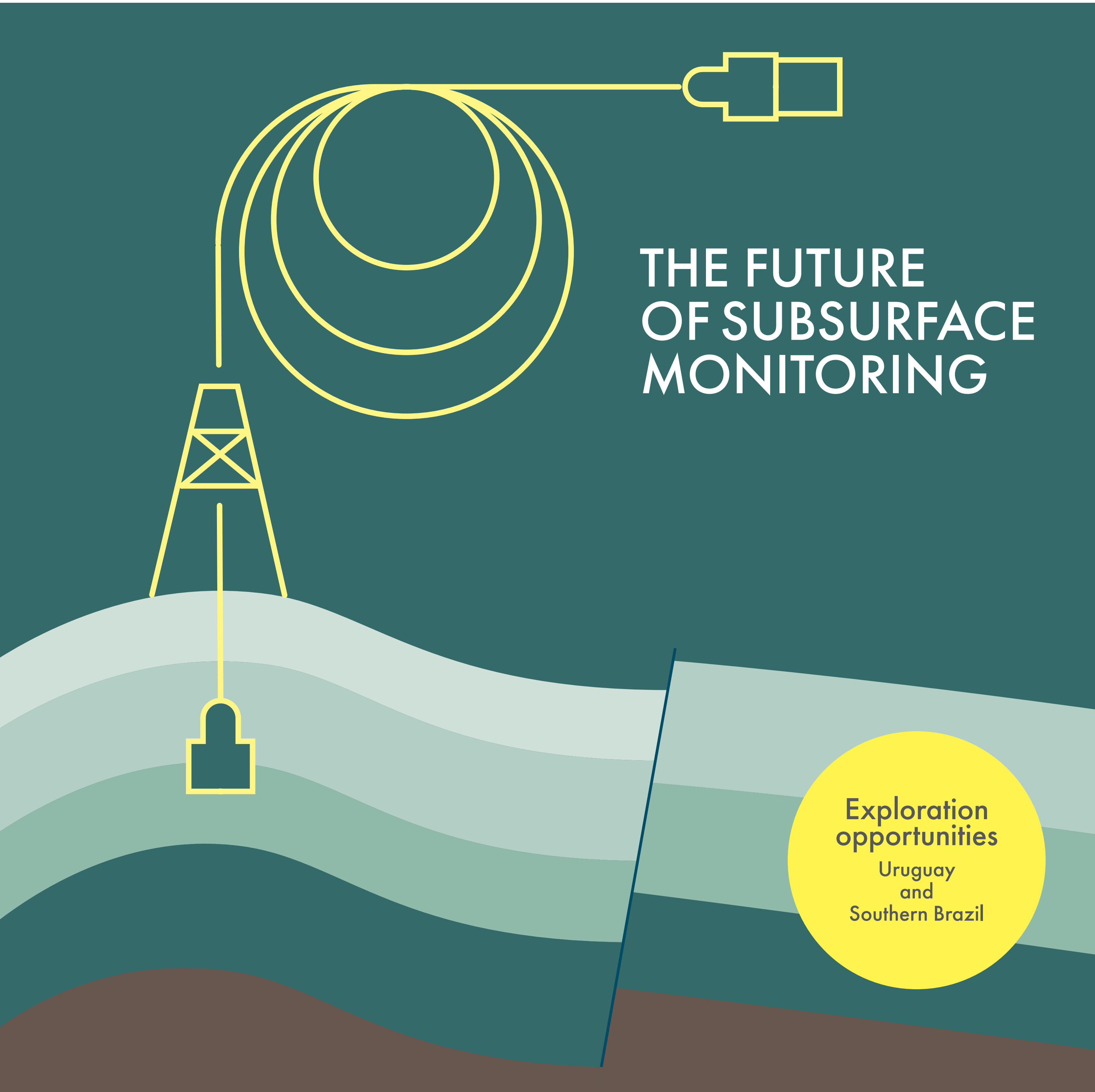
THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

VOL. 21

GEO ExPro 1 2024



THE FUTURE OF SUBSURFACE MONITORING

Exploration opportunities

Uruguay and Southern Brazil

GEO ExPro

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Print
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GxP PUBLISHING

COVER ILLUSTRATION: GEO EXPRO

Logging becomes filtering

AS WE ARE PRESENT at a number of Digitalisation conferences during the first months of the year, I got the idea to dedicate the cover story to a "new" way of logging: Logging using fibre optic sensing. OK, it is not entirely new, but the industry is becoming more and more aware of the potential that data acquisition using a tiny fibre cable can offer.

And where permanent installation can be difficult or cost-prohibitive, especially in older wells, there is now also the option to run fibre optic cables as an intervention. A slim and slick operation that does not even require the tool containing the fibre to be retrieved back from the hole, simply because it will decompose!

The amount and variety of data that results from fibre optic sensing along an entire well path is surely demanding a new way of thinking.

"Machine learning eats fibre optic sensing data for breakfast, lunch, and dinner"

One well can generate up to 2 Terabytes per day, so filtering becomes a key element of the data analysis and interpretation. As one of the people I spoke to for the cover story put it; you've got to feed machine learning algorithms with data. Fibre optic sensing does exactly that!

Henk Kombrink

BEHIND THE COVER

As reservoirs will become more challenging to produce from over time, with water inflow developing into an important issue to manage, monitoring fluid flow is getting more critical over a field's life. The same holds for shale gas reservoirs, where monitoring takes place from the start of production to see where the induced fracs are and how much these contribute to flow. Geothermal and CCS are two other realms where reservoir and overburden monitoring is key to make sure that operations run smoothly. For all these monitoring tasks, a tiny fibre optic cable can do the job nowadays. The same fibre optic cable we use to send our emails and download our films. Telecoms has made it into the oilfield!

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Be part of the conversation

Australian Energy Producers is the place to be for professionals in the energy industry with a comprehensive program covering key industry issues and an exhibition filled with the top organisations from Australia and around the globe

THE ANNUAL Australian Energy Producers Conference & Exhibition, previously known as the APPEA Conference and Exhibition, is Australia's largest and most anticipated energy event. The Conference and Exhibition is the go-to for explorers, developers and producers of essential energy - oil, gas and lower-emission fuels.

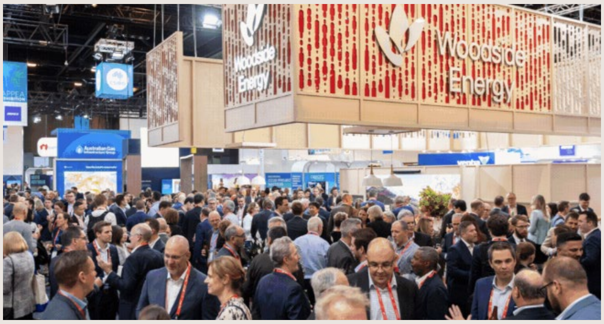
Greatly helped by a broad group of members, the conference plays a vital role in communicating to government, industry and community, as it serves as a platform to bring an important and unique perspective to the complex energy landscape. It is the people attending the conference who represent the businesses that are ensuring energy security and delivering substantial economic benefits to Australia while helping to deliver a cleaner energy future.

The theme for 2024 is Delivering the New Energy Economy. It sets an ambitious standard for our discussions, knowledge sharing and partnerships as we seek to lead the energy transition.

Australian Energy Producers 2024 provides an unparalleled opportunity for the industry to continue discussions around our journey to net zero emissions and the ever-present need to explore for, find and develop Australia's oil and gas. As we respond and adjust to a rapidly evolving global energy landscape, the Australian Energy Producers Conference & Exhibition will provide a platform for open conversation and candid debate.

In summary, if you want to hear the latest about the upstream sector in Australia, make sure you join over 2,300 delegates for what is set to be a great Australian Energy Producers Conference & Exhibition this year.

Further information at: https://energyproducersconference.au/



Energy Transition - Is the European approach different?

The AAPG Europe Regional Conference in Krakow in May this year will explore how the continent is adapting to the subsurface needs of the energy transition

GIVEN THE GLOBAL energy transition, an even deeper understanding of the many mature European basins is required now, not only with hydrocarbons in mind but also with a new focus on geothermal energy utilization, carbon dioxide storage and hydrogen exploration and storage. These rapidly emerging topics will have dedicated special sessions focusing mostly on European case studies but welcoming contributions from other parts of the world with the same geoscience challenges.

This meeting will have sessions that fit the general geological setting of the Carpathians and its foreland in Poland but also the broader East European Craton including various Ukrainian basins. Given the ongoing war in Ukraine, our Technical and Advisory committees are prepared to work on a solid technical programme incorporating many of the ideas AAPG Europe had for a meeting originally planned to occur in Lviv. We believe that the early summer of 2024 in Krakow will offer a good chance for many of our Ukrainian colleagues to attend.

The planned sessions will highlight aspects of the petroleum systems elements focusing on, for example, salt tectonics, clastic and carbonate reservoirs and structural geology. As to structural geology, we are planning to have not only a session devoted to thrust-fold belts in the European region but also discuss fault reactivation and inversion tectonics in folded belts and inversion with global case studies.

We are working with local and regional universities and research institutions across Europe to have a healthy mix of professionals from both the industry and the academia for this event. The 2024 AAPG Europe Regional Conference will take place in Krakow, Poland, from the 28-29 May.

Further information at: https://erc.aapg.org/2024

The conference field trip will explore the Outer Carpathians and some surface seeps are part of the programme!

PHOTOGRAPHY: BERND HILDEBRAND VIA PIXABAY; AAPG

Steering the net zero race

Aberdeen's annual upstream conference will explore the needs to keep the UK Continental Shelf in the race when it comes to both energy security as well as achieving lower emissions

FOR OVER 20 years, DEVEX has been the leading technical conference guiding the entire E&P project lifecycle covering exploration, production, appraisal, development and decommissioning alongside emerging areas like CCUS.

Our mission is to ensure a sustainable future by nurturing talent, fostering innovation and balancing sustainability with operational excellence. Led by a dedicated group of volunteers, who give up their time to help solicit talks and provide ideas for masterclasses, the conference has always been characterised by a genuine team effort to realise a broad programme that appeals to many.

This year, the conference will be chaired by industry veteran Brenda Wyllie, who has a proven track record of delivering a sound programme and a great line-up of keynote presenters.

In its 21st year in 2024, DEVEX continues its commitment to addressing industry challenges, emphasising the sector's crucial role in enhancing energy security and sustainability. DEVEX 2024 offers targeted sessions such as Electrification to drive emission reduction efforts, showcasing industry advancements through keynotes, talks, masterclasses, and technology insights. It's a valuable opportunity for collective learning, networking, and collaboration, shaping the future of the UK Continental Shelf.

Further information at: spe-aberdeen.org/events/devex-2024

The Devex Conference takes place on 28 and 29 May.

A room full of the best intentions

The CCS Symposium organised by the GESGB in December last year was full of people wanting to press ahead with carbon storage, but when is it going to happen at scale?

THERE IS LITTLE doubt that people have the best intentions, but when Hamish Wilson from Azuli International said that his company failed to raise any capital for CCS projects in the UK this year, it is a sign that something is not working, yet.

A few tonnes of CO_2 were injected into Nini West in Denmark this year. But the field is tiny, and even when full-scale injection takes place, it is not going to make a significant dent.

In contrast to Nini West, the Leman gas field in UK waters is big – and could therefore form a candidate for large-scale CO_2 disposal. Marta Puig Alenyà from Perenco gave an overview of the Poseidon project covering Leman field and the Triassic Bunter store in the overburden.

But, even though the integrity of the wells Perenco had so far looked at in Leman seemed ok, that was not so much the case for the overlying Bunter reservoir. No surprise in a way, because the Bunter interval is lacking the plugs that are present at the top of the Rotliegend gas reservoir.

It is not good news for the Bunter store as a potential injection candidate – legacy wells form the highest risk for CO_2 storage projects, as a representative of the licensing authorities reiterated.

Does this mean that a project such as Poseidon runs the risk of not progressing to full-scale injection even though the licence was granted?

Time will tell, but it is about time for something big to happen!

Henk Kombrink

Michael Larsen from Ineos Energy whilst presenting on the CO_2 injection test in Nini West during the GESGB Conference on Thursday 14 December.

PHOTOGRAPHY: DEVEX; HENK KOMBRINK

FIRSTS

"As long as there is demand for oil,
supply will be available."

Carole Nakhle – Crystol Energy

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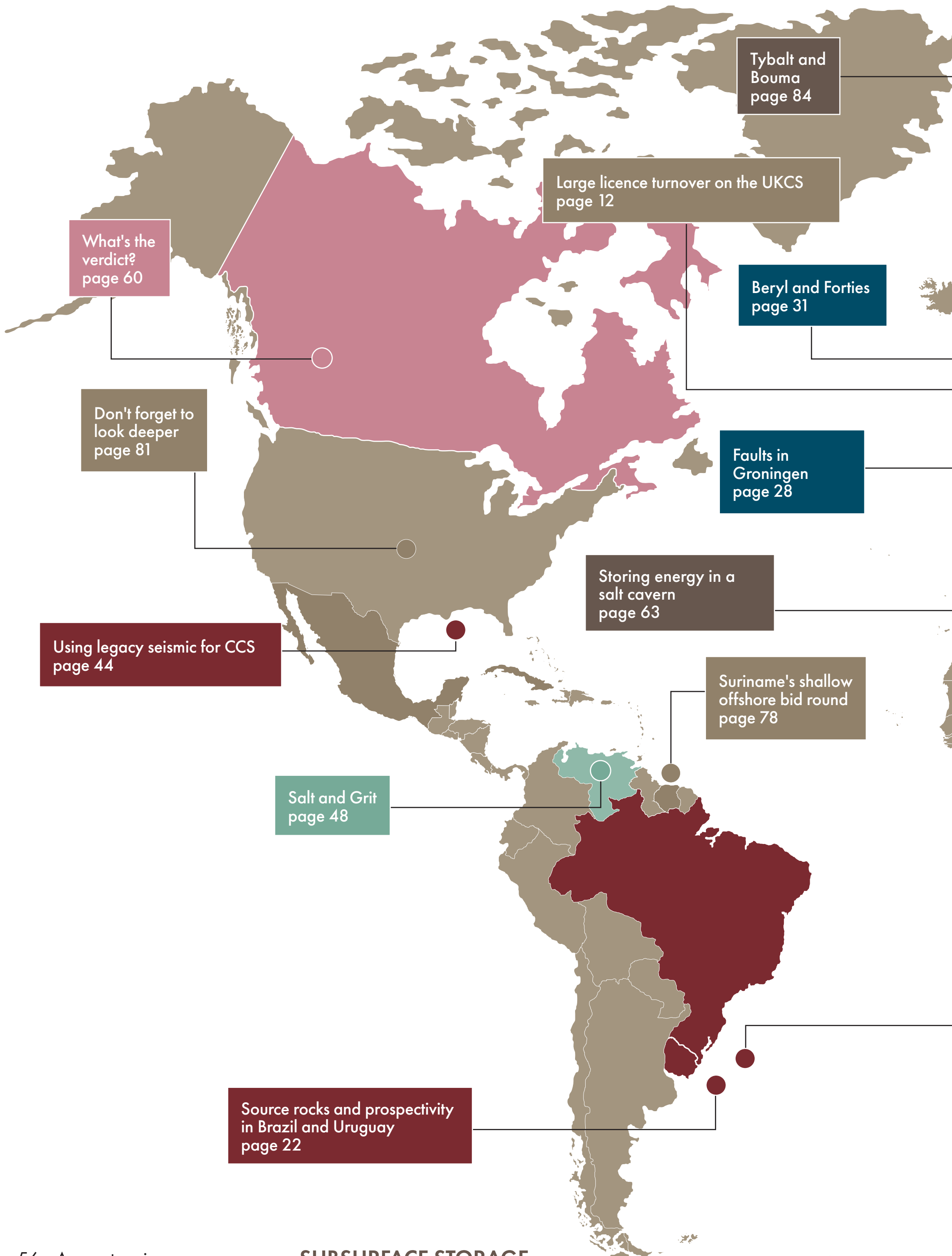

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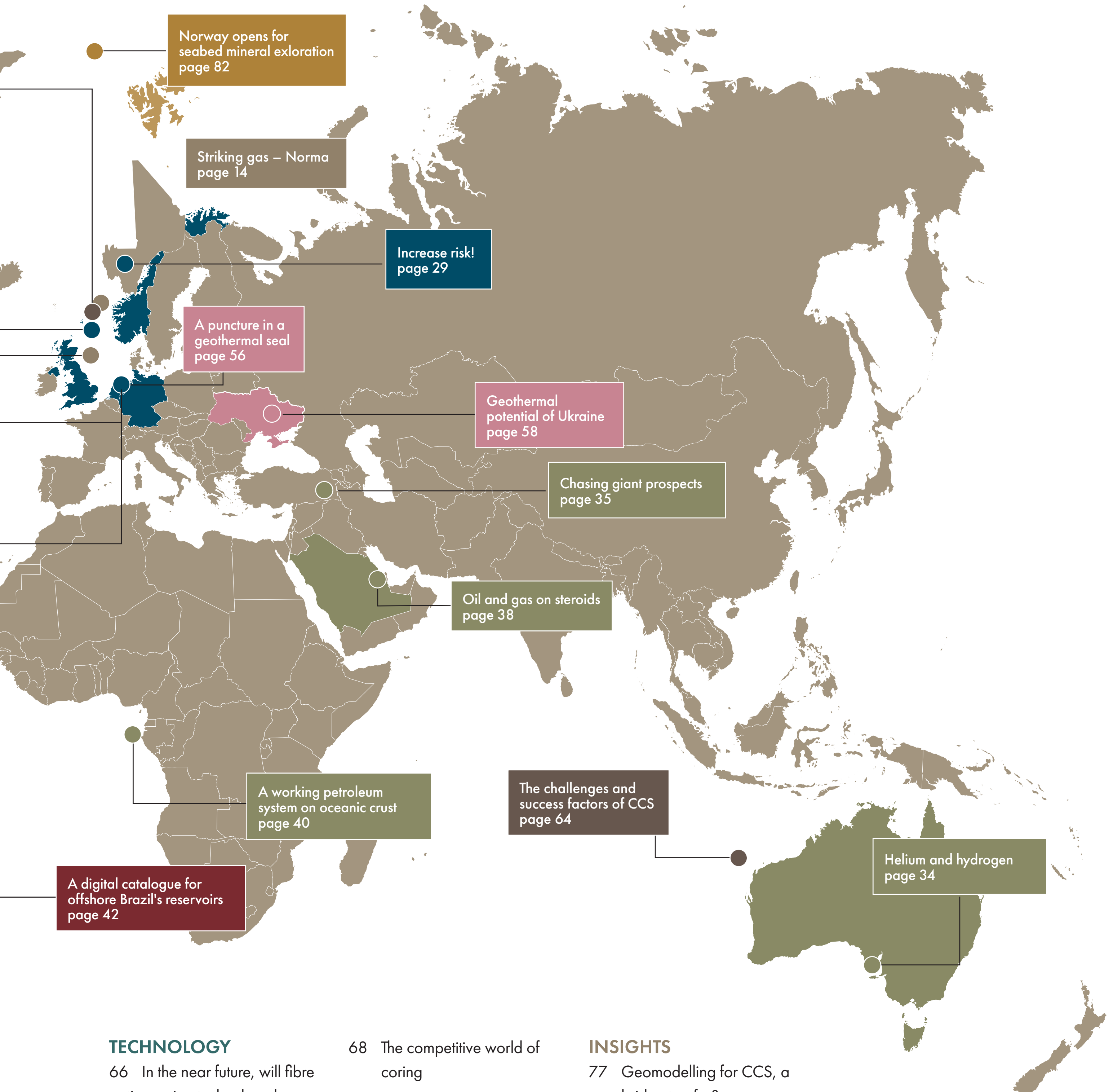

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Why?

There is a simple reason why oil and gas companies keep investing in new projects

Many question why oil and gas companies are still investing in the sector, at a time when the fight against global warming is intensifying and the world is keen on transitioning to greener sources of energy. The plain fact is that those companies continue to invest simply because there is a demand for their products and they are able to secure desirable rates of return – the most powerful driver of an investment decision.

Although the share of oil in the primary energy mix peaked in 1973 at nearly 50 percent, after the first oil shock, oil continues to be the largest contributor to the world's primary energy needs with a share of 32 percent, and if one adds natural gas, that share increases to 55 percent.

As the energy transition accelerates, demand for hydrocarbons is bound to peak though there is no consensus about when the peak will happen nor the speed at which demand will decelerate afterwards. As the International Energy Agency puts it "the demand outlook will not be linear in practice. There will inevitably be spikes, dips and plateaus along the way."

The OECD region provides a good example; there oil demand peaked in 2005 then 17 years later it is only 11 percent below that peak. As long as there is demand for oil, supply will be available and investment will continue in the sector. Curtail the latter, supplies will dwindle and prices will increase subsequently. From a climate perspective, that ought to be an acceptable outcome, but….

"As long as there is demand for oil, supply will be available"

Although demand eventually responds to prices, that adjustment does not happen instantly, especially when the alternatives are not readily available at scale, which is still the case at the moment. And it is not just about basic economics. The energy crisis of 2022 has reminded us that it is not only customers who dislike high energy prices, governments are equally sensitive to that. So, this conclusion may not be to everyone's liking, but it does seem that we can't just leave the oil and gas era behind, yet. ■

Dr Carole Nakhle is a leading voice in the debate on how the world's energy mix is evolving. She is the founder and CEO of Crystol Energy, a firm that specialises in energy investment, policy and strategies. In addition, she is a sought-after interviewee for various TV channels and has many advisory roles that complement her busy agenda.

Large licence turnover, but what's the value added?

The UKCS has seen many new licence awards recently but the work commitments are meagre

In recent weeks there has been significant coverage in the news about the latest UK licensing round. To backtrack, the 33rd Offshore Licensing Round officially opened on 7 October 2022 with applications closing on 12 January 2023. Almost 900 blocks were offered by the UK industry regulator the North Sea Transition Authority (NSTA) after a three-year gap. Given the failure and disappointment of many global bid rounds, it was quite encouraging for the NSTA that it received 115 applications covering 258 tracts submitted by a total of 76 companies.

> "...given the unusual and prolonged process, it remains to be seen how many of the licences awarded will be taken up."

To date, the NSTA has announced the successful bidders in two tranches on 22 October 2023 and more recently on 31 January. These two tranches cover acreage West of Shetland and the Northern and Central North Sea. The upcoming third tranche will include acreage in the Southern North Sea and East Irish Sea. However, given the unusual and prolonged process, it remains to be seen how many of the licences awarded will be taken up. A number of companies will have changed strategy and exploration decision makers, and in some cases decided to exit the UK offshore. There is also the impact of unsuccessful drilling during this period. An example being the much-awaited but seemingly disappointing North Sea Natural Resources-operated Devil's Hole Horst Prospect (27/05-1) on the western side of the Central North Sea, plugged and abandoned in December 2023.

> "...the industry considers the relinquishment policy shortsighted."

EXTREMELY LOW

If one looks at the applications in detail, a large number are for protection acreage. Others are applications for the same areas relinquished in recent years. Overall work commitments for the blocks involved in the first two tranches are extremely low, with most of the work being no more than desktop studies. It will come as a surprise that only one firm well has been committed in both tranches, by Shell and partner NEO Energy in Block 22/30d on the Eastern Central Graben. Total relinquished this block in 2020, located north of Shell's Shearwater gas/condensate field, possibly targeting the Gylen prospect.

MASS RELINQUISHMENT

In December 2023 there was a mass relinquishment of acreage in the UK offshore with over 80 licenses surrendered many of which had been awarded in the previous 32nd Round. The period following the 32nd has been a tough time and the industry considers the relinquishment policy shortsighted and extensions should

have been considered for continuity. The industry and overworked NSTA have to start from scratch again under new awards and terms. Large swaths of the UK offshore now remain open and it is unclear when this acreage will next be made available. A knock-on effect of this large turnover of acreage is that there are fewer farmout opportunities available especially for exploration. Those seeking deals will need to watch closely companies successful in the 33rd Round for opportunities.

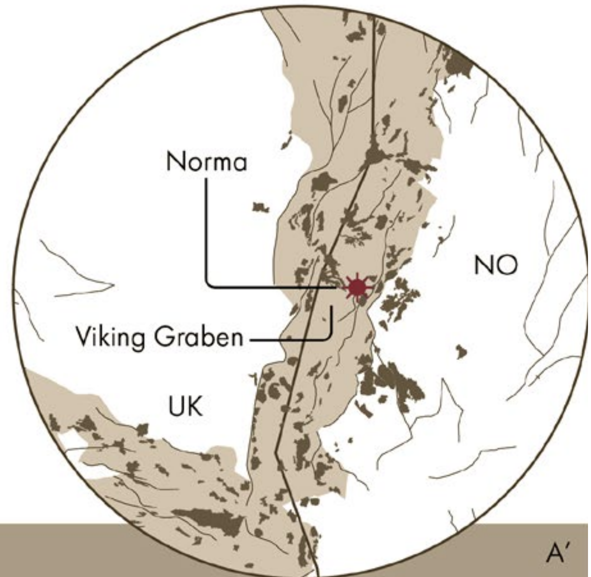
A POSITIVE NOTE

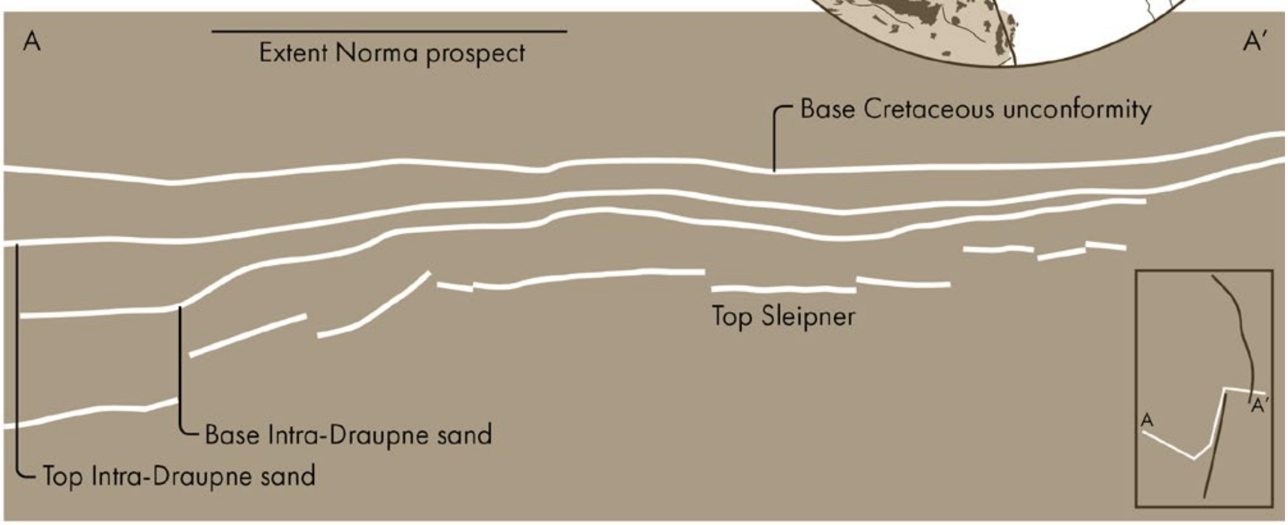
To wrap up on a positive note, in early February 2024 Deltic Energy announced that it has farmed out a 25% stake in Block 48/08b on the Southern North Sea to Dana Petroleum, a wholly-owned subsidiary of the Korea National Oil Corporation (KNOC). The Shell-operated licence contains the Selene prospect, which remains on track to be drilled in the second half of 2024. Selene is one of the largest undrilled structures on the Permian Leman Sandstone fairway. ■

Ian Cross - Moyes & Co

Exploring subtle traps in deeply buried plays

The discovery of gas and condensate in the Norma prospect in Norwegian waters may not be the last discovery in the deeper parts of the North Sea Viking Graben





MORE THAN ten years ago, the companies owning licence PL547S could not make their so-called Kuhegre South prospect work. Yet, in September last year, DNO and partners Source Energy (20%), Equinor (20%), Vår Energi (20%) and Aker BP (10%) found gas and condensate in the same Upper Jurassic reservoir that was mapped by Marathon and partners before. If this shows one thing, it is that recycling of acreage works. Maybe better imaging is also to thank for this, but a different pair of eyes may equally have contributed.

Estimated to contain between and 25 and 130 MMBoe, the intra-Draupne Formation sandstone reservoir is interpreted to be part of a fan system that was deposited into the South Viking Graben from the east in Late Jurassic times.

Looking at the schematic cross-section shown below, which is based on Marathon's relinquishment report from 2011, it is clear why there was some doubt on the validity of the trap – the intra-Draupne sandstone needs a stratigraphic trapping element to make it work. Marathon drilled a well (25/10-11 T2) further to the south to test if the Upper Jurassic section contained any sand, but surprisingly the well did not find any Upper Jurassic at all, so could not be used to de-risk the prospect. Another concern was the reservoir quality given the depth of burial at around 4,500 m.

Despite these risks, the 25/7-11S well that targeted the Norma prospect found moderate to good reservoir quality and a 16 m hydrocarbon column with 13 m of net reservoir. Given the seismic line and the interpretation of the top and base of the reservoir section, it looks likely that the total thickness of the intra-Draupne sandstone exceeds the thickness of the discovered column. Yet, the NOD press release mentions that it is uncertainty if the gas water contact was found, which may indicate that the reservoir is characterized by some intercalated fines. Given the nature of the deposit, being a set of amalgamated turbidite lobes, this is not a big surprise.

