THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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Exploration opportunities:
Australia
India

Myanmar:
Delayed but not Forgotten

GEONOVA

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GEONOVA

The Importance of Domestic Production

A dramatic consequence of the global re-routing of LNG streams in the light of the current energy crisis is that countries in Southeast Asia are increasingly facing blackouts. A country such as **Bangladesh** is an example; there is little domestic production of gas, so before the energy crisis unfolded it relied heavily on LNG. This LNG is now finding its way to countries with deeper pockets.

> "... Onshore oil exploration is now more a dream than a reality in Myanmar."
> Thomas L. Davis

This acute problem has only reinforced the need to boost domestic production, which is one of the reasons why Bangladesh is currently preparing a licensing round. Meanwhile, as **Neil Hodgson** shows in this issue, **India** is also trying to attract investors to test the potential of the country's Eastern Margin, which is largely unexplored.

The energy crisis is not the only factor why countries in Southeast Asia are struggling to keep the lights on. As **Thomas Davis** explains elaborately in the Cover Story, **Myanmar** is currently seeing a dramatic drop in domestic oil production, while gas is also on the decline. Here, the political situation has mostly caused foreign investment to dry up, with no change in sight.

In addition, any remaining hydrocarbons in Myanmar - especially onshore - will need to be found in complex fold and thrust belts, which does require patience, significant investment and a detailed inspection and thorough analysis of legacy data. A situation that requires a stable and supporting political climate, which is so far removed from the current status quo.

In other words, the energy crisis not only lays bare the need for an increased focus on domestic production in Southeast Asia and elsewhere, but it also reinforces the need for a political will to support the industry with data such that these increasingly small and challenging pockets can indeed be found.

Henk Kombrink

BEHIND THE COVER

When confronted with a picture of Wave Rock or Hyden Rock in Southwest Australia, what would be the first thought of a geologist when asked to explain its formation? A former cliff where a sea from the past washed up against for a long time? The answer is no. Wave Rock is an example of a "flared slope" that is formed at the base of a granitic inselberg (isolated mountain) due to concentrated chemical weathering by groundwater. Subsequent erosion of the weathered granite due to uplift or base-level fall has exposed this front.

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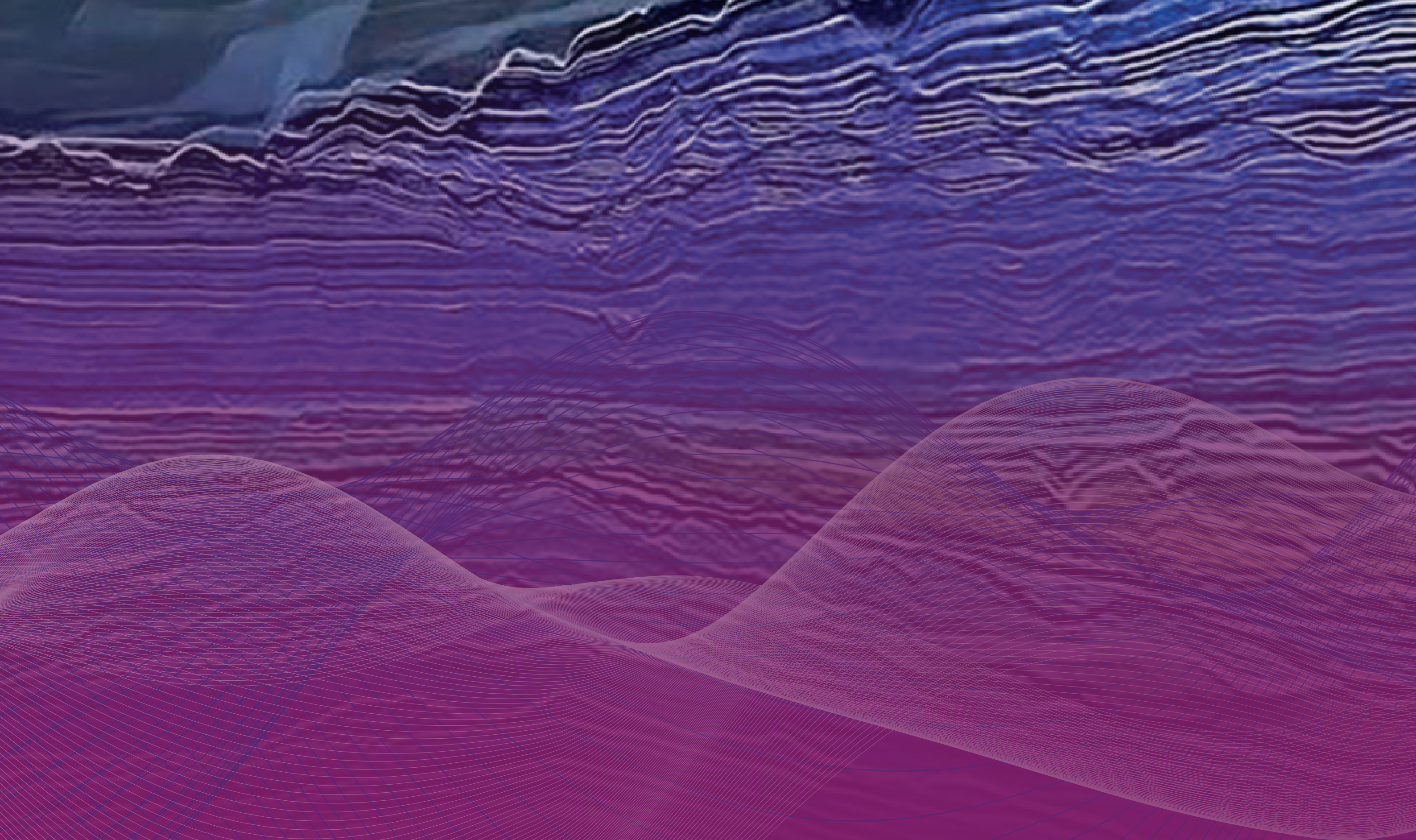
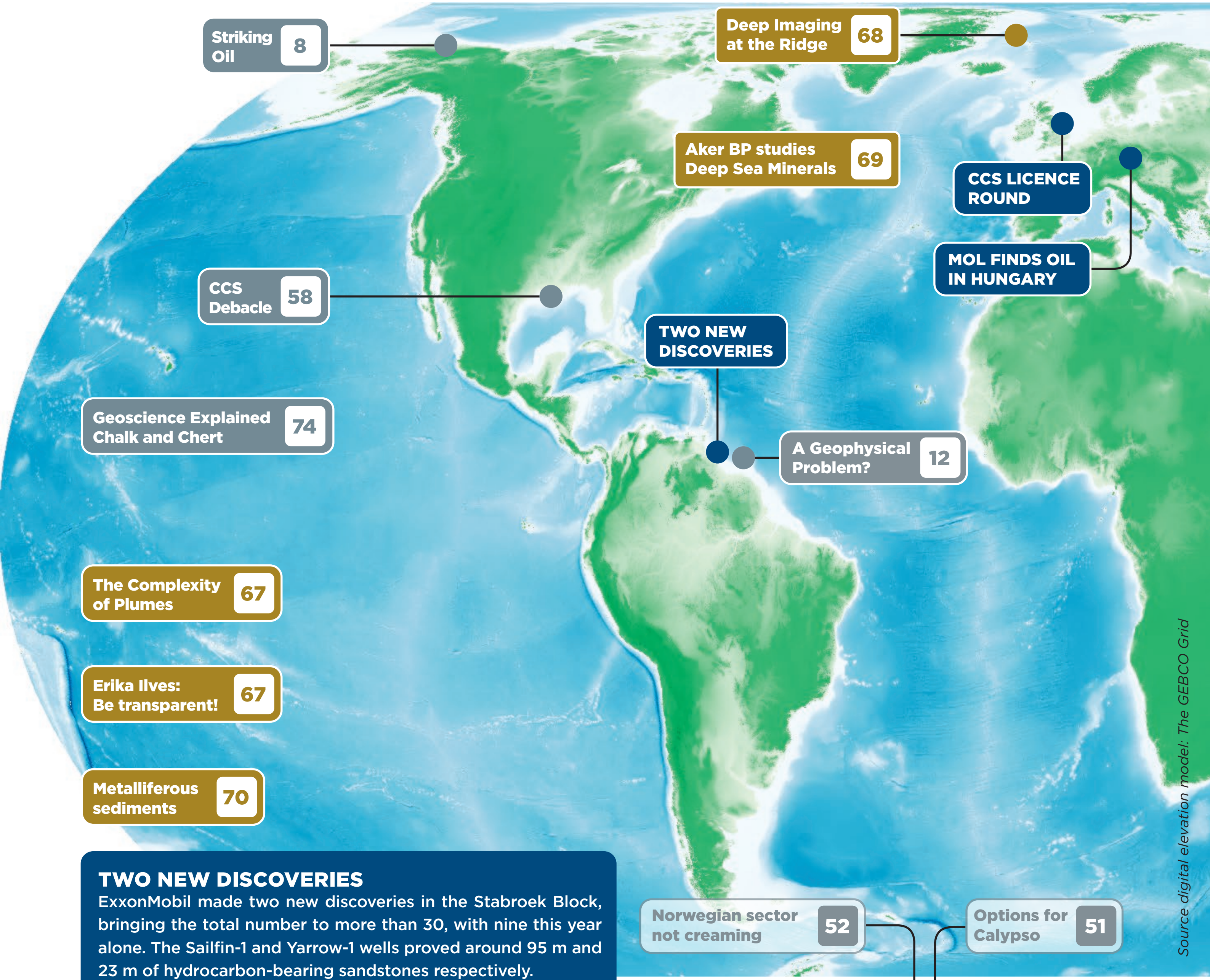




