THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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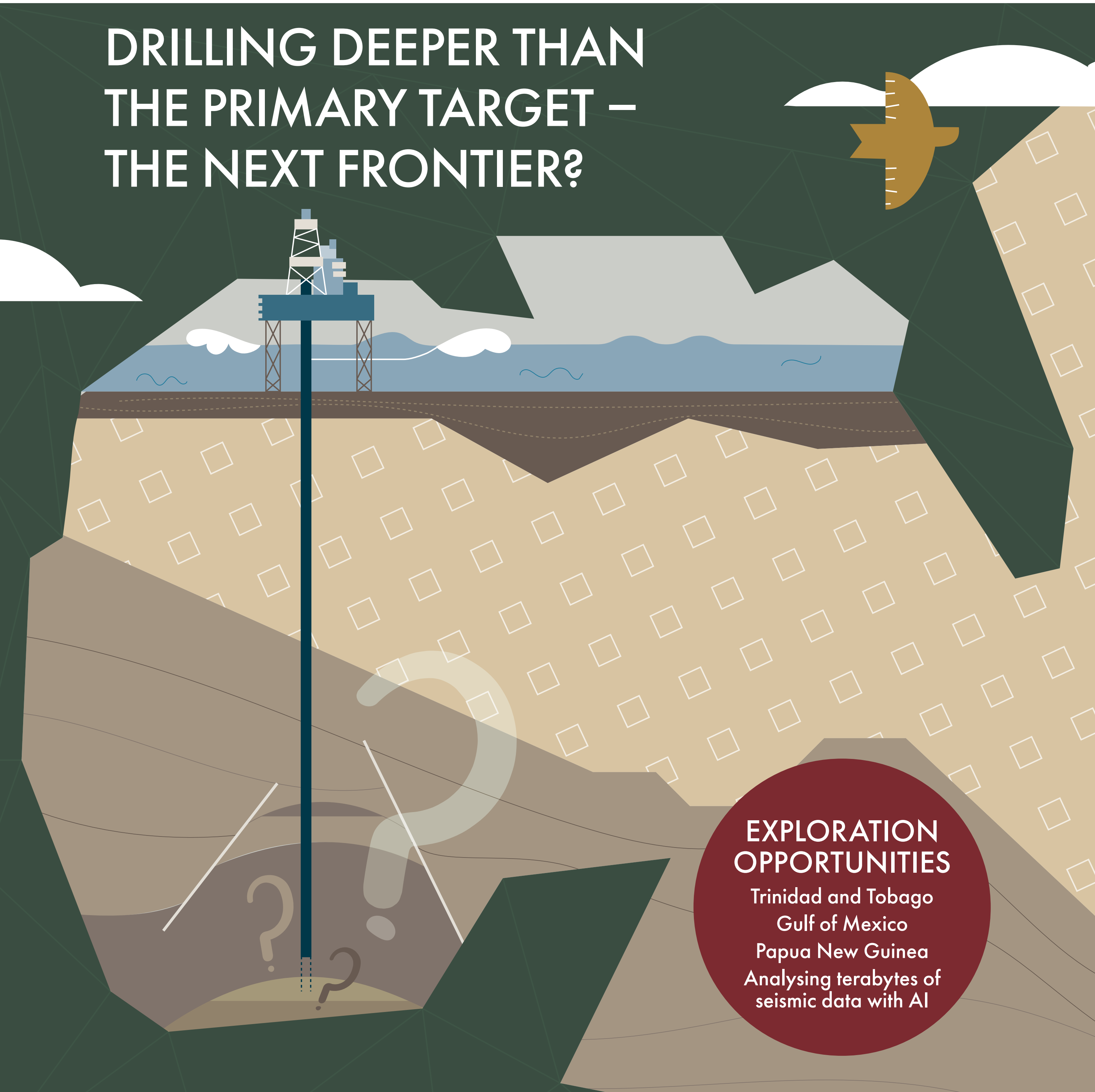
DRILLING DEEPER THAN THE PRIMARY TARGET – THE NEXT FRONTIER?



EXPLORATION OPPORTUNITIES

Trinidad and Tobago
Gulf of Mexico
Papua New Guinea
Analysing terabytes of seismic data with AI

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Working in oil and gas requires resilience

"IF THE OIL price drops even further, it is game over for the North Sea", a colleague commented in September 2014 when the big oil price tumble had just begun. I started my job in subsurface consultancy a few months before that. Consultant geologists who had spent years with a single operator suddenly popped back into the office, sharing the doom and gloom that was upon us. The first redundancy round did not take long to be announced.

Ten years later, I conclude that the risk of being made redundant is not the only dark cloud at the horizon of geo's working in oil and gas. How to tell your friends you work in oil and gas? Peer pressure and an unspoken push to stop any dealings with this industry is always nagging.

And there is another element – a shrinking community in mature basins. The decline in the number of people attending events is a very visible manifestation. When I attended my first Aberdeen PESGB talks in 2011, the crowd easily consisted of around 70 people. There was finger food, and sometimes even free beer. Today, around 20 people pay for their own drink.

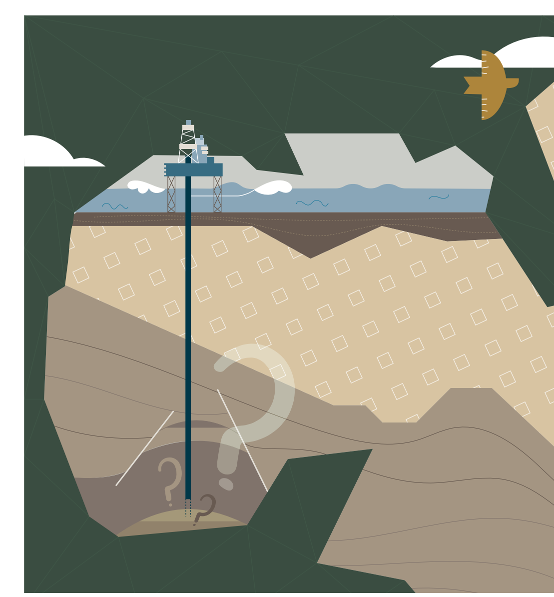
> "..the risk of being made redundant is not the only dark cloud at the horizon of geo's working in oil and gas"

For these reasons, one can only conclude; it requires stamina to work in oil and gas. Hats off to those willing to give it a try. Energy is not yet about wind and solar only.

Henk Kombrink

BEHIND THE COVER

Sometimes it is worth drilling a bit deeper than the original target of the well – sometimes there is a nice surprise lurking at greater depths! That is the main message the front cover portrays, in this case using an example from the Gulf of Mexico, illustrated by Lucia Perez-Diaz. Motivated by a LinkedIn post on the matter, we put out a request asking for more examples of this kind, which resulted in a good geographical spread of wells that did go a bit deeper. Check out the cover story to find out and read how even an entire LNG project has its origins in a deeper serendipitous find.



COVER ILLUSTRATION: LUCIA PEREZ-DIAZ

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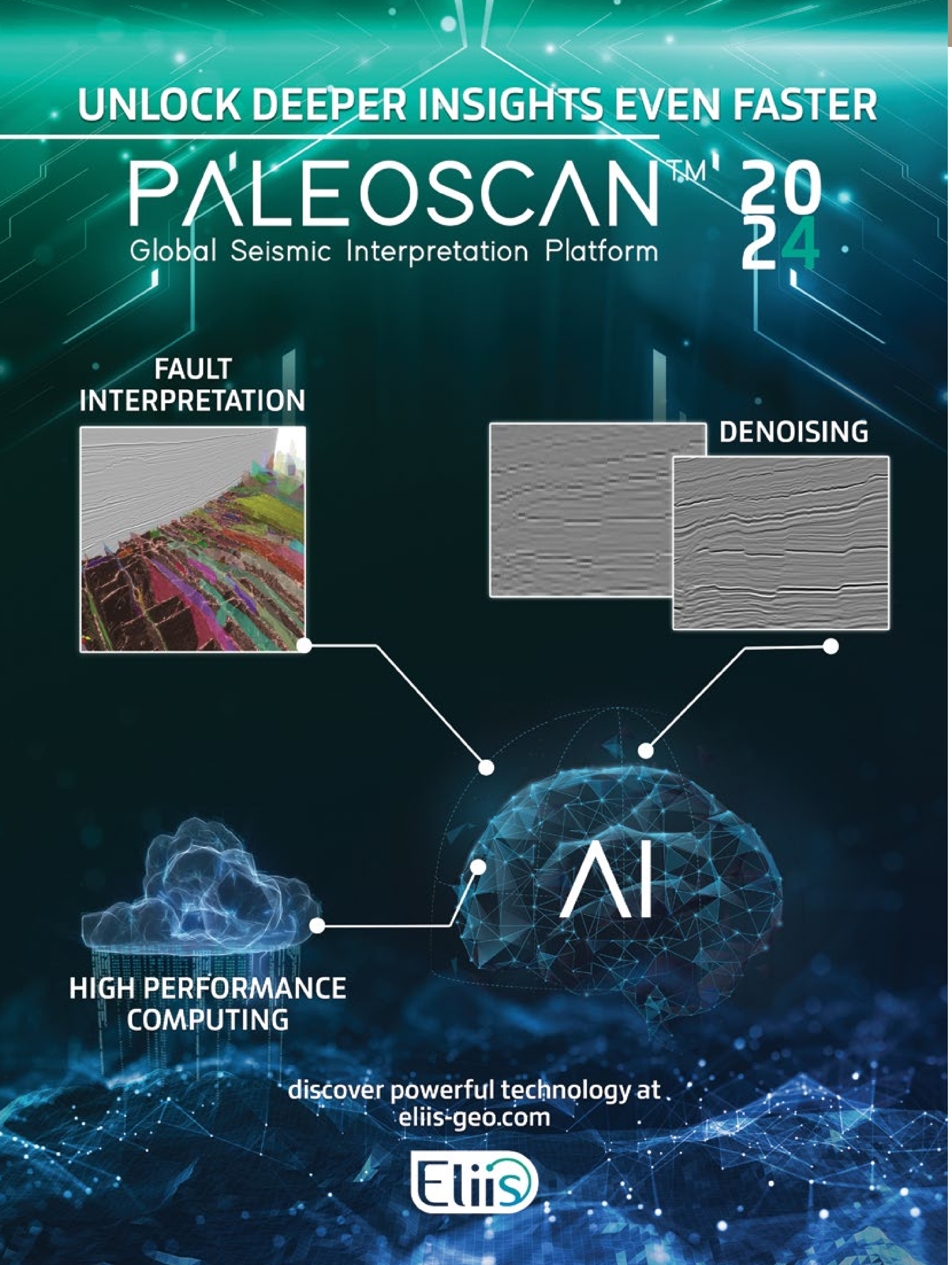

FIRSTS

"...the core of a successful sustainable energy system going forward should be high net energy reliable baseload sources complemented by intermittent forms in modern renewables"

Rodney Garrard - Arch Insurance

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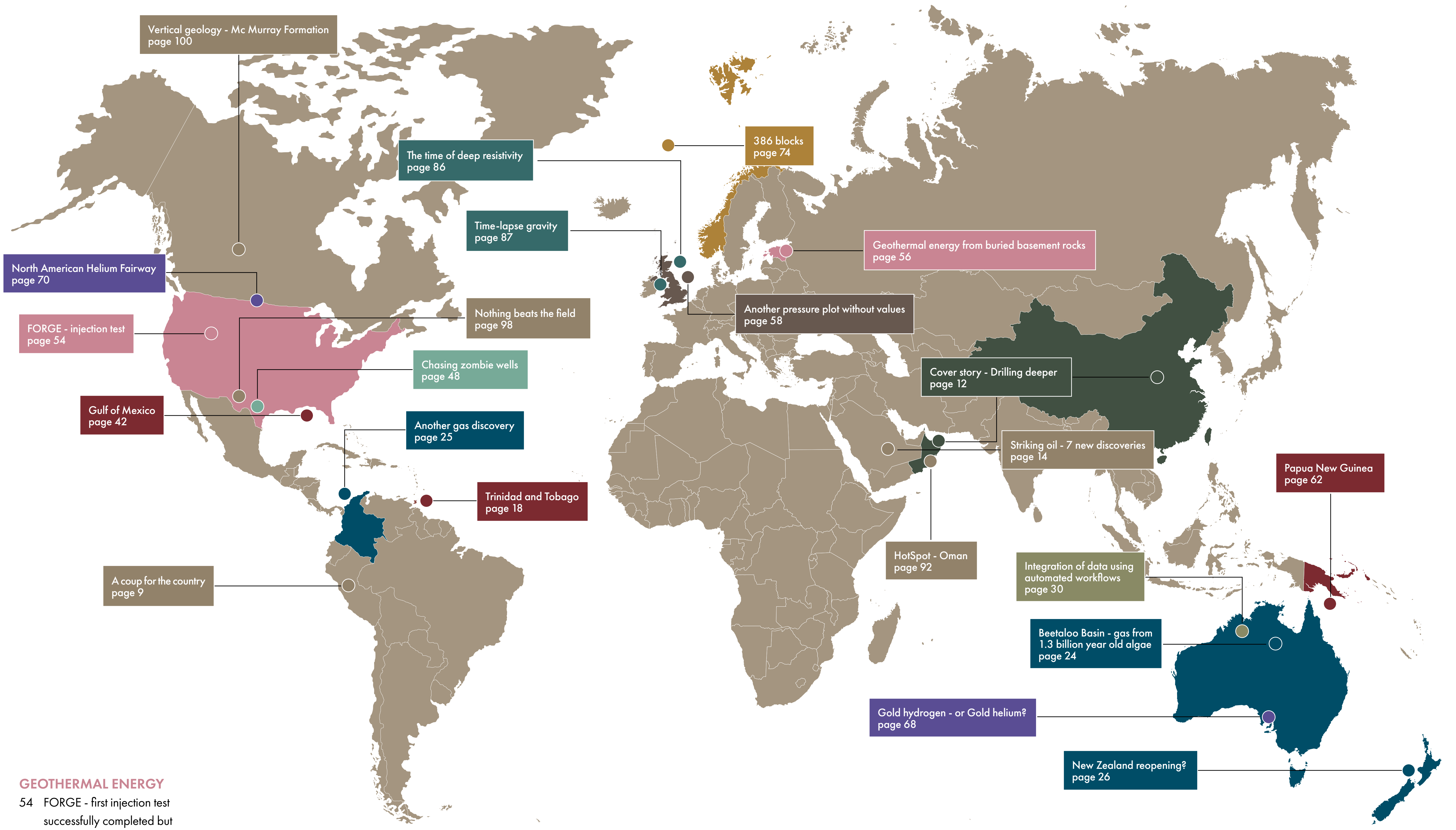

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The little big number

How LCOE has been a disservice for comparison of different energy sources

"Levelized cost of energy" (LCOE) measures an energy source's lifetime costs divided by energy output and is a metric often used for comparing the competitiveness of different energy forms to be considered profitable. The parameter can be a useful tool, but only to a limited extent as it has several flaws, and in its origin was never intended for comparison between different generation technologies.

Among other things, LCOE does not take into account the timing of when the electricity is delivered, or whether the electricity also comes with additional benefits that the power grid is dependent upon for reliable and secure operation. Thus, costs for natural gas and / or battery backup power for intermittent solar or wind farm projects are not considered, or the cost of expanding power grids to other regions with different weather patterns.

As mentioned in my first column in Issue 3, modern societies are completely dependent on a functioning system of reliable energy production. This is essential for an overall assessment of value.

Nuclear plants boast capacity factors of 93 %, on average, versus just 57 % for natural gas and 40 % for coal, i.e. they can operate almost year-round at full capacity. Intermittent sources like wind and solar have capacity factors of 35 % and 25 % (EU based), respectively.

Again full disclosure, I am not a nuclear industry veteran, but I am perplexed that many people, geoscientists included, do not appreciate the full value proposition of nuclear. Particularly when we think about moving to a resilient decarbonized grid and using land efficiently. The things that seem inherent in the definition of nuclear power are not compared effectively and valued by the LCOE metric.

Critics of nuclear power from Norway to Australia cite examples of high costs and construction overruns as some of the main reasons for choosing to build other energy technologies. Initial capital costs for nuclear are high, but given the energy payback, as measured by the net energy (energy supplied per quantity of energy used) nuclear is in a league of its own. Now, there are obviously no bad ideas when it comes to energy generation and we are going to need all forms in much larger quantities than currently forecast, but the core of a successful sustainable energy system going forward should be high net energy reliable baseload sources complemented by intermittent forms in modern renewables.

$$\text{LCOE} = \frac{\text{SUM of Investment, Maintenance and Fuel expenditures}}{\text{Energy generated}}$$

Nuclear power plant.

PHOTOGRAPHY: PIXABAY

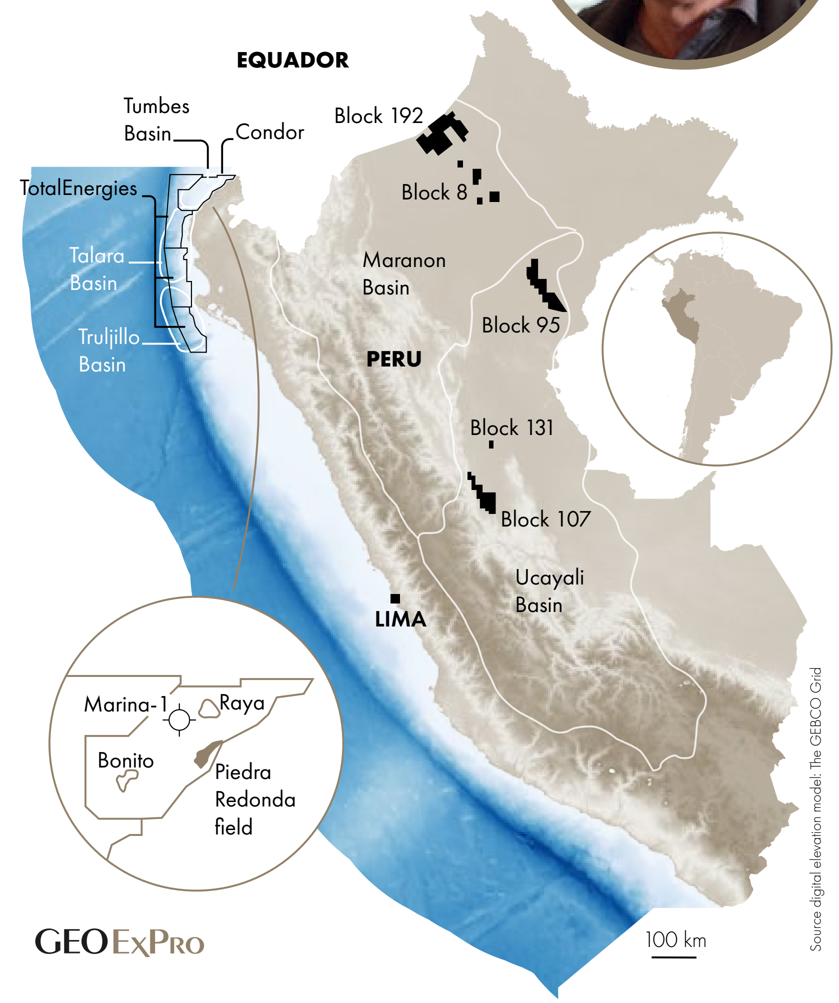
To bring attention to the LCOE calculation is important for two reasons. First, users of the metric when framing energy trade-offs should understand its simplifications and its intended use. Secondly, and even more importantly, it is to alert us to the limitations of this measure for capturing everything that matters, and why decisions must be made with the entire footprint of the material supply chain, land use, existing network capacity and job creation in mind. Otherwise, we are doing ourselves a disservice. ■

Rodney Garrard – Arch Insurance

A coup for the country

Under-explored Peru not only signed an interesting deal with TotalEnergies, there are other developments suggesting a renewed interest in exploration

The Ministry of Energy and Mines in Peru (Minem) recently indicated that the oil industry is 'being reactivated'. And so far, the signs are indeed pointing in that direction, particularly for the offshore. The deal signed by TotalEnergies and Perupetro for three offshore Technical Evaluation Agreements (TEA) covering large parts of the Talara and adjacent Tumbes forearc basins in the northwest of the country was probably the most impactful in that regard. The TEAs are valid for 24 months and will allow TotalEnergies to conduct geological and geophysical evaluation in return for the right of First Option for eventual negotiation and signing of a License Agreement.



The TotalEnergies TEAs are located in the same area as Condor Energy's TEA in the Tumbes Basin, which was signed in August 2023. Condor has reported that much of its work has been focussed on the Raya and Bonito prospects targeting Miocene reservoirs. The agreement area also contains Belco Petroleum's 1978 Piedra Redonda gas discovery and Karoon Energy's Marina-1, the most recent offshore well drilled in Peru in 2020.

Occidental's 61,002 km 3D seismic survey in the Trujillo Basin is another sign that Peru's offshore is being looked at. The three blocks, which were signed by Anadarko in 2017 ahead of the corporate purchase by Occidental in 2019, are in the second exploration phase. Previous work since award involved the reprocessing of 2D and 3D data.

ONSHORE

Earlier in the year, it was announced that Canadian company Altamesa Energy joined Petroperu, a state-owned entity, in Block 192. Production in the block, located in the Amazon jungle in northern Peru contiguous with Ecuador, was suspended in 2020 due to force majeure. Since it took over the operation, Petroperu has been conducting pre-operational work for the reactivation and start of oil production. The block is reported to contain some 17 oil fields.

In May 2024 PetroTal, the largest oil producer in the country, announced acquisition of Cepsa Peru which includes a 100 % interest in onshore Block 131. The block contains the producing Los Angeles oil field in the Ucayali Basin. PetroTal's flagship asset is its 100 % interest in Bretaña oil field (Block 95) in the Maranon Basin where production is around 20,500 BPD. Meanwhile, in Block 107 PetroTal plans two wells in 2025 / 2026 on designated prospects Constucion Sur and Osheki-Kametza targeting the Cretaceous reservoirs in the Ucayali Basin.

During the same month, Perupetro also signed an agreement with the Offshore International Group INC consortium for Block X (Talara) in the Maranon Basin, with momentum continuing in June when it signed the Temporary License Contract for Block 8 in the same basin with Upland Oil & Gas. ■

Ian Cross - Moyes & Co

Not one, but seven new discoveries announced in Saudi Arabia

But the impact of these discoveries on the country's ability to continue exporting hydrocarbons is unclear

EARLY JULY, Reuters published a short article stating that Saudi Arabia's energy minister announced the discovery of seven oil and gas accumulations in the country. As is often the case with press releases of this kind, it is hard to make sense of what was really discovered, and how much.

The statement says: "Two unconventional oil fields, a reservoir of light Arabian oil, two natural gas fields, and two natural gas reservoirs" have been discovered.

The first question is, what is the difference between a natural gas field and a natural gas reservoir? Could it be that the two natural gas fields indicate a find close to existing fields? Using the word field implies that production is already ongoing. A natural gas reservoir, in contrast, alludes to something a bit more "frontier". Saying that, when I spoke to a person with knowledge on the matter earlier this year, he said that "frontier exploration" does not really exist anymore in Saudi Arabia: Wells have been drilled all over the country and therefore it is slightly misleading to use frontier.

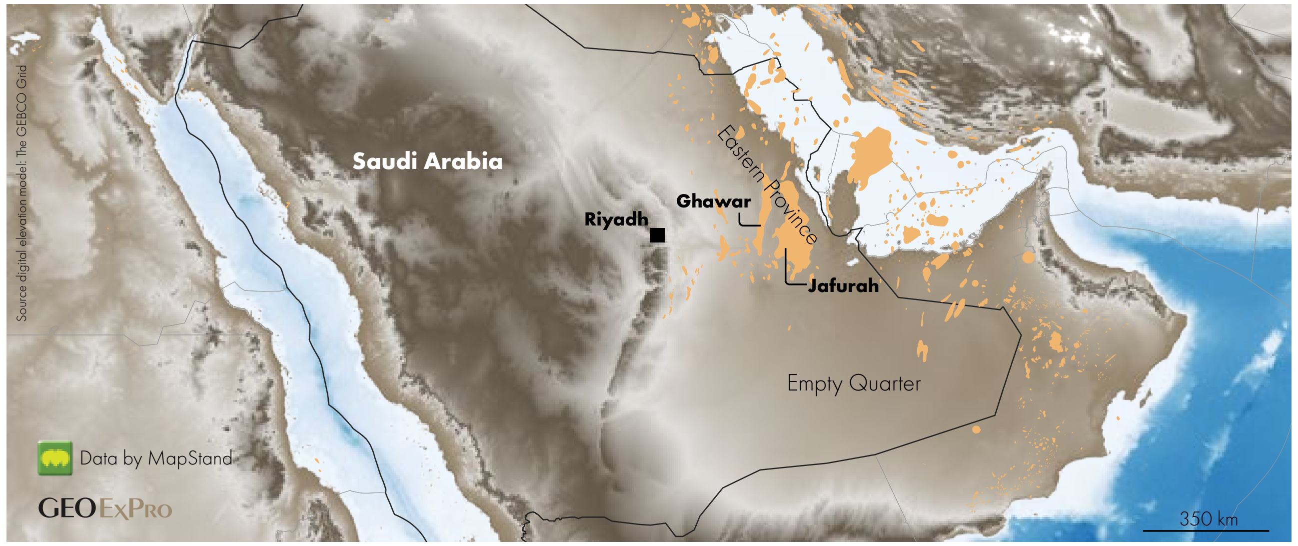
THE SEARCH FOR UNCONVENTIONALS

Another indication why using frontier exploration for drilling activity in Saudi Arabia may not be the most fitting term anymore is the fact that Aramco seems to target unconventional reservoirs – two unconventional oil discoveries are part of the announcement made. Combined with already known unconventional developments in the country, such as the production of tight gas from below the Ghawar oil field and the development of the Jafurah unconventional gas field, it is a clear sign that exploration is now targeting the more challenging reservoirs rather than focusing on frontier areas.

The discoveries were made in two areas of Saudi Arabia; the Eastern Province and the Empty Quarter – see map. The Eastern Province is clearly the hotspot of oil and gas production in the country, with lots of fields in production. It is likely that the two unconventional oil finds and the "reservoir" reported from this area are close to existing fields. There are not as many fields in the Empty Quarter, so the gas discoveries announced here may be more standalone.

The impact of these finds in terms of Saudi Arabia's ability to continue exporting oil – and maybe gas in the not-too-distant future – is unclear. Volumes were not mentioned in the press release. It may also be difficult to state volumes as well, given that it is a lot harder to come up with unconventional gas or oil volumes than when it is conventional hydrocarbons. It is more the unconventional nature of the discoveries that is confirming the way Aramco is going – targeting the more challenging reservoirs. ■

Henk Kombrink



COVER STORY

"When I came back from my lunch break – the excitement in the office was great. Only a few meters below the level where we had planned to call TD, the gas readings went all over the place"

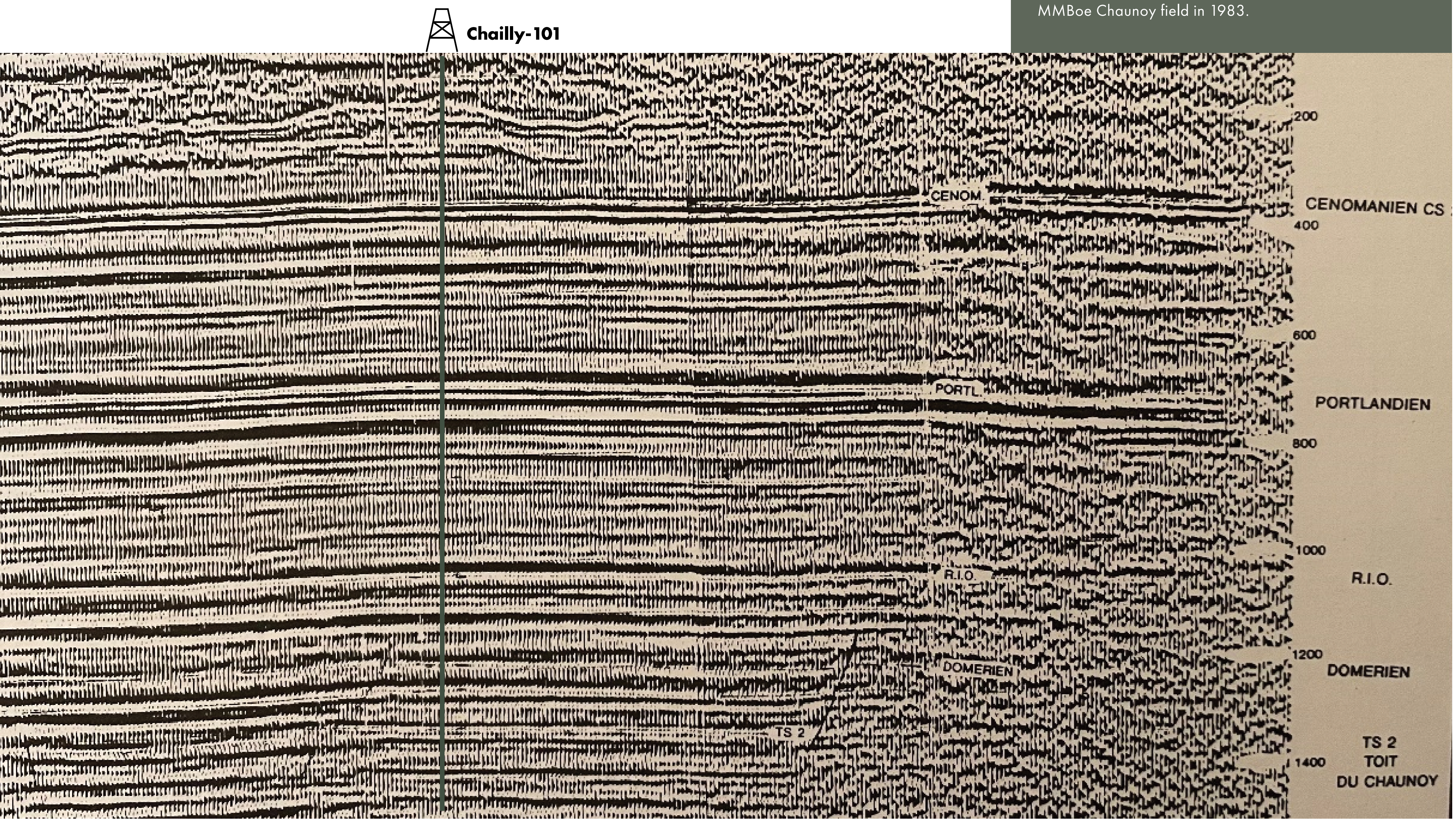
Meindert de Ruiter – former Team Lead for Central Oman at PDO

COVER STORY

DRILLING DEEPER THAN THE PRIMARY TARGET – THE NEXT FRONTIER?

Whether serendipitously or intentionally, drilling deeper than the main target has paid off in quite some cases. Here, we take a look at some spectacular examples from around the world

HENK KOMBRINK



SOURCE: MARC BLAIZOT

PARIS BASIN, FRANCE

The Chailly oil field was discovered in 1958 when the very low-amplitude seismic structure shown here was drilled. It proved oil in the carbonates of the Dogger (Middle Jurassic) at 1,600 m. It was the first important discovery in the Paris Basin with 14 MMbo in reserves. In 1967, the Chailly 101 well was deepened towards the Triassic and encoutered oil at 2,150 m in sandstone reservoirs. The discovered volume was small, but it opened up a new play in the basin, paving the way to the discovery of the 100 MMBoe Chaunoy field in 1983.

The idea for this story was born when I saw a LinkedIn post from Mike Smith in the US in which he posted about a well in the Gulf of Mexico that was drilled a little deeper than a previous exploration attempt very close by. It found the St Malo field. If only had the first well drilled a bit deeper.

Being such a good example of the benefit to drill a bit deeper than the primary target, I decided to put out a request on our LinkedIn page for more stories along these lines. And as always, there were quite a few good ones from all over the world.

Initially, based on the input I received, this story looked like going to be a series of serendipitous exploration successes, for a variety of reasons including an operations geologist being away for Christmas and unable to call TD. But then, I was made aware of an interesting project in China by Marc Blaizot – former global exploration manager at TotalEnergies. The Chinese seem to have made a real thing of going deeper and beyond “primary” targets, as we further describe in this article.

