THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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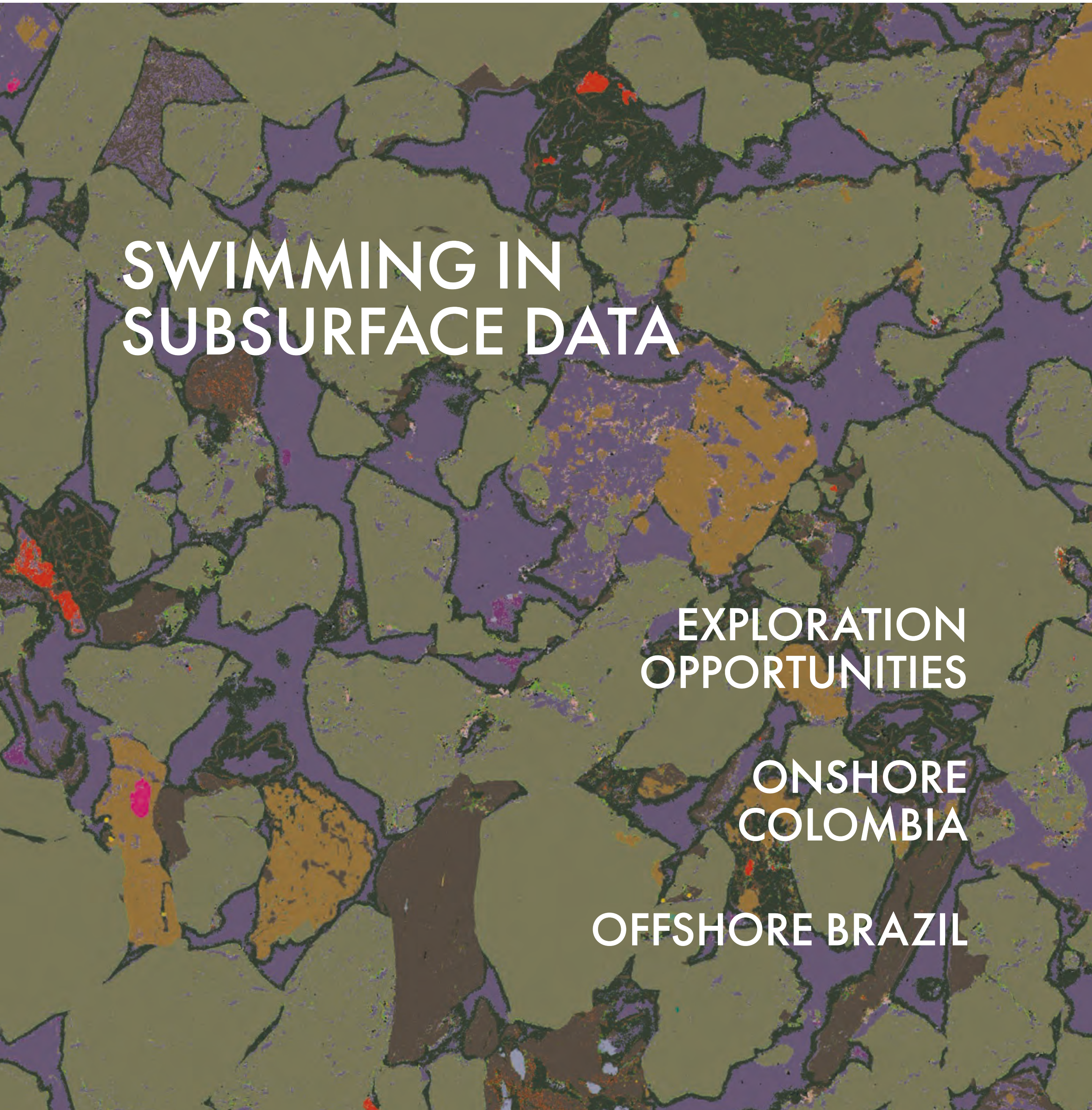

SWIMMING IN SUBSURFACE DATA

EXPLORATION OPPORTUNITIES

ONSHORE COLOMBIA

OFFSHORE BRAZIL

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Swimming in subsurface data

AS BASINS MATURE in terms of their oil and gas potential, the drive to release data to facilitate the exploration of niche plays increases. In parallel, with our ever-growing capabilities to store, process and analyse digital data, the restrictions regarding data access are much more limited than what they used to be. Combined, there is the ultimate recipe for a subsurface data lake.

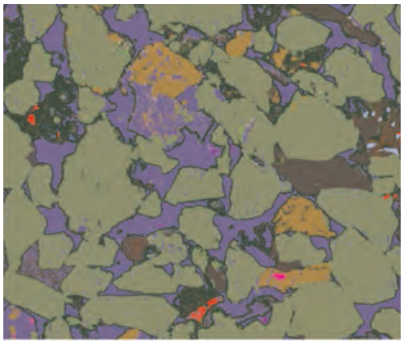
To an extent, that is indeed what is happening in some countries. Take the Released Wells Initiative in Norway as an example; this project involved the analysis of cutting materials from almost all exploration and appraisal well drilled on the Norwegian Continental Shelf. And not only from the reservoir section, but from the entire over- and underburden. It does not need explaining that this dataset is immense. The ultimate driver for creating it? Finding new plays and missed pay. The National Data Repository launched in the UK a few years ago is also undergoing rapid growth and variety in subsurface availability.

Together with other swaths of data being released these days, it is easy to understand that today's exploration questions revolve much more often around how to optimally use the available data rather than where to find it. The cover story addresses this question at length and from different perspectives. People from the intelligence business share how they manage data streams, while others explain how they benefit from what is available out there using social media. It paints a picture of increasing diversity in the ways data can be analysed and published. However, at the same time, one thing still remains important as ever, and that is human judgement. Machines can do more and more, but I do believe that making sense of things will stay a human trait for a while.

Henk Kombrink

BEHIND THE COVER

A simple excel sheet and a few photos. That is all that is required to do a basic mineralogical analysis of a thin section. This is how it was often done in the past, and this is how it is still done in some cases. However, as more challenging targets are being drilled these days, often at huge costs, it is no surprise that companies want to build a complete picture of how a reservoir looks like. QEMSCAN provided by Rocktype provides that picture, in the form of a fully digital image of the mineralogical content of the rock. This offers huge opportunities, as it allows the full analysis not only of the mineralogical content, but also of the spatial organisation of the pores because all information is stored in XY space. The work Rocktype performs is therefore a great example of how digitalisation is entering the geoscience space. The front cover shows a QEMSCAN image from a sample in the Norwegian Sea, beautifully illustrating rims of chlorite coatings around quartz and feldspar grains.



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SHEARWATER
Pearl
Pearl changes the rules of Ocean Bottom Seismic, offering better survey designs for exploration, appraisal, development, production optimisation and monitoring.
shearwatergeo.com
SHEARWATER

Can’t see your flare flame? You’ve found hydrogen!

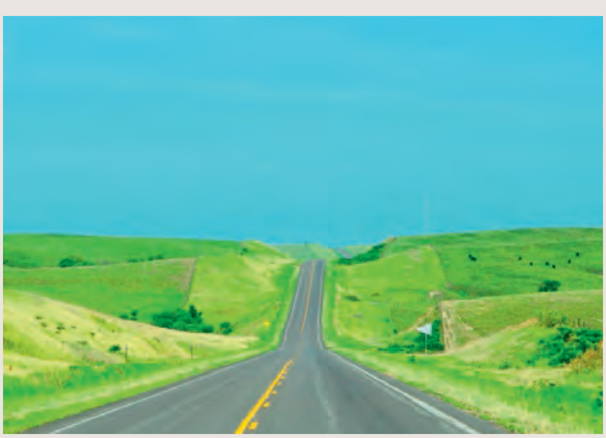
Although the hydrogen energy industry as a whole is advancing at a rapid pace, the exploration for naturally occurring hydrogen is still in its infancy. However, change seems around the corner.

THE INITIAL RESULTS of the world’s first wildcat well that specifically targeted natural hydrogen look promising. The Hoarty NE3 well, a joint venture between Hyterra Ltd and Natural Hydrogen Energy LLC, is located near Geneva city in Nebraska, USA, and targeted Precambrian basement. Wireline logging discovered two prospective zones with elevated H_2 concentrations and increased rock porosity. The high porosity is attributed to highly fractured zones in the basement. The source of the hydrogen is yet unknown but could be due to water-rock interaction.

Gas samples taken during swab testing did not yield conclusive geochemical results, but the gas evacuated from the annulus did burn with a clear, smoke-free flame. Hyterra states that “the flare burnt with a transparent flame and was interpreted to indicate the predominance of hydrogen.” However, it should be nuanced that a clear flame only means that hydrogen is the predominant combustible gas in the gas stream. H_2 is flammable at concentrations as low as 4% in air, which leaves plenty of room for the presence of non-combustible gases. To get a better understanding of gas composition, reservoir pressure and flow rate, an extended well test is scheduled to start in February and will last for approximately 3 months.

Mariël Reitsma, HRH Geology

Further information at hyterra.com



A typical Nebraska landscape.

SOURCE: UNSPLASH

Shifting toward a carbon-neutral and sustainable energy future

The 2023 Carbon Capture, Utilization, and Storage event in Houston, Texas, is set to explore the latest CCUS work and address related challenges and opportunities. Plan now to network and collaborate with industry leaders and experts.

THE MATURING CARBON MARKET has been a major driver for deployment of carbon capture, utilization, and storage (CCUS) projects within the geosciences and energy arenas. Both the subsurface technical knowledge and related data sets of the petroleum industry are major inputs required for the world to successfully move towards a carbon-neutral and sustainable energy future.

CCUS has experienced growing interest over the past two decades, due to the desire to reduce CO_2 emissions and to make industrial sources more environmentally sustainable. More recently, policy instruments and carbon credit mechanisms are providing opportunities that offset deployment costs and can result in CCUS being a potentially profitable enterprise.

Fully understanding the technical and business aspects of CCUS such as subsurface geologic storage and site selection, CO_2 enhanced hydrocarbon recovery and utilization, and reservoir modeling monitoring and risk assessment are critical in helping lead the way for successful net-zero operations and developments. These topics, and more, will be discussed elaborately at the event.

Further information at ccusevent.org

The 2023 Carbon Capture, Utilization, and Storage event, 25–27 April 2023 at the University of Houston in Houston, Texas, is set to explore the latest CCUS work and address related challenges and opportunities.

Check your wavelet at Seismic 2023

Taking place 19th and 20th April, Seismic 2023 promises to be another key event for the geophysical community in Aberdeen and further afield.

SPE ABERDEEN'S SEISMIC CONFERENCE started as a one-day event in 2017 and was the first conference of its kind in Aberdeen to focus on seismic acquisition, processing and interpretation. Quickly growing to a two-day event from 2018, Seismic has become increasingly popular amongst not only geoscientists and geophysicists, but also those in non-geo-related roles such as engineers and senior decision makers within operating and service companies.

With the introduction of a dedicated session for Young Professionals in 2019, Seismic aims to inspire and encourage the next generation of young engineers and geoscientists.

The conference has evolved over the last few years to reflect the shift of focus within the industry to carbon reduction and the UK's Energy Transition journey. The 2023 event will build on how seismic sustainably supports the UK's energy security of supply and Net Zero obligations, covering hydrocarbons, renewables and carbon storage.

Further information at spe-aberdeen.org

Seismic 2023 will take place at the P&J Live in Aberdeen.

Networking and technical learning back on the agenda for the Aberdeen subsurface community

PESGB and GEO ExPro have taken the initiative to launch the Aberdeen Energy Talks.

BEFORE THE PANDEMIC HIT in 2020, people regularly came together in the Aberdeen Atholl Hotel to join the Oilfinders Lunches. The newly branded Aberdeen Energy Talks form the successor of these popular meetings, which are taking place at the same location.

The first event took place in January. Scott Liebnitz from Shell presented the results of the Jaws well that was drilled in the Forties-Montrose area of the UK Central North Sea last year. Unfortunately, the well was dry, but the way it was plugged and abandoned deviated from how it was done in the past. Read more about this on page 66.

Following Scott's talk, Tom Morgan presented the Well Info platform he launched last year and how it aims to inform people about how the status of wells drilled in the North Sea area is changing. Read more about this in our cover story.

On the 18th of April, the North Sea Transition Authority will present about the latest UKCS licensing round in what promises to be another interesting networking and learning event.

Further information at geoexpro.com/our-events

Scott Liebnitz from Shell presenting the results of the recently drilled Jaws well in the Central North Sea.

SOURCE: SEISMIC 2022, PHOTO: INGVILD RYGGEN CARSTENS

A busy BEOS 2023

The second edition of the Business & Exploration Opportunities Show promises to be another great networking and business event.

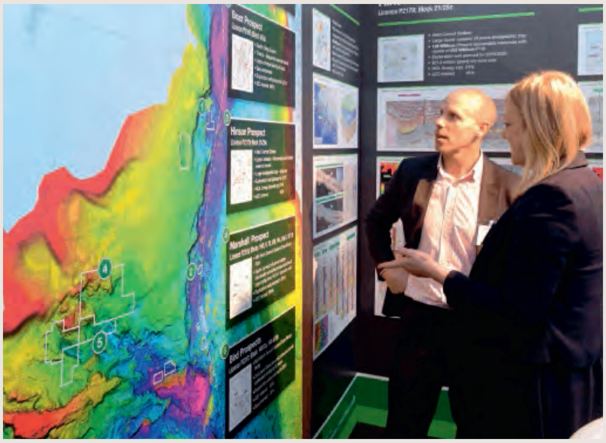
THE BUSINESS EXPLORATION Opportunities Show is a two-day event jointly organised by the AAPG and the PESGB. Taking place in London on 25-26 April, it brings together the best of the former APPEX and PROSPEX conferences into one great show.

BEOS 2023 focuses not only on the oil and gas business but also opportunities offered by the ongoing energy transition. The show has something for everyone; an abundance of investment opportunities, both international and UKCS; new technologies and emerging new businesses.

This is a time of great change which inevitably provides enormous opportunity. The show offers the ideal forum for building networks across the entire energy spectrum with governments, ministries, operators, investors, supply chain companies and technology providers amongst those attending. Sessions will cover the latest licensing rounds, global exploration opportunities, finance, technology, operations, and new themes such as hydrogen, CCS and geothermal, all in the form of overviews, panel debates and case histories.

Plan to attend BEOS 2023 and do not miss the opportunity to network, participate in one of the panel debates and develop your next business opportunity.

Further information at beosevent.com



BEOS takes place 25-26 April in the Business Design Centre in London.

Social enterprise in geoscience: Opening more learning opportunities for fresh graduates

Every year, more than 1000 new geoscientists graduate in Indonesia. However, finding a job is a big challenge.

OIL PRICE INSTABILITY and the recent pandemic have not helped geoscience graduates in Indonesia to quickly climb the job ladder. And, in contrast to what some people may think, the energy transition is not delivering many job opportunities for young geoscientists either.

In 2016, a social enterprise called INDOGEO was formed by several experienced geoscientists, which aims to help the young geoscientists in Indonesia. The social enterprise involves fresh graduates in projects while waiting for their formal jobs. INDOGEO recruits up to hundreds of fresh graduates and sets up projects for them to work on.

The activities include data gathering, data management and some analysis, which helps the industry and community. Typically, they collect published data from various publications, make a systematic repository and generate maps and reports. These maps are sponsored by the industry and some professional organizations. All the results of the enterprise are for public use.

INDOGEO is a virtual organisation and young geoscientists can join the projects from their home. They benefit from these activities as they learn to work remotely and also receive some training to sharpen their skills. The participants receive certificates for their involvement, which helps in finding formal jobs.

Herman Darman

More information at indogeo.org

Well site and operations training, March 2017.

SOURCE: BEOS, PHOTO: INDOGEO

New, flexible and modular CCS-upskilling approach launched

The implementation of successful CO_2 storage projects requires capabilities with strong adjacency to the oil and gas sector, supplemented with those specific to CO_2 storage. This requires flexible and adaptable approaches to the upskilling of key staff.

IN PARTICULAR, pressure-related CO_2 phase behavior, reservoir diagenesis due to CO_2 injection, CO_2 specific geomechanical response and halite growth in saline brines are relevant CO_2 specific skills areas with a requirement for upskilling, both for CO_2 injection in depleted reservoirs as well as deep saline aquifers.

Since many of those that will work on the transport and storage of CO_2 in the future are likely to come from the oil and gas sector, a flexible, modular training approach is likely to be most-efficient to develop these additional CO_2 specific skills with existing oil and gas professionals.

As the requirement for these new skills is highly dependent on the individual and the project activity at hand, a modern and agile training delivery approach is required. Self-paced e-learning is very suitable for this and would be a more logical choice rather than the more traditional Instructor-Led Training (ILT) approaches, that are less flexible.

RPS Energy is currently developing an extensive CCS self-paced e-learning portfolio, of which the first five courses (23 modules) have recently been launched. Further modules are planned for Geomechanics, Geochemistry, Fluid Dynamics and Reservoir Engineering in CCS-projects, to become available in the first half of 2023.

Henk Jaap Kloosterman

For more information: training.rpsgroup

PHOTO: UNSPLASH, SOURCE: NEWSNRELEAES.COM

Lorna Blaisse new CEO for Helium One

The principal geologist will take the lead in a critical time for the company as drilling is on the cards for 2023.

IN PURSUE OF OTHER opportunities, David Minchin announced his decision to step down as CEO of Helium One in early February.

Lorna Blaise has been with the company for two years. Before joining Helium One, she worked in the oil and gas sector where she delivered successful exploration campaigns.

It is an exciting time to be at the helm of Helium One. The company is currently negotiating a rig contract to drill a well in the Rukwa project in Tanzania, which is planned to take place this year.

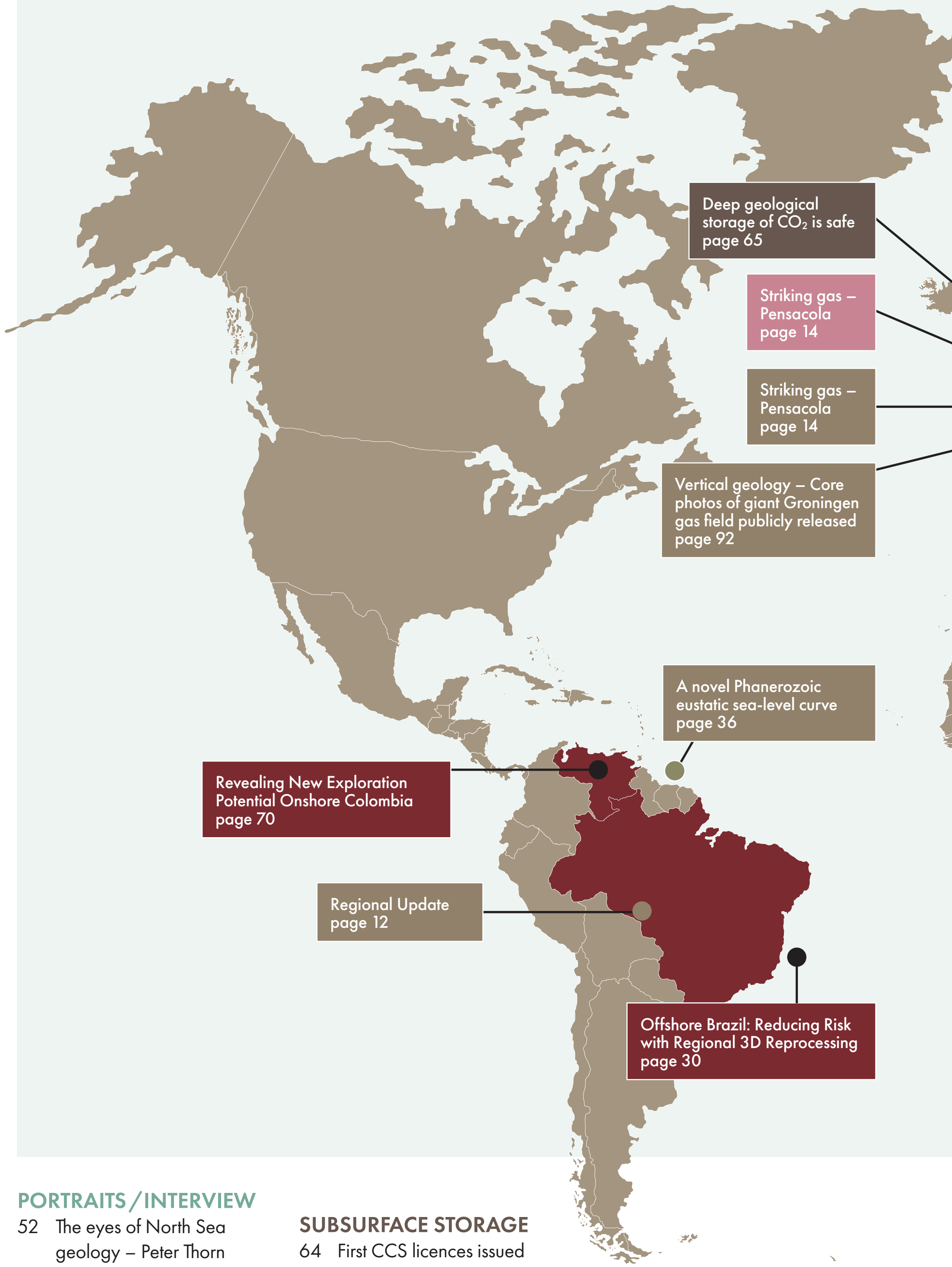
According to independent reports, Rukwa hosts up to 138 Bcf of P50 recoverable helium, making it the largest known primary helium resource in the world.

Helium One identified 21 prospects and 4 leads based on a high-resolution aerial gravity survey and 1,100 kilometres of re-processed seismic data. Analyses of surface seeps have shown that helium concentrations of up to 10.2% occur, which is very high compared to typical values of 0.1 - 0.3 % associated with hydrocarbon production.

Lorna Blaisse said: “I am delighted to have been given the opportunity to take leadership of Helium One at such a crucial time for the company. This is a strategically important phase for Helium One, but I have every confidence in the team as we remain focused on delivering a safe and successful drilling campaign this year, whilst also continuing to develop our wider helium portfolio.”

Further information at: helium-one.com

Lorna Blaisse, CEO of Helium One.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DEEP SEA MINERALS

Argentina's first deep water well

In South America's asset transfer and exploration landscape, Brazil continues to be the most active player. But one of the most exciting wells to be drilled this year is situated in Argentina.

2022 SAW THE award of around 60 blocks in Brazil, most as a result of the ANP's 3rd Open Acreage Concession Bid Round. However, licensing activity in South American has remained flat since 2019.

Uruguay's Open Round saw success with new blocks awarded to APA Corporation (Apache), Challenger Energy and Shell, driven by the successes off the coast of Namibia. Argentina, where unconventional liquid production in the Vaca Muerta basin continues to reach record highs, was the venue of awards to Chevron, Selva Maria and Recursos y Energia Formosa. Meanwhile, Colombia held the Ronda Colombia 2021 with 30 blocks reported to have received bids.

On the deal side Brazil has seen the largest number concluded over the past 12 months due to the ongoing Petrobras sales of onshore fields as they focus on the ultra-deep water. The most active companies in Brazil acquiring upstream assets were 3R Petroleum, Prio SA, Shell and Gas Bridge. The largest deal done was in Venezuela with the Rosneft sale to Russian government vehicle Roszarubezhneft. We do not see the widespread divestment of assets in South America as we see in other regions of the world.

Argentina will see what is touted as the country's first deepwater well drilled in 2023. The much anticipated high-impact Argerich-1 well will be operated by Equinor in Block CAN_100 situated in around 1,500 m of water depth and has a planned total depth of around 4,000 m. Equinor had farmed into CAN_100 in 2019 and took over operatorship from YPF. Shell is also a partner in CAN_100 after farm-in in 2021. Research suggests that the area is in a similar geological setting to the Orange Basin of Namibia where multiple giant oil discoveries have been made.

Landlocked Bolivia has suffered badly with its falling gas production. Gas production has seen a steady decline since 2015 and in a few years, Bolivia will turn into a significant importer. A serious push is needed by YPFB in Bolivia to reverse this trend for a country that was once the gas hub for supply to the southern part of South America.

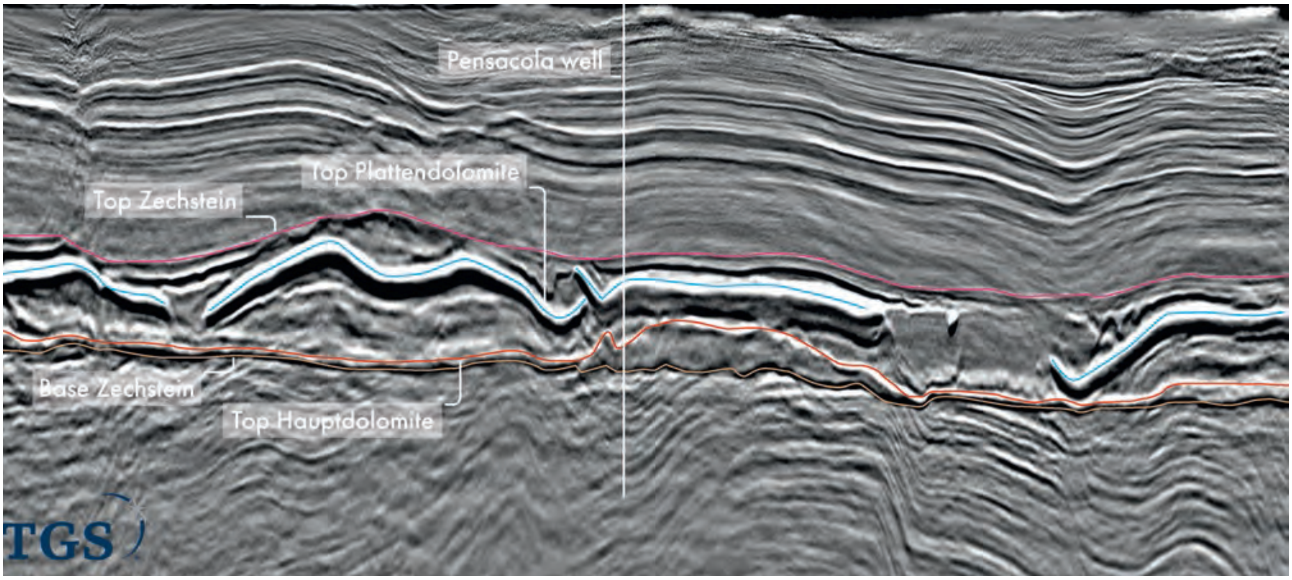
It remains to be seen what will happen in Venezuela. Ongoing discussions continue within the USA government to scale down sanctions. It is a step by step approach with Chevron given permission to produce oil and delivering its first shipment of heavy crude to USA refiner Phillips 66 in Texas in early January 2023. ConocoPhillips will be watched closely as it seeks to recover the large debt it is owed following nationalisation of its assets in 2007.

In another move, the US Treasury granted a license to Trinidad and Tobago to develop the Dragon gas field jointly/in business with Petróleos de Venezuela S.A. (PDVSA). The offshore field with reserves in excess of 4 TCF lies on the Venezuelan side of the maritime boundary and in the vicinity of the Shell-operated Hibiscus gas infrastructure. There are large undeveloped gas reserves in Venezuelan waters and the facilities of Dragon could be the springboard for a large gas hub exporting gas into Trinidad and Tobago.

Ian Cross – Moyes & Co ■

"We do not see the widespread divestment of assets in South America as we see in other regions of the world."

Argentina's first ever deep water well will be drilled this year by operator Equinor in licence CAN_100.

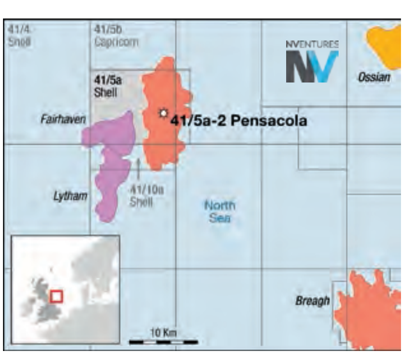


Seismic line across the Pensacola gas discovery, showing the top of the Hauptdolomite (top reservoir, red) as well as the overlying Plattendolomite (blue). The top and base of the Zechstein succession are indicated too. Seismic line kindly provided by TGS.

Gas in a Zechstein carbonate platform

Exploration activity in the UK has been depressed for a number of years, so the news of a gas find in the Southern North Sea has lifted spirits recently.

THE PENSACOLA WELL - 41/05a-2 - was spudded in November 2022. Deltic Energy worked up this Zechstein Hauptdolomite prospect, but with operator Shell farming in in 2019, drilling Pensacola became a lot more of a reality. The gas discovery was announced in January 2023, followed by a positive test result in February that proved 302 Bcf (8.5 Bcm) of recoverable gas in 16% porosity carbonates. Some light oil was found too. Given the size of the discovery, a standalone development could now be possible.



Pensacola is part of a series of isolated carbonate platforms that developed onto the southern margin of the Mid North Sea High in latest Permian times. The Pensacola platform has an elevation of more than 200 m above the time-equivalent basinal facies on either side, which is illustrated by the seismic line kindly provided by TGS.

It is likely that the underlying Carboniferous section is the main source for the gas. However, the Westphalian coals that are widely believed to be the main Carboniferous source interval are absent in the immediate vicinity of Pensacola, so long-distance migration needs to be assumed in that case. At the same time, a deeper Carboniferous succession may have been the dominant source, which then does not require long-distance migration. The oil source, as Mike Cooper from Trove News explained in a recently released video on the Pensacola discovery, could be within the Zechstein itself.

The well test results, which showed a peak of c. 4.75 mmscf/day declining to 1.75mmscf/day after 12 hours, are in line with expected results according to a Deltic press release. The company states that the flow rates are not representative of potential future production because the well is located at a down dip location of the structure (see seismic line). Future production wells will likely target the central part of the discovery.

