THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

VOL. 22

GEO ExPro 4 2025

Exploration Opportunities

Salt-driven structures, data-driven discoveries

Elastic MP-FWI imaging: Changing geophysics

Onset of maturity: A tool for getting your oil-finding game on

Self-similar structures and DHI indicators in the Greater Caribbean

Liberating well data with modern data science and AI

OIL

HOW ARE WE GOING TO PRODUCE THE NEXT 50 % OF THE WORLD' S RESERVES?

GEO ExPro

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GxP PUBLISHING

Descending and ascending

This summer, I visited a museum in the village of Veendam. The museum tells the story of how raised peat bogs in the north of the Netherlands were reclaimed primarily to provide the country with energy.

It was extraction on an industrial scale, turning a vast area of natural wilderness into what is now an agricultural hotspot dissected by straight canals dug to export the peat.

Two hundred years later, the same flat-lying landscape became the hotspot for another energy revolution when gas was found in Permian sandstones much deeper down. It allowed the country to export energy for decades, such was the size of the resource.

> "Fossil fuels still provide a better alternative than transforming an entire area through digging up the peat"

In terms of environmental footprint, it was certainly worth drilling deeper and producing the high-density and deeply buried gas, just from a few well pads.

But the well pads are now slowly being cleared as the gas fields are depleting. As a result, energy production is shifting to shallower subsurface levels again, with wind turbines, solar farms, and shallow geothermal having become much more prominent in recent years.

The ascent has begun, at least in this part of the world. But let's be clear about it, the demand for fossil fuels from deeper down is still very much alive, whether we want it or not. In comparison to reclaiming peat bogs, though, fossil fuels still provide a better alternative.

Henk Kombrink

BEHIND THE COVER

"You technical folk are always way too pessimistic about the future," Carole Nahkle said when I talked to her about producing the next 50 % of the world's hydrocarbon reserves. Maybe that is true, given the diversification of oil-producing nations and the volumes still awaiting development in countries like Venezuela. But I wanted to know a little more about it. For the cover story, I talked to a variety of people who are exposed to the development of new fields around the world. How do they reflect on how technology enables us to produce more, and are they concerned about the world running dry? And what's better than illustrating this with a section of oil-stained core from a petroleum province that will soon cease to exist, the Brent.

The photograph, from well 211/23-A-04, 12,727 ft, shows a section of oil-stained Rannoch sandstone.

PHOTOGRAPHY: NATIONAL DATA REPOSITORY

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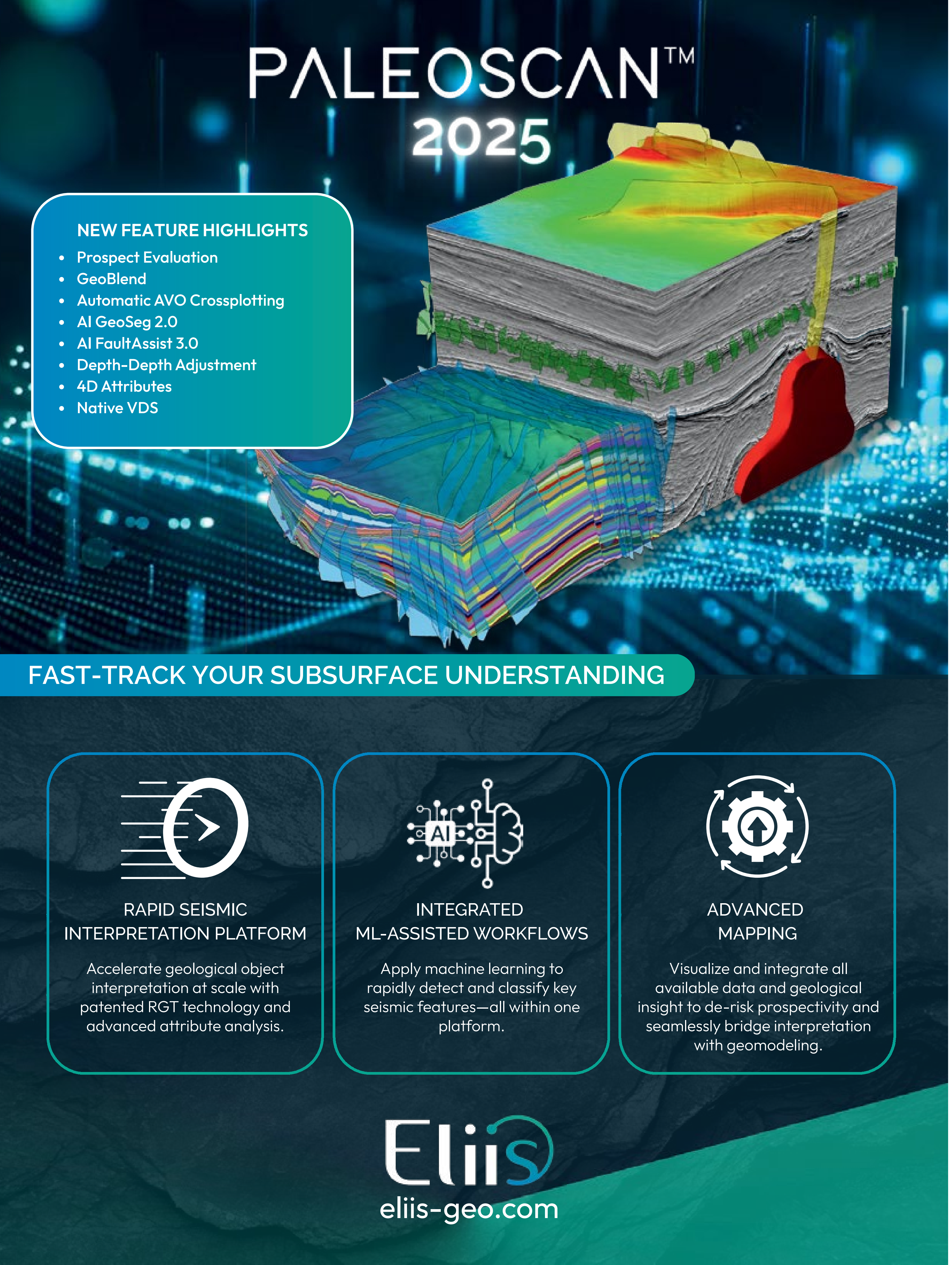

FIRSTS

"Radioactive waste disposal ultimately becomes a social decision"

Rodney Garrard

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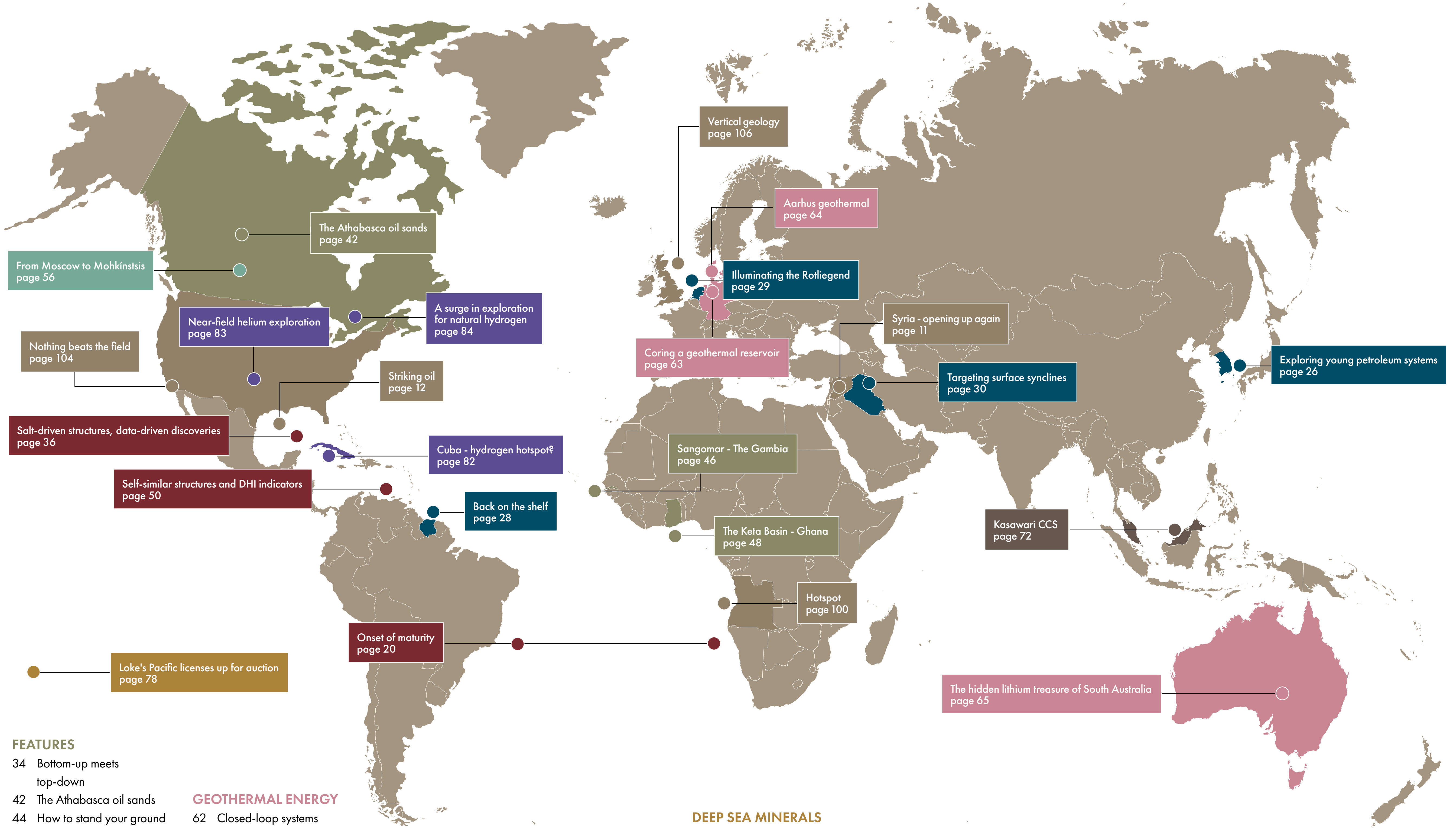

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"SOMEONE EVEN CALLED ME TO ASK HOW I WAS"

"People who have always worked offshore in the North Sea really don't know how good they have it," told a well service engineer to me when we got chatting at a birthday party the other day. He worked in other oil hotspots for 18 years, and one of the reasons why he moved to the UK is that he wanted to see his children grow up. "I was always away on jobs," he said, "because there is no consideration for having time off in many parts of the world. You're being sent from one job to the other, and if you refuse, there are others lined up to take your place. I do have time off now, and even receive calls from my employer to ask how I'm doing when I've done my back in. Unbelievable!"

A DISCOVERY THANKS TO A TILTED CONTACT

On my way home to Aberdeen, I sometimes bump into old acquaintances at the airport. And sometimes that results in hearing something interesting. In this case, I learned that the Halfdan field in Denmark only turned out a discovery – quite a big one actually – because of a tilted oil-water contact. If this would not have been the case, and the contact would have been flat as it is in most cases, the oil accumulation would not have existed. Just another example of how things can work in the subsurface.

MOVING BACK TO OIL

I see people moving back into oil who were previously fierce supporters of the energy transition and all its opportunities. It paints a clear picture; ultimately, people need a job, and if these jobs cannot be found in the energy transition, oil is still a place to go to. Even those who shout about geothermal the hardest may actually still earn pennies in oil. Let's sometimes step back a bit and acknowledge that oil still makes the world move, whether we want it or not.

BRAZIL MAKES A DIFFERENCE

On two unrelated occasions, I got to talk with someone about Brazil's policy to spend 1 % of their petroleum money on research and development. And it made me more aware of the difference this makes. Petrobras recently organised a workshop on geothermal and hydrogen, where they invited a whole group of experts from around the world to share their knowledge. All expenses paid. At the same time, research is being done on all sorts of energy-related matters, also on aspects that may be regarded as more academic, such as determining the exact age of the pre-salt reservoirs. It is fascinating to see how money can be spent wisely, with a simple rule in place.

ILLUSTRATION: PCH.VECTOR

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

Storing radwaste: Transcending the limits of geoscience

Given the timescales and uncertainties involved in designing "permanent" subsurface storage facilities, radioactive waste disposal ultimately becomes a social decision

TODAY, we have an estimated total of 370,000 to 400,000 tons of spent radioactive waste globally, which is the equivalent of 16 Olympic-sized swimming pools, that have been generated since nuclear power began in the 1950s. The question of storing this "legacy waste" safely in the subsurface continues to be a prime example of the intersection between managing uncertainty, geoscience, and social acceptance.

Before jumping into the specifics of geological uncertainties of rad waste disposal, two important questions remain as the nuclear renaissance builds momentum and more volume of spent fuel is generated: What is the plan for the disposal of waste generated by the serial production of next generation nuclear (e.g., SMRs), and will this be transparently communicated? As outlined in my last column, both have been damaging issues in the past.

From a subsurface perspective, what is unique for rad waste disposal projects is the geological uncertainty associated to long-term predictions. For rad waste, some safety concepts refer to "Until 100,000 years have passed, the requirement is that no one should receive more than 1 % of the dose from natural background radiation due to the waste." That's 0.02-0.05 mSv per year - about the same as a flight across the Atlantic or 5 dental X-rays.

Despite the geological uncertainties that are at play over such long timescales, there is consensus on the ideal host rock types, as well as the depth of construction. Many radioactive waste projects assume repositories at depths of 500 m or more in crystalline rocks, salt or clay formations. Nevertheless, a detailed assessment is required to assess suitable sites associated with a given storage capacity.

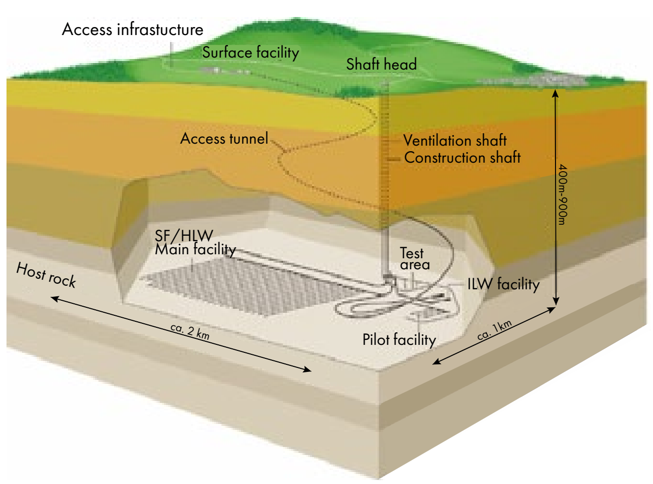
A field that is closely linked to the radioactive waste disposal programs is the social participation in the research programmes in various stakeholder forums. I was involved in the site selection phase of the Swiss waste repository and keenly observed the institutionalisation of the locally affected population in the research agenda from very early on, which is a very different experience from that of my previous life in the E&P industry.

This is a very important aspect, as experience has learned how detrimental cover-ups are. For example, at two facilities at Asse II and its sister project Morsleben in Germany, issues related to water inflows were largely kept under wraps, further straining the public acceptance of nuclear waste disposal in Germany to this day.

As a result, the public is very attuned to these events, which has caused social resistance at specific subsurface repository sites and not only in their local jurisdictions. Therefore, radioactive waste disposal has historically experienced negative public and stakeholder perceptions, which can interfere with the debate on a final storage solution.

We can therefore be curious to see what developments will take place in the next generation of nuclear development and to what extent society is finally prepared to follow more a path of waste prevention from the nuclear sector. We certainly have the tools to deliver, if we agree to do it. ■

Rodney Garrard



View of the Swiss concept for a SF/HLW/ILW repository in the Opalinus clay with inset of SF canister-emplacement tunnel and longitudinal section of emplacement tunnels for SF for the design option using low-pH shotcrete tunnel support. SF: Spent fuel; HLW: High-level waste; ILW: Intermediate-level waste.

ILLUSTRATION: NAGRA, 2002

This is the final and second part of a series on the geological storage of radwaste.

Syria – opening up again

While most exploration drilling in Syria over the past century has focused on onshore areas, vast untapped exploration potential remains. The Syrian government is currently working to reignite interest from the international community, with plans for upcoming roadshows and invitations for direct negotiations

IN MAY 2025, the US Treasury eased most sanctions on Syria, followed by the easing of restrictions by the UK and EU. While significant hurdles still remain, oil and gas companies are gearing up to renegotiate contracts and restart operations. The oil and gas history was very much the lifeblood of the economy of the country, with production reported to be in the region of 385,000 boepd in 2010.

Production dropped below 35,000 boepd following the civil unrest in 2014 and is now reported to be approximately 110,000 boepd, mainly from the northeastern region of the country currently under the control of the Syrian Democratic Forces (SDF), a US-backed, Kurdish-led military alliance.

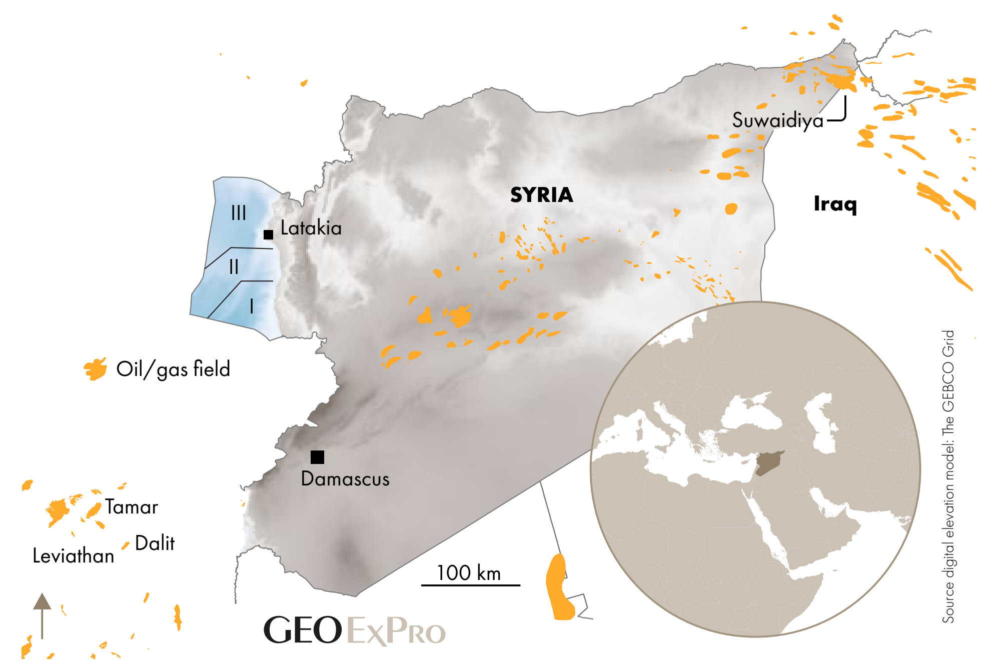
Exploration began in the 1930's in the eastern part of the country following the encouragement of oil fields discovered in neighbouring Iraq. Syria became an oil producer in the early 1960s with Deutsche Erdol AG's (DEA) discovery of the Suwaidiya field before losing the asset to nationalisation in 1964. Activities increased in the 1970's with companies such as Shell's subsidiary Pecten, Deminex, Chevron, Pennzoil, Rompetrol and Marathon holding licences. Historically, Syria's main production was from the central, eastern and northeast parts of the country.

Among the companies that have declared force majeure or slowed down operations since 2011 include Shell, TotalEnergies, ONGC Videsh, Suncor, INA, IPR, Septima Energy, Maurel & Prom, and Gulfsands, plus the Chinese representation of Sinopec, Sinochem and China National Petroleum Corporation (CNPC).

Previously, the Syrian Ministry of Oil and Mineral Resources (MOMR) and the General Petroleum Corporation (GPC), with technical support from CGGVeritas and the availability of 2D multi-client seismic, opened an offshore bid round in March 2011 comprising Blocks I, II and III. The offshore with its three main basins is under-explored and likely to be gas prone with similar geology to the other Eastern Mediterranean gas provinces, such as the southern Levantine Basin, with major discoveries at Tamar, Dalit and Leviathan in Miocene sediments. The round, which had a bid deadline in October 2011 was not concluded. As a result, no wells have been drilled offshore Syria, with the nearest drilling reported near the city of Latakia.

Ahead of the industry reopening in Syria, clarity is needed concerning the ownership of a number of fields and exploration acreage in the country particularly those that were acquired by Russian firms during the unrest, and the status of contracts. A somewhat low hanging fruit to kickstart the industry could be to a launch a bid round for the offshore. ■

Ian Cross - Moyes & Co



A subsea tie-back to a subsea tie-back?

bp's recent Far South discovery in the Gulf of Mexico shows that near-field exploration is still paying off

THE NAME of the discovery may suggest that it is the most distal find in the Gulf of Mexico ever, but that is not the case. bp's recently announced Far South find surely has more "neighbours" sitting in even more remote locations when looking at it from a USA coastline perspective.

Yet, the discovery is a success that deserves a note, both because it is a successful test of the Miocene play and it is also proving the point of acquiring new seismic – the discovery is located in an area that is part of the TGS / SLB Engagement sparse node OBN survey that was acquired in 2022.

Far South was drilled on Licence G36297, which was awarded to bp in 2018. Last year, it was reported that Chevron and Talos Energy farmed into the licence, but the latter transferred its equity back to bp during drilling of the Far South well. Chevron now holds 42.5 %, with bp having the remaining share.

THE MIOCENE PLAY

Whilst the nearby Constellation field produces from Pliocene sands, according to data from Westwood Global Energy shared with us, it is likely that the primary target for the Far South well was Miocene reservoirs.

Westwood also reported that nearly 50 wells targeted the Miocene play in the GOM since 2020, with 16 making potentially commercial discoveries. The average size of the commercial discoveries only stands at 34 mmboe, which suggests that the play has not delivered big discoveries over the past few years yet.

Source presence and maturity are viewed as low risk by Westwood, which is no surprise given the widespread occurrence of source rocks in the oil window in the Gulf, as well as the presence of proven fields around Far South. However, charge access is a trickier play factor according to the intelligence firm, with various dry holes in the sub-salt Miocene play due to the complex migration pathways required from the Tithonian source rock.

NEW SEISMIC

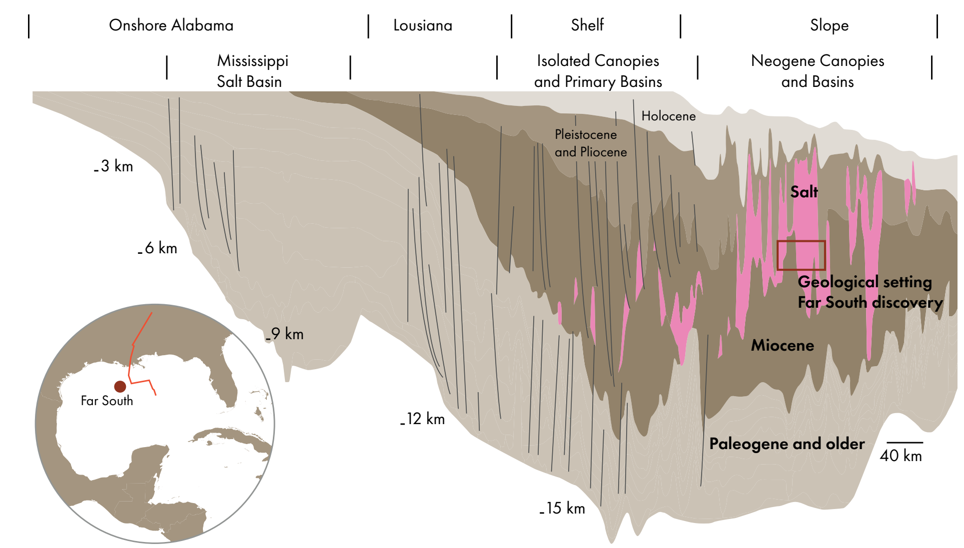
Newly acquired seismic data across the Gulf of Mexico is generally considered the main driver to continued drilling success in this mature basin, allowing companies to drill even deeper below mobile evaporites that have always obscured imaging.

The Far South discovery is located in the Engagement 2 seismic survey performed by TGS and SLB, which uses ultra-long offsets and FWI algorithms to build an accurate velocity model to improve imaging. The quality of the imaging will have been key to better map prospect volumes and to identify the reservoir sands.

A TIE-BACK TO A TIE-BACK

Volumes have not been shared by the operator, but a report from Rystad, which we have seen, estimates the Far South discovery to host a recoverable volume of nearly 70 mmboe. Rystad also expects that the project is likely to be approved in 2027 as a subsea tie-back to the nearby Constellation field, which is a single-well subsea tie-back in itself already. ■

Henk Kombrink



The geological setting of the Far South discovery in Miocene strata.

SOURCE: REDRAWN AFTER SNEDDEN & GALLOWAY (2019)

COVER STORY

"The rate of adoption from the industry over the past two years has been significant; companies trialling a lot of technologies"

Brent Brough – InflowControl

COVER STORY

PRODUCING THE NEXT 50 % OF THE WORLD'S OIL RESERVES

How the oil industry is slowly turning from a high-risk, high-reward business to a sector that puts engineering first

HENK KOMBRINK

In 1967, an oil embargo imposed by the Arab producers on a select group of Western nations failed badly. One of the reasons for this failure was the fact that the USA managed to ramp up domestic production by more than a million barrels a day.

"A decade later, this so-called swing production had virtually disappeared," writes Anna Rubino in her biography about Wanda Jablonski, the famous editor who single-handedly launched the very successful industry magazine Petroleum Industry Weekly.

The reason for the lack of swing production capacity ten years later was simply because the ability of the same American fields to quickly ramp up production had ceased. This example beautifully illustrates what happens when fields mature and the impact that can have on the security of supply.

How does that translate to how the world looks like today? With many of the big fields having been in production for decades, one would expect that the level of swing production capacity has reduced. At the same time, as some people will argue, more countries have entered the oil production club, such as Mozambique, Guyana and hopefully Namibia, which has diversified the market. But does that take away completely the risk of disruptions in supply to have an effect on the world's thirst for oil?

As data from many oil-producing countries is treated with the utmost secrecy, it will be a monumental task to make inferences based on that. What is possible, though, is to see what is happening around us at the moment. How do industry insiders look at the long-term ability to continue oil production?

For all the conversations I had, I took the starting point that we are at about 50 % of producing the world's reserves, and asked the question how producing the second half will look like. ►

THE SUBSURFACE GAMBIT

A conversation with Nelson Suarez – Houston

"Producing the next 50 % of the world's oil reserves will look very different from the first 50 %," says Nelson Suarez when we meet on Teams. He calls in from Houston, where he has been working of late. He travelled the world, though, and has been to many places, amongst some long stints in the Middle East. Combined with his background and expertise in petrophysics, he has witnessed the technological progress in terms of reservoir monitoring and drilling over the past few decades and is in a good position to share how he thinks the world will produce the next 50 % of its oil reserves.

"First of all," Nelson says, "I think that we haven't even reached peak oil yet. This is not only because of the increase in energy consumption and demand by developing countries. It also relates to our increased use of AI."

Nelson points out what the CEO of NVIDIA, Jensen Huang, recently said in a keynote speech: "One big idea is that every data centre in the future is going to be power limited. Your revenues are power-limited. You can figure out what your revenues are going to be based on the power you work with. We are now a power-limited industry, and our revenues will be associated with that."

How is the world going to produce the oil we need to power our data centres and live our comfortable lives?

"Producing the next 50 % of the world's oil reserves will be less glamorous than the first," says Nelson. "To come straight to the point, the times of easy oil are over, and it will take much more of an effort to keep on producing at the levels we know today. At the same time, and for good reasons, there is more pressure on the emissions that come with oil production, as well as the safety aspect of the whole process." All these things were of little concern, especially during the first stages of global oil production.

Nelson Suarez

> **"To come straight to the point, the times of easy oil are over, and it will take much more of an effort to keep on producing at the levels we know today"**

From a subsurface standpoint, Nelson identifies five key items that will characterise the coming decades of oil production. He calls it the subsurface gambit.

"The reservoirs we will increasingly produce from will be more complex than what we have seen before," he explains. "The times of the juicy sands that behave like a tank are mostly over, and the trick will be to offset the challenges posed by thinner, more fractured and less continuous reservoirs with technology to tap into these more efficiently."

Apart from a more complex architecture, reservoir quality will also be less than what we are used to. "With lower porosities and associated permeabilities, yet again we see a move towards advanced stimulation technology to enable the continuation of economic production," Nelson says.

There will also be more work done on managing the decline of brown fields in order to keep them going for longer. "Huge investments in enhanced oil recovery can be expected, carried out in collaboration with academia where much of the EOR brainpower resides," says Nelson. "Arresting the decline of the big producing fields, and the smaller fields as well, will be a hugely important thing in the decades to come."

UNCONVENTIONAL BECOMES CONVENTIONAL

It is 2011, and we are in Dubai. Nelson is being asked by his manager, Damien Bevillon, to perform a correlation and analysis of a few wells in an offshore field for which additional wells are being planned. The geologist who would normally take care of those things is on holiday. "Of course," says Nelson, and he started taking a look at the logs. Then he realises that there is an interval within the oil column that shows poor reservoir properties and has never been targeted by development wells before. Still, when doing his calculations, he arrives at the conclusion that the poor-quality interval has significant upside.

Two years later, the rocks nobody had paid too much attention to became the focus of the world's first offshore unconventional horizontal and multi-stage frac. "And I'm reiterating offshore," Nelson says, "because it is not the same as lining up a few hundred trucks. It came with many logistical challenges, but we did it successfully."

This story illustrates how unconventional oil and gas production has also settled in areas outside the USA, where the shale boom started in the early 2000's. China is going big on it, Argentina is too, and there are more places where it is just waiting to be tapped into. "I believe that unconventional oil will be a cornerstone of future production," says Nelson, "to a point where unconventional becomes the new conventional."

PHOTOGRAPHY PREVIOUS PAGE: EYEONICIMAGES VIA PIXABAY

The fourth factor Nelson identifies is the big challenge posed by exploration in hostile environments. How deep can we go, and will we ever resume exploration in what are now considered no-go zones such as the Arctic and the Antarctic? TotalEnergies' current negotiations with the Namibian government on the terms of their massive Venus development clearly demonstrate how the boundaries of what is technically possible and is economically sensible are being pushed.

The last point of the subsurface gambit Nelson identifies comes back to what Jensen Huang observes when he plans for his datacentres: The role of AI. "Let's face it," he says, "the oil industry has not been particularly fast when it comes to the adoption of AI, but I strongly believe that the time has now come for a big revolution in this regard." He paints a picture of tools that will not only look into the formation in the area around the wellbore, but also ahead of the drill bit. "Combining that with the sensors we already deploy, I see a future in which a reservoir model will be automatically updated as the well is being drilled, with the connected volumes changing as the bit proceeds."

"I'M EXCEPTIONALLY BULLISH ABOUT THE FUTURE"

A conversation with Brent Brough – Calgary

"As an industry, we have come a long way. From drilling vertical wells to slanted wells, then using slotted liners in horizontal wells, via passive inflow strategies to now active inflow control valves (AICV)," says Brent Brough, CCO at Norwegian Tech Company InflowControl.

The firm, which was formed by three former Statoil (now Equinor) employees, Vidar Mathiesen, Bjørnar Werswick and Haavard Aakre, develops active inflow control valves for downhole completions to maximise net hydrocarbon production. And net is an important word here, as the technology simultaneously minimises the inflow of unwanted fluids.

Brent started his career in Canada, but also spent significant time in Russia at Sakhalin, where he learned a lot about how the latest technology was applied in the long horizontal wells of the development. "When I came to Sakhalin Island in 2007, they were using a new type of completion that I hadn't seen in Canada before: Passive inflow control devices in the ERD (extended reach) wells to balance production conformance and defer water breakthrough. It was state-of-the-art at the time."

"We have progressed quite a bit since..."

The technology that is now being applied by companies such as InflowControl is a clear example of how the industry is moving towards maximising recovery factors from existing and new fields.

You often hear that the oil and gas industry is slow in adapting new tech, but Brent has a different perspective on that: "The rate of adoption from the industry over the past two years has been significant; companies trialling a lot of technologies," he says.

Brent is also adamant as to where the future of hydrocarbon production lies. "The future lies in a combination of new fields and redevelopment of older ones. We as a team see so many reservoirs around the world where there are huge volumes of hydrocarbons remaining. That is really the exciting part here."

"What could be done at the time when fields were initially developed is very different from what can be done today," Brent continues. "A lot of operators are now looking into this, and instead of the big ones, we see that it is actually the smaller players, with significant financial skin in the game when it comes to their assets, who are trying out new things to increase oil production."

Brent Brough

> **"...and instead of the big ones, we see that it is actually the smaller players, with significant financial skin in the game when it comes to their assets, who are trying out new things to increase oil production"**

THE LATEST DEVELOPMENTS

What are the latest developments the company is working on? "Something that has caused a bit of a stir in the subsurface technology community is an inflow device that does not look at viscosity differences, which is the standard approach, but rather isolates fluids based on density," Brent explains. "The reason to develop this tool is that in some major reservoirs, the viscosity difference between oil and water is so small, we wouldn't have the ability to differentiate them effectively using our "conventional" valves. But we now have a solution based on density valves, and with those, we can achieve a 30 to 60 % reduction in produced water this way. It opens up possibilities in quite a few reservoirs around the world."

"There are two more technologies that we are currently developing at the moment and that will be ready for deployment imminently," Brent continues. "We have been developing autonomous outflow devices for injection wells, which aim to autonomously manage injection such as in high permeability streaks in the reservoir that cause rapid water recycling." ▸

Another technology is around autonomous inflow devices for gas fields. It is a well-known phenomenon that gas wells suffer water breakthrough as much as oil wells do, but in gas wells, the effect can be even more detrimental to production. "Our team have therefore developed an AICV that only allows in gas and condensate but shuts off water," Brent says, and we plan to deploy this in a well soon.

The company is also tackling the unconventional space. "The typical norm today is to have no inflow control for long horizontals in unconventional production at all," Brent says, "but that is now changing as we have embarked on some projects in North America where we have retrofitted some old wells. We are also working on new projects with strategic partners where our valves manage production straight after stimulation."

In addition, the company developed an inflow control valve for thermal late-life SAGD (steam-assisted gravity drainage) applications as well, to extract more oil from the in-situ oil sands in Canada. In these late-life stages, operators inject non-compressible gases rather than steam because the reservoir is already heated up. The main reason for installing our autonomous valves in these settings in this late-life scenario is driven by the risk of the gases finding a quick way into the producer, bypassing the oil. Our valves subsequently make sure that these gases stay in the reservoir rather than being produced too quickly," Brent says.

SAYING NO

It is not a coincidence that Norway is the birthplace of InflowControl. "Norway is one of the leading countries in the world when it comes to recovery factors," says Brent. "This is really down to having companies like state-owned Petoro and governing body Norwegian Offshore Directorate, who have incentivised the focused use of technology for decades."

"However, Norway seems a bit of an outlier when it comes to the focused approach of field management discipline," admits Brent, meaning that there are significant opportunities for the company elsewhere. "Yet, we do say no to about a third of the calls for projects we get," he says. "The reason is that our technology may not fit all applications, and we don't focus on quick wins. Our approach is to better understand the entire field and deploy our autonomous valves customized for each reservoirs properties in such a way that it makes sense for longer-term reservoir management."

> "Norway is one of the leading countries in the world when it comes to recovery factors"

And to gain that insight into the reservoir, the company employs a large group of reservoir engineers. "I don't know another tech company that has more reservoir engineers in their subsurface department dedicated and focused on only reservoir management," says Brent. "We are roughly sixty people now, and ten of them are reservoir engineers optimising the design of our AICV completions in relation to the characteristics of the reservoir. It is absolutely paramount to understand the field and to understand our customers' needs."

So how does the future and producing the next 50 % of our world's reserves look?

"I'm exceptionally bullish about the future," concludes Brent. "We see so many opportunities, especially because reservoir monitoring is becoming more common place. Producing the next 50 % will be very different from the first, but I see tremendous opportunity to do it with smart technology."

"NO CONCERN AT ALL" – THE ECONOMIST'S VIEW

A conversation with Carole Nakhle – London

"I thought we would be speaking for 15 minutes, now it has turned into half an hour already!" Carole Nakhle is sought after when it comes to her view on the global swings and roundabouts of the oil business. She regularly appears on camera with various news outlets, and also finds the time to write commentary pieces, all the while she also runs her consultancy business Crystol Energy.

"Looking at the longer term, let's say around 50 years, I have no concern at all about the ability of the oil producers to satisfy demand. You technical people tend to focus too much on the subsurface; if the right price environment is there, investment will come in developing new resources."

It is refreshing to talk to an economist sometimes.

"My only concern," Carole continues, "is that there may not be enough investment in new projects at the moment, on the back of the narrative that new investments would not be required or should not be made on the back of climate concerns. This has, however, recently been u-turned by the IEA, as it is now saying that investments are needed to maintain supply."