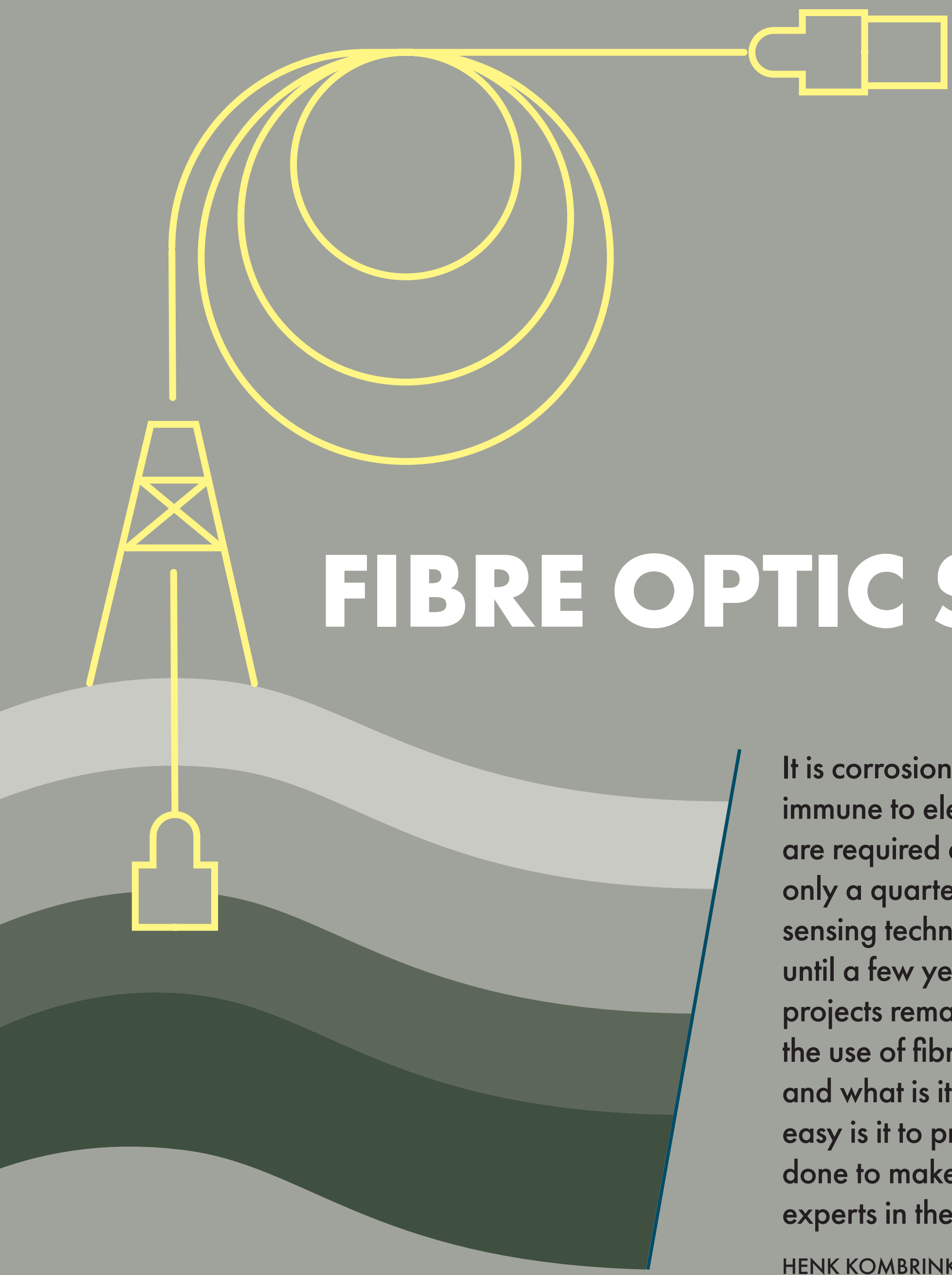
Norma is not the last time Upper Jurassic sands are being targeted in this area. One of the few high-impact wells that Westwood Energy Global identified in the Norwegian sector for this year is the Alvheim Deep well that will be drilled by Aker BP. This well is allegedly targeting a similar reservoir as DNO's well and may therefore herald a bit of a revival of the deeply buried Upper Jurassic play in the abyss of the Viking Graben. ■

Henk Kombrink

COVER STORY

"In 10 years, nobody would risk installing a subsea well without fiber optic sensing."

Garth Naldrett – Silixa



FIBRE OPTIC SENSING

It is corrosion resistant, has a long lifetime, it is immune to electric interference, no electronics are required downhole, and the "cable" is only a quarter of a millimeter thick. Fibre optic sensing technology has a lot to go for. Yet, until a few years ago, its uptake in subsurface projects remained limited. How widespread is the use of fibre optic sensing technology now, and what is it primarily used for? And also, how easy is it to process the data and what is being done to make it easier? We spoke to several experts in the field to find out

HENK KOMBRINK

With more challenging reservoirs being targeted nowadays, including low-permeability mudstones, and a drive towards improving recovery factors from existing fields, so comes the need to monitor reservoir performance better. On top of that, geothermal and CCS also require more and better monitoring techniques. It is probably thanks to these increasing subsurface requirements and the continuous technological innovation in the realm of fibre optic sensing that the time has come for the more widespread application of fibre optic sensing.

To find out about the state of play in the field of fibre optic sensing, I spoke to three experts in the Andres Chavarria, Technical Director at Luna Innovations, Garth Naldrett, Chief Product Officer at Silixa and Andrew Garioch, Field Operations Manager at Well-SENSE.

The conversation with Andres and Garth focused on permanent installation of fibre optic sensing technology and data processing, whilst Andrew sheds more light on performing well interventions using fibre optic technology. Some wells do not lend themselves for permanent installation, which is especially the case for

> "In 10 years, nobody will risk installing a subsea well without fibre optic sensing"

old wells where the workover required to fit a cable on a production tubing would be too costly an exercise.

NOT A NEW TECHNOLOGY

"When you drill and complete a new subsea well these days, electrical temperature and pressure gauges are being installed", says Garth. "Twenty-five years ago, it was a rarity for that to happen, but nowadays it is standard and accepted practice. Why am I saying this? Because I think that in 10 years, nobody will risk installing a subsea well without fibre optic sensing."

Fibre optic sensing is not new. "My first encounter with fibre optic cable technology was in the late nineties at the ETAP field in the UK North Sea", says Garth. "Given the high temperatures in the wells, people advocated for having fibre optic temperature and pressure gauges installed instead of electric ones. However, it turned out that the connectors were not as reliable as was hoped and electrical gauge reliability just developed faster during that time." It then took about twenty years until the first Distributed Acoustic Sensing (DAS) was installed in a subsea setting.

"It is the ability to take permanent measurements along the entire well path, rather than temperature and pressure gauges at a few locations along the well that form the real advantage of this technology."

DAS AND DTS

The main fibre optic sensors that are being used in oil and gas wells are DAS and DTS. "While Distributed Temperature Sensors (DTS) are quite straightforward in the sense that they record temperatures, Distributed Acoustic Sensors (DAS) measurements include seismic, acoustics, ultrasonic and even temperature", explains Andres. "There is a wealth of signals that saturate these instruments. And it is that wealth of data that needs to be filtered properly to get to the right people."

Permanent installation of fibre optic cables is increasingly being done in HPHT environments where conventional sensors are bulky and less reliable. In land wells, the fibre optic cables are often attached to the casing. In offshore wells, they are attached to the production tubing.

"It is the ability to take permanent measurements along the entire well path, rather than temperature and pressure gauges at a few locations along the well that form the real advantage of this technology", says Andres. "For leak detection, fibre is critical, because usually within a few seconds we are able to say at which depth the leak occurs."

What is the expected lifetime of these fibre cables? "The oldest ones operating in the field are around 30 years old", says Andres. But that was with the technology of that day. "I also know of cables fitted in steam-flood assisted oil production in SAGD and the Middle East, and these have been operating for at least eight years already. I don't know if they are very happy, but certainly, they have not degraded and continue doing their work."

"Compared with the limited activity pre-Atlantis, it really shows the growth the technology has seen over the past few years."

THE ATLANTIS PROJECT

The Atlantis project in the Gulf of Mexico has been a game-changer for the technology. Installed in 2020, it was one of the first times that fibre optic technology was installed in subsea wells. "Since then, we have done around 20 installations of DAS systems in subsea wells across the globe", Garth emphasises. "Compared with the limited activity pre-Atlantis, it really shows the growth the technology has seen over the past few years."

Garth Naldrett.

At Atlantis, a deep-water development in folded Miocene strata, the reservoir was hard to image using conventional seismic data, because of the presence of salt above the productive interval. To map the reservoirs with more confidence during the third phase of development, permanent fibre was installed in a number of newly drilled wells. "The advantage of this is that any repeat surveys do not add a huge cost to the OPEX of the field, because the "geophones" are already installed in the wells", says Garth. "And the repeat surveys are done anyway using ocean bottom nodes, so the additional data obtained through the fibre is essentially for free."

Another advantage of fibre optic seismic acquisition is that the resolution of the data is better than using conventional geophone acquisition on the sea floor, because the acoustic signal is only travelling one way through the subsurface towards the receivers below. Using ocean bottom nodes or streamers, the signal needs to travel back. In that process, the higher frequencies get lost ▸

Andres Chavarria.

"If you think the oil and gas industry is slow in taking up new technology, the subsea world can be even more of a challenge."

through attenuation, which leads to a loss of resolution compared to using DAS", says Garth.

"It's the ability to map reservoirs in a higher resolution and the low cost of repeat surveys that have been the driver behind the use of DAS in the Gulf of Mexico", continues Garth. "We think that there is equally a lot of potential in the pre-salt play in Brazil for instance, as these reservoirs are experiencing the same imaging problems as we see in the GOM."

Seismic acquisition through DAS will unlikely replace OBN surveys though. Because receivers are by default fitted in the existing wells, the further away from them the weaker the signal will be. This is probably the reason why BP is also still acquiring OBN surveys in addition to the data gathered through DAS.

ACCEPTING NEW TECHNOLOGIES

"The introduction of a new technology like fibre has not always been easy", says Andres, "because of existing solutions already on the market. That's why we have done a lot of flow loop work to make sure that the flow regimes that we can capture with fibre are representative of what the flow regimes in the well are. It is the same with seismic, where we had to use conventional geophones in combination with fibre to validate that you could get the same images of the reservoir."

But as the technology has now matured, certain operators don't require the validation phase anymore. Most of the service providers have also adopted the technology and made it part of their offering, which means that the technology is not being looked at as a disruptor anymore.

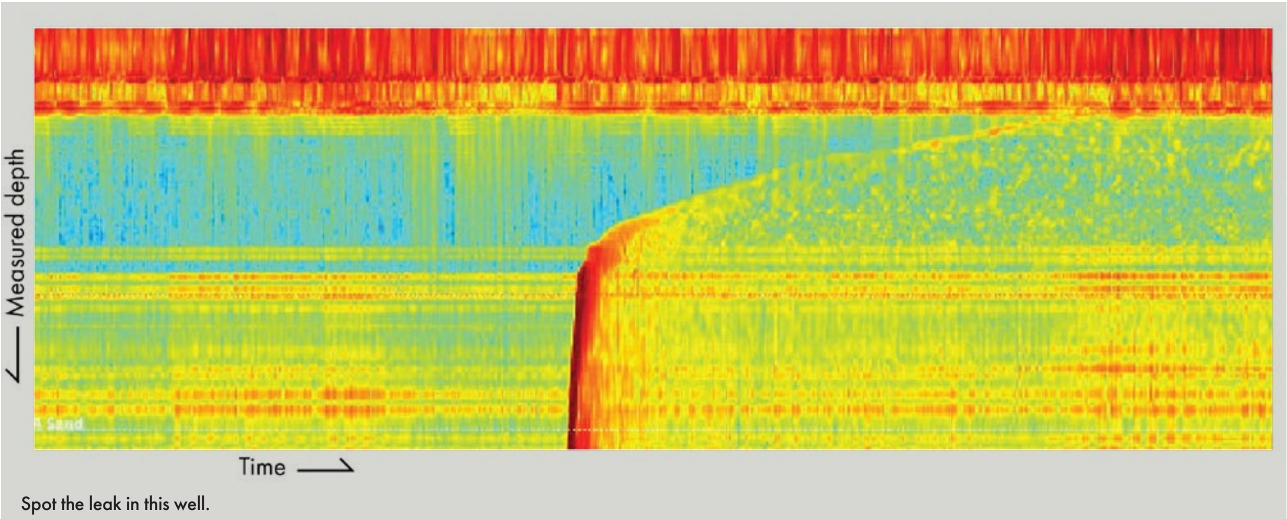
There is still a lot of R&D going into fibre optic sensing. For instance,

THE NORTH SEA VERSUS THE GULF MEXICO

Two flagship projects, one in the North Sea and one in the Gulf of Mexico, use fibre optic sensing in a very different way. Johan Sverdrup, operated by Equinor, uses fibre optic sensing in their production wells to monitor well integrity and fluid interactions in the reservoir, optimising downhole safety valves for production efficiency. "It's all done to ultimately reach a much higher recovery factor than conventional oil fields, plus the ability to identify integrity issues in the wells much quicker", says Garth.

BP however, uses the same technology in the Atlantis field in deep-water Gulf of Mexico for seismic monitoring, i.e. 4D seismic.

In the North Sea, seismic acquisition through DAS is not a big thing. "That's because the environment is more benign to repeat conventional surveys", explains Garth. Positioning is less of an issue without the loop currents that characterize the GOM, the water depth is much shallower, and the salt imaging problem is not so much of an issue with oil fields in the North Sea."



Spot the leak in this well.

SOURCE: WELL-SENSE

Andrew Garioch.

research is carried out to identify different fluids. “On the hardware side, we are always improving things, such as reducing the costs of components and reducing the spatial footprint of the kit. One of the main things that we have seen a lot of progress in is the number of interrogators needed to receive and record the data. Now, multiple wells with fibre optics can be plugged into the same interrogator, greatly reducing the operation's footprint”, says Andres.

“We can usually report the results of the measurements back to the client in as little as an hour after deployment”

Garth agrees that it is not always easy to introduce new tech. “If you think the oil and gas industry is slow in taking up new technology, the subsea world can be even more of a challenge. To install fibre optic cables, we need a connection between the tubing hanger and the subsea tree. This is also one of the most important parts of subsea wells, forming the critical element of the pressure control system in the wellbore. So, doing anything that could affect the well’s reliability or integrity is being looked at very critically. As a solution, what we’ve been doing is retrofitting electrical connectors with fibre optic connectors, which works. However, in some fields that is not an option and the type of connector also varies significantly, so there is surely no plug-and-play here!”

FIBRE OPTIC SENSING USING INTERVENTIONS

There may not always be a need for permanent installation of fibre optic cables, as existing tools sufficiently monitor production and pressure. In those cases, an intervention may be all that is required to obtain a dataset across that entire well path that would allow for immediate detection of leaks or identification of low-productivity reservoir zones.

Aberdeen-based company Well-SENSE have developed a methodology to effectively run well interventions using fibre optic technology. I visited operations manager Andrew Garioch at their facility to take a look in their workshop. It is surely a workshop, but it is nothing compared to the nuts and bolts nature of a conventional wireline tool workshop.

First of all, all the work is done in three mobile units that could be easily lifted and taken to any site in the world requiring their expertise. Secondly, nuts and bolts are quite rare because the tool is essentially an aluminum probe in which up to 30,000 feet of telecoms fibre optic cable is waiting to be unwound.

Deployment of the probe is also quite straightforward. It descends in the well through gravity. As an example, in a gas well it takes one minute and 30 seconds to reach TD at three kilometers depth. To push the tool in horizontal sections, pumping is the conventional methodology at the moment. “But we are working on a self-propelling mechanism that also takes away the need to do that”, says Andrew.

And what happens after data acquisition? “The aluminium probe will degrade in a matter of days, out of the way in the rat hole at the toe of the well”, says Andrew, “so there is no need to retrieve anything.”

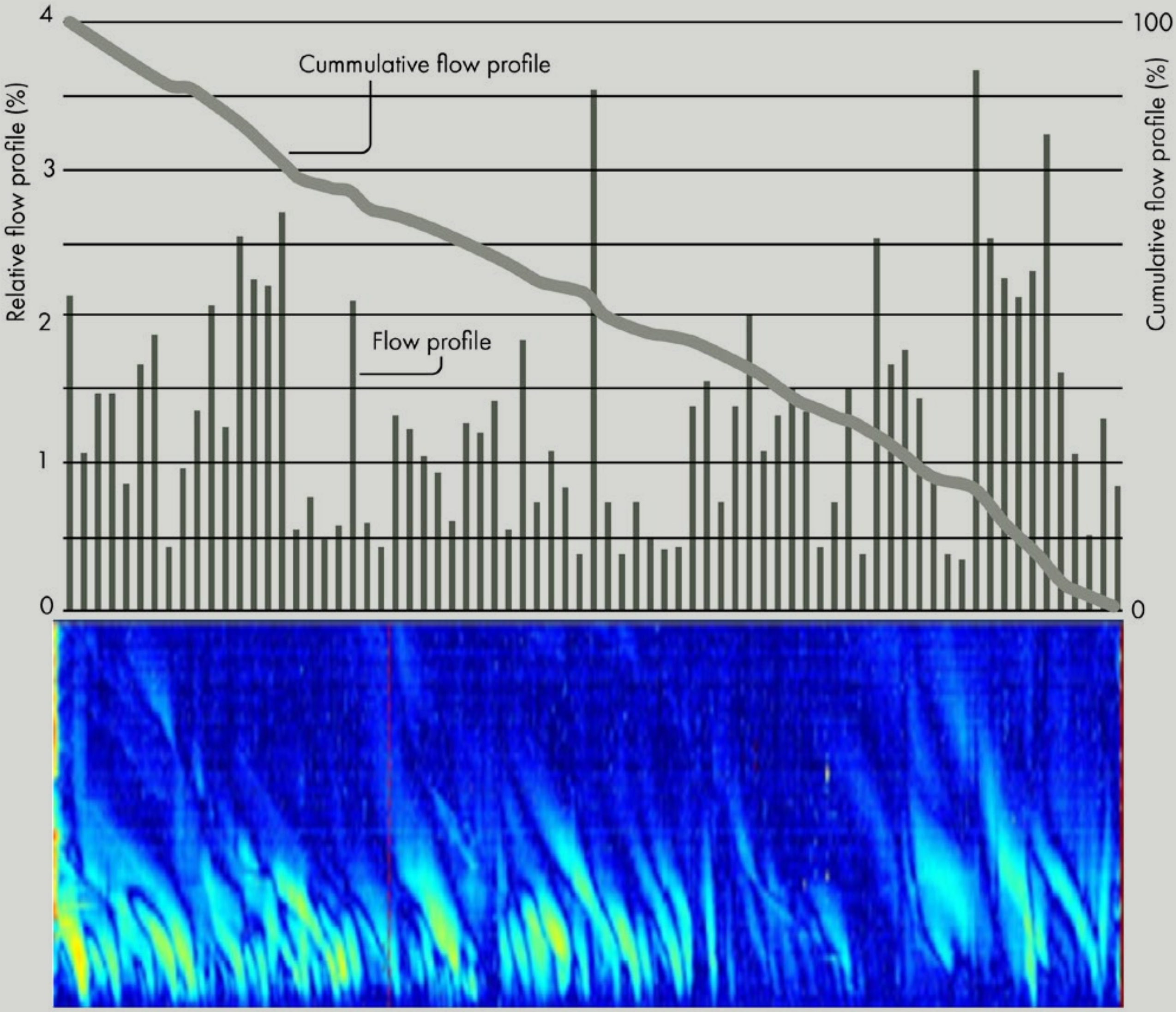
But, what looks like a great advantage has also resulted in questions, particularly from people in HSE. “What if we see the probe or fibre lift in the wellstream and compromising equipment?” is a question he sometimes gets. “My answer to that is twofold, says Andrew. “First of all, sand production is probably more “erosive” than the fibre left behind and second, if there is a concern about debris we can make the probe even more dissolvable, further reducing the risk.”

One example where interventions using fibre optics were really instrumental is when leaks occur as intermittent bursts after a phase of pressure build-up. “Conventional logging tools can easily miss such an event, but fibre optic sensing will always detect these, because of the full wellbore coverage provided by DFOS”, said Andrew. “And, we can usual- ▸

RESERVOIR SECTION

If fibre optic cables are being used for seismic data acquisition or leak detection in the overburden, the cables don’t need to be run through the reservoir section. That is different from when the technology is to be used for inflow monitoring and detection of non-productive zones or water breakthrough. In that case, the cables must be run across the reservoir section. However, that is not a trivial thing.

“It is the connection between the lower and upper completion, with the production packer as the barrier in between, that poses the challenge to get fibre into the reservoir section”, says Garth. There is no straightforward solution for that yet, especially on subsea wells, which is why there are several research groups at the moment working on that. “Once a technical solution has been found for this, I expect that the market opens up even more.”



Low-frequency DAS data is dominated by strain signals from depressurizing reservoirs and thermal components from fluids entering the wellbore (below). Various methods can subsequently be used to derive production profiles along the completed reservoir (above).

SOURCE: LUNA

APPLICATIONS IN CCS

It is the long operating life and the simple design that have caused fibre optic sensing to appear on the radar for CO_2 monitoring. With requirements to keep on monitoring CO_2 plumes until long after injection has finished, there is an obvious niche for the technology.

In an oil or gas field, the most important changes in the field's behaviour will be observed within the first three to four years from the onset of production. In contrast, in CCS the most critical phase in the lifetime of an injection project will be the tail end of the production cycle, as it is at these moments that integrity issues could start to play up, or plume behaviour may start to deviate from expectations. In addition, with any CCS project, there will be the requirement to keep on monitoring until after injection has ceased. "That's why the lifetime of sensors is more critical in a CCS project than in an oil and gas project and that's where fibre optic sensing comes in, because the material's lifespan is much longer than electrical sensors", says Garth.

And it is not only the seismic mapping of plume migration that fibre optic sensing can help with, it is also the recording of strain – so induced seismic events – and temperature. Strain measurements in particular are a vital aspect of CCS monitoring, given that induced seismic events have occurred in a number of CCS injection projects. The Castor site in Spain is a well-known example, where seismicity was observed within days after the start of injection, and continued until after injection had stopped due to movement of the pressure front. "It reiterates the need to keep on monitoring after injection has ceased", Garth says. "This year, we will be working with Perenco to monitor their injection trial in the Leman depleted gas field", he says. "As such, it will also be the first case of CO_2 injection into the UK North Sea."

ly report the results of the measurements back to the client in as little as an hour after deployment", concludes Andrew.

"Our market is expanding significantly at the moment", Andrew says. "We have recently had a lot of wins in Australia, and there are new opportunities in the mining sector. "The North Sea is a bit slower with reduced intervention activity and financial restraints associated with the windfall tax."

IDEAL FOR MACHINE LEARNING

With a single well being able to generate up to two Terabytes of data per day, how do you process the data? It is clearly one of the challenges the fibre optic monitoring industry is facing. "Believe me", Andres says, "I know companies that have shared years of fibre optic sensing data with me that no one has looked at, because it has not been processed."

> "In a way, it comes down to the ability to spot the discrepancies in the data stream straight away and put a little alarm bell on them."

"If there is one subsurface technology that lends itself for data crunching using machine learning algorithms, it is the data that come out of DAS cables", adds Garth. "The breadth of possibilities in DAS data is endless, as well as the size of the data stream. There is a lot of talk about digitalization", he continues, "but you do need data to feed the algorithms." Fibre optic sensing clearly provides this challenge, both in the data bandwidth as well as the rate of data generation realms.

"First of all, after a certain amount of time", says Andres, "data may be deleted if the analysis has shown that nothing is wrong in the well." But before that decision can be made, the data need to be analysed. "For that reason, we have focused on real-time processing in recent years, in order to get information on temperature, strain or acoustics to the relevant people at an operator. "In a way, it comes down to the ability to spot the discrepancies in the data stream straight away and put a little alarm bell on them", says Andres.

But how long do you keep the data? "It depends on the project we work for, sometimes it is a couple of weeks, and sometimes it is a month's worth of data", Andres explains. "Filtering the data is a great way of reducing the volume", he continues. "For instance, once you know at which frequency you see the response from a gas lift valve, you can isolate these through frequency decomposition and save these as snippets of the entire recording. These snippets are much easier to handle and can therefore be kept as long as the field is in production."

Another way of limiting the data that needs to be processed or kept is decreasing the sampling rate. "An example is DAS, where thousands of light pulses are being generated every second, let's say at 10 kHz", says Andres. "Especially for leak detection, we don't need to look at the data with such a frequency, and therefore down-sampling takes place to up to a frequency of 0,01 Hz. It is what we call low-frequency DAS, and the result is a fraction of the size of the original datasets."

"We have found that by far the best approach is to do this straight away at the data interrogator where the data come in, and process it in real time. First storing the data on a drive and then process it introduces another level of complexity that you'd really like to avoid", Andres says.

Silixa offers a similar solution. "Rather than sending all the data to the cloud, we analyse it on the spot, right on the platform at the well head, and only transmit the data that have flagged something of interest", says Garth.

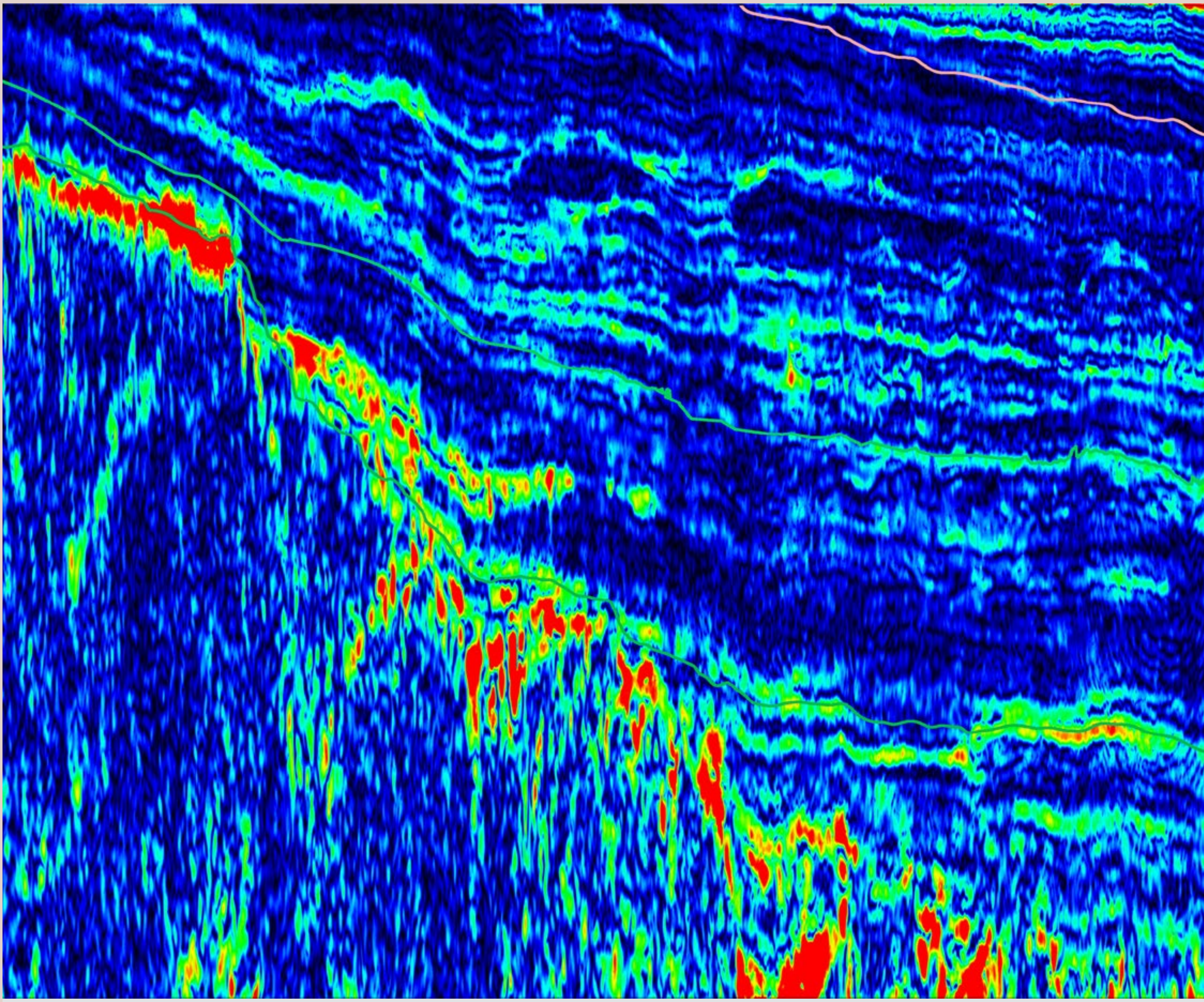
GEOTHERMAL

"The geothermal space is also an important market for us", says Garth. "We have clients in Türkiye and in the USA, where we operate in temperature ranges that would be difficult for electrical sensors to cope with." In geothermal, temperature measurements are obviously an important aspect of the data suite for monitoring temperature breakthrough, but especially in the US, where reservoir stimulation takes place in a project such as Utah Forge, we also detect fractures and inter-well flow connection." "It is exactly the same technique that is also being used for the unconventional space in the US shale gas sector. Using fibre optic sensing, we can illuminate the fractures, and see fluid communication from one well to the other. This provides a wealth of information on the performance of these systems", Andres adds.

"Some companies have their own software and analytical tools to analyse the fibre optic data", continues Andres. "We just supply the hardware and they do the rest. Others are lacking that expertise, and that's where we can help with our analytical solutions. But even with the most experienced users, there will always be aspects to the data that need looking at in a more scientific way because it is not entirely clear what it means. At the end of the day, the technology is still fairly new and evolves rapidly, leading to more and more events that detected – and more and more events to be then needs an explanation", Andres adds.