These test findings are in line with what Mike Cooper further explained in his video, in which he explained that Zechstein carbonates are sometimes showing high initial flow rates, followed by a rapid decline and pressure depletion. Limited connected GIIP is the most likely explanation for this, and it is against this background that the test results from the vertical well may not be too representative. Long horizontal wells with multi-fracs are probably the solution to really tap into the full potential of the Pensacola reservoir. ■

COVER STORY/ OPENING SECTION

"It is true that more data have become available, but that doesn’t mean that it is a matter of a button click and the magic happens."

Andrew Vinall – Ember Exploration

SWIMMING IN SUBSURFACE DATA

With more and more subsurface data being available in digital format, how is the intelligence business evolving?

SOURCE: UNSPLASH

TEXT: HENK KOMBRINK

IT IS NOT THAT LONG ago that people had to go to the Department of Energy and Climate Change – which is now the North Sea Transition Authority – to inspect composite well logs on microfiches. Now, as production data, licence boundaries, well updates and many more types of subsurface data are more frequently shared through online databases anyone can directly connect to via their home device, one can ask what the effect of this data democratisation is on the subsurface intelligence business. In this article, we explore this question from a number of perspectives.

We spoke to David Moseley (Welligence) and Alyson Harding (Westwood Global) to hear their views. Andrew Vinall also shares his experience when it comes to data availability when he moved into the intelligence business in the early 2000's.

Social media is an increasingly powerful way to share subsurface data. Mike Cooper from Trove 1st Subsurface is sharing how he presents information on subsurface projects through his online videos, which is a new way of disseminating industry insights. Tom Morgan started Well Info in his spare time, a platform providing updates on the North Sea well stock. He pulls data from several national databases to publish updates on wells through social media. Finally, Jamie Vinnels explains how he rapidly built a network on various social media platforms when he started producing his own subsurface commentary.

Based on these conversations, a picture starts to emerge of a more diverse way of sharing subsurface information with the wider public. ▶

"Conversations with people remain essential to add colour to the analyses."

David Moseley - Welligence

"DATABASE ARCHITECTURE is a key aspect in the way intelligence companies are able to respond to the changes in the way data is made available into the public domain", says David Moseley from Welligence. David is Vice President - North Sea Research at the company that puts a data-driven approach, accelerated by AI, at the forefront of their intelligence service.

"It's not hard to imagine that older databases are not entirely compatible with handling a constant feed of production data, to name an example of data that is now at our fingertips for some countries we report on. Integrating legacy systems with new data streams is therefore a challenge that some companies may face."

"Welligence was set up in 2016 and from the start, we have adopted a data-driven approach where we can run machine learning algorithms to inform economic models based on the millions of data points we mine. For us, that is one of the key elements of our valuation platform", David continues.

"At the same time", he admits, "one of the key challenges, especially now that so much data is readily at hand, is ensuring a proper QC of the data. For instance, authorities may report a completion date of a well as being the 1st of December, but we see that the rig has been off-site for months. It needs checking to spot this and correct for it. This ultimately needs human intervention because we cannot afford running models with bad data."

Big data is surely revolutionary, enabling companies like Welligence to run scenarios that would have been impossible to run even 10 years ago. At the same time, conversations with people remain essential to add colour to the analyses. It's something that cannot be replaced," says David, "as talking to people will provide us with a sentiment and opinion that is not reflected in any type of data."

Saying that, David sees that people's attitude towards sharing data has changed somewhat over the years. With more data being shared publicly, people seem less willing to share insights beyond that. "Because of that, those instances where we do get a bit more of a flavour about what is happening behind the scenes are really insightful and useful," David adds. In that sense, an element of scouting remains in the intelligence business.

SOURCE: DALL-E

"It is true that more data have become available, but that doesn't mean that it is a matter of a button click and the magic happens."

Andrew Vinall – Ember Exploration

ANDREW VINALL HAS WORKED in the subsurface intelligence business since 2003 and was part of the Hannon Westwood management team until the company was sold to private equity investors in 2015.

Asked about whether getting hold of data has become easier over the years, Andrew says: "Yes and No. It is true that more data have become available, but that doesn't mean that it is a matter of a button click and the magic happens. Data is often not in the right format and therefore needs to be crunched first. This can lead to a lot of work."

Another interesting observation is that data can sometimes seem unavailable, whilst in fact it is not. Andrew mentions the relinquishment reports from the Norwegian Continental Shelf: "Yes, the NPD only recently started releasing these valuable documents via their FactPages, but it was always understood to be possible to get hold of these documents if you could find the right people at the NPD," he says.

"Intelligence historically came from a financial rather than subsurface perspective", continues Andrew. WoodMac was started as a stockbroker in Edinburgh in the early 1970's, and accountancy firm Deloitte acquired much of fellow accountancy company Arthur Andersen following the Enron scandal of 2001. Ultimately though, it is a combination of subsurface and commercial information that translates into where and in whom to invest and where not to.

"For a long time," Andrew says, "WoodMac was the benchmark when it came to reports on asset and corporate evaluations, even though we knew that there were always things to improve as we could compare their reports to the assets we worked on ourselves."

The intelligence landscape is quite diverse nowadays, with a large number of companies operating globally such as Enverus, Westwood, NVentures and IHS. "All intelligence companies have their own niche and report, present and analyse the data in different ways", adds Andrew.

While Teams calls, Social Media, online investor forums and digital databases all form ways to get to subsurface information these days, it was a lot different in the past. "In our days, interviews with senior people within oil and gas companies were the most important way to gain insight into what they were up to. However, it was very important to correctly interpret what people had told you, because an incorrect interpretation could have serious implications," Andrew concludes.

"...the value to our underlying data and reports is immense."

Alyson Harding – Westwood Global

"THE AMOUNT AND VARIETY of subsurface data being made available is growing," says Alyson Harding. Alyson is the Technical Manager at Westwood Global Energy in London, where she oversees upstream activity in Northwest Europe.

The several hundred relinquishment reports that the Norwegian Petroleum Directorate has released since June 2021 is a good example. "As a subsurface intelligence business", she continues, "we incorporate details of the mapped prospects shown in the relinquishment reports in our own databases. Although this has added to the workload for the team to process this additional information, the value to our underlying data and reports is immense."

The UK NSTA has been releasing relinquishment reports for a number of years and we have been including this detail in our database and reports. More recently, Westwood has also expanded our intelligence service to include energy transition-related data, including carbon capture and storage and hydrogen, which has added to the amount of data to track. ▸

"I got kind of bored and underutilised sitting on the sidelines "refreshing" job pages that I decided to put my work out there and keep myself active."

Jamie Vinnels

"I GOT KIND OF BORED and underutilised sitting on the sidelines "refreshing" job pages that I decided to put my work out there and keep myself active, rather than just reposting work from others", Jamie Vinnels wrote in an email.

Jamie has been compiling subsurface data, maps and well results for some of the exploration hotspots around the world, while he waits for the job market to pick up in the Houston area. He is another example of someone who reaps the benefits of the availability of data released it into the public domain.

However, he felt that there was a bit of a lack of geological data integration work to better inform people who do not necessarily have the technical background when they want to invest. "I have found it rewarding to help people who have zero geological understanding to get better insights into the companies they invest in. I have also gained a substantial network of other industry folks and we have formed group messaging chats to discuss various stocks and activities, which has led to further opportunities", he adds.

"I have grown my network considerably by posting. My work has been featured in some Trove 1st Subsurface videos, and I've also had some great feedback from CEOs of companies like Eco Atlantic", Jamie replied when asked about the role social media plays in the things he does. "I was also a guest presenter on a recent podcast, interviewing Scott Macmillan, the Managing Director of Invictus Energy."

SOURCE: DALL-E

LinkedIn is not the only platform out there to post about subsurface insights. Twitter has several "E&P" advisors such as @equivestinvest run by Joanna Ponicka. For those who know a little about investing in subsurface opportunities, these can be a valuable resource.

Many people are also active on message boards like Yahoo, Reddit, Stocktwits, Hot Copper. "Discord is somewhat more structured. I have gained a substantial follower base under the name of Dan_Ashcroft, particularly on the ReconAfrica and Community Investment Server Discord servers. These focus more on smaller/junior companies, typically "penny stocks", where the hope is the initial drilling leads to large rises and then buyouts from mainstream companies", Jamie adds.

"The quality of advice from social media varies wildly from people who are clearly imposters to those who add significant value in helping people understand their investment", Jamie continues. "Some companies, like ReconAfrica, are pretty engaged as it provides them free investor relations. Many of their investors are retail investors, as in when any individual buys a stock, not just investment firms."

"But ultimately, I'd like to move back to the industry as a geoscientist. There is little substitute for access to the data and challenges one works with in an operator environment. Also, whether this way of working is long term financially worth it, is also a matter of debate."

"What I missed in today's upstream news landscape is a better overview of what is happening in the North Sea in terms of well activity"

Tom Morgan – Well Info

AN EXAMPLE of the "ease" with which meaningful data can be presented nowadays is the work that Tom Morgan has recently been doing for his Well Info platform. Using national well status databases from the UK (NSTA), Norway (NDR) and the Netherlands (NLOG), Tom reports on the status updates of hydrocarbon wells through automatically generated social media posts.

He built the software in his spare time next to his day job, without having a background in coding. Instead, with a geoscience degree and many years of experience in drilling, he does have the experience required to understand the upstream business.

"What I missed in today's upstream news landscape is a better overview of what is happening in the North Sea in terms of actual drilling," Tom said. "Exploration wells, especially the successful ones, get a lot of attention, but there is a lot more going on. For instance, with so many fields nearing the end of their lives, I thought it is important to share with a wider audience where decommissioning work is taking place."

Tom has shown that with today's technology, it is possible to achieve things that would have been impossible a few years ago. And it is not only plotting data on a map and posting on Social Media; he has also started posting about differences in overall well status between Norway, the UK and the Netherlands, taking the Well Info platform much more into the intelligence space.

"I'd still see myself as a data enthusiast with a laptop", Tom said. But the things he does with Well Info are clearly going beyond that.

"Subsurface experts who contact me don't have any significant issues with my assessments."

Mike Cooper - TROVE 1st Subsurface

A NEW WAY OF PROVIDING subsurface intelligence is the use of videos compiled by geoscientists. Sharing content in this way can be rewarding but daunting at the same time. That is what Mike Cooper from TROVE 1st Subsurface experienced when he shared his video on Invictus Energy's drilling in Zimbabwe.

In the videos, he questions some of the bold statements made by the company in terms of the prospectivity of the area and the results of the wells they drilled. Even though he clearly states that it is commentary from a technical point of view and he has no financial interests, the reactions from some people are simply rude. "Apart from positive feedback on the commentary provided, I experienced "trolling" for the first time, maybe because some are invested in the company and feel I challenge the narrative too much", says Mike. "Subsurface experts who contact me don't have any significant issues with my assessments", he adds.

It certainly results in visibility, but is it the visibility that is needed to generate an income? Mike's best-viewed video, with more than 24,000 views, is the one on TotalEnergies' Venus discovery in Namibia. In a way, it is no surprise; the video was released at the right time in order to benefit from the wave of publicity the well received. It is likely that the next spectacular discovery will generate just as many views. "Typically for YouTube channels, other videos do not get as many views, but we've still got over 145 views each day so far this year", says Mike.

"We are still at an early stage," Mike continues. "Producing these videos is hard work, both in the preparation as well as the execution. For us, the videos form a good way to raise awareness our TROVE databases. But it is still too early to conclude if this is the way forward even though we generally do get a lot of positive feedback. Similar to others in the service sector, we still experience a great level of budget scrutiny from potential buyers." ■

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NORTHWEST EUROPE

"I hope that this is the last year of strong focus on ILX and more focus onto frontier exploration. It will require close collaboration between companies to make more frontier exploration work, but this is exactly what Norway does well."

Sidsel Lindsø, page 24

Sidsel Lindsø, ExploCrowd.

Decline in Number of APA Round Awards Continues

Sidsel Lindsø from ExploCrowd reflects on the outcomes of this year's APA Round in Norway.

LIKE LAST YEAR, the NPD expressed gratitude for the diversity of companies interested in the 2022 APA round on the Norwegian Continental Shelf. However, the number of companies that applied for APA acreage and the number of licences awarded over time is declining since 2018. Sidsel Lindsø, the director of consultancy ExploCrowd, said: "One explanation for the limited number of awards is that the 2022 exploration budgets were still constrained due to the legacy of Covid-related events, even though oil and gas prices have recovered throughout 2022."

The fact that many of the awarded licences this year are simply extensions of already existing licences may also be a testament to the more limited efforts put into this round overall.

"At the same time, it is also important to be aware that due to the nature of these APA rounds, with a strong focus on infrastructure-led exploration, there is not a lot of new acreage on offer from one year to the other," Lindsø stressed. Although there is always a chance of finding something that had been missed before, the number of hidden gems will most likely come down as time progresses and drilling continues. "This is a drawback of the APA Rounds," Lindsø says.

"Against the backdrop of the energy situation in Europe," Lindsø concludes, "I hope that this is the last year of strong focus on ILX and more focus onto frontier exploration. It will require close collaboration between companies to make more frontier exploration work, but this is exactly what Norway does well."

Further information at npd.no ■

Will Petoro also publish a "2023 wells to watch"?

WHEN IT COMES to drilling risky exploration wells on the Norwegian Continental Shelf, state-owned Petoro is often one of the partners. Against that backdrop, it was interesting to see Petoro defining 5 wells to watch at the start of the year: Ormen Lange Deep, Bounty, Laushornet, Cambozola and Overly.

The Ormen Lange well encountered mainly siltstone with thin layers of sandstone and dolomite stringers in the Cretaceous and was declared dry. Situated on the Frøya High, the Bounty well was the third recent attempt to test prospectivity in this area of the Norwegian Sea. It may well be the last one for a while. The Laushornet well proved the targeted Cook reservoir, but no hydrocarbons were encountered. Cambozola never encountered the Lower Cretaceous reservoir. That leaves us with Overly, a small oil discovery in Miocene sands.

In summary, Petoro's wells to watch list for 2022 was disappointing. Will the company come up with a similar list for this year?

Further information at geoexpro.com

Map showing the location of the wells drilled as part of Petoro's wells to watch for 2022.

PHOTO: SIDSEL LINDSØ

Sunset across the Dutch North Sea.

PHOTO: HENK KOMBRINK

The Rise and Fall of the Dutch Gas Production

When the Groningen field was found in 1959 in the north of the Netherlands, one would think that the first offshore well in the Dutch sector was to be drilled soon after. That was not the case. "As usual, the Dutch government was late to the party," said Bert Manders during his Christmas lecture at the Petroleum Geological Circle in the Hague last year.

THE THEME of Manders' talk was to provide an overview on the Ups and Downs of the Dutch upstream sector. It was about time for him to present. He ran his newsletter, in which he reported on wells, licences and other subsurface activities in the Netherlands, for about 30 years. He never shied away from calling a spade a spade. That is why his audience was always eagerly awaiting the latest newsletter. And although he did not open any major can of worms during his talk, he still made his point clear on a number of occasions.

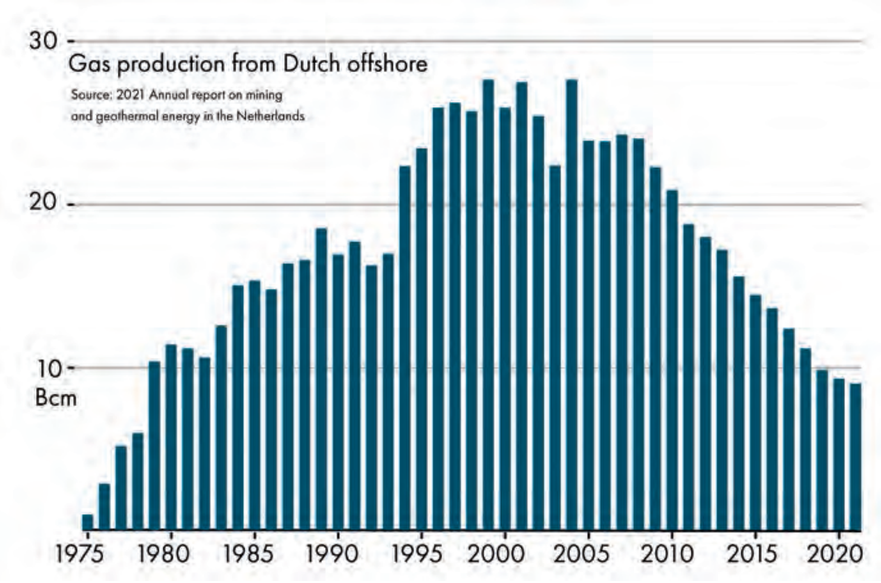
GRONINGEN LOOK-A-LIKES

An interesting observation at the start of Manders' talk was about the post-Groningen exploration phase that also finally kicked off in the Dutch offshore sector. Without today's understanding of the subsurface, companies were looking for Groningen-size analogues. This concept drove the popularity of certain blocks over others. As fields turned out to be much smaller than Groningen, despite being in the same stratigraphic reservoir, the most popular blocks turned out not to be the ones that ultimately delivered most. For example, the K15 block initially received no applications, but later turned out to be one of the most prolific in the Dutch sector; this block alone produced 69 Bcm, more than what currently remains in the entire Dutch sector in terms of reserves, excluding Groningen.

BEING THERE EARLY

It is clear that the first round of awards in the Dutch offshore sector did not necessarily result in the most attractive prospects to be licenced straight away. "However, it was still important to ▸

be there early," Manders said, "because that enabled companies to see what their neighbours were up to." This put companies in the position to make strategic acquisitions and build a portfolio at the right time. "NAM is a good example of that," Manders explained. "The Shell-Exxon joint venture wasn't very successful in the first round of awards, but made some important acquisitions such as blocks K8 and K11 from Signal Petroleum."



Gas production from the Dutch offshore over time.

THE GWWORK

Some companies active in the Dutch offshore sector did not have a strategy for doing acquisitions. For instance, TotalEnergies' focus in the last 20 years seemed to just exploit their fields primarily situated in the so-called pistolet area. The French did acquire a new 3D survey across their core area about ten years ago though, in an attempt to derisk any remaining prospects. As the survey did not result in the identification of new prospects, the conclusion was that the geologists had done their work well.

"THEY KEEP ON CHANGING THEIR BUSINESS CARDS"

Neptune Energy is a relatively new name on the block in the Dutch E&P sector, but looking back at the chain of company takeovers, Neptune in fact has a long legacy in the country. What started as Placid then became Occidental, TransCanada, GdF, Engie and now Neptune Energy. And that is not the end, with rumours circulating that Italian ENI is contemplating the acquisition of Neptune Energy. It is unlikely that the Dutch assets form the main reason for the Italians to consider this move. "The steady gas output in the Placid years improved considerably after the GdF take-over through acquisitions from NAM and by some excellent discoveries. However, production is in decline now" Manders added.

TIDYING UP PROPERLY

With around 1600 exploration, appraisal and development wells drilled in the Dutch offshore sector alone, an enormous project awaits to decommission about 750 unplugged wells. This is becoming a bit of an item according to Manders, as many companies have not really ramped up this activity yet. "Wintershall Noordzee is the best performer in the decom space," Manders said, "while NAM is the worst." NAM's strategy seems to have been to slim down operations on platforms to a bare minimum, without making a proper start with plugging and abandoning wells.

BOILING TATTIES

Manders illustrated how the strategy and public profile of EBN, the state-owned company that participates in most oil and gas developments and exploration wells in the Netherlands, has changed over the years. Before 2015, EBN profiled itself as an ambitious oil and gas partner with targets such as 30 Bcm in 2030. To further illustrate these plans, EBN's CEO Jan Dirk van Bokhoven was pictured in an annual report boiling his potatoes on a gas-fired stove. Since then, EBN seems to have dropped these production targets and replaced these with a strong focus on CCS and geothermal energy. In that capacity, the company is now becoming an operator, after embarking on a geothermal exploration drilling programme onshore. The first well is to be drilled near the Ajax stadium to the south of Amsterdam. Surely a landmark location to spud you first well as an operator.

Throughout his talk, Manders clearly painted the picture of the rise and fall of Dutch offshore oil and gas production. But despite the fact that the decline in production will not be reversed, he pointed out that in the current climate of record-high prices, there should be an increasing appetite to get those remaining prospects drilled in the years to come.

Let's see what 2023 brings. ■

SOURCE: NLOG

"NAM wasn't very successful in the first round of awards, but made some important acquisitions such as blocks K8 and K11 from Signal Petroleum."

How Does Wet Gas Form?

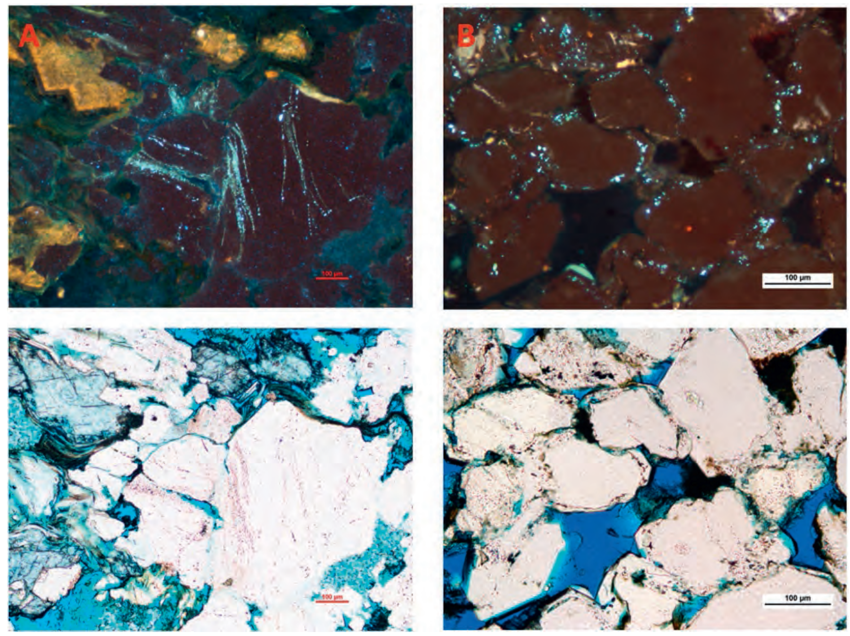
Fluid inclusion study suggests that wet gas accumulations form as a result of dry gas displacing oil.

A **STUDY PERFORMED** by Olav Walderhaug from Equinor, the main outcomes of which he shared with GEO ExPro, shows that out of 50 reservoirs classified as wet gas accumulations, 47 of these contain oil inclusions in diagenetic cements. The inclusions typically occur in quartz overgrowths, in albitized feldspar and in various carbonate cements.

Because of the very strong correlation between wet gas and oil inclusions in diagenetic cements, Walderhaug postulates that there is a strong indication that almost all wet gas accumulations in the North Sea used to be oil accumulations initially.

The observation that wet gas accumulations almost solely reside in previously oil-filled reservoirs very strongly indicates that wet gas does not usually arrive in a reservoir as a wet gas phase. In contrast, the data suggest that wet gas in most cases forms in the reservoir as dry gas displaces oil. The dry gas evolves to wet gas because the dry gas picks up heavier components from the oil it displaces.

Only in the few cases where oil inclusions are absent, data indicate that wet gas is the first hydrocarbon phase to enter a trap. In these rare cases, the wet gas may possibly have remigrated from a deeper trap where dry gas displaced oil.This further implies that expulsion of wet gas from source rocks, for instance by heating oil-generating source rocks to temperatures above the temperatures of the oil window, is of very limited or no importance for wet gas formation in the North Sea and probably also in other basins.



A: Abundant bluish white and light blue oil inclusions in healed fractures in quartz grains. Orange areas are ankerite cement. Micrograph obtained from the Statfjord Fm in well 35/9-6S at 3692 m RKB.
B. Numerous light blue oil inclusions in the dust rims on quartz grains. Micrograph obtained from the Farsund Fm in well 2/4-21 at 4996 m RKB. The upper micrographs are fluorescence micrographs, lower micrographs show the same areas in plane-polarized light. All scale bars are 0.1 mm. Both reservoirs currently hold wet gas.

WET GAS INCLUSIONS

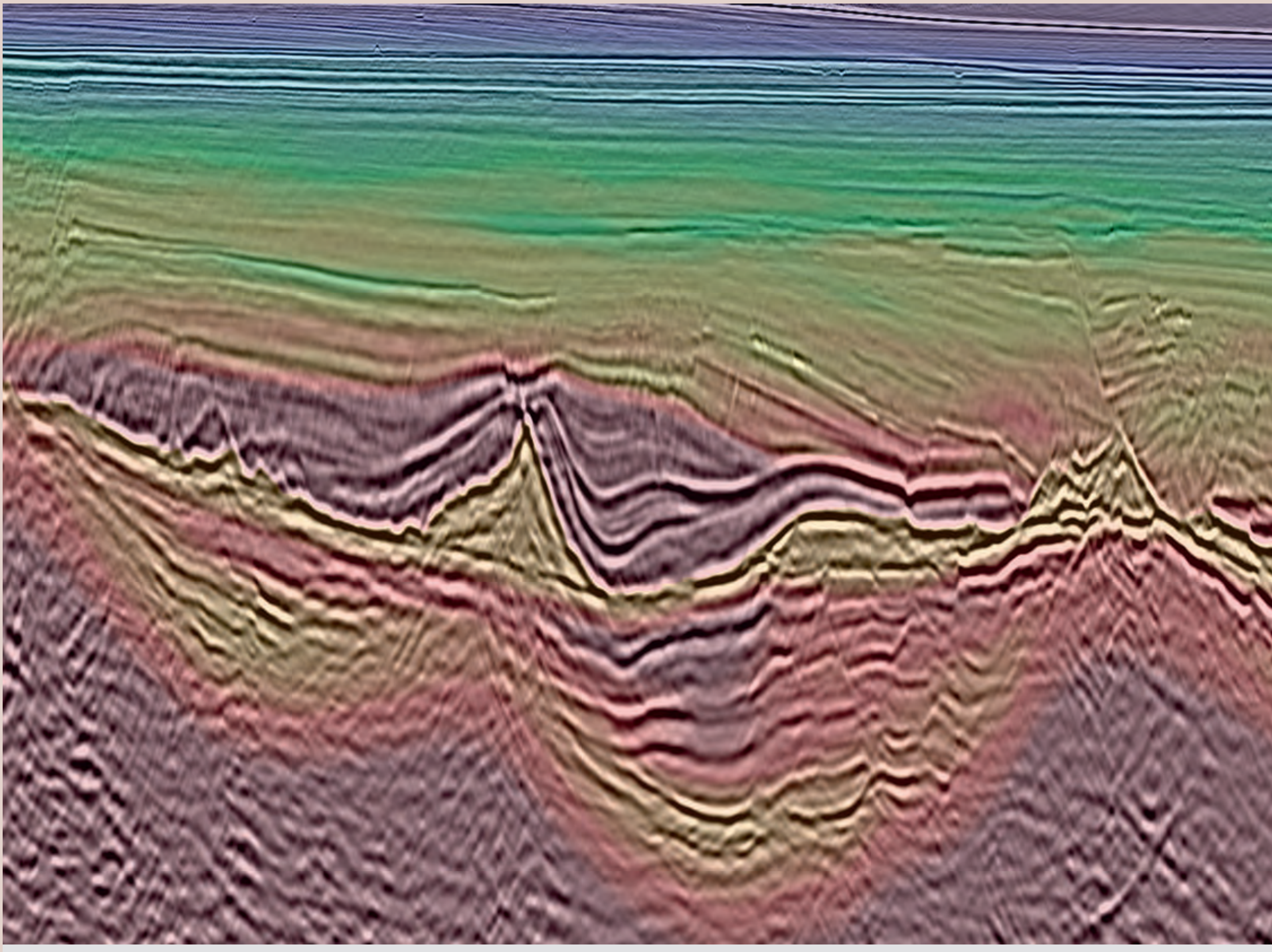
In eleven of the 50 studied wet gas reservoirs, the diagenetic cements also contain wet gas inclusions in addition to oil inclusions. Unlike dry gas inclusions that consist of little else than methane and therefore do not fluoresce, wet gas inclusions have a distinct blue fluorescence. Also, when viewed at room temperature, wet gas inclusions contain very large gas bubbles that fill most of the inclusion volumes, unlike oil inclusions where the gas phase at room temperature is much smaller than the oil phase. These characteristics enable rapid visual identification of wet gas inclusions.

In the examined North Sea reservoirs containing wet gas inclusions, they are found within both dust rims on quartz grains and in albitized plagioclase. This is a clear indication that gas must have displaced oil at moderate temperatures in most cases. The reasoning behind this is that albitization takes place at ca. 90°C and formation of quartz overgrowths typically starts at 70 – 80°C.

AN OLDER SOURCE ROCK?

