THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

GEOExPro

VOL. 19
4
2022

Gulf of Mexico:
Mature
–Significant Potential

Exploration opportunities:
Canada
Mauritania
Uruguay

GEONOVA

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THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

GEO ExPro

geoexpro.com

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GEO ExPro is published bimonthly.

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Layout: Žanna Škuļova, United Press
Print: United Press, Latvia

GEONOVA

THE BEGINNING OF THE END?

One aspect of the global energy situation that is not often mentioned is that some main hydrocarbon producing provinces are in an increasingly tight position when it comes to upscaling production. Drilling continues in the North Sea, but proven volumes are marginal. The Gulf of Mexico is also seeing smaller finds in return for lots of exploration wells.

The current situation is not only a result of Russia turning off the taps, it is also a reflection of the inability of “old basins” to produce more.

> In order to discover these increasingly smaller pockets, in order to tap into resources such as geothermal and deep sea minerals, in order to store carbon underground, knowledge about the subsurface is therefore getting even more important. That is where GEO ExPro comes in.

GEO ExPro will continue to be published bimonthly and include coverage of news, feature articles, analyses, statistics and knowledge, reflecting current trends in the energy sector from a subsurface perspective.

We report on fossil fuels, geothermal energy, marine minerals, subsurface storage and digitalization. In doing so, our ambition is to advance the product portfolio of GEO ExPro from “Nice to Know About” to “Key to Know About” and I am looking forward to shape the magazine that way!

Henk Kombrink

BEHIND THE COVER

Source: USGS

The Mississippi delta is one of the best examples of a river-dominated delta in the world, with its characteristic bird-foot pattern of river branches. Before extensive leveeing started in the 1930’s, the river avulsed approximately every 1,000 to 1,500 years.

Less obvious to the public, but even more important to the industry, is the close link between the sediments deposited by the Mississippi delta in the Gulf of Mexico, and its petroleum riches. Ultimately, it is in sands deposited by precursors of the Mississippi where oil and gas are found in at the present-day.

The delta started to take shape in Cretaceous times, around 100 million years ago, but from the Miocene onwards sedimentation rates increased dramatically, leading to more than 3 kilometres of Miocene sediments deposited in the Gulf alone. High sedimentation rates continued into the Holocene, which made the even some oil discoveries possible in Pleistocene sands.

And while the Mississippi-sourced sands form the most important hydrocarbon reservoirs in the northern Gulf of Mexico, in Mexican waters in the south, where siliciclastic input was much more limited, carbonates are the most important host for hydrocarbons. The petroleum geology of the Gulf in a nutshell!

Communication

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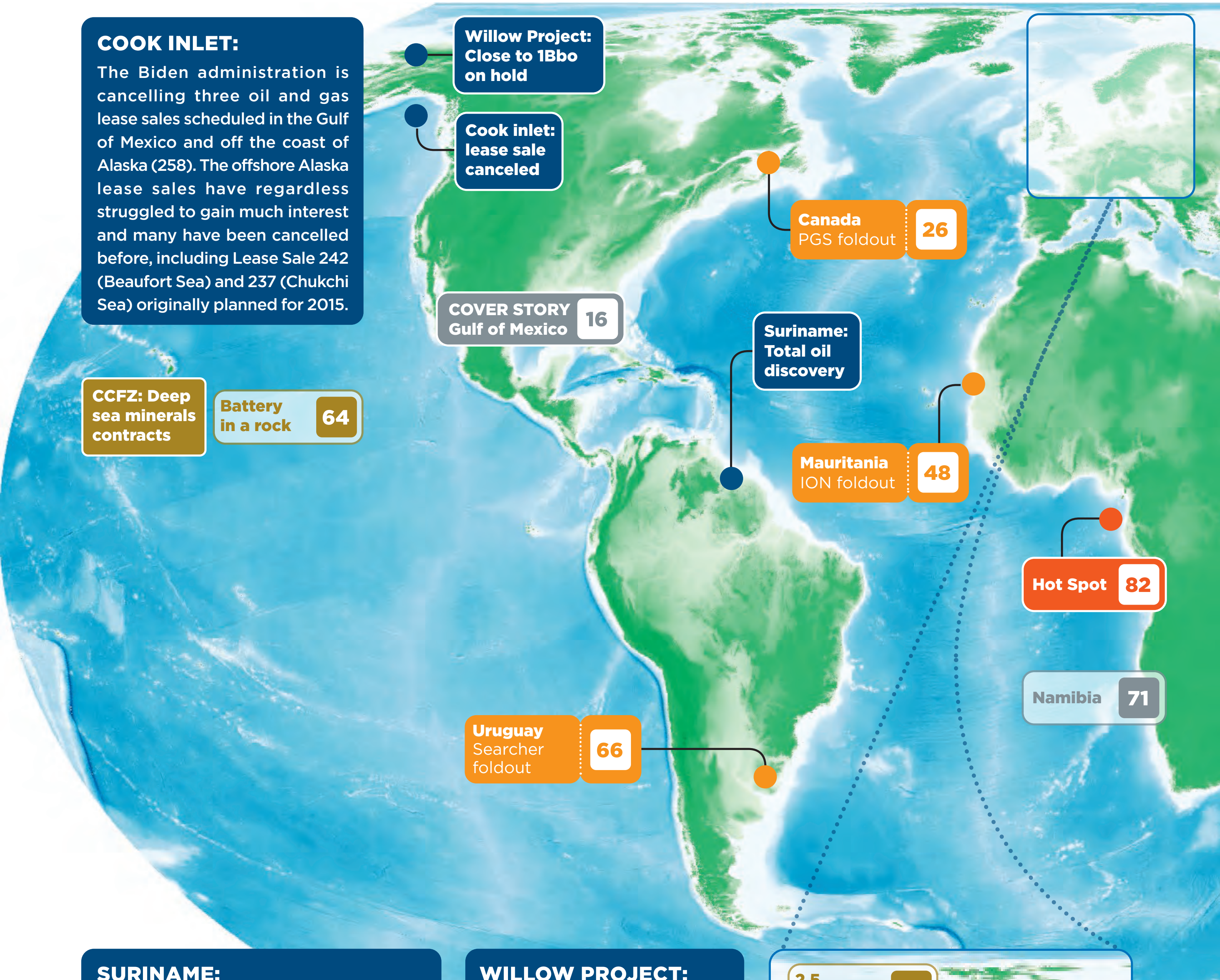
COOK INLET:

The Biden administration is cancelling three oil and gas lease sales scheduled in the Gulf of Mexico and off the coast of Alaska (258). The offshore Alaska lease sales have regardless struggled to gain much interest and many have been cancelled before, including Lease Sale 242 (Beaufort Sea) and 237 (Chukchi Sea) originally planned for 2015.



SURINAME:

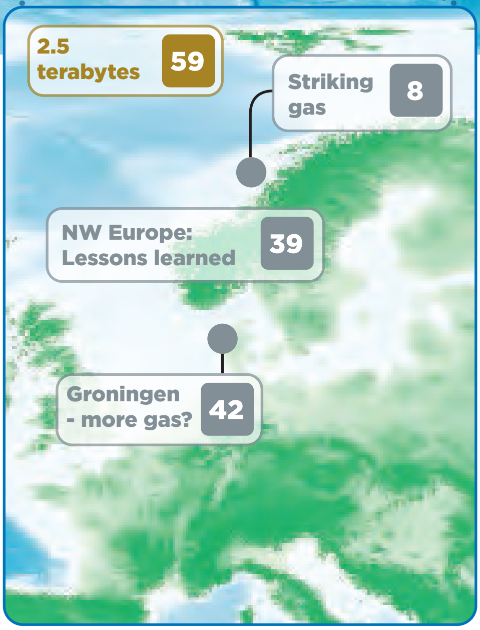
While Exxon has made a string of significant discoveries offshore Guyana with recoverable resources for the Stabroek Block of nearly 11,000 MMboe, TotalEnergies is successfully wildcatting Block 58 in neighbouring Suriname and heading for the first oil development by year end 2022.

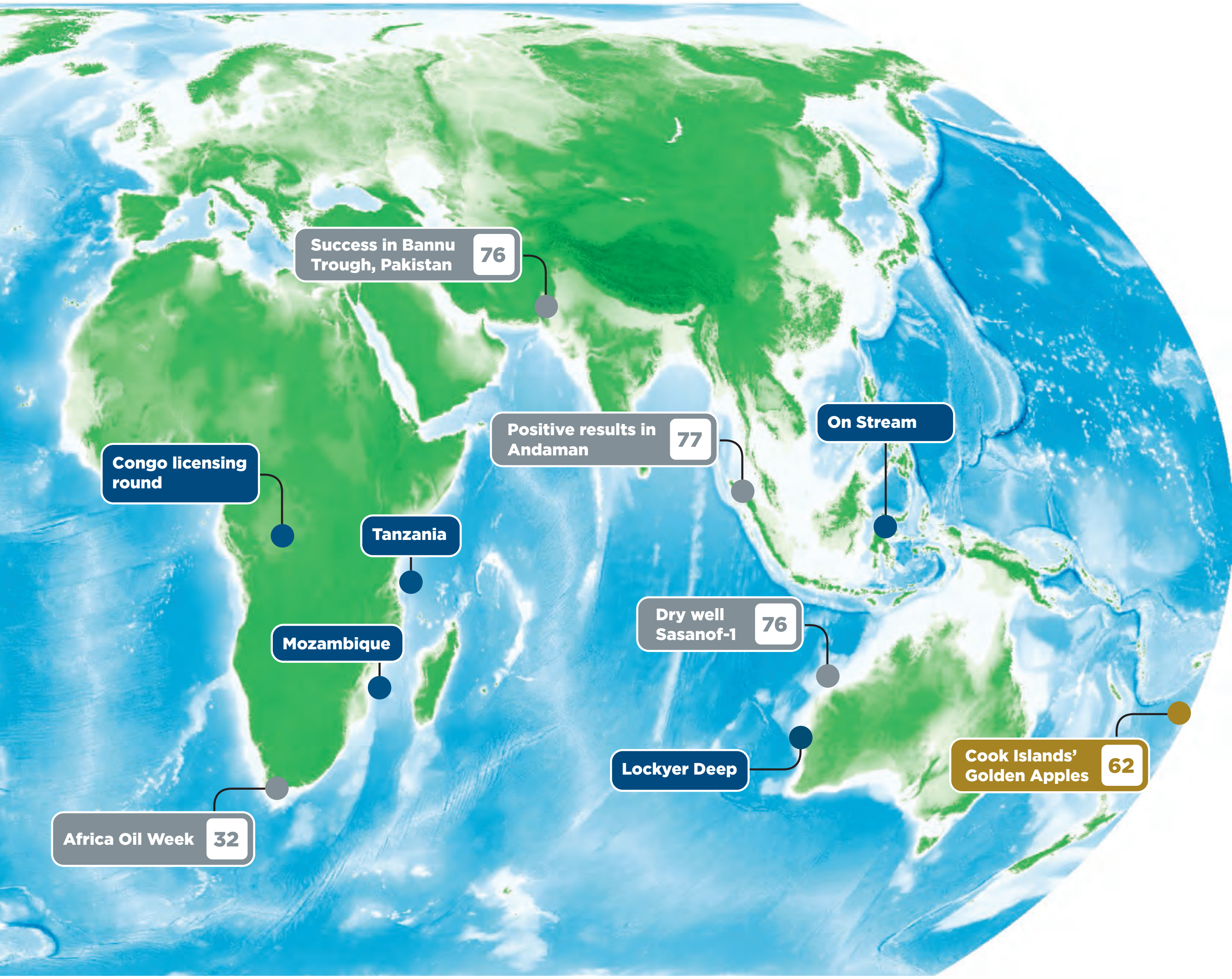
CLARION CLIPPERTON FRACTURE ZONE:

ISA has entered into 15-year contracts for exploration for polymetallic nodules, polymetallic sulphides and cobalt-rich ferromanganese crusts in the deep seabed with 22 contractors. The Metals Company is in the forefront in search for Ni, Co, Cu and Mn.

WILLOW PROJECT:

Prudhoe Bay, with 25 billion barrels of oil in place and approaching a recovery factor of 60%, remains the largest oil field in North America and ranks among the 20 largest fields ever discovered worldwide. In 2017, the operator ConocoPhillips made the Willow oil discovery within the National Petroleum Reserve of Alaska estimated to have resources of 450-800MMboe. The project is now on hold after a U.S. federal court judge in August overturned the project's previous federal approval, citing issues with the environmental assessment.





Source digital elevation model: The GEBCO Grid

LOCKYER DEEP:

Norwest Energy NL announced positive results of their Lockyer Deep-1 gas discovery offshore West Australia. With an estimated 2-3 Bcm in place, an appraisal programme is planned for later this year.

ON STREAM

New JML-1 platform on Jumelai field comes on stream. Operated by Pertamina, Jumelai is expected to produce 45 MMscf/d of gas and 710 Bpd of condensate.

CONGO LICENSING ROUND

The Democratic Republic of Congo is putting 30 blocks across the country on offer for licence applications in a drive to revitalise the hydrocarbon sector.

TANZANIA

Equinor has drilled a total of 15 exploration wells, resulting in nine discoveries with estimated volumes of more than 20 Tcf of gas in place.

MOZAMBIQUE

TotalEnergies is on track to deliver LNG from 2024 based on gas reserves of 65 TCF (12 Bboe) in the Mozambique Basin.

Showing Wit at Warka

ConocoPhillips and PGNiG prove the potential of Cretaceous deep marine sandstones in the Norwegian Sea and win the Exploration Innovation Prize 2022.

The path that led to the discovery of gas and condensate in the **Warka** prospect has not been smooth, especially for **PGNiG**. The Polish company first identified Warka in 2016, as the operator of the PL 799 licence. However, the licence partners could not come to an agreement on drilling Warka.

Then, PGNiG attempted to apply for the licence again in the APA 2017 licensing round but did not succeed in finding partners. As a result, the licence was not awarded.

Only in 2018, when **ConocoPhillips** became the operator of the PL 1009 APA licence application with PGNiG as a partner, the licence was awarded, including a firm well commitment.

A COMPLEX PLAY

The licensing history that ultimately led to Warka being drilled in 2020 is a testament to the perceived challenges of the Cretaceous play in the Norwegian Sea. With sand thickness and quality difficult to predict and map, and with Warka being a deeply buried prospect, it is easier to understand why it took some time to get it drilled.

The reservoir in the Warka discovery is of Albian age (Lower Cretaceous) and was the first one of this age to be drilled in the Norwegian Sea. The sandstones are interpreted as a deep-water turbidite sourced from the Sør High in the east.

One of the major questions the exploration teams had to answer was how the sandstones of the lobe got disconnected from the feeder channel in order to prevent migration further updip. This was addressed using geophysical and geological evidence, suggesting that this was indeed the case.

The depositional or conceptual model for the reservoir sands was an important factor in predicting the quality of the reservoir unit. Two end-members were defined, with one predicting a predominantly poor reservoir mostly consisting of debris-flow deposits, and the other one consisting of a sandy central lobe with hybrid events along the fringes.

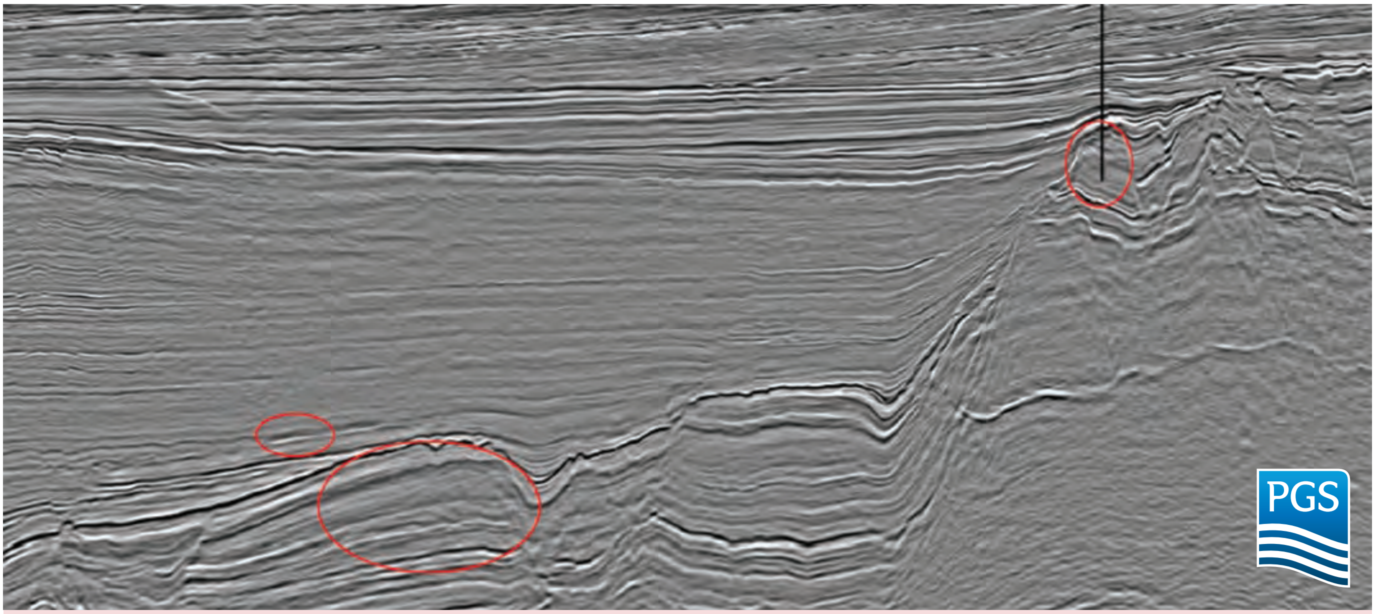
A SIZEABLE DISCOVERY

Then, in 2020, well 6507/4-1 was finally spudded, just to the northwest of the **Victoria** discovery. Classified as an HP/HT well, the total sand thickness of 37 m and an average porosity of 13,8% came in according to prognosis.

Gas condensate was found at a pressure of 800 bar and a temperature of 150°, resulting in a discovery ranging in size from **50** to **189 MMboe**. However, permeability data did show a more complex distribution than initially thought, which means that further appraisal is required to better understand reservoir architecture and permeability distribution.

The Cretaceous of the Norwegian Sea continues to deliver in terms of discoveries, but, as the Warka well has shown, also results in further questions to be answered. However, the only way to find out is testing with the drill bit, and that is what ConocoPhillips and PGNiG have done. For that reason, the companies were awarded the **GeoPublishing Exploration Innovation Prize 2022** in Oslo in June this year. ■

HENK KOMBRINK



NNW-SSE running seismic line showing the Warka prospect (small red circle on the left) close to the Victoria discovery (bigger red circle). The small circle on the right indicates the position of the Slagugle discovery, also made by ConocoPhillips. This section nicely shows the fault-block nature of Middle Jurassic discoveries such as Slagugle, where the Cretaceous of the Norwegian Sea is characterised by much more subtle trapping configurations. Seismic line by PGS.

GeoPartners

Multi-Client Seismic Africa • Mozambique

EXTENSIVE NEW 3D SURVEY IN THE ANGOCHE BASIN, OFFSHORE MOZAMBIQUE

inp
INSTITUTO NACIONAL DE PETRÓLEO

Available blocks in the Angoche Basin offshore Mozambique, with the location of the proposed 3D multi-client survey area

GEOPARTNERS LIMITED is pleased to announce the signing of an exclusive agreement with the **INSTITUTO NACIONAL DE PETROLEO ("INP")**, on behalf of the government of Mozambique, to conduct a major new multi-client 3D geophysical survey in the offshore Angoche Basin.

The project will comprise the acquisition of a minimum 12,000 square km of 3D multi-client data over blocks that will be awarded following the closure of the current 6th Licensing Round. Advanced new acquisition and imaging techniques will provide better illumination of complex structures to help reduce exploration risk and fast-track the region for potential production and development. Pre-acquisition permitting has started and it is anticipated that the 3D acquisition will commence in early 2023, with an expected duration of six months to complete and with early processed results available by end 2023.

Jim Gulland, Director of GeoPartners, announced, "We are honoured to have concluded this new agreement with INP to acquire this very large 3D seismic survey in the relatively underexplored but highly prospective Angoche Basin. The upcoming new multi-client 3D seismic acquisition program will help accelerate the identification of what will surely be the next wave of major discoveries in Mozambique."

Angoche Potential

Although undrilled, existing 2D and 3D seismic indicates the development of large-scale slope-fan sandstones, particularly within the Cenomanian/Turonian and Paleogene, with potential stratigraphic traps and structural closures draped over syn-rift highs. Reservoir development at these levels is supported by seismic amplitude and AVO anomalies, with potential DHIs. Seismic response indicates potential source development in the Aptian, equivalent to the Lower Domo Shale and a potential gas/condensate and light oil source.

For further information please contact GeoPartners:
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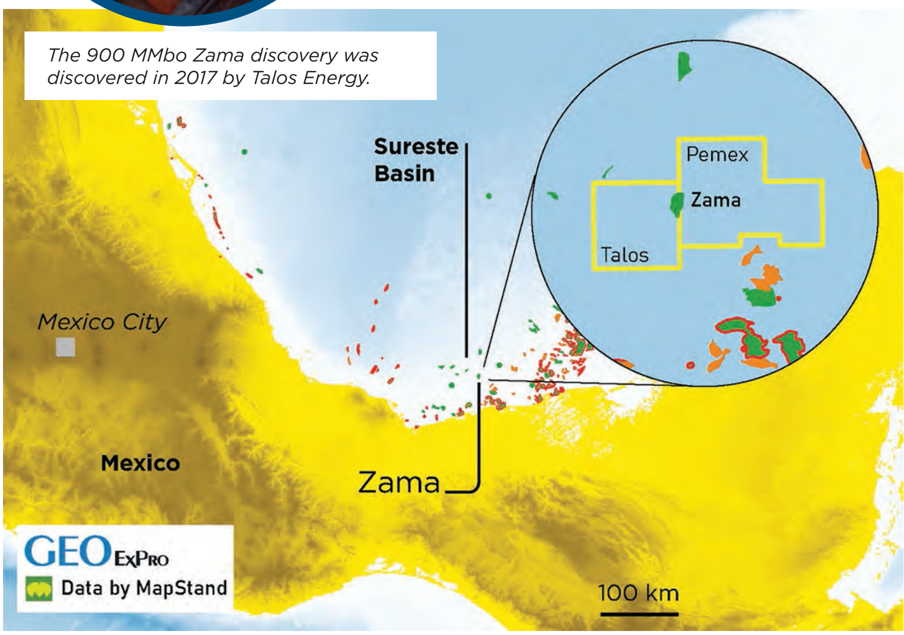
Telephone: +44 (0) 20 3178 5334 • Website: www.geopartnersltd.com

Bad News & Good News

While dollars may move "overseas" because of blocked lease sales, several recent discoveries confirm the Gulf of Mexico's prospectivity.



The 900 MMbo Zama discovery was discovered in 2017 by Talos Energy.

Talos Energy is the 8th largest producer in the U.S. Gulf of Mexico (Shell, BP and Chevron produce more than 50%), with production operations, prospects, leases and seismic databases spanning the basin in both deep water and shallow water. Proven reserves in deep water amount to 162MMboe. Daily production in 2022 is expected to be 60-64,000 boepd.

In May 2022, the Biden Administration cancelled two lease sales (259 and 261) in the Gulf of Mexico (and 258 in Alaska), citing "conflicting court rulings" for the Gulf of Mexico lease sales. In a separate move in June 2022, Republican-governed states asked a court to restore Lease Sale 257, the largest offshore oil-and-gas lease sale in U.S. history, which had been vacated earlier this year by federal Judge Rudolph Contreras.

The US Gulf of Mexico is the 2nd largest oil-producing basin in the United States.

BAD NEWS: DETRIMENTAL TO US OIL INDUSTRY

The 257-auction had, rather controversi-ally, been opened in November 2021 covering 80 million acres (over 320,000 sq. km) just four days after the landmark COP26 Climate Conference in Glasgow, UK. The sale represented the largest-ever oil and gas lease offering, covering an offshore area of almost half of the North Sea (570,000 sq. km).

The environmental groups immediately started showing concerns and in January 2022, a US federal judge blocked the sale of the leases, ruling that Joe Biden's administration "did not properly consider the lease's impact upon the climate crisis".

There is concern and nervousness in the USA that investment dollars will now move "overseas" to the detriment of the USA oil and gas industry. The delay precludes the ability to have these sales before the **National Outer Continental Shelf (OCS) Oil and Gas Leasing Programme** expired on 30 June 2022 and this means that lease sales won't resume, it is expected, until late 2023. Once the programme lapses, no offshore leases can be issued until a new plan is in place. The federal government is legally required to create a new plan, but the Biden administration has yet to propose one.

GOOD NEWS: A GIANT

Meanwhile, the Mexican government has announced that it is close to reaching a deal with Houston-based **Talos Energy** (founded in 2012) over the future unitization of the **Zama** oil field located in the southern part of the Gulf in the **Sureste Basin** in Mexico.

The field is reported to be around 900 MMbo in size and was discovered in 2017 in Block 7. Following successful appraisal drilling, the accumulation was found to extend into a neighbouring block operated by state-run **Petróleos Mexicanos** (PEMEX).

In July 2020 Talos Energy received a notice from Mexico's Secretaría de Energía (Ministry of Energy or SENER), instructing the Block 7 Consortium and PEMEX to unitize the Zama Field. Talos's partners are **Harbour Energy** and **Wintershall Dea**.

GOOD NEWS: SIGNIFICANT DISCOVERIES

The US side of the Gulf of Mexico has been the venue of a number of significant discoveries over the last 18 months or so. These included **Puma West** (BP, operator), **Leopard** (Shell), **Black Tip North** (Shell) and **Winterfell** (Beacon Offshore Energy).

Other positive news on the USA side of the Gulf was the announcement in May 2022 that Chevron had approved the development of the deepwater **Ballymore** project and expects to achieve first production from the field in 2025. Ballymore was discovered in 2018 and is expected to produce up to 75,000 barrels of oil a day. This follows from LLOG Exploration Company announcement of the proposed **Leon-Castile** deep-water development. First production from the development is expected by mid-2025. ■

Ian Cross, Moyes & Co

Land Nodal Systems in New Markets

The seismic acquisition industry is increasingly moving into the renewable energy domain, with Sercel being a recent example.

In June, the French company announced the sale of a 15,000 channel WiNG system to **Smart Seismic Solutions** (S3), a French seismic and geophysical survey contractor.

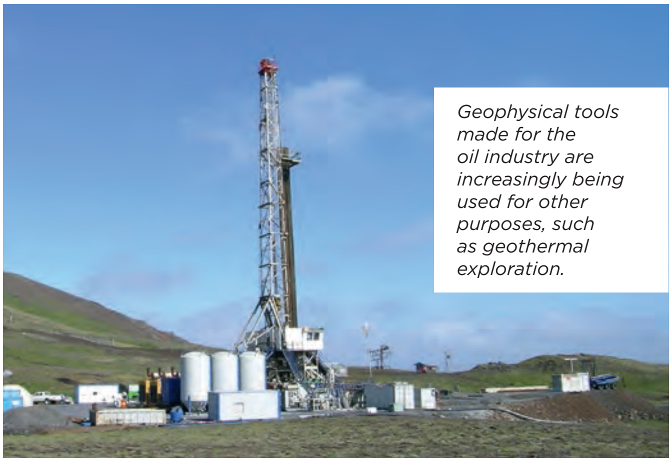
This new sale comes after S3 successfully deployed WiNG in Europe on a series of extensive clean energy and mineral projects such as helium, geothermal energy, and salt exploration.

Convinced by the performance of Sercel's land nodal system, S3 aims to utilise the equipment and supply its clients with leading solutions for seismic surveys, mainly focused on projects with a positive environmental impact. Featuring **QuietSeis®**, Sercel's ultrasensitive broadband digital sensor, WiNG nodes deliver what the company calls "optimal data quality for unsurpassed subsurface imaging". In addition, when equipped with Sercel's field-proven Pathfinder transmission management technology, WiNG provides operators with real-time visibility of the spread, ensuring "the most comprehensive and efficient quality control".

"With the WiNG featuring QuietSeis and Pathfinder technologies, we can offer our clients reliable equipment to deliver highly accurate imaging. Sercel continues to be a trustworthy solution provider that anticipates our needs and supports us in overcoming the most complex challenges even in difficult-to-access environments," **Patrick Robert**, Smart Seismic Solutions COO, says.

"This new sales contract demonstrates once again the performance and versatility of our latest-generation WiNG wireless nodal solution. Sercel is proud to leverage its recognized expertise in seismic data acquisition to support energy transition projects," **Emmanuelle Dubu**, Sercel CEO added. ■

Photo: Halfdan Carstens



Geophysical tools made for the oil industry are increasingly being used for other purposes, such as geothermal exploration.

The New Seismic Fashion

Seabed nodes gain momentum in the seismic service industry.

Photo: Shearwater

Irene Basili, CEO of Shearwater

"Controlling costs continuously form a major part of our way of operating," said **Irene Basili**, CEO of Shearwater.

Today, Shearwater is by far the leading seismic company globally. Whilst other companies have continued to turn the business over in recent years, Shearwater has grown to an extent that it currently owns the largest fleet in the industry, including source vessels.

The seabed market has had a slow development across the seismic acquisition industry, but Irene Basili does strongly believe it has tremendous potential driven by its superior data quality compared to towed streamer seismic. This must have formed one of the driving forces behind Shearwater launching the **Pearl System** at the recent EAGA conference in Madrid.

Pearl's small size and low weight allow for wider and denser spreads, reducing the operational time by a third compared with current deployments. The smaller size also means that surface vessel and subsea vehicles can carry substantially more nodes for deployment and makes large volumes of nodes easier to ship around the world.

Pearl is the first fully smart node that includes multiple methods of wireless communication and GNSS (satellite navigation), making it a fully wireless node for both data retrieval and charging. This also removes the need for complex connections and battery unit replacement onboard.

The multicomponent node design combines hydrophones with tri-axial microelectromechanical system (MEMS) accelerometers. The MEMS sensors measure the full bandwidth of the seismic wavefield, down to the lowest frequencies with industry-leading recording quality, making the Pearl node a perfect match for future technologies.

"Pearl is the lightest, smallest and smartest node ever developed. The technology combination it is packed with is an industry first, including fully wireless charging and data handling, battery life exceeding 150 days, and best in class MEMS," says **Massimo Virgilio**, CTO of Shearwater. ■

New Ways of Seismic Monitoring CO_2 Storage

Passive and persistent seismic monitoring serves as a key tool to ensure CO_2 storage operations are effective and safe. Future demand for induced seismicity monitoring at gigaton scales is therefore driving efforts to enhance signal resolutions and event detection/location capabilities.

At the same time, the economic and logistical considerations of persistent monitoring are steering toward permanently installed robust systems with the minimum number of channels, reduced infrastructure requirements, and minimal surface expression.

During an IMAGE 2022 technical presentation on August 31 in Houston, Geospace subsidiary **Quantum Technology Sciences** will discuss an alternative acquisition technology using volumetric phased array networks known as **SADAR®.**

By taking advantage of the three-dimensional array response and spatially coherent processing, SADAR optimally suppresses non-coherent noise while increasing coherent SNR prior to event detection. This reduces the uncertainty in determining seismic arrivals, especially for low SNR events.

SADAR arrays can be tuned and scaled to meet the design frequencies and wavelengths specific to the site as well as the required noise suppression. A SADAR array network is smaller compared to a typical linear or planar surface sensor network in terms of sensor count and deployment footprint.

The presentation will share the effective subsurface monitoring achieved in a deployment at Carbon Management Canada's Containment and Monitoring Institute outside Calgary, AB. ■

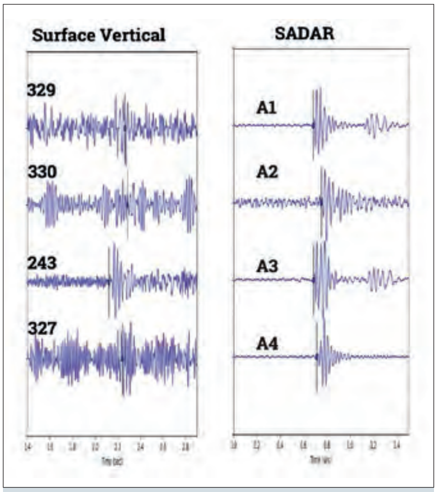


Illustration: Geospace

Signals of an example event across the SADAR network. SNR enhancement is evident by comparing a single surface channel (left) to the optimal beam (right).

When a BOP Doesn't Help

Study of a blowout in German waters illustrates to role of the subsurface in directing overpressured fluids.

Where most blowouts that happened in the North Sea relate to occurrences of shallow gas at a few hundreds of metres depth, possibly the biggest of all finds its origin in deeper strata.