Source digital elevation model: The GEBCO Grid

TWO NEW DISCOVERIES

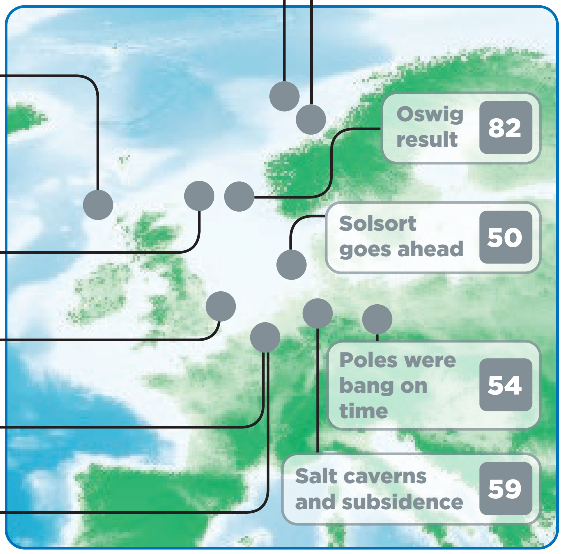
ExxonMobil made two new discoveries in the Stabroek Block, bringing the total number to more than 30, with nine this year alone. The Sailfin-1 and Yarrow-1 wells proved around 95 m and 23 m of hydrocarbon-bearing sandstones respectively.