This subsequently raises interesting questions regarding the source of the dry gas that displaced the oil in these reservoirs, according to Walderhaug. In several of the examined wet gas reservoirs, temperatures of around 90°C were already reached in Cretaceous times. Source rocks such as the Draupne Formation were not very hot at that moment and were therefore not expected to be producing large volumes of gas. On that basis, Walderhaug suggests that this could be an indication of the presence of a deeper pre-Jurassic source rock that expelled large volumes of dry gas. ■

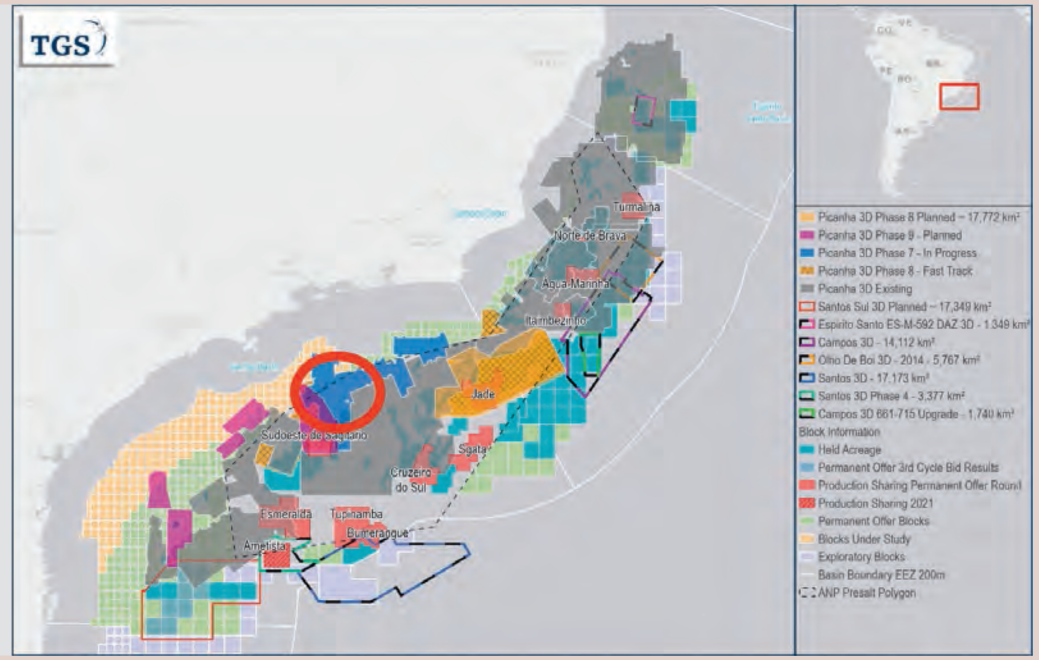
Offshore Brazil: Reducing Risk with Regional 3D Reprocessing

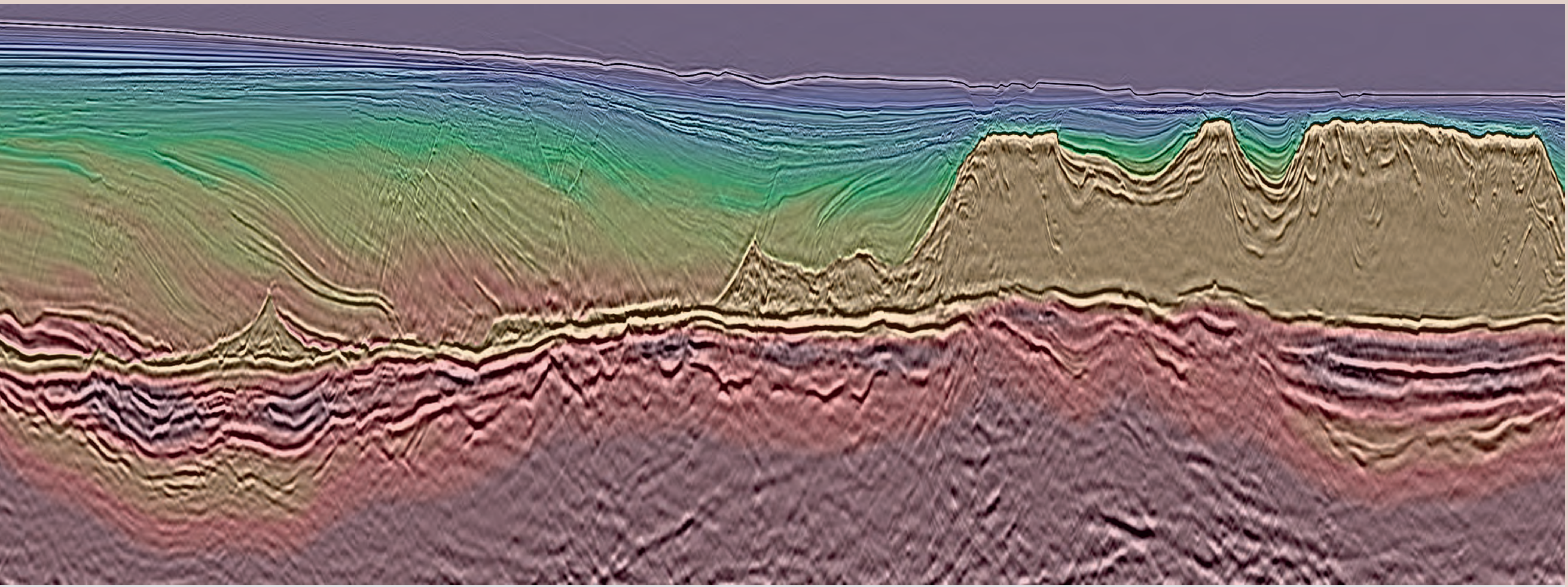


Kirchhoff migration, seismic cross section of Picanha Phase 7 with velocity model overlay in Santos Basin.

Legacy 3D seismic datasets dating back to the 1980's through mid-2010's have been reprocessed and imaged from field tape allowing for updated regional 3D mapping and evaluation of paleo-environmental conditions relating to the development of Brazil's super basin petroleum system. Isopach maps and semblance extraction assist in identifying Cretaceous and younger sediment depo-centers, salt thickness and evacuation patterns, and pre-salt source probability to reduce risk and increase exploration success.

Colored Pre-Salt Isopach Map relating mature Lagoa Feia source rock presence with Base of Salt structure contours displaying the fetch and hydrocarbon migration pathways to the pre salt lead. Interpreted seismic cross section displaying the Agua Marinha block.





Power of Picanha

Exploration and production in Campos and Santos Basins, Brazil has hit a crossroads unlike anything in the past two decades. Increases in sub-economic discoveries and dry holes are leading the industry to postpone investments and strategically await key well results before making further long-term commitments.

ANDREW HARTWIG, TGS, HOUSTON, TX

Trends such as infrastructure led exploration (ILX) and geopolitical policy uncertainties around low-carbon energy solutions continue to convolute the scope of the ever-evolving energy market. Through this lens, reprocessed 3D seismic data at the regional scale is the most cost-effective, fit-for-purpose subsurface instrument which can provide the risk reducing intelligence the industry covets to guide their disciplined investment strategies.

TGS' Picanha 3D seismic dataset provides a unique visual scope of the subsurface through three of the most prolific Brazilian offshore basins using an unprecedented reach of reprocessing and contiguous merging of vintage datasets over 260,000 km^2 of Brazil's Atlantic waters.

The results of the reimaged, seamlessly merged 3D seismic and subsequent attribute data allow for diverse applications to ILX or frontier exploration. Seismic interpretation and analysis of regional subsurface data supports the evaluation of basin's geologic history, depositional systems, and paleoclimate as they relate to the offshore petroleum system. Picanha 3D can be used to define these characteristics more confidently by differentiating key features based on broad observations which can be used to interpret hydrocarbon fetch and migration pathways to a high-profile lease blocks, such as Agua Marinha (Figure 1).

One hundred and seventeen datasets were merged and reimaged in a phased approach, from field tape, with a consistent workflow to achieve a contiguous, seamless result. Throughout the imaging process the team interpreted meaningful, well-tied stratigraphic horizons, not only to calibrate velocity model building, but also to build structure and isopoach maps at major geologic boundaries to evaluate sediment thickness, salt evacuation patterns, and pre-salt carbonate accumulations.

Applying such strategies in the evaluation of high-profile blocks on offer in during the Permanent Production Sharing Offer Round and future ILX territories, gives a substantial advantage to those with access to bulk Picanha licenses. Comprehensive maps of the three most distinct isopachs can be evaluated for broad basin architecture and exploration purposes for improved understanding of the heterogeneous petroleum system characteristics across the basins.

PRE-SALT SUPREMACY

The pre-salt isopach reveals where the deepest, most probable source kitchens are present in the syn-rift and sag basins. The underlying continental and transitional crust display horst and graben geometries producing syn-rift accommodation space for kerogen-rich, alluvial sedimentation into the restricted marine lacustrine environment. Structural interpretation, seismic character comparisons, and well-ties suggest the presence of a regional sub-areal volcanic layer at the crest of basement structures within the inner-rift basins however SDR-like volcanic characteristics are found the outer-rift basin. Campos basin pre-salt thickness averages 2500m thickness and Santos basin pre-salt average thickness is 1900m. The basal volcanic unit initiates paleo-environmental conditions for "hydrogen-rich organic matter in the [inner rift] lakes resulting in the deposition of laminated-calcareous black shales and calcareous shales with excellent source potential" (Mello, 2021) and permeable migration pathways to uplifted, high porosity carbonate reservoirs. Many questions remain in the chaotic, SDR volcanic rift of the outer-kitchen in both Campos and Santos Basins where a drastic increase in CO_2 is threatening recent development.

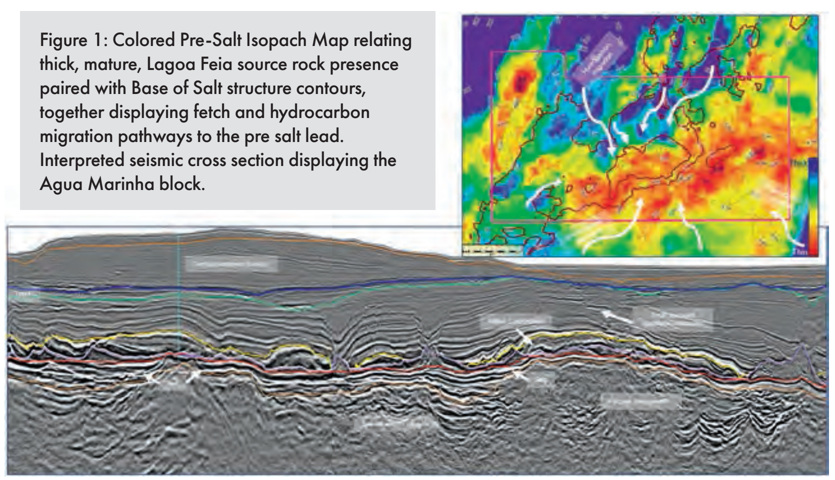


Figure 1: Colored Pre-Salt Isopach Map relating thick, mature, Lagoa Feia source rock presence paired with Base of Salt structure contours, together displaying fetch and hydrocarbon migration pathways to the pre salt lead. Interpreted seismic cross section displaying the Agua Marinha block.

DASH OF SALT

The Aptian Salt isopach (Figure 2) displays halite and layered evaporite thickness for the regional pre-salt reservoir seal and conversely, salt welds which provide windows for hydrocarbon migration into post-salt clastic turbidite systems. In Campos basin, evaporite deposition occurred in a shallow, restricted marine-platform, flooded, and evaporated during mid-Cretaceous thermal subsidence. Campos salt is substantially thinner than its southern counterpart in Santos, displaying evidence of sustained pulses of basinward, gravitational salt flow, with deep-water salt walls and ridges reaching up to 4.5 km thick, separated by deep, elongated, mini-basins, welded at the regional base salt level. In Santos basin, the 2 to 2.5km thick, blocky-salt sequence contains sub-parallel seismic reflectors representing evaporites of different chemical makeup, densities, and sonic velocities (Jackson and Hudec, 2017). These thick and folded, layered evaporites are uniquely isolated to south-eastern Santos, suggesting massive layered evaporite accumulation, filled from groundwater seepage, evaporating in a deep, isolated, adiabatic rift basin (Jackson and Hudec 2017).

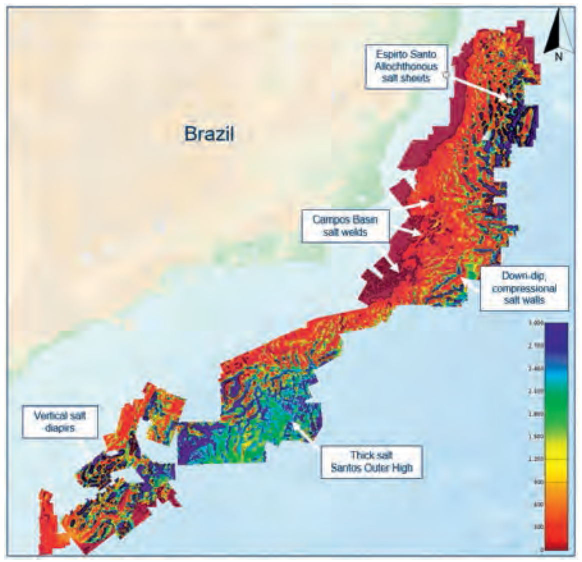


Figure 2: Picanha Salt Thickness Map demonstrating salt evacuation patterns and features.

POTENT POST SALT?

The Post-Salt Isopach, which displays the sediment thickness from the water bottom to the Top of Aptian Salt exhibits the mega-sequence of the open marine drift period, including drainage patterns of late Cretaceous depo-centers imprinted by down-dip, extensional salt deformation.

Acreage with deep, upper Cretaceous depo-centers in Northern Campos contain post-salt sediment thickness over 4800m, and in western and southwestern Santos, the post salt thickness reaches upward of 5,500 to 7,500m providing evidence of favorable burial history for post-salt source rocks such as the Itajai-Acu formation at the Atlanta field and Ametista Block.

Additionally, thick minibasins in outboard Campos, Espirito Santo and western Santos display complex, allochthonous salt structures signifying he possibility of under-explored play types such as "Gulf of Mexico style" salt flank amplitude truncations. Thorough investigation of these alternate play types may provide a new frontier for offshore Brazil exploration.

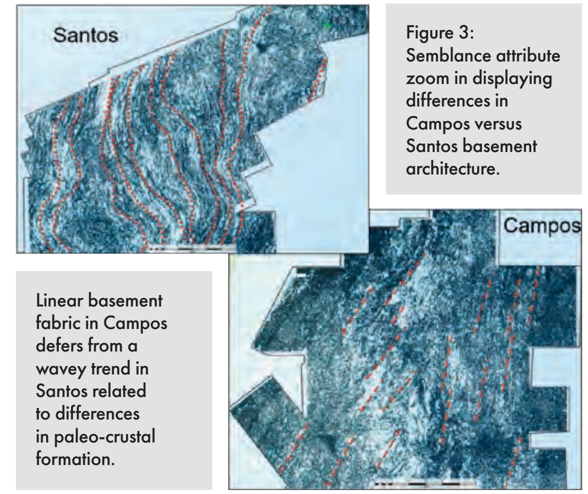


Figure 3: Semblance attribute zoom in displaying differences in Campos versus Santos basement architecture.

Linear basement fabric in Campos defers from a wavey trend in Santos related to differences in paleo-crustal formation.

SEMBLANCE IN "SIGHT"

Lastly, combining these maps with a Semblance attribute extracted along the interpreted basement horizon builds on the regional observations by relating basement fracture patterns to the distribution of sediment, salt, and pre-salt reservoirs. High-density, chaotic semblance trends are possibly related to rifted basement fabric and / or fractured facies that coincide with known reservoirs. We hypothesize that this character suggests to the presence of rift volcanics at paleo-lacustrine shorelines which controlled the accommodation space for deposition of Barra Velha & Lagoa Feia carbonates. Broad, wavey, and linear differences in the semblance character from basin to basin are likely due to hot-spot plume migration through Santos and not Campos Basin (Figure 3).

UP NEXT

The latest chapter of the Picanha story, Phase 7 (see foldout), completed in February 2023. The updated data merges seamlessly into the existing Santos Basin dataset, growing coverage in Northwest Santos Basin and expanding the application of these exploration techniques in both pre-salt and post-salt. As the energy environment and risk appetite changes, new play types will become commercial beyond the traditional outer-high pre-salt play. In preparation for this shift and focusing on ILX initiatives, Phase 7 is well positioned for up-dip, shallow water, inner-kitchen sourced, carbonate and clastic reservoirs in the Albian Gap extensional structural regime. Furthermore, the combination of Picanha with existing TGS Brazilian data library will continue to provide a unique and resilient perspective of Atlantic margin subsurface exploration.

CONCLUSIONS

Relating observations from key isopach maps across offshore Brazil and extracting attributes from regional horizons reveals insights that significantly de-risk potential pre-salt and post-salt targets. The recent strategy of merging and reprocessing legacy datasets no longer requires years and costs of permitting, planning, and acquiring new data to determine feasibility of Brazilian petroleum exploration blocks. Instead, the fit-for purpose data allow for a refocusing on the regional scale basin characteristics to revitalize the state of Brazilian exploration.

ACKNOWLEDGMENTS

The author would like to thank the processing, imaging team and interpretation teams of TGS, for their hard work and dedication providing the foundation for this study.

References published online. ■

FEATURES

"Lack of automation leads to late integration of data and prohibits continuous and iterative improvements..."

Martin Haege, SLB

A NOVEL PHANEROZOIC EUSTATIC SEA-LEVEL CURVE

Global mean sea-level is a key component within the fields of sedimentology, sequence-stratigraphy, paleoclimate, and oceanography. Hence, an improved understanding of eustatic sea-level in geological time aids in our understanding of the sedimentary record and the associated petroleum systems. We discuss the implications of this new methodology on expected facies in undrilled parts of the Guyana-Suriname Basin.

TEXT: DOUWE VAN DER MEER & KENT WILKINSON; CNOOC INTERNATIONAL

TRADITIONAL LONG-TERM EUSTATIC SEA-LEVEL reconstructions suffer from uncertainty in stratigraphic interpretations of the rock record, which leads to ambiguity. Sea-level reconstructions from plate tectonic modelling are limited in use due to a lack of preserved oceanic crust further back in time. As a result, Phanerozoic eustasy remains poorly constrained.

It is well known that the primary drivers for eustasy are changes in the rate of mid-ocean-ridge spreading and ice cap volume. The alternative method of sea-level reconstruction presented here integrates these two elusive drivers

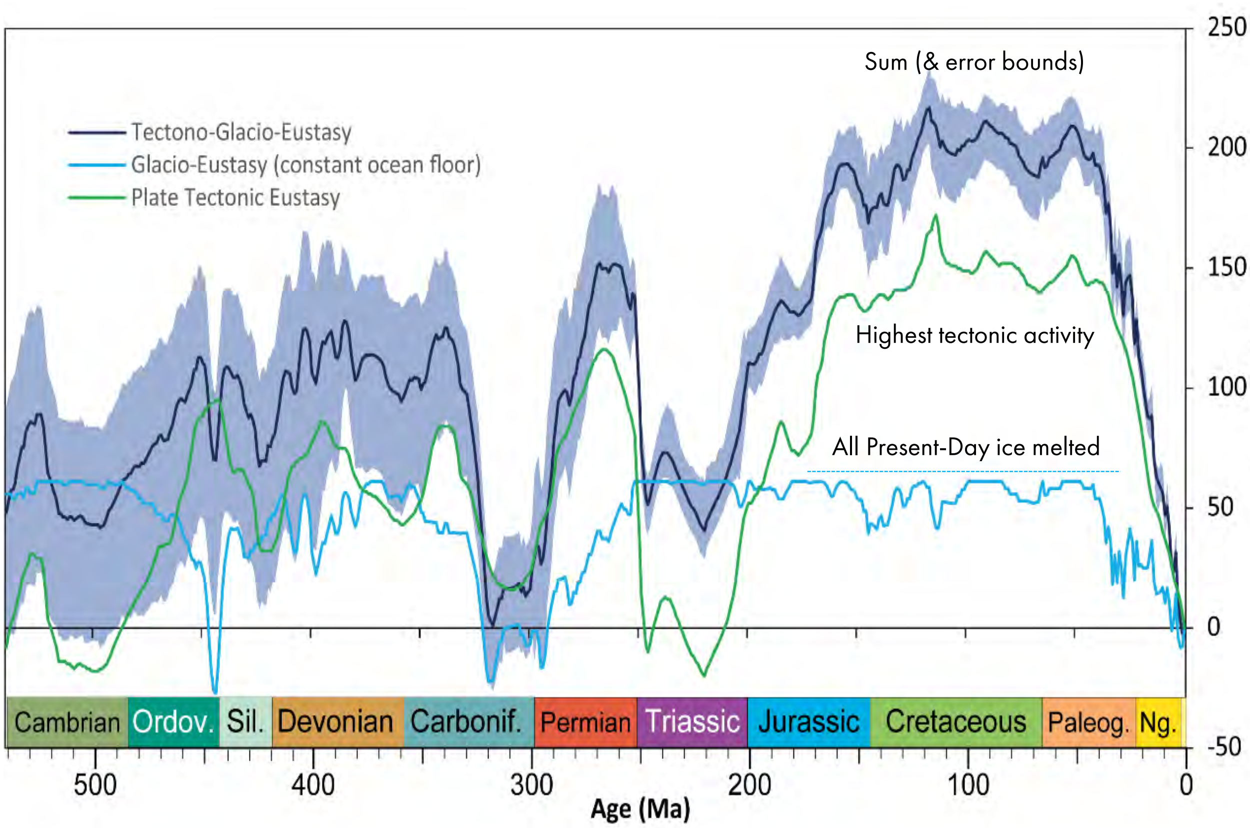


Figure 1. Isostatically compensated effects of plate tectonics, glaciations (>1Myr) and the combined Tectono-Glacio-Eustatic curve including RMS uncertainty ranges (shaded blue). Modified from van der Meer et al. (2022).

by using a corrected strontium global record to quantify plate tectonics and global average paleotemperatures to estimate continental glaciation.

GLOBAL TECTONIC EUSTASY

The well-constrained 87Sr/86Sr strontium isotope record derived from marine carbonates provides insight into plate tectonic activity. At first order, the strontium isotopes in carbonates record contributions of volcanism and weathering of radiogenic crust. We developed a novel approach to remove the weathering component using run-off estimates from paleo-climate modelling. This resulted in an overview of only the plate tectonic component of the strontium record, which was subsequently used as a proxy for mid-ocean-ridge spreading rates, and hence average ocean crustal age.

In turn, the oceanic crustal age was used to calculate water depths. A young and shallow ocean floor is found at mid-ocean ridges, whereas old crust leads to a deep ocean floor. From the tectonic component of the strontium isotope record, it follows that ridge spreading rates were twice as high in the mid-Mesozoic compared to the present day. This result is consistent with independent studies from plate tectonic models, and subducted slabs imaged in the mantle. The tectonic eustatic component leads to a sea-level amplitude range of up to 190 m.

GLACIO-EUSTASY

Water volume variations as a function of perennial ice sheets have a significant contribution to sea-level amplitude changes. To improve the tectonic eustatic reconstruction, we incorporated a glacio-eustatic component by estimating land and grounded ice sheets on the continental shelf through time. Global average paleotemperatures published by Scotese were used to estimate continental ice areas and volumes throughout the Phanerozoic.

Using the T = -10°C isotherm, paleo-latitudes for potential ice sheets were calculated and combined with digital elevation models in a paleogeographic reconstruction. This provided estimates of perennial ice areas through time in 1-million-year increments.

Average ice thicknesses were then calibrated with the well-studied Late Cenozoic icehouse conditions. Using the best-fit average ice sheet thickness for the late Cenozoic (1.4 km), ice volumes were obtained for short-lived Mesozoic and long-lasting Paleozoic icehouse times. This was finally converted to ocean water volume variation, leading to long-term glacio-eustatic amplitude of up to 90 m. ▸

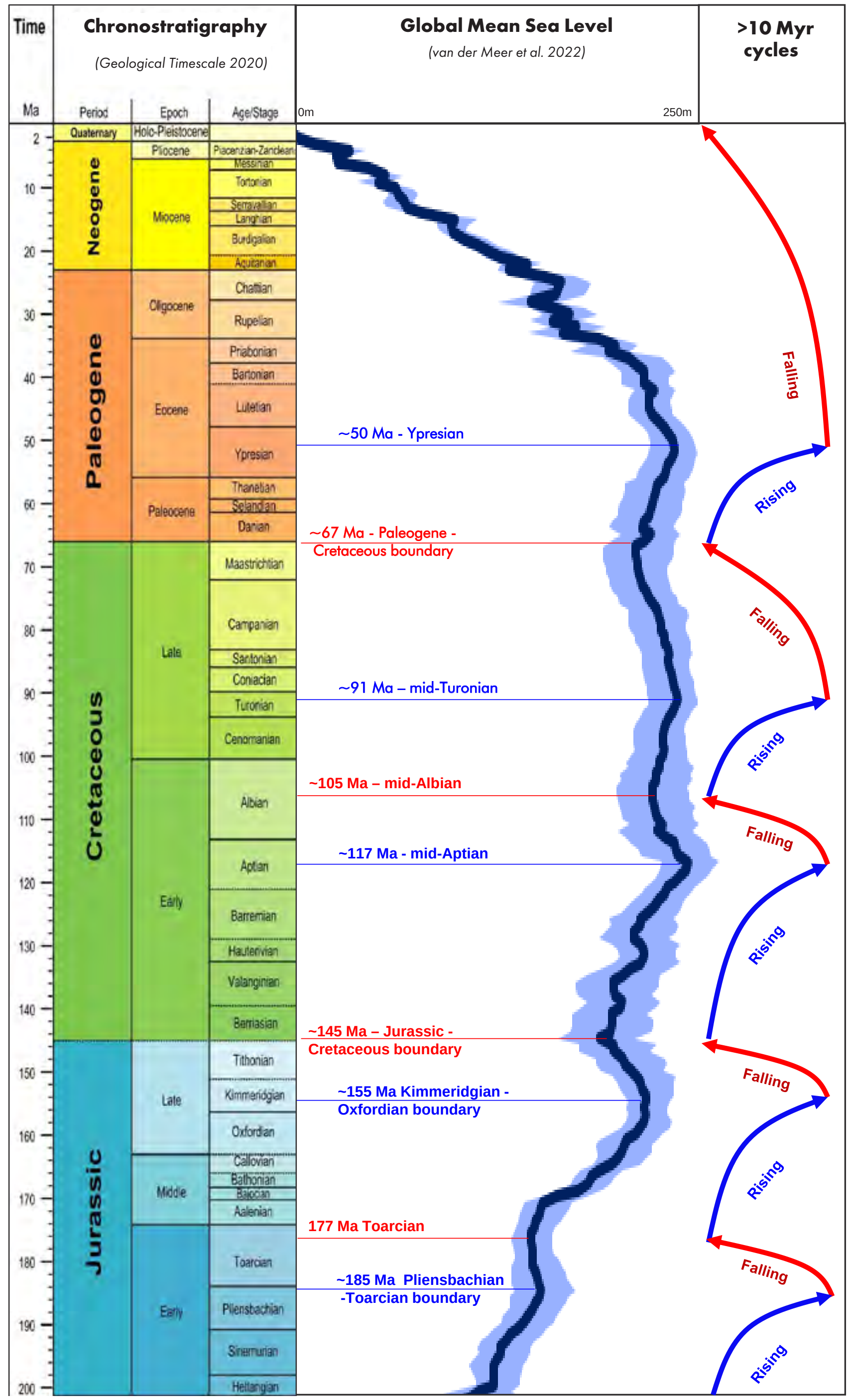


Figure 2. TGE curve zoomed in to Jurassic-Cenozoic with key sea-level cycles at >10Myr time-scales.

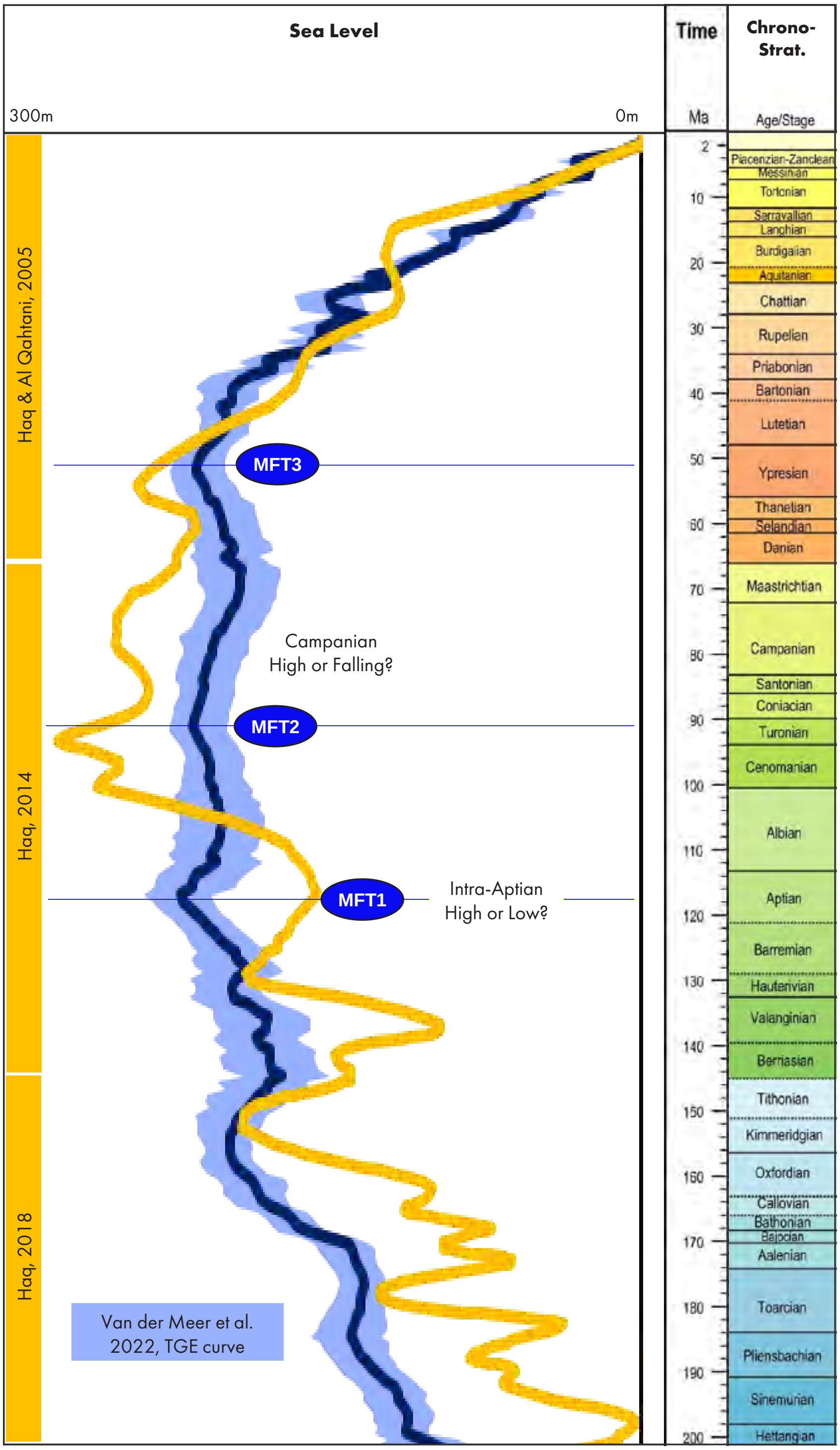


Figure 3. Comparison with the long-term curves of Haq et al. (2005, 2014, 2018, spliced together) for the Jurassic-Cenozoic. Key Maximum Flooding Times (MFT) marked which are discussed for the Guyana-Suriname basin.