So, the capabilities are surely there. "I wouldn't say it is complete, especially when it comes to standardization and integration with other types of data such as well logs, but there is certainly a solution in place that allows data to be rationalized." ■

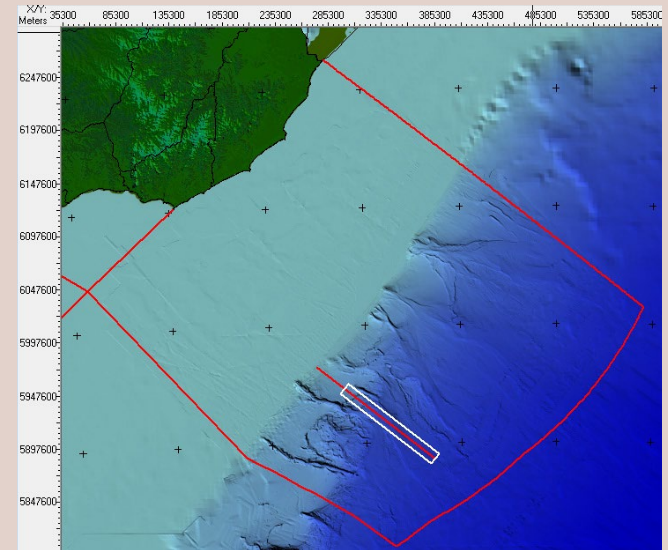
Why the conjugate margin in Uruguay and Southern Brazil may have even more to offer than the Orange Basin in Namibia

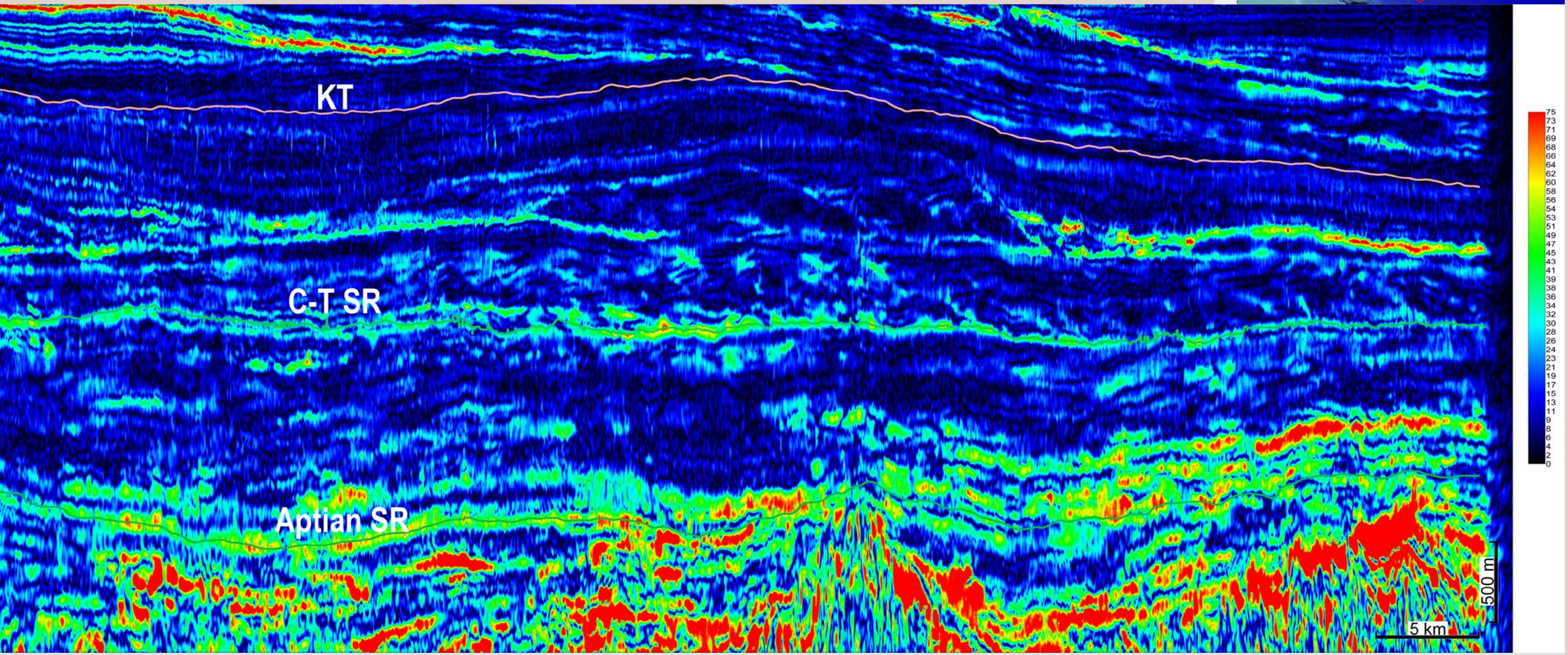


Punta del Este BG12 3D seismic line, reprocessed between 2013 and 2014. The sweetness attribute, which emphasizes reflectors with high amplitude and low frequency, highlights the potential Cenomanian-Turonian SR and other potential oil & gas accumulations.

The success of the Orange Basin in Namibia is mostly thanks to a thick Aptian drift source rock. However, it suffers from a lack of overburden for its Turonian source rock, leaving it immature. In contrast, not only are the Aptian and Turonian source rocks present in the Uruguay and Southern Brazil conjugate margin as well, but both are buried deep enough to be mature. The advantages of Namibia are therefore not unique to Gondwana's rift margins, but actually may be surpassed by twin blessings of mature Turonian and Aptian source intervals in the as yet undrilled Pelotas and Punta del Este Basins.

In support of this, Neil Hodgson, Karyna Rodriguez and Lauren Found from Searcher and Pablo Rodriguez and Bruno Conti from ANCAP show evidence from a recently reprocessed CSEM dataset that suggests the presence of resistive undrilled reservoirs at an analogous level to the Upper Cretaceous Graff and La Rona discoveries in Namibia.





Gondwanan break-up-basins and their multiple source rocks

The advantage of Namibia's conjugate margin in Uruguay and Southern Brazil is likely to be the sand and clay deposited by the Rio Grande

NEIL HODGSON, KARYNA RODRIGUEZ AND LAUREN FOUND, SEARCHER, AND PABLO RODRIGUEZ AND BRUNO CONTI, ANCAP

IN THE FACE of the embarrassment of riches discovered in the Namibian Orange Basin over just the last two years, one might speculate that had F. Scott Fitzgerald been trained in geology, the Great Gatsby might have opened as follows. "In its fragmented later years, Gondwana gave the Namibian passive margin some advice: "Whenever you feel like criticizing any other basin", she said, "just remember that the other basins in this world haven't had the advantages that you've had."

However, if Fitzgerald would have written that - he would have been mistaken.

Indeed, each of the passive margins fabricated during the fragmentation of the Gondwana supercontinent formed with identical processes - crustal thinning, extensional rifting resulting in the formation of lakes, rift volcanism, Seaward Dipping Reflectors (SDR) creation, rift-unzipping and marine incursions. These phases encompass several source rock-forming periods at times when standing water became anoxic, thus leading to the preservation of organic material. This tends to happen both during the syn-rift lacustrine phase as well as after marine incursions into the rift during the late syn-rift to drift phase.

It is the latter of these that has captured headlines in recent years with the discoveries in Namibia proving the presence and effectiveness of a prolific drift-source rock of Aptian age deposited on both SDR volcanics and oceanic crust in the deepwater Orange Basin. A simplified model for this Aptian drift source rock is that subsidence and marine incursions of a subaerial flood-basalt plain through a restricted connection to the marine ocean generated an embayment that was only around 150 km wide. Here, relatively shallow waters became repeatedly anoxic, allowing organic material to be preserved.

As the tip of the incursion moved north, flooding into successive lakes, the timing of onlap of anoxic deposits young in that direction too. However, the process of creating successive restricted basins is broadly the same. Only when full connection to circulation of the global ocean is established does this become more unlikely, except during periods of Global Anoxic Events (GAE). This concept was first proposed by Seymour Schlanger and Hugh Jenkyns arising from finding black, carbon-rich shales in

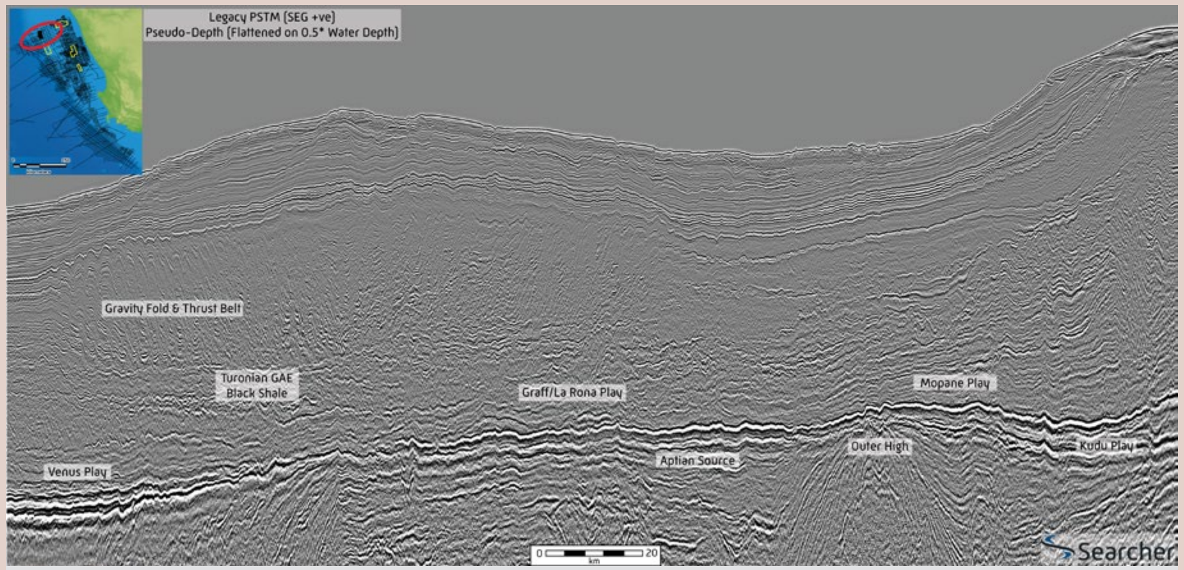


Figure 1: Orange Basin Example: Aptian Drift Source Rock on basement and Turonian Global Anoxic Event (GAE) source below the Gravity Driven Fold and Thrust Belt (GDTFB).

Cretaceous sediments in the Pacific, which they linked to similar, identical aged deposits from the Atlantic Ocean and known outcrops in Europe.

By the late 1980's, the Turonian GAE had been penetrated by numerous wells offshore Namibia, attesting to the veracity of the model. In Namibia's Orange Basin, the Turonian black shale overburden is mostly too thin to generate oil or gas, and only the Aptian is thermally mature outside of the interior syn-rift grabens. It is possible that beneath the famous Gravity Driven Fold and Thrust Belt (GDTFB) (Figure 1), the decollement surface is such a Turonian shale, just starting to mature and lose viscosity which – together with dynamic topography tilt - is what sets off the GDFTB.

Explorers can use this example of dual source rocks to explore the basins in the Atlantic that have not yet been explored. GAE black shales and drift-source black shales can both be ubiquitous within Gondwana's rifted basins. It is no surprise that Turonian and Aptian source rocks are responsible for 29% of the petroleum accumulations in the world.

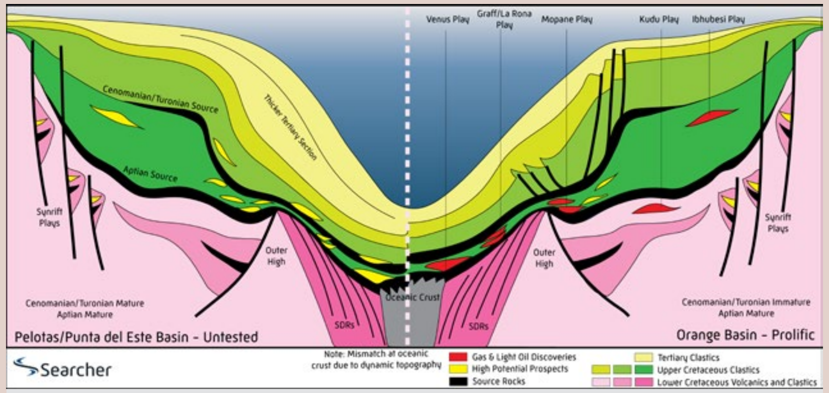


Figure 2: Aptian and Cenomanian/Turonian (C/T) source rocks model across the conjugate Orange and Pelotas Basins.

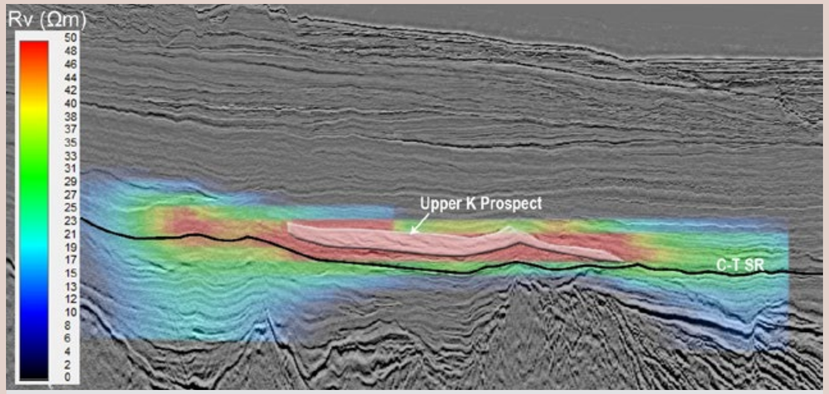


Figure 3: Co-rendering of vertical resistivity and seismic amplitude in a dip section through the Cretaceous prospect.

TWIN SOURCES OF THE PUNTA DEL ESTE BASIN

As the Aptian drift-source was deposited in a narrow restricted marine basin, it is not unreasonable to look for it not only in the Namibian Margin, but also in its less explored conjugate – the Uruguayan and South Brazilian Pelotas and Punta Del Este Basins.

The Punta del Este basin, located in the southwestern Uruguay offshore sector, shares similarities in its geology and hydrocarbon potential with the offshore Namibia Orange Basin. Seismic evidence for Aptian and Turonian source rocks includes identification of regional high-amplitude soft kick events associated with AVO Type IV anomalies, considered to be a positive source rock character. Similar events were identified offshore Namibia, which indicated the presence and maturity of a world class source rock. The key difference in the western conjugate is that both the Turonian and the Aptian are buried deep enough to be mature for hydrocarbon generation (Figure 2), mainly due to a thicker Tertiary section thanks to a high rate of sedimentation coming from the Rio Grande Cone.

To aid seismic identification of thick Aptian drift-source and Turonian GAE source rocks, ANCAP and EMGS have ingeniously reprocessed CSEM (Controlled Source Electro Magnetic) data with a novel Gauss-Newton inversion that allows resistive layers, such as those rich in organic material, to be imaged. The recently shared examples of reprocessed CSEM data (Rodriguez et al 2023) demonstrate the presence of resistive undrilled reservoirs at an analogous level to the Upper Cretaceous Graff and La Rona discoveries in Namibia's Orange Basin. Below this geobody there is a more subtle anomaly, but covering a large regional area which correlates with an AVO type IV anomaly suggesting it is detecting Turonian source rock (Figure 3).

The success of the Namibian Margin is derived from being blessed with a thick Aptian drift-source rock. However, it suffers from a lack of cover for its Turonian GAE source rock. The Conjugate Margin in Uruguay and Southern Brazil however not only has a thick Aptian source and a Turonian source, but BOTH are buried deep enough to be mature. The advantages of Namibia are not unique within Gondwana's rift margins but actually may be surpassed by twin blessings of mature Turonian and Aptian source intervals in the as yet undrilled Pelotas and Punta del Este Basins.

ACKNOWLEDGEMENTS

Authors would like to thank ANCAP and EMGS for providing access to data and allowing disclosure of the presented seismic and EM derived resistivity image.

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NORTHWEST EUROPE

"I wonder if success rates and profitability have actually been too high."

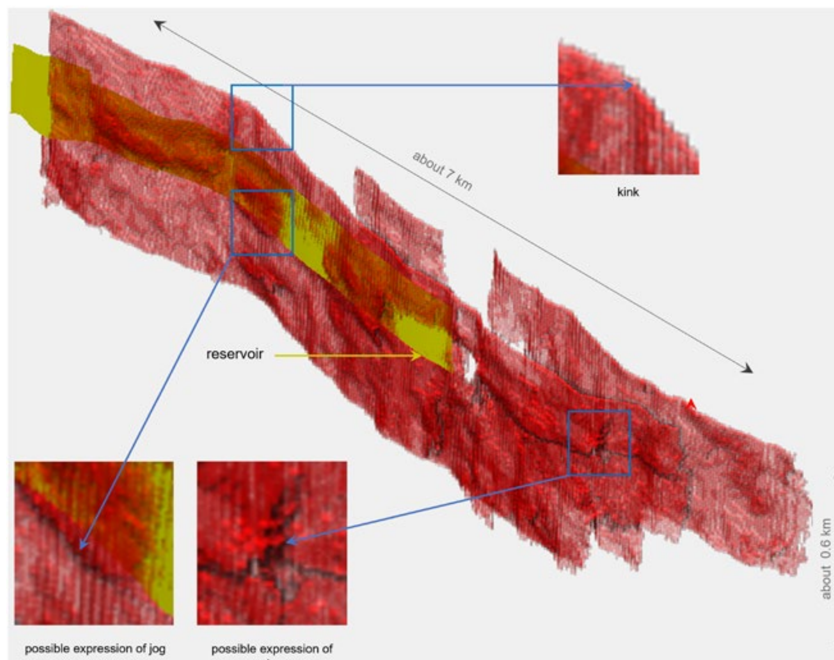
Anders Wittemann – Wittemann E&P Consulting

Not as straight as we sometimes think

In schematic diagrams, faults are often drawn as nice straight lines, but a new study on the Groningen field in the Netherlands suggests that this is too simplistic. Faults are more likely to be irregular, which has an important and positive implication in the Groningen case

Of course, field observations have long shown that faults are not the perfectly straight lines we often see in schematic cross-sections. However, subsurface data do not always allow the detailed interpretation of faults, especially at the depths where oil and gas reservoirs are often found. A small step or jog in a fault can easily be beyond the resolution of the seismic data, and especially land seismic is often not capable of resolving this matter of detail.

Rick Wentinck and Marloes Kortekaas published a paper in the Netherlands Journal of Geosciences recently in which they investigated fault irregularities in the Groningen field, the largest gas field in NW Europe that has recently seized production because of induced seismic events.



A detailed interpretation of a major NW–SE 7 km long fault in the Groningen field. The green surface gives an impression where the fault runs through the reservoir between a depth of 2.9 and 3.1 km. The fault shows possible expressions of sharp kinks along fault strike and of jogs along fault dip.

SOURCE: WENTINCK AND KORTEKAAS (2023)

Upon close inspection, the 3D seismic data revealed the presence of kinks, jogs and steps. However, these observations were made close to the seismic resolution and ideally would need more evidence to indicate their presence. Modelling work that was subsequently carried out did exactly that.

One important observation from the analysis of induced seismic events in the Groningen field is that ruptures have so far been limited to the Upper Permian reservoir. In other words, no propagation into the Carboniferous succession directly below the reservoir has taken place. The modelling work performed by the authors now suggests that it is fault irregularities that could be responsible for preventing ruptures to propagate further down, thus providing another hint of their presence.

The fact that ruptures have not propagated further into the underlying Carboniferous is a good thing. The authors write that if this had happened, it may have led to much stronger earthquakes in the Groningen field than what has been observed already.

Is the modelling work now full proof of the presence of fault irregularities? No, other mechanisms can equally explain why ruptures did not propagate into the Carboniferous. For instance, fault zones in the Carboniferous might have sufficient cohesion strength or they are experiencing a greater horizontal stress than was previously assumed.

But, reflecting on what field observations have already shown, it does make sense to assume that faults in a reservoir buried at 3 km depth show similar characteristics. If modelling subsequently includes these observations to arrive at an explanation of observed phenomena, it is tempting to think that the research is looking in the right direction. ■

Henk Kombrink

Increase risk!

In recent years, oil companies on the Norwegian continental shelf have focused on exploring for small volumes close to producing fields. It has been profitable but contributes little to maintaining the long-term production stability

RONNY SETSÅ

"HAVE WE run out of new ideas?", asked Kjersti Dahle from the Norwegian Offshore Directorate (NOD) rhetorically during her keynote speech at the recent NCS Exploration Strategy conference in Stavanger.

In previous years, the focus of oil companies operating on the Norwegian continental shelf has been on near-field exploration. The strategy is logical and profitable. Small discoveries that can be quickly put into production by being connected to producing fields are often very profitable with a short payback period, while also helping to extend the life of the larger fields. In many cases, near-field discoveries also contribute to reducing emissions per barrel for the fields they are connected to.

Dahle showed that between 2018 and 2022, the share of near-field wells on the NCS was 77% (121 wells). Only 23% of the wells (36) aimed to make discoveries in new areas.

The statistics agree well with several of the major companies' corporate goals - 80 percent of the wells are to be drilled close to existing fields, 20 percent are to be drilled to de-risk new areas.

But even though near-field exploration is lucrative, it does not significantly contribute to increasing proven resources. If resource growth is low, the fall of NCS production between 2030 and 2040 will be dramatic.

High resource growth therefore requires more exploration in frontier areas. Dahle urged companies to do more exploration in the Barents Sea in particular, where the NOD believes most of the prospective resources are situated.

Anders Wittemann.

Kjersti Dahle.

PHOTOGRAPHY: SIMON ØSTERÅS

"I wonder if success rates and profitability have actually been too high."

Anders Wittemann from Wittemann E&P Consulting confirmed that the Norwegian continental shelf is a profitable place for those engaged in exploration. For every kroner invested in exploration wells in 2023, companies have returned 3.20 kroner in the form of discovered value. After tax.

In light of the focus on near-field exploration, Wittemann wondered if success rates and profitability have actually been too high, providing no incentive to go after the big ones in frontier areas.

"Yet, there has never been a better time in history to conduct high-risk exploration", argued Wittemann. And by that, he meant gas, because Norway has become Europe's most important supplier of it.

"Companies have high profits, there are good prospects for sustained high gas prices in the future, we have pipeline capacity, Norwegian gas has much lower emissions than imported LNG and the NOD tells us that there are large remaining resources to be found on the Norwegian continental shelf", he summed up. "I've got one piece of advice in that light", he concluded: "Increase risk!" ■

No more drilling on Forties and Beryl – a perfect storm for the UK's energy security?

David Moseley from Welligence reflects on the consequences of Apache's decision to stop drilling on two of the UK's flagship oil fields

"I WOULD NOT call it a perfect storm", concludes David Moseley, vice-president operations Europe at intelligence firm Welligence at the end of his Aberdeen Energy Talk in January. He has just shown that the effect of bringing forward Cessation of Production (COP) at Forties and Beryl will of course have an impact on the volumes of oil produced from the UKCS, but that there are more pressing issues at the moment.

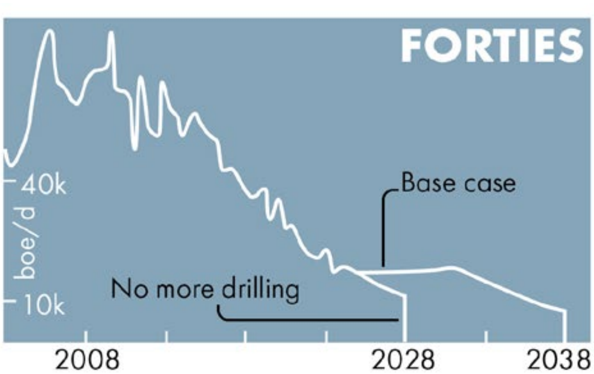
But to get back to Apache's decision, "It signals a complete shift in strategy", David added. The company entered the North Sea 20 years ago with the acquisition of Forties in 2003 and Beryl in 2012. And if one operator has lived to the mantra "maximizing economic recovery" (MER), it is Apache. Even though the company "only" operates two out of the current 59 producing hubs in the North Sea, it has produced the fifth most reserves in the UK since 2012. That is primarily thanks to a very active approach to drilling and development. Not only did Apache successfully explore for near-field volumes and brought these online in record time, it also drilled many infill wells on Forties and Beryl themselves.

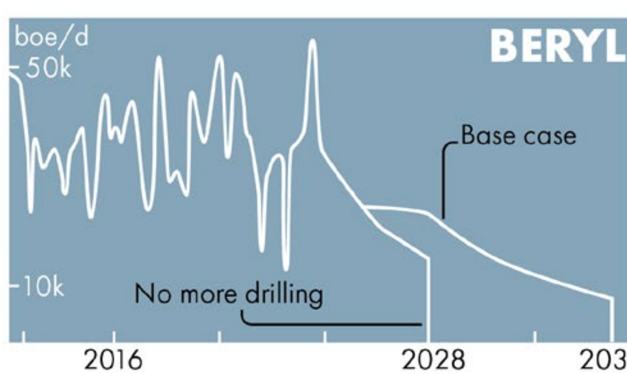
However, despite its success in arresting the decline, there is no getting away from the fact that the pipeline utilization of the Forties and Beryl hubs is low. "Let's remember that a field like Beryl once produced north of 150,000 barrels per day", David reiterates, "where nowadays it sits at around 20,000 barrels per day." Of course, this is the case for most hubs, but it shows how operating costs and emissions produced on a per barrel basis have been rising.

And with the shift in strategy of the regulator towards more scrutiny on emissions and a push for operators to electrify assets, it is no wonder that Apache HQ felt that their aggressive MER strategy did not align with government policy anymore. When the government introduced and then revised the EPL, such that it is now charged at 35%, it is no surprise that many companies reacted, especially those with big production portfolios such as Apache. Options to offset the EPL through capex are limited for many companies that have limited exposure to material development projects.

So, what is the consequence for the Beryl and Forties hubs themselves? David showed that ceasing future drilling at the Beryl and Forties hubs could result in around 70 MMboe of undeveloped volume remaining in the ground, with Beryl also having three undeveloped satellites adding a further 45 MMboe set to go undeveloped. This is not the best example of maximizing economic recovery for sure, but against the production profile of the UKCS as a whole, it is not too big a dent either. Let's see if another company sees opportunities. ■

Henk Kombrink





Production profiles in a previous base case scenario where drilling on Forties and Beryl would continue versus the current situation where no further drilling takes place. Based on data from Welligence Energy Analytics.

The price says it all

A back-of-the-envelope calculation shows how incredibly cheap fossil fuels are in comparison to geothermal and wind

HENK KOMBRINK AND MARIËL REITSMA

If one would look at the amount of news generated by energy transition projects compared to fossil fuel projects, we all know who the winner is. Society and governments are very focused on making progress on renewable energy generation, and that is for good reasons.

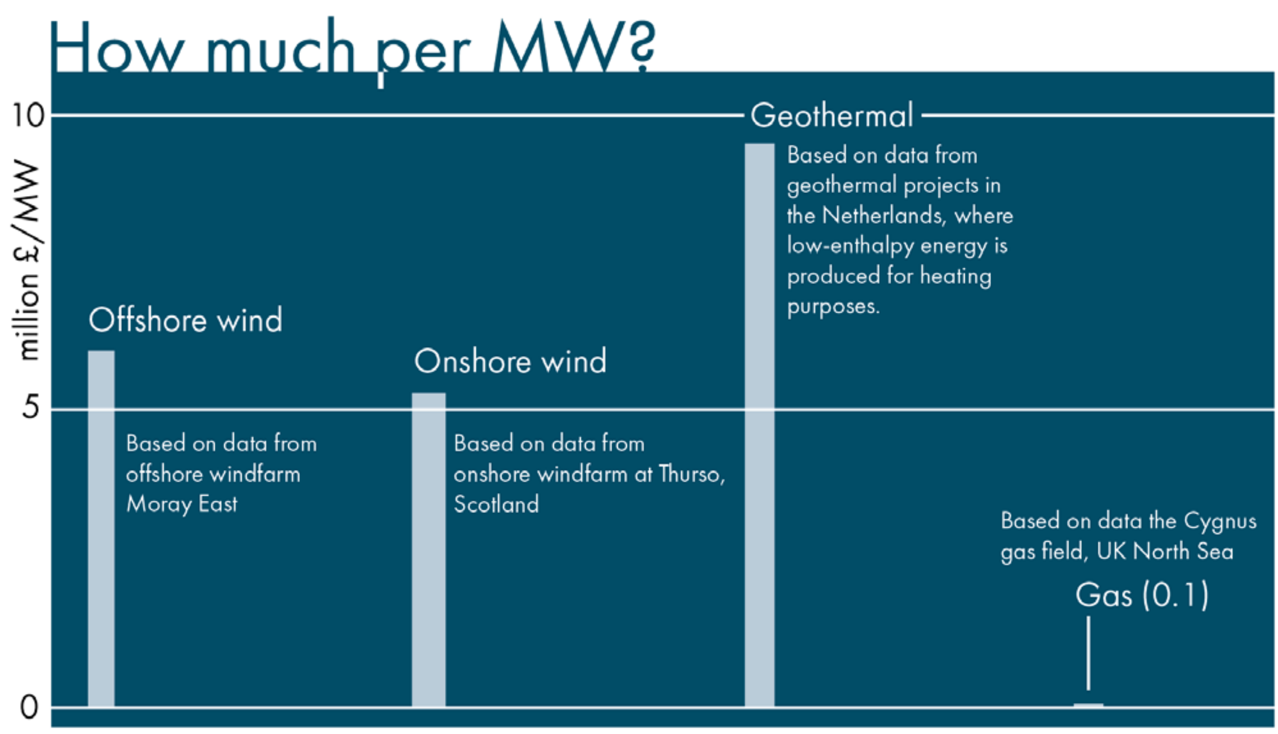
But at the same time, let us not forget that our society is built on fossil fuels. And it is good to add to that: Cheap fossil fuels. We performed a quick analysis that illustrates this by comparing the costs of drilling a geothermal and gas well and the construction of a wind turbine to the amount of energy these three energy producers provide. For simplicity, we ignored the infrastructure required for these projects, so this analysis only looks at the costs of drilling a well or putting up a turbine.

Let's take an offshore gas development in the North Sea as an example. Even though drilling a development well easily costs £40 million, the energy that one good producer well can be responsible for on a MW basis is around 425 MW, which takes us to a price of around 0,10 m£ per MW.

Onshore geothermal wells are cheaper than offshore gas wells, but have to be drilled regardless and also need expensive casing to make sure that brines do not corrode the metal in a few years. An average geothermal project in the Netherlands, where a fair amount of doublets have been drilled in recent years, is around £18 million. Given that one doublet produces around 2,3 MWe, we arrive at 9.5 m£ per MW. An offshore wind turbine is cheaper and arrives at 6 m£ per MW.

The conclusion is clear. Even though these calculations are based on a quick analysis and much more could be added to it, we believe it still sets the scene. The costs of energy per MW for a gas well are about 100 times as low as for a geothermal well. And it is too early to claim that geothermal and wind, once built, do not need maintenance and will not incur costs – so far the lifespan of these systems is very comparable to a gas well.