In 1964, at the very early stages of oil and gas exploration in the North Sea, an exploration well drilled in the German sector hit an overpressured dolomite within the Permian Zechstein succession.

A team of researchers recently published a reconstruction of the event in ES³. Using a range of geophysical and sampling techniques, the team acquired new data from the seafloor crater that resulted from the blowout.

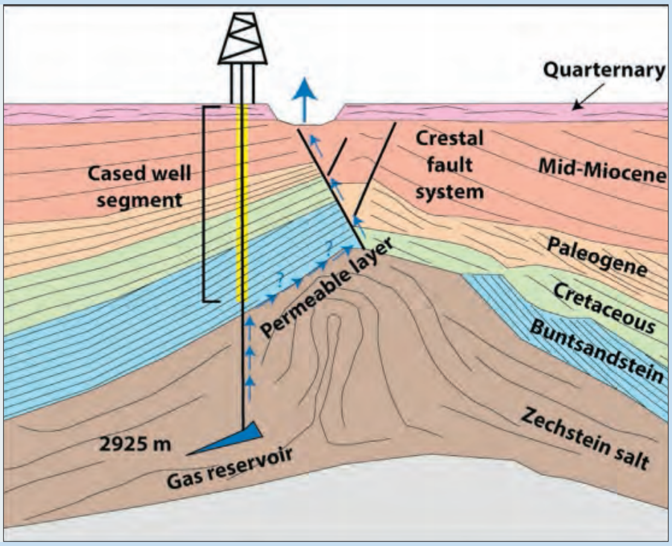
As the crater formed at about 100 metres away from the rig site, the gas released from the Zechstein most likely found a pathway that bypassed the wellbore. Even though seismic evidence remains scarce, the team suggests that Triassic sandstones and a fault formed the main conduits of the gas, clearly showing the importance of subsurface leakage pathways.

Since the event almost 60 years ago, the crater has been backfilled to a large degree and only releases some biogenic methane that is thought to be mainly related to the decomposition of recently deposited organic material. ■

Reconstruction of fluid pathway during the B1 blowout in German waters.

Formation of the Figge Maar Seafloor Crater During the 1964 B1 Blowout in the German North Sea. Earth Science, Systems and Society (ES³), 23 June 2022.

https://doi.org/10.3389/esss.2022.10053



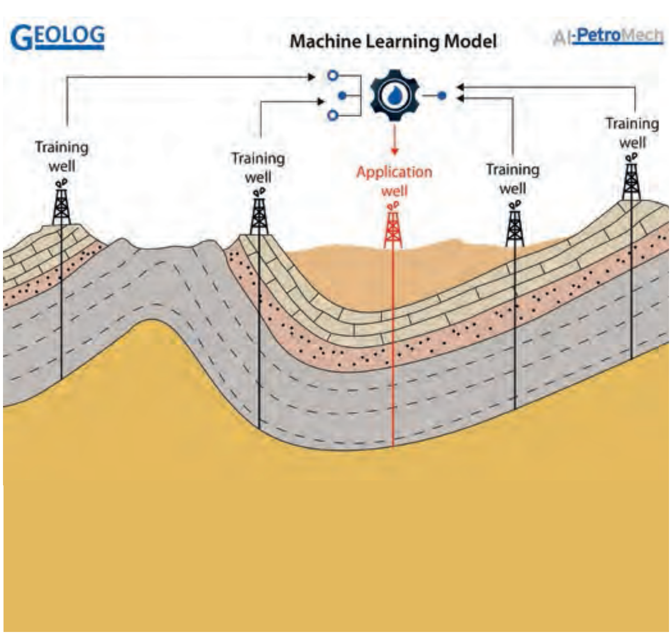
Source: Karstens et al. (2022) – ES³

Predict Geomechanical Parameters through Machine Learning

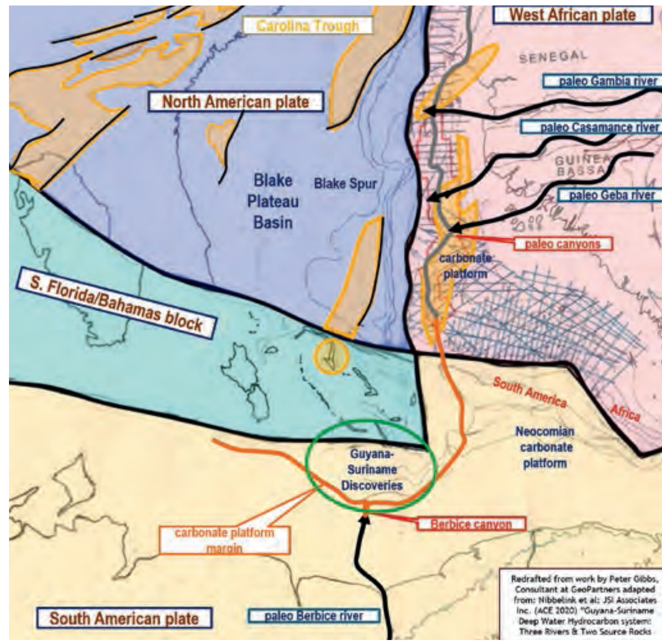
Geomechanical properties of rocks greatly determine how wells are drilled. Knowledge of these properties is essential for a wide range of operations, from planning the well construction phase to predicting the way the well will perform once completed, along with the behaviour of the entire field over time. These data are generally risky and expensive to obtain, with decisions having to be made regarding cost-benefit.

Utilizing drilling data combined with gamma-ray logs, **GEOLOG** developed technology that allows for a fast and reliable approach to derive accurate, synthetic geomechanical parameter logs. This is done by employing a machine learning model created from offset data, and then applying it to data sets of subsequent wells. This technology has been successfully tested in several geological settings such as carbonate reservoirs, clastic settings and unconventional plays.

The methodology can be considered as a viable backup of downhole tools when they are available and as a feasible alternative when the logs cannot be run for economic or technical reasons. After training the model on offset data, it is possible to predict the geomechanical parameters on subsequent wells in the same field without the requirement for expensive and potentially high-risk LWD or Wireline petrophysical logs being run. MWD gamma or XRF derived gamma data, along with surface drilling data, are sufficient to provide the required datasets. ■



Is the MSGBC Basin Africa's Guyana-Suriname Basin?



Whenever there is a major discovery around the globe, stakeholders in far-reaching positions always try to draw in the analogue benefits to their acreage positions. The Jubilee discovery in Ghana back in 2007 started a whole trend of analogue hunts along the West African margin, which largely proved disappointing; could we be mistaken now for drawing analogies from the enormous success in Guyana-Suriname into the MSGBC Basin? The MSGBC Basin is named after the countries in which it resides, namely Mauritania, Senegal, Gambia, Guinea-Bissau and Guinea-Conakry.

GeoPartners, following a detailed reconstruction of the Central Atlantic margin and resolving the accommodation space needed to adopt the Vema Wedge, can confirm a very good fit to the North American Plate, with the Demerara Plateau sitting immediately south of Guinea Bissau, prior to the opening of the Atlantic. This means prior to opening, the Neocomian Shelf edge identified in the MSGBC, shared the same shelf edge currently located in Guyana and Suriname.

There are further similarities with the prolific Guyana plays associated with the Berbice Canyon running into an embayment along the Neocomian margin. In the southern MSGBC, the Geba River can be seen to have carried sediment since the Neocomian, up to present day, into an embayment mapped predominantly in northern Guinea-Bissau. The presence of an embayment sets up the perfect conditions for the accumulation of oil prone source rocks and there is the added advantage of embayments limiting the dilution effects caused by oceanic currents, while providing a positive environment to redistribute fluvial and biogenic sediments.

So, in a brief answer to the title question; yes, in southern MSGBC, we can take confidence in using the Suriname-Guyana Bains as a predictive, conjugate analogue. ■

A Brand New AI Arena

GeoMind is a new technical spin-off out of Norway, ready to be launched at the SEG/AAPG IMAGE Conference in Houston.

OpenMind is its new seismic interpretation platform, solely visualizing and operating in 3D view. The ambition is to create the best auto-tracker in the world and add AI routines to scrutinize the seismic for geological useful information.

"GeoMind believes that it will be *impossible* for vendors to keep up, and always compete with new AI products, as the ingenuity and rate of new developments within companies worldwide are too fast. Instead, GeoMind is building an AI arena for any neural network to be imported or hard coded directly and finally executed in OpenMind. Anything coded in Python will be possible to add on to the OpenMind platform, and the software will be developed and fitted according to the demands from each customer", says **Brit Sauar**, Technical Sales Manager with GeoMind.

Anders Kihlberg and **Nils Petter Fremming**, two of the founders of Technoguide, the predecessor of Petrel, are now joining forces to re-create that energetic atmosphere, so special for a new start-up company, driven by smart heads, Nils is acting as an adviser to the new company.

Nils Petter Fremming has also been instrumental in developing Cognite, an AI-driven open platform software, a Norwegian technical success story for the oil and shipping industry.

Photo: Mårten Blixt

GeoMind will be present at IMAGE in Houston. From left to right: Flavio Ivan (CTO), Brit Sauar and Anders Kihlberg (CEO).

"The idea is not to develop another full-scale exploration software tool. OpenMind will extract as much geological information from the seismic as possible, bearing in mind the high cost of acquiring the seismic in the first place. The interpretation tool will act as an open platform for further activities," says Brit Sauar.

Exploration Needed!

During the International Oil Company (IOC) panel session at the recent AAPG ICE Conference in Cartagena (Colombia), leaders from several international majors stressed the need to ramp up exploration.

The future demand for oil and gas is uncertain, as it has always been, but the panel members of the IOC session in Cartagena agreed on one thing: **Recent years have brought about a rapid decline of reserves because of limited discoveries.** Therefore, they stressed that there is now an increased awareness that exploration needs to be stepped up.

All of the speakers touched upon the same issues: the Energy Transition, but with the need for oil and gas for several decades and energy security, especially triggered by the war in Ukraine.

John Ardill (Exxon Mobil) said that 70% of EM's assets are in the advantaged barrels category. He compared Guyana, as an example of fast-track exploration, with his experience in Angola in the 1990s. Traditionally, they are used to a 20% drilling success rate. Currently, the success rate for new wells in Guyana is 90% and the Liza field was developed in less than 5 years from discovery.

Elizabeth Schwarze (Chevron) made an interesting point: Although the use of fossil fuels will be lower in the future, new energy sources have historically been added to the existing ones, not replaced them. She mentioned geothermal as an interesting base-load renewable source and that Chevron has invested in a couple of companies, including Eavor (together with BP).

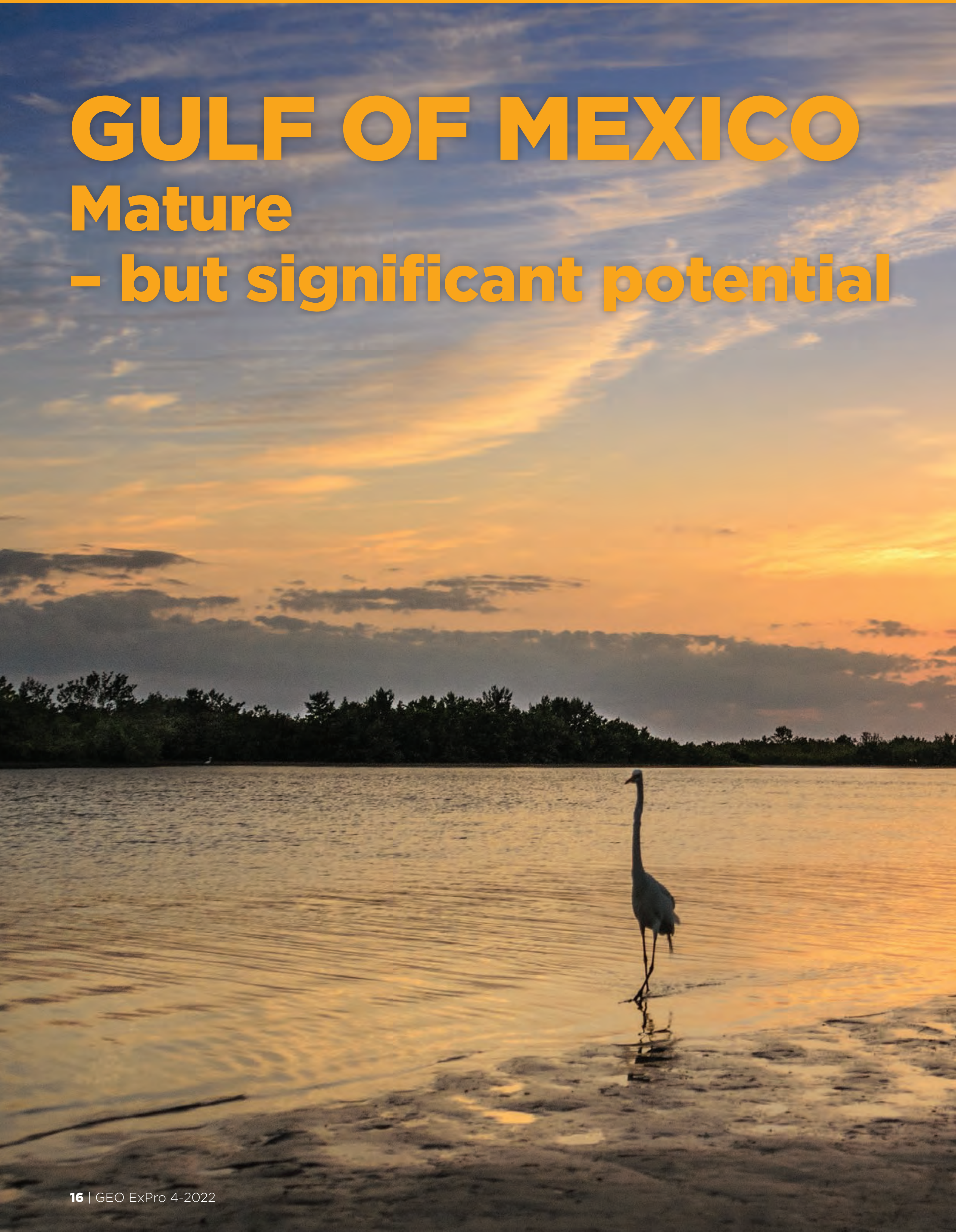
Marc Gerrits (Shell) included a focus on exploration as a future career and mentioned that it is seen by many as a 'sunset' activity. Since geoscience will be a critical discipline also in the future, it's important to change this impression in his opinion.

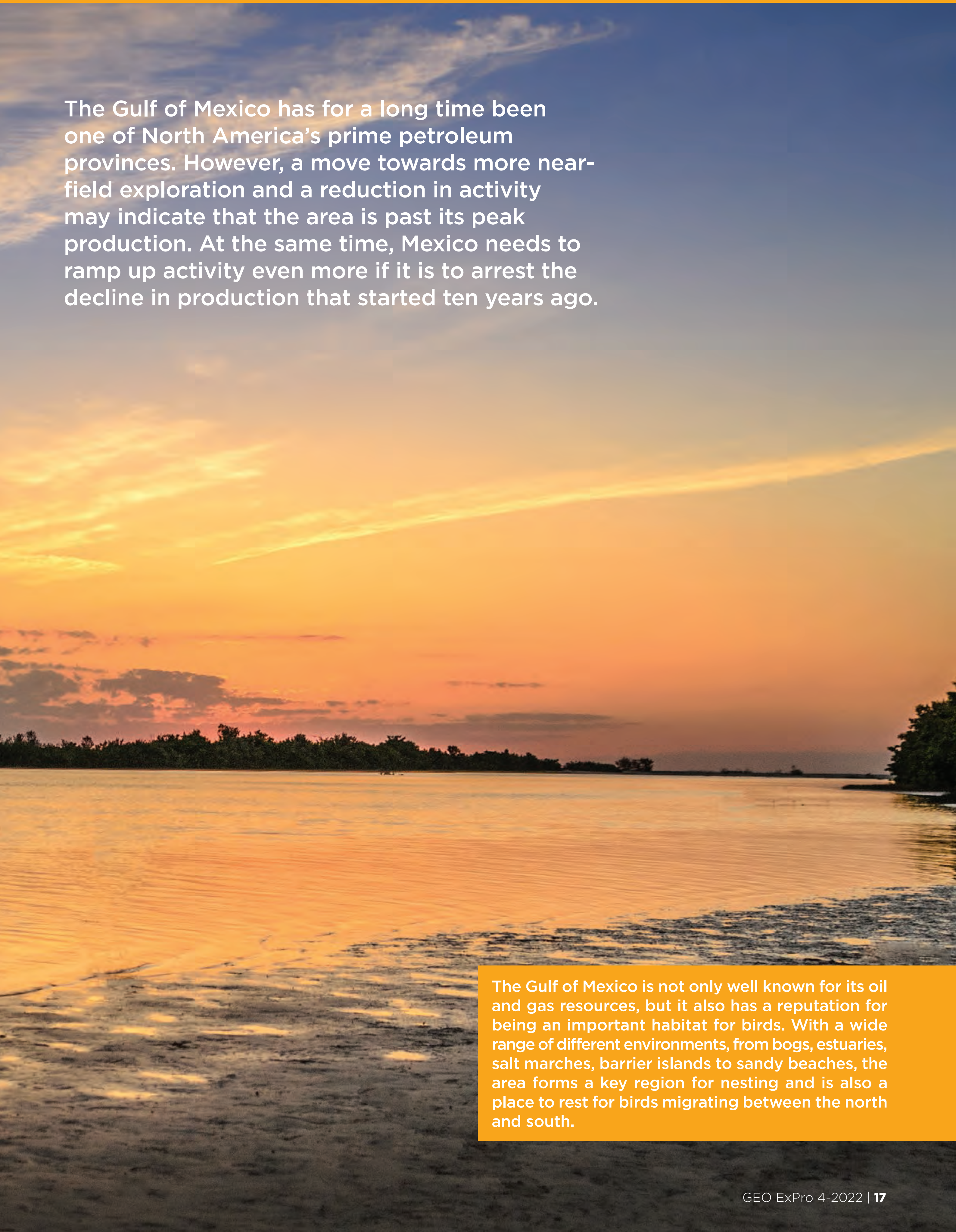
Erling Vågnes (Equinor) referred to his company's changing strategy. He did not specifically mention it, but they have made public their first energy transition plan. Over the last few years, Equinor has optimised its oil and gas portfolio and reduced the number of countries they are active in from 33 to 13. Their drilling success is improving, with recent successful exploration campaigns in the Troll area offshore Norway.

Photo: Halfdan Carstens

To sustain oil and gas production (image from Alberta, Canada), there is an increased awareness amongst industry leaders that exploration needs to be stepped up.

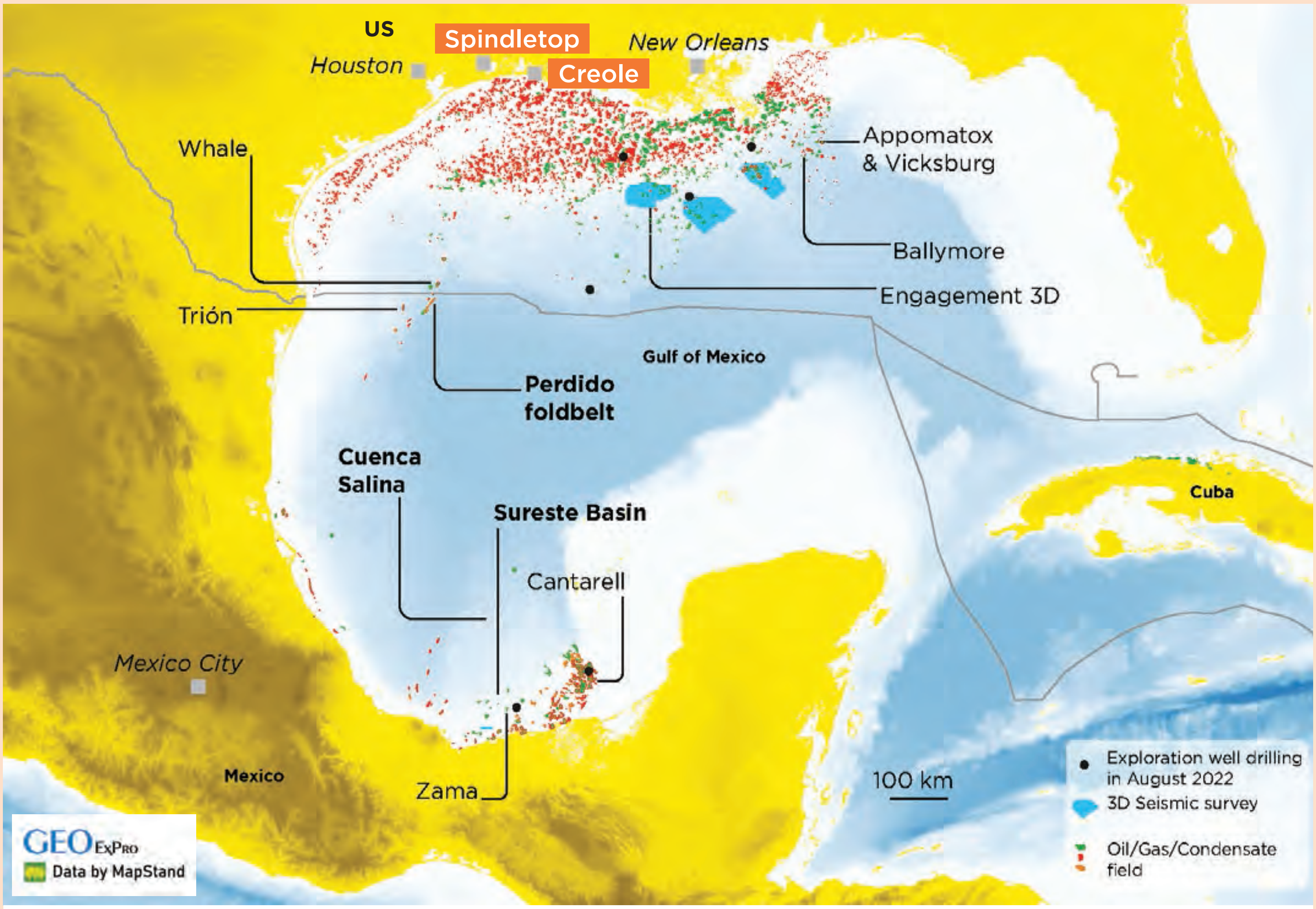
GULF OF MEXICO
Mature – but significant potential





The Gulf of Mexico has for a long time been one of North America's prime petroleum provinces. However, a move towards more near-field exploration and a reduction in activity may indicate that the area is past its peak production. At the same time, Mexico needs to ramp up activity even more if it is to arrest the decline in production that started ten years ago.

The Gulf of Mexico is not only well known for its oil and gas resources, but it also has a reputation for being an important habitat for birds. With a wide range of different environments, from bogs, estuaries, salt marches, barrier islands to sandy beaches, the area forms a key region for nesting and is also a place to rest for birds migrating between the north and south.



Seven exploration wells were actively being drilled in August this year, with four in the US Gulf, two in Mexican waters and one in Cuba. Also plotted are the 3D surveys acquired over the past three years (2019-2021). All three surveys in the US Gulf were acquired by TGS. A small survey was acquired in the Mexican Gulf to the southwest of the Zama discovery. Onshore fields in Mexico and the US are not shown on this map.

Text: Henk Kombrink

The Gulf of Mexico classifies as a **Super Basin**, with the US part already having an initial technically recoverable resource of more than 100 billion barrels of oil equivalent (Bboe). Defined by Fryklund and Stark in 2016, a Super Basin has a prolific petroleum system with remaining recoverable reserves greater than 5 Bboe and past production in excess of 5 Bboe. It also has a well-established surface infrastructure, ready access to markets, multiple petroleum systems and stacked reservoirs.

However, after decades of production and drilling, and the restrictions imposed on licence rounds both in the US and in Mexico, the future of the basin looks uncertain. Mexico has now seen a decline in production for some years, in contrast to the US where production did steadily ramp up until recently. But given the more mature state of the basin in US waters, the question can be asked for how long this situation will last.

TURNING THE TIDE

After decades of being a bigger producer of oil than the US Gulf, Mexico recently became a smaller player than its northern offshore counterpart. Years of steady rise in production levels in the US are testament to that, along with a long-term decline in Mexico. The most logical explanation for this is a higher level of infill and near-field drilling in US waters, where lots more fields are situated than in Mexico, alongside a more varied and established operator landscape.

At the same time, there seems to be more room for exploration in the south, where foreign companies have only been allowed to start exploring since 2014. With these differences in mind, it could well be that in a few years' time, production from Mexico could ramp up again if some big discoveries are being made.

MAIN DEVELOPMENTS 2009-2022

In 2009, William Galloway from the University of Texas stated that the Gulf of Mexico will continue to be a major player for decades to come (GEO ExPro, 2009, No. 3). However, as for the US, the 2014 oil price crash has led to companies shifting their activity to more infrastructure-led exploration with infill drilling. On top of that, in both the US and Mexico, new exploration blocks have not been offered for some years in the light of a governmental pushback against new oil and gas developments. This has also led to activity being limited on already awarded blocks.

A development that is unique to **Mexico** is the opening of the offshore for investment from foreign private companies in 2014, where state-run PEMEX had a monopoly on exploration and production before. This has led to an increase in exploration drilling following the 2015 bid round for the **Perdido Fold Belt** and the **Cuenca Salina**, with some success (see below).

In Mexico, the number of offshore wells drilled over the past 20 years has stepped up dramatically, from around 80 per decade before 2000 to more than 160 per decade post-2000. However, the success of **Cantarell** (discovered in 1975 with an initial reserve base of 17 Bbo) has never been replicated, and despite the number of wells being drilled has increased significantly, only two large

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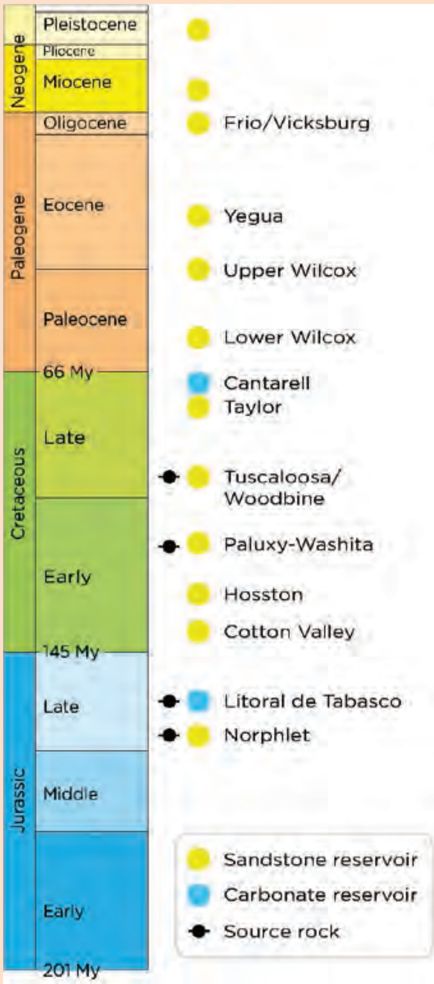


Schematic diagram showing main reservoirs in the Gulf of Mexico. Sandstones are dominant in the northern GOM, while the shallow part of the offshore in Mexico is dominated by Upper Jurassic and Cretaceous carbonate reservoirs.

A 75th Anniversary

Sound geological reasoning lay behind the bold move from onshore to offshore drilling in the Gulf of Mexico.

The very first Gulf of Mexico **onshore** well was drilled in Texas in **1866** based on oil seeps known by Indians. The discovery well did, however, not produce commercial quantities of oil and therefore lay dormant for nearly two decades until others returned to the field. By 1889, forty wells were producing. Even so, in 1890 the wells produced only 54 barrels of oil.

Offshore drilling began in modesty in **1897** in California by building a pier 90m out into the Pacific and placing a cable-tool rig on the end of it as an extension to the **Summerland Field.** This was followed by 400 wells, and the offshore field continued to produce for the next 25 years.

It was not until **1908** that the first shoreline well in the Gulf of Mexico was spudded with a subsequent discovery of the **Goose Creek Field** in Galveston Bay south of Houston. Several dry holes followed, and the field was abandoned. But a gusher in 1916 created a real boom, and more than 100 years later Goose Creek has produced more than 150 MMbo.

> ***For years, the Texas and Louisiana coastlands had yielded rich pickings for oil prospectors: its situation on the continental margin provided near-perfect conditions for the laying down of oil-rich sediments over millions of years, and its salt plugs and anticlines provided ideal hydrocarbon traps.***
>
> *Quentin Morton, GEO ExPro, 2016, No. 3*

In 1938 Shell Oil started experimenting with **seismic** testing off the Louisiana coast. A shooting boat would drop a single stick of dynamite into the sea and measure the seismic waves with geophones on the seabed. Superior Oil and Mobil followed their example in order to look for salt domes using much the same arrangements.

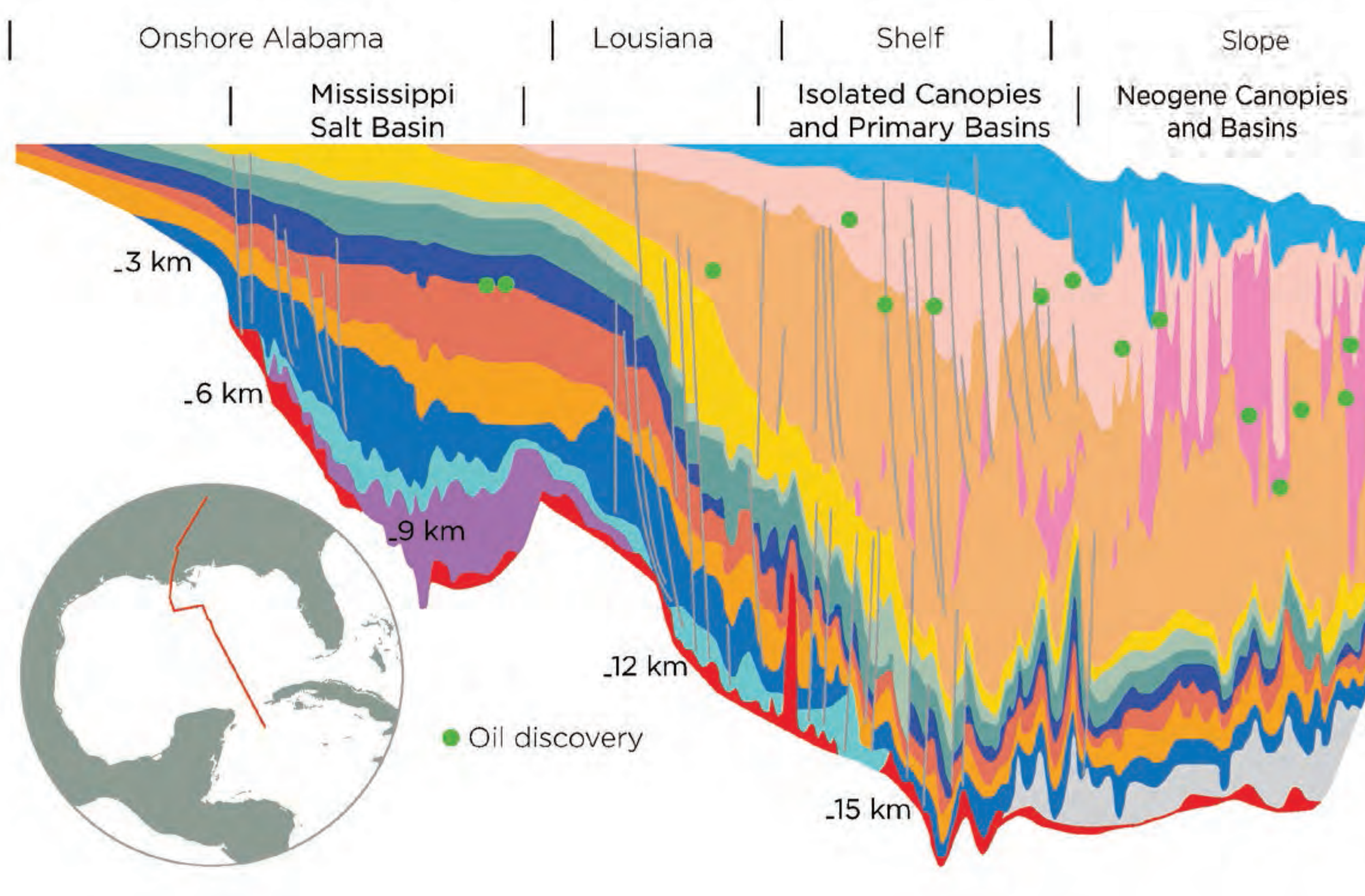
Pure Oil and Superior Oil were behind the real birth of the offshore oil industry in **1938** when the **Creole field**, about 1,5 km offshore in 5 meters of water, became the first producing field in open waters in the Gulf. The field was discovered using seismic data acquired a few years earlier. The oil lies in Lower Miocene sandstones at about 1,500 meters depth.