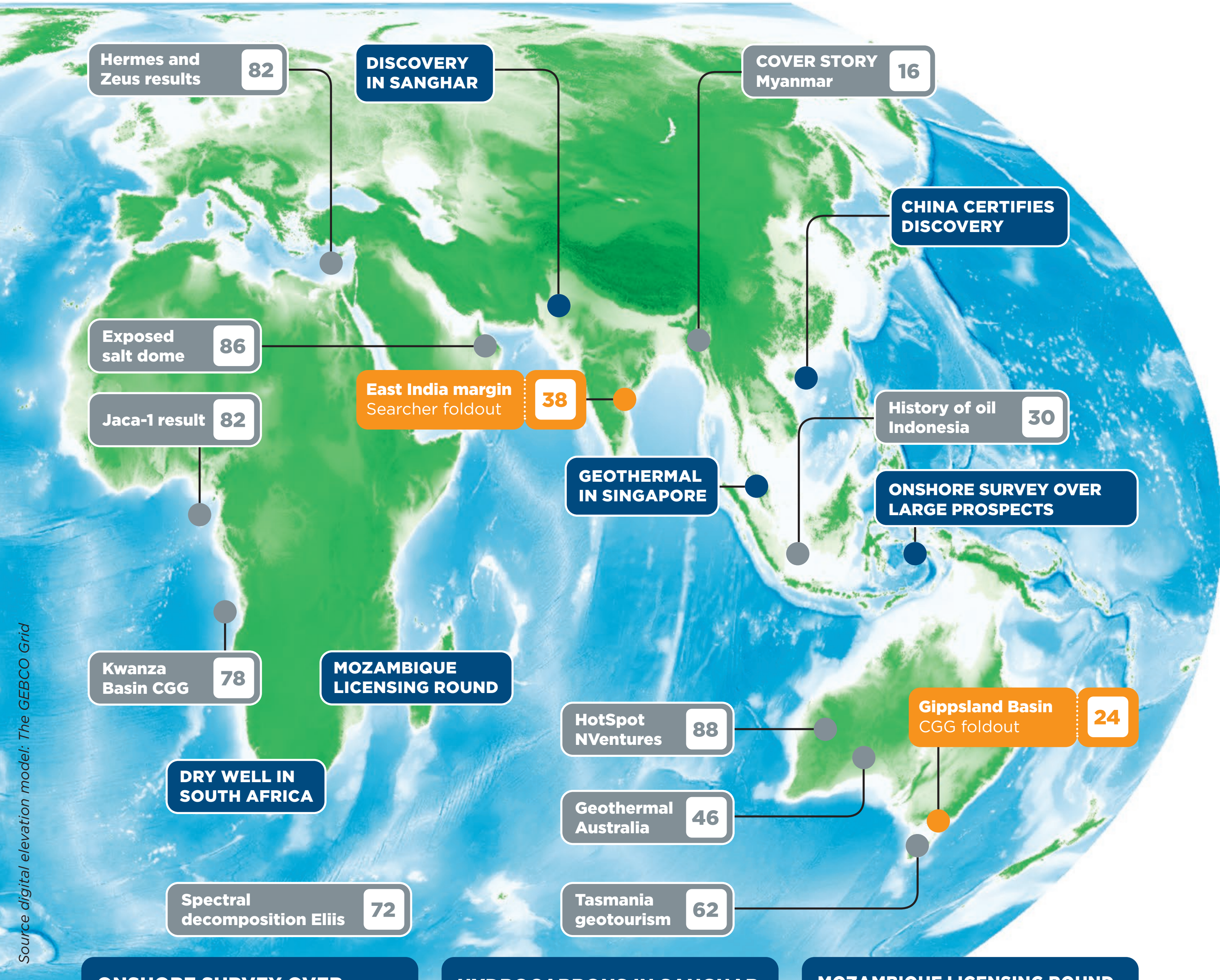
MOL FINDS OIL IN HUNGARY

In oil and gas hungry Europe, MOL has found a significant volume of oil near Vecses. The new well will produce between 700 and 1000 barrels per day, increasing Hungary's oil production by about 10%.

CCS LICENCE ROUND

To be awarded early 2023, the North Sea Transition Authority has said that the first UKCS Carbon storage round has attracted 26 bids, which means that first injection could take place in 2027.





Source digital elevation model: The GEBCO Grid

ONSHORE SURVEY OVER LARGE PROSPECTS

Lion Energy announced that the onshore survey acquired in the East Seram PSC on the island of Maluku in Indonesia is progressing well and within budget. It will cover prospects and leads with a best estimate prospective resource of 675 MMboe.

HYDROCARBONS IN SANGHAR:

Pakistan Petroleum Limited recently made a gas and condensate discovery through completing well Shahpur Chakar North-1 in the Gambat South Block. The well tested the Massive Sand of the Lower Goru Fm and flowed at 15.2 MMscfd and 321 bbl/d of condensate with a 32/64 choke.

MOZAMBIQUE LICENSING ROUND

The initial round results released by the INP suggests a lot of interest from China, which has submitted three bids in the Anoche Basin to the south of the Rovuma Basin. ENI also submitted a bid for an Anoche Basin block. The prospective Zambezi delta area did not receive bids.

CHINA CERTIFIES DISCOVERY

A gas discovery made by CNOOC last year has now been certified by the Chinese government. The deep-water discovery contains up to 50 Bcm of gas and may open a new play in the South China Sea.

GEOTHERMAL IN SINGAPORE

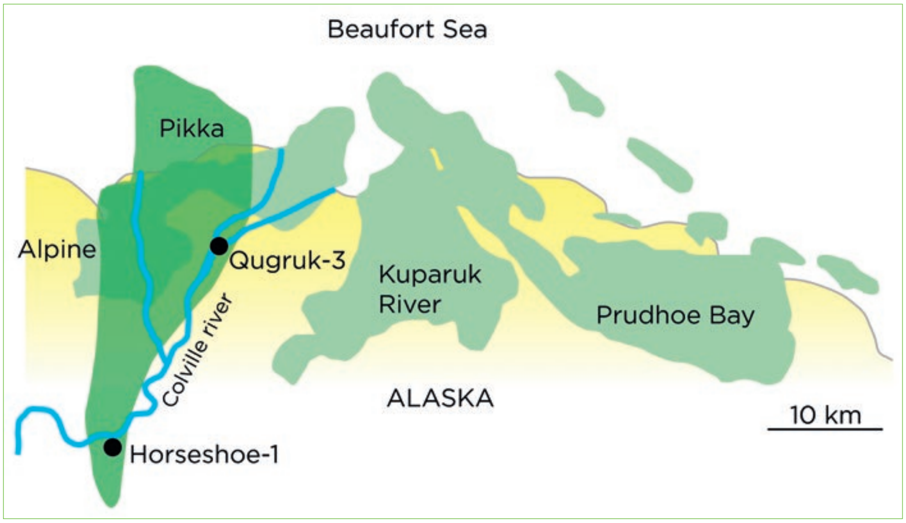
The Nanyang Technological University Singapore is drilling a 1.5 km test borehole to run temperature measurements to assess the geothermal gradient of the region.

DRY WELL IN SOUTH AFRICA

Eco Atlantic Oil & Gas announced that the Gazania-1 well has failed to find commercial hydrocarbons in Block 2B. Pre-drill estimates were in excess of 300 MMboe. The well was drilled in a rift basin play similar to Kenya and Uganda.

The Prospective Foresets Situated Below a Polar River

It took a long time before Pikka was discovered on the North Slope of Alaska. There is a river partly to blame for that.



In August this year, Australia-based **Santos** decided to develop the **Pikka** discovery on the **North Slope of Alaska**. It was not Santos that discovered the field, which contains almost **400 MMBoe** in 2P reserves. Proven in 2013, it was the small company **Armstrong Oil & Gas** that, partnered with operator **Repsol**, drilled the first well.

How did a small company find such a significant field as Pikka? At the end of the day, there are some major fields both to the east (**Kuparuk River** and **Prudhoe Bay**) and to the west (**Alpine**), in deeper reservoirs than where Pikka was found in.

As **Jesse Sommer** from Armstrong Oil & Gas explains in a video that is available through the AAPG online, the area of the Pikka discovery is situated right beneath the **Colville river**. Together with the many lakes that are situated on either side of the river, the acquisition of seismic data had always been an issue because even in the midst of winter the water did not completely freeze. This limited source locations.