It is therefore important to be mindful of the costs of the energy transition. It is maybe no surprise that in Scotland, where most of the electricity is generated by renewable sources, electricity is three times as expensive as the price of gas. ■



FEATURES

"But then we realized that this is mostly related to oil, whilst 70-80% of my time at the moment is related to gas projects."

Moawya Abdallah – EXPRO

This is the time of subsurface by-products

As exploration for new subsurface resources diversifies, so is the chance of finding a product that may not have been the initial target but turns out to add an attractive element to the mix.

MARIËL REITSMA AND HENK KOMBRINK

Speaking to an Aberdeen audience about 10 years ago, Jon Gluyas argued that the North Sea oil business was in essence a water industry. Looking at volumes of produced water from many of the late-life fields across the area, he was right. And this is of course still the case. Thus far, using the 70-80ºC formation waters for something else than re-injection has never happened though. With markets for heat being too far away, the economic case is simply not there. But it highlights an interesting perspective on the oil industry and the potential of its by-products.

Talk about by-products is something that can be observed more often these days, with for instance hydrogen and helium being a close couple in places and geothermal and lithium in others. There are even some cases where the initial by-product appears to become the most important target of the operation.

By-products have always been around in subsurface projects. Think about the production of helium from American and Qatari gas fields. But with an increase in exploring for new natural resources, there seems to be an uptick in the number of cases where by-products are suddenly seen as quite important to make the economic case for the project as a whole.

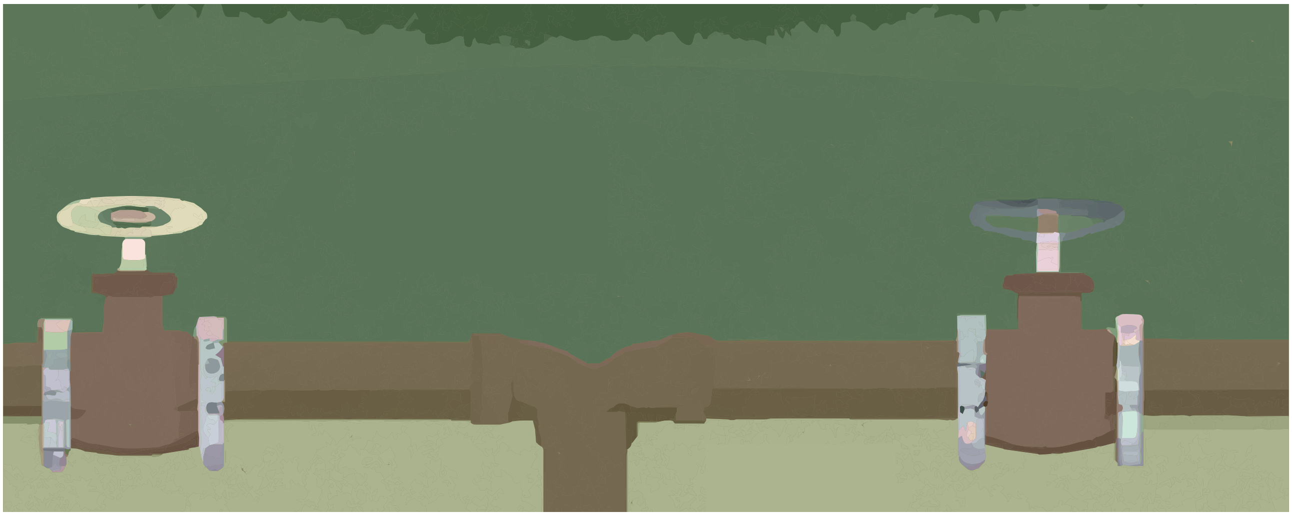
AUSTRALIA

The recent hydrogen exploration drilling campaign near Adelaide is an example of this. The company, Gold Hydrogen, suggested before drilling commenced that in case of success, the entire city of Adelaide could potentially be running on hydrogen from their acreage. As the results came in, even though hydrogen was found, helium as a by-product crept into the press releases. Analysis of the geological data found thin fracture zones that allow hydrogen to seep towards surface, however, the volume and production potential of the actual reservoir they connect to is still questionable. So it is no surprise that the 6.8% helium concentration became a more prominent feature in the reporting. Helium is a much more valuable gas and even small volumes can be economically produced.

UNITED DOWNS

The United Downs geothermal project is another example where the focus has diversified. Initially drilled as a doublet to produce electricity from 160º C brines from a major fault zone in granitic basement, it turned out that lithium concentrations in the brines are quite high. Now, the project also looks at ways to extract the lithium from the brine. And with the wells producing only up to 2 MWe, there must certainly be an economic driver to capitalise on another ingredient of the produced brine.

Maybe the geothermal water produced in the North Sea can be used after all. The UK government's net zero targets require the first offshore installations to eliminate their carbon emission by 2030 and harnessing latent geothermal heat could contribute to this. ■



Some projects may need two production lines in the future.

IMAGE CREATED BY DALL-E

Chasing giant oil prospects on the Arabian Platform in southeastern Türkiye

The recent discovery of more oil in the Zagros Fold and Thrust Belt has re-ignited exploration efforts despite the complex geology

MEHMET AKIF SUNNETCIOGLU, TUGBA OZDOGAN, TUGRUL ULUDAG, ELIF UZ, AHMET ERGUN GENIS, MEHMET SAHIN, GOKHAN KOSE, SEZER TURK, AHMET POSTAAGASI, UMIT NAYIROGLU, YUCEL DENIZ ERDAL, SEVGI KOSAL, TURKISH PETROLEUM

As part of the Arabian Platform, known as the most prolific oil province in the world without a doubt, southeastern Türkiye continued to be underexplored until recently. The USGS published several reports about the area in 2004, 2010 and 2012, estimating a total of 40 billion barrels of undiscovered resource potential for the complete Zagros Province. However, looking at the current state of play, the number of discoveries is lagging behind to reach that number.

Existing wells and surface geology of the northern margin of the Arabian plate in Türkiye have already proven that oil was generated and expelled from Jurassic to Lower Cretaceous source rocks, migrated through porous and fractured Cretaceous strata and were trapped in Miocene age folds and thrusts.

At the same time, there was an overall pessimistic view about the total resource and development feasibility of the discoveries, including from international oil companies. Therefore, majors exited the area, leaving only the national oil company of Türkiye (TPAO) to keep exploring with some local players.

Over the past five years, TPAO has put significant effort into further exploring the area. For instance, 3D seismic acquisition, despite the rough topographic conditions, has enabled a much better overview of narrowing down sites where to drill. These efforts have derisked the uncertainty and have resulted in giant oil discoveries in two structures with more than one billion barrel resource potential.

So, let's pose the question "Does the huge potential of the Arabian Plate petroleum system really extend toward southeastern Türkiye?", and try to give some possible answers from a geological perspective. ▶

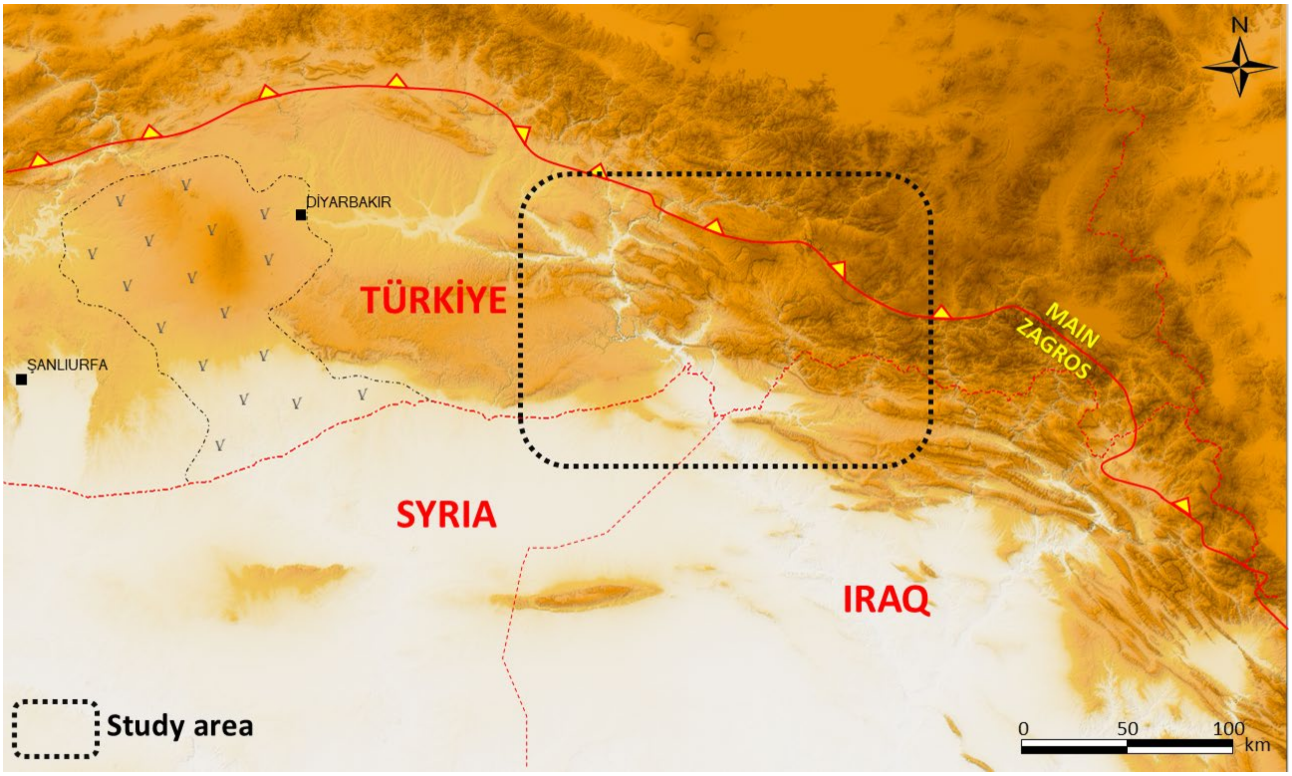
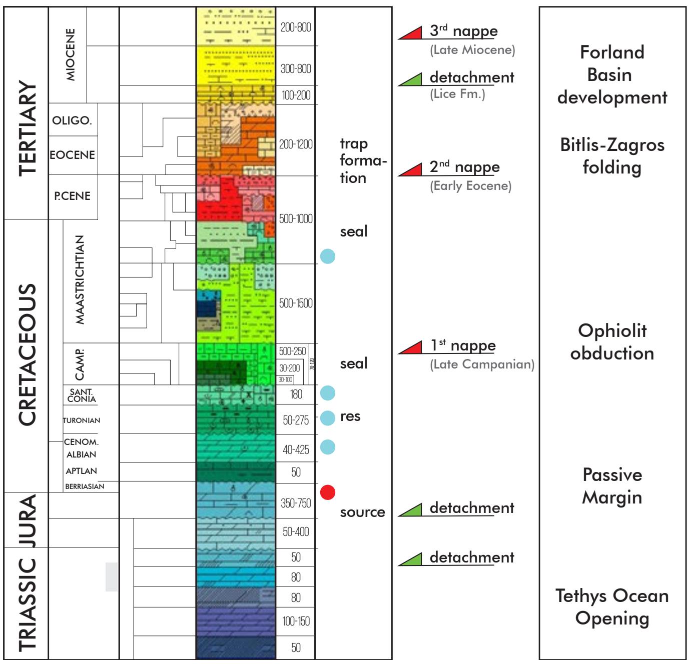


Figure 1: Overview of the study area in southeast Türkiye.

ZAGROS FOLD AND THRUST BELT

Tectonically, southeastern Türkiye is situated in the Zagros Fold and Thrust Belt. This thrust belt extends over 2,000 km in the northern part of the Arabian Platform. As the southeastern sector starts from the Oman-Hormuz Strait, the western end is represented by the junction of the East Anatolian and Dead Sea Fault Zones in Türkiye. The zone itself evolved progressively due to the closure of the Neo-Tethys Ocean between the Arabian and Eurasian Plates since the Late Campanian. Within a well-known tectonic zonation of the area, most of the prolific structures are located in the folded zone. Additionally, imbricated fault zones and allochthonous units are still under investigation.

Hydrocarbon System Summary



- **Sourse Rock**

  Jurassic and Early Cretaceous shales, clayey limestones (Sargelu, Chia-Gara, Şenoba Fms.)

- **Reservoir Rock**

  Cretaceous limestons and dolomites fractured and porous (Qamchatka or Mardin Grb.)

- **Seal Rock**

  Cretaceuos clayey limestonesand marls (Grmav Fm.) Oligocene evaporites

- **Trap**

  Miocene folds and thrusts

Figure 2: Overview of the key elements of the petroleum system in southeast Türkiye.

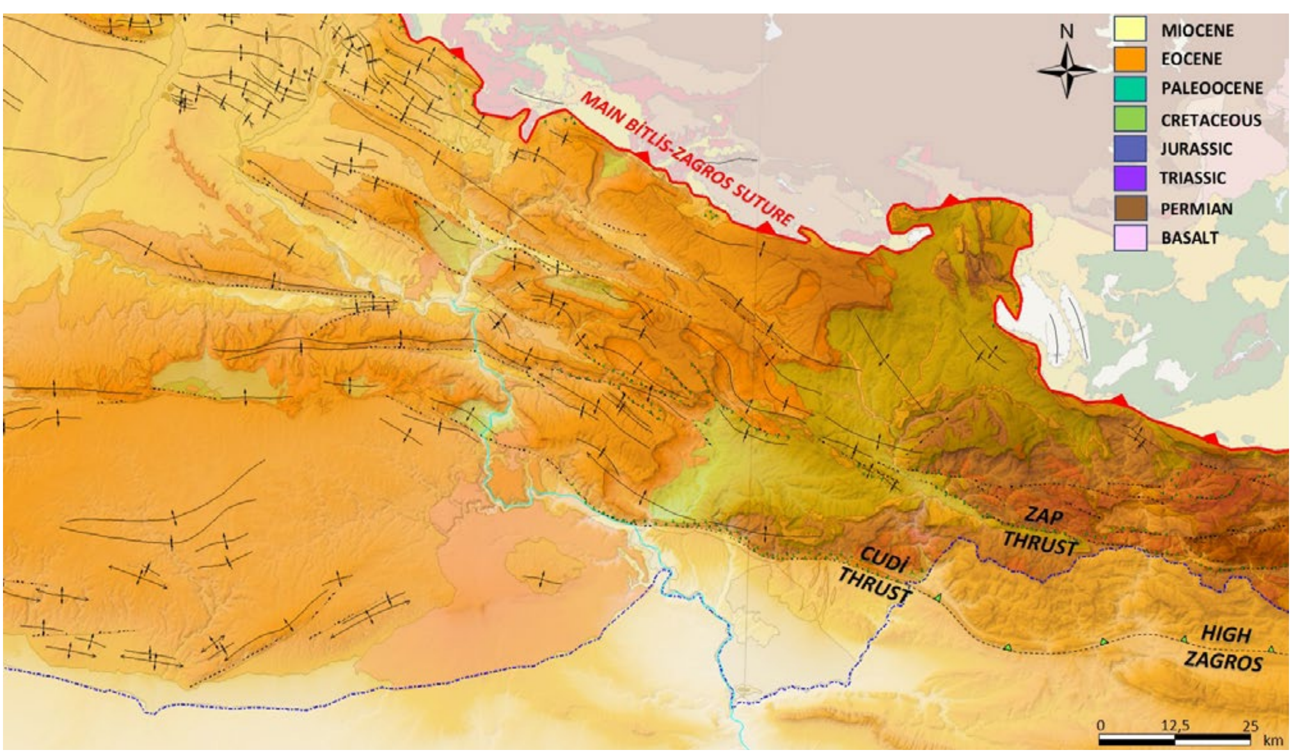


Figure 3: Detailed surface geology in southeast Türkiye. See figure 1 for location.

The folded zone of the thrust belt is characterized by prospective surface anticlines. These anticlines formed during the Bitlis-Zagros folding stage due to the continent-continent collision, commencing post-Eocene and becoming more intense during the Middle Miocene onwards.

As the surface is mostly covered by Eocene and Miocene sediments, Cretaceous carbonates are only partly exposed in the core of the anticline. They are oriented in a NW-SE or E-W direction and their axial traces show linear to curvilinear trends. Their shape changes from symmetrical to asymmetrical geometry and dimensions reach up to four to five km in the short axis and twenty km in the long axis. They are dominantly bounded by double plunging thrusts that formed above a relatively deeper detachment surface, e.g. Triassic evaporites or older. Each anticline is separated by Upper Miocene-Pliocene filled synclines and may represent en-echelon relay geometry in areal extent.

Widespread deposition of marine carbonates throughout the Cretaceous resulted in the formation of the reservoirs belonging to the Mardin Group, which are the major reservoir targets in the basin. The depositional environment of the Mardin Group limestones ranges from inner to outer ramp. Cenomanian-Turonian age thick highstand limestones are strongly affected by dolomitization and display evidence of subaerial exposure in addition to thermal dolomitization in the subsurface. Both dolomites and limestones are highly fractured, giving a strong contribution to production performance.

RAMPING UP

At the present day, daily production rate in the basin is quite low, as it stands at about 80,000 barrels per day. However, almost half of this production figure is from discoveries made in the last three years and based on the recent exploration results it is expected that production can be increased to up to two hundred thousand barrels per day in the next two years as further development plans have continued to progress.

Although the first discovery in the basin - the Raman Field – dates back to the 1940s, the recent discovery of two giant fields encourages focused exploration efforts and dedicated investments. When we revisit the question we asked above; despite the complex geology and the related uncertainty due to the highly tectonized nature of anticlines, there are still opportunities to find giant fields in southeastern Türkiye.

In addition, the existence of mostly undrilled low and high relief surface anticlines of 200 km elongation near the source kitchen are expected to be drilled in the next few years as new seismic data has become available. This could be the start of even more exploration success in near future. ■

References provided online

AN EXCELLENT SOURCE ROCK

During Jurassic and Cretaceous times, thick carbonate facies were deposited in passive margin settings of the Arabian Platform. During this time, sea-level fluctuations in conjunction with slow subsidence rate led to the formation of shallow intrashelf basins. Middle to Upper Jurassic organic-rich sediments of the Şenoba Formation accumulated in the basin as a source rock under anoxic conditions. Organic matter of the Şenoba Formation contains dominantly type-II and mixed type-II-III kerogens, showing that it is both an oil as well as a gas-prone source rock. Tmax and Vitrinite Reflectance (Ro%) values demonstrate that the formation is thermally mature and located in the late mature window. As the Şenoba Formation in southeastern Turkey can be classified as a good to excellent source rock, a wide spatial distribution of oil gravities has been found, ranging from 12° to 41° API in different oil finds.

Oil – and increasingly gas – on steroids

Impressions from the International Petroleum Technology Conference in Dammam

"WE WENT from two to nineteen mudlogging units recently", said a representative from Geolog at the recent IPTC Conference in Saudi Arabia. Almost 20,000 geoscientists and engineers came to Dammam in February, the place where oil was first found in Saudi Arabia in 1938. And whilst oil has been steadily produced from the Dammam field ever since, it is obvious that there is even more buoyancy for the industry in this part of the world at the moment.

Service companies are the barometer of the state of the industry, and the service company representatives I spoke to at the conference all shared a few important things: Saudi Arabia is changing, it is more open to business, it wants to attract in-house manufacturing and it is there for the long term. For some companies, this means a change in the way they are operating, but it surely means that there are possibilities in this country. And that is what drives confidence and motivation to be there for the long run.

Harald Førdedal from Interwell, a company that provides solutions across the lifecycle of oil and gas fields, shared the same vibe. "The country went from around 175 rigs in 2020 to around 330 today", he said. "Most of these rigs are being used for infill drilling into existing fields, and a smaller portion for well interventions." Drilling takes place both offshore as well as onshore, with the latter dominating the scene with around 250 rigs being active on land.

"I know British colleagues who have clearly expressed a wish to stay here, as the situation at home is just far from being rosy in terms of the oil and gas outlook."

A SENSE OF CHANGE

And it is not only a matter of foreign companies selling their kit in Saudi Arabia. Crown Prince Mohammed bin Salman Al Saud, or MBS in short, is busy changing the country to a place where the local economy is involved more, from using local agents to book travel with to manufacturing tools in the country. "MBS's objective is to make Saudi Arabia, as he puts it, "normal", writes the magazine Foreign Affairs in a recent article. He introduced a system to keep track of how much foreign companies involve local businesses, and the more points one collects the better the conditions to operate in the country.

PHOTOGRAPHY: HENK KOMBRINK

Obviously, the most prominent stand at the conference was Saudi Aramco's.

"For that reason", continues Harald Førdedal from Interwell, "our company is going to build a manufacturing workshop in Saudi, where previously this was done in Norway. This is an area of growth and a stable climate when it comes to oil and gas investments." By changing the way the company operates, it will be able to take part of that journey. "I know British colleagues who have clearly expressed a wish to stay here, as the situation at home is just far from being rosy in terms of the oil and gas outlook."

MORE DRILLING AND CORING

Alastair Craig from Core Lab shares the same sentiment. "The country has been opening up recently", he said, "and with formation damage being quite a common problem given that many wells targeting the carbonate reservoirs are being drilled overbalanced, there is the potential for a fair amount of formation damage project work." He also expects coring jobs to be picking up thanks to the drilling of more exploration wells.

BEYOND OIL

But what about the recent announcement to put a foot on the brake when it comes to producing more oil? "Yes, it caused a bit of a fright at the office", said Moawya Abdallah from EXPRO, the company that provides a range of well services in the region. "But then we realized that this is mostly related to oil, whilst 70-80% of my time at the moment is related to gas projects."

This is an interesting observation. Gas has become more important to the country in recent years, and EXPRO's project portfolio is a clear testament to that. "At the moment, gas is only used for domestic consumption in the country, but export is surely on the horizon too", said Moawya, "given the developments currently ongoing in the Jafurah field." The recent start of production of tight gas from the Ghawar field is another sign that gas production is higher on the agenda these days.

"But then we realized that this is mostly related to oil, whilst 70-80% of my time at the moment is related to gas projects."

Another reason to consider gas as a new entrant on the agenda of the Saudi government is the shifting focus on unconventionals. I spoke to several representatives from Aramco who work in this space, from exploration to development of unconventional reservoirs.

All in all, the picture that emerged from the various discussions I had at the conference is one of a country that wants to diversify away from oil, with a more open market that also benefits the local suppliers landscape. ■

Henk Kombrink

The location of the Dammam-07 well, which was the first to find oil in commercial quantities in Saudi Arabia in 1938.

A working petroleum system on purely oceanic crust

Drilling Jaca-1 in the Deep-Water Gulf of Guinea off eastern São Tomé and Príncipe Islands

CHRISTIAN NIÑO, PETRONAL, FRANCISCO SILVA, DIANA ROCHA, TERESA MARTINS, SARA PESTANA, GALP, AND MARTIN ZUBIRI, PAN AMERICAN ENERGY

For a long time, exploring for hydrocarbons in the deep waters of the Gulf of Guinea, east of the São Tomé and Príncipe (STP) islands, was not regarded as very attractive by the industry. The main reasons were the uncertainty regarding the presence of source rocks and the premise that this whole area was on oceanic crust and, therefore, under a cold thermal regime. This, coupled with the limited overburden, would make it difficult to mature any source rock. Not to mention the water depths being more than 2,200 m, with the associated logistical and operational challenges.

Galp is present in three exploration blocks in STP, being the operator in blocks 6 and 12, and partner in block 11 (Figure 1). Galp signed the PSC for Block 6 in November 2015 and is currently beginning the third phase of the initial three phases of the exploration term.

During the first exploration phase, Galp and Kosmos Energy acquired a large 3D broadband seismic of approximately 16,000 km^2 in a former partnership over Block 5, 6, 11 and 12, together with gravity, magnetic and bathymetry data. During this phase, oil samples from seeps were taken on the islands of São Tomé (Ubabudo) and Príncipe (Agua Clara).

The planning and drilling of the Jaca-1 well were the main activities during the second exploration phase. The primary objective of the well was to test a NW-SE elongated 4-way to 3-way dip closure of Turonian age. The

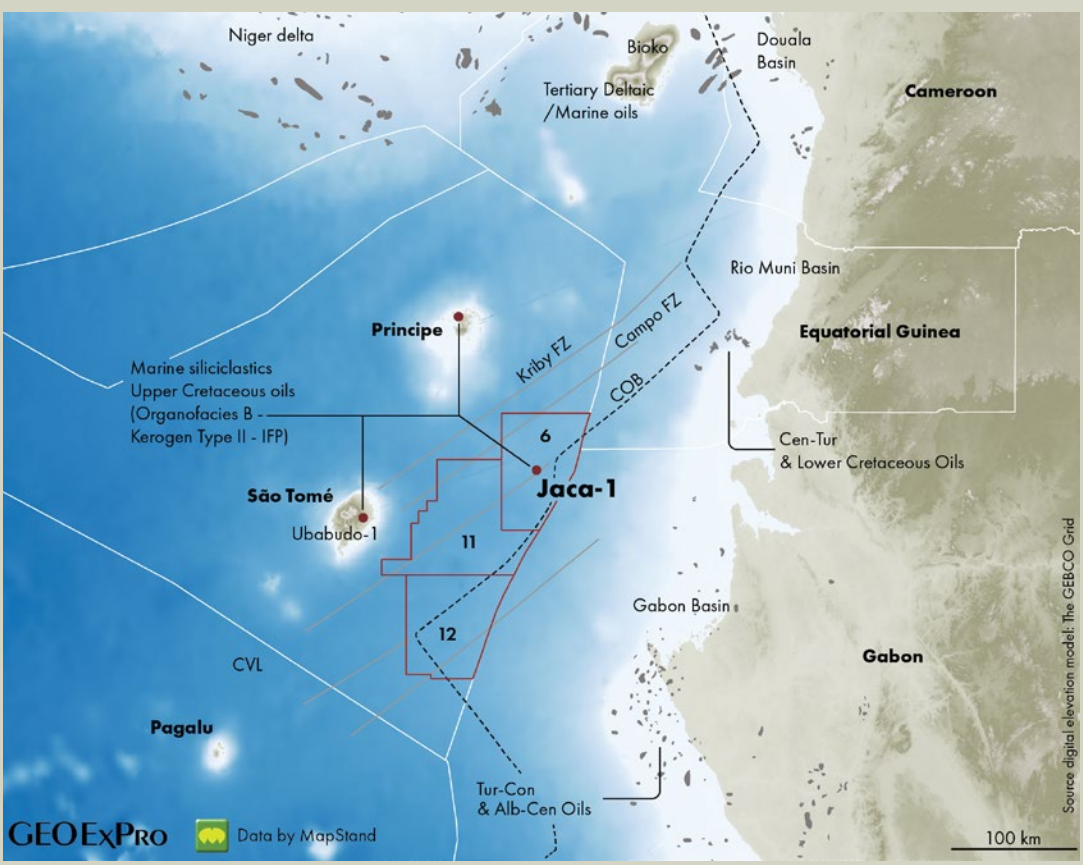


Figure 1: Location map of Galp exploration blocks in São Tomé & Príncipe, and main oil families in the surrounding basins.

well also had two secondary stratigraphic objectives of Campanian age. Another objective of the well was to drill the postulated Turonian and Cenomanian source rocks.

A PLEASANT SURPRISE

The well was spudded in water depths of approximately 2,550 m and safely drilled under a Technical Service Agreement with partner Shell in remote operating conditions to a total depth of 5,658 m MD.

The thermal regime observed at the well was slightly higher than the pre-drill estimation, which was a pleasant surprise. This is particularly noteworthy as no wells had been drilled in a purely oceanic crustal domain setting in this part of the Gulf of Guinea before.

Jaca-1 drilled a thick Upper Cretaceous sandy section of more than 700 m, with approximately 500 m of high-quality reservoir sands (Figure 2). MDT data confirmed the presence of four thin hydrocarbon-bearing zones whilst several fluid samples were collected (oil and water).

The oil samples indicated light oil, with GOR's around 1,000 scf/bbl and no signs of biodegradation. Geochemical analyses suggest that they were generated by an Upper Cretaceous marine siliciclastic source rock, probably the same source rock facies that generated the oil at the Ubabudo oil seep in the São Tomé Island.

Jaca-1 also drilled an Upper Cretaceous marine source rock. It corresponds to OAE 3 and, although immature at the well location, it has been correlated to the oils recovered from the Jaca-1 reservoir sands higher up. Petroleum systems modeling suggests that the kitchen is located towards the Campo and Kriby fracture zones in the northwest. Regional hydrocarbon migration is to the southeast, so the oil found in Jaca-1 has therefore proven mid to long lateral migration in addition to vertical migration up into the Campanian.

A WORKING PETROLEUM SYSTEM

Unfortunately, the well did not find a blocky reservoir at the main target in the Turonian, but encountered thinly bedded sands instead. Even though good porosities were observed in these sands, permeabilities turned out to be at the lower end of the spectrum and were water-wet. The well was therefore TD'd before drilling the postulated mid-Cenomanian source rock.

In summary, Jaca-1 proved the presence of a working petroleum system in the deep-water setting of the Gulf of Guinea, with the kitchen being located mostly on oceanic crust. Excellent Upper Cretaceous reservoir sands were also confirmed, with light oil being able to migrate both laterally from the source kitchen to the northwest as well as upwards to reach the Campanian reservoirs. ■

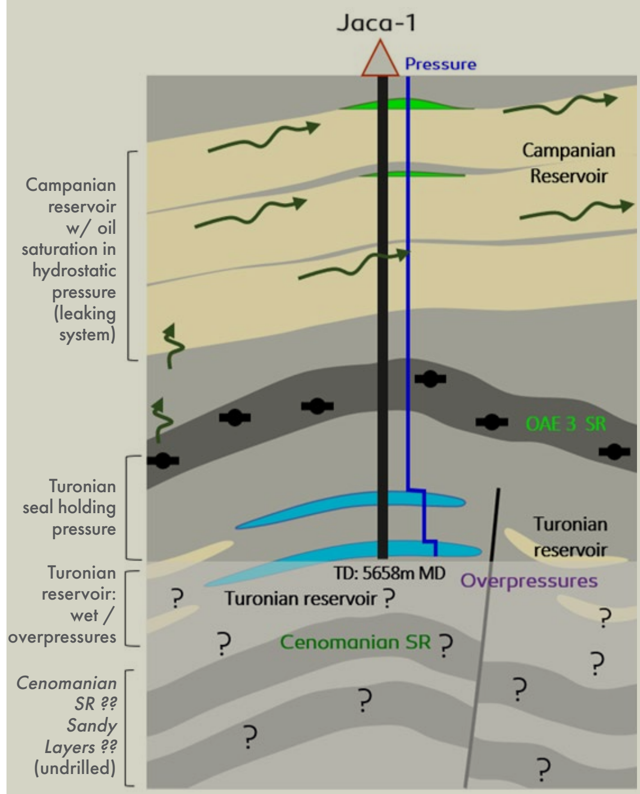


Figure 2: Schematic cross-section along Jaca-1 well illustrating the main well results.