> ***It was the advent of seismic techniques that transformed oil prospecting, both on land and sea.***
>
> *Quentin Morton, GEO ExPro, 2016, No. 3*

The first commercial offshore well, defined as "out of sight of land," was spudded in **1947** by Kerr-McGee in 6 meters of water and some 16 km off the coast.

By the end of 1949, the Gulf's offshore industry had discovered 11 oil and natural gas fields. Exactly 75 years later, the US Gulf of Mexico, with cumulative production of 55 MMboe, has proven to be one of the most important oil provinces of the world, not only because of the amount of oil and gas produced but also because of technical innovations in both seismic, drilling and production.

HALFDAN CARSTENS

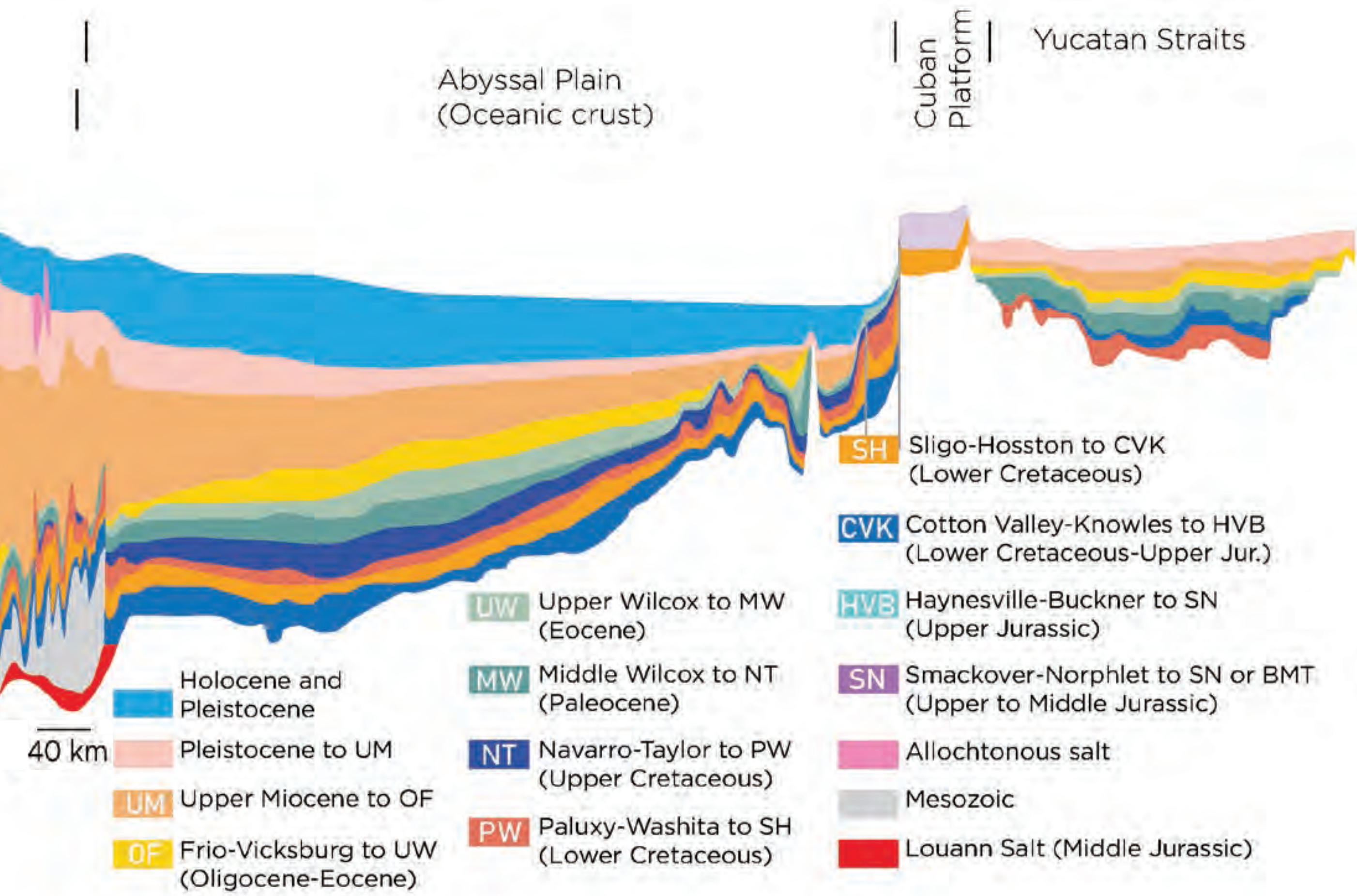


The Upper Jurassic Louann salt at the base of the Gulf of Mexico sedimentary succession, overlain by an up to 15 km thick succession of Cretaceous to Holocene sediments in shelfal areas. Most of these sediments were sourced from the North American continent. Green dots represent oil accumulations. Redrawn from Snedden and Galloway (2019), with additions by Robert Cunningham.

Gulf of Mexico Geology

The Gulf of Mexico (GOM) is a relatively young oceanic basin, where the oldest sedimentary strata are of Jurassic age. Having always been situated in hot and arid subtropics, the basin experienced periods when the connection to the open ocean was restricted. This caused the precipitation of extensive evaporite deposits such as the Upper Jurassic Louann salt that can attain several kilometres in thickness. This Louann salt and its subsequent diapirism has played an important role in generating hydrocarbon traps (see cross-section).

The Jurassic and Cretaceous stratigraphy of the GOM is characterised by a mix of carbonate-dominated deposits in areas that were devoid of siliciclastic input and the deposition of sandstones in other places. It is from the Paleogene onwards that the influx



of siliciclastics really kicks off in the northern GOM, which has led to the deposition of more than 10 kilometres of deep-water sediments and associated deltaic and fluvial deposits in more proximal areas.

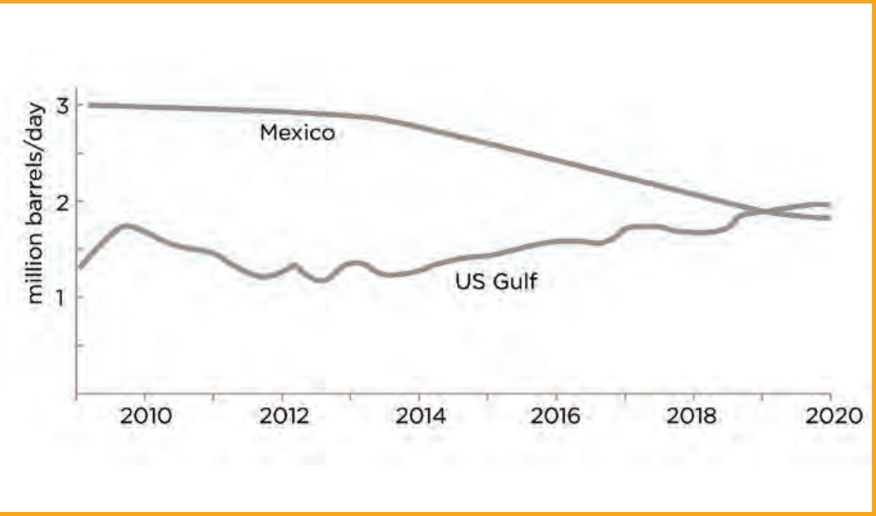
It is the sandstones deposited during the Cenozoic that form the most important reservoirs in the northern GOM, as is evident in the cross-section. At the same time, in the Mexican part of the Gulf, especially in shallow waters, naturally fractured carbonate reservoirs of Jurassic and Cretaceous age form by far the most important target reservoir even though Cenozoic deep water sandstones are now also targeted in the Perdido fold belt and the Sureste Basin. It is interesting to note that the carbonate reservoirs in Mexican waters were fractured during a Miocene compressional phase that only affected the southern part of the Gulf; that is why time-equivalent carbonate reservoirs do not form giant or supergiant fields further north in the northern GOM.

A unique aspect of the GOM is the presence of multiple source rock intervals throughout the sedimentary succession. The most important ones are found in the Upper Jurassic and the Upper Cretaceous (GEO ExPro 2009, No. 3), with a smaller contribution from Paleogene deltaic and marine source rocks.

GOM PRODUCTION

Mexico's liquid fuel production between 2009 and 2020 compared with oil production from the US Gulf. There is a stark difference between the US and Mexico, as the former has maintained and even increased production throughout the period, whilst in Mexico volumes have steadily come down over the years. Given the more underexplored nature of Mexico's deep-water regions though, there could be more potential to drive up production in this area than there is in the US Gulf. The production increase in the US is probably mostly driven by infill and near-field drilling in mature areas.

Source graphs: EIA.



Note that about 80% of Mexico's oil production is from offshore.

discoveries were made in Mexican waters over the past 10 years: **Zama** (~750 MMboe) in the Sureste Basin in the south and **Trión** (270 MMboe) in the Perdido fold belt in the north.

In the US Gulf, a few large discoveries have also been made. Shell has had success in the Perdido fold belt in 2018 where the company discovered the **Whale** field that may host up to 490 MMboe recoverable in the Paleogene Wilcox reservoir. In 2010, Shell also celebrated success in the deeply buried Jurassic Norphlet play by discovering oil in the **Appomatox** prospect, which followed on from the first offshore Norphlet discovery at the **Shiloh** prospect in 2003.

Together with the nearby Norphlet discovery **Vicksburg**, around 650 MMboe of recoverable oil was originally in place in Appomatox and Vicksburg. Chevron and partners discovered **Ballymore** in 2017, which is estimated to contain around **150 MMboe**, also in a Norphlet reservoir.

LIMITED SEISMIC ACQUISITION ACTIVITY

The level of recent seismic acquisition activity very much reflects the situation of near-field drilling. According to **SeisIntel, Searcher's** seismic acquisition monitoring and analysis portal, so far this year six surveys were carried out in the US part of the Gulf, five of which were performed over existing fields. Only **TGS's Engagement Phase II** survey may qualify as more of an exploration-driven survey.

In the three previous years (2019-2021), TGS also acquired the most extensive surveys in the GOM (see map), in addition to around 20 smaller ones by various companies.

WHAT DOES THE FUTURE HOLD?

Looking at the production curves shown in this article, the US Gulf surpassed liquid production in Mexico a few years ago. However, there is reason to believe that the gap between the two countries will not continue to widen as much as it has done recently.

For **US federal waters** in the north, the US Energy Information Administration (EIA) expects output to remain flat through to 2023. At the same time, S&P Global Commodity Insights forecasts that production may recover to the pre-pandemic record by the end of the year (2022). Energy consulting firm Wood Mackenzie is more optimistic and forecasts crude and natural gas production this year could jump to the equivalent of 2.3 million oil barrels per day.

In **Mexico**, production started to drop quite rapidly from around 2013, which is probably mainly driven by the natural decline in output from major fields such as Cantarell and the Ku-Maloob-Zaap complex. In order to arrest the decline, the National Hydrocarbons Commission approved the development of 20 "priority" fields in 2019. Looking at the most up-to-date government data, overall production from Mexico has stabilised at around **1.6 MMbo/d** over the past few months. Whether a ramp-up to Pemex's ambition of **1.9 MMbo/d** will be possible this year remains to be seen.

CAN EXPLORATION TURN THE TIDE?

Would the opening up of more areas for bidding rounds lead to a flurry of new exploration activity and the associated bump in production in the long run? That's probably where the US and Mexican parts of the Gulf diverge, with a possible more important role for Mexico given its underexplored nature of especially the deeper water region.

John Snedden and **Mike Sweet** from **The University of Texas at Austin** agree that the **US Gulf** is rather mature overall. Even though there have been some encouraging recent finds, they expect that it will be challenging to continue replicating the success the basin has seen over the past decades. This also forms the likely background to some recent headlines stating that even when the US GOM drilling makes a comeback, it won't close the supply gap. As with many mature basins around the world, declining production from ageing fields is the main driver behind this.

In **Mexico**, where exploration drilling has not been as intense as in the US, there seems to be more potential for future discoveries. "Especially in the Sureste Basin, there is significant potential for further discoveries," says **Karyna Rodriguez** from Searcher.

In this salt-influenced sedimentary basin, seismic imaging plays a key role in unravelling the remaining potential. Structural or combined structural-stratigraphic traps with direct hydrocarbon indicators (DHIs) identified in seismic, such as amplitude and AVO anomalies with depth conformance, have so far been a successful main target in this basin (such as Zama).

However, it should be noted that the large stratigraphic traps have also been identified. "In the Sureste Basin offshore Mexico, where the Tithonian world-class source rock is well established, future exploration needs to focus on the unexplored prolific siliciclastic stratigraphic play fairways to trigger the next big jump in the creaming curve," Karyna Rodriguez adds. ■

What is left in store?

US GULF OF MEXICO

In 2020, the Bureau of Ocean Energy Management (BOEM) estimated that the original reserves for the US part of the Gulf of Mexico (Outer Continental Shelf) stood at **61 billion barrels of oil equivalents** (Bboe) from 1325 fields. The larger part of this is gas (57 per cent).

A significant percentage (more than 90%) of that has already been produced from 911 fields, meaning that at around 5.7 Bboe remain in 414 fields. The larger part of this is oil (81 per cent).

The GOM were in 2014 assessed to contain undiscovered technically recoverable resources of 48 Bbo and 25 Bboe of gas (73 Bboe in total). If this holds true, the GOM has the potential to be a significant producer for many years to come, with oil being more dominant than gas.

MEXICO

Based on cumulative production data, original reserves in Mexico amount to around **66 Bboe** in 2020, with around **9 Bboe** left to be produced at the start of that year.

A COMPARISON

Comparing with other major producing basins, both Mexico and the US Gulf are bigger than the **UK North Sea**. The North Sea Transition Authority (NSTA) estimated that at the end of 2020, reserves stood at **4,4 Bboe** with **46 Bboe** produced. The **ultimate technically recoverable resource** will be in the order of **60 Bboe.**

Norway gets closer to Mexico though, with **6.5 billion barrels** left as reserves by the end of 2021, with **50 Bboe** produced. The **ultimate technically recoverable resources** in Norway are a lot higher than in the UK though, as this stands at around **100 Bboe.**

The Discovery that Changed the World

The 1901 discovery of oil at Spindletop not only changed the oil industry forever; the blowout had such a large impact that the world would never be the same again.

Spindletop Hill, Beaumont, Texas, January 10, 1901.

Late in the morning, on a clear winter day, all of a sudden, tons of clay, sand and water, and eventually a towering column of black, sticky oil, erupted roughly 50m into the air – twice the height of the derrick.

The Texas oil era had begun, first with the sound of a cannon shot and then with an ear-shattering roar caused by a blowout that would prove to be hard to control.

THE PERSPECTIVE

There was no significant oil production along the Gulf Coast until this spectacular discovery at Spindletop. Total Texas oil production was only 2,300 bopd in 1900, while the total US production was approximately 170,000 bopd. Those numbers explain why the estimated 100,000 bopd "eruption" in the blowout for 9 days caused so much excitement and revolutionized the oil industry.

The American oil era had begun more than 40 years earlier when oil was discovered by the famous colonel Drake at **Titusville**, Pennsylvania, in 1859. Later in the 19th century, oil was also found in Europe and Asia, notably in Baku, Azerbaijan. But it was the sheer volume of oil produced at **Spindletop** that made the difference.

The discovery well (Lucas) produced twice as much per day as all the producing wells in Pennsylvania combined. When developing the Spindletop field in the months to come, it turned out that the first six wells produced more barrels of oil per day than the rest of the world put together.

In 1902, Spindletop produced roughly 17 million barrels of oil, but only half that much in 1903 as production declined. By the end of 1902, more than 500 companies had been formed and 285 wells were in operation.

FROM COAL TO OIL

Easy access to oil made the industry change from hard coal to liquid oil. Ships and trains changed from coal-fired to oil-fired steam engines, and the automobile industry made use of oil for the new combustion engine. The new, light fuel also made flying feasible; in 1903 Wilbur and Orville Wright did their first flight into the air.

From being used mostly for illumination and as a lubricant and trading at 2 dollars a barrel, oil now developed into a huge industry and soon traded for a lot less. At some point, oil was down to 3 cents a barrel – less than the cost of water in some places.

Spindletop thus marks the transition to a world that is fuelled by crude oil, refined into various products that keep the world moving such as machinery, cars, trucks, trains and planes.

The incident at Spindletop had global consequences. The world would never be the same again.

HALFDAN CARSTENS

The full story of the Spindletop discovery is found in GEO ExPro 2008, No. 3.

UNDERLAIN BY A SALT DOME

This geological sketch of the subsurface at Spindletop is found on one of the posters that have been put up at the original location. It illustrates that the trap is associated with characteristic steep-sided, relatively flat-topped, circular Gulf Coast salt domes. Its diameter is about 1.5 km, and it is capped by limestone, anhydrite, and gypsum.

The oil is found in the Middle and Lower Miocene and to some extent in Middle Oligocene rocks. The sands are lenticular and so irregular that they cannot be correlated from well to well. The Spindletop field has been a prolific producer. The old cap-rock area has produced approximately 50 million barrels of oil and a flank area produced approximately 75 million barrels of oil up to 1936.

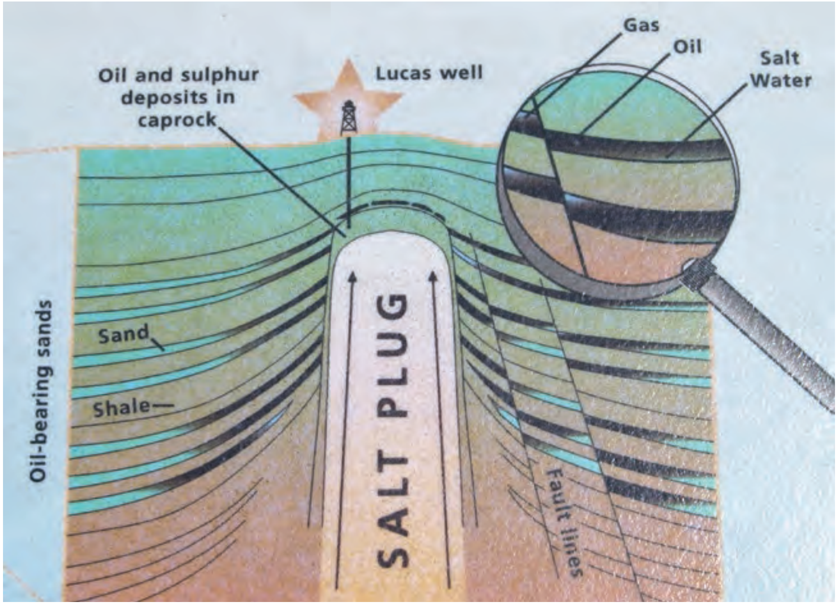
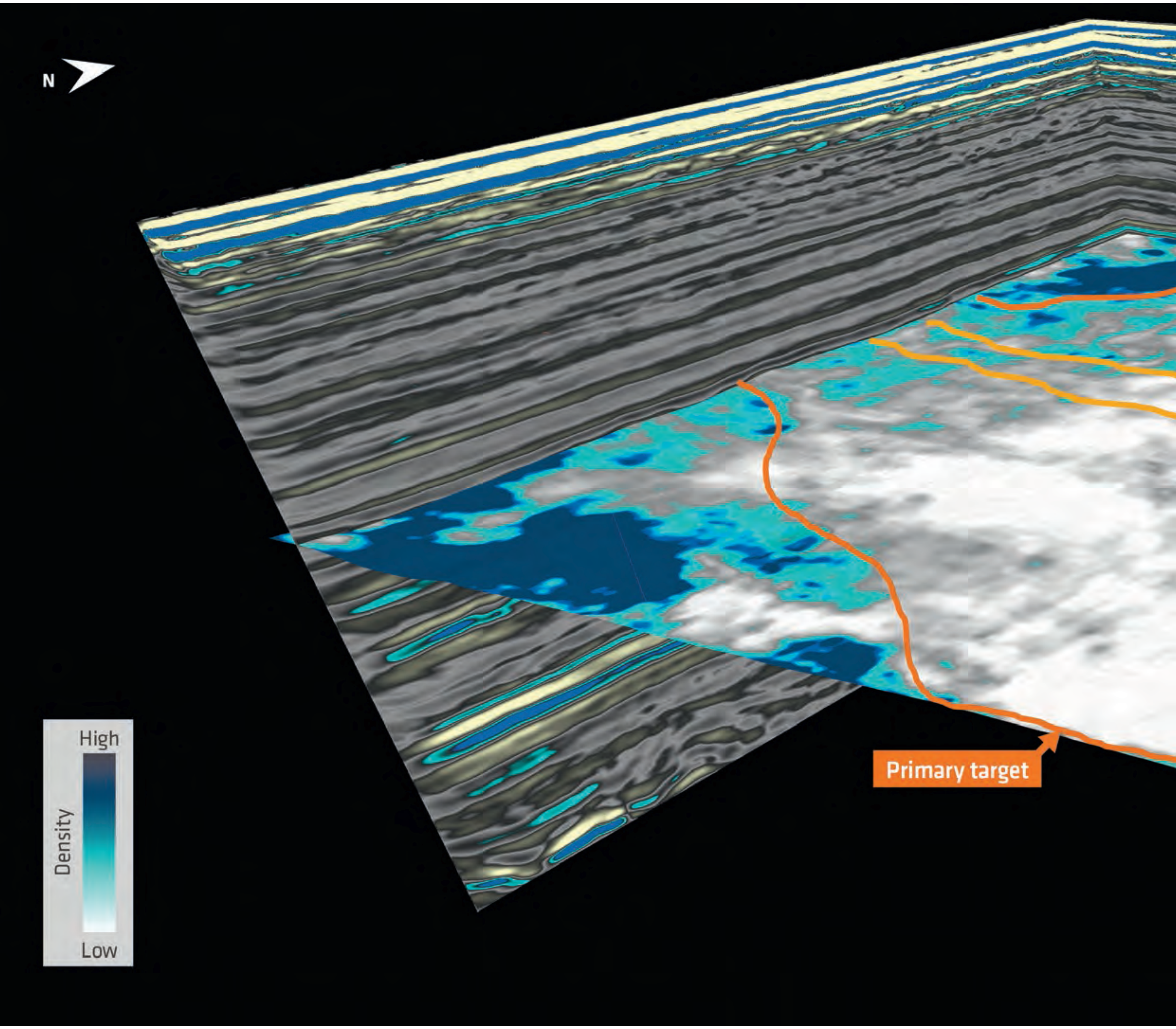


Photo: Halfdan Carstens

Potential Prospectivity Identified in the Orphan Basin

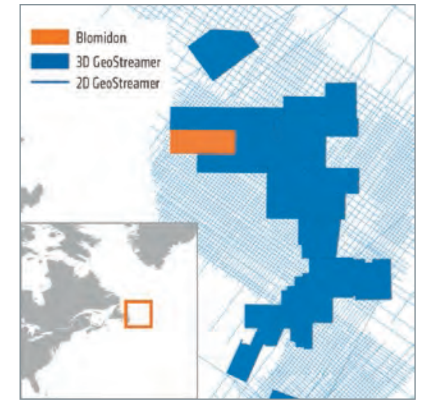
Offshore Newfoundland has promising hydrocarbon potential along the shelf and slope areas as proven by PGS Ultima.



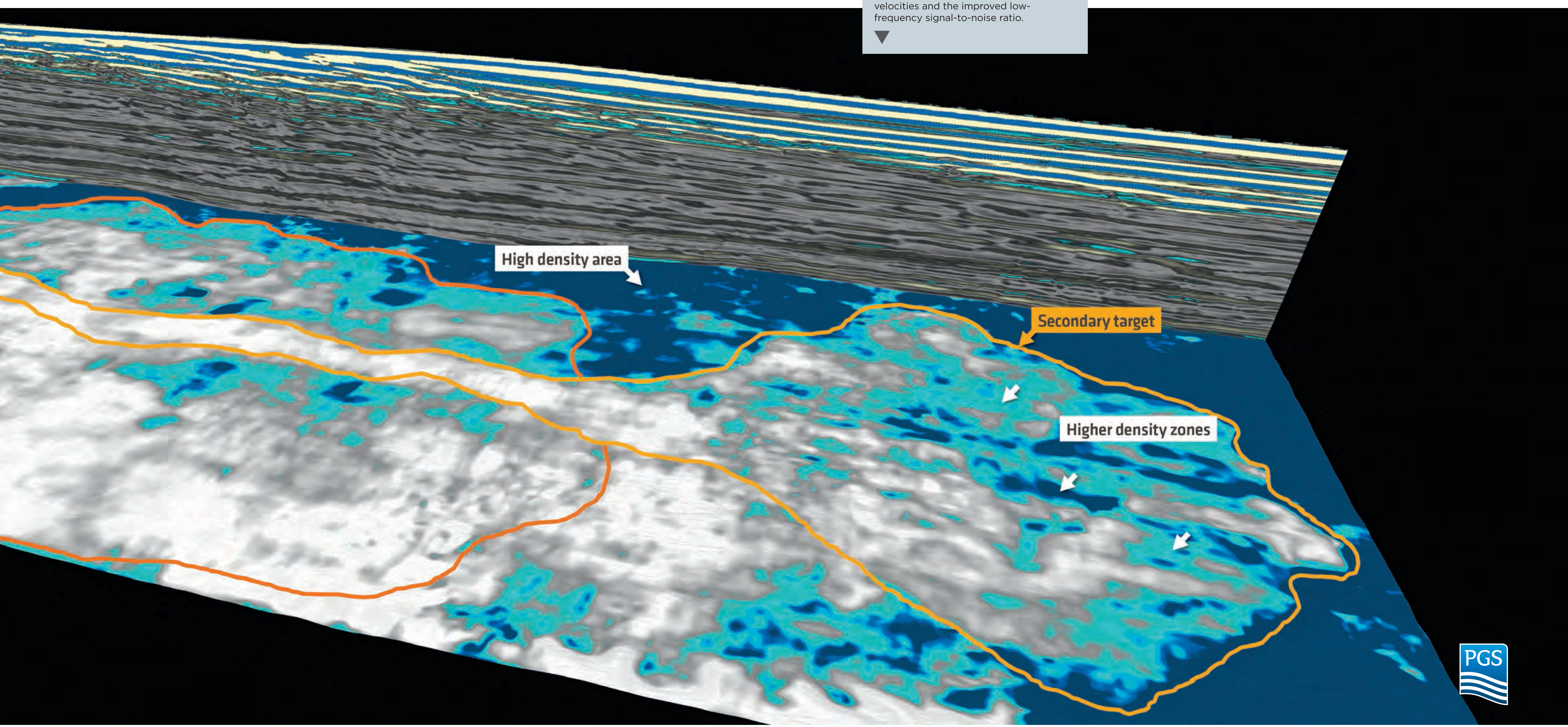
It has a proven petroleum system and established play concepts. Recent drilling success on the **Grand Banks** (Cambriol and Capahayden) has revived the interest of both local and international investors. **PGS**, in partnership with **TGS**, has been acquiring modern **3D GeoStreamer data** offshore Newfoundland and Labrador since 2015. The availability of such data has been a critical component in the success of the **offshore Newfoundland and Labrador** Call for Bids from 2015 through 2020.

Access to 3D data provides confidence when bidding on prize blocks and the use of high-end technology shortens the time to first drill and potentially first oil. The PGS/TGS data library comprises approximately 35,000 sq. km of 3D GeoStreamer data in the Eastern Newfoundland region defined under the Land Tenure System. The Call for Bids for this area closes in November 2022. High-end imaging technology, like PGS Ultima, and quantitative interpretation workflows, clearly demonstrate material size prospectivity in the eastern Newfoundland region, particularly in the underexplored **Orphan Basin**.

In this study, we demonstrate **PGS Ultima** provides not only the high-resolution velocity model but also relative impedance and relative density estimates in a challenging area in the Orphan Basin. The accurate inverted models provide additional understanding of prospectivity.



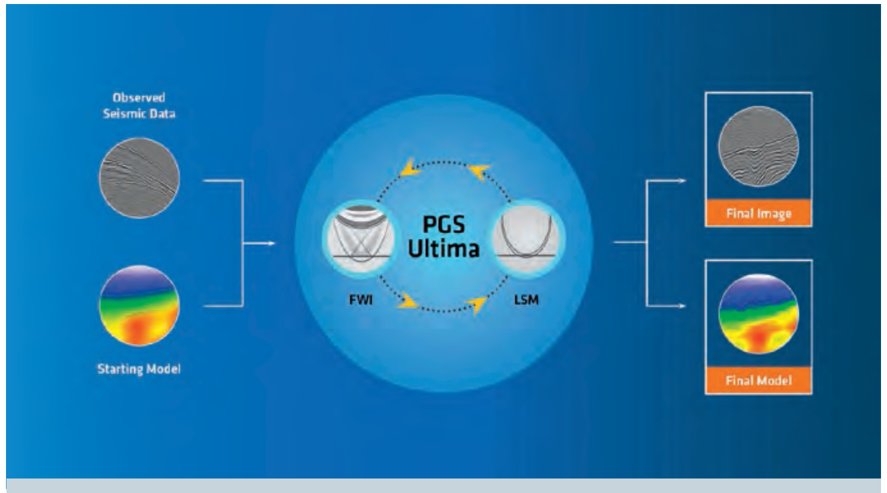
Joint PGS/TGS library. The Blomidon survey is shown in orange and the PGS Ultima test area covers 900 sq. km of that survey. The survey is a part of 35 0000 sq. km of contiguous 3D coverage.



A 3D display of the relative density attribute is shown both on the sections and the map. It is time-consuming and data quality-dependent to extract this property from seismic data in a conventional manner. However, PGS Ultima is an entirely data-driven workflow and it delivers reflectivity and relative density properties in a much faster timeframe. A notional interpretation of the displayed map indicates the presence of two possible overlapping marine fans. The primary fan feature (orange) was identified on the 3D GeoStreamer Blomidon dataset (Figure 2). The area covered by the PGS Ultima test was 900 sq. km and it confirms the primary fan and revealed a secondary fan feature (yellow) thanks to the more accurate velocities and the improved low-frequency signal-to-noise ratio.

A Paradigm Shift in Data Imaging

Accurate velocity and reflectivity models are essential for high-fidelity seismic interpretation.



The general workflow for PGS Ultima. Starting with observed seismic data with minimal pre-processing and an initial velocity model, FWI and LSM are iteratively implemented in a single inversion framework. A high-resolution velocity model and an accurate inverted reflectivity are output simultaneously. Relative impedance and relative density attributes can be output in addition to the main products.

Text: **Yermek Balabekov, Yang Yang, Sriram Arasanipalai; PGS**

Full Waveform Inversion (FWI) followed by Least-Squares Migration (LSM) is currently the high-end technique to invert for high-resolution velocity and reflectivity models. However, in a traditional sequential workflow, velocity and reflectivity are inverted separately and leakage between the two parameters is unavoidable.

FWI and data domain LSM share a similar framework, both aiming to minimize the misfit between modeled and recorded data. Accordingly, it is possible to solve both problems in a compact framework. **PGS Ultima** implements FWI and LSM in a joint scheme. The inversion scheme updates both velocity and reflectivity simultaneously at each iteration as summarised in the inversion workflow as shown in the figure above.

PGS Ultima has the potential to reduce the turnround time of a project as only a starting velocity model and minimal pre-processed data is required. A robust inverse-scattering image condition can efficiently separate the velocity and reflectivity updates and minimise the leakage between the two parameters.

The output of PGS Ultima is a high-resolution velocity model together with an accurate estimate of the earth's reflectivity with compensation for incomplete acquisition, poor illumination, and multiple crosstalks. Additional derivative properties such as relative density and relative impedance can be estimated directly from the inverted models.

DERISKING LEADS

The method was successfully applied to a dataset from **offshore Newfoundland and Labrador**. The resulting outputs deliver good amplitude fidelity and signal-to-noise ratio. The inverted models can be directly used to identify leads and reduce the risk when identifying prospects. The narrow azimuth (NAZ) 3D survey used for this study was acquired in 2020 using multisensor technology with 16 streamers, 100 m streamer separation and 8 km streamer length.

Of particular interest in this area are large-scale **Paleogene marine fan systems** that align along the shelf margin off the northeast Coast of Newfoundland. In this shallow water setting the main imaging challenges are multiples and strong velocity contrasts which make it difficult to identify prospects as the signal-to-noise ratio (SNR) is poor. The uplift from applying PGS Ultima to the data improves the identification and understanding of such prospects within the **Blomidon survey**.

