil and gas developments is set to be brought online over the next five years, with investment of \$55 B set to recover 4 bnboe. We dive into the subsurface to reveal some of the plays delivering this volume

DAVID MOSELEY, WELLIGENCE ENERGY ANALYTICS

PRODUCTION in the North Sea and in most oil and gas-producing countries in continental Europe is largely in decline. The upstream investment landscape in Europe is challenged by a combination of local and global factors, including fiscal regime changes and E&P companies exercising caution with capital deployment. Despite this, 21 new fields, each with reserves of >50 MMboe, are set to be developed across Europe, with start-up expected by the end of 2030. Here, we review a selection of those projects.

CORONA RIDGE – CAMBO, ROSEBANK, TORNADO

Cambo and Rosebank are large, remote, deepwater projects with good quality Tertiary reservoirs, primarily in the Colsay (Rosebank) and Hildasay (Cambo) sands, sitting towards the southwestern extent of the Corona Ridge in the Faroe Shetland Basin, West of Shetlands. Well control is high; however, development costs, combined with subsurface challenges including intra-volcanics at Rosebank, along with changes in ownership, and most recently revised environmental guidance, have slowed development. Upside both within the field area and in the surrounding acreage, including Blackrock, an intra-volcanic Colsay (oil) and Hildasay (gas) discovery, could see over 500 MMboe recovered from the area. The formation of Adura (Shell / Equinor in the UK) and a concerted West of Shetland strategy by Ithaca Energy means they are now as close as ever to reaching production. Together, both companies are also working to develop the Tornado gas condensate field, at the far south of the Corona Ridge,



Central Graben HPHT plays production profile.

targeting ~350 bcf in Paleocene sands (T38c interval) of the Lamba Formation.

CENTRAL GRABEN HPHT – FENRIS, HEJRE, JACKDAW Combined, the Fenris (Norway), Hejre (Denmark) and Jackdaw (UK) projects are set to contribute to the HPHT Central Graben plays, delivering their highest production rate in 20 years. Fenris has an Upper Jurassic reservoir in turbidites of the Farsund Formation at over 5,000 m depth, along with potential in shallow marine sandstones of the underlying Ula Formation, making it the deepest development on the Norwegian Continental Shelf. To the northwest, Jackdaw comprises an ultra-HPHT Heather Formation reservoir in a series of tilted fault blocks, which Adura is developing via tieback to Shearwater. In Denmark, INEOS' Hejre development is located in the Feda Graben with Upper Jurassic Fulmar-type sandstones at a depth of 5,100 m. Following discovery in 2001 and appraisal in 2005, DONG previously sought – but failed – to develop the project owing to a combination of factors, and ultimately its exit from oil and gas.

NORTH SEA MATURE PLAYS – BUCHAN, EKOFISK PPF, YGGDRASIL

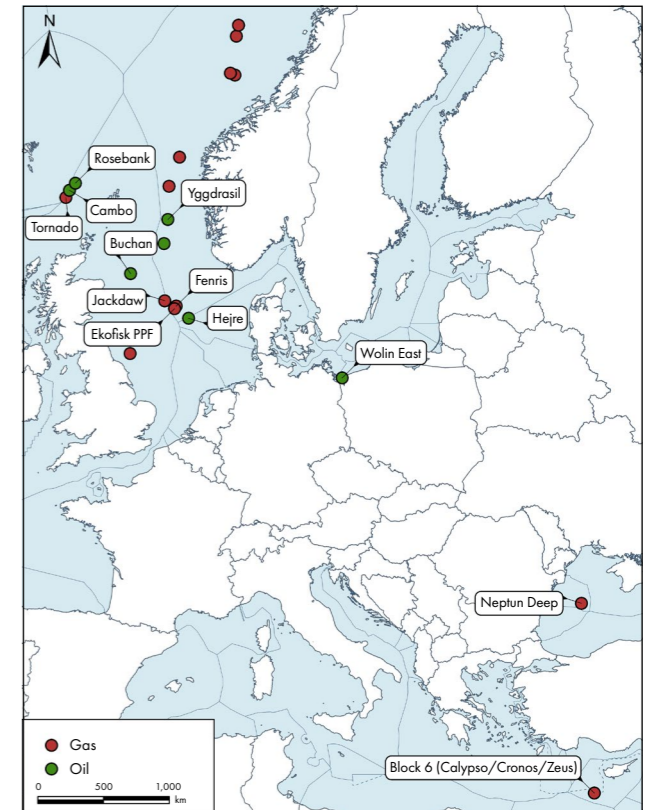
There remains significant potential in even the most mature North Sea plays. The combination of well-understood areas, with a wealth of data, makes for a clear investment case.

The Buchan redevelopment (NEO NEXT) comprises a tilted fault block with four-way dip closure, with reservoir in fractured and over-pressured Upper Devonian to Lower Carboniferous Buchan Formation sandstones. At shut-in in 2017, less than 30 % of the oil in place had been produced, and current plans are to recover ~70 MMbbl in the redevelopment. In Norway, the Ekofisk Previously Produced Fields (PPF) redevelopment includes the Albuskjell, Vest Ekofisk and Tommeliten Gamma fields, targeting gas condensate in the Maastrichtian Tor and Paleocene Ekofisk formations. While Buchan will form a new hub, PPF is set to help extend the life of the vast Ekofisk hub.

To the north, in the Middle Jurassic Brent play, the cluster development of ten discoveries forming Yggdrasil is currently the largest oil development in Europe with potential for over 700 MMboe, largely in the Middle Jurassic, but with additional volumes in the Eocene.

BALTIC SEA – WOLIN EAST

One of the most exciting projects outside the North Sea, the Wolin East discovery well drilled by CEP in 2025, found a 62 m hydrocarbon column in the Zechstein Main Dolomite of the Upper Permian. An appraisal sidetrack is planned this year, with production start-up mooted for 2030. Prior to the award of the Wolin concession in December 2017, CEP had successfully worked up multiple targets in Germany and extended these concepts across the border into Poland for the first time. Upside in the area has the potential to double current resources, while parallels have been drawn with play concepts further afield in



Key development projects in Europe, >50 MMboe and online by end-2030. Labels for those discussed here.

the Southern Permian Basin, including to the west in the UK Southern North Sea.

SOUTHERN EUROPE GAS PLAYS – NEPTUN DEEP, BLOCK 6 (CALYPSO / CRONOS / ZEUS)

OMV's Neptun Deep concession is set to deliver a wave of new gas into Romania, and is transformational for the country's energy supply. One of the biggest development projects in Europe, it is set for start-up later this year ahead of target. Comprising a stacked interval of fine-grained turbiditic Miocene sands, the project has sparked wider interest across the Black Sea, both locally and further south in Bulgaria, where the latest follow-on well, Krum-1, is targeting multi-Tcf potential in Pliocene-Miocene sands. Between the Black Sea, the Levantine basin offshore Cyprus with Eni / TotalEnergies' Block 6 project – also a multi-Tcf development that is set to be transformational for its country's energy mix – and upcoming frontier exploration in Greece, all eyes are on southern Europe gas.

This analysis was taken from Welligence's report: *The next 4 bnboe – key upstream developments to 2030* published in February 2026.

Please contact david.moseley@welligence.com for the full report.

SOURCE: WELLIGENCE

What are we risking and why is it important?

Some explorers believe that, when assessing the Probability of Success and volumes of an exploration prospect, it is best to risk the P90 or P50 volume. This is not correct; it confuses risk and uncertainty, and it leads to overprediction of prospect volumes

JAN DE JAGER

RISK IS ABOUT the chance of finding producible hydrocarbons; uncertainty is about the volume of hydrocarbons that may be found in the case of success. The geological Probability of Success (POSg) of an exploration prospect is linked to the expectation curve, which shows the range of hydrocarbon volumes that may be found in the case of success.

From the expectation curve, we can simply read off the chance to find more than any specific volume in case of success. The chance to find more than the P90 volume is 90 % in case of success, so the a priori chance of finding the P90 volume or more is 90 % of the POSg (De Jager, 2021). It makes absolutely no sense to risk the P90 or P50 volume for estimating the POSg. The chance to find the P90 volume is 90 % of the POSg – it is not the POSg itself.

Likewise, for a Minimum Economic Field Size (MEFS or commercial cut-off volume), the chance to find at least that volume is the POSg multiplied by the P value that goes with the MEFS.

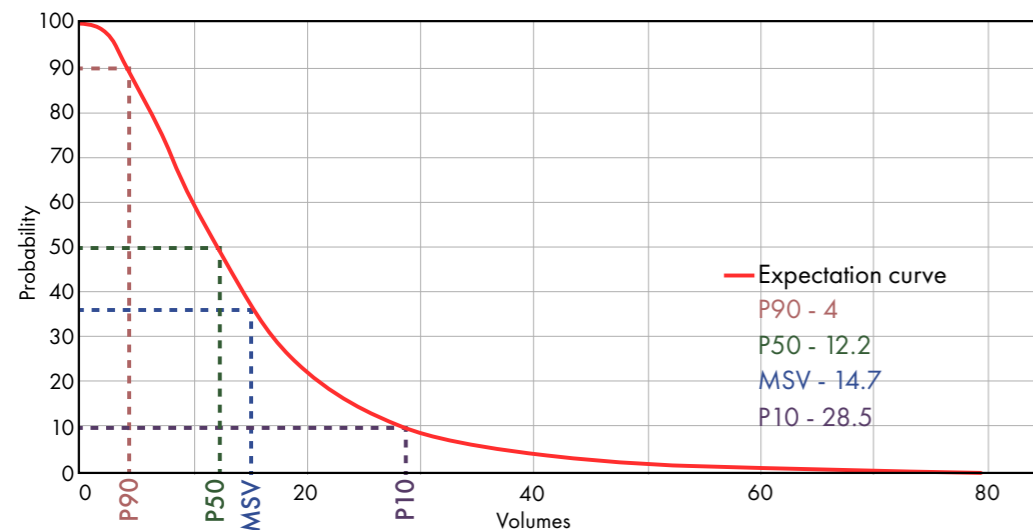
Risking a P90 volume also begs the question of whether we are actually able to differentiate between the chance of finding a P90, P80, P95 or any other P volume. Of course, we can't. Only once the expectation curve and POSg have

been established, can we read them off the chart of the expectation volume.

What this implies is that we need to be very clear about the definition of "technical success". The most useful definition I know of exploration success is: "A discovery that finds producible hydrocarbons that could be produced at a sustainable rate of production" (after Otis and Schneiderman, 1997).

Now, why is all this important? In practice, and strangely enough, I don't think that the estimated POSg is much affected by what we say or think we are risking: A technical success, the P90 or the P50 volume. What is affected is the predicted volume range. Risking the P90 is taken as an excuse to exclude small volumes from the predicted volume range. Those are then "in the risk", which is, of course, confusing uncertainty for risk.

And when we have put these smaller volumes in the risk, the P90 of the resulting expectation curve will be too high a volume and also the mean success and the P50 volumes will end up being too high. It is yet another factor, together with a series of biases that we tend to suffer from, that leads to overprediction of volumes, which we all know is a major shortcoming of exploration geologists. ■



From the expectation curve, the P90, P50 and P10 volumes can easily be read off. If the Mean Success Volume (MSV) is known, one can read off what the chance is to find at least the MSV in case of success. In this case, it is about 37 %. If the POSg of the prospect is (for example) 40 %, the a priori probability to find at least the MSV is 0.37 x 0.40 = 15 %.

References: Otis, R. M. and Schneidermann, N., 1997. A process for evaluating exploration prospects. AAPG Bull., 81 / De Jager, J., 2021. Handbook Risk & Volume Assessment. Self-published.

Keep that well

A recent discovery on the Norwegian Continental Shelf was drilled with a new development philosophy in mind

EQUINOR MADE a discovery in the North Sea recently, but that is not the biggest piece of news. What is interesting about the Omega Sør Alfa discovery (34/4-19S) is its location as well as the way the exploration well was drilled.

As the press release mentions, the licence in which the well was drilled has been owned by Equinor since 1979. In other words, since the start of exploration across the North Sea. That is quite remarkable, as many licences across the North Sea have now changed hands a few times, on the back of oil price fluctuations, drilling a duster, or a change in company strategy. But not PL057. The reason for that is simple: It hosts the giant Snorre field, which happens to be one of the earliest and biggest oil discoveries in the Norwegian North Sea. The life of Snorre as a main hub and producer is expected to last beyond 2040.

But within the perimeters of the licence, there must have been some little prospects lurking for a long time. And one of those was recently drilled, successfully.

Now, the way the Omega Sør Alfa prospect was drilled is the second interesting part of this story. It was drilled with a keeper well. In other words, a well that can be partly converted into a producer later on, therefore saving on the costs of drilling yet another new well later.

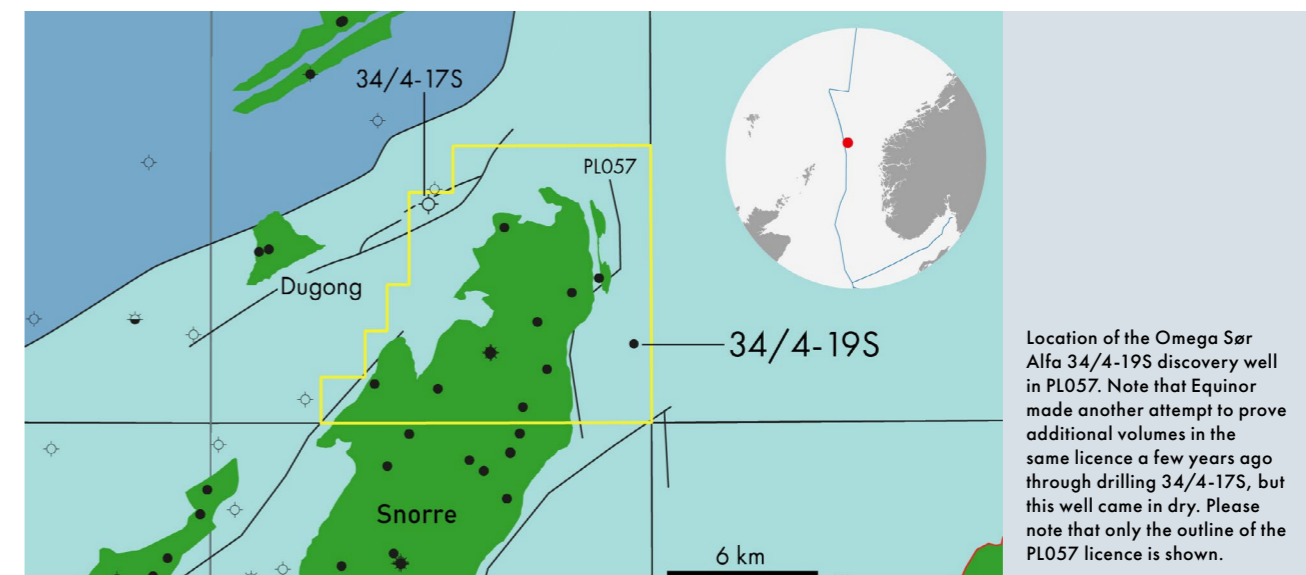
During the NCS Exploration Strategy Conference in November last year, Linda Aasum Burton from Equinor spoke about this well, making the point that her company is actively trying to accelerate the time between discovery and development, whilst lowering costs at the same time. In an email communication, she also confirmed that keeper wells have not been commonly used by Equinor for drilling exploration wells.

There has been criticism in the Norwegian E&P community about the time it takes to develop new finds – with DNO being vocal about the pace with which they aim to bring the recent Kjøttkake discovery online, whilst there is also the observation that costs have risen sharply, putting more pressure on the economics of what can easily be marginal developments.

Well 34/4-19S discovered oil in the Middle Jurassic Brent succession, encountering an oil column of 224 m, of which 127 m consists of moderate to good reservoirs. The plan is to hook up the discovery to the Snorre field infrastructure through a subsea development.

In that light, the keeper well on Omega Sør Alfa is something to take note of. At the same time, an analyst shared with us that the size of the discovery, which is thought to contain between 25 and 89 Mmboe recoverable, might be too large for a single well development, implying that more wells need to be drilled to effectively drain this barrel discovery. In addition, this is not the first time a keeper exploration well has been drilled across the NCS; the Løvmeis 6608/10-R-2 H well in PL1013 was drilled with a similar concept in mind in 2024. ■

Henk Kombrink



Location of the Omega Sør Alfa 34/4-19S discovery well in PL057. Note that Equinor made another attempt to prove additional volumes in the same licence a few years ago through drilling 34/4-17S, but this well came in dry. Please note that only the outline of the PL057 licence is shown.

Frac hit – how does it work?

A conversation with geologist Jessica Fallon about a mechanism that is familiar to those working in shale, but probably not so much to those in the conventional space

“LET’S START at a situation where we are drilling a 10,000 ft horizontal well in a prospective but yet undrilled shale play,” Jessica Fallon starts her explanation, “and we frac the shale along the full horizontal length of the well. The frac is pumped in isolated stages along the wellbore and can easily take between one and two weeks to complete. Following the last frac stage, there is a period of flowback, then the well is put on production, and everybody is happy.”

Then, some years later, in order to maximise the recovery of hydrocarbons from the lease, companies often drill a child well at a limited distance from the parent well. That’s when problems tend to arise.

“While frac’ing the child well,” Jessica says, “we sometimes observe a pressure spike in the parent well.” In other words, a connection is estab-

lished between the parent and child well. This can cause the parent well to produce fluid and even sand from the child well’s frac. In some cases, a drop in production rate is observed in the parent well, too, with the ultimate recoverable volumes being negatively impacted.

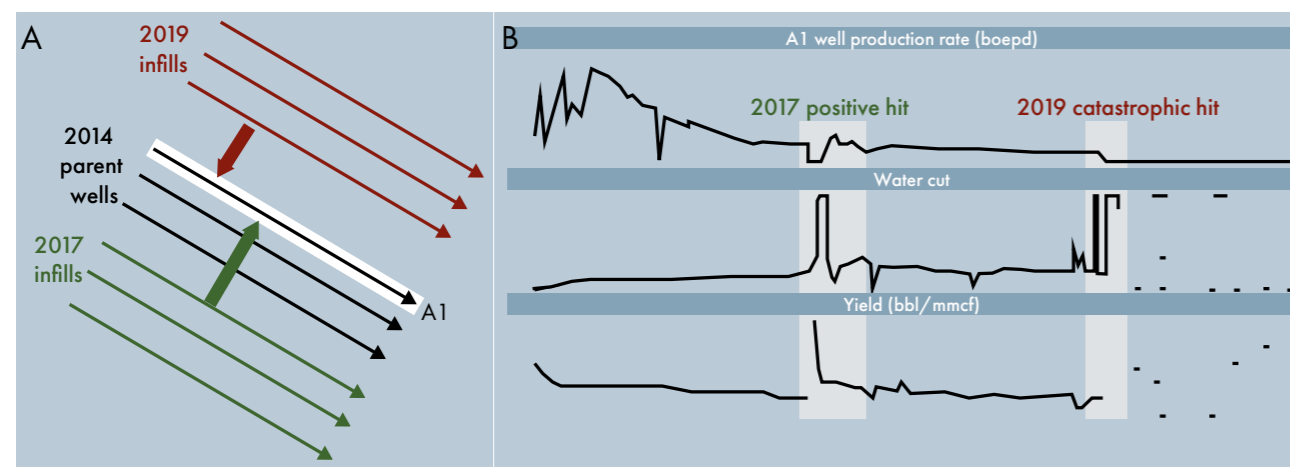
“The way I see it,” says Jessica, “is that production from the parent well changes the stress pattern in the subsurface, creating a “pressure sink” around the parent well. This causes the fractures from the child well to preferentially make their way in the direction of the parent well. These fracs are “captured” by the lower pressure rock around the parent well instead of opening up new rock for the child well.”

To prevent situations like that, wells tend to be drilled at larger dis-

tances from each other than in earlier years when this phenomenon was not recognised yet. Around ten years ago, when shale was still in its early days, a distance of around 600 ft was quite common; these days it is more in the order of 1,000 ft.

Another way to prevent the issue is to drill multiple adjacent wells from a single pad and frac them all at once, before any production or pressure depletion occurs. It is also possible to map pre-existing fracture systems in the shale using seismic attributes, and decide not to frac some intervals in the well where you think it is likely for faults to connect, but that always needs to be balanced against the loss of production. “You can imagine that is a difficult discussion,” concludes Jessica. ■

Henk Kombrink



A: Well sticks for parent and infill wells. B: How a frac hit can both have a positive as well as a negative impact on production from the parent well. In the production graphs, there is a period of a few weeks before and after the frac where the parent well was likely shut in to try and mitigate the impact of the offset frac, and then (after) flowing back water and recovering from the frac hit. There is a little gap in boe and water production for the shut-in time, and then after that, a longer period of “flowback” where the frac water is being produced, and then after that, an uplift in production (boe) as a result of the 2017 interaction. The 2019 frac hit is catastrophic because it knocks the well completely offline – it stops producing hydrocarbons and only flows water, unlike in 2017, it doesn’t recover. It is pretty far along on its production profile, so close to the end of its life anyhow, but it might have carried on with a low rate for a good while longer.

SOURCE: LIU ET AL. (2023) - URTEC: 3873139

“It is quite a risk hiring you”

Every time a round of redundancies is announced, we hear a variety of silver lining statements from those who were let go, such as “this could be a great opportunity to explore new directions.” However, this sounds a lot easier than it is, writes geophysicist Oscar Miron, who transitioned from oil and gas to the shallow seismic business

OSCAR MIRON, GEOPHYSICIST

YES, SOME people will break out of the shackles of their former role and flourish in a completely different career. But let’s not forget that for others, the road ahead is long and painful. Why is that? I think that hiring managers too often ignore the experience built up in previous roles, dismissing that as irrelevant for the position they need to fill.

Here is my experience.

I worked very happily, for 20 years, as a geophysicist in the oil and gas sector – until the day I was made redundant. For six long and painful years thereafter, I pursued hundreds of opportunities outside the oil and gas sector, only to receive an almost equal number of rejections.

Until one day, during a job interview for a role as an interpreter of shallow seismic data. I showed the interviewer the latest results from an oil and gas project that I had worked on. But he could not tell the difference between deep and shallow seismic. Cut a long story short, I was offered the job. Success, at last!

After celebrating for a couple of hours, I burst into tears at the realisation of what I had just done; after six years of hearing excuse after excuse about why I should not be considered for a role in a sector where I had “no experience,” I had just succeeded in securing a job in a new sector.

Certainly, for the first six months, I was a junior in my new role. This is not a surprise, right? New methods, new software, absolutely everything was new. But fairly soon, the balance be-

gan to tip in my favour. Within a year, I was interpreting shallow seismic and side-scan sonar, and I did some coding to analyse and reformat topographic and hydrographic data. In addition, I was instrumental in securing very lucrative long-term contracts by creating deliverables for the client that none of the competitors could match.

Flashes of feedback from potential employers still come to mind sometimes: “You are such a risk”, or “I know you will fit in and do well, but I can not hire you.” Now I can look back and say, “Risk? What risk? I had already achieved similar things

in the oil and gas industry, as my CV had clearly shown. In other words, my ability to succeed was already proven, and it was therefore only a matter of time to achieve the same in my new role; and a short time it was indeed.

This narrow mindset in our profession is what I call the Enemy Within. Successful stories about transferable skills are out there – they do exist. But still, for those who fail to secure roles in a different sector of geology or geophysics, it is often the mindset of technical managers, not the candidate’s unsuitability, that puts obstacles in the way of success. ■



Oscar Miron.

PHOTOGRAPHY: OSCAR MIRON PRIVATE ARCHIVE

Salt of the Earth:

Imaging the Gulf's hidden structures



The Gulf of America is a vital part of US energy infrastructure, with its future increasingly dependent on new seismic technologies to tackle complex geology. As exploration advances into salt-dominated regions, operators are relying on advanced imaging and novel acquisition technologies to better map subsurface formations, improving visibility beneath salt layers and deepwater sediments that previously hid critical structures.