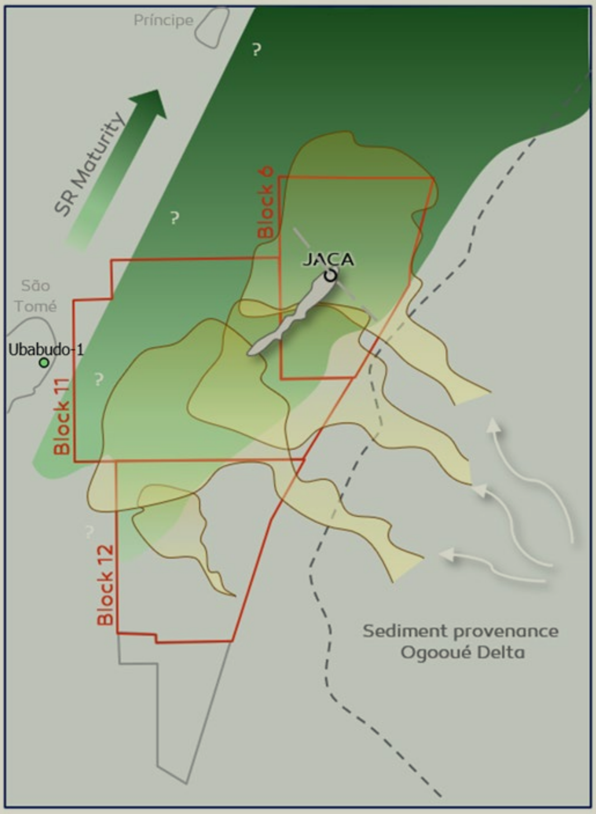


Figure 3: Simplified maturity map for the drilled OAE–3 SR.

A new and unique multi-client core scanning and thin section digital catalog from pre-salt reservoirs offshore Brazil

Datasets provide operators with unparalleled geological information to further de-risk exploration

JAMES SHREEVE AND LUCAS ROCHA FRASCAROLI, GEOTEK, AND FÉLIX GONÇALVES, SOLINTEC

THE PRE-SALT reservoirs in Brazil are home to some of the world's largest oil and gas reserves and one of the most exciting exploration frontiers. However, until now the exceptional depth of more than 5,000 m below sea level with around 2,000 m of salt overlying the reservoir, has caused significant challenges to de-risk locations for drilling exploration wells.

The industry therefore needs to capitalize on any data that already exists from these reservoirs. Here, we describe how digital core data forms a key part of the solution, providing a continuous dataset along cored intervals in addition to the traditional plug measurements.

A NEW SOLUTION REQUIRED

Historically, exploration teams have had to make do with limited data types from core samples. The resolution of these data is usually low. They typically range from three to five core plug measurements per meter with or without essential metadata. Sparse resolution along with uncertain data quality can hinder any geological model. Data uncertainty can cloud precise decision-making, creating additional costs for acquiring new core.

Accessibility is a further issue.

WHAT ARE THE BENEFITS OF THESE INNOVATIONS TO INDUSTRY EXPERTS?

The pre-salt digital catalog has yielded a comprehensive suite of deliverables, transforming how operators approach pre-salt reservoir exploration.

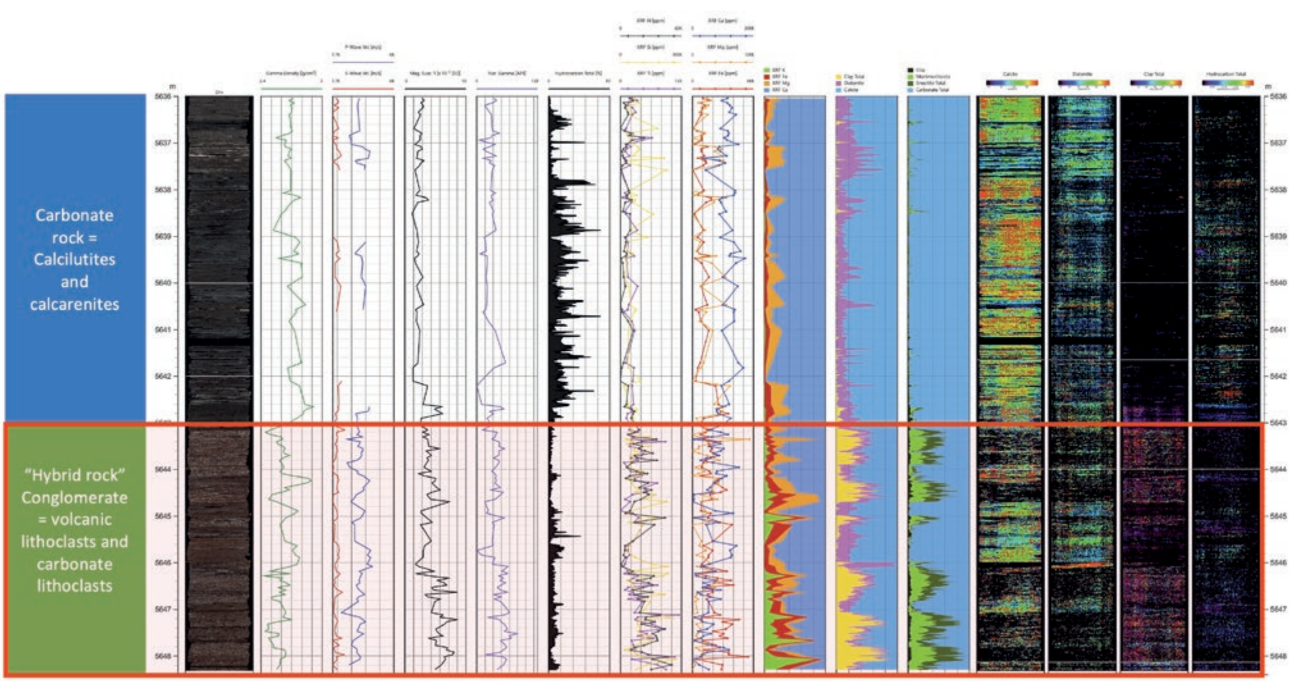
Digital Accessibility
All data is accessible online, enabling remote work with core data and eliminating the need for physical sample distribution.

Objective Analysis
Using automated, multi-sensor technology to acquire repeatable and depth-co-registered measurements.

Data Integration
Comprehensive, high-resolution data from the core to pore scale that can be used to ground-truth wireline and seismic data and cross-validate subjective visual descriptions.

Geological Insight
Discover the variability of the depositional system through well-to well correlations and apply to the reservoir model and characterization.

AI/ML Ready
Depth-coregistered data from multiple datatypes that are ready for the ML/AI revolution in geoscience studies.



Multi-sensor core logging data and hyperspectral imaging data from 4-BG-7-SPS - Barra Velha Formation.

SOURCE: GEOTEK

Without a centralized system for easy retrieval of these historical data, they are often scattered across numerous repositories. Professionals have to spend valuable time and resources locating the necessary information.

There is also the challenge of how records are stored. Until now, much of it comes in paper form. These are difficult to access and use. The transition from paper to digital formats is time-consuming and prone to errors, often compromising the integrity of the data.

These challenges underscore the need for innovative solutions – solutions that the Geotek-Solintec multi-client project now provides.

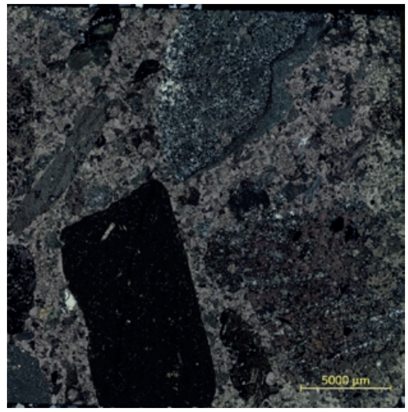
PRE-SALT DIGITAL ROCK CATALOG

The digital core catalog is ML/AI-ready, spanning two scales of measurement: The core scale (mm to m) and the pore scale (<sub to mm). At both scales, the catalog provides data that was never before acquired from these complex rock formations. The core scale is represented by hyperspectral imaging and multi-sensor core logger (MSCL) measurements of 1,164 meters of core from 16 wells. Data acquired from the cores includes ultra-high definition visible and UV images, combined with petrophysical, mineralogical, and geochemical properties.

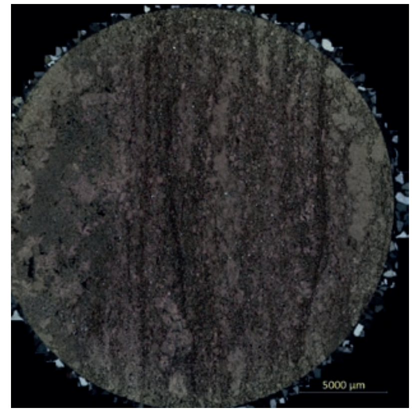
The pore-scale data is represented by digital high-resolution twins of 3,003 thin sections that correspond to the same intervals as the core samples. These thin sections offer a microscopic view of the rock's composition and structure, providing critical insights into the reservoir's characteristics. This level of detail is invaluable for understanding the geological and petrophysical properties of the pre-salt layers. It also perfectly complements the MSCL and hyperspectral datasets from the core.

USING THE DATA FOR LITHOLOGY CLASSIFICATION AND ANALYSIS

Data from the rock catalog enable



4-BG-7-SPS – 5,777.50 m. Hybrid sandstone with volcanic rocks fragments (crossed polars).



4-BG-7-SPS - 5.777,50 m. Laminated mudstone (crossed polars).

SOURCE: SOLINTEC

early lithology classification within the Barra Velha Formation. They distinguish two facies and deliver an understanding of the geochemical and mineralogical distribution within and between these units.

The upper section of this data example is a carbonate reservoir dominated by calcite with 1 m thick intervals of dolomite. These rocks are hydrocarbon-bearing with evidence of the dolomite-rich intervals having a lower proportion of hydrocarbons. A sharp contact at 5,643 m spells the introduction of a conglomerate. This is rich in volcanic lithoclasts interpreted from the reduction in carbonate mineralogy and the elevation of silicon (Si), aluminium (Al), iron (Fe), and titanium (Ti), with a decrease in calcium (Ca) and magnesium (Mg).

The hyperspectral imaging shows that these facies of the Barra Velha Formation have 1-2 m thick clay intervals composed of smectite and montmorillonite, and lower amounts of illite dispersed throughout. The clay is derived from the volcanic clasts within this conglomerate, which were re-worked during its deposition.

The elevated magnetic susceptibility, indicative of clays and volcanics, combined with generally erratic chemical and mineralogical downcore profiles, all support a heterogeneous conglomerate facies. The identification of pore-filling clay intervals, pervasive across the core, combined with the heterogeneous nature of the facies all contribute to a reduction in reservoir quality. This is why the hydrocarbon content is lower in this section.

These conglomerate rocks, with their pore-filling clay and the nature of their clasts, could become an important marker bed and regional barrier to hydrocarbon production - essential for the geological model.

UNPRECEDENTED ACCESS TO HIGH-QUALITY, OBJECTIVE DATA

The digital rock catalog is delivered with visualization software and represents significant progress in the geological evaluation of these pre-salt reservoirs. Exploration teams now have access to a wealth of high-quality, objective data, surpassing what was previously available. This means:

- More informed decision-making
- Reduced risks
- A saving of time and money
- Enhanced understanding of valuable resources

Through this pioneering work, Geotek and Solintec have advanced the level at which geological data is available for pre-salt operators in Brazil. Learn more about the benefits to your specialist research work from the Geotek Solintec Pre-Salt Reservoir Digitalization Project. ■

Rejuvenating legacy seismic for screening carbon storage sites in the Gulf of Mexico

A major challenge in the US Gulf of Mexico is transforming disparate public datasets into a quality-controlled database. CGG has successfully created and used a database for its Storage Play Quality Index (SPQI) carbon storage screening methodology and applied its latest imaging technologies to rejuvenate the legacy seismic data

NEVILLE BROOKES, RAVI KUMAR, GREGOR DUVAL AND SIMON OTTO, CGG

THE LAST TWO years have seen a rapid growth in interest in carbon storage on the US Gulf Coast. Carbon storage operators have been racing to take key acreage positions through Local State Bid Rounds and Shallow Water Gulf of Mexico (GOM) Lease Sales. The associated area of interest stretches across the coastlines of both Texas and Louisiana and contains high-quality reservoirs for carbon storage which occur within the Miocene clastic section at 2,500 ft – 10,000 ft.

SCREENING - DATA AND WORKFLOW

To support operators in screening potential carbon storage sites, CGG created a quality-controlled and consistent database of legacy data. Data types include well log suites, deviation surveys, check shot surveys, well test data, core data, biostratigraphy, water chemistry and formation pressure data. The available information was a mix of analogue and digital data, totalling thousands of data files in some wells.

Data science workflows were developed to identify, evaluate, extract and enhance the data into a consistent digital database. Over 600 wells were selected for mapping and approximately 400 wells were used for extracting petrophysical properties.

The process of SPQI mapping incorporates key properties for carbon storage evaluation mappable at play scale, including depth, structure, reservoir and seal properties, water chemistry, injectivity and containment integrity. Figure 1 shows the extent of the database and the screening study.

Stratigraphy is used to identify the key aquifers and build the framework of the geological model. This was developed using biostratigraphic data, including micropaleontological and nannofossil distribution data. Key surfaces were tied to seismic reflection data using time-calibrated well logs. The structural framework was based on over 70,000 km of 2D seismic and approximately 25,000 km^2 of 3D seismic.

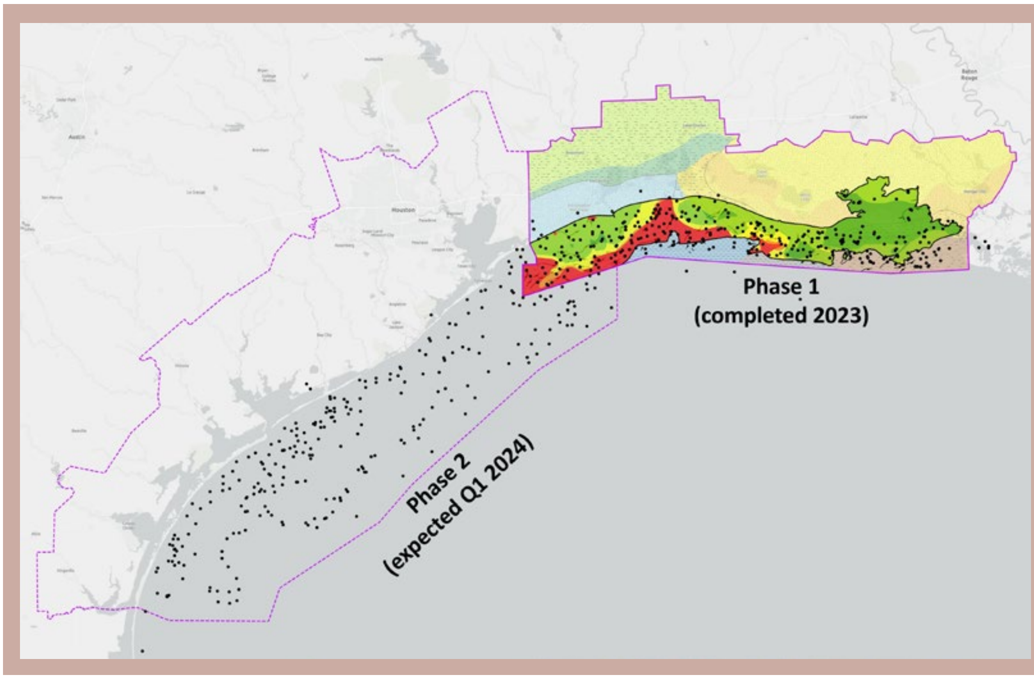


Figure 1: Example of an SPQI map for one of several plays identified in the Miocene (red indicates poor areas, green optimal areas) (image courtesy of CGG Earth Data).

A total of 16 key properties were extracted from the well data, mapped, and combined to produce a composite SPQI map (Figure 1). This was performed for each play to identify the most prospective geographic areas to investigate further for carbon storage sites.

REJUVENATING LEGACY SEISMIC

Following successful screening of the targeted aquifers, seismic imaging then becomes critical to the next stage of characterising carbon storage sites in 3D.

CGG carried out a reprocessing pilot study in the High Island offshore area of the GOM. The legacy seismic image used vintage narrow-azimuth (NAZ) data which had not benefitted from modern-day processing techniques, such as deghosting, model-based water-layer demultiple (MWD) and full-waveform inversion, resulting in problems with shallow-water multiples, poor to non-existent shallow overburden imaging and poorly imaged faults.

In this example, the legacy seismic was reprocessed using state-of-the-art Time-Lag FWI algorithms that utilize iterative data fitting, using the full wavefield of seismic data, including multiples and diving wave energy, to update the velocity model and reflectivity image simultaneously.

Figure 2a shows how the smooth legacy data velocity model lacks detail to represent the complex geology. In contrast, the 35Hz FWI velocity model exhibits high-resolution results, imaging the faults more accurately and better defining stratigraphic layers and features of the underlying geology.

Figure 2b compares a legacy Kirchhoff PSDM image with the 35Hz FWI Image. The FWI Image filled in the missing information in the shallow section and enhanced the amplitude fidelity of stratigraphic events. This improved approach benefited from least-squares fitting of the data and improved utilisation of the lower frequencies, resulting in broadband images ideally suited to reservoir mapping and delineating possible escape routes for CO_2 from potential storage sites.

The FWI velocity provides a detailed subsurface model which was augmented with well data to enable the generation of a detailed 3D pore pressure prediction volume. In Figure 2c, significant pressure changes can be identified across faults. Cold colours indicate pressures close to hydrostatic pressure (~0.45 psi/ft). Hotter regions are significantly overpressured. At the pink horizon level on the geopressure map, overpressured fault compartments can be recognised that would likely pose significant development challenges in terms of compartmentalisation of the pore space and low pressure headroom for injection.

PROVIDING CRITICAL SUPPORT TO SITE CHARACTERISATION

After evaluating a large volume of legacy wells and seismic data, the SPQI mapping approach identified high-grade areas suitable for carbon storage sites in the shallow water GOM. Meanwhile, the rejuvenation of the legacy seismic data, using Time-Lag FWI reprocessing, has been shown to significantly enhance the seismic imaging, providing essential detail and insight into the true subsurface complexity and thus providing critical support to the site characterisation phase. ■

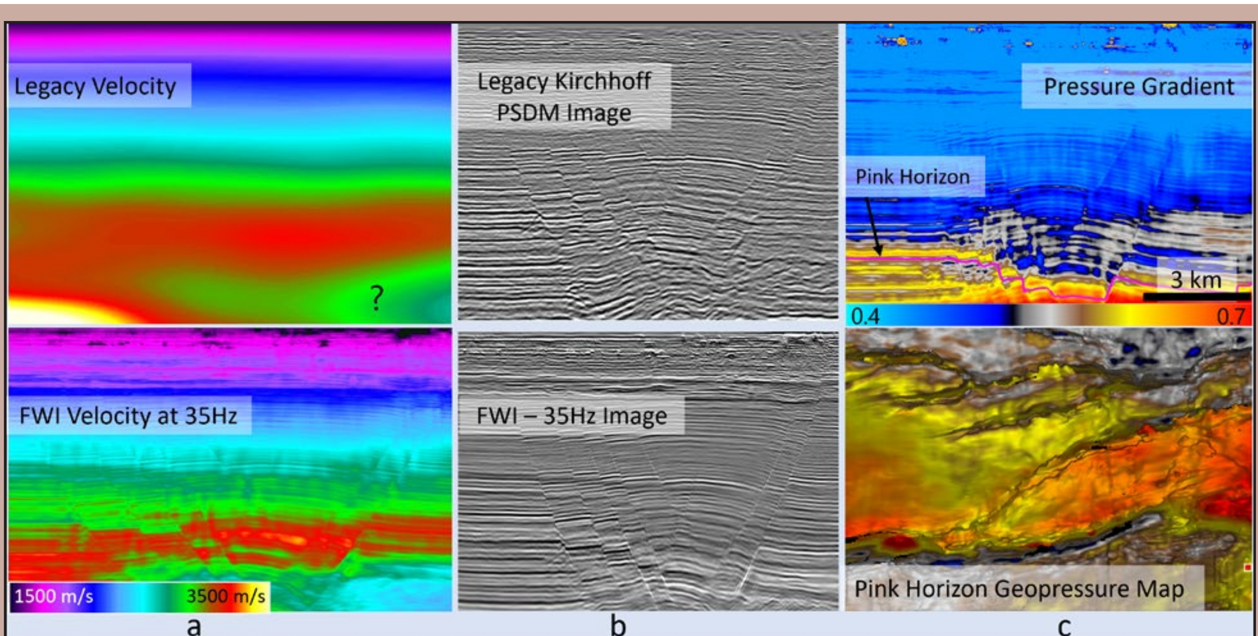


Figure 2: Comparison of legacy seismic and FWI image data (image courtesy of CGG Subsurface Imaging, data courtesy of Seitel).

PORTRAITS AND INTERVIEWS

"When I was 21, and had successfully finished my geophysical engineering degree, I really felt like a grown-up and was ready for the world."

Clara Rodríguez Rondón - ExploreTerra

SALT AND GRIT

Clara Rodríguez Rondón's career shows how ambition, determination and curiosity can open up the world

HENK KOMBRINK

"MY FASCINATION with geology started with asking myself a question", says Clara Rodríguez Rondón. "I grew up in Venezuela, in a town called San Juan de Los Morros, in a landscape that is characterised by the presence of rolling hills and valleys, close to the town there are a series of enigmatic higher peaks that consist mainly of limestone. "I always wondered where "Los Morros" came from", she says. "As my mother is a soil scientist, she took me to the mountains towards the end of secondary school when we had to do a little research project. We took some samples and analysed these in the lab. It really confirmed for me what I wanted to do."

A YOUNG STUDENT

"I left school to go to university when I was 15 years old, and I already felt like an adult", laughs Clara. It was a big step to leave home at that age and move to Caracas, the capital of Venezuela. "I started studying geophysical engineering, primarily because the nearest place where I could do a pure geology degree was too far away from home and this degree still had some geology as part of the curriculum."

"I don't know if I would recommend other people to do the same thing as I did, leaving school at such a young age to go to university, but I made it! The last year of of university included an exchange program with Oklahoma University, which was just great for a 19-year-old student; living on campus at OU was a great experience."

"When I was 21, and had successfully finished my geophysical engineering degree, I really felt like a grown-up and was ready for the world", Clara continues. Straight away, she joined Schlumberger and the world opened up for her. She travelled to Indonesia for training, delivered presentations ▸

to clients all over the place before she became involved with the Petrel support team: First as a helpdesk support member, then as an onsite consultant and instructor.

"At some point, when I was delivering a training class, making people go through the books that were so characteristic of the Petrel teaching courses, I said to myself; I want to be one of those geoscientists that I am delivering this training to! But to make that happen, I realized that I needed a master's degree, and I started to look around for options."

Clara then found out that obtaining a Master's degree could be done in the UK in just a year. "So, I filed an application for a degree at Imperial College, and I was accepted. I then told Schlumberger that I was leaving, only to realise that I couldn't afford to live in London and pay for the degree myself… Fortunately, the company decided to sponsor me, on the premise that I would take a job with them upon completion of my master's degree", says Clara. "That sounded like a plan to me."

BRAZIL AND SALT

Clara's PhD project was about salt stratigraphy, salt tectonic controls on sedimentation, and salt dissolution in the Santos Basin, offshore Brazil. The Santos Basin has never received the same attention as the Campos Basin when it comes to exploring the post-salt succession. But because a major 3D survey by CGG was available for interpretation, there were plenty of things for her to get stuck in.

One of the highlights of her work was the discovery of an entirely new depositional post-salt system that had not been identified before. "It was amazing to see how the salt-induced topography influences depositional systems", Clara says, "and it is amazing how much one can reconstruct through meticulous analysis of seismic data."

FALLING IN LOVE WITH SALT

As Clara embarked on her master's course, her husband, who also worked for Schlumberger at the time, moved to the UK as well. So when she finished the course, she asked if it was possible to stay in the UK for a while.

"I was offered a position at Schlumberger WesternGeco, and got involved with seismic interpretation multiclient projects all over Africa. It was a major change in my career", she says, "but it was surely something that I was ready for. Working with industry experts such as Malcolm Francis and trying to unravel the sedimentary and tectonic history of all these basins was a great experience."

"It was also the time when I fell in love with salt, and the myriad of things that seismic data allows to interpret when looking at the interplay of salt- and deep-water sedimentation. And since I happened to be on a four-year cycle in terms of my career", Clara jokes, "I decided to talk to Chris Jackson from Imperial and asked him if there were any opportunities to do a PhD in this field. I had some savings, so even when the company would only sponsor my tuition fee this time, I could still afford it."

And it all happened! With two young daughters to take care of as well, Clara embarked on her PhD project on the Santos Basin in Brazil. "Because I had two kids and with the third one on the way when I was approaching the end of my project, it took a bit longer than 5 years. But when I finished without corrections, I certainly had a major feeling of achievement and felt I had demonstrated that it surely was possible to fulfill my dream of becoming a recognized geoscientist", she says.

"THE RODRIGUEZ FROM THE SANTOS BASIN IS A WOMAN"

Clara never travelled to Brazil during her PhD project, but more recently she finally got the opportunity to go to Rio and present her work at the International Congress of the Brazilian Geophysical Society. And because she had published her work in scientific journals, her work was already well-known to people at Petrobras, the national oil company. "When I met with the group I presented for, I overheard a person saying: "The Rodriguez of the Santos Basin is a woman!" It confirms the gender bias that still exists in the industry, and it is something that Clara feels passionate about tackling.

"It confirms the gender bias that still exists in the industry, and it is something that I feel passionate about tackling."

A SINGLE TRIP TO HOUSTON

After completing her PhD in London, Clara talked to Schlumberger again to see if there was an opportunity for her. "There was", she continues, "but not really around the corner. I was offered a position in Houston, to again work in the multiclient team of WesternGeco, but now looking at the Gulf of Mexico. From that point of view, it was very exciting to close the loop from studying the sedimentary basins of the South Atlantic and now the Gulf of Mexico."

The working environment in which Clara arrived in Houston was quite different from what she had seen in the UK. "I was the only woman in a team of 7 men, and that felt a bit uneasy at times, and it was exacerbated by the fact that competition between people is quite fierce in that part of the world", she says.

"We had moved as a family, with my husband giving up his job in London and the kids having to settle into a new school. It was all quite a hectic time, and you constantly feel the pressure to make things a success. For me, this was a time when social media became a channel to connect to other people around the world."

PHOTOGRAPHY PREVIOUS PAGE: PRIVATE

SOCIAL MEDIA

It was at that time that Clara initiated a network of women working in Geoscience in the Latin American region, GeoLatinas. The initiative has grown steadily over the years to what is now an informal network of around 1,000 women with a geoscience background.

"I think it is important, especially given the gender bias that still exists out there, to give female geoscientists more of a voice", says Clara. Social media has been instrumental in setting up this network. "Especially Twitter (now X), Facebook and Instagram have shown to be great platforms to spread our message, organize talks and give our members more visibility. We continue our activities until today."

"It has also brought me a lot as a person", says Clara. "Being invited to talk at conferences, visiting universities, so much of that is thanks to the visibility that we created through posting our activities on social media."

NO HOME TO GO TO

Whilst working on exploration projects in the Mexican part of the GOM in Houston, Clara got the idea that working for an operator active in the same area would be a logical next step.

A few years before, Petronas had made an ambitious entrance into Mexico and had staffed up a sizeable group of geoscientists. "I knew someone from Petronas from my time at Imperial", Clara explains, "so I got in touch with him to ask if there was any need for a salt expert in their Mexico exploration team." And they did! Early 2020, as the pandemic started to unfold, Clara moved to Mexico City, ready to start her new job. "But as soon as I arrived, they told me that I couldn't go to the office the next day", she says.

Clara worked from the staff apartment for a couple of weeks, until Petronas said she had to go "home". "But I had no home to go to! I had no Venezuelan passport anymore, and I had resigned from my job in the US and I had therefore lost my Visa, and we had left the UK thinking we wouldn't come back. Ultimately, a lawyer advised us to go back to the UK and wait for things to improve. So we ended up living from our suitcases for a year instead of a few weeks", Clara laughs.

Clara Rodríguez Rondón.

PHOTOGRAPHY: CAROL CONTRERAS

> "Working for an operator finally meant that we owned the blocks, we owned the wells and we owned the results! That was such a difference from what I had seen before."

NOBODY WANTED TO TURN ON THE CAMERAS

How was it to learn to know a new team from the other side of the world? "At the start of the pandemic, nobody wanted to turn on their cameras", says Clara. "There was not the culture of doing that yet, so at some point I asked the person I was talking to switch on the camera. And it worked, people got used to it a little more and it surely helped build a professional relationship, even though I was so far away."

In September 2021, the family finally moved to Mexico City. "Mexico is the closest to home I got in many years, and in many respects that was great and made me feel at home", Clara says. "Working for an operator finally meant that we owned the blocks, we owned the wells, and we owned the results! That was such a difference from what I had seen before." ▶

Clara Rodríguez Rondón.