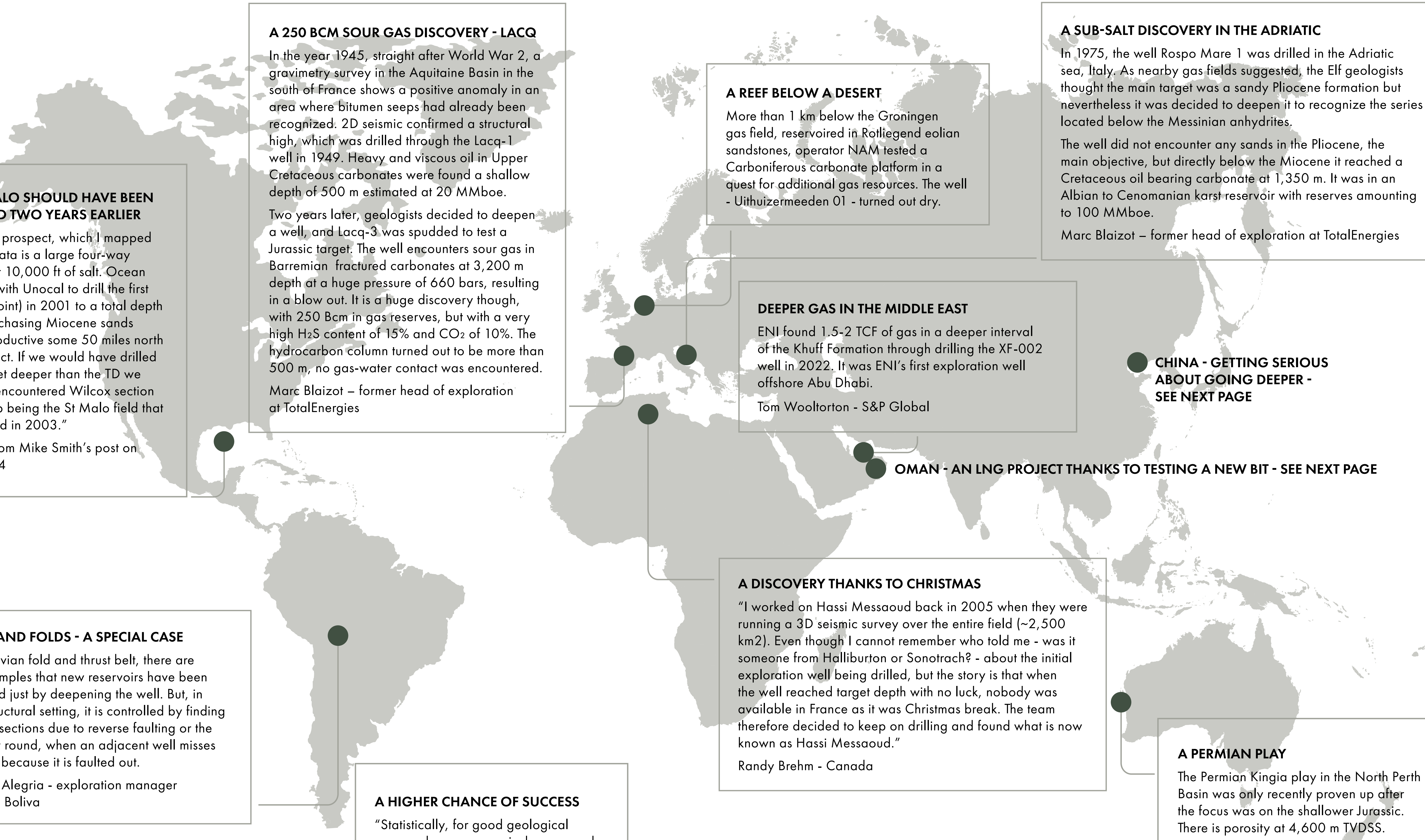
The China example is not an isolated case. In quite a few other places around the world, companies are chasing resources deeper than where the “first generation” of oil and gas reserves came or come from. It is a sign that the industry as a whole is moving towards finding and producing deeper, and more technically challenging resources.

Saudi Aramco developing tight gas beneath the Jurassic Ghawar field is a good example of this. Similarly, on a much more modest scale, the Permian Kingia Formation in the Perth Basin of Western Australia is also an example of a deeper stratigraphic interval that has more recently come on the radar.

In other words, the industry is really testing what some people may have called “economic basement” a while ago. It reminded me of the observation Rodney Garrard made in his column for the magazine (Issue No. X 2024): “We are not moving away from hydrocarbons, hydrocarbons are moving away from us.”

So, in the end, this story is a mix of serendipitous finds – the best ones to tell about at the coffee machine – and the more “planned” campaigns. Altogether, a clear sign that going deeper can be called a new frontier. ▶

COVER STORY



HOW ST MALO SHOULD HAVE BEEN DISCOVERED TWO YEARS EARLIER

“The "Boffus" prospect, which I mapped on TGS 2D data is a large four-way closure under 10,000 ft of salt. Ocean formed a JV with Unocal to drill the first well (Dana Point) in 2001 to a total depth of 26,850 ft chasing Miocene sands which are productive some 50 miles north of this prospect. If we would have drilled some 500 feet deeper than the TD we would have encountered Wilcox section that ended up being the St Malo field that was dicovered in 2003.”

An excerpt from Mike Smith’s post on LI - June 2024

A 250 BCM SOUR GAS DISCOVERY - LACQ

In the year 1945, straight after World War 2, a gravimetry survey in the Aquitaine Basin in the south of France shows a positive anomaly in an area where bitumen seeps had already been recognized. 2D seismic confirmed a structural high, which was drilled through the Lacq-1 well in 1949. Heavy and viscous oil in Upper Cretaceous carbonates were found a shallow depth of 500 m estimated at 20 MMboe.

Two years later, geologists decided to deepen a well, and Lacq-3 was spudded to test a Jurassic target. The well encounters sour gas in Barremian fractured carbonates at 3,200 m depth at a huge pressure of 660 bars, resulting in a blow out. It is a huge discovery though, with 250 Bcm in gas reserves, but with a very high H_2S content of 15% and CO_2 of 10%. The hydrocarbon column turned out to be more than 500 m, no gas-water contact was encountered.

Marc Blaizot – former head of exploration at TotalEnergies

THRUST AND FOLDS - A SPECIAL CASE

In the Bolivian fold and thrust belt, there are some examples that new reservoirs have been discovered just by deepening the well. But, in such a structural setting, it is controlled by finding repeated sections due to reverse faulting or the other way round, when an adjacent well misses the target because it is faulted out.

Fernando Alegria - exploration manager at YPFB in Boliva

A HIGHER CHANCE OF SUCCESS

“Statistically, for good geological reason, deeper reservoirs have a much higher chance of receiving charge than younger ones.”

Zhiyong He - Founder of ZetaWare

A REEF BELOW A DESERT

More than 1 km below the Groningen gas field, reservoired in Rotliegend eolian sandstones, operator NAM tested a Carboniferous carbonate platform in a quest for additional gas resources. The well - Uithuizermeeden 01 - turned out dry.

A SUB-SALT DISCOVERY IN THE ADRIATIC

In 1975, the well Rospo Mare 1 was drilled in the Adriatic sea, Italy. As nearby gas fields suggested, the Elf geologists thought the main target was a sandy Pliocene formation but nevertheless it was decided to deepen it to recognize the series located below the Messinian anhydrites.

The well did not encounter any sands in the Pliocene, the main objective, but directly below the Miocene it reached a Cretaceous oil bearing carbonate at 1,350 m. It was in an Albian to Cenomanian karst reservoir with reserves amounting to 100 MMboe.

Marc Blaizot – former head of exploration at TotalEnergies

DEEPER GAS IN THE MIDDLE EAST

ENI found 1.5-2 TCF of gas in a deeper interval of the Khuff Formation through drilling the XF-002 well in 2022. It was ENI’s first exploration well offshore Abu Dhabi.

Tom Woolterton - S&P Global

CHINA - GETTING SERIOUS ABOUT GOING DEEPER - SEE NEXT PAGE

OMAN - AN LNG PROJECT THANKS TO TESTING A NEW BIT - SEE NEXT PAGE

A DISCOVERY THANKS TO CHRISTMAS

“I worked on Hassi Messaoud back in 2005 when they were running a 3D seismic survey over the entire field (~2,500 km2). Even though I cannot remember who told me - was it someone from Halliburton or Sonotrach? - about the initial exploration well being drilled, but the story is that when the well reached target depth with no luck, nobody was available in France as it was Christmas break. The team therefore decided to keep on drilling and found what is now known as Hassi Messaoud.”

Randy Brehm - Canada

A PERMIAN PLAY

The Permian Kingia play in the North Perth Basin was only recently proven up after the focus was on the shallower Jurassic. There is porosity at 4,600 m TVDSS.

Nik Sykiotis - project geologist

COVER STORY

FINDING GAS BENEATH GAS

CNOOC recently issued a press release discussing the results of the first ultra-deep well (Bozhong 19-6 Condensate Gas Field D1 Well) completed in the Bohai Bay area, offshore China. This is interesting from multiple points of view.

First, it gives away what China is focusing on in the light of their recent announcement to set up a special company dedicated at drilling deeper wells. The press release fits into this, and suggests that China is not only looking to find deep gas in onshore basins like the Tarim, but is also looking at finding hydrocarbons beneath existing assets.

Secondly, the reported terminal depth of the well at more than 6,000 m is worth noting. This depth is indicated as a red line in the cross-section shown here. The section shows the Bozhong 19-6 condensate field and was adapted from a publication by Mingcai Hou and co-authors. The exact location of the newly drilled well is unknown, but if this section is anything to go by, it suggests that the company drilled either into fresh unweathered basement or very deeply buried clastics on its sides. This poses the question: How can flow rates of 6,300 barrels of oil equivalent per day be achieved in such a subsurface setting?

We received some interesting feedback on a LinkedIn post when CNOOC had just published the press release.

Tako Koning, an experienced petroleum geologist who worked in fractured basement reservoirs during his long career, argues that looking at possible analogues for this discovery is useful. He wrote: “For example, the oil column in the Bach Ho oil field, Vietnam, is 1,500 m, entirely in fractured Precambrian granite. Buried hill basement oil fields in Chad also have such thick oil columns in fractured Precambrian granites. Another analogue is the Suban gas field, South Sumatra which has a 1,250 meter gas column in fractured Pre-Tertiary granites. The point being, depending on the intensity of the regional and local tectonics, the fractures in basement can extend down to great depths.”

Eleanor Oldham from Merlin Energy noted: “I have worked with some fractured basement fields so this piqued my interest and led to a quick online search. I found a paper which does indeed suggest that CNOOC identified a secondary target of fractured reservoir below the primary weathered layer. These two reservoir zones are depicted as separated by a tight interval. My assumption would be that this recent well was successful at discovering pay in the deeper, secondary target. Although, I admit there are currently not enough details to back up this assertion.”

It is worth following what the Chinese are doing when it comes to drilling deeper. They seem to be exploring subsurface domains that are not being considered by many others.

HOW TESTING A NEW DRILL BIT ULTIMATELY RESULTED IN A MAJOR LNG PROJECT

It would be great to attribute a spectacular gas discovery to the inquisitive and persistent nature of a person or a group of people working on the exploration campaign. But in the case of the Barik 1 well in Central Oman, the well that kickstarted what was to become the country’s only LNG project, nobody can make that claim. When Barik 1 was drilled in 1991, TD was called at around 4,500 m without encountering a sniff of hydrocarbons.

The idea of the well was to drill the first of a series of deep-seated domes in the Ghaba Salt Basin that were mapped on seismic lines before. The target reservoirs were initially supposed to be of Mesozoic age, in analogy to the already known time-equivalent carbonates and siliciclastic reservoirs from the northern part of Oman. When the bit had clearly started drilling onto the Paleozoic without encountering any hydrocarbons, it was therefore decided to abandon the well.

“It was during the morning brief that we heard that the driller had however sought permission to drill a little further to test a new bit”, says Meindert de Ruiter when I speak to him over the phone. Meindert was the Team Lead for Central Oman at PDO at the time, and was part of most routine meetings that took place discussing drilling progress. “We did not expect any issues doing so, so the driller was given the go-ahead”, says Meindert.

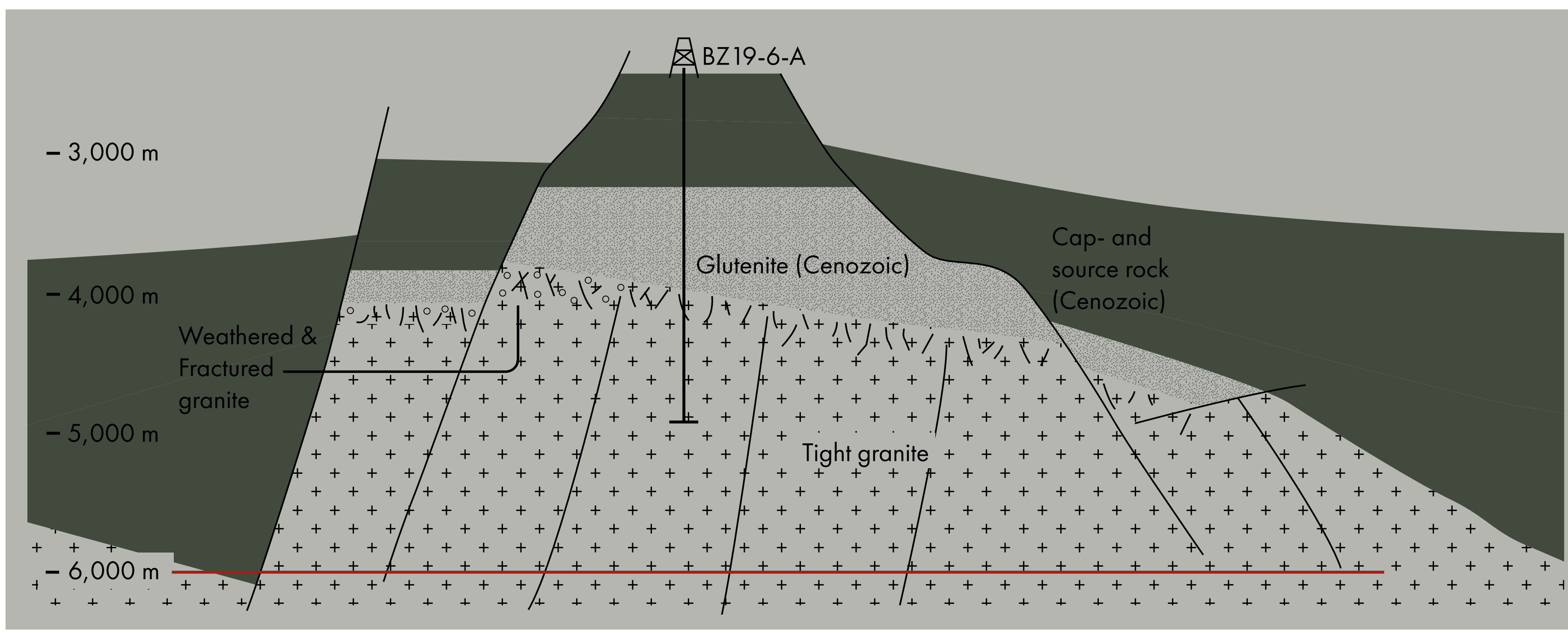
“But when I came back from our lunch breaks – in Oman we enjoyed lunch at home in those years – the excitement in the office was great. Only a few meters below the level where we had planned to call TD, the gas readings went all over the place.”

Rather than finding gas in Mesozoic rocks, the bit had proven the Ordovician Barik sandstone instead.

“Reservoir properties of the sands at the well were not great” remembers Meindert, “but it is gas so you do not need great permeabilities to make the reservoir work.”

The Barik-1 well had thus kickstarted the development of what soon became to be a new cluster of fields that would justify the construction of what still is Oman’s one and only LNG facility that operates three trains at Qalhat.

Thanks to Evert van de Graaff for making us aware of this story. ■



Cross-section showing the BZ-19-6 oil and condensate field, Bohai Sea. We added the 6,000 m level in red - the depth to which a new well into the field was recently drilled. Cross-section redrawn from Hou et al. (2019).

A bit of core from the Haima Group in Oman, of which the Barik Formation is part.

PHOTOGRAPHY: MEINDERT DE RUITER

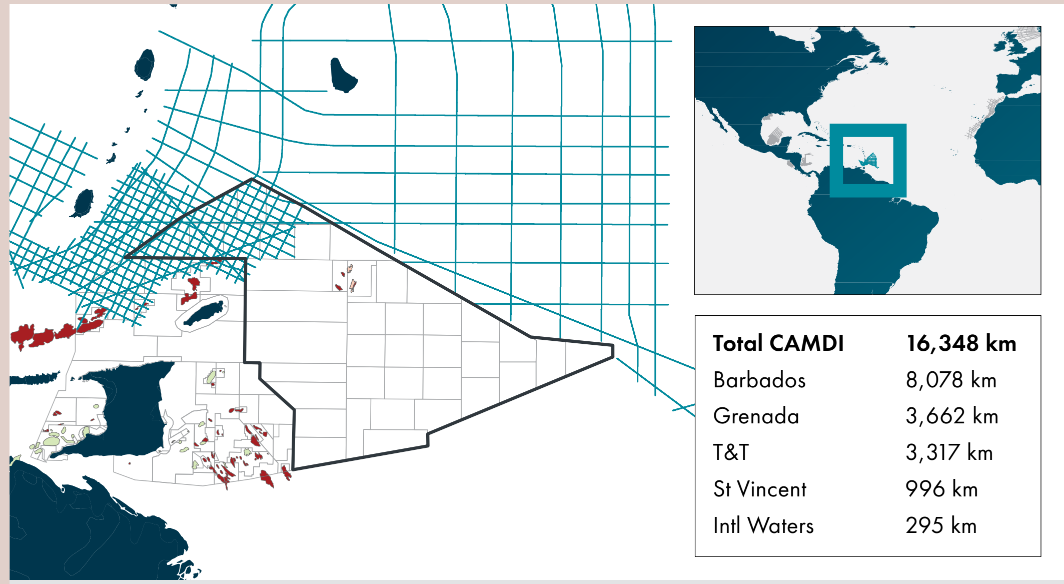
T&T deep water bid round: A gateway to energy opportunities

In today's energetic climate, where there is a growing demand for reliable energy sources, the importance of exploring and developing new oil and gas reserves cannot be overstated. The Tobago Trough remains an underexplored region with significant exploration potential. To unlock this potential, Geoex MCG acquired 16,348 km of longoffset high-resolution 2D seismic data in the Caribbean, of which 3,315 km are in Trinidad and Tobago (T&T)'s marine acreage.

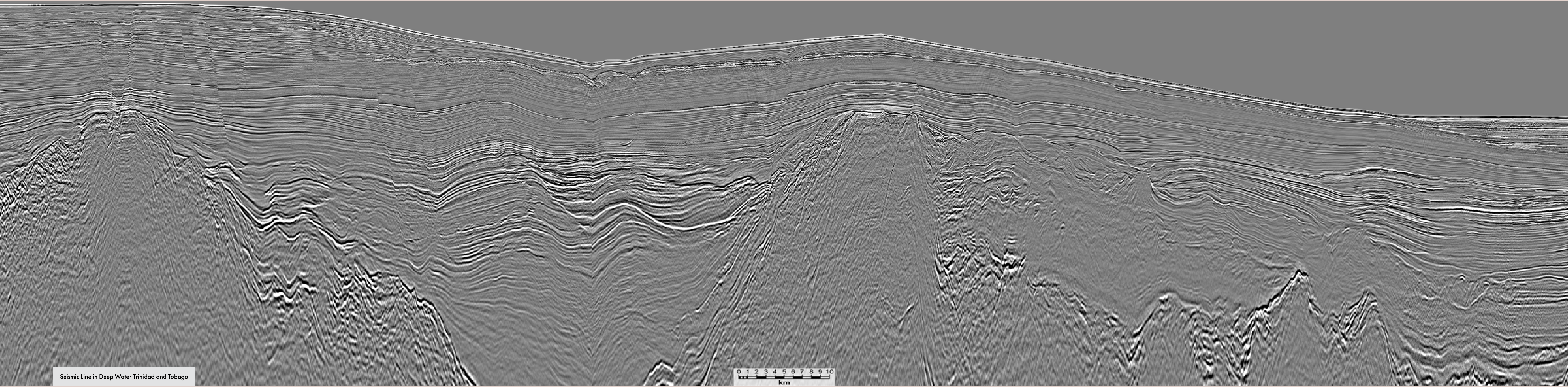
This survey aims to enhance the understanding of the regional tectonic framework across the various basins in the Southeastern Caribbean, linking producing areas to the deeper part of the Tobago Trough. The Ministry of Energy and Energy Industries (MEEI) of Trinidad and Tobago is expected to launch a Deep Water Competitive Bidding Round in late 2024. CAMDI data in T&T covers part of the deep-water blocks and represents a key dataset to upcoming licensing rounds with high quality PSTM, PSDM, gravity and magnetic data available.

Geoex MCG

Government of the Republic of Trinidad and Tobago
Ministry of Energy and Energy Industries



Map: Geoex MCG CAMDI Seismic Lines over T&T Bid Round Blocks.



Seismic Line in Deep Water Trinidad and Tobago

Trinidad and Tobago: A vital 2024 deepwater frontier

The Caribbean Atlantic Margin Deep Imaging seismic survey (CAMDI) spans 16,348 km with long offsets (12 km) and a deep record length (18 seconds). This transnational survey covers acreage across the maritime borders of Barbados, Trinidad & Tobago (T&T), Grenada, and St. Vincent

JENIFFER MASI, GEOEX MCG AND DONNA-MARIE LEZAMA, MINISTRY OF ENERGY AND ENERGY INDUSTRIES, TRINIDAD AND TOBAGO

THE CARIBBEAN Atlantic Margin Deep Imaging seismic survey (CAMDI) spans 16,348 km with long offsets (12 km) and a deep record length (18 seconds). This transnational survey covers acreage across the maritime borders of Barbados, Trinidad & Tobago (T&T), Grenada, and St. Vincent.

CAMDI's regional grid provides a better understanding of the tectonic framework of the different basins along the Southeastern Caribbean and Western Atlantic Margin of Northeast South America. The detailed grid over Trinidad & Tobago and Grenada is designed to provide more localized detail to aid in the identification of oil and gas prospects while tying the producing areas of T&T to the underexplored deeper part of the Tobago Trough.

Approximately 3,315 km of the CAMDI survey are located offshore Trinidad & Tobago, covering shallow and deep-water blocks.

PREFERENTIAL SETTING FOR HYDROCARBON ACCUMULATIONS

The CAMDI MC2D survey is situated in close proximity to the producing areas of the Orinoco Delta and Northern T&T. The tectonic history of the region has afforded a preferential setting for hydrocarbon accumulations.

Tectonics offshore T&T were significantly influenced by the North / South American tectonic plates and their interaction with the Caribbean plate. During the late Jurassic to Early Cretaceous, significant rifting occurred between North and South America. Following this rifting, the Caribbean plate migrated eastward from the Late Cretaceous onwards, relative to the North and South American plates to its present-day position. The complex structural setting, geometries and subsidence mechanisms of the basins located in this area are controlled by several fault systems, that resulted from major tectonic events in the southeastern Caribbean as result of this migration.

The CAMDI survey area in Trinidad and Tobago remains largely unexplored, yet several biogenic gas fields, such as Hibiscus, Sancoche, and Orchid, have been discovered nearby. The producing intervals are Miocene and Pliocene aged turbiditic and deltaic sands, deposited during the progressive easterly progradation of the Orinoco Delta Structural trapping is crucial in this region, as reservoirs are often found against faulted structures and within turbidites.

EVIDENCED EQUIVALENT OF LA LUNA FORMATION

While most target intervals and discoveries are located in Pliocene intervals, The CAMDI MC2D survey shows a regional distribution of multiple, structural traps and potentially high-quality sheet turbiditic reservoirs. Overlying hemipelagic marine clays would form the sealing facies with migration into the reservoirs (Miocene – Eocene) occurring along a combination of thrust and transtension strike slip faults associated with the deformation front (Figure 1).

All the essential hydrocarbon elements for a functioning petroleum system are present in the region. Distal DSDP and ODP wells offshore Venezuela and Barbados have provided evidence of a regional Upper Cretaceous source rock equivalent to Venezuela's La Luna Formation. Maturation is predicted to have commenced during the Miocene in the Eastern Venezuelan Basin and continued from the late Miocene to recent times offshore Trinidad. Onshore in Barbados, the Woodbourne oilfield produces oil and gas from the Eocene Scotland Group,

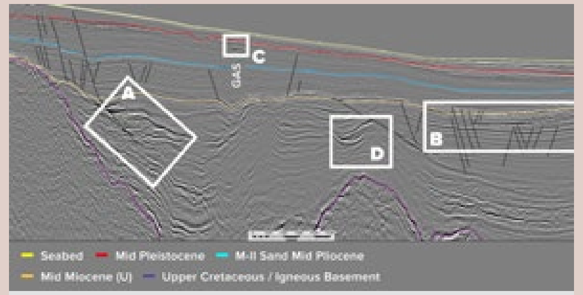


Figure 1: SSW-NNE Seismic Section across T&T with interpreted horizon.

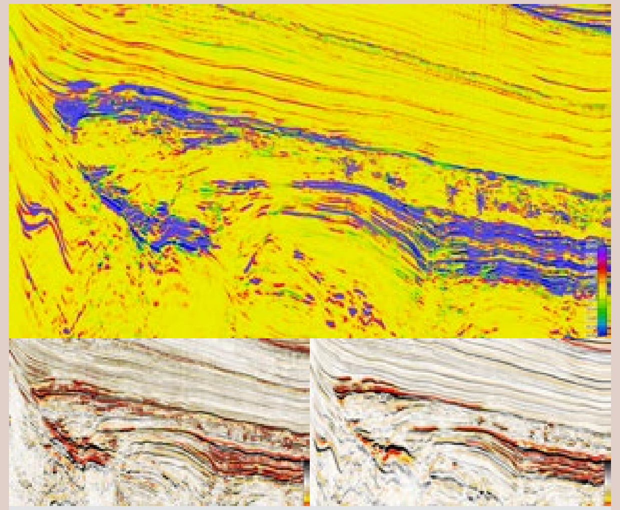


Figure 2: ERG Example. Near Stack – Far Stack

sourced from a La Luna age-equivalent source rock. While this oil play with further reservoir-seal pairs provided by the Plio–Pleistocene deep marine pelagic sediments remains unproven due to the lack of well penetrations in the Tobago Trough, the CAMDI MC2D survey reveals a distinctive regional high amplitude horizon that could represent the Top Cretaceous Mejillones Complex (Figure 1).

DISTINCTIVE AVO RESPONSES

Evaluating amplitude differences between the offset stacks using common AVO techniques such as the Enhanced Restricted Gradient (ERG) inferences can be made regarding the hydrocarbon content of the reservoirs as well as locations of oil / water contacts. The ERG provides an initial interpretation of the likelihood of AVO effects and therefore the presence of hydrocarbons within a reservoir by highlighting areas where an AVO response of type II, IIp or type III is present. These response types are defined by their negative amplitude with offset features which often indicate hydrocarbons within the reservoir. CAMDI shows several areas highlighted by the ERG, such as the one shown in Figure 2.

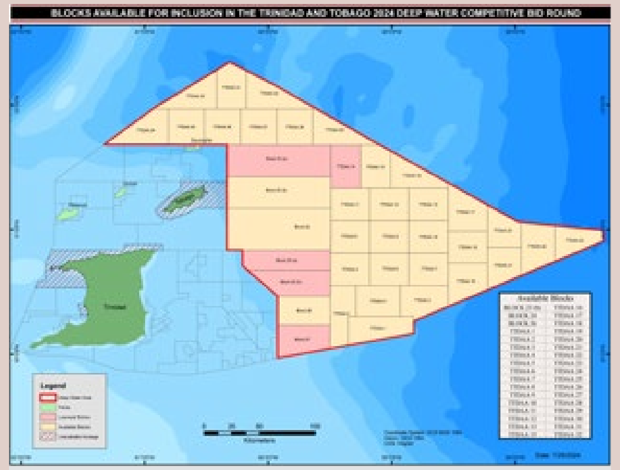


Figure 3: MEEI – Blocks to be considered for inclusion in Trinidad and Tobago's 2024 Deep Water Competitive Bid Round.

DEEPWATER COMPETITIVE BID ROUND

Trinidad and Tobago (T&T), a twin island republic located in the southernmost part of the Caribbean, has a long history in the energy industry, having been involved in hydrocarbon exploration for more than 150 years, with commercial crude oil production beginning in 1902. T&T plays a pivotal role in discovering untapped oil and gas resources, which can bolster energy security and support economic growth, and has produced over 3 billion barrels of oil to date, with natural gas production remaining stable, averaging 2.448 billion ft^3 per day over the period January to June 2024.

T&T has significant oil and gas infrastructure and with the discovery of the deepwater Calypso development fields off the east coast of T&T, consisting of Bongos, Bele, Tuk, Hi-hat and Boom, there is an expected peak rate of production of 800 million ft^3 of gas per day from these fields.

T&T remains an oil and gas province, with proven petroleum systems, high in prospectivity and unlocked potential. With the global demand for energy continuing to rise, there is a need to ensure a stable and reliable supply of traditional hydrocarbons during this transitional period.

ANNOUNCEMENT

The Ministry of Energy and Energy Industries of Trinidad and Tobago will launch its 2024 Deepwater Competitive Bid Round by the end of 2024 and it is expected to remain open for a period of six months. All of the open deepwater blocks, as identified in the map in Figure 3, will be considered for possible inclusion in the bid round. The bids received will be evaluated by a Technical Evaluation Committee, after which successful bidders and the award of blocks will be announced; this evaluation process is expected to be completed within four months.

FISCAL AND TECHNICAL TERMS

The Government of Trinidad and Tobago has a series of attractive fiscal and technical terms to excite participation in its bid rounds, such as:

- An exploration period of 9 years;
- Fiscal terms, such as 12.5 % royalty to be paid by the Minister, adjustment of price classes and production tiers based on the current economic climate, cost recovery up to 80 % etc.

The Ministry is currently reviewing these and other fiscal and technical terms to determine their inclusion in the 2024 Deep Water Competitive Bid Round, such as the facilitation of Multi-Client acquisition and / or data licensing to fulfill work commitments.

OIL & GAS

"Even without other issues on the radar, a very real question is why would you explore for stuff that for CAPEX & OPEX costs will be $30 / boe and more, never mind finding cost, when more than enough is dotted around a score or so countries that can do it for $25 / boe or less from stuff already found?"

Dave Waters - Paetoro Consulting

Imagine – heating your house using gas produced by 1.3 billion-year-old blue-green algae

Gas from the Beetaloo Basin in Australia is special – it is sourced by primitive forms of organic matter that make up the oldest petroleum system in the world. Now, the basin may be on the cusp of gas being produced

COMPARED to gas from the Beetaloo Basin, shale gas from the US is just a teenager, with the age of the Pennsylvanian source rocks hovering around 350 million years. The Beetaloo cyanobacteria – blue-green algae – are about four times older than that. It boggles the mind when one realises that gas generated from the Beetaloo Basin may in fact soon be used to provide energy to sustain our modern way of living.

Producing shale gas from the Beetaloo Basin has been on the radar for quite a while, but the remote location of the basin in the north of Australia has struggled to attract the investment needed to develop its resources. But some companies have not given up. For instance, Tamboran recently issued an announcement stating that its development plan was awarded Major Project Status by the Northern Territory Government.

Some are less convinced of the future of the basin: The Institute of Energy Economics and Financial Analysis recently published an article casting doubt on hopes that the basin may become a shale gas hot spot, mainly because it would not be able to compete with cheaper LNG produced elsewhere.

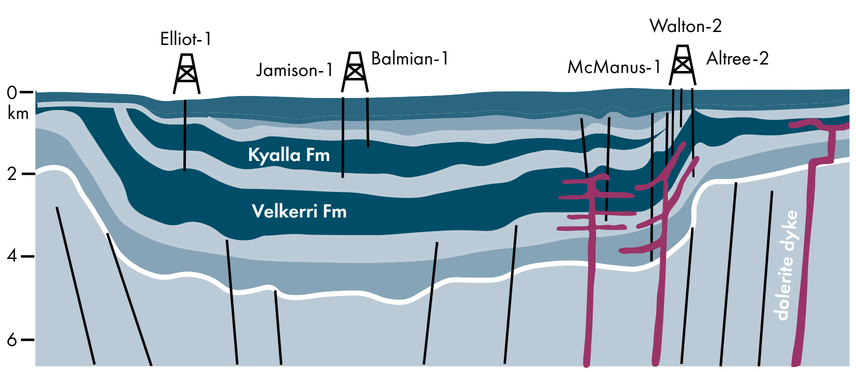
Yet, as Rhodri Johns – a geologist who performs economic analyses of hydrocarbon projects in Australia – told me at a conference the other day: "I am keen to know who has ever made a correct prediction on the way shale gas investments turned out."

A NEW WAY TO DETERMINE SOURCE ROCK MATURITY

So, there seems to be momentum behind the basin, and if only from a geological point of view, it is interesting to be aware of. For instance, the classic Vitrinite Reflectance methodology to measure the maturity of the source rock does not work in this basin, as vitrinite did not exist at the time. Therefore, as Mohinudeen Faiz and co-authors write in a recently published paper in the journal Organic Geochemistry: "No well-defined method exists to accurately assess thermal maturity nor define their hydrocarbon generation windows in source rocks of this age." Instead, the authors defined a new reflectance methodology using algae instead: alginate reflectance (Ra).

Their organic petrographic and geochemical analyses indicate that alginite reflectance (Ra) increases with thermal maturity, showing consistent relationships with depth, atomic H/C of kerogen and aromatic molecular ratios of extractable organic matter in the shales. "These findings represent a refinement of the existing source rock maturity evaluation methods for the Beetaloo Sub-basin and serve as a guide for assessing other Precambrian petroleum systems worldwide", the authors conclude in their paper. ■

Henk Kombrink



Cross-section showing the two main candidates for shale gas production in the Beetaloo Basin, the Kyalla and Velkerri Formations.

CROSS-SECTION SOURCED FROM: YANG ET AL. (2019)

Another gas discovery confirmed in Colombia, but the real excitement has yet to start

With Petrobras announcing a successful appraisal well on the Uchuva discovery, another gas find is confirmed. Now it is waiting for the world's deepest water well to be spudded a little further north later this year – Komodo

Key wells drilled offshore Colombia. The outline of the thermogenic play is based on work from Luis Carlos Carvajal-Arenas and co-authors, as published in GEO EXPRO Issue No. 2 2024.

"YOU WILL BE hard-pressed not to find gas out there", was Joshua Turner's response to the news of Petrobras' reported success drilling the Uchuva-2 appraisal well. The area where the well was drilled is known as a biogenic gas province, which probably explains his comment. The well was not drilled too far from the first offshore gas discovery made in Colombia – Chuchupa-1, completed in 1979, which opened the biogenic gas play for the country.

In that sense, the statement from Petrobras that the well is "in line with the company's long-term strategy, aimed at replenishing oil and gas reserves through the exploration of new frontiers" is maybe a little far-fetched, as it is unlikely testing an entirely new play.