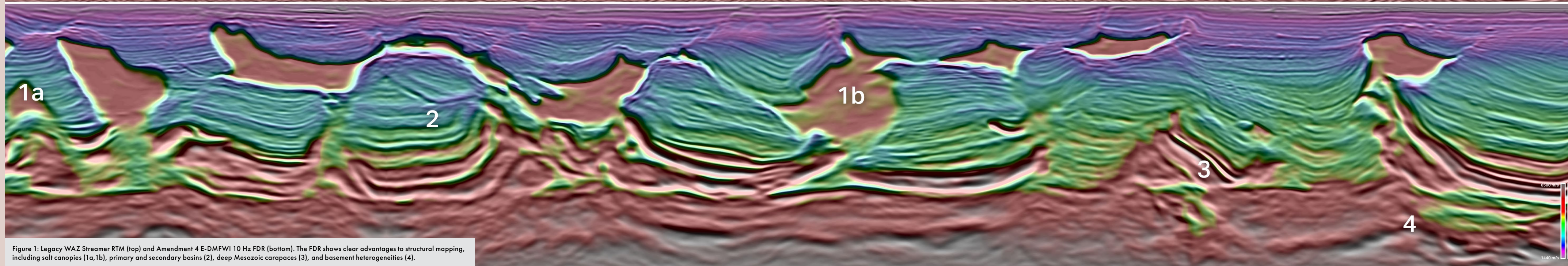
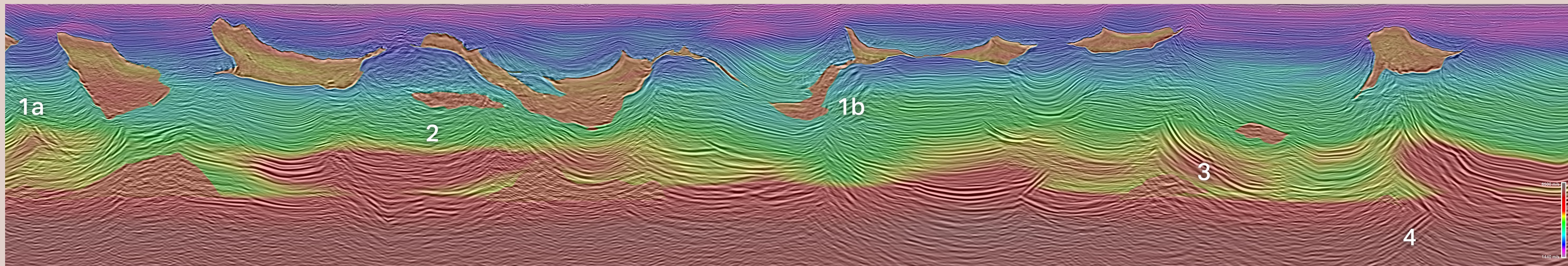
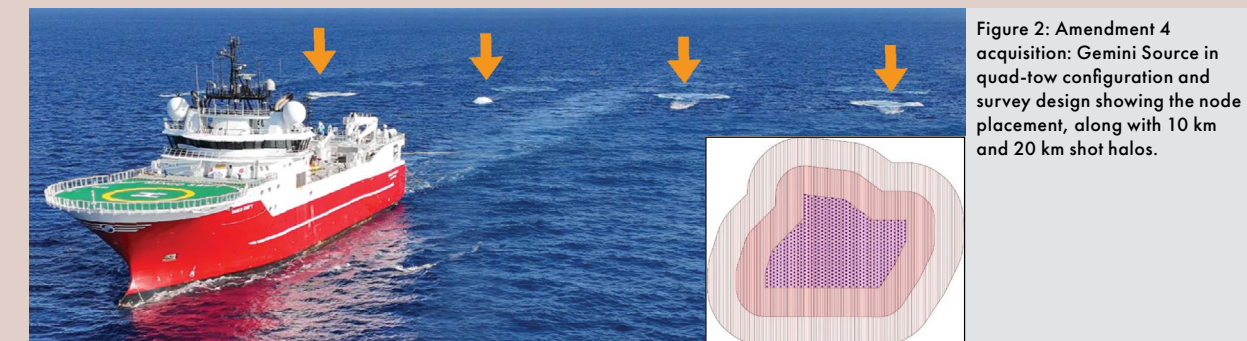


Figure 1: Legacy WAZ Streamer RTM (top) and Amendment 4 E-DMFWI 10 Hz FDR (bottom). The FDR shows clear advantages to structural mapping, including salt canopies (1a,1b), primary and secondary basins (2), deep Mesozoic carapaces (3), and basement heterogeneities (4).

Gulf of America: Integrating technologies to see beyond the salt

CLAY WESTBROOK AND ANDREY BOGACHEV, TGS

The Gulf of America (GOA) remains a central pillar of US energy infrastructure, and its future potential is increasingly tied to the integration of new seismic technologies that can address the region's complex geology. As exploration moves deeper into salt-dominated provinces, operators are turning to advanced acquisition and imaging solutions capable of resolving the entire subsurface column, from the seafloor through thick, rugose salt and into pre-salt and basement intervals. These integrated technologies, which combine innovative source designs, ultra-long offset acquisition, and high-end imaging workflows, are dramatically improving illumination beneath salt and deepwater sediments, revealing structures that were previously obscured by complex velocity regimes and challenging overburden.

AMENDMENT 4: LOW FREQUENCIES, DEEP INSIGHT
TGS's Amendment 4 program in Mississippi Canyon (Figures 1 and 3), Gulf of America, represents a major advancement in deepwater seismic imaging, demonstrating the impact of integrating multiple next-generation technologies into a seamless acquisition and processing workflow. By pairing Gemini enhanced frequency source (EFS) technology with ultra-long offset OBN acquisition, the project generates a broadband, high-energy wavefield capable of penetrating thick salt and illuminating deeper, structurally complex targets. When combined with elastic dynamic

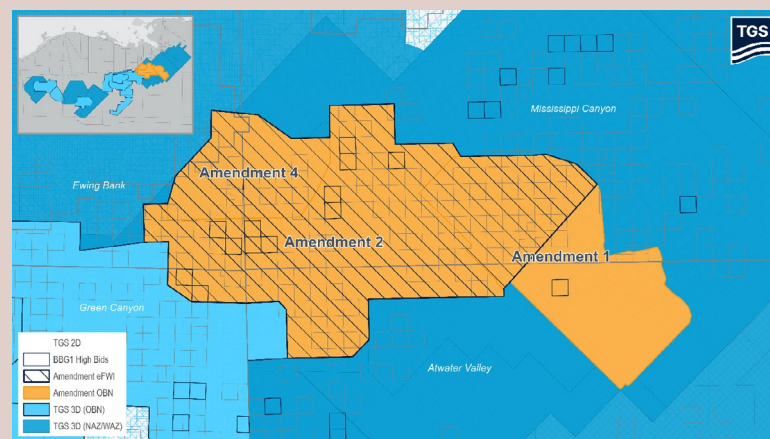


Figure 3: Map showing Amendment 4 along with Amendments 1 and 2 (in partnership with SLB).

matching FWI (E-DMFWI), this dataset achieves a level of subsurface clarity and velocity model fidelity that conventional approaches cannot match. The result is a premium seismic product engineered to resolve challenging geological features across the shelf, slope and deepwater domains.

Amendment 4 was acquired using quad-towed Gemini's deployed from two source vessels. The design aimed to increase operational efficiency while delivering even better offset coverage compared to previous multiclient long-offset OBN surveys. This new configuration achieved longer halo offsets by providing full 10 km shot halo coverage, complemented by a strategically decimated 10–20 km extended halo (Figure 2). The result is a more efficient survey that captures more ultra-long offsets needed for complex velocity model building in deepwater salt provinces.

This enhanced acquisition geometry directly improves velocity

model convergence, particularly in areas dominated by thick, rugose, or multi-layered salt. The combination of long offsets and multi-azimuth illumination strengthens the inversion of complex velocity fields, enabling a more accurate representation of salt bodies and the sediments that surround them. With these improvements, interpreters gain clearer visibility into basement heterogeneities, which historically have been poorly imaged due to limited subsalt illumination. This represents a fundamental shift in subsurface interpretation, as structures previously obscured beneath salt can now be resolved with greater confidence. Salt-related geometries, including welds, canopies, feeders, and subsalt traps, become more coherent, while the salt-sediment interface is imaged with sharper definition, reducing uncertainty in structural mapping (Figure 4).

Beyond salt imaging, the improved illumination compared

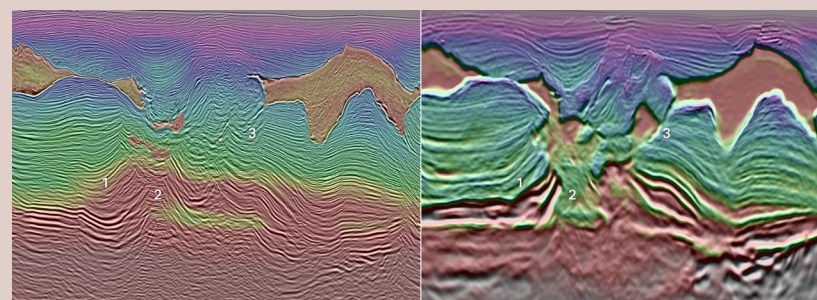


Figure 4: Early-Out 10 Hz E-DMFWI FDR (right) shows improved structural placement (1), better salt feeder definition (2), and salt-sediment interface (3), relative to the legacy WAZ streamer RTM (left).

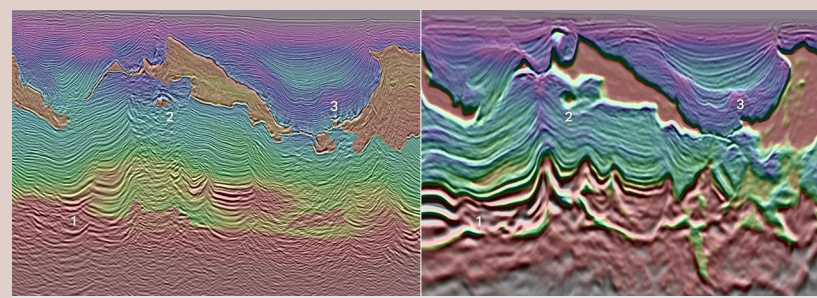


Figure 5: Early-Out 10 Hz E-DMFWI FDR (right) shows improved source rock interval imaging (1), better stratigraphic coherence (2), and overpressured shale / low velocity intervals (3), relative to the legacy WAZ streamer RTM (left).

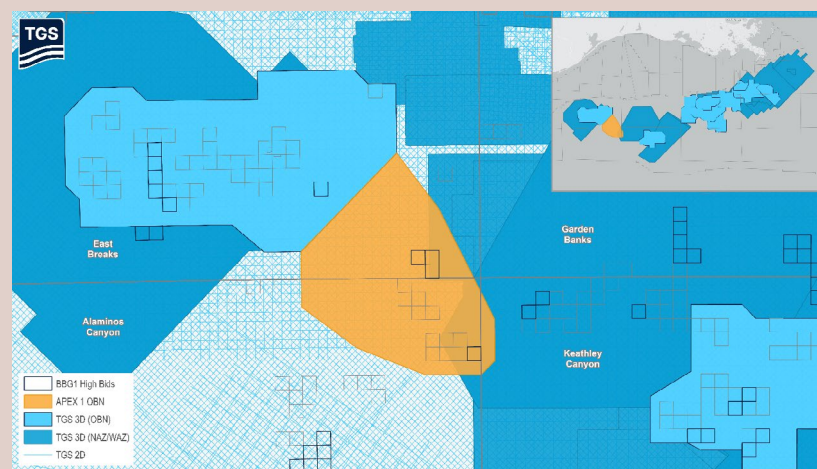


Figure 6: Map showing APEX 1 (in partnership with SLB).

to legacy streamer data enhances the resolution of overpressured and mobile shale bodies (Figure 5), which are common in deepwater Gulf settings. These shales often create drilling hazards, influence pore pressure regimes, and complicate well placement. Better imaging of their geometry and internal fabric provides critical insight into operational risks and well planning considerations, enabling more accurate prediction of pressure ramps, potential wellbore instability zones, and areas prone to

fluid migration. Additionally, clearer delineation of shale and sediment boundaries helps identify pressure baffles and trap seal elements, which are essential for evaluating hydrocarbon trapping mechanisms and reducing exploration risk.

A NEW STANDARD FOR DEEPWATER SUBSURFACE IMAGING

Amendment 4 demonstrates how a carefully engineered combination of advanced source technology,

long offset OBN acquisition, and state-of-the-art imaging workflows can fundamentally reshape subsurface interpretation in the deepwater GOA. The program delivers clearer velocity models, sharper salt sediment interfaces, and improved visibility into basement and shale-related features relative to legacy streamer data. These gains translate directly into operational value: better-defined drilling targets, improved hazard assessment, and a more reliable understanding of trap integrity and pressure architecture. As operators continue to pursue increasingly complex reservoirs, Amendment 4 stands as a benchmark for how integrated seismic innovation can reduce uncertainty and unlock new opportunities in mature deepwater basins.

APEX: THE NEXT LEAP IN MULTICLIENT EXPLORATION

When we ask where long-offset OBN solutions are headed next, TGS already has the answer with APEX. Building on the latest technological breakthroughs, the APEX acquisition concept represents the new generation of multiclient seismic in the GOA, with APEX 1 now delivering the first full implementation (Figure 6). Designed as a true OBN-only survey with denser node spacing and enhanced spatial sampling, APEX removes the dependency on legacy streamer data and delivers a premium standalone subsurface product built for the complex salt provinces driving the next exploration cycle. By uniting Gemini-enhanced frequency source technology, a purpose-built OBN geometry, and high-end imaging from the outset, APEX sets a new benchmark for multiclient seismic and provides a scalable solution for unlocking frontier potential across the most complex subsurface areas in the GOA and beyond. With this survey currently underway, the industry is already watching closely and eager to see the first results from APEX 1 coming this summer.

FEATURES

“It is interesting to see how Canadian drilling technology and experience is being applied to revive mature assets in Brazil”

Tako Koning – Geological Consultant

Applying Canadian oil industry technology abroad

How Alvo Petro found a niche in gas-hungry Brazil whilst also investing in a Canadian oil project to gain further experience, ready to be exported in the future

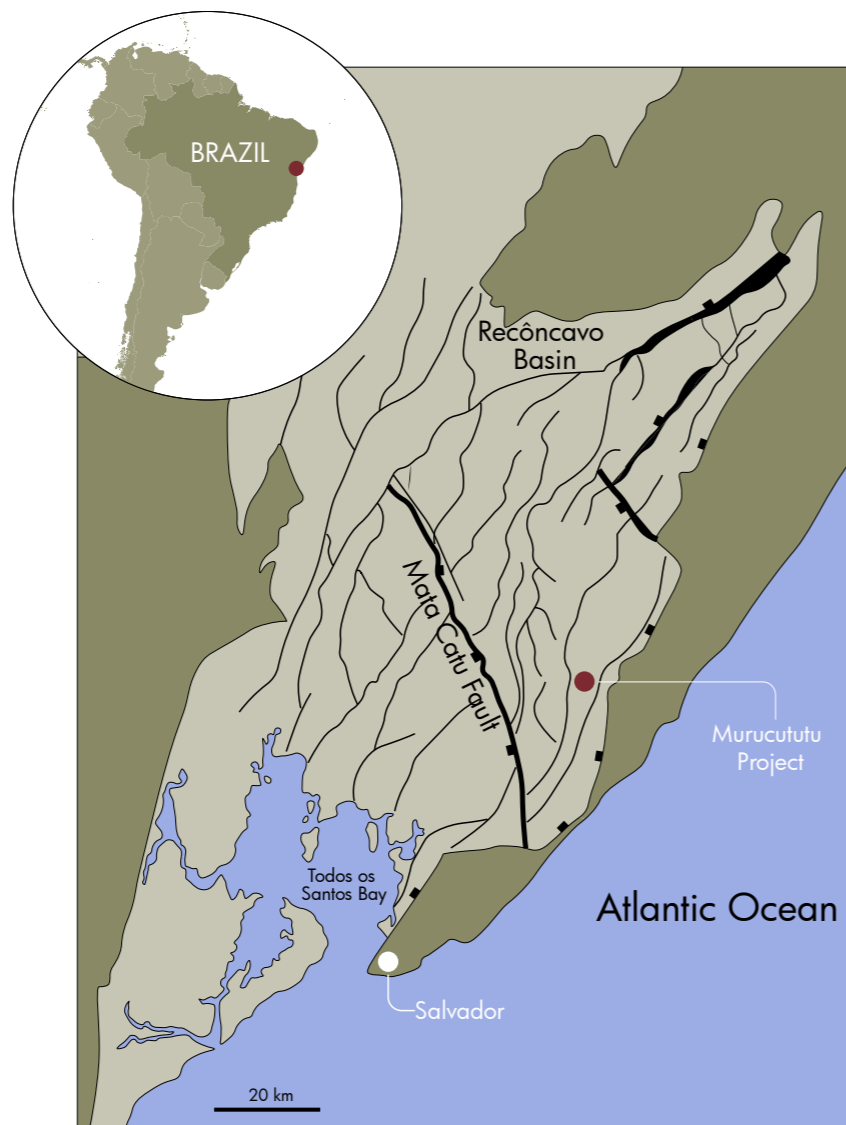
TAKO KONING, GEOLOGICAL CONSULTANT

ALVO PETRO ENERGY is one of the many Calgary-based Canadian energy companies involved in international exploration and production. Like most of those companies, Alvo Petro is listed on the TSX Venture Exchange. Alvo Petro was incorporated in 2013 and subsequently signed a contract with Brazil's energy regulator, the Agência Nacional do Petróleo (ANP), to become the operator in exploration and production blocks in the Recôncavo Basin, onshore Brazil.

In 2020, the company distinguished itself by becoming the first independent company in Brazil to deliver natural gas into the local distribution network. Five years later, in 2025, Alvo Petro expanded its focus even though it stayed closer to home this time around; the company joined an oil field development program in Canada's western province of Saskatchewan. The well designs used by operators in this oil play include several configurations including Open Hole Multi Lateral wells.

ALVO PETRO IN THE RECÔNCAVO BASIN

The Recôncavo Basin in the state of Bahia is the oldest producing basin in Brazil. The basin is an intracontinental half-graben formed during the Late Jurassic – Early Cretaceous. The basin covers 11,500 km² and contains over 6,000 m of pre-, syn-, and post-rift sediments, including major oil and gas source rocks and associated reservoir sandstones. It currently pro-



Location of Recôncavo Basin with structural framework and Murucutu field.

duces approximately 40,000 boepd, of which 50 % is gas.

Alvo Petro's production in the basin is primarily natural gas with a small volume of oil and condensate. Sales in Brazil in January 2026 amounted to

2,900 boepd with a production mix of approximately 90 % gas. Gas production averaged around 16.3 MMcfd.

Although Brazil is a major producer of natural gas, what is underappreciated is that Brazil is also a major import-

er of gas. The country imports 32 % of its gas via pipeline from Bolivia and increasingly from Argentina (via Bolivia), along with LNG imported from the USA, China and various African countries. Bolivia itself has seen a major drop in domestic gas production in recent years, which has caused this shift in gas sourcing. The importing of expensive gas has resulted in domestic gas prices in Brazil needing to be kept on par with imported gas.

Consequently, Alvo Petro significantly benefits from high gas prices, which in January 2026 were \$10.70/Mcf. However, their success is also due to their ability to use appropriate technology, such as reprocessed 3D seismic and developing a deep understanding of the geology, thereby unlocking the significant remaining potential in this mature basin.

Alvo Petro's Exploration Manager is Calgary-based Nanna Eliuk. In a recent presentation to the International Division of the Canadian Energy Geoscience Association, Ms Eliuk reviewed the Murucutu field, which Alvo Petro discovered in 2022. The field produces gas and condensate from Cretaceous early rift deposits including lacustrine turbidites and gravity flow sandstones. Four wells are already in production, including a well which came on pro-

AN EMERGING ENERGY SUPER-POWER

In the past decade, Brazil has experienced extraordinary success in exploration in the pre-salt formations in the deepwater Campos and Santos Basins. This has resulted in Brazil's oil and gas production ramping up to current oil production at 4.0 MMbpd and natural gas at 195 MMcfd. Brazil ranks as the 7th largest oil producer in the world and is the world's 9th largest economy. Onshore, the picture is different, with some assets being late life and benefiting from new pairs of eyes to squeeze the last barrels out.

duction in mid-2025 at the Initial Production rate of 1,100 boepd.

Nanna Eliuk said that just as Brazil is a net gas importer, the state of Bahia consumes more gas than is produced due to the large industrial complex in Camaçari near the city of Salvador, with a population of approximately 3 M people. This complex is within 5 km of Alvo Petro's gas discoveries. The city gate at Alvo Petro's gas plant is capable of supporting significant expansion of gas sales volumes as additional wells and facilities are developed.

CANADIAN SUCCESS STORY

In 2025, Alvo Petro also began participating in the Mannville Stack play fairway in southwestern Saskatchewan. This is a Lower Cretaceous shallow-depth, multi-zone oil field development program which has attractive economics through the application of multilateral drilling technology. The

well-designs used by operators in this oil play include several configurations, including multi-leg horizontals and fish-bone patterns. Wells can be open-hole or cased, and some even include small fracs. Operators continue to deploy a variety of fit-for-purpose designs and patterns based on localised geology and economic optimisation.

Alvo Petro is beginning to benefit from the Mannville Stack, where eight new oil wells have been drilled and brought on production, adding incremental oil production through the company's Canadian portfolio.

According to Ms Eliuk, the technical know-how they are acquiring in Saskatchewan may also be applied to their Brazilian operations. In January 2026, sales volumes rose 8 % from the fourth-quarter average to a record level of 3,100 boepd, supported by stronger output in Brazil and higher sales volumes in Canada. ■



Production facilities.

SOURCE: REDRAWN FROM MAGNAVITA ET AL

PHOTOGRAPHY: ALVO PETRO

Western Pyrenees foothills – the hotspot for natural hydrogen

Play-based approach of exploration opportunities and challenges in the Mauléon Basin, France

HENRI PUNTOUS AND JEAN-MARC FLEURY, TERRENSIS
MOLLY BOKA-MENE, AURORE LAURENT AND BENOIT HAUVILLE, 45-8 ENERGY

THE GROWING interest in hydrogen within the context of the energy transition has recently led to renewed scientific attention, resulting in the identification of numerous natural occurrences across a wide range of geological settings.

Academic studies have significantly improved the understanding of hydrogen generation mechanisms, in particular, water-rock interactions in continental environments. These advances suggested that significant quantities of hydrogen may be generated and trapped. It has led to the emergence of an exploration sector dedicated to natural hydrogen resources.

In April 2022, natural hydrogen was incorporated into the Mining Code in France. 45-8 ENERGY (associated with STORENGY) and TERRENSIS have already been granted exploration licenses in the south-west of the country, illustrating the growing momentum toward assessing native hydrogen as an economically viable energy sector.

WHY THE WESTERN PYRENEES?

The Mauléon Basin, located along the western edge of the French Pyrenees, has recently emerged as a promising area for natural hydrogen exploration. This interest is supported both by sustained academic research, which has identified the key components of a regional hydrogen system, and by the extensive dataset inherited from a century of oil and gas exploration.

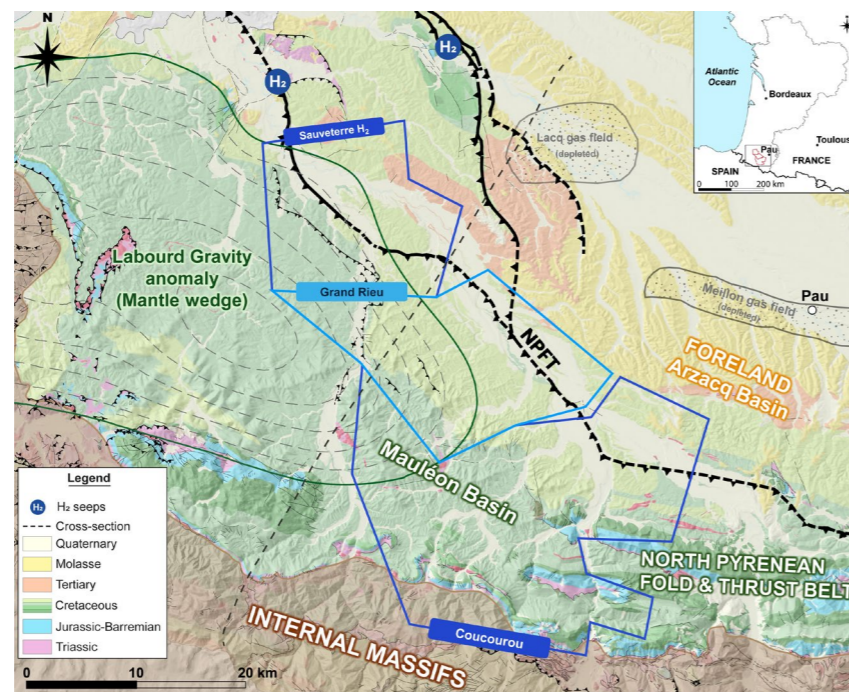
Large-scale passive seismic acquisition (Maupasacq, 2018), the re-interpretation of legacy geophysical data and documented shallow hydrogen occurrences collectively indicate the presence of an active hydrogen-generating system. This system is interpreted to be associated with serpentinisation processes affecting mantle-derived rocks beneath a structurally complex sedimentary basin, offering favourable conditions for hydrogen generation and potential subsurface accumulation.