TECTONO-GLACIO-EUSTATIC CURVE

Both components - long-term glacio-eustatic and plate tectonic eustatic reconstructions - were combined and isostatically corrected, resulting in the Tectono-Glacio-Eustatic (TGE) curve shown in Figure 1. The overall amplitude has a range of around 250 m throughout Phanerozoic. From a geological perspective, sea-level is very low at the present day due to the presence of polar icecaps and reduced oceanic crustal spreading. A similar situation occurred during the Late Paleozoic icehouse approximately 300 million years ago.

"From a geological perspective, sea-level is very low at the present day due to the presence of polar icecaps and reduced oceanic crustal spreading."

Global Mean Sea-level was very high (+200 m) during the Late Jurassic-Eocene greenhouse period. This correlates well with published gross-depositional environment (GDE) maps when large parts of continental shelves and present-day land were flooded. Based on the TGE curve and present-day hypsometry, there was approximately 30% less land area during that time.

MEGA-SEQUENCE STRATIGRAPHY AND COMPARISON TO HAQ CURVES

The TGE curve provides insight into the eustatic driver of passive margin stratigraphy, which acts in addition to other factors such as local tectonics and changes in sediment supply. At >10 Myr time scales, five rising-falling sea-level cycles are interpreted since the Jurassic (Figure 2). In comparison with other published sea-level curves that were based on plate tectonic models, stratigraphic methods or continental flooding mapping, there are differences in trends and amplitudes.

The TGE curve and the compilation of three different published curves by Haq are illustrated together over a focused Jurassic to Cenozoic time period (Figure 3) for the purpose of investigating second-order features. Qualitatively, there is a general agreement between the two curves that there are several Maximum Flooding Times (MFT). There is consensus on the Cenomanian-Turonian peak, the Paleo-Eocene peak and a subsequent falling sea-level during the Cenozoic and finally the Late Jurassic peak.

Noteworthy opposing trends are seen in the Berriasian, Aptian, and Campanian. Also, where trends agree, significant differences are noted in second-order amplitudes (i.e., Berriasian-Valanginian). To test the mega-sequences inferred from the TGE curve, examples from the prolific Guyana-Suriname Basin passive margin will be illustrated in the following section.

"The sea-level curves provide food for thought for the interpretation of deeper stratigraphy imaged in seismic data, which is yet to be tested by the drill bit."

APPLICATION TO THE GUYANA-SURINAME BASIN

The Guyana Basin formed during the Jurassic opening of the North Atlantic. Plate reconstructions suggest rifting and early seafloor spreading began with NNW/SSE extension (c. 190–160 Ma). Since the Liza discovery in 2015, 11 Bboe of recoverable hydrocarbons has been discovered in dominantly deep water stratigraphic traps in the Upper Cretaceous.

Within the limits of stratigraphic dating uncertainties, the TGE-curve highs and lows correlate well with first-order maximum flooding surfaces and sequence boundaries as seen on seismic and penetrated by wells. The key play is created between the late Albian-Ceno-Turonian marine source rocks (MFT2) and the regional top seal of Paleo-Eocene shales and deep-water carbonates (MFT3). In between these maximum flooding times, the TGE curve illustrates a period of falling sea-level corresponding with the deposition of the Santonian to Maastrichtian deep water turbidite channel complexes and basin floor fans. In contrast, during this Upper Cretaceous period, the Haq curve suggests a rising sea-level, which would not fit the Guyana-Suriname basin stratigraphy very well.

Interestingly, MFT1 corresponds to an intra-Aptian maximum flooding in the TGE curve, but a sea-level low in the Haq curve. This part of the Guyana-Suriname basin stratigraphy has not yet been penetrated by deep water wells and hence it remains to be seen which curve would fit the basin stratigraphy best. The sea-level curves provide food for thought for the interpretation of deeper stratigraphy imaged in seismic, which is yet to be tested by the drill bit.

It may also have implications for potential pre-Albian source rocks, which have been postulated but are yet to be proven.

AN INNOVATIVE TOOL

In summary, the published Tectono-Glacio-Eustatic curve provides an innovative tool for understanding and interpreting global Phanerozoic stratigraphy. At least since the Late Cretaceous, a good correlation has been observed with mega-sequence stratigraphy of Guyana-Suriname basin, where second-order features of the TGE curve are in agreement with the timing of deposition of the main petroleum system play elements. The model can even be used to infer depositional facies in undrilled successions below the proven petroleum fairway.

References provided online. ■

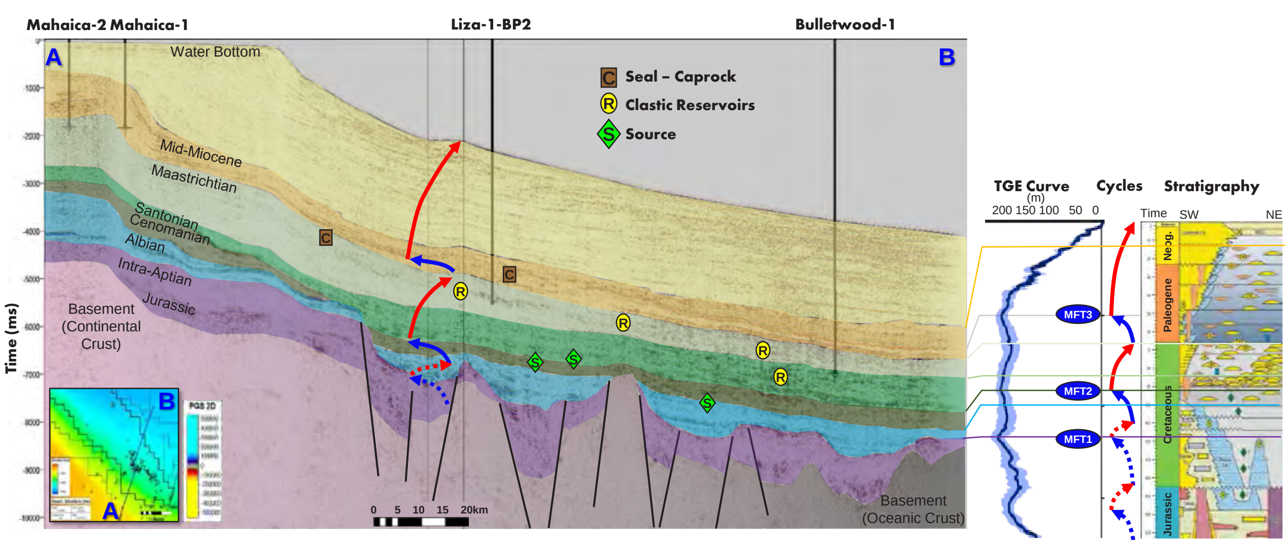


Figure 4. SW-NE seismic line with key seismic markers, and petroleum system elements. Source rocks and seals correlate with Maximum Flooding Times, Key deepwater reservoirs with falling sea-level/low stands. Seismic Line proprietary to PGS and GGMC (Government of Guyana).

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EFFICIENT IDENTIFICATION OF RESERVOIR FLOW CONNECTIONS

Traditional reservoir characterisation workflows solve most of the geological and geophysical interpretation and reservoir modelling problems. However, the turn-around time from interpretation via modelling to prediction is typically slow. The handover of results and insights between domains is mostly manual, and it is difficult to keep track of different versions of raw data, derived data, and interpretations.

TEXT: MARTIN HAEGE, JARLE HAUKÅS, AICHA BOUNAIM, SLB

LACK OF AUTOMATION leads to late integration of data and prohibits continuous and iterative improvements to the end-to-end workflow. Until recently, workflow automation and work step customisation has required software developer skills. However, recent advancements have permitted and started the journey of democratising innovation.

Here, we address the challenge of updating reservoir models with key information from subsurface-related observations in an automated and efficient manner. By quickly screening the impact of different scenarios, the team can more easily identify crucial domain work and make better decisions. When performing those reservoir model updates, it is important to provide repeatable and reproducible workflows that keep track of any changes or updates to the data.

For illustration purposes, a case study from the Ekofisk field in the North Sea is presented demonstrating an automated reservoir model update with geophysical information.

> "Lack of automation leads to late integration of data and prohibits continuous and iterative improvements..."

AUTOMATION ENABLED BY LIBERATED DATA

An important prerequisite for automatic analysis and knowledge sharing is to have data easily available. Data should not be tied to an application, but rather be served from a common repository. In this article, the term liberated data refers to data that are available from shared storage and can serve multiple applications.

A set of recipes is presented that supports both local storage and cloud storage, accessing data directly from files or through cloud data application programming interfaces (APIs). Recipes are based on a set of open-source extensible Python libraries. Data liberation enables automated data management within each recipe, allowing the user to focus on generating and sharing insights from the data.

BREAKING DOWN DOMAIN SILOS BY INTEGRATING DATA FROM DIFFERENT DOMAINS

Subsurface data and models are typically associated with a specific domain; e.g., geophysics, petrophysics, or reservoir engineering. An important aspect addressed by recipes is to extract relationships between the data in time and space. For example, a seismic survey is associated with the portion of the subsurface it covers, and the time interval over which it has been acquired.

Those time and space relationships are used to automatically identify relevant data for a specific study. More- ▸

over, these relationships enable analysis and visualisation of data from different domains in tandem.

AUDITABILITY THROUGH CUSTOMISED DISPLAYS

Auditability and quality assessment are key elements in all analyses. It is important that all steps that contribute to an insight or decision are traced, and that each analysis step can be assessed. By having domain experts themselves compose the images and describe what they illustrate and why they are important, domain knowledge is automatically preserved and shared.

When new data arrive or when interpretation or modeling steps are updated, the actionable insights can automatically be recreated. By monitoring insights and decisions over time, work processes can be evaluated and improved. The project team can thus focus their efforts where the impact on the decision is the greatest.

Figure 1 illustrates the aspects that are addressed. Teams and individuals have access to all the data and insights throughout the process. The analysis is tied to a problem statement, allowing relevant data to automatically be pulled together. Each domain brings data from processing, modeling and interpretation steps as needed, feeding a set of customised displays.

These displays allow quick audits within the domain, and knowledge sharing across to other domains. Moreover, they represent actionable insights that support decisions. The process is powered by liberated data and workflow automation, allowing every insight to be revisited and repeated as the problem statement is updated or refined or as new information arrives.

EKOFISK CASE STUDY

The above-described concept of recipes and actionable insights is exemplified on a case study in the Ekofisk Field in the North Sea.

The Ekofisk Field is a Chalk field, where water injection helps displace the oil mostly sitting in low-permeability, high-porosity matrix rock. The background for this case study was the start-up of a new water injector, which caused a huge increase in water cut at a nearby producer. Several attempts were made to mitigate the problem (Aamodt et al. 2018), but the producer was eventually shut down.

The objective of the analysis was to identify and characterise possible fluid pathways between the injector and the producer by using injection and production data, time-lapse seismic data, and reservoir simulation models. The problem statement is as follows: "Given the data available, identify possible flow connections between the injector and the producer, and translate the identified connections into reservoir model updates to enable an uncertainty/scenario screening loop."

Some of the analysis steps that connect information from geology, geophysics, and reservoir engineering data are presented. All steps are combinations of reusable analysis recipes implemented in Python.

DATA GATHERING AND SELECTION OF TIME AND SPACE SUBSET FOR STUDY

At the beginning of a study, existing data and facts are gathered, so that actionable insights can be created. One of the recipes contains functions that quickly and automatically scan through storage locations to discover all available data.

The first step of the analysis is to automatically extract all relevant data, with the name of the injector as the only required input. Figure 2a is an image produced as a reference when extracting the injector startup time. The injector startup time is inferred from historic water injection data. The display confirms that the date extracted is representative.

Figure 2b shows the location of the injector (I1) and producers (P1-P7) in the vicinity of the injector that are active within 1 year after injection startup. Figure 2c shows the producers sorted according to the maximum water cut within 1 year after injector startup to confirm the issue of increased water cuts. As can be seen from the figure, the producer that experienced a dramatic increase in water cut can automatically be identified.

By using injector startup time, injection rates, and production water cuts, relevant time-lapse seismic surveys (S1-S9 in Figure 2d) are identified.

GENERATION OF ACTIONABLE INSIGHTS

Actionable insights are generated based on the gathered information. Figure 3 provides an example of such actionable insights which are produced with the same zoom-in for easy comparison: (3a) A seismic amplitude map and available horizons to identify if any of the relevant horizons are not signal consistent, (3b) a fault map in seismic resolution, (3c) small-scale fractures not captured

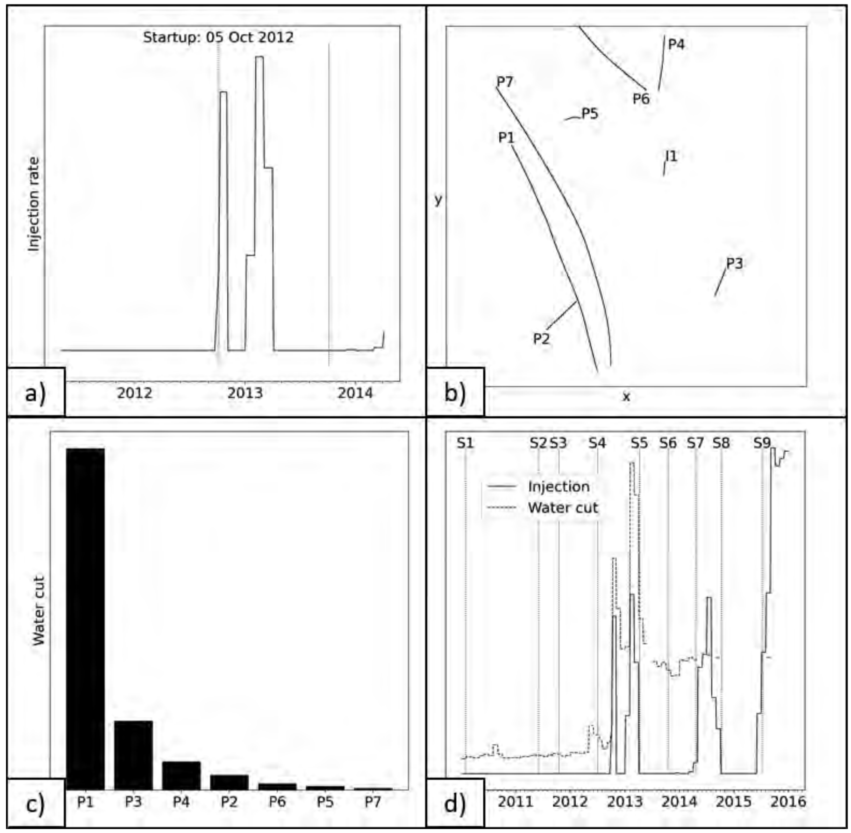
ACTIONABLE INSIGHTS

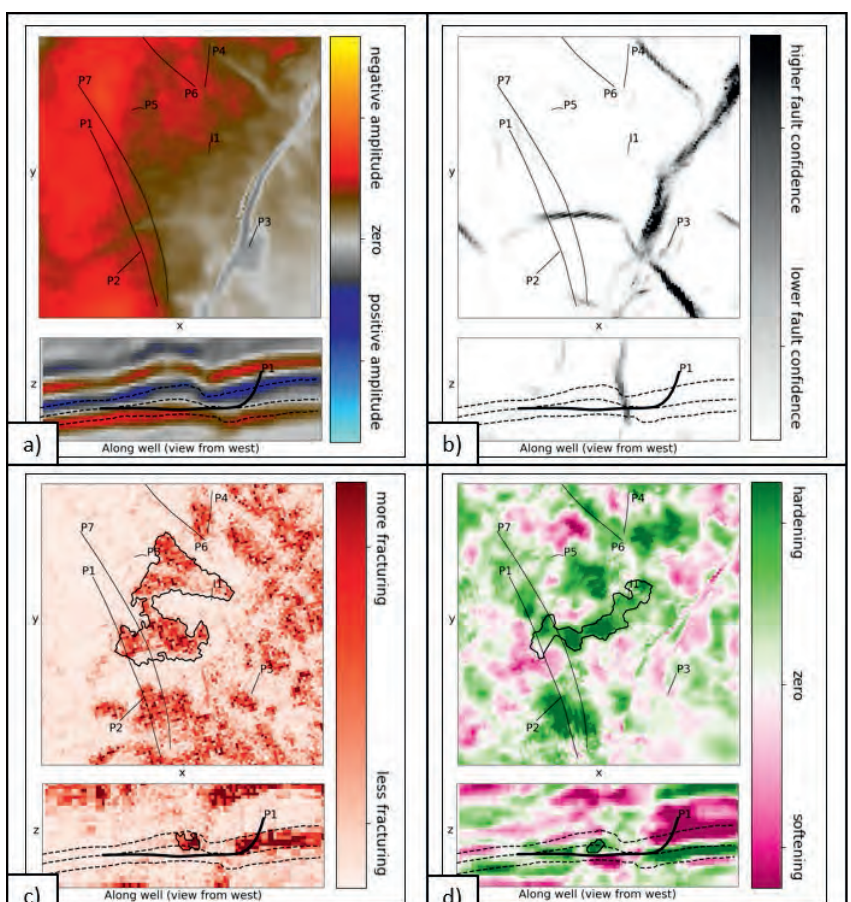
In this article, the term actionable insights is introduced to describe a set of images that highlight key aspects of subsurface data and models, and thus motivate and drive domain work and support decisions. By automating how these insights are created, links between a decision, data, and assumptions available at the time of the decision can be established.

We also introduce recipes. Recipes orchestrate and enable the generation of actionable insights from subsurface data and models are presented. The focus is on three key aspects: 1) automation enabled by liberated data, 2) breaking down domain silos by integrating data from different domains, and 3) auditability through customised displays.

Figure 2: Selection of time and space subset for study; a) Time interval of interest at I1, b) wells in area of interest, c) water cut information of nearby producers (P1–P7) in time interval of interest d) seismic time lapse data of interest (S1–S9).

Figure 3: Actionable insights generated automatically from relevant geoscience and reservoir engineering data based on well names and time span. All information is shown in top and side views. The top views are at the reservoir level. Side views are along the producer P1. a) seismic amplitude, b) faults, c) small-scale fractures, d) 4D time strain. Polygons in c) and d) delimit extracted geobodies.





by standard fault interpretation workflows, and (3d) 4D seismic time strain information to look for interpretable hardening/softening effects.

Figure 3c shows a high degree of small-scale fractures (rock fabric) between the injector I1 and producer P1. The rock fabric is a seismic attribute that captures subtle, small-scale changes in seismic reflections usually not depicted in common fault extraction techniques (Haege et al. 2013). Boersma et al. (2020) validated the rock fabric attribute with well data and suggest its usage as indication of potential fluid pathways within the Ekofisk Field. Figure 3d indicates a 4D time strain response in the same area, which represents fluid movement and/or a pressure change.

Both insights, i.e. rock fabric and 4D time strain observations, can carry information about the flow connection between the injector and producer. Therefore, one of the possible actions is to extract those observations as geobodies. The geobodies are extracted automatically with the condition that they are connected to the injector (see Figure 4).

The next step is to turn those geobodies into grid properties to update the reservoir model. One of the recipes links each geobody to a set of grid cells in the reservoir model, and allows flexible property modifications in those cells only, keeping the rest of the grid property unchanged. Figure 5 shows an example of an updated permeability model scenario using upscaled ▸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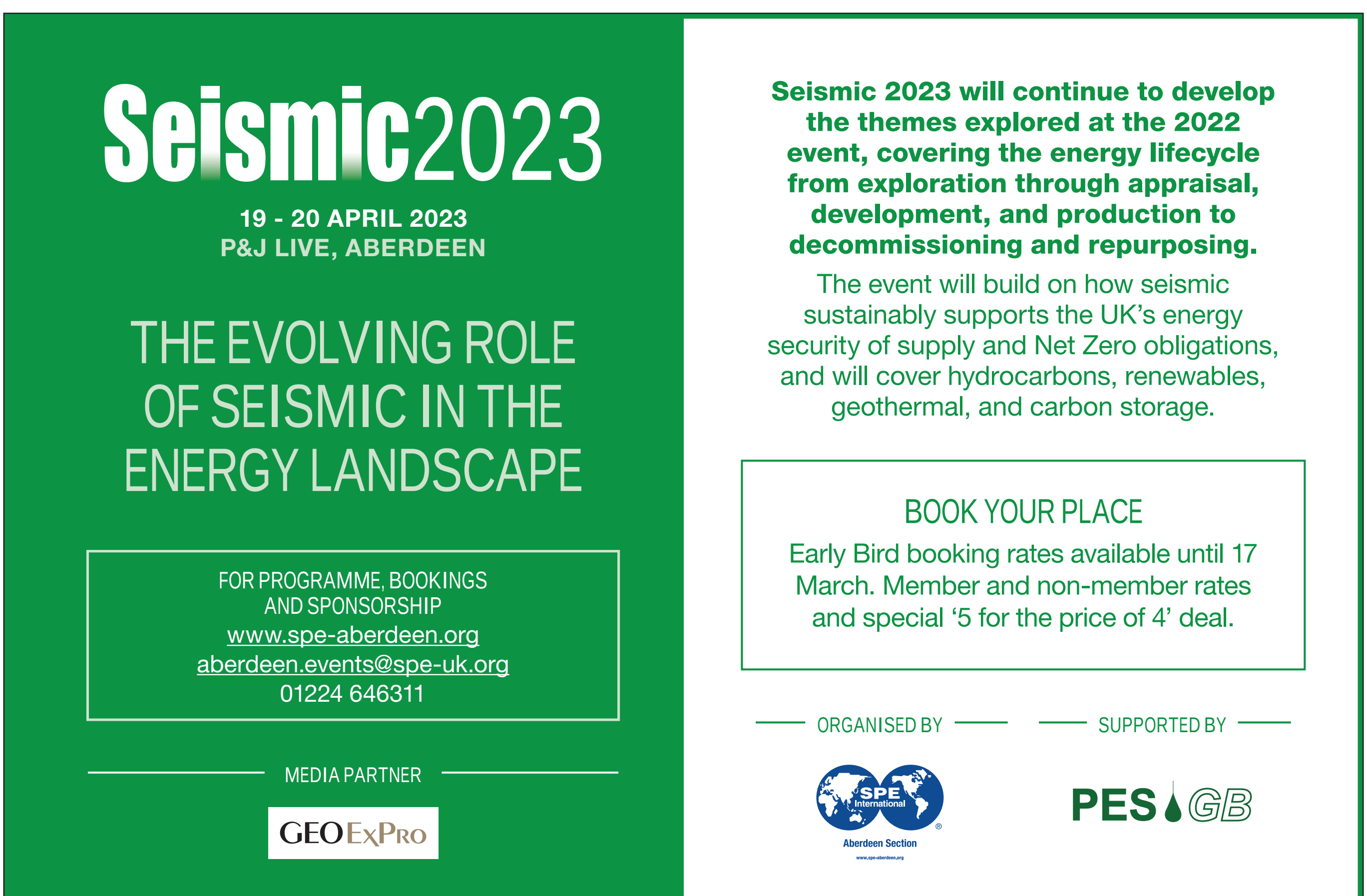
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rock fabric as well as upscaled 4D time strain information. The rest of the permeability model is left unchanged.

An important aspect of this workflow is that a flexible uncertainty and sensitivity analysis can be performed. This includes, for instance, the mapping of features into different grid resolutions to investigate potential upscaling issues (e.g., preserving fault and fracture connectivity in the model), parameter permutations of seismic attributes to generate an ensemble of plausible geological scenarios, or a signal-to-noise analysis based on seismic time-lapse data.

All those investigations can be run automatically in an uncertainty loop to screen various scenarios. The outcome of the re-evaluated model is available immediately and shared across domains, based on which a decision can be made by the team. The lesson learned can be automatically applied to other parts of the field and refined as needed.

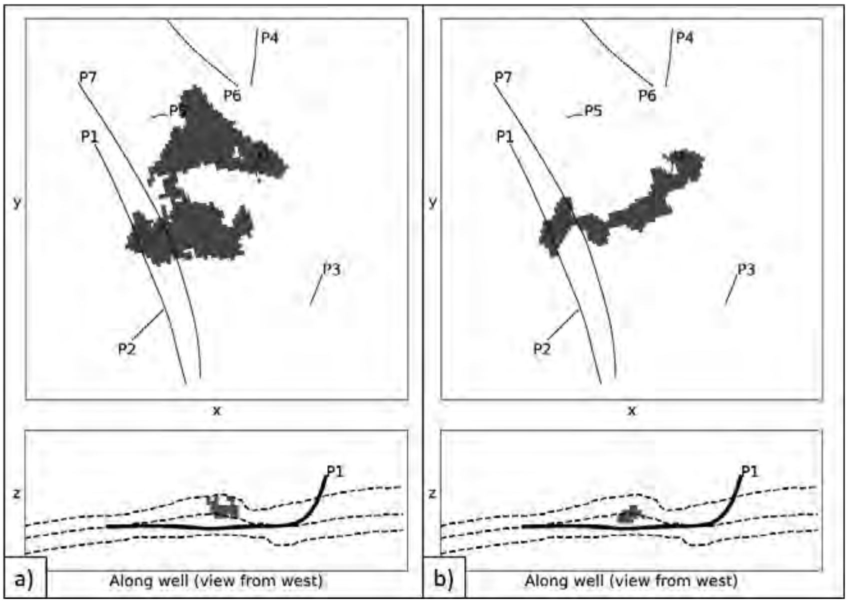

Figure 4: User driven automated extraction of possible flow connections, a) rock fabric, b) 4D time strain. The outline of the geobodies is highlighted with polygons in Figure 3 c) and d).

ASSISTING THE DECISION-MAKING PROCESS

In this article, we introduced a new concept of actionable insights. The insights are generated by a set of recipes and contain key information of subsurface-related observations that are directly used to update reservoir models. All steps are performed automatically with limited input required from the petrotechnical expert, which makes those insights reproducible at any time.

The recipes are designed in Python such that they can be used and customised by non-developers and enabled by data liberation and cloud computing technologies. The outcome assists the decision-making process by presenting all available data and various scenarios in a fast and efficient manner to the stakeholders.

References and acknowledgements available online (geoexpro.com). ■

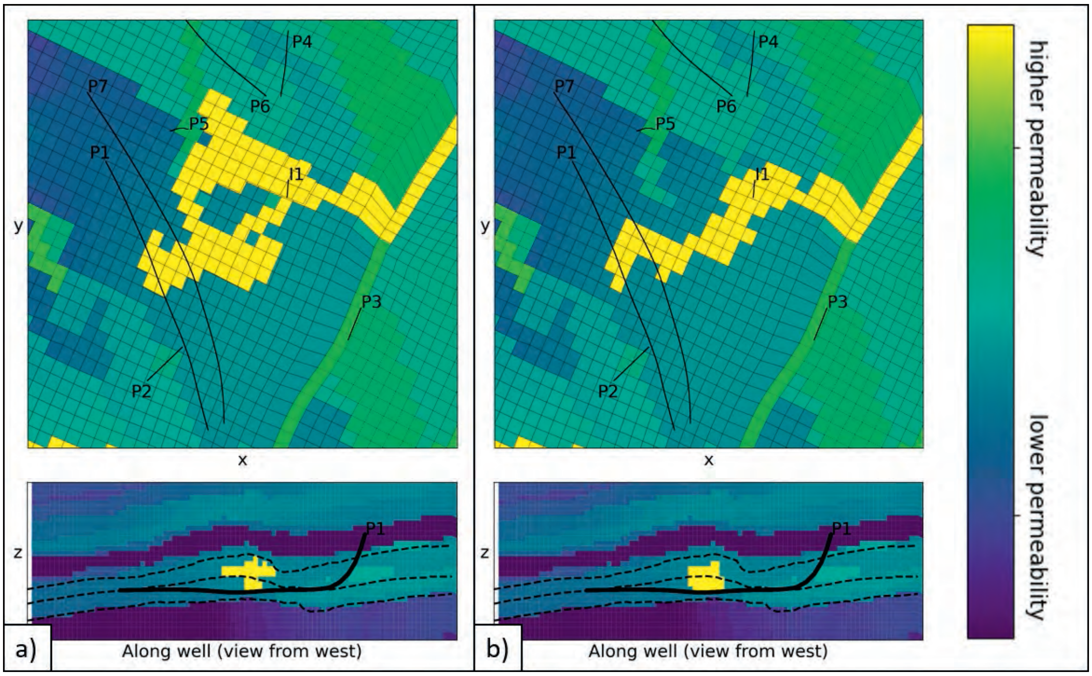

Figure 5: Extracted potential flow connections translated into grid property updates, enabling uncertainty and scenario screening loops. Property shown is the permeability model with upscaled a) rock fabric and b) 4D time strain information update.

ISRAEL'S 4TH OFFSHORE BID ROUND (OBR4)

PROXIMITY. STABILITY. SECURITY.

Israel's 4TH Offshore Bid Round (OBR4) was launched in December 2022.

Following numerous Multi-TCF discoveries made in the Levant Basin over the past two decades, the Ministry is promoting further exploration based on the large Yet-To-Find potential that exists offshore Israel.
Zones E, G, H and I are offered for bidding.

With the East Med increasingly recognized as an exploration hotspot close to the European market, we foresee significant interest in OBR4 and invite all relevant stakeholders to engage with us. Submissions are open until June 29, 2023, with results expected soon after.