The real frontier well has yet to be spudded, and that is the record-breaking Komodo-1 exploration well in approximately 3,950 m of water. And in contrast to the biogenic gas play that is characteristic for the "shallower" shelf, Komodo will be drilled in an area without any legacy well control. However (Issue No. 2 2024), as Luis Carlos Carvajal-Arenas and co-authors pointed out in a recent article, the prospect is characterised by a double flat spot and a class 3-AVO anomaly which is conformable with structure, so there are some positive indications for the presence of hydrocarbons.

What type of hydrocarbons will be found though is a matter of debate. Again pointed out by Luis Carlos in his article, recent findings at the Orca and Orca-Norte wells may point to the presence of a thermogenic petroleum system in the area as well. He writes that in an interview, top-executives at Ecopetrol stated that the Orca Norte-1 well is a gas discovery with a different composition than what was found at Orca-1. More importantly, it was confirmed that the Orca well not only encountered gas, but also instances of heavy oils and crude oils.

This follows on from more indications for the presence of a thermogenic petroleum system as suggested by piston core studies, oil slicks and condensate fluids derived from early production from the Chuchupa well amongst others.

Taking this all into account, the authors included all previous observations and proposed a thermogenic hydrocarbon system for the Colombian Basin with mature Cretaceous (?) source rocks. Let the Komodo well begin. ■

Henk Kombrink

A SHORTFALL

"There is optimism over the potential of Colombia's Caribbean Sea", writes Welligence in their LinkedIn post about the Uchuva-2 well when it was spudded. "It's a long-term opportunity - the country is facing near-to-medium term supply shortfalls that have already led to increased LNG imports", the upstream industry intelligence company wrote.

Why political endorsement of the oil and gas industry won't bring back the majors straight away

And geoscientists play a key role in communicating this to decisionmakers

It is too easy to think that a policy reversal in favour of oil and gas exploration such as the one that was recently announced for New Zealand will immediately result in the comeback of explorers.

In 2018, Jacinda Adern's coalition announced a ban on offshore oil and gas exploration in response to the desire to shift away from fossil fuel production. However, the country has seen itself struggling with the increased risk of blackouts as the system relies more and more on intermittent wind and solar energy. The new and more centre-right government has now made the call to re-open the door for drilling, despite the fact that this is still subject to parliamentary approval.

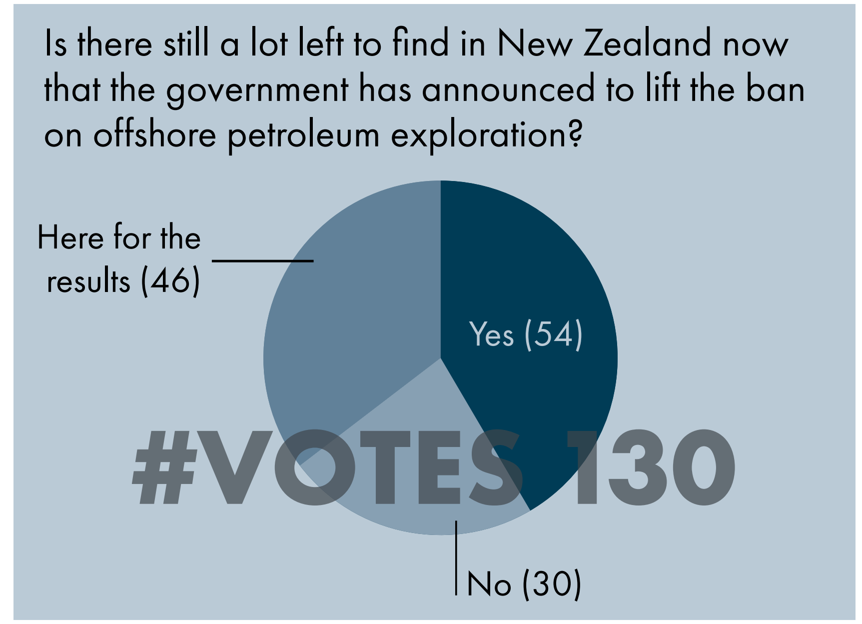
But how effective will this be? Based on a poll, in which we asked our followers if they believe that New Zealand is a place with exploration potential, it can be inferred that the picture is more complicated than some politicians want it to be.

NOT EVEN WORTH GOING BACK INTO

First of all, 23 % of the 130 respondents think that New Zealand's offshore does not even hold prospective resources anymore. Opening up for exploration may therefore not result in commercial find.

Still, 40 % of respondents do think that exploration will result in the discovery of valuable resources. Still a majority. But is this enough for the country to turn on the taps tomorrow?

Compare this map to an infrastructure map of the North Sea or the Gulf of Mexico: New Zealand barely has offshore pipelines, except the ones connecting the Maui and Kupe fields. It is therefore easy to see how almost any offshore discovery in New Zealand waters will need new infrastructure constructed, requiring high upfront investments.



"Even without other issues on the radar, a very real question is why would you explore for stuff that for CAPEX & OPEX costs will be $30 / boe and more, never mind finding cost, when more than enough is dotted around a score or so countries that can do it for $25 / boe or less from stuff already found?" –

Dave Waters, Paetoro Consulting

According to some conversations I had, and the comments provided at the post, even in the case of a discovery it is still very much the question if any of these potential future discoveries can in fact be capitalized. The problem is two-fold.

DISTANCE AND CONFIDENCE

Even if a discovery is being made, the question then becomes how to get it to market. The infrastructure for this is simply lacking in most parts of New Zealand, and one isolated find will therefore require to be of significant size in order to meet the economic threshold to make it.

The second aspect is political. Even though the political wind may now be in favour of exploration, what will the status be after the next general election? This is all far from certain. Energy companies will be much more reluctant to make a decision to enter a country when political winds can change with every individual election. The timeline required for finding and developing hydrocarbon resources is just way longer than one electoral cycle.

Based on these observations, it seems unrealistic when the New Zealand government expects a big upturn in the market as a result of changes in legislation. The industry needs much more to come back. A long-term view on oil and gas exploration and development is thereby paramount. Geoscientists can help convey that narrative, as they are aware of the uncertainties with regards to what is there, and the length of time that is often involved from discovery to first oil. ■

Henk Kombrink

FEATURES

"... people tend to forget that there is a significant geoscience component to well decommissioning"

Ruth Thomas - Well-Safe Solutions

Integration of structural and stratigraphic data using automated workflows

An example from the Exmouth Sub-Basin, offshore Western Australia

HUSSEIN ABDALLAH, SVEN PHILIT, AND NICOLAS DAYNAC, ELIIS

Geoscientists rely on their pattern recognition ability every day, comparing already known sedimentary and structural fabrics with new ones when diving into new datasets. However, with the increase in size and availability of seismic surveys, it also becomes more important for interpreters to rely more on automated tools and artificial intelligence to ease the burden and shorten E&P workflows. Here, we discuss how new AI fault extraction algorithms, sophisticated automatic facies classification techniques and a new simplified workflow to create watertight zero-offset horizons can be integrated into an advanced seismic interpretation workflow.

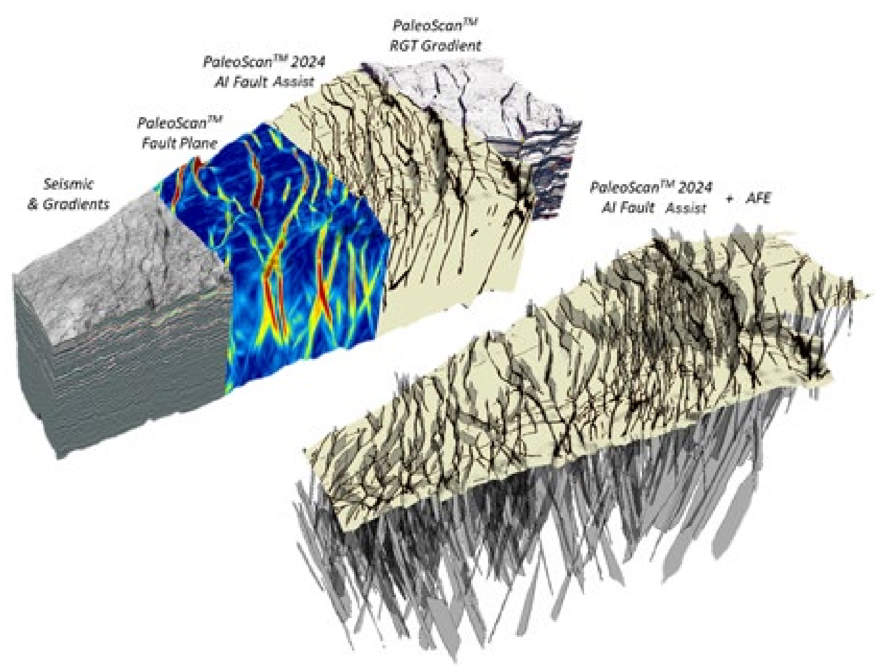


Figure 1: Mosaique of PaleoScanTM Fault Plane attribute, AI Fault Assist and RGT Gradient volumes on the Exmouth Seismic cube, and subsequent extracted fault network.

EXMOUTH SUB-BASIN

A case study was conducted in the Exmouth sub-basin, part of the Carnarvon Basin, which is situated 20 km offshore Western Australia. We used the Exmouth seismic block complemented by artificial well trajectories and empirically picked well tops for the purpose of the demonstration of our method. The seismic survey comprises a dense and complex fault network resulting from an extensional phase lasting from the latest Triassic to the Early Cretaceous. Hundreds of faults are visible in the seismic volume, striking mostly North-Northeast and extending over Triassic, Jurassic, and Lower Cretaceous intervals. The Upper Jurassic play of the Exmouth sub-basin includes two separate turbidite systems marked by erosive channels. These turbidite systems contain reservoir-grade sandstones and may be prospective in structural or stratigraphic traps.

AI-DRIVEN FAULT EXTRACTION

The new AI-powered algorithm was applied to accurately and swiftly characterize the entirety of the North-Northeast striking faults of the Triassic, Jurassic, and Lower Cretaceous intervals to create an AI fault probability volume. The created AI fault probability volume accurately captures the faults visible in the seismic volume and, in comparison, matches with the fault signal derived by a standard vector field algorithm (Figure 1).

The resulting fault probability volume is displayed in binary values, with 1 representing the highest fault probability. To extract faults, this volume is then smoothed with a Gaussian function to retain only the maximum pixel value along the steepest gradient direction within a specific window size in time-slice. This latest step allows the production of a 'skeleton' made of only the fault probability extrema. The faults are finally extracted and filtered in the dip-azimuth filter to obtain the final QC'd fault set. This final fault set can then be used to constrain the subsequent stratigraphic interpretation and geo-modeling processes and can be integrated with key horizons to facilitate structural interpretation at the reservoir level.

AI FAULT ASSIST

The 'AI Fault Assist' algorithm relies on a 3D deep learning neural network designed to detect fault probability. The model was trained on very large synthetic and labeled datasets representative of a diverse mix of geological settings. The synthetic training data incorporates seismic volumes of different frequencies, signal-to-noise ratios, and distinct fault types (normal, reverse, and transform) with distinct fault characteristics.

HONOURING WELL-TOPS AND FAULT NETWORK

Now, we continue the workflow that will ultimately produce a clean fault-horizon intersection network while also respecting stratigraphic well tops. We rely on a dynamic horizon edition toolset to adjust the horizon's lateral resolution, apply zero-offset fits between the horizon and well tops, and accurately align the horizon with the 3D faults to make it watertight. The workflow ideally derives data from chrono-stratigraphic stratal slices extracted from the Relative Geological Time (RGT) model.

In the first step of this workflow, the RGT model is used as input to extract the closest surface to a specified set of well tops via minimization methods, offering the smallest vertical mistie between a well top series and a value of the model. In the case of this study, we extract the nearest surface from the 'Top Reservoir' top from our RGT model, corresponding to the stratigraphic level containing the Upper Jurassic turbiditic system.

As a second step, the lateral resolution of the horizon is homogenized to 50 meters in the In-line and X-line directions since the Exmouth sub-basin survey resolution is laterally anisotropic.

The third step involves fitting the horizon to the 'Top Reservoir' top: zero-offset horizon flexing is conducted by calculating the vertical offset between the horizon and the tops at well locations and then interpolating the values using the inverse distance method. The fit of the horizon with the well tops can either be local if a radius distance is specified for the interpolation, or global and interpolated over the whole survey. In this example, a global fit is preferred. Once the values are interpolated, horizon flexing can be initiated to eliminate the interpolated mistie by vertically shifting the horizon (Figure 2).

The final step of this workflow consists of fitting the flexed horizon with the available 3D faults extracted from the AI Fault Assist algorithm. The horizon is accurately fitted with the edges of the 3D faults of the Exmouth sub-basin survey. The alignment is achieved by vectorizing the horizon and creating triangulated surfaces adjacent to the faults to allow the horizon to fit the faults perfectly.

When supported with relevant attribute mappings, this approach provides a more robust interpretation, facilitating subsequent decision-making (Figure 3).

NOT LIMITED TO AMPLITUDE ONLY

We use the Kohonen self-organized map unsupervised automatic classification technique. The originality of our approach is that it is not limited to the amplitude of the trace to perform the classification but can also exploit its phase, frequency, sweetness, or envelope.

In this case study, the filter was retained on a vertical size of 7 samples, centered on the horizon, to extract 4 classes that are relevant to the intended geological target. In addition, the extent of the classification is limited to a restricted AOI to enhance the relevance of the discretization of the classes, thus revealing facies distribution and heterogeneity more precisely. A post-classification Gaussian smoothing is finally applied to enhance map quality.

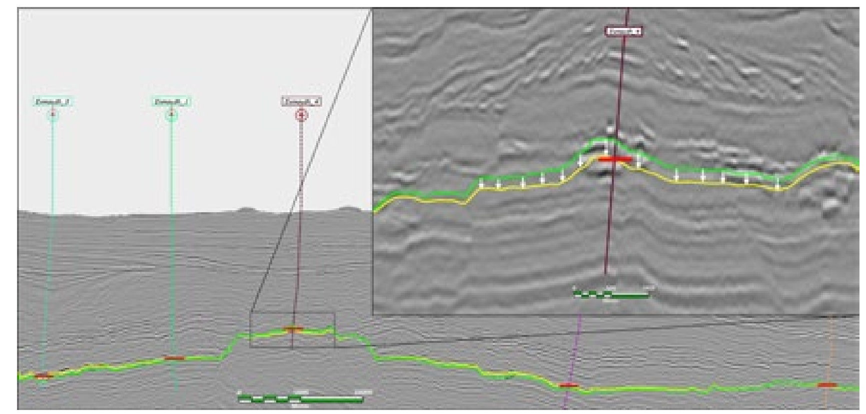


Figure 2: Horizon flexing induced to eliminate the horizon's mistie with the 'Top Reservoir' well tops. The image displays the intersection of the original (green) and flexed (yellow) horizons along a 2D seismic line between wells. The flexed horizon is stratigraphically more accurate and can be used for further assessment and development projects with higher confidence.

WAVEFORM CLASSIFICATION

Waveform Classification is an automatic pattern recognition technique applied to seismic data to group similar traces together in distinct classes. If the seismic signature or processing quality is good, the classification can be efficiently used to reveal variations in lithology, fluid content, or reservoir limits.

Figure 3 displays a comparison of mapping the target channel using a simple seismic amplitude and a ►

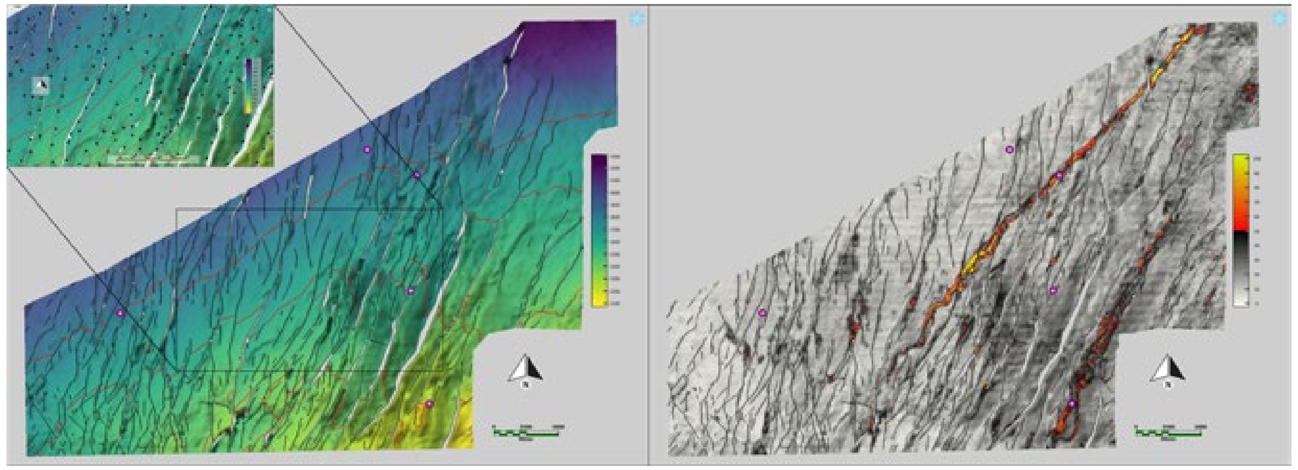


Figure 3: The target 'Top Reservoir' horizon after having been fitted to the Exmouth fault network. (Left): Structural and topographic map. (Right): Amplitude Anomaly map using the RMS Amplitude to highlight two separate turbidite systems.

waveform classification. The comparison shows that the signature of the channel is revealed with more detail when applying waveform classification: Many heterogeneities are distinguished in the channel and could be interpreted as different facies of the channel, and/or subsequent sequences of deposition of a turbidite system.

In our example, since the two channels are classified in one operation, we can correlate facies characteristics of the same class between the two channels: If for instance a well crosses the green class in one of the two turbidite systems and strikes a hydrocarbon reservoir with a certain fluid saturation and granulometry, similar properties could be inferred in the green class zone in the other channel.

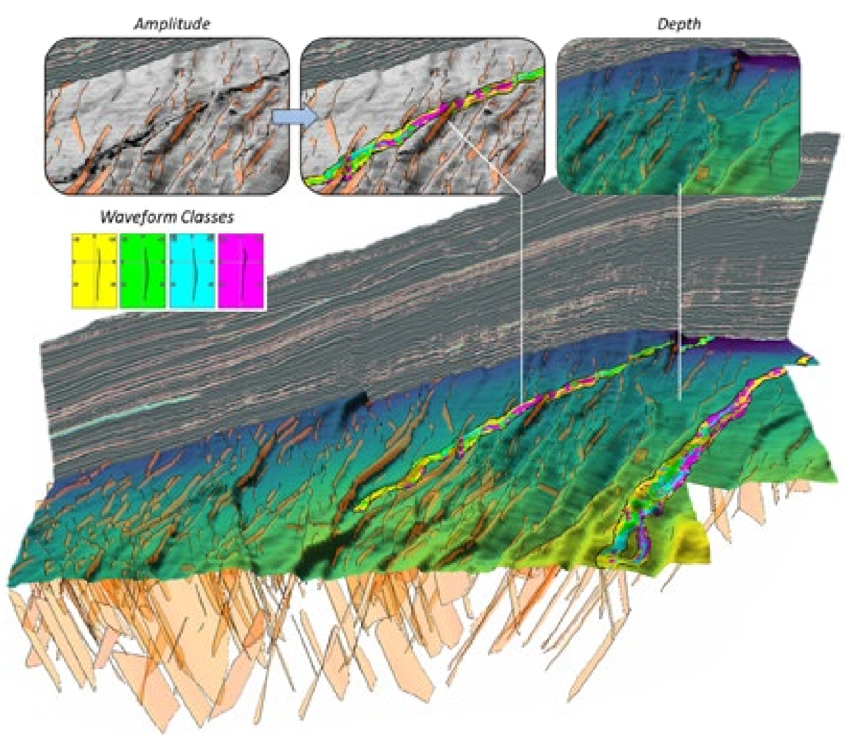


Figure 4: Waveform Classification of the late Jurassic Turbidite systems and the topographic map corresponding to the 'Top Reservoir' horizon. 4 classes were used to classify within the borders of the turbidite system while applying the envelope filter, thereby facilitating facies distinction according to the seismic amplitude.

AN ADVANCED INTERPRETATION WORKFLOW BASED ON AUTOMATION

The presented study showcases the immense benefits of integrating automated tools into advanced interpretation workflows to optimize results while shortening E&P workflows. The AI Fault Assist algorithm provides a reliable fault extraction method that reduces the time needed for structural interpretation while yielding consistent results. Using an original dynamic edition toolset, horizons can be fitted to well tops eliminating their vertical offset. This toolset uses extracted faults by the AI Fault Assist to create vectorized watertight horizons on the fly. These watertight horizons facilitate decision-making by combining structural and attribute data.

To complement these results, using the automated waveform classification, allows us to go a step further towards reservoir characterization. Finally, these tools and the presented advanced workflow serve as an example of numerous other workflows relying on automation.

ACKNOWLEDGMENT

The authors would like to thank Geoscience Australia for their permission to use the Exmouth seismic data of block HCA2000A. ■

What can resistivity tell you about your prospect?

Resistivity measurements can provide information about reservoir parameters that can not be extracted from seismic. In this article, we provide the reasoning behind this assertion and discuss what information can be extracted from resistivity and how these can be used to impact exploration performance

DANIEL BALTAR, EMGS

Over the last few years, significant advancements have been made in the field of seismic quality, fundamentally transforming the landscape of geological exploration. The increase in bandwidth coupled with improved migration and inversion algorithms has provided interpreters with unprecedented detail, enabling a more nuanced understanding of subsurface structures. However, despite these technological advancements, exploration success rates have remained relatively stagnant. The primary reason for this is that the key uncertainties in prospectivity evaluation, whether at play or at prospect scale, are not resolvable through increased understanding of seismic properties and detail only.

The primary challenge lies in the link between the properties being measured by seismic data and the existing geological uncertainties. While seismic data excels in revealing variations in compressional and shear wave velocities, which are influenced predominantly by lithology and porosity contrasts, it falls short in areas where permeability and fluid contact location or saturation calculations are critical. Permeability, the ability of the rock to transmit fluids, and the precise location of hydrocarbon-water contacts are essential factors in the determination of the viability of a reservoir as an economic producing field. This is particularly true offshore, where high operating costs make flow rate a key economic factor. Flow rate is itself heavily driven by permeability and pressure. Seismic data, despite its increased detail, cannot directly resolve these aspects because the parameters being measured, elastic properties and density, are not primarily influenced by factors such as permeability, column height, pressure or saturation.

INFERRING PERMEABILITY

In contrast, resistivity measurements provide valuable insights into these critical areas. Resistivity is mainly driven by the amount of water present in the sediment, with low resistivity indicating high water content and high resistivity indicating low water content. The amount of water in the sediment if hydrocarbons are present is intrinsically linked to the reservoir's permeability and pressure. The amount of water removed from the sediment and, hence, the amount of hydrocarbon filling it, directly correlates to the difference in pressure existing between the different fluids present and the permeability that allows the movement of those fluids. The ability to detect changes in resistivity allows geologists to infer variations in total water content and, by direct extension, the permeability and pressure in the reservoir.

LOCATING HYDROCARBON-WATER CONTACTS

Moreover, resistivity is a powerful tool for locating hydrocarbon-water contacts. Hydrocarbons and water have distinctly different resistivity values, so by mapping lateral changes in resistivity within the same formation, geologists can identify the boundaries between these fluids. This capability is crucial for improving the understanding of a reservoir's extent, its pressure, and permeability before drilling. This can significantly improve exploration performance, by allowing the identification of low potential targets and altering the drilling sequence, favoring higher potential, in terms of the volume and flow rate, targets to be drilled early in the sequence.

A MORE COMPREHENSIVE UNDERSTANDING

To achieve a substantial improvement in exploration success rates, integrating resistivity data derived from Controlled Source Electromagnetic (CSEM) surveys offers a promising solution. CSEM technology involves generating an electromagnetic field at the surface and measuring the response due to the propagation of that field through the subsurface. This response is sensitive to variations in resistivity, that can be assessed through imaging methods equivalent to seismic full waveform inversion. By combining seismic and CSEM data, geologists can achieve a more comprehensive understanding of subsurface's prospective potential, addressing the limitations of each method when used in isolation.

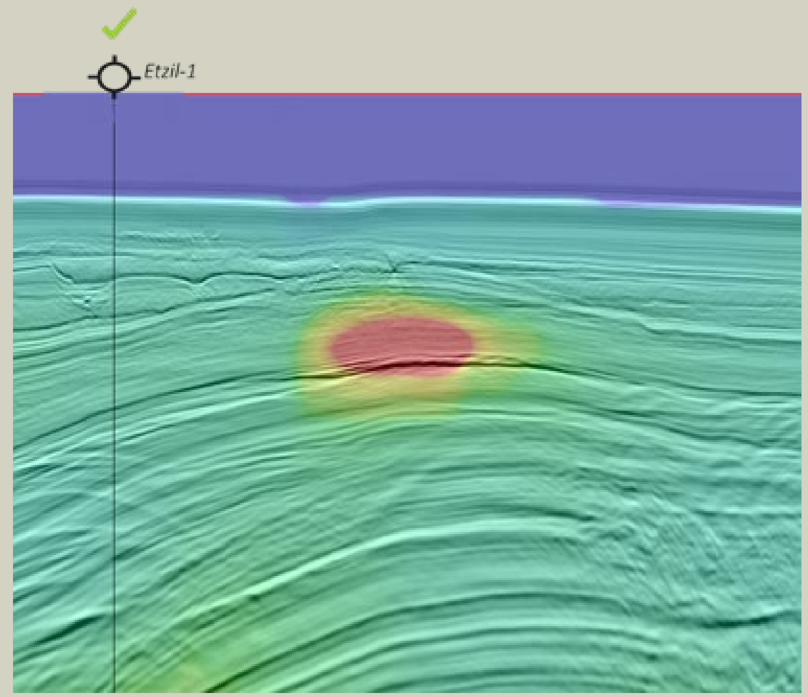
The effective deployment of CSEM technology needs to be carefully planned and executed to maximize its impact. It requires inclusion in the exploration work program from the outset, making sure it is deployed in a timely manner and at the right scale, so that results are available to the team when decisions are made, and that enough data is available to impact all potential opportunities. Another key factor is to ensure that the right personnel and resources are available to carry out a fully integrated evaluation of the prospectivity. This includes geophysicists who specialize in CSEM data interpretation, as well as experts in seismic data, and geologists, to collaboratively analyze and integrate the datasets in a common geological model. The success of this approach hinges on the seamless integration of seismic and CSEM data, allowing for a more holistic assessment of the subsurface.

THE RECIPE FOR GREATER EXPLORATION SUCCESS

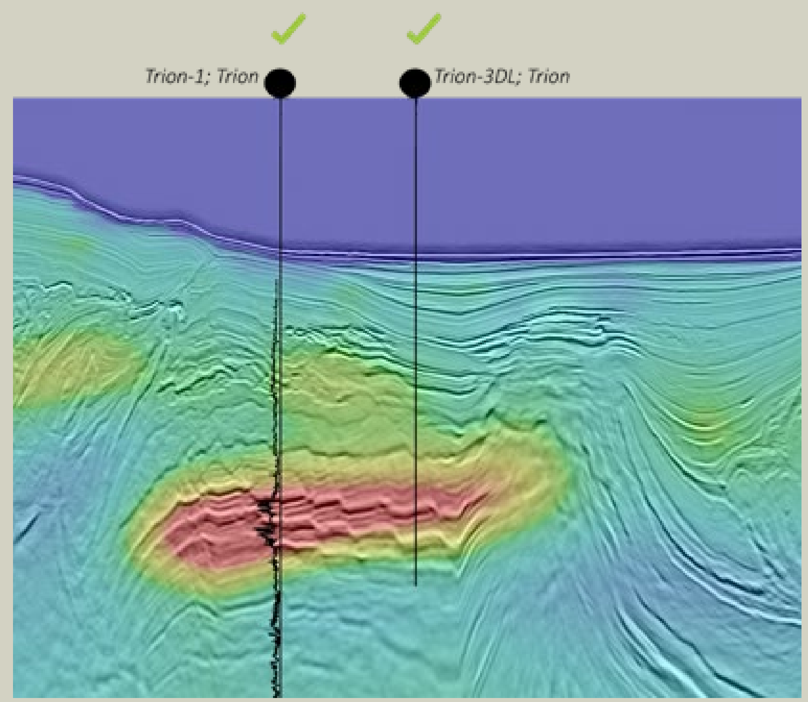
While seismic advancements have greatly enhanced the detail available to interpreters, they have not significantly improved exploration success rates due to inherent limitations in addressing key geological uncertainties. Resistivity measurements derived from CSEM technology offer a valuable complementary tool by providing insights into reservoir permeability, pressure and fluid contact placement. To realize this step change in exploration success, it is essential to incorporate CSEM into the exploration workflow, supported by a team of specialists who can deliver an integrated evaluation of the existing prospects. By doing so, the industry can better address the challenges of exploration and improve the likelihood of discovering economically viable hydrocarbon reservoirs. ■

THE PROOF IS IN THE PUDDING

The Etzil and Trion wells offshore Mexico prove the point that resistivity can help identify hydrocarbon contact location through the lateral changes in resistivity. In the Trion case, a large hydrocarbon column was proven through drilling, while in Etzil's case the drilling proved the absence of a hydrocarbon-water contact at the well location as could be interpreted by the absence of a lateral change in resistivity.



Section with seismic and CSEM on the Etzil prospect offshore Mexico.



Section with seismic and CSEM on the Trion field offshore Mexico.

SOURCE: EMGS

The geoscience of decommissioning

"At a pivotal moment in my career, around 7 years ago, I decided that my future lay in decommissioning", said Ruth Thomas when we met at her office in Aberdeen. "So, I embarked on my second masters degree from The University of Aberdeen, which was purely dedicated to decommissioning."

"LET'S NOT TRY to sugarcoat it, it wasn't always easy", she continues. "The pandemic unfolded, and taking care of homeschooling, a full-time job and completing the university modules on the side was a challenge."

But it paid off.

Ruth is now the Subsurface Manager at Well-Safe Solutions, a company that is a key player in the decommissioning space in the North Sea and beyond.

She knows what it is to drill a well. Ruth spent more than 20 years in the upstream E&P business with CNR, Apache, Talisman and Repsol Sinopec. The heydays were her first years with Talisman (2007 - 2009), when the exploration team still consisted of around 35 people and exciting discoveries were being made.

...people tend to forget that there is a significant geoscience component to well decommissioning

But times have changed. Drilling, especially exploration drilling, is a rarity across the UK Continental Shelf. Instead, rigs are now increasingly being used for plugging and abandoning wells which have ceased production.

A LOGICAL MOVE

Ruth's decision to move into decommissioning therefore looks like a very logical one. "Yet, people are not queuing up to work in this sector", she says. "It is not yet considered to be the career of choice, as the industry is working to do more to appeal to the next generation – who often have to contend with conflicting narratives about the future of the energy sector both at home and abroad."

"However, people tend to forget that there is a significant geoscience component to well decommissioning", Ruth continues. "And not only to tick some boxes like "this sand is not hydrocarbon bearing", but to an extent that geoscience can help shave millions off the well abandonment bill.

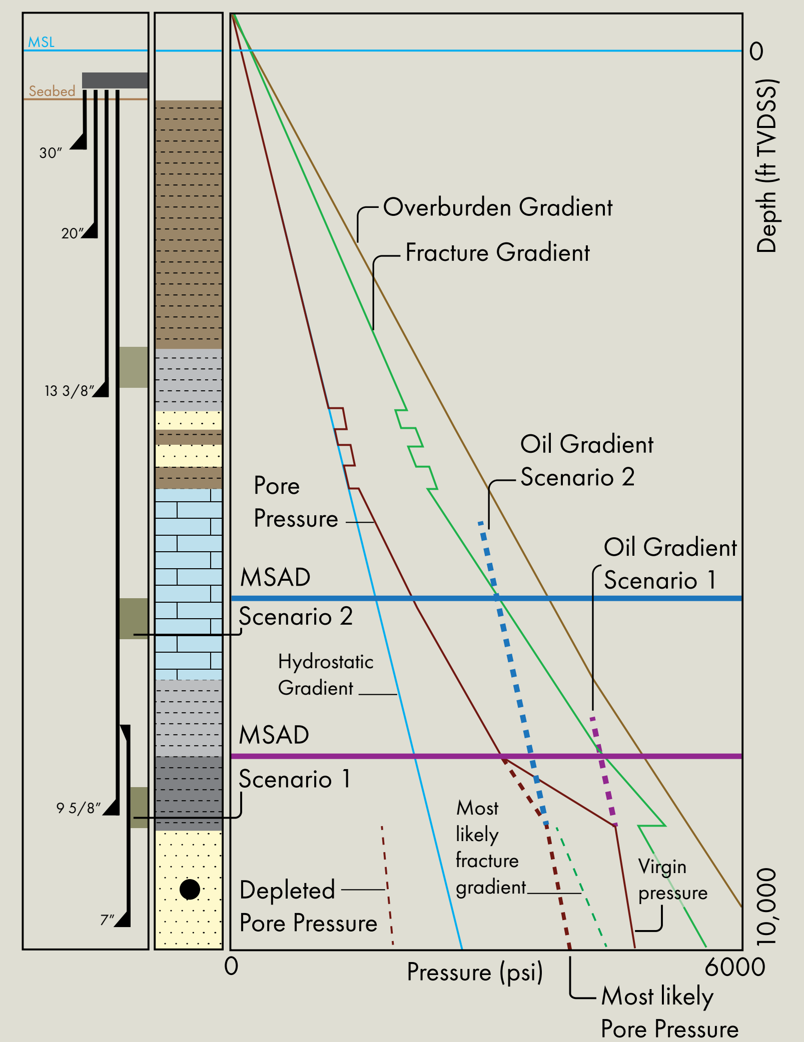
How? "The key thing in decommissioning is not just the isolation of the hydrocarbon-bearing reservoir", explains Ruth. "That is a given. But rather, the million-dollar question may be where to place abandonment plugs to maximize their efficacy for isolating the entire geological system, overburden and reservoir. Often, drillers and management will always advocate for a plug to be set as deep as possible", Ruth says, "but going deeper without due cause can be challenging, inducing higher costs and more uncertainties regarding unforeseen integrity issues."