A VERY COMPLEX MIX

"Through the experience of my PhD and the work I had done, I quite naturally became the salt and sediment fairway expert", Clara continues. "And there is a lot to do on that front. It is the most complex sedimentary basin I've worked on so far. You've got everything you can imagine; salt tectonics, shale tectonics, volcanic activity during deposition, post-depositional deformation and syn-depositional deformation. This, in combination with the fact that the geophysical expression of all these factors combined is not always that clear, makes it quite a challenge to successfully explore for hydrocarbons. That's why we did see quite a few surprises in the wells we drilled and the seismic we interpreted. In turn, this is probably part of the explanation why a few companies have decided to leave Mexico."

"Petronas also downscaled its footprint in Mexico a lot last year", Clara says. "I was in charge of a regional project, integrating all the data from six of the ten blocks the company participated in. But then, the number of blocks was reduced drastically." As a result, the company let many people go in November last year. "I was part of that. Initially, I had hopes of being able to stay, also because I had just achieved the principal level, but that did not materialize unfortunately."

"It was a true shock to be called to a venue and hand over my laptop. It all goes so fast, it was overwhelming."

A NEW CHAPTER

"It was a true shock to be called to a venue and hand over my laptop", says Clara. "It all goes so fast, it was overwhelming."

"But shortly after it happened, I got that nagging question, what do I now do with all the things I learned? And I wasn't the only one thinking that. Together with a few people I had closely worked with, we decided that this was the right time to set up a consultancy and training company. And that's how we set up ExploreTerra. We feel that we have a lot of expertise to offer to the upstream sector when it comes to exploration and appraisal studies, especially when looking at our joint experience in Mexico."

"In addition, we also want the ExploreTerra vehicle to be a place where people with relevant experience but who may not have paid work at the moment will be able to gain more visibility and potentially deliver courses to companies that need their expertise", Clara continues. "The GeoLatinas community nicely fits into this model."

Clara and her family have now moved back to the UK, where a new chapter has started. "I'll admit, ExploreTerra is at a very early stage, is not paying our bills at the moment", she says. "That's why I'm also looking for other job opportunities."

Given her 21-year successful career, very much characterised by grit, and a lot of salt, I have little doubt that she will find another exciting position, and look forward to following how the next few years will unfold. ■

PHOTOGRAPHY: PRIVATE

GEOTHERMAL ENERGY

"But the main question is,
are the drilling costs too high for closed-loop
systems to become commercial? At the moment,
they simply can't be."

A new closed-loop horizontal geothermal well solution

Using a vacuum inner tube, Danish company Green Therma developed a 1-3 MW well configuration that does not suffer from the issues seen with conventional open-loop doublets

KIM GUNN MAVER, GREEN THERMA

In Europe, deep geothermal heat production for district heating and to a lesser extent district cooling is mainly based on the conventional doublet geothermal well solution. Examples are the wells operating in Munich and Paris and the ones being drilled in the largest ongoing European project in Aarhus, Denmark.

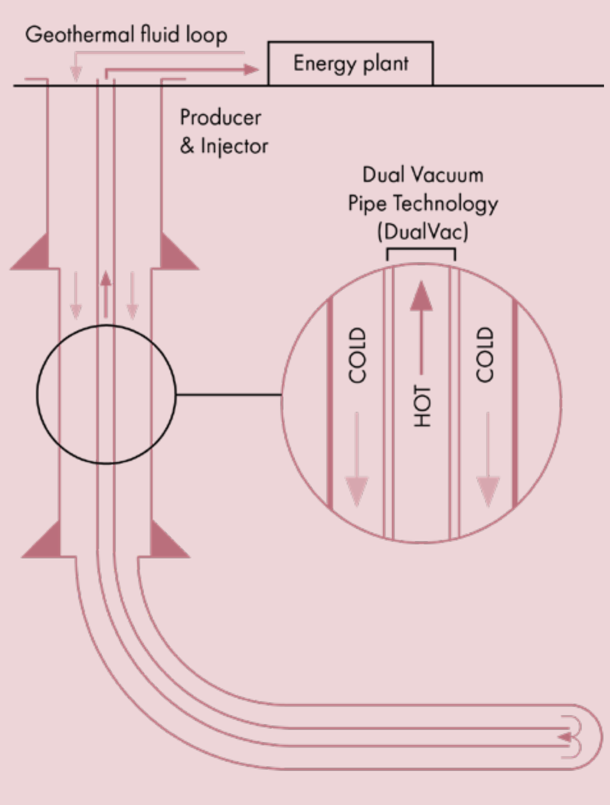
The doublet well solution uses one well to produce formation water and another well to inject the cooled liquids some distance away. The solution is dependent on the geothermal reservoir's thickness and parameters such as porosity, permeability, and geochemistry to ensure hydrologic connectivity between the wells to maintain production. Besides extensive maintenance requirements due to corrosion, scaling and clogging, the specific geological reservoir requirements severely limit the locations where the solution is viable for geothermal heat production.

Closed-loop well solutions have been proposed to manage the issues with the doublet well solution based mainly on a co-axial, pipe-in-pipe technology. Cold water is circulated down through the outer casing and returned as heated water inside the inner tubing. Other solutions have been implemented that work similarly to a heat exchanger approach, using multiple wells connected by individual downhole branches.

A VACUUMIZED INNER TUBING

A new geothermal closed-loop well solution with a patent-pending vacuumized inner dual tubing and a horizontal section has been developed. The well is drilled to a vertical depth of two-four km depending on the temperature requirement, with a two-five km horizontal section either as a single well or a group of independent wells depending on the required power demand (MW). Each well will be completed with the vacuumized dual tubing technology.

The circulation fluid will be heated by flowing down between the lower completion liner and tubing in the horizontal section of the well. The circulation fluid is returned to the surface in the inner vacuumized dual tubing completion with a two-three % heat loss, compared to a normal 30-40% heat loss.



Schematic illustration of the Geotherma well configuration.

The successful execution of the solution is through the use of proven oilfield drilling technology and services with a simple well completion. The drilled depth determines the temperature of the returning circulation fluid, the thermal conductivity of the geological formation of the horizontal well completion, and the fluid flow rate controls the power output that is expected to range from one to three MW.

The solution has a wide application with the main geological challenge being locating the horizontal section in the formation with the highest possible thermal conductivity to optimize the energy production. ■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A puncture in a geothermal seal

Two sidetracks were required to get to TD in one of the wells in the Delft geothermal drilling project. This left one leg of the doublet with an unplugged section in the sealing unit of the target reservoir, which opens up the possibility for cross-flow to the overburden. How have the authorities responded? We take a further look

More than fifteen years ago, Delft University of Technology (TU Delft) was one of the first institutions in the Netherlands to come up with the idea to warm their premises and surrounding residential areas using geothermal energy. It took quite a few years before the producer and injector wells were ultimately drilled, mostly because of the skewed heat demand throughout the year and the complicated business model that comes with this, but the wells were finally drilled in the second half of 2023.

So, in July last year, the time had come for the drill bit to hit the ground, aiming for the Lower Cretaceous Delft Sandstone at a depth of around 2.2 km and temperatures close to 80 degrees Celsius. The project is owned by a consortium of companies including Shell and has a large scientific component led by Delft University of Technology. The scientific aspects include a coring program, a logging program, and the installation of monitoring facilities in the wells and in boreholes around the doublet.

The first well, which will be the producer, was successfully completed in September 2023. The second well, the future injector, took a little longer. This was caused by borehole stability issues, thought to be due to an unstable section in the overlying Vlieland Claystone Formation.

A COMMON ISSUE

The Vlieland Claystone Formation is not new to borehole stability issues, and drillers have therefore always argued to case off the formation as quickly as possible. Even though a drilling mud was used that did not interact with the mudstones, an increasing amount of cavings were observed whilst drilling. Mud losses then occurred, indicating further wellbore stability issues, after which the drill string also became stuck. This led to the decision to abandon the hole and drill a sidetrack above the troubled zone.

Drilling a side-track, even two, is not uncommon. What is more of an issue is the fact that the sealing unit above the Delft Sandstone reservoir was penetrated during the first drilling attempt, without the ability to abandon the hole properly due to the drill string being stuck higher up in the section. This can subsequently lead to flow of brines from the Delft Sandstone to reservoirs in the overburden, which is an unwanted situation with regards to the presence of aquifers.

The Dutch authorities have therefore recently stipulated that any penetration of the sealing unit of a geothermal reservoir should be plugged to prevent cross-flow in the subsurface, especially because injection of water in the reservoir will locally lead to an increase in pressure. The sealing formation needs to be able to sustain this local pressure rise as induced fracking of the seal may take place otherwise. An open-hole penetration of the seal, as is the case now, may lead to pressure being dissipated in that direction.

WHAT DO THE VARIOUS PARTIES SAY?

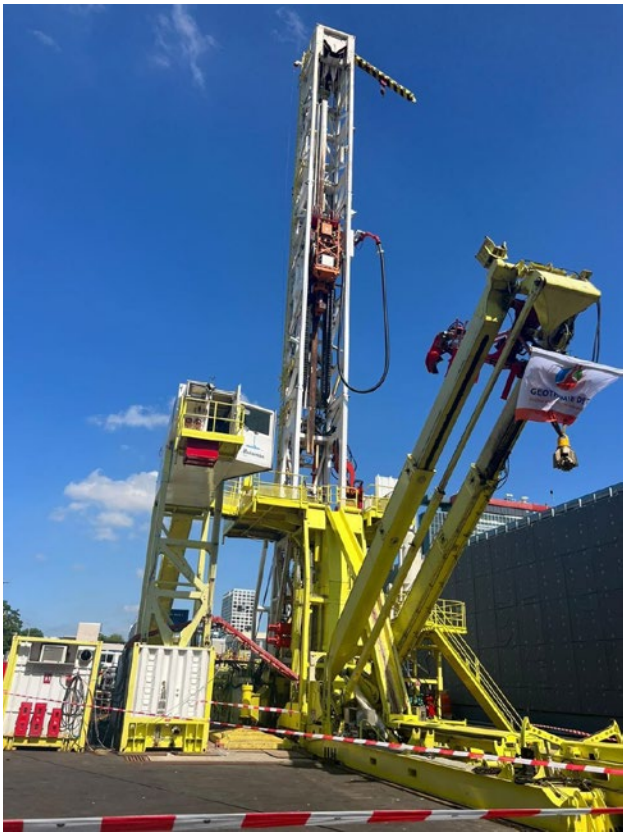
In a document released by the Ministry of Economic Affairs and Climate, various institutions and the Delft geothermal project consortium (GTD) itself assess the risk for cross-flow to the overburden.

GTD writes that the sealing Rodenrijs Member shows ductile behaviour, meaning that, over time, the hole may close itself. In addition, the well bore is filled with drilling fluid, which will also block flow through the caprock. On that basis, the consortium concludes that the risk of flow through the entire Rodenrijs Member is very unlikely.

TNO – Geological Survey of the Netherlands – takes a more conservative stance and writes that cross-flow to the Rijswijk Sandstone Member cannot be excluded. However, based on a modelling exercise, the institute does conclude that the amount of cross-flow is likely to be limited and

Core from the target reservoir – the Delft Sandstone Member – at surface.

PHOTOGRAPHY: DELFT GEOTHERMAL PROJECT



Delft Geothermal drilling site.

will not impact freshwater aquifers in the shallow overburden.

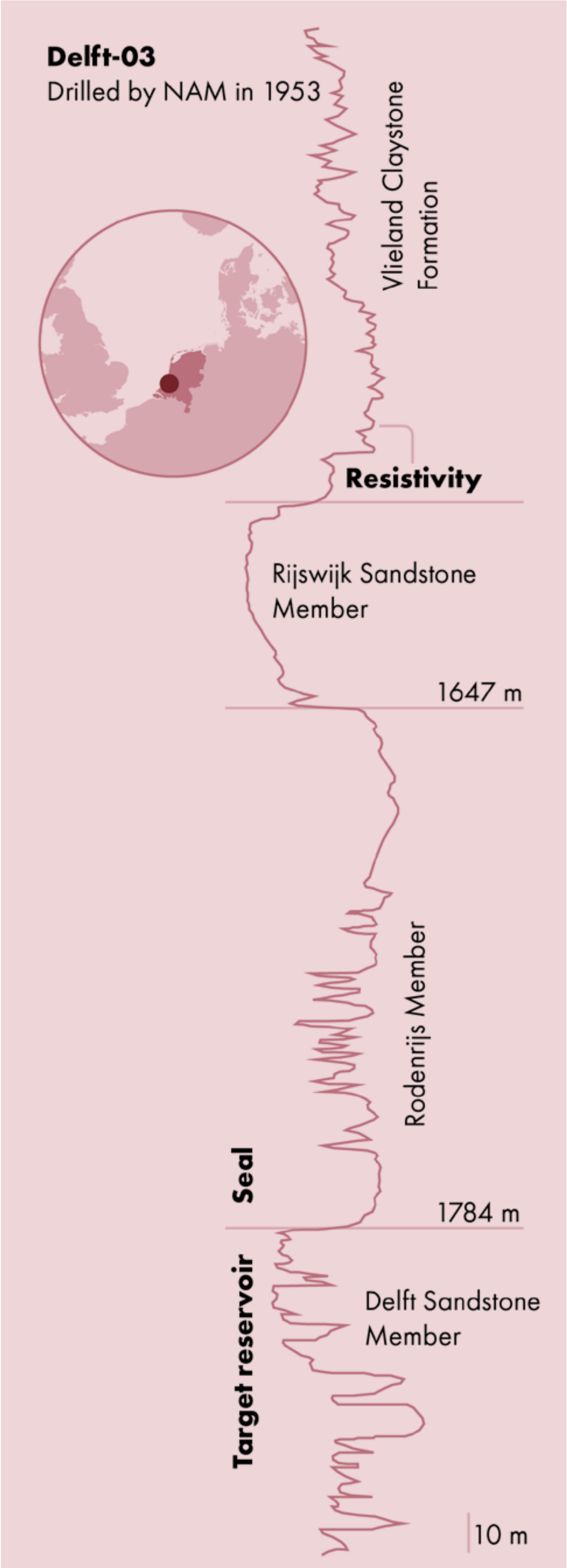
State Supervision of the Mines is even more critical about the project as they claim that GTD's reasoning as to why the risk of cross-flow is negligible is not supported by literature references, modelling work or a quantitative approach. Their recommendation therefore includes performing a dynamic modelling study and a well test to back up the claims made.

Following recommendations of another three governmental bodies, the minister ultimately granted the consortium a permit to start production of geothermal energy from the project, whilst stipulating that a well test and the dynamic modelling work are to be carried out to monitor and better understand the risk of cross-flow.

NO COMPLETE STOP

The above clearly shows how the authorities emphasize the importance of seal integrity when it comes to geothermal energy production. That is also why it is now mandatory to plug a well at the sealing unit in case of abandonment. The fact that the Delft project ended up with an unplugged well is unfortunate, but at the same time, it is good to see that a flagship project of that kind is not stopped because it has not met one of the design criteria. Instead, it seems that reason has prevailed with a workable solution in place. ■

Henk Kombrink



A resistivity log from well Delft-03 that was drilled just a few hundred of meters to the west of where the two geothermal wells of the Delft project were drilled last year.

Geothermal potential of Ukraine

Even though geothermal energy development is at an early stage in Ukraine, thanks to its oil and gas drilling legacy there is a wealth of data available to better constrain the hot spots

TARAS POPADYNETS AND YULIIA DEMCHUK, GEOTHERMAL UKRAINE

Ukraine has several geothermal sites and resources, especially in the Transcarpathia region and in the southern part of the country. However, the development of geothermal resources has not been extensively implemented due to various factors such as limited investment, technical challenges, legislation gaps and tariff policies with a dominance of traditional energy sources. There were some initiatives and studies exploring the feasibility of geothermal power generation and direct use applications, but widespread commercial implementation has so far been limited.

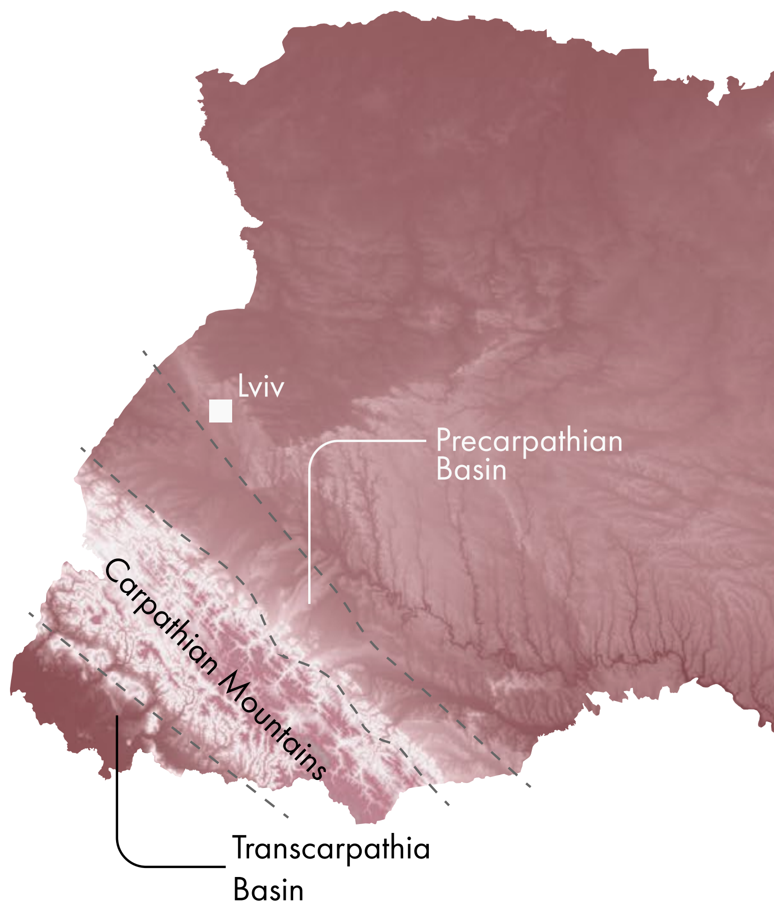
The most promising areas in Ukraine for future geothermal development are:

- Transcarpathian Basin
- Precarpathian Basin
- Dnipro-Donets Basin and Donets fold belt
- Black Sea Basin
- Scythian Plate

The highest subsurface temperatures in Ukraine were recorded in the Transcarpathian Basin, which is characterised by an average temperature gradient of around 5,5° C/100 m. Typical aquifers in this area are Neogene andesites, tuffs, tuffites, sandstones and argillites, occurring at depths of around 500-1,000 m.

Precarpathia and the adjacent territory in the Lviv region are recognised as another priority area for research and potential development of geothermal resources with average geothermal gradient of about 3°C/100 m.

From 1978 to 2002, nine geothermal energy facilities were built in Ukraine, including on the Autonomic Republic of the Crimea (five), in Transcarpatia (three) and in the Kherson region (one). The total heat capacity of these facilities was 11.2 MWth. As of 2020, only three of these were working with 1.5 MW of heat capacity and no installed capacities for electricity generation.



Geothermal Ukraine

Geothermal Ukraine (GU) plays a significant role in promoting and raising the profile of geothermal energy production across Ukraine. Amongst many activities, the organisation facilitates R&D and implementation of technological innovations aimed at increasing the efficiency and environmental sustainability of geothermal energy production in Ukraine.

The organisation is collaborating with Icelandic companies Verkis and ISOR in the framework of the joint project "Geothermal Direct Use in Ukraine", which aims to identify and assess prospective geothermal direct use applications in the western regions of Ukraine.

To exchange ideas with countries where geothermal energy production is more advanced, GU participates in international conferences and workshops. Despite the war in Ukraine and the challenging times, the GU team continues to work and promote geothermal energy.

Ukraine has a long history of oil and gas production, dating back to the late 19th century, with thousands of oil and gas wells being drilled mainly across the Dnipro-Donets Basin, the Carpathian region, and the Black Sea coastal areas.

Information obtained from oil and gas wells was invaluable for assessing the geothermal potential in the most prospective regions: Temperature and pressure data that is crucial in understanding the geothermal gradient and heat flow, porosity and permeability for evaluating the feasibility of extracting heat from geothermal reservoirs, and gravity, seismic and magnetic surveys for understanding subsurface geological structures. Analysis of fluids extracted from oil and gas wells provided useful information about the composition and temperature of subsurface fluids. ■

SOURCE DIGITAL ELEVATION MODEL: THE GEBCO GRID

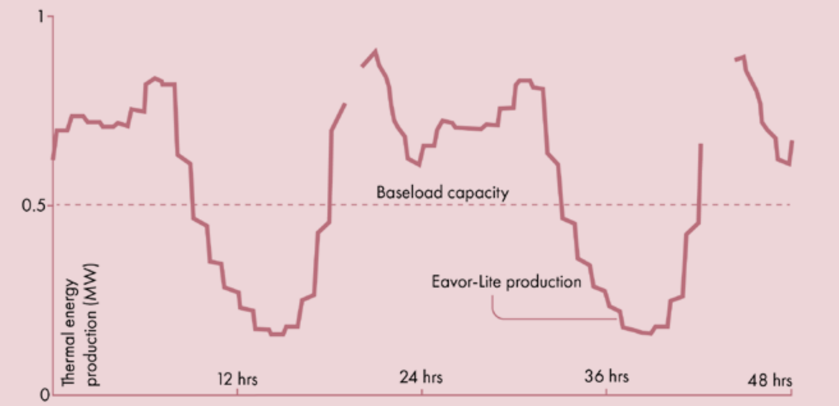
After four years of production, what is the verdict?

Eavor's full scale demonstration project in Canada has run smoothly, but is the amount of energy produced sufficient to warrant drilling these wells?

WHILST DRILLING of Eavor's landmark geothermal closed-loop drilling project in southern Germany has reached the deepest point recently, the company also released a report summarising the past four years of geothermal energy production from their test site in Canada.

Eavor-Lite started producing in December 2019 and has since been running. The project consists of two vertical wells drilled to a depth of 2,400 m into the tight Rock Creek Formation. The wells are connected by two parallel laterals of approximately 1,700 m long. Fluids are pumped into one well, flow through the laterals, and are subsequently produced from the other well. Whilst doing so, the fluids are warmed up through conduction – the lateral wells have an open hole completion, but permeabilities of the exposed formation are near zero.

The million-dollar question now is; how much energy has the system been producing? A website mentioned 20 GWhth over the four years of operation, which sounds quite good. But when we look at the graph below, it appears that the 20 GWhth translates to an average thermal energy production of 0.5 MWth. And how much is that?



A 48-hour production cycle from the Eavor-Lite project, showing a baseload capacity of 0.5 MW. Energy production can be adjusted to meet demand though. Adapted from Figure 7 in Eavor (2023).

NOT MUCH

Well, it is not much. That is not a surprise of course. Heat transfer through conductivity is known to be much slower than through convection. Open-loop geothermal systems produce around 15 MWth per injector-producer pair, so around 30 times more than the Eavor-Lite project. To that can be added the additional drilling costs of completing the two connecting laterals. These are not required for open-loop systems that rely on fluid migration in porous reservoirs.

At the same time, the Eavor-Lite project demonstrated system reliability with an uptime of 99.6%. Moreover, energy production can be timed to demand through the storage of heat downhole and producing it when demand is higher. In addition, closed-loop systems do not suffer from scaling, corrosion sand issues and temperature breakthrough, which is a significant advantage compared to open-loop systems.

But the main question is, are the drilling costs too high for closed-loop systems to become commercial? At the moment, they simply can't be. It is known that open-loop geothermal projects have thin margins, so with an energy production of 30 times less and significantly higher drilling costs, it doesn't take a rocket scientist to conclude that this form of energy production is still very much in an experimental phase and will no doubt need a significant technological breakthrough. ■

Henk Kombrink

The Eavor-Lite surface facility in Canada.

PHOTOGRAPHY: EAVOR MEDIA KIT

SUBSURFACE STORAGE

"..it is the mindset that you have to embrace when joining another sector. I must admit that I had to learn this to an extent."

Rodney Garrard

"It is important to embrace what matters in other subsurface realms"

Rodney Garrard has observed siloed thinking on many occasions, including with himself

"HAVING WORKED in oil and gas for years, I was convinced I knew how to drill a well", Rodney Garrard says. "Then I moved to Switzerland to join NAGRA, the company that is researching and coordinating the construction of a nuclear waste disposal site. I was initially hired to oversee the coring data acquisition programme, which I felt comfortable doing having been exposed to this type of work for so long." He subsequently turned his hand to an integrated petrophysical data acquisition programme for NAGRA too - both for de-risking operations and providing critical data with which to feed the safety concept.

But even though Rodney was going to work on a project that looked so similar to what he had done before, in reality, drilling a data borehole was very different from what he had experienced.

"But I did not fully grasp that, to the point where I didn't oversee the data acquisition in the way I should have done."

"Drilling a data (research) borehole is so different from drilling a development well in an oil field", he says. "With an oil well, the end goal is to produce oil. Data acquisition is important, but ultimately, even when gaps in data exist, the success of the well is determined by the volume of hydrocarbons produced. That is not the case with a research borehole such as the ones we drilled with NAGRA. Budgets are relatively smaller, the goal is to get the data we need, and there is only one chance to do it right", Rodney emphasizes. "It is a completely different mindset."

IT'S THE MINDSET

And it is the mindset that you have to embrace when joining another sector. "I must admit that I had to learn this to an extent", continues Rodney. "For instance, in Nuclear Waste Disposal projects, temperature records are a primary parameter in the data acquisition process. Way more important than they are in oil and gas. But I did not fully grasp that, to the point where I didn't oversee the data acquisition in the way I should have done. I thought I knew, but I didn't. Only after this realization, I was "tuned in" and made sure that the measurements were done to meet the exact project specifications."

Rodney Garrard.

Rodney's experience shows that the same subsurface setting can be approached very differently depending on what the goal of drilling is. But there are a lot of cross-overs at the same time. When people in CCS are concerned about the integrity of a seal, they could equally consult literature on nuclear waste disposal research, because in both cases the same rule applies: No seal, no deal!

Rodney now works in the global energy insurance industry. One of the important things he brings to his work environment is the notion that in subsurface projects there is no such thing as zero risk. "Therefore, in order to insure projects successfully, which is always the final hurdle before things can really kick off, we have to assess whether a sound technical review process was followed", he concludes. Having been exposed to multiple industries now, and learning about data acquisition objectives in different industries, Rodney feels that he is in a much better position to do so. ■

Henk Kombrink

PHOTOGRAPHY: PRIVATE

Wind and solar energy – temporarily stored in a salt cavern

Dutch company Corre Energy is looking at options to store excess renewable energy as compressed air in salt caverns

One of the major challenges for the energy transition is the storage of excess energy that can be used at times when the wind does not blow or the sun does not shine. Corre Energy in the Netherlands is looking at storing excess wind or solar energy in the form of compressed air into salt caverns in the northern part of the country as a solution to this problem. How does this work? We caught up with Corinne Faassen from Corre Energy to hear about the plans.

"The project is in its planning stage; the caverns still need to be created", Corinne emphasises. "There are salt caverns in the northern part of the Netherlands already, but we are looking at deeper targets than the existing ones, allowing for a larger pressure drawdown. In addition, creating the caverns with air compression in mind is an opportunity as well, because the shape of the cavern is important to ensure stability, both from a rock-mechanical as well as from a subsidence point of view."

TEMPERATURES BIGGEST CONCERN

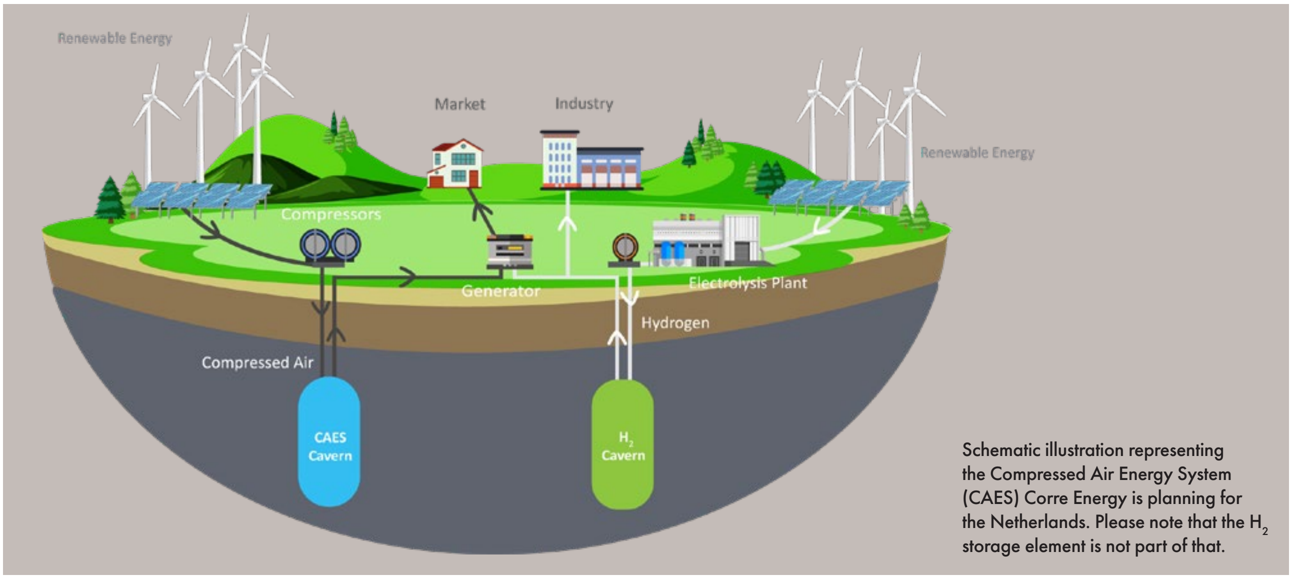
"When it comes to the stability of the salt cavern walls", Corinne explains, "it is not so much the pressure changes that are the biggest concern, but the associated temperature changes when pressures drop due to air production. We have identified that the salt wall could incur some microcracking (dilation) when pressures and temperatures suddenly drop and especially when these low temperatures continue for a long time. It is a complex combination of absolute pressure, pressure change rate, temperature change, and duration of pressure reduction during air extraction."

It is not clear yet how severe these microcracks are, as salt is known for its self-healing capacities, especially when pressures and temperatures rise again during a consequent air injection phase. "In order to mitigate this, further sensitivity studies will be done to get insight in how these four factors interact, and in which order the processes take place at and in the cavern wall. Based on these findings, the safe operational constraints will be determined", Corinne adds.