The top image in the figure to the right is the relative impedance property extracted at the target interval. There are two potential reservoir fairways shown on the map. Both are notionally interpreted as marine fans. The primary target (orange outline) was delineated using the underlying data but PGS Ultima was able to improve the image in the distal part where a secondary fan feature (yellow) has become more apparent. This is thanks to the increased signal-to-noise ratio at low frequencies and more accurate velocities. Both the primary and secondary fan features have encouraging low relative impedance responses (light gray). Lateral heterogeneity is seen within the secondary fan, note the variation of the dark (harder rock) and light (softer rock) colours.

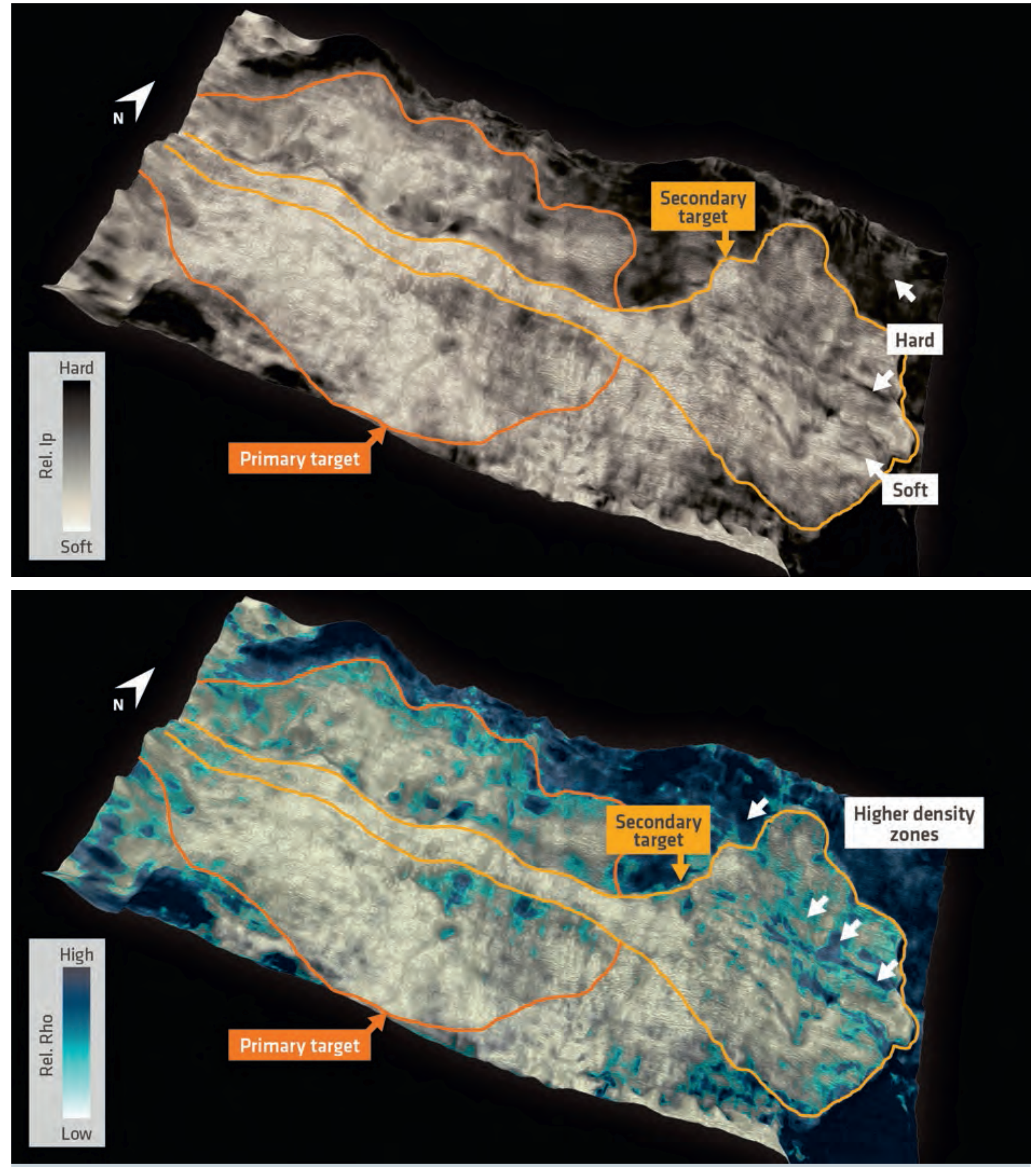
An overlay of the relative density map and the relative impedance is shown on the bottom image of the figure to the right. The joint interpretation of both attributes confirms the delineated secondary fan geometry and the relative density attribute provides additional insight. A higher relative density signals a change in the reservoir property or a different fluid phase in the distal part of the secondary fan feature. Revealing such details is important for risk mitigation in the Orphan Basin.

A RELIABLE SOLUTION

Traditionally, it has been difficult to produce a reliable density attribute as final and fully processed very high angle stacks (above 45 deg.) with a good signal-to-noise ratio would be required. This would mean that the exploration team would have to wait until the end of the data processing phase, which normally takes several months. Sometimes the duration of the processing phase overlaps with the bid round schedule and puts exploration teams under pressure to meet deadlines.

PGS Ultima can help in these situations. It is a fast data-driven approach that delivers direct estimates of the subsurface velocity, reflectivity, and their derivatives, relative impedance and relative density. Depending on the geological setting and the target level, it can even start from minimal pre-processed input data and can be run very effectively, enabling the technical teams to perform prospectivity and lead risk assessments in a shorter time frame. ■

All images courtesy of PGS



Examples of outputs from PGS Ultima: Top) the relative impedance (rel.Ip) map and Bottom) is the relative density (rel.Rho) overlayed with the impedance for a joint interpretation. There is general agreement between the two predicted properties. Both the primary and secondary fan features have a favourable low relative impedance response (light gray). When overlayed with the relative density on the bottom map the right portion of the secondary fan demonstrates a break in relative density, signaling a change in the reservoir property or a fluid change.

Photo: Pixabay

While Europe needs gas from Africa, the Africans need energy to fight poverty.

Opportunities for African Gas are Plentiful

Africa is the new energy frontier that could provide long-term relief for Europe's gas demand. This reality is likely to spark increased investment and exploration in the coming years.

Text: Paul Sinclair, VP Energy for Africa Oil Week

The International Energy Agency's 10-point plan to reduce the European Union's reliance on Russian natural gas makes no mention of Africa.

Rather, it sees increased production from Azerbaijan and Norway as likely to provide some additional gas in the short term.

However, African leaders are already moving to address European and global needs. They'll be gathering in Cape Town in October for Africa Oil Week, the continent's leading energy conference.

Africa is the new energy frontier, offering a wide mix of energy solutions that could provide long-term relief. This reality is likely to spark increased investment and exploration in the coming years.

NORTH VS SUB-SAHARAN AFRICA

Algeria and **Egypt** are already significant gas exporters to Europe and can rely both on LNG (Liquified Natural Gas) cargoes and gas pipelines to do so.

Last month, Algeria announced spare capacity at the **Transmed pipeline** that could boost supplies to Europe. However, it must choose whether it is willing to jeopardise its relations with Russia.

Sub-Saharan Africa lacks the gas infrastructure to ramp up gas exports to Europe – at least in the short term. The region has onshore LNG export facilities in **Nigeria**, **Angola**, and **Equatorial Guinea**, and one Floating Liquified Natural Gas (FLNG) terminal in **Cameroon**.

Nigeria, Angola and Equatorial Guinea have all struggled to supply feedstock to their terminals and to operate at full capacity since 2020 OPEC quotas and years of underinvestment in upstream gas production.

PIPELINES AS AN ATTRACTIVE SOLUTION

"While trans-Mediterranean pipelines have been successfully delivering gas to Europe from North Africa, it remains to be seen whether sub-Saharan African countries can replicate that success," says **Mickael Vogel,** Director & Head of Research at pan-African investment-research firm Hawilti.

Nigeria has Africa's largest gas reserves and has long wanted to supply gas by pipeline via **Morocco** and **Algeria**. "However, they cannot be commissioned in the short-to-medium term," he says.

LNG TERMINALS ON THE RISE

Increased African gas supplies to Europe are only likely to come from already-scheduled facilities and deliveries from projects that broke ground in recent years.

Italian company **Eni** has recently started production of its Floating Liquified Natural Gas (FLNG) project off **Mozambique**. The 3,4mtpa (million tons per annum) facility was successfully moored last winter and is only Africa's second FLNG unit after Cameroon.

TotalEnergies is hoping to resume construction this year of their **Mozambique** LNG terminal, which is not expected to produce before 2026. However, most supply contracts secured from the terminal are with Asian traders and off-takers. Little capacity is expected to be reserved for the European market.

One mega-project likely to benefit from the current scenario is **Tanzania** LNG – a multi-billion-dollar venture that would monetise almost 50 Tcf (1,4 trillion m^3, for comparison, the Groningen gas field, the largest in Europe, had 2,8 trillion m^3 of recoverable gas) of gas discovered offshore.

It could become a strong gas supplier to Europe before 2030 if construction starts by mid-2023.

DON'T UNDERESTIMATE FLOATING LNG

The reshaping of Europe's energy security raises many questions, chief amongst them the long-term demand for gas in Europe. In the ever-changing global gas market, FLNG is the wild card – and one which sub-Saharan Africa would do well to put on the table.

By next year, the continent will have three floating LNG vessels in operation in **Cameroon**, **Mozambique**, and **Senegal/Mauritania**. A fourth could start operating in 2023 off the Republic of **Congo**, where Eni is fast-tracking a modular, flexible liquefaction project with technology from New Fortress Energy.

"Because floating LNG allows the development of smaller, or even stranded gas reserves, it can be implemented across a wide range of assets with a shorter time to market. This makes it attractive when gas supplies need to be secured in record time," says Vogel.

"FLNG projects are indeed a lot more flexible in how and where they deliver their cargoes. A major reason is that they can rely on shorter supply contracts of less than 10 years," he says.

ENERGY NEEDED FOR GROWTH

Whether Africa can become a preferred gas supplier to Europe is not the only question. As I pointed out in a recent article, "Africa needs to lift nearly half a billion" people out of poverty. In addition, nearly half of African states have seen no real economic growth in two decades.

This means Africa has little choice but to utilise both hydrocarbons and green energy to power its economies and drive social upliftment.

Whether it can bring such reserves to market will now depend on increased stakeholder engagement and the development of meaningful, flexible, and rapid solutions. ■

Africa Oil Week (AOW) takes place from 3-7 October 2022 in Cape Town, under the Patronage of the South African Department of Mineral Resources and Energy, with the theme 'Sustainable Growth in a Low Carbon World'. AOW advocates for the sustainable development of Africa's hydrocarbons. The next few years promise many opportunities for the African oil and gas industry. AOW is the global platform for stimulating deals and transactions across the African Upstream. The event brings together governments, national and international oil companies, independents, investors, the G&G community and service providers, offering unrivalled opportunities that drive investment and deal-making across the continent, thus shaping the future of Africa.

Edited by: Henk Kombrink

Significant potential

As the world is grappling with an energy crisis, the need to diversify the energy mix is more acute than ever. Geothermal energy is only a small player today but has the potential to grow significantly given the number of projects that is ongoing.

From low-temperature buffering to producing electricity from >100° C fluids, geothermal drilling projects tap into a wide variety of deep and shallow subsurface settings that oil and gas exploration has never focused on before.

The drilling of deep wells in the southwest of England forms a prime example of the fascinating geology that is currently being tested for geothermal purposes in the UK. One project, United Downs, has completed drilling two deep wells (~ 5 km) into a major fault zone in granitic basement and anticipates starting electricity production in the very near future.

At the same time, Denmark is preparing for some big geothermal projects in the years to come. Read about these projects here.

0,002%

Share of global energy production compared to oil

Annual oil production: 36 billion barrels
(100 MMboepd)

Annual geothermal production: 0,08 billion barrels oil equivalents
(0.2 MMboepd)

Drilling kilometres of granite

Two deep geothermal projects in the UK tap into energy stored in major basement fault zones.

Over the past couple of years, two deep geothermal projects kicked off in the southwest of the UK – Cornwall. In an area that has long been known for its elevated heatflow due to the presence of granitic basement rocks in the subsurface, the projects are designed in such a way to produce water at depths of more than 4 kilometres from permeable fault zones dissecting the granites.

The United Downs project started drilling the first well in 2018. Two wells were completed through a major, near vertical fault zone called the Porthtowan Fault; a producer and an injector well. No advanced kit was needed to detect the fault zone during drilling. Mud losses turned out to be the perfect indication of drilling through heavily fractured rocks.

"The fault zone is formed of a series of extensive faults and has a width of approximately 600 m in which the rocks have been extensively fractured and broken, resulting in increased flow capacity," Hazel Farndale – geologist at the United Downs project - explained.

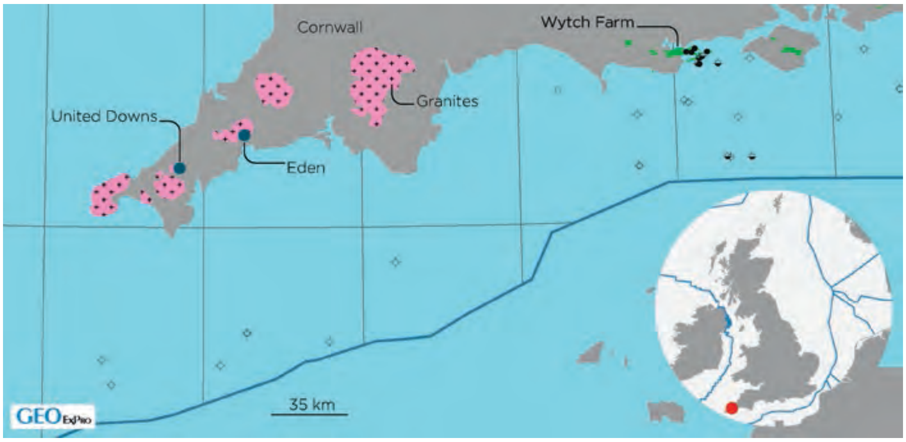
The future United Downs production well is one of the deepest onshore wells in the UK at 5,075 m TVD, and first transects the fault zone at around 4,100 m depth. The injection well is significantly shallower and was drilled through the same fault zone, reaching 2214m TVD. Yet, it is thought that the two wells are in hydrodynamic contact, which should ultimately lead to pressure re-equilibration given that no net loss of water will take place.

A so-called "Binary" power plant is currently under construction that will process the ~160° C brine to produce between 1 and 3 MW of electricity initially.

INDUCED SEISMICITY

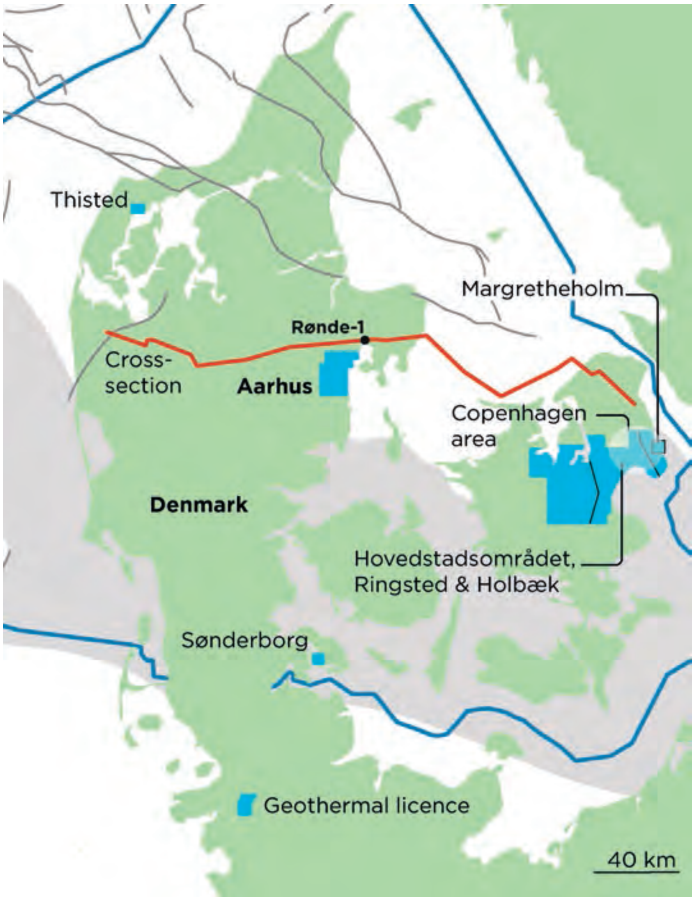
Close by, a second geothermal project targeting the same geology started more recently – the Eden project. During injection testing earlier this year, induced seismic events with a magnitude of 1.7 were felt. Even though this is far too low to cause damage, some reports of people having felt the tremors were noted.

The project was ceased for a while to investigate the matter. It clearly shows the risks associated with production from basement rocks, which is well known from projects in Switzerland and France. With that in mind, it will be interesting to follow the project once production and injection are in full swing.



A game-changing geothermal project

Given its size, the Aarhus geothermal development has the potential to set a new standard for Denmark.



Plans are to drill up to seventeen wells – each to a depth of around 2,500 m. That is the scale of the geothermal development that may be realised in the city of Aarhus in Denmark. With a low geothermal gradient, the water will, however, not be high enough for producing electricity. Instead, it will be used to supply Aarhus' district heating system with up to 20% of its heating demand. Aarhus has a population of about 350,000.

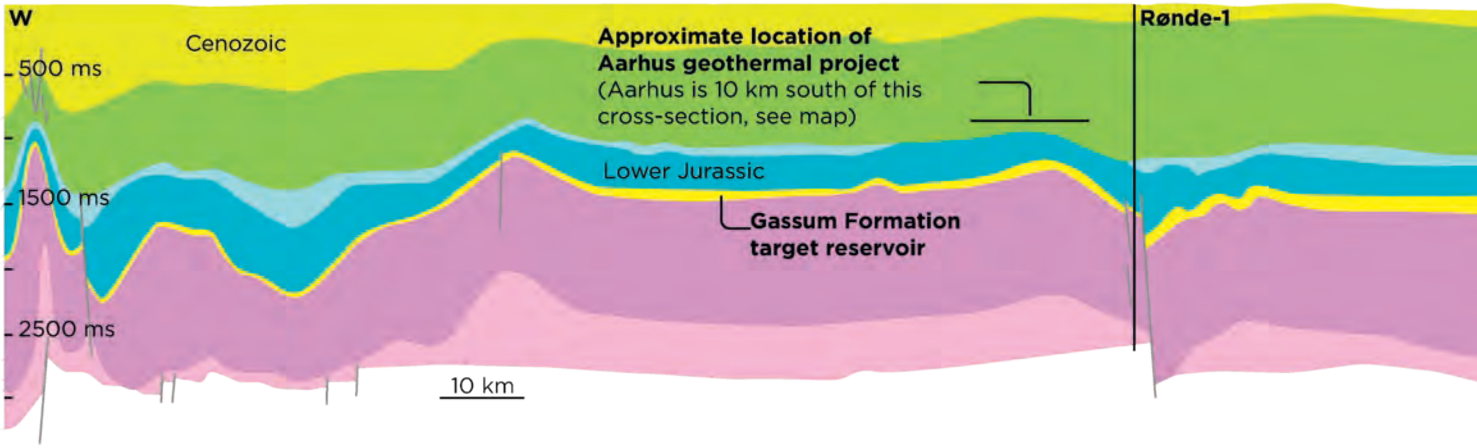
The company behind the plans is **Innargi**. Founded by Danish conglomerate A.P. Møller Holding in 2017, the company has demonstrated to be an ambitious player with plans for geothermal developments not only in Aarhus, but also in Copenhagen.

The **110 MW** Aarhus development is going to be significantly larger than, for example, the currently operating geothermal project in Denmark – **Thisted**. Thisted is a two-well development (one producer and one injector) that supplies around **7 MW**, so the Aarhus project is going to be 15 times larger in terms of energy produced.

Split up into 10 producers and 7 injectors, it is a big and ambitious project as it doesn't happen often that so many deep wells are being drilled in one campaign. In the Netherlands, where more than 20 geothermal energy projects were realised in the past decades, most are just two-well developments.

The Triassic **Gassum Formation** will be the main drilling target for the wells. Innargi said that two to three exploration wells will be drilled first in order to assess the subsurface flow properties of the sandstones. Seismic acquisition will not be part of the exploration phase.

If the exploration results are positive, the remaining wells will be drilled with an anticipated spacing of around 800 m between the producer and injectors. The estimated economic lifetime of the project is thought to be 30 years.



East-West trending cross-section through Denmark, showing the structure of the subsurface up to the base of the Permian Zechstein. The main reservoir target – the Lower Jurassic/Triassic Gassum Formation is indicated in yellow.

WATER VERSUS OIL

The Thisted geothermal site produces up to **7 MW** of energy. As 1 barrel of oil equates to approximately 6.1 x 109 J, and with 1 MW being equal to 1,000,000 J/s, the Thisted site produces an equivalent of around **98 barrels of oil** per day, from a single well.

The Aarhus project could produce energy to the equivalent of **1,540 barrels** per day. If compared to an offshore single-well oilfield, a geothermal project such as Thisted, and even Aarhus, is being dwarfed. For instance, the **Cook field** in the UK Central North Sea produced around **5,700 barrels** per day in late life.

However, when compared to onshore oil fields, the energy produced by Thisted does fall in the same range. In a brochure published by the UK Onshore Operators Group, it is mentioned that approximately 300 operating wells onshore UK produce in excess of **20,000 barrels** of oil per day. That averages to 66 barrels of oil per day per well, which is very much in the same range as the Thisted project.

RISK IS COVERED

A factor that must have been a key driver in getting this project over the line is that Innargi covers the subsurface risks associated with the project. This includes filters and downhole pumps, as it was these aspects that caused problems in previous geothermal projects in Denmark (see below).

All in all, when successfully implemented, it is easy to see that the geothermal community should follow the project closely, especially because out of the three projects realised so far, only Thisted is still operational. Below is a short account of these projects.

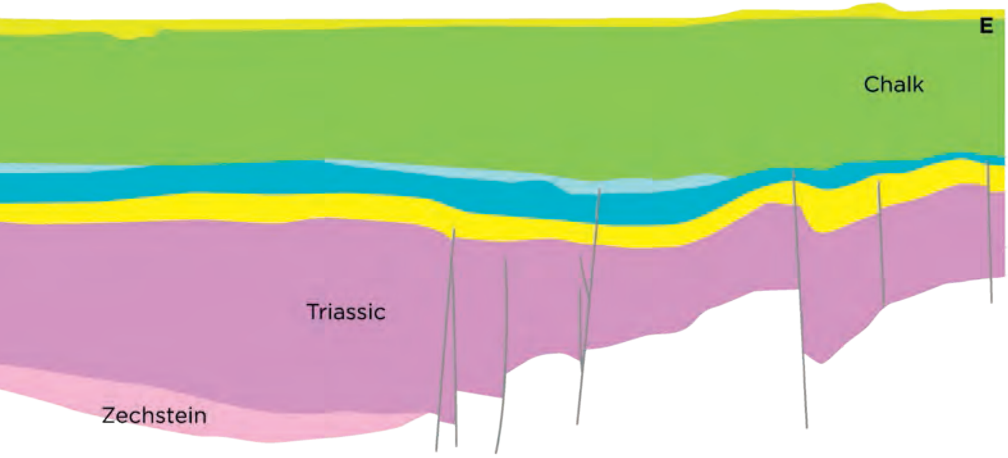
NOT A LOT OF SUCCESS SO FAR

The **Sønderborg** geothermal project was closed due to slight geological and mostly technical reasons. There was no water in the primary Triassic Bunter sandstone target, so the operator had to use the shallower Triassic-Lower Jurassic Gassum formation at only 1.2 km depth. Due to this, all filters were wrongly designed but used anyway and accidental corrosion of the steel pipes in the saline environment clogged up everything. The geothermal fluid extracted had an average temperature of around 48° C and a salinity of 15%.

Similarly, the **Margretheholm** project was closed due to coatings inside the pipes. This was mainly driven by the precipitation of salts from the Triassic Bunter reservoir inside the filters and the pipes. As the casing had the wrong design, the coating could not be removed, which led to the early closure of the project.

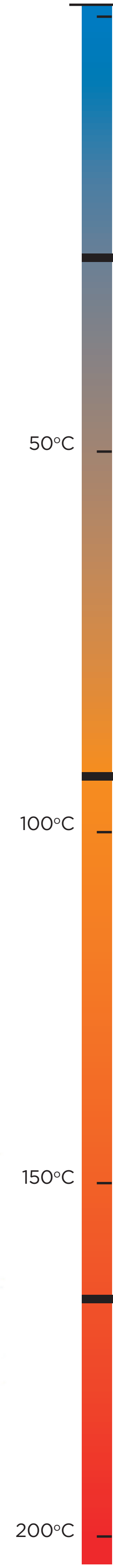
In contrast, the **Thisted** geothermal project has been a success since its start-up in 1984. Initially planned to extract water from the Bunter sandstone, an exploration well proved that permeability was too low. For that reason, the Gassum reservoir was selected instead, and with the filters designed correctly, the plant has already successfullyoperated between October and April fordecades.

Henk Kombrink



The cross-section is derived from the Linde/Karlebo interpreted seismic line that is available through the GEUS Geothermal portal (https://data.geus.dk/geoterm).

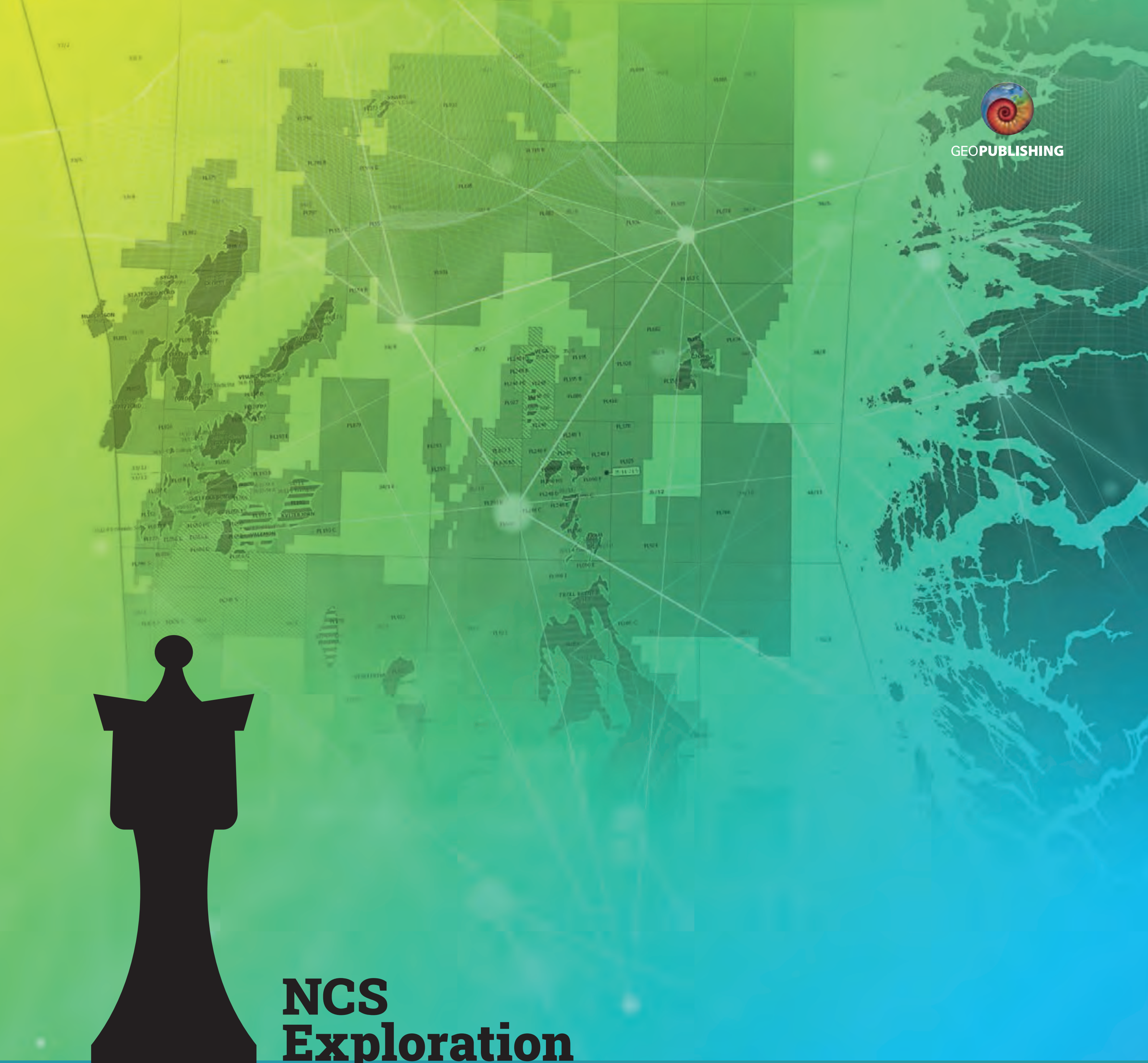
GEOTHERMAL ENERGY



Low-temperature geotherminal energy.
Temperatures under 30° at depths between 10 and 200 metres. Used to heat or cool single-family homes, apartment blocks or commercial buildings. Heat pumps are used to raise the temperatures for heating or lower them for cooling. Main use in shield areas.

Deep low-temperature geothermal energy.
Temperatures between 30°C and 90°C collected at depths ranging from 200 to 2,500 metres. Connected to an aboveground heating system, this technique can be used to heat entire neighbourhoods or industrial parks. Main use in shield areas.

High-temperature geothermal energy.
Working with temperatures over 150°C, either by using wells with steam far below the surface to produce electricity, or by injecting water into hot, dry rock deep underground, then recovering it back at the surface. Main use in areas of divergent and convergent plate boundaries.



Disappointing first half year

Exploration drilling in Norway has not delivered to expectations this year as the aggregate volumes appear to be small.

True, **Aker BP** proved up to **11 Bcm** of gas (68 MMboe) in the Norwegian Sea through completing the **Storjo** well recently. Celebrated as a success on the back of a strong desire to rapidly bring more Norwegian gas to the European market, when looking at the wells drilled on the Norwegian Continental Shelf (NCS) this year the overall results are certainly not worth a feast.

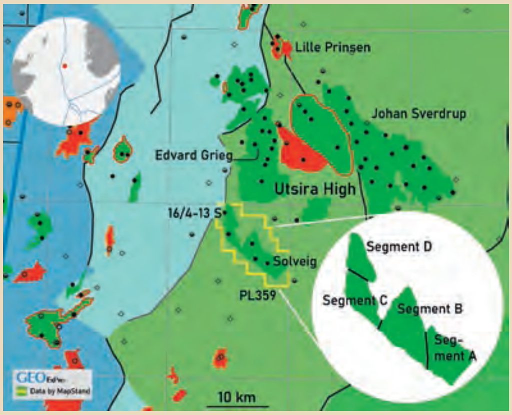
Ormen Lange Deep, Cambozola, Laushornet, all prospects that were drilled this year and that could have added healthy volumes. Especially in the case of Ormen Lange Deep, operated by Shell, the discovery of additional volumes would have been straightforward to develop because the target was situated below the producing Ormen Lange field. However, despite high hopes and anticipation, none of these wells came in as a discovery.

Out of 16 genuine exploration wells spudded on the NCS this first half year, 10 were dry and six resulted in a find. At first glance, not too bad a result, but adding up the preliminary volumes – between **111** and **223 MMboe** combined, the result can only be seen as disappointing. For instance, last year's result was between **370** and **740 MMboe** for the whole year.

To this can be added that even though volumes may sometimes be looking good, it depends very much on the deliverability of the reservoirs whether extraction is worthwhile. For instance, when reading the press release on the Storjo well, it becomes clear that the three Jurassic reservoirs hosting most of the discovered gas are all interpreted as having poor reservoir quality. It Is therefore no surprise to see that appraisal is needed before any decision on development can be made.

Solveig – a complex character

The oceans are essential for future welfare in general and natural resources in particular.



"The devil is in the detail," said **Ronald Sørlie** during the **NCS Exploration – Recent Discoveries** conference in June. He alluded to the results of well **16/4-13 S** recently drilled near the Solveig field on the Utsira High. Oil was found in the Segment D compartment, but to conclude that it is just an extension of the **Solveig** field to the southeast would be an oversimplification.

> **Solveig** produces oil from sandstones and conglomerates of Rotliegend (Permian) and Devonian age. The reservoir contains oil with a small gas cap at a depth of 1,900 metres and is segmented into several compartments with different contacts. Production started in October 2021.

As stressed by Sørlie, the oil encountered in Segment D is namely from another source rock than the oil found in the other compartments that make up the Solveig field. The oil in segments A, B and C shows the presence of two distinct populations that have mixed across the field. Segment D oil has demonstrated to be yet another type of oil that shows the same signal as the oil in **Edvard Grieg** further to the north, which has been interpreted as a later charge from a different source kitchen than the oil in the main Solveig field.