A PLAY-BASED APPROACH

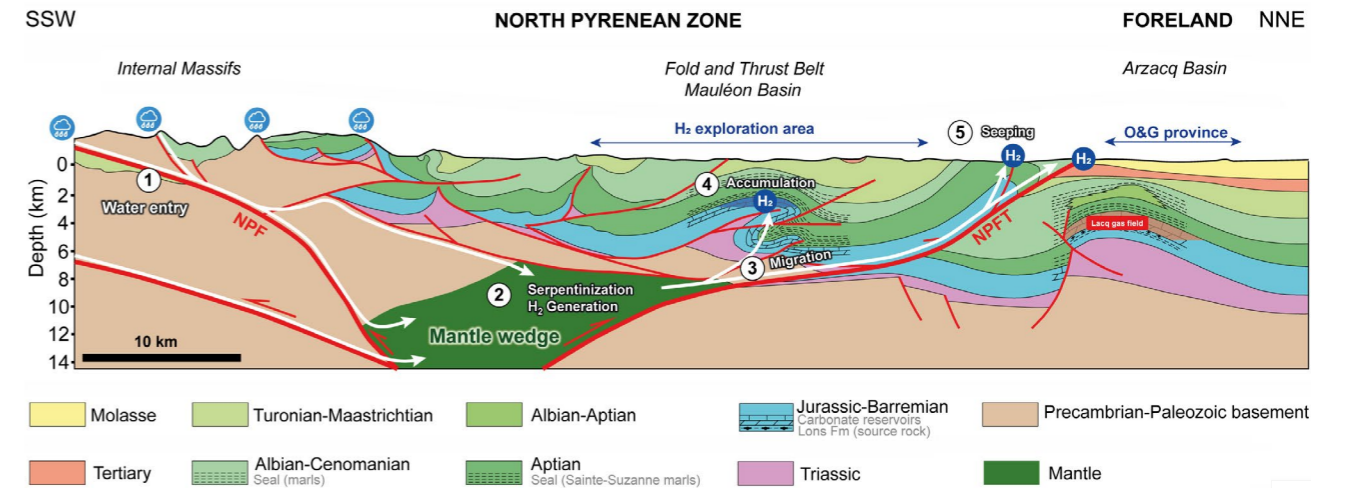
Source rock – the presence of a large gravity anomaly, the “Labourd Anomaly,” in the Mauléon Basin has

been recognised for several decades. Recent reinterpretations, supported by passive seismic data derived from local earthquake tomography, have imaged an approximately 300 km² wide high-Vp body (~8 km/s), interpreted as fresh mantle material. This relatively shallow mantle occurrence (~8-10 km depth) is thought to have been exhumed during the Cretaceous basin hyperextension and subsequently incorporated into the orogenic wedge during the Tertiary Pyrenean compression.

Recent academic studies, based on gravity and magnetic modelling, further suggest the presence of partially serpentinised mantle rocks within this body, indicating ongoing



Reservoirs, seals and trap mechanisms evidenced from legacy hydrocarbons exploration data.



H₂ generative system of regional extension, evidenced by new research studies based on geophysical and geochemical data acquisition.

hydrogen generation. Meteoric waters are inferred to circulate at depth through active hydrothermal systems, as evidenced by microseismic activity and the numerous thermal springs located along the northern edge of the mountain belt. Fluid circulation is likely to be facilitated by several major south-dipping frontal thrust faults, which could serve as efficient migration pathways from the crust into the overlying deformed sedimentary cover.

Reservoirs and Seals – extensive legacy oil and gas exploration data, primarily acquired in the Arzacq Basin during the 1960s and 1980s, have demonstrated the presence and effectiveness of regionally extensive reservoir-seal systems in Aptian-Albian high-porosity reefal carbonates and Barremian-Upper Jurassic highly permeable fractured platform carbonates. Deeper, more speculative exploration targets have also been identified beneath the evaporitic Triassic-Lias sequence. Many of these formations are further documented by numerous outcrops in the internal zones, particularly within the Chaînons Béarnais. In the nearby Lacq gas field, the presence of a large gas column has generated significant overpressure, providing a clear demonstration of the exceptional sealing capabilities.

Migration, trapping & preservation – natural hydrogen generated at depth can migrate upward or laterally toward targeted reservoirs through the well-developed Pyrenean fault system, within favourable structures such as faulted anticlines, efficiently focusing migration into effective traps. The optimal target depth for hydrogen preservation – minimising microbial activity – is over 2 km.

EXPLORATION TARGET IDENTIFICATION

Ongoing efforts by both operators aim to characterise the structural configuration of the natural hydrogen exploration area. This work involves retrieving and reprocessing legacy 2D and 3D seismic data, integrating it with recent passive seismic acquisitions specifically designed to image hydrogen targets, and reinterpreting historical well data to better constrain the lateral extent of key reservoir and sealing formations identified in the petroleum system.

In 2024, Terrensis conducted a dense hybrid passive seismic survey (450 sensors over four months) to generate a high-resolution Vp model for future seismic planning and establish a baseline for local microseismicity. The resulting tomographic models significantly aided the reprocessing of

vintage 2D seismic data, particularly due to the strong velocity contrast between the Upper Jurassic reservoir interval and its overburden. A similar survey is planned for late 2026 over the Grand Rieu license.

These integrated datasets will support the development of a consistent regional geological model of the Mauléon Basin. Depending on the outcomes of these investigations, future active seismic acquisitions may be required to further mature exploration leads already identified within the basin.

IDEAL LOCATION FOR OFFTAKE

The Mauléon Basin has a unique set of exports route available for local markets, paving the way of the transition to a local carbon-free energy.

Several possible offtake pathways have already been identified. The region’s strong transport infrastructure supports hydrogen distribution for mobility applications. Existing natural gas infrastructure can accommodate hydrogen blends of up to 10 %, enabling integration into the domestic gas network and access to future cross-border hydrogen networks. Possible future demand potential could also arise from the opening of major industrial facilities nearby.

Long-distance up-flank oil migration offshore Brazil

3D basin modelling incorporating pre-salt geochemical data reveals new exploration areas in Santos and Campos Basins

SHARON CORNELIUS, KENNETH SHIPPER, PAUL MANN, CBTH PROJECT, UNIVERSITY OF HOUSTON AND ANDREW PEPPER, THIS IS PETROLEUM SYSTEMS

THIS ARTICLE discusses the results of a four-year 3D Earth modelling project that included detailed seismic mapping of 17 surfaces between the seafloor and the top of the Moho, using a detailed grid of both 2D and 3D seismic data from TGS covering 592,000 km² across the combined areas of the Santos, Campos, and Espirito Santo salt basins. The TGS dataset includes ION data recorded to a depth of 40 km and allows detailed mapping of the Moho and constrains the depth to the top of crystalline basement, which can be validated by other seismic profiles. Geopost Energy Brazil, a division of Katalyst Data Management, provided hundreds of well data wireline logs and mud logs. ANP provided geochemical data for 84 pre-salt wells covering all three basins. The ANP dataset also included paleontological reports that helped estimate paleo-water depths for each chronostratigraphic unit in each well.

ASSEMBLING THE DATA FOR BASIN MODELLING

We corrected bottom-hole temperatures (BHTs) and uploaded them to the ExCaliber Earth modelling software from Xplorlab. Detailed lithological content was extracted from the mudlogs by calculating the percentages of clay found in shale, sandstone, and marl for each chronostratigraphic unit per well. Similarly, the percentages of quartz were calculated in shale and sandstone. In addition, the percentages of carbonate, organic matter, evaporite, and volcanic rocks present in each

chronostratigraphic unit were calculated. These ANP wells were reasonably distributed throughout the study area, except in southern Santos, which has become an area of intense exploration interest due to bp's big discovery in the Bumerangue block, announced last August. Seven more wells in southern Santos were added to the project for heat flow and lithological data, even though they did not have geochemical data. We also compiled data in the form of organic carbon and pyrolysis data, including the hydrogen index (HI) and Tmax. All of these accumulated and derived lithologic data were gridded on a per chronostratigraphic-unit basis and then uploaded into ExCaliber, where values of radiogenic heat production (RHP) were inverted for 91 well locations. Crustal RHP and thickness are important in understanding and predicting variations in

the thermal profile across the two rift zones, given their large sediment thicknesses. The resulting 91 1D basin models, along with derived RHP values at each well, were then uploaded into ExCaliber for 3D basin modelling.

Output included predictions for three different source rock intervals: The Barremian (which often contains interbedded volcanic units), the Aptian pre-salt (Organofacies C associated with lacustrine facies), and the Albian post-salt (Organofacies A or B associated with marine carbonate or shale facies). Standard thermal stress (STS) maps were generated for all three source rock interval mid-points. The most important of these is the pre-salt Aptian source rock map. The combined Aptian and Barremian oil and gas production, loosely termed "pre-salt", currently supplies about 80 % of Brazil's total oil and gas

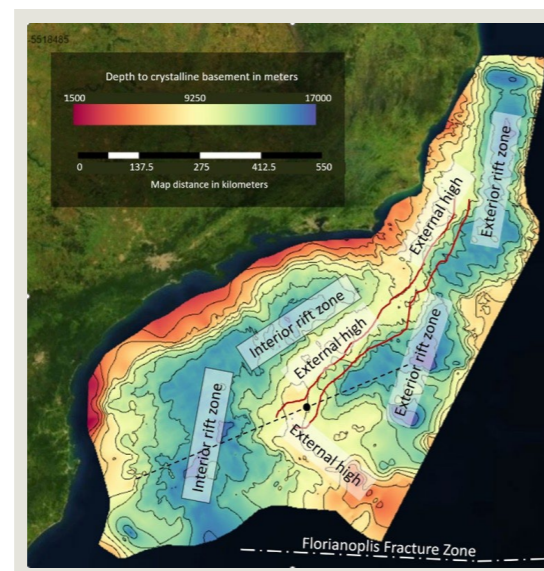


Figure 1: Depth to the crystalline basement map for the study area, showing the three main structural features: The Interior rift zone, the External High, and the Exterior rift zone. The seaward-dipping basin faults are shown in red with the bp Bumerangue discovery well, shown by the black dot. The black dashed line is the location of the arbitrary line through the 3D model in Figure 3. The Florianopolis Fracture Zone separates the non-volcanic Santos, Campos, and Espirito Santo combined basin from the volcanic Pelotas Basin.

production per ANP. Based on our work with well data, a rough estimate for the Aptian contribution to this pre-salt total production would be 85 – 90 % at the present time.

In terms of exploration implications, the UEP map shows potential for oil discoveries in the southeastern extension of the External High in southern Santos, and along the Cabo Frio High in southern Campos. The large exploration block east of Bumerangue belongs to Equinor, which recently applied for three drilling permits. bp will drill an exploration well in the Tupinambá block (adjoining Bumerangue to the west) during 2026 and then drill the first field development well in Bumerangue before the end of 2026, per bp's VP of Exploration, Bryan Ritchie.

NEXT STEP: QUANTIFY SOURCE POTENTIAL AND SECONDARY MIGRATION

The most significant outcome of this 3D basin modelling is that not all oil found on the External High was locally expelled: There is significant migration up the flanks of the External High from the adjacent Interior and

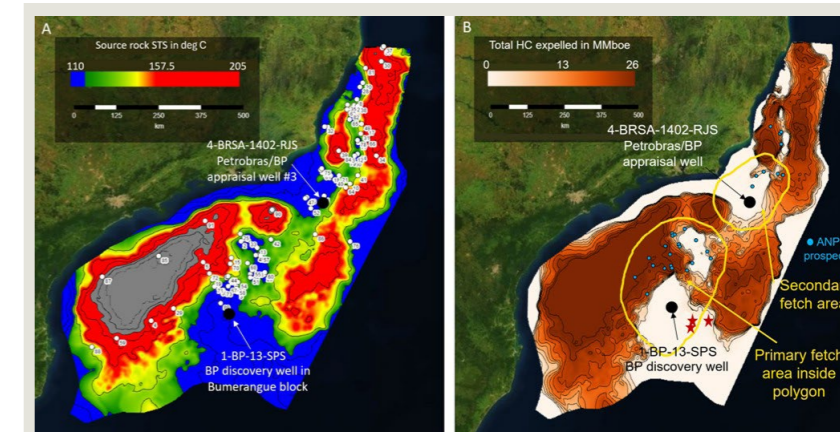


Figure 2A: An STS map of the pre-salt Aptian source rock penetrated at the 91 numbered well locations. The STS color bar is shown for a typical Organofacies C lacustrine kerogen: Blue indicating immaturity for oil expulsion, green indicating oil expulsion, yellow indicating the oil-to-gas transition, and red indicating the dry gas expulsion window. The bp discovery well 1-BP-13-SPS location is shown along the southeastward extension of the External High, as is the location of the third appraisal well 4-BRSA-1402-RJS for the Petrobras / bp consortium along the Cabo Frio High. Note that both oil wells are located within a predicted thermally immature area shown in blue. Also note that both immature areas shown in blue are located on structural highs surrounded by two oil expulsion kitchens, i.e., they require lateral migration.

Figure 2B: An intensity map showing the summation of the total oil and the total gas expelled (mmboc/km²) from the pre-salt Aptian source rock. The map provides a summary of the total oil and the total gas expelled for the fetch areas shown. Note the locations of the proposed Equinor drilling sites shown by the red stars.

Exterior rift zones, now confirmed by geochemical basin modelling.

Our ongoing work is to quantify lateral variation in source Ultimate Expellable Potential (UEP) within an evolving Cretaceous-Cenozoic paleo-

geographic context. These paleo UEP estimates will allow us to quantitatively address charge flux and migration losses to define effective lateral migration pathways to drilled and un-drilled prospects.

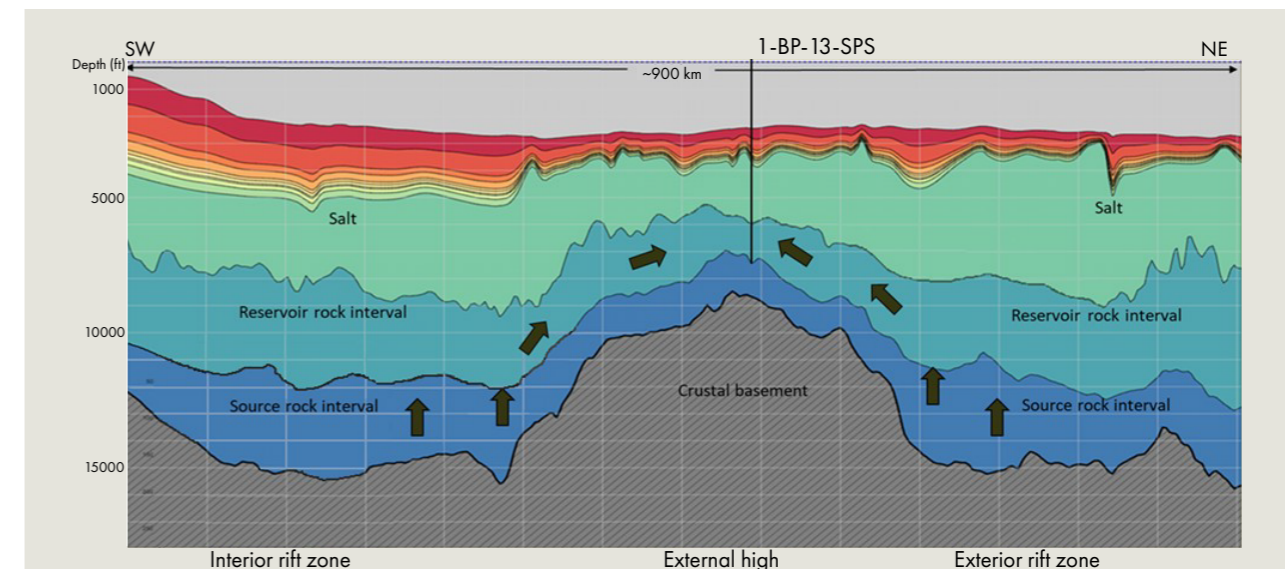


Figure 3: Arbitrary line through 3D basin model along strike, going from the Interior rift zone across the External High, passing through bp's discovery well 1-BP-13-SPS location, and then to the Exterior rift zone. The image is greatly exaggerated vertically: The depth scale is 18 km while the horizontal scale is 900 km. Black arrows indicate upward migration of oil from the Interior rift zone to the west and the Exterior rift zone to the east into potential reservoirs along the crest of the External High. Not shown are two major crustal faults extending from the basement up into the overlying salt, located approximately 50 km on either side of this well and the arbitrary line location (see Figure 1).

United Downs – it is too early to uncork the bottle

How a geothermal project turned into a lithium mining exercise and why all the celebrations around its start-up are a little premature

MAYBE IT IS because I am connected with Ryan Law on LinkedIn, but the number of posts about the success of the United Downs geothermal project was unstoppable for a good while. And it still continues. So many people and companies are celebrating the first energy delivered by this project, which has been in the making for such a long time. And yes, it is an achievement that the project finally got going after what must have been many hurdles to cross.

But to call this a success for the energy transition is too early in my view.

This project – which relies on the production of hot brines from a 5 km deep well drilled through a fault zone – has materialised because it was commissioned in a wealthy country where policy and decision makers care more about the green image of a project than the ratio between money invested and energy returned. There is no other way to see it.

In an interview with ThinkGeoEnergy, the CEO of Geothermal Engineering, Ryan Law, was quoted as saying, “Sometimes you have to act on instinct, not just on numbers”. I think this is not good advice, in this particular case. If there is no confidence in the **potential** to make money with your endeavour, the only way to explain the fact that it doesn’t collapse is that there are major subsidies involved. And that is the root of the problem straight away.

It is for a reason that the BBC, in their article about the project, wrote that even the British Geological Survey (BGS) is of the opinion that this project might be hard to repeat due to the high costs. And that while the BGS is otherwise a promoter of the use of geothermal energy.

Yet, the number of people celebrating its success, as well as the number of articles doing the same, is increasing steadily. Hardly anyone is asking the question: Is this all worth it?

IS IT WORTH IT?

Let’s start with the supposed 3 MW of electricity generation this deep geothermal project delivers. That’s very little for a project costing at least £50 M. As noted on LinkedIn, it is more expensive than nuclear power from one of the UK’s most costly reactors currently under construction – Hinkley Point C – at about £25 K per kW installed for United Downs versus roughly £13 K per kW for Hinkley Point.

Just using the 3 MWe output as a benchmark, I arrive at £17 M per MWe for United Downs, where Hinkley Point



The HAS Innovarig drilled the two wells for the United Downs geothermal project.

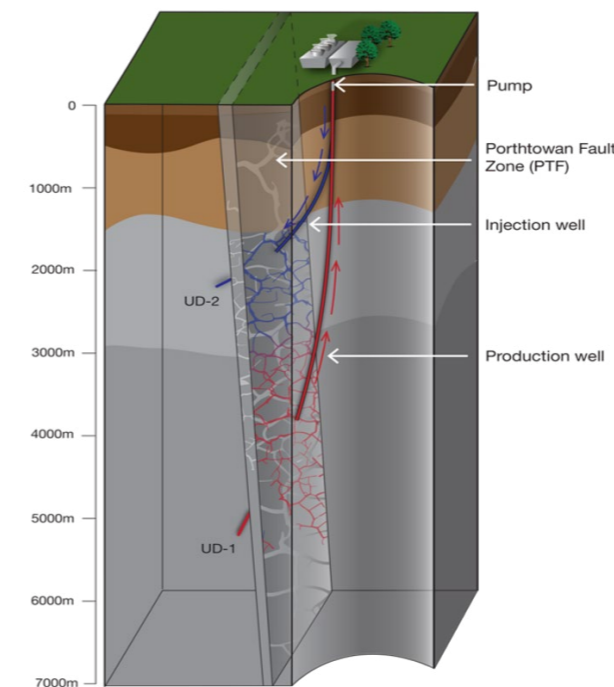
would be in the order of £15 M per MWe using the latest cost estimate of £50 B and an energy output of 3,200 MWe. And to prevent any confusion, Hinkley Point is being used as an example project for cost overruns.

To those who call this geothermal energy project baseload – wait until the SLB submersible pump breaks down. There is only one production well in the system, and a work-over is required to swap the pump. It is way too early to call this baseload energy.

On top of that, it is even questionable if the project actually makes 3 MW. Ryan Law seems very keen to talk to the media that agree to simply copy his claim that the project delivers 3 MW and powers 10,000 homes, but he did not respond to the various emails I sent in which I asked how much the project is actually delivering to the grid as we speak. Nor did his media team, who were responsive a while ago, until they told me about the failure of the ESP that I subsequently reported on. I have not heard from them since. Nor did the energy company – Octopus Energy – that is buying the electrons from United Downs, even when a representative initially seemed happy to engage.

And there are more reasons to assume United Downs is not delivering 3 MW. The contract for difference that the company was awarded only went up to 2 MWe. Also, in a recent presentation at the SPE’s Geothermal Conference in Aberdeen, Ryan Law said that the lithium mining exercise that is now associated with the project is much more lucrative than the electrons sold to the grid. Then there is the ESP. As Elliot Yearsley pointed out in one of his recent articles for GEO EXPRO, pumped geothermal projects sometimes consume around 20 % of the energy they produce. In other words, is the 3 MWe quoted taking that parasitic load into account? And in an article in the Financial Times (Camilla Hodgson, 26 Feb 2026), the author writes that “any excess energy” will be sold to Octopus following consumption by the lithium extraction process.

Of course, this is all just circumstantial evidence, but for me, the signs are there that the 3 MWe is only



SOURCE: GEOTHERMAL ENGINEERING

The concept of the United Downs geothermal project relies on production of 180° C brines from the deeper well and re-injection via the shallow well. Both wells penetrate the same sub-vertical fault zone.

an upper limit that could be achieved if everything lines up, and possibly when the lithium process would cease. Why would Ryan Law not be more forthcoming in replying to my enquiries if the plant produces as the press release states?

THE GEOTHERMAL TURNED LITHIUM PROJECT

Then there is the lithium aspect to this project. Let’s first realise that at the outset of the whole exercise, lithium was not in the picture at all. It was all about geothermal energy.

But then, lithium came along. The brines from the deep United Downs wells turned out to contain healthy concentrations (360 ppm) of the element for which the price has seen a steady rise since late last year. The project secured even more funding to build the extraction plant and now aims to produce up to 100 t of lithium carbonate per year.

Even though that is only a minor amount, given that Ryan Law himself confirmed that it is much more profitable than the energy sales, you can only imagine how pleased the team must have been when the lithium “discovery” was made.

With the price of lithium carbonate now hovering around \$23 K per tonne at the end of March, United Downs would make USD 2,3 M/yr with the currently stated production numbers.

WHY THIS PROJECT SHOULD BE LOOKED AT WITH CAUTION

In conclusion, it is my opinion that the United Downs project is yet another (partly) publicly funded project that should be perceived with caution rather than with too much of a celebratory tone.

If decision makers choose to continue supporting these projects, it is important to realise the sheer costs of it, and that the claim of baseload energy is only partly true. The geological risk, which I did not even discuss here, is also very high for a project of this cost. What about induced seismic events, what about cold water breakthrough, what about clogging up the fractures? In my view, the geological risks alone could already be prohibitive for an investment of this kind.

Proponents cite the advances in drilling technology and the associated cost reduction that can be realised. That is very true, and I want to keep an open mind to that. But so far, it must be stated that the project has not demonstrated that it can deliver energy in a cost-competitive way. Rather the contrary. It is therefore too early to open the champagne, the more so if you realise the effort required to arrive at just 3 MW. It took 15 years to reach this point. How long will it take for this to scale, given the unique geological setting?

Henk Kombrink

Morocco's oceanic crust – A new exploration paradigm

Modern Super-Regional profiles observing an entire margin are often difficult to procure as the emphasis in seismic acquisition is becoming increasingly focused on smaller scale high-definition 3D volumes. In margins where the expected success has not yet been realised, these large regional profiles can be particularly insightful. They offer new perspectives on petroleum system-controlling features that have an impact at scales far larger than can be resolved when examining a more localized, prospect specific, 3D. Geox MCG's regional 2D seismic survey offshore Morocco provides an opportunity to conduct such an analysis (Figure 1). Despite numerous wells in the proximal domain of the margin, the distal portion of the Morocco offshore, more specifically on oceanic crust, remains significantly underexplored. This regional long offset 2D provides significant insights into key locations for further exploration invoking an untested petroleum system that has been demonstrably active.