A SIGNIFICANT ENERGY BUFFER

The amount of energy that can potentially be withdrawn is significant. "In case of an urgent need", Corinne explains, "we could potentially draw down 320 MW for 3.5 days from two caverns we have planned at a depth of around 1,100 - 1,300 m." Saying that, it is important to realise that 50% of the energy produced will be required through either the burning of gas or H_2 to get the decompressed air up to a temperature ready to be entering the turbine that will generate the electricity. In that sense, the process will still need a source of energy over and above the compressed air. But the potential is clearly there. ■

Henk Kombrink



Schematic illustration representing the Compressed Air Energy System (CAES) Corre Energy is planning for the Netherlands. Please note that the H_2 storage element is not part of that.

SOURCE: CORRE ENERGY

The challenges and success factors for CCS in Australia

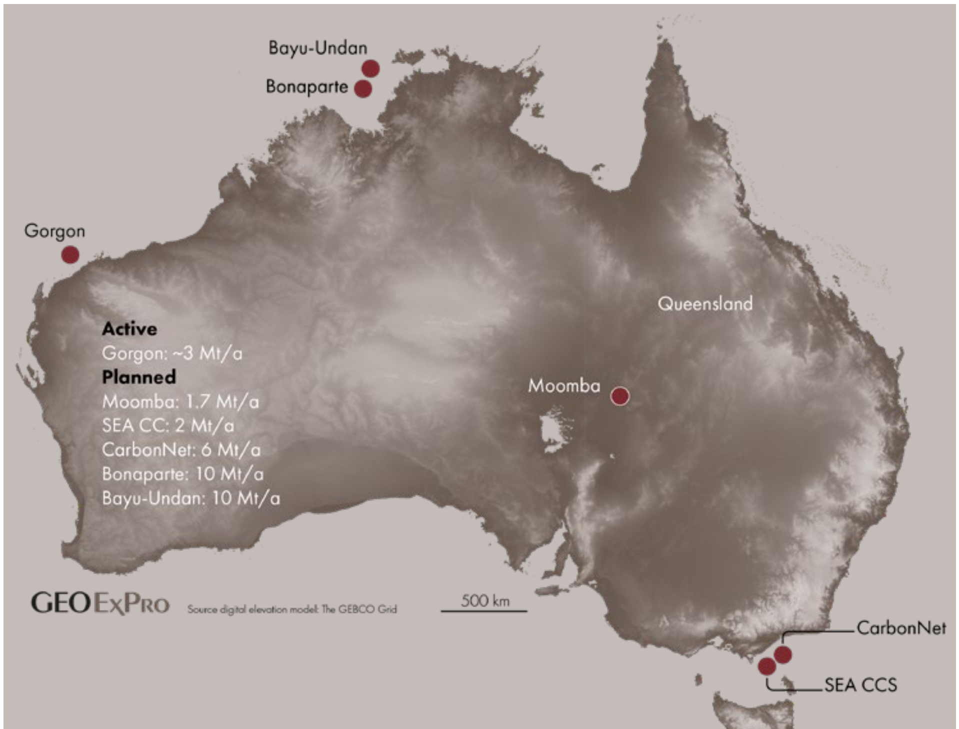
With the second carbon storage project due to come on stream this year, CCS needs to ramp up significantly to make a serious dent in annual emissions

KIM MORRISON, EXPLORATIONEDGE

Per capita, Australia is one of the highest emitters of CO_2 in the world, only superseded by Saudi Arabia. This is mostly due to the country's coal and gas exporting activities, and of course because of its low population of about 25 million people. When the emissions from coal and gas export are included, Australia is responsible for around 4,8% of global emissions or around 1.7 billion tonnes per year.

So, there is a clear incentive for Australia to ramp up carbon storage projects. And, with sedimentary basins present along the western and northwestern shelves, along the southeast coast and in Queensland, there are ample suitable locations where this can take place, and is taking place already – the Gorgon CCS project is situated along the NW shelf.

There is progress when it comes to administering CO_2 storage activities in Australia. For instance, Santos became the first company to officially book CO_2 storage resources using the Storage Resources Management System (SRMS) in 2022, in the leadup to the start-up of their Moomba project, which is due this year. The company booked 9 million tonnes of 2P storage resources, and 91 million tonnes of contingent resources in the Cooper Basin.



The planned and existing CCS projects in Australia.

NOT ENOUGH

However, when combining Gorgon and Moomba, with a combined storage rate of around 5 million tonnes a year, much more needs to be done if more than 1% of Australia's emissions are to be abated.

There are a few more projects in the pipeline though. SEA CC, CarbonNet, Bonaparte and Bayu-Undan will add another 31-35 million tonnes of CO_2 storage to the existing projects, which then amounts to around 10% of Australia's emissions. Ultimately, the aim is to store around 140 million tonnes per year by 2040, which means that a lot more projects need to appear on the radar soon, given that these projects can easily take 10 years from concept to injection.

WHAT IS THE COST OF DOING NOTHING?

One of the challenges that clearly needs to be overcome to realise this goal is the assessment of risk versus reward – what is the impact of doing nothing? At the same time, a series of fit-for-purpose and not too onerous guidelines regarding monitoring and risk of leakage are required that do not form a show-stopper at the project scoping phase. Only then we will see the 2040 deadline being met. ■

TECHNOLOGY

"The methodology could only be developed now because of the emergence of deep machine learning models and the ability to store large databases."

Christophe Germay – Epslog

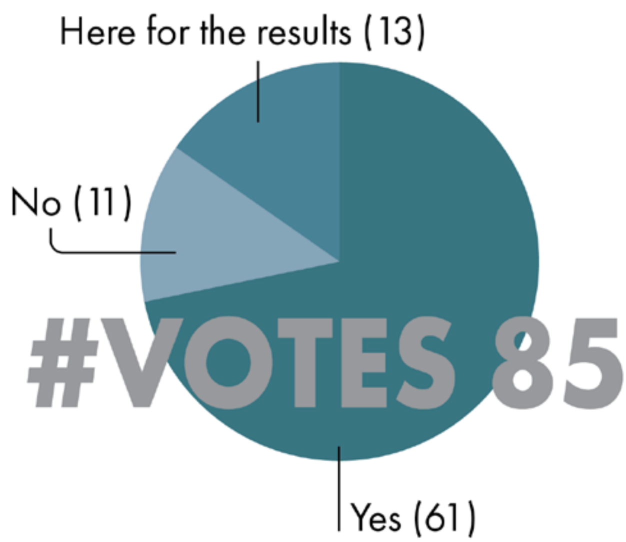
In the near future, will fibre optic sensing technology be used in most of the newly drilled oil, gas, geothermal and carbon storage wells?

That's the question we asked our followers on LinkedIn

FIBRE OPTIC sensing technology in oil, gas, geothermal and CCS has recently proven to be a powerful tool to monitor fluid flow in reservoirs, pinpoint the location of fracs, check wellbore integrity and acquire seismic data. And where computing power was previously a challenge to process the data resulting from continuous monitoring, there are now solutions available to process in real time and filter the data adequately.

Based on the conversations about the technology we had with experts on the matter, it already became clear that fibre-optic sensing is a promising way to quickly obtain information along the entire well. As mature fields are becoming more challenging to produce from, and new fields are located in more complicated geological settings such as salt overhangs, it does make sense to deploy data acquisition methodologies that allow the operator to make better informed decisions, and fibre optic sensing seems to increasingly fill that gap.

It is probably no coincidence that Equinor, the operator of the giant Johan Sverdrup field in Norwegian waters, has deployed fibre optic sensing technology in their production wells whilst simultaneously setting the bar very high when it comes to the ultimate recoverable volume from the field. The fibre optic data will allow Equinor to regulate oil and water inflow in such a way that water break-through is kept to a minimum and wells will produce at lower water cuts for longer.



A CLEAR MAJORITY

Against that background, it may not be too much of a surprise to see that the majority of voters in the poll believe the fibre-optic technology is indeed a technology that will find its way into many of the wells that will be drilled in the future, be it for oil and gas, geothermal or carbon capture and storage. Out of a total of 85 voters, 61 people from a wide variety of technical backgrounds are of that opinion.

Only 11 people indicated that they do not believe fibre optic sensing is going to be fitted in all newly drilled wells. One voter in this group is a person who is well embedded in the subsurface technology realm in Equinor, which is an interesting observation given that this company is a front runner in the application of the technology.

As always, there is a number of people who is more interested to see how other people think rather than casting a vote themselves. Thirteen people voted "Here for the results", with employees from Shearwater, Petrobras, CNOOC and TGS to name a few. Another LinkedIn member works in the geothermal industry and is involved in planning new wells; maybe the poll result added gravitas for this technology to be used – the more so because the target reservoir in this case are fractured carbonates. ■

Henk Kombrink

PERMANENT OR INTERVENTION?

Fitting a wellbore with permanent fibre optic technology may still be a challenge or cost-prohibitive for older wells, but the use of disposable fibre optic tools allows for interventions to be done in a very time efficient manner. This has also opened the door for monitoring wells in mature assets.

Grain size distribution matters

Due to the advance in computing power, sedimentology is now entering a new phase of machine learning

CHRISTOPHE GERMAY, EPSLOG

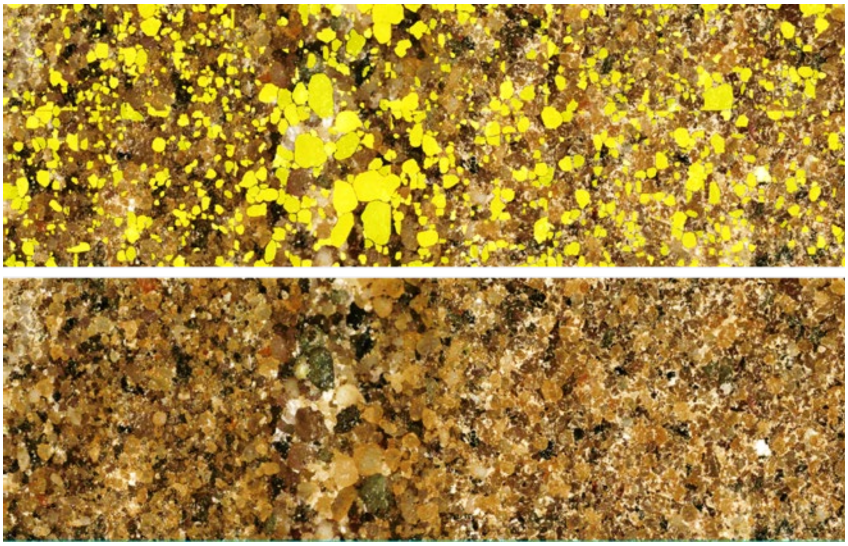
For sedimentologists, describing the grain size of core samples is key because it provides valuable information about the sedimentary environment, depositional processes, petrophysical properties, and the history of the area where the samples were collected.

However, sedimentological descriptions involve interpretation and can be influenced by subjective factors such as the observer's expertise and perception. Observing individual grains on a cored surface is not always straightforward, let alone sampling an entire length in detail if you would just have a handless at your disposal. Equally, where a single observation of the "average" grain size per foot of core can be practice when it comes to manual core interpretation, it is the sorting and grain size distribution along the cored length of a reservoir that can reveal a lot more information about its flow characteristics.

To make the process of grain size determination more objective, Epslog has developed a specific methodology where ultra-high resolution images are taken continuously along the core. Using these images, a deep machine learning algorithm was subsequently trained to perform a segmentation of each identifiable grain. A post-processing algorithm then sorts every detected grain into a predefined bin, such that a distribution grain size profile can be established for each cm of core.

The methodology could only be developed now because of the emergence of deep machine learning models and the ability to store large databases.

Sedimentologist can use calculated grain size to support their decision, work more rapidly and more efficiently. Such kind of approach opens the door to a more robust and efficient way of working and can be extended to other geological descriptions based on photographs. ■



SOURCE: EPSLOG

Ultra High-Resolution images of a cored sandstone, with the yellow segments representing the detected grains through Deep Machine Learning Algorithms.

The competitive world of coring

Innovation in coring means reducing rig time, so there is a major drive to come up with new ideas

Until wireline logging came into swing, cutting core was the most important way to obtain reliable information about the targeted formation. With the advance of wireline logging though, the need to cut core has diminished, but it has certainly not entirely disappeared. Especially in exploration wells, cores are still cut routinely because of the value these samples bring when it comes to better understanding reservoir parameters.

A downside to coring, especially at great depths, as often happens in the oil and gas industry, is the fact that at the moment the wellsite geologist calls coring point, the drill string needs to be pulled out of the hole in order for a coring assembly to be fitted. This adds significant rig time, which is why drilling managers are not always keen on seeing core taken.

LOOKED AT FOR A WHILE

But, it would be a lot easier though to convince a drilling manager to cut core when a coring assembly is already down the hole whilst "conventional" drilling is taking place. This was already realized in 1969 when a patent was filed by Mr or Mrs Elenburg, who suggested to pump shorter segments of core to surface in the drilling fluid rather than keeping them in a core barrel. Apparently, this solution did not make the cut though, leaving a range of other mechanisms to be proposed over the years, with many of them having some sort of limitation.

Norwegian company Coreall now seems to have found a solution that does enable one assembly to alternate between coring and drilling whilst being able to log the core as it enters the barrel, thereby enabling geologists to evaluate the core in real time. This has led to a major reduction in rig time, with much less or no tripping required any more.

"Patents form a good source of information to see what innovations have been made."

A very special bit of core from the North Sea; the transition from Rotliegend sandstones to overlying Zechstein shales.

Even though the company was not available for comment, the five patents that were filed by the company over the past years can be easily found through Google Patents. Every patent also comes with a description of the technology and a history of previous inventions in the same category. As such, everyone can easily check what the invention is about and how to potentially develop something else that may be even better.

And competition is fierce in the world of coring. We came across a magazine called Coring, which is run by a team in Bulgaria. One of the articles runs the following headline: "BG Drilling launches its latest development to compete with Norwegian technology." Let's put it out there. The article is probably talking about a Norwegian technology that is more applicable to the mining sector, but the tone says it all. Maybe that is the reason why Coreall was not so keen to talk to us about their invention? ■

Henk Kombrink

DEEP SEA MINERALS

"The combination of seismic and EM is therefore an elegant solution for identifying sulphides."

Bent Kjølhamar - TGS

Norway opens for seabed mineral activities

In a world's first, the Nordic country has now opened part of its Exclusive Economic Zone for exploration and potentially mining of seabed minerals

EARLY JANUARY, the four largest political parties in the Norwegian parliament voted to open an area covering about 280,000 km^2 for seabed mineral activities. In a reaction, environmental organizations, as well as the opposing parties, have argued that it is premature to open for activities in the deep sea, given that more research is required before responsible mining is possible.

In turn, the Government stated that more data on deep-sea ecosystems, environments, and resources will need to be gathered first. In addition, according to an agreement made by the four majority parties, exploration companies will always need to get approval from the Parliament on their Plan of Extraction before mining activities can commence.

This means that while Norway has technically opened for exploration and extraction in the deep sea, actual mining may not happen at all unless the industry firmly demonstrates that the mineral resources are technically and economically feasible to extract with an acceptable environmental footprint.

POSSIBLE LICENSING ROUND IN 2024

The Ministry of Energy is now expected to start a licensing process, in which potential applicants may provide input on which areas they consider most interesting from a resource perspective.

At the Deep Sea Minerals 2023 conference in Bergen in December, Director General Lars Erik Aamot at the Ministry of Energy stated that a licensing round will probably be announced this year.

Area in blue that has now been opened up for deep sea minerals exploration.

He explained that it is the Ministry's strategy to open large areas and then do a stepwise process to make sure the most prospective, far smaller areas end up as exploration targets.

QUANTIFYING THE UNKNOWN

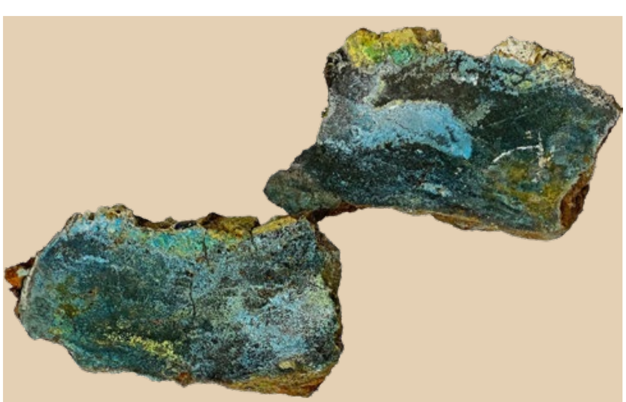
The Norwegian Offshore Directorate - NOD, previously Norwegian Petroleum Directorate - published its first resource assessment for minerals in the deep sea in January last year. The NOD evaluated the potential for sulphides along the ridges and crusts on seamounts.

Although the numbers presented are calculated based on relatively sparse data sets and do not meet the standards of international classifications of mineral resources, the potential is clearly there.

As an example, the total amount of copper in sulphides is estimated to be 38 million tonnes. That is equivalent to almost two years of global production. For the battery metal cobalt, the estimated amount - 1 million tonnes in the sulphides - is sufficient to manufacture around 75 million electric vehicles. The crusts are expected to contain a wide variety of metals, from cobalt, manganese, and lithium to the more exotic constituents of the periodic system such as gallium, niobium and rare earth elements.

Given the small number of sampling locations Norway still has on the deep-sea mineral resources, more surveys are needed. By allowing the commercial players to start exploration, their upcoming work programmes will contribute to accelerated data collection and broader knowledge building. Which is exactly what is needed. ■

Henk Kombrink



Green copper mineral deposit on a darker sulphide sample, acquired by the Norwegian Offshore Directorate at the Mohns Ridge in 2020.

SOURCE: NOD

Finding deep sea minerals with oil and gas technology

The sulphide deposits on the Norwegian continental shelf can form the basis of a new industry. Well-known Norwegian exploration technology can help us map them

DAG HELLAND-HANSEN, EMGS, AND BENT KJØLHAMAR, TGS

"WITH CONVENTIONAL exploration for oil and gas, electromagnetic measurements (EM) are used to map resistivity in prospects - hydrocarbons are more resistive than brines. When we are looking for minerals, the opposite is true. It is comparable to using a metal detector to look for coins on the beach", explains Dag Helland-Hansen, EVP Global Sales and Exploration Advisor at EMGS.

EMGS is among the companies that have positioned themselves for a possible new industry on the Norwegian continental shelf. In the deep sea on the Norwegian shelf, the "coins on the beach" are represented by metal-rich massive sulphide deposits (seafloor massive sulfides, SMS).

Dag Helland-Hansen, EVP Global Sales and Exploration Advisor at EMGS.

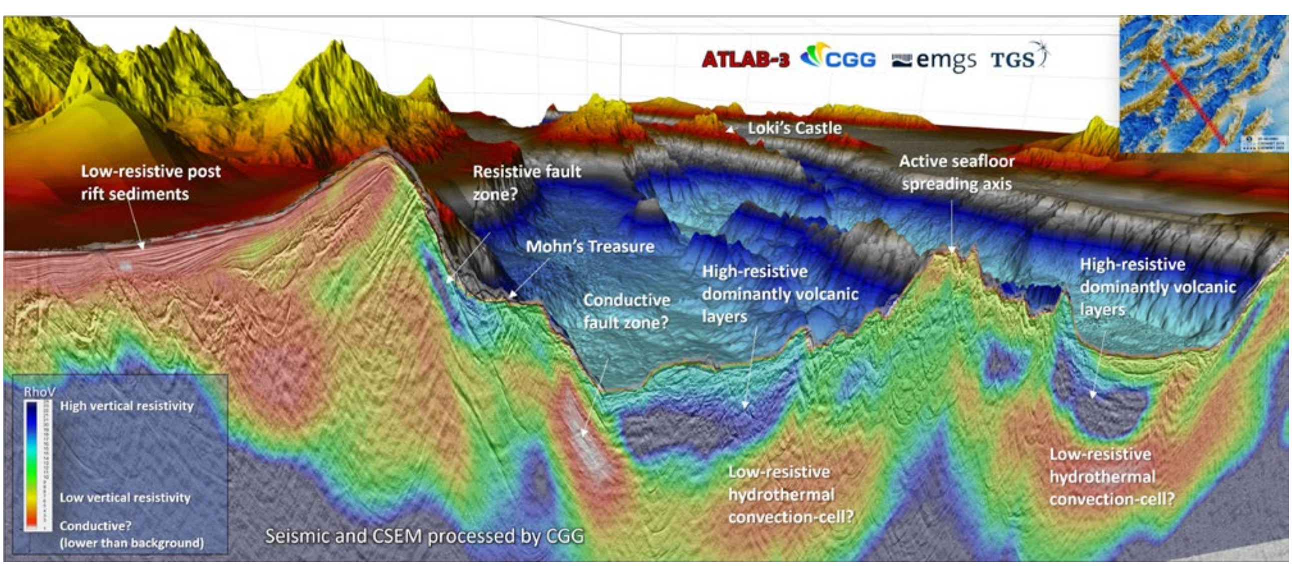
Bent Kjølhamar, Senior Geologist at TGS.

SEISMIC AND EM – AN ELEGANT SOLUTION

Traditional geophysical exploration methods such as EM can play an important role in finding the hidden sulphide deposits. However, electromagnetic measurements are not the only exploration method suitable for marine mineral mapping.

"Seismic data is crucial for getting a picture of the structures and layers on and below the seabed. With a geological understanding of how and where the sulphides occur in the back of your mind, the seismic can tell us which geological bodies stand out as possible targets", says Bent Kjølhamar, senior geologist at TGS.

Kjølhamar adds that seismic data can also provide a clue as to what ▶



This seismic line runs across the spreading axis at the northernmost part of the Mohns Ridge. The (almost) inactive sulphide deposit Mohns Treasure is located on the slope to the left in the foreground. The active hydrothermal field Loki's Castle is in the background. EM data is superimposed on the seismic data, which makes it easier to interpret different rock types and processes. We see, among other things, a possible conductive fault zone under the Mohn's Treasure. The bathymetric inset map shows the northernmost part of the Mohnsryggen at approx. 73 °N. The lines show where geophysical data was collected during the ATLAB-3 cruise in 2022.

SOURCE: ATLAB, CGG, EMGS AND TGS

kind of rock a given geometric body identified in seismic data consists of. "Published data show that sulphide deposits often have somewhat higher seismic velocity and they will typically have a higher density than the surrounding sedimentary or volcanic layers. This will normally give a good contrast and a strong seismic reflection."

However, he admits that there are also other structures at the mid-ocean ridges that have similar signatures, namely fresh volcanic rocks, be it solidified lava or intrusions.

"But this is where EM comes to the rescue. It can distinguish mineral deposits from volcanics because the former are far more conductive than the latter. The combination of seismic and EM is therefore an elegant solution for identifying sulphides", the senior geologist explains.

Helland-Hansen adds: "An EM signal in itself is not sufficient. It is low frequency and cannot provide a precise position of a possible conductive body. But if we put the EM data on top of the seismic data, we can map the geological bodies and determine which of them are conductive. We have then narrowed them down to interesting targets for the exploration companies."

DEEP IMAGING CONSORTIUM

It is obvious to Kjølhamar and Helland-Hansen that service companies such as TGS and EMGS should join forces and deliver joint geophysical solutions regarding the search for sulphide deposits.

Not only have they both worked for several years to understand how the technologies of their companies can be applied to finding deep sea minerals. They have also had the opportunity to test the technologies on the Norwegian continental shelf through the NTNU-led consortium ATLAB, which most recently carried out a cruise along the Mohn Ridge in 2022.

ATLAB started as a pure research project to achieve a new understanding of the formation of the Atlantic Ocean. However, it gradually became clear that the research was very relevant to understanding the hydrothermal systems under the seabed and therefore also the formation of the mineral deposits in this unique environment.

Both Helland-Hansen and Kjølhamar were instrumental in expanding the consortium's focus towards applied research on deep-sea minerals. With that, more industrial companies joined the consortium as well. During the 2022 cruise, EMGS learned that conventional acquisition with nodes on the ocean floor and a source towed deep, near the ocean floor, is most cost-effective for good EM imaging.

HILLY TERRAIN PRESENTS CHALLENGES

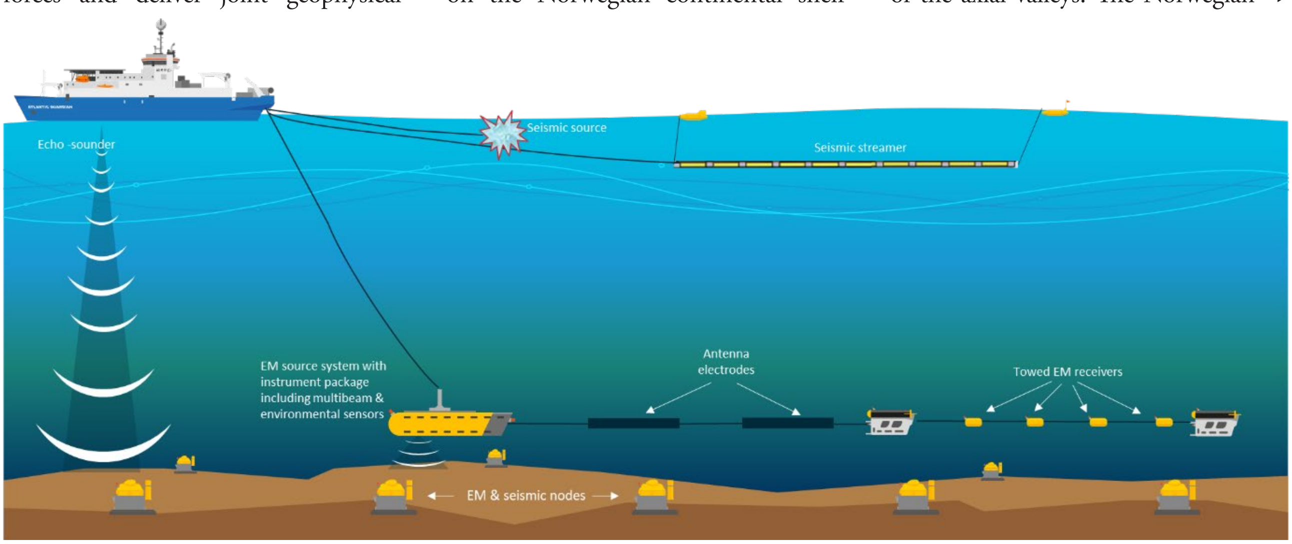
The hydrocarbon-prospective areas on the Norwegian continental shelf are usually located where the seabed is relatively flat. In contrast, the landscapes at the mid-ocean ridge are more reminiscent of the western and northern Norwegian mountain areas. In the "valleys" we find sediments deposited by ocean currents. These can be 300 meters thick. In steep terrain and on the peaks, where the ocean floor crust is usually exposed, they are generally absent.

The EM source should be towed as close to the seabed as possible so that the signals are not absorbed in the water column. At the same time, the operator must avoid colliding with a rock face.

Despite this, Helland-Hansen is satisfied with the data they have collected so far, and has plans for how to tow the source more slowly and closer to the seabed in all kinds of terrain during future collections.

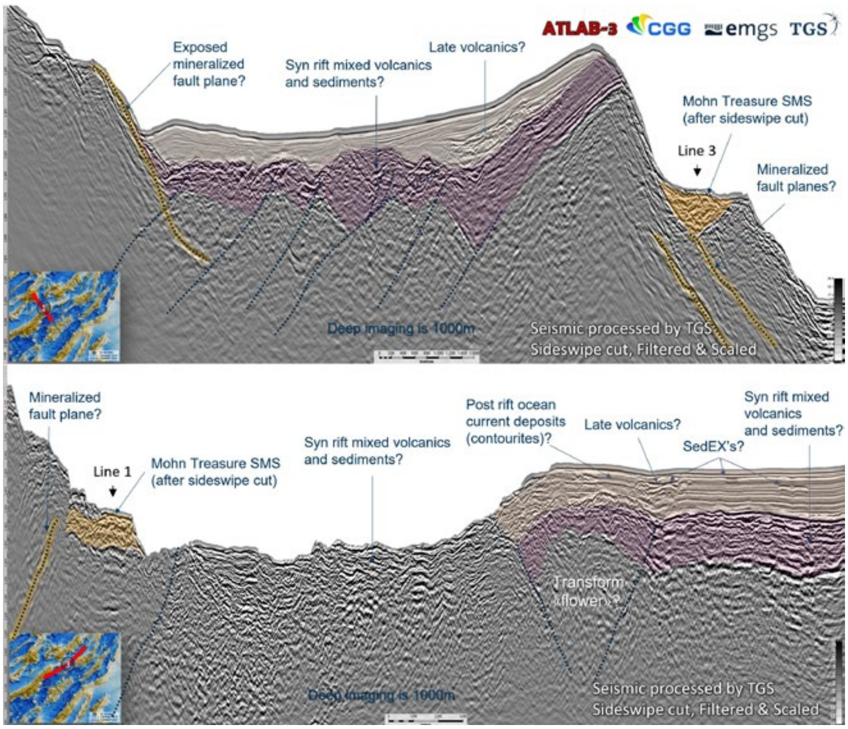
Kjølhamar adds that it is difficult to avoid this type of topography if sulphides are to be found. "At the end of the day", he says, "the prospects tend to be located along steep slopes, mainly on the side of or above deep fault planes that can be seen on seismic." The explanation lies in the fact that the faults often form conduits for deeply circulating mineral-rich water to reach the seabed.

Sulphides also occur as axial deposits, i.e. on volcanic ridges in the centre of the axial valleys. The Norwegian ▶



One ship, more measurements. Conceptual sketch for combined collection of EM and seismic data, as well as sonar measurements.

SOURCE: ATLAB



Two perpendicular seismic lines crossing Mohns Treasure, contributing to a better structural delineation of the sulphide deposit. Mineralizations and rock types are interpreted based on seismic and CSEM data. We see rotated fault blocks, and the purple-marked areas are interpreted to represent the active seafloor spreading period with mixed volcanic and sedimentary layers. The 2-300 meter thick sedimentary unit was deposited following the active spreading phase. Below Mohns Treasure we see a cone-shaped body that may represent further mineralization.

Offshore Directorate wrote in the 2023 resource assessment that the frequency of flank deposits is significantly higher than for axial deposits. They also regard flank deposits as superior in terms of tonnage and weight.