Another interesting point Carole makes is about the notion that it is not only the Middle East that can act as a swing producer. In some ways, the US shale patch has also demonstrated that it can. "Maybe not as quickly as the Middle East could do, but certainly the US industry can respond fairly quickly to shifts in demand and price by ceasing production from wells and reducing the number of active rigs." In other words, as Carole has said in other interviews, the landscape of oil producers has diversified and has therefore resulted in a more robust and resilient landscape of suppliers.

A CHANGE OF CENTRE OF GRAVITY

The country that always comes up when talking about remaining oil reserves is Venezuela, with an estimated 300 billion barrels yet to be produced. "Venezuela is an example of a country where the value of the resource that is sitting in the subsurface is not an indication of the prosperity the country enjoys," says Carole. "This is a self-inflicted situation the country finds itself in through adverse policies and nationalisation. In a way, with the world not even experiencing a shortage of oil supply at the moment, imagine what would happen if Venezuela will start to massively invest tomorrow?"

The typical subsurface view of rapidly depleting reservoirs in places like the North Sea is not a reason for Carole to start getting concerned about a shift of global oil production to places that are politically less stable.

> "The main problem with your statement is, why would you be so sure that a basin like the North Sea is going to lose its importance entirely?"

"The main problem with your statement is, why would you be so sure that a basin like the North Sea is going to lose its importance entirely? Carole asks. "Even the UK is still a significant player, and look at Norway, there are two other areas – Norwegian and Barents Seas – that are still in the game too. And who knows what kind of technology will arrive tomorrow that will enable the extraction of more resources from the North Sea? In other words, I think it is too easy to conclude that petroleum production will soon cease in areas such as the North Sea."

THE ROLE OF UNCONVENTIONALS

Carole does not see the model of the US shale revolution happening in other places. "The USA is unique, maybe with parts of Canada included, where the main factors enabling unconventional production come together," she says. "Availability of rigs, infrastructure, sparsely populated land, experienced people and, very importantly, private landownership. That is a big enabler and forms a big incentive to develop shale gas and shale oil. Finding a similar situation elsewhere in the world is challenging."

On that basis, she is sceptical about how easy it will be to replicate the same model elsewhere, even when knowing that the USA is not sitting on the biggest unconventional resources to start with. "Yes, Saudi Arabia is developing what we can call unconventional gas, but for now, this seems to be mainly for domestic consumption and in terms of costs will also be much more expensive than the more conventional oil and gas that the country has been producing for so long. In that sense, the US model does not seem to be matched."

WE WILL NOT RUN OUT, BUT THERE WILL BE CHANGES NONETHELESS

Overall, there is confidence that the world will not run out of oil. The advance of technology has compensated for that, with an almost incomprehensible array of sophisticated tools and methodologies that allow operators to squeeze more barrels out of their reservoirs than ever before. I believe that this advance in technology is now starting to change the face of the oil industry significantly.

The industry started with just lucky shots, sometimes guided by the odd surface seeps. That element of risk – you drill a dry hole or you drill a gusher – has been the backbone of the industry until now. For decades, the potential reward for drilling a successful well has strongly outweighed the completion of quite a few dry holes. This element of risk, and the careers that have been made on the back of that, has had a big effect on how the industry planned for its future.

That concept of high-risk and high-reward has already changed onshore USA, where unconventional oil and gas is not so much about finding the closure that contains hydrocarbons. It is now about finding the sweet spots that tend to be more regional and widespread. Supported by a massive drilling industry that is required to produce these much tighter rocks, developing these resources successfully has meant that the industry has become less exposed to geological risk and more exposed to engineering risks.

Carole Nakhle

Combining this with what people have told me, and even though Carole Nakhle does not immediately see a repeat of the US shale patch, still there seem to be signs that unconventionals are becoming more important in places outside the USA: ExxonMobil signing contracts in Azerbaijan for tight oil, Canada continuing to be a major player in unconventional oil sands, and China ramping up as well, there is a picture emerging that hints towards a shift in the industry towards reducing geological risk whilst becoming much more of an engineering subsurface business at the same time. And on top of that, as Brent Brough explained, and Nelson Suarez backed up too, technology will also be of utmost importance to unlock more volumes from already existing fields, again causing a shift towards the engineering part of the game.

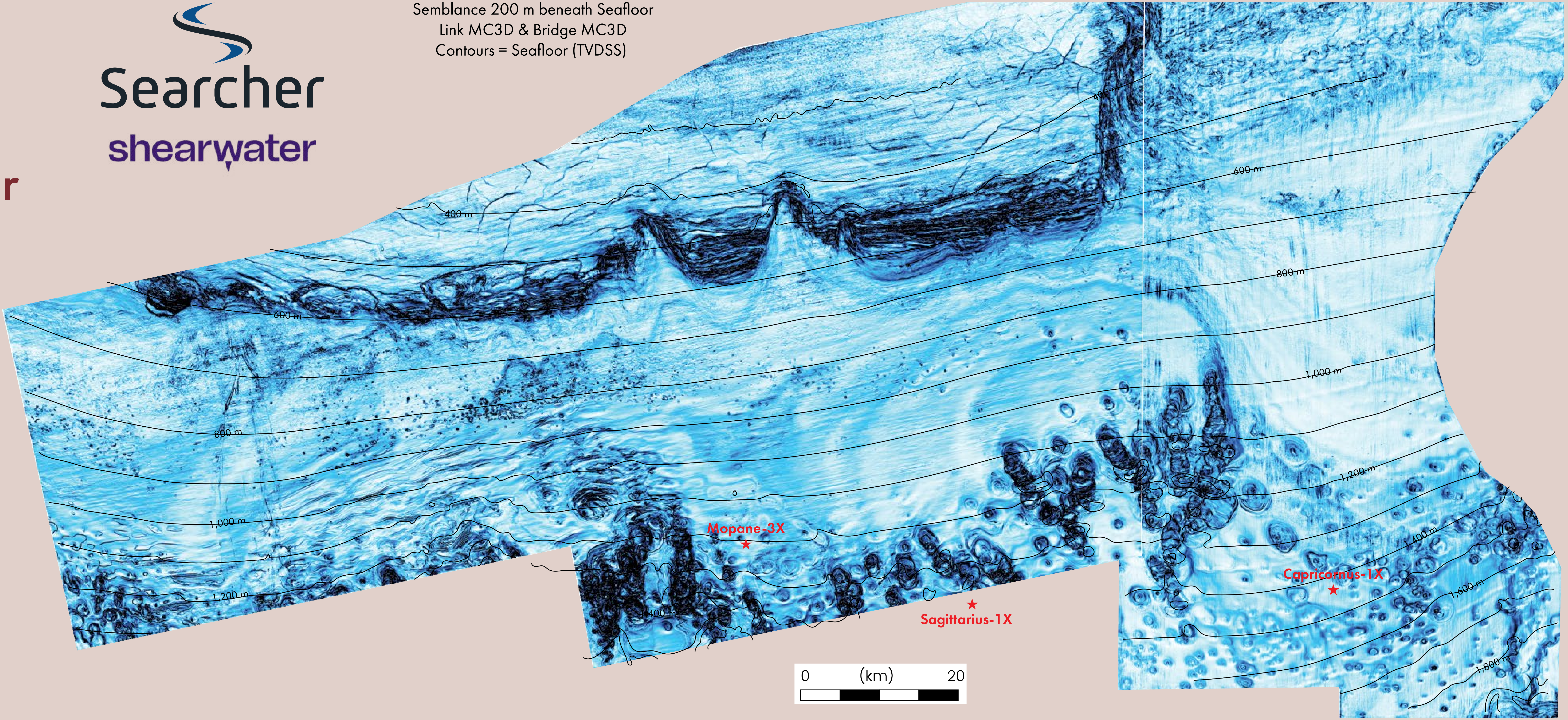
In conclusion, I believe that where the first 50 % of the world's oil was mainly produced from fields that were found with a real explorer's mindset, producing the second half will be characterized by much more of an engineering approach from basins we already know. Is conventional exploration, therefore, on its way out? Well, in some ways it seems to be the case already, when looking at the year-on-year decline in seismic surveys being acquired, and with the recent news that TGS is selling off two of its acquisition vessels. Interesting times, especially for reservoir engineers. ■

COVER STORY

Onset of maturity: A tool for getting your oil finding game on

Searcher
shearwater

In the hunt for oil and gas, explorationists work in convolution space between the sensory, observable or empirical world, and the conceptual constructs of idealized systems. Here we investigate several of the world's most hydrocarbon-exciting basins where modern high-resolution 3D seismic allows spatial and temporal observations of phenomena attributed to fluid-flow, to determine if these may be correlated with the causal mechanistic basin-models that constrain generation as we seek to understand how hydrocarbons are forged and released into the thick, dark cycles beneath the crust.



Semblance 200 m below seafloor over the Link Survey. Elliptical and "coffee bean" shaped large migrating pockmarks are observed in the western parts of the Link and Bridge (lower part of the figure as shown) in addition to non-migrating "narrow pipe heads", especially clear to the southwest (right-hand side of figure).

Decoding the spatial correlation of pockmark evolution and oil discoveries

Integrating fluid flow indicators, seismic DHI, and source rock modelling to reduce exploration risk

KARYNA RODRIGUEZ, LAUREN FOUND AND NEIL HODGSON, SEARCHER

In 1752, at the height of the Age of Reason, Erich Pontoppidan, a Danish theologist, wrote, "It should be assumed that in the ocean as on land there exist here and there, seepages of running oily liquids or streams of petroleum and other bituminous liquids." Before all modern geology was even a thing, and delightfully conflated with tales of sea monsters and other wonders, the Bishop's vision rode shotgun for fluid escape being a key observation supporting the presence of a working hydrocarbon system.

Over the last three years, Searcher has acquired over 28,000 km² of new 3D multiclient seismic data offshore the Orange and Pelotas Basins in the South Atlantic, 1,800 km² of 3D seismic data in the Gulf of Papua, and accessed 8,500 km² of Wide Azimuth 3D seismic data offshore Nova Scotia. Studies from these datasets addressing presence and effectiveness of key exploration risk elements; source, reservoir and trap have been much discussed in GEO EXPRO over the last years. All of these basins have seabed pockmarks and strong satellite slick support for the presence of working oil generative systems, but since the 2024/25 Mopane and Capricornus discoveries in the Orange Basin, we can now correlate observations of subsurface flow with oil discovery.

Seabed pockmark trends, indicating points where subsurface fluid flows (oil, gas or water) reach the seabed, are observed on Searcher's MC 3D datasets in all four basins. With the discoveries of oil on these data in Orange Basin,

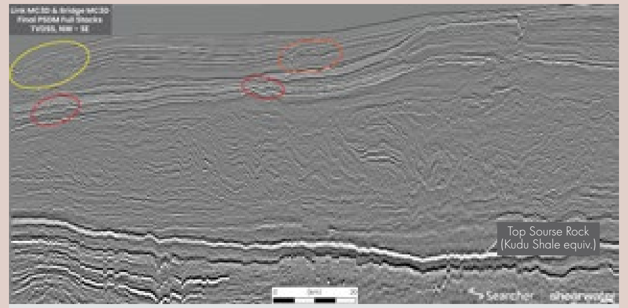


Figure 1: Multi-client 3D composite PSDM seismic line from the shelf to Outer High in Namibia's Orange Basin. Modern migrating pockmarks are clear at the sea bed in the west (yellow ellipse), and paleo-pockmarks (orange ellipse). In places, these are spatially correlated to small-scale faulting through the seal above the Gravity Driven fold and thrust belt (red ellipses).

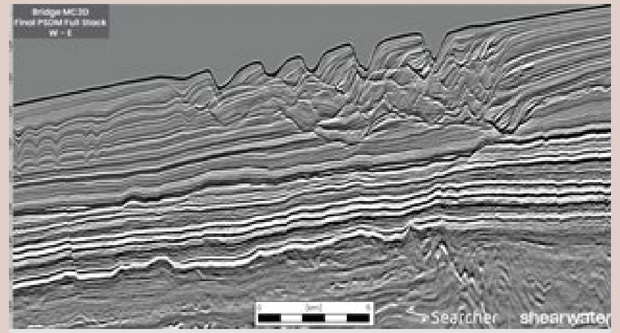


Figure 2: Left-hand side. Close up of westward migrating pockmarks associated with the Capricornus-1x discovery.

the spatial correlation of the characteristics of pockmarks, and source maturity modelling suggests these may be hydrocarbon generation and phase indicators.

In the Orange Basin, the larger migrating seabed pockmarks features (Figures 1 and 2, approximately 1,500 m wide and 250 m deep) are densely concentrated over and inboard of the Outer High, a basement ridge trending SE-NW along the basin margin. Oil seepage and slicks are also abundantly observed on SAR satellite images, such as those captured by Clément Blaizot in the same area (Figure 3, RHS). These larger pockmarks, whilst initiated by fluid flow to the surface, are understood to have subsequently migrated down slope under down-dip (gravity-driven) seabed current flow (Figure 3) locally focused through notches / canyons in the shelf edge.

Using exploration well and BSR-derived geothermal gradients to model the maturity of the Aptian source rock over and inboard of the Outer High (Figure 3), the larger pockmarks near the current seabed are spatially well correlated to the modelled, relatively recent generation of oil. On Figure 1, earlier forming large migrating pockmarks are located further to the east. When the early pockmarks formed to the east, the Aptian source rock was buried by an identical thickness of sediment to that above the source rock today in the west. The early pockmarks showed the onset of maturity of the source rock to the east, which migrated with further burial to the west. Today, the source rock to the east could be generating gas, feeding the narrow "pin prick" fluid pipes seen to the east (Figure 3). Fortunately, late gas is not charging the plays over the inner basin as exploration wells in this fairway are still discovering light oil. In April 2025, Rhino Resources drilled the Capricornus 1-X well, discovering 38 m of Lower Cretaceous sand which produced 37° API oil-on test at rates in excess of 11,000 stb/d.

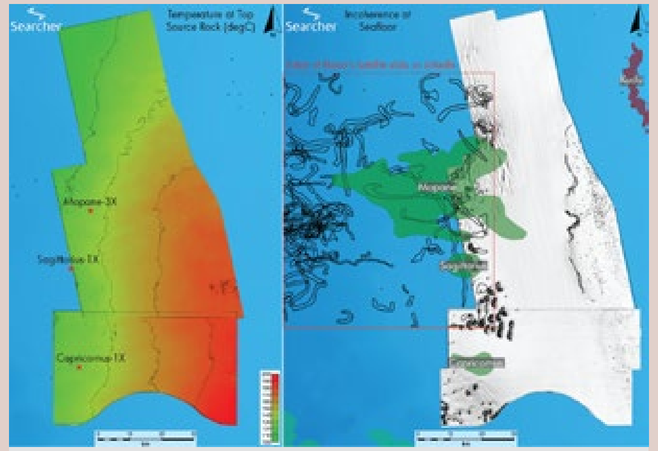


Figure 3: Left: Present day thermal map of the Aptian Source rock over the Link and Bridge 3D survey areas. Oil generative source rock "green", condensate to gas generative source rock "red". Pockmarks associated with light oil discoveries Mopane-3X and Capricornus 1-X inboard of the Outer High in the Orange Basin. Right: Overlay of Clément Blaizot's LinkedIn Satellite slicks (black polygons) on seabed map showing the large pockmark distribution.

pockmark clusters are also spatially correlated with numerous stacked AVO Type III anomalies in the underlying Gravity Driven Fold and Thrust Belt (GDFTB). There is possible bimodal correlation of the location of the pockmarks to small faults observed cutting the uniformly bedded mudstones above the GDFTB, however this fluid pathway observation requires further definition.

Taking the spatial correlation of modelled oil mature source to pockmark trails across the Atlantic to the Pelotas Basin, it's cool to observe linear pockmark trails located above the thick (up to 400 m) Aptian source rock that is again modelled to lie in the oil generative window (Figure 4). There are strong AVO and other DHI's (Direct Hydrocarbon Indicators) throughout the Cretaceous and Early Tertiary plays crossed by the inferred pathway of the hydrocarbon to the seabed, suggesting that the Pelotas is an extraordinarily exciting basin to explore.

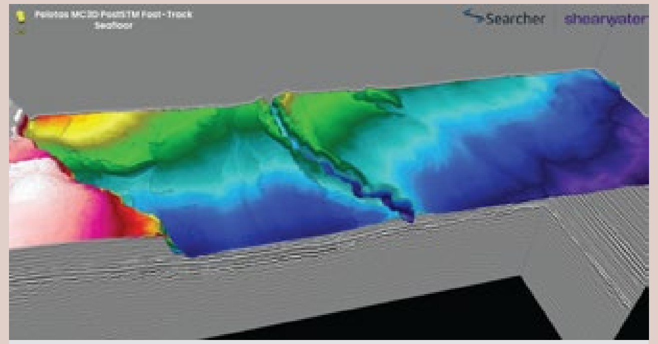


Figure 4: Southern Brazil Pelotas Basin pockmark trend revealed on 2024 Multi-client Pelotas dataset. This lies above the thickest Aptian source rock interval (approximately 400 m), modelled to be in the oil window using a BSR-derived geothermal gradient.

A similar relationship has been observed in the Punta del Este Basin to the south, published in GEO EXPRO (Vol. 21, Issue 1, 2024) as part of a joint Searcher Ancap publication. Many authors have noted the correlation of very similar pockmark trails in seabed channels to underlying oil discoveries (for instance, Bryan Cronin recently from the Ghanian Tano Basin, but also examples from Angola, etc).

In frontier exploration mode, pockmarks and fluid pathway indicators that correlated with seabed sampled oil can be found in deepwater Nova Scotia, where Searcher offer one of the world's most rigorously acquired and processed wide Azimuth (WAZ) 3D datasets, the huge Tangier 3D. One recent well drilled in the Tangier 3D area discovered oil in a sub-salt canopy setting. Here we have integrated all the compelling DHI's and pockmark information revealing a stacked AVO Type III sand channel play (Figure 5), similar to the Yatzil-1 discovery made by ENI in the Campeche salt basin in the Gulf of Mexico. A license round was announced and opened here this month.

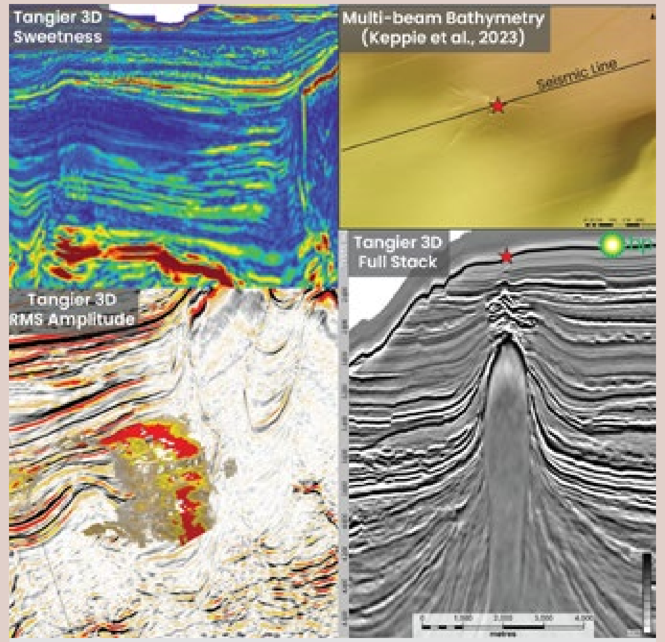


Figure 5: Elektra prospect identified in the Tangier 3D dataset offshore Nova Scotia. Inferred Mid Jurassic source rock modelled to be in the oil window, depth conformant stacked salt flank Avo Type III anomalies and pockmark with seabed sampled oil seep. This prospect is part of the 2025-2026 offshore Nova Scotia Bid Round offering.

Pockmark observations and oil discoveries make a good start to this story. Pockmark evolution, suggestive of early-generated fluid (oil) and late-generated fluid (condensate / gas), provides a spatial correlation that supports a causative model. Getting this story together, i.e. "integration" of fluid flow phenomena with seismic DHI's and source rock maturation modelling, is a developing toolkit to reduce (or accurately assess) phase risk. Bishop Pontoppidan would approve – and we need to integrate every observation we can make if we expect to get our oil finding game on.

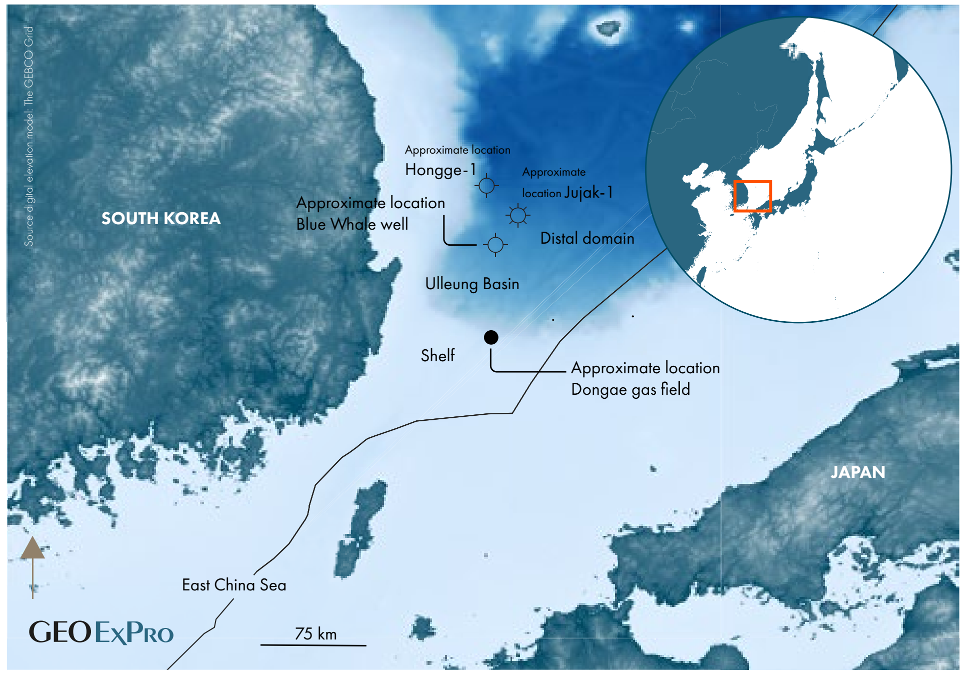
OIL & GAS

"... when exploration geoscientists build new plays and prospect portfolios, they must: Step back and model the entire tectonic region, apply learnings from analogue geologies, collaborate closely with well-design engineers to prognose structural deformation, and replace gut feelings with multiple, testable hypotheses"

Graham Banks – Route to Reserves Consulting

Exploring young petroleum systems comes with risks

The recently drilled Blue Whale well in South Korean waters targeted a sizeable deep-water sandstone prospect in what could be seen as a Jubilee-type analogue closure. But the source rock for this young petroleum system has yet to be determined



Any exploration well carries risk, and ultimately, it is the drill bit that will either prove or disprove a play concept. In South Korean's Ulleung Basin, despite the presence of a small number of gas finds, one of the risks when it comes to further exploring its potential is the age of the basin and its infill – has there been enough time for gas to migrate into the omnipresent deltaic and related deep-marine sandstones? The age of the main reservoir targets is Miocene, with subsequent Plio / Pleistocene burial required to "switch on" the associated kitchens.

It is a question that makes even more sense when one realises that the source rocks of the thermogenic gas that is known from the largest gas field - Donghae - has never been drilled to date. Is it an organic-rich interval at the base of the Ulleung Basin's sedimentary infill, or is it rather the more dispersed organic matter that forms part of the more distal and marine succession of the sedimentary wedge? It makes petroleum systems modelling quite a tricky exercise.

Thus far, Woodside and ENI have drilled the most northerly located wells in the basin (Jujak-1 and Hongge-1). Hongge-1 drilled a closure along a transform zone, where the reservoir was ultimately contaminated by significant amounts of CO_2.

The timing and duration of gas generation must certainly be questions that have been asked by operator KNOC after drilling the recent dry Blue Whale well in Korean waters. The well was highly anticipated, not only by the Koreans themselves but also by operators that had previously been looking at the Ulleung Basin. With a gas-hungry market close by and the likelihood of obtaining star status when hitting a giant, there is certainly an appeal to exploring this part of the world.

Reservoirs are aplenty. The Ulleung Basin – even when many Koreans will not like this – are ultimately sourced and transported by major fluvial systems that derived from the South China Sea. Small tributaries from the Korean peninsula – the more favourable candidates for the Koreans – would certainly not have resulted in such an amount of juicy reservoir sands delivered. This preference for locally sourced sands is not unique to the Koreans, by the way – a similar story can be told about Israel and their preference to source the Tamar reservoir sands from their country rather than from the Nile and its precursors. But that is a by-the-by.

The Blue Whale well was dry, but that doesn't mean that there is no exploration potential left. There are multiple – albeit subtle – plays to be further explored, both in the deep-marine as well as in the more shelfal realms of the northeasterly-prograding depositional system. ■

Henk Kombrink

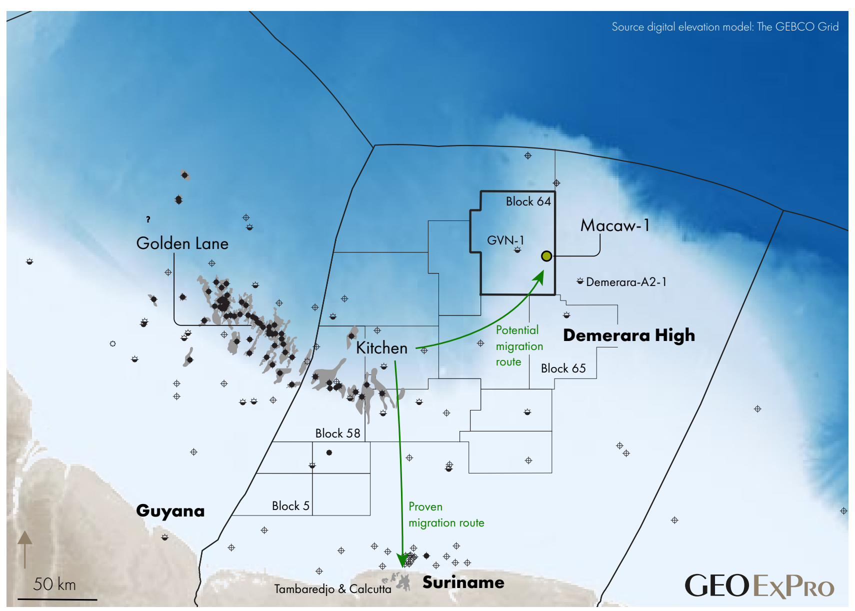
Back on the shelf

In what is the onset of an exciting exploration campaign offshore Suriname, we take a look at the Macaw-1 well that is currently being drilled by TotalEnergies on the Demerara High

As TotalEnergies is moving ahead developing its deep-water discoveries in Block 58 in Suriname waters, there is a drive to discover more resources nearby. And rather than focusing on deep water, as was done in recent years, the shallows of the Demerara High have come back on the radar, again. Not only for TotalEnergies, but also for other explorers; Shell is planning on drilling the Araku Deep-1 in Block 65, and Chevron may have identified another hydrocarbon migration pathway heading south from the kitchen in the north – they will target the Korikori prospect in Block 5.

The shelf has had a few periods of exploration activity before, and it is the information derived from these wells that can subsequently be used as material to learn a bit more about what the French are targeting with Macaw-1 in Block 64.

The closest well was drilled by Tullow in 2021; Goliathberg-Voltzberg North-1 (GVN-1). Did this well drill a similar target as Macaw-1? Both wells are situated on the Demerara High, but it is thought that the Tullow well was planned in such a way that it tapped into a Canje source rock preserved in a local and small mini-basin on the Demerara shelf. Given that the well was dry, this might indicate that the source rock maturity was insufficient. Another risk that can probably be linked to GVN-1 is migration. Even if the source rock from the local Canje pool would have been in the oil window, hydrocarbon migration would probably have taken place in a radial manner, lacking structural focus, leading to a risk of underfilling reservoirs surrounding the mini-basin.



When looking at the absolute distance oil might need to migrate out of the kitchen towards the currently drilling Macaw-1 well, it is of the same order of magnitude as the distance the oil travelled to the Tambaredjo and Calcutta fields. From that perspective, it may not seem too far-fetched an idea.

It looks like there is no mini-basin at the location of the TotalEnergies well, which makes it likely that the company works with a Lower Cretaceous Canje source rock model that migrated from the kitchen in the west. This is the same source rock that also generated the Golden Lane discoveries. However, the distance is long and, so far, no commercial discoveries were made on the Suriname offshore shelf apart from the Tambaredjo and Calcutta heavy oil fields that are located just onshore. This, however, has shown that long-distance migration does work.

Whether the TotalEnergies well is in the right place to be on the receiving end of a long-distance migration path from the deeper parts of the basin is unknown. In that respect, Demerara-A2-1 drilled by Exxonmobil in 1977 seems to be in that very spot, where migration pathways from the kitchen in the west meet. It's interesting that this was already understood in the 1970s, using much more rudimentary seismic data.

Another possibility is that Macaw-1 targets a deeper source rock in Jurassic carbonates. These carbonates could also form a potential reservoir, being intercalated with more basinal mudstones that might have generated hydrocarbons. There have been reports of indications that a lacustrine source rock is present on the Demerara High, even though the evidence for that seems a little flaky.

Whatever the play model that TotalEnergies favours, a discovery at Macaw will be a very encouraging sign for Suriname in general and the Demerara High in particular. ■

Henk Kombrink

OIL & GAS

Better illuminating the Rotliegend beneath a heavily deformed overburden

To de-risk remaining gas prospects in a geologically complex part of the Dutch North Sea, Shearwater acquired an OBN survey that did not come without challenges

In April of this year, the main stakeholders in the offshore energy landscape in the Netherlands signed the so-called "Sector Accord", which brought more clarity and momentum to exploring for and subsequently producing what remains to be found.

The OBN survey by Shearwater in the K15 and K18 offshore blocks, which was the first OBN survey ever acquired in the Dutch sector, serves as a good example of the effort to find these additional gas resources.

Preparations for the 1,000 km^2 survey, which was supported by NAM, Shell, Wintershall, Tenaz, ONE-Dyas, RockRose Energy and EBN, already started in 2020 with acquisition kicking off in September 2022. However, with the first autumn storms also arriving, the North Sea had a few surprises for the crew.

The currents moved some of the nodes over about a 100 m distance, requiring them to be picked up and redeployed. That ultimately led to a total survey duration of 186 days instead of the planned 72, but despite this set-back, the results are reported to be of excellent quality.

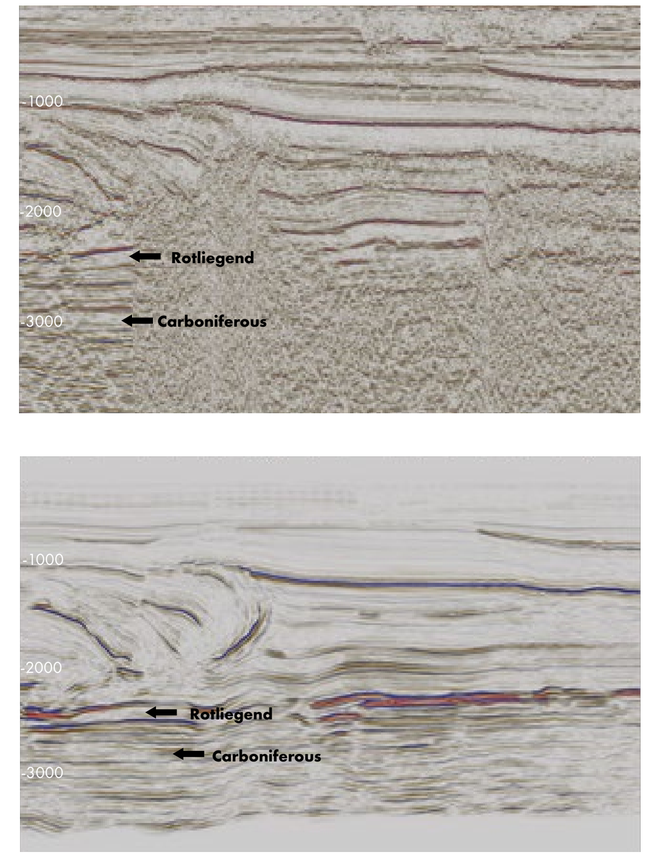
ROTLIEGEND PROSPECTS

Situated at the northern edge of the Broad Fourteens Basin, which is a Jurassic graben system that was inverted in Cenozoic times, the surveyed area is one of the most geologically complex in the Dutch offshore. This is mainly because overthrusting resulted in the juxtaposition of strata that are challenging to image at the best of times; i.e. the evaporites of the Zechstein and the Upper Cretaceous Chalk. For that reason, the limited offset of the legacy surveys did not bring the level of detail required to further de-risk the mostly Rotliegend prospects that sit below the Zechstein evaporite succession.

Recent advances in long-offset OBN technology, primarily gained in the Gulf of Mexico, formed the main driver to invest in this survey, for which a minimum largest offset of 9 km was used. The results indeed show a clear uplift in imaging of the sub-salt Rotliegend and Carboniferous succession, with fault blocks being better illuminated. Work has now started to de-risk the Rotliegend prospects and hopefully, with the Sector Accord now in place, get them drilled in the next few years, before the other surrounding assets cease production.

With Canada-based Tenaz Energy having taken over NAM's offshore assets, there has been a very recent change of ownership in the survey area, but new eyes can sometimes be a good thing when speeding things up. ■

Henk Kombrink



Legacy (top) and new OBN lines (bottom) showing the uplift in imaging of the complex geology.

SOURCE: EBN, SHEARWATER

Why target the surface synclines in the flat foreland of a fold-and-thrust belt?

Exploration results in Iraqi Kurdistan reinforce old-school analyses

GRAHAM BANKS, ROUTE TO RESERVES CONSULTING

IMAGINE an onshore petroleum province that has three proven plays and a supergiant oil field suddenly opening up for international business and exploration companies. Except, it has no modern seismic data, no recent wells, and almost zero data available from historic oil fields. This was Iraqi Kurdistan in 2006 - 2010. Imagine the stampede of junior petroleum exploration companies, followed soon after by National Oil Companies and petroleum supermajors. It was exhilarating.

Imagine yourself as an Exploration Director. Where in 30,000 km² would you lease exploration license blocks using only anecdotes in textbooks, surface geology maps being hastily created from pre-Google Earth satellite imagery, and a few PDFs of wireline SP logs from 1970s wells? A, B or C?

A. The Zagros Foothills Zone (ZFZ): Flat topography; long, linear surface synclines between emergent thrusts; >2 km thick molasse overburden; the region's dominant petroleum topseal eroded off the occasional hills; rumours of reservoir overpressure.

B. Zagros Mountain Front Zone (ZMFZ): The first belt of textbook, whaleback anticlines–each 40 km² and 0.5 km tall–capped by the region's dominant petroleum reservoir.

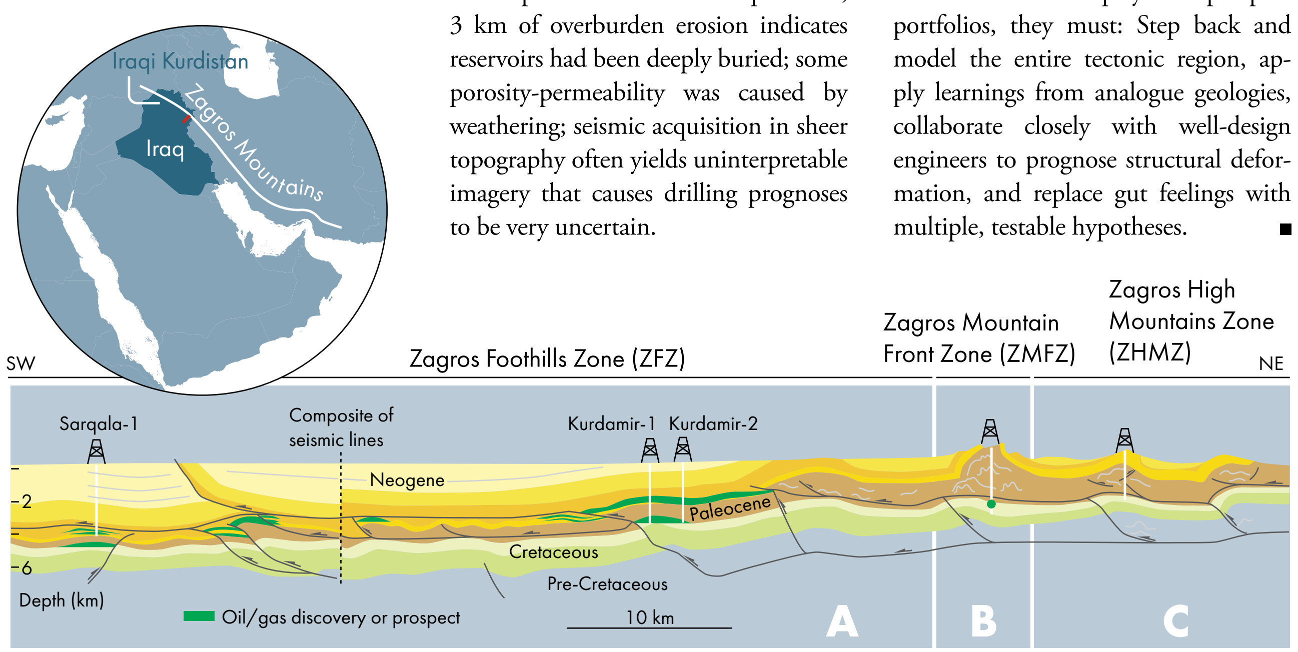
C. Zagros High Mountains Zone (ZHMZ): Several belts of whaleback anticlines – each up to >50 km² and >1 km tall – that expose new plays containing high porosity-permeability.