> **Edvard Grieg** produces undersaturated oil from alluvial, aeolian and shallow marine sandstone and conglomerate of Late Triassic to Early Cretaceous age at a depth of 1900 m. Oil is also proven in the underlying basement.

The main reason why Segment D is different from the rest of the Solveig compartments is probably related to the structural setting. Even though segments A, B and C display different contacts and are separated by faults, the fault zone separating Segment C from D is characterised by a larger throw.

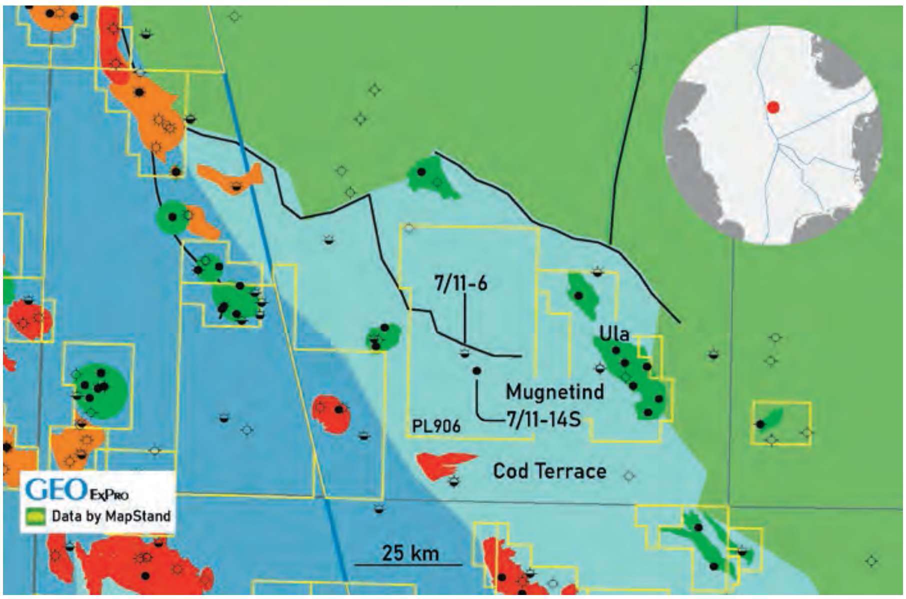
The age of the reservoir is another aspect of the field that was not straightforward. At the early stages of Solveig drilling activity, the idea was that most of the alluvial reservoirs were of Triassic age. However, the picture has shown to be more complex than that. The unexpected discovery of the Zechstein Kupferschiefer in one of the Solveig injector wells clearly suggested that much of the reservoir section is of Upper Permian (Rotliegend) age instead.

In addition, work on different compaction trends within the reservoir section also suggested that a major unconformity separates a more compacted from a less compacted zone. This unconformity is now interpreted as the Saalian unconformity, which separates Devonian alluvial braid plain and fan conglomerates from Rotliegend aeolian and fluvial sandstones.

The current plan for drainage of the Segment D field is part of Phase 2 of the overall Solveig development. This phase includes the development of the northern part of Segment B, which is mainly characterised by a Devonian reservoir section, in addition to drilling a multi-lateral well consisting of two legs in the southeast corner of Segment D.

Expect the unexpected

The recent Mugnetind well in the Norwegian North Sea showed that geoscientists always have to be prepared to look beyond the limits of what seems possible according to local well data.



One of the lithological scenarios Aker BP modelled in order to arrive at the seismic response seen at the **Mugnetind** prospect was a 20 m thick coal. Given the offset well data in the area, this was deemed a genuine end-member. However, the drill bit proved that it was rather an underestimation.

During the most recent **NCS Exploration – Recent Discoveries** conference in Oslo, **Ryan Paton** from Aker BP presented the results of the 7/11-14S exploration well his company completed on the Mugnetind prospect.

The Mugnetind prospect is located in the Central North Sea, 12 km to the west of the Ula field (Ula produces oil mainly from sandstone in the Upper Jurassic Ula Formation at a depth of 3,345 m). The structure, which is caused by a salt dome and the overlying Mesozoic stratigraphy, had been targeted before by well 7/11-6 before. This well proved residual oil shows and was interpreted to have just missed the mapped closure.

A SANDY ULA?

The targeted reservoir section was the Upper Jurassic Ula Formation that can be subdivided into an Upper and Lower sandstone. The Lower Ula was the main target of the two, given its expected quality. However, the reservoir presence of the Lower Ula did constitute one of the main risks.

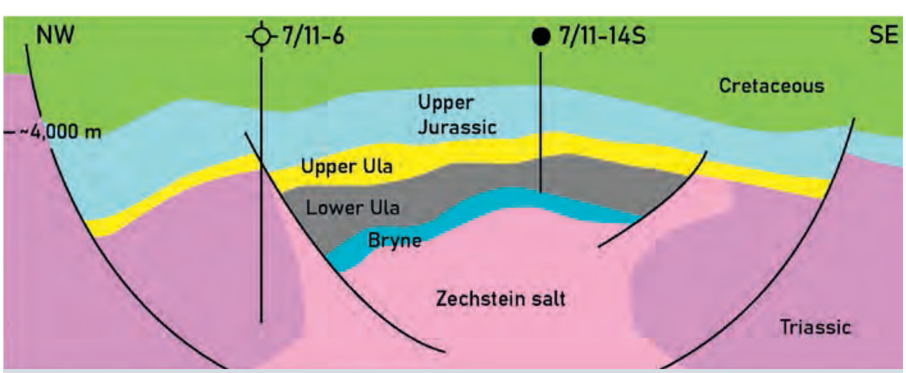
The Upper Ula was encountered as expected, with a 7 m pay zone and an oil-water contact at 3,998 m TVSS. Then, suspense built as the well drilled into the section where the Lower Ula sandstone should have been found.

However, rather than sands on the shakers, coaly fragments were found. This continued, not for 20 m, but for a staggering 70 m. True, a few thin clastic intervals were encountered, but the overall lithology was clearly dominated by coal.

A VERY THICK COAL

How to explain a coaly sequence 70 m thick? When looking at the present-day depth of burial of 4,000 m, it may have represented a more than 500 m thick succession of organic material at surface in Late Jurassic times. Was it a local collapse structure that developed on top of the incipient salt dome once halokinesis had started? If the collapsed structure remained disconnected from clastic fairways and remained near groundwater level for a long time, it can be seen how it might have become a site of prolonged peat growth.

So, even though the geological scenario was considered highly unlikely, 7/11-14S clearly showed that the unexpected still has to be expected!



NW-SE trending cross-section through the Mugnetind prospect in the Norwegian North Sea. The grey colour of the Lower Ula Formation represents the coaly nature of what was encountered by well 7/11-14S. Redrawn after a cross-section published by Longboat.

Source: NAM

A methane atom as a work of art along a motorway in Groningen.

Pressure is mounting on Groningen

While Russia increasingly uses gas supply as a geopolitical tool, there could be a way to sustainably produce more gas from the Groningen field, a group of specialists argues. Nitrogen may be the answer.

Text: Henk Kombrink

Europe is in dire need of additional gas supplies following the commitment from most countries to cut down on imports of Russian gas. This need becomes even more acute now that Russia has stopped gas supplies of its own accord, despite long-term contracts being in place.

The European Union (ex UK) consumed around **340 Bcm** (2,100 MMboe) of gas in 2021, with up to 40% (155 Bcm/975 MMboe) of that being supplied by Russia before the war in Ukraine started in February this year. Whilst the UK hardly imports gas from Russia, many countries in central Europe rely on it to a large extent.

A POLICY U-TURN

It is because of the threat of gas supply shortages that Germany has already announced a U-turn in its policy not to drill more hydrocarbon wells in the German North Sea. In late spring this year, the Germans opened the door to the development of the cross-border **N05-A** discovery. Discovered in 2017, with estimated reserves of **5 Bcm** (31 MMboe) in Permian Lower Rotliegendes sandstones, operator **ONE-Dyas** has been waiting a long time before the field can finally be developed from Dutch waters.

But the N05-A development will not bring much relief. Even when the additional prospects and nearby Turkoois discovery are being tied back to N05-A, it will not generate a major bump in gas supply. What is needed is something bigger to step in.

GRONINGEN – AN UNFORESEEN CHALLENGE

There is one field that would allow lowering the amounts of LNG that are now being imported and that is the **Groningen field** in the Netherlands with estimated remaining reserves of around **450 Bcm** (2,800 MMboe). Although Groningen gas will unlikely be making its way to countries like Bulgaria and Poland, households and industries in Germany, Belgium and northern France that have been burning Groningen gas for decades, are ready to use it.

The big issue that overshadows the Groningen field is the possibility that induced seismic events will increase in frequency and possibly intensity when gas production is ramped up again. It is for this reason that the Dutch government has forced the operator **NAM** (a Shell/Exxon 50/50% joint venture) to cease production this year.

Would there be a way to produce the gas without causing an increased risk of earthquakes? A group of subsurface and technical specialists from the Netherlands thinks there is.

THE ANSWER MIGHT BE NITROGEN INJECTION

A group of four specialists with a wide range of relevant experience in the oil and gas sector – working under the name of **Group Groningen 2.0** - proposes to inject nitrogen into the northern part of the field where production has already ceased. By doing so, the reduction in pressure related to

THE GRONINGEN GAS FIELD

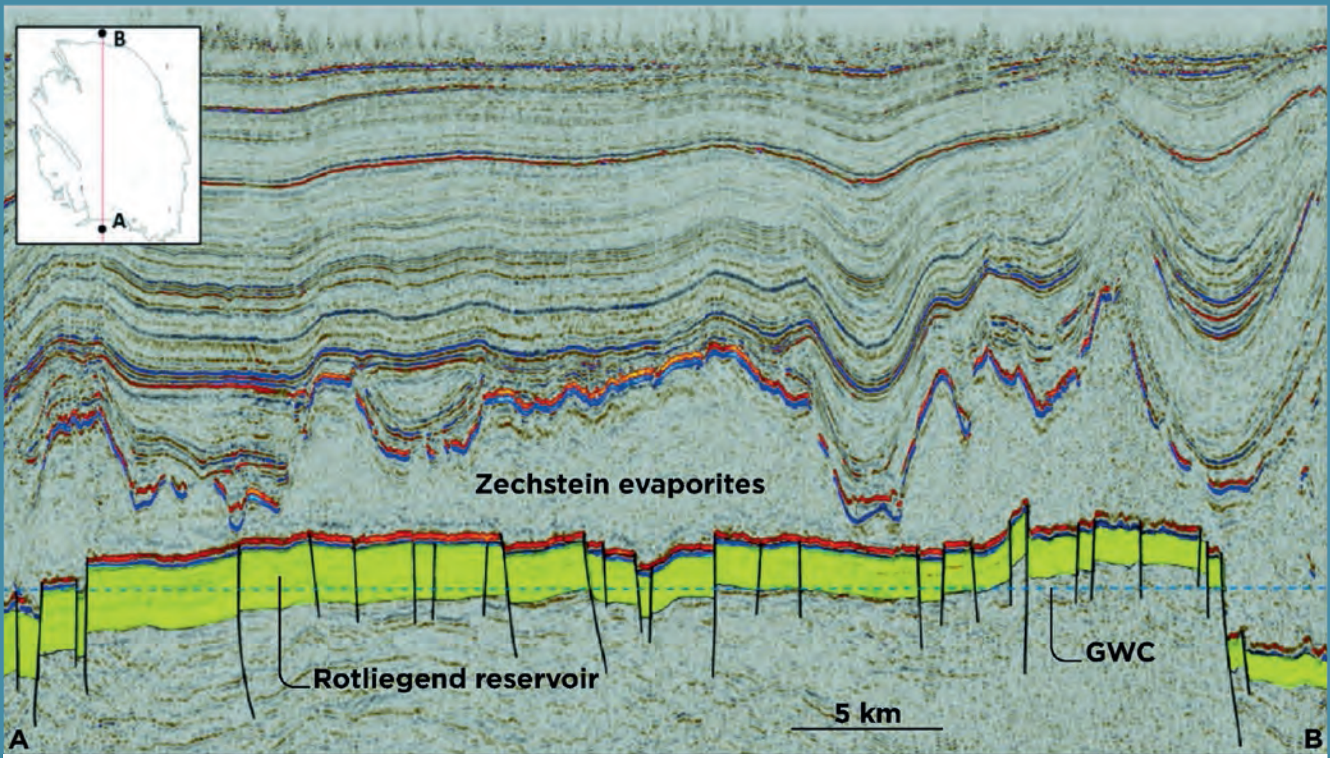
The giant Groningen gas field was discovered in 1959 through drilling well Slochteren-01. It took several years and appraisal wells for NAM to realise the size and extent of the field, and even decades later the recoverable volumes were still revised upwards. The ultimate recoverable volume amounts to 2,900 Bcm.

Groningen gas – which contains up to 17% nitrogen itself - is reservoired in Upper Permian Rotliegend sandstones (see also page 72). Buried to a depth of around 3,000 metres, it is sealed by a thick layer of Zechstein anhydrites. As the cross-section below shows, the field is very low relief, but many (extensional) faults dissect the reservoir succession.

The first recorded seismic event that can be related to production and reservoir depletion in Groningen took place in 1991. Whilst magnitudes remained low for years, between 2001 and 2013 seismicity increased from two ML ≥ 1.5 events in 2001 to 29 ML ≥ 1.5 events in 2011 and 2013. The largest event to date with ML = 3.6 occurred in August 2012 near the village of Huizinge.

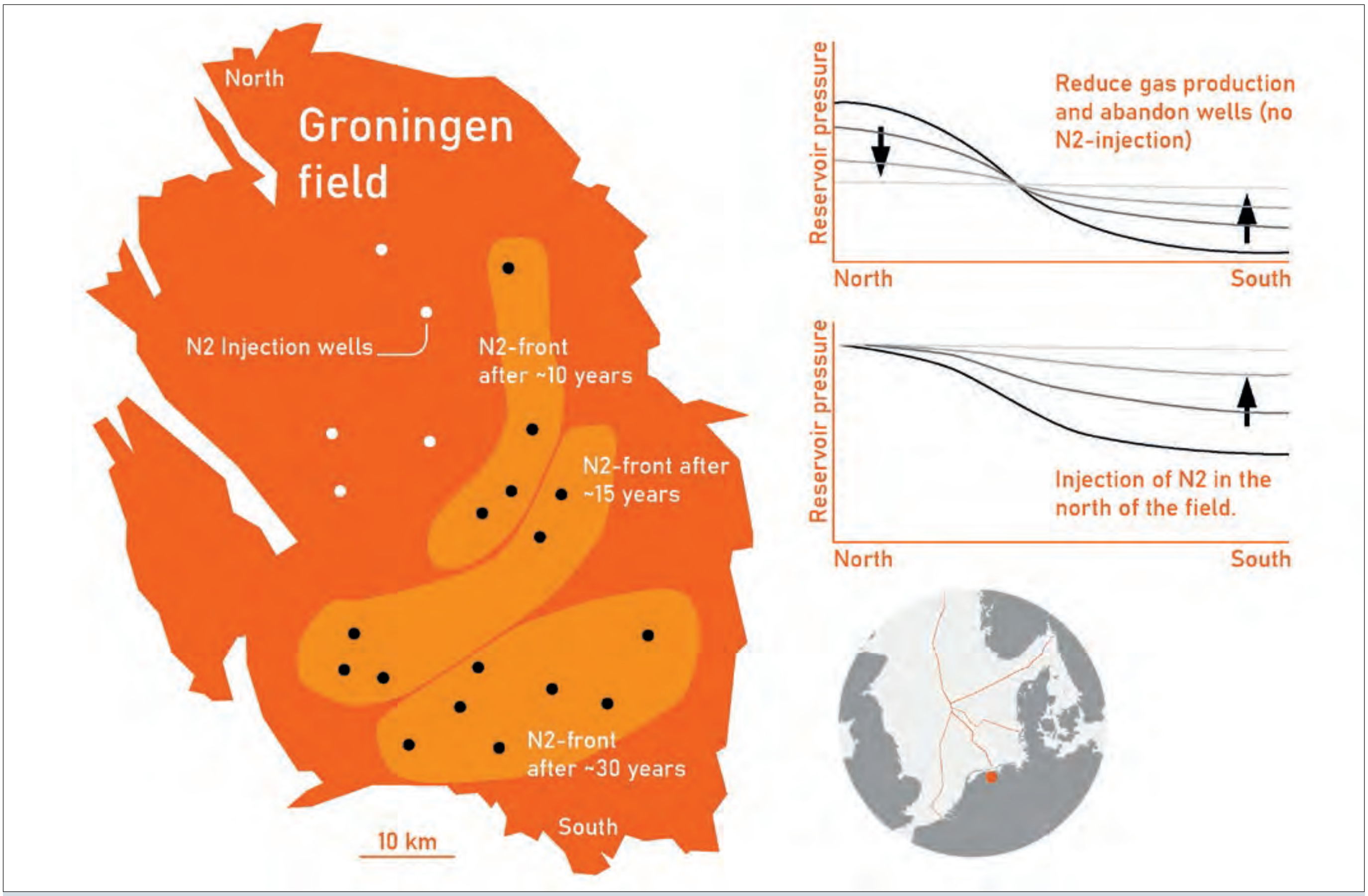
From that moment, the call for a rapid decrease in gas production ultimately led to the decision to completely cease production this year. However, for reasons well known, the abandonment process of wells has now been temporarily halted in order to open the taps again should the ultimate need to do that arise.

Adapted from De Jager & Visser (2017)



N-S trending seismic line through the Groningen field, showing the Rotliegend reservoir in yellow, the overlying Zechstein evaporites and the gas-water contact (dashed line).

Map and diagrams redrawn after Overleggroep Groningen 2.0.



Schematic outline of the Groningen field, showing the arrival times of the injected N_2 in number of years following start of injection in the north. The graphs on the right show how pressures in the field re-equilibrate in a situation without additional N_2 injection (above) and with N_2 injection (below).

NITROGEN INJECTION IS NOT NEW

Injection of nitrogen is not a new technology. NAM has been using it in the De Wijk gas field in the north of the Netherlands to sustain production for a number of years already. The biggest nitrogen injection in the world is in Mexico, where PEMEX started using the gas in 2000 to maintain pressure in the biggest oil field of Mexico at the time, Cantarell. The project resulted in an increase in production from 1.6 MMbbl/d to 1.9 MMbbl/d in 2002, rising to its peak in 2004 of 2.1 MMbbl/d. However, production rates could not be maintained and began to decline rapidly in the second half of the decade. In 2021, only 0.16 MMbbl/d was produced from Cantarell.

production of gas is counterbalanced by the introduction of nitrogen. This is anticipated to subsequently reduce the risk of induced seismic events. The idea is that the injected gas will ultimately find its way to the south of the field as the years of injection progress.

NAM already carried out a feasibility study for nitrogen injection in 2012-2013, but the project never came off the ground. At the time, it was envisaged that all remaining 600 Bcm (3,780 MMboe) of gas in Groningen was to be produced, which came with a big investment in a nitrogen plant, drilling of injection wells all across the field and the construction of nitrogen reinjection units with all production clusters.

Now that production from Groningen has already been scaled back, a nitrogen injection project is much more manageable according to the group. They propose to mostly reuse up to 15 existing wells in the northern part of the field, in which 0.4 to 1 Bcm of nitrogen will be injected on an annual basis. Selection of the injection wells should happen on the basis that they are as far removed from reservoir faults as possible, such that the risk of induced seismic events is kept to a minimum.

Whilst injection would take place in the northern part of the field, the nitrogen front would slowly migrate southwards, thereby pushing methane further towards the existing production wells in this part of the field.

THE HOLY GRAIL?

Is nitrogen injection the holy grail? No, it will not be a quick fix, as testing will need to be carried out to prove the concept in Groningen. That is why the technique will not alleviate pressure on supply this winter. However, given the dire situation with regard to gas supply and the lack of tangible workarounds that do not cause a rapid rise in CO_2 footprint such as the transportation and generation of LNG, the project should at least be looked at as a possibility.

References provided online.

UK North Sea: A Step-change in Imaging Quality

New OBN imaging illuminates the full potential of deeply buried and salt-influenced reservoirs.

Text: **Steven Bowman, Ramez Refaat, CGG and Per Helge Semb, MagSeis Fairfield**

It is often said the best place to find oil is in an oil field and if that is true then perhaps the second-best place to find oil would be below an existing oil field. These principles, along with a focus on targeting complex high-pressure, high-temperature (HPHT) reservoirs to address industry needs, motivated CGG to acquire in 2020 a 1,650 km^2 high-density Ocean Bottom Node (OBN) multi-client survey with **Magseis Fairfield** across two highly prospective areas in the UK Central North Sea (Figure 1).

The targeted **Cornerstone OBN survey** combined with CGG's latest imaging technology complements CGG's regional high-quality Cornerstone Evolution towed-streamer surveys by generating subsurface images of unprecedented quality in the most challenging areas to significantly de-risk field development and near-field exploration.

LOCATION AND BRIEF EXPLORATION HISTORY

Phase 1A of the OBN survey covers the Marnock field, at the heart of the **Eastern Trough Area Project (ETAP)**, which produces gas condensate from Triassic Skagerrak Formation sandstone reservoirs. Also covered are the Mungo, Monan and Mirren fields which all produce mainly oil from Paleocene Forties Formation sandstone reservoirs within four-way dip-closures created and pierced by the diapiric movement of Permian Zechstein salt.

The fields contain steeply dipping reservoir units with widespread slumping and sliding observed (Pooler & Amory, 1999). The **Murlach field**, previously named Skua, which produced oil and gas between 2001-2004, and the **Birgitta gas condensate discovery** are currently being developed as tie-backs to ETAP with both expected to commence production by 2025. Both will produce from Skagerrak Formation reservoirs.

The smaller Phase 1B of the OBN survey is centered over the **Fram field** which began production in 2020. After an earlier unsuccessful attempt to appraise Fram through development using a standalone FPSO in 2012-13, it is now tied-back to the Shearwater platform. The Fram field produces gas condensate from Forties Formation sandstones within a four-way dip-closure pierced by a Zechstein salt diapir.

The survey also covers **Capercaillie**, discovered in 1983 and successfully appraised in 2017, with a tie-back to the **Stella hub** planned. This light oil and gas condensate accumulation, within a three-way dip-closure with pinch-out of the Lower Eocene Rogaland sandstone reservoir towards the southwest, is part of the same play that contains the **Abigail** and **Vorlich fields**.

OBN VERSUS TOWED-STREAMER

The Phase 1A and 1B datasets imaged with CGG's proprietary TLFWI technology deliver a step-change in imaging quality

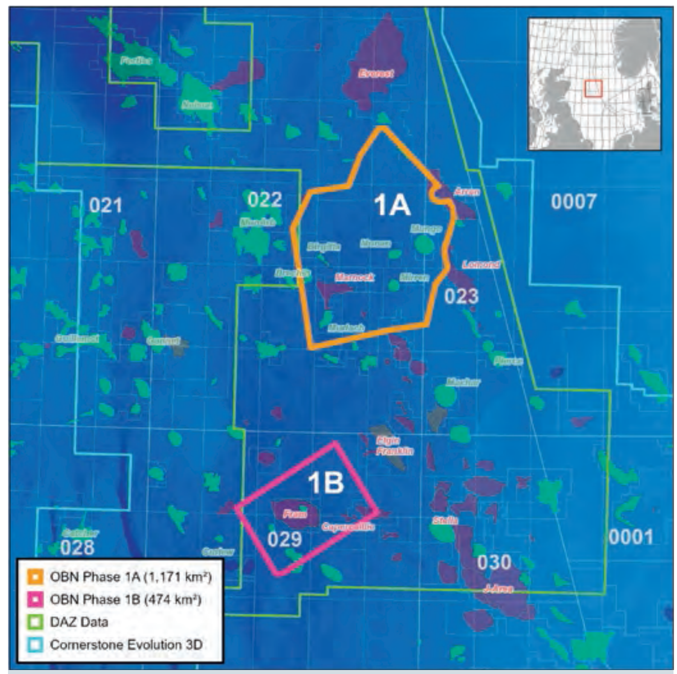


Figure 1: Location map for the OBN Phase 1A and 1B surveys overlying CGG's Cornerstone Evolution towed-streamer surveys.

Source: CGG

even when compared to CGG's market-leading towed-streamer Cornerstone Evolution multi-client surveys. The biggest uplift is observed below the Base Cretaceous Unconformity (BCU), on the steeply dipping flanks of Zechstein salt diapirs and beneath those same salt diapirs (Figure 3).

Within the Phase 1A survey area, the sub-BCU geology consists of a series of Triassic pods and rafts and Jurassic inter-pods that formed in response to halokinesis. The Triassic pods and rafts are predominantly composed of Lower Triassic Smith Bank mudstones overlain by prograding Middle and Upper Triassic Skagerrak sandstones and mudstones.

The monotonous mudstones of the Smith Bank Formation have historically appeared seismically transparent and were further obscured by high levels of noise (Goldsmith et al., 2003). However, CGG's OBN imaging delivers outstanding results resolving low-impedance contrasts and detailed fault patterns within the Smith Bank and Skagerrak Formations allowing regional correlation of seismic markers (Figure 3). Several Triassic fields suffer from stratigraphic and/or structural compartmentalisation and the OBN data helps overcome these development challenges, contributing towards higher production efficiency.

MAPPING INTRA-SKAGERRAK BARRIERS IN MURLACH

The **Murlach field** is penetrated by three wells which encountered different parts of the Skagerrak stratigraphy. The wells show

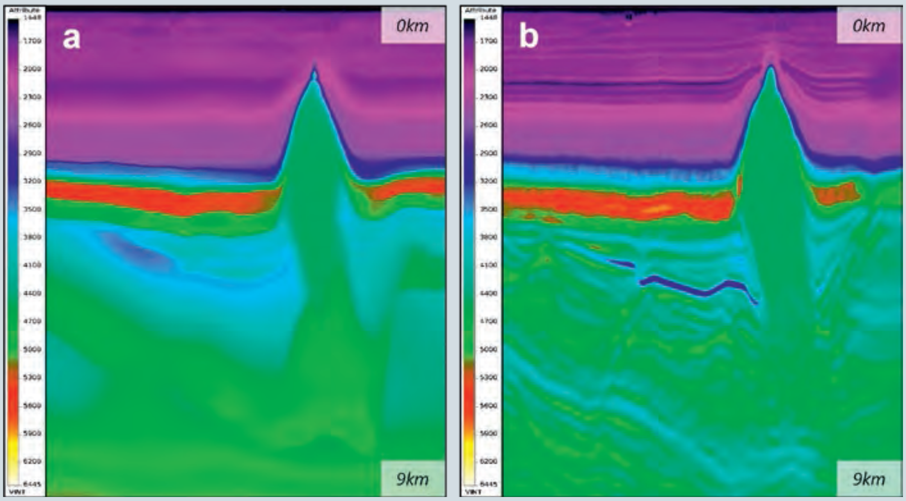


Figure 2: Comparison of: a) towed-streamer Cornerstone Evolution, and b) OBN velocity models, demonstrating the uplift achieved from the OBN dataset and CGG's advanced imaging, with discreet geological features identifiable in the velocity model.

ACQUISITION AND IMAGING

Both phases of the OBN survey were acquired using a 100 x 300 m node spacing and a 50 x 50 m source grid. Representing the largest OBN survey ever acquired in the North Sea, it was specifically designed to address the challenges associated with deeper Jurassic and Triassic reservoirs, typically under HPHT conditions, and the presence of complex structures associated with halokinesis.

Long-offset and full-azimuth acquisition was utilised to deliver a rich low-frequency signal (Refaat et al., 2021) with the aim of achieving enhanced noise removal and significantly improving illumination of deep targets and steeply dipping reflectors. The OBN survey is suitable for use in 4D seismic analysis.

Following acquisition, the OBN data was imaged using advanced demultiple, **Time-Lag Full-Waveform Inversion** (TLFWI, Wang et al., 2019) for improved velocity model building and high-resolution absorption (Q) imaging to provide a high-fidelity broadband and Quantitative Interpretation-compliant dataset. Full-Waveform Inversion (FWI) accurately computes highly detailed, data-driven models of subsurface velocity, Q and reflectivity (Figure 2) by minimising the difference between observed and modeled seismic waveforms.

TLFWI is a proprietary CGG technology that delivers further dramatic improvements in seismic imaging by minimising classic FWI issues related to cycle-skipping from an inaccurate initial velocity model, amplitude mismatches and poor signal-to-noise ratio.

It has improved the entire section of the velocity model from the complex overburden to intra-chalk and sub-chalk layers including below the BCU (Refaat et al., 2021).

PS imaging, coming from the converted waves, has been used to complement conventional PP imaging. It provides increased resolution, additional information on rock properties for more stable and reliable elastic rock-property inversion, details about fracture orientation and improved imaging through gas clouds which attenuate P-wave energy (Casasanta & Gray, 2015). A full PS processing and velocity model building sequence has been applied to the PS data.

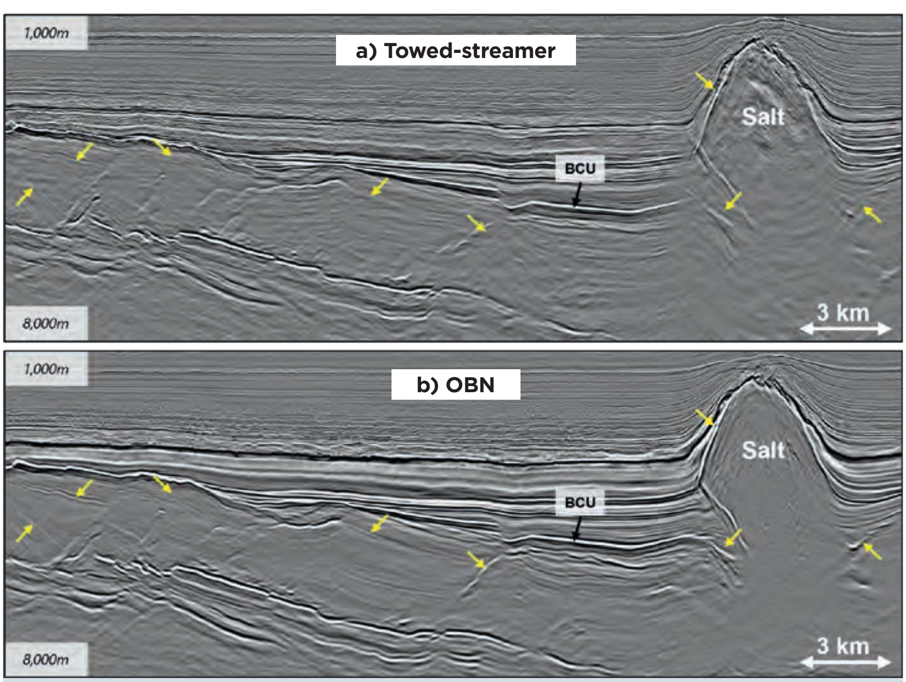


Figure 3: Comparison of regional WSW-ESE seismic lines: a) Cornerstone Evolution towed-streamer, and b) OBN, showing the enhanced resolution of sub-BCU reflectors and improved illumination of sub-salt structures on the OBN data. Arrows indicate key features.

differences in the depth of the oil-water contact (OWC), strontium isotopic ratios and oil geochemistry over a distance of less than 2 km, indicating that the field is compartmentalised (McKie et al., 2010).

Murlach is a four-way dip-closure at the crest of an easterly tilting Triassic raft. The Skagerrak reservoir subcrops the BCU where it has been eroded with truncation of dipping reservoir units which become younger towards the east. Intra-Skagerrak reflectors, and their subcrop pattern on the BCU, are clearly imaged with CGG's advanced technology and the OBN dataset (Figure 4). Correlation of these reflectors clearly indicates that the 22/24b-7 well penetrated younger reservoir units than the 22/24b-9 well which encountered the deeper OWC.

Compartmentalisation within the **Murlach field** is likely to be stratigraphic, rather than structural, with Skagerrak sandstones vertically separated by regionally correlatable shale packages (McKie et al., 2010).

It will be crucial for development wells to be suitably placed with horizontal wells required to intersect multiple reservoir units which may not be in communication with each other.

DEEPER AND MORE COMPLEX

There is a growing trend in the Central North Sea to explore deeper, undrilled sub-BCU reservoirs adjacent to and beneath salt diapirs. After all, in order to develop, a salt diapir needs to exploit a weakness in the overburden which is usually a fault and therefore large, rotated fault blocks are often observed beneath them. Examples of such discoveries include **Culzean** and **Isabella** with further leads and prospects associated with the Mungo, Fram and Scoter Diapirs to name a few.

Towed-streamer seismic data, even multi-azimuth, has generally struggled to fully illuminate and image sub-salt fault blocks. Through the combination of OBN acquisition and TLFWI for velocity model building, these targets can now be mapped with greater confidence (Figure 3) allowing operators to capitalise on near-field, infrastructure-led exploration targets.