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NEW STUDIES IN THE LEVANT BASIN OFFSHORE ISRAEL

For the past 20 years, hydrocarbon exploration has had an enduring focus in the Levant Basin, with around 85 Tcf (2,400 BCM) of gas (GIIP) discovered during that period. It has re-invigorated activity in Israel, Egypt and Cyprus and opened up new plays.

N. STRONACH[2], M. GARDOSH[1], M. KACHKACHEV SHUIFER[1] AND B. HOLZWEBER[2]

(1) MINISTRY OF ENERGY, ISRAEL; (2) GAFFNEYCLINE, UK

THE ISRAELI MINISTRY of Energy has been at the centre of these activities, both from a technology and analysis and interpretation perspective. It has also facilitated recent initiatives and research partnerships, not only involving operators in the area, but also organisations such as BEICIP, Petrostrat, CGG, the Geological Survey of Israel, Gaffney-Cline and the Ministry of Energy itself.

The results of this work include (1) the review of fundamentals of hydrocarbon plays in the area, including stratigraphic correlation, source models and reservoir concepts, (2) the refinement of the existing principal play and (3) boosting the play and prospect inventory.

The aim of this article is to provide an overview of the conclusions of these projects, which form a foundation for the Israeli 4th Offshore Bidding Round (OBR4), recently launched by the Ministry of Energy.

OPENING AND CLOSING OF THE TETHYAN OCEAN

The geological history of the Levant Basin results from the breakup of Gondwana and the opening and subsequent closure of the Neotethys Ocean. The age of extension is Permo-Triassic to Mid Jurassic. Magmatic activity occurred, but without sea-floor spreading (Gardosh et al., 2010).

Variations in crustal attenuation control basin subsidence and sedimentary facies in the Mesozoic and provide the foundation for the evolution of the Levant Basin. For example, the facies change from onshore and nearshore Mesozoic shelfal carbonates and clastics transitioning into slope-basinal mudstones with turbiditic sandstones offshore.

Late Cretaceous reversal of Tethyan plate motion led to compression in the northern part of the basin. Older extensional features were re-activated, and a series of "Syrian Arc" folds and thrust faults were created, particularly along the eastern margin of the basin (Gardosh et al., 2008).

Doming to the south of the Levant Basin during the Oligocene-Miocene resulted in erosion and transport of siliciclastic sediments into the basin, ▸

Figure 1: Location Map

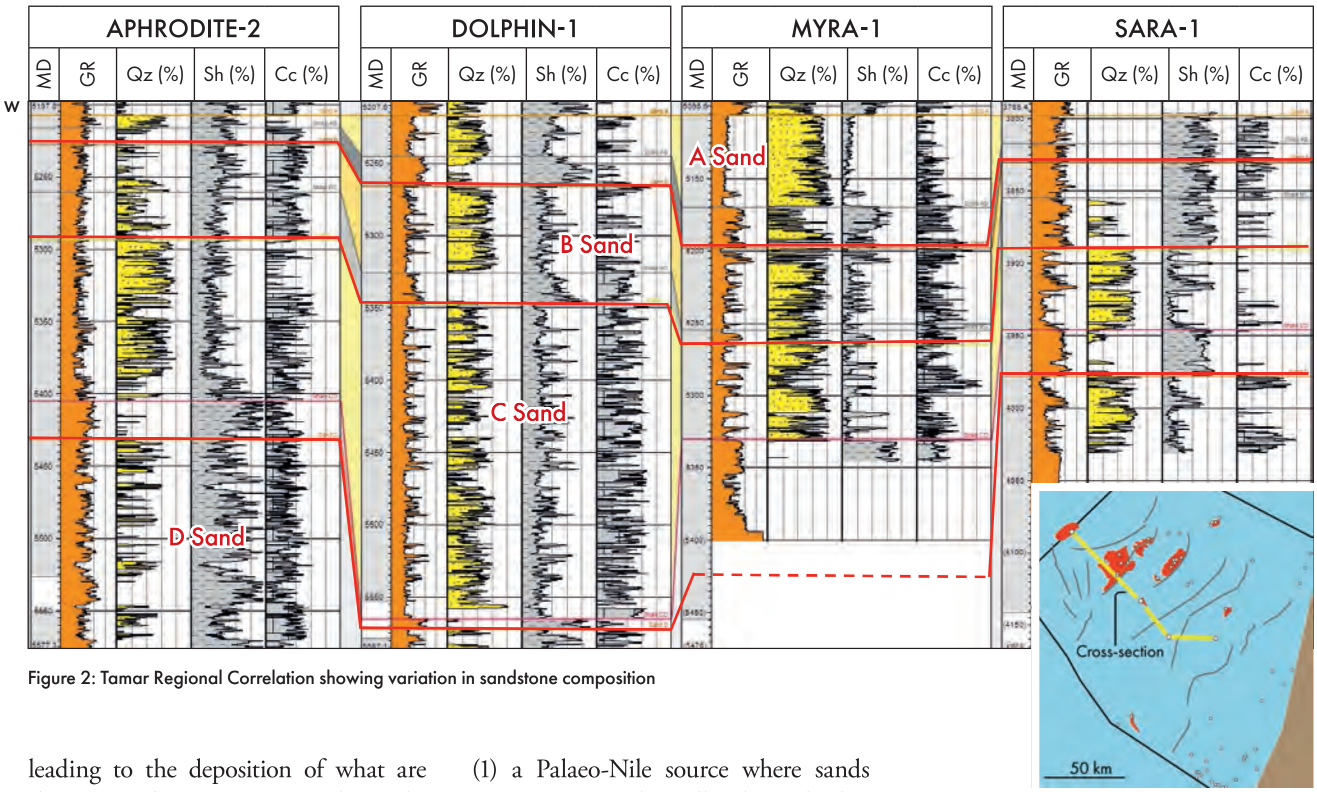

Figure 2: Tamar Regional Correlation showing variation in sandstone composition

leading to the deposition of what are the principal gas reservoirs today. Subsequent closure of the Mediterranean Sea during the Latest Miocene led to the partial desiccation of the Levant Basin and deposition of the Messinian evaporite beds.

THE MAIN ESTABLISHED GAS PLAY: TAMAR SANDSTONE AND ITS EQUIVALENTS

Turbidite sandstones of Oligo-Miocene age (discovered at Tamar-1 by Noble Energy; Figure 1) are the most prolific gas reservoir in the Israeli offshore, of which the net sand thickness can exceed 150 m (Needham et al., 2017). Basin-wide correlation, from the Dalit to the Aphrodite field, shows four distinct sandstone layers (A, B, C and D) and biostratigraphic work confirms these as Aquitanian to Burdigalian in age.

Although the sandstones can be correlated overall, reservoirs range from high net-to-gross, quartz-rich sandstone in the centre, to lower net-to-gross, quartz-poor sediments with greater mudstone and carbonate content at the flanks (Figures 2 and 3; Kachkachev-Shuifer, 2021).

Two controls on sandstone distribution have been previously proposed: (1) a Palaeo-Nile source where sands were transported axially along the basin (Steinberg et al., 2011) and (2) a Levant source where sands were transported across the Levant and Sinai shelf (Gardosh et al., 2008). New mapping of thickness, lithology and mineral composition favours the second model, where, for example, mapping of detrital quartz provides a proxy to define the orientation of the overall system (Figure 3). Regional seismic mapping of the Tamar Sand packages (Top A Sand to CD Shale) shows a 200 - 400 m thick depocentre oriented NE to SW, centered on the Tamar Field (Lippman, 2021).

The inferred sediment pathway aligns with the position of stratigraphically younger sediment fairways along the regional palaeo-shelf edge. For instance, the position of the younger and well-recognised Middle Miocene Afiq Canyon (Figure 3) suggests a long-lived zone of shelf to basin transport. Seismic interpretation has linked the established fields with the Levant and Sinai margins with recognition of possible Tamar correlative units containing candidate channel and lobe complexes (Figure 4).

ADDITIONAL CENOZOIC PLAYS

Other Cenozoic sandstone reservoirs lie above and below the Tamar Sandstone, and range in age from Oligocene to Late Miocene. As such, these correspond to additional episodes of relative sea level change and/or source reactivation. The age of the younger sandstone units has been confirmed by new detailed biostratigraphic work (Petrostrat, 2021) in offshore wells as Mid Burdigalian, Early Langhian and Serravalian, which places them in a robust regional context of relative sea level change. An even younger phase of sandstone deposition took place during the Tortonian, established by dating in the Afiq Canyon area in the south (Figure 3).

Sandstone systems may be both confined by erosional surfaces (e.g. in the Afiq Canyon) or display an unconfined character. Canyon incision took place in multiple stages from the Oligocene to Early Miocene, and sedimentary fill displays up-dip termination caused by truncation through younger events. Potential traps have a complex mix of stratigraphic and structural geometries. Interpretation of these geometries can be achieved by the simple mapping of reflector terminations but is also supported by seismic amplitudes as well as other seismic attributes such as spectral decomposition and AVO.

MIDDLE TO UPPER MIOCENE PLAYS

The Afiq Canyon Fill is the most important example of this play, but other sand fairways of this age are also thought to be present. The existence of good quality sandstone reservoirs within the Afiq Canyon (Figure 3) fill is demonstrated by several wells; for instance, Shimshon-1 encountered gas within sandstones of Serravalian age. This discovery established the Middle to Upper Miocene play in the basin, which is younger than, and distinctly different from the Tamar Sandstones play.

The play comprises a complex of stacked submarine channels and fans deposited within the overall confines of the Afiq Canyon. Most potential reservoirs have been interpreted within the Mid to Upper Miocene successions, in the latest stages of canyon erosion and fill, partly subcropping the Base Messinian unconformity. However, similar high-amplitude events in the earliest canyon fill may have been overlooked thus far. Interpreted traps are stratigraphic in nature, with fans onlapping onto highs within the canyon, and onto the canyon walls. Lateral facies changes within the canyon fairway into overbank/inter-channel units provide an additional trapping mechanism (Figure 4).

The Afiq canyon system is a long-lived element in the Israeli offshore, but in more distal locations, in the western part of the offshore, detailed seismic stratigraphic, attribute and spectral decomposition work has shown the existence of other more ephemeral channel/canyon systems within the uppermost Middle and Upper Miocene section and at the Basal Messinian unconformity.

PLAYS BELOW THE TAMAR SANDSTONE

Seismic interpretation was also carried out to map sandstones pre-dating the Tamar complex in the southern part of the Israeli Levant Basin. These are distinct as they are developed proximal to the main Tamar depocentre. While sediment provenance is likely to be the same, transport into the basin is probably separate from the channel system sourcing the main Tamar Sand reservoirs. Combination traps have been interpreted, combining lateral facies changes with dip closures and truncation at the base of the Afiq Canyon. Channel incision and levees are visible on seismic and locally coincide with amplitude anomalies where areas of channel incision display the brightest amplitude response (Figure 4).

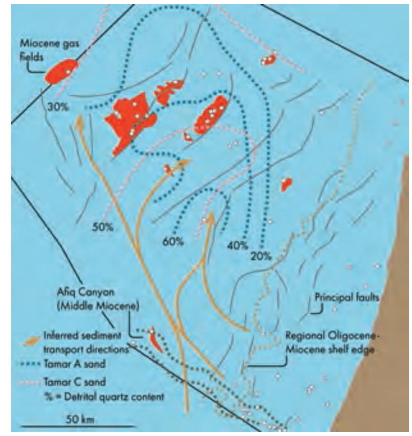

Figure 3: Tamar Sandstone Palaeogeography

NEW PLAYS IN THE TAMAR SANDSTONE

In addition to sedimentary process, ▸

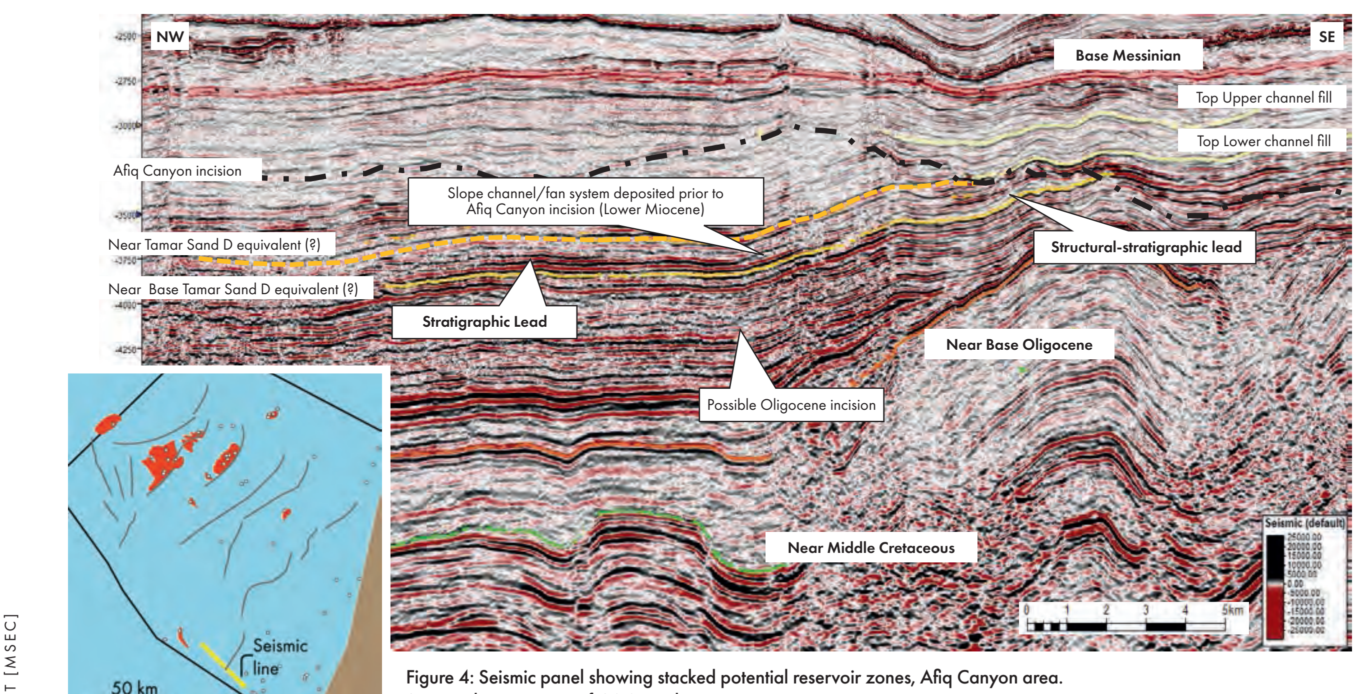

Figure 4: Seismic panel showing stacked potential reservoir zones, Afiq Canyon area. Seismic data courtesy of CGG Earth Data.

there is also a structural picture emerging. Established fields such as Leviathan and Tamar comprise ancestral, NE-SW trending Mesozoic highs, that have undergone reactivation during the Latest Cretaceous to Miocene "Syrian Arc" event. In the area between these highs, there is a complex of further fault trends across the basin, mostly conjugate to the main NE-SW structures, which are important in focusing structural activity, especially during episodic wrench tectonics and uplift. In part, these faults are manifested as short sub-parallel swarms of NW-SE striking faults at Miocene level, often termed as the "Piano Key" fault system (Joffe et al., 2022, Ministry of Energy, 2022).

Major Mesozoic faults exert direct control on Miocene faults, for example on the northern side of the Leviathan Block. Here, normal fault splays exhibit flower structure geometries that merge downwards and laterally into the North Leviathan Fault, suggesting a dextral motion on the master fault (Figure 5). Subsequent uplift of the main block led to formation of onlapping sediment wedges.

Elsewhere, rather than relating to a deeper master fault, Miocene fault patterns show more distributed arrays. Each consists of SW and NE-dipping normal faults, separated by oblique transfer zones, across which the sense of dip can change. Faults appear to nucleate within the Tamar Sandstone interval, soling out upward within the Middle Miocene. Downwards, the faults sole out at various stratigraphic levels, but commonly within the Oligocene. The overall sense of shear observed supports an anticlockwise rotation of the Leviathan Block, cf. Steinberg et al. (2018).

The detailed interpretation of faulting not only supports the understanding of basin kinematics, but also defines potential hydrocarbon traps, in combination with onlapping sediment wedges onto the major highs. It is significant that the main intervals of structural activity appear to have taken place both before and after the deposition of the main Tamar Sandstone and are therefore expected to contain correlative submarine sandstones within the Aquitanian to Burdigalian.

PETROLEUM SYSTEMS

Biogenic gas is a proven hydrocarbon source offshore Israel and has charged most of the Cenozoic reservoirs. However, there is also evidence of thermogenic gas and oil generation, charged from Mesozoic source rocks in the eastern part of the basin. For example, high condensate-gas ratios from samples in the Karish field, in the north, point to more widespread liquid-prone (thermogenic) source rocks in the Mesozoic section. A new database of source rock data has been compiled by the Geological Survey of Israel (GSI, 2021), which demonstrates several intervals of oil and gas prone source rock in the Jurassic, Lower and Upper Cretaceous. This is expected to pave the way for better future modelling of kitchens for the deeper, more distal parts of the basin.

AN ACTIVE HUB

The Eastern Mediterranean area, and in particular offshore Israel, remains an active hub of research and exploration. New integrated studies have improved the understanding of the basin's geological history and have led to expansion of the play and lead inventory for future exploration and development activity.

New work is not only expected to maximise the economic exploitation of resources, it also facilitates possible future carbon storage projects now that the distribution, control and properties of the main sandstone units are much better known. ■

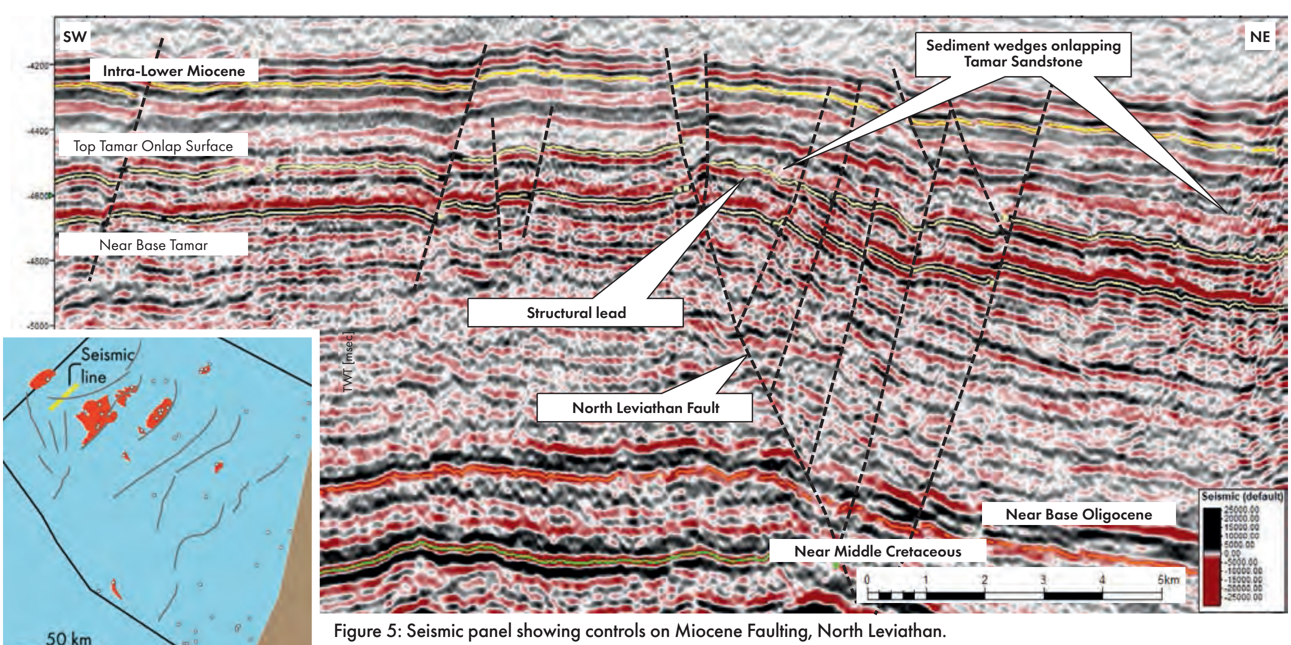

Figure 5: Seismic panel showing controls on Miocene Faulting, North Leviathan. Seismic data courtesy of CGG Earth Data.

PORTRAITS AND INTERVIEWS

"...2014 seems to have been
a watershed moment for the UK industry."

Peter Thorn

THE EYES OF NORTH SEA GEOLOGY

Well site geologist Peter Thorn has seen a lot of North Sea rocks sliding under his microscope, maybe more than anyone else. Here, he reflects on his career and how the profession of a wellsite geologist has changed over the years.

TEXT: HENK KOMBRINK

"I NEVER INTENDED to join the oil and gas industry," says Peter Thorn whilst we are being served a coffee in a café overlooking Aberdeen Harbour on a cold and crisp winter's day. Now, Peter is one of the most experienced well-site geologists in the greater North Sea area. With more than 35 years of working both offshore and onshore behind him, sitting 100's of wells, there are few who can claim to have more experience than him. For that reason, he's gained a strong reputation and is especially in demand when it comes to drilling HPHT wells.

THE ONLY COMPUTERS ON THE RIG

"The well site geologist and mudlogging professions have changed a lot over the decades," Peter continues while a supply vessel slowly leaves the quay to provide supplies to one of the many platforms still out there in the North Sea.

> "..samples retrieved from the shakers had a much more prominent position in the real-time interpretation process."

There was a lot more geology involved in the job. "Logging while drilling wasn't used or was very basic, so the samples retrieved from the shakers had a much more prominent position in the real-time interpretation process," Peter explains.

"Coring also seems a thing of the past," Peter says. "The number of meters of core I cut I don't remember, but it's a lot. And rather than sleeved coring, where the wellsite geologist often won't see the whole core because it is hidden in an aluminium cylinder, we were also tasked with laying out the core in 1-m sections and put these into wooden boxes. We may not have done a detailed interpretation, but it was always very satisfying to see a whole core and not just rock chips. Nowadays, many geologists have never seen a coring job."

"The use of MWD/LWD tools was less common and the tools used more basic therefore drilling parameters such as ROP, torque and weight on bit were essential for geological interpretation and also for overpressure evaluation. The shape of the cuttings can tell a lot about downhole conditions and oversize, elongate splintery cavings indicative of overpressure."

Without real-time logging, it ▸

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"While oil fluorescence is fairly easy to detect using water-base muds, I've never been 100% convinced of oil fluorescence whilst using oil-based muds."

was also more challenging to discern a hydrocarbon-bearing reservoir from a water-bearing one. Especially in the case of oil-based mud, the ability to interpret a show will always be surrounded with uncertainty. "While oil fluorescence is fairly easy to detect using water-base muds, I've never been 100% convinced of oil fluorescence whilst using oil-based muds," Peter says. "Connection gas and gas-readings form very important indicators, if not the most important ones," he adds. It is an important observation, especially for the office geologist who is looking for missed pay in the right-hand column of old composite logs.

"Being a mudlogger may not be seen as the most exciting job on the rig, but it was the mudloggers and wireline engineers who were the first to get access to a computer," Peter continues. Yet, the capabilities of these machines were very limited. "I remember witnessing my first Cement Bond Log and because the computer lacked the capability to store the generated data, the print-out of the data recorder was all we had. To put things into further context, all communication to onshore took place via Telex, a way of sending messages that the younger generation will have never come across."

INTERPRETING ROCK FLOUR

"Many things have changes over the decades," Peter continues. "The attitude towards safety dramatically improved and communication technology enables people in the office to monitor progress real time. "Back in the days, I brought a stationary box with me offshore that contained all the data and information I needed, nowadays decisions are being made onshore as the data can be watched on mobile phones."

"Drilling is also much faster," Peter continues, "we drilled 5-10 feet per hour in the Chalk 30 years ago, now it is up to 50 feet in the same amount of time. The arrival of PDC (polycrystalline diamond compacts) bits changed our interpretation routines dramatically," Peter further explains. This type of drill bit creates distinct PDC shaped cuttings in mudstones but typically mills the sandstones into much smaller particles, called rock flour, which can make it challenging to identify when the reservoir has been penetrated.

The major progress made in logging while drilling tools has made lithological descriptions part of a broader suite of data. However, interpreting the rocks will always remain critical. "I remember talking to a team onshore whilst we were drilling a horizontal well," Peter recalls. "The geomodels of the engineers indicated that the well was heading towards the base of the sandstone, but I had noted that coarser-grained intervals were preferably found near the top of the sandstone, and that was what I was seeing in my samples." A clear example of how the geology and simple observations can sometimes be so powerful.

"Back in the days, I brought a stationary box with me offshore that contained all the data and information I needed."

FULL CIRCLE

Does Peter's career as a whole stand for the coming and going of UK oil? He concludes: "Since the crash in 2014, my work routine has made a major shift in the sense that I had a stable and always fully booked agenda of rotations before 2014. Since then, work has been more erratic. No, I've never sat at home too long, I've been lucky, but 2014 seems to have been a watershed moment."

If experienced people like Peter Thorn note a change in work routines and work availability, it is something to take seriously. Will 2014 be the year when trust and confidence in the offshore oil and gas sector has left the UK for good? Even though prices have recovered in the meantime, uncertainty in economic robustness has been replaced by uncertainty in political support.

Maybe, if Peter would have finished his PhD in mining geology in 2023, his career would indeed have continued in mining rather than oil and gas. Maybe, his career perfectly encapsulates the rise and decline of the UK's oil and gas industry. ■

MINING AND ABERDEEN

When looking at his academic years, nothing hinted towards a career in petroleum. "I came to Aberdeen to carry out a PhD, studying tungsten mines in Bolivia. I spent about a year in and around the mines, it was a fascinating time," Peter says. Aberdeen University at the time had a strong foothold in hard rock geology.

Even when Peter joined the offshore industry as a mudlogger in 1984, he still intended to join the mining industry again, where he had also worked for a year prior to his PhD.

It worked out differently. The mining sector experienced a major slump at the time, and with oil and gas drilling booming globally as well as in the UK, it wasn't difficult to see why the change from hard rock to soft rock was not a temporary one.

GEOTHERMAL ENERGY

"It is important to be aware that this shallow geothermal solution is part of a process whereby the subsurface plays a key role."

Paul Fowler, GreenGlove Boreholes

Steamy headlines do not guarantee steamy results

The city of Geneva is upbeat about its geothermal potential following the completion of a 3D survey. But how justified is this?

"THE GEOTHERMAL POTENTIAL of Geneva is confirmed", stated the press release that was issued by website geothermies.ch in November 2022. This headline was not the result of a successful geothermal production test, it followed the successful acquisition and interpretation of a 3D seismic survey. According to the press release, the results are a major geological discovery.

Prior to the seismic acquisition, the geologists who wrote the report thought that faults in the Geneva area displayed a NW-SE strike direction. However, following the interpretation of the 3D survey, a more complex fault pattern with a dominant WSW-ENE strike direction was revealed, with smaller faults branching off. A major surprise, according to the group of researchers.

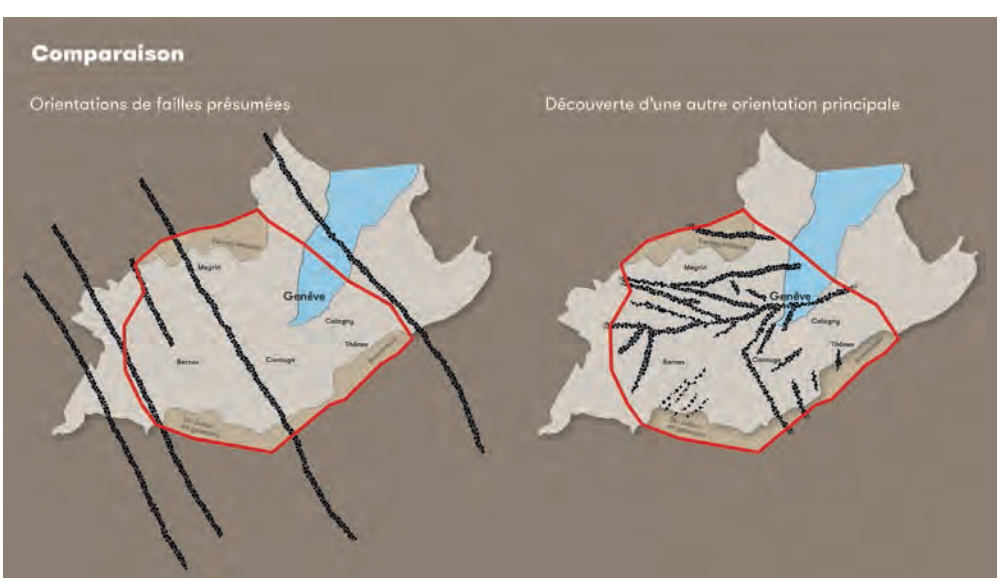
"...the pre-seismic acquisition fault interpretation presented by the geothermal study was oversimplified and did not do justice to previous scientific work."

For those who have ever been to Geneva, the city panorama is dominated by the Salève thrust, which exposes Upper Jurassic and Lower Cretaceous carbonates in an impressive cliff front just south of the city. The strike of the Salève thrust is NE-SW.