Most companies flocked to the ZMFZ (B) and ZHMZ (C) to, "drill the biggest anticlines" and, "prove new, deep plays." With only limited success. There are several likely explanations that are evident from scrutiny of the surface geology and analogue orogenic belts: Petroleum system components are exposed to meteoric processes; 3 km of overburden erosion indicates reservoirs had been deeply buried; some porosity-permeability was caused by weathering; seismic acquisition in sheer topography often yields uninterpretable imagery that causes drilling prognoses to be very uncertain.

Instead, WesternZagros Resources and I selected ZFZ (A). Why? Experience exploring other orogenic belts provided confidence that: The thick molasse overburden and near-surface synclines would enable good seismic imaging of the underlying anticlines; high probability of retention of tall petroleum columns; similarities between the anatomy and uplift mechanisms of the Zagros and Canadian Rocky Mountains orogenic zones; a strategy to pursue the most probable reservoir traps rather than the biggest surface anticlines.

As proof of our hypotheses, WesternZagros Resources discovered the Kurdamir oil-gas field and Sarqala oilfield in the ZFZ in fault propagation folds on excellent seismic imagery. Fifteen years on, the ZFZ has yielded almost all of the petroleum fields and produced barrels of oil and gas.

To conclude, when exploration geoscientists build new plays and prospect portfolios, they must: Step back and model the entire tectonic region, apply learnings from analogue geologies, collaborate closely with well-design engineers to prognose structural deformation, and replace gut feelings with multiple, testable hypotheses. ■



The most successful wells were drilled in the Zagros foothills.

REDRAWN AFTER THE ORIGINAL COMPILED BY GRAHAM BANKS

Why peer reviews often don't work

Every E&P company is obsessed with their drill sequence. And for good reasons, because that's where the money is spent and where the money is made – in the long term. But are the right processes in place to ensure that the best prospects are being drilled first?

GIS PAX PLAYER

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

REPUTATIONS are both made and destroyed in the aftermath of the drill sequence. But what is behind the ranking that determines where the rig goes next? It is the prospect evaluation process, the process that determines which prospect has the largest potential.

In turn, to make sure that it is genuinely the highest potential prospects that end up at pole position in the drilling sequence, many companies use a peer review process, where the "prospect police" sit with the evaluation teams and agree on volumetric and risk assessments for each potential drillable feature.

This peer review process is not required for smaller companies that only have one licence and two prospects, but the larger companies, especially those that operate in more than one basin, surely need some form of oversight in their attempt to allocate capital most sensibly.

Some peer review styles are dictatorial, some are collaborative. In some companies, the same people fly all over the world to ensure consistency, even though it is permitted in places for their recommendations to be ignored by the exploration manager. It others, it isn't. No matter what the organisational style is, the result of the peer review system is that in most companies, there is only a very small number of approved and drill-ready prospects. In other words, it is all quite shallow.

And there are other significant drawbacks of the peer review process. The first obvious one relates to the boss. If he or she is in the room, forget about an objective and technically focused discussion – people will be more concerned about keeping their jobs. It is a lot better without the boss being around, but still, it rarely happens that the same review done by the same team twice will result in the same number. Let alone when the evaluation is carried out with other experts. In addition, non-exploration managers who sometimes get involved at a later stage have the tendency to throw out the risky prospects that have a POS of less than 20 %. It is these prospects that may hold your next big find!

In contrast to what many companies think, there is an alternative to the peer review system: Numeric split risk maps. In most basins, the risks associated with reservoir presence, seal, trap and charge can be established from the data. If this is organised in split risk play maps, peer reviews tend to be much quicker. The added benefit is that you now maintain a set of maps that capture a range of prospects rather than having to discuss each individual prospect during a separate meeting. And last but not least, by having this system in place, many more prospects can be ranked in one go, providing more depth to the portfolio that ultimately determines the drill sequence. ■

Henk Kombrink

IMAGE: TOODLINGSTUDIO VIA PIXABAY

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

Global trends in petroleum fiscal terms: A race to the top?

With upstream capital available for oil and gas in rapid decline, many countries have implemented more favourable conditions to attract investment. But not all

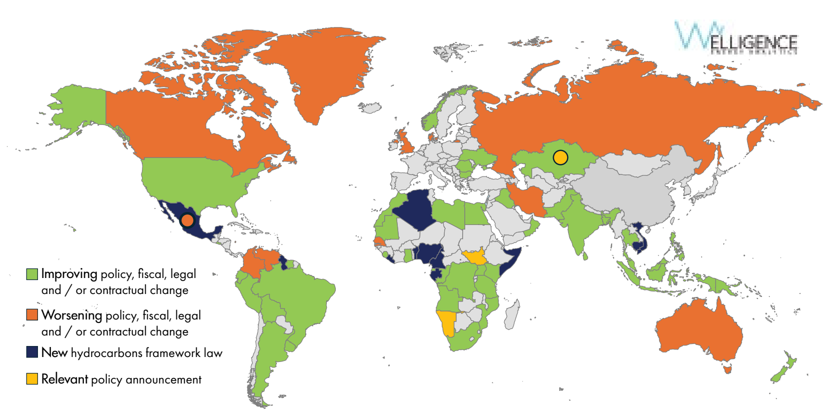
CARLOS BELLORIN AND RUARAIDH MONTGOMERY, WELLIGENCE

As competition for upstream investment intensifies, countries across the globe have responded with a wave of fiscal and regulatory reforms aimed at attracting limited capital. Since the 2014 oil price crash, upstream capital availability has declined dramatically - from a $779 billion peak to around $550 billion annually - forcing governments to rethink their hydrocarbon strategies. Between 2019 and 2025, at least 72 countries introduced major changes to their petroleum fiscal frameworks. Most of these reforms have been investor-friendly, though a minority of jurisdictions have pursued more adversarial paths.

INVESTOR-FRIENDLY REFORMS DOMINATE

Out of the 72 countries that enacted reforms, 62 made positive changes, including targeted incentives for mature or undeveloped assets, adjustments to model contracts, or complete fiscal framework overhauls. Some countries, such as Angola, Nigeria, and Brazil, focused on enhancing their existing fiscal regimes. Others, such as Libya and Indonesia, introduced new model contracts designed to improve operational flexibility and bankability. Meanwhile, jurisdictions like Guyana, Vietnam, and Gabon opted for full-scale legal and regulatory overhauls, aiming to modernize outdated petroleum laws and respond to changing investor expectations.

Key motivations behind these reforms include declining domestic production, a reduced pool of E&P capital, and growing urgency to monetize stranded or underexplored assets that may lose relevance amid the energy transition. Governments also increasingly recognize, that without robust fiscal incentives - especially for small and mid-sized operators - access to financing will remain constrained.



Select hydrocarbon policy, fiscal, legal and contractual changes (2019 - 2025). Countries subject to USA and / or EU sanctions are classified under the 'worsening' category.

SOURCE: WELLIGENCE

REGIONAL REFORM LEADERS

Africa has emerged as a leader in investor-friendly changes, with 25 countries reforming their fiscal or legal frameworks. Southeast Asia also stands out, with every hydrocarbon-producing country implementing changes. In the Middle East, Oman and Iraq have introduced new contractual models aimed at providing more flexibility and improved upside potential. Latin America, however, presents a mixed picture: While Brazil, Trinidad & Tobago, and Uruguay moved toward greater competitiveness, Mexico and Colombia introduced investor-adverse policies.

A SMALL GROUP MOVES AGAINST THE TIDE

Ten countries took countercyclical actions that may deter investment. These include windfall taxes in the UK, exploration contract halt in Colombia, and the partial reversal of the 2014 energy reforms in Mexico for a more state-centric approach. Such measures, often driven by political or ideological motives, can damage investor confidence and may be difficult to reverse, even under new leadership.

WHAT COMES NEXT?

While fiscal terms are a critical component of investment decisions, they are only part of the story. Other factors include the cost of entry, regulatory efficiency, and implementation capacity. In today's capital-constrained environment, governments not only need to offer competitive terms - they must also execute efficiently to convert interest into investment. ■

FEATURES

"It is the mines that attract the headlines, but the vast majority of the resource, especially those at depths greater than 60 m, will be or are being extracted through in situ recovery solutions, which means drilling steam injection and oil production wells"

Graham Spray – AGAT Laboratories

Bottom-up meets top-down

They have only met about four times. Yet, Martin Neumaier and Lukasz Krawczynski work together like they have been colleagues for many years

IF THERE is one positive aspect to this day and age, it is the ability to form solid working relationships even when people are living at opposite ends of the world; Martin enjoys the French sun near Montpellier, whilst Lukasz makes the most of Adelaide's moderate climate. Both grew up in Germany though, but they never met each other.

It was at a conference that they shook hands for the first time. It was 2019, and the AAPG had organised what we now know as the last Hedberg Conference in Houston. It was attended by the world's leading basin modellers and petroleum systems analysts.

"There were a lot of big names around," says Martin. "Seasoned experts were celebrated for their lifetime achievements in organic geochemistry, and basin modelling experts presented the future of basin modelling. It was a highly specialised conference, but it was very theoretical and, in my eyes, it was lacking pragmatic and decision-focused approaches."

TOP-DOWN AND BOTTOM-UP

"It was the first time I attended a conference focusing exclusively on petroleum systems, meeting the gurus," adds Lukasz. "The majority of workflows presented were very labour-intensive, focusing on fully coupled 3D basin models. I was mentored by Zhiyong He and Andrew Murray, advocates of a more practical approach to petroleum systems analysis (PSA) with a strong focus on "top-down" PSA."

"Bottom-up petroleum systems modelling is the classic approach that comes with reconstructing the 4D structural, depositional and thermal evolution of sedimentary basins. Combining this with source rock parameters, hydrocarbon generation, expulsion, migration and retention is subsequently predicted, as part of a process-based numerical simulation," explains Lukasz.

"Top-down PSA starts at the other end of the spectrum, relying much more on studying the hydrocarbon PVT, geochemistry and seal properties of fields and discoveries. Modelling is not necessarily part of the study, and if it is, it is mostly done in a very pragmatic way, using 1D simulation or map-based workflows. This allows people to make predictions on the type of hydrocarbons without the need to create a basin-scale model. And because we do not rely on large grids or complex algorithms, those workflows are much faster, allowing for quick scenario testing and probabilistic predictions," adds Lukasz.

> "Top-down PSA starts at the other end of the spectrum, relying much more on studying the hydrocarbon PVT, geochemistry and seal properties of fields and discoveries… those workflows are much faster, allowing for quick scenario testing and probabilistic predictions"

PAPUA NEW GUINEA

Lukasz presented his top-down PSA study in the Papuan Basin in Papua New Guinea. Without trying to reconstruct the 3D basin history, Lukasz was able to make a case for oil discoveries being primarily associated with structures that have undergone thin-skinned deformation, whereas condensate/gas discoveries seem to be linked to thick-skinned deformation. Doing it this way, he had arrived at a quantitative and predictive model explaining the variation in observed reservoir fluids in a much faster and yet scientifically sound way.

EYE-OPENING

When Martin saw Lukasz's presentation, he saw someone proposing a fresh approach to petroleum system analysis. "It opened my eyes," Martin says. "I had just left Schlumberger after ten years, where we always pushed for the classical bottom-up simulations as being the only solution. I picked it up immediately and saw the potential of this approach to bring oil versus gas predictions into the very heart of prospect assessment, and with that decision making."

"Standard prospect assessments deal very poorly with fluids," adds Lukasz. "You are expected to know if your prospect holds oil, or gas, or both, and the respective column heights. I saw people coming up with far too optimistic scenarios, some of which were physically not possible. Bottom-up basin modelling is very limited in that perspective. Top-down PSA fills that gap between petroleum systems and prospect assessment."

DEVELOPING IDEAS

Coming back from the Hedberg conference, Martin started developing the concept further. "Quickly surpassing the capabilities of spreadsheets, I started to learn to code."

A PUB AND A NAME

The name top-down PSA as a methodology was coined in a pub by industry stalwarts Zhiyong He and Andrew Murray, two passionate members of the petroleum systems analysis community. Zhiyong is the driving force behind the Zetaware software, and Andrew Murray has been consulting for more than ten years following a career as Woodside's principal advisor on petroleum systems.

Within months, Martin created 20,000 lines of code that performed a "source to trap" probabilistic risk and volume assessment. He then showed his prototype to colleagues and friends. "There was no ambition to make it a real product initially – I just did it by passion," he adds. But without being aware at the time, Martin had set the foundation for Ariane, a new prospect assessment software.

Lukasz was one of the early adopters and supporters of the software. He worked for Australia-based Santos, where he was involved in basin modelling for petroleum systems and carbon storage projects. When he saw early versions of Ariane, he was impressed and encouraged Martin to turn Ariane into commercial software.

A TEAM EFFORT

But Martin could not do this alone. He was joined by Ben Kurtenbach, who led the development of Schlumberger's basin modelling software, and Ian Bryant, who did all the strategic acquisitions for Schlumberger's exploration software portfolio. Together, they founded Germany-based ArianeLogiX.

Today, five years later, and with the assistance of advisors such as Lukasz, Andrew Murray, Jan de Jager and other very experienced E&P professionals, Ariane is a prospect assessment platform for oil and gas, carbon storage and natural hydrogen which has been adopted by major international E&P companies.

Lukasz Krawczynski (left) and Martin Neumaier (right) at the 2024 EAGE Workshop on Advanced Petroleum Systems Assessments – In Pursuit of Differentiated Barrels, Kuala Lumpur. July 2024.

PHOTOGRAPHY: PRIVATE ARCHIVE

> "...it's not about bottom-up versus top-down PSA. Both have their place in the workflows. The type of project determines whether you choose one or the other. Ideally, bottom-up meets top-down; this is where you have the greatest confidence"

"Ariane has gone a long way since its inception at the Hedberg conference," Martin reminisces, "and despite the fact that we have added many modules, fluids are still at the heart of it."

STILL A LOT LEFT TO EXPLORE

"When I left Santos last year," Lukasz says, "I did not need to think long about the name of my own consultancy business – Top Down Petroleum Systems." In that capacity, he continues working with Martin on the development of Ariane, whilst also working closely with Andrew Murray on other projects.

"Don't get me wrong, it's not about bottom-up versus top-down PSA. Both have their place in the workflows. The type of project determines whether you choose one or the other. Ideally, bottom-up meets top down; this is where you have the greatest confidence."

"We link the various PSA approaches to quantitative and probabilistic prospect assessment and solid decision making," concludes Martin. "There is still a lot to explore, also beyond hydrocarbons." ■

Henk Kombrink

Gulf of America: Salt-driven structures, data-driven discoveries

ANDREY BOGACHEV AND CLAY WESTBROOK, TGS

The Gulf of America (GOA) remains a vital hub for U.S. energy security, contributing over 15 % of the nation's oil production. Yet, the region's potential is far from fully tapped, particularly as exploration shifts into the geologically complex salt provinces of the Western GOA. To unlock these opportunities, the industry is leveraging new seismic technologies that push imaging from the seafloor to the basement, illuminating structures once hidden beneath thick salt and deepwater sediments.

Figure 2: Amendment 4 and Amendment E-DMFWI, 1 and 2 (in partnership with SLB).

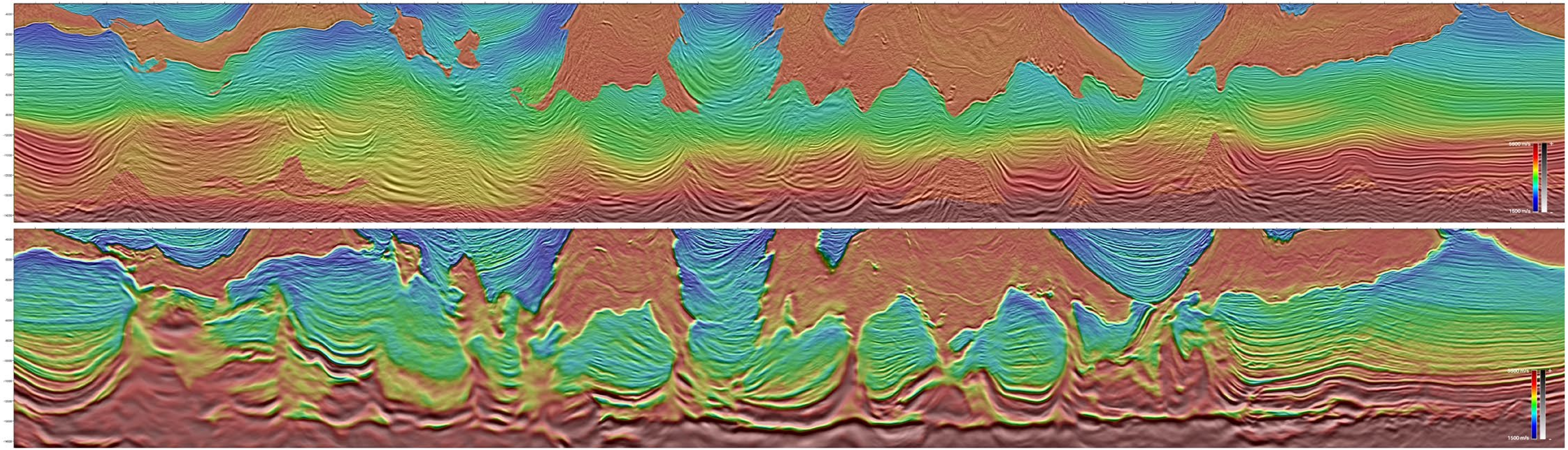


Figure 1: Top: Legacy Wide Azimuth Streamer RTM data. Bottom: Amendment E-DMFWI 24Hz FDR.

SOURCE: TGS

Sharper imaging, smarter exploration

How cutting-edge seismic techniques are transforming risk assessment in the GOA

Since 2019, long-offset Ocean Bottom Node (OBN) technology has become a cornerstone for advanced imaging in the GOA, providing clearer views of subsurface structures that help reduce drilling risks and improve prospect evaluation. Recent Amendment surveys by TGS and SLB demonstrate the power of pairing long-offset OBN with next-generation processing techniques, delivering cleaner images that enhance structural interpretation and stratigraphic mapping.

Elastic Dynamic Matching Full Waveform Inversion (E-DM-FWI) Derived Reflectivity (FDR) further sharpens this lens, addressing illumination challenges beneath salt canopies while improving reflector continuity and the clarity of salt-sediment interfaces (Figure 1). These advances are critical for identifying and de-risking salt-related traps and improving the predictability of reservoir presence, quality, and continuity.

High-resolution imaging now extends from the basement to the seafloor (Figure 4), offering unprecedented clarity of geological structures. This leads to a deeper understanding of tectonic history, including the identification of previously obscured fault systems and structural boundaries. Enhanced delineation of deep carbonate formations - marking the base of the prospective Miocene section - improves our understanding of regional salt tectonics and sediment pathways. Additionally, clearer imaging of salt body geometry allows refined interpretations of depositional environments and bypass zones, which are essential for predicting reservoir quality and continuity.

BUILDING HIGH-FIDELITY VELOCITY MODELS

High-resolution seismic imaging relies on a robust, accurate velocity model. Using FWI workflows, these models now capture the complex velocity contrasts associated with salt geometry and subsalt sediments, reducing structural uncertainty in depth imaging. This enables better identification of source rock intervals and highlights the influence of basement topography on the deposition of organic-rich sediments, often linked to productive hydrocarbon source rock.

Figure 3: Single source vessel towing 4 Gemini sources, one per gun string during Amendment 4 OBN acquisition.

GEMINI: LOW-FREQUENCY POWERHOUSE FOR DEEP IMAGING

To maximize the value of long-offset OBN, low-frequency energy is key. Enter Gemini, TGS's advanced low-frequency source technology designed to enhance deep imaging and feed low frequencies essential for FWI convergence. Generating energy down to 1 Hz, Gemini represents an environmentally enhanced approach to seismic source design, delivering low frequency signal at very long offsets and extending the subsurface reach of surveys across the deepwater Gulf.

Its operational simplicity, towing four Gemini sources on a single vessel (Figure 3), and its point-source design streamline data processing while reducing HSE exposure, improving operational efficiency and reliability, and simplifying handling, all while maintaining high data quality. By enabling a broader, deeper bandwidth for imaging, Gemini helps unlock the potential of underexplored plays within complex salt provinces.

AMENDMENT 4: A TRANSFORMATIVE STEP FORWARD

TGS's Amendment 4 project in the Mississippi Canyon (Figure 2) is a showcase of what happens when cutting-edge technology converges. By combining Gemini low-frequency source technology with long-offset OBN acquisition and E-DMFWI processing, Amendment 4 delivers a premium seismic product designed to illuminate complex subsurface features from the shelf to the slope. This approach positions operators to better understand challenging structures, refine drilling targets, and reduce exploration risk.

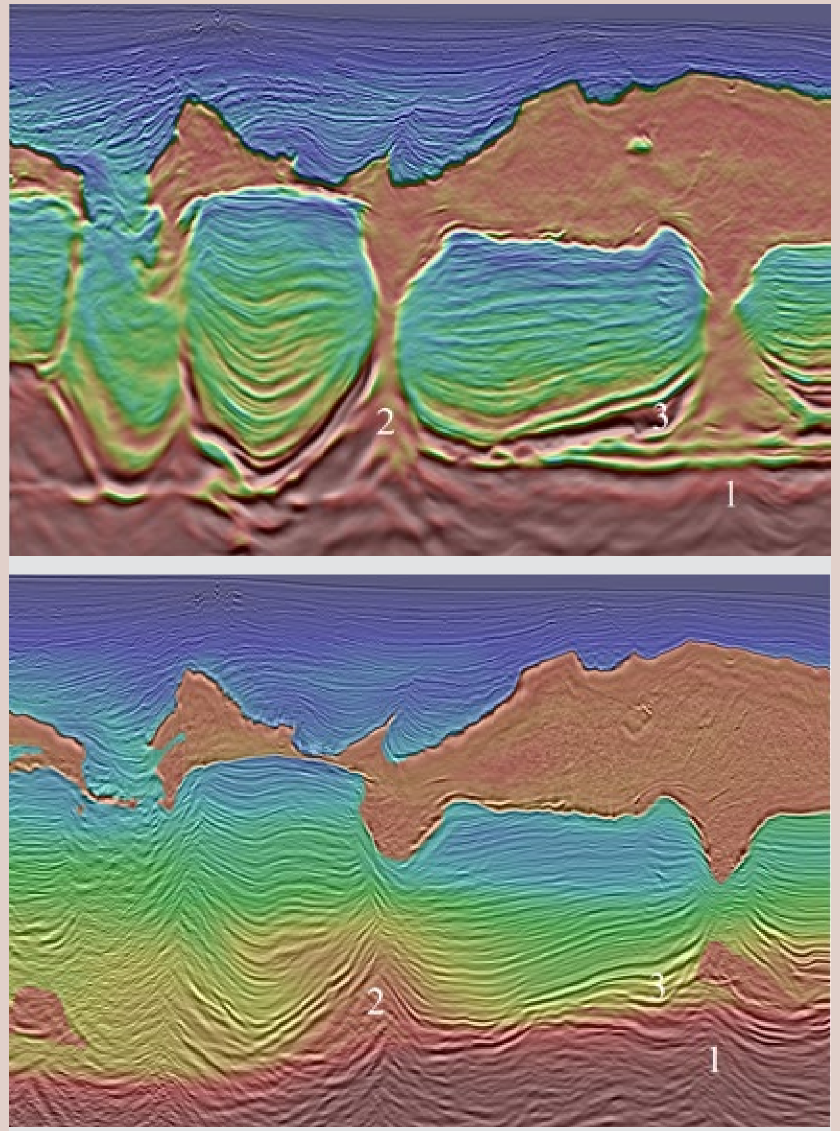


Figure 4: E-DMFWI 24 Hz FDR (top) shows: (1) improved basement imaging (2) better clarity of salt feeders and (3) deep carbonates, relative to legacy WAZ streamer RTM (bottom).

DRIVING TOWARD THE FUTURE

The Gulf of America's potential is tied to our ability to see deeper and clearer beneath complex salt bodies and deepwater sediments. As exploration activity moves westward into areas with higher geological complexity, adopting advanced seismic tools like long-offset OBN, Gemini low-frequency sources, and E-DMFWI becomes essential for finding the next wave of reserves. These innovations not only advance the science of seismic imaging but also contribute directly to US energy security and economic growth by enabling smarter, more successful exploration campaigns.

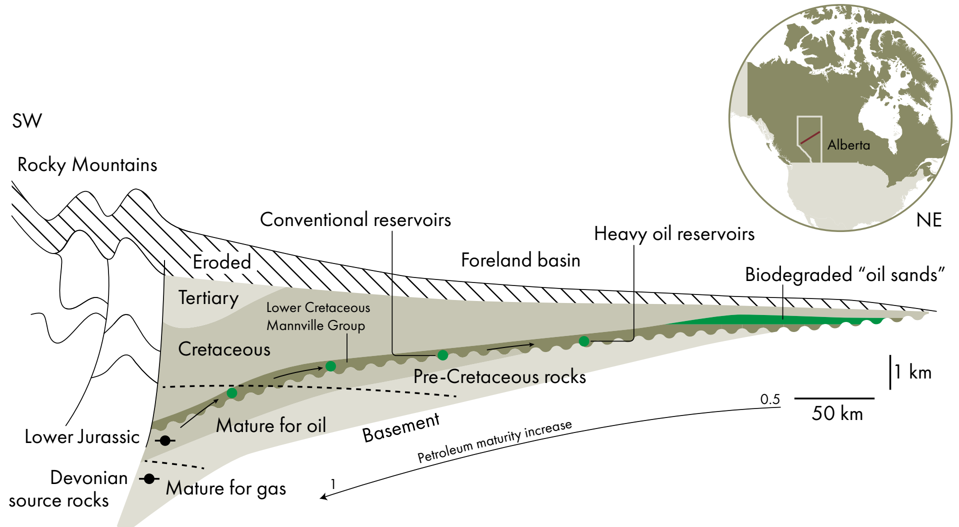
By investing in these technologies today, the industry is building the foundation for tomorrow's discoveries, ensuring the Gulf of America remains a cornerstone of sustainable, reliable energy supply for years to come.

The Athabasca oil sands

Where do they come from and how is it produced these days?

RECENT governments in Canada have not been particularly supportive of the oil industry, which mainly concentrates in Alberta. Some people are even actively contemplating separation from the Canadian federation and going it alone. Yet, it must still be concluded that despite the narrative and adverse legislation coming from Ottawa, oil production has increased steadily from the North American country.

There is one play that is responsible for this steady production growth. The Athabasca Oil Sands province of northeast Alberta. Situated in the most distant and shallow realms of the Rocky Mountains foreland Basin, the oil sands province hosts one of the largest oil resources in the world. And where open-pit extraction dominated at earlier stages, now it is predominantly through in-situ steam-assisted gravity drainage (SAGD).



Schematic cross-section showing how oil generated in the foreland basin of the Rocky Mountains makes its way via carrier beds in Lower Cretaceous rocks to where it is currently found today; both on deeper conventional traps as well as at the shallow and distal end of the spectrum, where the oil is currently being mined as well as produced through SAGD.

REDRAWN AFTER FOWLER & MORT (2017)

How did the oil get where it is currently produced from? And why is it being found at such shallow depths? In this article, we go back to the basics; Graham Spray from Agat Laboratories took the time to walk me through a presentation that he gave for a group of engineers in Fort McMurray, the town that can be considered the heartland of the Athabasca oil sand region.

THE BASICS

First of all, the area in which the oil sands are found is about the same size as England. It is considered that this vast space hosts about 1,700 to 2,000 billion barrels of oil, of which 10 % is currently booked as reserves. The implication of these numbers is that 98 % of Canada's oil reserves are in the oil sands. And it is all very shallow; the deepest deposits are about 600-800 m, whilst about 10 % of the total area is within mineable depths.

"It is the mines that attract the headlines," says Graham, "but the vast majority of the resource, especially those at depths greater than 60 m, will be or are being extracted through in situ recovery solutions, which means drilling steam injection and oil production wells."

LOOSE SANDS

The reservoir sands in which the oil is found are unconsolidated. This doesn't mean that they are young, though; the age is Lower Cretaceous. However, the sands never experienced significant burial, and combined with a mature mineral assemblage, of which 90 % is quartz, cementation is not a particular concern in this play.

"This lack of lithic fragments has another important advantage when it comes to steam-assisted production," says Graham, "because the mineralogical changes induced by the steam injection do not take place. The upper part of the oil-bearing succession in the area do consist of more immature sands, compromising an effective drainage of the oil."

NO-MAN'S LAND

There is currently a no-man's land between the areas where surface mining takes place and the areas where SAGD drilling happens. These are the areas where the overburden is too thick for open pit mining, but too thin for drilling. The reason for the latter is that a successful steam injection project needs a sufficiently thick overburden to prevent the steam, which is injected under high pressure, from making its way to surface in an uncontrolled way. That's why other technologies are trialled in these areas, such as "microwaving" the oil.

The sands of the McMurray Formation, in which most of the oil is found, was deposited by a Mississippi scale river system that drained the North American craton from south to north. "Only a small part of the sand fraction is from the Rocky Mountains that now form such a prominent feature to our west", says Graham, who is calling in from Calgary. At the time of deposition of the McMurray sands, the Rocky Mountains were not a huge topographic feature yet, as this only started in Late Cretaceous times.

The oil in the McMurray sands, even though the visitor centre in Fort McMurray will tell you that it resulted from in-situ transformation of organic material, is actually from the proximal part of the foreland basin where Devonian (Exshaw) and Lower Jurassic (Nordegg) anoxic shales were buried as a result of mountain building and the subsequent formation of a foreland basin. The oil thus migrated from west to east.

BIODEGRADATION AND GLACIATION

Most operators would prefer finding light oil over heavy oil. But if the oil in the Athabasca province would not have experienced biodegradation when it finally arrived in the area where it is now being found, after a long lateral journey through permeable carrier beds, there would not be any oil to produce left. The reason for that is the glacial cycles that took place in the last two million years.

The sealing units that occur on top of the McMurray sands were put to the test during the repeated loading and unloading as a result of the advancing and retreating ice caps. In combination with the overburden being scraped away – around 500 m was removed in places – the seals would not have been able to withstand the capillary pressure exerted by light oil", Grahan explained. "It was thanks to the fact that the oils had been biodegraded already, with lower mobility as a result, that the seal breaches did not result in the oil leaking away."

THE FUTURE

"Given the socio-political situation as it is at the moment, I think it is unlikely that more mines will open," says Graham. This is the reason why we will probably see the gap widen between oil produced through SAGD and mining – at the moment, they are approximately on par with each other.

The technological advancement leading to operators being able to pump more oil out of the ground is increasing rapidly. "Twenty years ago, when I started, it was quite common for operators to achieve a recovery factor of around 20 % using SAGD," says Graham. "Then I worked for a company that aimed at 60 % recovery, whilst a couple of years ago, a 90 % recovery was not exceptional, even reaching levels of 98 % in the very core of the reservoir."

What causes this step-change in oil recovery? I ask. "I think a lot is due to well placement techniques," continues Graham, "but there is a level of underestimation as well. We have a tendency of being wishy washy about things as geologists, but the reality is that the technique is just very effective. When we cut a core from a reservoir that has been stripped off the oil, it looks like white beach sand," he says.

It looks like Canadian McMurray oil is here to stay for a while.

Henk Kombrink

A panoramic view of Alberta's oil sands extraction site.

PHOTOGRAPHY: SHARAFMAKSUMOV VIA ADOBE STOCK

How to stand your ground as a YP working in the oil and gas industry?

At times when (social) media are quick to paint a negative picture of the oil and gas industry, young professionals are more challenged than ever to justify their career choices whilst maintaining a more factual narrative about the industry they work in

"LET'S not forget that the oil and gas industry is not the sole source for the environmental problems the world is facing," wrote one of the young professionals during the afternoon-long session organised by the Devex Conference YP committee in May 2025. It already paints a picture of the level of guilt experienced by the young geoscientists and engineers who recently joined the upstream business.

For the session, which took place in Aberdeen, Scotland, four presenters from various positions with connections to the industry were invited to share their views on how to communicate in today's diverse landscape, with the aim to ultimately have a more balanced discussion about the role of the oil and gas sector in today's energy mix.

The talks were followed by round-table conversations, and this write-up is a result of what was discussed, as a way to generate a tangible outcome of the conversations and to make the point that the oil and gas industry still attracts young people to work in. And that these people are not the climate-change deniers that some would expect them to be.

Lucinda Layfield from Equinor taking part in the round-table discussion at the Devex YP Event in Aberdeen.

DINNER TABLE DISCUSSIONS

Lucinda Layfield from Equinor gave an everyday example of the types of discussions young professionals face when being confronted with people who have a very different point of view. In her case, it was her father-in-law who challenged the role of the oil and gas industry in today's society. Initially unprepared to counter the arguments made, she quickly realised that she needed a basic mental fact sheet for making a more informed case as to why oil and gas are still required, and that new field developments on the UKCS do not necessarily mean a blow to the UK's carbon budget. In doing so, she felt much better prepared and even when her father-in-law would still disagree, she felt on more equal footing.

This experience was echoed by quite a few people in the audience who experienced similar situations, who also confirmed that having some facts at hand does help in setting the scene. At the same time, some participants mentioned that their background is very much rooted in oil and gas, which meant that they did not often find themselves in a confrontational situation like that. But regardless, facts over feelings were seen as important ways to make the point that switching off oil and gas tomorrow is not the way to go.

THE ROLE OF SOCIAL MEDIA

Christopher Banks from SLB made the point that we should be careful putting too much trust in social media as a vehicle to get the facts right. "Social media," he said, "is designed to trigger a reaction from us, be it positive or negative, with the ultimate aim to spend as much time on the platform as possible." This is an important observation, as it rightfully questions the integrity of social media as vehicles to source impartial views from.

This was further augmented by the views expressed by one of the YPs in the audience, who said that he and some of his peers have totally disengaged with social media because of the overall feeling that every post or article has something to sell. Instead, he set out how they go back to historical documents to better understand the present day. I was particularly interested to hear that, because it made me better understand the way some YPs look at the current communication landscape. It also made me appreciate why a YP recently turned down my offer to accept a copy of our magazine – I guess that, according to this student, it falls into the same category of "having something to sell". The tone with which it was said was still fairly confrontational, though, but that is a by-the-by.

PHOTOGRAPHY: DEVEX

ENERGY CRISES

John Underhill from Aberdeen University, the most senior member of the team of presenters, remembered the times of the oil crises in the 1970's and the energy rationing that followed as a result. "The North Sea bailed out the UK when these big fields were found and put on production," he said, "and that seems to be completely forgotten about in today's narrative." In that sense, he also advocated to have a more balanced and factual view on the energy trilemma of energy security, affordability and sustainability, and that a cliff-edge policy does not seem a logical approach.

Realising that John is one of the few academics who has always been quite open about his support for the oil and gas industry, he operates in an academic landscape that is very much anti-oil. This has also been experienced by those students who showed an interest in working in this sector whilst studying at university. One participant noted that "university friends instigated a lot of discussions around the oil and gas industry, often fuelled by a student getting an internship or grad program in the industry. Often, it was the geoscience / environmental students who pushed back against the industry on the basis of morality."

A FUTURE

What the round-table discussions really highlighted, first of all, is that there are still students out there who see the merit of working in the oil and gas industry, going against the tide that there is no future for this sector that continues to be scrutinized by the media and some members of the public. Most people seem to agree that a factual discussion is the most important way to make the case for an industry that still produces more than 80 % of the world's energy, and that it is valid to sometimes be more vocal about that. YP's working in oil and gas are not insensitive to calls for environmental concerns at all; they are the new voices of an industry that are worth being heard. ■

Henk Kombrink


John Underhill making his point to convenor Emily Walker from SLB.

Revisiting the southern boundary of Sangomar

Is the story really settled?

Recently published maps of the Sangomar field offshore Senegal depict the southern boundary of the accumulation exactly lining up with the maritime boundary between Senegal and The Gambia, suggesting that there is no extension into The Gambia. Such a coincidence should raise eyebrows with any geologist or even with those without much knowledge of subsurface geology. It just looks odd to see an oilfield boundary lining up with what is essentially a human-derived line. That's why I published a story last year (GEO EXPRO Vol.21, Issue 5, 2024) about the possibility that a small part of the Sangomar field does extend into The Gambia.

In fact, during the initial exploration and appraisal of Sangomar, which took place between 2014 and 2020, companies involved in exploring the area were all of the opinion that Sangomar did indeed extend into The Gambia. The boundary took a much more natural shape at the time. The implications for a country without commercial hydrocarbon production were substantial: There was considerable optimism that The Gambia might soon realise its first oil revenues. And with Australia-based FAR, through its subsidiary FAR Gambia, drilling two wells – Samo-1 (2018) and Bambo-1 (2021) - in Gambian waters, there was real excitement that things would materialise.