WHERE GEOSCIENCE COMES INTO PLAY

A key element of the subsurface basis of design for abandonment workflow is to ensure that plugs are set below the crossing of the hydrocarbon pressure gradient with the fracture gradient, Ruth explains. This depth is known as the "minimum safe abandonment depth" and setting plugs beneath this depth is designed to prevent fracturing of the overburden upon recharge of the reservoir". And this is where geoscience comes into play. "Let's say that the pressure in a reservoir drops from 250 bar to 175 bar during the production lifetime", she continues. "The most conservative estimate in that instance is to assume that the reservoir pressure will return to the same level as it was found in when the first exploration well was drilled (virgin pressure). That assumption is of course safe, but the implication is that in some cases, especially where the reservoir was highly overpressured when it was first discovered, the depth window into which to set the reservoir-isolating plug is quite narrow and very deep at the same time", she says.

RACE TO THE RESERVOIR

"The start of any well abandonment project is a meticulous analysis of all the subsurface and well engineering data, including log and seismic data, drilling, completion and intervention history and integrity status", Ruth explains. "Gleaning a complete picture is often hindered by the simple fact that many wells were drilled under the "race to the reservoir" concept, which means that log data coverage and information can be limited, particularly along the overburden section of the well", she says. "In that case, we resort to using information from offset wells, and the drawing of a plumbing diagram to ensure both vertical and lateral containment can be achieved through an optimized isolation strategy. That is where the value from the subsurface is realised".



Example of an abandonment study that resulted in the safe assumption of a lower recharge pressure, with the implication that the Minimum Safe Abandonment Depth (MSAD) could be set at a shallower interval in the well. The assumed return to virgin pressure is unduly conservative (Scenario 1) and is only the assumption where modelling has not demonstrated otherwise. However, it is a common assumption because operators tend not to place any importance on modelling for decommissioning and also put in place multiple layers of conservatism. This is fine where it has almost no impact on the well abandonment strategy / MSAD – but in this instance, it has a major impact on the complexity of the operations because the calculated MSAD is so deep. Hence, a re-modelling exercise was performed using regional mapping and MBAL to calculate the connected zonal volumes and therefore likely recharge potential. This resulted in a significant reduction in expected recharge pressure (Scenario 2), with a significant impact to the abandonment complexity, operational time and therefore cost.

FIGURE REDRAFTED AFTER: WELL-SAFE SOLUTIONS

"Especially when it means that packers have to be milled or lower completions have to be recovered, the process can be very risky and time-consuming, and therefore costly", Ruth adds.

But what if the assumption of reservoir recharge returning to virgin pressure is not always the right one to make? What if pressure recharge can be modelled to be restricted, by a smaller connected volume, for example, such that a lower value can be assumed as the "final" pressure for the purposes of calculating the minimum safe abandonment depth? It is a valid question, and one that has serious cost implications as well. And geoscience has an important role to play here.

"In order to better understand pressure build-up following cessation of production, the building of a dynamic model of the wider geological system is recommended", says Ruth. This may be quite a significant project in itself, but if the results of such a study can make a case for lower, more realistic, ▸

Ruth Thomas at her desk in the office in Aberdeen.

PHOTOGRAPHY: HENK KOMBRINK

recharge pressures, it forms a good technical basis for subsequently placing the abandonment plugs at a higher level in the well. If that prevents costly additional operations in compromised wells, it is a win-win, and it is thanks to geoscience that these decisions can be justified."

LEAKY OVERBURDEN

"The concept of isolating formations is a very valid one", reinforces Ruth. "But that does not mean that we should assume that nothing in nature ever leaks. It is not true. Even the most effective geological seals have some inherent permeability", she says, "and I think that is an important message to get across. We can try to design wells, materials and methodologies to eradicate flow to the best of our ability, but seeps to the seabed were how we discovered hydrocarbons in the first place, and they will continue to occur long after we are gone. It is an important concept to get across to policymakers", says Ruth, "not because it legitimizes not doing a good job, but it puts into a geological perspective, the challenges we have when working in well abandonment."

Ruth's transition from the world of oil and gas production to well decommissioning shows that there is a compelling, viable route for geoscientists to carve out a future as the global energy sector pivots to a greener future.

It is this specialist knowledge which will be vital in effectively supporting the world's energy demands in a more sustainable way and enabling our net zero ambitions. ■

Henk Kombrink

Peat: So hot right now

Offshore wind requires geoscience to bring energy onshore in the most cost-effective way

"THE OFFSHORE wind sector is still very much a geotechnical exercise", I was told recently by someone with knowledge on the matter. "But that model is due an update."

Despite what we tend to hear on social media, and what industry leaders preach during panel discussions about the energy transition and the many job opportunities that will bring to new geoscience graduates, the number of geoscientists in wind development companies seems to be very limited so far. "But the thing is", the person I talked to said, "we need geoscientists to move from a reactive to proactive industry."

The planning of export cable routes from offshore wind farms to onshore connection points requires a significant level of geological input and guidance. And it is the mapping of peat and organic-rich sediments that is a critical element in that regard.

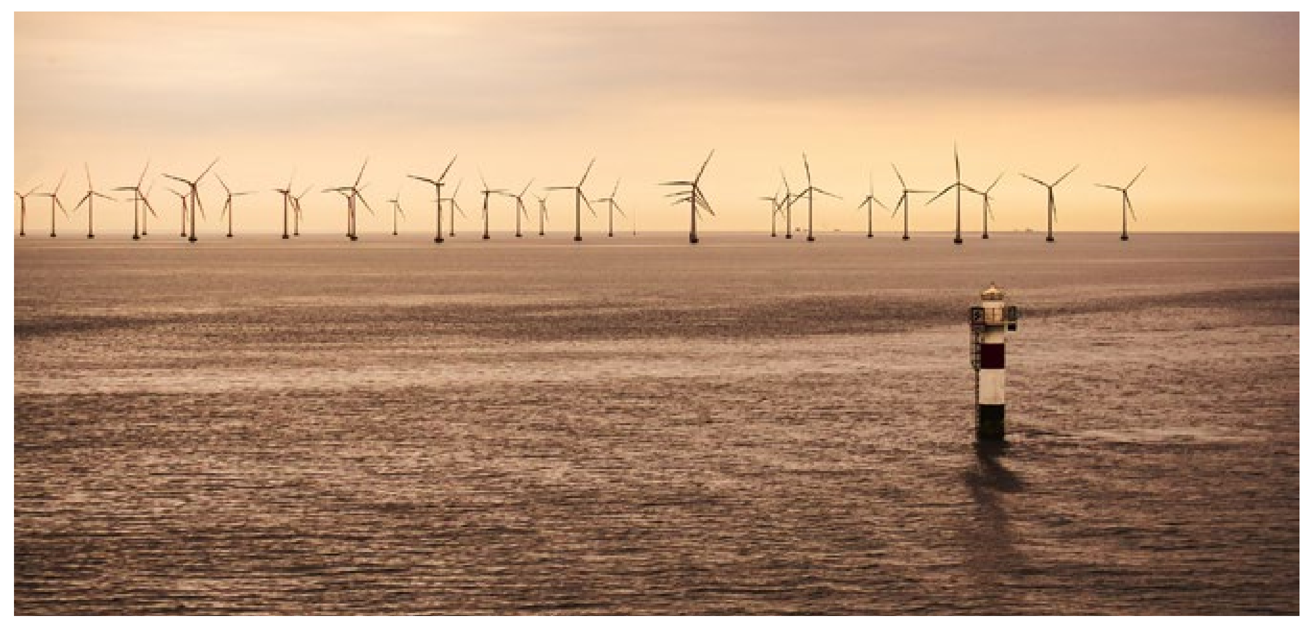
"In a way the work is almost like that of oil and gas explorationists because it requires integration of sparse 2D seismic data with limited borehole information and interpretation of regional depositional environments. In subsea cable engineering, avoiding peat and organic sediments in the subsurface is critical to export cable feasibility, route selection, engineering design cost and wind farm operation optimization. To achieve these goals, one needs to understand where peat and organic sediments can be expected in the subsurface".

WHAT IS AT STAKE?

Wind farm geoscientists are primarily interested in the last 20,000 years of geological history. Dramatic Holocene sea-level rise over the past 12,000 years, in response to glacial melting, has been a key driver in that sense – coastal systems have shifted dramatically landward as once exposed land drowned. This drowning and flooding of low-lying coastal and terrestrial areas generated many areas prone to organic sediments and peat deposition.

Organic sediments act as thermal insulators with high resistivity characteristics. Like much in the world of sedimentary geology, thermal characteristics of organic sediments vary depending on several depositionally linked variables: Organic matter content, concentration (TOC) and facies type. Organic mudstones tend to be on the lower end of the spectrum, with fibrous peat claiming the crown as king of insulation. Such organic sediments do not allow export cables to dissipate heat and can lead to curtailment of wind farm generation potential, and in the worst cases, cable failure.

In some markets, even with the most expensive engineering solution, a poor route can kill a project. Whilst upgrading of export cables can be a viable engineering solution, it also is accompanied with higher costs, particularly in new markets with immature supply chains. In most cases, operators are over-engineering export cable designs to lower risk and at ▸



PHOTOGRAPHY: PTNORBERT VIA PIXABAY

Offshore wind turbines.

Example of an "unexpected" layer of peat whilst enlarging drainage channels in the Netherlands. This occurrence is very local and limited to a channel fill, but more extensive peat layers are common in coastal areas that experienced rapid post-glacial sea-level rise.

PHOTOGRAPHY: HENK KOMBRINK

higher costs to the project. But, there is another way to de-risk this element of the project: Geoscience.

GEOSCIENCE APPLICATION

The geological solution is understanding the distribution of organic sediments and avoid them altogether, or as much as feasibly possible. This isn't rocket science, but geoscientists need to be included at the earliest planning stage to add value, and to highlight that the sediment in which an export cable is placed is important. This requires a three-stage approach; initiated by collating all public information such as core data, lithology information, academic literature, surface mapping and generating a top-down ground model.

This is followed by planning an export cable route guided by the top-down geological model. This phase is also accompanied by the minimum commitment seismic data, CPT data and geotechnical core data. Pick the wrong route, and it will significantly impact the business case as all export cable routes must obtain a minimum data tranch to meet certification requirements set by government authorities. There is also an element of seabed real estate competition as grid connection points can be limited.

Analysis of acquired data is the third step: Seismic interpretation, application of sequence stratigraphy, sedimentological analysis of core data, and integration of borehole CPT and lab thermal data to create an integrated geological model. Interpretation products include not only depth grids and isopachs maps but also depositional environment maps with associated facies.

Isolating facies to depositional environments is key to understanding and predicting organic sediment spatial distribution, types of organic content and possible thickness. Integrated 3D static geological models are highly sought by stakeholders and are a valuable communication tool. Of course, additional data acquisition may be required to further refine the geological model and meet minimum development criteria.

Furthermore, although the static model is primarily a means to better understand risk, it can also be used as the basis for CPT property modelling and thermal uncertainty modelling. By creating integrated 3D geologic models, projects can make better proactive decisions, run scenario modelling, inform engineering design and test boundary conditions of business cases.

KEY TAKEAWAYS

As described above, proactive geological modelling approaches are very similar to the type of work done in oil and gas exploration, with similar sparse dataset conditions.

Project management and leaders need to consult geoscientists at the earliest phase of export cable route planning to avoid costly mistakes, late development of alternative routes or terminal route selection. The wind industry needs to move away from "we can engineer our way around anything" to predictive geological modelling in order to optimize costs, improve operating efficiency and tackle key project risks.

Collaboration between geoscientists, geotechnical engineers and subsea cable engineers is integral to achieving an optimized export cable route. Better collaboration between all three sub-disciplines is desperately needed in the offshore wind industry, academia and across representative professional bodies and organizations. ■

Henk Kombrink

Unlocking Gulf energy: The impact of advanced seismic technologies on exploration

In the dynamic landscape of the Gulf of Mexico (GOM), advanced seismic technologies are revolutionizing oil and gas exploration. Since its introduction to the multiclient market in 2019, long-offset Ocean Bottom Node (OBN) technology has significantly enhanced imaging accuracy, transforming subsurface exploration. The Amendment 2 survey in the Mississippi Canyon protraction area, co-produced by TGS and SLB, exemplifies this impact, enabling more accurate identification of new prospects and reducing drilling risks. As exploration shifts to the geologically complex Western GOM, innovations like low-frequency source technology and Elastic Full Waveform Inversion (Elastic FWI) are poised to further enhance the subsurface images. These advancements promise not only to unlock new resources but also to ensure the GOM's continued contribution to America's energy security and economic prosperity.

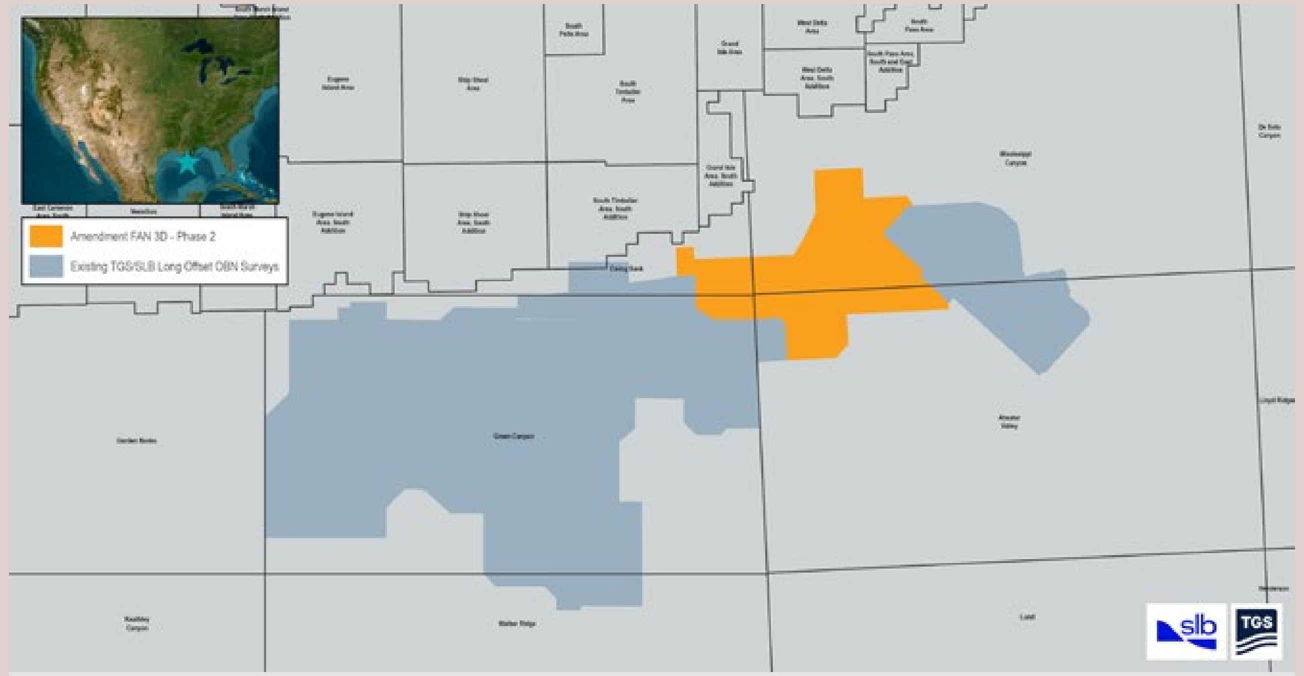


Figure 1. Amendment 2 Long-Offset OBN survey location.

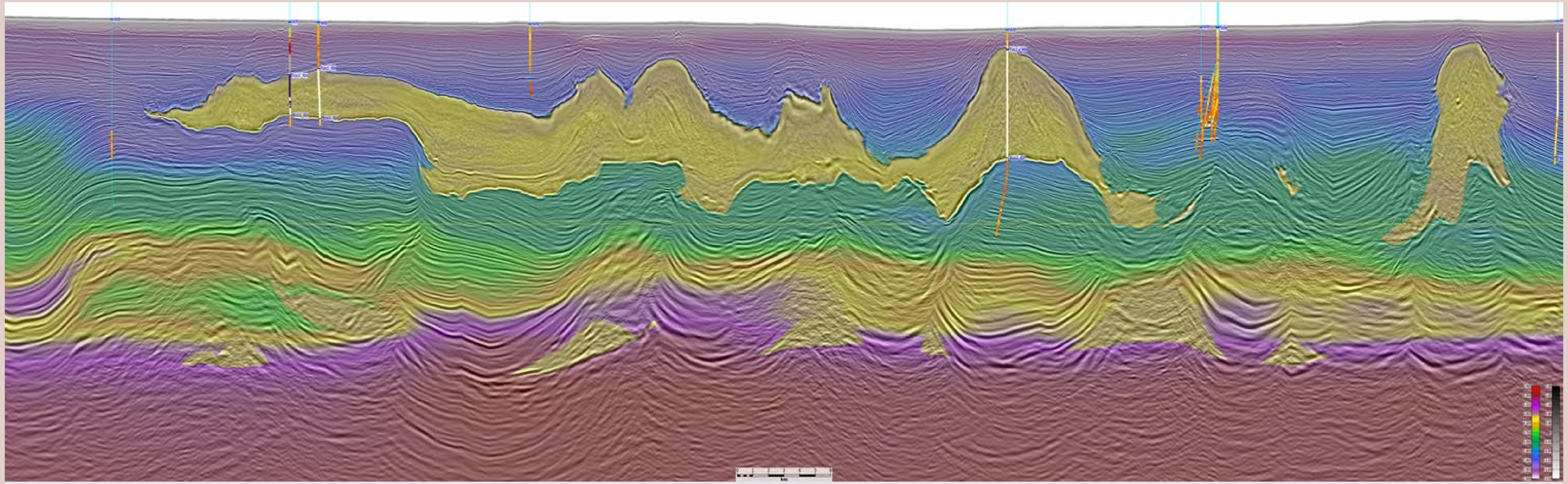


Figure 2. RTM stack. Legacy Wide Azimuth Streamer data.

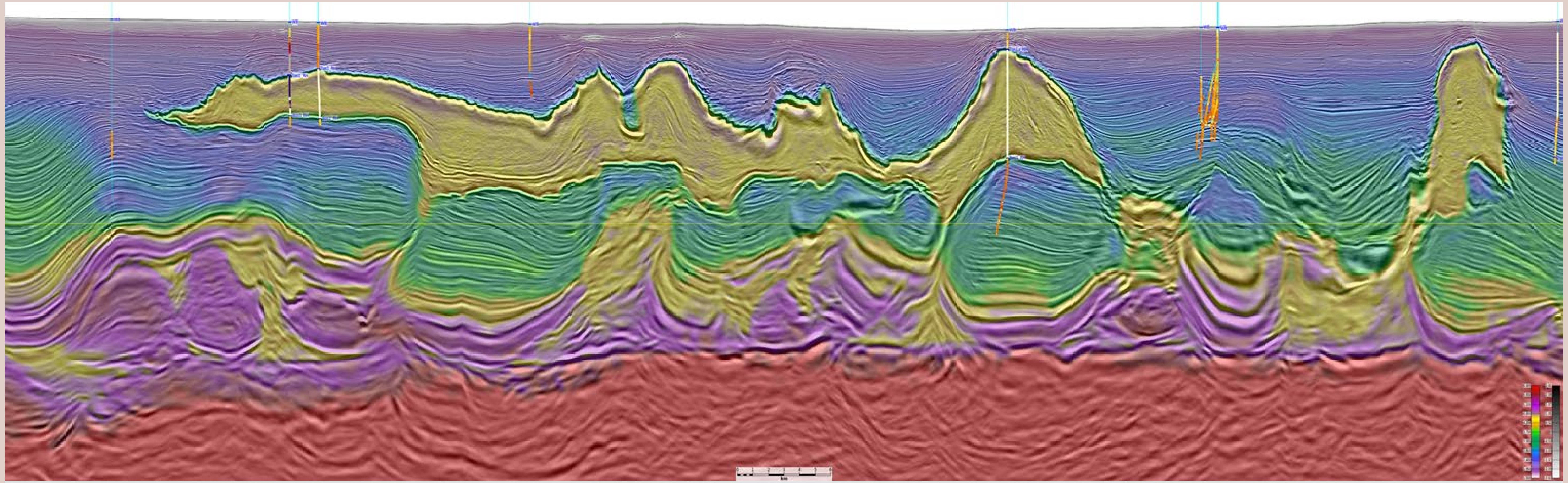


Figure 2. RTM Stack. Amendment 2 OBN plus Streamer.

Finding treasures beneath the waves: The role of advanced seismic technologies in the Gulf of Mexico

ANDREY BOGACHEV, TGS

THE GULF OF Mexico (GOM) has long been a cornerstone of America's energy landscape, providing significant oil and gas reserves. As exploration ventures into increasingly challenging areas, the need for advanced seismic technologies has never been greater. The long-offset Ocean Bottom Node (OBN) technology, introduced to the multiclient data market in 2019, has become a transformative tool in exploration and development, offering unmatched imaging accuracy and clarity. With the GOM contributing over 15 % of the United States oil production, the adoption of innovative seismic technologies like long-offset OBN will be the key to unlocking billions of dollars in untapped energy reserves.

THE POWER OF LONG-OFFSET OBN

The Amendment 2 survey (Figure 1) in the Mississippi Canyon protraction area exemplifies the transformative potential of long-offset OBN technology. This dataset, co-produced by TGS and SLB, provides a significant uplift in imaging quality (Figure 2), allowing for the identification of new prospects with greater confidence. This advanced technology is crucial for de-risking drilling activities, especially in mature basins like the GOM, where the presence of extensive salt structures poses significant challenges to subsurface imaging.

SEISMIC DATA INSIGHTS: AMENDMENT 2 SURVEY

The Amendment 2 survey data has been instrumental in guiding recent exploration efforts. For instance, during the US Gulf Lease Sale 259, companies utilized a Fast Track product derived from this high-quality seismic data to make informed bidding decisions. This underscores the critical role of accurate subsurface models in minimizing drilling risks and costs. As the industry anticipates the next bidding round in 2025, companies equipped with long-offset OBN multiclient data will be better positioned to secure the most promising exploration blocks.

THE ROLE OF LOW-FREQUENCY SOURCE TECHNOLOGY

As exploration moves toward the more geologically complex Western GOM, continuous innovation in OBN technology becomes imperative. The adoption of low-frequency source technology, such as Gemini and TPS, represents a significant advancement in seismic acquisition and imaging. The industry must embrace and integrate low-frequency source technology to maximize the value derived from long-offset OBN data.

Low-frequency sources can penetrate deeper into the earth and provide more recorded low-frequency energy compared to a conventional source. This capability is particularly valuable in areas like the Western GOM, where the extreme complexity of the subsurface creates a higher uncertainty of input models for Full Waveform Inversion (FWI). Recording lower frequencies can help FWI to converge to a true model faster and reduce the risk of using a less accurate input. By integrating low-frequency source technology into future long-offset OBN surveys, the industry can achieve even greater precision in subsurface imaging, further reducing exploration risks and costs.

ELASTIC FWI: A LEAP FORWARD IN IMAGING QUALITY

Another key innovation in seismic data processing is the use of Elastic Full Waveform Inversion (Elastic FWI). Unlike Acoustic FWI, which only considers compressional waves, Elastic FWI takes into account both compressional and shear waves, providing a more comprehensive and accurate subsurface model. This is especially advantageous when used on OBN data, as it can reveal subtle geological features, particularly around salt structures (Figure 3).

Elastic FWI has the potential to revolutionize seismic imaging, offering detailed insights into rock properties and fluid content. As TGS and other industry leaders continue to refine and deploy this technology, the ability to make informed exploration and production decisions will be significantly enhanced.

LOOKING AHEAD: THE ROLE OF INNOVATION IN GULF EXPLORATION

As the energy industry evolves, the need for innovative technologies like long-offset OBN and Elastic FWI becomes increasingly critical. These advancements not only enhance our ability to discover and develop new resources but also play a crucial role in ensuring the GOM's continued contribution to America's energy security and economic prosperity. The recent advancements in seismic technology reflect a broader trend of continuous innovation in the industry, paving the way for new exploration opportunities, particularly in the Western GOM, where traditional streamer data often fails to provide high-quality subsalt images.

Looking forward, the continued refinement and deployment of these technologies will be essential in unlocking the full potential of the GOM. The industry's commitment to innovation will not only help meet the BOEM's ambitious production forecasts but also ensure that the echoes of discovery in the Gulf continue to resonate for years to come.

The US GOM remains a critical hub for oil and gas exploration, and technologies like long-offset OBN and Elastic FWI are at the forefront of this effort. As the energy industry navigates the challenges and opportunities of the 21st century, these innovations will be key to unlocking remaining resources and driving sustainable growth. The future of exploration in the Gulf is bright, and with continued investment in cutting-edge seismic technologies, we are poised to discover even greater treasures beneath the waves.

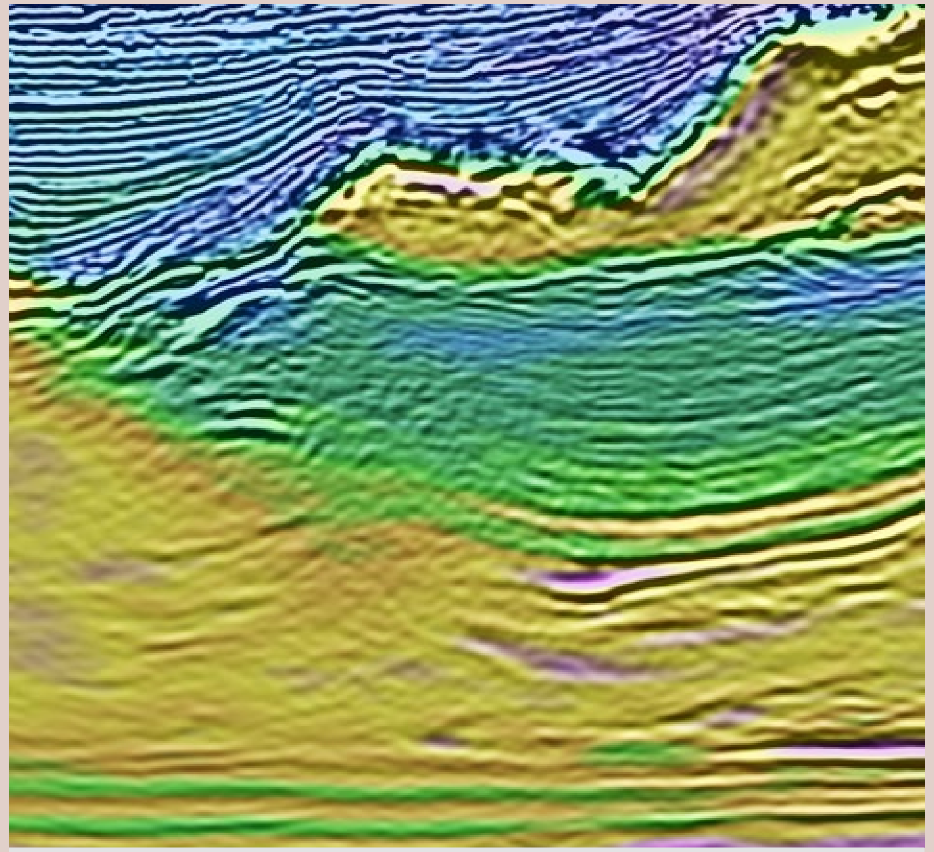


Figure 3. RTM Stack: Amendment 2 Acoustic FWI model

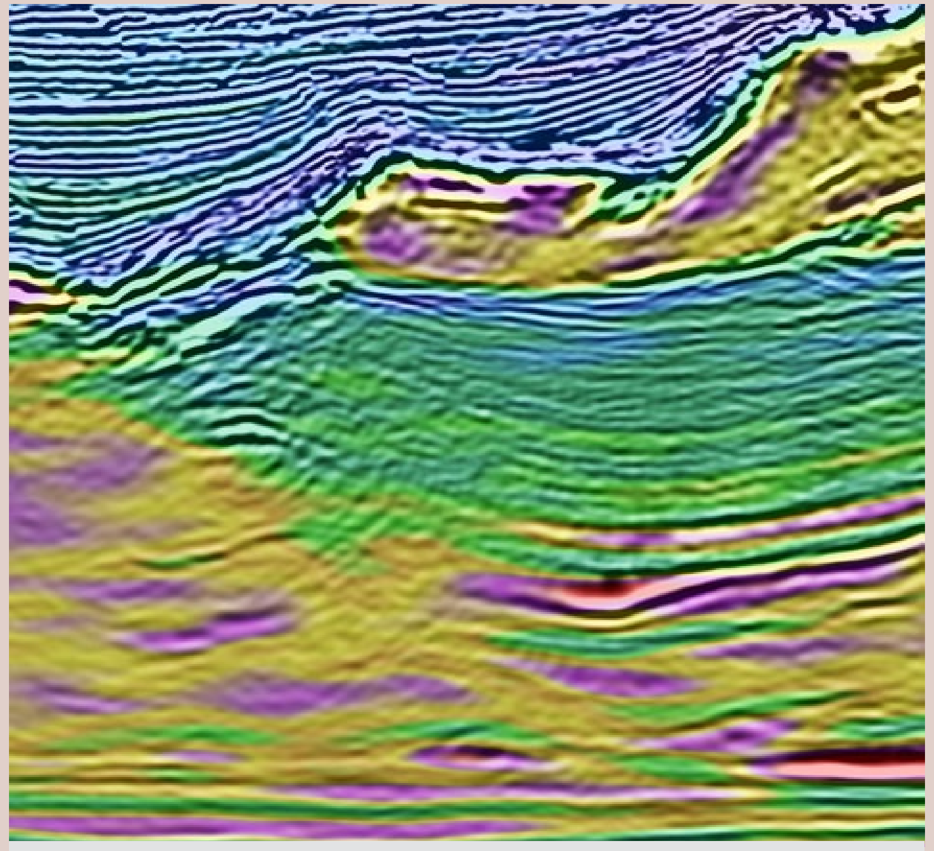


Figure 3. RTM Stack: Amendment 2 Elastic FWI model

PORTRAITS

"We have to go back to a situation where companies take full ownership of the lifecycle of wells"

Sarah Stogner

CHASING ZOMBIE WELLS

Lawyer Sarah Stogner literally exposes the lack of poor well abandonment practices in the Permian Basin and is trying to hold operators to account. She does that in her own unconventional way, driven by a desire to produce hydrocarbons in a way that can benefit all stakeholders in an area. And it is being noticed

"IT DOESN'T have the dramatic fire and oil shooting out like the bp Macondo well. No, here, in the Permian Basin, wells are spewing fully saturated brine instead", says Sarah Stogner from her car, when I speak to her in early July, when she is on one of her rounds to find more abandoned wells that are leaking reservoir fluids to surface. "But remember, we are in a sandy place here, with all but sand from surface to where our aquifer is at around 50 feet down. And as we all know from the beach, sand doesn't hold the water very well, so these brines are an immediate and real threat to the freshwater we rely on everyday."

"Everyone likes modern-day conveniences but very few appreciate the price of consumption"

Sarah is a lawyer, but people might equally think she has a background in drilling.

"I graduated from law school in 2008, and relatively soon after I started representing large oil and gas companies in disputes with their well control insurers. So for instance, you've got a well that has a control incident, such as a blow out. Companies then pay millions of dollars to drill a relief well or recomplete the well. Often, there are contractor tools lost in the hole as well. In those cases, as with so many things when millions of dollars are at stake, it is cheaper to pay lawyers to fight about it than just pay the claim. My role was to represent oil and gas operators against well control insurance companies. And in that position, I really learned the technical aspects of how to drill a well."

It is the knowledge she gained in her corporate role that paid off when her life took a turn a few years ago. "In 2021, when I separated from my husband, a friend and ranch owner here near Crane in West Texas offered her pool house for the summer. Her parents passed away relatively quickly just before that and she was left to manage the ranch. Around that time, she spotted some odd things related to previous well pad locations, but she did not have the expertise to fully investigate it. So, in return for offering me a space to live, she

Sarah Stogner.

PHOTOGRAPHY: PRIVATE

asked me to use my oil and gas experience and do some field work in my spare time and possibly send some nasty letters companies demanding a clean up. It grew into something bigger than that."

"About a week and half after I moved in, the Estes-24 well, later named the Red Bucket well, started flowing brines at surface. It turned out to be a well that Chevron plugged in the 1990's. Initially, they simply put a red bucket over it to prevent the spray from contaminating a wide area. It took them over 12 weeks to re-plug the well."

It was the start of Sarah's mission to tackle the many problems caused by improperly abandoned wells in the Permian Basin. And she is still on the same mission today.

What is the root cause behind these issues? "The money folks, who are in charge of operations, seem disconnected from the field now", Sarah says. "There is no sense of responsibility. However, I still firmly believe in the (technical) people who run this industry, as it is these people who work so hard to make sure that we can live a comfortable life. We have to go back to a situation where companies take full ownership of the lifecycle of wells, and work together with the ranchers to ensure that bad things do not happen."

An orphaned well in Pecos that has catastrophically failed. Supported by the landowner, an investigation was carried out to assess where flow was coming from.