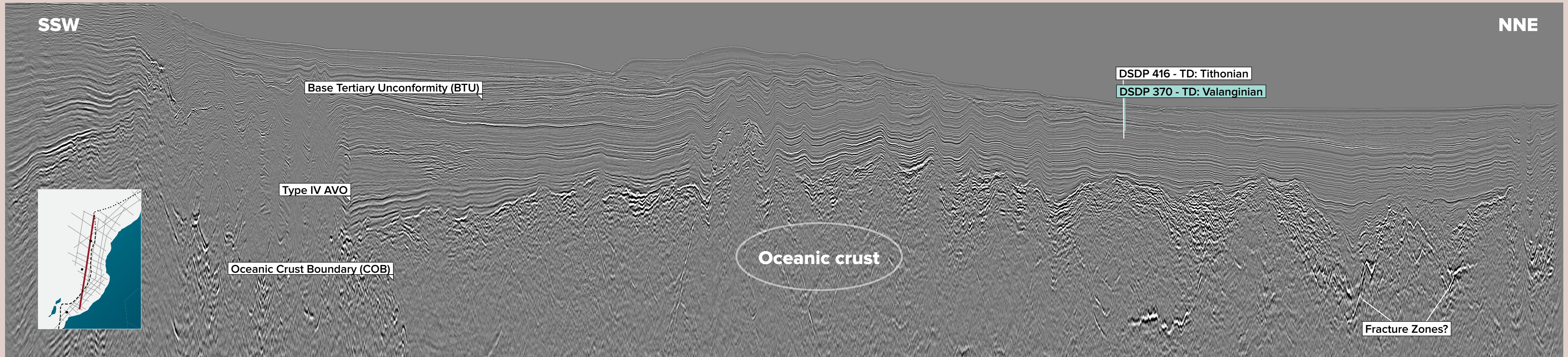
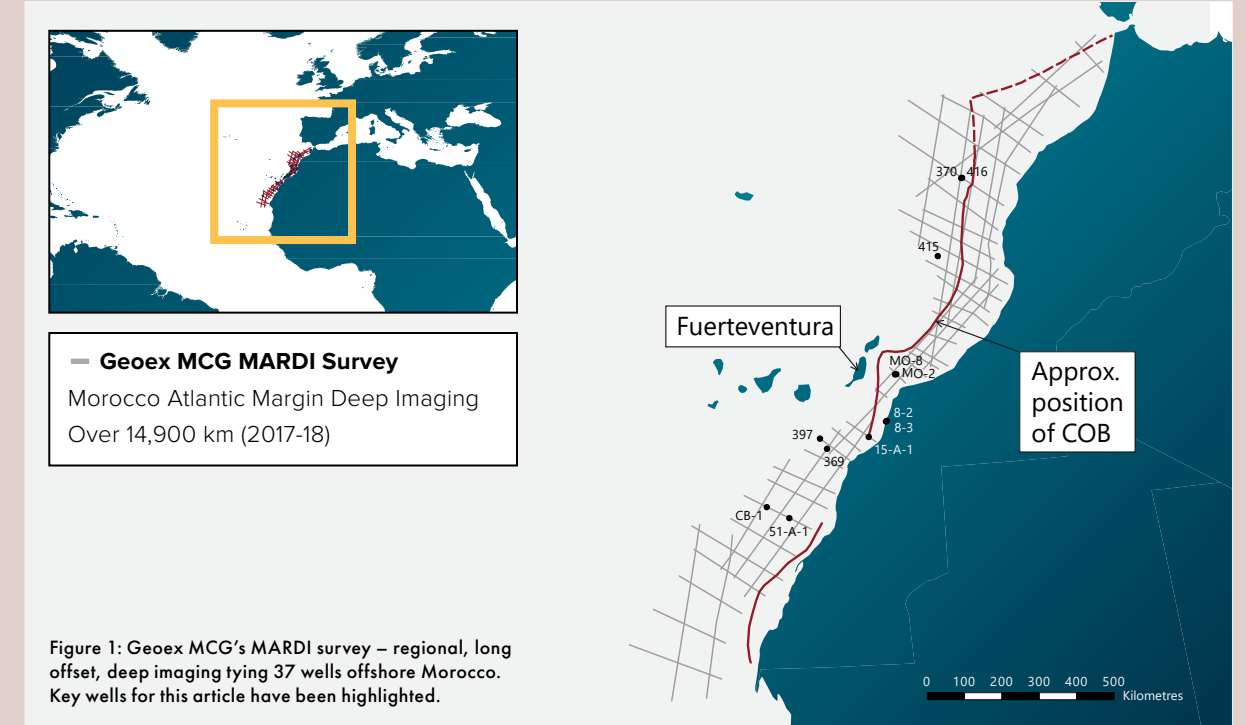


Figure 1: Regional profile in Morocco providing evidence of source rock maturity on oceanic crust.

Jurassic source rocks on oceanic crust – Establishing the new ‘hot’ topic offshore Morocco

MIKE POWNEY, GEOEX MCG

MOROCCO PROVIDING AN “IN-VOGUE” FRONTIER

Unequivocally, source rocks can generate significant quantities of hydrocarbons atop oceanic crust and therefore conventional thinking of where to explore for oil and gas has been challenged in recent years with numerous global locations now viable candidates for exploration. Prior to the discoveries in Namibia, the concept of mature source rocks on oceanic crust was often met with a degree of scepticism. Since these discoveries, there has been a willingness to explore deeper offshore with upside being provided by larger potential discoveries. As such the next Namibia “self-similar” prospect is being chased across the West African margin with evidence of working petroleum systems on oceanic crust being evaluated. One such location that provides this evidence in deeper waters, whilst still being frontier, is Morocco.

Using Geoex MCG’s Morocco Atlantic Regional Deep Imaging (MARDI) survey, a better understanding of the location of potential oceanic crust source rocks (OCSR) is afforded. This data can also be used to help determine potential thermal maturity from the plethora of wells tied by the data.

Thermal maturity understanding is furthered by the seismic profiles geographical location. Traversing the Continental to Oceanic Crust Boundary (COB), analysis of the crustal types present in Morocco, given its long-offset nature, can

subsequently lead to the identification, generation and evaluation of leads and prospects associated with the deeper offshore section of the margin.

THE ROCKS RULE THE ROOST

Exploration in Morocco has seen a series of wells drilled on continental / transitional crust with a Cretaceous source rock perceived as the most likely candidate to charge reservoirs sufficiently. Unfortunately, despite numerous promising results, namely Spansah 51-A-1, CB-1, Alisio 15-1 and MO-2/-8 etc., commercial quantities have yet to be discovered. Therefore, a new perception of the petroleum system is required to fulfil the evident potential. This article illustrates that this innovation takes the form of investigating deeper into the stratigraphy onto oceanic crust towards significantly underexplored territory.

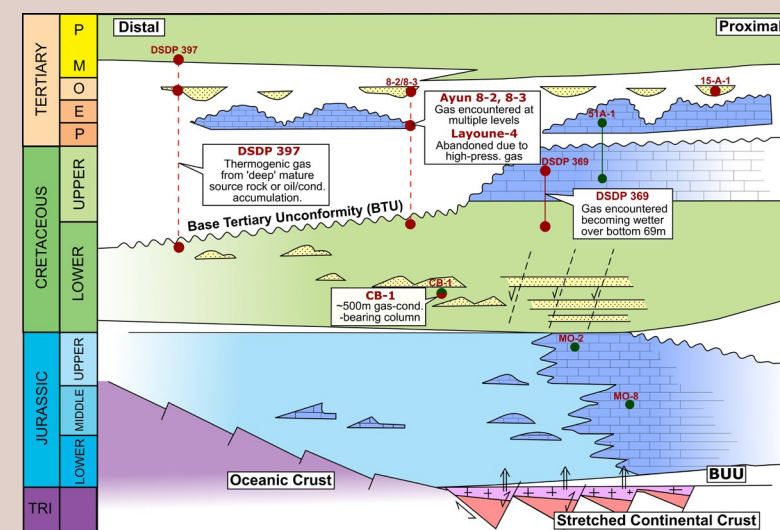


Figure 2: Outline of the existing known hydrocarbon encounters offshore Morocco.

To prove that OCSR’s exist in the offshore demonstrable proof is required. In the offshore realm of Morocco, DSDP 397 provides unique insight into this potential. This corehole encountered thermogenic gas whilst drilling, providing a strong indication that source rocks in the offshore have a good level of maturity. As is well-established; to generate thermogenic gas, organic rich source rocks are required to be within a temperature window of ~120-200 degrees. This exists offshore Morocco providing significant evidence of a deeper source rock. Additionally, the MZ-1 well, drilled in 2015, is reported to have encountered Lower Jurassic organic rich mudstones in the lower sections. This further demonstrates the potential for a Jurassic petroleum system along the Moroccan margin. The understanding of encountered ORI’s are summarised in Figure 2.

BIGGER PICTURE EXPLORATION – IMPLEMENTING REGIONAL IDEAS FOR LOCALISED SUCCESS

Evaluating how the required maturity was generated within the margin is a poignant ‘piece of the puzzle’ which requires a regional perspective. Geoex MCG’s MARDI dataset covers a total of approximately 15,000 km, tying a total of 36 wells constituting both DSDP coreholes and industry wells. The regional nature of the survey is best demonstrated by large strike lines which, in some instances, are greater than 700 km along the north and south of Morocco. By interpreting this data, widescale regional tectonics can be evaluated providing insights of the tectonic setting.

A poignant feature of the seismic is the unconformity marking the transition between the Cretaceous & Paleogene intervals, termed “the Base Tertiary Unconformity” (BTU). This interval can be mapped on a regional basis throughout the seismic data. The causation of this large unconformity is understood to mark the initial, and subsequent pulses of collision between Eurasia and Africa providing the necessary uplift on a regional scale to create a distinct feature on the regional data. Lack of recognition of a feature such as this could be possible when reviewing smaller, more localised 3D volumes which would subsequently result in an underestimation of maturity levels and the misinterpretation of the timings of optimum hydrocarbon expulsion, migration and charge in the deep basin. The proposed system is outlined in Figure 2.

To fully understand the implications of this unconformity on the thermal maturity, AFTA (Apatite Fission Track Analysis) and VR (Vitrinite Reflectance) data was procured from DSDP coreholes above and below the unconformity. Following the results and re-working of the biostratigraphy, it became clear that the missing section was significant.

In the DSDP coreholes, ~30Ma of missing section was observed and, in some locations, even greater time hiatuses were encountered measuring

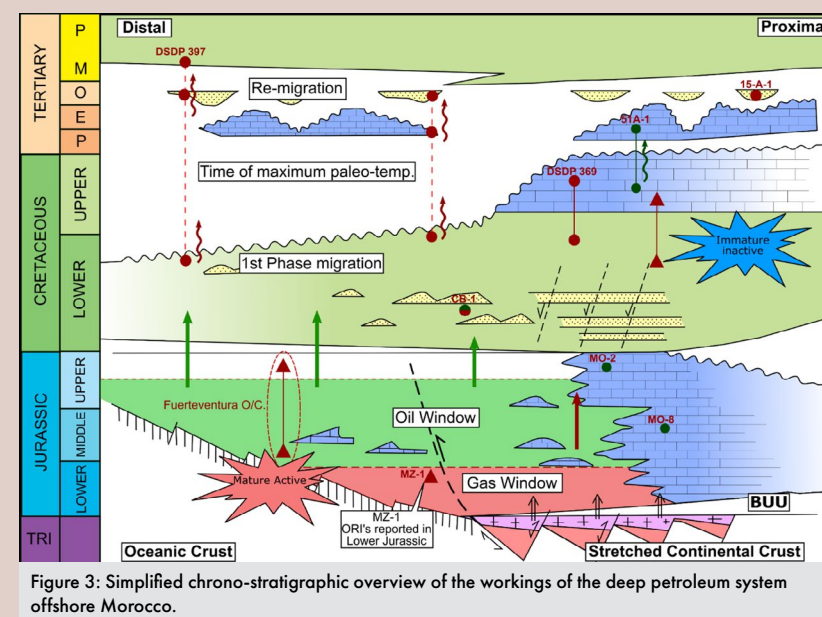


Figure 3: Simplified chrono-stratigraphic overview of the workings of the deep petroleum system offshore Morocco.

at ~100Ma. Furthermore, AFTA and VR results indicate that the intervals below the BTU were hotter in the past compared to present day when evaluated against a continuous geothermal gradient. This has positive implications for source rock maturity on oceanic crust offshore Morocco whereby the Jurassic system was active prior to the uplift and creation of the BTU.

Geoex MCG then extrapolated the relevant temperature data to understand the locations whereby Jurassic source rock material may have developed on oceanic crust. One such area is shown in the respective foldout. Here type IV AVO responses, often considered to demonstrate the presence of source rocks, are present within the Jurassic. This is clearly on oceanic crust; highlighted by the presence of the COB, the cessation of the associated salt bodies and the rugose nature of the crust.

With source rocks in the Jurassic somewhat established, further consideration regarding how these source rocks have positively contributed to the petroleum system is evaluated. Given the evidence presented in this article, particularly by DSDP 397, Tertiary reservoirs can only be charged by hydrocarbons re-migrating from deeper accumulations. This is evidenced in the form of DHI’s that indicate hydrocarbons are seeping across the BTU and charging

Tertiary reservoirs where available (termed re-migration on Figure 3).

PATHWAY TO THE NEW FRONTIER – HE WHO DARES, WINS

Whilst the Cretaceous petroleum system in Morocco has been tested by several wells, there is yet to be a significant hydrocarbon discovery other than that of Chariot in the very north of Morocco. Most of the historical exploration has focused on the Cretaceous petroleum system following the provision of encouragement through technical success / shows in the basin. However, it is apparent that new innovative thinking is required to start exploring deeper into the basin, invoking a Jurassic source rock. To do this, large regional profiles provide excellent insight into the large-scale processes that are potentially missed when reviewing smaller 3D volumes. In Morocco, these regional profiles have provided excellent insight into the potential workings of the petroleum system over oceanic crust which remains significantly underexplored and requires further insights and drilling to evaluate the full potential. This reflects an excellent and unique opportunity for those operators wishing to delve deeper into the offshore with much of the southern acreage in Morocco currently open and more importantly, on oceanic crust.

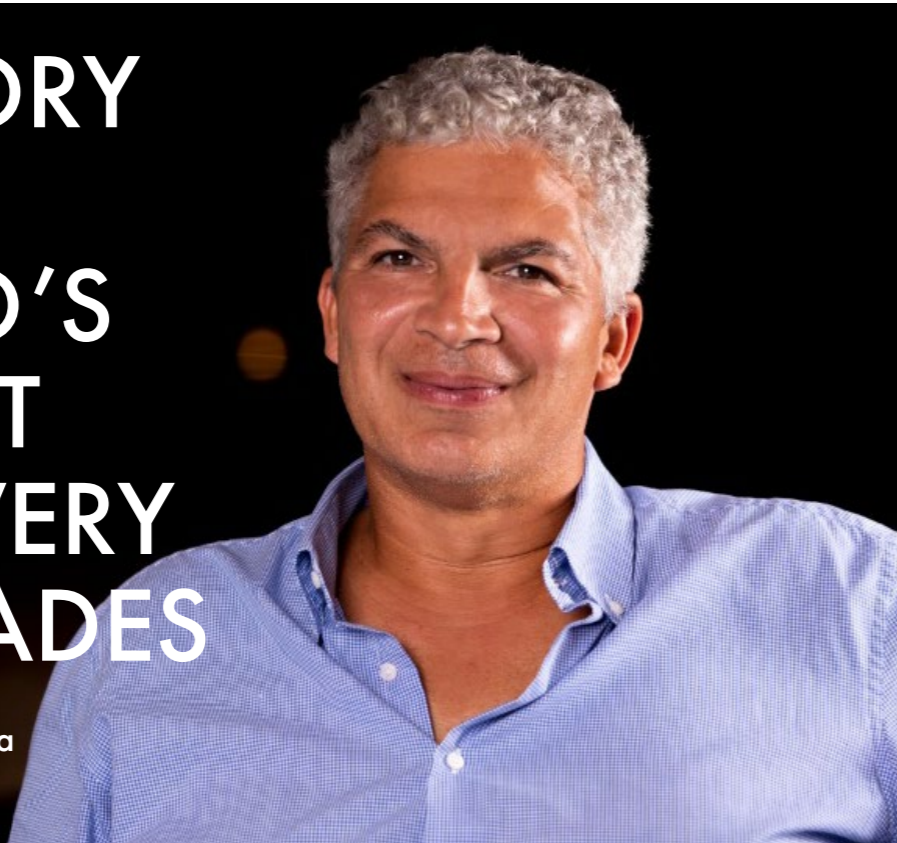
PORTRAITS

“In this industry, you need to have something that sets you apart from the rest. It’s one of the foundations of successful entrepreneurship and winning as a business. With Mexico, I was convinced that I was in the right place”

Ivan Sandra

THE STORY BEHIND MEXICO'S BIGGEST DISCOVERY IN DECADES

The story of Ivan Andrea
HENK KOMBRINK



WHAT DOES IT take to make the biggest discovery a country has seen in decades? How do you do that as a newcomer? You do that because you see things coming. Because you are prepared. Because you did the groundwork first.

All these things led to the discovery of Zama in 2017. And which company made that discovery? Not one of the majors. It was a small outfit called Sierra Oil and Gas. How did they win the block, and how did they manage to raise the capital to drill the well?

That's the story Ivan Andrea, the founder and CEO of Sierra, will share in this interview. A story that starts in Venezuela, takes us to colder climes in Norway, Vienna and London, but ultimately leads to Mexico, where Ivan still lives today.

It is a story of the power of data, the power of networks, and the power of being a first mover. That's the returning themes of Ivan Andrea's career as a Geoscientist, as an Explorer, as a CEO and as an Author.

THE START – VENEZUELA

"I grew up in Venezuela in a family of petroleum experts," says Ivan. "My dad, Rafael Andrea, was and continues to be a prominent figure in the industry. But also my sister, as she stood at the foundations of Jason Geosystems in the Netherlands."

Initially, Ivan embarked on a mechanical engineering course at Baylor University in Texas in 1993. But when he was told to prepare a talk on a subject of choice, he decided to do it about the Orinoco Delta, a mighty river he loves. "Why don't you go and study geology?" his professor asked. "I switched," says Ivan, "and I never looked back."

And whilst still studying, Ivan had an experience that he drew upon for the rest of his career. "I worked as a summer intern at Petroleum Information in Houston, the predecessor of IHS," he says, "when Venezuela was opening up as a country to foreign investment. I saw how an intelligence company was getting ready for it, as well as my own family members, with my dad and sister being heavily involved."

Soon it was his own turn, as Ivan moved straight back to his home country after finishing his bachelor's degree in Geology in Texas. He was quick in securing a job with bp, as the company saw opportunities in the country, especially after the success it had in neighbouring Colombia.

"All bp's top explorers and leaders were in Venezuela," Ivan says, "and I had the opportunity to work on regional screening of the entire country, as well as drill the very first exploration well by the private sector in Venezuela since the apertura."

"It was a crazy time," says Ivan, who also realised that he benefited from being Venezuelan and having a network that was working for him. "One day," he says, "I was sent to Maturin to present our well programme to the government to obtain the drilling permit. There I was, as a 23-year-old, surrounded by all these bp senior people who were flown in to help make the case to get these wells approved. When the door opened for the meeting, the government director who was sitting there turned out

to be the godfather of my brother and a close friend of my dad!"

The surprise on the faces of all the bp people was clearly visible, and the rest of the meeting went in a much more informal way whilst Ivan presented the technical case for drilling the first well on the Guarapiche block. A few weeks later, we got the go-ahead," he laughs.

LEARNING THE ROPES OF FINANCE IN OIL

By his mid-twenties, Ivan had already been recognised as being a potential leader, as he was selected as part of bp's class of recruits to follow a special trajectory within the company. As such, Ivan moved to Norway in 1997, where he was part of the team discovering the giant Ormen Lange field. A year later, he moved back to Venezuela, where he continued his job with bp.

Following a Master's and MBA programme in Edinburgh, as well as another international project for bp in Egypt, Ivan saw himself moving to London in 2001 when a global oil recession had impacted his career prospects in the industry.

"I moved into investment banking with Meryl Lynch," he says, "where I became part of the equity research group doing the upstream models of European companies, including deepwater oil and gas investments." That's where he learned that data forms the backbone of financing, a lesson that would stay with him throughout his subsequent endeavours.

At Meryl Lynch, he led the technical research and production models for major European companies. It was also the start of a series of publications about insights into the top-50 global deepwater projects. "It wasn't very common in those days," Ivan says, "but for me, it was second nature as I had seen my dad working on databases for Venezuela all the time."

Apart from databases, another important thing Ivan learned during those years in banking was to interact with people from outside the financial world. "My life has revolved around explaining technical information to non-technical people," he says.

In that capacity, he also invited the secretary-general of OPEC, who happened to be a Venezuelan, Alvaro Silva Calderon, to come to London to give a talk. And so he did, in 2004.

These invites also turned out to be good for Ivan's personal career, as a few months after the talk, he got a call from OPEC, asking him to apply for the role of head of oil supply. It made him move to Vienna in 2005. "It was amazing," he says, as he was to find out about a true turning point in the industry.

THE ONSET OF SHALE

"In May 2006, I reported to the OPEC research team that the decline of onshore US production had stopped," Ivan says. "In the years prior, the decline used to be around 0.5 MMbbl/yr."

The team wondered why this was happening; are they drilling more strip-per wells, or is there something else at play here? It turned out to be the very beginning of the shale revolution. No one was talking about this at the time yet.

"When I included in my monthly report that the growth of non-OPEC supply was going to ramp up by MMbbl/d, it caused astonishment and turmoil to the OPEC research team and the Economic Board," Ivan says.

But it did not result in an immediate reaction from OPEC countries, as Ivan's team also saw that China was ramping up its oil imports to fuel the country's economic expansion at the time. Rather than putting measures in to try and regain market share, Ivan was asked to build a database on OPEC spare capacity expansion plans. An interesting task given what was unfolding in the USA.

Around 2007, Ivan's position at OPEC became complicated. In Venezuela, Hugo Chávez was becoming more extreme in the pursuit of his communist agenda, and being the highest-ranking Venezuelan in OPEC, whilst not a supporter of the regime, it was time for him to move on.

Ivan became the head of international upstream strategy and business development at Statoil, now Equinor. The

company he joined was still very much focused on the North Sea, and had drilled around 300 dry wells in the area over a period of ten years. Something needed to change, whilst Ivan also noted that there were no geoscientists in the top leadership team. "There was a sentiment that we needed to capture reserves and we needed to grow," says Ivan.

As such, Statoil was the first company to embark on an international joint venture in shale gas, besides moving to Canada, Brazil and the Gulf of Mexico at the same time. "Trust me," Ivan says, "there was a desire to move into many more international opportunities, including Turkmenistan for example. My team's role was to scrutinise these opportunities using a data-grounded approach and make sure that we didn't touch the white elephants out there."

But was shale a bit of a white elephant in the end as well? "I now believe that shale is a good reserve machine," says Ivan, "but it's not the money machine that we might have expected it to be." Statoil divested most of its shale assets again, maintaining only a small non-operated share in the Marcellus shale.

"What I also pushed in those years was deepwater exploration," says Ivan. "Remember, apart from the deepwater hotspots like Angola, Brazil, the GOM and Nigeria, there was no real driver yet to explore more deepwater regions. Instead, companies focused on the Arctic at the time; that's where many expected the next wave was going to be."

In 2008, something else happened that would shape Ivan's career. Statoil sent him to Mexico to evaluate opportunities to enter the country. Even though it was too early to make the move – the country had not opened up sufficiently – he made some observations that proved to be critical for what would unfold just a few years later.

"I saw that most international oil companies thought that Mexico would open up through Pemex," he says. "All of them had people in the country signing MoUs with the state oil company. But even at that time, years before the country really opened its doors for foreign ▶

PHOTOGRAPHY: IVAN SANDREA PRIVATE ARCHIVE

investment, I realised that was not the way to do it.”

Before we get to how Ivan would do it instead, there is one more episode in his career that is also worth sharing because it helps us understand why he had success in Mexico later.

THE MIDWIFE OF OPEC

In the summer of 2011, Ivan made another interesting career move. He was asked to become the CEO of Energy Intelligence. And that is an interesting fact, because the roots of the company go back to Wanda Jablonski, the journalist who single-handedly established Petroleum Weekly, the publication that was read by everybody in the industry who wanted to stay informed about oil developments. In fact, it was Wanda Jablonski who played an instrumental role in bringing the people together who were at the basis of the formation of OPEC.

“It was my first experiment as an entrepreneur working with investors, in an environment I was very much at home in, surrounded by data and analytical tools,” says Ivan.

“Another thing I really focused on in my role was to boost Energy Intelligence’s competitor intelligence service and country risk,” Ivan continues. It did not take long before it turned out that these things would become very useful in what was to unfold.

It was 2012. Where Mexico was still very much closed for opportunities four years earlier, when Ivan went there with Statoil, now he clearly got a sense that things were moving. “It made me decide to become more serious about it,” he says. It also meant that he decided to leave his role at Energy Intelligence and started to gradually embark on the adventure that led to the discovery of Zama in 2017.

BUILDING UP THE PICTURE

It was a bold move for sure, but Ivan had done his own competitor analysis. “I knew that the country was still completely dominated by Pemex, and I also knew that even abroad, nobody had the knowledge that would enable them to move faster than I would do,” he says.



Ivan Sandrea and his dad, Rafael Sandrea, with the drill bit used for the Zama discovery well.