However, as I described in the previous article, after the drilling and completion of these two wells, both of which were targeting reservoirs thought to be within the possible extension of the Sangomar field, the mood turned around quickly. FAR reported that both wells had been unsuccessful and soon after relinquished their licence after failing to attract new joint venture partners.

In the article, I argued that even though the Bambo well was reported dry, this does not allow the conclusion that there is no Sangomar oil to be found in The Gambia at all. Here, I'd like to add some observations further supporting that view, in addition to looking back at a FAR presentation that is still accessible and that sheds an interesting perspective on the matter. Finally, I will draw attention to a recent development – the shift of the northern boundary of the A2 exploration block in which the two exploration wells were drilled.

THE PROBLEM WITH "POOR RESERVOIR QUALITY"

The main reason for FAR to discount the Bambo-1 well results was the observation that the quality of the Sangomar-equivalent section encountered in the well was too poor to be regarded as a reservoir. This may be true, but that doesn't mean it justifies the conclusion that all strata representing the extension of Sangomar into The Gambia have the same poor reservoir properties.

There are plenty of examples of oil exploration wells that "undiscovered" a field before the next well hit the jackpot. An instructive example is the Forties field in the UK North Sea that was first drilled by a well that accidentally penetrated a levee system of the deep-water turbidites that make up the field's reservoirs. It was only with the second well that better quality reservoirs were found. The same might have happened with Bambo; there must be a sedimentological explanation behind the well result, and therefore it would still be very particular if that facies boundary would line up exactly with the international boundary.

THEY WERE ALL CONVINCED

Prior to drilling the Bambo and Samo wells, there was little doubt that Sangomar extended into The Gambia. Peter Nicholls, FAR's chief geologist, articulated this in a video that can still be watched online. He says: "… Woodside and the other joint venture partners in SNE all see that the Sangomar field does extend into The Gambia, so that's not a contentious issue. It's the way it is seen and mapped as just extending into our block (A2). So, we are now going through an evaluation to see what volume we now have in our block."

It is of particular interest to hear Peter saying that all joint venture partners had the same vision about Sangomar extending further south. This only puts more question marks to the maps that are now circulating. Woodside Energy, having operated in the region throughout, is uniquely positioned to influence interpretations of the field's extent. The subsequent shift in the mapped boundary of Sangomar, now terminating at the Senegal – Gambia line, appears to be a post-hoc redefinition. Was this shift geologically justified? Or was it a convenient administrative closure that, intentionally or not, excluded The Gambia from further discussion?

SHIFTING BOUNDARIES

Then there is the more recent issue of redrawing offshore block boundaries by The Gambia's government in 2023. While two of the A2 block's corner coordinates remained unchanged, the northern boundary was shifted more than a kilometre to the south, resulting in the Bambo well falling outside the new block limits.

This raises several questions. What justified this redefinition, which resulted in the Bambo well being excluded from the block? The result is a 1.1 km strip of marine territory between the A2 block and the national border that coincidentally corresponds to where any transboundary Sangomar extension would logically lie.

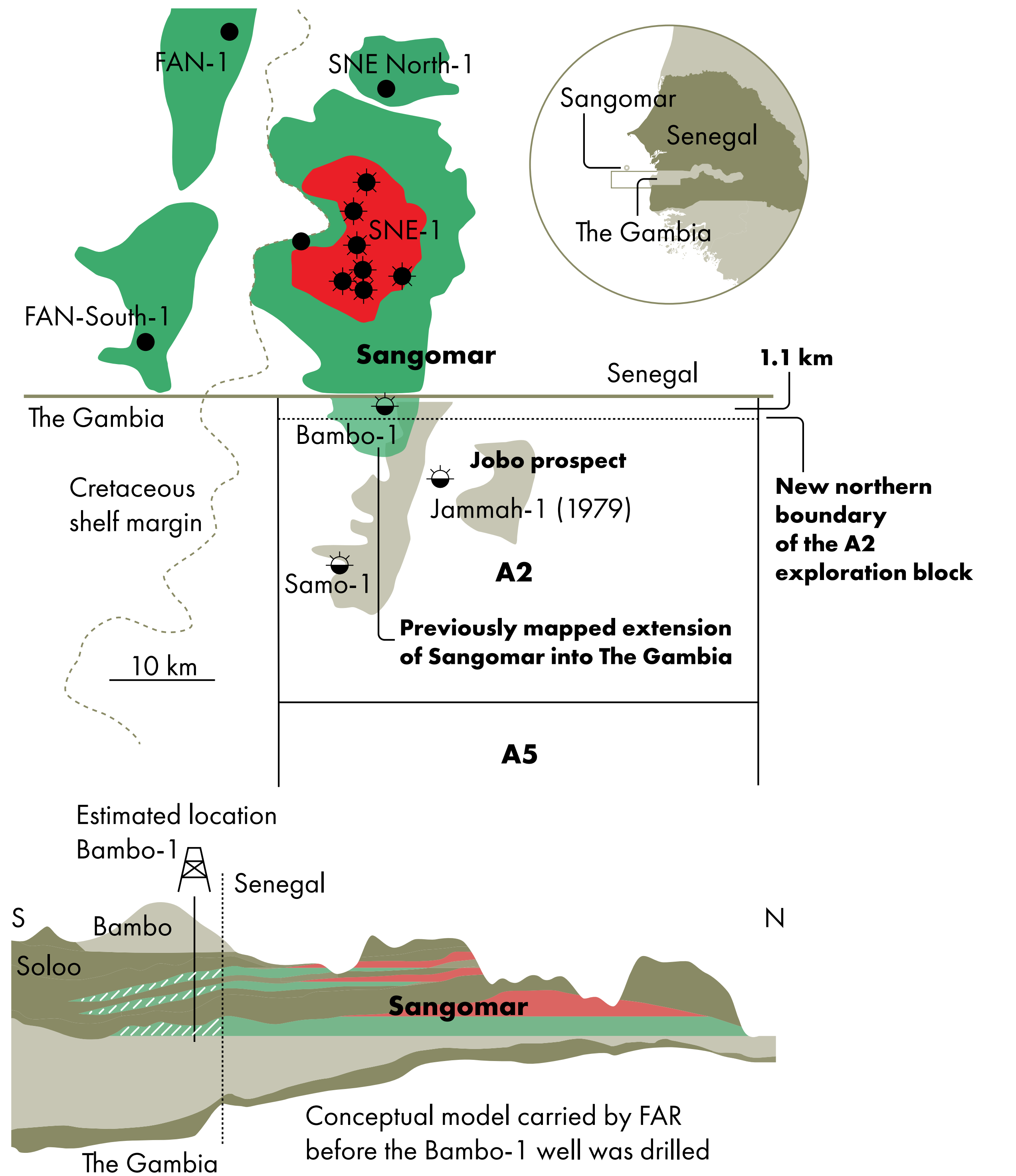


ILLUSTRATION: REDRAWN AFTER FAR

Is this shift unrelated to administrative housekeeping? Or does it hint at an intentional move to delink the Bambo data from future licensing rounds and potential resource claims?

THE CASE REMAINS OPEN

In conclusion, despite recent maps suggesting Sangomar does not extend into The Gambia, well results, geological observations, previous work done by exploration geologists in the area, and recent block boundary changes all keep the question very much alive: Is it really true that there is no Sangomar reservoir extension in Gambian waters?

Until there is comprehensive disclosure of the reservoir data, and an assessment of reservoir quality based on seismic inversion results, the possibility of a Sangomar extension into Gambian waters must remain an open and serious question. ■

Henk Kombrink

Are half of the Tano Basin's reservoirs in the Keta Basin?

A new 3D seismic survey will further de-risk an underexplored yet prospective part of Ghana's offshore

BEN SAYERS, GEOPARTNERS, AND MATT TYRRELL, TROIS GEOCONSULTING

GHANA'S ascendancy as a significant oil and gas producer commenced with the landmark Jubilee discovery in 2007, leading to first oil in 2010. This success was subsequently reinforced by the discovery of Tweneboa, Enyenra, and Ntomme (TEN) fields.

While historical exploration efforts have predominantly concentrated on the Tano Basin in both Ghana and Côte d'Ivoire – highlighted by recent success at Baleine in the Deep Tano Basin – a compelling new focus is now shifting eastward to the offshore Keta Basin. This basin presents a geological setting ripe for renewed hydrocarbon exploration.

Despite its inherent potential, the Keta Basin has, to date, remained somewhat overshadowed. Previous deepwater exploration efforts by ENI, Afren, and Devon Energy have yielded only one sub-commercial gas discovery at Tarpon-1. However, a comprehensive re-evaluation of the Keta Basin's sediment provenance history, integrated with past well results, strongly suggests that the basin shares more geological commonalities with the productive Tano Basin than previously presumed, thereby indicating the potential for analogous hydrocarbon resources.

For International Oil Companies (IOCs), the Keta Basin should represent a very attractive frontier, characterised by its extensive running-room, strategic proximity to existing oil discoveries, and considerable scale, aligning perfectly with modern exploration priorities; all set in an existing oil-producing nation.

Here, we delineate three pivotal reasons underscoring the Keta Basin's compelling similarities to the Tano Basin, positioning it as a high-potential, yet underexplored, frontier.

1. PROVENANCE AND TRANSPORT PATH: KETA'S CRETACEOUS SANDS HAVE THE SAME PROVENANCE AND TRANSPORT PATH AS TANO'S

A common challenge in many discoveries across the Transform Margin has been the sub-commercial nature of reservoirs. While most wells have encountered hydrocarbon presence, reservoir quality is often compromised due to the mineralogical immaturity of the sands.

The Tano Basin stands as a notable exception to this trend, boasting sandstone reservoirs with excellent permeabilities that support viable flow rates, enabling fields to progress to development. Sourced from the Sourou Basin and traversing the Palaeozoic Volta Basin, these systems are much more mature in terms of mineralogical content than many other reservoirs found along the broader Transform Margin.

Crucially, prior to the inversion of the Saltpond High in Early to Mid-Cretaceous times, both the Black and White Volta fluvial systems were actively feeding the offshore Keta Basin (Figure 2a). The subsequent uplift of the Saltpond High during the Campanian redirected the Black Volta fluvial systems westward into the Tano Basin, depositing the prolific Mahogany and West Cape Three Points fan bodies. These fans are now host to numerous significant discoveries, including the Jubilee, TEN, and Sankofa Fields (Figure 2b; Grant et al, 2018). Consequently, the Keta Basin is endowed with the same mineralogically mature Cretaceous sandstones as the Tano Basin, a critical factor for reservoir quality.

2. MULTIPLE SOURCE ROCKS AND POST-TRAP FORMATION EXPULSION: A TANO ANALOGUE

Modelling of source rock expulsion, utilising available well data from the Keta Basin, demonstrates a favourable timing of trap formation. The syn-rift source rock is modelled to expel hydrocarbons towards the end of the Cretaceous, while the Cenomanian-Turonian source rock expels in the mid-Eocene in deep water settings and the mid-Miocene in shallower waters.

Throughout the West African Transform Margin, a significant exploration risk is posed by late-stage tectonism, leading to trap breach. In Côte d'Ivoire, this is a primary cause of deepwater well failures. The success observed in Tano correlates strongly with a period of tectonic quiescence after trap formation. Similar observations are evident in Keta, where inversion ceased in the Campanian, ensuring that transform-related traps remained intact post-charge. Figure 1 shows a Geoseismic section, with source and reservoir units marked.

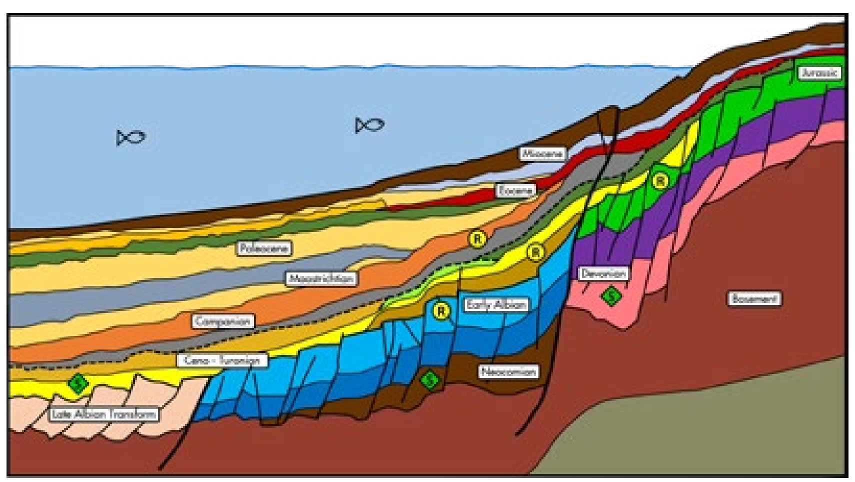


Figure 1: Geosection sketch through the Keta Basin showing the tectonic architecture and the main hydrocarbon play elements.

3. EXPLORATION HISTORY: KETA'S UNDEREXPLORED POTENTIAL PARALLELS EARLY TANO

The Keta Basin's deepwater exploration history is remarkably limited, with only three 3D seismic surveys and six wells drilled to date. Dolphin-1, spudded in 2000, followed by NAK-IX and Keta-1 in 2001 (both drilled on 3D data), all yielded oil fluid inclusions within Albian-Cenomanian shelf-slope deposits. The only deepwater wells in the basin were Tarpon-1 (Devon Energy, 2003), Cuda-1 (Afren, 2008), and Nunya-1 (ENI, 2012), drilled on two 3D surveys. While Cuda-1 and Nunya-1 exhibited oil shows, Tarpon-1 encountered a gas-bearing sandstone in the Mid-Miocene. The most recent well, Starfish-1 (Ophir), was dry but notably encountered 230 m of good quality, Tano-style sands in the Lower Cretaceous.

When compared to the Tano Basin's exploration history prior to the 2007 Jubilee discovery, the results in Keta are strikingly comparable. The first speculative 3D seismic surveys in deepwater Tano were acquired from 2000 onwards, prompting Tullow to license the deepwater acreage in 2004. By 2007, the Jubilee Field had been discovered in just the second phase of drilling. Similar successes could readily be replicated in the Keta Basin, which has yet to experience a second, more comprehensive drilling phase.

FUTURE EXPLORATION OUTLOOK AND GOVERNMENT SUPPORT

The combination of these below-ground geological factors positions the offshore Keta Basin as an area with significant future exploration potential in Ghana. While seal integrity has historically been considered a primary exploration risk in the Keta Basin, new high-resolution 3D seismic data and integration with newly defined geological models will actively de-risk this concern. The interpreted development of effective seal lithologies and the favourable timing of trap formation, particularly the pre-charge Campanian onlap traps, significantly enhance confidence in seal effectiveness across prospective intervals.

In recognition of this potential, GeoPartners is planning to acquire a 14,000 km² 3D seismic survey in Q4 2025 (Figure 2). This data acquisition is anticipated to be instrumental in de-risking identified prospects, providing advanced subsurface imaging, and attracting further investment required to fully assess the hydrocarbon potential of the Keta Basin.

Additionally, the current government, facilitated by the Petroleum Commission as regulator, has expressed a clear and positive commitment to enhancing Ghana's oil and gas sector. Initiatives are underway to streamline exploration processes and foster an attractive investment climate, aiming to position Ghana as a key destination for energy investment over the forthcoming years. ■

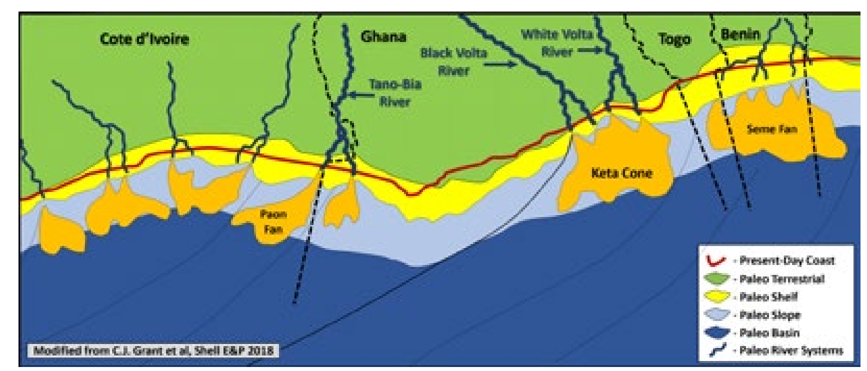


Figure 2a: Map showing the paleo-drainage patterns of the Volta and Tano Basins in the Lower Cretaceous, before the uplift of the Saltpond High in the Campanian. Note how the Volta River systems are feeding the Keta Basin.

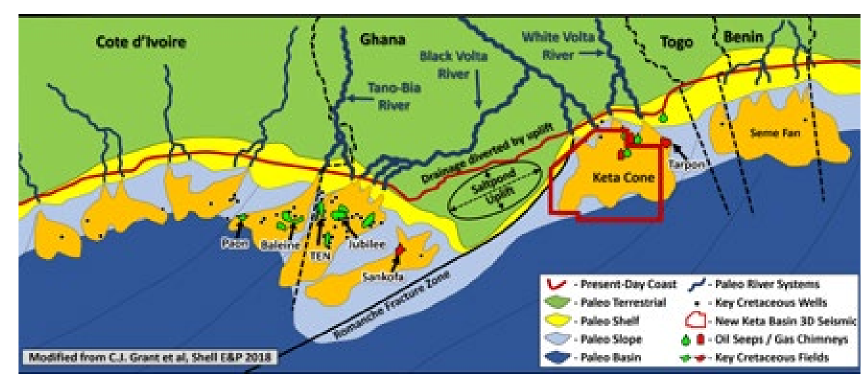


Figure 2b: Map showing the paleo-drainage patterns of the Volta and Tano Basins after the uplift of the Saltpond High in the Campanian. Note how the Volta River systems are now feeding the offshore Tano Basin.

Geoex MCG

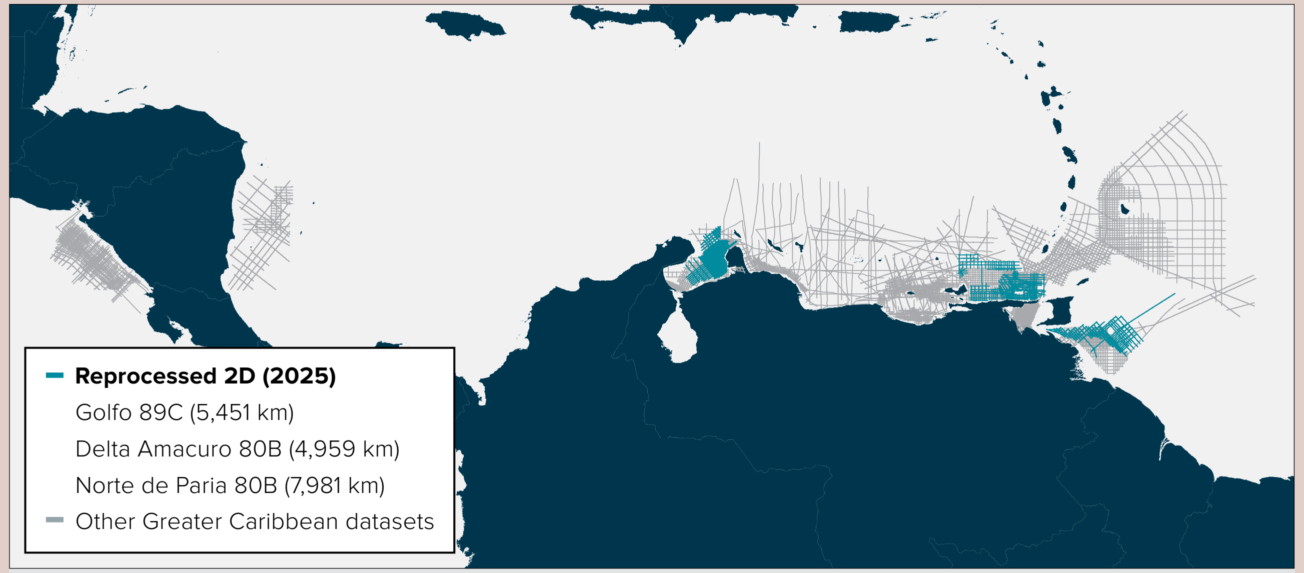
dug

Self-similar structures and DHI indicators in the Greater Caribbean

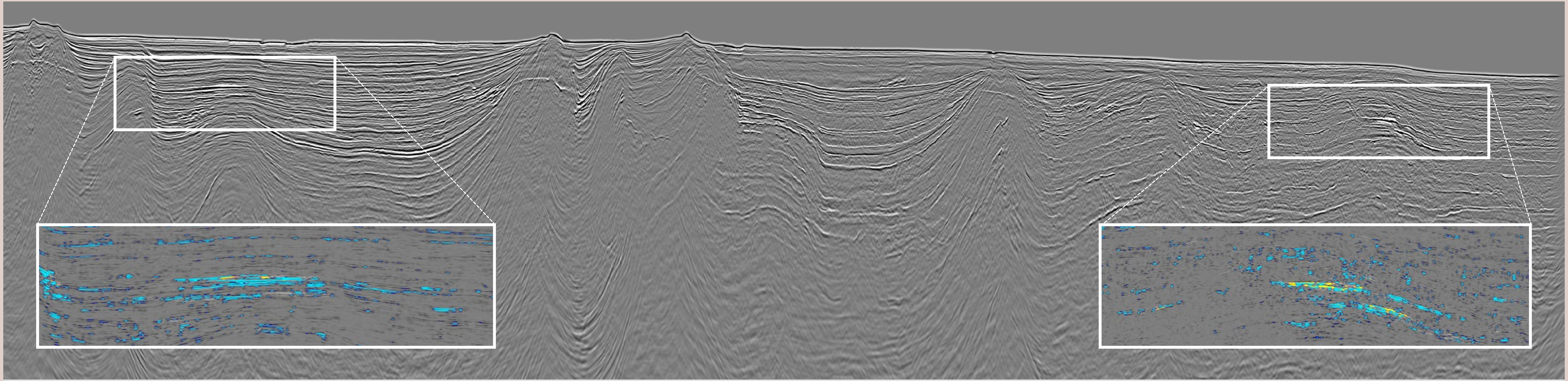
As remastered and HD versions of albums and films get released, new things are seen and heard in some all-time classics that improve the overall experience. The contrast is often relatively low from the old version to the new, as more is squeezed out of the legacy recordings.

In seismic data, however, there can often be some "chalk and cheese" type comparisons as a result of reprocessing. These reprocessing efforts usually lead to considerable detail emerging from the data that is otherwise unseen. As modern processing algorithms improve, the difference between legacy and reprocessed seismic data becomes clearer with each iteration.

In order to reveal these hidden gems in existing seismic data, Geoex MCG, in partnership with DUG Technology, have recently reprocessed data offshore the greater Caribbean in order to provide useful insights into the margin formation and petroleum system locations.



Map: The Greater Caribbean Basin Synthesis Campaign.



A seismic profile from the Delta Amacuro 80B survey situated to the south of Trinidad. Here self similar structures with a comparable ERG signature are observed.
Highlighted: A (fars-nears)*fars display is used as a proxy for Type II/III AVO's, showing similarities between the left and right hand side of the profile.

Bridging proven plays and frontier potential

The offshore of the Caribbean has experienced a dramatic and enduring tectonic history full of movement and continuous accommodation. Forming in the Late Cretaceous in the Eastern Pacific, the Caribbean plate began to migrate eastward relative to the North and South American plates behind an east-facing Great Arc of the Caribbean to its present position. As a result of this eastward shift, a series of strike-slip faults were generated to accommodate such a dramatic landscape change, most notably the San Sebastian and El Pilar faults. Constraining the timing of these events is pivotal to the understanding of the petroleum systems for trap formation and thermal history.

MIKE POWNEY, GEOEX MCG, JULIAN SHERRIFF AND STEPHEN DOYLE, DUG TECHNOLOGY

TIME TO FIND SOME PERL(A)S

As expected, the location of predominant deposition similarly shifted throughout the tectonic history of the region. The Orinoco River deposited large quantities of sediment into the offshore, migrating through geologic time across the top of Northern South America to the present-day point of deposition towards the East of the paleo depositional locations.

This river system was key to the reservoir development, which is plentiful in numerous locations offshore, particularly the Orinoco delta, and the La Luna source rock, which is prolific across the region, generating significant quantities of hydrocarbons.

The time equivalent interval to La Luna in Trinidad, known as the Naparima Hill formation, has also generated significant quantities of hydrocarbons. The exploited fields, such as Mejillones, Patao, Dragon and Hibiscus, have provided significant volumes with prospectivity further affirmed by discoveries to the south of Trinidad, including Manatee / Loran and Makain / Cocuina.

This further indicates an extended working petroleum system and proves that large accumulations are found in multiple settings. bp has recently confirmed a positive FID to develop these fields, supporting the development potential.

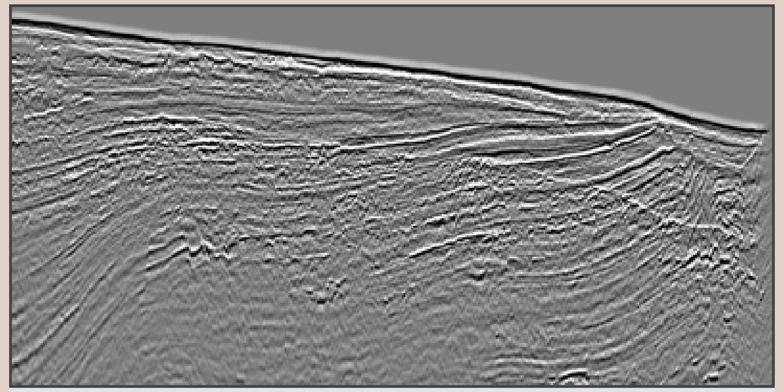


Figure 1: A BSR indicating gas is spotted throughout the data set, indicating hydrocarbon accumulations.

Utilising developments associated with this FID will also increase exploration upside and viability by using the new reprocessed seismic data sets to extend exploration from the proven producing areas to the frontier.

EXCELLENT REPROCESSING LEADS TO INCREASED TRUST

In order to further explore these frontier regions, several surveys have been reprocessed by Geoex MCG and DUG Technology in the aforementioned regions, which are strategically placed to tie these existing discoveries within a frontier environment.

The works undertaken predominantly focused on improving the overall subsurface imaging using more advanced reprocessing workflows. By completing steps such as DUG's Broad deghosting, several multiple elimination algorithms, amplitude Q compensation and anisotropic pre-stack depth migration, the overall image is far superior to the legacy data.

This has elucidated the deeper section and provides confidence in the amplitude fidelity that previously did not exist with the legacy information. Furthermore, the data is also available in the Pre-Stack Depth domain, which provides an accurate understanding of the depth to target with further angle stack and gather information available to allow interpreters to complete AVO analysis.

DESERVES A STANDING (AV)OVATION

Following this improvement, identifying the fields and exploring for self-similar structures serves as a useful proxy to possible further discoveries in frontier areas. Moreover, any observable DHI's that show similarity to the fields can, in theory, be used to de-risk structures in a frontier area, providing a more attractive prospect.

Although the debate regarding their validity is often had, these features provide an indication of encouraging prospectivity, and therefore it is argued that their presence, rather than their absence, provides an advantage. Data sets that traverse fields as well as frontier areas allow the geoscientist to confidently extrapolate seismic interpretations away from existing fields to identify self-similar structures, reducing the uncertainty around exploration.

As shown in the seismic section (fold-out), self-similar undrilled structures exist to the south of producing areas. These areas show a similar display, AVO analysis, and a similar size and geometry to that of the discovered fields. Whilst further investigation is required to further de-risk this type of feature, the evidence is overwhelming to suggest that similar hydrocarbon volumes could be found in what would be a similar depositional environment.

BSRS SOUTH OF TRINIDAD

A further feature that has been widely observed in the seismic data to the south of Trinidad is a Bottom Simulated Reflector (BSR). These features, as shown in Figure 1, crosscut existing sedimentary strata and run parallel to the seabed but have a reversed polarity. This effect is caused by the negative acoustic impedance contrast between sediments containing gas hydrate and free gas underneath the gas hydrate stability zone. As this is present within the data, it provides encouragement regarding the likelihood of exploration success.

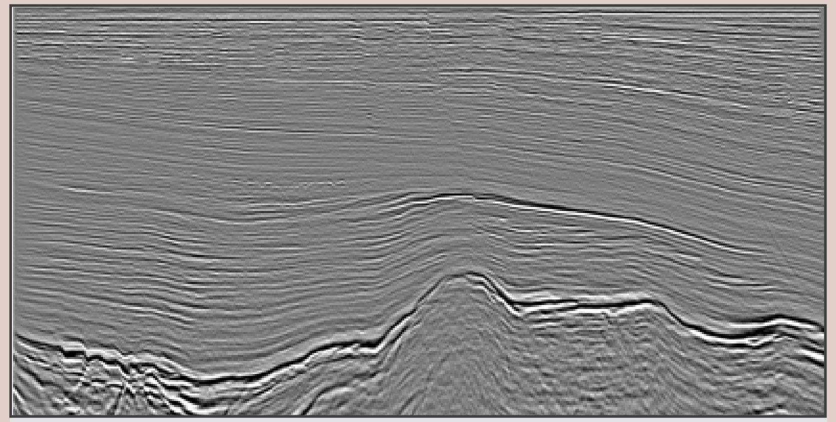


Figure 2: Another Perla type structure is observed in close proximity to the 17 TCF discovery – more investigation to prove this viability is underway.

A 'SEISMIC' SHIFT IN DEPOSITIONAL TRENDS

Whilst the La Luna equivalent source rock provides excellent volumes of hydrocarbons across the region and likely in the frontier areas, a secondary petroleum system exists that also produces significant quantities of gas. Discovered in 2009, the Perla discovery was made in Oligo-Miocene (Chattian to Aquitanian) carbonates categorised by porosities of ~ 20 %. Whilst this particular discovery is not shown in this article, a self-similar structure is displayed in Figure 2. The difference between the two is the lack of faulting throughout the structure of the second example, although the overall geometry and size remain the same. Geoex MCG will continue to map the depositional environments in these areas to better constrain and understand the possibility of a significant accumulation in this region.

A third survey, imminently finalising, is located in the Norte de Paria region. Here, the main discoveries are clearly highlighted on the data as well as significant areas of frontier acreage that will be similarly analysed.

THE TRUTH IS IN THE DRILL BIT

Like all methodologies in exploration, the aim is to de-risk and provide further confidence that expected volumes will be encountered. The exploration debate regarding the usefulness of these types of DHI features continues. But despite these discussions, and not knowing until the drill bit is in the ground, these DHI's provide encouragement that hydrocarbon fields are likely to exist in frontier environments.

In the context of the Greater Caribbean, we've seen that numerous bright amplitudes, flat-spots and self- similar structures to existing fields can be seen within a frontier gas environment. Whilst also providing information regarding potential oil and gas exploration locations, these newly reprocessed seismic surveys also help to further constrain the timing of key tectonic events, which would provide key information for a thorough basin synthesis.

Reprocessing has been concluded on all three of the surveys discussed in this article and is available for review.

PORTRAITS

"I was the first generation of students that graduated in the Soviet Union without having a job lined up for me..."

Svetlana Bidikhova – Absolute Imaging

FROM MOSCOW TO MOHKÍNSTSIS

Svetlana Bidikhova witnessed the monumental changes her home country underwent during the 90's while she built up a completely new life in Alberta

HENK KOMBRINK

Svetlana on the glass floor of Calgary's iconic landmark - the Calgary Tower.

PHOTOGRAPHY: SVETLANA BIDIKHOVA PRIVATE ARCHIVE

"I WAS the first generation of students that graduated in the Soviet Union without having a job lined up for me," says Svetlana Bidikhova. "When I started university, few people were familiar with CVs, job interviews, or the need to search for work."

Svetlana grew up in a world that radically changed as she embarked on her professional career towards the end of spending eight years at university, as socialism ended and a market economy was introduced. But it was not the first big change that she was about to experience.

> "I was the first generation of students that graduated in the Soviet Union without having a job lined up for me..."

In this interview, Svetlana tells the story of her fascinating career, which started in Moscow in the early 1990's, taking us to the epicentre of the Canadian oil industry in Alberta and Calgary (Mohkínstsis), later. It is a story that is so human, characterised by the desire to build a future and the willingness to work hard for it.

LIVING MINERALS

"My parents gave me a book about minerals when I was a child," Svetlana says at the start of our conversation. "But not an ordinary minerals book with a long series of factual descriptions of physical properties. Instead, the writer discussed the minerals as if they were living organisms with characters and the like." This resonated with Svetlana, who had initially considered studying psychology. "The brain is such an amazing thing," she says, "and therefore the mineral characters captured my attention."

The book created a link to a world that Svetlana was completely unaware of before: The world of geology.

But she also had a talent for numerical science, thanks to her father, who is a physicist. Rather than embark on a more theoretical study, though, she looked for something more applied and found out that geophysics was a perfect match. "I had never heard about it before, but the minerals book and my numerical skills made the perfect combination."

Svetlana joined the Oxford of the Soviet Union, the Lomonosov Moscow State University, following a series of challenging oral and written tests. "The great thing about the university," says Svetlana, "was the diversity of our courses. It wasn't just about mathematical skills, we were also expected to master writing to almost the same extent. It shows how the curriculum was designed to not only make you a specialist, but also provide people with broader skills."

And it was all for free.

"As the university attracted the most talented students from all over the Soviet Union, we had a very diverse group of people," Svetlana says. "It was a real melting pot."

English was not part of the curriculum. But as the world opened up in the mid-1990's, Svetlana quickly cottoned on to the fact that English would become an essential part of her future. She began seriously improving her English skills and used her extracurricular work as a technical and non-technical interpreter for American businessmen - who were flocking to the country for business, conferences, and new opportunities - as a way to further develop her language proficiency.

Exshaw Formation of Alberta.

Then, as her eight years at the university came to an end, the moment arrived for Svetlana to start looking for work.

"When I started at university, all I knew was that a job would be chosen for me somewhere in the country," Svetlana says. "Sure, you could file your preference if you wanted to stay in Moscow," she adds, "but there were no guarantees as the locally-based positions were always the most popular." But now, as the entire political system was in upheaval, she was suddenly expected to look for a position herself. "It was such a surreal situation for us," she says. "But what do you do? You adjust and get on with it."

INPUT OUTPUT

This is the right moment to provide a sketch of the "geophysical landscape" in the Soviet Union during the mid-1990's. Despite the oil industry being an important part of the economy, geophysical tools were mostly imported during that time. Names such as Input Output, which ultimately became ION, were one of the few companies that had a foothold in the country.

"The company I ultimately joined after graduating," says Svetlana, "was started by someone who had the vision and mindset to start producing seismic recording equipment locally, which I think was a very clever idea. But in order to do that, we needed to explore the market and find the best suppliers." It heralded a few years of travelling around the world to meet with potential manufacturers, and Svetlana was very much in her element. She also benefited greatly from the fact that she had learned to speak English during her university years.

But as Svetlana was working hard with her first employer, the chaotic economic and societal transition in the Soviet Union posed some real challenges. "We saw how the country's assets ended up in the hands of a small group of people, and how ordinary people's savings evaporated overnight. It was a rude awakening that pushed us to start exploring different options."

It is in that light that Svetlana and her husband decided to look for places to move to. As she had been in Calgary on business already, and Canada had opened its doors widely to foreign workers, they decided to apply for immigration. ▸

PORTRAITS

"The doors opened widely," she says. "With both of us being highly educated and with a daughter already, the process of getting approvals did not take long." The young family moved to Calgary in 1999.

BARREN LAND

But the move to Calgary did not mean that the subsequent job search was an easy one. "You are on barren ground, my stepmother said, alluding to the situation we found ourselves in," says Svetlana. "My husband's English was not good enough yet, so I was destined to be the breadwinner in the beginning" she says.

The oil and gas sector was very depressed in the 1990's, which meant that Svetlana needed to look at other sectors to benefit from the experience and university degree she had gained.

She ended up in the usual trap of job adverts requiring experience working in Canada, even at entry level. "It was the president of the engineering company Pure Technology who made the difference," Svetlana explains. "He was willing to make a bet, even though they hired someone else at the same time, with the idea to test both employees independently. I was not aware of this at all, but at the end of the six-month period, I was the one who could stay," Svetlana laughs.

Even though Pure Technology operated in the infrastructure sector, Svetlana learnt a lot of things that were instrumental during the rest of her career. For instance, the company was one of the first to trial fibre optic sensing to monitor the safety of large infrastructural projects, such as pipelines and bridges, long before fibre optics became a thing in oil and gas. "We had the same issues that we are experiencing today," Svetlana says, "with data filtering and noise reduction being the biggest challenges. But looking back, it is fascinating to see how much of an early adopter my company was at the time."

BACK TO OIL

When oil prices improved in the early 2000's, the draw of the industry became more prominent and Svetlana landed a job with GX Technology, which was later acquired by Input Output, or ION Geophysical. "I started at the very bottom of the organisation," she says, "but I saw the growth opportunities in this industry and decided it was worth the leap, despite having to work myself up through the ranks first to even be at the same level again compared to the job I left behind."

During her time at Shell, part of the work involved coordinating helicopter trips to deliver seismic equipment to hard-to-reach areas.