PHOTOGRAPHY: SARAH STOGNER

"We have to go back to a situation where companies take full ownership of the lifecycle of wells"

LACK OF REGULATION

It is not only the lack of responsibility with the upper echelons of operating companies that has caused this situation of leaky wells contaminating groundwater resources. Groundwater that is used to provide drinking water for cattle farmers and the like. According to Sarah, the regulator has been complicit for decades in letting this situation unfold. The name of the regulator? The Railroad Commission.

On social media, Sarah is very open about the lack of action from the Railroad Commission. She advocates that the three main commissioners accept money from the oil industry, creating an environment in which proper supervision is not possible anymore. ▸

WHY THE RAILROAD COMMISSION?

Historically, the Railroad Commission was created in the late 1800's to regulate what the name suggests; railroads. Back in those days, the term "people getting railroaded" was frequently used when the expansion of the rail network in Texas caused landowners to face a railroad being constructed right through their property. It is easy to see why this needed a regulatory body.

When oil subsequently became a thing in Texas in the early 1900's and the crude was increasingly transported across the rail network, the idea was born to lump the two activities together, which meant that it regulated both railroads and oil and gas for about 100 years. It was around 2005 that the Railroad Commission decided to abandon the regulation of the railroads and put that under the umbrella of the ministry of transportation. So what we're left with is an agency that regulates oil and gas, exploration and production and pipelines and surface mining, including CO_2 injection.

The commission is headed up by three elected officers. But why do they not change their name to better reflect what they regulate? "They enjoy the anonymity", says Sarah. "They have defended keeping the name to save the millions of dollars it would cost to change their name and replace all the stickers on their vehicles, but really, it is preposterous", she adds. "The fact that most Texans have never heard of the Railroad Commission really comes to their advantage, says Sarah, and they have little inclination to change that situation and remain under the radar."

An orphaned well in Pecos that was "plugged" by an RRC contractor about two years ago. It was excavated in July 2024 and confirmed that it is leaking water and volatile organic compounds.

PHOTOGRAPHY: SARAH STOGNER

And that is why there is a situation whereby operators can continue doing the bare minimum to get a "No further action letter" from the Railroad Commission, enabling them to state that "We have plugged the well according to Railroad Commission guidelines". "But the real expertise is within these companies", Sarah says firmly, "and it is these companies that should tell the RRC how to plug a well and make that the standard."

"In the North Sea", she continues, "companies have to go and prove cement bonds when abandoning a well. Here, there is no such thing at all. We only have to blame ourselves for this."

LOCATING WELLS

How do you find the wells that are leaking? "Ranch owners usually spot something first and then get in touch with me. I also work with a surveyor who worked with Mobil Oil before and he uses digital data to pinpoint locations that may be worth a look. Once we get on location, we use a metal detector to determine where the well head is, as it is usually cut off around 3 feet below surface. The well head itself is often still lying there, so that is a good indicator of being close. We then use a backhoe to dig a hole and expose the casing. Sometimes it is already bubbling through the production string or through the annulus. In that case, I've got some welders who weld a cap on."

HOW COMPANIES DEAL WITH THE EXPOSURE

Then there is the question how operators deal with Sarah's findings. "At first, I thought, it is Chevron, they will deal with this properly. Only to find out that they went the way I had seen before with them contracting the lawyer heavyweights to deny that there is a problem in the first place. They also tried to sell off their wells to smaller operators, thereby claiming that their responsibility had ended. But if Chevron plugs a well, it then keeps the responsibility to keep them secure and plugged even when it sells the ownership. The crux of our case is that they still have the responsibility to monitor the wells and ensure that shallower groundwater resources are not affected by leaks."

But just pointing out that a well is leaking is not enough ammunition unfortunately. "I have excavated around 100 wells now and have data loggers registering temperature and pressure on 45 to 50 of those. A lot of those wells see some sort of pressure up to around 450 psi. In this way, I am building a portfolio of evidence."

"My ultimate goal is to get landowners properly compensated for the loss of their pore space and all the associated problems. It is a big deal these days. Because in many cases, it will not be possible to go back into these old wells and plug them properly as they have just completely rusted away. The least I can then do is make sure that my clients are properly compensated for this." ▸

An old Gulf well. Water, oil, and gas were found in all annular spaces at surface.

The ranch I am living at has around 300 wells on it alone, spread over 22,000 acres. I have got clients all over Texas for whom I am doing similar things. It is a problem all over.

In a response to this, oil and gas companies working in the Permian Basin have therefore bought a lot of land in the Permian Basin. "I guess that around half of the land is owned by operating companies. They wait till the problems get too bad for any surface activities to be undertaken, the point at which the land is bought. But it can not be the long-term solution. Our groundwater is a public resource and it deserves to be protected properly", emphasises Sarah.

"In the North Sea companies have to go and prove cement bonds when abandoning a well. Here, there is no such thing at all. We only have to blame ourselves for this"

SILVER LINING

"Operators really know how bad it is. They also know that they have got tens of thousands of wells they are responsible for whilst actively trying to deny there is a problem. Selling off your wells to smaller operators who do not have the funds nor the expertise is not a solution either. If these wells are subsequently orphaned and plugged by the RRC, it is not even a guarantee that the problem has gone. I have excavated three wells plugged by the RRC that were still leaking."

But not all companies are responding the way Chevron does. "There is one company I want to mention specifically and that is ConocoPhillips", says Sarah. "They are actively reviewing their well plugging procedures because they seem more aware of the potential problems they can prevent by spending some more money on the front end of things."

Sarah ran for a seat on the Railroad Commission for a number of years, but is not running this year. "Instead", she says, "a friend of mine with decades of experience in oil and gas will be on the Libertarian ticket, as a third party candidate."

It has something to do with the stigma that women still face in the industry. "She is a woman, so she does not know what she is talking about… It stinks, I know, but if it helps to make a difference to how the RRC is run, that is fine with me." Instead, Sarah is running for the district attorney position, which is the criminal prosecutor.

Even though Sarah has not made it into the RRC (yet), social media has been and continues to be instrumental in spreading her message. "It is amazing how effective it is to publicly shame people and I will continue doing that if it helps shake up the way we think we can work and put the burden of our lack of responsibility on our grandchildren." ■

PHOTOGRAPHY: SARAH STOGNER

GEOTHERMAL ENERGY

"This project is not just about expanding our geological knowledge but also about finding practical solutions to energy and resource challenges"

Aivar Auväärt - Geological Survey of Estonia

FORGE – first injection test successfully completed but no pressure equilibrium achieved

A nine-hour injection test at the FORGE geothermal project proved connection between the injection and production well, but data show that pressure continued to build as the test progressed, possibly suggesting the existence of a wider fracture network

A COUPLE of months ago, the FORGE project in Utah, USA, reported a successful stimulation and circulation test at their flagship Enhanced Geothermal Systems project. "These tests in stimulated hot dry granite are the culmination of two years of planning and in-depth data analysis", stated Professor John McLennan in the press release that was issued on 23 May.

The 9-hour injection and production test successfully demonstrated a connection between the two wells that are around 90 m from each other at around 2,600 m depth. This was achieved by commercial-scale stimulation conducted at both wells in multiple stages.

The good thing about the FORGE project, which is sponsored by the US Department of Energy (DOE), is that the data obtained during drilling and testing have all been made publicly available. A whole raft of different datasets, ranging from GIS, seismic, 3D earth models to core photographs and production data are all ready for download at the project's Data Dashboard.

PRODUCTION DATA

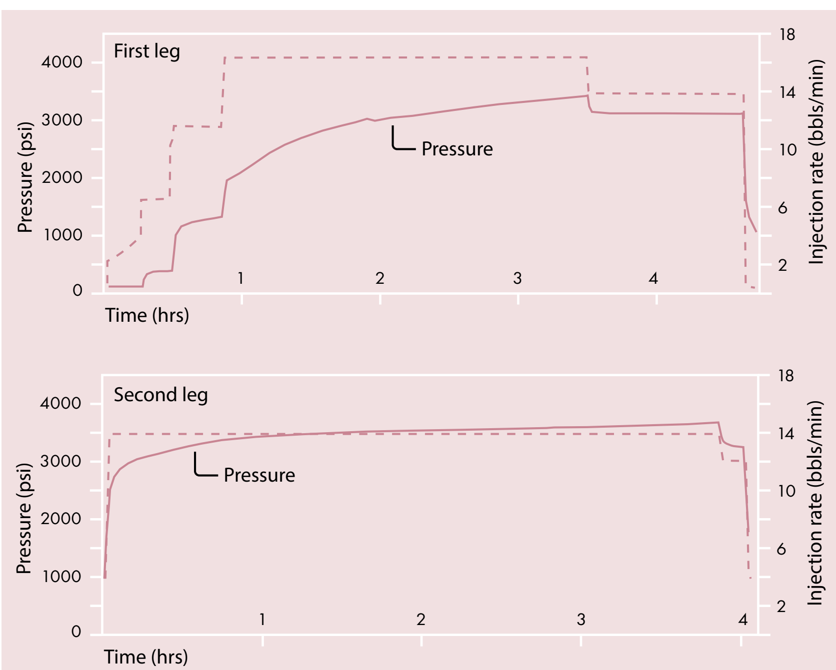
We took a closer look at the injection data available from the 9-hour test that was performed in May. The interesting thing about this is that it allows us to look beyond what is stated in the press release, making some observations based on the data.

Looking at the pressure envelope during the first leg of the two ~ 4 hour periods of water injection, a few observations can be made. The most important one is that the primary treating pressure continues to rise during the "injection plateau" of around 16.4 barrels per minute. This indicates that the system is not in equilibrium yet, and water is "disappearing" in the fracture network surrounding the wells and pressuring up the system. This is corroborated by the fact that the corresponding production only achieved up to 8 barrels per minute.

The second leg of injection, which lasted another four hours, applied a slightly lower injection rate of 14 barrels per minute. Yet, the pressure envelope still shows a slight increase over time until the very moment when injection rates were dropped.

These observations pose an interesting question: When will a stable pressure regime be achieved? The ticket question in that sense is probably whether or not the induced fractures are connected to a wider network that causes fluids to dissipate away from the wells rather than migrate from the injector to the producer. This in turn exposes a risk that is inherent to any EGS project; creating a connection between the induced fractures and a wider existing network. ■

Henk Kombrink



Injection and pressure envelopes for the two ~ 4 hour legs of the FORGE injection test.

SOURCE: FORGE

Removing barriers to geothermal project development

That is the purpose of a new deep geothermal well classification the International Association of Drilling Contractors (IADC) is developing

TRYING TO work with the current myriads of non-standardised terms, definitions, and well design types for geothermal projects is challenging. Interest in the sector is growing rapidly, but its technical complexity and lack of a standard nomenclature are inhibiting the clarity of debate worldwide. The challenge of the IADC Geothermal Committee is to bring simplicity and standardisation to the entire geothermal 'ecosystem'.

The motivation of this committee is to create universally acceptable guidelines for the benefit of the geothermal community, operators, investors, and regulators. We talked to Kevin Gray and Daria Ivakhnenko from Black Reiver Geothermal Consulting, members of the IADC Geothermal committee steering group who were the instigators of this classification initiative.

How would regulators and investors benefit from the Classification?

"Regulators will be able to use the Classification to more easily identify the risks that may exist within geothermal projects. The Classification part of our work, in conjunction with the evolving guidelines, aims to help bring clarity and, hopefully, a more widespread harmonisation of the current globally diverse permitting processes."

"For any well categorised within the framework the IADC Geothermal Committee is developing, it will be easier for the authorities to identify the required regulatory input. Thus, it will simplify the process and shorten the time required to receive approvals. It will also help identify wells that may benefit from a regulatory 'light touch' approach within, for example, the environmental aspects of the permitting system."

"Investors have become quite excited about this development too, as it gives them a shortcut to the first-stage due diligence as it more clearly defines the specifics and complexity of a geothermal project. It will help them evaluate the risks associated with a specific project, which goes a long way in making an investment decision. In addition to the classification itself, the committee have been developing a risk assessment tool that assigns an overall project risk to any classified well."

What was the most difficult classification issue?

"Without a doubt, that was the Well Design and Construction categories. Too many entrenched opinions and existing temperature-based geothermal well classifications often lead to heated discussions as soon as any temperature threshold is raised. This Classification is based on well construction, the practicality of 'putting a hole in the ground', hence we decided to move away from existing academic disputes and concentrate on well equipment operating temperatures."

"The result was to define wells that require no active cooling measures and those that need additional cooling strategies for the downhole tools or surface drilling equipment."

"In the end, the committee chose the most straightforward and pragmatic approach of using the existing API and ISO drilling equipment standard operating temperatures. Beyond these thresholds, mitigating measures such as insulated tubulars or cooling techniques are required." ■

Henk Kombrink

Geothermal drilling operations in Hamburg, Germany.

SOURCE: GEOTHERMIE-WILHELMSBURG.DE

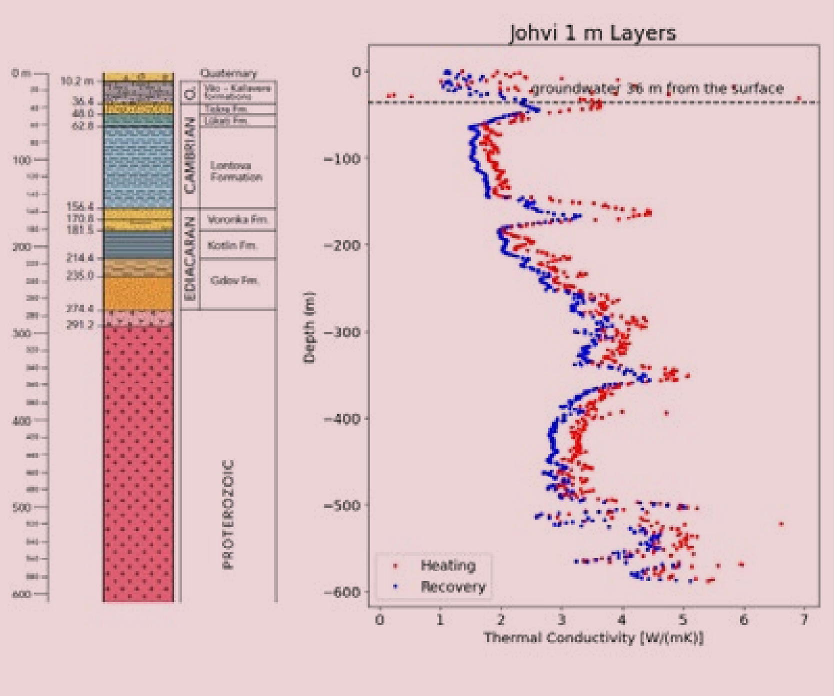
Geothermal energy from buried basement rocks

A new geothermal research project in Estonia taps into heat stored in basement rocks buried below hundreds of meters of poorly conductive sediments

Closed-loop shallow geothermal boreholes drilled up to a depth of around 200 m are quite common in Estonia. But recently, the Geological Survey decided to embark on a project to tap into deeper geothermal resources by drilling into basement rocks buried beneath an interval of sedimentary strata in the northern part of the country.

The goal of the project is to produce the energy "stored" in basement rocks that are overlain by a succession of siliciclastic sediments. This is based on the concept that a 150 to 300 m thick succession of isolating sedimentary rocks forms a barrier for heat to be effectively transferred to surface, leading to relatively high temperatures in the topmost part of the igneous succession.

In southern Finland, a geological analogue to northern Estonia, this concept has already been successfully applied and it is expected that the thermogeological properties are comparable in Estonia, if not superior. For instance, geothermal gradients of up to 35° C / km have been measured in in basement rocks in northern Estonia, compared to 18° C / km in other places. This has resulted in a 5° C temperature anomaly in the higher gradient areas. Further drilling is now needed to better map these positive anomalies.



Thermal conductivity of the Jõhvi PA-1 borehole located in the northeast of the country, measured using a distributed temperature sensing cable at 1 m intervals. The "Heating" series was obtained with the help of a heated copper wire using a constant power of 10W/m. The "recovery" data is a passive way of detecting conductivity. It can be seen that the thermal conductivity of the basement is higher than the overlying siliciclastic rocks.

SOURCE: GEOLOGICAL SURVEY OF ESTONIA

CHALLENGES

While the geo-energy potential in northern Estonia is promising, it comes with its own set of challenges. Drilling boreholes through the unconsolidated sedimentary rocks to reach the crystalline basement increases costs. However, the economic feasibility demonstrated by similar projects in southern Finland provides a strong incentive to overcome these challenges.

The initial idea was to drill at least 600-700 m boreholes, but the length limitations of U-tube borehole heat exchangers restricted the project to 500 m boreholes. However, another way of tapping into deeper strata is now being considered without the use of a U-tube pipe. In this case, a single tube will be lowered in the borehole, with water being circulated downward through the open hole and subsequently produced back up through the tube. The heat exchanger is then used to transfer the energy from the top of the borehole to the low temperature district heating network.

The risk of these open hole circuits is the presence of a fracture system in the basement rocks, with a loss of fluid as a result. That is why only water is used as a circulation fluid, and work is being done at the same time to find ways to close off the fractures. ■

Henk Kombrink, with input from Aivar Auväärt, Geological Survey of Estonia

SUBSURFACE STORAGE

"Consider an old well with leak
An answer we're going to seek
Using models of paths
Rate, pressure and maths"

Mike Byrne - Axis

Another pressure plot without values

At the recent DEVEX Conference in Aberdeen, another operator confirmed once again the sensitivities around pressures in a future carbon store – this time for the planned Endurance project

IT IS THE third time in a matter of a few months that a pressure plot was shown during a carbon storage presentation without values on the vertical axis – it is becoming a bit of a trend and it shows the sensitivities around pressure build-up in saline aquifer stores.

This time, it was a talk delivered by Nicolas Bouffin from bp. He presented about the Endurance project in the UK Southern North Sea. However, during a conversation after the talk, Nicolas said that pressure values could be found in the online-available Endurance Storage Development Plan.

WHAT THE REPORT SAYS

When checking the Endurance Storage Development Plan, it is stated that the Röt Clay, which is the sealing unit directly overlying the Bunter reservoir, returned 264 bar (3,830 psi) as a fracture pressure when analysed through an MDT mini-frac test at 1,363 m in well 42/25d-3. MDT and RFT testing of the reservoir itself suggested that the aquifer is at 140 bars at around the same depth as where the Röt Clay was analysed, leaving a 124 bar pressure window.

bp does not expect pressure issues during the first phase of the project, which aims at injecting 100 million tonnes of CO_2 during 25 years into the Triassic Bunter reservoir. The document does however state that for subsequent development phases, where CO_2 injection exceeds 4 million tonnes per year, brine production may be required to maintain reservoir pressure below cap rock fracture pressure limits. The exact moment when this would be required depends on the connectivity of the system or the potential on (unlikely) structure baffling.

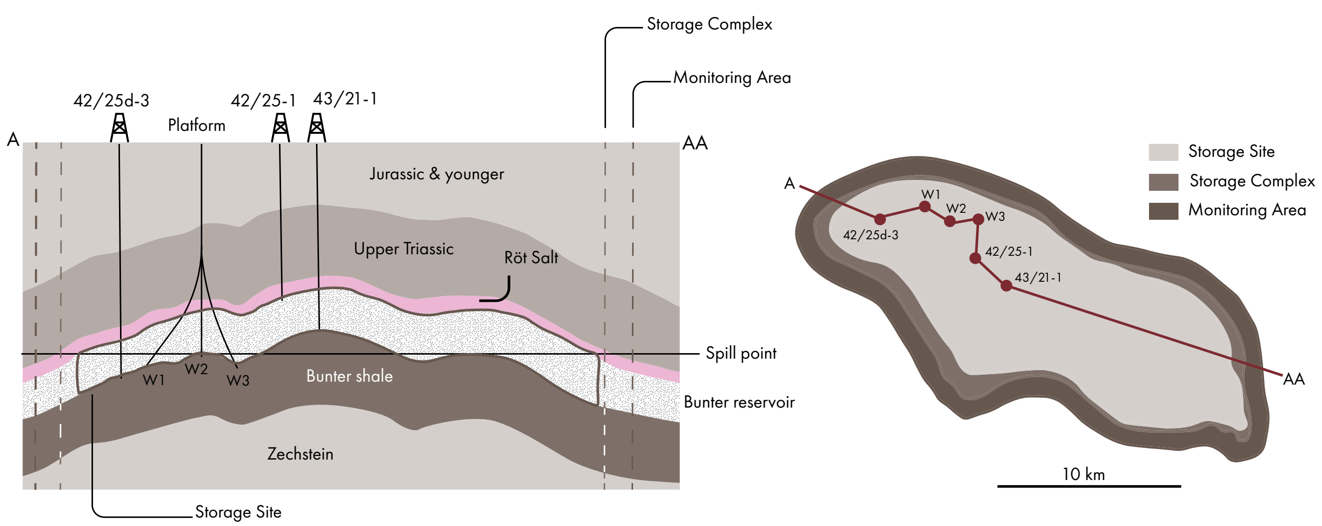
It is the connectivity of the Bunter reservoir that will indeed be the critical factor when it comes to how efficiently a pressure front will be able to dissipate. And there seem to be two end member models.

TWO END MEMBERS

The first and more positive end member is one of a large connected aquifer that even communicates with the abandoned Esmond gas field 50 km away - which produced from the Bunter too. The second and more pessimistic end member is one of a much less connected Bunter reservoir, which obviously will have a detrimental effect on the storage capacity. The main observation in support of this is the fact that halite cementation is a frequently observed phenomenon in the Bunter. The wells that were drilled around the Endurance closure – all targeting deeper strata – indeed suggest that the Bunter is much more clogged up than in the wells drilled in the Endurance closure itself.

In other words, it is the uncertainty in connected reservoir volumes that create the environment for pressure to be such a sensitive factor. ■

Henk Kombrink



Cross-section showing the Endurance carbon storage site as well as its storage complex and monitoring area.

Applications of Computational Fluid Dynamics in Carbon Capture and Storage Well Design

COMPUTATIONAL Fluid Dynamics (CFD) has been used for many years to optimise the design of conventional oil and gas production and water injection wells. With the increase in Carbon Capture and Storage (CCS) projects and well planning, CFD has now also been implemented to enhance understanding and improve the design of CCS wells.

CFD is used to model the leak rate of CO_2 through abandoned wells and to verify that the leak rates are As Low As Reasonably Possible.

The risk of loss of well integrity due to differential thermal response in the overburden and potential well failure during cold CO_2 injection is modelled using coupled CFD and Finite Element Analysis (FEA).

Applying methods developed for conventional oil and gas wells, the injection of CO_2 into subsurface CCS stores is modelled to optimise well and overall development design.

Mike Byrne is Manager of Rock Properties at Axis. With 35 years' experience in Formation Damage and Stimulation, Mike has twice served as an SPE distinguished lecturer and is a leading authority on Formation Damage, laboratory testing and advanced numerical inflow modelling. ■

Henk Kombrink

AN ODE TO CARBON STORAGE MODELLING

Consider an old well with leak
An answer we're going to seek
Using models of paths
Rate, pressure and maths
We de-risk the leak so to speak

There once was a well in construction
Designed to allow it to function
Inject CO_2 to help save the planet
Sealed from surface to store

With steel tubing, cement in addition
Subjected to freezing condition
So a team of bright sparks got to ponder
Could we forecast and not just wonder
CFD and FEA were the tools that were found
To keep CO_2 under ground

A well filled with water is fine
But a well filled with acid's a swine
When we shut the well in
Could movement begin
CO_2 and water combine?

Phase change in this system is complex
With changes in thermodynamics
Dense phase, liquids and gases
Compete as the plume advances
But how to predict is a challenge to all
Coupled models have answered the call
High rates and velocities a worry
CO_2 going in, in a hurry
Erosions a problem that can be predicted
CFD can help show what's afflicted

Injectivity, viability
Joules Thompson cooling, uncertainty ruling
Use CFD and we can believe
Injection that we can achieve

(Read by Mike Byrne at this year's DEVEX Conference in Aberdeen, June 2024)

Is carbon capture and storage really a fantasy?

That is what a new investigative journalism report concludes

In July, the Pulitzer Center published an article entitled "Documents, Whistleblowers, and Public Comments Are Clear: Oil Companies Know Carbon Capture Is Not a Climate Solution".

The authors state that whilst major oil companies claim that carbon capture and storage will be essential for helping society achieve net-zero emissions, internal documents as well as information shared by industry whistleblowers reveal an industry that is decidedly more realistic about the emissions-reduction potential of CCS than it presents publicly.

But is this is a surprise? Of course it is not. It is the result of trying to force commercially driven businesses to take on an activity that is essentially a utility. Until a better model for large-scale CCS has been found, such as the carbon takeback obligation, the public cannot expect carbon storage to ramp up to a point where it really starts to make a dent.

What the authors exposed is the difference between corporate communication and what many well-intentioned people working in the energy sector will say when you talk to them privately. It is something that I experience so often when talking to people at the periphery of carbon capture-themed conferences.

The oil industry knows that there is no money to be made with just storing CO_2 in the subsurface. That is why it is doing CO_2 EOR in the US, and that is why Equinor only started injecting CO_2 in Norway as a response to hefty fines when it wouldn't. Cash was always the driver, long before the climate became a hot topic.

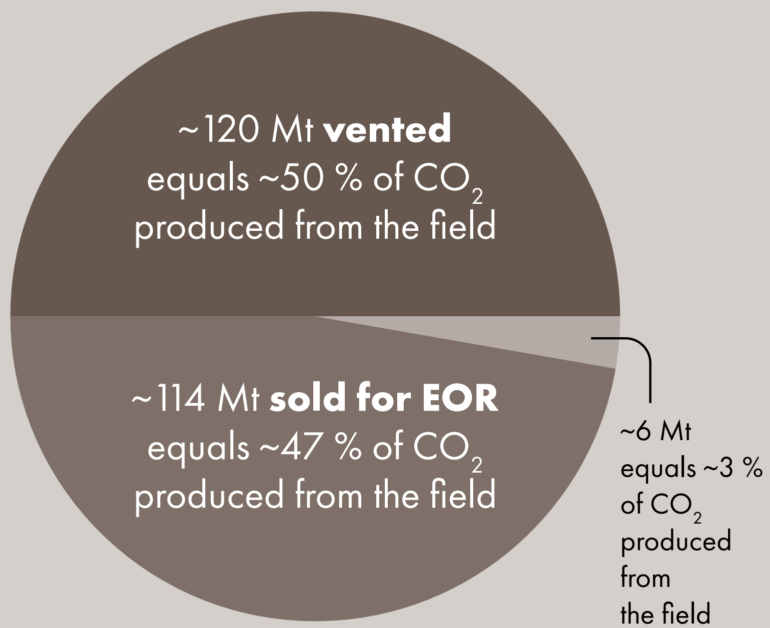
The authors do reveal well how limited the scale of today's activities are. Take the LaBarge CO_2 storage project in Wyoming, widely celebrated by Exxon as one of the most longstanding CO_2 storage projects in the world. They quote a study from The Institute for Energy Economics and Financial Analysis (IEEFA) that only 3 % of the CO_2 that has come out of the ground – the field has a 66 % CO_2 content - has been re-injected in LaBarge.

I attended a talk by Patricia Montoya from ExxonMobile at the IMAGE conference in 2022. She only talked about the millions of tonnes that were so far injected and the plans for drilling another injection well, but the overall picture, which includes the much bigger volume of CO_2 that has so far been vented, was not mentioned in the talk. It is very useful to have that perspective.

However, as happens often, the subsurface is taking the hit in the Pulitzer Center piece. Unnecessarily. The authors leave the impression that subsurface storage is unsafe when they quote Carolyn Raffensperger, executive director of the Science & Environmental Health Network in the US: "When CO_2 is actually sequestered underground, there's no guarantee it stays there…."

Investigative journalism is a good thing. But it should not come as a surprise that oil and gas operators have a different narrative about CCS behind closed doors. It is societal pressure that is partly to blame - forcing a commercial industry into a venture requiring subsidies. To really make it work, a carbon takeback obligation should be forced upon the global industry instead. But please do not start casting doubt that the subsurface cannot hold the CO_2. It is safe to do so, as many geoscientists will be able to confirm. ■

Henk Kombrink

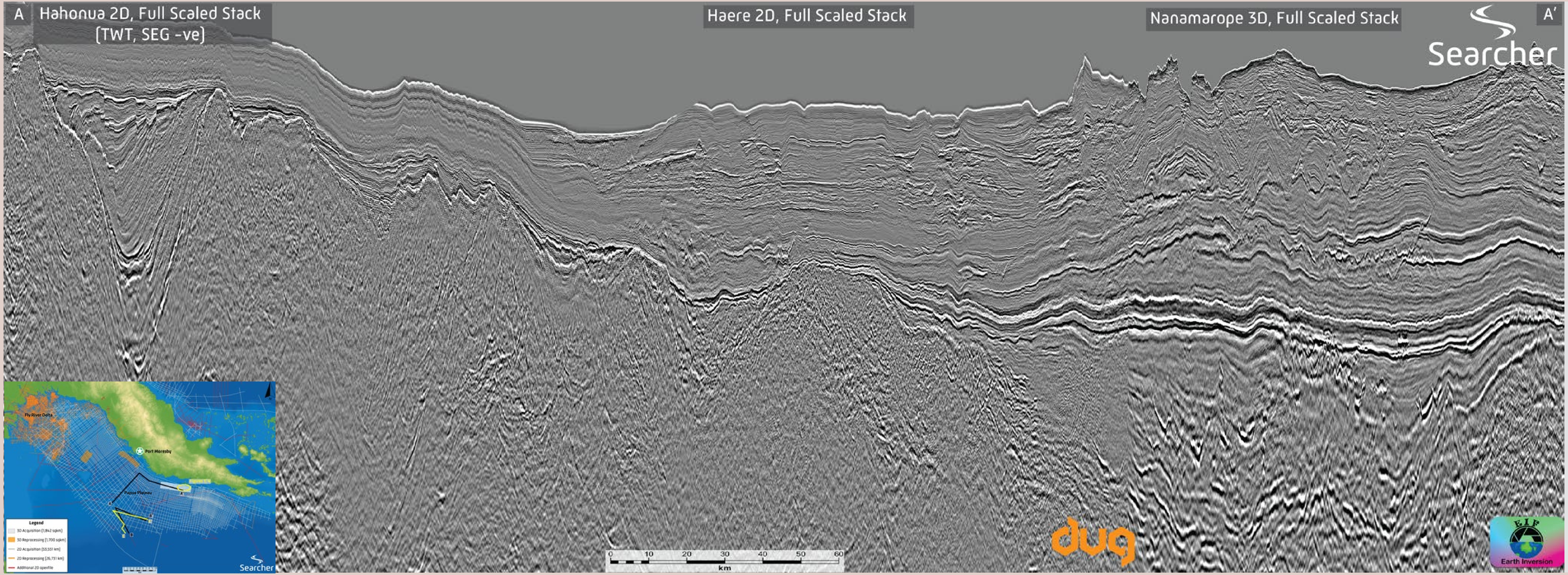


CO_2 produced from the LaBarge field and the way it is has been dealt with. Only around 3 % was stored as part of the CCS program.

SOURCES: IEEFA ESTIMATES, EXXONMOBIL AND ENERGY PROCEDIA

Exploration of the Papuan Plateau: How revolutionary geophysical technology reveals new seismic insights

This is the story of how a basin that was previously thought of as "cold", with only a thin veneer of Tertiary sediments deposited on top of oceanic crust, was transformed into an attenuated continental crust mode with high geothermal gradients and thick preserved sedimentary sequences. All thanks to advances in geophysical imaging technology. In combination with additional geochemical and airborne gravity gradiometry, this has allowed for the identification of a potential oil province. Now it is waiting for the first well to be drilled to test this newly defined play.



(A-A') A 280 km arbitrary line across the Papuan Plateau and Aure Fold & Thrust Belt, highlighting deep Mesozoic depocentres preserved beneath the Early Tertiary Coral Sea breakup, and the complex imaging in the overburden.

Holding out for a hero: How evolving geophysical technology revolutionised a Frontier Basin

LAUREN FOUND, NEIL HODGSON, KARYNA RODRIGUEZ AND HELEN DEBENHAM, SEARCHER

A LOT CAN change in twenty years. In 2004, the Nintendo DS had just been released, Facebook was taking its baby steps and Jennifer Saunders graced the world with one of the best covers of a pop song known to man in Shrek 2. Much like the titular character one of the highest grossing films of the year, the offshore geological story of Papua New Guinea had been holding out for a hero, which came ten years later in the form of rapidly advancing seismic acquisition and processing technologies.

The Gulf of Papua, a region spanning 187,000 km^2, is roughly equivalent in size to the Anglo-Dutch Basin, but has had less than thirty exploration wells drilled, and only three in the last twenty years. All drilling has been constrained to the Fly River Delta searching for gas in carbonate buildups and basin floor fans lying in shallow water (<500 m).

A very sparse seismic coverage beyond the Fly River Delta (Base Map, red lines) supported the interpretation of a shallow, cold Papuan Basin, with a thin veneer of Tertiary sediments on top of oceanic crust associated with the opening of the Coral Sea in the Early Tertiary (Figure 1, B-B'). Full of imaging challenges and multiples, likely restrained by processing technologies available at the time, the seismic did not lend itself to a complex geological interpretation.

This began to change in 2006, when Searcher, in partnership with Spectrum, acquired the Lahara Seismic Survey. Originally processed with a PSTM workflow, this imaged previously unseen depocentres and provided hints of preserved sedimentary sequences beneath the Coral Sea Breakup Unconformity beyond the Fly River Delta. 2014 reprocessing with a PSDM workflow, quickly followed by the acquisition of two long-offset 2D broadband surveys in 2015 and 2016 in partnership with BGP, covered the Gulf in a grid of 10x10 km to 5x5 km seismic that imaged to 35 km depth.