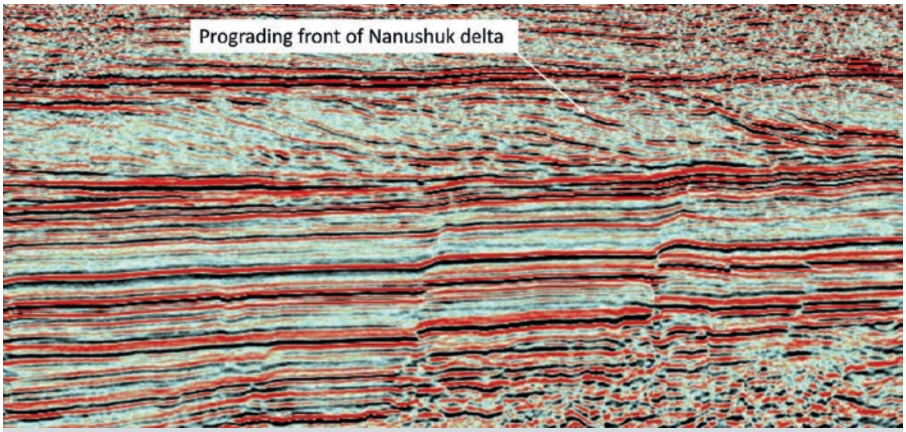
That is why the near-offsets were not widely available for the area, which limited the imaging especially of the shallower prospects at the depths where Pikka was later found (around 1,000 m). In addition, the absence of near-offset data also prevented the use of AVO techniques. But data quality was not the only reason Pikka was discovered late.

Until that moment, the Cretaceous Nanushuk Fm, in which the Pikka oil is reservoired, had not been the main focus of exploration for a long time. Although it was proven to be a host for hydrocarbons from the start of exploration in the area in the 1950's, the small volumes found mainly further south were too small to warrant development. When Prudhoe Bay was discovered, the biggest US onshore field, attention focused on the deeper part of the stratigraphy and the Nanushuk play was forgotten.

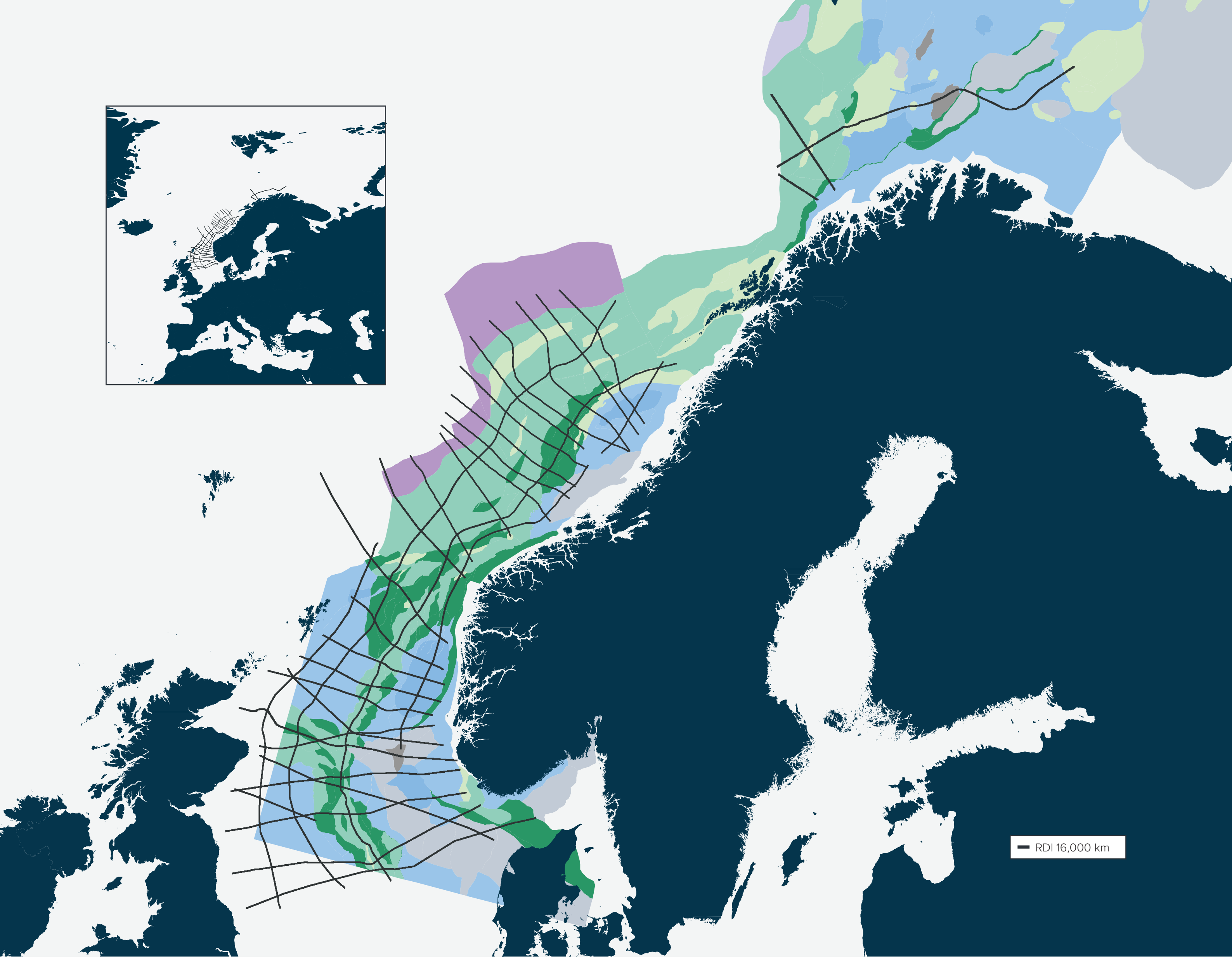
It was the realisation that stratigraphic traps are generally overlooked that made the people from **Armstrong Oil & Gas** realise that there may be something to explore for in the North Alaska foreland basin. Namely, Nanushuk prospects rely on stratigraphic pinch out of shelf delta sands.

So, following careful mapping of the eastward-prograding Albian-Cenomanian delta fronts, the company concluded that these sands formed a decent secondary target to the primary Jurassic target they had mapped a little bit deeper.

The discovery well **Qugruk-3** did indeed find an oil-bearing Nanushuk sand at around 1,200 m. The thickness of the sandstone and the pay zone exceeded expectations, which prompted a more targeted drilling campaign that ultimately also led to the drilling of the Horseshoe prospect in 2017 and the realisation that the two prospects were in fact part of the same pool. Pikka was born, and first oil is now expected in 2026 at a rate of **80,000 barrels/day**.