And Ivan had another advantage. His dad, Rafael Sandrea was an established figure in Mexico as the founder of the petroleum engineering graduate programme at UNAM University in Mexico City. In other words, he had name recognition, and it came with a few ways to build connections in the country. Connections that did not rely on a relationship with Pemex.

Ivan started in a way that was familiar to him now. With the help of some people he involved in his venture, he started building databases and knowledge. Not through Pemex, but through academic work such as scouting through doctoral theses, PhD dissertations and publications.

Initially, Ivan wasn’t sure that he would start an oil company himself. He was also playing with the idea of marketing his Mexico database to potential newcomers once the country announced the first licensing round.

But no matter how his work was going to be used, Ivan was convinced of its competitive advantage, also because he had seen the value of data not only in his previous positions in London, but also in Venezuela when the Apertura unfolded just as he started with bp. And this was a position he wanted to be in.

“In this industry, you need to have something that sets you apart from the rest,” Ivan says. “It’s one of the founda-

tions of successful entrepreneurship and winning as a business. With Mexico, I was convinced that I was in the right place.”

And he knew people who could help him. Mark Shann, his life-long business partner, had already spent time in Mexico for bp. Ivan also enjoyed the support of two people who had just retired from the industry in Mexico and had proven to be real explorers and geoscientists: Raoul Gonzalez and Mario Limon. They were happy to fill Ivan in, especially through the stories they shared.

So for about a year, whilst he still had a job with EY in London, Ivan managed to build an overall picture of the petroleum geology in Mexico with the help of all these people. Then, by December 2013, when the momentum behind the country’s opening up increased further, he decided to go for it more seriously. He started contacting some investors.

Initially, this wasn’t met with a lot of enthusiasm. “Why do you need to do all this research?” was the question he received multiple times. Others were telling him it was too early. Yet, he managed to raise a bit of funding, which kept his small project going.

FROM A MILLION TO A BILLION

Then, as 2014 arrived, and his team had grown to around twelve people by

springtime, Ivan was invited by the Encap Fund in Houston. After presenting his case, he was asked how much money he needed. “Around 3 million,” he said. “What if we give you 500 million?” they replied.

Once back in London, Ivan went to meet his investor friends at the Riverstone Fund, and they recommended him to talk to Jim Hackett, the former boss of Anadarko, who also worked for Riverstone. So a week later, Ivan flew back to Houston and met with Jim, who immediately invited him to come to New York to meet the Riverstone leadership team.

To cut a long story short, following his visit to New York, Ivan had secured 1 B in capital, with an equal amount provided by the two funds he had been talking to. By that time, the financial foundation for the company was in place, so in September that year, Ivan and 15 others signed the paperwork that heralded the official start of Sierra Oil and Gas.

But let’s be clear. Even by that time, still nobody had an idea yet how and when Mexico was going to open up.

THE LEADING INDEPENDENT

Ivan laughs when he shares the tagline of Sierra: Mexico’s leading independent. “Of course,” he says, “there was no independence yet, so what were we leading?” But regardless, the company rapidly grew to around 25 people during the second half of 2014, just in time as things really started happening.

When it became clear that the opening was going to be organised in early 2015, Ivan had already started to talk to potential partners, and found those in Talos and Glencore. “However,” he says, “it was the start of the downturn, and some companies got into financial trouble. Glencore was one of them, and they pulled out.”

Sierra needed a partner like Glencore, because one of the requirements for a valid bid was to have one partner with a balance sheet of 1 B. Talos only had 20,000 bbl/d of production; Sierra had none.

“So, within a month of the bid submission date, we had to find a new partner to replace Glencore,” Ivan says. “It was probably one of the most stressful periods of my career.” But, he managed and brought in Premier Oil, whilst Sierra maintained leadership and the largest share in the partnership.

Ivan handed in the bid himself, after having spent the night in a “secret” hotel to minimise the risk of getting intercepted. The team prepared two versions: One fake and one real. When he arrived at the office where he needed to hand over the documents, he found himself surrounded by the major companies that were there to do the same: Statoil, ENI, Hunt Oil and ONGC.

But what happened? Sierra became the winner of the only two blocks awarded during that first round, outbidding Statoil by just 1 %. It was a big moment, because finally, Ivan could justify the company’s tagline: The leading independent.

COMPETITOR ANALYSIS

What made Sierra’s bid the winning bid? “The process was very transparent,” says Ivan. “It was a combination of a minimum work programme as well as the royalties and government take we would offer.”

“Let’s go back to the time we had to produce the bid, and remind ourselves that oil prices were very low. That’s why our competing bidders offered a low government take of around 40 %. We offered 68 % instead, whereas Statoil offered 65 %.”

“We even went as far as hiring game theory specialists to better understand and anticipate how our competitors were going to bid for the blocks. My background in competitor analysis also came in very handy. We knew that some companies were more inclined to drill wells than to commit to government take,” Ivan explains.

Statoil was not happy with Sierra winning the Zama block, especially because they were outbid by just a few points. They also had identified the flat spot at Zama, which ENI had also done.

Ivan heard that Statoil even started conversations with the government, arguing that Sierra was not capable of carrying the burden of the partnership, and made the case that a big international operator should do it instead.

THE REAL KICK-OFF

Once the team had won Block 7, in which they had identified the Zama prospect, the moment to buy all the subsurface data they could get their hands on to be ready for future rounds had arrived.

At the same time, people at the ministry called in to the office to enquire who Sierra Oil and Gas actually were. “At the end of the day,” says Ivan, “even though we were the leading independent now, we were still small for international standards.”

Together with Talos and Premier Oil, Zama-1 was drilled in 2017. It was a major discovery, with around 2 billion barrels of oil in place and an estimated 800 MMbo recoverable. And that with the first ever offshore well drilled by an independent company in Mexican waters in 70 years.

“Apart from the flat spot in the seismic, it also demonstrated that it paid off to focus on the shallow water area first, instead of moving into deepwater straight away,” says Ivan. It was a huge moment for the company, the partnership, and the country of Mexico.

“We had a party every time we won acreage in the five licensing rounds we participated in,” says Ivan. “But you can imagine the atmosphere during the party that followed the discovery of Zama was something that will stay with me forever.”

And Sierra did more. “We drilled ten exploration and appraisal wells with a 67 % success rate,” says Ivan. “80 % of the discoveries made in the last ten years were made in the acreage Sierra originally owned.”

“And why did Pemex not drill Zama before, given the flat spot in the seismic?” I ask. “Because Pemex does not drill flat spots,” says Ivan. “The state oil company drilled 14 dry holes in the Zama area before we came in.” ▶

PHOTOGRAPHY: IVAN SANDREA PRIVATE ARCHIVE

“Pemex is not a typical exploration company,” Ivan continues. “The company outsources seismic interpretation to service companies and outsources drilling to service companies. If Pemex was a good explorer, they would not be in the situation they are in today. They drill wells, but they are not explorers, that’s the best way to summarise it.”

The decision not to wait for Pemex until the opening was announced in 2015 was a crucial one. “In fact, says Ivan, “until today I have never had a formal meeting with Pemex. Sure, I meet them at conferences, and have nothing against the people working there, but there was no need to “partner” with them to learn where the sweetspots were. In fact, I’d say it was even better not to listen to them because it would take you on their line of thinking, which is not very much exploration-driven.”

“Pulling together the data ourselves was the best thing we could have done,” Ivan continues. “And write about it. Because that was another major surprise. In a country with a 100-year history of oil and gas exploration, there was no book available about the petroleum geology. So we decided to do it ourselves. We kept it short, but it covered the basics. How come Venezuela had thousands of books when the Apertura happened in the 1990s, but there was nothing of quality in Mexico? It is a question that still puzzles me.”

AFTER ZAMA

What happened after the Zama discovery? “We had created value, now it was about managing that,” says Ivan. As the political mood was shifting again in favour of a more nationalistic approach, the funds backing Sierra were getting a little bit concerned. What if something like Venezuela would happen? They started to test the water for buyers in 2018 and ultimately sold the entire Company in 2019 to DEA, who had been scouting around for acreage in the country for a while.

But there is another side to the success of Sierra, too. Ivan is open about that. As the company got established, he ended up in hospital due to a stress-related illness. In addition, he and his partner separated and

continued to live in different parts of the world. “Building a business often comes at a significant personal cost,” says Ivan, “and I am no exception to that.”

But the sale of Sierra did not mean Ivan took a back seat. In fact, he continued to use his talent for finding opportunities and investments, this time investing in Caribx, an exploration company with a large offshore license in Honduras and joined the board of Havfram, a Norwegian offshore service company that was looking to convert itself into an offshore wind business during the pandemic. “Nobody wanted to do oil and gas investments for a few years,” says Ivan, “so the timing was right to venture into wind. I helped secure an investor with \$800 million for them, shared the leadership team, and then left that business again.”

Ivan’s spell in wind was relatively short-lived. He always kept an eye on oil and gas, and in 2022 founded Westlawn Americas Offshore (WAO) with interests in Brazil, GoM, and Peru with private capital. During his leadership, WAO, deployed over \$1.5 B in offshore assets and is now an important non OP partner to several companies including Oxy, Chevron, Brava and Beacon.

One of the most exciting things Ivan is currently working on is Honduras, where he bought some acreage in 2020. “It was a licence Shell divested when they bought BG,” says Ivan. “We’re about to farm out soon, after which we’ll hopefully embark on a massive exploration drive there, on a scale that nobody has done in the country yet. I think of Honduras as having the potential to be the next Suriname or a mini Guyana.”

In addition, Ivan also reveals he is working on something big in Latin America, and has raised over \$2.5 B for it. What that will be, we have to be a little bit patient, but now knowing Ivan’s skills and eye for opportunities, it will certainly be interesting to keep an eye on what he is going to pull off.

THE AUTHOR

“I write every day,” Ivan says at the end of our conversation. “Memos to myself and papers that I don’t finish.”

“I’m also working on a manuscript called The Next Wave, as I want to put down my thoughts on how this industry is moving forward and will keep on producing 100 MMbbl/d for decades to come.”

“A shift from public to private ownership in the industry is probably going to be an important part of that, including a shift from accountants running the companies to more engineers and geoscientists. We also need more entrepreneurship and leadership willing to take risks, and willing to drill wells and explore.”

“Today, that is all very hard. The share price goes down as soon as you announce you’ll drill a well, because it means you’ll spend money. What I see is that there are a lot of good companies out there, but their value is a fraction of what they actually represent,” Ivan says.

Is the wave of privatisation already happening? “Yes, see for instance Carlyle and ADNOC wanting to privatise Santos. But it’s not many,” he admits, mentioning that he is only aware of one company in Europe, as well as Continental in the US, where the owner, Harald Hamm, took the company private. But there are not many who dare to do it.”

Consolidation is what we see in Norway, in the GoM, in Canada. Everywhere, the number of companies operating in these well-established petroleum plays has come down significantly, as take-overs are seen as a way to expand the reserve base.

“Of course, it is an expression of the level of maturity in these areas,” says Ivan, “but even more so, it is an expression of the lack of balls to go out there and find yet another Johan Sverdrup.”

That’s why Ivan is a strong supporter of the return of the risk-taking but yet well-informed explorer.

He shows me the drill bit that was used for the Zama discovery well. It is on display in his house in Mexico, like a genuine museum piece with a glass cover on top. Will we see more drill bits ending up in this room over the next few years? I’m sure that Ivan is planning on doing so. ■

GEO THERMAL ENERGY

“Sometimes we even have to hoist the rig over a building just to reach the drilling location”

Ryan Gatherer – Geothermal Drilling Service

World's largest geothermal reserves?

The Fervo Cape Station Enhanced Geothermal Systems (EGS) project in Utah has cited a "reserves report" by a petroleum consultant that claims that the project can support over 5 GW of development. This would make it by far the largest geothermal project in the world. But how likely is this? Based on public domain information, Elliot Yearsley analyses the situation

ELLIOT YEARSLEY

BY CONVENTION, geothermal reserves are reported as net recoverable energy – usually as Megawatts of electrical generating power (MWe) – for a specified period of time. It is also helpful to state the assumed capacity factor, the time the plant is operating at installed capacity. Finally, the internal power requirement or parasitic load is a key aspect; this is approximately 5 % for many operating plants, but pumped well projects typically require 20-25 %. EGS projects would likely require an even higher parasitic load.

Guidelines for the estimation of geothermal reserves are outlined in a number of reporting codes, including the Australian Geothermal Reporting Code (2010). The Australian code mimics the SPE Petroleum Resources Management System (PRMS) in key ways, including the distinction

between resources and reserves. Importantly, reserves require that *deliverability must have been demonstrated*. Typically, demonstrating deliverability requires either production history or well testing that establishes stable flow rates, which has not been convincingly shown for Cape Station.

THE CAPE STATION RESERVES REPORT

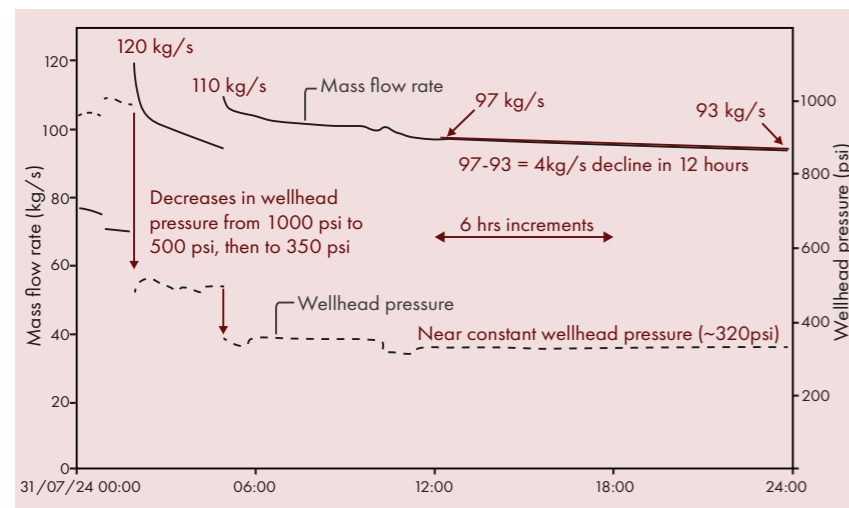
Fervo refer to a reserves report obtained from Degolyer and MacNaughton (D&M), which D&M state is in accordance with the SPE-PRMS. In that case, they would be aware of the difference between reserves and resources; the former require that production comes from *commercially established* technology, whereas resources are potentially recoverable and can come from unproven production technology. It's difficult to see how the

reserves criteria could have been met for Cape Station prior to commercial production. D&M may have been convinced by Fervo's project in Nevada, which is advertised as a "commercial scale demonstration". But there is no production history for that project in the public domain, and it is shown by Fervo to deliver only about 2 MWe (net), or less.

D&M use the heat-in-place method, also known as stored heat, and state that Fervo's enhanced geothermal system "successfully unlocks thermal recovery factors ranging from 50 to 60 %, tripling the amount of useful thermal energy reserves compared to conventional geothermal technology". For context, and a cautionary tale, a useful summary of conventional geothermal recovery factors comes from Malcom Grant, who found that recovery factors depend strongly on the definition of volume. For a wide definition of volume, i.e. one that includes undeveloped areas, Grant found that the average recovery factor was only about 5 %.

RAISING QUESTIONS

The Cape Station reserves report raises an important question on the use of the term reserves, which does not seem to fit the project. Until the advertised power sales are demonstrated and production history is available, the more speculative term resources may be more appropriate. The magnitude is also in question, relying on a recovery factor 10 times higher than previously documented recovery factors. ■



24 hours of production data provided by Fervo, red font annotated by Elliot Yearsley.

Slim is smart

Why smaller boreholes are a big win for shallow geothermal

"WHY DRILL 150 mm when 120 mm will do?" That simple question sparked an ongoing discussion between Bruce and his son Ryan Gatherer. Bruce has spent more than 35 years in the drilling industry and now works for Iceland Drilling, travelling the world to drill deep geothermal wells for power production. Ryan followed a different path – into the world of shallow geothermal in the Netherlands with Geothermal Drilling Service – but the dinner table conversations are often related to drilling challenges and optimisation. Lately, they've focused on one thing: Going slimmer.

"Every job I do is different," Ryan says. He operates a compact two-tonne drilling rig designed for tight access projects – often in small residential backyards. "This isn't a large construction site where you can easily move a 15 t rig and manage cuttings without constraints," he says. "Sometimes we even have to hoist the rig over a building just to reach the drilling location. Everything is bespoke – from access to cutting removal."

Working in confined spaces forces careful planning and efficiency, and reducing borehole diameter is very much part of that.

SLIMMER MEANS SMARTER – BUT NOT EASIER

Cost efficiency is always a consideration. But as Ryan emphasises, smaller doesn't mean simpler. "The slimmer the hole, the more critical borehole stability becomes."

The Dutch shallow subsurface is full of sandy, water-bearing and unconsolidated formations. These are highly prone to collapse, with margins for error shrinking as the diameter of the hole decreases. That's where discipline in drilling fluid preparation becomes essential.

Like many contractors, Ryan relies on bentonite-based drilling mud to stabilise the borehole. "It acts like wallpaper," he explains. "It lines the borehole wall, limits sediment movement, and helps prevent collapse due to its slightly higher density than the groundwater."

But the real difference lies in preparation. "Mixing bentonite properly takes patience. It's like wallpaper paste – it needs time to fully hydrate. If you rush it, the fluid doesn't have the viscosity or cohesion required. It can simply disappear into permeable formations before it's ready to do its job."

Waiting for full hydration improves fluid performance dramatically, particularly in slim holes where hydraulic margins are tighter and fluid loss is less forgiving. Through careful fluid management and continuous optimisation, Ryan has now successfully drilled 120 mm boreholes to 150 m, capable of accommodating two 32 mm geothermal loops.

"Some people didn't believe it was possible," he says. "But it works." ■

The benefits are immediate: Less ground cuttings, reduced grout volume, smaller environmental footprint thanks to faster drilling and improved site logistics. And critically, proper grouting remains easier to control when volumes are optimised, reducing the risk of crossflow between water-bearing layers.

Reducing borehole diameter by 30 mm may seem incremental, but it results in a reduction of waste production from 2.65 m³ to only 1.70 m³. In practice, it represents a meaningful step toward smarter, leaner shallow geothermal installations.

"It requires planning, it demands patience and also depends on fluid discipline. But when done properly, slimmer truly is smarter," concludes Ryan. And sometimes, innovation starts with a simple question from dad. ■

Henk Kombrink



Drilling rig on a driveway for two boreholes with a diameter of 120 mm and 150 m deep. Here, we're using a vibrating screen to collect all the drilling soil in big bags.

PHOTOGRAPHY: RYAN GATHERER

The critical role of cement

And other learnings from the Geretsried deep closed-loop geothermal system in Germany

IN JANUARY this year, during a presentation at the Canadian Energy Geoscience Association (CEGA), Eavor’s VP Drilling Performance, Mark Hodder, shared some insights on the drilling aspects of the Geretsried deep geothermal project in southern Germany. For me, this was the first opportunity to hear from Eavor about this project directly.

The most important learning, at least that’s what I took home from attending the talk, was about the quality of the cement used to fill the annulus between the liner and the formation at the point in the well where the twelve loops – which later became six – were to be drilled.

This aspect of the project turned out to be critical when it came to the time it took to drill the laterals. The cement had to prevent drilling fluids from flowing through the already completed loop once drilling of the next one had started.

A whipstock and a packer were used to enable kicking off the sidetrack for each loop and hydraulically seal off the liner itself, respectively. The cement was supposed to form the outer barrier between the formation and the liner. As it turned out, the quality of the cement was not sufficient, as Hodder explained. This resulted in fluid communication between the two boreholes once the milling of the liners had been completed for the second loop.

SHUTTING DOWN OPERATIONS

As a result of this, Eavor was forced to shut down operations on one rig whilst drilling with the other, and vice versa. Therefore, drilling times per lateral almost doubled. “Next time we will need better cement,” concluded Hodder.

During the Q&A, someone in the audience asked why Eavor decided to

use a liner and not place a packer in the open hole to seal off the first loop. According to Hodder, there was not enough confidence in the integrity of the formation – an Upper Jurassic tight carbonate succession – to be able to do this properly. Borehole instability issues experienced in the first loop may have been the rationale behind that line of thinking.

Namely, in contrast to what previous wells drilled in the area suggested, the Geretsried wells suffered from borehole stability issues. It led to stuck pipe on multiple occasions, with the associated delays and re-drilling of one of the lateral sections.

Based on these observations, it is now increasingly clear why it has taken Eavor so long to complete the six loops that are now in production. The average number of days for each of the first four laterals was 108 days, whilst the last two laterals could be drilled in 54 days each, thanks to optimising bits and oth-

The Geretsried deep geothermal project originally entailed the drilling of four sets of twelve closed loops, thereby forming a giant radiator in the subsurface. The first set of closed loops has now been completed, but with only six loops instead of twelve. The energy produced from this first system amounts to 0.5 MWe. We published an account of that in GEO EXPRO Vol. 23, Issue 1, 2026 of the magazine, concluding that this level of energy production seriously questions the validity of the investment.

er parameters. Hodder expects that once the cement is of better quality and simultaneous drilling is allowed again, around three weeks should be possible per lateral, meaning a reduction of 80 % compared to the first four laterals. ■

Henk Kombrink



The Geretsried geothermal drilling site.

PHOTOGRAPHY: EAVOR

SUBSURFACE STORAGE

“I sometimes feel that the CO₂ storage business is not so much about putting CO₂ in the ground, but rather to keep an entire academic research community, conference industry, and a contingent of geoscientists in a job”

Henk Kombrink

Carbon capture and mineralisation pilots in the Middle East

Carbon storage is most commonly thought of as pumping supercritical CO₂ into depleted hydrocarbon reservoirs. However, it is also possible to mineralise carbon in (ultra)mafic rocks in the subsurface. Tech company 44.01 has been conducting multiple pilot tests in the United Arab Emirates and Oman

44.01 NAMED their company after the mass of the molecule that is central to their business: Carbon Dioxide. They use CO₂ captured from industry or the atmosphere and dissolve it in water to create a carbonated injection fluid, a kind of sparkling water. The fluid is injected deep underground, where it dissolves minerals within mafic or ultramafic rock. This creates an ion-rich fluid that spreads through the existing fracture network while the captured CO₂ reacts and mineralises to carbonate.

44.01 first trialled this concept in Oman; they injected CO₂ captured at an ammonia plant into peridotite at 100 to 400 m depth. Monitoring the composition of the injected solution demonstrated that 88 % of the CO₂ was mineralised as carbonate within 45 days of injection.

Of course, this raises the question of whether the newly precipitated minerals will clog up fluid pathways, thus preventing further injection. Interestingly, because carbonation of peridotite

results in a volume increase, this could conveniently cause fracturing or so called 'reaction-driven cracking'. This process increases permeability and leads to the exposure of fresh reaction surfaces, enhancing further mineralisation.

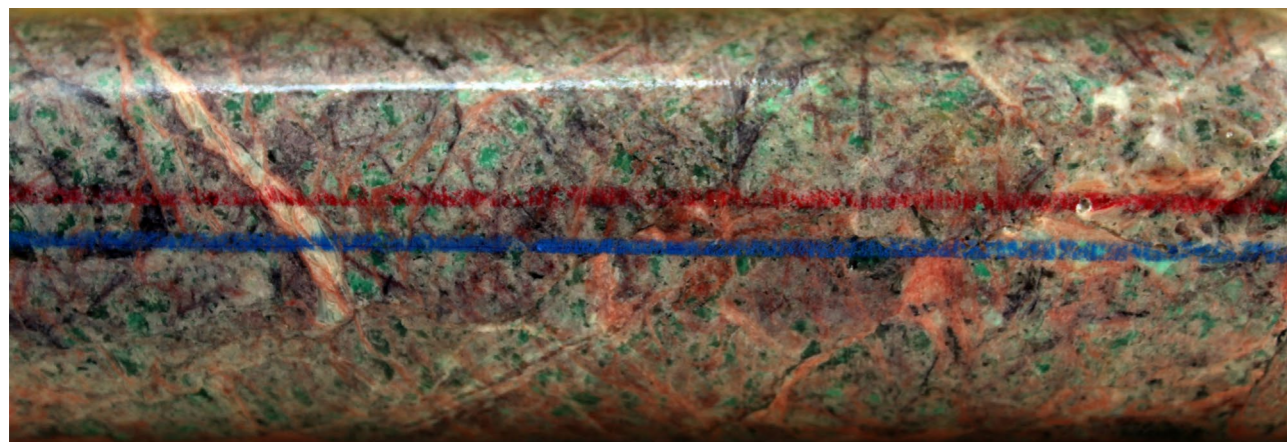
However, it is yet to be seen which process, precipitation or cracking, will dominate during injection on an industrial scale. It does seem likely that additional permeability enhancement, such as fracking, will be needed to accommodate injection rates.