These new seismic insights (Figure 1, C-C' and Foldout) were one of the key tools in revolutionising interpretations of the Papuan Plateau. Rather than thin and structureless sediments overlain on oceanic crust, a complex sedimentary package exists, including thick preserved sequences below the Coral Sea Breakup Unconformity. Large horsts and grabens with internal structures have been mapped, mimicking the stratigraphy below the breakup across the inboard region, but without the thick overlying Tertiary carbonates present across the Fly River Platform. In addition to these new observations, a Moho event could be mapped across the Gulf, challenging industry held views of the crustal nature at the time. The seismic data, along with complementary Geochemcial and Airborne Gravity Gradiometry (AGG) surveys, revealed that the vast majority of the Papuan Plateau is indeed underlain by attenuated continental crust with high geothermal gradients.

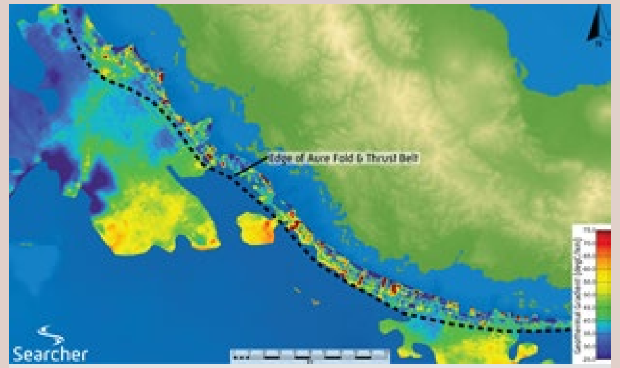


Figure 2: Approximate geothermal gradient derived from BSR thickness mapping across the Gulf of Papua.

These are mapped on the modern seismic using bottom simulating reflectors (BSRs), which can be used as a data-led proxy for geothermal gradient in frontier basins (Figure 2). Gradients range from 30-35° C / km in the Fly River Delta to 40-50° C / km around the basement highs and within the Aure Fold & Thrust Belt (FTB). This allows the synrift and Late Cretaceous-Paleogene early post-rift sections to be hot enough to sit in the peak oil generating window, supported by observed geochemical and seep data.

This new interpretation of the crustal nature and heat flow across the region allows for the extension of the prolific onshore Mesozoic plays, such as the recent discoveries at Muruk (Santos, 2016) and P'nyang (ExxonMobil, 2018). Investigations into the prospectivity and potential petroleum systems have continued across the extensive datasets, inclusive of Searcher's 2023 acquisition of Nanamarope 3D, a survey within the Aure FTB covering a large Mesozoic depocenter. Whilst in the foredeep on the Papuan Plateau the oil source is synrift, within the fold belt, the stacking of thrust sheets matures the source rocks in duplex thrusts, just at the critical moment when huge structures are forming above them.

Due to the complex nature of the geology in the area, including a canyon-ridden seafloor, several modern and high-end processing technologies, including multiple iterations of Full Waveform Inversion (FWI) and Q tomography modelling were utilised (Figure 3), resulting in the clearest insights into the complicated shallow geology and deeper depocentres to date. The high-resolution 3D data allowed for the improved interpretations of petroleum systems elements, including Direct Hydrocarbon Indicators (DHIs), where foredeep gas is trapped in very large low-risk traps against the leading thrust of the fold belt (Figure 4).

With the extensive multi-disciplinary geotechnical datasets acquired and reprocessed over the last twenty years, the offshore Gulf of Papua has been transformed from a shallow and cold region to a prospective continuation of the synrift generated oil provinces so prolific in the onshore and across the basins of northern Australia. Similar to Hollywood's favourite ogre, the Papuan Plateau's layers have started to be peeled back through the rapid technological advances and now it awaits its next hero - a champion to drill an exploration well.

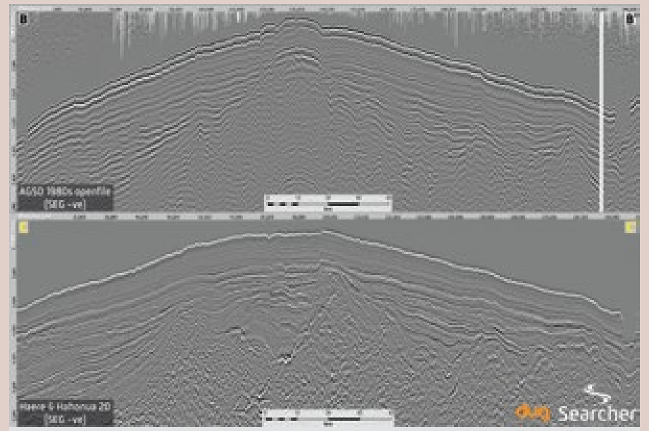


Figure 1: (B-B') 1980s vintage openfile seismic data across the outboard Papuan Plateau, plagued by imaging challenges that supports the interpretation of a bland, thin sedimentary sequence on oceanic crust (top). (C-C') 2015 / 16 PSDM seismic from the Haere and Hahonua Regional 2D surveys across the outboard Papuan Plateau, highlighting the complex geology and preserved pre-breakup section previously hidden beneath poor imaging (bottom).

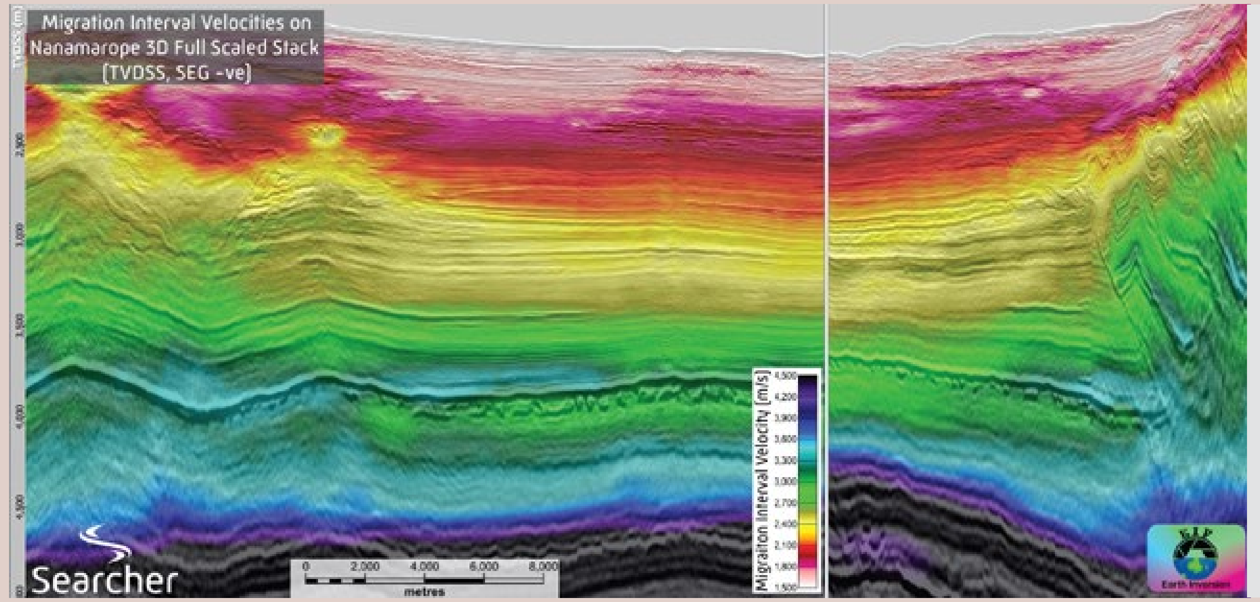


Figure 3: Migration interval velocities overlain on the 2023 Nanamarope 3D survey, highlighting the complex FWI and Q tomography velocity modelling carried out to optimize the shallow imaging.

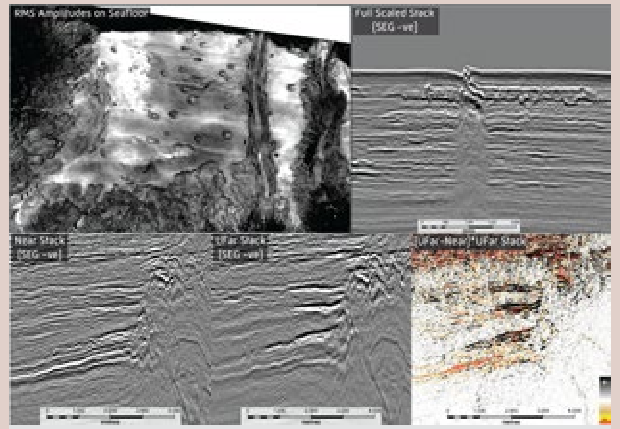


Figure 4: Direct Hydrocarbon Indicators across Nanamarope 3D, including pockmark clusters across the seafloor (top left), shallow gas plumes breaching the seafloor (top right) and stacked AVO anomaly leading the fold belt (bottom), which all provide evidence of an active hydrocarbon system in the Aure FTB away from the Fly River Delta.

NEW GAS

"Today, helium is in such great demand that the majority is sold via offtake agreements to not only global gas distributors, but also private companies that want to secure their supply"

Mariël Reitsma - HRH Geology

NEW GAS

Gold hydrogen – or Gold helium?

Based on an analysis of published results and plans, it looks as if Gold Hydrogen puts emphasis on helium rather than hydrogen in their South Australia Yorke Peninsula project

On 22 May, Gold Hydrogen's share price reached its highest level so far at 2.09 Australian dollars. A few days later, following the release of an ASX statement on 27 May announcing the results of the interim well test results, a more than 30 % reduction to 1.42 AUD took place, only to hover around that value since with a further slow decline in the last few weeks.

In contrast to the sentiment one gets when looking at the Gold Hydrogen share price, reading through the May 27 ASX document, the published results are presented as being very promising, with high measured purity levels of both natural hydrogen – up to 95.8 % H_2 across 7 zones in well Ramsay 2 – and helium purity levels up to 17.5 %. Why did investors not decide to back the company more?

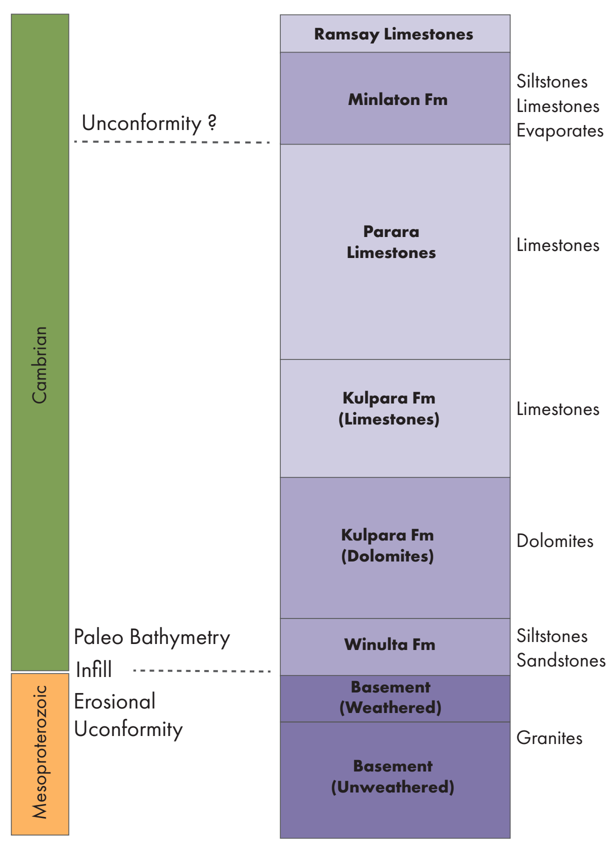
It is possibly the lack of concrete numbers that forms the basis for the lukewarm reaction on the market. Despite the fact that the company writes that hydrogen and helium were brought to surface, no rates, pressures or volumes were presented. Therefore, Gold Hydrogen is planning an extended exploration well testing program for the two wells it drilled so far; Ramsay 1 and Ramsay 2, to be carried out in July. This includes flow testing of both Ramsay 1 (open hole) and Ramsay 2 (cased and perforated) to understand future well performance. Installing a downhole pump to remove formation water before being able to lift gas to surface is part of the procedure. At the time of going to print at the end of July, no further results have been made public yet.

NOT ONLY HYDROGEN

It is not only hydrogen the company is after, but also helium. This gas was found in different stratigraphic intervals, which means that it likely has a different source. The helium shows two zones of enhanced concentration; down in basement rocks and in the overlying Kulpara Formation. It is the Kulpara Formation that also exhibits the highest porosity values across the entire drilled interval of the Ramsay 2 well.

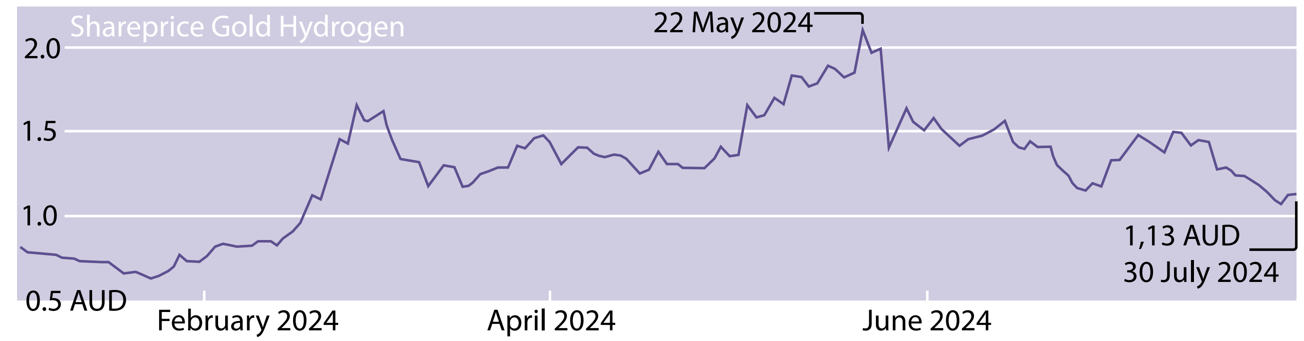
Hydrogen concentrations are higher in the shallower section above the Kulpara Formation where porosity values seem low overall when looking at the well log presented in the ASX document published on 19 December last year. This suggests that the hydrogen is mainly concentrated in fracture zones. It is only in the unweathered basement rocks at the bottom of the Ramsay 2 well where both helium and hydrogen show elevated readings.

The Yorke Peninsula in Southern Australia, with the Ramsay 1 and Ramsay 2 wells indicated in the centre of the area where a new grid of 2D seismic lines has now been acquired for Gold Hydrogen. Will it result in a better understanding of the fracture network where the hydrogen seems to reside? Or is it to better map the Kulpara Formation where positive helium readings were obtained?



Lithological representation of the stratigraphy as found on the Yorke Peninsula.

SOURCE: GOLD HYDROGEN INVESTOR PRESENTATION; SOURCE MAP: GOLD HYDROGEN



Gold Hydrogen's share price over the past few months, showing the share price maximum reached just before the interim well test results were announced on 27 May. Since then, the price has slowly fallen to a value of 1.13 AUD at the end of July.

Despite the fact that hydrogen does not seem to be associated with porous and permeable reservoir units, it looks as if Gold Hydrogen is moving towards a model that encompasses a productive reservoir. This is based on the following observation in the 27 May ASX document: "From the different formations tested in the Ramsay 2 well, a constant fluid influx was observed during the Stage 1 well test, indicating the permeability of the tested formations. A further reservoir engineering analysis is now underway to calculate a more detailed estimate of the formation permeability and potential productivity at each particular depth."

Based on this, and the observation that it is mainly helium and not the hydrogen that is associated with the porous section of the Kulpara Formation, could it be that Gold Hydrogen is in fact mainly after helium? The perforated zones in the Ramsay 2 well are predominantly targeting the high helium readings as well.

SEISMIC DATA

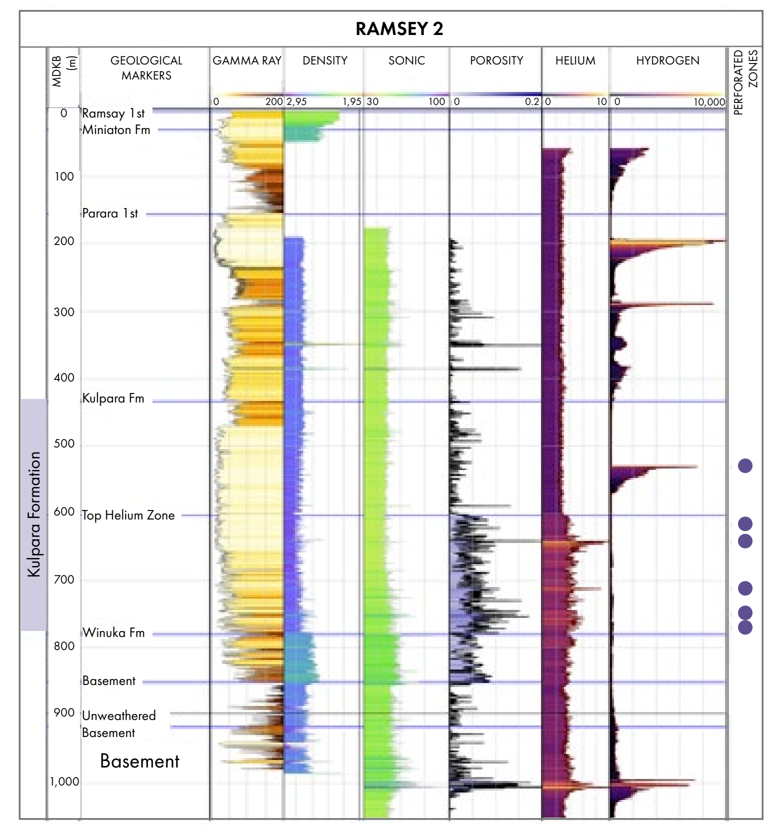
There is another sign that Gold Hydrogen could be moving towards better understanding the nature of the Cambrian Kulpara reservoir. As the company announced in June, the acquisition of a seismic survey has begun covering the Yorke Peninsula. In total, around 650 km of 2D lines will be acquired.

Apart from mentioning that the survey aims find better drilling locations, it is not clear if it is designed to map fracture systems – in which the hydrogen seems to be concentrated – or map the extent and thickness of the Kulpara Formation – in which the helium seems to be concentrated.

With a line spacing of 5 to 10 km, it seems more likely that the Kulpara Formation is being mapped rather than the distribution of a fracture network. For the latter, a 3D survey would be much better suited.

In conclusion, this project is still open to many uncertainties. Based on what we described here, it looks as if Gold Hydrogen is now focusing more on the helium side of the story than on the hydrogen part. But the overall lack of data on both the helium and hydrogen systems is the likely cause for the share price not to be rocketing yet. ■

Henk Kombrink and Mariël Reitsma



Well log from the Ramsay 2 well (taken from the 19 December ASX release), showing from left to right Gamma Ray (yellow / orange), Density, Sonic, Porosity, Helium and Hydrogen. The perforated zones in the well are also indicated by the black dots – taken from the 27 May ASX release. The depths of the perforated zones suggest a focus on helium.

SOURCE: GOLD HYDROGEN

The North American Helium Fairway

Whilst it is the explorers that generally draw the headlines, the producers of helium quietly beaver away providing the market with yet another key product to help run modern society

As always, news outlets concentrate on the handful of exploration companies trying to prove additional (helium) resources. For instance, Gold Hydrogen announced a record find of 17.5 % helium in the gas stream at their Ramsay project in South Australia, while Pulsar Helium boosted about their well test that yielded 14.5 % helium on the Topaz project in Minnesota, USA. However, reserves for these projects still have to be accurately established and production is certainly some time away.

In the meantime, exploration, drilling and production quietly continue over the Alberta - Saskatchewan – Montana Helium Fairway that stretches across the Canadian American border. In this area, wells generally contain less than 1 % helium but volumes are large and easy to produce. Moreover, the helium is mainly associated with nitrogen, smaller fractions of CO_2 and minimal hydrocarbons, making it relatively 'green' because of the low carbon footprint.

The Saskatchewan – Montana Helium Fairway is underlain by the Archean aged Wyoming craton. The helium is generated in the granitoid basement as a by-product of radioactive decay of uranium and thorium. It subsequently migrates upwards into unconformably overlying sedimentary rocks and is trapped at Cambrian and Devonian levels most of the time.

For example, First Helium is developing their assets in the Worsley area in western Alberta, Canada. In this locality, Devonian marine sediments unconformably overlie the pre-Cambrian basement. Extensional faulting of the basement created a horst and graben system with carbonate platforms being established on the horst blocks. The reef trend is visible in seismic data throughout the area. When the basement faults were subsequently reactivated and extended into the Devonian reefs, hydrothermal fluids dolomitized the limestone around the faults and created additional porosity. Eventually, helium from the basement migrated along the faults and became trapped in the dolomite. In order to tap into these reservoirs efficiently, First Helium has drilled horizontal wells in the reef deposits for efficient production. The reservoir contains around 0.85 % helium.

Today, helium is in such great demand that the majority is sold via offtake agreements to not only global gas distributors, but also private companies that want to secure their supply. In practice this means the produced helium is purified to the desired level on-site and then directly shipped to end users, for example to space and tech companies. ■

Mariël Reitsma, HRH Geology

"In the 20th century, hydrocarbon exploration campaigns targeted the area but found very large fractions of inert gas in their prospects and moved on. Now, companies such as Royal Helium, North American Helium and Avanti successfully use this legacy data to their advantage in their quest for the noble gas."

Royal Helium drilling the Climax-2 well in 2021, targeting an extension of their helium prospect.

SOURCE: ROYAL HELIUM

DEEP SEA MINERALS

"What they – or anyone else – did not consider, was that the potato-sized metallic lumps found in vast swathes in certain parts of the deep sea may act as batteries in their natural state"

Ronny Setså - GeoPublishing

Your "catch of the day" causes plumes and marine devastation at a much larger scale than any deep-sea mining activity will cause anytime soon

Modelling plume behaviour in advance of future deep sea mining projects is important, but let's not forget that the fishing industry scrapes and disturbs the seabed at a much larger scale

In the fourteenth century, British fishermen from Essex sent a petition to King Edward III from England. They wanted him to ban a new type of fishing gear that some people were dragging along the seafloor. It was so heavy, they claimed, that it destroyed the seafloor and caused a by-catch of all sorts of unwanted fish and other animals.

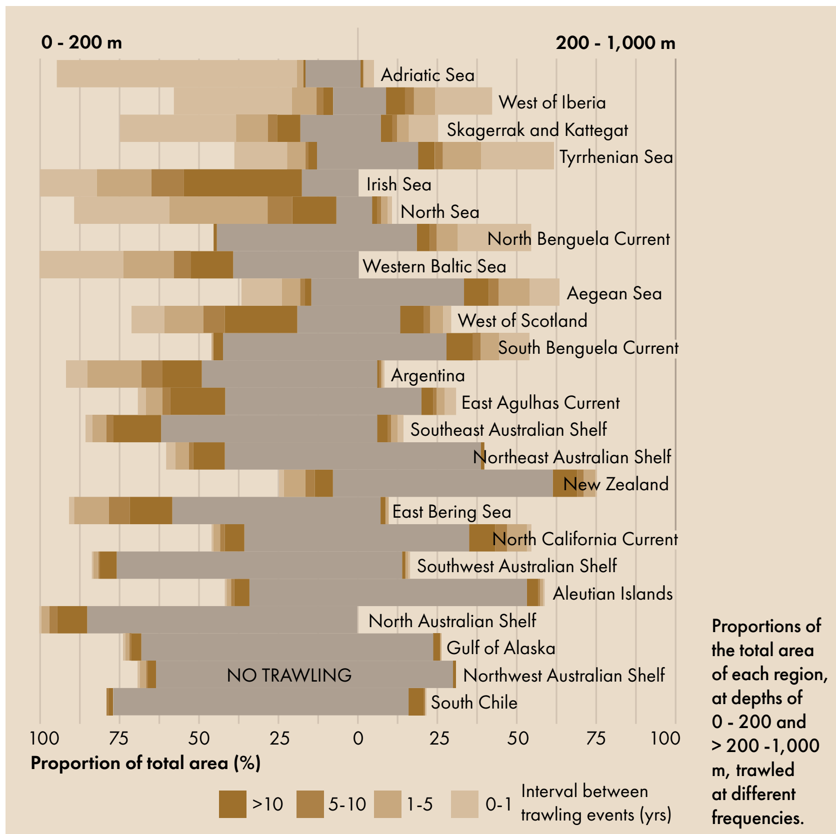
The King promised to investigate the matter, but there is no record of what happens next, says the voiceover at the start of the magazine about the effects of bottom trawling. Seven hundred years later, thousands of fishing vessels routinely trawl the sea floors of the world's continental shelves, at increasingly larger depths, to feed a growing population. The letter to King Edward III did not create that much of a stir apparently.

A paper published by Ricardo Amoroso and his many co-authors in 2018 provides some statistics on the matter. Based on high-resolution satellite vessel monitoring systems and logbook data on 24 continental shelves, the team estimates that an area the size of more than 1 million km², similar to the size of a country like Egypt, is routinely trawled. And European countries are the worst offenders, with more than 50 % of the seafloor affected compared to much less in other parts of the world.

Testament to the omnipresent nature of trawlers is this sentence in a thesis that was recently published by a PhD student in the Netherlands. During experiments to monitor plumes caused by a scaled mining vehicle, she writes: "Even though plume monitoring suffered interference from bottom trawling activities in neighbouring areas…" Isn't it telling that you cannot run an experiment on one of Europe's shelves without experiencing interference from trawling nearby?

Am I saying that we should just go ahead with deep-sea mining without any concern around habitat destruction? No. But I do feel it is irrational to prevent deep-sea mining from taking place given the sheer scale of seabed disturbance that is already happening around the world's continental shelves – repeatedly. It is odd to allow that to happen whilst preventing a new sector from trialling methods that will ultimately help power the energy transition. ■

Henk Kombrink



SOURCE: AMOROSO ET AL. (2018) - WWW.PNAS.ORG/CGI/DOI/10.1073/PNAS.1802379115

The big nodule and oxygen debate

New research indicates that polymetallic nodules on the seafloor can create electric currents strong enough to split water into hydrogen and oxygen molecules. The research paper has however met criticism

Nodules were originally termed "a battery in a rock" by The Metals Company (TMC) to convey to the public the need for deep sea minerals in the energy transition. What they, or anyone else, did not consider, was that the potato-sized metallic lumps found in vast swathes in certain parts of the deep sea may act as batteries in their natural state.

In a research communiqué published in Nature Geoscience, an international team of researchers recently proposed that polymetallic nodules produce oxygen by splitting water molecules through a process known as electrolysis.

During several cruises in the Clarion-Clipperton Zone (CCZ) in the Pacific Ocean in 2021 and 2022, Andrew Sweetman from the Scottish Association for Marine Science and his team gathered data using benthic chambers on the seafloor.

The team found that O_2 consistently accumulated in the chambers, indicating an excess of oxygen production. Several lines of inquiry were pursued to explain the net "dark O_2 production" (DOP). They eventually realized that DOP was only observed when nodules were present in the experiments, suggesting that the phenomenon was linked to their presence.

According to the research note, an input voltage of a bit more than 1 V is required to split seawater into hydrogen and oxygen molecules at the CCZ seafloor. This is comparable to the voltage in a household AA battery. Furthermore, lab experiments have shown that nodules may reach surface voltages high enough to facilitate electrolysis.

SOURCE: KOELLE, WIKIMEDIA COMMONS

A polymetallic nodule collected in the Pacific Ocean in 1982.

THE CLARION CLIPPERTON ZONE

The CCZ is located in international waters between Mexico and Hawaii. It is considered the largest nodule field in the world. The area is managed by the International Seabed Authority (ISA), and a handful of states are sponsoring exploration activities while awaiting the ISA to complete and adopt necessary regulations that may enable future mining. ISA has communicated that this may happen in 2025.

Although the discovery opens the possibility that deep-sea nodules may represent a significant source of oxygen production, Sweetman told the BBC that he does not believe his study will put an end to the plans for nodule harvesting. Still, he argued that the hypothesis needs to be explored in greater detail and that the information and data we gather going forward need to be used if we are going to do mining in the most environmentally friendly way possible in the deep ocean.

"SERIOUS CONCERNS" REGARDING VALIDITY

It remains to be seen whether the dark oxygen hypothesis stands up to scrutiny. The Metals Company (TMC), one of the most prominent explorers in the CCZ, was quick to release a statement on the Nature Geoscience communiqué.

TMC said that they were "surprised to see such a flawed paper" published and that the methodology and findings raise serious concerns about the validity of both their data and their conclusions.

For one, TMC argued that the data were not collected under conditions representative of the environment in the area. They further point out that although the paper was accepted in Nature, it had previously been rejected by several other journals. TMC also notes that Nature has taken a strong view against deep-sea mineral sourcing.

The Metals Company also mentions the existence of contradictory studies that show net oxygen consumption, not net production, at the seafloor. Also, one paper using the Sweetman et al. methodology, measured only O_2 consumption in the Korean license area of the CCZ.

Ending the statement, TMC informs that their team is preparing a comprehensive rebuttal. ■

Ronny Setså

386 blocks

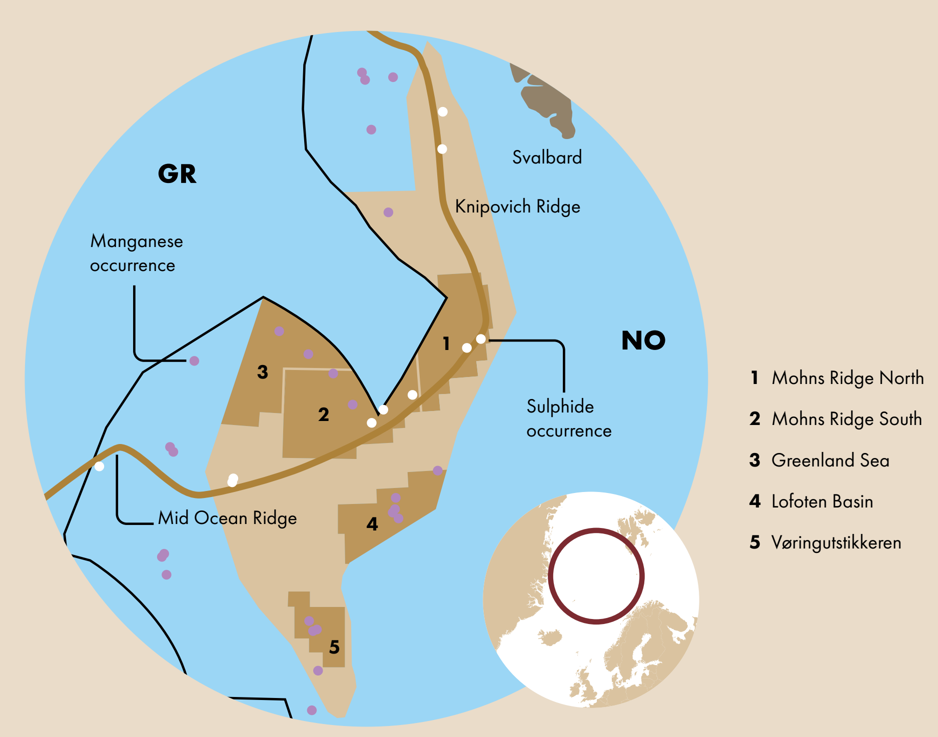
The Norwegian Ministry of Energy puts up 386 blocks for companies to apply for deep-sea minerals licences – only after a public consultation

IT IS 59 YEARS since Norway announced the first round of hydrocarbon concessions for the Norwegian continental shelf. At that time, the offer included 278 blocks south of the 62nd parallel, of which 81 were applied for and 78 awarded. The first economic discovery, Ekofisk, was made four and a half years later.

Now, a new round of concessions for the Norwegian continental shelf is underway. This time it is about mineral resources. And again, the Norwegian authorities have chosen a strategy based on making available a very large number of blocks.

Earlier this year, the Norwegian Offshore Directorate (NOD) invited explorers to nominate blocks in the Norwegian and Greenland Seas in connection with the first licensing round for deep-sea minerals. Through these nominations, the exploration companies have given their input on which areas they are most interested in and consider most prospective. As a result, the Ministry of Energy announced at the end of June that a proposal was now put forward including a total of 386 blocks.

However, it remains to be seen which blocks will be accepted for mineral operations as a public consultation is being held first.



The proposed blocks (dark brown) amount to approximately 38 % of the area that has been opened up for mineral activities (light brown).

SOURCE: NORWEGIAN OFFSHORE DIRECTORATE

WHAT CAN BE FOUND?

The NOD divides the blocks into five areas: Mohns Ridge North and South, the Greenland Sea, the Lofoten Basin and the Vøringutstikkeren. It is the two former areas that cover the spreading ridge where several active and extinct hydrothermal sources have been identified. It is at the spreading ridge that we find sulphide deposits.

The other areas will primarily be prospective for polymetallic crusts. We also note that the Knipovich Ridge, which is the extension of the mid-ocean ridge to the north, is hardly included in the Ministry of Energy's proposal. The reasons could be, among other things, lower prospectivity seen from the eyes of the industry, or a geographical location that is less suitable for possible future extraction because of longer shipping routes to the mainland.