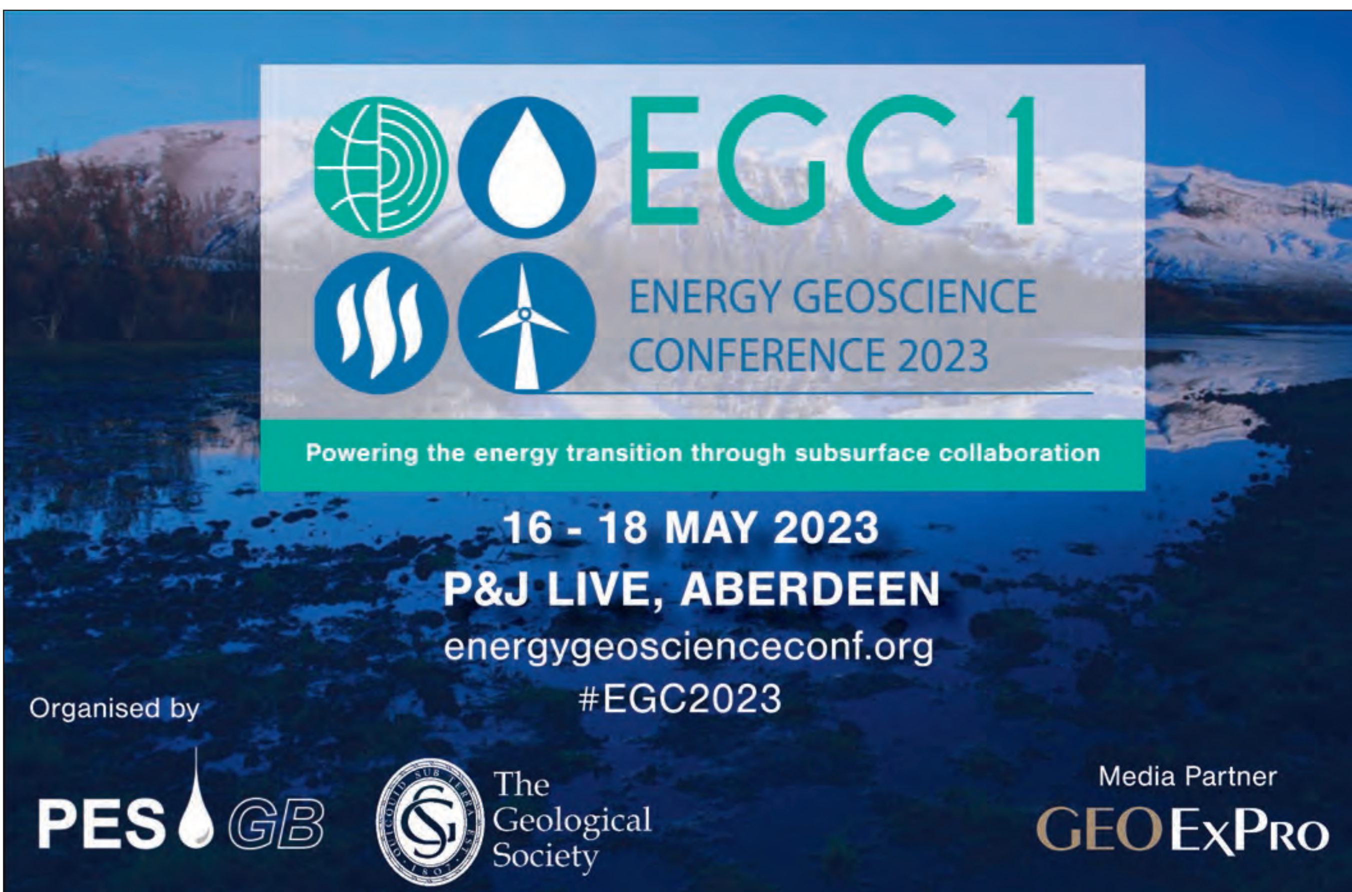
With that in mind, it is already quite surprising that the geologists, prior to the acquisition of the seismic survey, had only "expected" a fault strike direction that is perpendicular to the Salève thrust front.

Only last year, a group of geologists led by Damien Do Couto published a detailed paper in the Swiss Journal of Geosciences on the origins of hydrocarbons in the Geneva Basin, in which a detailed geological map of the area was included. Although the map does indeed show a prominent NW-SE striking normal fault and some smaller faults trending in the same direction, it also reveals a network of thrust faults more or less parallel to the Salève direction. It is what one would expect from such a subsurface setting. Therefore, the pre-seismic acquisition fault interpretation presented by the geothermal study was oversimplified and did not do justice to previous scientific work.

Based on the interpretation of the denser fault network showing other strike directions than expected, the group subsequently draws the conclusion that the geothermal potential of the Geneva Basin is confirmed. That conclusion seems a little oversimplified too. It is usually the drilling of a well that requires geothermal potential to be firmed up. And these wells were drilled, not too long ago. With mixed results. In other words, the claim that the city of Geneva is ready for geothermal energy production is a little too upbeat. ■



Two maps showing a "before" interpretation of faults in the greater Geneva area (left) and the faults that were mapped based on the newly acquired seismic lines (right). Based on recently published literature, the "before" interpretation gives a too simplistic view of the geological setting. Source: geothermies.ch



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Ashley Lowthian from GreenGlove Boreholes at the Rotomax Li rig.

PHOTO: HENK KOMBRINK

A shallow geothermal borehole in a single day

While open-loop deep geothermal energy production is still lagging behind in the UK, shallow closed-loop systems are being completed more and more.

"We are operating five rigs continuously across the UK," Ashley Lowthian from GreenGlove Boreholes tells me when I visit him and his colleague at a drill site in Garthdee, Aberdeen. Ashley is responsible for drilling 24 boreholes to a depth of around 120 m into the Aberdeen granite, with the aim to provide a new housing development with energy from the subsurface. His previous drilling job was in London: "We are all over the place," he says, "and continuously expanding."

"We drill a hole in about a day," Ashley further explains, "so it is an entirely different ballgame as drilling deep geothermal wells." Many of the processes involved in drilling these shallow boreholes are the same as drilling deeper wells though, but now it is happening in a miniature format. For example, a casing is used for the top 5 m to stabilise the hole; the rest is drilled open hole either with air or water. Cuttings are being collected in a skip standing next to the drilling equipment.

Once the drill bit arrives at the

"We drill a hole in about a day, so it is an entirely different ballgame as drilling deep geothermal wells."

desired depth, circulation continues to a point where the hole is as clean as possible. Then, three tubes are lowered into it. "Why three tubes?" one would ask. Two tubes are coupled through a U-shaped connector (see image). These will be used to circulate the water through. The third tube, with an open end at the bottom of the borehole, will be used to pump geothermally conductive grout into the hole.

Once the borehole is filled with grout, the subsurface element of the project is completed. The next step is to connect the pipes to a heat pump that will be used to elevate the circulated fluid to the temperature required for underfloor heating.

"It is a real example of how the subsurface forms an integrated part of the energy transition."

"It is important to be aware that our solution is part of a process whereby the subsurface plays a role in a chain of other project requirements," ***Paul Fowler*** from GreenGlove Boreholes explains. "For instance, in the Aberdeen project, we hope to get a temperature gain of around 4°C when you compare the injected versus the produced fluid."

The temperature down at 120 m is only around 10 to 12°C, which explains the seemingly small increase. "However, even a temperature difference of 4°C is already a win, and means that the heat pump will require less energy to get the fluid temperature at the desired level. "It is a real example of how the subsurface forms an integrated part of the energy transition," Paul adds.

Because the projects are closed-loop and need to be situated right next to the targeted property, the subsurface is not a key factor in placing the wells," Paul confirms. "The geology is still important to be aware of when it comes to the way we design and drill the hole, but once the tubes are in and the hole has been filled, the substrate is not of a major concern to us."

This illustrates the difference between shallow closed-loop and deep open-loop geothermal systems; the former is engineering-driven, whilst the latter requires more of a geoscience approach to get to the right reservoir. The energy transition will surely need a lot more tubes and small drilling rigs than ever before. ■

500 SHALLOW BOREHOLES

A single borehole such as the ones drilled in Garthdee can produce between 2 and 20 kW each. That means a deep geothermal open-loop project consisting of a 5 MW doublet is equivalent to around **500 shallow boreholes** of 10 kW each.

An impression from the drill site once the tubes have been placed in the borehole.

Connector linking the injecting and producing tube

PHOTO: HENK KOMBRINK

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Mapping a fault using induced seismic events

Learnings from induced seismic events related to production testing in granitic basement enables better reconstruction of subsurface setting.

PHOTO: PIXABAY

TWENTY YEARS AGO, Australia saw the start of a big geothermal project in deeply buried basement rocks. Situated in the Cooper Basin, the project included several phases of production testing and stimulation, but commercial operations never took off. The plant ultimately closed in 2015 after drilling of six deep wells.

However, the data acquired during the several phases of injection and production continue to be one of the largest and best controlled data sets, both on the geological setting as well as regarding the induced seismic events that took place during and after operations.

Today, as geothermal energy production is being increasingly looked at to decrease dependency on fossil fuels, there is a number of projects planned or in development where geothermal energy is also being extracted from basement rocks. The United Downs and Eden project in Cornwall in the UK are just two examples, both of which aim to produce hot water from a fault zone at comparable depths (> 4 km) as the project in Australia. For that reason, the learnings from the Cooper Basin project are worth being analysed and considered until today.

MORE THAN 75,000 INDUCED SEISMIC EVENTS

The initial objective of the Enhanced Geothermal System in the Cooper Basin was to generate more than 100 MW from a number of production and injection pairs completed into the granitic basement, with the deepest well reaching a depth of 4850 m. Four wells were clustered in the so-called Habanero area, while the two other wells are located further away (Jolokia and Savina).

Between 2003 and 2012, several phases of hydraulic stimulation took place, with an array of geophones monitoring induced seismic events. The analysis of these events shed some interesting light on the nature of the granitic basement, with the a clear difference observed between the Habanero and Jolokia wells. The Savina well was abandoned due to borehole problems.

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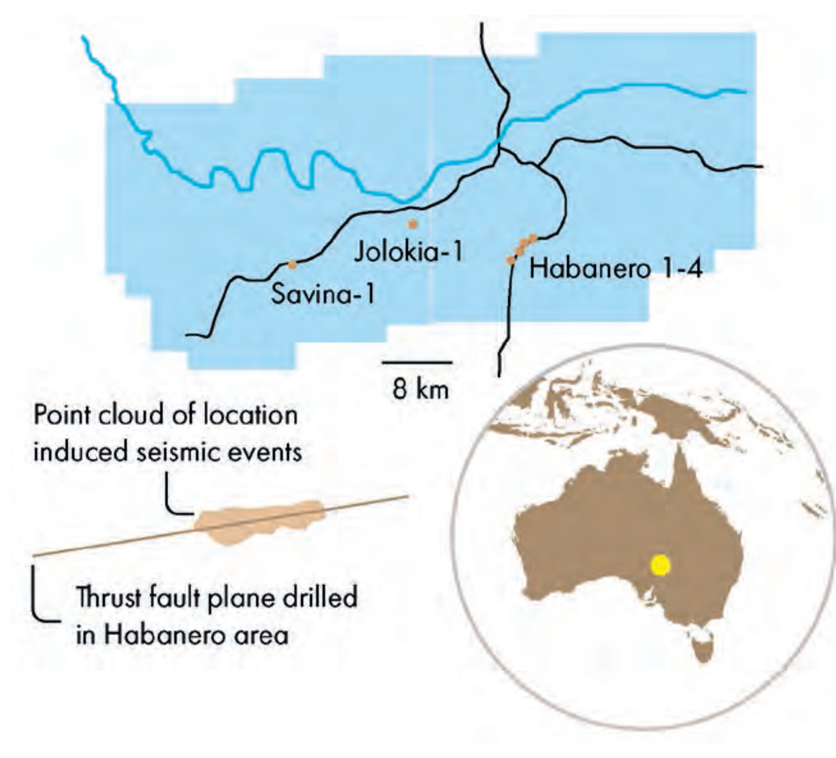
Following definition of the hypocentre locations of the seismic events observed in association with the Habanero well tests, they all lined up along a slightly dipping plane (see figure). Subsequent drilling and coring confirmed that a sub-horizontal thrust fault dissects the granitic basement in the area. It also appeared that induced seismic events, which varied in magnitude between 1.6 and 3, radiated away from the wells over time up to around 1000 m away from the wellbore. Researchers also observed that due to the induced earthquakes, stress redistribution within the fault zone took place towards the periphery of the reservoir. This has the potential to trigger larger magnitude earthquakes if the fault is critically stressed.

In contrast to the experience at Habanero, testing the Jolokia well resulted in hardly any fluid injection, and hence very little induced seismic activity was detected.

FAULTED BASEMENT ONLY

The main conclusion from these tests in the Cooper Basin is that unless a fractured zone is present in granitic basement, the rocks cannot be considered a reservoir because they are completely impermeable. It is also interesting to note that it was the analysis of the induced seismic events that helped locate and map the geometry of the thrust fault. Based on these findings, the field development plan had to be significantly revised downwards in terms of expected energy extraction, mainly because it was the fault zone only that promised to be capable of bringing water to surface. In the end, geothermal energy production never took off. ■

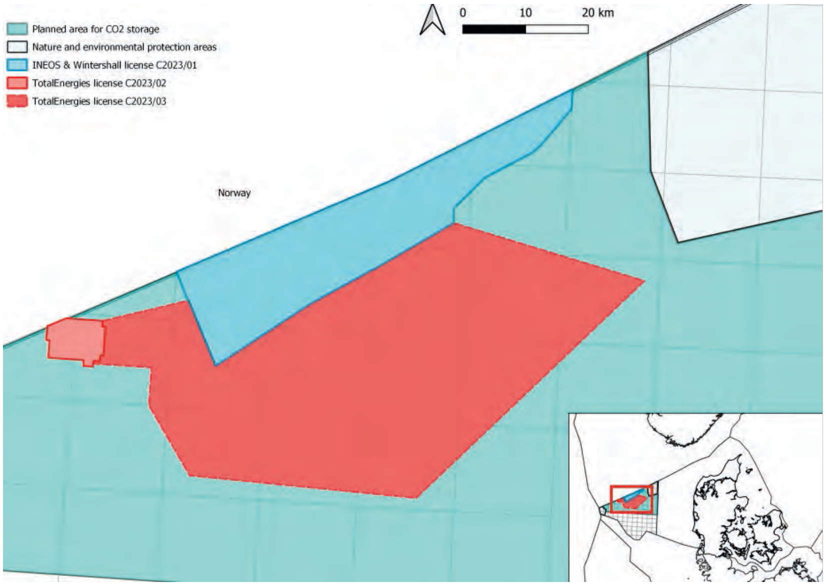
This article is partly based on findings published by Stefan Baisch and Robert Vörös from Q-con.



SUBSURFACE STORAGE

"...it is worth investigating the possibility to store gas in subsurface sites in Indonesia, preferably close to where the main market is."

Edison Sirodj



Map showing the location of the awarded CCS licences in the Danish offshore.

First CCS licences issued in Danish offshore

The Danish Energy Agency (DEA) awarded licences for exploration of full-scale CO_2 storage in the Danish North Sea.

TOTALENERGIES and a consortium consisting of INEOS E&P and Wintershall DEA have been awarded three licences in the northern part of the Danish North Sea.

TotalEnergies EP Danmark A/S was awarded two licences and the partnership between INEOS E&P and Wintershall Dea International is awarded one license. The licences cover areas with depleted oil and gas fields and previously unexplored saline aquifers. All the licences contain the necessary geological structures that are suited to serve as permanent CO_2 storage locations in the future. The timing and design of the final CO_2 storage facilities will depend on the upcoming exploration and research work.

The captured CO_2 will likely be transported either via specially designed ships or through existing or new pipeline infrastructure.

The two applications in this round came from TotalEnergies EP Danmark A/S and a consortium consisting of INEOS E&P and Wintershall Dea, and both applications met the requirements.

“Granting the first exclusive permits for full-scale CO_2 storage in the North Sea is an important step into the future. CO_2 capture and storage is an important element in the green transition. Today’s licences are the result of effective implementation of the first Danish political agreements on CCS", said Kristoffer Böttzauw, DEA’s director. Nordsøfonden, the Danish state oil and gas company, will represent the interest of the state and participate with a share of 20% in each of the coming new licences.

Based on a press release from the Danish Energy Authority.

Vår Energi and Equinor withdraw from Barents Sea CCS project

Changing energy demand situation behind the decision.

WITHIN THE CONTEXT of the current gas crisis and the amount of money that can be made selling gas, it may not be too much of a surprise to see that two major Norwegian players have decided to withdraw from Horisont Energi’s Blue Ammonia project that also included carbon capture and storage.

Horisont has already found a new partner in ammonia production specialist Fertiberia. However, it will require an operator if it wants to advance the project toward development.

Meanwhile, Vår Energi and Equinor now have to find other ways to export Barents Sea gas to market, as the only LNG facility in the Barents Sea region is at capacity processing gas from the Snøhvit field. There is no pipeline connecting the Barents Sea to Europe.

The decision will also create more momentum to step up exploration in the area, as Rune Oldervoll from Vår Energi hinted in a press release: “Our goal is to establish an export solution for gas in the Barents Sea with the capacity to both utilise proven resources, as well as contribute to a larger area solution for further development and value creation in the region.”

More info at: horisontenergi.no

Artist impression of Barents Blue project.

SOURCE: DEA, HORISONT ENERGI

Balmedie beach, NE Scotland, overlooking the UK North Sea.

PHOTO: HENK KOMBRINK

Deep geological storage of CO_2 is safe

A report written by specialists from industry and academia states that more than 99.9% of injected CO_2 remains in the subsurface. It should take away concerns regarding the suitability of the subsurface to store CO_2, but only for the scenarios investigated.

ACCORDING TO modelling work carried out for the project, 25 years of injection operations and 100 years of post-injection monitoring result in the retainment of more than 99.9% of the injected CO_2 within the storage complex.

This is the outcome of running two different scenarios, representing "typical" UK storage sites; one for a depleted oil/gas field and one representing a (partially) confined saline aquifer. Despite the identified risks, the authors conclude that the possibility of major or moderate leakage rates from a deep geological storage site is improbable.

However, it is important to note that the two modelled storage sites do not represent all CCS initiatives currently planned on the UKCS. The trick is in the words "partially confined" when it comes to saline aquifers. A partially confined aquifer is one that is sealed at the top with lateral movement possible. However, no matter in which direction the fluid migrates, it will not reach the surface.

This definition does not apply to at least two carbon storage sites currently in various stages of progression in the UK. In the Endurance case in the Southern North Sea, the Triassic reservoir has limited lateral confinement as it crops out at surface away from the storage site. The Acorn project, in the Central North Sea, is an open aquifer. As Bob Harrison explained in a comment on LinkedIn, these sites carry a higher containment risk because lateral confinement is more of an issue.

It is surprising that the study did not model an open aquifer scenario, given the importance of these sites in current carbon storage plans on the UK Continental Shelf.

More information at:
gov.uk/government/publications ■

TWO SCENARIOS

Two different scenarios were run to represent the features of UK storage sites; one for a depleted oil/gas field and one representing a (partially) confined saline aquifer. For depleted oil or gas fields, there is a higher probability of a well containment issue taking place than a geological containment problem due to the fact that oil or gas fields will have had a number of exploration, appraisal and development wells drilled. These wells, especially older ones, are more likely to experience integrity issues. At the same time, although well containment issues are less likely in saline aquifers due to the fact that these structures have not been extensively drilled, geological uncertainties around the reservoir and seal do expose more of a risk.

A CCS way of abandoning wells

The case history of the recently drilled Jaws well in the UK North Sea shows that by updating the abandonment strategy of exploration wells, the potential for future CCS projects in the area is safeguarded.

"THE GEOSCIENCE BEHIND WELL ABANDONMENTS is getting more challenging when we want to accommodate requirements for potential CCS projects in the area," said Scott Liebnitz during the first Aberdeen Energy Talk in January.

Scott presented the story behind drilling the Jaws well (22/12d-13), completed in 2022, to explore the potential of the Upper Jurassic Fulmar sandstones on the eastern margin of the Forties-Montrose High in the UK North Sea. Even though a good reservoir section was found, the Fulmar sands turned out to be water-wet, most likely due to a lack of hydrocarbon migration into the closure.

The Jaws well was drilled in an area where the Paleocene Forties sandstone constitutes a potential candidate for future carbon storage projects. The Forties reservoir is a regionally extensive deep-water turbiditic fan which is in relative hydrodynamic communication. The Paleocene sandstone is also an important reservoir for nearby fields; Shell-operated Nelson and Apache-operated Forties are examples of this in the immediate vicinity.

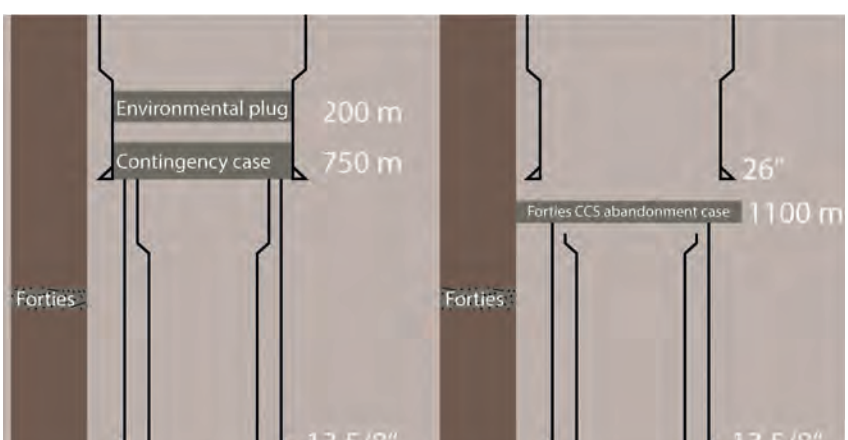
"..should the Forties sandstone be used as a reservoir to inject CO_2 in in the future, the conventional way of abandoning this well would not have been sufficient."

As the Jaws well was dry, it was decided to abandon it straight away. The conventional way to abandon wells of this kind, where the Forties reservoir is water-bearing, is to set an Environmental Plug in the Nordland Group at a depth of around 200 m. In case the Forties would have been oil-bearing, the plug would have been required at a deeper interval (750 m), but still in the same 26" casing.

However, should the Forties sandstone be used as a reservoir to inject CO_2 in in the future, the conventional way of abandoning this well would not have been sufficient. In that case, a plug was required approximately 500 m below the 20" casing shoe, which means that an additional 1,000 m of casing was to be pulled out of the hole in order to expose the 13-5/8" outer casing.

The main rationale behind arriving at this particular depth is the ability of the plug to contain a super-critical CO_2 gas gradient, which was determined together with experts from the NSTA.

This had a knock-on effect on the abandonment costs of the well. However, Shell designed and delivered the Jaws well according to the current CCS requirements, in close collaboration with partners and the NSTA, eliminating the risk of future CO_2 leakage pathways.



Conventional abandonment design (left) versus CCS case abandonment design (right) for the Jaws well. Adapted from Shell.

NOT THE ONLY WELL

The way 22/12d-13 was abandoned does not apply to older wells drilled in the same area. In the past, quite a few wells in the immediate vicinity of Jaws also targeted Mesozoic reservoirs. With the Forties being dry in many of these cases, most of these wells will not have cement plugs across the entire Forties, and no Cement Bond Logs to confirm the Top of Cement (TOC). For that reason, these older wells run the risk that the Forties reservoir is not completely isolated. So, even though the Jaws well is robust against future CCS potential if it is launched in the area, there are still many challenges to overcome to realise such a project. Even so, it's important that operators do not add additional wells that may not be suitable in the future, with an optimised abandonment that de-risks the well as far as reasonably possible. ■

Indonesia – now is the right time to look into underground gas storage potential

Whilst gas storage has proven vital to bridge the gap between demand and supply in many countries, Indonesia is currently lacking this capability. The West Java province would benefit from a gas storage facility because it is not well-connected to the national gas network and is experiencing a decline in regional gas production.

TEXT: EDISON SIRODJ

INDONESIA IS HEAVILY RELIANT on gas for a variety of purposes. This is particularly true for Java, which is the most densely populated island of the Indonesian archipelago, and which is hosting a number of industrial complexes that consume significant amounts of gas in a number of fertilizer and petrochemical plants.

Looking at Java as a whole, it is West Java that is currently facing a situation where gas supply is at risk in the short to medium term. Information released by the Department of Energy and Mineral Resources of the West Java Province has confirmed that the supply of gas to the industrial market can possibly start declining this year already. The industry has seen this coming; the Kujang fertiliser plant on West Java recently decided to increase their production capacity at a subsidiary in the east of the island around Cepu, where gas supply is less of an issue.

The problem partly lies in the fact that East and West Java are not connected through a gas pipeline. At the same time, gas production is declining rapidly from fields that are feeding into the West of Java.

It shows that even though Indonesia as a whole is a gas exporter, some regions within the country can still experience a shortage of supply. For that reason, it is worth investigating the possibility to store gas in subsurface sites, preferably close to where the main market is, such reservoirs can be filled in times of low demand and produced from when demand is higher.

This does not take away the need to ultimately connect West Java to the gas fields of East Kalimantan in order to guarantee security of supply in the West.

OLD FIELDS

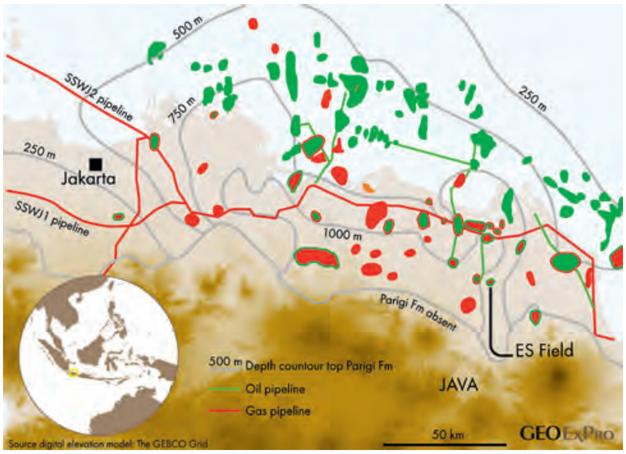
Along the northern coast of offshore western Java, a number of oil, gas and condensate fields can be found. Many of these fields, most of which host oil and an overlying gas cap, started production in the 1970's to 1990's but are currently sub-economic for oil production due to natural decline. Production of the gas cap is currently still taking place from some of these accumulations, but for many the anticipated cessation of production will be in the next few years.

In order to guarantee the security of supply, West Java also receives gas from fields near Sumatra, further to the west. For that reason, the SSWJ1 and SSWJ2 pipelines were constructed. However, the gas fields in Sumatra are also depleting, which makes an even stronger case for building an underground storage facility. Only in that way, uninterrupted supply can be achieved during times of higher demand.

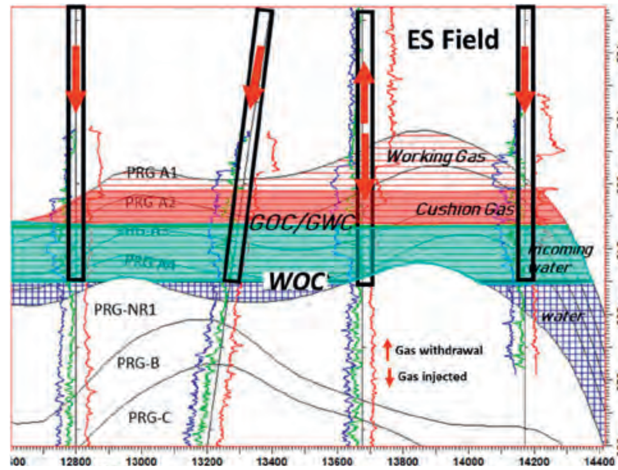
But where are the best candidates for gas storage in the West Java area? The well-known Parigi carbonates form a logical candidate.

A typical landscape in West Java, dominated by rice fields.

PHOTO: EDISON SIRODJ



Depth contour map of the Parigi Formation and the oil and gas fields in West Java, of which many are reservoired in the Parigi carbonates. The SSWJ2 and SSWJ1 pipelines distribute gas from the South Sumatra Basin to West Java directly.



Cross section of gas injection and storage models inside the Parigi limestone reservoir in the ES field.

PARAGI CARBONATES

Drilled in 1968, Well A-1 was the first to discover the Upper Miocene Parigi carbonates in the West Java Basin. Since then, many more wells demonstrated the regional presence of this carbonate succession, which can attain up to 450 m in thickness. A number of oil, gas and condensate fields were discovered in isolated carbonate build-ups of the Parigi carbonate.

With an overall shallow depth of burial, ranging between 800 and 1000 m, the diagenetic alteration of this succession did not change the primary depositional textures to a great extent. For that reason, the reservoir quality is primarily controlled by the original depositional facies of the carbonates. The pore system mainly constitutes of interparticle microporosity within the carbonate mud matrix of wackestones and packstones; only locally dissolution has created and enhanced both porosity and permeability in carbonate mud by enlarging the micropores and increasing their interconnectivity. (Bukhari et al., 1992).