A second test site is located in Fujairah. During the initial stage, direct air-captured CO₂ was mixed with seawater and injected into peridotite. This resulted in the mineralisation of approximately 10 t of CO₂. Now 44.01 has teamed up with its first industrial customer, Holcim, with the plan to inject CO₂ captured from cement production. 44.01 has started injecting at a rate of 5 t/day and hopes to increase to 20 t/day. The borehole has an estimated CO₂ capacity of 25,000 t/year.

Carbon capture and mineralisation (CCM) mimics the natural process of silicate rock weathering. It entails the conversion of CO₂ to carbonate minerals via fluid-rock reactions. The process is an accelerated version of surface weathering due to elevated subsurface temperatures and an increased CO₂ concentration. During the carbonation process, atoms of magnesium and calcium in olivine and pyroxene combine with CO₂ to form secondary carbonate minerals such as magnesite and calcite, permanently locking CO₂ in the subsurface.

The Fujairah project will generate essential data on techno-economics, injection performance and long-term storage validation, insights that will guide 44.01's future commercial-scale projects.

Mariël Reitsma



Drill core sample of carbonated peridotite (Listwanite) from the Samail ophiolite in northern Oman.

PHOTOGRAPHY: DIORIT VIA WIKIMEDIA COMMONS



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The subsurface is a key factor in explaining the poor result of the recent Danish CCS tender

With the majority of applicants dropping out at the last minute, the combination of stringent rules, penalties and subsurface uncertainty proved too much of a hurdle for most potential candidates, even when a fund of €4 B awaits

DENMARK IS one of the countries that aims to be a leader when it comes to climate change mitigation measures. That's why the government launched a tender process in October 2024 for businesses to apply for a juicy pot of €4 B to fund carbon capture and storage projects.

The idea was to have a competitive tendering process, hoping that companies would submit equally competitive bids, thus driving down the costs of the individual project plans.

The tender process seemed to attract interest, with 16 companies applying to be prequalified, and 10 ultimately qualified to tender. But as the deadline was approaching, one after the other dropped out, to the point where only one company remained. Why did that happen?

Apparently, the imposed timelines for development of the chosen projects were so strict that applicants did not see this work. Penalties were introduced, too, which provided further reason for companies to withdraw.

From a government point of view, it can be understood that there is a desire to put a deadline on projects relying on subsidies in order to justify the spending.

But the reality of CO₂ storage site screening, validation and construction has been proven to take longer than two years, as previous cases have shown. In the UK, some have been on the go for a decade and have still not progressed to FDP.

"We tried to stop this process at the very start," someone with knowledge on the matter told me during a phone conversation, "because we could see the time and money being lost on pro-

posals that were ultimately not going to be submitted."

And that's exactly what has now happened. At the last minute, just before the round closed in February this year, a second bidder came in, preventing just one being submitted, but the result was a lot poorer than expected at the start.

The website of the Danish Energy Authority lists the revisions in the tender documents that were made following initial criticism of the imposed timelines. More flexibility was introduced to make a change in plans if a site turned out to be unsuitable. It was also allowed not to proceed with development at all, following a detailed geological assessment.

But it was either too late or the rules were still too stringent. The Danish CCS tender process is now regarded as a failure.

Is there the possibility that the CO₂ will be carried abroad when the process to look for a site in Denmark itself is so challenging? "There are no criteria in the tender to use Danish storage sites," writes Tobias Johan Sørensen from the Danish organisation CONCITO in an email to us. The evaluation is strictly 80 % costs and 20 % project maturity, with maturity obviously dragging the Danish sites down compared to Northern Lights, for example. However, Aalborg Portland (one of the submitters) has publicly stated that they are aiming for the CO₂ storage to take place onshore Denmark."

The outcome of the tender process will be announced in April. ■

Henk Kombrink

PHOTOGRAPHY: JULIAN HACKER VIA PIXABAY



A Danish land- and seascape.

The CCS parallel universe

Yes, some projects are progressing, but there also seems to be a lot of inertia in getting CCS projects off the ground. In the meantime, an entire community has been built around what seems like the hope that things will really take off

SOMETIMES, I cannot prevent the feeling that the CO₂ storage business is not so much about putting CO₂ in the ground, but rather to keep an entire academic research community, a conference industry, and a contingent of geoscientists in a job.

When it comes to academia, I see professors winning grants to do research that they previously funded through sponsorship from oil companies. Now, they carry on basically doing the same thing through a CO₂ storage potential justification. It also begs the question of how independent and innovative academia actually is these days. All this research seems rather like following the money.

Is academia to blame for that? I don't think so. In my eyes, the blame is the decline in public funding without any strings attached. As a society, we have to put back some trust in

researchers to come up with genuine research topics, even ones where we don't see the immediate benefit.

"In the other parallel world, there are the fancy conference rooms and students with poster tubes around their shoulders, all hoping for a future in which they will earn their pennies on the back of projects that ultimately go ahead"

Then on to the events industry. Every well-respected society has started to put CO₂ storage events, webinars, talks, you name it, on the agenda. Especially since many of the traditional oil industry exhibitions have decreased in size, I am quite sure that professional societies see the CO₂

storage sector as a way to compensate for the loss in revenue now that SLB doesn't buy the multi-story stands at conferences any longer. Except maybe at ADIPEC.

But, I also see a certain fatigue in the CCS events creeping in. And that is no surprise; how long can you sustain holding talks without there being a new tangible project to report on?

There are many geoscientists who have capitalised on the wave of CO₂ storage plans in recent years. That came at the right time, as so many traditional oil and gas jobs seem to have been lost. I remember hearing a colleague say, "I have extracted carbon for all my career, now it is time to put it back". He has now retired, and even though he spent a fair few years in the CCS business, not a single tonne was injected whilst he was there.

Two parallel universes have thus been created; one in which people continue to work on supplying the world with grey but useful energy. People who are often silent on social media. In the other parallel world, there are the fancy conference rooms and students with poster tubes around their shoulders, all hoping for a future in which they will earn their pennies on the back of projects that ultimately go ahead. But the reality so far seems a lot more stubborn.

I do think that we are already on our way back to more realism, though. The industry has become more vocal about what its ultimate core business is. That does not mean that CCS should be abandoned altogether, but I hope that the hype will wear off a bit. ■

Henk Kombrink

ILLUSTRATION: LUNAVERA ART VIA ADOBE STOCK





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SEABED MINERALS

“With polymetallic nodules, the environmental impact is less than that of terrestrial mining, which can require blasting, tunnelling, overburden removal, and large amounts of fresh water. Instead, seabed nodules are simply collected from the seafloor”

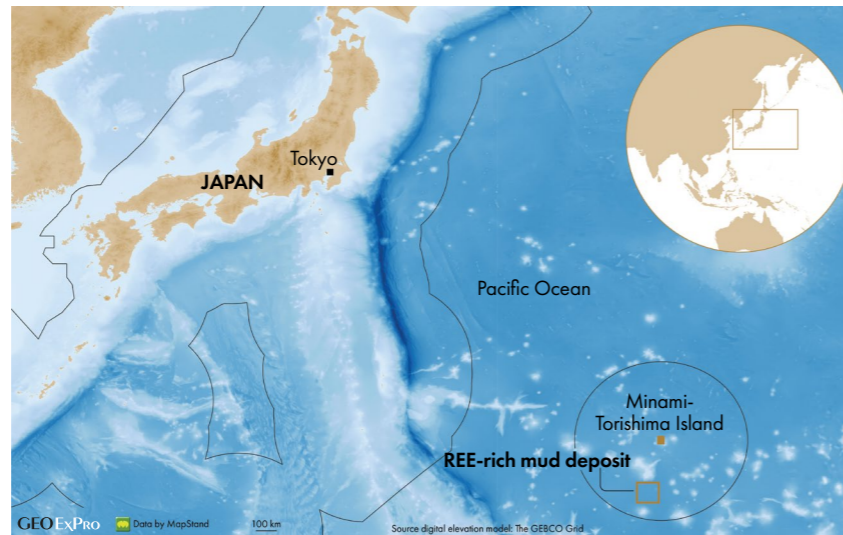
James Deckelman – Deep Sea Minerals

Japan retrieves rare-earth-rich mud from 6,000 m in deep-sea's first

A Japanese test mission has lifted REE-rich mud from the seabed off Minami-Torishima, showing that such deep-sea deposits can be accessed. The samples will now be analyzed, and further trials are needed before commercial extraction can be considered

JAPAN HAS successfully retrieved sediment containing rare earth elements (REE) from the seabed off Minami-Torishima Island in the Pacific Ocean, some 1,900 km south-east of Tokyo.

At nearly 6,000 m below the sea surface, the mission marked the world's first test recovery of rare-earth-rich deep-sea muds at such depths. First identified by the Japan Agency for Marine-Earth Science and Technology (JAMSTEC) in 2013, this deposit could provide Japan with a stable, long-term supply of REEs critical to its high-tech, energy, and defence industries.



THE DEPOSIT

The Minami-Torishima deposit lies entirely within Japan's exclusive economic zone (EEZ), which simplifies legal and regulatory issues compared to international waters. Early estimates suggest that the deposit may contain 16 Mt of REE oxides. The most promising area (102 km²) and the uppermost 10 m of the mud could yield 1.2 Mt of REE oxide, potentially meeting global demand for yttrium, europium, terbium, and dysprosium for decades.

Core samples obtained during the initial deep-sea research cruise demonstrated total REE grades up to 0.5 %, comparable to many terrestrial deposits. Separation and selective processing could enhance the resource's economic value by increasing the grade in the lifted mud.

The mud itself is geologically unique. REE-rich muds in the Pacific, like those near Minami-Torishima, contain fish-bone debris composed of biogenic calcium phosphate, which

accumulates REEs from seawater. Low sedimentation rates and high biological productivity have contributed to the formation of thick, REE-enriched layers. The mud represents a distinct fourth type of deep-sea mineral resource, alongside nodules, massive sulfides, and polymetallic crusts.

A CHALLENGING UNDERTAKING

The REE-rich muds targeted in this project have the consistency of clay and cannot be scraped or dredged like harder deep-sea deposits. Japanese engineers are developing a "subsea factory" system: Machinery placed on the seafloor mixes the mud with seawater, mills it into fine particles, and pumps it as a slurry through reinforced riser pipes to the surface.

Building pipes capable of reaching nearly 6,000 m while withstanding immense pressure, abrasion, and constant stress is a significant engineering challenge. On the seabed, machinery must function reliably in near total darkness

and extreme pressure to agitate and feed the mud into the riser. Early development work has also highlighted that underlying sediment layers are weaker than expected, which could complicate operations.

Refining rare earths from the complex mud mixture is a separate challenge. Japan's refining infrastructure needs to be adapted and expanded to handle future output.

If the lab analysis yields positive results, the project partners aim to initiate trial operations in January 2027, using a system capable of extracting 350 tons of mud per day. For now, the January 2026 mission represents a significant proof-of-concept, demonstrating that rare-earth-rich mud can be accessed and recovered from extreme ocean depths. The results place Japan at the forefront of developing deep-sea mining concepts and technologies, even when cost-effective extraction and processing is yet to be proven. ■

Ronny Setså

The benefits of being a second mover

A conversation with James Deckelman, CEO of Deep Sea Minerals, about how his company is reaping the benefits of research and development carried out in the seabed minerals space and how it is now moving ahead quickly as opportunities open up

"I WAS IN OIL and gas for most of my career," says James Deckelman, the CEO of Deep Sea Minerals, when we meet online. "And the opportunities I have had in that sector are amazing. But when I was approached with a new opportunity last year, I did not think long. There is now tremendous movement in the critical minerals space, unprecedented support from the US Government, and progress being made within the International Seabed Authority."

So this is a time of great importance to the seabed mineral industry.

"We recognise that companies such as The Metals Company (TMC) have paved the way for this industry through significant capital investment in environmental studies, exploration, test mining, and processing pilots," says James. "At Deep Sea Minerals Corporation, we can benefit from this and other work using a second-mover advantage."

"Apart from TMC, we are the only other publicly-traded company in this space," continues James. "We offer investors a low entry threshold with significant upside, low volatility, little dilution, and no debt to serve." Deep Sea Minerals Corporation was established in 2022 and is listed on the Canadian Securities Exchange.

"We have two licence applications in preparation," says James. "One is through the NOAA framework in the Pacific Ocean's Clarion-Clipperton Zone, which we expect to have filed by the time this magazine goes to print. The other application is in the Cook Islands, within the Islands' Exclusive Economic Zone. We are also studying other opportunities, including those in American Samoa."

The company is pursuing polymetallic nodules exclusively. "Polymetallic nodules have been studied for decades, as well as environmentally responsible ways to recover them. Multiple companies are working on harvesting technology now," says James. "With polymetallic nodules, the environmental impact is less than that of terrestrial mining, which can require cutting, blasting, tunnelling, overburden removal, large amounts of fresh water, and longer permitting times. Instead, the seabed nodules are simply collected, where they lie unattached to the seafloor."



James Deckelman.

"There is now tremendous movement in the critical minerals space, unprecedented support from the US Government, and progress being made within the International Seabed Authority"

Deep Sea Minerals is pursuing an asset-light model. "We don't intend to own our own vessels, and we will use equipment that is available to the industry as a whole," says James. "In the near term, processing will continue to take place abroad, but eventually in the USA, where defence, clean-energy, and data-centre demand is soaring. We have a long road ahead, but we can quickly capitalise on the technology that is being developed today and the groundwork that has been laid by our predecessors. We hope to deliver our first cargo of nodules in three to five years." ■

Henk Kombrink

Are sea cucumbers in a pickle?

The International Seabed Authority has wracked its brain over a fair and equitable mining code for years. Yet, it still can't make up its mind about the future of seabed mineral exploitation. In the meantime, a study shows that megafauna like sea cucumbers actually prefer to settle in the areas where the seabed is disturbed

IN MARCH this year, the International Seabed Authority (ISA) member states met and negotiated over two weeks in Kingston, Jamaica, to discuss the future of seabed mining. But yet again, the council concluded without adopting a mining code or approving seabed mining in international waters.

Major stumbling blocks during the negotiations were environmental concerns and establishing a model to distribute financial and other economic benefits among member states. The deep seabed is recognised by the UN as 'common heritage of humankind'; it is to be governed collectively and should not be dominated by those with the greatest financial or technological advantage.

The ISA council also raised concerns over the US's unilateral deci-

sion to potentially award exploitation licences to its nationals. The USA is not one of the 172 member states of ISA and seems willing to break international law to award recovery permits. The Metals Company (TMC) applied for such a permit, hoping to start commercially collecting polymetallic nodules in the Clarion-Clipperton Zone (CCZ) in the Pacific Ocean. Until now, TMC has been able to legally explore the CCZ thanks to a partnership with the Pacific Island countries of Nauru and Tonga. Both nations were granted exploration rights by the ISA.

As an ISA exploration contractor, TMC has collected a wealth of environmental data, which has been submitted to ISA's DeepData catalogue. The open-source database has been accessed and analysed by countless researchers to study the abyssal plain

ecosystems and the effects of deep-sea mining. This has resulted in a threefold increase in the number of new species described in the CCZ. Scientists estimate that more than 6,000-8,000 species are found in the region, around 90 % of which are yet to be described.

It is thanks to these studies that a better picture is being built of the environmental impact of nodule mining. And in contrast to what opponents might want, the results don't always look too gloomy. One study on the long-term impact and biological recovery of seabed damage due to nodule mining in the CCZ found that after four decades, organisms have begun to re-establish despite persistent physical changes to the seafloor.

Megafauna, such as sea cucumbers, had migrated 10 m from the disturbed seabed to the plume area, where sediment agitated during nodule collection resettles. In addition, significantly higher numbers of megafauna were found in the plume area than in the undisturbed area further away.

Despite these encouraging observations, the Deep Sea Conservation Coalition calls on governments to adopt a moratorium on deep-sea mining. So far, 40 countries have signed and are in support of at least a pause in mining activities until certain environmental conditions can be met. In other words, it seems the mining companies are in a pickle while sea cucumbers live their best life. ■

Mariël Reitsma

PHOTOGRAPHY: NOAA



Sea cucumber seen at 5,100 m depth on the abyssal sediment of the Clarion-Clipperton Zone. The animal is approximately 60 cm long.

NEW GAS

"To date, Gold Hydrogen carries only prospective hydrogen and helium resources in Ramsay and despite drilling four appraisal wells, has not upgraded any resources to contingent"

Arnout Everts – AEGEO

Until now, hydrogen exploration wells were drilled half-blind

Viacheslav Zgonnik and Jonathan Allard are putting an end to that as they developed software to model hydrogen generation, migration and trapping

THERE IS OFTEN an element of coincidence associated with how companies form. That also applies to how Viacheslav Zgonnik and Jonathan Allard from French tech start-up HyReveal came together two years ago.

While Viacheslav was drilling the first dedicated hydrogen exploration well in the USA, Jonathan, who had a position in an oil and gas exploration consultancy firm, got more and more intrigued about hydrogen exploration.

Jonathan therefore decided to get in touch with the company that was drilling the well in Nebraska, to enquire about the project. He also reached out to Viacheslav via LinkedIn, and only then did they realise that they were only 3 km from each other, in the Paris region.

“We realised that there is a lot of material already available in the oil and gas industry that we could use, but that needs to be adapted for the hydrogen

business,” explains Jonathan. “That was the main reason for us to form the company, to overcome the exploration pain points by smartly repurposing the concepts that are already out there for oil and gas.”

“I’m quite sure that the main pain points for most hydrogen exploration wells drilled so far are in the source rocks and the charge risk” – Jonathan Allard

“In short, our expert team is building a basin modelling toolbox for hydrogen exploration,” says Viacheslav. “Like in oil and gas, where you de-risk an area through modelling source rock maturity and charge, we are doing something similar for hydrogen.”

“Microbiology is a key factor that we needed to include,” says Jonathan, “because hydrogen is consumed in this

way. If you don’t include it, you therefore underestimate the risk of drilling a hydrogen prospect.”

At the same time, some building block elements are very similar to what “conventional” basin modelling software uses, such as horizons and faults, and burial history. Moreover, the solution HyReveal developed, called IORIGIN, also models hydrocarbons, but can do even more gases like helium, nitrogen, hydrogen sulphide or carbon dioxide.

One of the things that HyReveal is developing the software for is to create a link between surface hydrogen measurements and what is happening in the subsurface. Because often, surface samples are used to prove that there is a promise of finding hydrogen deeper down, but how valid is that? “That’s the question we want to answer using a model that predicts how hydrogen is being sourced and how it migrates to surface,” says Jonathan.

But how to make sure that the model is actually reproducing results that make sense? “That’s a key aspect indeed,” says Jonathan. “We reproduced the digital twin of published lab experiments simulating the different ways natural hydrogen forms. That way, we have a tuned model that is calibrated against published experiments. We also used the gas data from the well Viacheslav drilled in Nebraska to use as a calibration of our model. More case studies are ongoing.”

“I am convinced that we are only in the very first phase of hydrogen exploration,” concludes Viacheslav. “Years ago, we wondered if natural hydrogen exists. Now, we are slowly getting better at finding it, with the right tools.” ■

Henk Kombrink

PHOTOGRAPHY: HYREVEAL



HyReveal’s team. From left: Frederic Schneider, Maximilien Verdier-Paoletti, Viacheslav Zgonnik, Théo Hamadé, Nolwenn Simonot, Jonathan Allard and Dan Lévy.

Too early to declare a commercial success

Analysis of released well data from Gold Hydrogen’s flagship Ramsay project in Australia illustrates why its hydrogen resource is still classified as prospective

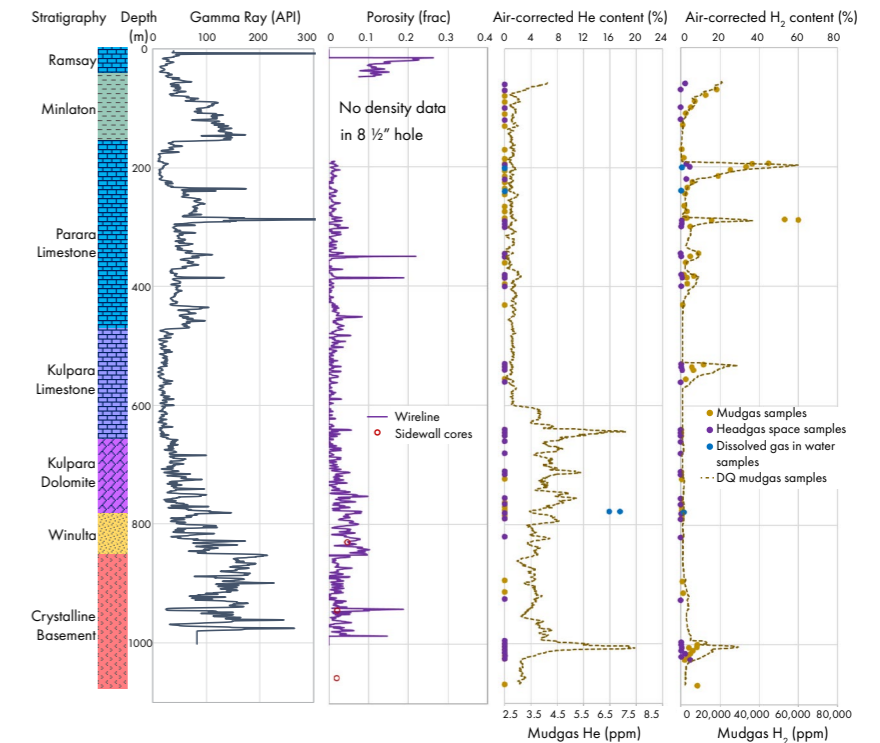
ARNOUT EVERTS, AEGEO

GOLD HYDROGEN holds an exploration license on the Yorke Peninsula of Southern Australia. The play concept assumes hydrogen generation in Proterozoic basement, with localised trapping in the overlying Cambrian sediments. As obvious structural closures are lacking, the gas is thought to reside in fracture systems or stratigraphic traps.

Ramsay-1 and Ramsay-2 are redrills of a 1931 well where “flammable gas”, later identified as hydrogen, was reported. Ramsay-1 suffered total losses whilst drilling most of the well. Ramsay-2, a redrill of Ramsay-1 to obtain better gas data, had only minor losses and predominantly good data.

Hydrogen and helium concentrations vary wildly. Mud gas data show localised hydrogen “spikes” up to 60 %, mostly in the shallower part of the Cambrian overburden. The helium datasets are inconsistent. Whilst real-time data suggests helium increases in the lower half of the Cambrian succession, this is not reflected in laboratory samples. However, water samples near the base of the Cambrian do contain 16-18 % dissolved helium.

The reasons for compositional variability are unclear. The fracture system could be poorly connected, with only some fracture clusters linked to the deeper source. Equally, residual and dissolved gas may not be in compositional equilibrium due to ongoing migration. Another explanation is that large corrections for sample contamination result in significant errors. Given this variability and interpretation ambiguity, it will be challenging to predict and target hydrogen and helium sweetspots in future wells.



Petrophysical and gas-composition analysis of Ramsay-2.

Wireline logs and the scarcity of valid MDT points suggest most of the Cambrian is tight. A hydrostatic pressure trend, with no indication of elevated pressures in any of the gas show intervals, suggests that the system is dominantly aqueous with minimal, if any, free gas.

Short flow tests were done using a downhole submersible pump. Statements by Gold Hydrogen that “some of the hydrogen and helium resources may co-exist with groundwater” and “exploration well testing is expected to require pumping groundwater from the geological formation” indicate the operator also concluded Ramsay is dominantly an aqueous system.

A Productivity Index (PI) of 34 bbl/day/psi and a gas-water-ratio (GWR) of 3.05 scf/bbl were reported for commingled flow from the

base Cambrian in Ramsay-1. Suggesting that at 500 psi drawdown, water production is 17,000 stb/d and 52 Mscf/d of solution gas. Assuming a helium content of 17.5 %, the maximum sampled yield might be around 3.3 MMscf/yr. Assuming a hydrogen content of 60 %, again the highest observed concentration, the yield would be 30 t/yr.

To date, Gold Hydrogen carries only prospective hydrogen and helium resources, despite drilling four appraisal wells. This suggests that Gold Hydrogen recognises that the Ramsay wells do not convincingly demonstrate commercial recovery potential for hydrogen and / or helium. To raise the prospects for commerciality, testing of Ramsay-3 and Ramsay-4 need to yield much better productivity and ideally, find some trapped free gas. ■

A helium prospect without a trap

Most helium is co-produced with natural gas, however Helium One demonstrates in Tanzania that a classic hydrocarbon play setting is not required

AFTER THE INITIAL hype of helium exploration in the Rukwa basin in Tanzania, things went quiet for 18 months. This is partially because Helium One's exploration permit expired, and they had to apply and wait for a mining licence for the next phase of their operations. No doubt a lot of work was done behind the scenes, but now things are moving again at the wellsite, too.