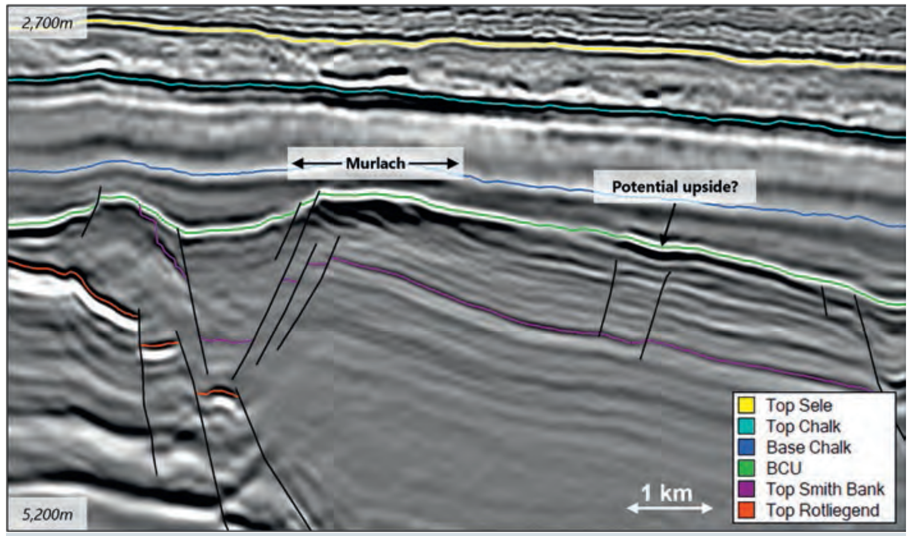


Figure 4: WSW-ESE OBN seismic line through the Murlach field, showing the truncation of dipping inter-bedded Triassic Skagerrak reflectors beneath the BCU.

SHALLOW BUT STILL COMPLEX

Focusing now on shallower reservoirs, the Fram field appears to be a relatively simple four-way dip-closure but there are both structural and stratigraphic controls on the distribution of hydrocarbons. The distal fine-grained sandstones thin, and become absent, towards the south whilst the structure is compartmentalised by radial faulting (Figure 5). There is enhanced resolution of the Top Forties reflector on the OBN dataset with steep dips and onlap geometries onto the salt diapir much more clearly defined.

Mapping allows the distribution of hydrocarbons, observed as a Type-II AVO anomaly, to be easily visualised. Also, the clearly imaged radial faults in **Fram** coincide with a shut off in amplitudes caused by reservoir compartmentalization. The OBN dataset imaged with TLFWI will allow a greater understanding of the Fram field as production continues and importantly provides a baseline survey for any future 4D acquisition.

OUTLOOK AND MACROECONOMIC FACTORS

The **Cornerstone OBN** acquisition together with CGG's proprietary imaging has unquestionably brought a step-change in image quality compared to towed-streamer acquisition, especially for deeper, sub-BCU reservoirs and around salt diapirs where reservoir units are often heavily faulted and steeply-dipping. It will allow for the effective development and monitoring of producing assets and facilitate near-field exploration.

These objectives are consistent with the UK's 2050 net-zero strategy, since domestic production has a much lower carbon footprint than imports, and they increase energy security at a crucial time. Following the successful acquisition and imaging of the OBN Cornerstone survey, CGG plans to acquire and image additional multi-client OBN surveys in the North Sea.

References provided online.

All images courtesy of CGG.

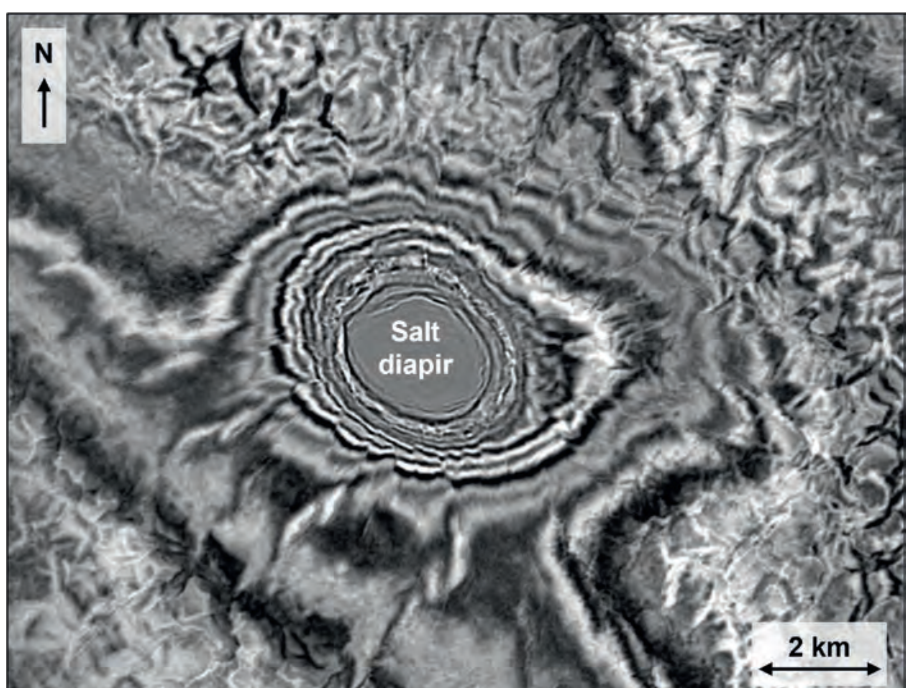
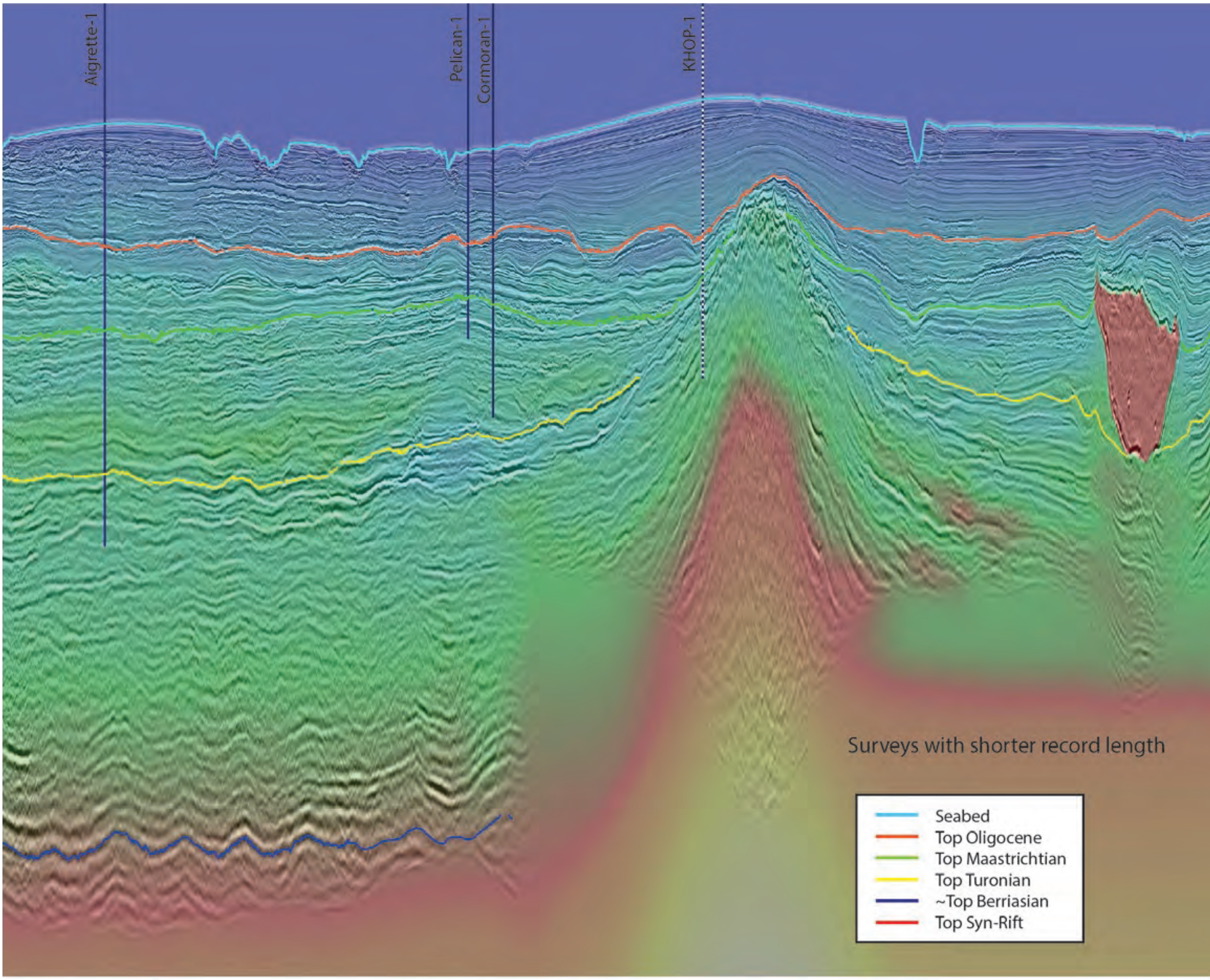


Figure 5: Depth slice through the Fram field with radial faulting clearly seen offsetting reflectors and leading to compartmentalisation of the Forties formation reservoirs.

Chasing the Many Plays of the Mauritanian Margin

ION's new mega-regional re-imaged 3D seismic dataset across the Mauritanian continental margin provides new insights into numerous plays.



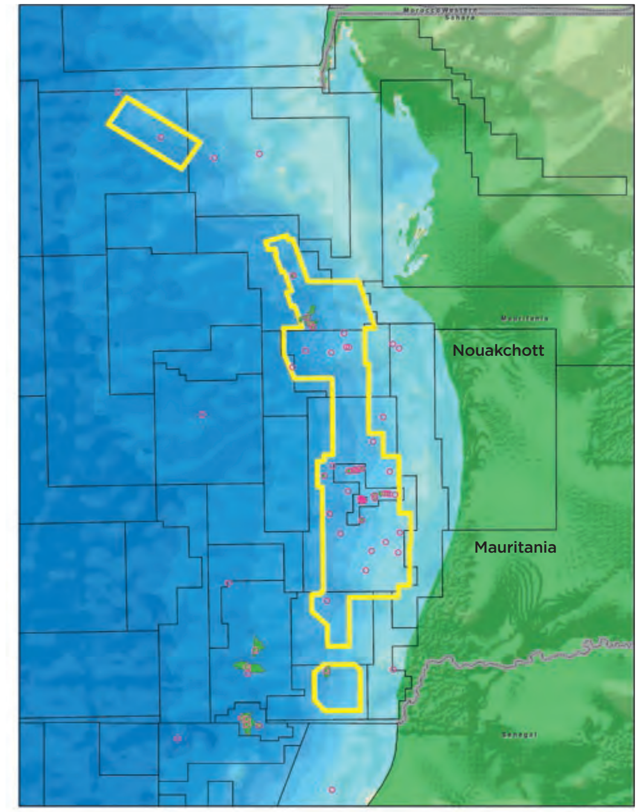
The Mauritanian offshore forms the northernmost part of the MSGBC Basin, spanning the central part of North West Africa's Atlantic Coast. The MSGBC Basin is named after the countries in which it resides, namely Mauritania, Senegal, Gambia, Guinea-Bissau and Guinea-Conakry. In recent years, numerous globally significant discoveries have been made along the northern part of the MSGBC Basin in Senegal and Mauritania, opening up the basin to analogue hunting and more in-depth exploration into additional untested play potential.

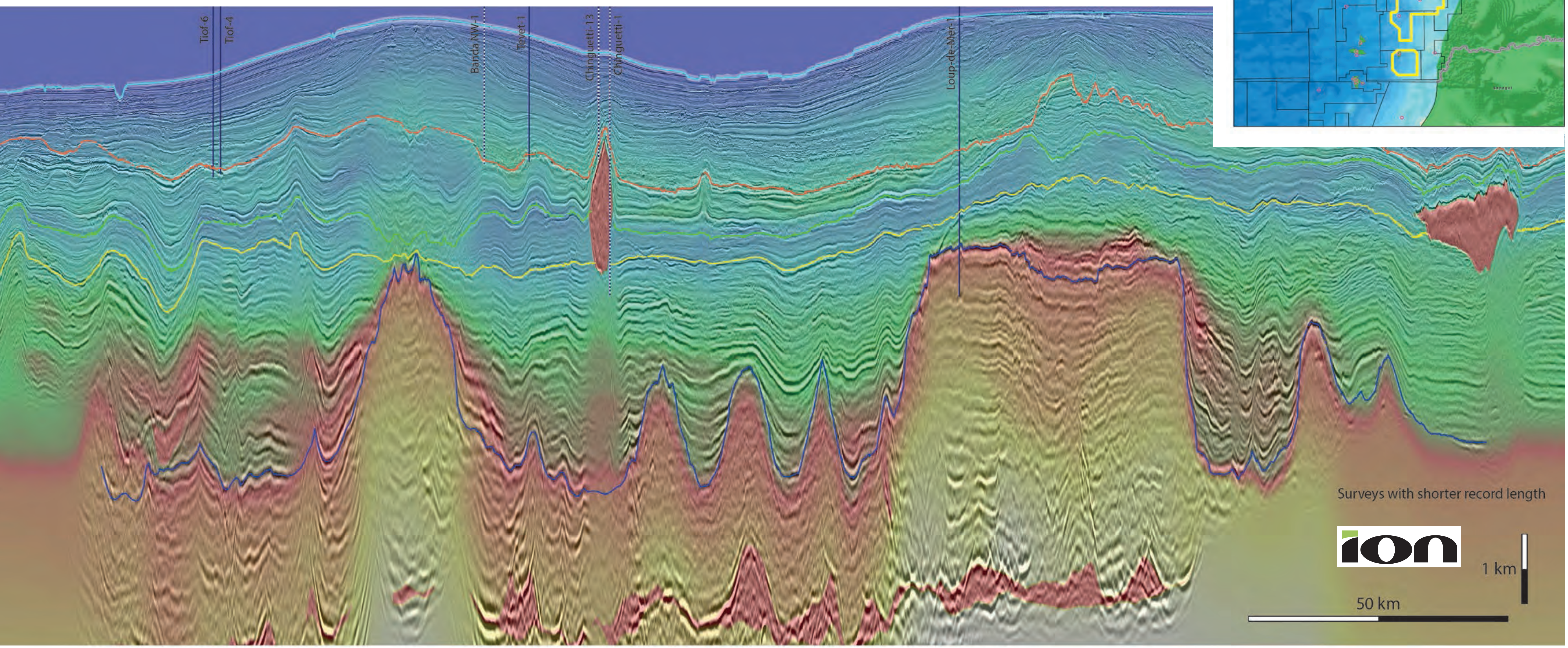
ION's new reimaged 19,100 sq km seismic dataset offshore Mauritania allows for mega-regional mapping and interpretation of the geological play potential of the offshore margin along with detailed analysis of the considerable proven and untested play potential.

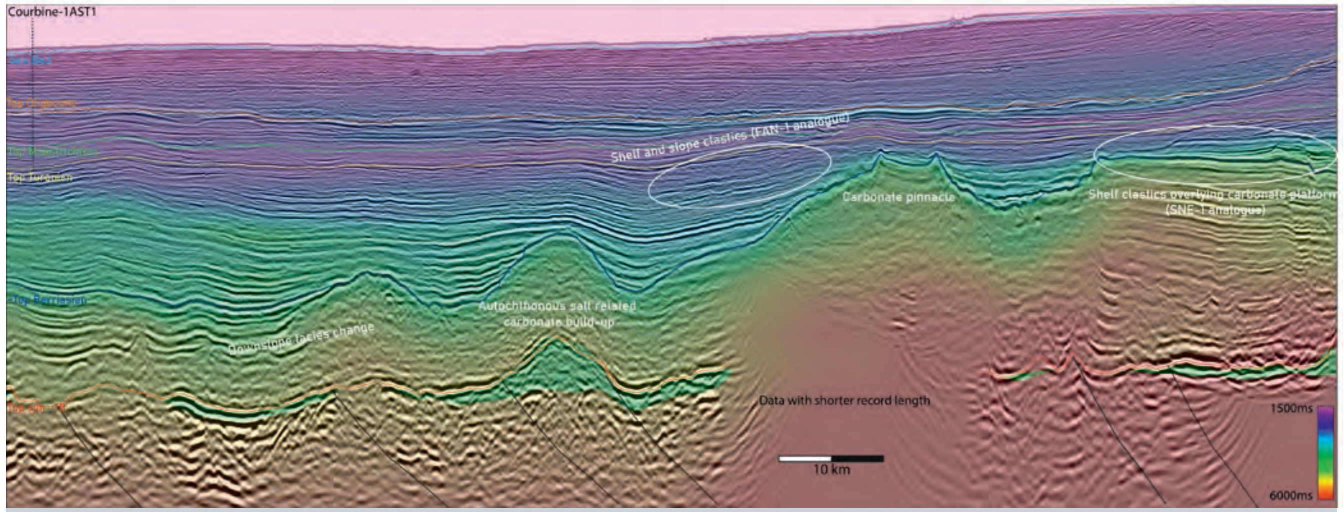
A composite line through the newly reimaged 3D seismic data (see below) encapsulates the large range of proven and untested plays from the Mauritanian margin.

The value of the mega-regional dataset lies in the consolidation of the whole geological history of the margin, from the syn-rift section and overlying carbonate platform through to the complex and regional Cretaceous and Cenozoic clastic plays and their interaction with allochthonous salt. In particular, regional mapping of the mega-clastic systems throughout the Cretaceous is key to understanding both the intra-channel plays (e.g., Pelican) and the deep-water basin floor systems (e.g., Greater Tortue-Ahymehin) and opening the doors to further discoveries.

North to south mega-regional arbitrary seismic line along the Mauritanian continental margin showing the key horizons and features.







PSDM transverse with velocity overlay through the Mauritania 3D data, showing the syn-rift section (including allochthonous and partially migrated Triassic salt, deposited in half grabens), the overlying carbonate platform and Cretaceous to recent clastics.

Building a Fully Integrated Dataset Offshore Mauritania

ION's Mauritania 3D products allow the explorer to build a greater understanding of the potential of this emerging province on a single, integrated, high-quality dataset.

Text: Elisabeth Gillbard, Senior Geologist, ION
Paul Bellingham, VP New Ventures, Eastern Hemisphere, ION

A full range of processing techniques
Imaging of the Mauritanian 3D data is now complete using a full range of modern processing and imaging practices, including MWD de-multiple techniques, deghosting, interpretation-led FWI and tomographic velocity modelling, and high-frequency RTM alongside full bandwidth Kirchhoff migration. The data was fully calibrated with well data from across the survey area.

In 2022, ION fully re-imaged from field tapes 19,100 sq km of 3D seismic data over the offshore Mauritanian coastal basin.

The 3D dataset is comprised of 12 vintage seismic surveys, acquired between 2000 and 2004, which have been merged and re-imaged into one contiguous, tied dataset in depth. An overview of the multiple identified plays across the basin can be seen in the fold out.

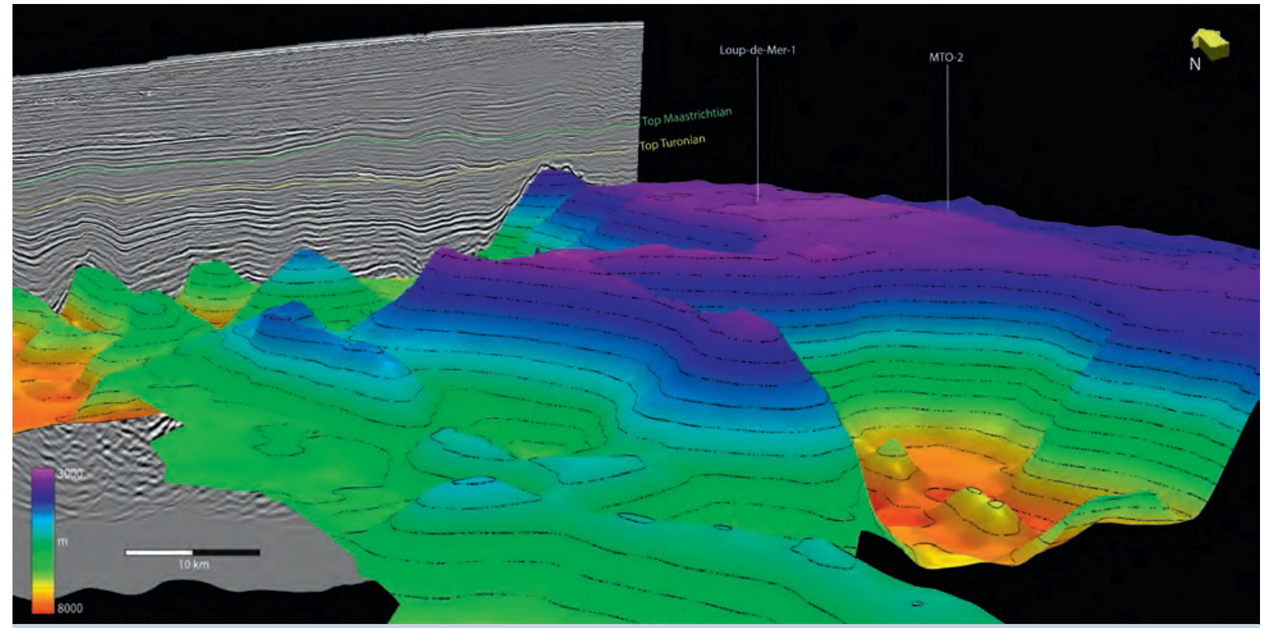
The high-resolution images in this article allows for a more detailed analysis at prospect level.

GEOLOGICAL RECAP

The MSGBC Basin was formed as part of the break-up of the Atlantic that was initiated during the Triassic. During the early stages of the Atlantic rifting, the Mauritanian offshore underwent salt deposition within the rifted grabens. Extension had largely ceased by the **Early Jurassic** and carbonate deposition dominated across the shelfal parts of the MSGBC Basin.

Throughout the **Early Cretaceou**s, a major transgression occurred, resulting in the drowning of the carbonates, which was largely complete by the Valanginian. During the Aptian-Albian, the platform areas were dominated by large deltaic systems delivering clastic material into the deep basin. By the start of the Late Cretaceous, the western parts of the margin were in a deepwater environment, with the deposition of high-quality source rocks during the Cenomanian-Turonian.

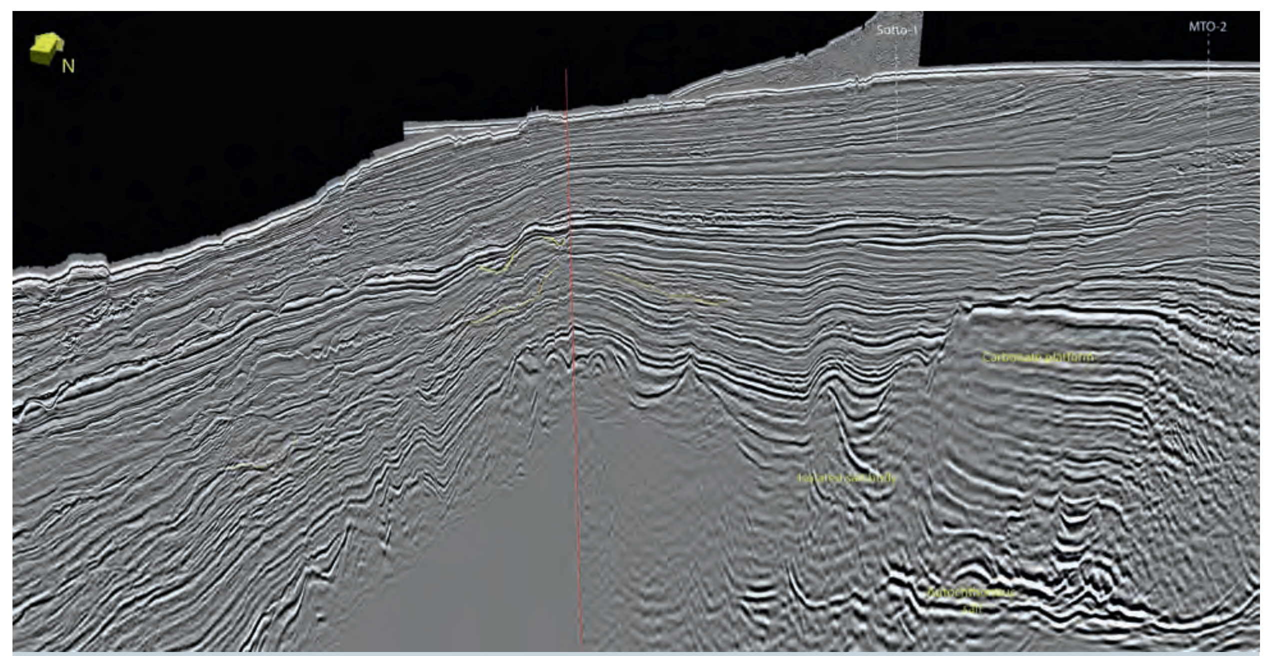
Regression during the **Late Cretaceous** resulted in numerous deltas building out across the platform. These sand-rich systems delivered large quantities of coarse clastics to the deep basin via large slope channels and basin floor fans, leading to the mobilisation of the Triassic evaporites. This lowstand phase, coupled with episodic inversion events in the outboard part of the basin, resulted in a phase of uplift and the development of anticlinal structures. These structures appear to have reactivated Jurassic extensional faults from the Santonian through to the Miocene. Throughout the **Cenozoic**, the main depocentre focussed on the central part of the Mauritanian offshore, where large quantities of mud and coarse clastics were deposited. Major regression from the Eocene-Oligocene resulted in a significant erosional surface and the deposition of lowstand clastics in channel and canyon systems.



Jurassic to Early Cretaceous carbonate platform with E-W seismic overlay showing potential for middle and Upper Cretaceous clastic systems (analogous to SNE and FAN) within structural closures relating to salt migration and carbonate pinnacles.

A MULTITUDE OF PLAYS TO CHOOSE FROM

Exploration in the Mauritanian coastal basin has traditionally focussed on the Cenozoic salt-draped channel plays, as proven by the discovery of the **Chinguetti** Field in 2001. Since this time, nearly 80% of exploration has targeted this play, but more recent exploration in the deep-water and in neighbouring Senegal has shown the massive potential for Cretaceous channel sand plays and shelfal clastics above the carbonate platform. Untested potential also exists in the deeper Jurassic-Lower Cretaceous carbonate platform and underlying syn-rift section.



Composite dip and strike lines across the southern part of the Mauritania offshore basin showing the large and complex channel systems throughout the Lower and Upper Cretaceous delivering sand to the deep offshore. Note the underlying structure relating to salt migration and the changing character of the carbonate platform.

SUCCESSFUL ANALOGUE HUNTING

The discovery of the **Fan** Field offshore Senegal in 2014, closely followed by the **Sne** Field, reignited exploration enthusiasm for the stagnant MSGBC Basin. Both were clastic plays resulting from significant sand input during the middle Cretaceous, and both are likely to be present in Mauritania, where the geology is comparable. Since these discoveries, the huge gas field **Greater Tortue-Ahmeyim** was discovered offshore Mauritania in a genetically related play to the **Fan** field.

The expression of the carbonate platform across the Mauritanian margin mirrors that which underlies the **Sne** and **Fan** plays in neighbouring Senegal. The figure above shows the relationship between the carbonate platform and the overlying Lower to mid-Cretaceous clastic systems.

TRACKING THE CRETACEOUS MEGA-CLASTIC SYSTEMS

Previous studies have identified several major clastic systems entering the northern part of the MSGBC Basin, depositing deltaic facies and associated down slope systems off the Mauritanian margin since the carbonate platform was flooded during the Early Cretaceous. The switch in major depocentre from south to north is evident in the foldout section, which shows a thick Lower Cretaceous succession in the south and central areas and a thickened Upper Cretaceous system in the north. Locating and genetically relating the shelf sands and downslope transport systems is key to understanding the potential for clastic input into play fairways.

The Lower to mid-Cretaceous system, focussed primarily in the south and central parts of the basin, was fed by the Senegal River, and reached maximum clastic deposition during the Aptian-Albian. Significant bypass of the shelf is known to have occurred during this period, with large sand deposition downslope as proven in several deep-water wells (e.g., Tortue, Hippocampe, Marsouin). Upslope on the platform, sand facies have been penetrated at multiple stratigraphic levels, but often without significant thickness or net to gross (e.g., Courbine, Chinguetti 6-1). In contrast, the Upper Cretaceous system has proven well-developed reservoir sands both on and off the shelf from the Coniacian to the Maastrichtian (e.g., Pelican, Aigrette, Lamatin, Fregate).

A WEALTH OF TRAPS

Mapping of ION's Mauritania 3D data has revealed the extent and complex nature of the clastic depositional systems throughout the Cretaceous and across the whole Mauritanian basin margin. Tracking the major systems both on the shelf and across the slope allows for identification of reservoir potential and a greater understanding of the evolving clastic system. Along with the identification of numerous structural traps, often related to the interplay between the Triassic salt and overlying carbonates, the potential for stratigraphic elements is apparent within distributary systems and downslope sand bodies. ■

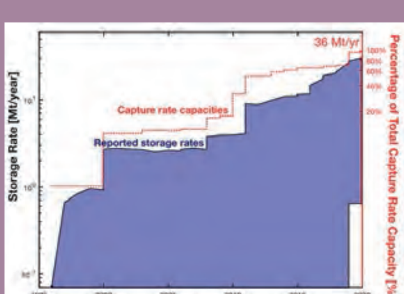
Not enough

Study shows that less CO_2 is stored than commonly reported.

In order to really get an idea on the amount of CO_2 injected on a global scale, one should look at how much was actually put in the ground rather than looking at the reported capture capacity. That is one of the main conclusions drawn by researchers from **Imperial College London** that was published in Environmental Science & Technology Letters in July this year.

Based on public domain data, the researchers concluded that the capture capacity of all projects combined is **19-30%** higher than what was actually injected. In order to arrive at a more realistic number of injected CO_2, the researchers call for a more centralised and consistent way of reporting volumes, which also should include elements such as independent auditing.

Another conclusion the authors draw is that carbon storage contributes significantly to the mitigation of today's emissions. Is that the case? Total injected CO_2 in 2020 amounted to around 31 million tonnes. When compared to the total amount of emitted CO_2 on a global basis (31.5 Giga tonnes), the percentage of injected CO_2 is only 0.001%. Not really a significant percentage yet, and a reminder that it is time to rapidly upscale the technology.



Source: Zhang et al. (2022)

Southern North Sea could become the main UKCS carbon store

Most areas offered in first CCS licence round are located in the Southern Permian Basin.

Given the proximity to industrial clusters, the presence of many (depleted) gas fields and lots of saline aquifers at the same time, it is no surprise to see that the Southern North Sea features heavily in the first CCS licensing round as announced by the **North Sea Transition Authority** (NSTA) a few months ago.

As noted in the NSTA press release, the areas were chosen to prevent overlap with offshore wind developments. This is most likely because lessons have already been learned from the Endurance CCS licence, where there is a significant overlap with a wind farm due to be developed (Hornsea Four).

John Underhill from Aberdeen University recently noted that care should be taken when planning future use of the seabed and the subsurface, because the presence of a wind farm may hinder or escalate the costs of seismic monitoring. In that sense, it seems that a careful approach was taken this time when it comes to designating areas for CCS licence applications and offshore wind developments.

CCS AND GAS FIELDS

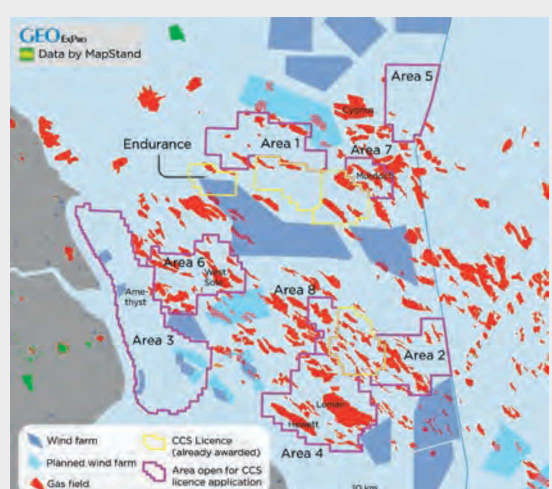
Eight areas are now on offer across the Southern North Sea to file a storage application before September 13. Together with the already awarded licences and a few more areas offered elsewhere on the UKCS, there is now the potential of storing 20-30 million tonnes of carbon dioxide (CO_2) by 2030 according to the NSTA. In comparison, the Sleipner project in Norway has stored 1 million tonnes per year since 1996.