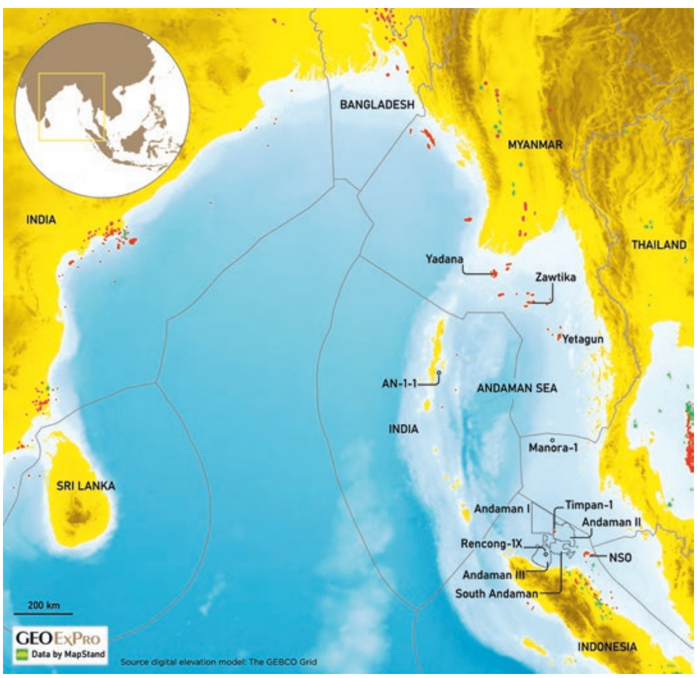


Screenshot from Big Island/North Island 3D seismic survey infosheet available on dggs.alaska.gov/gmc/seismic-well-data.php


RDI 16,000 km

Attention for Andaman

Following recent drilling success, multiple companies and countries are now increasingly looking to further prove the potential of the Andaman Sea.



In Southeast Asia, industry attention in recent months has been very much focussed on the deep-water Indonesian portion of the **Andaman Sea**. This is a consequence of the **Harbour Energy Timpan-1** gas and light oil/condensate discovery announced in July 2022. The play-opening wildcat was drilled to a total depth of 13,818 ft subsea and encountered a 390 ft gas column in Oligo-Miocene aged sandstone reservoirs.

The well, located in the Andaman II Block PSC, tested at a rate of 27 MMCFGD and 1,884 BOPD (58-degree API). Harbour is partnered in the PSC with **Mubadala** and **BP** (who had bought the KrisEnergy working interest in 2020).

Immediately after Timpan-1, **Repsol** spudded the much-awaited **Rencong-1X** wildcat in its Andaman III Block PSC. Petronas had farmed into this PSC, taking a 51% stake. The main play in this PSC, originally awarded to Talisman in 2009, are Late Eocene to Oligocene carbonate build-ups.

The Andaman Sea occupies a significant part of the Indian Ocean and has seen spurts of exploration activity over the last 45 years with mixed success. The vast sea covers parts of the offshore of India, Myanmar, Thailand and Indonesia, and running roughly north-south is the boundary between two tectonic plates.

First reports of oil and gas exploration in the Andaman Sea were in the late 1950s when the Indian national oil company, **ONGC**, undertook surveying and mapping. India's first exploration well, **AN-I-I** in 1980, was a small gas discovery. In the Thai sector of the Andaman Sea, exploration started in 1968 when 17 blocks were awarded. Early operators included Amoco, Esso, Oceanic, Pan Ocean, Placid Oil, Union Oil and Weeks; however, subsequent drilling by Esso, Union Oil and Placid were largely unsuccessful. The last drilling attempt in the Thai sector of the Andaman Sea was **Kerr-McGee's Manora-1** in 2000. Later, PTTEP was awarded three deep-water Andaman concessions in 2007 as a consequence of the Thai 19th Bid Round but did not drill before relinquishment.

On the northern side of the Andaman Sea, the **Zawtika**, **Yadana** and **Yetagun** gas fields are located in Myanmar, while in the south the **Arun**, **Kuala Langsa** and **North Sumatra Offshore** (NSO) fields are situated in Indonesia waters. All of these are significant hydrocarbon fields.

According to media reports, India's **ONGC** is planning a drilling campaign in the Andaman Sea, which follows the acquisition of some 22,500km of 2D seismic data under its National Island Exploration Project. Up to four deep-water wells are planned. In recent months, there have been press reports that majors **ExxonMobil** and Shell were in discussions to join ONGC in its deep-water Andaman Sea acreage.

India continues to push ahead with its efforts to explore the Andaman Sea, and in October 2022 it announced the offer of four ultra deep-water blocks as part of its Offshore Bid Round (OALP Bid Round-IX). These four blocks are undrilled and cover an area of over 53,000 sq km.

Future exploration activity in the Indian sector of the Andaman Sea will be watched closely by the Thailand Ministry of Energy, who may be seeking to promote acreage in this area in the near future. In the Indonesian sector, Harbour will be looking to continue its success with appraisal drilling on Timpan-1, plus additional drilling of other prospects, from late 2023. 3D seismic acquisition is also planned over the eastern side of the Andaman II PSC during late 2022, whilst the South Andaman PSC and the Andaman I PSC will also see some exploration activity in the near future; both are operated by Mubadala Petroleum, with Harbour as a 20% working interest partner. ■

Ian Cross, Moyes & Co

The Energy Opportunities Conference 2023

The American Association of Petroleum Geologists (AAPG), like its members, constantly strives to find new and innovative ways to prepare energy professionals to meet current and future challenges.

Photo: AAPG

For the past four years, **AAPG's** Energy Opportunities has connected decision-makers with the trends, tools, strategies to shape the world's energy future.

The initiative started in the Latin America and Caribbean Region but is now attracting speakers and attendees from throughout the America's as well as Australia, Africa, Asia and Europe. The inaugural Energy Opportunities Conference, held in Cartagena in 2018, gathered decision-makers in the exploration, investment, finance, legal, technology and government sectors of the energy industry.

The initiative expanded globally and moved to virtual space in 2020 and 2021, offering a series of executive forums and virtual conferences helping decision-makers navigate the challenges related to COVID-19, low oil prices and the accelerating energy transition.