During the exploration campaign, it took Helium One multiple wells to get things right and discover the best play type to produce helium from. Thanks to well Itumbula West-1 (ITW-1), the company found that drilling straight into basement faults and the surrounding damage zones is the best approach. Quite simply, this is because helium uses the faults as migration pathways. Helium forms in the Pre-Cambrian basement as a by-product of radioactive decay. The elevated heat

flow provided by the upwelling mantle in the East African rift setting then liberates the helium from the uranium and thorium-bearing minerals, and it migrates up section. The helium subsequently accumulates in shallower aquifers, without there being a structural or stratigraphic trap. It eventually reaches the surface, as evidenced by salt ponds in the area with active seeps that contain up to 10.2 % helium.

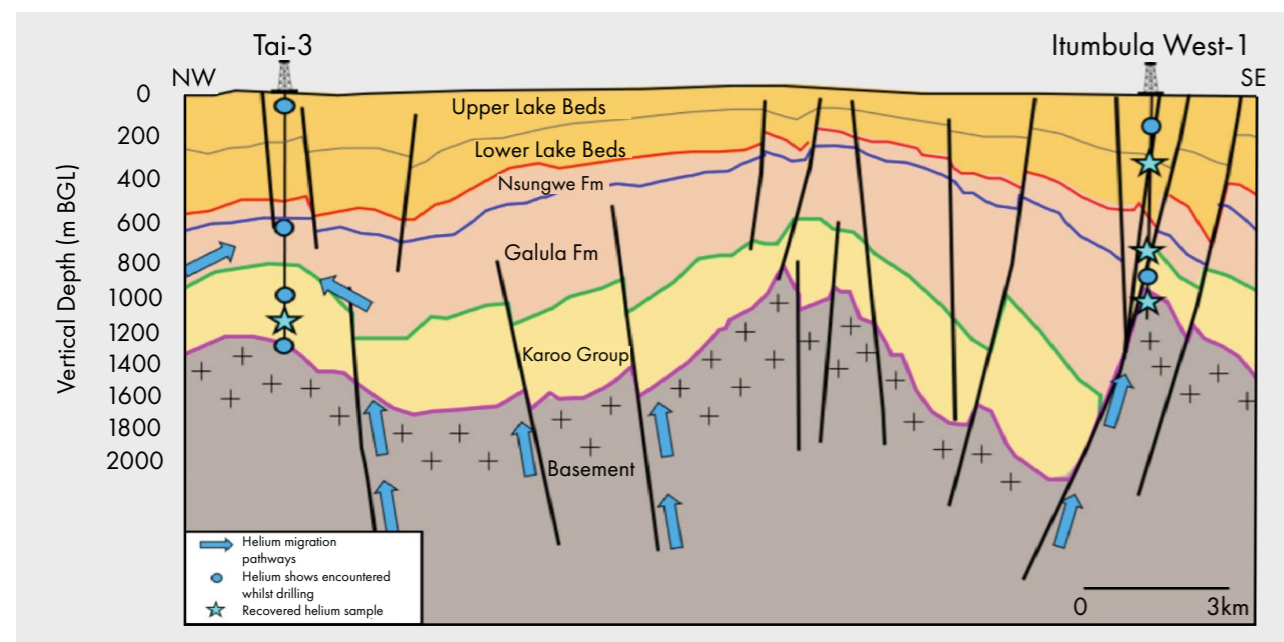
The Itumbula discovery is a fault-bounded basement horst with a thin sedimentary cover. ITW-1 tested two major faults and found helium in two aquifers: fluvial-deltaic sediments of the Karoo Formation and in weathered basement. Water samples from both aquifers contained over 5 % helium. Helium One is planning a five-well campaign to further appraise the area.

Helium One sourced an Electric Submersible Pump (ESP) to produce the basement aquifer. A 20-day test at the start of the year demonstrat-

ed a six-fold increase in flow rate to 15,000 bbls/day compared to the natural flow rate during the extended well test. The produced fluid had a Gas-Water ratio (GWR) of 0.06 m³/m³. The ESP was set at 1,061 m MD within the fractured basement, with a packer in the lowermost Karoo Fm to reduce comingled flow. However, the 90° C water temperature and measured salinity suggest basement isolation was not fully achieved. The contribution of the Karoo aquifer is thought to have lowered the GWR.

There is no plan to reinject the produced water, and Helium One is evaluating disposal options. The wastewater could possibly be used for geothermal energy and / or irrigation. Nitrogen is the only other gas present and can be safely vented to the atmosphere. Helium One has now embarked on a farmout process to find a suitable industry partner. ■

Mariël Reitsma



Cross-section through the Southern Rukwa Basin in Tanzania with the Tai-3 and Itumbula West-1 wells. Both wells are covered by the new mining license.

SOURCE: HELIUM-ONE.COM

TECHNOLOGY

“The true risk is not that we will fail to innovate, but that we become so efficient at iterating that we mistake speed for progress”

Eric Andersen – Next Phase Solutions

Mistaking speed for progress

Is doing something faster an innovation, or is it the natural progression of technology?

ERIC ANDERSEN, NEXT PHASE SOLUTIONS & ADVISORY



MUCH OF the AI we see today is very domain-specific and, in my mind, one-dimensional. People continue to operate in their own realms, developing algorithms that produce results at great speed.

I attended a very good conference not long ago where many algorithms and workflows were presented that produced incredible results in a very short time.

“The true risk is not that we will fail to innovate, but that we will become so efficient at iterating that we mistake speed for progress”

However, at the end of the conference, the fundamental problem of ineffective collaboration and multi-disciplinary assimilation remained. The produced results still required time-consuming handover and manual incorporation.

AI gives us the means to iterate, fine-tune and customise at an unprecedented pace and scale. But when it comes to the way we work, is this innovation or just an evolution of doing the same thing faster?

Geoscientists are good iterators. By default, we model and tune a variety of scenarios to get the most realistic, economical or feasible idea on the table. Whether it is tweaking a reservoir model or reviewing many well designs, we are always focused on incremental improvements that, we hope, yield material benefits.

Rarely does an innovation come along that leads to a step change in that process.

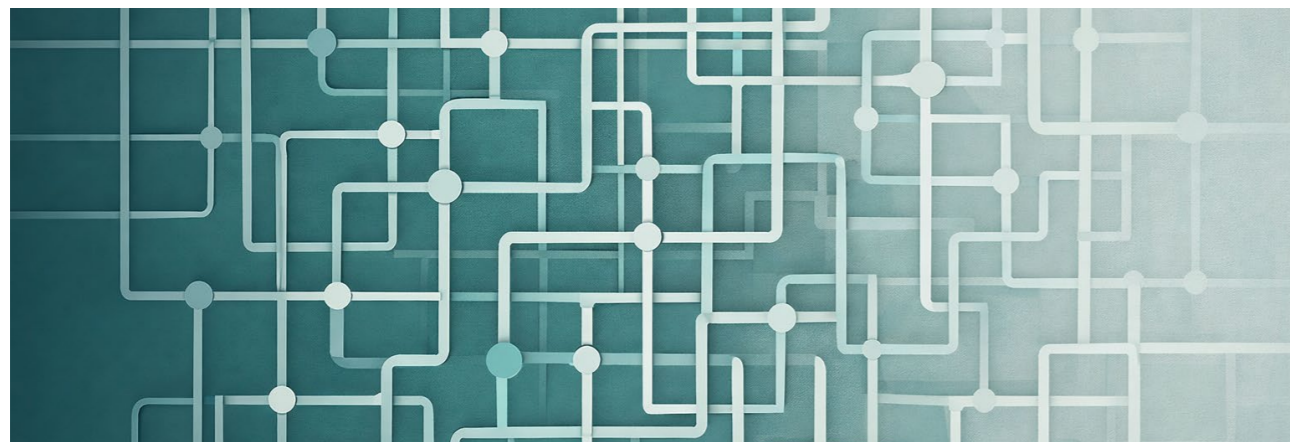
For example, automated fault extraction and interpretation is the equivalent of improving a workflow at great speed. At the same time, AI-assisted inversion, a process based on in-depth, multidisciplinary understanding, is much less popular.

Here's the rub... One of these replaces a manual, time-consuming process that requires high levels of iteration, whereas inversion is a specialised science. Theoretically, it should be a better business decision to automate inversion and yet it hasn't happened.

The way I see it is that innovation is often wrongly associated with novelty and perceived as not grounded in reality, whereas the tools to iterate are already in the hands of workers today. In my mind, when it comes to the way we work, true innovation comes when systems meld together and become symbiotic. Information flows easily while solving complex multidimensional problems.

But the point I am trying to make is that if we just keep iterating, then who is thinking about the innovation layer?

The true risk is not that we will fail to innovate, but that we will become so efficient at iterating that we mistake speed for progress. While automated fault extraction and rapid modelling provide significant operational wins, they remain refinements of existing paradigms. If we allow the 'Efficiency Dividend' – the time reclaimed by these tools – to be swallowed by further iteration, we forfeit our chance at the next step-change. The next innovation has to come from someone who, hopefully, has used the time freed up by iteration of the last technology to find the next breakthrough. ■



When complexity increases, speed alone is not progress.

ILLUSTRATION: CHAT GPT GENERATED BY GEO EXPRO

Turning the tide

On the consumption and production of water in the unconventional business, and how the dial is changing towards a complete preservation of local fresh water resources

LEEN WEIJERS, LIBERTY ENERGY

THERE IS a big difference between conventional and unconventional hydrocarbon production when it comes to water production. When drilling a well in a new conventional oil or gas field, the perforations in the well are always placed in such a way that only the oil or only the gas will be produced. The fact that this is possible is because nature has already done the separation, with clear oil-water and a gas-oil contacts as a result. Of course, over time, there will be mixing as contacts shift and gas may come out of solution, but the initial phase of production tends to be free of water if things are done correctly.

That does not apply to unconventional. In unconventional resources, the ultra-low permeability of the rock has not allowed the formation of separate oil and gas columns. It is essentially still located in the plankton graveyard where the kerogen matured into oil and natural gas. Once drillers

and frac'rs have completed their visit to these unconventional resources and wells start to produce, it means that water, oil and gas are flowing back up the well at the same time. Shale production is intermingled from the start.

But even though water is co-produced from the start, until recently, it was mostly fresh water that was used for the frac'ing operations. In other words, there was no recycling of produced water in an attempt to use it for frac'ing a neighbouring well. This has led many people to claim that frac'ing puts too high a demand on fresh water resources that are already scarce in most parts of the Permian Basin. But how does this compare to other forms of fuel production?

Most bio-ethanols require a boatload of water per product produced. Do you need 27 gal of biodiesel for your “green” truck? To make that requires an Olympic swimming pool of water, meaning that one gallon of bio-ethanol requires almost

25,000 gal of water. Crude oil is orders of magnitude more efficient in its water consumption – on average, in liquid-rich shale basins, about 1 gal of oil is produced over the lifetime of a shale well for every 0.6 gal of water used to frac it.

The good news is that Texan frac'rs are working hard to reduce their freshwater use. At the moment, they are about halfway into replacing that freshwater barrel for frac water with a (produced water) recycled barrel. In 2025, about 45 % of all West Texas frac water was produced water. In the next few years, the expectation is that no fresh water will be used anymore, and production will be unlocked exclusively by recycled produced water.

On balance, the issue of tight water availability in the early days of the Shale Revolution has now completely reversed, and instead of worrying “where to find enough water to frac,” the industry is now hyper-focused on “what to do with the excess produced water”. ■



View from airplane of the Permian Basin, Texas.

PHOTOGRAPHY: CAVAN VIA ADOBE STOCK

Drilling problems? Ask your CEO

A conversation with Henrik Tingström, one of the co-founders of startup company Wellvector

HENRIK TINGSTRÖM didn't need much time in the industry to see how much unstructured data was being left on the table. It was during internships at oil majors that he first realised the potential of organising this information, and with prior startup experience and fundraising already under his belt, he teamed up with fellow entrepreneur Axel Jørgensen to form Wellvector in September last year.

Initially, the duo focused on offset well analysis. "We noticed quickly that drilling activity can come to a halt due to unforeseen challenges, and how an AI-powered analysis of existing legacy documents from nearby wells can accelerate solving the issue at hand, or even being caught in the planning phase."

The response from the market was immediate. "In some cases, we showcased the platform to more than 50 client representatives at a time," says Henrik.

Recognising the immense interest, Henrik and Axel focused on the core challenge: Making an operator's own proprietary data work for them. They partnered with the Head of Development, Filip Sjöstrand, from KTH AI Society in Stockholm, to build a system that digests the complex reality of drilling.

"The main types of input data we ingest today are text, images, schematics, and plots from Well Reports and Daily Drilling Reports (DDR), which we compress not only into short, tailored summaries, but also into diagrams and other types of visuals – all interpretable and stored in a way that AI can read," Henrik explains. The output is designed to

be a decisive operational advantage, whether used for tender work, drilling operations, well planning, or asset acquisitions.

The platform operates via a "manager agent" or a CEO, where users interact with their data through specialised sub-agents and mapping tools.

A critical pillar of the technology is data sovereignty. "An important aspect here," says Henrik, "is that the model will never learn from the data, to prevent situations where two different operators are looking at the same source and one benefits from the learnings achieved by the other."

Initially, Wellvector worked on projects with proprietary data supplied by operators. "But then we felt like we were just running individual projects, without the possibility to scale," says Henrik. "That's why we have now started to delve into public-domain databases as the base platform, using Norwegian and UKCS offshore data from Sodir / Diskos and the NDR at the same time. We are now in the process

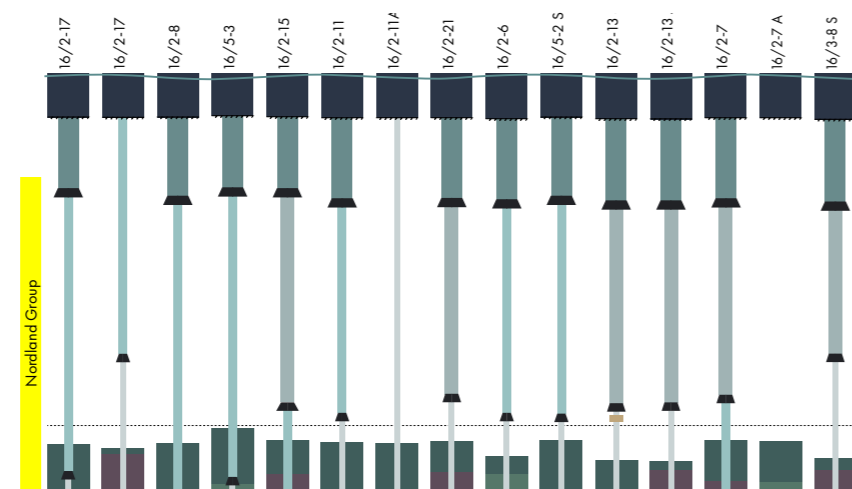


Henrik Tingström.

of standardising these two different datasets."

Backing the company is a group of seasoned professionals from the oil and gas industry, hedge funds, and tech sectors across Scandinavia, the US, the UK, and the Middle East. "I believe it is the combination of our AI-first approach, combined with practical experience, that forms the main driver of the enthusiasm we experience today," says Henrik. "And I am very much looking forward to how this journey continues!"

Henk Kombrink



Casing setting depths and completion details.

SOURCE: WELLVECTOR

INSIGHTS

"Reservoir brines are not merely waste streams – they are complex geochemical systems that may contain a variety of dissolved elements with industrial value"

István Nagy-Korodi

You may not be thinking about politics...

Aberdeen: Back for the first time in a very long while. Writing this from the city itself

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

I LIVED HERE for many years. Worked hard. Played harder. Drink and jazz and mountains and surfing and brass-banding and drink. Foundational geoscience and drilling. I made the best friends and learnt to love our industry. I was with Talisman and CNR, both solid, low-cost and dour.

The Oxford English Dictionary notes dour as “characterised by severity, sternness, or grim fortitude; hardy, robust”. Yet sternness is a strength, and fortitude is survival. Is Aberdeen dour? It has certainly survived. Just.

Aberdeen has been the Schrödinger’s economic centre for the UK for over 50 years; the essential gateway for national wealth whilst simultaneously expendable to the whims of global politics and corporate decisions. National politics barely feature: Laissez-faire in the good times, deckchair arranging on the Titanic in the desperate times.

The title of this article is from the multivariant and routinely hatched quote: “You may not be thinking about politics, but politics is thinking about you”. Misattributed to Pericles. Prior to working in Aberdeen, I scraped

an MSc at Royal Holloway and in the local village, I bought a shabby, softened-by-use, leather-bound copy of Dante Alighieri’s Divine Comedy. Dante is also a regular victim of misattribution, but I do like his / not his: “The darkest places in hell are reserved for those who maintain their neutrality in times of moral crisis”.

There will be no neutrality from me today.

As the USA and Israel attack Iran, we have seen oil prices double due to yet more global insecurity, just as we saw gas prices rocket in February 2022 when Russia invaded Ukraine for the second time. Heads of companies and countries will be meeting to position, protect, consolidate and identify opportunities. Most will be impotent.

I miss the naive simplicity of yesteryear when George W Bush took a sheep-like coalition into Iraq on a single, well-presented lie. We mocked his mildly mangled wordplay. Yet we forget two things: His 2008 congratulatory speech on Obama’s victory was delivered with genuine, non-political respect. His stunned incapability on the morning of September 11th 2001,

whilst reading to second-graders. At that moment, he was giving his time to the youngest of the nation. Bush: An unexpected beacon of eloquence and compassion.

When did we last see Trump visit a school, a rehabilitation hospital, or a retirement home? Though, to be fair, regarding the schools, there may well be safeguarding issues.

In time, the big and brash, such as Trump or Putin, always prove themselves to be everything we try to bring up our kids not to be: Humourless, bullying, Dunning-Kruger ignorant. Conversely, the gentle, such as Zelensky of Ukraine and Carney of Canada, demonstrate that quiet is not the same as weak.

Back to Aberdeen.

I have plans this week to work hard and play hard. To meet people. Aberdonians by birth, by loyalty, by capability. Those who have kept the machines running, the discoveries coming, the bits turning, the black-gold, revenues and royalties flowing. Cogs in our creaking, wheezing industry. I’d like to say essential, irreplaceable cogs, but such parts are routinely discarded whilst the creaking and wheezing continues – attacked from outside by politics, cannibalised from inside by those demanding more meat, more meat, more meat.

Tough times make tough people. Aberdeen. Exemplar, not exception. Right across our UK economy: Tayside, Tyneside, Wearside, Teesside, Humberside, East Anglia, Essex, Merseyside, Barrow in Furness. Nietzsche said, “*That which does not kill us makes us stronger.*” Really? ■



PHOTOGRAPHY: HENK KOMBRINK



Fittie, Aberdeen’s historic fishing village by the North Sea.

No B without A

Why is an integrated approach key to understanding how to design both the surface and subsurface infrastructure of a geothermal heat distribution network

IN OIL AND GAS, production is influenced by market demand, but it remains relatively decoupled from end-use consumption – you produce hydrocarbons, sell them, and the relationship between producer and consumer is largely transactional.

In geothermal, however, the situation is fundamentally different, especially for district heating networks. Not only must heat demand be closely aligned with the design of the wells, but the heat source itself must also be located close to the consumer.

“At the end of the day, it is much better to have an understanding of these factors prior to making the investment rather than at a later stage”

This makes the system inherently coupled: Poor alignment can lead to premature depletion of the thermal resource or an inability of the subsurface to meet long-term energy demand. In this context, another key factor is not only the size of the district, but also the thermal capacity of the reservoir supplying the heat.

That’s where the work done by reservoir engineer Sorin Sirbu from Rock Flow Dynamics comes in. He uses a subsurface model that represents a geothermal reservoir, in combination with a surface network that shows where the consumption of the heat will take place. In addition, the model also takes into account the distance between the wells and the consumers as well as the specs of the pipelines, as this is yet another critical factor in the success of geothermal projects.

Looking at the model he’s got running, I ask Sorin what the most important factors are when it comes to creating a successful project. It turns out that not all are related to geological uncertainty.

One of the key factors determining how much energy remains available at the surface is the heat transfer along the tubing – that is, the heat exchange between the produced fluid and the surrounding formation as it flows up the wellbore.

“We can work with a wide range of different material heat transfer properties,” says Sorin. “To stay on the safe side, I tend to use conservative estimates, so we avoid disappointing results once the system is operational.”

Obviously, subsurface factors also play a critical role, with the timing of injected water breakthrough being one of the most important. A proper understanding of reservoir

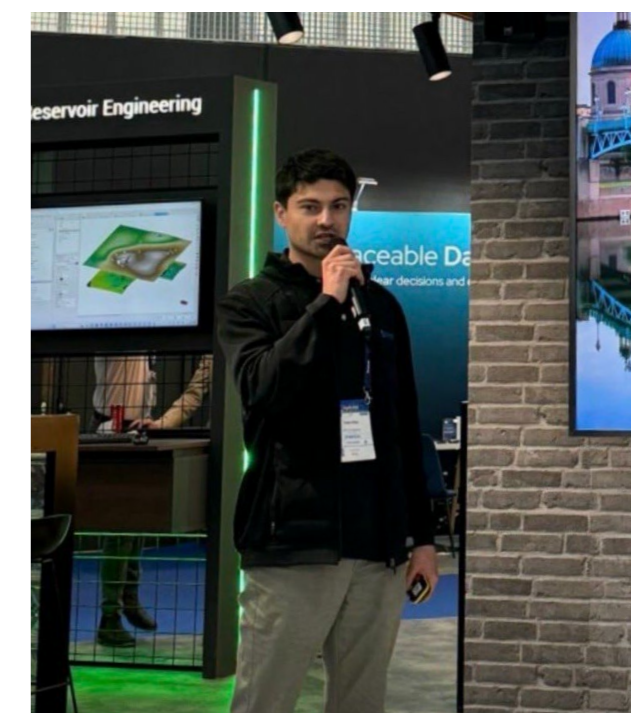
heterogeneity is therefore essential, as high-permeability zones or fractures could be the primary drivers of early “cold” water breakthrough.

“I try to design the model in such a way that the fluids have warmed up sufficiently so that, even if a breakthrough occurs after a few years, the production temperatures have returned to the initial reservoir temperatures,” explains Sorin.

The timing of the breakthrough is also highly dependent on reservoir properties and well distance – it can occur early, at an optimal time, or in some cases never at all. This is why dynamic simulations are essential for predicting system performance.

For all these reasons, an integrated approach is key: Only by considering the combination of above-ground demand, temperature drawdown, and subsurface fluid re-heating can the optimal distance between injector and producer be determined. In turn, this will influence the density of wells that can be accommodated in a certain area. “At the end of the day,” concludes Sorin, “it is much better to have an understanding of these factors prior to making the investment rather than at a later stage.” ■

Henk Kombrink



Sorin Sirbu.

PHOTOGRAPHY: RFD

Conjugate margins in the Indian Ocean

Exploration activities in the area oceanward of the Strait of Hormuz choke-point

MADELEINE SLATFORD, NVENTURES

THE CONCEPT of conjugate margins as a geological model on which to base exploration strategy is well established in the Atlantic, where the extensional plate boundaries and geomorphology are clear and definitive. But other oceans also have conjugate margins, and it is worth looking at the Indian Ocean in this context.

Many of the countries surrounding the ocean, including Mozambique, India, Indonesia and Australia, are established offshore hydrocarbon producers, while in others, the industry is nascent. This applies to Somalia, for instance. In other places, the E&P business has traditionally focused onshore, such as in Oman and Pakistan.

EXTENSIONAL, TRANSFORM AND COMPRESSIONAL BOUNDARIES

The Indian Ocean's crustal architecture is defined by extensional, transform and compressional boundaries. The

conjugate margin in the Arabian Sea, associated with the Owen Fracture Zone, places southern Arabia and parts of east Africa against south-west Asian coastlines, in which India's Mumbai High carbonate platform is the significant petroleum province. Clastic plays remain lightly explored, while historically, exploration activity has been on a nation-specific basis, and it is not obvious whether a pan-regional approach to exploration has been considered or progressed.

However, recent activity levels in the western part of the ocean suggest that things are changing.