PHOTOGRAPHY: SVETLANA BIDIKHOVA PRIVATE ARCHIVE

While Full Waveform Inversion is the buzzword today, it was depth migration at the time. "In geophysics, Svetlana explains, "technology always follows step-changes in computing power. In the early 2000's, it was depth migration that could finally be done on a big scale. In some ways," she says, "it paved the way for horizontal drilling, because with a much better handle on structure, it became possible to navigate the drill bit at a much higher precision."

"It was a genuinely new thing, and some geophysicists were uncomfortable with it," Svetlana recalls. "A more senior colleague of mine at the time was asked to pick up the baton and drive our depth migration service forward, but he claimed that after a career of time migration, it was too late for him to learn something new. He knew that applying this technology would come with teething issues, and wasn't willing to go through that phase again."

Svetlana saw the opportunity and put her hand up. She subsequently became the driver behind the new service, even though she was very well aware that there would be instances where indeed you "learn from your mistakes. And these mistakes happened, of course," she laughs. "But that's what life is all about, isn't it?"

Magnificent Rocky Mountains.

EXPERTISE AT SHELL

As the Calgary oil boom continued, with major players also moving in, the next opportunity for Svetlana came along in a yet unconventional way. "I was at a friend's wedding when someone from Shell Canada said that they were looking to recruit experienced hires,“ said Svetlana. "I already worked in the same building as Shell, and had for years considered working for them, so this came at such a good moment," she says.

Her years at Shell are not so much characterised by working on a single technology like she had done at GX Technology and ION Geophysical, but rather focused on advancing technology worldwide as part of a global team of experts. "The expertise I saw in this company was unrivalled," Svetlana says, "with so many great people, especially in Rijswijk and Houston. This almost academic part of the business, while closely tied to operations, was unique and made significant, if mostly quiet, contributions to the success of producing assets."

As the first few years with Shell were characterised by growth and optimism, the last few years, up to 2016, had a rather different feel. Operators started to withdraw from the Canadian oil patch as oil prices were taking a hit after 2014, and environmental pressures mounted on the production of oil from oil sands. "Our centre of land seismic expertise was gradually downsizing and moved to Houston," Svetlana explains. "We were 75 people in my first years with the company, but at the end there were only three left."

"It was not only sad to see the demise of the Calgary group of land seismic expertise, but also how this entire group of highly technical professionals supporting assets was heavily reduced in size. We live in different times now," Svetlana says, "and there seems to be less of an appetite for long-term investment in technology that might only bear fruit in the longer term."

THE CHALLENGES OF BEING A BUSINESS OWNER

Having gained such a wealth of experience, Svetlana was ready to jump into the great unknown yet again, but now as a business owner. Together with a former colleague she had known for a long time, they established GeoVectra in 2016, offering services in seismic processing.

It came with challenges she had not faced before.

"Being a business owner exposed me to the dilemma between offering the best technical quality versus making ▸

a surplus at the end of the day," says Svetlana. "In our profession, there is always the call to be made between running a processing job for one or three months. And guess which one is more expensive but comes with better quality data?"

"Reflecting on those years," she says, "I have too often found myself in this situation where you need to make that call, whilst my natural inclination is always to go for the best technical solution no matter the costs."

It made Svetlana re-establish her career options and following a short but fascinating spell at DMT, working with a team of highly skilled German specialists on a series of exciting projects, she joined the company where she is currently at in the role of Vice President Geophysics; Absolute Imaging. "An aspect I really like about this place is that there is a real vision," Svetlana says, "not only in terms of technology, but also when it comes to entering new markets."

IT'S HAPPENING IN INDIA

"One of the bold moves Absolute Imaging made is setting up an office in India. It opened up a new world for us," Svetlana says. "Where the Calgary market is very well established, India is a country where there is an incredible energy to drive things forward."

The business dynamics are also very different from what she has seen in Canada. "Simply put," Svetlana continues, "there is a highly competitive environment thanks to the entrepreneurial spirit in the country and the number of people who have the talent to embark on new adventures. But even in this competitive environment, thanks to the rapid economic development the country is experiencing, there are still opportunities aplenty. It is fascinating to work in such an environment," she says.

A PROUD ALBERTAN

During the more than 25 years she has now spent in Canada, Svetlana has become a proud Albertian.

"The people in this country are amazing," she tells me as we near the end of our conversation. "The drive to make things work and plough on despite challenging circumstances is exemplary. And let's not forget that this is all supported by a very broad mix of people from many different walks of life and different backgrounds."

> "I feel that offering support to young professionals is badly needed at the moment..."

Svetlana feels rooted in Canada and Calgary in particular. It is for that reason she is also an avid mentor, trying to help the next generation of industry professionals through providing insights or just offering listening time.

"I feel that offering support to young professionals is badly needed at the moment," Svetlana concludes, "also because these people start their careers in times so different from how I started more than 20 years ago. Back then, there was widespread support for the oil industry. That is not the case any more, and many people in Alberta who work in the industry feel a level of frustration with this, also because there are still so many opportunities that cannot be further explored at the moment."

Svetlana Bidikhova has proven to be very good at adapting to changing circumstances. When she embarked on her studies in Moscow in the early 1990's, she was unaware of a world where one needed to apply for a job. Jobs were made for you. When this system collapsed, she was amongst the first to turn that situation around in her favour. And when she emigrated to Calgary with her young family, she also managed to secure a rewarding job quickly, even though oil was at a low, embarking on a rewarding career in the industry soon after. We decided to meet again in twenty years' time to talk about what comes next. I am already looking forward to it, because I know it will be another great story. ■

GEOTHERMAL ENERGY

"Claims of universal geographical scalability of Closed Loop Geothermal Systems (CLGS) in power generation at competitive prices are not supported by simulation results"

Sri Kalyan Tangirala – Global Change Research Group, IMEDEA

Are deep closed-loop geothermal systems doomed?

New study shows that deep closed-loop geothermal systems drilled in moderate heat flow settings are unlikely to be economic, partly due to a significant decline in reservoir temperature during the initial production period

"CLAIMS of universal geographical scalability of Closed Loop Geothermal Systems (CLGS) in power generation at competitive prices are not supported by simulation results," is what the authors conclude in a recent publication in Communications Engineering, a Nature portfolio journal.

That's not a very promising assessment, which is based on modelling work performed by the authors. They claim that a rapid temperature drop during the initial days and months of production in the laterals of CLGS systems quickly leads to a deterioration of project economics, even when a high number of laterals was drilled.

For a reservoir temperature of 180° C, the authors expect that the total revenue of these systems fails to recover the lifetime costs incurred, even with 30 multilaterals and a production rate of 75 kg/s. "This makes that CLGS's are not scalable for solely electricity generation," they conclude.

That is quite an outcome, even when it may not come as too much of a surprise given that other experts have reached similar conclusions.

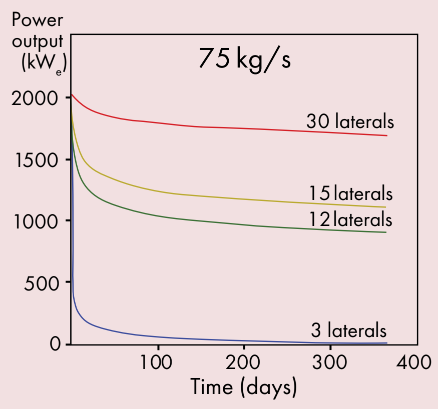
The project that immediately comes to mind in this regard is Eavor's Geretsried project in Germany, which is the first attempt globally to realise a commercial-scale deep subsurface closed-loop geothermal system.

Are the conclusions presented by the authors of the paper in direct conflict with the economics that Eavor will have generated to justify the project? We don't know, given that the Canadian company has not been open about its finances despite a high level of government subsidies. However, we do know that the company is not only relying on electricity generation. It also aims to supply direct heat to the village of Geretsried, which will improve the project economics.

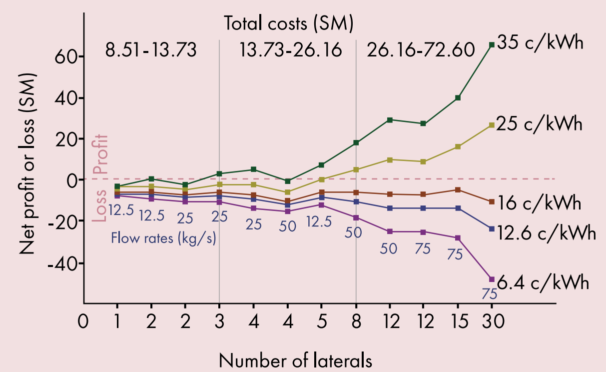
On the other hand, the number of laterals Eavor is planning per injection-production pair is "only" 12, which is much lower than the maximum of 30 the researchers modelled. The more laterals, the less the energy loss. At 12 laterals, the researchers estimate a 30° C temperature drop in the reservoir directly surrounding the laterals within a year.

Whilst it is unlikely that the Eavor engineers are unaware of the effects modelled by the researchers, it will put even more of a strain on project economics, as well as the claim that these loops can be drilled everywhere given that a local direct heat solution may be needed to improve the business case. ■

Henk Kombrink



Power output (or electricity generation) capacity during one year in the 75 kg/s case. The blue curve runs along the x-axis after a while because the temperature drops below 100° C, which makes it unsuitable for electricity generation.



Net profit or loss curves for twelve of the modelled cases with different electricity prices for the base horizontal drilling price of $400/m. Flow rates corresponding to the laterals are shown in blue numbers. Please note that wholesale electricity prices in Europe have only rarely exceeded 15 c/kWh in 2024, whilst in the USA a price of 6.4 c/kWh is already seen as high.

GRANITE OR LIMESTONE?

The authors of the paper have run their models using granite as the bedrock in which the geothermal loops were drilled, possibly with the idea in mind that Eavor also reports drilling their wells into granite. But is that true? When speaking to some people on the matter, it turns out that Eavor is drilling their wells in the Upper Jurassic limestones instead. Looking at this paper reporting on a previously drilled well near Geretsried, the lithology at the depth of the Eavor loops is an Upper Jurassic limestone indeed. Why would Eavor claim on their website that they are drilling in granite when this is obviously not the case?

SOURCE: TANGIRALA & VILARRASA (2025)

Coring a geothermal reservoir in oil and gas heartlands

Drilling has been a very common thing in Lower Saxony in northwest Germany, but not so much for geothermal energy

LOWER SAXONY, the German state that finds itself in the northwestern part of the country, has a rich history in drilling and coring. But until recently, activities on that front were exclusively centred around oil and gas. No surprise; the state hosts the majority of oil and gas fields in Germany and therefore, places like Celle, Lingen and Hannover have a significant oil industry presence.

However, that picture is changing, with many fields being decommissioned, combined with limited additional exploration potential and a political climate that is not favourable to oil and gas exploration either.

In that light, with the presence of a drilling industry and the associated service sector, it is a little surprising in some ways that it took until this month that the first "core for a future geothermal doublet" was cut in Lower Saxony. The area surely has potential, especially in the Triassic Rhaetian sandstone, which is a target in successful geothermal projects further east in Germany and in Denmark as well. For instance, Innargi's flagship project in Aarhus targets the Triassic Rhaetian sandstone to supply the town with geothermal heat.

Strictly speaking, it is not the first core cut for a geothermal project, though. In 2009, a deep borehole was drilled in front of the main office tower of the Geozentrum Hannover (BGR), with the aim to test the deep geothermal potential of the Lower Triassic Detfurth Sandstone at around 3,700 m. However, the project was a failure as the sandstone was unproductive, and following stimulation the borehole completely clogged up with halite cement.

The core that was now acquired is not from such a great depth. The Rhaetian sandstone was found at around 2,500 m. With a first run of core measurements indicating a >800 mD permeability, and a series of successful hydraulic tests, the properties of the reservoir also look favourable. From a total of 107 m cut core with a recovery of 98.6 %, 44 m of Rhaetian sandstone was sampled. The core will now be investigated in more detail.

The project was carried out under the framework of the DemoCELL R&D project, which is funded by the Federal Ministry of Economic Affairs and Energy. Partners are Baker Hughes INTEQ GmbH and the University of Göttingen.

The drilling location is situated near the village of Ahnsbeck, just east of Celle. It is part of a geothermal exploration licence that was awarded to Baker Hughes INTEQ in 2023. Several other licences exist in Lower Saxony, but this is the first that has now progressed with putting some pipe in the ground. It is anticipated that the energy will be used for local heating purposes. ■

Henk Kombrink

Matthias Franz (r) and Fabian Käsbohrer from Göttingen University at the drill site.

PHOTOGRAPHY: MATTHIAS FRANZ PRIVATE ARCHIVE

Has the Aarhus geothermal project become a little less geothermal than initially planned?

Based on feedback received by the company following a recent announcement, and observations made through earlier reports, it could well be that heat pumps will have a more important role in the Aarhus geothermal project than initially foreseen

In a recent statement on LinkedIn, geothermal exploration and development company Innargi announced that its flagship project in Aarhus, Denmark, will be developed differently from what was originally foreseen. Where the idea was to build seven production facilities with associated wells to supply around 20 % of the city's heat demand, now the plan is to only have three production sites in the north of the city.

At the same time, the company made clear that they will maintain the same energy output of 110 MWth.

This made me wonder; how does that work? Assuming that fewer wells will be drilled, how would it be possible to secure the same energy output? Have the test results of the three wells drilled so far been so much better than foreseen? I asked a few questions along these lines, to which the company responded.

When the first plans for the project were announced in 2022, 17 wells were planned. That number will now come down. "At this point, we have not concluded the total number of wells we will drill across the city," a company spokesperson wrote. "We are still working on the new development plan and are therefore still designing the layout of wells depending on what we know about the subsurface now." However, the person added that it is expected fewer wells will be drilled than the 17 originally planned.

On top of that comes the well that was drilled in the south of the city, where the company did not find the reservoir characteristics they expected in the Triassic Gassum Formation. The press release clearly stated that it is in the north of the city where the three production sites will be located. In other words, the well that was drilled in the south will unlikely be part of the development plan and will therefore be a loss to the project. "Decommissioning a well is, of course, a cost that affects the project's economy. But we have planned for the costs associated with understanding the subsurface in Aarhus and consider this an important step to reduce the subsurface risk for future drilling in Aarhus," the spokesperson said.

Innargi was unable to share the test results of the three wells that were drilled so far, as they are still working on finalising the development concept.

What to make of all this? First of all, Aarhus is still a flagship project given the size of the development, even when the number of production locations has now been reduced to three. However, reflecting on the information received, I find it hard to see how the company will be able to deliver the same amount of thermal energy when drilling fewer wells. In fact, there is an indication in an earlier company announcement that hints towards other ways to "compensate" for the loss in geothermal energy production: Heat pumps.


Production testing ongoing in Aarhus.

In the LinkedIn post, the company celebrates the arrival of heat pumps at one of the Aarhus production sites. This is what the post said: "In Aarhus, the natural geothermal heat from beneath our feet is approximately 70° C, but in Kredsløb's district heating grid, they need to receive temperatures of 80° C. That's where the heat pump steps in. It boosts the energy extraction and raises the temperature, unlocking the full potential of geothermal. In fact, thanks to heat pumps, we can recover up to 50 % more energy than we would from just the first heat exchange alone."

To me, it seems logical that the ultimate energy output of the project as a whole is measured only after the fluids exit the production site, so after the heat pump cycle. That means there is flexibility when it comes to how much geothermal energy is produced; if it is less than foreseen, the heat pumps just need to work a little harder. Even though Innargi did not confirm this to be the case, it is my take on why the same level of energy output can be maintained. I guess the costs of this are more manageable than drilling more wells, which is supported by a comment from somebody I recently spoke to and who was directly involved in drilling the wells: "The financial scrutiny was significant, to the point that I felt nothing could go wrong."

In other words, Aarhus is still an important geothermal project, but it looks likely that it has become a little less geothermal than initially planned. ■

Henk Kombrink

PHOTOGRAPHY: INNARGI

The hidden lithium treasure of South Australia

For two centuries, South Australia's Cooper Basin has been synonymous with exploration. First hydrocarbons, now a world-class lithium resource

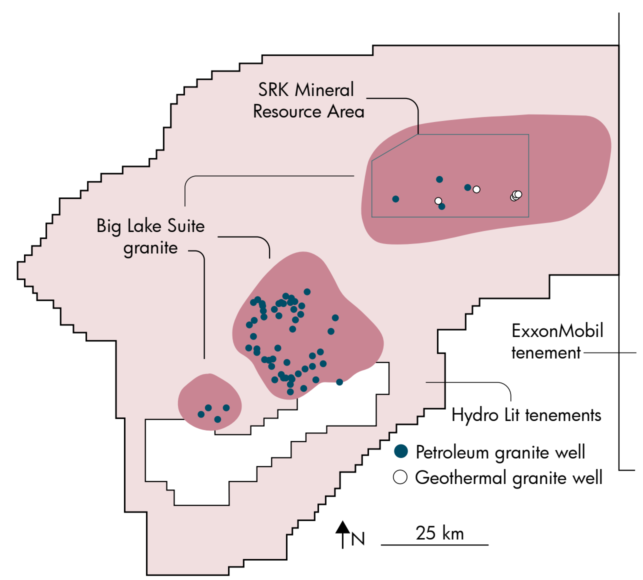
GEOFF FREER, HYDRO LIT

Despite receiving just 165 mm of rain annually, Coopers Creek flows year-round, an anomaly that has lured generations of explorers in pre-history to early European settlers. Exploration by geologist Reg Sprigg, founder of Santos and Beach Energy, led to drilling the Moomba-1 well in 1965, unlocking Australia's largest onshore gas field in the Cooper Basin. It also heralded the discovery of the Big Lake Suite granite (BLS granite) basement, with its unrealised lithium-brine potential, which is today attracting global attention.

Hydro Lit's Cooper Lithium Project isn't just another resource play, it's a geological jackpot. Fluids trapped within the granite have very high lithium concentrations and minimal impurities, positioning Australia to become a major force in the global battery supply chain as the world faces a looming lithium shortfall.

FROM HOT ROCKS TO LITHIUM RICHES

In 2003, a geothermal drilling campaign by Geodynamics targeting the BLS granites made a surprising discovery. Instead of hot dry rocks, they struck wet fractured rock with brines at 200° C, flowing up to 40 l/sec. Over a decade, water samples from five deep wells revealed lithium levels up to 320 mg/l, with minimal impurities. The geology tells a remarkable story: 300 million years ago, glacial waters flooded exposed granite. Subsequent burial and heating by radioactive decay caused leaching of lithium from hydrothermally altered minerals into a vast, fractured reservoir now forming the lithium resource for Hydro Lit's Cooper Lithium project.



A RESOURCE OF GLOBAL SIGNIFICANCE

A Mineral Resource Area (MRE) covering only 700 km² of Hydro Lit's 10,000 km² mineral leases holds a JORC-inferred 25.2 million tonnes of lithium carbonate equivalent. Recovering only 10 % of those fluids and utilising Direct Lithium Extraction (DLE) could supply batteries for 40 million electric vehicles.

The hot brines also offer a rare dual benefit: Clean geothermal energy for emissions-free lithium extraction. Backed by generous R&D tax and critical minerals production incentives and full control of the lithium-rich fairway, Hydro Lit holds a strategic first-mover advantage, even as major players like ExxonMobil eye the region too.

THE FUTURE BECKONS

Hydro Lit is deploying advanced geophysics to pinpoint high-flow fault zones for targeted extraction. A 12-month pilot project is set to prove lithium recovery and geothermal technologies, with results expected by late 2026. The goal: Deliver low-cost, green lithium just as the world confronts a looming supply crunch.

Explorers Burke and Wills missed their rescue arriving at the Dig Tree a day too late. While Geodynamics geothermal project missed its commercial mark, it left behind a rich trove of data. Unlike Burke and Wills, whose poor timing resulted in their deaths along Coopers Creek, Hydro Lits timing is perfect to lead Australia's next critical mineral revolution. And this time, they know exactly where to dig. ■

Elastic MP-FWI imaging: Changing geophysics

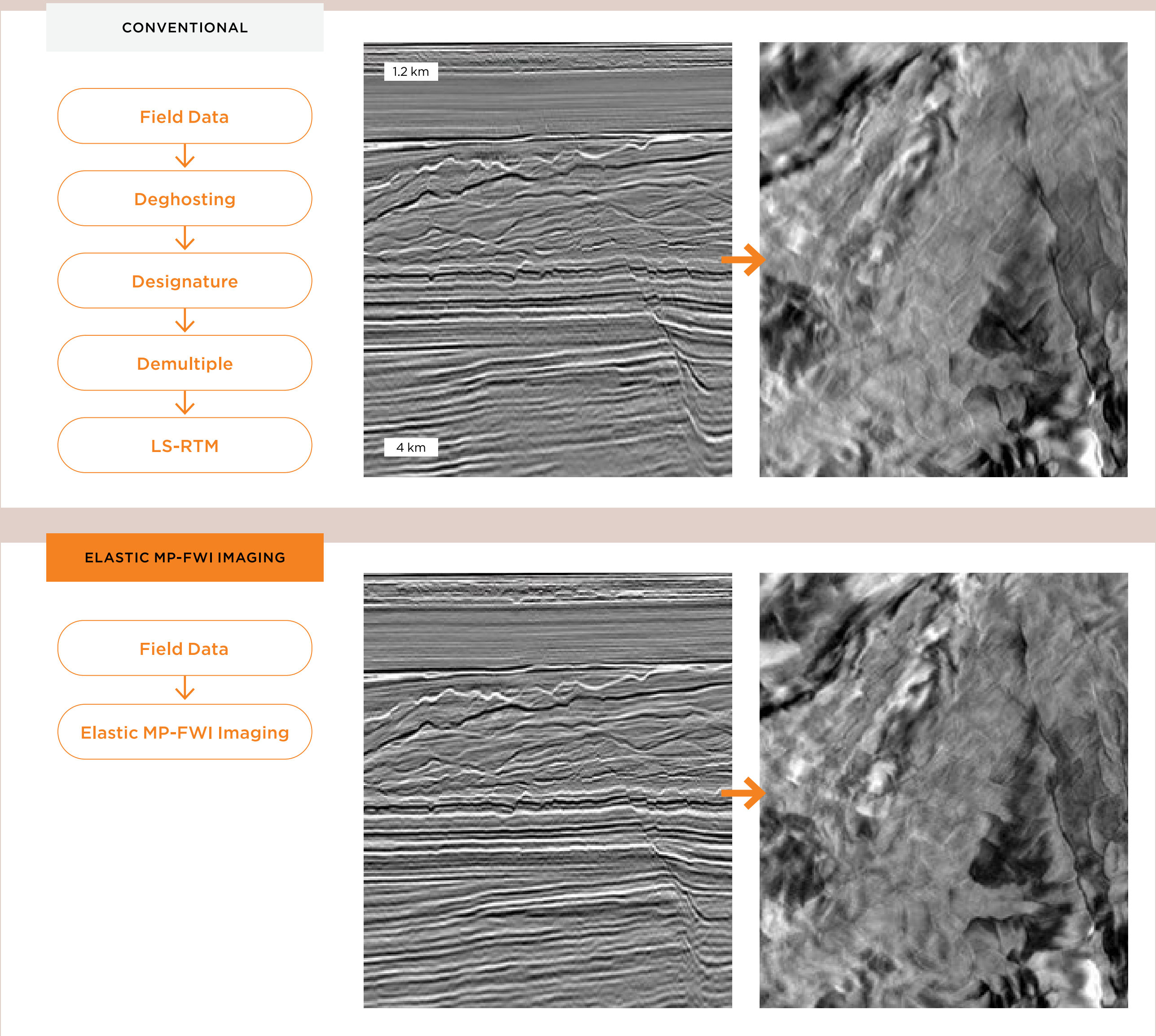


Figure 1: A section and depth slice comparison of conventional processing and imaging (top) and 60 Hz visco-elastic MP-FWI imaging reflectivity derived from raw field data (bottom). An increase in resolution is evident as well as improved structural consistency with depth.

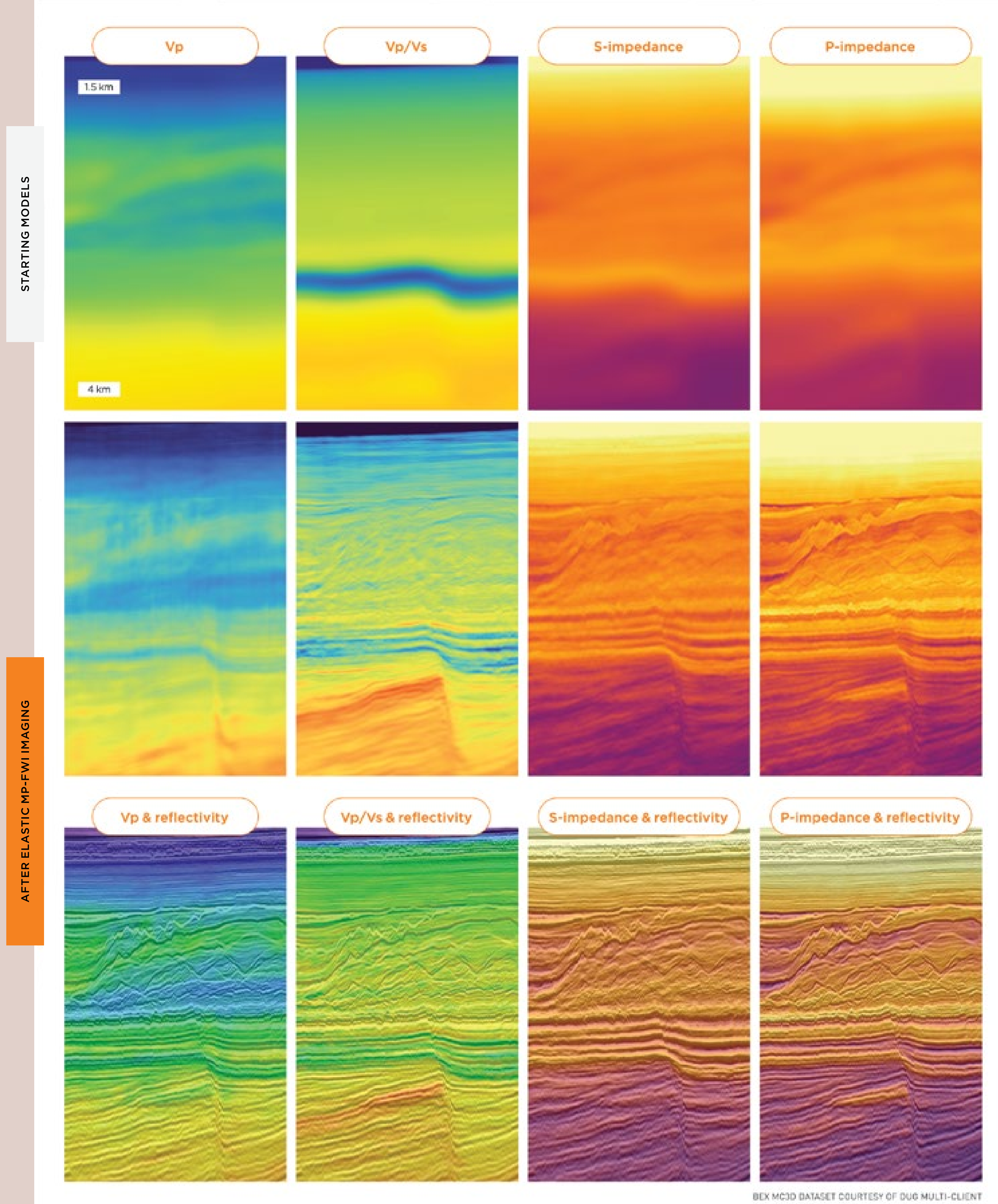
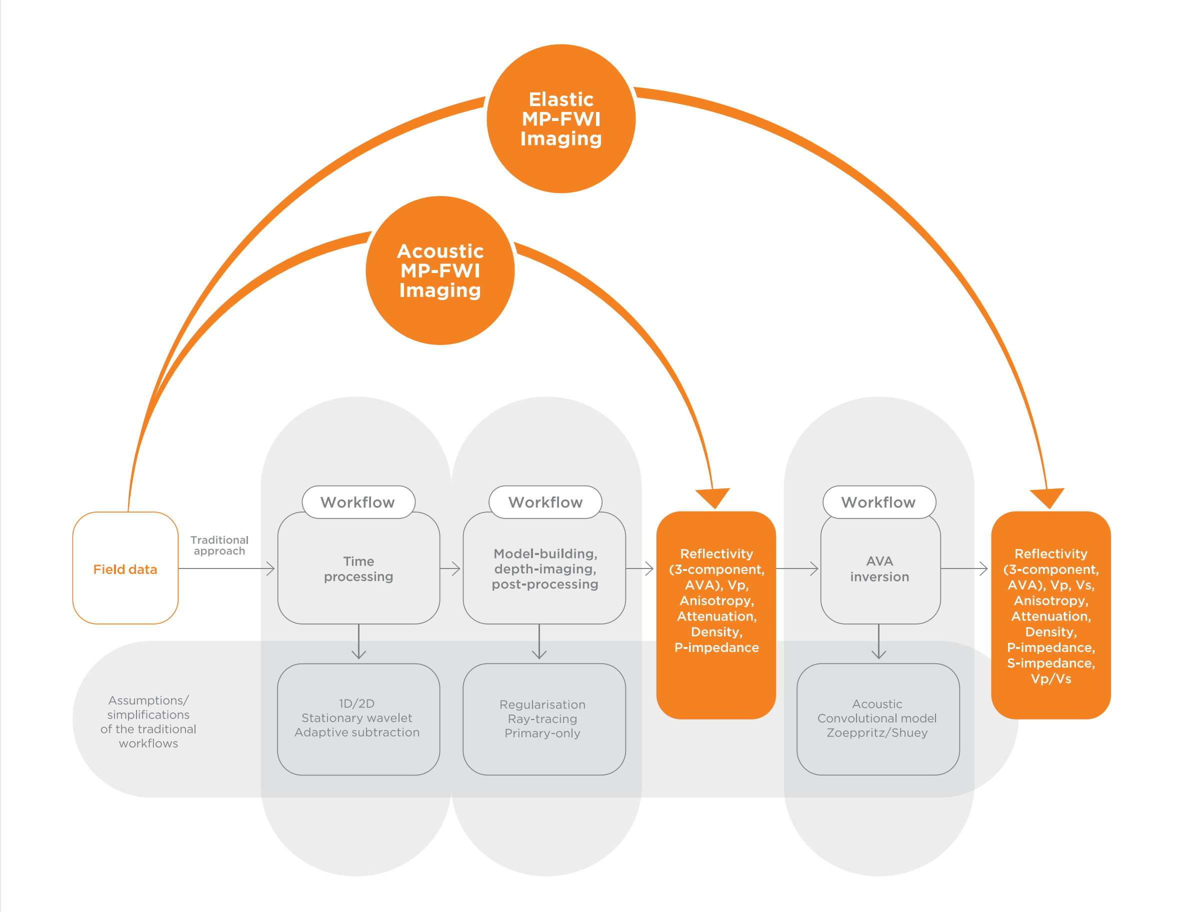


Figure 2: Initial models (top), inverted 60 Hz visco-elastic MP-FWI imaging models (middle) and inverted models co-rendered with the derived reflectivity (bottom). A significant increase in resolution has been achieved using elastic MP-FWI imaging with a gas reservoir and flat spot readily observable.

Multi-parameter full waveform inversion is rapidly changing what's possible with seismic data, turning decades-old approaches on their head to deliver high-resolution rock properties from field data in ever-decreasing timeframes.

Conventional workflows contain many assumptions, approximations and simplifications. A significant amount of time and effort is required to condition the input data, resulting in the attenuation of a substantial amount of information through highly subjective workflows.

Multi-parameter full waveform inversion (MP-FWI) imaging offers a new approach. This novel application of FWI enables the simultaneous inversion of a range of parameters, including velocity, reflectivity, and rock properties. Since FWI can model the full wavefield, the inversion can use all the acquired information. The use of primary and multiple reflections enables the determination of high-resolution velocity and reflectivity in a least-squares manner, thereby bypassing the model-building and imaging workflows. Now, with visco-elastic MP-FWI imaging, it is possible to invert directly for elastic parameters without the need for AVA inversion. Entire workflows can now be bypassed using this novel, superior technology.



Deriving rock properties from field data with elastic MP-FWI imaging

TOM RAYMENT, JAMES McLEMAN AND JENNIFER BADRY, DUG TECHNOLOGY

The seismic method has proven to be an invaluable tool to determine subsurface structures and properties since the first experiments in the 1920s.

The conventional processing, imaging, and inversion workflows for deriving reflectivity and elastic rock properties have evolved over the last century to use increasingly accurate physics, enabled by advancements in high-performance computing. However, this workflow still contains a wide range of assumptions, approximations, and simplifications, which are mainly due to the fact that legacy acoustic imaging algorithms are limited to using primary reflections. As a result, a significant amount of time and effort is required to remove parts of the recorded data that these algorithms are unable to handle, such as surface waves, converted waves, source and receiver ghosts, internal multiples and free-surface multiples. These workflows can be very lengthy and subjective to implement.

This processing and imaging approach yields pre-stack image gathers or angle stacks, which are used in a subsequent inversion step to determine elastic rock properties, such as P-impedance and Vp/Vs ratio. However, their assumptions still ultimately limit their resolution and amplitude fidelity in regions with high impedance contrasts or complex geology.

A NEW ERA OF ELASTIC LEAST-SQUARES IMAGING

Elastic multi-parameter full waveform inversion (MP-FWI) is a novel form of FWI that can bypass these legacy workflows. The algorithm realises Tarrantola's original vision for FWI, solving for elastic parameters and high-resolution reflectivity directly from raw field data. The full wavefield is modelled, and so the inversion can use all the acquired information. The use of primary and multiple reflections enables the determination of high-resolution Earth models in a least-squares manner. By employing complete and accurate physics and by solving the elastic wave equation, MP-FWI imaging is able to provide much-improved outputs compared to the conventional approach in a much-reduced timeframe.

CASE STUDY FROM AUSTRALIA

Here, we present a case study that demonstrates the benefits of high-frequency visco-elastic MP-FWI-derived rock properties.

This narrow azimuth towed streamer data was acquired in 2006 on the Australian North West Shelf, approximately 115 km northwest of Barrow Island. This region contains rapidly changing shallow velocity variations due to localised channel features and carbonates.

Well data located within the survey area and regional knowledge were used to build an initial low-frequency Vp/Vs, density, and anisotropy models, which, combined with a legacy Vp model, formed the input to elastic MP-FWI imaging. Through this approach, a simultaneous update of Vp, P-impedance and Vp/Vs was performed up to a maximum of 60 Hz using a frequency stepping scheme. From these output parameters, others were derived, including Vs, S-impedance, density and reflectivity.

For comparison, a conventional processing and imaging workflow was also implemented, which included designature, deghosting and demultiple. 60 Hz acoustic LS-RTM full and partial angle stacks were generated using the output velocity models from the 60 Hz elastic MP-FWI imaging.

The reflectivity derived from elastic MP-FWI is shown in Figure 1, with a depth slice at 2,570 m, in comparison to the reflectivity generated by the full-angle LS-RTM. It is important to note that the elastic MP-FWI results used the raw, unprocessed shots as input, whereas the LS-RTM used highly processed input data.

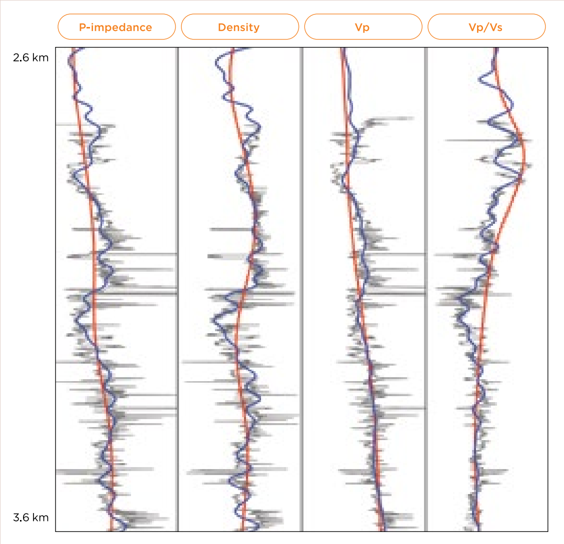


Figure 3: Well logs (grey) compared to initial elastic MP-FWI imaging models (red) and final 60 Hz elastic MP-FWI imaging models (blue). Elastic MP-FWI imaging has added significant resolution that accurately ties the wells.

The reflectivity generated by elastic MP-FWI demonstrates an increase in resolution compared to the acoustic LS-RTM, where subsurface channel features and complex faulting are sharper and more clearly delineated. A fault shadow is resolved by elastic MP-FWI imaging, and deeper events are more coherent compared to the conventional LS-RTM.

The elastic MP-FWI imaging initial models, final 60 Hz models and those same models co-rendered with the derived reflectivity are shown in Figure 2. A dramatic increase in resolution has been achieved using MP-FWI imaging, with the presence of a gas body and associated flat spot readily identifiable in the Vp and P-impedance. As expected, this fluid effect is not observed on the inverted S-impedance.