Areas 2, 4, 6 and 8 are all situated in the **Rotliegend** fairway and also include major fields such as **Hewett**, **Leman** and **West Sole**. Repurposing a Rotliegend field for CO_2 injection looks like a possible option in these areas.

Instead, there are no fields in Area 3 at all, except from a small part of **Amethyst**. The Rotliegend in Amethyst is thin, as it is situated along the southern margin of the Rotliegend fairway, so it is unlikely that the Permian forms the most important target in Area 3. It may be that proximity to emitters formed the most important reason to select this area.

Areas 1, 5 and 7 are in the northern part of the Southern Gas Basin. Both Areas 1 and 7 are covering the Carboniferous fairway with fields such as **Murdoch**. Whilst it could be a possibility to inject CO_2 in Carboniferous reservoirs, the often more challenging reservoir architecture and not always favourable reservoir properties may also warrant a look in the overburden where the Triassic could form a candidate.

Finally, Area 5 is situated to the east of the **Cygnus** field, which produces from Rotliegend sandstones sourced the north. Could there be potential in the Rotliegend in Area 5? It is sparsely drilled compared to other parts of the SNS, so this area will also need some reconnaissance. ■



Map showing current CCS licences together with the areas where new applications can now be submitted.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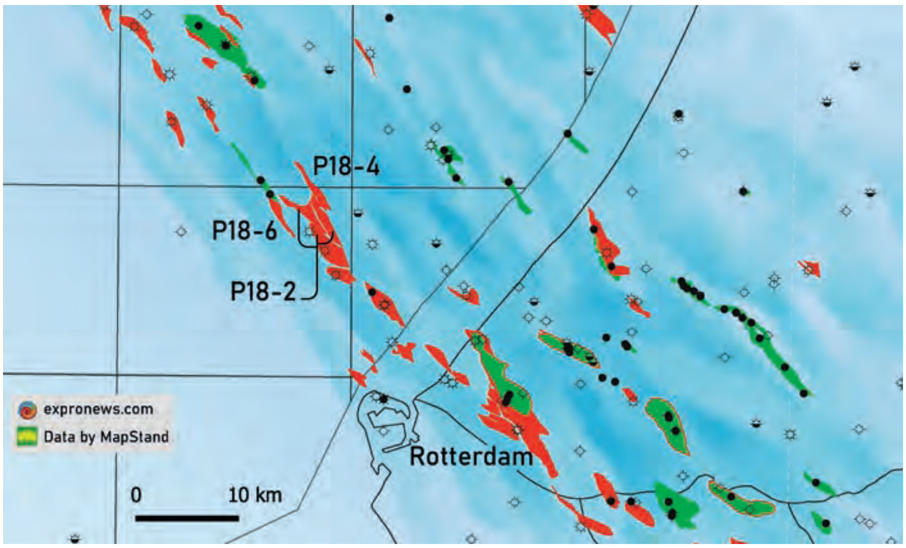
A critical well abandonment project

Operations on an old producing well in a gas field were successfully completed in the Dutch sector, bringing CO_2-storage in the field a step closer



Storage of CO_2 in depleted gas fields comes with advantages and challenges. On one hand, depleted fields have proven to be secure sites in terms of caprock integrity and reservoir properties, but on the other hand, wells drilled into the structure form potential leakage pathways for CO_2.

The **Porthos project** in the Netherlands is an example of a carbon storage site that will use abandoned gas fields (P18-2,4&6) in Triassic sandstones. As such, some of the production wells will now be converted to injection wells, whilst other wells will be permanently abandoned.

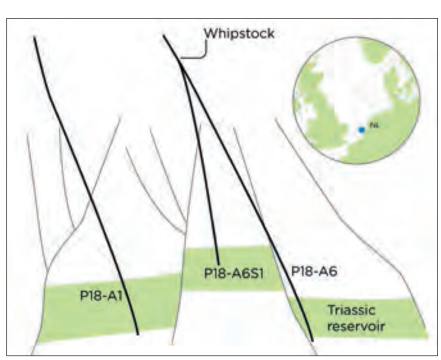
There was one, or better two, wells in the P18 project that caused some complications when it comes to accessing the reservoir sections.

When the operator at the time, BP, side-tracked production well **P18-A6** in 2003 to drain another fault block, the parent well was not cemented above the reservoir. In order to drill the side-track (P18-A6S1), a so-called whipstock was put in the hole in order to deviate the drill bit and make sure the new hole kicked off at the right depth. Putting a whipstock in the well also meant that access to the reservoir section of the parent well was not possible any more, unless the whipstock could be pulled out.

So, the partnership was facing the challenge of fishing the whipstock when converting to CO_2-injection. Failing that, a milling operation or even drilling a new well, bypassing the whipstock, were options considered.

A person with knowledge on the matter recently confirmed that the whipstock was successfully retrieved from the well, which has allowed access to the parent well. The process must have taken longer than anticipated though, as it was scheduled for 3.5 months rather than 6. Regardless, with both the side-track and the parent well now being abandoned, Porthos has come a step closer to first injection. ■

Henk Kombrink



Edited by: Halfdan Carstens

2,5 terabytes of data

Vast amounts of digital data acquired by the Norwegian Petroleum Directorate (NPD) pertaining to subsea minerals in the deep water of the Norwegian Sea have recently been released to the public.

Midway between Norway and Greenland, we find a small piece of the world's longest mountain range (65,000 km), and it has long been known that this global subsea volcanic mountain range contains minerals and metals that may be of interest in supplying critical minerals to the green shift.

Two types of deposits have been proven in Norwegian waters that have the potential for commercial mining: **massive sulphides** and **manganese crusts**.

According to **Torgeir Stordal**, acting director of NPD, the Directorate is experiencing great demand for the data and advocates that they have now released one of the most comprehensive datasets on seabed minerals globally, 2,5 terabytes in total.

More info on npd.no/en/facts/seabed-minerals/

Interactive map available on npd.no

Deep Sea Surveys in the Norwegian sector of the Norwegian/Greenland Sea. Also shown are some important mineralisations.

The extraction of minerals accelerates rapidly

The oceans are essential for future welfare in general and natural resources in particular.

According to a recent OECD report ("The Ocean Economy in 2030"), the ocean economy is a key source of food, energy, **minerals**, health, leisure, and transport upon which hundreds of millions of people depend.

In other words, the ocean economy is essential to the future welfare and prosperity of humankind and is driven by a combination of population growth, rising incomes, **dwindling natural resources** as well as **pioneering technologies**.

INCREASED DEMAND

Over the last 30 years or so, global extraction of metals and minerals (including fossil fuels) rose from less than **40 billion tonnes in 1980** to almost **70 billion tonnes in 2008**, an annual increase of over 2%. Given the prospects of rising population and growing prosperity, extraction rates are expected to accelerate further over the next two to three decades, reaching around **100 billion tonnes by 2030**.

> Due to its plentiful reserves of oil, natural gas and minerals, and abundant supplies of fresh water, the next three decades or so might see a rapid growth in the prosperity and power of the Arctic regions grouped around the Russian Federation, Alaska, Canada and the Nordic countries.

Industries affected include **offshore wind**, tidal and wave energy, **oil and gas exploration**, offshore aquaculture, **seabed mining**, cruise tourism, maritime surveillance, and **marine biotechnology**.

The main drivers behind increasing demand for natural resources are, according to the report, economic growth and population.

Given limitations on some land-based mineral resources, concerns about declines in the quality of some ores and possible shortages of some rare metals, interest in **deep-sea exploration** is expected to be sustained over the long-term future.

OECD emphasizes the importance of **polymetallic nodules** and **seafloor massive sulphides** (SMS) and estimates that even if only half of the thousands of underwater sulphide systems mapped so far are viable, annual seafloor production would represent **several billion tonnes of copper** alone (world output today of copper is roughly 21 million tonnes).

THE X-FACTOR

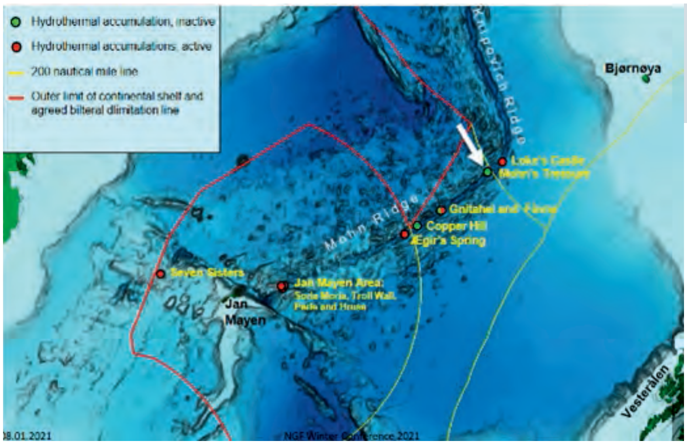
Unsurprisingly, OECD is of the opinion that for most metals and minerals, the issue is expected to be less about whether global supplies will be adequate to keep up with demand and more about the **negative environmental effects** associated with **extraction, use and emissions**, as well as about price levels and price fluctuations.

OECD will present highlights from the report at the Deep Sea Minerals conference in Bergen, October 25-27.

Getting Closer to Finding SMS-

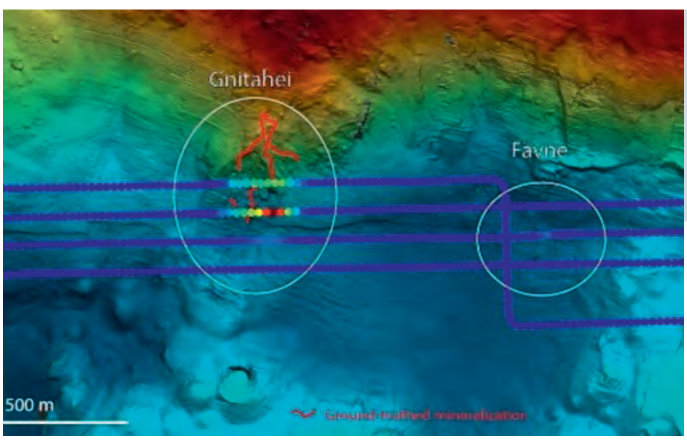
Researchers at the University of Bergen have shown that self-potential measurements can detect sulphide deposits in the deep sea.

Illustration by Harald Brekke/NPD



Mapped hydrothermal fields in the Norwegian Sea.

Illustration: Onstad, Barreyre and Pedersen (2021)



Measurements of self-potential show anomalies close to sulphide deposits at the Mohns Ridge in the Norwegian Sea.

Two types of deep-sea mineral deposits have been discovered in Norwegian waters: **solid sulphides** and **manganese crusts**. The technological challenge is to map their presence and volumes, and both universities and technology companies are involved. “There are several methods for detecting **sulphides**. We have seen, through several cruises, that self-potential is a geophysical measurement method that works well,” said **Solveig Lie Onstad**, PhD candidate at the Department of Geosciences and the Centre for Deep Sea Research at the University of Bergen (UiB).

The occasion was a seminar hosted by NPD in early summer in connection with the release of the dataset that may be the most comprehensive found globally on deep-sea minerals.

The deep-sea researchers at UiB have, in cooperation with the Norwegian Petroleum Directorate (NPD), carried out a number of cruises along the spreading ridges in Norwegian waters, and can take credit for the discovery of several of the sulphide deposits found so far.

The deposits are formed by hydrothermal vents that occur along the spreading zones. The vents carry mineral-rich, boiling hot water up to the seabed, and the sudden encounter with the cold seawater causes the minerals to precipitate. Sulphide deposits occur at both active and fossil (inactive) hydrothermal sources.

DETECTED ANOMALY

For extraction purposes, it is the passive deposits that are of interest as they host much less biological diversity. They can be more difficult to find than the active ones though, as they do not generate a warm, mineral-rich and detectable plume in the water column.

“**Gnitahei** is a sulphide deposit that was discovered solely because we saw an anomaly in the SP data,” Onstad said.

Gnitahei is located on the Mohns Ridge between Jan Mayen and Bjørnøya in the Barents Sea. Close to Gnitahei is another sulphide deposit, **Fåvne**.

Gnitahei and Fåvne are two different deposits. The main difference being that Gnitahei is inactive, while Fåvne is an active hydrothermal sulphide deposit.

According to Onstad, the researchers were able to identify Fåvne by several measurement methods. “We registered a temperature signal, we saw turbidity in the water, as well as a small SP signal.”

Measurements of the SP strength in a given area can thus work well for explorers that are searching for extinct sulphide deposits. But SP measurements also provide another parameter of interest.

“In addition to the *strength* of the SP signal, we can also measure the direction. We have seen that the data simply are “pointing us” to the sulphide deposits,” Onstad said.

A METHOD WORTH USING

Exploration companies should take note of the experiences that UiB researchers

Self-potential (SP) is a measure of electrical voltage differences in rocks. Such stress differences can occur, for example, in rocks that contain conductive minerals and metals, including sulphides. This type of measurement can be performed in the deep sea using self-propelled and remote-controlled underwater robots (AUVs) equipped with sensors.

deposits

have had with the use of AUVs and measurements of SP as an exploration method. However, the method is not without difficulties.

Along the spreading zones in the deep sea, the terrain can be rough with deep valleys and high peaks. This is a challenge for the AUVs, which should fly at a certain height above the seabed, while of course avoiding colliding with the terrain. "Optimal flight altitude during data collection is 40 – 70 meters," Onstad commented.

"The fact that the AUVs have to operate close to the seabed also means that they cannot cover large areas per unit of time, which in turn means that they have to fly in lines over a terrain with high line density (many parallel lines)," Onstad explained.

The research fellow also pointed out noise in the data caused by vertical movements in the water column as a possible challenge, and that the method only measures electric current, and thus does not say anything else about the physical properties of the rocks.

"The benefits outweigh a lot of the drawbacks. We have shown that SP measurements detect sulphide deposits and that a strong and clear anomaly means a high probability of a nearby deposit. Even weaker anomalies show a clear trend towards the source. Self-potential is a method worth using," concluded Solveig Lie Onstad.

RONNY SETSÅ

Norway has initiated an opening process that may lead to areas in the Norwegian Sea being announced in 2023 or 2024. The Norwegian Petroleum Directorate (NPD) is currently conducting a resource evaluation of Norwegian marine mineral resources, and concurrently, commercial exploration companies are preparing by acquiring knowledge and developing technology and exploration methods.

ISA – An Important Player

The largest potential for deep sea mineral exploitation is beyond national jurisdiction. This is called The Area which effectively covers over 50 per cent of the world's oceans' seabed.

At the core of ISA's mandate is the need to ensure the effective protection of the marine environment from harmful effects that may arise from deep-seabed-related activities in the Area.

"The Area is defined in the Convention as the seabed and ocean floor and subsoil beyond national jurisdiction limits. Establishing the exact geographical limits of the Area thus depends on the delineation of the limits of national jurisdiction, including the delineation of the continental shelf extending beyond 200 nautical miles from the baseline of the territorial sea."
ISA

The Area and its resources are to be considered the common heritage of humankind, on behalf of which ISA – **the International Seabed Authority** – acts. ISA, based in Kingston, Jamaica, is an intergovernmental body of 167 member states, as well as the European Union, established under the 1982 UN Convention on the Law of the Sea. It is noteworthy that the United States of America is not a member. However, the US has observer status along with 29 other states. 32 non-governmental organizations also have observer status (including Greenpeace and World Wildlife Fund).

The areas being explored in which ISA is in control are in the **Clarion-Clipperton Zone**, **the Indian Ocean**, **the Mid-Atlantic Ridge**, **the South Atlantic Ocean**, and **the Western Pacific Ocean**.

Contracts currently pertain to each of the three mineral resources for which the Authority has adopted regulations on prospecting and exploration. These are **polymetallic nodules**, **polymetallic sulphides** (SMS), and cobalt-rich **ferromanganese crusts**.

NO ENVIRONMENTAL IMPACT

As of 31 May 2022, 31 contracts to 22 contractors for exploration had entered into force, of which 19 were for polymetallic nodules, 7 were for polymetallic sulphides and 5 were for cobalt-rich ferromanganese crusts.

Exploration activities consist primarily of geological studies, mineral resources assessments, and environmental surveys and sampling, and have very limited or no environmental impact. Other activities include the development and testing of mining technology and mineral processing techniques.

Contracts are granted for an initial period of 15 years. States sponsoring these contracts include 10 developing States and six small island developing States (Cook Islands, Jamaica, Kiribati, Nauru, Singapore, and Tonga).

The most recent contract was issued to **Blue Minerals Jamaica Ltd.** (sponsored by the Government of Jamaica) in April 2021 to explore polymetallic nodules in the CCZ. The geographical area available for exploration by Blue Minerals Jamaica Ltd. covers almost 75,000 km_2 (equivalent to roughly 12 North Sea quadrants).

The Area consists of all ocean space outside Exclusive Economic Zones (EEZ), generally extending 200 nautical miles beyond a nation's territorial sea, within which a coastal nation has jurisdiction over both living and nonliving resources. Source: ISA

Cook Islands' Golden Apples

As one of the Pacific island states is preparing for deep sea mining, resistance to harvesting polymetallic nodules may now be countered by innovative technology that leaves little or no environmental footprint.

The Cook Islands is a self-governing island country in the South Pacific Ocean in free association with New Zealand. It comprises 15 islands whose total land area is 240 km². The Cook Islands' Exclusive Economic Zone (EEZ) covers 1,960,000 km². In comparison, Alaska has a land area of 1,700,000 km². The total population is less than 20,000. The islands are renowned for their many snorkelling and scuba-diving sites, crystal-clear water, diverse marine life, and a strong connection to Polynesian culture.

Three international companies have recently been awarded mineral exploration licences offshore Cook Islands: **Cobalt (CIC) Limited**, **Moana Minerals Limited** and **Cook Islands Investment Company (CIIC) Seabed Resources Limited**, the latter co-owned by the Cook Islands Government.

The licences allow the companies to find out if mining is a viable option, which includes reviewing the environmental risks, and the companies have budgeted between USD 55.4 million to USD 71.7 million to conduct exploration over the next five years.

RICHES ON THE SEA FLOOR

The potato-shaped polymetallic nodules pave the bottom at a depth of five km and are loaded with expensive minerals like cobalt, copper, manganese and nickel.

Mark Brown, Cook Islands Prime Minister, who is also the Minister for the Seabed Minerals Authority, attended an official ceremony when the licences were signed. He compared the Cook Islands situation to Norway's high standards of living, made possible through the exploitation of abundant oil and gas resources.

Brown sees revenues from the sought-after minerals bringing infrastructure improvements to airports, ports as well as schools.

"Today our people are leaving to pick apples in New Zealand, tomorrow, we will have our own apples to pick, and they sit on the floor of our ocean," Brown said and used the term "golden apples" for the polymetallic nodules.

LAUNCHING BETTEREV

Many nations, 600 marine scientists and policy experts, industry majors like BMW, Google, Samsung, and Volkswagen, as well as environmental groups like **Te Ipukarea Society**, a non-government organisation in the Cook Islands, have called for a 10-year-moratorium on seabed mining.

Renee Grogan, co-founder, director, and chief sustainability officer of California-based **Impossible Mining**, however, looks at it differently, according to **TIME magazine**.

"A ban on seabed mining, she says, will only shift the environmental burden to land-based metal mining, which destroys ecosystems while leaving a toxic legacy of tailings ponds," she says.

Grogan has therefore launched an initiative to push for an independent standards body (BetterEV) that would require mining companies to avoid habitat destruction at sea and on land, eliminate toxic waste, preserve biodiversity, protect communities, maintain freshwater sources, and stay carbon neutral.

SAVING THE FAUNA

For this purpose, Grogan's battery-metal start-up company is now developing marine robots that would hover above the sea bottom to literally pluck individual metal nodules from the seabed.

Very importantly, image sensing technology will identify megafauna present on the nodules before plucking and will leave those nodules untouched, allowing for the preservation of nodule-dependent fauna.

Deep sea mineral mining may be closer than environmentalists would like to think.

Woven from the leaves of the coconut tree, the green basket is known in the Cook Islands as a "kete" or "raurau" and is used to carry things that are of value to our people, such as fruits, fresh produce, and fish. In this case, it is carrying pieces of nodules. Photo: Seabed Minerals Authority

TUVALU WITHDREW

In December 2021, Circular Metals Tuvalu Ltd. applied to the International Seabed Authority (ISA) to approve a work plan for the exploration for polymetallic nodules in the Area. The area under application covers 74,460 km2 divided into eight blocks in the reserved areas held by ISA in the Clarion-Clipperton Zone in the Pacific Ocean. Tuvalu is located a few thousand km northwest of the Cook Islands and was the fourth Pacific country to pass laws for deep sea mineral activities, joining the Cook Islands, Fiji and Tonga. In April this year, however, Tuvalu's government withdrew its support for deep-sea mining in the country's deep waters. Foreign Minister Simon Kofe stated that the seabed mining sponsorship was a result of legislation passed by a former government. There is also strong pressure from various groups in Tuvalu to ban seabed mining.

Battery in a Rock

Seabed mining for polymetallic nodules may take place very soon as suitable technology is now being tested.

Nodules were first discovered by **HMS Challenger** which circumnavigated the globe between 1872 and 1876.

Everywhere they went and sampled the seafloor, they brought up large quantities of polymetallic **nodules** displaying a wide range of morphologies and internal structures. They were recovered from the Pacific, Indian and Atlantic Oceans. Later, in the 1960s it was stipulated that they might represent an unlimited supply of mineral resources.

Today, several companies are pursuing nodules, in particular in the **Clarion-Clipperton Zone (CCZ)**, and the **International Seabed Authority** (ISA) has issued 18 licences covering some 150,000 km^2 in this area, while one licence is issued in the Indian Ocean.

The CCZ is about the size of the United States spanning 5,000 km across the central Pacific Ocean, at depths of 4,000 – 5,500 m.

A STRANGE PIECE OF ROCK

The Metals Company have given the name "rock batteries" to these nodules. This is because polymetallic nodules contain rich concentrations of the base metals needed to make batteries, such as nickel, copper, cobalt, and manganese.

According to the Belgian company **Global Sea Mineral Resources (GSR)**, the composition and size of nodules vary slightly depending on where they are found. On average, each is rich in nickel (1.3%), cobalt (0.2%), manganese (27%) and copper (1.2%).

OPERATIONS THAT DO NOT EXIST

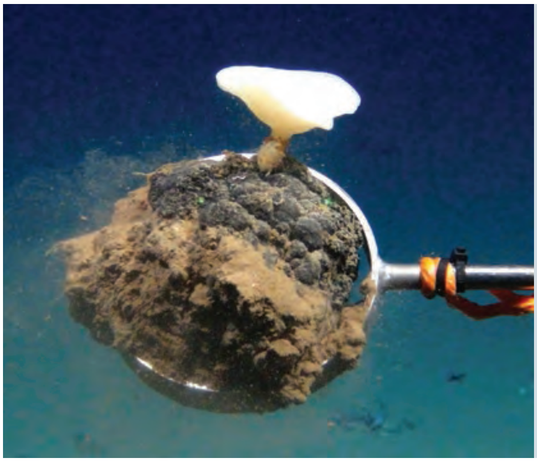
One possible method to harvest nodules is as follows:

The primary tool is a collector vehicle that is essentially a vacuum cleaner that drives around, picking up nodules as well as the top 5-15 cm of the seabed. Sediments that are not wanted will pass through the collector vehicle and be immediately returned at the back.

Patania II operated by GSR at 4.5 km below the surface is the pre-prototype of a seafloor nodule collector that was designed to withstand pressure of over 451 bar.

Last year, the Norwegian company **DeepOcean** assisted The Metals Company in gathering some 75 tons of nodules in the CCZ. DeepOcean is a global company that provides underwater inspection, maintenance and repair services for the oil industry worldwide. ■

Erika Ilves, Chief Strategy Officer at The Metals Company, will give a talk at the Deep Sea Minerals conference, October 26-27, in Bergen, Norway.



Nodule Polymetallic nodules are formed as accretions at 4500 meters in the deep ocean. They grow very slowly, about 1 cm per every million years, meaning that the potato-sized ore shown here is 10 million years old. The habitat formed by polymetallic nodules is home to specific sessile and mobile fauna. There is currently no ongoing mining for nodules. Photo: ROV-Team, GEOMAR

THREE TYPES OF DEPOSITS

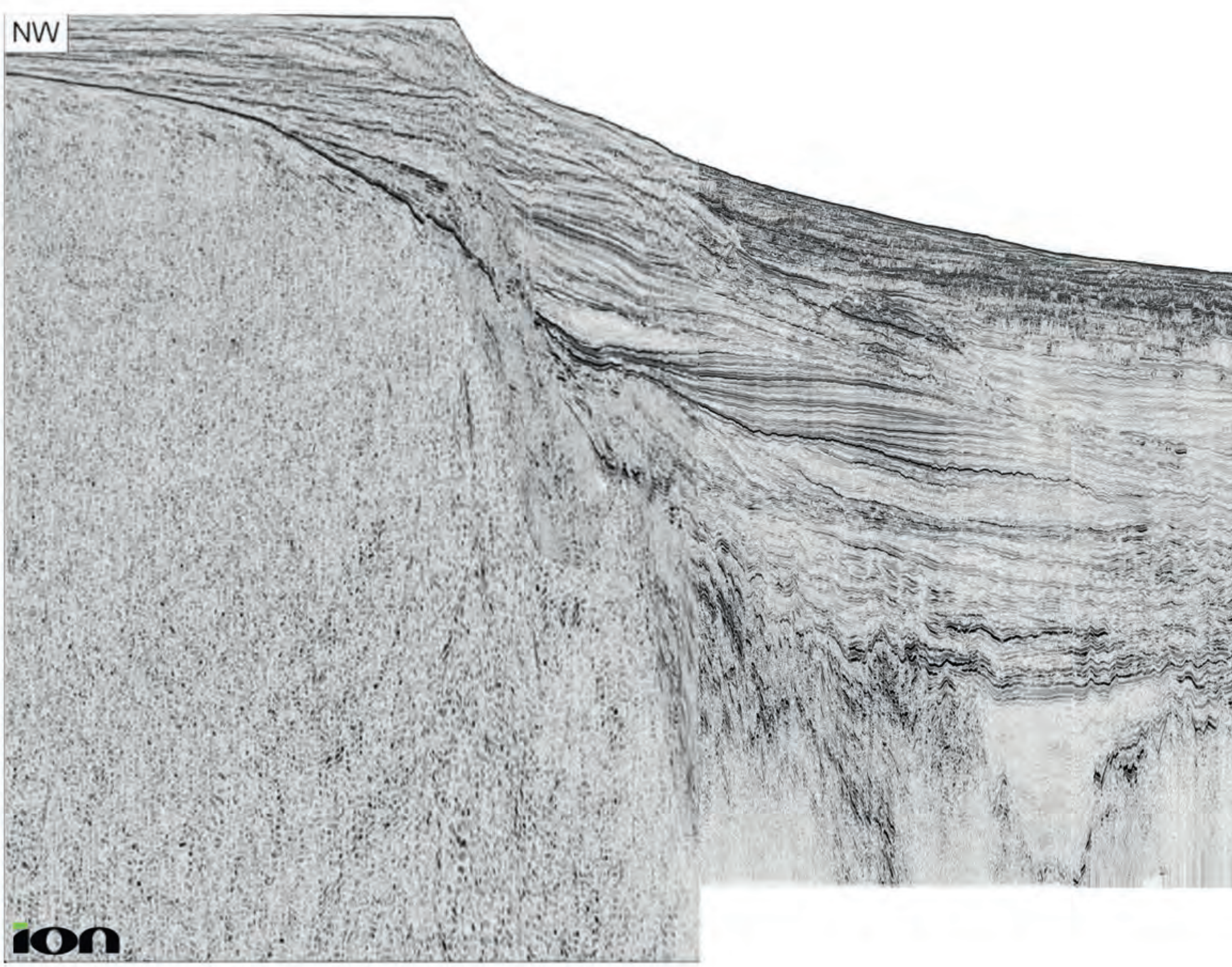
Seafloor massive sulphides (SMS, also known as polymetallic sulphides) form at hydrothermal vents when seawater penetrates the ocean's crust and becomes heated and chemically modified through interaction with crustal rocks and, sometimes, by input of magmatic fluids. The hot hydrothermal fluids then rise back toward the seafloor and precipitate minerals as they cool along flow paths and upon mixing with seawater. A wide variety of minerals form through hydrothermal activity, but seafloor massive sulphides are formed from reduced sulphur and may be enriched in **copper**, **zinc**, **iron**, **gold**, and **silver**.

Polymetallic nodules (manganese nodules) form a top sediment covering the abyssal plains of the global ocean. These nodules form by the accretion of iron and manganese oxides around a tiny nucleus, such as a large grain of sand, a shark tooth, or an older nodule fragment. Polymetallic nodules are usually potato size and grow very slowly. Nodules have high concentrations of battery metals in a single ore such as **manganese**, **nickel**, **copper**, **cobalt** and sometimes **lithium**. Unlike land ores, they do not contain toxic levels of heavy elements, and producing metals from nodules generates 99% less solid waste, with no toxic tailings.

Ferromanganese crusts (also called cobalt-rich crusts) grow very slowly, at several millimetres per million years, and precipitate onto exposed rock surfaces throughout the ocean. They do not form where sediment blankets the seafloor. In the oldest parts of the seafloor, some crusts have been forming for over 70 million years and can be over 20 centimetres thick. They are especially enriched in **cobalt**, **manganese**, rare metals such as **tellurium**, precious metals such as **platinum**, and **rare earth elements** (REE).

Source: USGS/The Metals Company

The Rise of Venus in Uruguay's Pelotas Basin



In a ceaseless battle for the attention of passionate explorers, the Orange Basin currently holds court after the Venus-1 and Graff-1 discoveries of 2022. Yet, exploration for analogue plays can be sought not only within the same basin, but also where similar conditions of formation have reproduced the same plays: The Uruguay conjugate margin.

Seismic reconstruction showing the correlation of proven Aptian source rock between the conjugate Orange and Pelotas Basins. Left: Ancap's PSDM seismic section, Pelotas Basin offshore Uruguay and Right: Searcher's pseudo-depth seismic section, Orange Basin offshore South Africa.

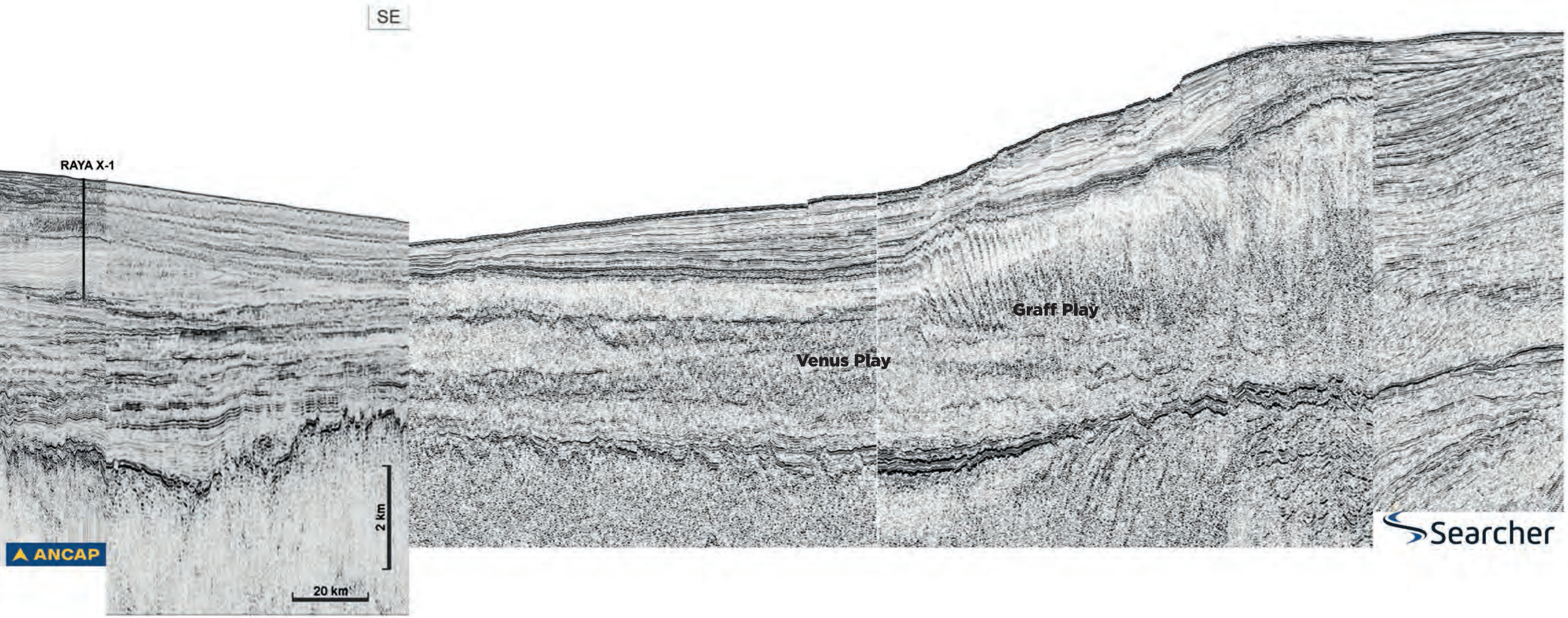


Illustration: Searcher

Uruguay Plays Namibia on Number 1 Court

Text: Karyna Rodriguez, Neil Hodgson (Searcher), Pablo Rodriguez, Bruno Conti & Hector de Santa Ana (ANCAP).