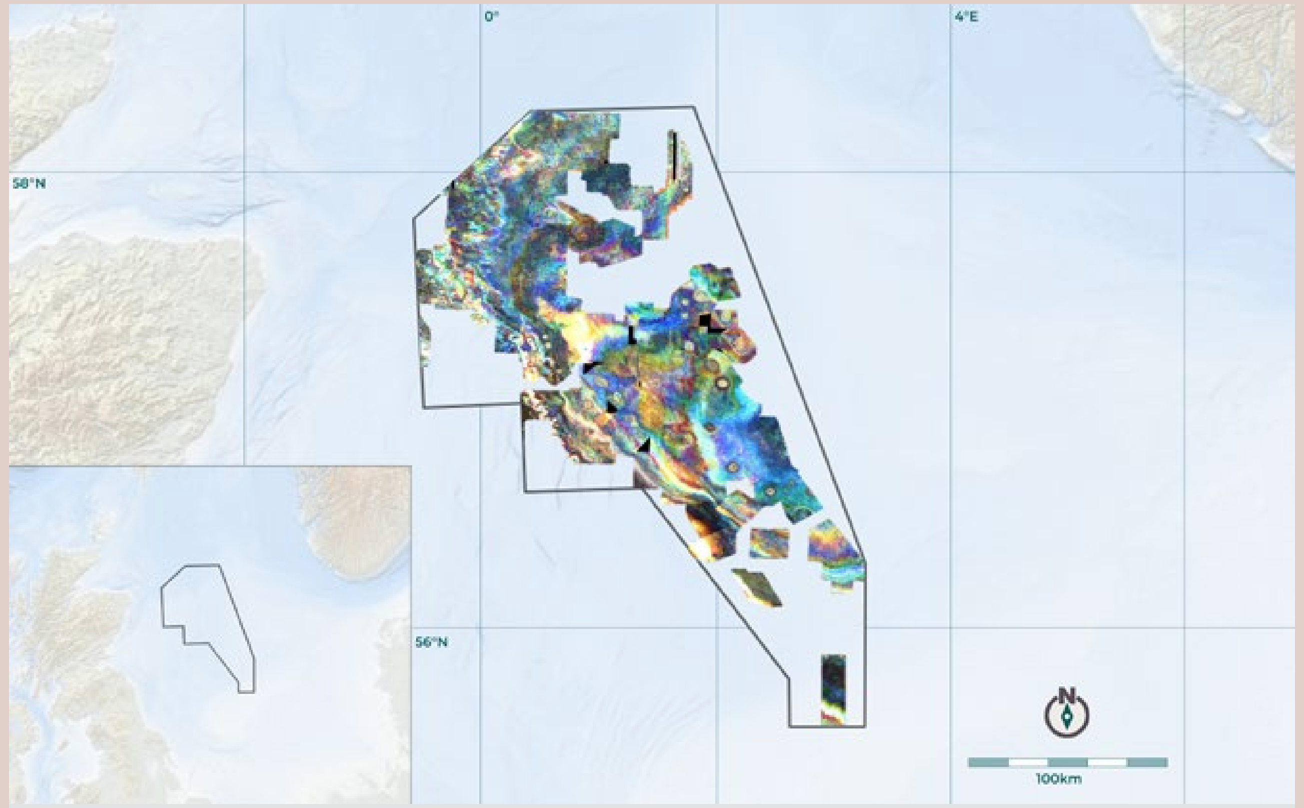
Norway is among the first countries in the world to formally and publicly open seabed mineral operations. Commercial exploration is also underway around the Cook Islands and in the Clarion-Clipperton Zone in the Pacific Ocean. Other countries such as India and Japan conduct exploration activities under state auspices.

Despite the fact that the upcoming licensing round aims to hand out extraction permits to the exploration companies, the companies will not be able to start extraction until they have been approved for an extraction plan. It must be approved by both the Ministry of Energy and Parliament. The current plan is that permits can be awarded in the first half of 2025. ■

Henk Kombrink

With 'real-time' reservoir management now within reach, energy companies are seeing they simply have no choice but to adapt to the growing technology landscape

AI applied to seismic interpretation marks a revolutionary step in oil and gas exploration and production where maximizing recoverable resources while minimizing expenditure remains a top priority for operators. With AI, it is now possible to rapidly analyse terabytes of seismic data over multiple volumes, G&G teams are moving towards 'real-time' reservoir management, to rapidly identify and rank prospects and ultimately, bringing assets online faster than ever thought to be possible.



Basemap: Location of the UKCS 3D Seismic Merge - Central North Sea (polygon) with an associated High Definition Frequency Decomposition RGB colour blend along time slice 1960 ms.

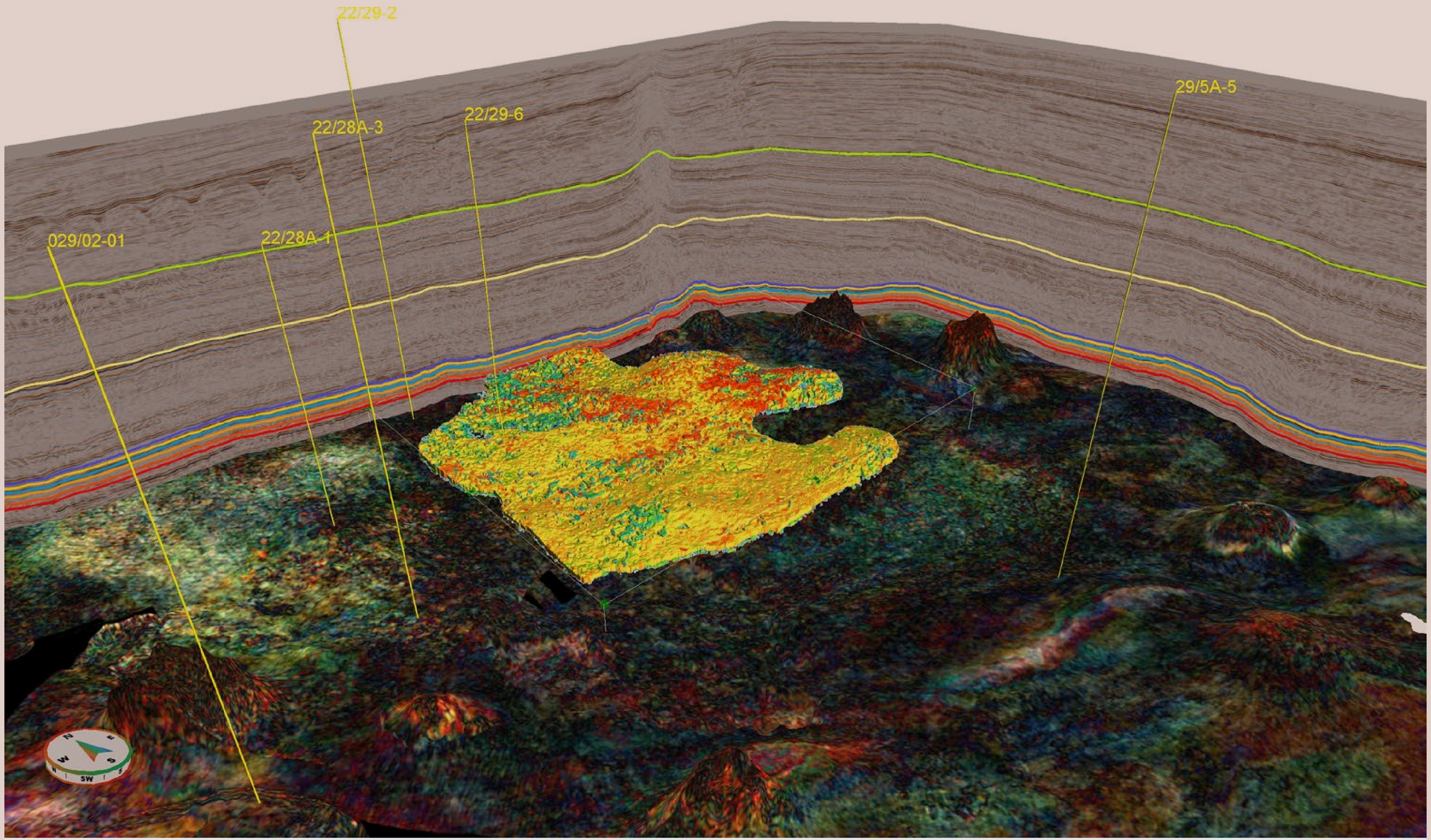


Figure 1: A selection of North Sea well paths intersecting a High Definition Frequency Decomposition RGB colour blend. Combining AI results with other volumes, such as frequency decomposition colour blends, allows the interpreter to simultaneously analyse the structural and stratigraphic features in previously unattainable detail and in record time. The RGB colour blend is draped on an AI Horizon with an AI Features volumetric Geobody of the Halibut slide.

Why the key to E&P success lies in seismic interpretation

ABDULQADIR CADER, HARRY WHITTAKER AND CIARAN COLLINS, GEOTERIC

TIME IS MONEY

Bringing new assets online quickly brings a significant advantage to energy companies where time is money. Operators are constantly seeking ways to compress the timeline from data acquisition to first oil and these workflows rely on having a thorough understanding of the subsurface thousands of meters below ground where no human has ever set foot. The interpretation of seismic data to model and predict subsurface properties which are otherwise unknown, directly impacts revenue. Here, the key to gaining a competitive edge is accuracy and speed. Advanced seismic interpretation software of today harnesses the power of artificial and human intelligence to reduce interpretation time from months to weeks with no compromise on quality.

OLD FIELDS, NEW PERSPECTIVES

While not a new concept, oil and gas operators have been focusing on near-field exploration opportunities in recent years, drawing parallels with the adage, 'making the most of what you already have'. Infrastructure-led exploration commonly equates to a lack of new seismic acquisitions and operators are left to make do with older, poor quality data. Geoscientists are turning to AI to gain a much clearer image, particularly in deeper sections where data quality is most challenging. Skilled interpreters leverage AI to reveal the hidden stories in legacy seismic data and existing fields, unlocking resources that may have never been discovered without the advancements in seismic interpretation technology.

PREDICTING THE FUTURE

In an ideal world, asset managers would have perfect visualisation of the subsurface to fully understand the size of the reservoir and future production with pinpoint precision. Today, geoscientists incorporate AI into interpretation workflows to achieve the best possible view: Rapid insight into the dynamics between structural and stratigraphic complexities, even beyond the conventional view of seismic resolution, exported as model-ready products so reservoir engineers have a clearer understanding of field performance to increase production.

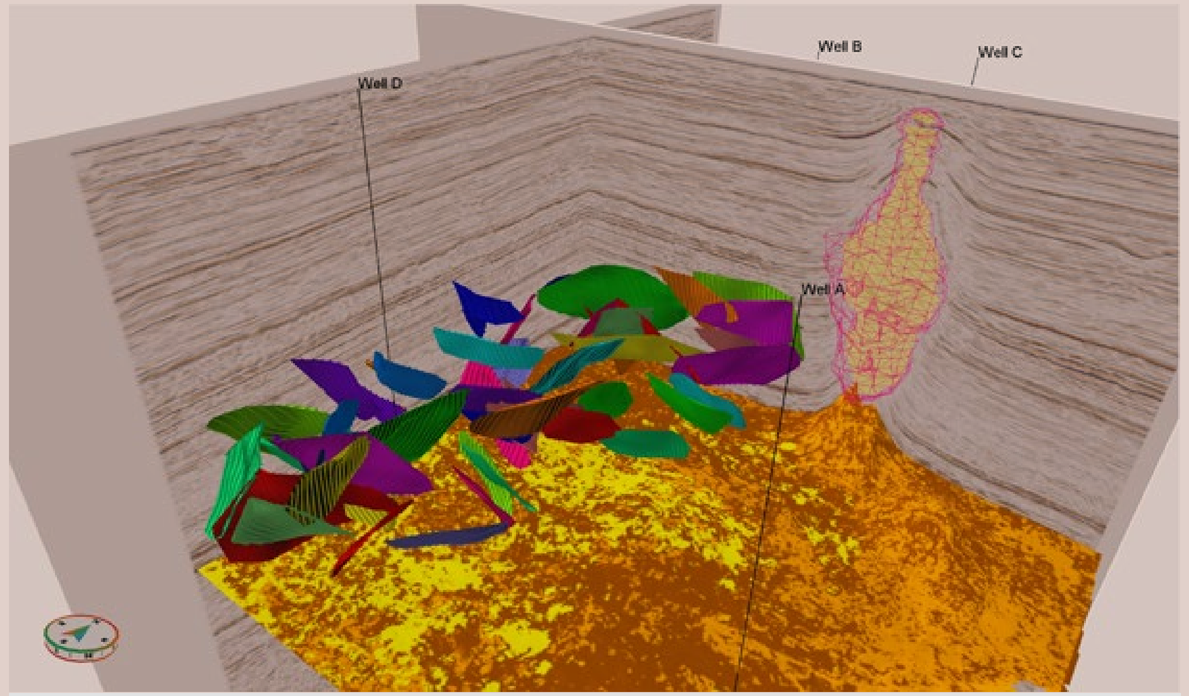


Figure 2: Model-ready 3D fault surfaces extracted automatically within a defined area of interest, producing detailed 3D fault networks even in poorer quality legacy data. Facies classification is applied using markers directly from well paths. In the background a salt body (pink mesh) has been delineated using AI Features evaluated after applying 2D data labels (yellow).

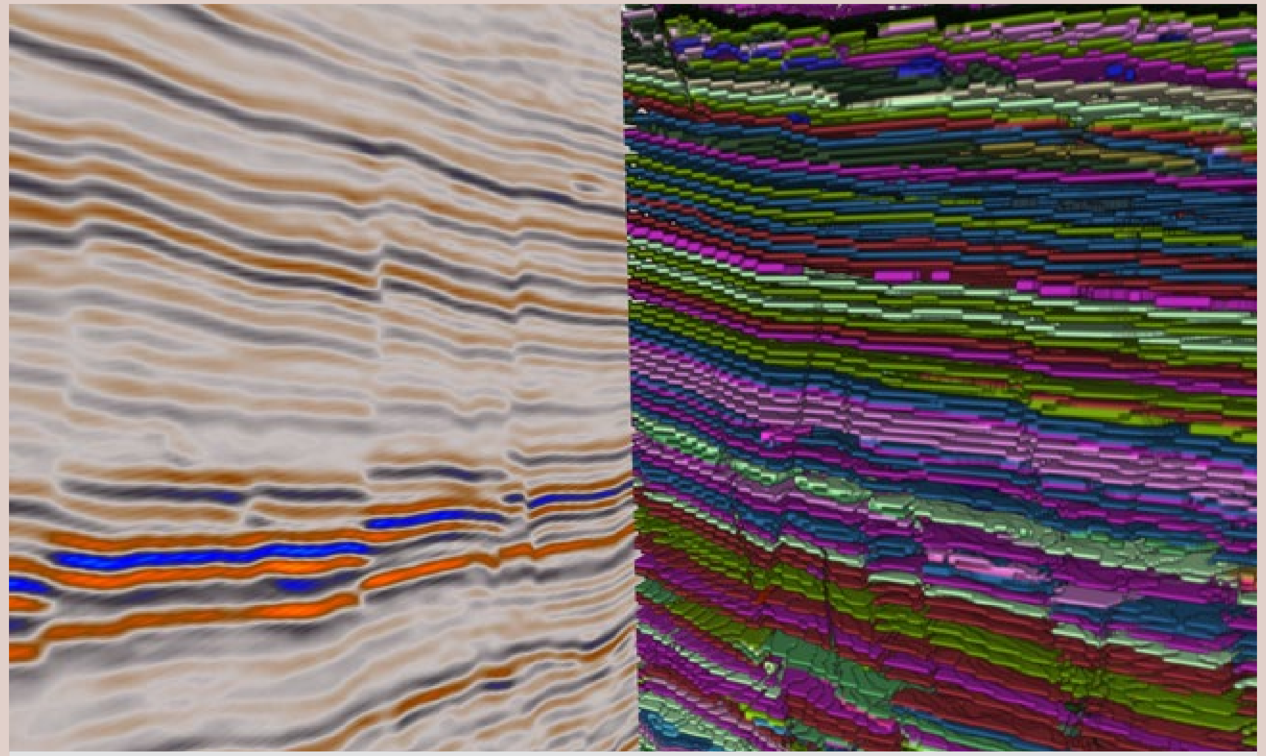


Figure 3: Geoteric AI Horizons detects every event from surface to region of interest in just hours, significantly accelerating the starting point for geoscientists, and enabling rapid CCS site screening and containment analysis. Left: Reflectivity data with user-guided AI Horizon extraction visualised as surface overlays. Right: AI Horizon volume generated from the reflectivity data. Delivered with an extremely high density and accuracy of interpretation, illustrated by the angular unconformity.

QUALITY OVER QUANTITY

Once potential hydrocarbon reserves are identified either in new or existing fields, the challenge shifts to maximizing production while minimizing costs and environmental impact. Drilling fewer wells with higher success rates to safely drive the lowest possible cost per barrel is the goal. Achieving it is only possible if the most accurate geological information is extracted from the available seismic data; one missed fault can cost millions. With today's technology, geoscientists have 3D visualisation of 3D fault networks to observe the delicate structural interplay in highly complex settings to drill successfully and safely.

NO MARGIN FOR ERROR IN CCS

With increasing environmental concerns and a ground swell of rising ESG commitments, energy companies are eagerly looking to re-purpose existing and depleted fields for Carbon Capture and Storage (CCS) projects. Furthermore, others are looking to leverage the wealth of available seismic data and experience to identify potential virgin storage sites; AI is the step change in the way in which existing E&P workflows can be optimised to meet net zero demands. Understanding storage capacity, the risk to containment, and the seal capacity are all critical elements affected by the presence of faulting that can be most clearly understood using AI. Traditional attributes simply do not capture the level of detail required to assess and monitor CCS activity safely – the impact of risky CCS on local ecological systems, not to mention the wider environment could be catastrophic.

ALL ROADS LEAD BACK TO SEISMIC

Seismic interpretation is the bedrock on which successful exploration and production efforts are built. As techniques continue to advance, the precision and reliability of seismic interpretation will only improve, further solidifying its critical role in energy's future. Once considered a risk in the subsurface world, AI is now standard practice and not adopting advanced technology is where energy companies fall at the first hurdle. All roads in this business lead back to optimizing the first challenge and AI-infused technology is the only route to a fast return on expensively acquired data and with real-time reservoir monitoring now within reach, energy companies are seeing they simply have no choice but to adapt.

DIGITALISATION

"I am probably the only tape machine specialist left in Northwest Europe"

Egil Simones - ET Works

The forgotten value of (seismic) tapes

At the periphery of conference exhibitions, one often finds the small niche companies that provide essential services. At the EAGE Annual in Oslo in June, we met Egil Simones from ET Works, who told us that even the newest data centers rely on the value of "old-fashioned" tapes

"I AM PROBABLY the only tape machine specialist left in northwest Europe", says Egil Simones from ET Works when we meet at the EAGE Conference in Oslo. Egil is surely a specialist, he became involved in copying seismic data when he was 19 years old and has stayed close to it since. He now maintains and services the IBM machines that read seismic data from tapes.

"There are still warehouses full of round 9-track tapes – you can see one of those in the photo. For instance, at Schiphol airport in the Netherlands, there are two of those warehouses", says Egil. If these tapes do not get copied onto the more modern 34 or 35 series ones, the risk is that the data get lost as the shelf life is around 30 years. And there should be another incentive to copy data from 9-track tapes to newer ones. "The data from 200,000 9-track tapes can now be stored on just one of the latest 35-series tapes", says Egil, "so imagine the space that can be saved this way."

Egil Simones at his stand at the EAGE Conference in Oslo.

PHOTOGRAPHY: HENK KOMBRINK

The data from 200,000 9-track tapes can now be stored on just one of the latest 35-series tapes

TAPES IN DATA CENTRES

It is not only seismic data that is stored on tapes though: They are a lot more important than many people may think. "As the amount of data we generate has grown exponentially", says Egil, "data centers have not been able to add flash data storage at the same pace. For that reason, part of the data used and generated today – including the movies we watch – is still being stored on tapes."

As the seismic industry has consolidated, Egil has seen his client base contract simultaneously. "There is still a demand", he says, "but the diversity of operators has certainly shrunk. At the same time, he is also involved with projects to supply machines to African countries, as part of the initiative from the Norwegian government to support low-income countries to set up their own data archives instead of relying on Western support. "I've made around 100 trips to Africa in total, Egil says, "and it is fascinating work to teach people how to deal with seismic data."

Will he be back at EAGE next year? "I do not yet know", concludes Egil. "Due to the contraction in the seismic industry, there is not a very diverse client base left. From that perspective, it is worth asking the question if it is worth to invest in booth space, even if it is a small one at the periphery of the exhibition floor." ■

Henk Kombrink

Digitisation before digitalisation

Before any fancy workflows can be applied to digital seismic data, it first needs to be available in a digital format. And there is a lot of seismic data that is only available on paper, because digital records have either been lost or deteriorated to a point they can not be read any more. That is where seismic vectorising comes in

RICHARD TAYLOR, PETROSCAN

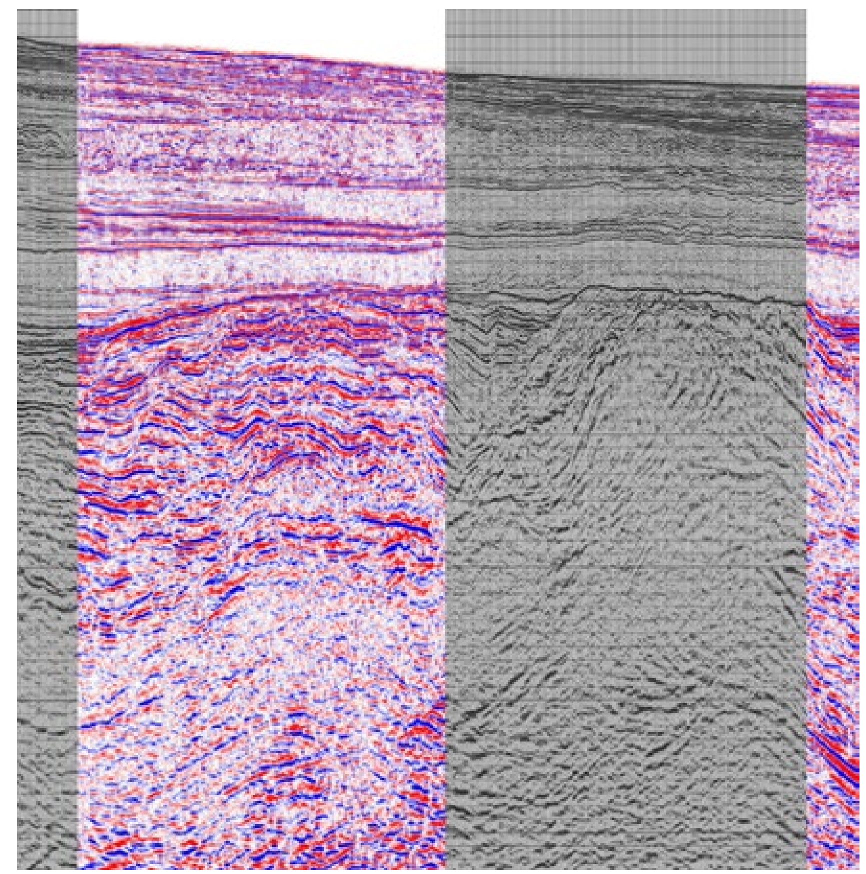
WHEN A country where some previous exploration efforts took place decides to run another licensing round in an attempt to attract interest from the global exploration community, legacy data quickly becomes one of the ticket items to lure the experts in. However, as we have seen in many cases, the only available data for an area of interest is often in hard copy or scanned image format, whether it be seismic, VSPs, wells or maps. Data in these formats can be difficult to assess and integrate into existing projects, as well as being inconvenient to manage. And because there are other countries competing to attract the same explorers, having a consistent and digital subsurface dataset is a great way to create that competitive edge.

Fortunately, legacy data can be reconstructed to a modern format, thereby restoring its versatility and value. Converting a scanned seismic image to SEG-Y enables the user to exploit the fullest potential of the seismic - the digital product allows integration of vintage data more seamlessly into existing digital projects as well as more effective interrogation, processing and management of this data and associated metadata.

Rather than a static hard copy or scanned image, through the vectorising process not only the seismic data, but also the acquisition and processing parameters, associated velocities and any displayed information such as curves or graphs can be more immediately and effectively used.

Seismic vectorising is the conversion of pixels to amplitude and frequency domain. For that reason, the quality of the output depends heavily on the quality and display type of the original section. For instance, paper data can physically degrade, or interpreters have put their colouring pencils to use. A paper copy can in turn be a scanned or reproduced version of an earlier original. Yet, end users are often surprised at what data can be salvaged through vectorising a seemingly irredeemable image. In rare cases, a seismic hard copy optimally scanned and prepped can be converted into a digital product almost indiscernible from the original data.

The market for this service ebbs and flows with the tide of global exploration interest - there are peaks and troughs. However, we consistently see that clients realise that vectorised seismic provides a viable low-cost option. Especially if you own the hard copy already, why not get more from your existing data before acquiring new? ■



The benefit of retaining the original amplitude dynamic range through full waveform reconstruction is demonstrated here in a mash up of original (black and white) and scanned seismic (coloured) with vectorised SEG-Y.

Data is not the new oil

That is what Thomas Halsey concludes in an article about the digital transformation in the upstream sector

"DEEPLY MISLEADING", that is how Thomas Halsey describes the commonly cited phrase "Data is the new oil". At least when it comes to data held by the upstream industry. The main reason for that? "Conversion of the sheer mass and heterogeneity of upstream datasets is not an easy and cheap exercise", he argues in a long read published by the Journal of Petroleum Geology as part of a series dedicated to SPE's Grand Challenges in Energy. Halsey worked for ExxonMobil for more than 26 years and is currently professor in the Department of Chemical and Biomolecular Engineering at Rice University.

"A key principle", he continues in the article, "is that digital transformation should be value-driven". A lot of data held in a myriad of places is not economically useful. The data that is, often "requires substantial spending on quality assurance, data curation, data transfer to points of computation, and the use of highly paid domain experts to interpret data analysis and make business decisions that there is no pathway to reliable value based on the data."

BUSINESS DECISIONS ARE LEADING

Therefore, he argues that business decisions should drive the way the digital transformation is taking shape. Improving business decisions through better access to and a better ability to analyse data has the potential to substantially reduce costs along the way, thereby forming a clear economic driver for implementing it.

"Detecting subtle hints towards the presence of hydrocarbons in a seismic survey that may be missed by human interpreters is good example of how new digital capabilities, here in the form of pattern recognition, have made their way into the upstream sector", continues Halsey. The seismic industry remains a world of highly technical disciplines, but thanks to the advent of high-performance computing and easier access to data as a result of cloud computing, opportunities to derive more value from these datasets have certainly increased.

The drilling industry is another upstream sector where access to digital data has exploded in recent years. The use of real-time drilling data in combination with models predicting the optimal drilling parameters has resulted in drillers being able to optimize rate of penetration. "The machine-learning component of such innovations need not be terribly sophisticated", concludes Halsey, but the key is the ability to combine models with the rich data sources available in modern operations."

DO NOT COUNT ON HAVING IT ALL

To conclude, there may be legal limitations to how "local" subsurface data could be used in a global sense, argues Halsey. Seismic data can be owned by governments, who can impose restrictions on its use. He does not mention the seismic acquisition companies, but these players are equally likely to prevent the widespread dissemination of their datasets that have been recorded at great expense. In that case, there is a business rationale behind keeping data within the limits of the organization. ■

Henk Kombrink

TECHNOLOGY

"Monitoring strategies for offshore Carbon Capture and Storage (CCS) cannot simply replicate those used in the oil and gas industry, which often rely on 4D seismic methods"

Hugo Ruiz - Reach Subsea

The time of deep resistivity

During this year's DEVEX Conference in Aberdeen, multiple operator presentations demonstrated the value of deep resistivity LWD tools. It shows how this technology has become mainstream to unlock volumes that are more challenging to get to

Times are gone that deep resistivity tools are only being used for geo-steering. The inverted data help build geomodels, help estimate net pay thickness away from well data and see beyond the seismic resolution of 3D surveys. At the annual DEVEX conference in Aberdeen in June this year, I counted four operator talks during which deep resistivity tools were discussed as part of development drilling campaigns.

First of all, the Equinor team beautifully illustrated how deep resistivity tools have helped better understand the architecture of the Maureen sandstone reservoir in the Mariner field, Northern North Sea. Where the seismic data did not show any structural features in what initially looked like a tank of sand, the deep resistivity tool used in the horizontal development wells clearly picked up internal thrust faults. This could subsequently be related to production data, which helped explain why some closely spaced wells do not see pressure communication. A clear example of better understanding reservoir architecture in a sand that was supposed to be much more homogeneous pre-drill than it turned out to be in the end.

In another interesting example, Andy Miles from Harbour Energy demonstrated the value of the deep resistivity tool for drilling thin injectite sands in the Catcher field, UK Central North Sea. Where the tool was previously used for landing wells in the right location, now the team also uses the inverted data to better estimate net pay thickness across the seismic cube. This is done through calculating net reservoir thickness based on the inverted data along the wellbore, which feeds into the sum of negative amplitudes net pay estimation. The regression then enables the team to estimate net pay thickness from seismic amplitude away from well control.

On the second day of the conference, Nick Bortnik from Serica Energy illustrated what is supposedly a fairly novel way of using the deep resistivity tool in the Evelyn development. Here, thinly bedded oil-saturated sands and the over - and underlying mudstones are sometimes challenging to differentiate between with the tool. And finally, Nick Allan from NEO Energy illustrated how his team had sleepless nights about the question whether a fault was present in the target reservoir or not, narrowing the depth window in which the hanging wall compartment had to be entered. Again, deep resistivity helped steer the well to a successful outcome. ■

Henk Kombrink

Andy Miles from Harbour Energy presenting about the Catcher field.

PHOTOGRAPHY: DEVEX 2024

The largest part of the value of the Deep-directional-resistivity (DDR) logging-while-drilling (LWD) technology lies in the automatic inversion of the measurements, improving the detection of geologic and fluid boundaries within a radius of investigation of more than 30 m around the wellbore in real time.

Time-lapse gravity

The missing piece in the CCS monitoring puzzle?

HUGO RUIZ, REACH SUBSEA AND HELEN BASFORD, SPIRIT ENERGY

Monitoring strategies for offshore Carbon Capture and Storage (CCS) cannot simply replicate those used in the oil and gas industry, which often rely on 4D seismic methods. Regulations mandate monitoring throughout the project's entire lifespan, including decades post-closure. The economic sensitivity of CCS projects implies a need for cost-efficient solutions, making expensive high-resolution methods like seismic less financially viable too.

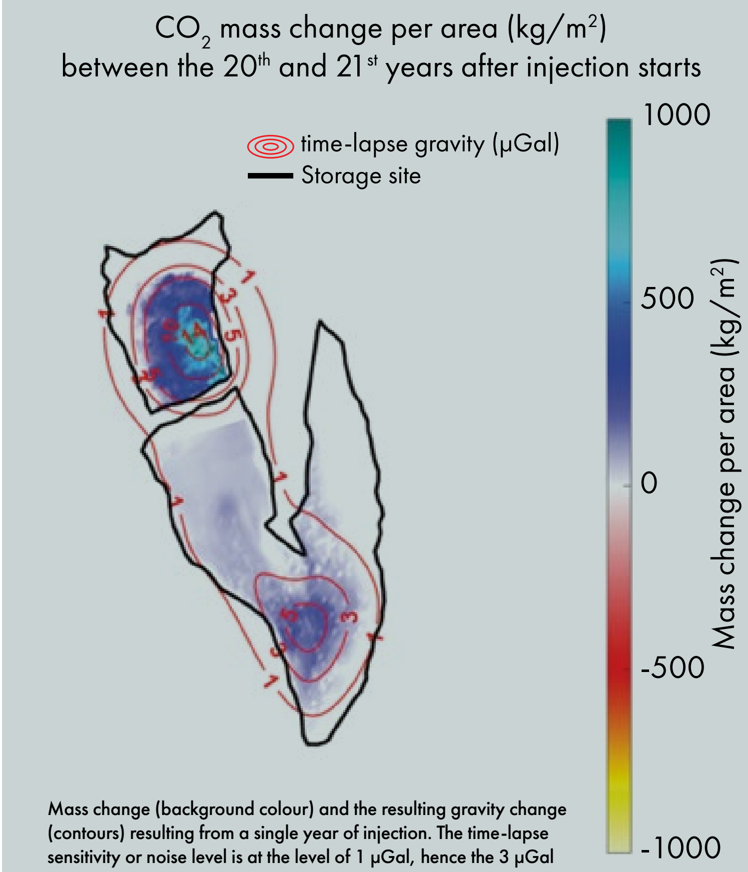
Operationally, the presence of other infrastructure, such as wind farms, complicates the systematic surveying required for seismic monitoring. Additionally, 4D signal detectability can be low when CO_2 is injected into depleted gas reservoirs due to the weak seismic contrast with the preexisting residual gas. Feasibility studies indicate that in some cases, it could take decades to achieve detectable 4D seismic signals.

This has led to growing interest in an alternative, less mainstream monitoring technology: Time-lapse gravity and seafloor deformation monitoring. This mature technology has been commercially used for 25 years in Norway to fully replace or complement 4D seismic in gas-producing reservoirs.

The technology involves tracking changes over time at predefined seafloor locations of two magnitudes. The first magnitude is the gravitational field, which provides information about mass changes and fluid flow in the reservoir. The second magnitude is water pressure, which is processed over time to measure vertical seafloor deformation. Vertical seafloor deformation indicates reservoir compaction (seafloor subsidence) or expansion (seafloor uplift).

The technology achieves an accuracy of 1 μGal for time-lapse gravity changes and 2 mm for depth changes. A 1 μGal accuracy is three orders of magnitude better than that obtained for exploration applications. With an accuracy of 2 mm, this technology offers the most precise measurements of vertical seafloor deformation over large areas. ■

SOURCE: REACH SUBSEA AND SPIRIT ENERGY



Mass change (background colour) and the resulting gravity change (contours) resulting from a single year of injection. The time-lapse sensitivity or noise level is at the level of 1 μGal, hence the 3 μGal contour is very significant. Note that the gravity change map precisely delineates the movement of the CO_2 plume.