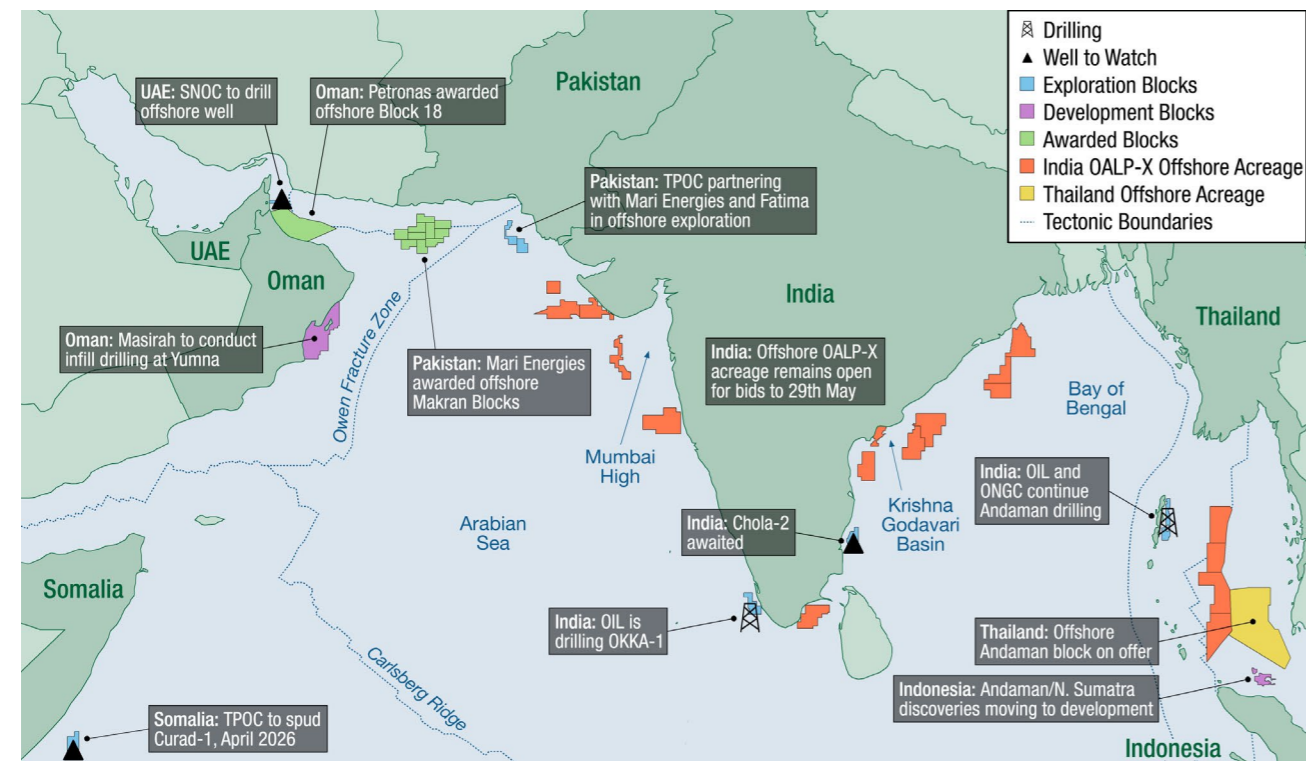
TPOC (a subsidiary of TPAO), fresh from E&P success in Türkiye's Black Sea, reportedly acquired 15,000 km² of 3D seismic around Blocks 152 and 153 in Somalia. Now, the company plans to drill the first offshore exploration well in over 40 years, Curad-1, beginning in April 2026.

TPAO also entered Pakistan as a result of the 2025 offshore licensing round, partnering with domestic companies



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MESA region bid rounds and drilling activity.

SOURCE: NVENTURES

Mari Energies and Fatima Petroleum to explore the area around the 1985 stranded gas discovery Pakcan-1. Play types in both situations appear to be classic 'passive' margin plays, characterised by stratigraphic traps, marine channel and fan systems and gravity-driven anticlinal folds. On modern or reprocessed seismic data, leads in these plays are often associated with DHI's, supported by surface seeps.

Mari Energies has also taken a key position in the underexplored Makran Basin, offshore western Pakistan. This accretionary wedge has long been overlooked due to remoteness and perceived limited prospectivity. Its counterpart is the Batinah coast of NW Oman, where Petronas, partnering OQEP, has recently been awarded offshore Block 18, as part of the 2025 licensing round. This is a vastly underexplored frontier, despite Oman's status as a mature hydrocarbon-producing nation onshore. With the exception of the shallow water Yumna field, which has a Cretaceous clastic reservoir, previous drilling offshore Oman, including Eni's two deepwater wells, has not been successful. However, the density of drilling is exceptionally low.

In the UAE emirate of Sharjah, one of the few with an Indian Ocean coastline, SNOG is planning to play-test an offshore exploration well in the near future. If successful, this will undoubtedly help to de-risk Block 18 Oman and, perhaps by association, its conjugate margin.

Meanwhile, further along the Oman coast, Masirah Oil is planning infill and development wells at the Yumna oil field and has some exploration targets for interested joint venture companies.

MOVING EAST

Moving east, the conjugate margin model is more ambiguous as transform and convergent margins dominate. In the Kerala-Konkan basin in India's far south-west, seen as a conjugate to Madagascar across the Carlsberg Ridge, OIL is drilling the OKKA-1 exploration well, with results expected in June 2026. Madagascar itself is expected to open up for explorers this year as well.

The long-running OALP X bid round in India, now due to close on 29th May 2026 after numerous extensions and relaunches, offers potential in most of India's key offshore basins, including the Andaman basin, associated with a convergent margin, which has been the focus of recent drilling campaigns by OIL and ONGC. These campaigns have so far yielded only one discovery announcement, OIL's Vijaya Puram-2 in September 2025, which flowed gas on test. While gas was reported as being 87% methane, the test flare, as seen on social media, was described at best as "intermittent", and media speculation that the basin represents "the next Guyana" seems unlikely. This has not, however, deterred Thailand from offering one large offshore Andaman block in a planned licensing round, spanning most of the Mergui Basin.

Meanwhile, Zawtika in Myanmar has been onstream since 2014, and at the southern end of the Andaman Basin in Indonesia, exploration successes such as Tangkulo and Timpan are moving into the development stage. This complex convergent margin region merits a multi-national approach.

ONGC is also expecting to spud appraisal well Chola-2 in the offshore Cauvery Basin, which will de-risk this 2024 gas condensate discovery. At the same time, Cairn has a drilling campaign planned in the deepwater Krishna Godavari Basin, where it has de-risked leads through the integration of CSEM technology and seismic data. These basins are essentially passive margins formed during the break-up of Gondwanaland, and their conjugate pairs are considered to be in eastern Antarctica.

PROXIMITY TO GLOBAL MARKETS

Taking a pan-regional strategic approach to the Indian Ocean reveals a variety of potentially play-opening activities and opportunities, and a growing diversity of active companies keen to take advantage of them. Notwithstanding geopolitical instabilities, proximity to growing markets in Africa and Asia, oceanward of the Strait of Hormuz choke-point, is an added benefit. ■

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What else is hiding in your reservoir brine?

Lithium was only the beginning

ISTVÁN NAGY-KORODI, CONSULTING GEOLOGIST



FOR MORE than a century, petroleum exploration has focused on hydrocarbons. Yet, sooner or later, every producing oil and gas field also brings something else to the surface: Formation water. Vast volumes of saline fluids accompany hydrocarbon production, typically treated as a technical by-product requiring handling, treatment, or disposal. But these fluids may represent something more. Reservoir brines are not merely waste streams – they are complex geochemical systems that may contain a variety of dissolved elements with industrial value.

Lithium has recently drawn attention to this overlooked aspect of petroleum systems. In several basins around the world, formation waters associated with oil and gas production contain lithium concentrations comparable to those found in some conventional lithium brine deposits.

However, lithium is only one element in a much broader geochemical picture. Formation waters are the result of long-term interactions between rocks, fluids, and heat within sedimentary basins. Over millions of years, processes such as mineral dissolution, diagenesis, and hydrothermal circulation gradually enrich brines with a wide range of dissolved elements.

The resulting fluids carry a chemical fingerprint that reflects basin evolution, burial history, and fluid migration pathways. While sodium and chloride dominate most formation waters, trace elements can reach surprisingly high concentrations in certain geological settings.

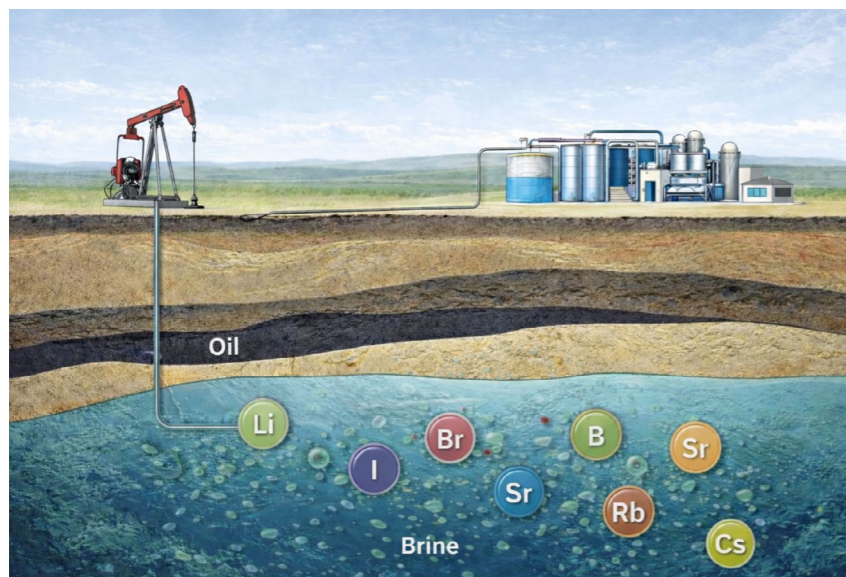
In the 1st part of this series, I would like to mention bromine (Br), iodine (I), boron (B), strontium (Sr), rubidium (Rb), and caesium (Cs). These elements are used in industries ranging from electronics and phar-

maceuticals to energy storage and specialty chemicals.

Growing demand for batteries and energy storage has triggered global exploration for lithium resources, including those hosted in oilfield brines. Several sedimentary basins – such as the Smackover Formation in the USA and parts of central and eastern Europe – have demonstrated that petroleum reservoirs may host significant lithium concentrations in their formation waters. This has led to increasing interest in Direct Lithium Extraction (DLE) technologies, which aim to selectively recover lithium from produced brines. For petroleum operators, this introduces a potentially attractive concept: Turning produced water from a cost centre into a co-produced resource.

Many elements found in reservoir brines already have established industrial uses. Bromine is widely used in chemical manufacturing and drilling fluids. Iodine plays a crucial role in pharmaceuticals and medical imaging. Boron is essential for glass production and fertilisers, while strontium is used in ceramics, electronics, and specialty alloys. Rubidium and caesium, though less common, are critical for advanced technologies, including optical systems and atomic clocks. Individually, these elements may occur in moderate concentrations. However, when considered together, they suggest the possibility of multi-element recovery strategies from formation waters.

Lithium may have started the conversation, but the real question for geoscientists is far broader: What else might be hiding in your reservoir brine? ■



CRMs in produced water.

ILLUSTRATION: CHAT GPT GENERATED BY ISTVÁN NAGY-KORODI

The tricky part of resource assessments within gas-dominated basins or petroleum systems

Two critical learnings to take into account

LUKASZ KRAWCZYNSKI, TOP DOWN PETROLEUM SYSTEMS ANALYSIS AND MARTIN NEUMAIER, ARIANELOGIX

WHEN CONDUCTING prospect resource assessments within gas-dominated basins, there is a low likelihood of oil or mixed-phase accumulations being filled to spill. If this is not properly considered, prospect resource assessments may overestimate predicted oil volumes, thereby creating unrealistic expectations for subsequent exploration programs. Let's take a closer look at the factors influencing this.

The first critical learning relates to the controls on hydrocarbon phase in saturated, gas-prone petroleum systems and their relationship to the Sales trap classification scheme (Sales, 1997). Class 1 traps, or filled-to-spill traps, require strong seals that retain a gas column while, during the charge process, displacing the oil leg and any excess gas updip, ultimately leaving behind a gas-only accumulation. Class 2 traps are associated with intermediate seal capacity, where the gas cap leaks vertically and a dual-phase column is preserved. In these cases, the trapped oil volume depends on both the bulk charge volumes and the vertical relief of the structure. Class 3 traps are characterised by weak seals, where both oil and gas leak vertically, leaving behind an underfilled oil-only column. In general, oil columns are more likely to be encountered in structures with greater vertical relief, as the higher buoyancy pressures increase the likelihood of exceeding seal capacity.

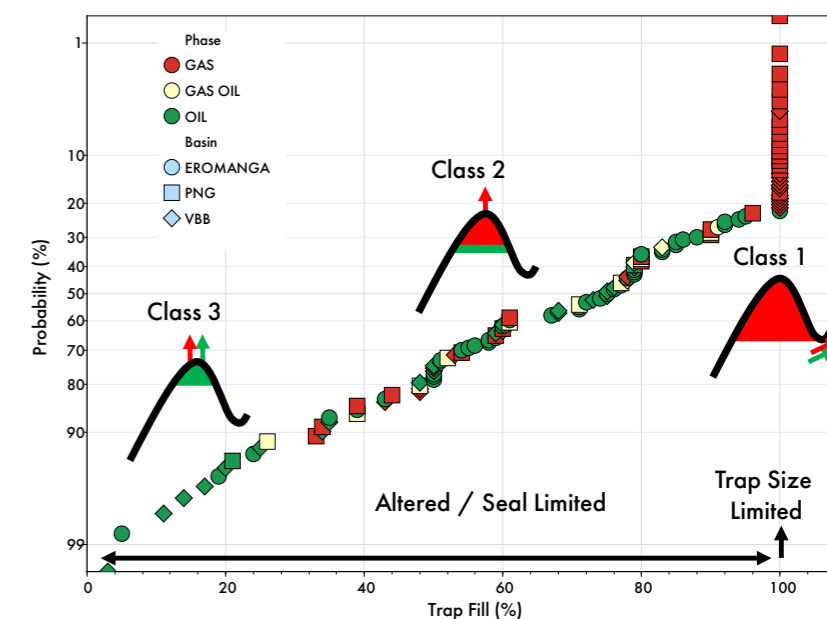
The trap classification scheme can be applied to the column height characteristics observed for a specific basin. Here, we show the column height distribu-

tion by hydrocarbon phase and trap fill percentage for the Australian Eromanga and Vulcan-Bonaparte basins and the fold and thrust belt of Papua New Guinea. It is evident that Class 1 traps are primarily trap-size limited, resulting in filled-to-spill, gas-only accumulations. In contrast, Class 2 and Class 3 traps commonly contain altered hydrocarbons or are seal-limited, resulting in underfilled oil-only or mixed-phase accumulations. The degree of underfilling reflects the balance between gas removal from the accumulation – which leads to overall volume shrinkage and a reduction in column height – and the charge characteristics, our second key point.

The charge volume and gas-liquids ratio (GLR) of the underlying petroleum system control the available vol-

umes of fractionated oil. For a GLR of 20,000 scf/bbl, at least 8 Tcf of gas is needed to leave behind 220 mmbbl of oil at the depth and pressure of the Class 3 trap by migration fractionation, while still leaking oil still contained within the gas. If the charge is richer in liquids, less overall gas charge volume would be needed to fractionate 220 mmbbl of in-place volume out.

In contrast, for a higher GLR charge, significantly higher bulk charge volume would be needed for the same result. Overall, the less liquids dissolved in the charging gas, the more needs to transit through the leaky trap to fractionate sufficient amounts of oil. This highlights the challenge of fractionating significant oil volumes in petroleum systems characterised by higher GLR. ■



Column height distribution by hydrocarbon phase and trap fill percentage for the Australian Eromanga and Vulcan-Bonaparte Basins and the fold and thrust belt of Papua New Guinea.

Tectonics or soft-sediment deformation?

Some key criteria for each

MOLLY TURKO, DEVEN ENERGY



SOFT-SEDIMENT deformation (SSD) refers to structures that form during or shortly after deposition, while sediments remain unlithified, water-saturated, and mechanically weak. These features develop prior to significant compaction and cementation, when elevated pore pressures and unstable grain frameworks allow layers to deform ductilely. In contrast, tectonic deformation, primarily faulting and folding, results from regional or local stress fields acting on lithified strata. For subsurface interpreters, distinguishing between these two styles is critical, particularly in structurally complex or reservoir-prone intervals.

Several practical rules of thumb can help differentiate SSD from tectonic deformation in core, image logs, and seismic data. First, SSD is stratigraphically contained. Because it forms contemporaneously with deposition, deformation is restricted

to specific intervals. Faults or folds that abruptly terminate at bedding interfaces and have no apparent impact on overlying strata are strong indicators of SSD. These structures are typically smaller in scale and lack evidence of brittle deformation.

In contrast, tectonic deformation commonly cuts across multiple stratigraphic units of differing ages. Faults generated by regional stress regimes are throughgoing and may extend across large portions of the stratigraphic column. They are often accompanied by brittle deformation fabrics, including fracture networks, cataclasis, slickensides, and mineralised veins. Damage zones characterised by increased fracture intensity, as well as synthetic and antithetic fault splays, are hallmarks of tectonic fault systems.

The nature of the fault plane itself can also be diagnostic. Faulting during SSD is commonly gravity-driven or related to localised instability in mechanically weak sediment. These faults tend to be relatively clean-cut and lack a pronounced damage zone. Because the sediment is unlithified, deformation is more ductile in expression and does not produce the brittle fabrics typical of tectonic settings.

Scale provides another useful discriminator. Tectonic folds may be broad, regionally extensive, and involve multiple stratigraphic units, often with associated fracturing in zones of tensile strain or thrusting near fold hinges. SSD folds, by contrast, are smaller in scale and confined to the depositional unit in which they formed.

Context is equally important. Structural observations should be evaluated alongside the tectonic history of the basin. Small-scale thrusts and contorted bedding in a region with no history of orogenic compression may instead reflect gravity-driven deformation, such as mass-transport deposits in deepwater settings. Integrating depositional environment, structural style, and basin history reduces the risk of misinterpretation.

Distinguishing SSD from tectonic deformation directly impacts fault analysis, reservoir compartmentalisation models, paleostress interpretations, and predictions of mechanical behaviour. Misidentifying stratigraphically confined slump features as tectonic faults can lead to erroneous structural maps and trap geometries, while overlooking true tectonic faulting may underestimate seal risk or compartmentalisation. For exploration and development teams alike, recognising the timing and mechanics of deformation is fundamental to predicting subsurface architecture and fluid flow.



Tectonic fault juxtaposing two separate Cambrian units.

PHOTOGRAPHY: MOLLY TURKO PRIVATE ARCHIVE

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View from Monte Carqueijo north-westward on Lomba Vermelho ('Red Ridge'), western Maio, Cabo Verde

Coruja Formation (Paleogene) submarine lava breccias and flows.

Monte Penoso Formation (Neogene) subaerial lavas and lava breccias form the top of the succession.

Carqueijo Formation (Albian to Santonian) mixed siliciclastic and carbonate rocks include thin sandstone-prone packages derived from the African mainland. Together, they document changing climate and weathering rates.

Mid Atlantic ocean floor at outcrop

The island of Maio, Cabo Verde, 600 km the west of Senegal, is the only place where Cretaceous mid-ocean floor of the distal Mauritania – Senegal – Guinea Bissau – Conakry (MSGBC) Basin is exposed, providing a unique opportunity to study the early stages of mid Atlantic opening at outcrop. The Basement Complex of Maio comprises four units: Tithonian? to Valanginian pillow basalts of the Batalha Formation (not shown here) were extruded not far from the mid-ocean ridge of the nascent Atlantic. They are overlain by bedded limestones of the Valanginian to Aptian Morro Formation, which gradually pass into the mixed succession of the Albian? to Santonian Carqueijo Formation, dominantly mud - to siltstones and siliceous limestones. The Basement Complex is capped by Paleogene submarine lava flows of the Coruja Formation. These are overlain by Neogene subaerial lavas of the Monte Penoso Formation, which formed after the island of Maio had risen above sea level. The entire Basement Complex has been intruded by basaltic dykes, which account for up to 40 % of total thickness, and caused fragmentation and thermal alteration of the strata, making study of the sediments challenging.

Text: Simon Schneider, CASP and Colm S. Pierce, University College Dublin
Photography: Simon Schneider

Bedded pelagic limestones of the Morro Formation (Valanginian to Aptian) yielded biostratigraphically significant macrofauna.



Sands out of Africa

Thin, enigmatic sandstone-prone packages record the interaction between sediment-gravity-flow and bottom-current processes. These sandstones are distal equivalents of Late Cretaceous reservoir intervals in the MSGBC Basin. Their presence and provenance provide clues to basin configuration and indicate sediment pathways that extended well beyond the Mauritanian – Senegalese shelf, with implications for reservoir strata development and distribution. Two different sandstone signatures have been identified – one indicating a north-easterly source, and a second one, where the provenance is unknown, highlighting our still very limited understanding of west African geology.

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.

The very first core cut in the UK North Sea

Well 38/29-1 missed both primary targets, but the operator can be forgiven. It was the very first wildcat drilled in British waters

IT IS BOXING DAY 1964, a day most people in the countries around the North Sea don't think about spending a day at sea. Yet, the crew of the Global Marine Mr Cap Barge was about to spud a well that would go down in history as the first exploration attempt to find oil or gas in the British part of the North Sea.

What made American Overseas Petroleum decide to drill this well, and why now, in the midst of winter, when the North Sea is often a very choppy place?

The most likely explanation – a dash for gas. It was only five years earlier that NAM – an Exxon-Shell joint venture – had found the massive Groningen gas field in the north of the Netherlands. Once the giant size of the accumulation became known to other oil companies out there – mostly American ones – a real Wild West scenario unfolded in the countries around the North Sea, because the idea was that the Groningen reservoir could extend into the offshore.

And that idea was correct. However, the location of 38/29-1 was not, even though it is easy to say that with the benefit of hindsight. Going back to the early 1960s, when the North Sea was almost a complete Terra Incognita, where would you go first? In that regard, it is not too much of a surprise that the company decided to spud where they did.

The well was located on what was at the time described as the Northumbrian Arch, now known as the Mid North Sea High. Projected offshore using onshore outcrops in England, this high must have had an expression in the earliest seismic lines that were available to the geologists planning the well. And where do you go when you want to drill for hydrocarbons? A high!

So that's a structure identified, but a closure could not be interpreted on the seismic data because of the poor quality. For that reason, the well had a fairly slim chance of finding something

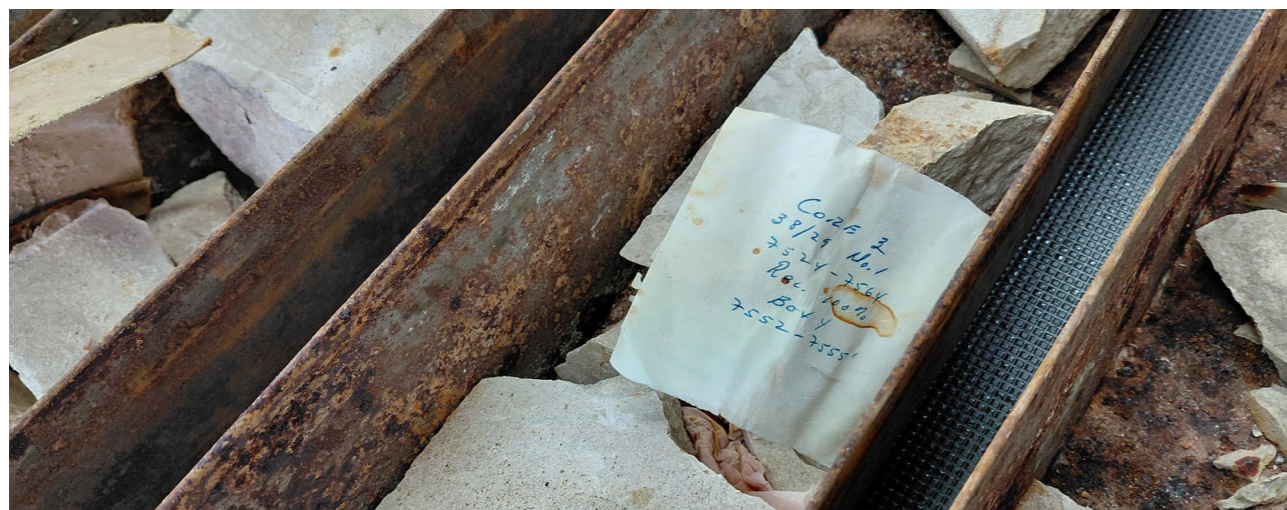


from the get-go. And it didn't find anything, indeed.

But, four cores were cut, in the Triassic, two in the Permian Zechstein, and one in the underlying Devonian. The primary targets, the Permian Rotliegend sands that had proven gas-bearing in Groningen and the Carboniferous that was known from onshore UK, were absent.

Looking back at the numerous discoveries made in subsequent decades, the location of 38/29-1 stands out as an area where no fields have ever been found. It is the deep basins on either side of the Mid North Sea High that have proven to be particularly prospective, illustrating how the exploration strategy changed in a short period of time; rather than the big highs, smaller fault blocks in the deeper basins proved to be the places to go.

Henk Kombrink



The cores of well 38/29-1 are stored in metal boxes. This way of packaging must have gone out of fashion soon after; wooden boxes became the norm. For good reasons.

PHOTOGRAPHY: HENK KOMBRINK

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