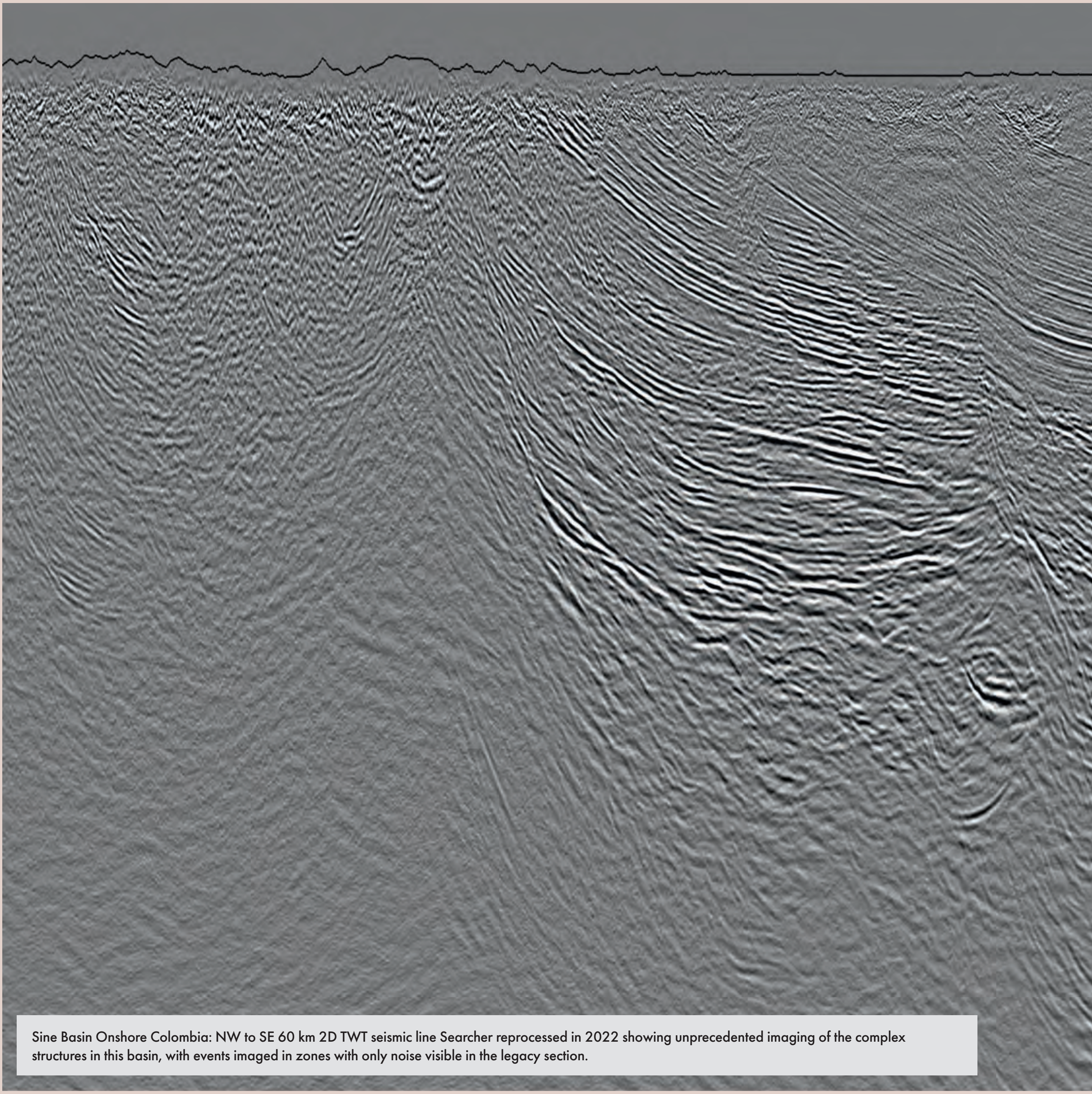
The reefs are generally in the form of ramps with the fore reef position pointing south while the reefs on the surface are steep with their axes oriented towards E-W and NE-SW. There are a few isolated reefs that developed on top of paleohighs, such as the ES field.

ES FIELD

The Parigi carbonate constitutes the largest reservoir in the ES field. The first well test was carried out in January 1979 from well EGS-1 at a reservoir pressure of 1258 psi. The cumulative production in March 2014 amounted to 10,67 million barrels of oil and 80 Bcf (2,3 Bcm) of gas. Based on current economic models, it is expected that oil and gas production from the ES field will cease in 2024.

Following time-depth conversion of the top reservoir and several intra-formational horizons, a geological model of the field was made. This model was subsequently populated with a porosity attribute, constrained by well data. It is estimated that four injection wells will be required to fill the reservoir volume up to 59 Bcf in two years. With an anticipated cushion gas volume of 13 Bcf, the total working volume of for this field is expected to be 47 Bcf (1.3 Bcm). ■

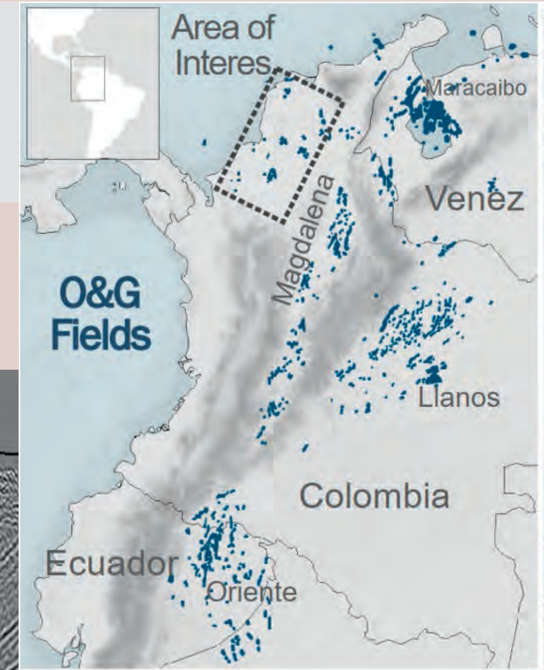
Revealing new Exploration Potential Onshore Colombia

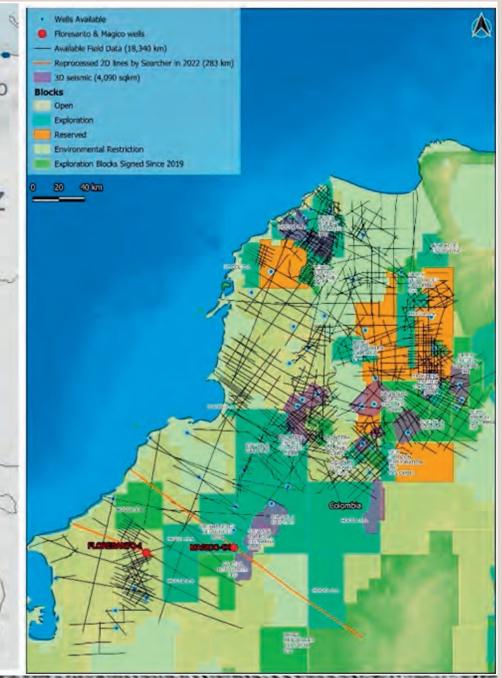


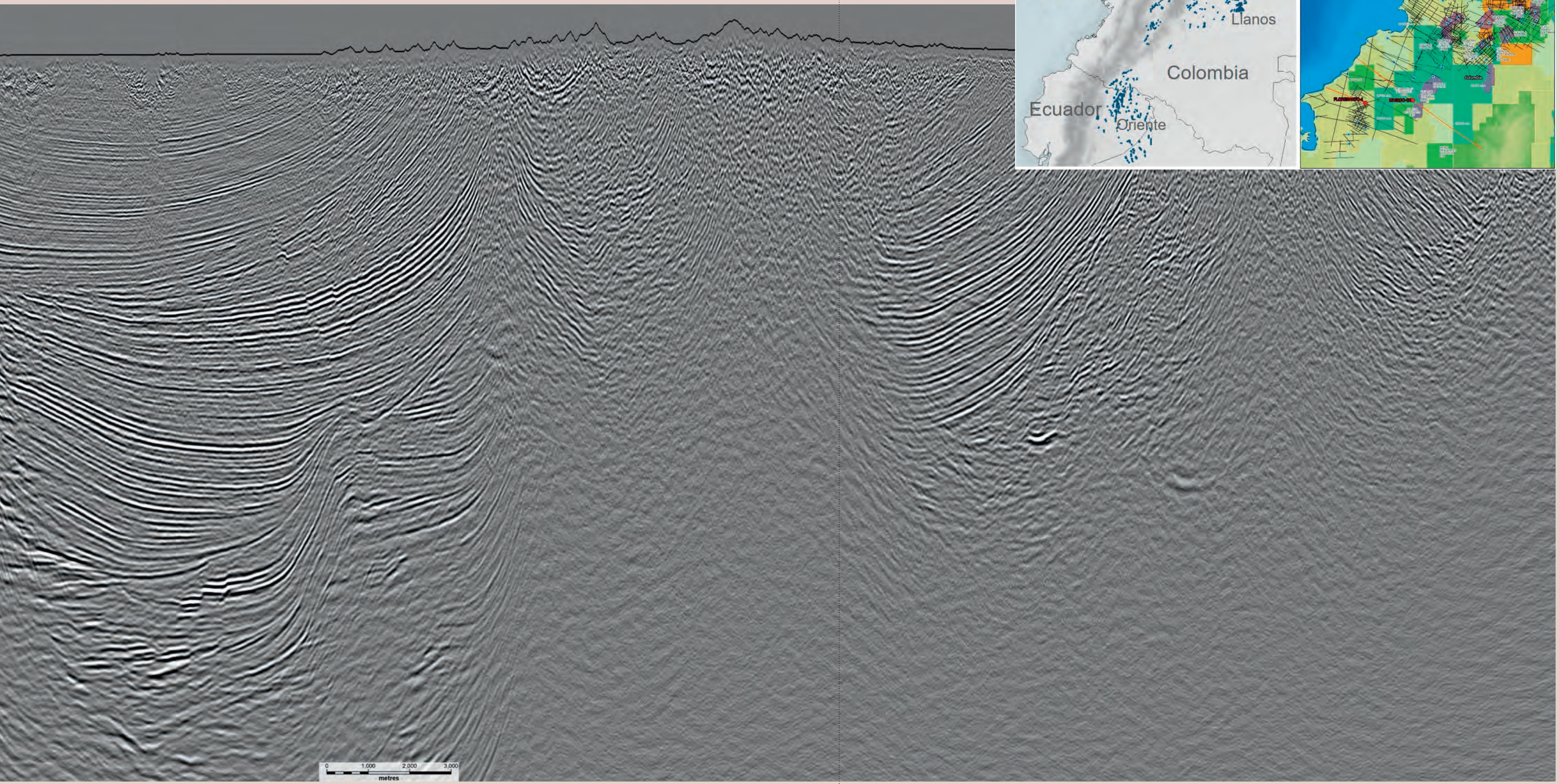
Sine Basin Onshore Colombia: NW to SE 60 km 2D TWT seismic line Searcher reprocessed in 2022 showing unprecedented imaging of the complex structures in this basin, with events imaged in zones with only noise visible in the legacy section.

Once again, reprocessing of legacy seismic data, this time in the Sinu Basin onshore Colombia, is providing a critical tool for understanding the geological evolution in order to better evaluate the hydrocarbon potential in this hugely underexplored prolific hydrocarbon basin.

Location of area of interest and data available for Searcher's reprocessing project onshore Colombia.







Shale or Salt – Diapiric Dance Onshore Colombia

Despite having positive well results in the 1920's and 1940's, the Sinu and San Jacinto basins remain as some of the least explored areas onshore Colombia. This is due to the classic combination of investment diverting success in neighbouring basins and lack of modern, clear seismic data.

TEXT: NEIL HODGSON, KARYNA RODRIGUEZ AND ANDRES MESA, SEARCHER GEODATA UK LTD AND ROB YORKE, AGT

The latter has led to unchallenged geologic understanding of the prospectivity. Over the past few years, the application of advanced processing algorithms to legacy data has allowed geological interpreters to challenge the established geological models with paradigm changing insights that will turn this region into a flourishing area for new hydrocarbon discoveries.

PROVEN HYDROCARBON POTENTIAL

Explorers first targeted these basins in the early 1900's, and several small discoveries were made between the 1920's and

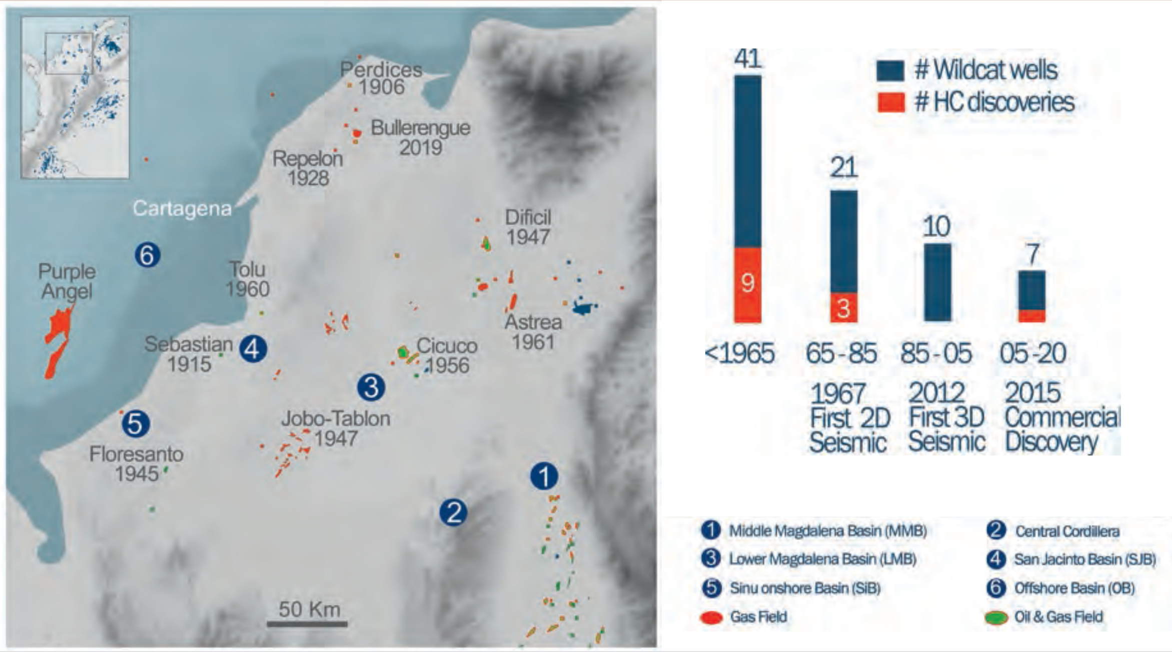


Figure 1: Exploration history in the Sinu and San Jacinto Basins. Map showing the main discoveries and bar chart showing the significant decrease in number of wells drilled in these basins.

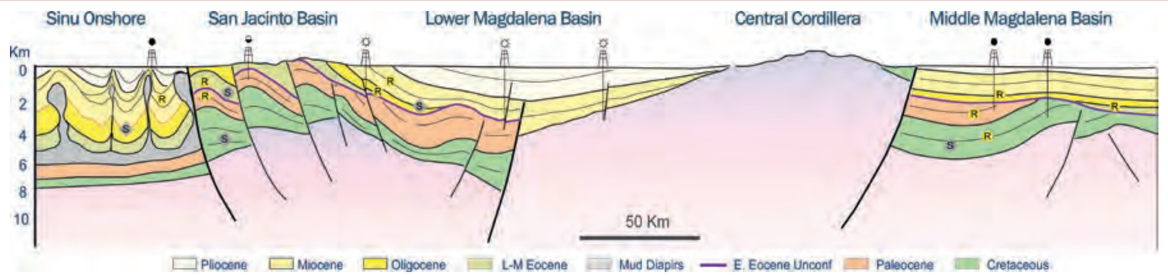


Figure 2: Geologic Cross Section and Regional Stratigraphy onshore NW Colombia.

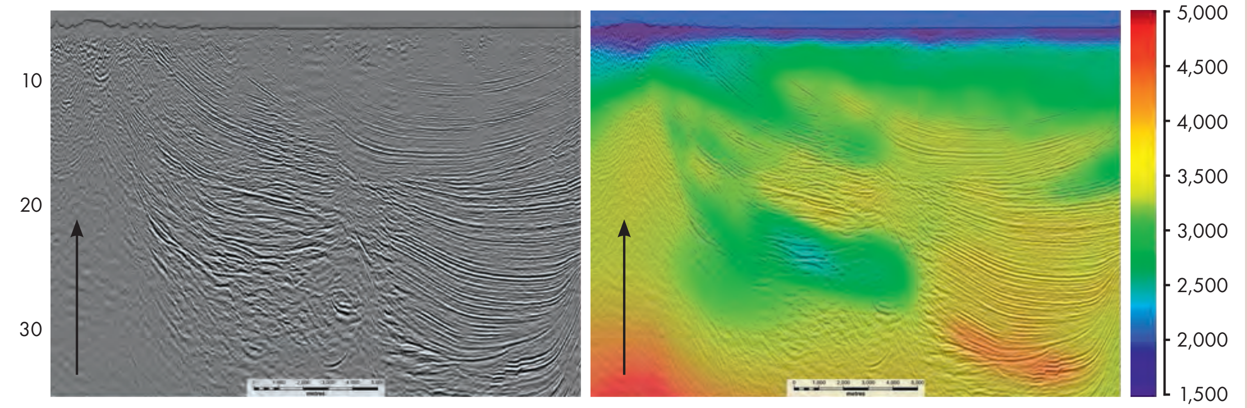


Figure 3: 2022 Searcher reprocessed 2D seismic line in Sinu Basin. Arrow points to diapiric feature previously interpreted as a shale diapir. Note the high velocities obtained by velocity scanning which allowed a significant improvement in seismic imaging and which could be interpreted as indicating the presence of salt. Other lines reprocessed in this basin indicate the same high velocity.

1950's using surface geology to guide the drill-bit. These wells not only showed that there was potential for oil and gas (Figure 1), but they also revealed that surface geology in this thrust belt did not always reflect subsurface geology. However, numerous large commercial discoveries during the 1940's and 1950's in the Lower and Middle Magdalena basins moved attention there. Sinu and San Jacinto today have about 1 exploratory well per 820 square km, whereas the Lower Magdalena basin has 1 exploration well per 350 square km.

SEISMIC IMAGING CHALLENGES

High structural complexity in the region inhibited early explorers working without seismic, yet the complexities of structure and geology has meant that the subsurface seismic images acquired to date have not generated much appetite for further exploration either. Some of the seismic imaging challenges faced in this project include rough topography resulting in statics both as near surface refractors and subsurface events as well as making signal alignment difficult.

The strongly thrusted environment results in rapidly changing velocities due to highly structured geology. Legacy seismic suffers from poor signal to noise due to penetration of source depending on whether it was dynamite or vibroseis and dissipation of source energy. Finally, legacy acquisition methods from the 1970's to 2000's are often associated with limited and/or poor offset distribution.

Additionally, older data acquisition methods for recording relied mainly on manual data entries with many errors in observer's and survey notes. Capturing and fixing these errors can be a very manually intensive job, as well as building geometries and quality control by hand. This latter task is best undertaken by those senior geophysicists who worked on these problems 30+ years ago, as that generation of geoscientist are familiar with the old methods and understand observers logs.

NEW GEOLOGICAL INSIGHTS

Recent regional studies allow the definition of a new understanding of basin evolution that is changing the perception of the area. Just as has been observed in the Magdalena Valley basins, there is now recognition of a major unconformity associated with deformation and erosion which took place during the Early to Middle Eocene.

It has also become clear that there is a marine Cretaceous sequence with good source rock characteristics that can be modelled to explain the distribution of liquid hydrocarbons from oil seeps and wells. Regional studies have also now demonstrated that several sequences of marine reservoirs occur throughout the Tertiary, such as the recent Hocol operated Eocene reservoired Bullerengue commercial gas discovery (2019), in the north of San Jacinto.

As part of a regional reprocessing project (See Basemap on foldout page), using state-of-the-art technology focusing on critical aspects including rigorous near-surface velocity modeling (Refraction Tomography) and depth imaging with careful velocity model building (time migration is not considered to be adequate), great improvement has been made on imaging hydrocarbon systems in the Sinu basin.

According to these results, the areas commonly associated with mud diapir outcrops (Figure 2), are now related to higher velocities than expected, suggesting the presence of salt in the section (Figure 3), implying that an alternative geological model can be proposed for these complex structures. Additionally, unexplored thick Cretaceous sedimentary sequences have been revealed along the San Jacinto Fold Belt.

EXPLORATION IN THE SINU AND SAN JACINTO BASINS REVIVED

Even though the Lower Magdalena Valley (LMV) has a well-established history of successful exploration and production, and the hydrocarbons systems are well established, refraction tomography will reveal significant additional potential in the basin. This will re-kindle the LMV creaming curves and many stratigraphic levels.

In the Sinu and San Jacinto basins, which represent some of the least explored areas onshore Colombia, the application of advanced algorithms to reprocess legacy seismic data are challenging the established hydrocarbon systems and their inherent geological models directly.

In the Sinu Basin, the trap systems previously modelled to be related to mud diapirs could in fact be related to the presence of salt. In turn, along the San Jacinto Fold Belt, the geometry of structures and the presence of a thick unexplored Cretaceous sedimentary sequence, are some of the key insights that will allow explorers to understand these prospective areas in a new and innovative way.

New data, unleashing new geological possibilities, reveals plays hitherto discounted. The re-imagined geological evolution of the Sinu and San Jacinto basins is incredibly exciting, encouraging a new era of exploration activity in the very near future. References provided online. ■

DEEP SEA MINERALS

"...the extraction of sulphides within a one km^2 area at the Mohnsridge can make Norway more than self-sufficient in copper, cobalt, gold and silver..."

Aker BP

This piece of sulphide was picked up by the Norwegian Petroleum Directorate at Mohnsryggen in 2020.

Norway Releases Mineral Data from the Deep Sea

The Norwegian Petroleum Directorate has made available data on the mineral composition of sulphides from Norwegian waters. This will be of great benefit to exploration companies and research institutions.

THE NORWEGIAN PETROLEUM DIRECTORATE (NPD) has conducted mineral mapping in Norwegian waters for a number of years. This work was further prioritised after the Seabed Minerals Act was adopted in 2019 and the subsequent decision taken by the government in 2020 to initiate the process that could lead to the first seabed mineral licensing round in 2023 or 2024.

There are two types of mineral deposits within the Norwegian economic zone - massive sulphides and manganese crusts.

Last year, the NPD already announced the release of large amounts of deep sea data gathered during research campaigns, both their own and from cruises carried out in collaboration with universities. Now, the NPD is making available a new set of data – analyses of sulphide samples they have collected.

The lists contain detailed information about each analysed sample, including site name (name of the sulphide deposit), exact position data and depth, brief description of the sample and, last but not least, the metal and mineral content. The data can help exploration companies to better understand the mineral resources in the deep sea and how concentrations can vary within a sulphide deposit.

Further information at npd.no

2023 will be decisive

Acting NPD director Torgeir Stordal said that 2023 will be decisive when it comes to starting exploration and extraction on the Norwegian continental shelf.

FIRST AND FOREMOST, the Norwegian Petroleum Directorate (NPD) is about oil and gas. But acting director Torgeir Stordal also dedicated some of his time to presenting an update on the status of seabed minerals on the Norwegian during his live stream on the 9th of January this year.

He pointed out that the NPD has analysed data collected from scientific and own expeditions over a ten-year period and consolidated this knowledge in a resource assessment that has now been published. In parallel with this, the NPD has assisted the Ministry of Petroleum and Energy with the impact assessment regarding the exploration and extraction of seabed minerals. The report is currently out for consultation and will form an important basis for the ultimate decision to open parts of the shelf for exploration.

Stordal confirmed that a political decision regarding the opening is expected this spring. It could open the way for Norway to award licenses for exploration already this year or next year.

Further information at npd.no

NPD director general (interim) Torgeir Stordal.

PHOTO: NPD, ARNE BJØRØEN - NPD

The ore factories at the bottom of the sea

Along the oceanic spreading ridges, boiling hot and mineral-rich fluids penetrate the seabed from deeper down. Where flow is sufficient, metres-high chimneys are formed as mineral precipitation takes place when the hydrothermal fluids are confronted with cold seawater.

When doing a dive with an ROV, chimneys are often the first thing appearing on camera as they approach hot springs on the seabed. It's like a group of trees on a grassy plain.

"In Norwegian waters, we have observed hydrothermal chimneys that are 10 to 15 metres high. In the Pacific Ocean, there are chimneys that protrude up to 30 meters above the seabed," explains Rolf Birger Pedersen, professor and head of the Centre for Deep Sea Research at the University of Bergen (UiB).

Pedersen is considered a pioneer in Norwegian deep sea research and has previously led expeditions through the Centre for Geobiology and the KG Jebsen Center for deep sea research, both at UiB.

The chimneys are a spectacular sight. They were first observed in the Pacific Ocean in 1979, and in Norway at the Jan Mayen hydrothermal fields (***Soria Moria, Perle & Bruse*** and ***Trollveggen***) on the Mohnsryggen in 2005.

The mid-ocean spreading ridge stretches 65,000 km through the world's oceans and is by far the world's longest mountain range. About five percent of this mountain range lies in Norwegian waters (economic zone) and mainly comprises the Mohns and Knipovich ridges between Jan Mayen and Svalbard.

In some cases, the hydrothermal activity can be observed on the seabed in the form of hot springs where boiling hot, mineral-rich water flows out of chimneys and cracks, but also through sediments. The Centre for Deep Sea Research at the University of Bergen (UiB) has the best knowledge of these hot springs.

TEMPERATURES OF UP TO 400°C

"We need three elements to get a hydrothermal source: water, heat and a porous medium through which the water can flow, explains ***Håvard Hallås Stubseid***, research fellow at the Centre for Deep Sea Research and the Department of Geosciences at UiB.

Among other things, Stubseid works on understanding the size and frequency of underwater volcanic eruptions along the spreading ridge and has had the opportunity to participate in several deep sea expeditions in recent years. ▶

Active chimneys at the Fåvne field on Mohnsryggen spew out hot, mineral-rich water from underground. The chimneys are coloured yellow-brown by bacteria that live by oxidizing iron.

PHOTO: CENTRE FOR DEEP SEA RESEARCH.

Rolf Birger Pedersen is professor and head of the Centre for Deep Sea Research.

"Due to the high pressures at the bottom of the oceans," Stubseid explains, "water temperatures can reach several hundreds of degrees before it boils. The highest temperatures scientists have recorded at hot springs are around 400 °C.

"High temperatures give the water a great ability to carry elements with it. However, this ability quickly disappears as it encounters seawater and cools down," Stubseid continues. A chimney is the result.

The "smoke" is often black, but sometimes white. Stubseid explains that this is controlled by temperature and mineral content. "Black chimneys" usually emit water that maintains higher temperatures and/or has a higher iron content compared to the white ones. The iron content has the greatest influence on the colour."

Chimney formation can happen surprisingly quickly. "On several cruises, we have set up temperature sensors on the chimneys to obtain long-term measurements. When we have returned the following year, we often had problems finding the sensors because they had become part of it. A chimney can grow several metres a year," Stubseid points out.

"Due to the high pressures at the bottom of the oceans, water temperatures can reach several hundreds of degrees before it boils."

RICH IN METALS

Chimneys mostly consist of sulphide minerals and sulphates, whilst silica makes the chimneys more solid. But the chimneys do not live forever. If they grow large enough, they can become unstable and collapse. Fast-growing chimneys usually live shorter than slower-growing chimneys.

The chimneys, and the collapsed remains – the gravel piles – contain metals such as copper, zinc, cobalt, gold and silver. In abundant concentrations, if we compare with mineral deposits on land. It is the high contents that make the sulphide deposits economically interesting as a mineral resource.

The Norwegian Petroleum Directorate (NPD) carried out several cruises to the deep sea in recent years. Some of these together with the Centre for Deep Sea Research, others with UiT Norway's Arctic University. In 2022, the NPD began publishing more of the data sets acquired. Amongst the datasets were analyses of the mineral composition of sulphides.

Two chimney samples from the ***Mohnsskatten deposit*** on Mohnsryggen showed that one sample (S88) contained more than ***14 percent copper*** and 0.1 percent cobalt, while another (S34) had a significantly lower copper content (0.7 percent). But, on the other hand interesting levels of gold (11 grams per tonne) and zinc (12.2 per cent). For comparison, several copper mines are operated on land on deposits with concentrations of less than 0.5 per cent.In this context, it is also worth mentioning that the oil company Aker BP, which is one of several Norwegian stakeholders when it comes to mineral exploration in the deep sea, has made calculations that show that the extraction of sulphides within a one km^2 area at the Mohnsridge can make Norway more than self-sufficient in copper, cobalt, gold and silver.

According to Pedersen, the metal content in the sulphide deposits is controlled by a number of factors, mainly temperature, pH and the type of rock the water circulates through.

"We often see that liquids that have relatively high temperatures, for example above 300 °C, tend to precipitate more copper than liquids that maintain somewhat lower temperatures. It may also mean that sulphide deposits will generally be more copper-rich below the seabed, where the temperatures are higher, than on the seabed."

The professor also says that there are indications that water that flows through peridotite (mantle rocks) is richer in copper than water that has flowed through the seabed plate rocks basalt and gabbro.

The depth of the seabed will play a factor too. At great ocean depths, the water will be able to attain higher temperatures before it boils and can thus potentially dissolve and transport metals in higher concentrations than in shallower ocean areas.

"We see that the deposits at a depth of around 100 meters are poor in metals. At a depth of 600 to 700 metres, we often get zinc-rich deposits, and at a depth of several thousand metres, the copper content becomes more dominant," explains Pedersen.

PHOTO: STIAN SERVOSS

IT'S OKAY TO BE LUCKY

We know of nine active, named hydrothermal springs around Jan Mayen and along the Mohnsryggen and Knipovichryggen. Finding such sources using only visual mapping is like looking for a needle in a haystack. Both technology and systematic research are needed.

Most of the active springs were found after first discovering a hydrothermal "cloud" in the water. The cloud rises from the hot source, and when it cools, it will lose its buoyancy and begin to spread sideways into the water masses. The temperature of the cloud will then only be marginally higher than the surrounding seawater, but this anomaly enables the researchers to detect them.

In addition to technology, you also need patience and courage to find hot springs. But luck also helps.

PhD scholar Håvard Hallås Stubseid inspects the university's ROV (left), which can dive to a depth of 6,000 metres. On the right is the tethering equipment known as the Tether Management System, to which the ROV is connected when it carries out subsea operations.

"A chimney can grow several metres a year."

NEW DISCOVERIES AWAIT

The UiB researchers have carried out cruises in Norwegian deep sea areas since 1999. They have systematically collected water samples along the entire Mohn Ridge. Based on samples and analyses, Pedersen believes that they may find several more active hydrothermal fields along the ridge.

The most recent discovery in Norwegian waters was made in the summer of 2022. The German-Norwegian expedition, in which representatives from the NPD participated and which was led by German MARUM, also aimed to find new hydrothermal fields along the 500 km long Knipovich Ridge.

A discovery, which was made west of the southern part of Spitsbergen, has now been named ***Jøtul***. Jøtul is the first field found on the Knipovich ridge. However, it should be mentioned that the discovery was made based on observations of anomalies made by UiB researchers already in 2016.