In Figure 3, the well information is in grey, the initial models are in red, and the elastic MP-FWI imaging models are in blue. The elastic MP-FWI updated models correctly predict these properties as measured at the well location, demonstrating that the crosstalk between the various inverted parameters has been successfully resolved.

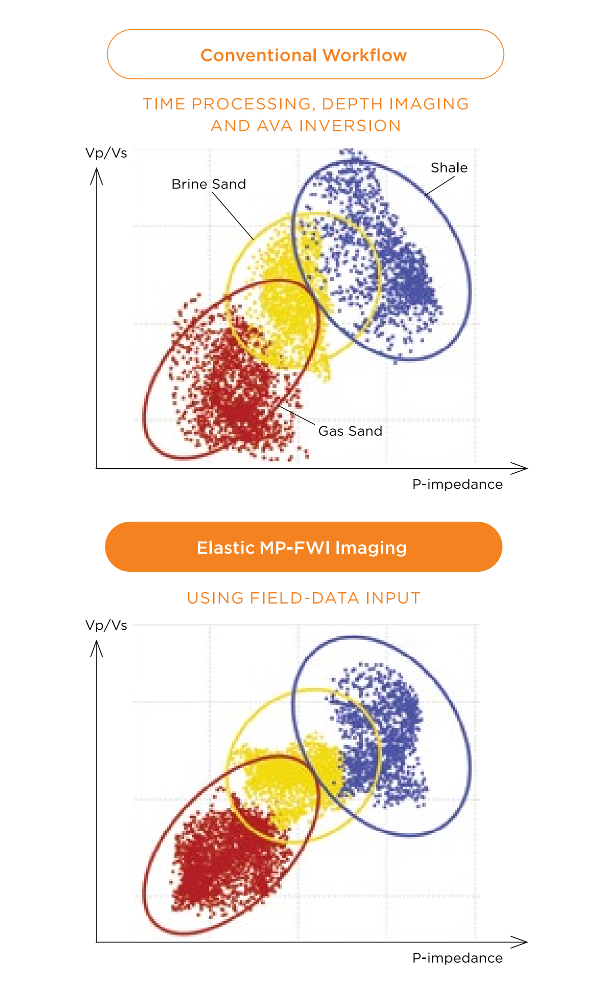


Figure 4: Crossplots of Vp/Vs and P-impedance for conventionally-derived parameters and elastic MP-FWI imaging-derived parameters.

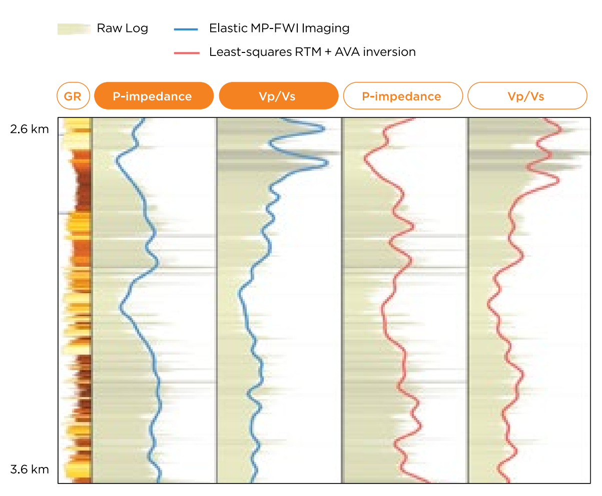


Figure 5: Well log comparisons of P-impedance and Vp/Vs derived through the conventional processing, imaging and AVA inversion workflows and elastic MP-FWI imaging.

The conventionally processed LS-RTM angle stacks were used to obtain estimates of P-impedance and Vp/Vs ratio through a conventional AVA inversion. Crossplots of Vp/Vs and P-impedance are shown in Figure 4, and a comparison to a well is shown in Figure 5. The crossplots show a tighter distribution with elastic MP-FWI imaging compared to LS-RTM, indicating a reduction in noise and uncertainty. A significantly better match is observed between the elastic MP-FWI-derived models and the well information, demonstrating that the accurate physics and reduced subjectivity of the elastic MP-FWI approach have yielded superior results.

A TRANSFORMATIVE BREAKTHROUGH

Elastic MP-FWI imaging is a revolutionary technology for seismic data, which is delivering much improved results over decades-old conventional workflows. The use of the full wavefield and superior physics enables bypassing of processing, model-building, imaging, and AVA inversion workflows, allowing for the derivation of high-resolution Earth models in significantly reduced timeframes. With these new developments, is it time to question whether the conventional workflow is now obsolete?

ACKNOWLEDGEMENTS

The authors thank DUG Technology for permission to publish these results and DUG Multi-Client for permission to use the BEX MC3D dataset.

SUBSURFACE STORAGE

Kasawari – gas production has commenced, but when does the CO_2 storage project?

Is AI's suggested start-up date for South-East Asia's flagship CCS project still credible? We asked a few people, but have been unable to find out what the current status is, potentially exposing challenging conditions in getting the project over the line

At industry events in South-East Asia, the Kasawari CO_2 storage project has been a talking point for years. It should be the first large-scale CO_2 storage project in the region, and one that justifies developing gas fields that suffer from relatively high levels of the greenhouse gas.

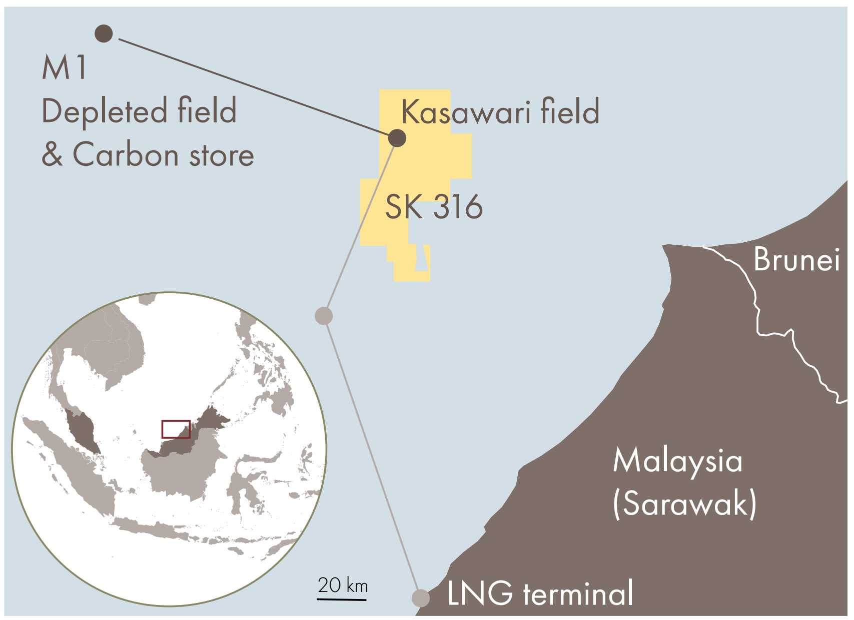
A simple online search shows that the project has already had quite some milestones achieved, with most sources citing a start of injection towards the end of this year.

However, a recent article from the Borneo Post suggests that injection is now projected to only take place in 2029, possibly 2030: "Petronas eyes first CO_2 injection date by end 2029, early 2030 in Kasawari". Other people I tried to contact, including two from Petronas, have either not responded or were unable to share more information on the status of the project.

Timing is quite important. If the CCS component of Kasawari will only become operational in 2029 or 2030, the field is expected to have passed peak production already, and most of the CO_2 will thus have been released into the atmosphere.

Could it be possible that the project is facing headwinds? The financial side of things may be a sticking point. Is the operator taking responsibility of all the capital expense, or is the government chipping in? Both organisations have made net zero commitments, but ultimately, the development of these high-CO_2 discoveries is competing for (foreign) investment, and if there is a significant CO_2 price tag that would land on the operator, the attractiveness of these projects will quickly drop. ■

Henk Kombrink



THE KASAWARI CCS PROJECT

The Kasawari gas field, which was discovered in 2011, is located offshore Sarawak (SK 316) and is reported to contain 3.2 Tcf of recoverable gas, of which approximately 22 % is CO_2. Gas production commenced in August 2024 at an initial rate of 200 mmscf/d, ramping up to 900 mmscf/d later.

The Kasawari carbon capture project entails the construction of a dedicated platform next to the gas production facilities, from where the CO_2 will be transported through a 140 km long pipeline to the depleted M1 field, where the gas will be injected. In total, it is estimated that between 71 and 76 million tonnes of CO_2 will be injected, probably based on the assumption that the project will start this year.

The M1 field is a Miocene carbonate reservoir that forms part of the so-called Mega Platform. The carbonates of the M1 field were one of the last surviving parts of the greater platform, thereby forming the most elevated closure in the area.

An under-communicated factor for CCS

Monitoring future CO_2 storage requires more than just seismic. Pressure measurements on the seabed can provide valuable complementary information about reservoir conditions and how much storage space is available

Ola Eiken.

"WE DID NOT want the same unexpected situation like we had at Ekofisk," recalls Ola Eiken, CEO of Quad Geometrics. He refers to the discovery of 2.5 m of seabed subsidence that had occurred since the start of oil production. "When Statoil was preparing the Troll oil and gas field for start-up in 1995, we wanted to monitor subsidence from the start."

Echosounders, the standard at the time for seabed measurements, were too imprecise. A colleague of Ola suggested a simple solution: Measure the water pressure!

> **"I think many people did not realise the precision that water pressure measurements provide"**

"The method proved to be very precise, with 2-3 mm accuracy at 300 m depth – on par with onshore measurements. I think many people did not realise the precision that water pressure measurements provide," Ola continues.

Trondheim-based Quad Geometrics specialises in high-precision measurements of gravity (gravimetry) and vertical movements, offshore and onshore. Twelve years ago, Ola brought his expertise and technology from Statoil into the company, which he started together with a colleague from the Scripps Institution of Oceanography in San Diego.

FROM SUBSIDENCE TO UPLIFT

The method is simple: Pressure sensors are placed on a pad on the seabed, record data for a few minutes before the pressure sensors are moved with a remotely operated underwater vehicle (ROV) to the next measurement point. A network of reference sensors outside the measurement area provides the necessary corrections, including for tides.

Ola understood early on that the technology is also well suited to monitoring uplift. Where oil, gas or groundwater extraction contributes to subsidence, fluid injection results in the seabed being lifted up.

> **"For large-scale CCS projects, understanding and managing pressure is crucial. Storage capacity depends on compression of the formation water and pore expansion. The expansion causes uplift – and by measuring this, the capacity increase is directly quantified"**

Since 2021, Quad Geometrics has taken part in the SHAPE (Seafloor Height from Aqua PressurE for offshore CO_2) research project together with Equinor and NGI. The project investigates measurement methodologies related to offshore CO_2 storage.

"For large-scale CCS projects, understanding and managing pressure is crucial. Storage capacity depends on compression of the formation water and pore expansion. The expansion causes uplift – and by measuring this, the capacity increase is directly quantified," Ola explains.

AN UNDER-COMMUNICATED FACTOR

Repetitive seismic measurements (4D) are considered the gold standard for tracking the CO_2 cloud in a reservoir, such as at Sleipner (since 1996), Snøhvit (since 2008) and soon at Northern Lights' Aurora – Norway's first commercial CO_2 storage.

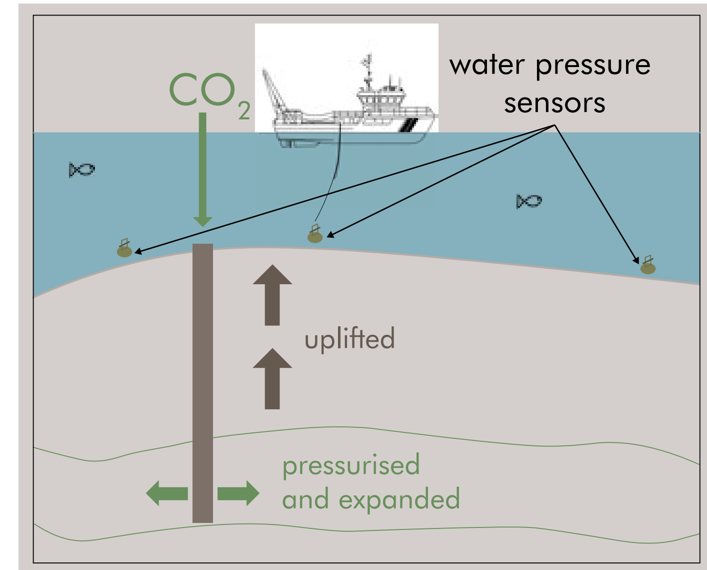
"But seismic data does not show the pressure in a reservoir very well. The pressure increase moves faster and affects a larger volume of the reservoir than the greenhouse gas itself," Ola points out.

He believes that pressure measurements have received too little attention. Good pressure control can be crucial for the success of large-scale storage of CO_2. Snøhvit illustrates this. Shortly after injection began in the Tubåen formation in 2008, the pressure rose sharply near the well.

"The problem was that the reservoir experts did not have much information about what was happening some distance away from the well. Models suggested barriers and poor formation properties in certain parts of the reservoir, but it was not possible to get to the bottom of this."

The decision to switch injection to another formation (from Tubåen to Stø) was made in 2011. Ola emphasises that broader pressure information could have provided a better insight into the reservoir conditions in Tubåen. Perhaps based on this information, a switch to Stø would have been made at an earlier time, or perhaps the reservoir challenges in Tubåen could have been handled?

PHOTOGRAPHY: OLA EIKEN PRIVATE ARCHIVE



Sketch of the concept that has been investigated in the SHAPE project, where measurements of water pressure are used to determine seabed elevation

CONFLICTS

Pressure can also create conflicts with neighbours. In academic circles – and most likely also internally in companies – it has been discussed how adjacent licenses for CO_2 storage can affect each other. This will also have to become a topic for the authorities' supervision of the business.

The Troll aquifer, which the Northern Lights will use, extends across several licenses for CO_2 storage on the Horda platform. If neighbouring operators also begin injection in the coming years, they will therefore share the same storage space. And it is ultimately the pressure that determines how large volumes of greenhouse gas can be stored in a given formation.

In this context, there are still unanswered questions related to whether the companies can operate side by side with predictable storage capacities and not least how to optimise injection strategies for best utilisation of the capacity without one operator outcompeting other operators within one aquifer.

"Pressure is an under-communicated factor in this context," says Ola.

THE FUTURE OF PRESSURE MEASUREMENTS

The SHAPE project is in its final phase, and the results could be of great benefit to a future industry on the Norwegian continental shelf. Little work has been done on this type of measurement of offshore CO_2 storage previously.

He hopes that the SHAPE project will help elevate the role of pressure in the CCS debate, i.e. to put the value of such information, and the challenges associated with pressure increases in reservoirs, higher on the agenda.

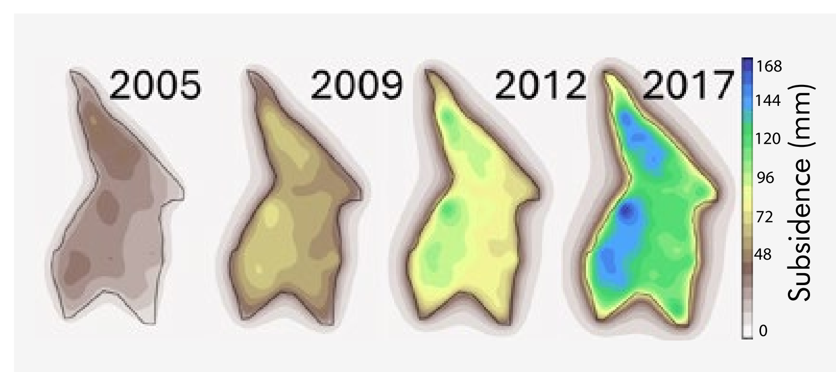
"For Equinor, this is of course relevant knowledge. They have a lot of data on subsidence at Troll, and are involved in CCS projects both southwest of Troll (Northern Lights) and east of Troll (Smeaheia)."

The existing Troll measurement network is therefore in a very favourable position, and an expansion of the network into the adjacent CCS licenses will have a limited cost.

"Within the SHAPE project, we have had discussions about the way forward for the technology. Some see the value of such pressure measurements, while others are still unsure whether the measurements will be accurate enough to register relatively small changes on the seabed."

Regardless, Ola is convinced that pressure will increasingly be a topic of discussion when we plan for future CO_2 storage on the Norwegian shelf. "Then it is important to have good solutions for how we can register this parameter over large areas in a cost-effective manner. The measurements at the Troll field have demonstrated over 25 years that this is possible." ■

Ronny Setså



Measurements of subsidence and uplift provide a lot of valuable information about the processes taking place in a reservoir. The figure shows subsidence at the Troll field.

SOURCE: REDRAWN AFTER QUAD GEOMETRICS; PARTNERS IN THE TROLL LICENSE / SHAPE PROJECT

SEABED MINERALS

"...we do need to incorporate technology into the public debate about seabed mineral extraction, as it is technology that will be able to facilitate shifts in the environmental impact to an extent that it could be acceptable to move forward"

Annemiek Vink – BGR

Loke's Pacific licenses up for auction

Loke's deep-sea mineral licenses in the Pacific are up for sale, with British authorities wanting to see British ownership

EARLY APRIL, the adventure was over. Loke Marine Minerals went bankrupt. “We have been looking for capital for a long time. We received a bridge loan from our key shareholders, but we were unsuccessful in raising additional capital,“ CEO Walter Sognnes told the Norwegian newspaper Dagens Næringsliv.

Since the company was founded in 2019, Sognnes and his colleagues have worked on technology development related to the exploration and extraction of deep-sea minerals. The business strategy involved two geographical areas and two types of mineral deposits: Manganese-rich nodules in the Pacific Ocean and polymetallic crusts in the Norwegian economic zone.

In both areas, unpredictable above-ground circumstances have made it difficult for companies wanting to explore and extract marine resources. This also affected Loke.

In international waters, relevant players have long been waiting for the International Seabed Authority (ISA) to finalize the regulations (“the mining code”), with the new Secretary-General stating that this could still take a few years. The consequence could be that companies now turn their backs on the ISA’s authority, and instead choose to rely on American legislation. This is something The Metals Company has already embarked on. In Norway, the expected licensing round for seabed minerals was abruptly halted in December last year.

THE MOST IMPORTANT ASSETS

The two deep-sea mineral licenses in the Clarion-Clipperton Zone (CCZ) in the Pacific Ocean, UK1 and UK2, are the most important assets in Loke’s bankruptcy estate. Both licences are owned by Loke’s subsidiary UK Seabed Resources (UKSR).

The CCZ is considered the world’s largest nodule resource. Within the two licenses, it is estimated that 750 million tonnes of ore can be found, with 8, 10, and 1.4 million tonnes of copper, nickel and cobalt, respectively.

To put these figures into perspective, global copper production in 2024 was approximately 23 million tonnes. The resource is larger than the world's largest undeveloped onshore nickel deposit. The licenses contain almost five times the global cobalt production in 2024. Sognnes has previously stated that the present value of the company's full-scale plan for the licenses is more than $30 billion.

Amongst the interested parties for UKSR's licenses are Loke's founders and TechnipFMC, which is one of Loke's owners. Greenpeace has also reportedly shown interest, allegedly as a marketing stunt.

Mining.com, referring to the Financial Times, states that the upcoming sale is of security policy interest to the UK, and that the authorities can intervene in the auction process if necessary. From their side, it is desirable that the licenses are controlled by a British company. This could give British TechnipFMC an advantage in the bidding process.

We asked Walter Sognnes for an update on the bidding process near the end of June, but he said that he had no news to report at this time. The question now is who will win the licences, and whether a possible new incarnation of Loke will also turn its attention to the Norwegian shelf again. ■

Ronny Setså

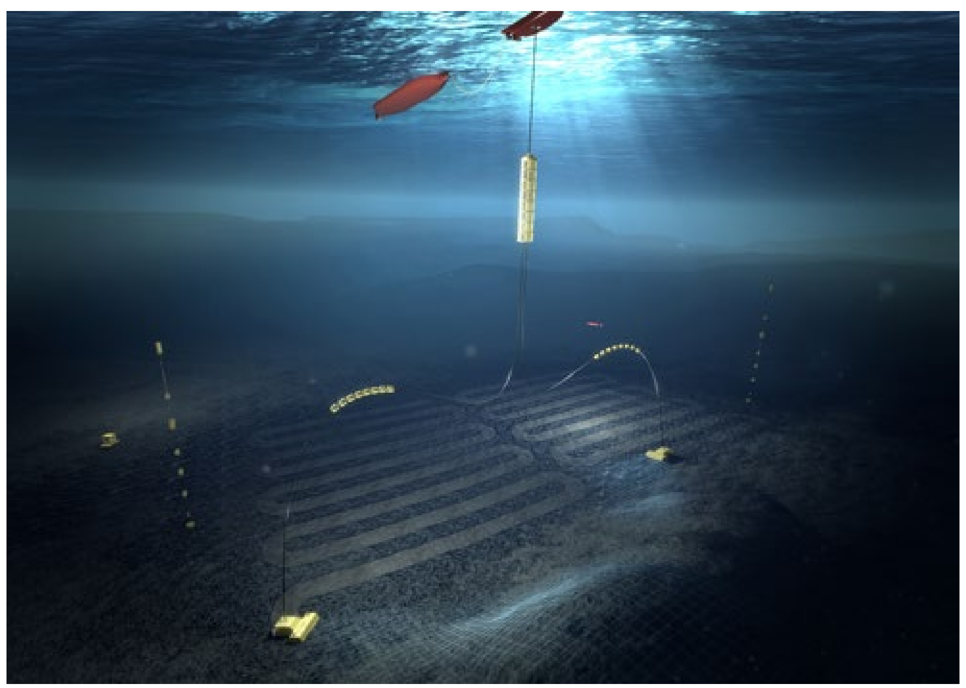


ILLUSTRATION: LOKE

Conceptual sketch of nodule extraction on the seabed. Loke aimed for production in the Pacific Ocean in 2030.

Technology is always missing in the debate about seabed mineral extraction

Annemiek Vink argues that technology plays a key role in reducing the environmental impact of seabed mineral extraction to the point where it is vital to include it in any debate about its future

IMAGE: IMPOSSIBLE METALS

Successful demonstration of the Eureka II Autonomous Underwater Vehicle. November 2024.

“IF YOU talk to organisations opposing seabed mineral extraction,” says Annemiek Vink, “they all speak about the terrible environmental damage that this will cause. But none of them relate this to technology and the role it plays in reducing the environmental impact.”

Annemiek works at the BGR in Hannover, Germany, and has been closely involved in research projects analysing the potential effects of seabed mineral extraction for a long time.

“The link between environmental damage and technology is very strong, with bad technologies producing a much more pronounced impact than more advanced methods. In other words, I feel that the debate is incomplete without involving an informed contribution from the technology side when discussing the impacts of seabed mineral extraction.”

“For instance,” Annemiek continues, “when we look at harvesting polymetallic nodules from the seafloor, the sediment plume that is generated by modern machines that suck up the nodules as they drive across the seafloor is much more confined than modellers were predicting about a decade ago. Rather than dispersal over hundreds of kilometres, it is rather 1 to maximally 2 km instead, and remains very close to the seafloor.”

“I also know that GSR, the Belgian company that built one of the first prototypes of a tracked nodule collector, which was tested at 4.5 km depth in 2021, have identified more than 10 ways to adapt and change their collector to reduce water and sediment intake and maximise the density of the particles that are being ejected, so that they settle even faster.”

“At the same time, there is no getting away from the fact that any machine driving across the seafloor will inevitably cause a plume of some dimension,” adds Annemiek.

“But companies are looking at other ways of doing this. For instance, Impossible Metals, a US-Canadian start-up company, is looking at AUV’s that hover over the seafloor to pick up the nodules mechanically with considerably less disruption of the seafloor sediment.”

Then there is the concern about mid-water plumes, which are caused by the return fluid stream once the nodules have been separated from surplus water, sediment and nodule fines on the surface vessel. There is abundant life at mid-water depths, causing serious concern with stakeholders. “However,” says Annemiek, “there is no need for mid-water plumes at all. Return fluids can be brought back entirely to where they came from, or there are ways to engineer things in such a way that there is no return fluid required at all. Yes, these will be more expensive solutions, but if that is the price we need to pay for a more responsible extraction, we have to accept that.”

“What all this shows is that we do need to incorporate technology into the public debate about seabed mineral extraction, as it is technology that will be able to facilitate shifts in the environmental impact to an extent that it could be acceptable to move forward,” Annemiek concludes. ■

Henk Kombrink

Crushing report on TMC's deep-sea mining plans

Financial investigation firm Iceberg Research believes The Metals Company's (TMC) plan to extract deep-sea nodules is flawed and compares the company to the failed Nautilus Minerals project

"WE BELIEVE the economics of TMC's operations are not viable and that the company will be a repeat of Nautilus. We expect Gerard Barron to leave the ship when this becomes obvious, as he did with Nautilus."

These are the concluding words in Iceberg Research' latest report on The Metals Company (TMC). The small, secretive firm is known in financial circles for its activist approach and short-selling reports on companies it believes to be overvalued, flawed, or fraudulent.

By the time the report was published, TMC's stock had soared 290 % year-to-date, fuelled by its pivot to US permits under the Deep Seabed Hard Mineral Resources Act (DSHMRA) and President Trump's executive order to fast-track deep-sea mining permits. The report, however, sees the stock rally as unsustainable, warning of icebergs ahead for TMC's economic viability.

ICEBERGS AHEAD

Iceberg Research compares TMC to Nautilus Minerals, a failed deep-sea mining venture where TMC's CEO Gerard Barron and founder David Heydon were early investors, reaping profits by selling shares before its 2019 bankruptcy. Nautilus went bankrupt after operating costs escalated without a pre-feasibility study (PFS).

Iceberg warns that TMC is repeating this pattern, lacking a PFS for its Nori-D project in the Clarion-Clipperton Zone (CCZ) despite claiming completion in November 2024, a claim undermined by the absence of expert sign-off by March 2025. A PFS is a critical document that estimates economically viable reserves.

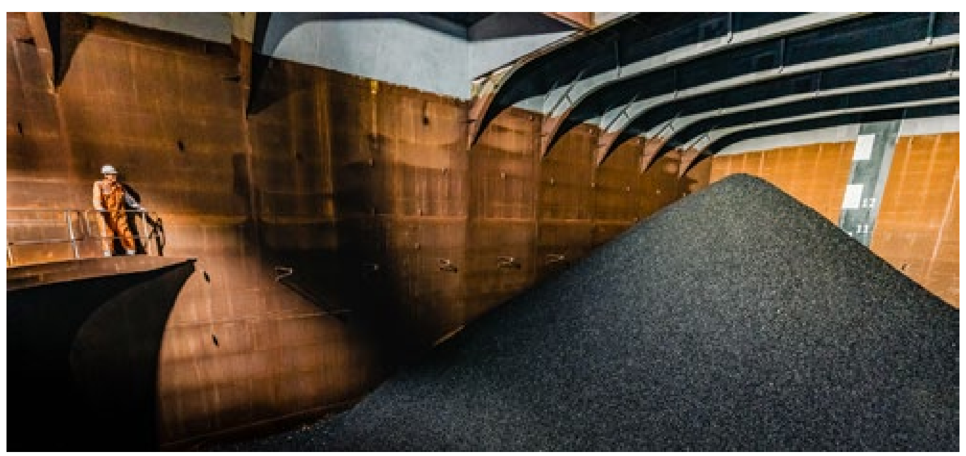
Furthermore, Iceberg believes TMC's economic assumptions are overly optimistic, questioning whether mining in harsh conditions in the deep sea could be cost-competitive with mining metals in open pits onshore. The research firm believes this is not the case, and the reason why the largest mining companies in the world haven't shown interest in deep-sea mining.

Commodity prices further weaken TMC's case. In 2021 and 2022, metal prices had soared due to fears of supply crunches and increasing demand for electric vehicles. Fast forward to today, and the prices have mostly decreased, and are below TMC's original assumptions, with copper being an exception. The decreases are driven by Indonesian supply and the rise of lithium iron phosphate (LFP) batteries, which demand fewer metals.

The research firm adds another nail to TMC's coffin – the nodule collection numbers. In 2022, the company conducted a pilot test and reported collecting 4,500 tons of nodules. Their stated sustained production rate was 86 tons per hour. Iceberg Research found this number to be significantly less than TMC's previous assumptions of 146 tons per hour.

In summary, Iceberg Research estimates a devastating net present value for TMC's nodule project of negative $721, compared to TMC's initial estimate of $6.8. Consequently, Iceberg believes the economics of TMC's operations are not viable and that the company will face bankruptcy, as Nautilus Minerals did. ■

Ronny Setså



In 2022, TMC successfully collected and brought aboard 4,500 tons of nodules during a pilot mining test.

PHOTOGRAPHY: TMC

NEW GAS

"If my interpretation proves correct, it could not only revolutionise Cuba's economy, but it could represent the beginning of the replacement of oil as a source of energy"

Marcello Rebora – Geologist

Cuba – the next hydrogen hotspot?

Based on results from previous hydrocarbon exploration drilling, geologist Marcello Rebora argues that the waters south of Cuba hold tremendous potential for natural hydrogen

"I HAVE concluded that this area should not be explored for oil, but for hydrogen instead. And I believe that the potential is colossal," wrote Marcello Rebora in a recent email.

In the nineties, Marcello was involved in hydrocarbon exploration offshore southern Cuba. More recently, he started to look at the data again, out of curiosity. His review of seismic, well, gravity, geological and geochemical data in the Golfo de Ana Maria and Guacanayabo, where his company held licences at the time, led him to conclude that the area has potential to make a commercial hydrogen find.

"There is an ophiolite at a convenient depth, there are basement faults acting as conduits, there are porous reservoirs and there is a proven sealing unit. All the ingredients needed for a successful natural hydrogen play," wrote Marcello. "And this is further supported by surface seeps."

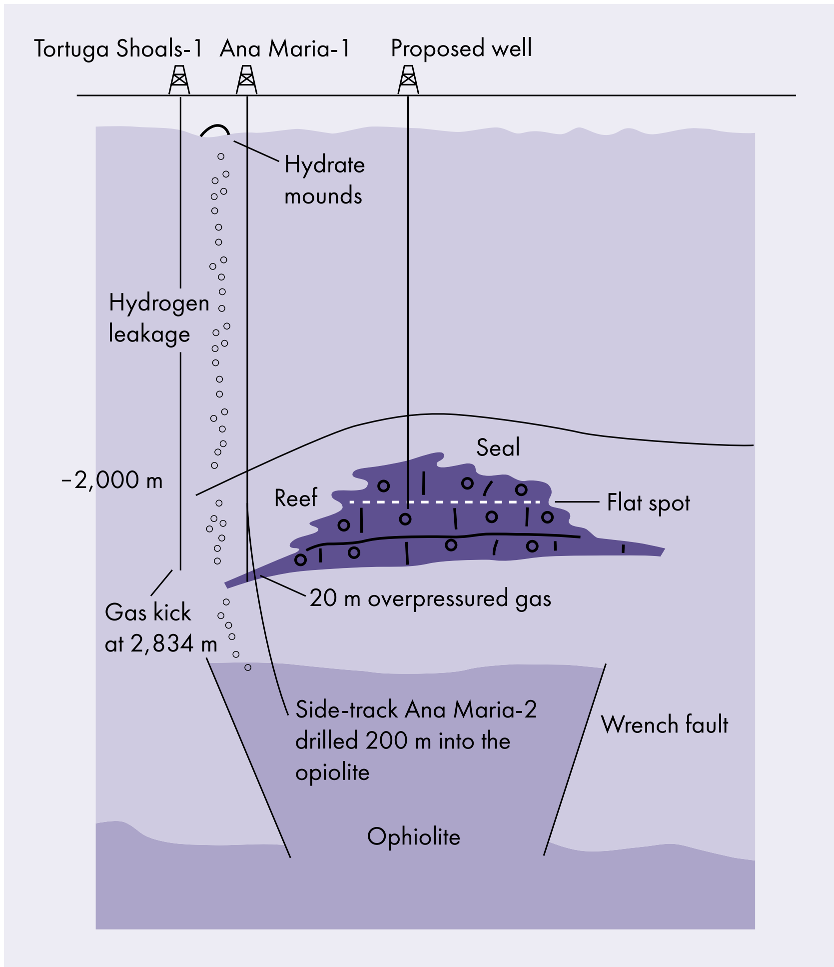
Here is a short summary of how Marcello came to this conclusion.

CLIPPING REEFS

"In 1996, our group drilled the well Ana Maria-1 from an island some 1.5 km from the nearest marine seismic control, practically as a stratigraphic test. It ended up being drilled downdip from a cluster of Upper Cretaceous reefs," writes Marcello.

"The well found a limestone section deposited in a basinal and talus position, containing debris from an adjacent rudist reef. Some of the limestone samples were replaced by dolomites containing sphalerite and uranium, deposited from hot fluids derived from the underlying ophiolites."

The limestone section in the well consisted of 20 m of overpressured gas, which suggests a good seal.



"At that time, the rig didn't have the equipment to prove the presence of hydrogen," adds Marcello, "but with the overpressured section being about 800 m deeper than the adjacent reefal structure that shows a flat spot, the obvious conclusion is that it is full of gas."

Years before this, the well Tortuga Shoals-1, drilled by Stanolind and also based on limited seismic control, did not reach the reef either, but also contained rudistic debris in the samples and had a gas kick at 9,300 ft.

The obvious follow-up well to drill the reef properly, which was named Bajo Corales-1, was never drilled as investment was diverted elsewhere at the time.

WHAT NEEDS TO BE DONE NOW

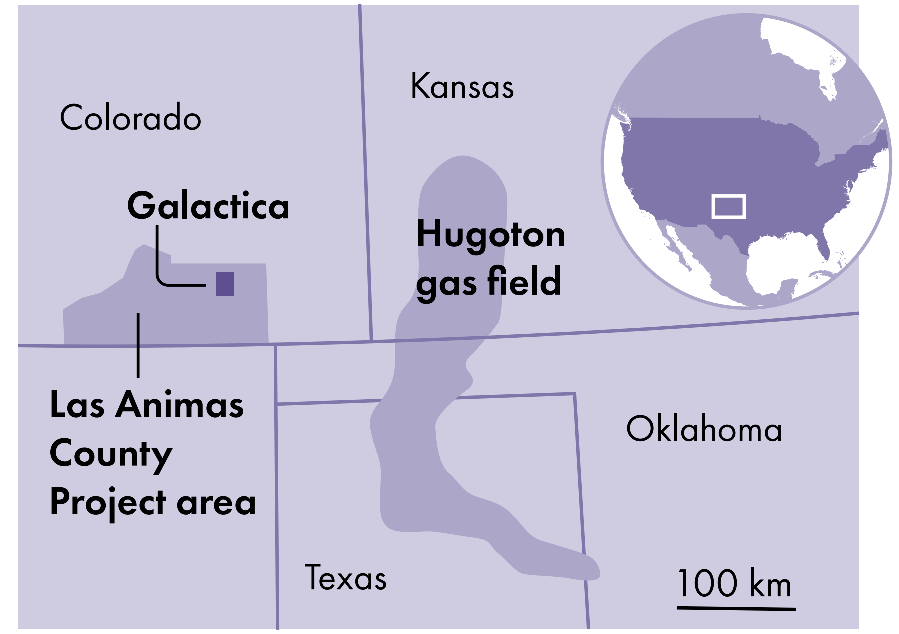
Combined with the results of a gravimetric survey that points to an uplifted basement core beneath the reefal structure that was clipped by the Ana Maria-1 well, Marcello now argues that all that needs to be done is to drill the crest of the reef with a new well and test the gas. "If my interpretation proves correct, it could not only revolutionise Cuba's economy, but it could represent the beginning of the replacement of oil as a source of energy," he concludes. ■

Henk Kombrink

Successful near-field helium exploration

With the Hugoton gas field depleting, companies are drilling for helium further west

BLUE STAR Helium and joint venture partner Helium One, have successfully concluded a six-well development campaign at the Galactica project in Las Animas County, Colorado. The company reported positive results across all wells, with helium concentrations ranging from 0.4 % to 3.3 % and stabilised flow rates between 250 and 500 Mcf/day. The wells will be tied back for commercial production, which is expected to start later this year.



The Galactica helium field is part of the Las Animas Arch, a basement-related anticlinal uplift that flanks the Hugoton embayment. The Hugoton gas field is the largest natural gas field in North America and is well known for its helium enrichment. Traditionally, the Hugoton Field has provided a significant portion of the helium market and currently still accounts for nearly a fifth of global helium supply. However, due to declining production and steady demand, helium exploration and production activities are now shifting west.

SHALLOW EXPLORATION WELLS

Contrary to the carbonate reservoirs found in the Hugoton field, helium in Las Animas County is found in the Lyons Sandstone Formation. The Lyons Sandstone was deposited in a nearshore environment during the Middle Permian and exhibits evidence of both shallow marine and aeolian processes. The formation is divided into the Lower and Upper Lyons Sandstone, separated by an erosion surface and shale-rich middle member.

Blue Star's exploration campaign in 2022 confirmed the presence of helium in both the Lower and Upper Lyons Sandstone. It also indicated superior reservoir quality in the Upper Lyons Formation. This presumably explains why all six development wells were completed in the Upper Lyons Sandstone, at depths of around 365 m. However, Blue Star Helium has identified an additional six to ten locations for infill wells at Galactica, which will potentially target the Lower Lyons Formation.