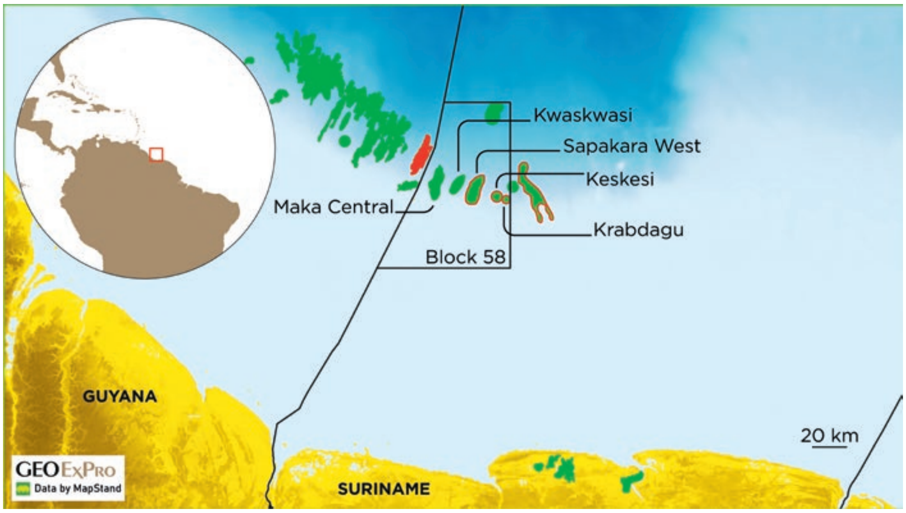
Conversations continue in-person at the 2023 **Energy Opportunities Conference in Mexico City** on 22-23 March. The event features plenary sessions and panels along two themes: *Balancing Energy Security and Sustainable Development and Resources and Technologies Fueling the Energy Transition*; an exhibition featuring new technologies and investment opportunities; and one-on-one meetings in private conference rooms.

Learn more at energyopportunities.info.

A Geophysical Problem?

TotalEnergies recently announced a delay in FID of Suriname Block 58 fields, citing subsurface issues as the main factor.

It does not happen very often that a company's CEO uses subsurface technical language to explain the reason behind corporate decisions. However, **TotalEnergie**'s **Patrick Pouyanné** does not shy away from venturing into the G&G world, as he recently testified during a press conference about his company's plans in Block 58 in Suriname.



TotalEnergies, together with **Apache Corporation**, has made five discoveries in this block in recent years, for which an FID is now anticipated. However, the can has now been kicked further down the road. Pouyanné cited reservoir complexity and a lack of correlation between seismic results and well data as the reason for the decision.

How to interpret these words? Apparently, technical people in the company were also surprised with the statements from their CEO, as we found out. Even though further information has not been shared with us, it seemed that technical people within the company were not necessarily aware of there being as issue with regards to the correlation between well and seismic data.

Arthur Deakin from **OilNow** rather thinks that the more stringent fiscal terms on oil-profit sharing in Suriname, coupled with high rates of inflation, debt defaults and political patronage are behind the decision.

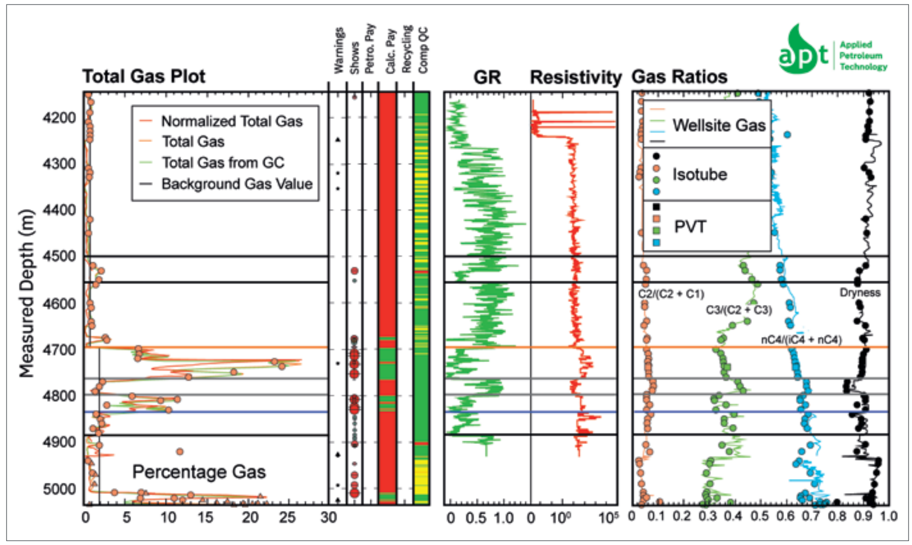
APT Girasol – Well Site Gas for Reservoir Evaluation and Phase Prediction

New software program efficiently integrates gas data within the overall well analysis workflow.

Well site gas is often an under-used resource in the industry. While often assessed during the operational phases, the data is rarely fully integrated with complimentary data such as petrophysics and PVT, despite offering multiple applications across the E&P cycle.

Good business practices encourage cost discipline and as logging suites are reduced, primarily to less robust LWD datasets, so every effort should be made integrating across as much data as possible.

Advances and applications of well site mud gas, of crucial interest to geoscientists and engineers, such as pay and GOR have been proposed previously. **APT** have developed a program specifically designed for working with well site gas data under the name **Girasol**.



Girasol includes correction for drilling parameters and a flexible, compositional correction required for wells drilled with oil-based mud. The software facilitates the efficient integration and interpretation of this underused data type, which means a much more informed post-well analysis without the costs of additional logging.

New Exciting Partnership in Geothermal Drilling Space

Sage Geosystems Inc. (Sage), a transformative geothermal development company, will receive investment from Ignis H2 Energy Inc. (Ignis) and its sister company Geolog International BV (GEOLOG).

"After a thorough review of the companies and technologies in geothermal storage and power generation, we are excited to partner with **Sage** given the team's track history in technology development and commercialization coupled with their innovative developments in geothermal," said **Richard Calleri**, CEO of **GEOLOG** and **Ignis**.

Sage aims to vastly expand the use of geothermal energy production beyond the well-known volcanic hotspots across the world. To that end, the company developed a range of different solutions to tap into the geothermal energy of areas where wells can reach the 150-200°C subsurface temperature zone using conventional drilling techniques adapted from the oil and gas sector.

"We are fully committed to support Sage in their evolution and growth. Sage and Ignis will benefit from GEOLOG's expertise in subsurface characterization and global presence giving them a clear path to faster geological evaluations and international expansion," adds Richard Calleri.

The strategic partnership will help accelerate the deployment of Sage's proprietary technologies that vastly expand the reach of economic geothermal development, including much-needed long duration, low-cost energy storage solutions ("Battery+") that will help balance the grid as intermittent renewable resources such as wind and solar continue to rapidly expand and experience increased curtailment.

Cindy Taff, CEO of **Sage** says: "We are excited at Sage to work with Richard and his teams at Ignis and GEOLOG as we move to implement our geothermal storage and baseload technologies in the field. Their global experience in more than 70 countries and their state-of-the-art subsurface characterization technology will be extremely valuable to our efforts."