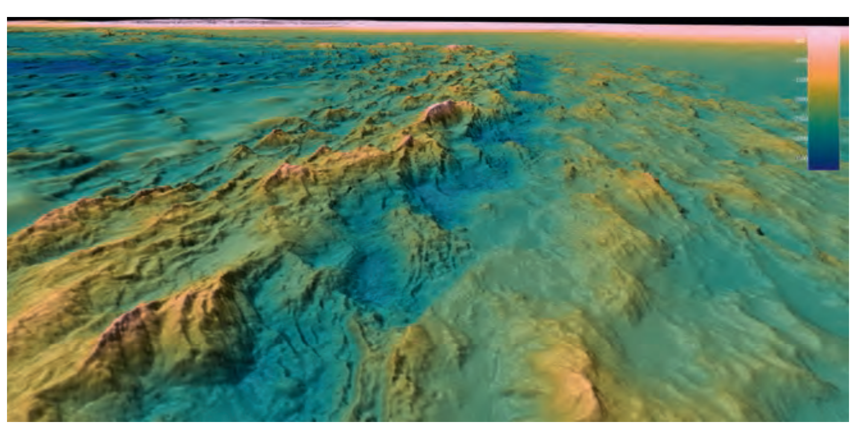
IT IS QUIET IN THE GRAVE

From a resource perspective, it is the inactive, extinct fields that are most interesting, both because it is technically demanding to operate in extreme temperatures, but also because significantly more life exists around the active sources.

"However, inactive sources are much harder to find. The anomalies that we have exploited to find the active springs will not be present if there is no outflow of warm, mineral-rich water," explains Pedersen.

He points out that some deposits along the Mohnsryggen are in a sort of intermediate stage. They are dying out, with a greatly reduced but still measurable outflow. "We thought for a long time that the ***Mohnsskatten*** was dead, but during a UiB tour in 2020 we observed signs of outflow and life in the area, which testifies to ongoing activity."

Another challenge with inactive springs is that they can be so old that they have begun to be covered, either by sediments that are deposited continuously, or by lava flows that are deposited sporadically. "There is a lot of volcanic activity along the Norwegian ▸



A perspective map showing central parts of the Mohnsryggen seen from the southwest, with the vertical scale exaggerated (2x). The ridge separates the Greenland Sea (on the left in the picture) from the Norwegian Sea. The elevated terrain along the central part of the ridge is 1-2 km higher than the surrounding landscape.

PHOTO: SIMEN VIKØYR; ILLUSTRATION: CENTRE FOR DEEP SEA RESEARCH spreading ridges. The research I take part in has shown that there is an average of one eruption per year along the 500 km long Mohnsryggen. The eruptions help bury old sulphide deposits," says Stubseid.

Mineral deposits that are covered by sediments and/or lava will be very demanding to find and exploit. But the researchers have already identified some inactive sources. ***The Mohn's treasure***, which is admittedly not completely inactive, but dying out, was found by scraping the seabed and collecting and analysing samples which turned out to be sulphide-containing.

Pedersen notes that high-resolution bathymetric data based on mapping with an AUV can also be of great use in tracking down fossil deposits.

GNITAHEI

The inactive source ***Gnitahei*** was found using a geophysical method called self-potential. In short, self-potential is a measure of electrical voltage differences in rocks, and such differences can, for example, occur in rocks that contain conductive minerals and metals, including sulphides.

UiB researchers discovered Gnitahei by letting an AUV fly over the terrain and measure the strength and direction of the electrical voltage differences. The data "pointed" into the direction of the deposit.

Stubseid adds that Gnitahei is a unique fossil deposit because it is probably not in danger of being buried anytime soon. "It sits on the footwall of a large fault. Therefore, it is not covered by sediments or lava. This also allows us to look down into the deeper parts of the hydrothermal system," he adds.

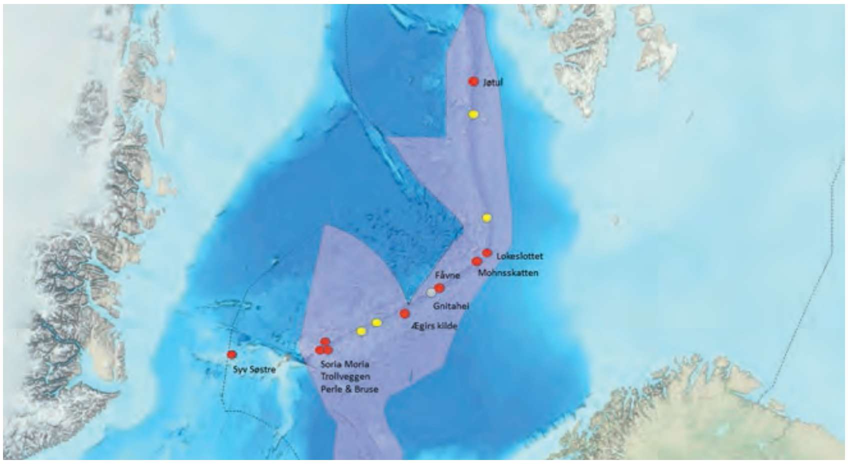
"It is the inactive, extinct deposits that will be looked at if Norwegian waters are being opened for exploration and possible extraction."

OASES IN THE DEEP SEA DESERT

"Organisms that die and sink are gradually eaten up on the way down. There is very little "food" that reaches down to a depth of 3,000 metres and that's why some use the term "desert" for the deep seas," says Pedersen.

But when the researchers discovered ***Lokeslottet*** in 2008, they also saw an "oasis of life" that had never seen light before: "Microorganisms utilise the substances that the hot springs carry up to the seabed through chemosynthesis. They can oxidise iron, methane and other elements and obtain energy through the electron transfer that then takes place."

The microorganisms are responsible for the primary production at these hot springs. They provide a basis for life for larger organisms that can live in symbiosis with the microorganisms, or that can graze on them. The largest organisms the UiB researchers have seen at hydrothermal springs are crabs and shrimps.



The map shows known, named hydrothermal springs. The red ones are active, the grey circle marks an inactive source, and the yellow circles represent areas where a hydrothermal cloud has been observed in the water column, without the source being detected. The area shaded in purple represents the area proposed for opening to mineral activities by the Ministry of Petroleum and Energy. Black dashed line marks the outer limit of the Norwegian continental shelf.

MAP DATA OBTAINED FROM THE NORWEGIAN PETROLEUM DIRECTORATE AND UIB

THE OPENING PROCESS IS PROGRESSING

Last autumn, the Ministry of Petroleum and Energy (OED) presented the long-awaited impact assessment (KI) regarding the exploration and extraction of deep-sea minerals on the Norwegian continental shelf.

State Secretary ***Andreas Bjelland Eriksen***, who presented the report during the Deep Sea Minerals Conference in 2022, clearly expressed that the ministry sees the report as an important decision-making basis for the further opening process.

The OED explained in the consultation document that the opening process facilitates further knowledge acquisition so that any future extraction can be done with an acceptable degree of environmental impact.

The OED has subsequently received input from the consultation bodies and intends to submit a report to Parliament on the opening of the Norwegian continental shelf for mineral activities in the spring of 2023. The report could open the way for Norway to award licenses for exploration as early as this year or next year.

At the same time, there is no reason to believe that the active hydrothermal sources will be considered targets for possible exploration and extraction. It is the inactive, extinct deposits that will be looked at if Norwegian waters are being opened for exploration and possible extraction. ■

Anette Broch Mathisen Tvedt, CEO of ADEPTH Minerals.

PHOTO: HALFDAN CARSTENS

Cores are essential

ADEPTH Minerals is moving forward with the development and testing of exploration and monitoring technologies to prepare for future mining in the deep sea. What they currently lack most of all, are physical samples, such as cores.

WE SEE THE NEED for an improved coring technology that allows us to go deeper and retrieve cores at an angle, said *Anette Broch Mathisen Tvedt*, CEO of the Norwegian deep sea minerals explorer ADEPTH Minerals.

Tvedt spoke at last year's Deep Sea Minerals conference in Bergen, hosted by GeoPublishing.

According to Tvedt, there are several steps that need to be taken before deep sea mining can become a reality in Norway. This includes knowing that the resources are there and in sufficient grades and tonnage, knowing that the resources can be extracted with limited environmental impact, knowing that the companies can show the value of minerals to society and finally, that the technology is sufficiently advanced ►

"What we in ADEPTH and the industry need now, is more physical samples to analyse. We need more cores."

to meet the companies' needs.

"Data is crucial for us. We are a data-driven company that will utilise data in a smart way and constantly look for new technology to improve exploration," said Tvedt.

MORE CORE

Tvedt felt that the amount of available geophysical data sets is improving and expressed gratitude to the Norwegian Petroleum Directorate, as well as some universities, for sharing their data from past cruises in the deep sea, mainly along the Mohn's and Knipovich ridges."What we in ADEPTH and the industry need now, is more physical samples to analyse. We need more cores."

ADEPTH Minerals is developing a new concept for deep sea coring together with Seabed Solutions and DeepOcean. The concept, ***FlexiCore***, is based on land-based technology and equipment and consists of a coring system that is mounted on a marine excavator.

"We recently tested FlexiCore on land. Early 2023, we plan on doing a deep sea test together with the University of Bergen," she added.

Tvedt and her team are also exploring fitting other sensors onto the excavator in order to collect geophysical and water column data in parallel with the coring operations.

"Our exploration toolbox includes many different tools and will consist of drilling, mapping and environmental monitoring technology. The combination of multiple complementary technologies will enable time and cost-efficient data collection, minimising our environmental footprint and reducing emissions," Tvedt concluded. ■

SOURCE: ADEPTH MINERALS

FlexiCore.

"I felt like in a knowledge vacuum."

As GEO ExPro celebrates its 20th Volume this year, Halfdan Carstens, one of the founders, reflects on why he started the magazine.

WHEN STARTING OUT my career at Saga Petroleum in the late 1970s, about ten years after the first oil discovery in the Norwegian sector in 1968, I was curious to learn about the oil industry. I therefore regularly read the World Oil and Oil & Gas Journal but did not get the answers I was looking for. My colleagues, most of whom were also new to the industry, were of little help", explains Carstens in an email.

"I felt like in a knowledge vacuum. Working for Saga in Houston for some time was a real eye-opener, which broadened my horizon", Carstens continues. Starting a journal for explorationists did not surface until 20 years later. "It only happened after I had 5 years of experience running a journal for geologists in Norway", he adds.

Connecting with the readership is a key aspect for any editor. "The best way to interact with the readers has for me been to go to visit them in their own working environment and be present at seminars and conferences, continues Halfdan. "For a long time, I believed there was no other way, but then came social media and turned the game upside down."

"For a long time, I believed visiting readers in their own working environment was the only way to interact with readers, but then came social media and the game was turned upside down."

A DAUNTING PROSPECT?

Many people think it is daunting to fill a 90-page magazine with interesting content six times a year and come up with ideas that cover the remit of the publication, but Carstens does not share that experience. "In fact", he says, "it has rather been the opposite, we did not have enough pages and manpower to cover all the stories that we wanted to include."

Carstens worked at PGS before embarking on his journey into the publishing business, which is just one of the reasons why he has always been a supporter of including seismic lines in the magazine. The concept of having seismic foldouts in the magazine is one of his ideas.

Asked about his current favourite seismic line, Carstens says: "As of now, I am preoccupied with the Ice Age, the reason being that in 2023 it is 200 years since the Danish-Norwegian professor Jens Esmark discovered an end moraine in the Norwegian mountains and concluded – as the very first one in the world – that Norway and Scandinavia must have been covered by a thick ice sheet a long time ago. My favourite seismic line is therefore bound to be one that covers a gas reservoir in the North Sea (Peon) that consists of sand deposited by a glaciofluvial delta during the Ice Age."

But it's not only seismic data Carstens comes out of bed for. He is also behind the election of Norway's national rock, which took place in 2008. The winner at the time, Larvikite, is amongst his favourites too, even though oil explorationists will not often come across this type of rock: "It is an igneous rock made up of entirely feldspar (monzonite)", Carstens concludes. ■

PHOTO: HENK KOMBRINK.

Halfdan Carstens at the opera house in Oslo, Norway. Despite Norway's resources when it comes to building stones, white marble from Carrara in Italy was used for this landmark project.

Perth Basin Gearing Up for Busy 2023-24

Ian Blakeley
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After a decade with only a handful of exploration wells drilled in the onshore Perth Basin, 2023 and into 2024 are gearing up for a flurry of activity, with two rigs expected to be working concurrently. Elsewhere, gas developments are progressing, with the Walyering field and Waitsia Stage 2 soon to be onstream and West Erregulla fully appraised and ready to be developed. Deals and M&A have also sparked into life. Meanwhile, some companies are looking to the future, making positive moves towards the energy transition with the planning of carbon capture, renewables and low carbon hydrogen.

MINERAL RESOURCES has two wells planned in EP368, starting with the Lockyer-2 appraisal. This will be followed by North Erregulla Deep-1 in Q1 2023 to test the southern extension of Lockyer Deep. North Erregulla Deep-1 will be an S-shaped deviated well and is aiming to test the oil potential in the Arranoo/Dongara/Wagina formations. The Kingia Formation is around 50 m updip from the Lockyer Deep-1 gas discovery, with coring planned upon confirmation of gas at North Erregula Deep 1. Lockyer-3 and -4 appraisals are also in the planning stage. Another well is planned in the neighbouring EP 426 to the east, in 2024.

Upon completion of the Mitsui/Beach joint venture (JV), the Waitsia Stage 2 development drilling campaign includes the Elegans-1 (L 2 permit) and Gynatrix-1 (L 1) wells in the Mitsui-operated acreage during 2023. The wells are targeting gas in the Kingia and High Cliff sandstone reservoirs.

Following Mitsui's wells, Beach is planning a three to six well exploration drilling campaign. Trigg-1 in EP 320 is expected to be drilled first around Q3 2023. It is on-trend and updip from the West Erregulla gas field and the recent South Erregulla discovery and it forms a strong analogue to the 2021 Lockyer Deep gas discovery. Success would further de-risk adjacent prospects, with North Trigg-1 expected to test the northern extension of the prospect.

In EP 469, Strike Energy plans to drill Erregulla Deep-1 and Southwest Erregulla-1 following the South Erregulla appraisal drilling campaign, scheduled for late 2023/early 2024. Erregulla Deep-1 will target a relatively low-risk, high-grade conventional gas exploration prospect in the Erregulla Deep structure, covering over 20 square km at the Kingia level between the West Erregulla and Lockyer Deep gas pools. Reprocessing of 2D seismic data and calibration with the South Erregulla-1 gas discovery has identified a contiguous structure extending northwards from South Erregulla and updip into EP 469. Southwest Erregulla-1 will target the 15 square km structurally elevated fault block, which has similarities with the gas-bearing Tarantula-1 ST1 fault block on the Beharra Terrace.

Millstream Chichester national park, West Australia.

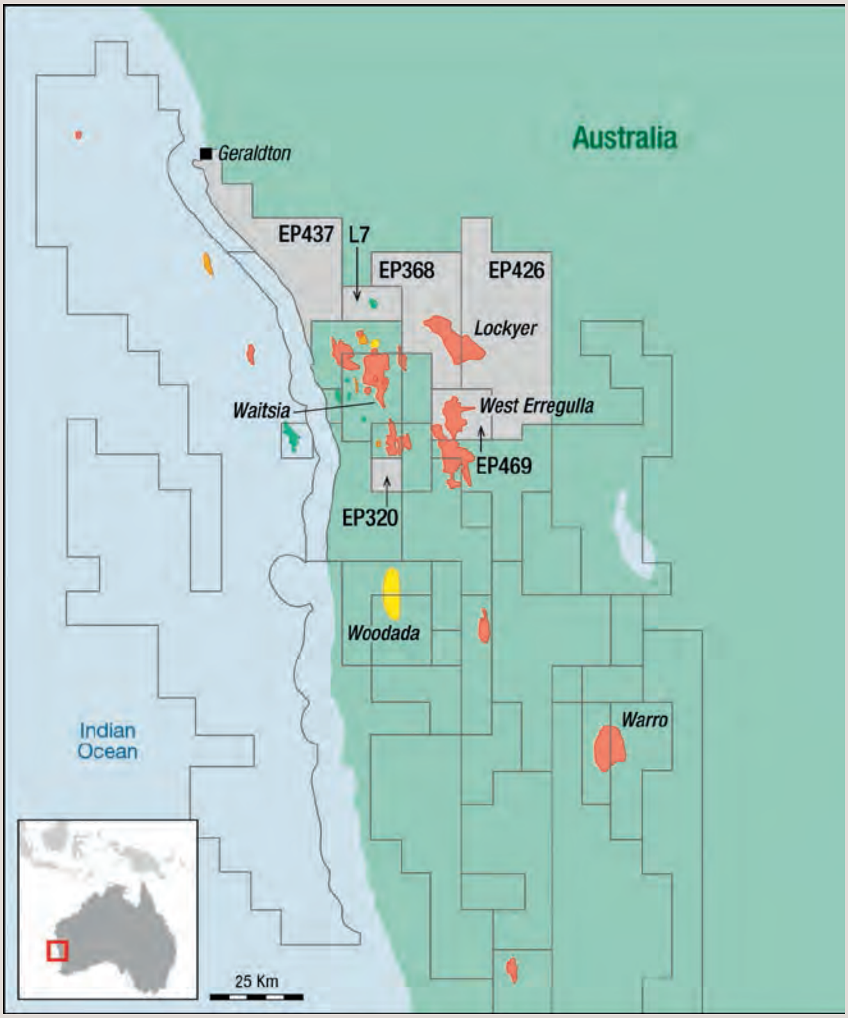
FROM: CHRIS STENGER - UNSPLASH

DEALS AND TUG-OF-WAR TAKEOVERS

Triangle Energy has farmed out 25% working interests each to Talon Energy and New Zealand Oil & Gas in permits L7 and EP 437 late 2022/early 2023. The Bookara 3D seismic across the permits has been processed and is being evaluated. The seismic is showing early promise and identification of well targets is planned, with drilling expected in Q1 2024 in the L 7 permit.

With elevated gas prices and a limited number of strategic, high-quality assets in the basin there has been a mini-spike in M&A activity. Warrego Energy has been the subject of a takeover in recent months with an initial offer and subsequent withdrawal from Beach. Since then, Hancock Energy and Strike have been braced in a tug-of-war to acquire Warrego with a number of counter bids.

In mid-December 2022, Mineral Resources made a takeover bid for its JV partner in Norwest Energy, its partner in EP 368 and EP 426. However, Norwest recently advised its shareholders to reject the bid.



THE ENERGY TRANSITION IS PROGRESSING

There is an emerging and growing demand for clean ammonia for export, which also provides a conduit for transporting hydrogen. Several hydrogen projects are planned and are at various stages of development in the Perth Basin.

The Mid West Clean Energy Project, led by Pilot Energy, is split into three stages. The first stage is the Cliff Head Carbon Capture and Storage (CCS) Project, which is expected to extend the Cliff Head Project life by 10-20 years. The field, once depleted, will have up to 50 million tonnes of CO2 storage. This stage is low risk and low capex with straightforward repurposing of existing infrastructure and start-up by 2026. The CCS provides the foundation for the second stage, which is the production of blue hydrogen scheduled online in 2027. A third stage would see the integration of green hydrogen/ammonia production by 2030.

"The past decade may have been sedate in the Perth Basin, but the next 24 months have the potential to add new oil and gas resources, a new mix of companies, and a gradual transition to new energy."

South of Perth, Woodside announced the H2Perth blue hydrogen project in October 2021, with construction estimated to start in 2024, subject to approvals and FID. This project would produce up to 1,500 tonnes of hydrogen per day for export in the form of ammonia and liquid hydrogen.

Meanwhile, Strike is developing Project Haber to manufacture low-carbon urea and ammonia, aimed at replacing the region's reliance on fertiliser imports. The project will utilise gas from the Greater Erregulla gas resources to produce blue hydrogen. However, the project aims to integrate a 10 MW electrolyser to produce 1,825 tonnes per annum of green hydrogen. Over the project's life, Strike intends to eventually replace the use of raw gas as a feedstock with renewable hydrogen.

The past decade may have been sedate in the Perth Basin, but the next 24 months have the potential to add new oil and gas resources, a new mix of companies, and a gradual transition to new energy. ■

Jonathan Craig, Editor, NVentures Ltd

Discover a Clear Path to Your Success

Energy is everything. It's how we feed our people, move through the world, build, learn, and create. The future of energy is the future of us all.

And yet, this is a volatile industry. Shockingly disruptive events have rocked the energy market over the last few years. Pandemics, wars, wildly variable oil futures, rapidly-changing energy policies, inflation— these events are serious challenges.

But this volatility can also present incredible opportunities.

Change and Opportunity

The energy industry is evolving rapidly. Surging prices, energy shortages, inflation, regulation— to thrive in today's market, you have to be adaptable.

But the willingness to change isn't always enough. You need to know how to change, and when. And, you need this intelligence as quickly as possible.

Create More Value, Faster

An adaptable, decisive, fast-moving business can create value out of volatility. But to do this, your business needs:

- Clear, actionable intelligence of the entire energy ecosystem
- A single source of truth that brings all the data together
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Enverus is a single source platform for management, development, and acquisition, within the entire energy value chain. From early-stage investment to full-scale development, we provide the actionable intelligence, in-depth analysis and speed to support your changing energy strategy.

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Enverus is the most trusted knowledge & analytics platform in the energy industry, with real-time access to analytics, insights, benchmark costs, revenue data and more.

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ENVERUS

Find out today how Enverus can help you remain agile, seize opportunities and focus on your core business in an ever-changing energy world.

The Corinth Canal

THE OUTCROPS along the sides of the Corinth Canal in Greece are the result of one of the biggest civil engineering projects carried out in the country. This photo was taken by Ross Grant from Equinor in 2022 at a site where maintenance work on the sides of the canal was carried out.

The canal cuts through faulted Quaternary and Neogene formations. The Pleistocene succession in this photo was deposited between approximately 500 to 100 thousand years ago. It shows how tectonically active the area is; the Corinth Rift is the most active European rift, with a present-day extension rate of 1.5 cm per year.

The succession is an alternation between sands and silty marls that were deposited in an environment that alternated between lacustrine and marine conditions. The foresets in the middle of the outcrop were deposited by migrating dunes. The darker horizons contain more plant material and were probably deposited during marine incursions.

FEATURE YOUR OUTCROP

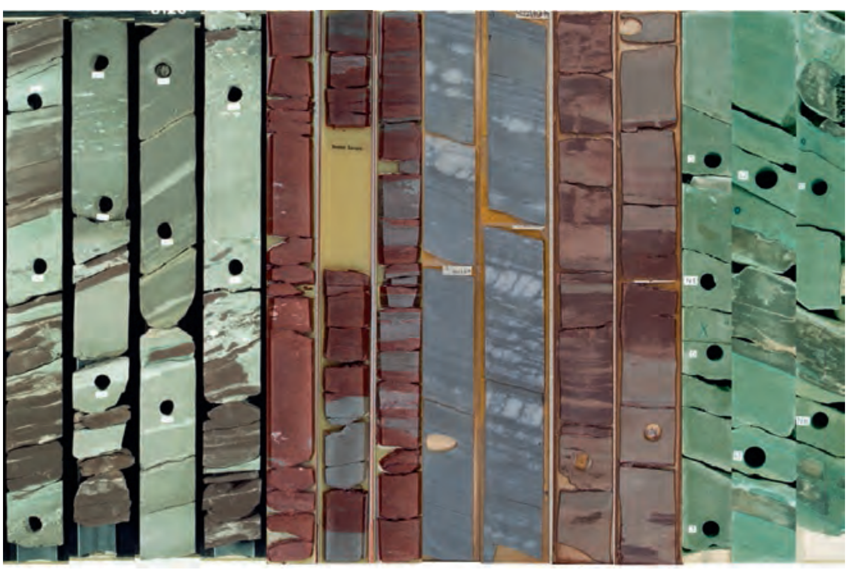
In this series, we show a range of outcrops to give more context to what core interpretation typically allows. Do you have a suggestion for an outcrop feature? Get in touch with Henk Kombrink – henk.kombrink@geoexpro.com.

Core photos of giant Groningen gas field publicly released

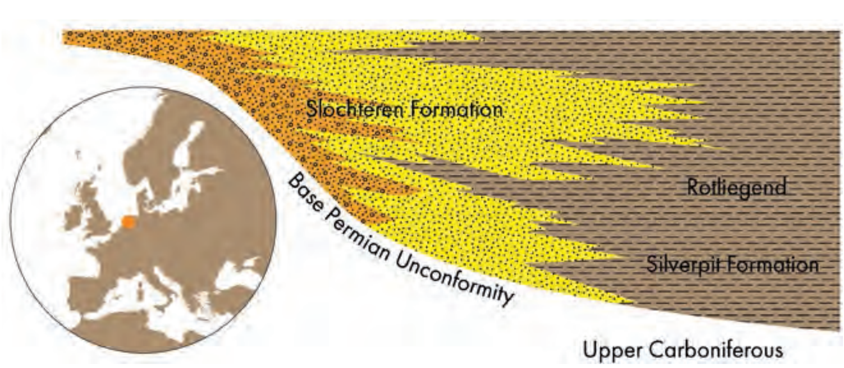
As production from the onshore Groningen field in the Netherlands is drawing to a close, operator NAM releases more subsurface data.

FOLLOWING THE RELEASE of the Groningen field static model in 2020, Nederlandse Aardolie Maatschappij (NAM), in collaboration with a Data publication platform of Utrecht University (EPOS-NL), has now made available a vast collection of core photographs from 67 wells in the Groningen field.

In contrast to countries such as the UK and Norway, core photographs from wells drilled in the Netherlands are not easily accessible, if they are in the first place. That is why this release is quite a step forward for those wanting to study the Upper Permian Rotliegend reservoir of the biggest onshore gas field in Europe.



Core photos from a number of wells in the Groningen field, the Netherlands.



Generalised section of the Rotliegend succession in the Groningen area. The south of the field (left hand side of the cross-section) is characterised by coarse-grained deposits, whilst the northern part of the field is finer-grained and shows more intercalations of the mud-rich Silverpit Formation.

HOW TO

Be aware that you will need to download the entire 37 Gb database first before being able to see any images. So, make some arrangements as to where to download the dataset to. You will also need unzip software to unpack the data, but the freely available 7-zip feature can do the job.

This is the website to go to: https://epos-nl.nl/data_storage_access/

A LOT MORE THAN WIND-BLOWN SANDS

Looking through the images, it will quickly become clear how varied the Rotliegend Groningen reservoir is. While some people may associate the Rotliegend of the Southern North Sea with a dominance of aeolian sandstones, the Groningen field cores show that fluvial deposits are at least as important.

As Jan de Jager and Clemens Visser describe in a recently published paper on the geology of the Groningen field: "The Groningen field area is envisaged as a low-relief depositional plain. Sand was introduced to the plain both by fluvial streams coming from a source area in the south and by winds with a strong easterly component. The sedimentary characteristics point to a variety of depositional processes including transport by fluvial streams, suspension settling in ponded areas, desiccation and subsequent transport as clay clasts, wind ripple and dune sedimentation, adhesion of wind-blown sand onto damp surfaces, and repeated precipitation and dissolution of salt minerals."

In short, there is plenty to investigate! ■

PHOTO: NAM, SOURCE: NLOG

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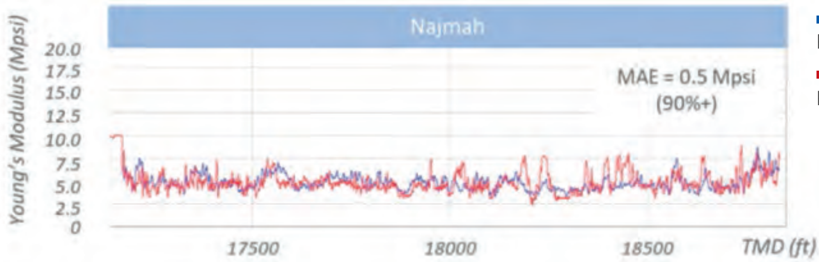
AI-PetroMech

Geomechanical Data in Real-Time

Model Building and Validation – Offset Wells
Trained with previous wells in the same basin

GeoMechanical Parameters Prediction to a New
Well Utilizing depth-based drilling parameters



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DigitalCuttings

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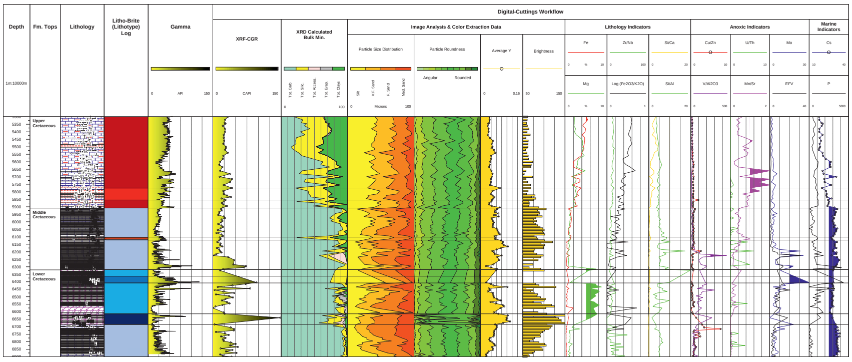

Digital-Cuttings™:

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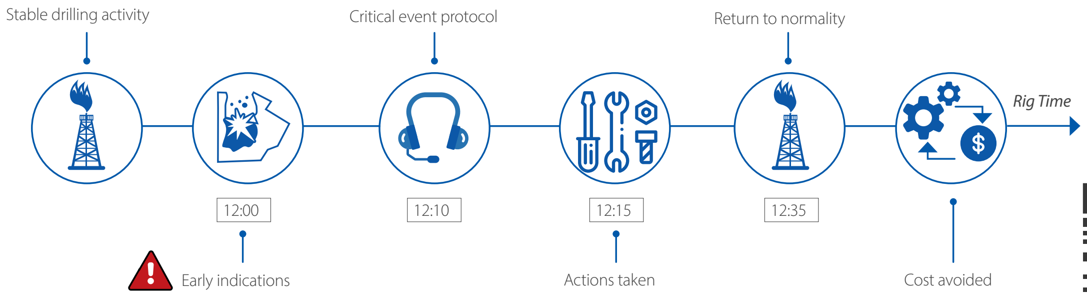

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