Also regarding seismic acquisition, hilly and steep terrain can present challenges. Kjølhamar firmly believes that 3D collection is necessary to obtain sufficiently good data. During the ATLAB-3 cruise, however, only 2D seismic data was collected.

"When we collect 2D seismic in hilly terrain, we get a problem with so-called side sweep. This is not a problem with 3D seismic. Another disadvantage of 2D measurements is of course that they only cover a narrow field along the acquisition line. As sulphide deposits are far smaller - on the order of 0.1 – 1 km^2 - than most hydrocarbon accumulations of commercial interest, it is easier to miss them."

"It can be solved to some extent by running many parallel 2D lines, or dense 2D grids, but then it will quickly justify acquiring 3D seismic to be sure that all present deposits are mapped within a given area", notes the senior geologist.

Helland-Hansen points out that 3D collection also provides a better product for EM data. "In short", he says, "3D EM provides better precision in spatial dimensions. This was also tested and confirmed during the cruise in 2022 with a mini-3D collection."

One of the data sets to be collected during ATLAB's 2022 cruise was seismic with nodes on the seabed. Dropping and retrieving the nodes from a depth of 3,000 meters was successful, but the data was incomplete. Temperatures turned out to be the biggest challenge.

"The nodes were simply not set for temperatures below 0 °C. Only one of the nodes collected data, as the temperature around it was just above zero. However, this is not a big problem, as long as we are aware that such cold water masses can be present in the deep sea and adjust the nodes accordingly", says Helland-Hansen.

POSSIBLE TO DISTINGUISH BETWEEN METALS

As mentioned, the EM technology is based on measuring electric current in the underground. We know very well that metals are excellent when it comes to conducting electricity - but can the EM signal tell anything about what kind of metals are found in a deposit, and at which concentrations?

"As of today, this is not information we have tried to get out of EM data sets. But theoretically, it should certainly be possible, and this will be the next step for us in technology development", says Helland-Hansen.

"EMGS has experience in determining rock properties in the oil and gas business. Part of a future solution that provides information on the content of sulphide deposits could be the use of IP."

The EMGS director talks about Induced Polarization, a geophysical method that is related to EM and is used, among other things, by the mining industry on land to find ores.

Briefly, the method works by sending electrical signals underground, followed by measuring the response that comes back to the receivers. Sulphides can preserve an electric field for a short time after the electric signal is sent, and this effect, induced polarization, can be measured and used to distinguish, for example, copper from iron.

The latter metal is of no value to the exploration companies, and so IP can, for example, be used to identify the "bad" prospects.

The ATLAB Consortium is planning another cruise this year, during which the various exploration techniques can be tested further. In combination with the recent government approval for commercial exploration, it can be expected that more activity and innovation will take place in this space, using technology from the oil and gas business. ■

SOURCE: ATLAB, CGG, EMGS AND TGS

INSIGHTS

"Seldom do we consider what might be happening deeper, especially in basement rocks. However, what happens there can just about always have an impact on what's going on in the sedimentary section above."

Molly Turko – Devon Energy

Geomodelling for CCS, a bridge too far?

Raffik Lazar

With the ramping up of CCS projects across the world comes a unique challenge: how to accurately build static reservoir models in a CO_2 injection context?

RAFFIK LAZAR, GEOMODL INTERNATIONAL

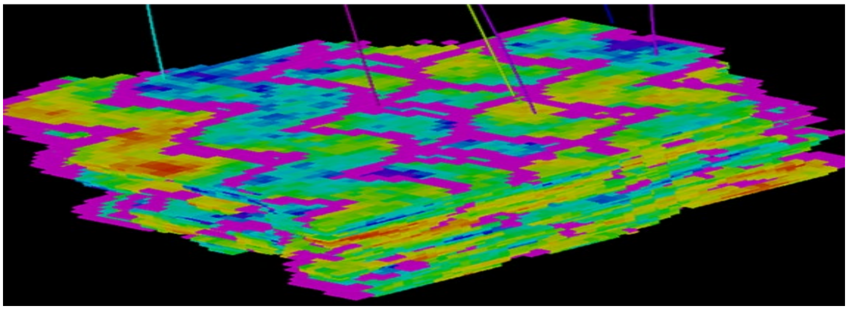
TRADITIONALLY, geomodels are built in a simplistic fashion, taking into account the inherent degree of uncertainty in the input data. Attempting to accurately depict an unseen geological object, often multiple thousands of meters deep underground, carries its fair share of challenges. Trying to guess a puzzle image with only a few pieces would sum up very well the daunting task faced by geomodellers.

To this day, the uncertainty associated with geomodels has been accepted by the geological community and the other users of their models. After all, there is no need to reach geoperfection to understand the bigger picture.

"Trying to guess a puzzle image with only a few pieces would sum up very well the daunting task faced by geomodellers."

Simple geomodels are often used to estimate the hydrocarbons in place. More complex geomodels, focusing on capturing the sedimentary variability in the reservoir, are built when trying to predict the dynamic behaviour under production and/or injection or more complex processes such as EOR.

Having a simplified geological image is acceptable as long as the physics in the reservoir is honoured. Moreover, no one will complain as long as the reservoir is producing within the uncertainty envelope of its dynamic prediction.



A NEW CHALLENGE

With CCS comes a new challenge, setting the bar higher if not the highest it has been to date. Injecting CO_2 in a mature reservoir brings a unique challenge at two levels.

First of all, the geomodel that will be used for monitoring CO_2 injection needs to be free from multipliers and other manual edits because this erodes the predictive power of the model.

Secondly, a thorough understanding of flow paths in the depleted reservoir is required to estimate how much CO_2 can be stored and which pathway(s) the fluid will follow from its injection entry point till its -hopefully! - final resting place.

A HIGH DEGREE OF REALISM

Geomodellers are therefore facing a unique situation where the degree of accuracy of static reservoir models must reach a level never attained before. This will be associated with the following key points:

- Faster turnaround time, close integration and multiple loops with reservoir engineers
- Critical look at data to make sure it is representative, including rapid identification of outliers
- The routine use of seismic 4D capability to have a real-time picture of the fluid movement in the reservoir and the ability to alter the geomodel accordingly
- Use of more powerful yet complicated interpolation algorithms to better represent the geology of the reservoir whilst honouring physics
- Geomechanics, although a niche capability at the moment, will have to be part of the routine workflow
- Locating faults or fractures in the reservoir with a superior degree of certainty and accuracy, predicting the effect on flow paths, storage and sealing properties.

In conclusion, more predictive geomodels will be the stepping stone for successful CCS injection projects. But in the current context, where geomodelling expertise is increasingly lost through the retirement of experienced people and a strongly reduced enrolment in geology courses at the same time, geomodelling for CCS might prove to be a bridge too far. ■

Suriname second shallow offshore bid round

Brought to you in association with NVentures www.nventures.com

Suriname bid round acreage will be popular, sandwiched between two major petroleum provinces

JONATHAN LEATHER, ASSOCIATE EDITOR, NVENTURES

THE SECOND shallow offshore bid round in Suriname was launched in November 2023 at the ICE Conference in Madrid. Management Presentations and Virtual Data Rooms have been available since 18th December 2023, with bids due on 31st May 2024. There are 11 Blocks on offer, covering a total of 34,520 km^2 in water depths of 150 m and less, including some areas never previously licensed.

The blocks lie on the offshore continental shelf to the north of Tambaredjo and to the south and southeast of the recent light oil discoveries made in the deeper water Guyana-Suriname Basin. The Tambaredjo Field is a billion-barrel onshore field discovered in the 1960s with heavy, biodegraded oil in shelfal sandstones of Paleocene age.

The Campanian-Santonian distal shelf and intra-slope turbidite plays of the deepwater area were opened up by the Liza-1 well offshore Guyana in 2015. These plays have now been successfully extended into Suriname's offshore where a series of substantial discoveries have been made by Apache and TotalEnergies in Block 58 and where the play has recently been extended further east into Block 52 with the success of the Roystonea-1 exploration well drilled by Petronas and ExxonMobil in late 2023.

AN OLDER SOURCE ROCK

In addition to the prolific Albian to Turonian-aged source rocks - locally referred to as the Canje Group - that supply these discoveries, recent petroleum systems analysis commissioned by Staatsolie has also confirmed the generative capacity of the Lower Cretaceous Aptian source rocks. This reduces the reliance on long-distance migration in the blocks on offer, and opens up the potential in the deeper Aptian and Jurassic stratigraphy.

The potential for multiple plays is therefore present, including stratigraphic and structural traps in both carbonate and clastic plays of the Upper and Lower Cretaceous, as well as the overlying Tertiary stratigraphy. Over 90 prospects and leads have been identified on the current bid round acreage on the existing 2D and 3D data. Proven analogues are found for the deeper plays on the North African conjugate margin, and in the newly opened South Atlantic Pelotas and Orange Basins.

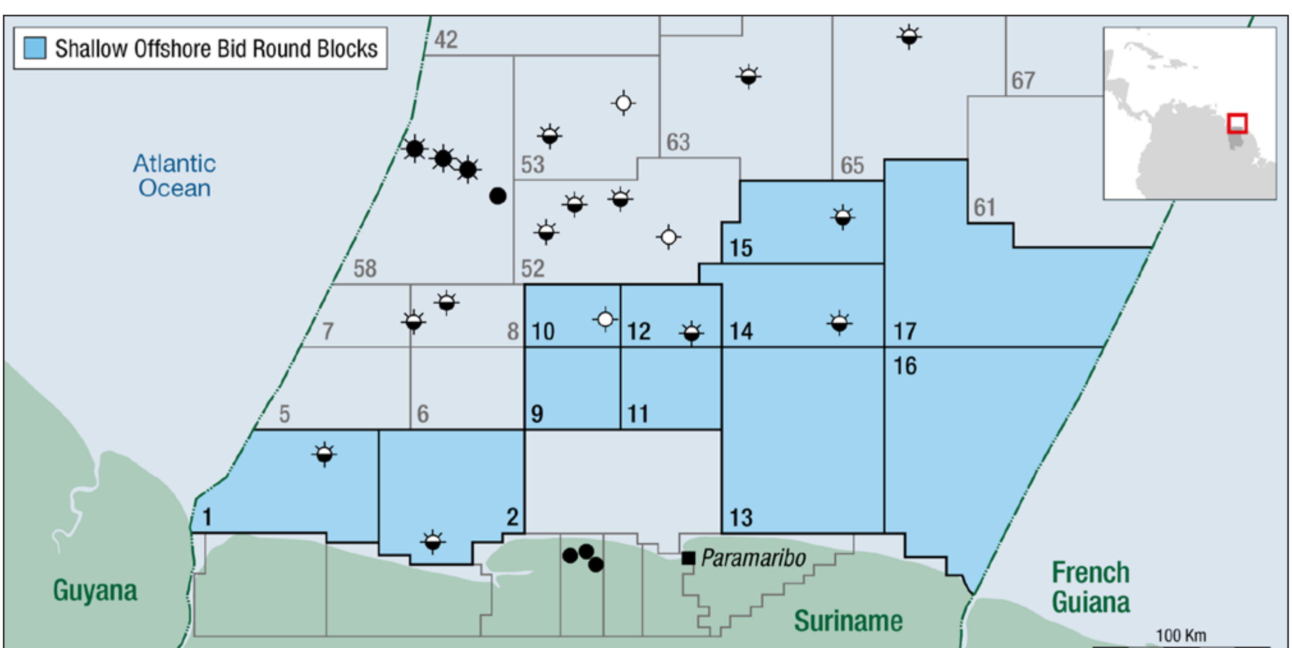


Figure 1: Shallow Offshore Bid Round offered blocks.

SIGNIFICANT ATTENTION EXPECTED

The 2024 Bid Round data room consists of a data package of 12 wells, 15,000 km of existing 2D seismic data and 4,371 km^2 of 3D seismic. Recently acquired multiclient 3D seismic covering the blocks of interest is also available to lease, and is being managed separately by the acquiring consortium consisting of BGP, CGG and TGS. This covers the western parts of the open acreage, Blocks 1,2, and 9-12.

All blocks are offered on an initial 3-year Exploration Phase basis, comprising competitive "minimum work programme" terms with additional biddable components:

- For blocks completely covered by the newly acquired multi-client 3D seismic data, the minimum commitment is to lease the 3D data and commit to a well in the first Exploration Phase
- For blocks with only existing 2D, or that are only partially covered by the new 3D, the commitment will require the lease or acquisition of 3D seismic, followed by a drill or drop decision
- Blocks with very limited data are being offered on fully biddable terms

The acreage on offer also benefits from new, more favourable, fiscal terms.

This is the third Surinamese bid round held since 2020, following on from the Shallow Offshore Bid Round in 2020/21 and the Demerara Bid Round in 2022-23. Given the interest that was shown in these rounds with blocks awarded to companies including TotalEnergies, Chevron, Shell, and QatarEnergy, the second shallow-water bid round is also expected to receive significant attention. ■

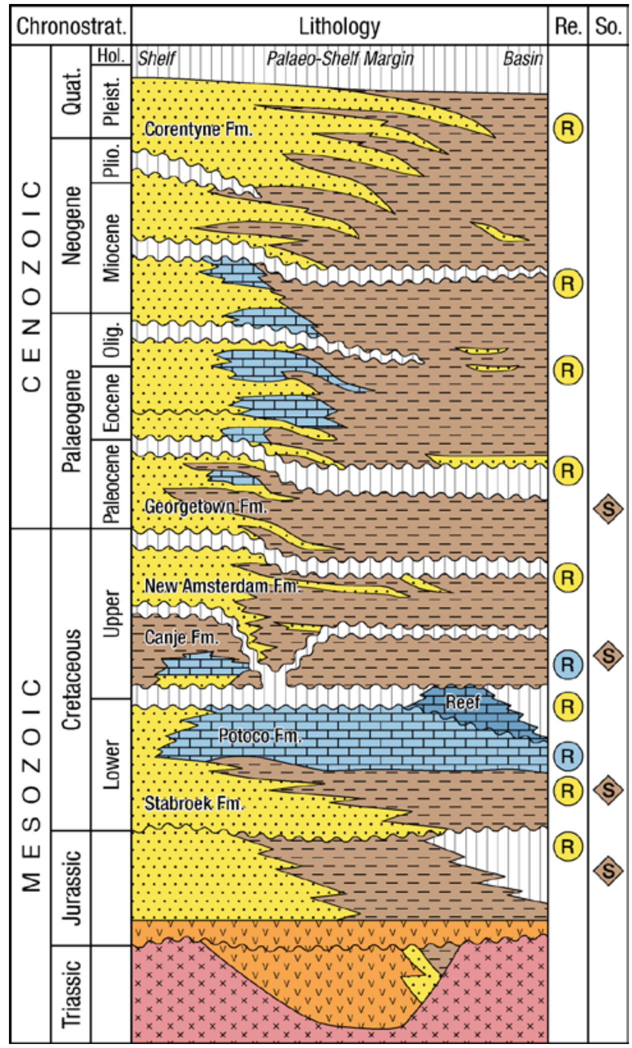


Figure 2: Generalised stratigraphy, reservoir, and source intervals of the Guyana-Suriname Basin (after Nemčok et al, 2015).

PHOTOGRAPHY: PIXABAY

Can a seal fail?

David Rajmon

Ideas such as a seal failing due to fluid pressure or breaking mechanically are often used to explain a lack of hydrocarbons in a mapped closure. But is this how it really works?

DAVID RAJMON

A SEAL IS a rock that has a higher capillary entry pressure relative to other adjacent rocks. The higher the contrast, the greater the hydrocarbon column it can hold. The sealing capacity is a function of interfacial tension between the hydrocarbons and water. It is not a function of seal thickness or fluid overpressure. So, all that is needed to hold the entire hydrocarbon accumulation is a single layer of pore throats.

Once a hydrocarbon column builds sufficient buoyancy pressure, the fluid enters and flows through the seal pore throats - either between grains or in fractures. The flow continues as long as there is sufficient pressure to drive it. Seals act as a valve. There is no permanent pressure damage that would drain the entire trap. The seal simply releases the fluid and pressure that exceeds its sealing capacity and it can do so repeatedly and over hundreds of millions of years. Using the term "failing" is therefore a misconception.

That's why we see long-lasting low-saturation gas chimneys on seismic. Somewhere underneath there is a trap filled to maximum capacity and leaking at the rate of hydrocarbon charge. Seeps are a good thing!

Experiments with sieves submerged in water holding an air cap illustrate this nicely. In these experiments, a burst of air is periodically released and the air column below decreases to about a half. A recent more realistic experiment imitating the sediment and slow charge shows gradual air release and the air column stays the same.

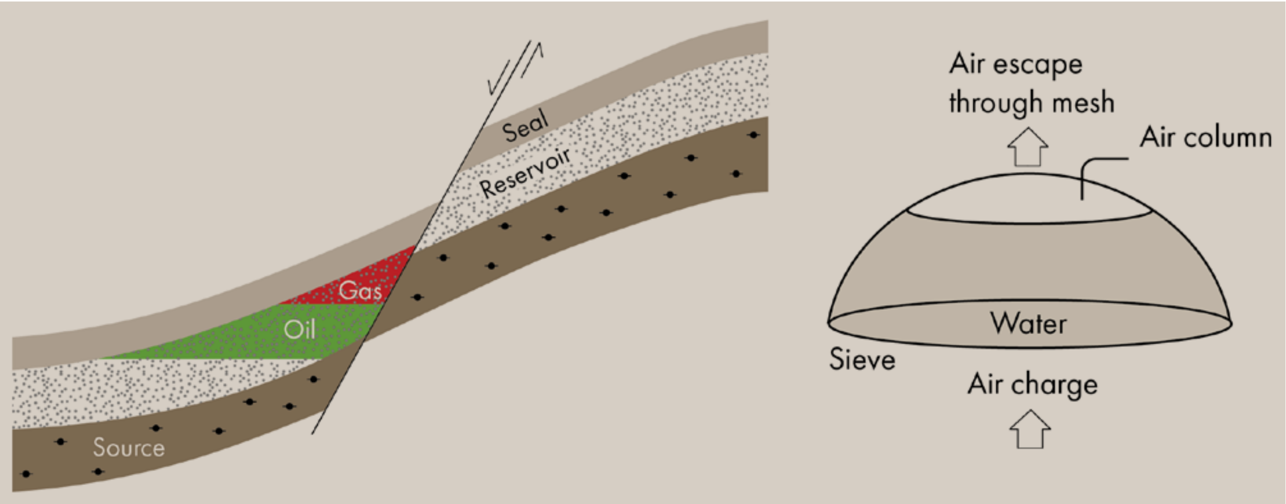
MECHANICAL BREAKING LOOKS MORE PROMISING... BUT IS IT?

First, can a rock fracture from increased hydrocarbon fluid pressure? It seems reasonable from the perspective of leak-off tests. But as Zhiyong He recently pointed out, it is unlikely. Hydrocarbon generation is an extremely slow process, in the order of 0.01 cm^3 per year per cubic meter of source rock - more than 8 orders of magnitude slower than the pumping rate for shale fracking. Generated pore pressure likely dissipates as fast as it grows.

Second, clay-rich seals are ductile under mechanical deformation and form a fold rather than a discrete fault. With increasing displacement and less clay in the sedimentary sequence, deformation will look more like a fault. But then the shales on the fault will smear, and brittle rocks may grind to a fine-grained sealing fault rock. The maximum potential sealing capacity may be reduced but a wide range of actual sealing capacity is still possible.

Third, can we talk about a seal failure if the fault was active long before the first hydrocarbon charge? To me, it is a part of geological history that either created a fault seal or did not. Provided enough time, fractures and fault rocks may cement under elevated burial temperatures. Thus, faults carry a range of possible sealing capacities that may be higher or lower than the adjacent sedimentary seal capacity.

In summary, it matters what we call things. To me, the term "seal failure" seems rather overused and misleading. ■



Don't forget to look deeper

As geoscientists, we should create a habit of "looking deeper" when working a new basin, you never know what you might find

MOLLY TURKO AND ALEX BIHOLAR, DEVON ENERGY

Dr. Molly Turko,
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As oil and gas geoscientists, we often focus on the reservoir we are targeting. Seldom do we consider what might be happening deeper, especially in basement rocks. However, what happens there can just about always have an impact on what's going on in the sedimentary section above.

The basement can be a culprit for geothermal and geochemistry anomalies observed in produced fluids. It can also set up structural trends or lineaments that develop during later tectonic events impacting things like structural traps, migration pathways, breached seals, and depositional trends of the reservoirs above. Therefore, studying the basement should be a vital step when exploring for a prospect or developing a play.

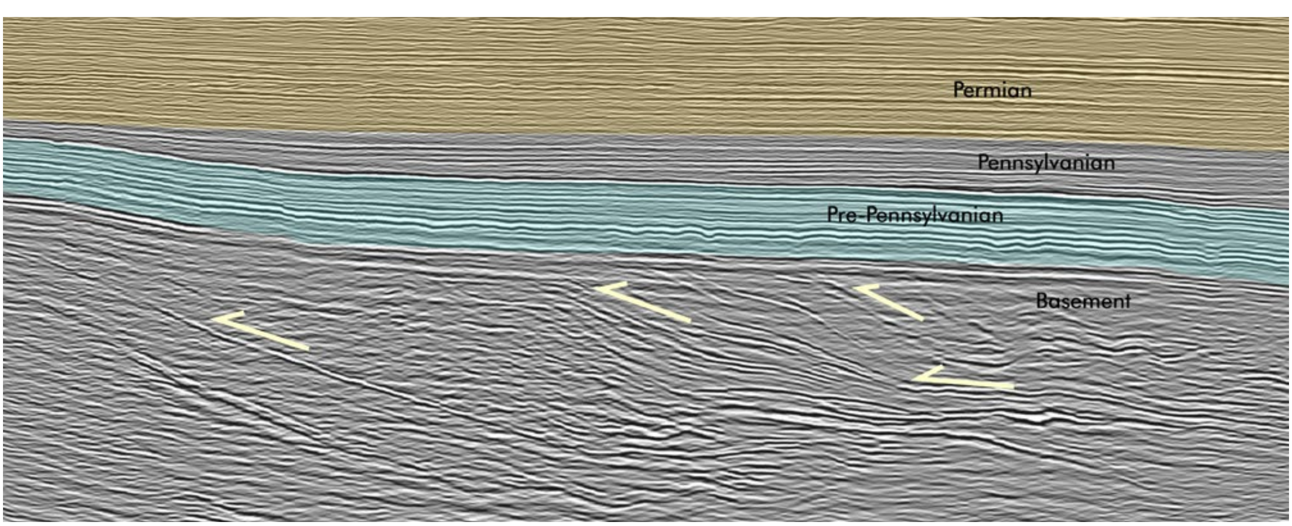
TWO OROGENIES

The seismic line shown here is from west Texas, where we see relatively flat-lying Permian and Pennsylvanian strata, gently dipping pre-Pennsylvanian age strata, and more steeply dipping intra-basement reflectors. The intra-basement reflectors were initially very puzzling. However, with some knowledge of the tectonic history and looking at nearby outcrop data, we can presume that what we're looking at is part of the Proterozoic-age Grenville Orogeny and these are likely meta-sediments that were sheared in an ancient fold and thrust belt.

Following the Grenville Orogeny were periods of erosion and deposition, removing much of the Precambrian topography. This was followed by passive margin subsidence resulting in deposition of carbonates and shales in the Tobosa Basin, the precursor to the modern Permian Basin. The region was then subject to the Pennsylvanian Orogeny where Grenville-age structures and younger strata were deformed. While much of the substantial deformation occurred during the Pennsylvanian, some of the activity did linger into the Permian, affecting many of the reservoirs targeted today. The Pennsylvanian age structures impacted paleo-bathymetry, guiding sediments to their final Permian depocenters. These structures tend to overlie deeper Grenville-age deformation, suggesting that many of the Grenville-age structures were either reactivated or controlled the location and orientation of Pennsylvanian-age structures.

SHAPING DEPOSITIONAL PATTERNS

Although the resulting structures at the Permian level may appear subtle, the impact from the Grenville and Pennsylvanian orogenies had a huge role in shaping Permian depositional patterns. We can identify areas where faults were more easily reactivated versus areas where the basement was more stable during deformation. This may identify migration pathways, seal breaches, and subtle traps. We can also identify terrane boundaries and tie that to geothermal anomalies. So, although often overlooked, the type of basement rock, the fabric, and the structural deformation are all important things to consider and understand for successful prospecting in a basin. ■



SOURCE: DEVON ENERGY

Tidally-influenced fluvial deposits

Denmark may not be the country you would first associate with spectacular outcrops, but there are certainly some nice sections to be found. This Lower Miocene outcrop is located west of the city of Aarhus on the Danish mainland, in an area that beautifully allows the reconstruction of variations in sea-level, sediment supply and climatic fluctuations around 21 million years ago. At the time, the Norwegian continent formed an important source of sediments that were shed into the North Sea Basin through southward flowing rivers. The fact that these deposits can now be seen at surface is due to the subsequent Pliocene and Pleistocene uplift of the eastern part of the wider North Sea.

The cross-bedded sands in this outcrop belong to the Addit Member of the Billund Formation. They are part of a mostly fluvial and fine-grained succession that was deposited in an incised valley fill once sea-levels started to rise again. The rhythmic deposition of mud drapes between different cross-bedded sets suggests a tidal influence, as well as the thinner mud drapes that can be seen on the faces of individual foresets. A beautiful example of tidally-influenced sedimentation.

Photography: PGK field trip, 2010

FEATURE YOUR OUTCROP

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

Bouma and Tybalt

Taking a look at a core from the Upper Jurassic Tybalt discovery in the UK Northern North Sea in the context of the classic Bouma sequence

MARCOS ASENSIO

Marcos Asensio

THE BOUMA sequence – proposed by Arnold Bouma – has been a cornerstone in the interpretation of turbidites and high-density sediment currents since its publication in 1962. The Bouma sequence is a model of sediment-laden gravity flows and sedimentary structures. It represents the waning of a turbidity current as it passes over a single point.

An ideal Bouma sequence begins with a massive sand interval (Ta) characterized by high-energy. This interval often has mudclasts ripped from the base and dish structures may be present. This facies is followed by a laminated sand interval (Tb). Although the flow continues under upper flow regime conditions where energy is high enough to carry sand grains by traction, this facies represents a decrease in the energy of the sedimentary flow. We then move on to sands with ripple lamination (interval Tc), followed by laminated silts (interval Td), and finally, fine laminated silts (interval Te), marking the end of the turbiditic sedimentation process.

A RARE FIND

However, it has been known for a long time that the entire Bouma sequence is quite rare to find, either because of erosion of the top part of the succession, or the high-energy initiation is missing in the more distal parts of the turbidite lobes. Where to place the Tybalt cores (well 211/08c-5) in that regard?

When looking at the light-coloured sandstones in the photo, the most striking observation is that they are structureless from the base to the top of the succession, clearly suggesting that these sands belong to the massive sand (Ta) type of deposit. In other words, the elements expected as a result of decreasing energy conditions are missing. For that reason, the sediments in this core are likely from a more proximal part of the lobe system.

Another interesting observation is that it is not only the base of the sandstone that shows an erosional contact; the top is also characterized by an erosional transition to the overlying mudstones. This can be explained by another turbidite flow that did not result in deposition at this particular location but resulted in the removal of part of the previously deposited succession instead.

So, even though the cores here do not show the full Bouma sequence, the concept can still be applied. A generalized recognition of all the Bouma sequence facies and their evolution throughout the turbidite lobe is presented in the illustration. ■

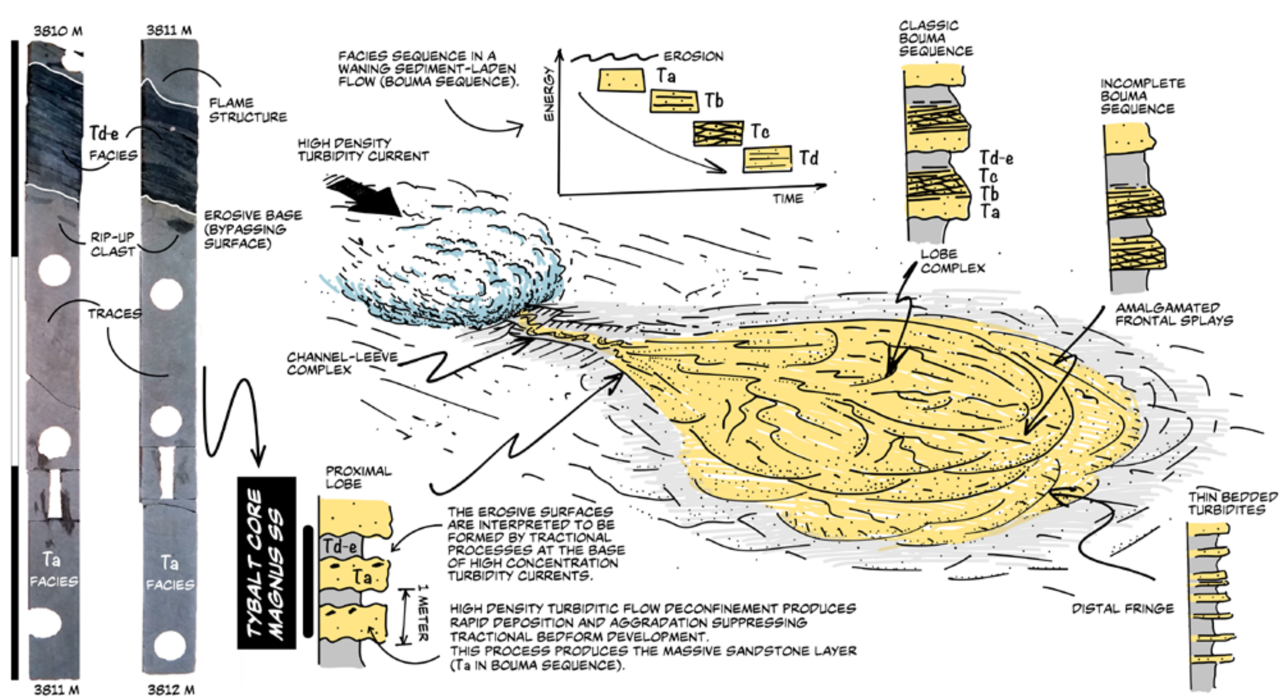


ILLUSTRATION: MARCOS ASENSIO