Blue Star Helium is not the only operator in the region. Desert Eagle owns the Red Rocks project, which is surrounded by Blue Star's Galactica acreage. Red Rocks has been producing helium from three wells for the past 2.5 years. Mosman Oil and Gas holds acreage directly north and northeast of Galactica; here, the Lyons Formation closures are prognosed at shallower depths. The first well, at the Billy Goat lease, reached a total depth of 220 m. However, Mosman has not released further data because Desert Eagle is interested in acquiring the asset. The Richardson well at the 'The Bard' lease, directly north of Galactica, encountered the Lyons Formation 140 m deeper than expected and flowed water rather than helium. ■

Mariël Reitsma, HRH Geology

HIGH LEVELS OF CO_2

In addition to helium, the Galactica Field contains high levels of CO_2, with concentrations ranging from 48 % to 98 %. Both gases are likely sourced from the underlying Precambrian basement. Helium is generated during uranium and thorium decay, while CO_2 results from prograde metamorphism. Metamorphic temperatures are also required to release helium from the parent mineral, allowing it to become a free gas phase. Blue Star Helium plans to produce both CO_2 and helium at its Pinon Canyon Plant. Hydrocarbons are not present in the Galactica Field.

A surge in exploration for natural hydrogen

Straddling the border between Ontario and Quebec, the Timiskaming Graben in Canada is on the radar in the search for natural hydrogen

THE GLOBAL search for natural hydrogen is centered around a few hotspots, and the Timiskaming Graben in Canada is one of them. The graben is located on the Canadian Shield, which is composed of mafic and ultramafic rocks, banded iron formations and kimberlite intrusions.

Faulting associated with the Timiskaming Graben may have started as early as 2.4 billion years ago and has been reactivated multiple times during periods of crustal extension, such as during the break-ups of Rodinia and Pangea, as well as through the various orogenies responsible for the formation of the Appalachian Mountains. Even today, the graben faults remain seismically active.

Both serpentinization and hydrolysis are likely occurring to at least some extent in the Timiskaming basement, with the deep-seated faults serving as fluid pathways for water and hydrogen circulation.

But what evidence supports the presence of natural hydrogen in the region? One of the first clues was the discovery of dissolved hydrogen in the groundwater of gold mines. In some instances, hydrogen makes up over half of the gas in solution. The mines are also associated with forest rings, semicircles of sparse and stunted tree growth observable from the air.

More than 2,000 of these forest rings, ranging from 50 m to 1.6 km in diameter, have been found in the boreal forests of northeastern Ontario. Although the correlation between these tree rings and hydrogen remains unclear, exploration companies view them as a positive indicator for hydrogen prospectivity.

Forest rings in northeastern Ontario, 49°29'24"N 80°05'24"W. Rings are ~145 m in diameter.

PHOTOGRAPHY: GOOGLE EARTH

SURVEYING FOR HYDROGEN

Record Resources and Quebec Innovative Material Corp (QIMC), with land holdings on opposite sides of Lake Timiskaming, agreed to a joint study of dissolved hydrogen in the lake waters. This study was conducted in the winter of 2025, while the lake was frozen. Depth profiles revealed a hydrogen anomaly at the thermal boundary between the cold surface water and the slightly warmer deep water. This is interpreted as evidence that faults exposed in the lake are outgassing hydrogen.

QIMC has also done an extensive soil gas sampling campaign on the Quebec shore of Lake Timiskaming. Based on these results, they drilled eight shallow hydrogen monitoring wells, with one well showing over 2 % hydrogen gas at 75 m depth. Now, a deeper drilling campaign is planned with wells reaching between 500 and 600 m depth, gaining more general geological insight as well as detailed understanding of the fault and fracture system obscured by Quaternary sediments.

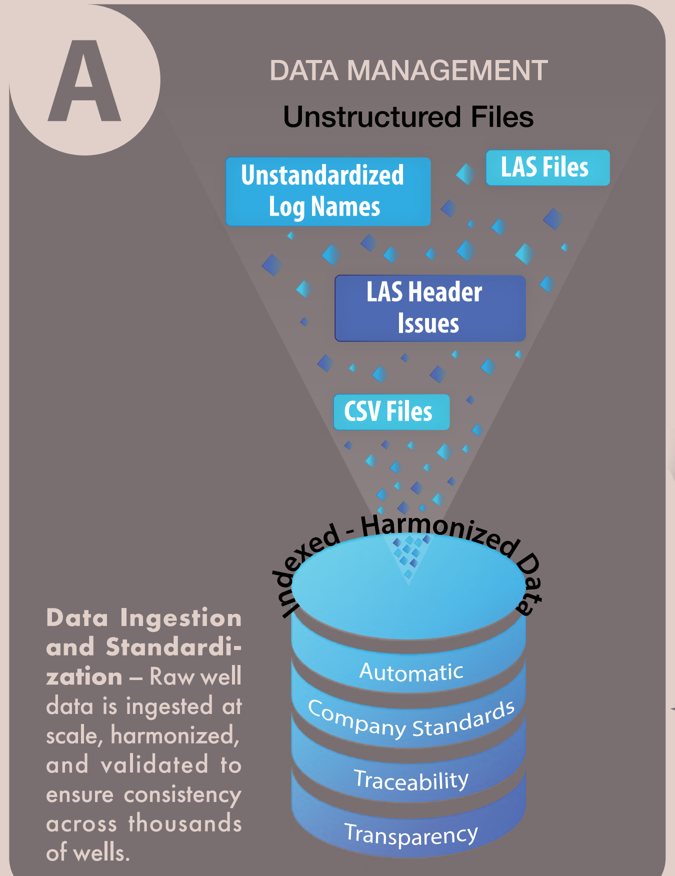
These findings leave no doubt that hydrogen is generated in the basement rocks of the Timiskaming Graben. However, the next and more important question is: If and where is hydrogen trapped in economically viable quantities? ■

Mariël Reitsma, HRH Geology

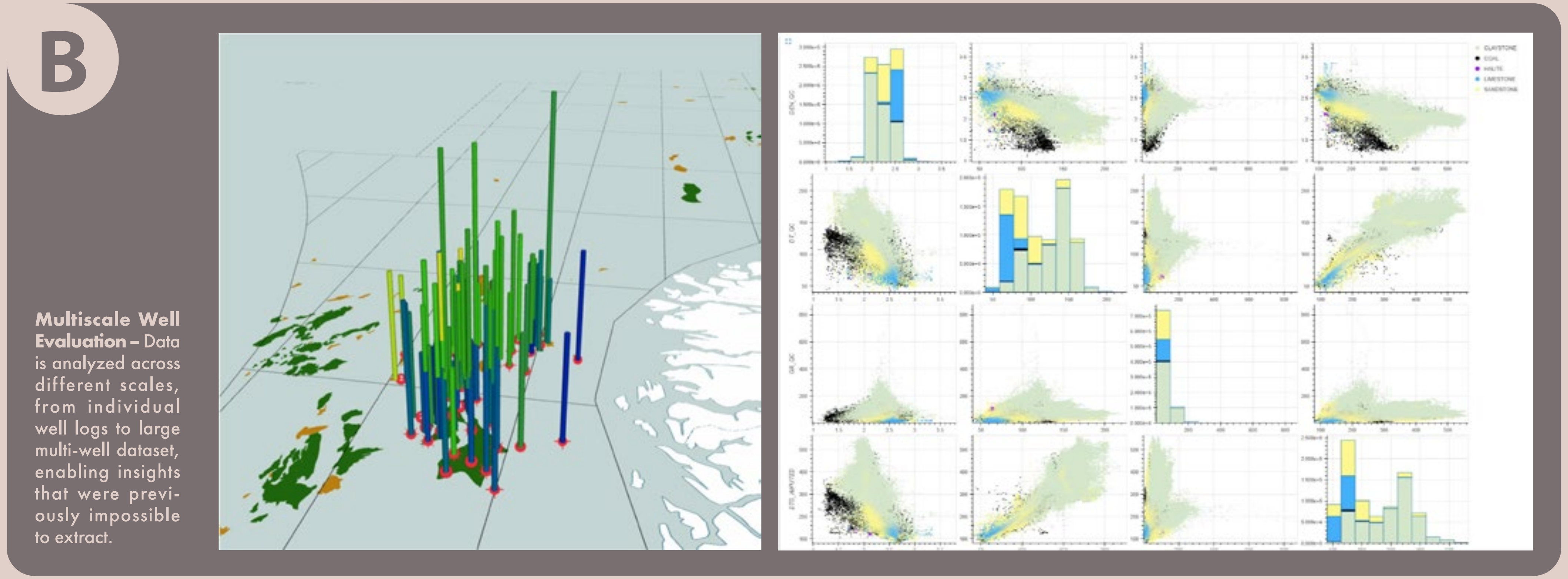
Liberating well data with modern data science and AI

The Norwegian Continental Shelf (NCS) Big Data Well Conditioning project illustrates how AI-driven workflows transform subsurface analysis. As shown in Figures A through E, the process begins with large-scale data ingestion and harmonization (A), followed by ML- based enrichment using models trained across diverse geological settings (B and C). This enables prediction of missing logs and key properties like porosity and water saturation (D). Automated petrophysical analysis, including uncertainty quantification (E) ensures reliability for exploration and Carbon Capture and Storage (CCS) applications. Together, these workflows provide scalable, high-resolution insights that improve data quality, accelerate decision-making, and support strategic initiatives such as carbon storage and field development.

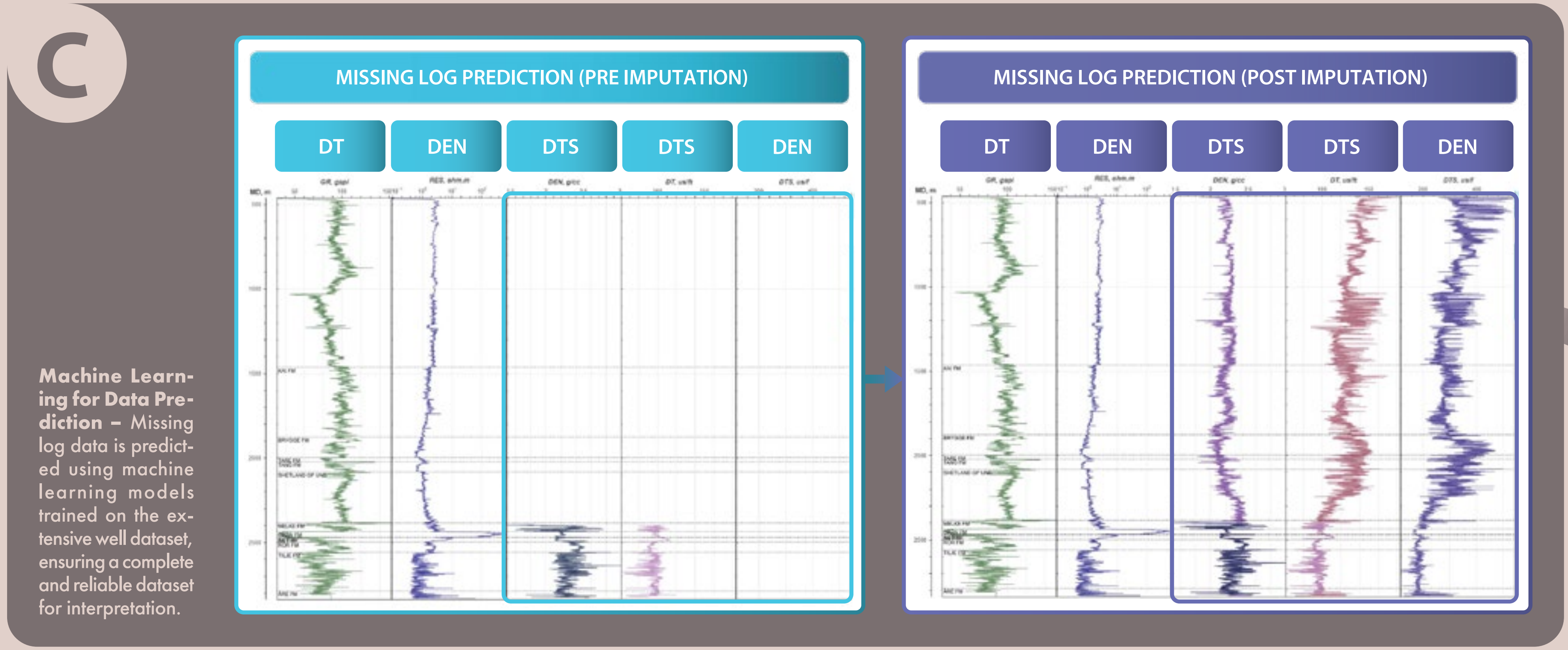
EARTH SCIENCE ANALYTICS



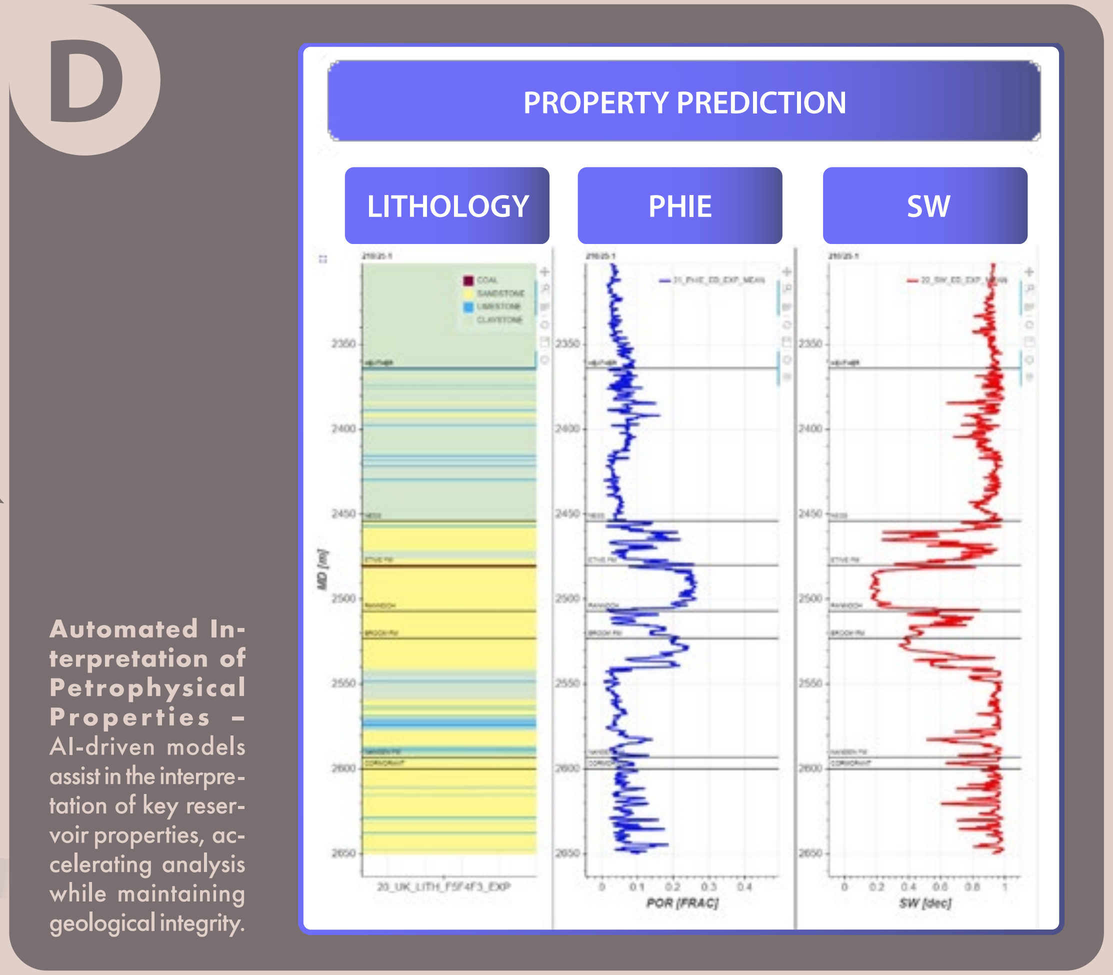
Data Ingestion and Standardization – Raw well data is ingested at scale, harmonized, and validated to ensure consistency across thousands of wells.



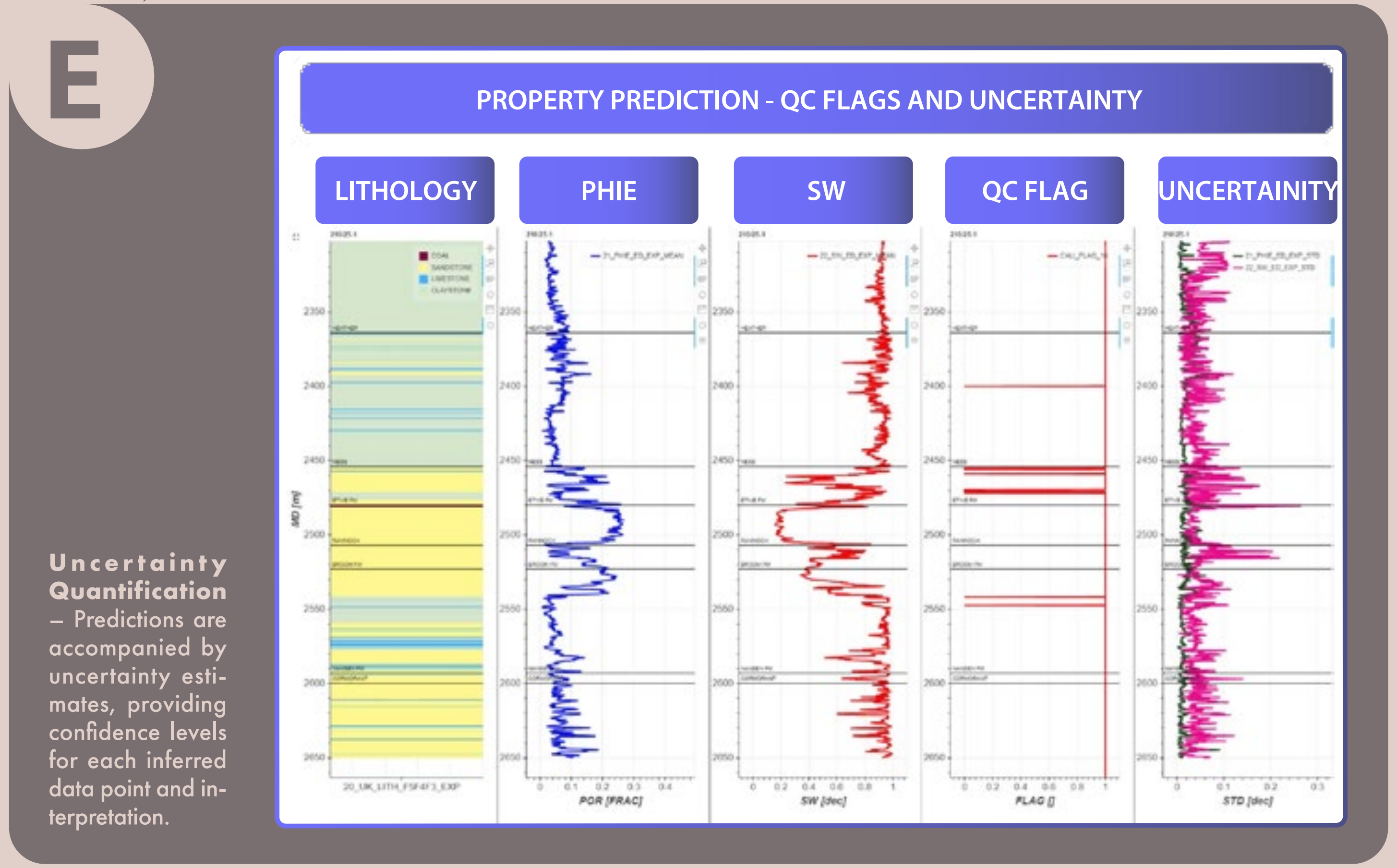
Multiscale Well Evaluation – Data is analyzed across different scales, from individual well logs to large multi-well dataset, enabling insights that were previously impossible to extract.



Machine Learning for Data Prediction – Missing log data is predicted using machine learning models trained on the extensive well dataset, ensuring a complete and reliable dataset for interpretation.



Automated Interpretation of Petrophysical Properties – AI-driven models assist in the interpretation of key reservoir properties, accelerating analysis while maintaining geological integrity.



Uncertainty Quantification – Predictions are accompanied by uncertainty estimates, providing confidence levels for each inferred data point and interpretation.

AI-driven well data revolution: Unifying traditional expertise with modern data science

The oil and gas industry is navigating a transformative era fueled by the convergence of geoscience, data science, and artificial intelligence. As the volume and complexity of subsurface data grow exponentially, traditional well data workflows - once rooted in manual QC and interpretation - are becoming insufficient. In response, new methodologies have emerged, leveraging modern data science to transform static, fragmented well datasets into dynamic digital resources. Two key efforts that exemplify this transformation are the "Go Digital for Wells" initiative, using EarthNET, and the Earth Science Analytics large-scale Big Data Well Conditioning project on the NCS.

BEHZAD ALAEI, THERESIA MARIA CITRANINGTYAS AND WILLIAM REID, EARTH SCIENCE ANALYTICS

The NCS Big Data Well Conditioning project is a living example of this workflow in practice, incorporating over 2,000 wells and 30,000 km of log data, and has produced a unified and consistent dataset for the region. ML models were trained to impute missing logs, resulting in a 5-fold increase in log coverage and enabling downstream prediction of porosity, lithology, and water saturation across the dataset.

INTEGRATED WORKFLOW: FROM DATA TO INSIGHT (FIGURE A)

Both workflows begin with a foundational data management phase. In the NCS study, logs, core data, lithology descriptions, and metadata were aggregated from diverse sources and merged into a centralized digital data lake. A harmonization process compared overlapping data from different channels, flagged inconsistencies, and resolved discrepancies to produce a high-quality baseline.

MULTISCALE WELL EVALUATION AND MACHINE LEARNING FOR DATA ENRICHMENT (FIGURE B AND C)

The ML pipeline uses the curated, high-diversity datasets to train algorithms - including Random Forest, Light GBM, and XGBoost. In the NCS project, more than 350 models were trained across four geological provinces. These models predicted missing logs (e.g., density, sonic, shear sonic) and derived properties, such as lithology, porosity (PHIE), and water saturation (SW). Cross-validation and blind testing ensured model robustness, and output logs were ranked with priority flags to guide usage based on prediction quality.

AUTOMATED INTERPRETATION OF PETROPHYSICAL PROPERTIES (FIGURE D)

These workflows emphasize automation without compromising geological context. In "GoDigital for Wells," petrophysical properties are interpreted with AI support, reducing manual workload while maintaining consistency. The NCS project extended this automation to include adaptable pay analytics: Users can apply custom porosity and water saturation cutoffs to evaluate reservoir quality, calculate net pay, and generate maps of prospectivity.

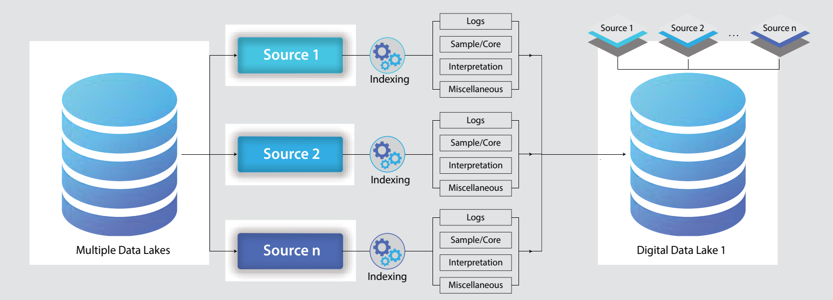


Figure 1: Data ingestion and standardization schematic, showing how raw well data is ingested from multiple sources at scale uniformly, harmonized, validated, and all connected through the digital data lake.

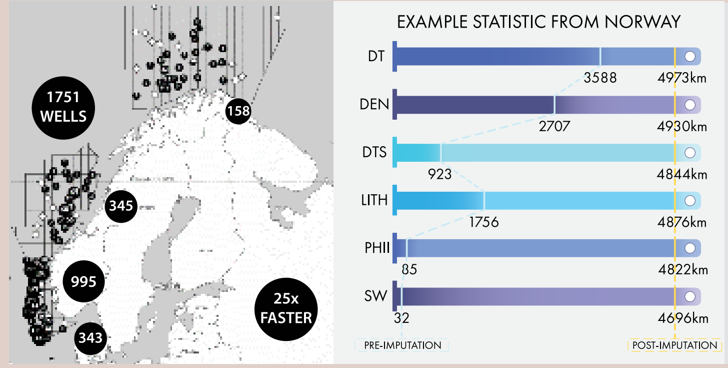


Figure 2: Image showing the fivefold increase in log coverage for the NCS project.

UNCERTAINTY QUANTIFICATION AND QUALITY ASSURANCE (FIGURE E)

Every prediction is accompanied by uncertainty estimates, enabling probabilistic analysis. This feature allows users to make informed decisions with transparency on data reliability—crucial for exploration, development, and CCS site evaluation. In the NCS caliper-based QC process flags 'bad hole' conditions, further enhancing prediction confidence.

REAL-WORLD APPLICATIONS AND RESULTS

The outcomes of these workflows are both quantitative and strategic:

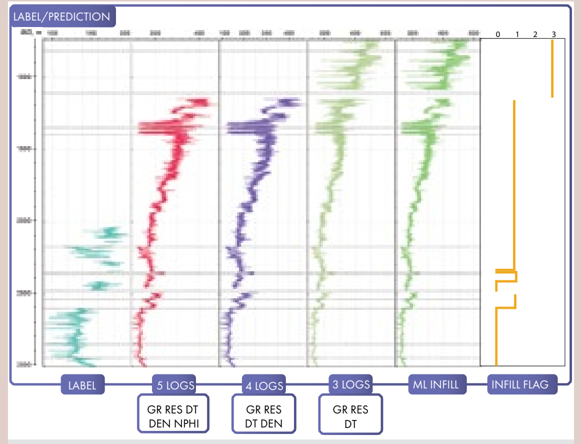


Figure 3: DTS machine learning model prediction and imputation, built using combinations of logs as features. The imputation priority goes from left to right on the, while the origin of the log prediction is shown by the ML-flag.

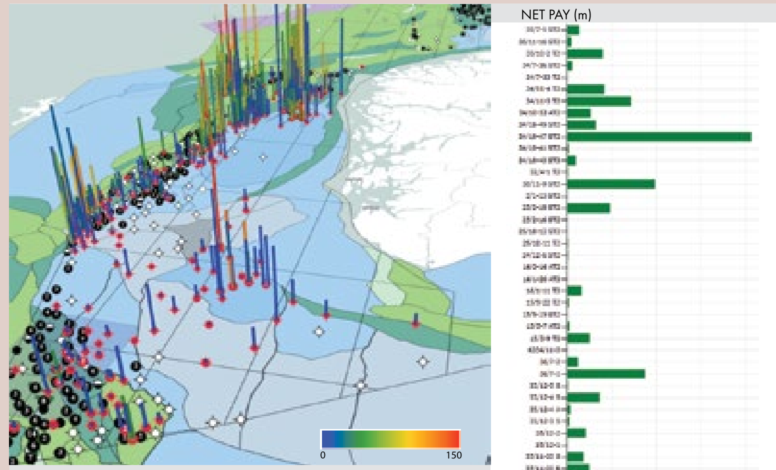


Figure 4: Adaptable pay analytics by querying the data with a cutoff on water saturation and porosity.

In the NCS project, the coverage of shear sonic logs increased 5-fold, and interpreted reservoir properties expanded significantly (Figures 3 and 4).

Exploration teams can now identify previously overlooked pay zones using ML-enriched data (Figures 4 and 5).

Field development geoscientists and engineers leverage high-resolution petrophysical models for depth conversion and uncertainty assessment.

This process also adds significant value to CCS screening by leveraging the consistent, high-quality datasets to assess rock properties and injectivity. Earth Science Analytics exemplifies this approach with a comprehensive evaluation of CCUS capacity and risk in Gulf of Mexico. Integrating seismic data from Geoex MCG, 4,000 wells, and ML-predicted reservoir properties enables data-driven site assessments and informed decisions for offshore carbon storage (Figure 6).

TRANSFORMATIONAL BENEFITS ACROSS THE ENERGY SECTOR

- Scalability: ML models handle thousands of wells across basins, enabling macro-scale geological interpretations.
- Data accessibility: Cloud-based digital lakes break down data silos, promoting cross-functional collaboration.
- Improved interpretation Quality: AI models offer consistent predictions and reduce subjectivity.
- Efficiency gains: Automated QC and interpretation reduce time-to-insight, enhancing project delivery.
- Informed decision-making: Uncertainty quantification enables risk-aware planning and strategy.

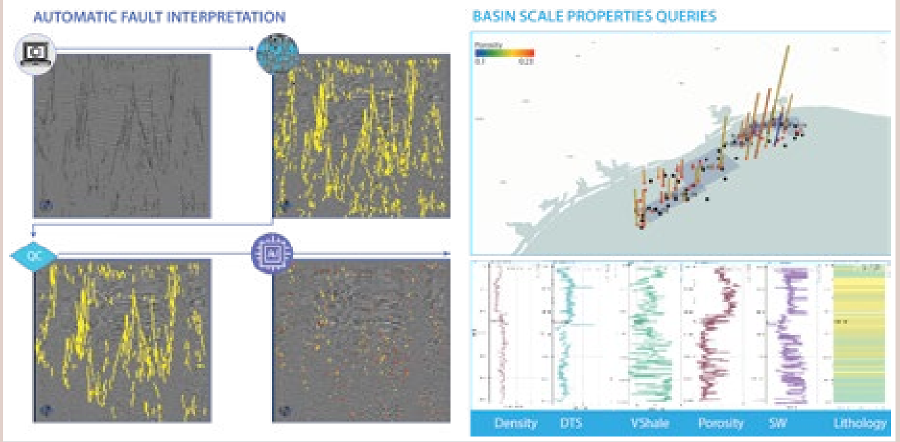


Figure 5: CCUS MCG GeoEX project; Basin-scale reservoir property analysis from well data, e.g. Vshale, water saturation, and lithology; Automated fault interpretation using ML models.

PAVING THE WAY FOR THE ENERGY TRANSITION

Although these workflows were originally designed for oil and gas development, they are proving crucial in the evolving energy landscape. In CCS applications, consistent and enriched well data support site characterization, reservoir modelling, and injectivity prediction. The same tools are adaptable to geothermal energy, unconventional resources, and basin-scale modelling.

CONCLUSION

The NCS data set, now enriched through ML, provides a robust foundation for subsurface analysis across multiple use cases. CCS project offers a real-world example of how digital transformation can directly contribute to climate solutions by enabling data-driven carbon storage evaluation.

The digital revolution in well data is not a future possibility—it is a current reality. By embracing AI-driven workflows such as "Go Digital for Wells", the industry is unlocking new efficiencies, insights, and opportunities. These approaches demonstrate that when traditional geoscience expertise is combined with advanced data science, the result is a smarter, faster, and more confident path to understanding the subsurface. In an era where decisions must be made quickly, confidently, and with long-term sustainability in mind, intelligent, well-designed data workflows are no longer optional—they are essential.

DIGITALISATION

"Ultimately, the challenge isn't about AI itself. It's about our imagination, our courage to ask different questions, and our willingness to invest in new paradigms. Technology is neutral; it's what we ask of it that shapes the future"

Dan Austin – Geologist

AI and the future of subsurface discovery: Are we asking the right questions?

Is it ethical to apply powerful tools to extend the life of an industry whose future is contentious?

DAN AUSTIN, SEKAL

THE QUESTION at the heart of geoethics today isn't just whether we should use artificial intelligence (AI) in geoscience, it's how we use it, to what end, and what that says about our values.

We've built increasingly sophisticated technology, yet much of its application still revolves around what is affectionately known as "painting the map" - incrementally extending known discoveries. The real challenge isn't just in optimisation. It's in rethinking what exploration means in a world where the data is already largely in hand. The philosophical pivot must be: Should we use AI to ask better, fundamentally different questions about the subsurface, or just faster versions of the same ones?

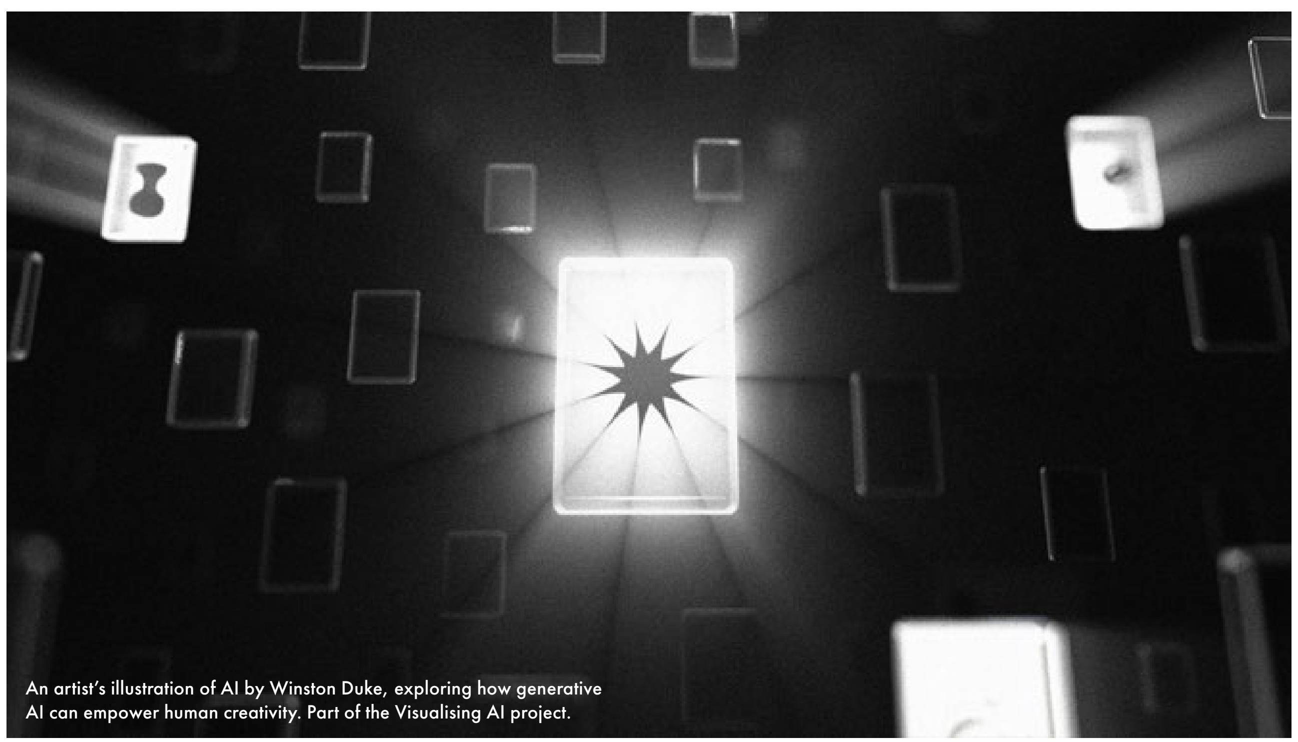
From a practical standpoint, the argument for AI is compelling. It's cheaper, safer, and potentially greener. It de-risks expensive up-front investment without requiring intensive capital or human labour. That alone makes it ethically attractive - if it helps reduce environmental impact while meeting today's energy demands.

But, we must also recognise that AI reflects the bias and risk-aversion of its human operators. If we use it only to automate workflows in pursuit of conventional prospects, we aren't innovating - we're just doing the wrong thing faster. That may make sense economically in the short term, but it's strategically hollow.

The real opportunity lies not in using AI to indefinitely prolong the age of oil and gas, but to identify new conceptual models and solve fundamental subsurface problems. This shifts our focus from "How did we miss that field?" to "How did we miss this approach?"

AI's capacity to process and analyze vast datasets in ways fundamentally different from human cognition is crucial here. An advanced AI could perceive and interpret data in novel ways, leading to discoveries that human intelligence, with its inherent limitations and trained perspectives, might consistently overlook. For subsurface exploration, this means AI could identify geological formations, fluid pathways, or even resource types that don't neatly fit into existing human-derived models. This could revolutionize our understanding of Earth's subsurface and how we interact with it.

Ultimately, the challenge isn't about AI itself. It's about our imagination, our courage to ask different questions, and our willingness to invest in new paradigms. Technology is neutral; it's what we ask of it that shapes the future. ■



An artist's illustration of AI by Winston Duke, exploring how generative AI can empower human creativity. Part of the Visualising AI project.

SOURCE: UNSPLASH.COM

DIGITALISATION

Seabed mapping – let AI do the work

Trawling through footage looking for special seabed features can be a very time-consuming task. Recent work has demonstrated that it can be done faster

"I SPENT days, if not weeks, trawling through high-resolution photos," a geoscientist from an oil and gas company recently told me. Why did he do that? He carried out this task because of a new field development, which demanded a new gas pipeline to be built. Before that work can begin, it is common practice to have an ROV capture the trajectory in high-resolution photos and videos, resulting in a massive amount of data to be analysed.