The "Most interesting Basin in the World" ball has been batted across the Atlantic regularly for the last 30 years. Early deep-water success in the **Campos Basin of Brazil**, followed by the **Tano Basin of Ghana**, then across to the **Guyana-Suriname Basin** has led to the latest success in the **Orange Basin** of Namibia and South Africa.

This rally of ever bigger discoveries has occurred as explorers ventured into ever deeper water and is set to continue as courageous companies are lining up to enter offshore Uruguay, the conjugate to the Orange Basin, to bring glory back across the pond.

Like super-star tennis aces, the Orange Basin plays have unique and novel properties, but exploration for these defining characters can be sought not only within the same basin, but also where similar conditions of formation have reproduced the plays: across the Atlantic on the Conjugate Margin (see seismic line on this page).

NEW BALLS PLEASE

Yet, are the Orange Basin plays really only for the courageous? On the face of it, the ultra-deep-water counter regional dipping Cretaceous sand fans and channels of **the Venus play** might seem exotic – but still that is only because the steady progression into deeper water only now allows us to access this inherently low-risk play: well-sorted sands sitting on mature source rock in counter regional structures covered with several kilometres of clay.

Likewise, the contourite-constrained slope channel traps of **Graff** are only now being recognized as seismic imaging improves and more deep-water mixed system discoveries are being made: high quality winnowed constrained channel turbidite sands updip of mature thick source rock with contourite drift top and lateral seal.

Whilst both plays are low risk, they are unproven in Uruguay, even though direct analogues to the discoveries of Venus and Graff respectively in the Orange Basin are recognized. Most importantly, they both have the potential for huge reserves in good reservoirs – key for deep-water "advantaged" resources which can be developed and brought to market quickly.

It has been reported that **the Venus discovery** could contain in excess of **13 Bboe** (World beater: TotalEnergies' Venus discovery in Namibia may be biggest ever deep-water find | Upstream Online), which would make it the world's largest deep-water field. The two discoveries in Namibia have the resource potential of the entire Guyana-Suriname or Tano Basins, discovered with just two wells.

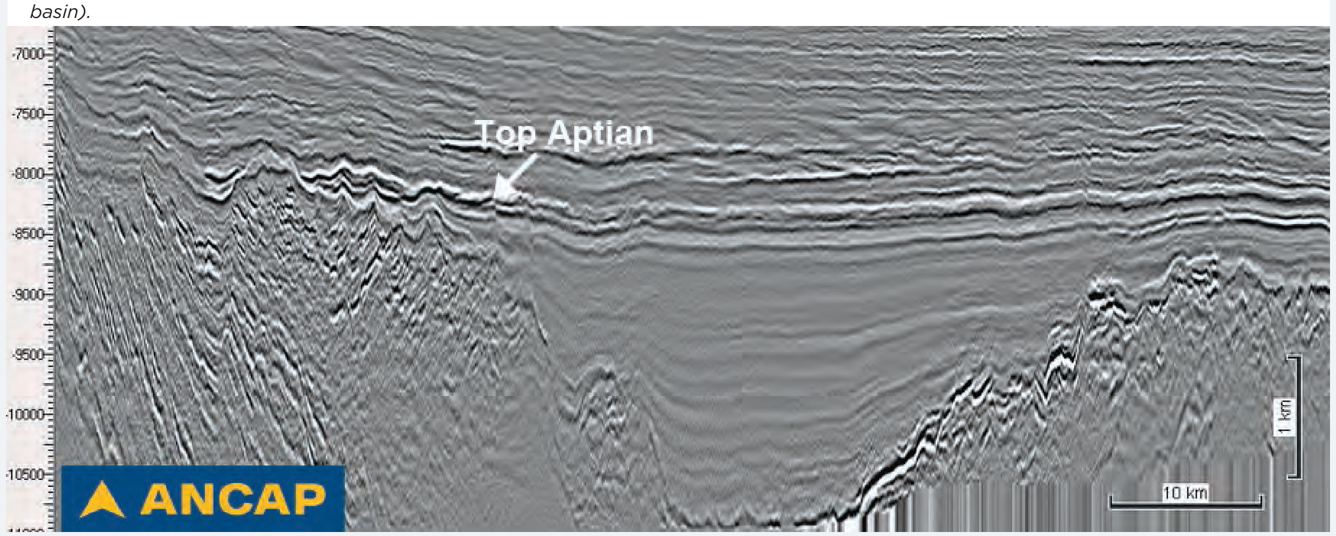
Similarly, on the conjugate margin in Uruguay, a prospective resources study for leads and prospects identified offshore Uruguay (Reporte de Recursos Prospectivos de Petróleo y Gas, Uruguay (ancap.com.uy)) published ahead of the Venus discovery, identified analogous deep-water opportunities each with best estimate resources in excess of **1.4 Bboe**.

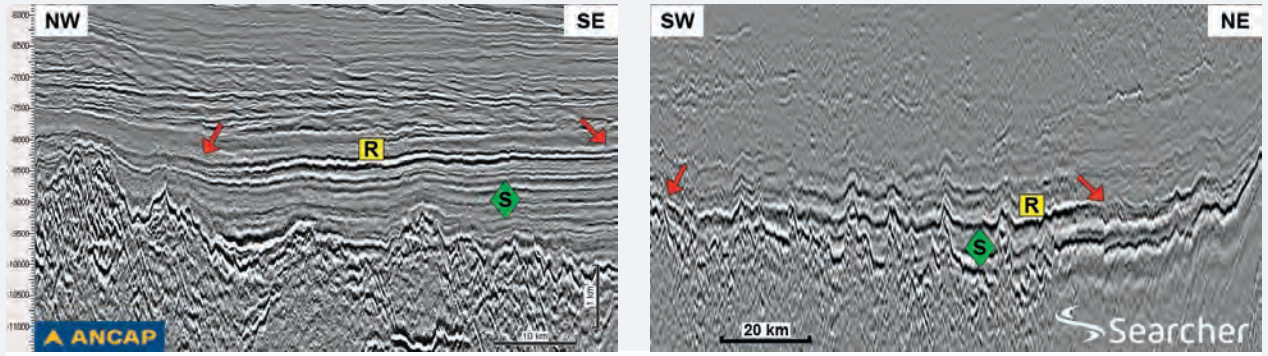
FIRST SERVE: SOURCE ROCK ACE

In both of the Orange Basin plays the source rock is Aptian in age, sitting on oceanic crust and deposited in a restricted marine basin. This basin formed not long after drift began, and marine transgression switched the SDR (seaward dipping reflector) machine off and allowed Penrose Oceanic crust to form.

These Aptian basins are likely to be relatively shallow water (see DSDP 361) and anoxic, allowing the preservation of organic material. The same conditions of shallow water-restricted marine basins would have formed on both sides of the proto-Mid-Atlantic ridge, and indeed are clearly visible in the Pelotas basin offshore Uruguay. Here, the Aptian source rock, which can reach up to 3,000 m in thickness, has the same characteristics as the Orange basin equivalent unit.

Aptian source rock proven offshore Namibia extends into Uruguay where it is found up to 3 km in thickness (PSDM section from Pelotas basin).





Left: Offshore Uruguay seismic section in depth over Delmira Prospect showing high amplitude event labelled as R (reservoir) overlying a thick Aptian source rock section (S). Right: Venus discovery extension into South Africa, showing a high amplitude anomaly overlying proven Aptian source rock. Note both sections are in Depth showing counter regional dip offshore at reservoir level.

The same diagnostic characteristics of a good quality mature source rock (Davison et al., 2018) are observed in Uruguay. These sequences can be mapped along the Uruguayan margin at the base of the slope and have Direct Source Indicators (DSI's) as ubiquitous low frequency, type IV AVO characteristics indicating the presence of thick organic rich source rocks.

Although it is straightforward to map out the isopach of sediments on top of this Aptian source rock, and high grade the areas with more than 3,000 m of sediment, due to a lack of well penetrations the geothermal gradient is an uncertainty.

It has been widely reported that the geothermal gradient at reservoir level over oceanic crust at Venus-1 was high, ca 35°C/km. It has also been rumoured that the geothermal gradient at TD (Total Depth) of Raya-1 (with TD at Oligocene, where a lack of faults that connect the Cretaceous source rock with Cenozoic reservoirs as well as thick Paleocene shales, prevent hydrocarbons from migrating towards Cenozoic reservoirs) was similarly high. To constrain this, the isopach of the extensive gas-hydrate layer (forming a Bottom Simulating Reflector (BSR)) offshore Uruguay, has been mapped to derive a base BSR-geothermal gradient, which has in turn been used to model thermal maturity at Aptian level.

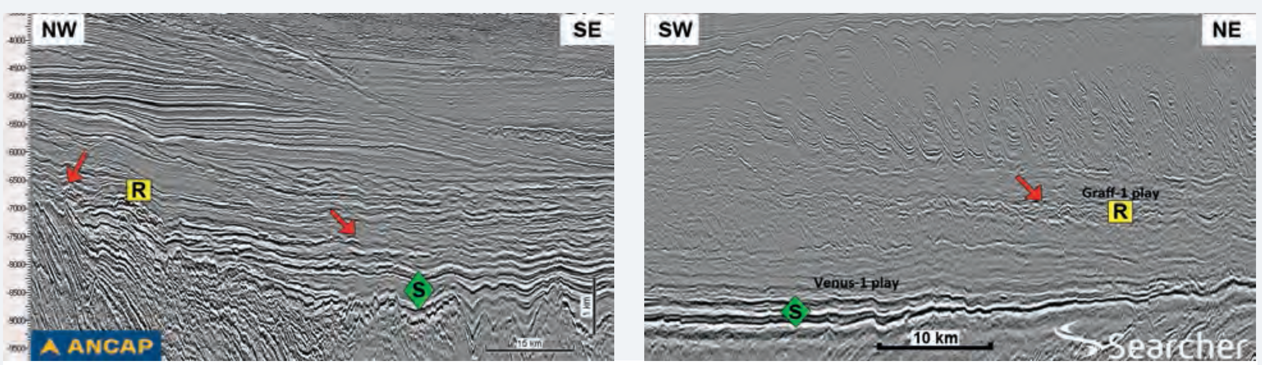
The results indicate widespread hydrocarbon generation with present day oil generation in the ultra-deep-water realm. Such oil generative basin modelling is unsurprising in the area as there are direct analogies to the proven Namibian margin and Direct Hydrocarbon Indications from fluid inclusions in the Cretaceous sequence of Lobo and Gaviotín wells, gas chimneys recognized in seismic, and microseeps detected in surface geochemistry studies, all of which demonstrate a working petroleum system.

SECOND SET: PLAY TYPE COMPARISON

The Venus discovery in Namibia comprises two thick fans totalling gross 137 m of sand deposited directly onto the Aptian source rock. These fans are deposited in counter regionally dipping structures, where the distal end of the fan provides the pinch out. The dip is controlled by plate subsidence and loading, and so structures and traps are ubiquitously huge. Whilst it is speculated that these fining upward units are deep-water sandstones of turbidite apron-fan association, it is also possible that these comprise relatively shallow water pro-delta deposits.

At the time of deposition, the Aptian basin had not flooded back over the SDRs of the Orange Basin outer-high (when that happens in the Albian there is a possible carbonate build-up play established there) suggesting water depths of less than 200 m at the basin floor.

Fluvial systems could carry mature sands out through gaps or canyons between SDR edifices in the outer high. This is very likely to be similar to the depositional system of the Uruguayan Margin where thick fan-like sequences are mapped on 3D datasets in addition to intricate aggrading channel belts



Left: Offshore Uruguay seismic section in depth over Chafalote Prospect, with total recoverable resources over 2 Bboe (Gristo et al., 2021), showing high amplitude event labelled as R (reservoir) overlying a thick Aptian source rock section (S). Right: Graff discovery extension into South Africa (water depth compensated 2D seismic line).

prograding out onto the basin floor.

Contourite drifts and other mixed systems abound on this margin. Younger sediments of Albian and Late Cretaceous age are winnowed and sculpted by contourites to create plays and traps as yet untested on a series of terraces up the slope. These, charged by Aptian source rock, provide exciting and new low risk traps on this margin.

In recent years, the role of sea bottom currents flowing parallel to the shore (contourite currents) has been recognized in their interactions with turbidite gravity driven currents which create 'mixed' or 'hybrid turbidite-contourite systems'. Significantly, contourite currents can winnow the turbidites, stripping out the fine clastic component, leaving the turbidite enriched in coarse clastic content.

These hybrid systems have been associated with significant discoveries such as the **Mamba** and **Coral** fields offshore **Mozambique** with an accumulation in the order of 80 TCF (13.8 Bboe).

It has been reported that the secondary objective at the Graff-1 well was a play associated with a mixed or hybrid system (Bijkerk et al., 2021) and from reported results it is inferred that an accumulation was encountered in this play with a potential of over 3 Bboe. An analogous play has been identified by ANCAP offshore Uruguay, where impressive contourite drifts confirm interaction between turbidites and contourite currents.

CONJUGATE MATCH POINT: ADVANTAGE URUGUAY

With energy security and energy independence at the top of many nations' political agenda, it has become urgent to find new significant accumulations. Deep-water plays keep defying paradigms and yielding the largest discoveries. These discoveries are to be found in deep-water not only on the West African Coast in analogous situations to Venus and Graff, but also on the South American Atlantic Margin – where similar depositional environments and geology have created comparable low risk traps. The game is on for explorers to take the analogue set of plays in deep-water and match the discoveries on the path to exploration glory, and the world's future low-carbon advantaged energy.

References provided online. ■

One well

While onshore Uruguay has seen four exploration wells drilled, the offshore sector has had just one exploration attempt so far.

Uruguay has not been lucky on the global exploration stage. The only company that tested the hydrocarbon potential of Uruguay's offshore is **TotalEnergies**. The French company drilled the dry **Raya-1** well in 2016 in a record-breaking water-depth of 3,400 m.

Onshore, a few more wells were drilled, but as this article in GEO ExPro (2018, No. 6) explains, one of the most recent wells (**Cerro Padilla-1**, drilled by Schuepbach Energy Uruguay in 2017) only found 2 metres of oil-saturated reservoir in Permian sandstones. Albeit uncommercial, the well was the first to bring oil to surface in the country.

Hopes for economic quantities of oil recently increased again following the discovery of oil in Namibia. This has now led to the award of three new offshore licences in June this year by Uruguay's oil refining and fuel distribution company **ANCAP**. UK-based company **Challenger Energy Group** (CEG) was already awarded their licence in 2020.

Given that Shell is the operator of the **Graff** discovery offshore **Namibia**, it is no surprise to see that the company is one of the operators now also having a foothold in Uruguay. TotalEnergies, the company behind the **Venus** discovery offshore Namibia, is seemingly taking a more careful approach on the opposite side of the continental margin, probably driven by some intelligence obtained before.

It will be Apache's (APA) task to prove that the block they were awarded is in fact prospective where TotalEnergies failed to prove hydrocarbons. The American company's program includes a well commitment, while Shell's includes licensing of already available seismic data. ■

HENK KOMBRINK

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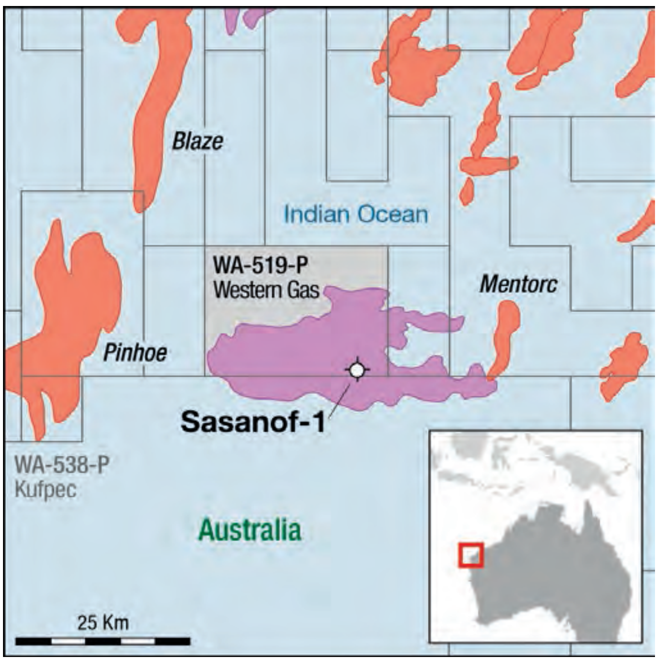

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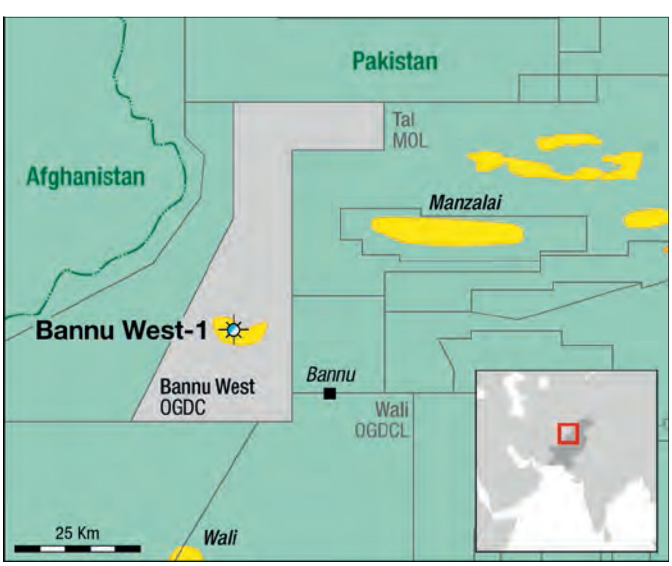
All that brightens is not gas, as Sasanof fails to deliver

Big things were expected from the **Sasanof-1** well, NW Shelf Australia, operated by **Western Gas** and partnered by minnows Global Oil & Gas, Prominence and Clontarf. Unfortunately, the 7.2 Tcf (1.2 Bboe) prospect, which was on trend with the giant gas fields of Scarborough and Io-Jansz in the Carnarvon Basin, disappointed. 40 m of net Barrow Group sand (Lower Cretaceous Berriasian delta front sands) was encountered, however logs confirmed that the sands contained water.

The 400 sq km prospect manifested a striking amplitude anomaly on modern PSTM 3D, similar to the adjacent **Mentorc** gas field. **Clontarf Energy** highlighted that initial technical analysis indicated that the expected western seal of the targeted stratigraphic trap was breached, and allowed migration of gas out of the prospect. Sasanof 1 was drilled between May and June 2022 to a TD of 2,390 m in Licence WA-519-P. ■

Further Success in the Bannu Trough

Operator Mari Petroleum Company Limited (MPCL) has reported a gas condensate discovery at Bannu West-1ST-1 in the Bannu West Block, located in North Waziristan, **Pakistan**. MPCL has to 55% working interest along with OGDCL and ZPCL. The well was spud on 6 June 2021 and drilled to a TD of 4,915m.



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During testing, the **Paleocene Lockhart Limestone Formation** flowed gas at the rate of around 25 mmcfgd with wellhead pressure of 4,339 psi and around 300 BPD condensate at 32/64 inch choke size (Pre-acid). Further, the **Hangu Formation** also flowed gas at the rate of 1.6 mmcfgd with pressure of 297 Psi at 32/64 inch choke.

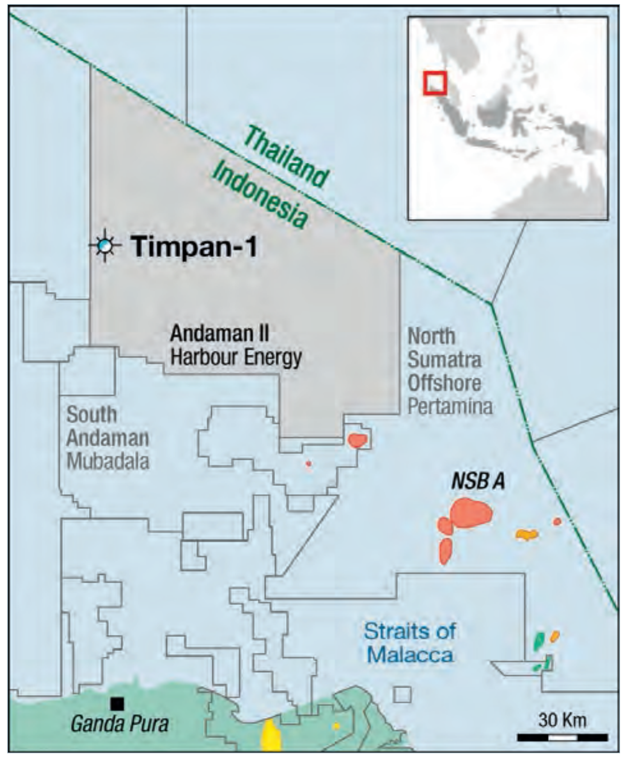
The Bannu Trough basin of the **Khyber Pakhtunkhwa (KPK) province** has seen new exploration efforts by the likes of Mari Petroleum, OGDC, Zaver Petroleum and PPL. The Bannu and nearby Kohat Potwar basins are foreland depressions hosting Proterozoic to Mesozoic and Paleocene petroleum systems with mild structuration form the Marwaht and Khisor ranges to the east.

Although only 150 km west of Islamabad, the acreage being explored around Wali, Bannu West and Zindan is close to the "red zone" of security issues with Afghanistan. OGDCL reported a gas discovery at **Wali 1** on the li Block to the south in July 2021. Hungarian MOL are understood to be testing at a wildcat (Surghar x1) in the Kohat Potwar basin adjacent to Bannu, with a similar geological setting. ■

Impressive results from the Indonesian Andaman

Harbour Energy, with partners Mubadala and BP, have reported a gas condensate discovery with excellent test results at **Timpan 1**, in Block Andaman II, northwestern Indonesia offshore. The Timpan prospect targeted 300 MMboe of hydrocarbons with gross play potential up to 12 Tcf and 400 mmb of condensate. **The Andaman Basin** is represented by a deep Oligo-Miocene clastic depression in this area, with the only shows to date in the north in Thailand and to the south of where the well was drilled. Timpan 1 was drilled between May and July 2022 and encountered a 119 m gas column in a high net to gross, fine grained sandstone reservoir with associated permeability of 1 to 10 mD. A full data acquisition programme included wireline logging, 73 m of core recovered and a drill stem test. Harbour announced that during testing the well flowed at 27 mmscfgd and 1,884 bpd of associated 58 deg API condensate through a 56/64" choke. While the well has encountered a material gas accumulation, further work will be required to establish commerciality and the full potential of this play across the licence.

A 3D seismic survey is understood to be scheduled over the block in Q3 2022. Harbour and Mubadala have interests over three large adjacent blocks in this basin. This could be the largest gas discovery in Indonesia for over 20 years, and all eyes are now on the **Recong 1X** exploration well to the south, where Repsol and Petronas are preparing to spud in the Andaman III Block. ■



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The Biggest Flooding Event in North Sea Geological History

Large complex of dunes, dryland rivers and sabkhas drowned in a split second of geological time.

In Late Permian times, around 255 million years ago, the area that now occupies the North Sea, parts of Britain and the area stretching from the Netherlands to Poland formed an amalgamation of deserts and ephemeral fluvial systems that ultimately drained into a playa lake. This is what is currently called the Southern Permian Basin.

It is the time of Pangea, when all continents were still welded together. The **Southern Permian Basin** was far from the open ocean, with the closest connection probably being situated in the north towards the Arctic. In this setting, whilst subsidence did take place with the resulting deposition of the typical **Rotliegend** facies associations, the area gradually "sunk" below global sea level.

So, when Pangea started to break up again in Late Permian times, sea water that probably originated from the north could make its way into what must have become the equivalent of a nearly dried up pool. The aeolian landscape of the Southern Permian Basin drowned and turned into a shallow sea.

This event is recorded in the cored section shown above. It is from development well 48/11b-A5 in the **Pickerill field** in the UK Southern North Sea and shows the transition from parallel laminated dune sands on the right to the darker Zechsteinkalk to the left. In many places across the basin, the so-called Kupferschiefer black shale is directly overlying the Rotliegend sands. Here, it is lacking, which is probably because of the peripheral location of the well with respect to the basin boundaries (see map).

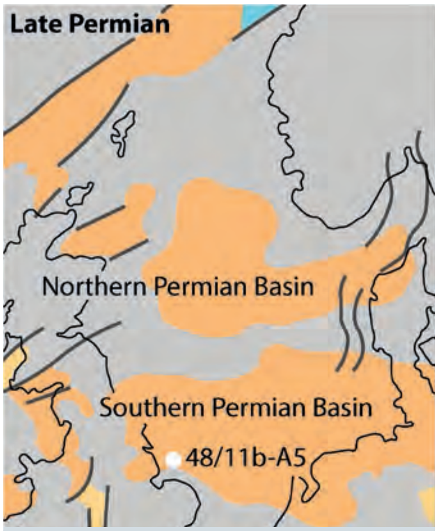
This peripheral setting is probably also the reason why the Rotliegend-Zechstein transition was cored in the first place, as the aeolian succession is relatively thin in the area. In order to ensure that the Rotliegend would be fully cored – which is where the gas used to reside – drillers must have decided to start coring just before the expected top Rotliegend.

Sections such as these tell the fascinating story of the geological history of the wider North Sea area and form a reminder that under certain circumstances environmental changes can happen within "split seconds" of geological time. ■

Henk Kombrink

Photo: Henk Kombrink.

Cored section from well 48/11b-A5, showing parallel-bedded Rotliegend aeolian strata (1) overlain by Zechsteinkalk (2), separated by a sharp horizontal surface (3). The keen observer will notice that the sandstones just below the boundary (4) do not show clear sedimentary structures, which may point to reworking during the flooding event.



Map showing the outlines of the Southern Permian Basin (orange) and the location of the cored well.

The cored section used for this article is held by North Sea Core CIC, the organisation that takes delivery of redundant core from the UK Oil and Gas Industry in order to save it from going to landfill and make it available for the wider geological community. Visit northseacore.co.uk for more information about this project.

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GEOPUBLISHING

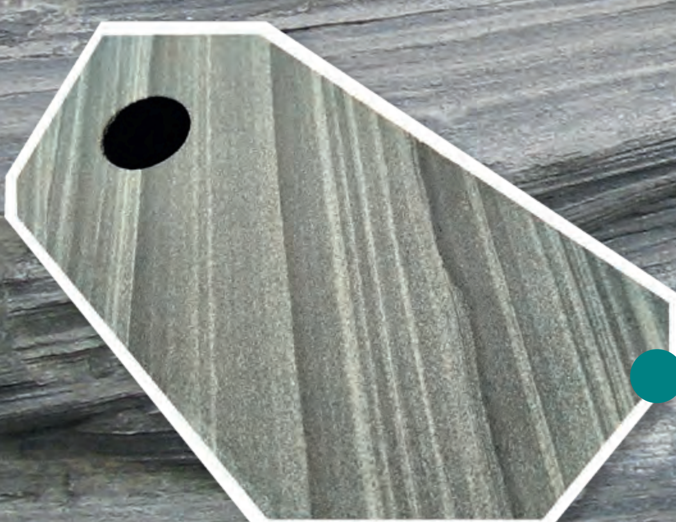
These Lovely Hummocks

Mostly formed in a shallow marine depositional setting, hummocky cross-stratification is a sedimentary structure that is commonly found in sandstones. It is a type of cross-bedding that is caused by the action of large storms, at depths where normal wave activity does not have an influence on what happens at the sea floor.

Especially when there are two or more minerals with different densities making up the sand composition, the sorting that takes place when the laminae are being formed results in a spectacular interplay of truncation and wavy bedding.

The example shown here is from the Upper Carboniferous (Namurian) along the Northumberland Coast, Northern England. These sandstones form part of the so-called Yoredale cycles, deposited in an environment where sea-level changes resulted in an alternation of shallow marine to terrestrial deposits.

Henk Kombrink



The Middle Jurassic Rannoch Formation from the Brent Group in the Northern North Sea is a really good example of hummocky-cross-stratified sandstones. These form important reservoirs in the Brent province. Compared to the other Brent formations though, the Rannoch tends not to be the best quality given a higher degree of compaction and the occurrence of calcite-cemented zones.

Outcrops allow a much better inspection of sedimentary features than "1D" core data. In this series, we feature a range of outcrops to give more context to what core interpretation typically allows.

Do you have a suggestion for an outcrop feature? Please email Henk Kombrink (henk@geo365.no) for more information.

Photo: Henk Kombrink

Breaking New Ground in São Tomé & Príncipe

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Jaca 1 tests the yet undrilled deep-water blocks offshore São Tomé and Príncipe for Shell and Galp.

The curtain is yet to come down on oil and gas wildcatting for the **West Africa margin**, as explorers continue to break new ground in new basins, in a world hungry for hydrocarbons. The Jaca 1 well to the east of São Tomé is an example of that.

The first blocks in the **São Tomé** and **Príncipe Exclusive Economic Zone** (EEZ, (blue colour in the map) were awarded separately to Equator Exploration and Oranto in 2010, who added to the multiclient 2D seismic campaigns acquired by PGS between 2001 and 2005 with proprietary 3D seismic surveys over Blocks 5 and 12 and further geological studies. These induced a string of new entrants to bring new investment in 2016.

Kosmos Energy spearheaded the campaign, farming in to four contiguous blocks against the border with Gabon and Equatorial Guinea. The US based firm, well known for cracking the Upper Cretaceous West Africa play from **Ceiba to Jubilee** in Ghana, saw an amplitude anomaly in Late Cretaceous horizons that coincided with a deep marine depositionary model of turbidites and fan systems being fed by the Rio Muni coastal basin to the northeast and the Ogue fans to the east and south.

Soon after Kosmos joined Equator/ Oando, major firms such as Shell, BP, Galp and TotalEnergies took large contiguous positions across the basin. TotalEnergies had already had limited success in the Joint Development Zone (JDZ) to the northwest of the CVL, but this play is very much associated with the thrust front of the Oligo-Miocene Niger Delta play. Since 2016, a number of large 3D surveys have been acquired, and while Shell has consolidated its position, Kosmos Energy cut short its "third innings" and exited most of their blocks in a broad West African transaction with Shell (with the notable exception of Block 5, to the north of the Jaca well).

A DIFFERENT SOURCE ROCK

This untested frontier play is supported by a number of structural ridges formed by transform faults running northeast-southwest through each block, adding structural and trapping opportunities to a high-impact Cretaceous clastic play. In this area the Lower Cretaceous formations, sitting on oceanic and proto-oceanic crust, provide potential source rock facies deposited during the early spreading phase of the South Atlantic.

These Lower Cretaceous source rock concepts have since been de-risked in other major West African basins as seen at the GTA and Sangomar discoveries in Senegal, and most recently at **Venus** and **Graff** in the Orange Basin of Namibia. Most West African wildcatting at the time of Kosmos' entry relied on the prolific Cenomanian – Turonian (CT) source kitchen across the transform margin and the passive margin of the Gulf of Guinea. For reservoir analogues, a strong correlation is to be found to Late Cretaceous Campanian and Santonian sands at Ceiba to the east (Equatorial Guinea) and deepwater wells in northern Gabon, but the source rock and charge story would be a new test of this Early Cretaceous model.

FOLLOW-UP POTENTIAL

A discovery at Jaca 1 could de-risk nine deep-water blocks and 50,000 sq km of frontier acreage. The well will target Upper Cretaceous Campanian and Santonian turbidite and slope sands, some of which are draped over, or pinch out against, elongated ridged highs created by the Bata Transform Fault or fracture zone. Apto-Albian source facies may charge the prospect, and several other stratigraphic-structural leads flank the prospect. Similar fracture zone play fairways exist across most of the acreage here from Block 3 in the north to Block 13 in the south.

Depending on the results of the well, a number of follow-on play tests could be drilled by BP to the south in Block 13, Galp and Equator in Block 12, and Shell and Galp, and Oranto in Block 3. Results could also influence activity further afield, where open acreage has similar play concepts in the adjacent north Gabon basin, and also in EG 24 Equatorial Guinea, located between the Ceiba Okume-Ovenge fields and Block 5 STP. ■

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