PROMISING RESULTS AT MORECAMBE FIELDS

Recent modeling for the Morecambe fields in the UK shows promising results for the feasibility of time-lapse gravity and seafloor deformation monitoring. The results demonstrate significant and robust time-lapse gravity signals after one year of injection, indicating an excellent capability to delineate the CO_2 plume. Additionally, measuring seafloor uplift shows potential for mapping the pressure plume, which is the area of the reservoir and surrounding aquifers experiencing a pressure increase due to CO_2 injection. Delineating the pressure plume is crucial in areas with nearby fields or abandoned wells.

The results from feasibility studies for the North and South Morecambe depleted gas fields highlight the potential of a broad application of this technology. This offers a viable path forward for monitoring CO_2 storage sites in a sustainable and cost-efficient manner, overcoming the operational limitations of 4D seismic. Adopting such innovative technologies will be critical to meeting regulatory requirements while ensuring the long-term success and economic viability of CCS projects.

Seeing around OBM

Differentiating between oil from oil-based mud and the formation fluid has always been a challenge, especially with cuttings. A technique being developed by Applied Petroleum Technology (APT) and Equinor helps resolve this

GEOCHEMICAL analyses focused on characterising oil are frequently challenged by contamination with oil-based muds (OBM). This renders the results either uncertain or in some cases unusable, particularly in solvent extraction of cuttings samples.

The solution could be to acquire more downhole samples, but the costs of doing that is simply prohibitive in most cases. Instead, cutting samples are ubiquitous and once collected can be analysed in a laboratory cost-effectively. Reducing the requirement for downhole samples by just ~20 % would offer significant cost savings and the method will provide more information for engineers to work with.

That is the reason why APT and Equinor embarked on an R&D program to design an analytical approach and associated data analytical method that can extract useful information on the reservoir petroleum from OBM-contaminated cuttings samples.

MAXIMISING SIGNALS

Modern oil-based muds are variable in composition, but due to toxicity reasons, their aromatic content is often very low. In addition, the compound content will principally be synthetic and different from what we would expect in a natural petroleum. Therefore, approaches that maximise the aromatic and polar signal may provide a way to see 'around' the OBM.

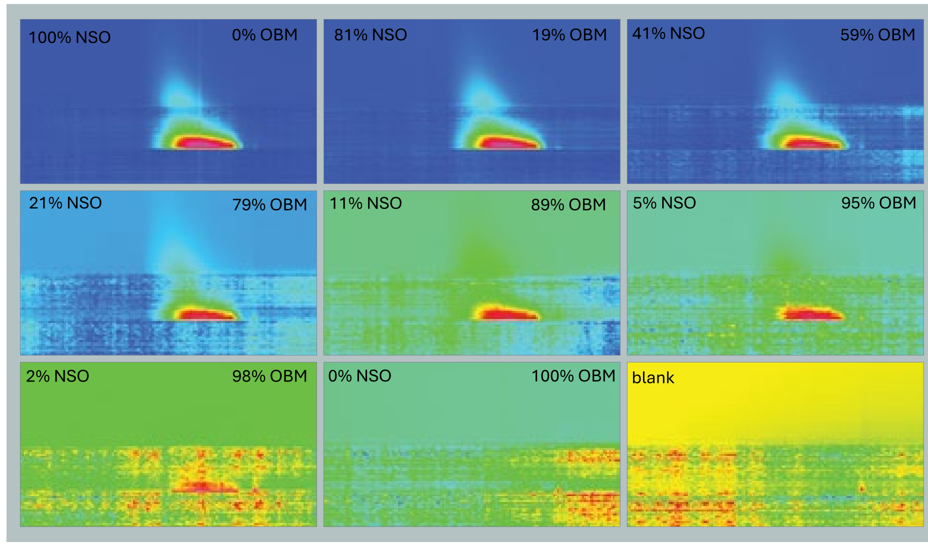
Gel-permeation chromatography (GPC) is a particular type of liquid chromatography. With this method, the separation mechanism relies solely on the size of the polymer molecules in solution rather than any chemical interactions between particles and the stationary phase. The size of polymer molecules in solution can subsequently be converted into molecular weights through calibration. Combining the GPC with Ultraviolet (UV) and Infrared (IR) detector images the fraction of the fluid least impacted by contamination, thereby seeing around the OBM. None of these technologies are novel but to date, very little work has been done in applications relevant to the E&P sector.

SHOWING PROMISE

In the initial phase, a wide range of good quality petroleum fluids, spanning 48° (API 11 - 59°) were analysed to prove the concept that GPC-RI-UV can generate data that can be used to predict physical properties with a high degree of confidence. After establishing this, the focus of the R&D program shifted to optimising preparation and the GPC set-up for highly contaminated (low signal-to-noise) samples. These results have shown promise, and the project is now moving to assess a range of case studies selected to provide a proof of concept.

Beyond the R&D focus of providing a cost-efficient and robust reservoir fluid property prediction tool using a range of sample types, including OBM contaminated cuttings, future applications include a wide range of issues from flow assurance monitoring to identification of zones of flow potential in well abandonment planning. ■

Henk Kombrink



A series of Isoabsorbance plots looking at signal dilution (100 % oil 0 % OBM) through to 0 % oil 100 % OBM). NSO is Norwegian standard oil.

SOURCE: APT

INSIGHTS

"Unrealistic expectations and promises about the time and work involved in a basin modelling exercise lead to incorrect results with large uncertainties, defeating the purpose of the project"

David Rajmon

Is Multi-Point Statistics the future of reservoir modelling?

We will be surfing the summer mood by diving into the realm of Multi-Point Statistics (MPS) and how this algorithm can be considered as the future of geomodelling

RAFFIK LAZAR, GEOMODL INTERNATIONAL

IN OUR QUEST to build more realistic reservoir models, we stumble upon the challenge of how to fill up the blanks between well data. Many robust algorithms are widely used in the industry to overcome this problem, with Kriging and Sequential Gaussian Simulation as one the most important candidates, both with their pros and cons. But with computer power capability going up all the time, the MPS algorithm is now looking for a more widespread usage.

MPS uses training images as the backbone to understand the variability of a sample point and its direct neighbours. The idea is to go beyond the variogram limitation used in Kriging by capturing complex transitions and lateral variation between different geological facies. MPS ultimately renders complex geology more accurately. Training images can be anything from a conceptual geological drawing to a prior object model to maps and other satellite images.

Let's focus on the latter: The quality of current satellite imaging has increased multi-fold to the point that modern analogues can now be seamlessly used to constrain subsurface models.

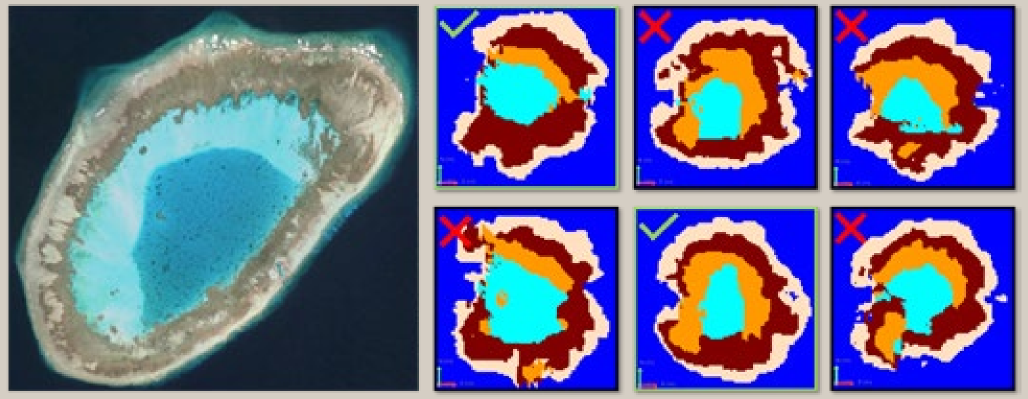
The illustration shows how a high-resolution satellite image of the Erica Reef off the coast of East Malaysia, that can be used as training images for building a geological model of the Tertiary-aged carbonate reservoirs found in Southeast Asia. A minimal imaging treatment has been applied to increase the contrast between the different facies belts in order to improve the training image quality and maximize the algorithm chance of producing realistic models.

The succession of facies belts is the key here. The presence of a clear reef rim, detrital back reef area and inner lagoon are distinguishable from the satellite image and can be directly infused in the model. Detailed morphology related to the current strength and windward / leeward side of the reef controlling the thickness of the rim is also a phenomenon that can be reproduced using MPS.

While the outputs are far from perfect, some realizations managed to "make the cut" by capturing the intertwining of the five distinctive geological facies in a realistic fashion. The resulting models are worth investigating deeper as alternative scenarios for both volumetrics quantification and dynamic flow prediction.

MPS is not limited to modern day carbonate reservoirs. Fluvial systems, alluvial fans, highly fractured outcrops can also be used as training images to feed into the MPS algorithm and produce more realistic models in other reservoir settings.

In our current quest for better development of remaining hydrocarbon reserves and predicting CO_2 migration and storage in a depleted field in the case of CCS projects, having an accurate reservoir picture is the prerequisite and the differentiator between a prone-to-fail or a successful development / storage project. MPS simulation is the vehicle to ensure that your facies belts are being dealt with properly. ■



Satellite photo of the Erica Reef in Malaysia and corresponding MPS realisations. Note that it is the architecture of facies belts MPS can model correctly, even though there are less representative cases too.

Oman – beneath the surface

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

Are tectonic quiescence, preserved source rock, stratigraphy, and the presence of mobilised salt, the ingredients to attract operators to further exploration?

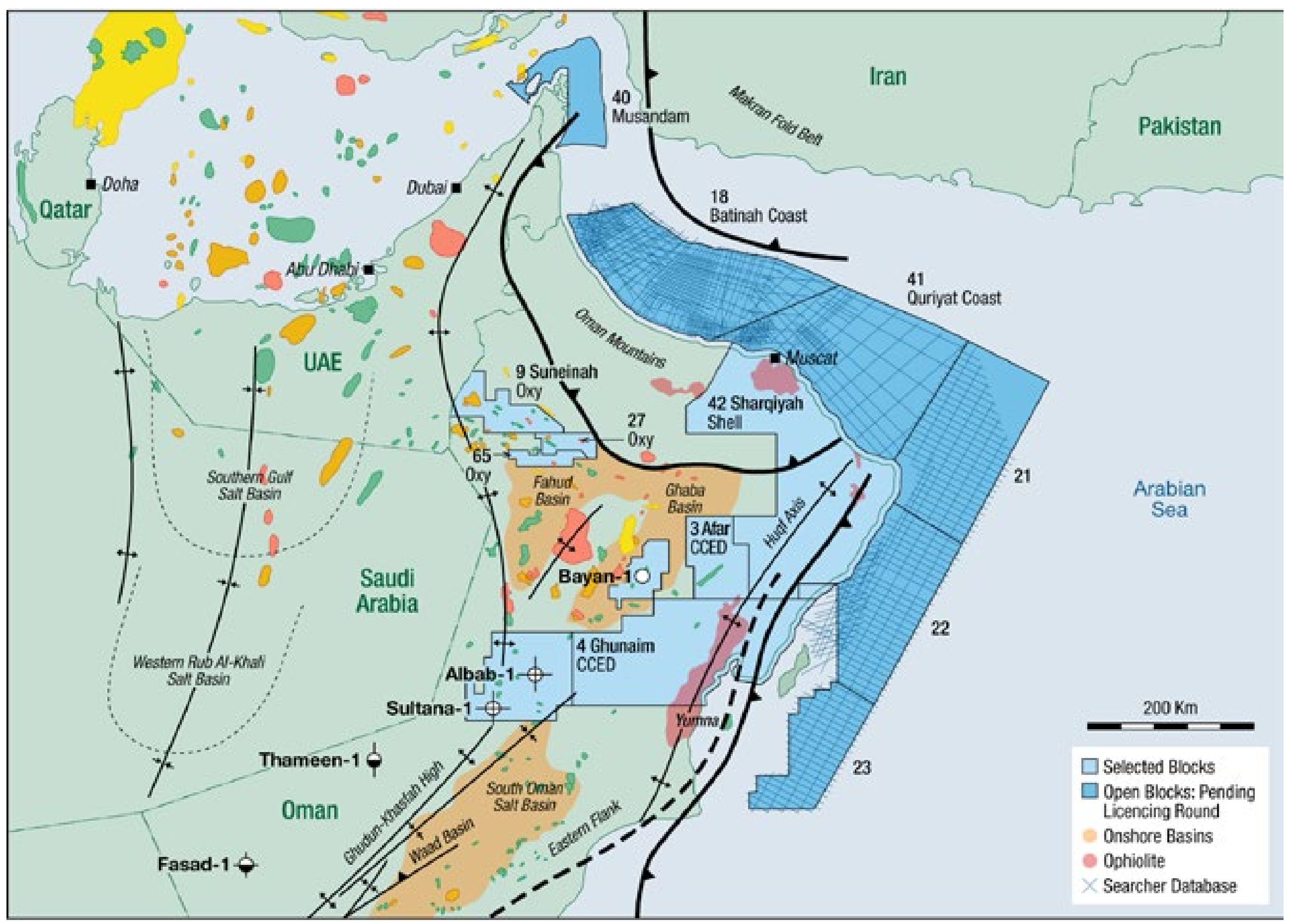
De-risking using recently acquired seismic data may provide the confidence required for operators to bid in the next licensing round.

MADELEINE SLATFORD, NVENTURES

Much has been written, including in this magazine, about the fantastic outcrop geology of Oman, the wonderful exposure, the preservation of salt at surface in the arid climate, and the incredible geological laboratory this provides.

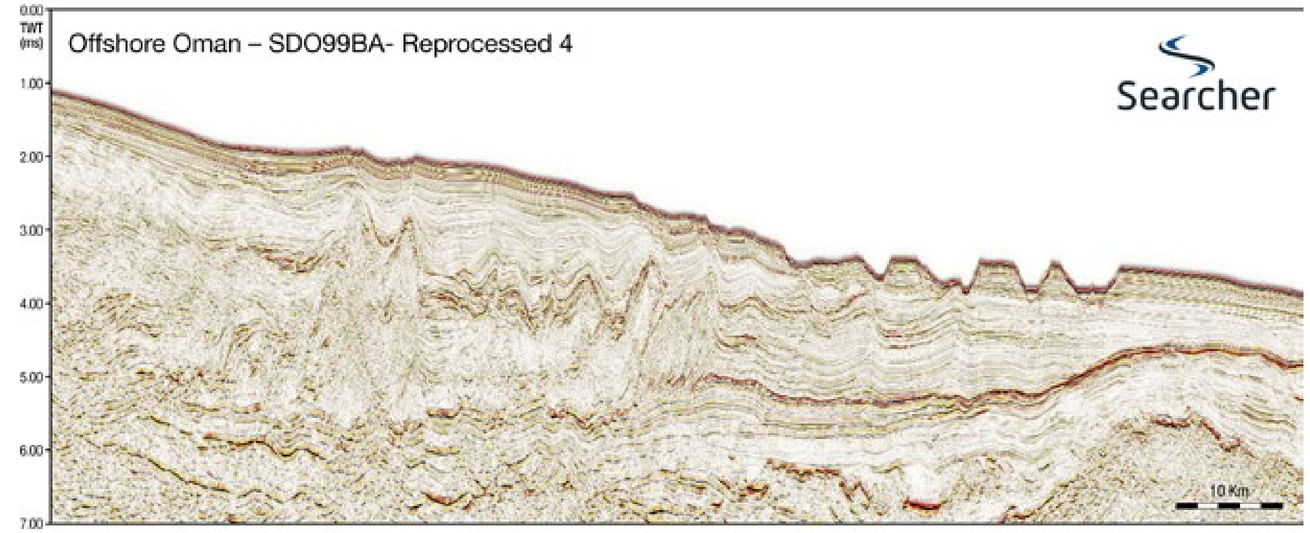
But what about the subsurface? How has the geology determined prospectivity and what are hydrocarbon and energy transition explorers up to in the various basins of the diverse country?

Oman is a mature hydrocarbon province with its first discovery taking place in 1959 (Fasad-1, Cities Service, oil shows), quickly followed by declaration of commerciality of the Fahud Field in 1964, which came onstream in 1967. While parts of the country appear geographically very remote there is significant established oil and gas infrastructure which enables some new exploration to be classed as ILX.



Oman license map.

SOURCE: NVENTURES



Offshore Oman. Reprocessed seismic section.

SOURCE: SEARCHER

GEOLOGY

Oman's geological lifespan is very long. Being part of the Arabian Platform it displays a stratigraphy from the Proterozoic through to the Tertiary, being essentially tectonically quiescent through many of these millions of years. This enables the world class oil-prone Neoproterozoic/infra-Cambrian source rock (Huqf Supergroup) to be preserved and effective. The source rock owes its richness to the completely different atmospheric conditions persisting in the "snowball Earth" of 650-590 million years ago.

The presence of salt, with its thermally insulating properties, means that the source rock is seldomly overmature and is in the oil generation window at the present day. Infra-Cambrian intra-formational stringer carbonates, such as those being targeted for production in blocks 3 and 4, provide an effective reservoir and short migration route. The Late Cretaceous closure of Tethys and the obduction of the Semail ophiolite in the east of Oman, extending into the eastern emirates of UAE (where it is being explored for hydrogen), mobilised the salt, creating traps and migration pathways both in and beyond the salt basin areas.

RECENT EXPLORATION AND DEVELOPMENT

Overlying reservoirs however can be somewhat challenging, as the Palaeozoic reservoirs have typically lost porosity and permeability, leading to production challenges. For instance, Tethys Oil discovered a 40 m hydrocarbon column in the Ordovician Hasirah Fm at Thameen-1 in 2020. However, moveable hydrocarbons were not proven and the well is to be re-entered in mid-2024 for further testing.

Occidental, operator of producing fields in northern Oman Blocks 9, 27 and 65, has conducted a vigorous E&P campaign in recent years and has been able to place at least 16 successful exploration wells, some drilled as horizontals or multi-laterals, on immediate production. The company claims this is achieved by using innovative technology and a process named "Oxy-jetting" to add incremental production (Oxy Q2 2023 report).

The Cretaceous carbonate Shu'aiba Formation reservoir accounts for much of the onshore oil production. Offshore, Cretaceous reservoirs have proved productive in the Masirah Graben, where Masirah Oil has established oil production from the Aruma Group sands at the Yumna Field. Nearby exploration, including in deepwater, by Eni, has not yet yielded any positive announcements. The presence of overthrusted ophiolitic material may complicate imaging and reservoir quality.

CURRENT ACTIVITIES

The diversity of Oman's geological features is matched by a wide range of active companies, from NOCs such as PDO, CCED, OQ, to international independents including Tethys Oil and Hydrocarbon Finders. The country also continues to attract and retain supermajors including bp, Shell, Total Energies as well as the previously mentioned Occidental and Eni. While there are no reports from TotalEnergies' recent two well campaign onshore Block 12, Albab-1 and Sultana-1, Shell is due to drill on Block 42 in 2024 and Eni / bp recently suspended Bayan-1 in Block 77.

A bid round is expected to be announced in 2024 with up to six offshore blocks available. Recently reprocessed seismic data by Searcher (32,000 km of 2D and 2,500 km² of 3D seismic) will be a valuable derisking tool for companies anxious to explore these frontiers. ■

Uncertainty - the most important result of basin modelling

Unrealistic expectations and promises about the time and work involved and rushing through a modelling exercise leads to incorrect results with large uncertainties, defeating the purpose of the work

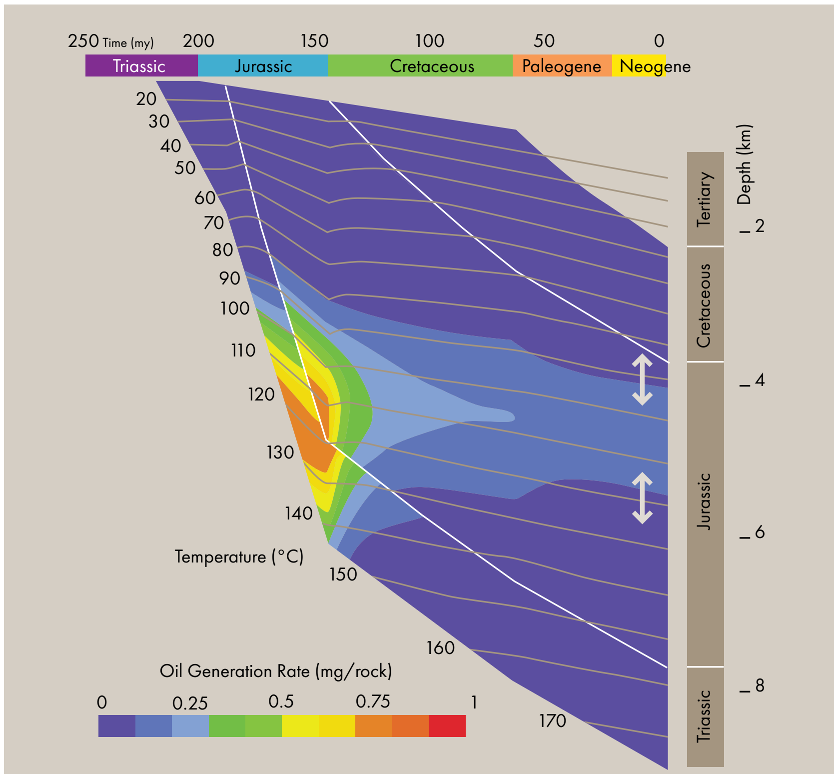
DAVID RAJMON

I HAVE LONG wanted to write about uncertainties in basin modelling. Despite their general acknowledgement, they are commonly underestimated due to various biases and psychological pressures. Explorationists sometimes live in a denial of their true magnitude.

We do not have to go too far into the modelling process, even reviewing the basics can be instructive. Take the depth horizons, for example. Even under favourable circumstances at basins with many calibration wells, the uncertainty in the horizon depth can be tens of meters near calibration wells. Moving away from well control, the uncertainty quickly rises to hundreds of meters. In the deep basins, the uncertainty in the basement depth can easily be more than 1 km. These uncertainties derive from the size of the seismic loop, gridding interpolation between seismic lines and time-depth conversion.

Chronostratigraphic interpretations further complicate matters. In one region of the Suriname-Guyana basin, two different interpretations placed the Cretaceous section 400 meters apart in depth despite having wells drilled through it.

These uncertainties translate into varying source rock maturity, hydrocarbon expulsion scenarios and predicted volumes and types of hydrocarbons. For example, 500 to 1,000 m range at a temperature gradient of 30° C / km corresponds to 15-30° C. And vice versa, uncertainties in temperature and maturity calibration data are often on the same scale and translate to equivalent uncertainty in depth. It can mean a difference between peak oil expulsion and no oil or gas dominated expulsion.



Schematic illustration of a burial history model with indicated two 800 m depth ranges spanning immature to oil expulsion zones or oil to gas expulsion zones.

Next time you are presented with modelling results, do not get carried away by glossy headline pictures and do not assume the "experts" know. Always look for an indication of uncertainty and consider how realistic it is. Are the presented "warm" and "cold" scenarios truly reflecting the horizon depth uncertainties? A look at a 1D model provides quick guidance. Look at temperature hundreds of meters below and above the horizon of interest and it gives you an indication of the uncertainty in the temperature and expulsion timing on a burial plot.

Making the model more complicated or calculating more equations does not make the model more accurate or precise. In fact, complex models obscure the problems whereas simplicity drives understanding. Sometimes data do not allow us to build a sufficiently precise model. It still does not mean the modelling exercise was useless. The value of basin modelling lies in the identification and quantification of the uncertainties. The results then guide further evaluation, realizing what matters, what does not and what can be done to narrow the uncertainties. ■

Strike-slip kinematics for pop-ups and pull-aparts

A rule of thumb to locate anticlinal structures along regional strike-slip fault trends

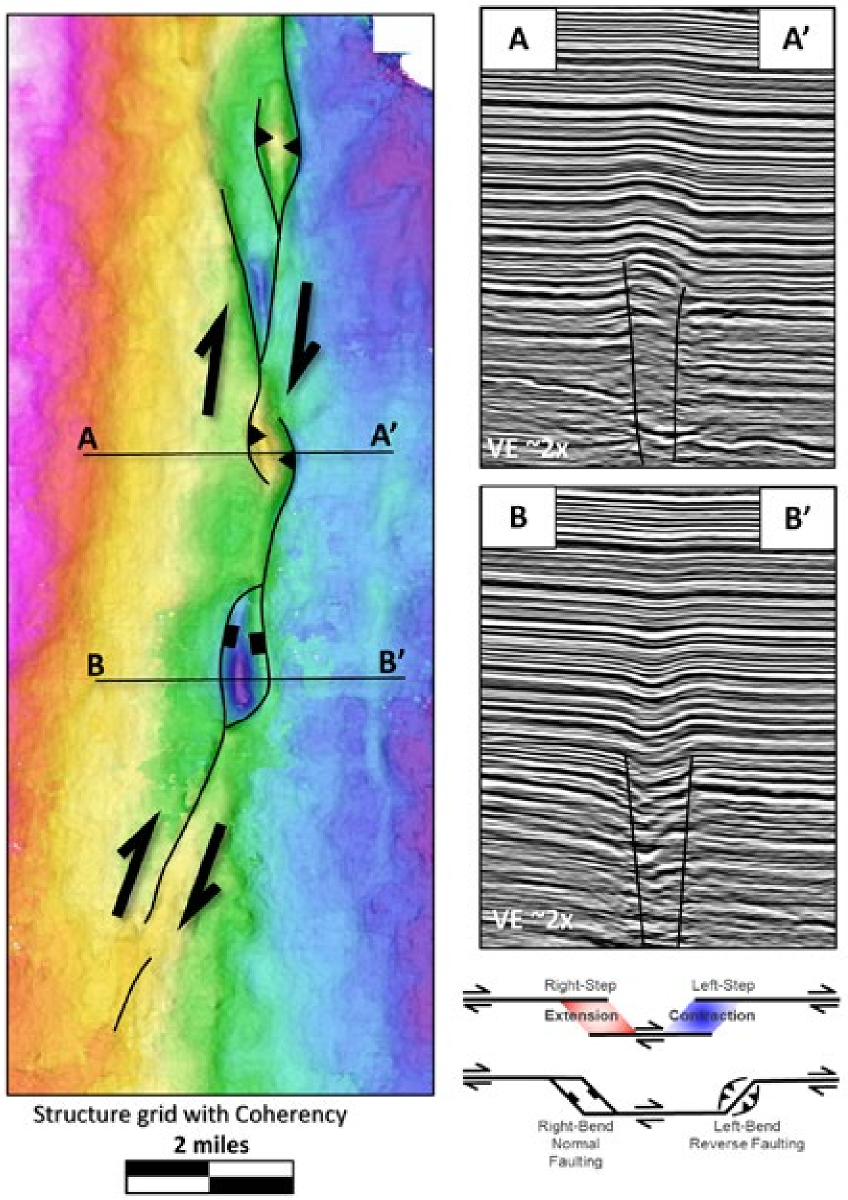
MOLLY TURKO, DEVON ENERGY

Pop-ups and pull-aparts, releasing- and restraining-bends, positive- and negative-flower structures. These are the various names given to the little, and big, structures that develop along strike-slip faults. They often form when a fault bends or steps along-trend and are great kinematic indicators for determining if a strike-slip fault is left-lateral (sinistral) or right-lateral (dextral), which can often be difficult to decipher with subsurface data.

A good rule of thumb is that if the fault slip sense and step sense are the same, you will end up with a graben or extensional feature, but if it is the opposite, then you'll end up with an anticlinal or contractional structure. So if a right-lateral strike-slip fault takes a step/bend to the right, you'll end up with a pull-apart graben - releasing bend, negative flower structure - between the fault segments, but if a right-lateral strike-slip fault takes a step / bend to the left, you'll end up with a pop-up contractional structure - restraining bend, positive flower structure.

The figure shows a series of north-south oriented high-angle faults indicative of strike-slip. Where the faults step right, we see a graben-like feature in the cross-section (B-B'), but where the faults step left, we see a contractional anticline (A-A'). Both types of structures, pop-ups and pull-aparts, can occur along the same fault trend, but whether things go up or down, depends on the direction of the bend or step. The kinematics along the fault trend in the figure indicate that this is a right-lateral strike-slip system.

This rule of thumb is great for determining slip sense along strike-slip faults and can help with finding structural traps along the contractional steps where anticlinal structures can be expected. Once you can determine the slip sense - left lateral or right lateral - along a larger trend, just look for steps or bends opposite to the slip sense. These have the potential to create large anticlinal traps along regional strike-slip fault trends. ■



Where this right-lateral fault steps right, a graben-like feature develops (B-B'), but where the fault steps left, we see a contractional anticline (A-A').

NOTHING BEATS THE FIELD

Deep-water Delaware

This photo shows a road cut in the Permian (Guadalupian) Brushy Canyon Formation off US Highway 62/180 in the foreground. The west-facing exposure, with the Delaware Mountains in the background, shows a submarine-channel fill on the left and associated finer-grained, thinner-bedded channel-margin and/or overbank deposits on the right. The Brushy Canyon Formation represents deep-water deposits bypassed across a carbonate platform in the Delaware Basin, the western subbasin of the greater Permian Basin.

Photography and text: Jacob A. Covault, Jackson School of Geosciences, The University of Texas, Austin

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.

Translating and expansional McMurray point bars

The Lower Cretaceous McMurray Formation from Alberta, Canada, renowned for its extensive oil sands, offers a unique glimpse into ancient sedimentary environments and processes

MARCOS ASENSIO

IN THE CAPTIVATING world of sedimentary geology, point bars offer a window into the dynamic processes sculpting fluvial and near-coastal landscapes.

The classical model of (expansional) point bars is best known from fluvial systems, where sediments accumulate in their inner bends. As the river flows, its velocity wanes on the inner side of the meander, allowing part of its bed load to settle.

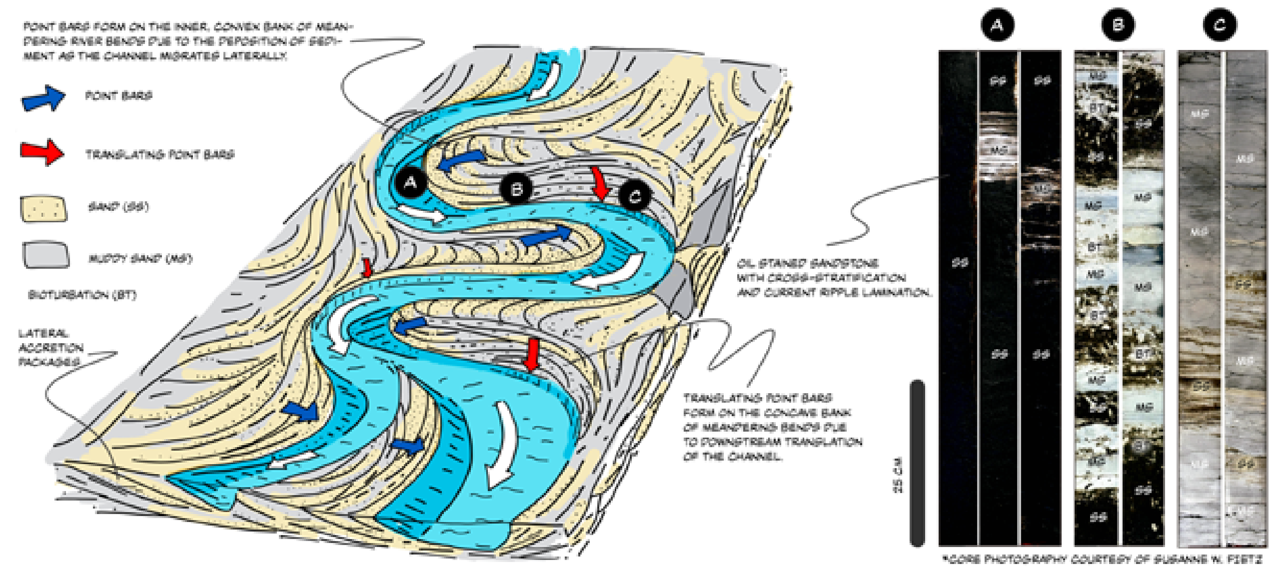
Morphologically, point bars are characterized by laterally dipping accretion surfaces, recording the progressive buildup of sediment as the river migrates laterally. This is further illustrated by the diagram shown here.

In a paper recently published in Sedimentology, another building block of meandering channels was meticulously described by Suzanne Fietz, who currently works at BGR in Hannover, Germany. Based on a combination of high-resolution seismic data and an extensive core description exercise using data from the McMurray Formation in Canada, she has been able to better distinguish translating point bars from the more "classical" and expansional point bars.

In her paper, she describes that translating point bars are readily identified in plan-view by their concave-shaped scroll bar patterns, which contrast with the convex scroll-bar patterns typifying expansional point bars. In fluvial settings, translation occurs when flow impingement takes place against erosion-resistant channel banks, leading to partial flow deflection into an upstream circulating eddy current. In a more sea-ward environment, tide-dominated translating point bars are often affected by bidirectional flow. Ebb-directed flow dominates sediment transport in the lower part of the channel and enforces seaward accretion of the bar.

The diagram also shows the relative positions of translating and expansional point bars within a meandering channel system, further illustrated by three cored intervals from different parts of the sedimentary system. What is striking in this example is the decrease in sand content when moving from the expansional point bar (A) via the upstream part (B) to the more downstream part (C) of the translating point bar.

Identification of these architectural elements does not necessarily lead to the conclusion that one is dealing with a fluvial system though. Similar gross depositional characteristics can be observed in both coastal, estuarine and fluvial settings. The study of cores and ichnofacies is always required to further point to the depositional environment at play. ■



3D diagram showing the sedimentary setting of expansional and translational point bars in a fluvial environment, further illustrated by representative cores from the McMurray Fm.

DIAGRAM BY MARCOS ASENSIO AND CORES FROM FIETZ ET AL. (2023)