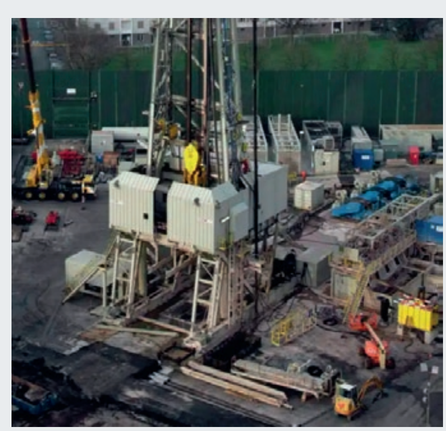


Photo: Sage

Resoptima Partners with Aker BP, Sval Energi, and NORCE to Reduce CO_2 Emissions from Oil and Gas Production

The project aims at leveraging Resoptima's reservoir modelling and reservoir management technologies to help reduce CO_2 emissions associated with oil and gas activities.

Left to right: Truls Olsen-Skåre (Sval Energi), Atila Mellilo (Resoptima) and Morten Heir (Aker BP).

The initiative is grounded in **Resoptima**'s long-standing thought leadership and unique software solutions for the management of subsurface and dynamic uncertainties through its ensemble-based modelling system. Resoptima will coordinate this pioneering project with scientific input from **NORCE**. **Aker BP** and **Sval Energi** will contribute with data, expertise, and pilot testing of the technologies, while the Research Council of Norway is providing financial support for the project.

The scope of the project is relevant to all upstream oil and gas operators, and once validated by all parties, the software solution will be added to the commercial portfolio of Resoptima for licensing on a global basis.

The main goal is to establish algorithms to enhance oil production while minimising CO_2 emissions. This will be achieved primarily by optimising the selection and location of additional wells aiming at reducing both their number and length.

In addition, the partnership will better model reservoir drainage to optimise water injection and reduce water production, as these activities rely on carbon-intensive power generation. This approach will contribute to a better operation of wells both in production and injection modes.

"Oil and gas will remain an important component in the energy mix for years to come," said Resoptima CEO **Atila Mellilo**. "It is therefore very important to develop technologies that contribute to the de-carbonization of oil and gas production, ensuring that development and production activities are taking place in the most sustainable way, with the lowest possible emission levels."

The Most Cost-Effective Way of Monitoring CO_2 Injection

As the momentum behind injecting CO_2 builds, so is the market that aims to serve the industry with tools to monitor injected carbon dioxide.

The business case for Carbon Sequestration and Storage is challenging, and that is the reason why there is a huge drive to come up with ideas to carry out the process of monitoring as cost-effectively as possible. That is where start-up **SpotLight** comes in.

Photo: Henk Kombrink

Habib Al Khatib, Founder of SpotLight, at the Global Energy Transition Conference in The Hague (November 2022).

Co-founded by two former CGG employees and based in **Massy**, France, SpotLight has developed a new way to drastically reduce the operational and financial footprint of CO_2 plume monitoring.

Proven onshore already, the company will now trial the new methodology offshore at **INEOS & Wintershall's Greensand** CO_2 injection pilot in the Danish sector.

"The silver bullet," according to founder **Habib Al Khatib**, "is the fact that we know where the CO_2 is injected. We can then model and predict how the seismic response will be. As such, we aim to put **simulation** at the heart of our monitoring strategy. Since CO_2 is generating a strong 4D response, we can detect very frequently the reservoir behaviour at a strategic location and compare it to the simulation to validate the model, instead of acquiring a full 4D seismic survey."

Validation of the simulated response will only require a fixed array of conventional receivers installed in such a way to maximise signal to noise ratio. The monitoring exercise then entails performing several shots from one location (spot).

If the results of the monitoring survey confirm what the simulation exercise predicted, no further action is needed. Only when the results deviate from the simulation outcomes, which may indicate that CO_2 is migrating in an unanticipated direction, more expensive monitoring tools such as 4D seismic may be required.

GeoConvention 2023

Hosted from Calgary in Canada, GeoConvention 2023 offers a truly hybrid conference through an immersive virtual experience.

Taking place from 15 to 17 May 2023, the **GeoConvention** conference (geoconvention.com) will build on the success of the 2022 hybrid program, bringing in-person delegates and throughout the world a focused program featuring the latest developments in the geosciences and energy spaces.

With over 50 technical sessions identified, GeoConvention 2023 will feature a fully integrated program representing a diverse collection of earth science disciplines, including geology, geophysics, petrophysics, minerals, water, earth, environment and the energy world.

From live panel discussions to targeted technical content, GeoConvention provides the ultimate opportunity for delegates to expand their knowledge and push their capabilities to the next level. Plus, through the hybrid format, the full program will be offered virtually through November 2023 so delegates may catch up on missed talks or revisit key content at their leisure.

Program highlights include Sedimentology, Geomechanics, Geothermal, Carbon Sequestration, Seismic Processing, Water Disposal, Critical Minerals, Microseismic and Case Studies.

GeoConvention invites you to join thousands of geoscience and energy professionals, students, and academic leaders, as a presenter, exhibitor, or delegate through one of the largest integrated geoscience and energy conferences. ■

ACTeQ Releases Software to Estimate Greenhouse Gas Emissions for Geophysical Surveys

Tools allow users to compare the emissions and fuel consumption for multiple candidate survey designs.

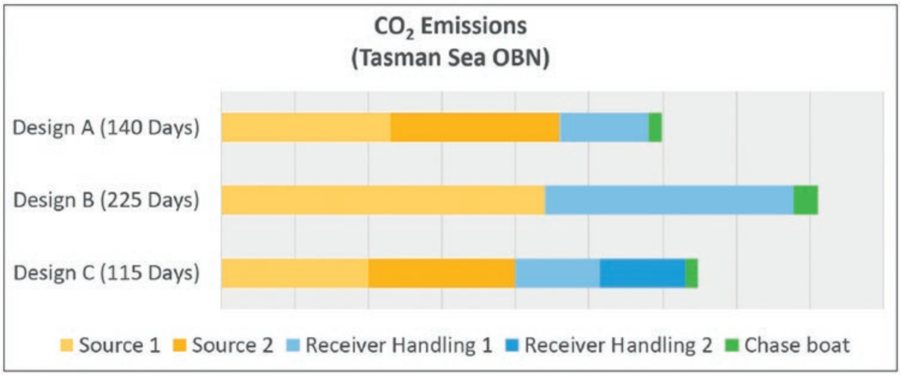
It is increasingly important to better understand emissions related to offshore and onshore geophysical operations. That is why **ACTeQ** has developed software to accurately monitor this and fuel consumption.

Emissions estimates from geophysical survey operations are calculated using the **"Guidance for Estimating and Reporting Greenhouse Gas (GHG) Emissions"** which was recently published by the **EnerGeo Alliance**.