The geoscientist described going through the photos one by one, describing what he saw and trying to find any obstacles or gullies that could compromise the integrity of the pipeline. It all sounded like a monumental task, especially because of the amount of data available for analysis.

MAPPING LIFE

Then, totally independent of this initial story, I saw a post on LI the other day from Dani Schmid. He is the founder of Norway-based Bergwerk, a company that specialises in developing tools that help minimise the impact of natural resource extraction.

One of the projects that Bergwerk has recently been involved with is the use of seabed imagery to automatically detect and classify marine benthic life. The main driver for the project is Norway's ambition – or at least for some people in Norway – to start a seabed minerals industry. One of the key aspects of this future industry is the emphasis on environmental monitoring; a detailed environmental baseline assessment will always be required before any activity can take place.

In collaboration with Aker BP, an oil and gas company with a strong presence on the Norwegian Continental Shelf and a commitment to gathering and sharing seabed data, Bergwerk developed an AI-powered methodology to detect marine organisms characteristic of the North Atlantic region. The results were published earlier this year in Frontiers in Marine Science.

The team used the so-called DeepSee dataset, which is a comprehensive collection of annotated images from the Arctic Mid-Ocean Ridge, the Norwegian Sea, and the Greenland Sea. Designed to support the development of ML models capable of detecting and classifying benthic organisms, the DeepSee object detection model was trained on this dataset.

Following rigorous testing, the workflow is now capable of processing vast amounts of footage quickly with high precision and accuracy, identifying most species that occur in the area. As such, the model provides a valuable addition to the traditional workflow of manual annotation by significantly reducing the load on marine biologists.

In the paper, the authors already mention the application of their workflow to pipeline laying projects. And given the technology available, it should also be possible to expand the model's capability and include the identification of drop stones that can form unwanted obstacles for a pipeline that prefers to go straight ahead. It could have saved the geoscientist I spoke to quite some time. ■

Henk Kombrink

Comparison between manually annotated (A) and detected labels (B) in an example image. Instances that are labelled in the ground truth image and not found by the DeepSee model, and vice-versa, are encircled in black. The average precision and recall of the model detections for the image are 0.72 and 0.83, respectively. However, it is evident that the 'false positives' detected by the model are indeed valid detections that were missed in the annotated dataset. When corrected, the average precision and recall increase to 1 and 0.91, respectively.

IMAGE: WWW.FRONTIERSIN.ORG

Shale 3.0

The recent URTeC Conference in Houston highlighted where the technological challenges lie to maintain output from the US' shale patch

JOE VERSFELT, V-GLOBAL EXPLORATION CONSULTING

With reports that output from the US shale basins is creaming, combined with price pressure on production and environmental concerns, there has never been a better time to invest in technology to ensure competitiveness. And it is needed, given the importance of US LNG in the global market, especially the EU.

The recent URTeC very much breathed this mindset.

From new seismic acquisition and processing technologies, to dynamic drilling and geosteering data integration tools to optimise well placement and completions, the industry's continuing hunt for leveraging differentiating technology and common-sense collaboration was palpable.

Joe Versfelt.

It's what the market calls "Shale 3.0."

As could be expected, improving oil and gas recovery from maturing assets in the Permian basin was one of the key topics during the event. This is increasingly being done through a better understanding of parent-child wells' performance through iterative dynamic modelling of wells. All with the objective to improve resource development strategies, planning, and execution to increase production and recovery.

The potential for Artificial Intelligence (AI) came across in many disciplines discussed during the conference as well. Ranging from deriving more insights from data than would otherwise be possible, such as seismic, logs and drilling and completion data, to decreasing cycle time and automating repetitive tasks. However, one of the concerns that is now being talked about is how data and operations will be safeguarded. It seems as if the industry is now increasingly waking up to that question.

At the same time, increasing penetration of oilfield digitalization at scale is also lowering operating costs, with examples being presented on improving drilling and completion execution, reservoir surveillance, production performance, fluid reinjection and safety and environmental performance.

Reducing emissions and carbon capture, utilization and storage (CCUS) at scale to combat climate change also featured heavily at URTeC. In that light, the Permian Basin hosts a prime example of engineering that goes into CO_2 capture; Oxy, through its subsidiary 1PointFive, operates the largest direct air capture (DAC) facility of this kind.

Staying with the environmental side of things, changing approaches on managing increasing volumes of produced water from oil and gas production in unconventional resources is also a big thing in Shale 3.0. Water resource conservation, both at surface and in the subsurface, has become ever more critical, as civil and agricultural communities rightly point out the sheer volumes of wastewater injection and the relation to induced seismicity.

In that regard, the Texas Railroad Commission recently announced increasing permit requirements for wellheads and wastewater reinjection, which is estimated to increase disposal costs by 20-30 % or up to $1 per barrel of water. This will hopefully incentivise the industry to become more efficient when it comes to managing waste water streams. ■

PHOTOGRAPHY: JOE VERSFELT PRIVATE ARCHIVE

INSIGHTS

"A 1 % TOC rock might be potentially good in the laboratory, but in the complex reality of subsurface petroleum systems, it's insufficient"

David Rajmon – Geosophix

Energy is politics, is community, is pride

A journey through the landscapes that shaped Wales

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

My dear friend William invited me last month to Brecon, mid Wales. Another dear friend, Ian, lives in Penarth, just outside Cardiff, south Wales, so it made perfect sense to pop-in to see him enroute.

The political and community history of south Wales is all about the geology; most famously "The Valleys", an extension of mining towns and villages each accessing incrementally deeper carboniferous coal-measures.

Penarth was a major coal exporting port and has the remnants of 19th century individual and community wealth: Grand family houses, imposing town offices, public baths, gardens and libraries, and the obligatory promenade and pleasure pier.

Penarth Pier.

PHOTOGRAPHY: ANDREW VIA ADOBE STOCK

Ian and I took a bus north, through towns with names I was familiar with, though had never visited: Pontypridd, Abercynon, Treharris, Mountain Ash, Aberdare, Methyr Vale, Tredegar.

And then we got to Aberfan.

Aberfan is a scar in the Welsh mining collective memory. A community disaster, unimaginably horrific. On the morning of 21st October 1966, one of the colliery spoil tips, saturated with water, flowed down the hillside and engulfed the local primary school. 116 children and 28 adults died. In a moment, a town lost a generation.

Ian told how his father, a miner, was one of many who rushed to assist, pulling out child after child from the sodden, suffocating, blackness. He worked uncovering the school: 20 hours of shovelling, home for a bite to eat and a nap, and back again. Day after day. Never speaking about what he saw.

We changed buses at Methyr Tydfil, with time to enjoy lunch at a traditional Welsh Valleys Italian café. Italian immigrants arrived in the late 1800s and again in the early 1930s, escaping crushing poverty or fascism, and finding employment and safety. The cakes were Welsh, but the coffees and ice-creams were Italian.

Margaret Thatcher took a personal dislike to industries and communities that didn't bend to her economic view of the world, and the miners and mining communities were, in her mind and her speeches, "the enemy within". It took her ten years, but eventually her political single-mindedness destroyed mining and the miners, and with it, UK energy independence.

And as history repeats itself, we currently have political parties directing their energy policy to destroy the UK's current energy independence of oil, and with it, North Sea communities like Aberdeenshire.

Communities based on geology. A plentiful resource and human resourcefulness. Quality jobs provide pride. Pride cements the community. Rugby, brass bands, and male voice choirs add colour.

To end: A gloriously bright day, the bluest skies, the whitest clouds. The bus headed up high into the Brecon Beacons, under the majestic Pen-Y-Fan, and that is when I remembered the travel instructions from Will, the most geological travel instructions I've ever been given:

"You'll know when you're on the approach to Brecon; the landscape changes from Carboniferous to Devonian".

And it did, quite noticeably.

Thanks, Will. Thanks, Ian. ■

Blurring the line between geology and reservoir engineering

Jordan Connolly explains how her work with tNavigator enables efficient communication between what was always considered two distinct silos – the world of geomodellers and reservoir engineers – and how there is more of a crossover now

HOW OFTEN has it happened that a dynamic simulation grid turns out to be not fit for purpose because something goes wrong – too fast a pressure build-up, too fast a water breakthrough, you name it.

"Often," says Jordan Connally from Rock Flow Dynamics (RFD).

Previously, it took a reservoir engineer to find out what was wrong with their dynamic model, before it had to be sent back to the geoscientist to re-create the grid with the necessary fixes. These steps easily added days to a process that was already quite long to start with.

> "I don't need to upscale our reservoir grids anymore, which not only helps preserve the geological features in the model, it also allows me as a geologist to check the dynamic model myself"

Jordan Connally.

PHOTOGRAPHY: JORDAN CONNALLY PRIVATE ARCHIVE

TECHNOLOGY AT THE RESCUE

"With the progress that has been made in recent years when it comes to computing power, this can all be done more easily," says Jordan. "First of all, I don't need to upscale our reservoir grids anymore, which not only helps preserve the geological features in the model, it also allows me as a geologist to check the dynamic model myself."

"And because of that, I see how the dynamic model looks before handing it over. That means I can do a quick screening to see if it behaves in the way our reservoir engineers will expect it to behave. It doesn't make me a reservoir engineer, but I do appreciate more what it entails. You don't need to be an expert to observe teething issues," she says. "In addition, this workflow also suits increasingly fast-paced environments like the North Sea, where leaner teams are handling broader scopes under tighter deadlines."

"YOU'D BETTER RE-TRAIN AS ACCOUNTANTS"

Jordan joined RFD in 2019, after working in an Aberdeen shop while searching for geoscience positions. "I started to have that feeling that the career advisors that came into my Geology course at Aberdeen University were right in saying that we should all get retrained as accountants instead of geologists," she laughs. "But looking back now, I see that the far majority of my class has landed relevant jobs in geosciences, be it in oil and gas, renewables or in mining."

THE NEXT GENERATION

Jordan represents a new generation of subsurface experts who do not think along the rigid lines of the silos that represented the reservoir engineering and geomodelling communities. "Technology helps to break these barriers down," she adds. "Of course, it is unlikely that the two disciplines will merge into one; geologists are probably too arm-wavy for that, and reservoir engineers too analytical on the other hand." But at the same time, she sees that communication is more straightforward these days. ■

Henk Kombrink

HOT SPOT

It's all in the planning

The stage is being set for a major E&P drive in Angola

PETER ELLIOTT, NVENTURES

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

ANGOLA is host to a number of recent exploration highlights, driven by a well-organised and energetic energy regulator, ANPG and a strong appetite for low-risk growth in the upstream sector. Wildcat drilling activity remains low for now, but major reforms to licensing strategy are set to ramp up the number of awards, well commitments and seismic surveys. ANPG recently announced 23 licensing opportunities on- and offshore, in four distinct offerings (Figure 1), whilst announcing their ambition to assign 50 new blocks in the coming years.

THREE HOTSPOTS

Angola recorded its peak production of 1.9 mmbopd in 2008, from the traditional heartlands of the offshore Lower Congo Basin post-salt bonanza of the 1990s. Future production highs can be expected from three further areas of sustained activity: The rush to mature near-field exploration in the Oligo-Miocene deepwater play as the supermajors consider A&D options; the latent potential of the pre-salt mega-play in the Kwanza and Lower Congo basins; and the re-emergence of the exciting pre- and post-salt potential onshore the Lower Congo and Kwanza basins.

Exploration drilling activity has been reasonably subdued, although often successful in the mature offshore basins (Figure 2). Following on from the major success at Agogo by Eni and partners in Block 15 in 2021 - the discovery is now on production - ExxonMobil and partners have tested the Likembe prospect in Block 15, and Azule drilled Lumpembe in Block 15/06. TotalEnergies re-entered the Block 20 Kwanza play with Grenadier 1 in 2023 (with Petronas), then returned to the hugely successful Dalia play in 2024 with a deep Dalia target (Dalia 6). Further infrastructure-led exploration has paid dividends for Azule in Block 1/14 (with 1 TCF at the Gajajeira 1 discovery) and Chevron in Block 0 (Well 119-D). ExxonMobil carried out a wildcat campaign in the Namibe Basin in the south of the country in Block 30, but to no avail. Independent AIM-listed Corcel attempted a field rejuvenation project at Tobias 13 in 2023, onshore Block Kon 11, and while that was not hugely successful, it does begin the story of what is likely to become a major series of exploration drilling campaigns onshore Angola in the next few years.

LOTS OF ACTIVITY

ANPG held a bid round for a number of blocks in 2023, including the onshore. Early results suggested a successful round, and some of those awards still stand. Afentra took Blocks Kon 15 (with Acrep) and Kon 19 (Sonangol), while Etu Energias (previously Somoil) were awarded Con 2 and 8 in the onshore Lower Congo Basin, usually partnered with Effimax and Simples Oil, although the firm now appears to have interests only in Con 1 and Con 6. Likewise, early awards of Kon 13 (Serinus) and Con 7 (Enagol) appear to have fallen away, and Canadian junior MTI Energy no longer appear to be active, having taken interests in four onshore blocks in 2021.

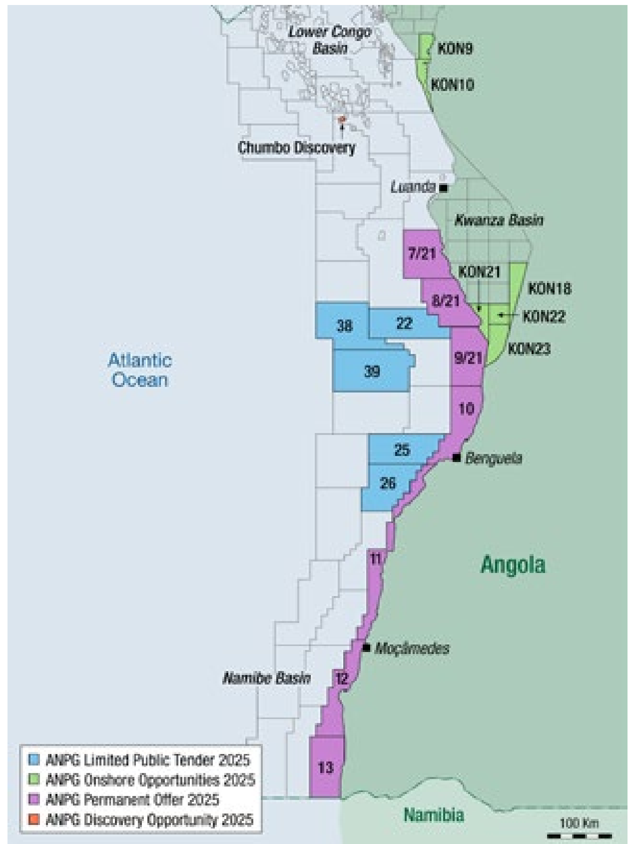


Figure 1: Recent licensing rounds in Angola.

More recent activity onshore has proven more permanent (Figure 3), with Corcel strengthening its position in the Kwanza Basin, and the likes of Afentra, Walcot and Oando taking major onshore positions. Corcel now hold interests in Kon 11, 12 and 16, with a major new exploration well planned for Kon 16 in the coming months. Sintana have taken a stake in that campaign, extending its impressive exploration reach in southwest Africa to new, exciting plays. Early 2025 saw Oando (the major Nigerian independent) take a stake in Kon 13, to be joined there by Walcot. Walcot themselves are investing in blocks Con 3 and 7. Afentra will add to its onshore portfolio with an RSC for block Kon 4. Negotiations for these latter awards (Figure 3) are still underway (July 2025). In the far south of the country, two large reconnaissance licences have been award in the Etosha – Okavango districts, to ReconAfrica and to Xuan Thien Group.

SOURCE: NVENTURES

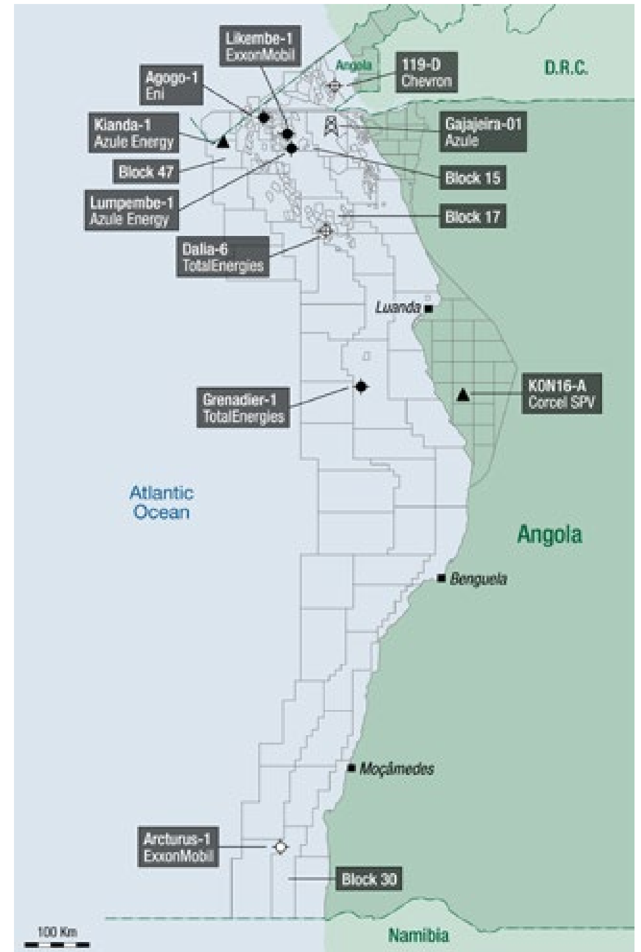


Figure 2: Exploration and development wells across Angola.

Offshore, a number of awards have been completed, including Blocks 49 and 50 for Chevron. Azule plan a major ultra-deepwater wildcat at Kianda 1 in Block 47 in the near future, with Equinor and Sonangol. Block 6/24 was awarded to Sonangol EP and the Australian RedSky Energy (35 %) and Acrep (15 %) in 2024. Afentra, meanwhile, has been busy strengthening its equity position in Blocks 3/05 and 3/05A, a major production hub for them, buying Etu Energies' piece in 2025.

AHEAD OF THE CURVE

Angola is ahead of the curve when it comes to attracting fresh upstream investment in new and existing basins, coinciding with what looks like a nascent hydrocarbon renaissance globally. ANPG are working on various strategies to expedite these goals, with greater transparency and access in what was seen as a "supermajor's playground", world-class data management and promotion, and strong communications for planned acreage offerings. Whilst the main fiscal regime mechanisms remain the same, based on Production Sharing Contracts, fiscal incentives have been provided to firms extending production in well-established Lower Congo Basin core hubs. For example, TotalEnergies and partners have won an extension and improved terms on Block 17, the prolific Girasol/Dalia hub, with the licence now up for renewal in 2045. TotalEnergies expects to recover an extra 300 mmboe from the new deal. Likewise, Block 15 has been extended out to 2037 for the ExxonMobil operating group, again with fiscal incentives to extend production and encourage ILX. Block 15 is home to 4 active FPSOs, including the Kizomba hub.

New acreage opportunities are now defined by ANPG in their current promotional campaign (Figure 1). The regulator is offering 23 blocks as follows; 7 shallow to deepwater blocks in the Kwanza (7/21, 8/21 and 9/21) and Benguela (10, 11 and 12) and Namibe (Blok 13) basins under a Permanent Offer regime; five deepwater offshore exploration blocks in the Kwanza (22, 38 and 29) and Benguela (25 and 26) Basins are offered under the 2025 Limited Public Tender scheme; 10 onshore Blocks are being promoted, six open (Con 9 and 10 and Kon 18, 21, 22 and 23) and 4 as part of what appears to be a farm-out process (Con 5 and Kon 5, 17 and 20). Finally, the Chumbo field offshore is available as an "Opportunity with Discovery" asset divestment in the Block 18 area (32.5 mmbo contingent resources).

Angola continues to be a powerhouse of production and exploration in West Africa, and clearly intends to remain competitive in the global E&P race for new barrels. The country benefits from a strong industry regulator, decades of production experience, and great geology. The prolific Lower Congo Basin continues to deliver, and there is great potential in the revitalised onshore salt basins, while further upside is yet to be revealed in the deepwater pre-salt. The Namibe Basin is yet to show its hand, with only two wells to date, either side of the border. ■

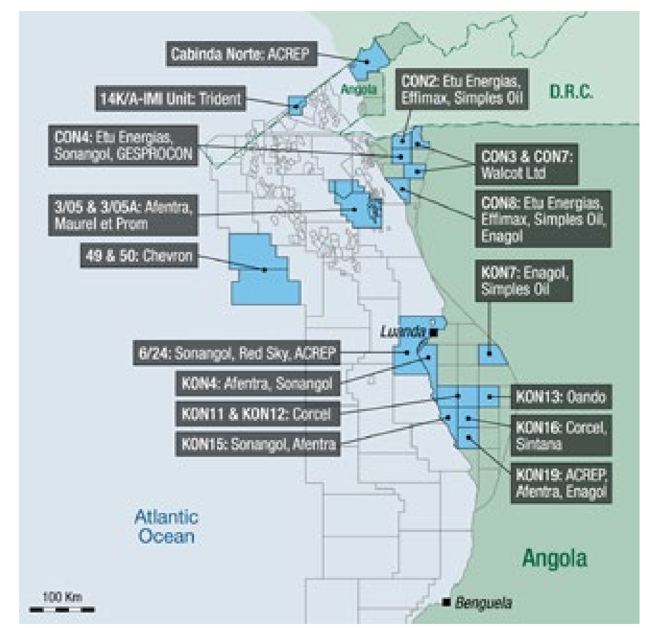


Figure 3: Key exploration deals and block awards in Angola.

What is a good source rock?

Or – why a 1 % TOC won't work in the real world

DAVID RAJMON, GEOSOPHIX

I recently worked in a well-established basin with proven hydrocarbon accumulations. To my surprise, all reports and published papers routinely talked about local source rocks with barely 1 % Total Organic Carbon (TOC) and low Hydrogen Index (HI) kerogen as the main sources charging the system. They discussed other sources only marginally if at all. Not surprisingly, geochemical data and simple expulsion and migration modelling clearly pointed towards different sources.

In petroleum system analysis, the term "good source rock" is used frequently - almost casually. Most geochemical literature defines a "good" source rock as one with a TOC content above 1 wt. %, often alongside indicators of quality such as kerogen type and maturity. But in practice, this threshold is inadequate to explain hydrocarbon accumulations in working petroleum systems.

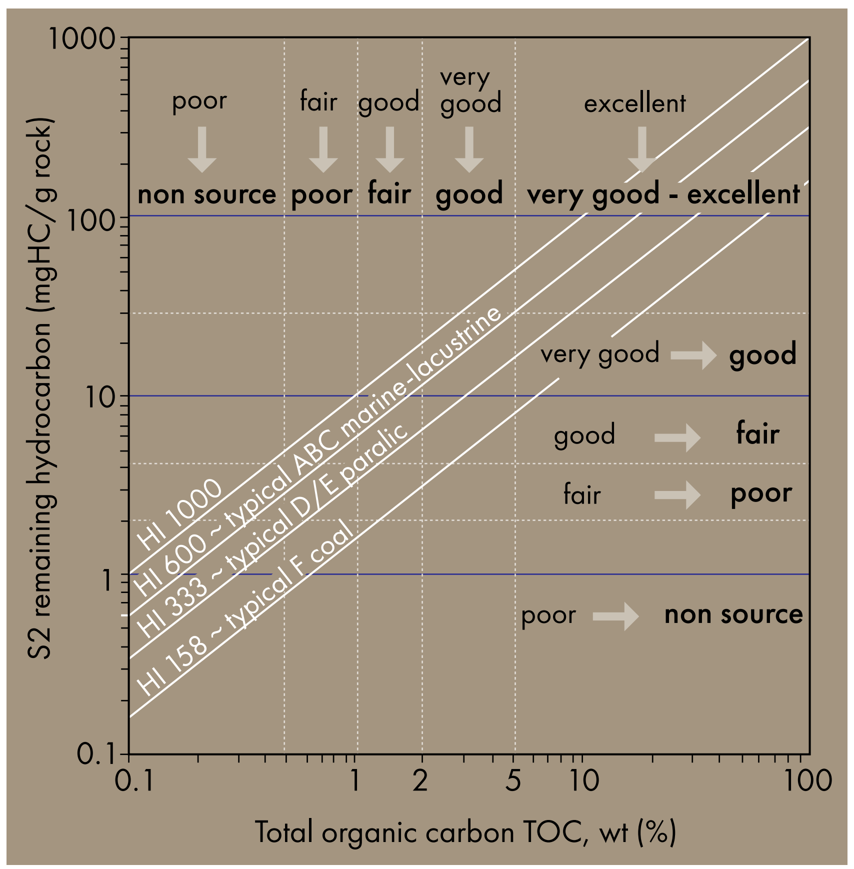
The traditional TOC classification - commonly citing values of <0.5 % as poor, 0.5 - 1 % as fair, 1-2 % as good, and >2 % as excellent - fails to account for one critical fact: Expulsion is not enough. A source rock must expel enough hydrocarbons not only to generate fluids but also to saturate migration pathways, charge microtraps, and overcome capillary thresholds along the route to a viable reservoir trap. Otherwise, most expelled hydrocarbons are lost to dispersion and adsorption before they ever reach a structural or stratigraphic trap.

In practice, the most productive petroleum systems correlate with source rocks having TOC contents well above 2 %. My senior colleagues and mentors pointed out this observation to me a long time ago.

This concept can be illustrated with simple expulsion and migration modelling in Trinity, a forward basin modelling software. Simulations using a 1 % TOC source rock will typically show hydrocarbon expulsion, but once minor migration losses are introduced - such as leakage into secondary porosity or inefficient carrier bed saturation - the system fails to charge the traps. The model becomes sensitive to assumptions: Permeability, saturation thresholds, and distance to trap. A seemingly "good" source rock ends up underdelivering, especially when scaled to field or basin level.

In contrast, models with source rocks above 2 % TOC demonstrate greater robustness. They not only expel more hydrocarbons but also buffer against migration losses and charging inefficiencies. The difference between 1 % and 2 % TOC is not just quantitative - it is qualitative in terms of system behaviour and outcome.

Ultimately, we should revise our language and expectations. A 1 % TOC rock might be potentially good in the laboratory, but in the complex reality of subsurface petroleum systems, it's insufficient. For confident trap charge and commercial accumulations, a truly good source rock starts at 2 % TOC. This small difference can make or break a basin's prospectivity - and our understanding of its petroleum system. ■



Typical HI values for various organofacies after Trinity (ZetaWare).

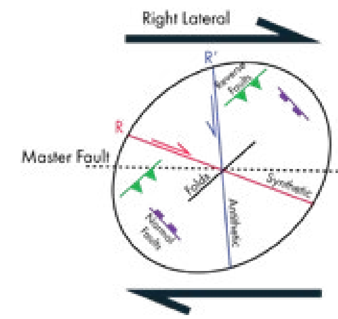
The evolution of fault interpretation

From strike-slip dominance to kinematic understanding

MOLLY TURKO, DEVON ENERGY

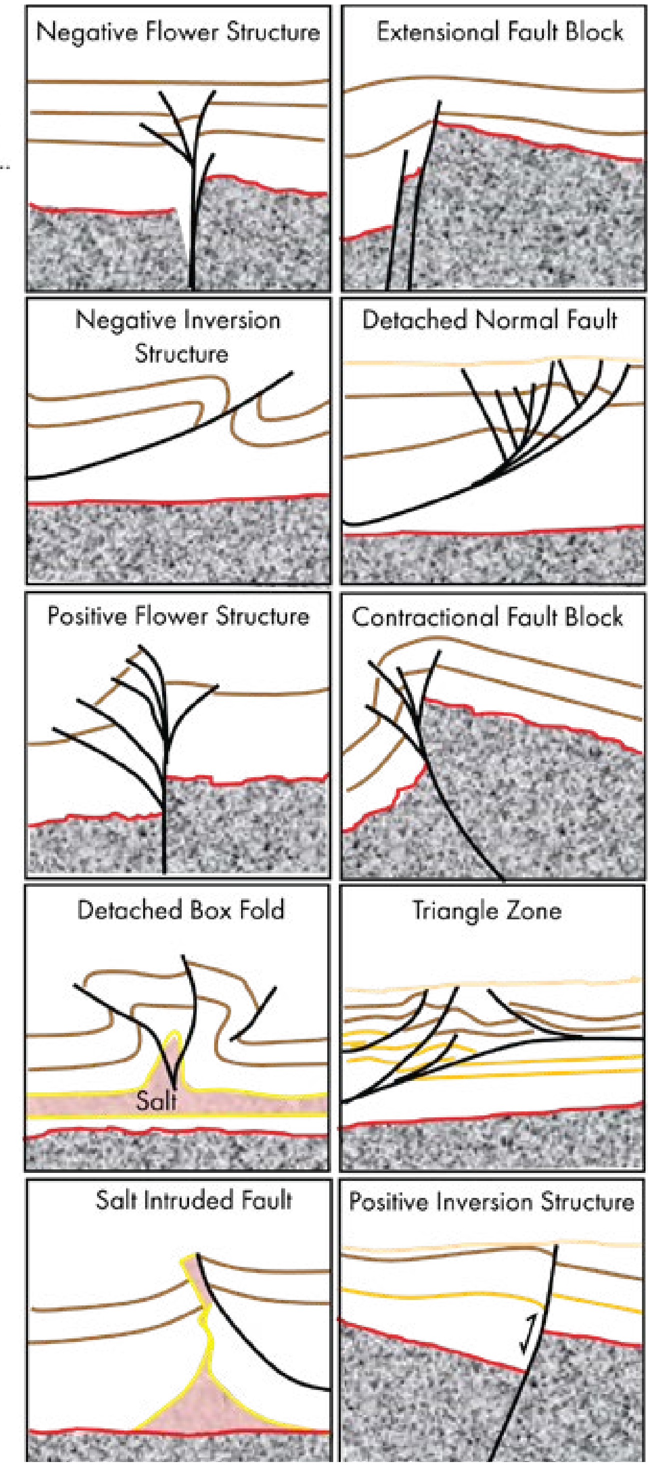
Before the advent of 3D seismic data in the 1980s and 2D seismic in the 1970s, subsurface geologists typically depicted or interpreted faults as vertical or nearly vertical. Consequently, these faults were often kinematically classified as strike-slip, despite the actual dip being unknown. The seminal work of Wilcox and Harding in the early 1970s on strike-slip faulting, particularly their development of the strain ellipse, gained widespread traction. This model explained the orientation and types of structures forming along major strike-slip fault zones, termed "wrench faults." Geoscientists enthusiastically applied the strain ellipse to interpret fault azimuths on maps, leading to a trend where many faults were assumed to be strike-slip.

The strike-slip model became so dominant that Harding published a follow-up paper in 1990, cautioning against its universal application. He outlined alternative interpretations for structures resembling positive or negative flower structures, particularly without 2D or 3D seismic



data. These alternatives, illustrated in the figure, included contractional or extensional fault blocks, faulted detachment folds, salt structures, and more.

Interpreters should consider more than just geometry when analyzing faults. Factors such as deformation timing, tectonic setting, and stress regime are critical. For instance, flower structures are unlikely in rifting environments, where normal faulting - possibly at high angles - is more common. Similarly, in fold-and-thrust belts, a "pop-up" structure might indicate a faulted detachment fold rather than a flower structure. Advances in 3D seismic have refined our understanding of faulting since the 1970s, but this serves as a reminder for geologists, especially in frontier basins or when relying solely on well data, to integrate kinematics, tectonics, and stress orientations into their interpretations. ■



Alternative interpretations of structural settings that resemble flower structures.

SOURCE: MODIFIED FROM HARDING (1990)

Flame structures

Outcrops remind us of the risks of applying a layer-cake approach to correlating well data. Turbidite lobes pinching out, channels abruptly transitioning to floodplain deposits or carbonate platforms only developing on local highs, all of these phenomena can often be observed in outcrops on a relatively small scale. Well data alone don't always allow identification of these rapid transitions, which may lead to sands being over-correlated.

This photo clearly demonstrates that even on a smaller scale, direct correlation of strata can sometimes be tricky. Shown here are so-called flame structures in soft-sediment deformed turbidites overlying bioturbated mudstones, disrupting connectivity on a small scale that would not be picked up by well logs, let alone seismic data. The flame structures form part of a deepwater lobe of the Cretaceous Point Loma Formation of California, USA.

Photography: Ali Jaffri, Applied Stratigraphix

FEATURE YOUR OUTCROP

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

Submarine avalanches in a serendipitous find

Coring in well 15/21b-50 started earlier than planned, but the result was still good

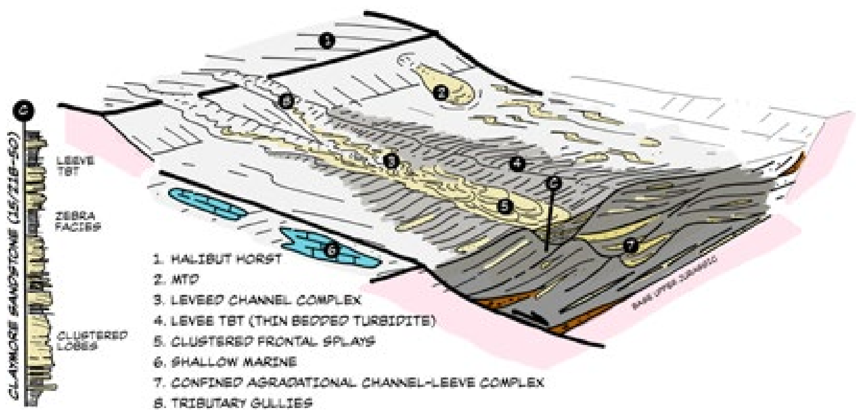
MARCOS ASENSIO

IN THE DEPTHS of the North Sea lies one of the most spectacular records of turbidity currents: The Claymore Sandstone. During the Upper Jurassic, these rocks were born from a geological phenomenon as violent as it was fascinating.

Imagine sediment-laden river floods cascading down the fault scarps of the Halibut Horst toward the North Sea basin floor 150 million years ago.

These gravitational flows, heavy with sediments, descended at extraordinary velocities across the seafloor. As they lost energy in deeper zones, they deposited their load in characteristic sequences: First the coarsest sands, then the finer ones, as can be seen in the first meters of core.

These sands, interpreted as clustered lobes at the base, record high-density flows with excellent connectivity. Higher up, the zebra facies, with their alternating rhythm of sands and shales, were formed by more diluted flows at the margins.



Depositional facies diagram for the Claymore sands cored in 15/21b-50.

At the top, channel-levee complexes acted as true sedimentary highways and internal barriers.

Each new discharge pulse built a new floor in the future reservoir. Layer upon layer, over millions of years, up to 152 m of reservoirs with excellent porosity and permeability accumulated.

But when the well was drilled in this location, it was never planned to core the Claymore sands. The reason? Geologists hadn't mapped them when they mapped the prospect and planned the well. The primary target was deeper down, the Upper Jurassic Piper sands. So, when sands hit the shakers at the expected depth, people thought the targeted Piper reservoir had been reached, and coring started.

The Claymore Sandstones perfectly illustrate how turbidity currents can generate world-class reservoirs, also when it is a serendipitous discovery. ■

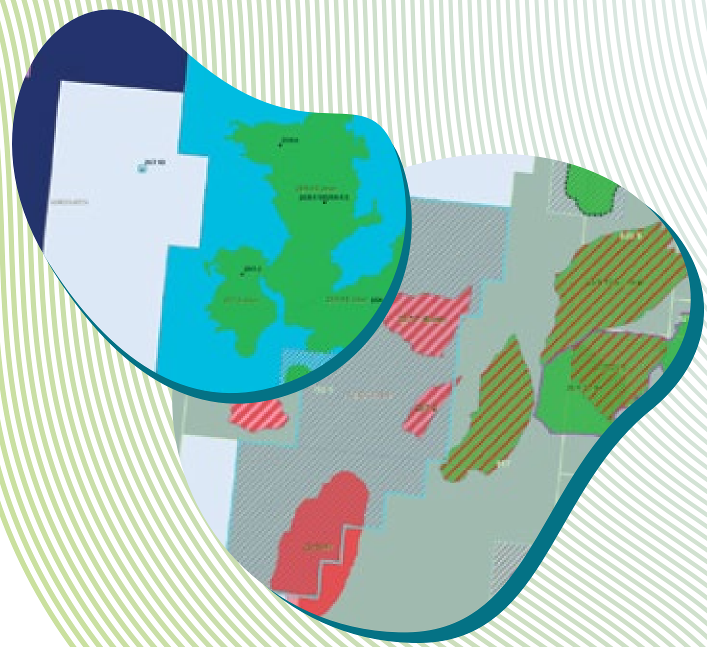
Cored section of well 15/21b-50, from 8,662 to 8,710 ft.

ILLUSTRATION: MARCOS ASENSIO

"We help petrophysicists carry out high-quality interpretations by offering a consistent, clean database specific to North Sea exploration."

Geoactive

Unlock the Potencial of the North Sea



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Designed to streamline your exploration efforts across the Norwegian North Sea, our comprehensive well database, curated using DISKOS data, provides a powerful tool that lets you focus on strategic decision-making, ultimately enhancing your productivity and efficiency.

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