Estimates are based on information such as the drag associated with towed equipment and variations in ocean and tidal current. In addition to the environmental benefits, these tools will also create value for operators and service providers since low emissions and low fuel consumption often lead to lower cost and reduced personnel exposure in the field.

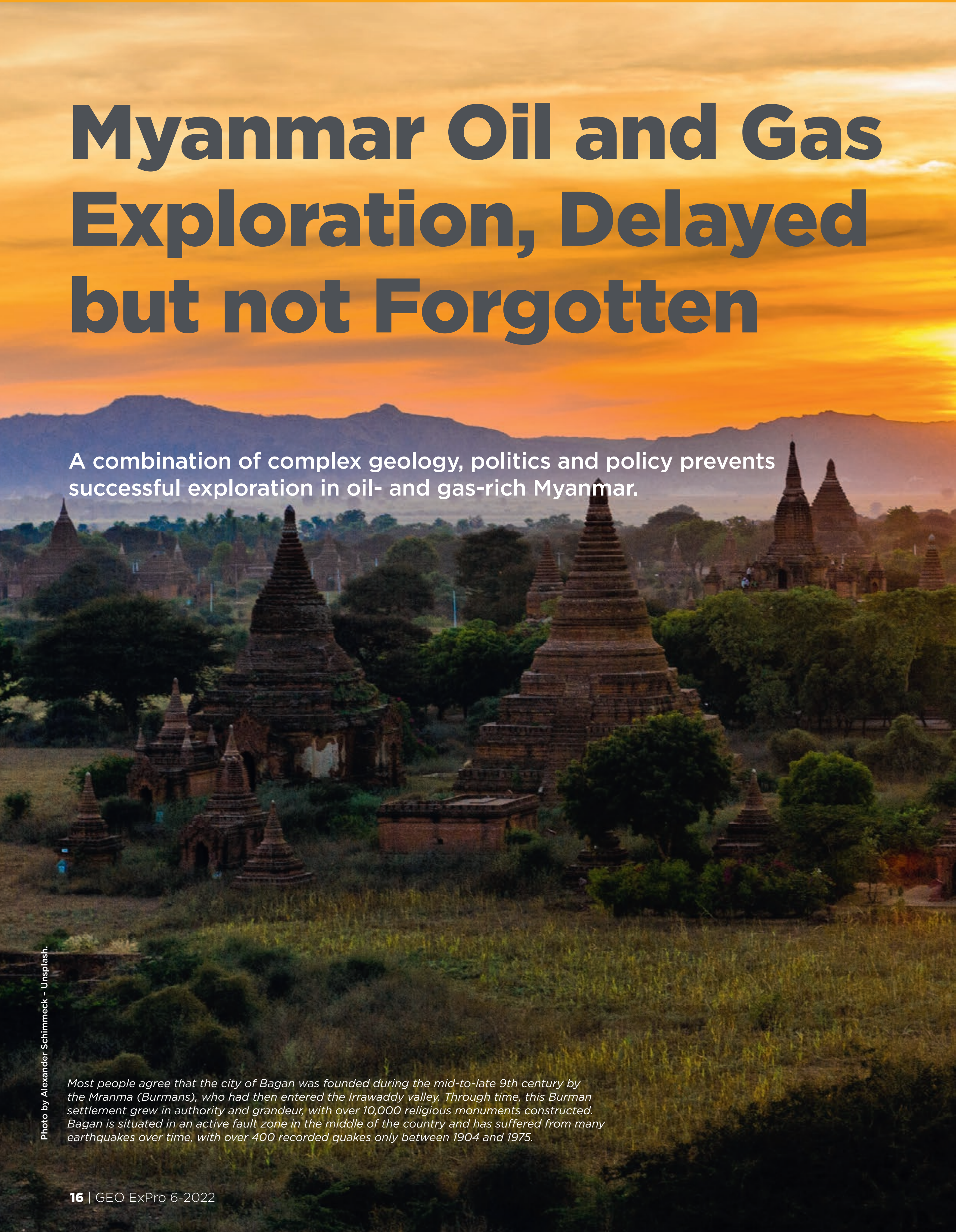
ACTeQ's TesserACT software also includes several other environmentally focused tools such as **Weighted Path Optimization and Compressive Sensing** that deliver cost-effective onshore survey designs with the minimum environmental impact.

Damian Hite (CEO) said "ACTeQ is committed to creating value for our customers through multi-variate optimization of geophysical surveys. We balance geophysics with cost, safety and environmental impact." ■



Myanmar Oil and Gas Exploration, Delayed but not Forgotten

A combination of complex geology, politics and policy prevents successful exploration in oil- and gas-rich Myanmar.



Most people agree that the city of Bagan was founded during the mid-to-late 9th century by the Mranma (Burmans), who had then entered the Irrawaddy valley. Through time, this Burman settlement grew in authority and grandeur, with over 10,000 religious monuments constructed. Bagan is situated in an active fault zone in the middle of the country and has suffered from many earthquakes over time, with over 400 recorded quakes only between 1904 and 1975.

Photo by Alexander Schimmeck – Unsplash.

Text: Thomas L. Davis, PhD, PG

In 2015, Duncan Witts described Myanmar as "**one of the World's current hotspots for oil and gas exploration…**". Forward to 2022, exploration and foreign investment have significantly declined due to operating difficulties, politics, and security concerns, showing for the umpteenth time that the economy of energy rests on the pillars of politics, policy and price.

For centuries, Myanmar (Figure 1) has been a marginal oil producer at a fraction of its considerable potential. Yet, geologists estimate that the country has significant potential for proving additional reserves of oil and gas. In addition, there is a range of enhanced oil recovery opportunities, e.g. thermal and water floods, plus gas storage in depleted oil fields.

At present, civil unrest consisting of pro-democracy protests in response to the February 2021 Coup d'état and armed insurgency in the countryside will delay any opportunities for years, unless a radical political change takes place overnight. Conversely, the attention from foreign energy players to Myanmar during the last two to three decades will not be easily forgotten against a backdrop of falling production and increasing domestic energy demand (Figure 2).

This article provides a summary of some recent issues affecting the oil and gas sector and its consequences. It shows that especially in complex geological settings such as the onshore fold and thrust belt, the combination of political stability and perseverance is key to unlocking the basin's potential.

OPENING UP

Only a small number of international E&P companies were in Myanmar before 2012 when a new Foreign Petroleum Law (FPL) was passed, making available numerous onshore and offshore blocks to foreign investment.

Foreign direct investment (FDI) from 2012-16 reached a total of USD 28 billion, which was about three-quarters of the FDI in the previous twenty-two years period (Figure 2). Initially, FDI increased with the transition to a more

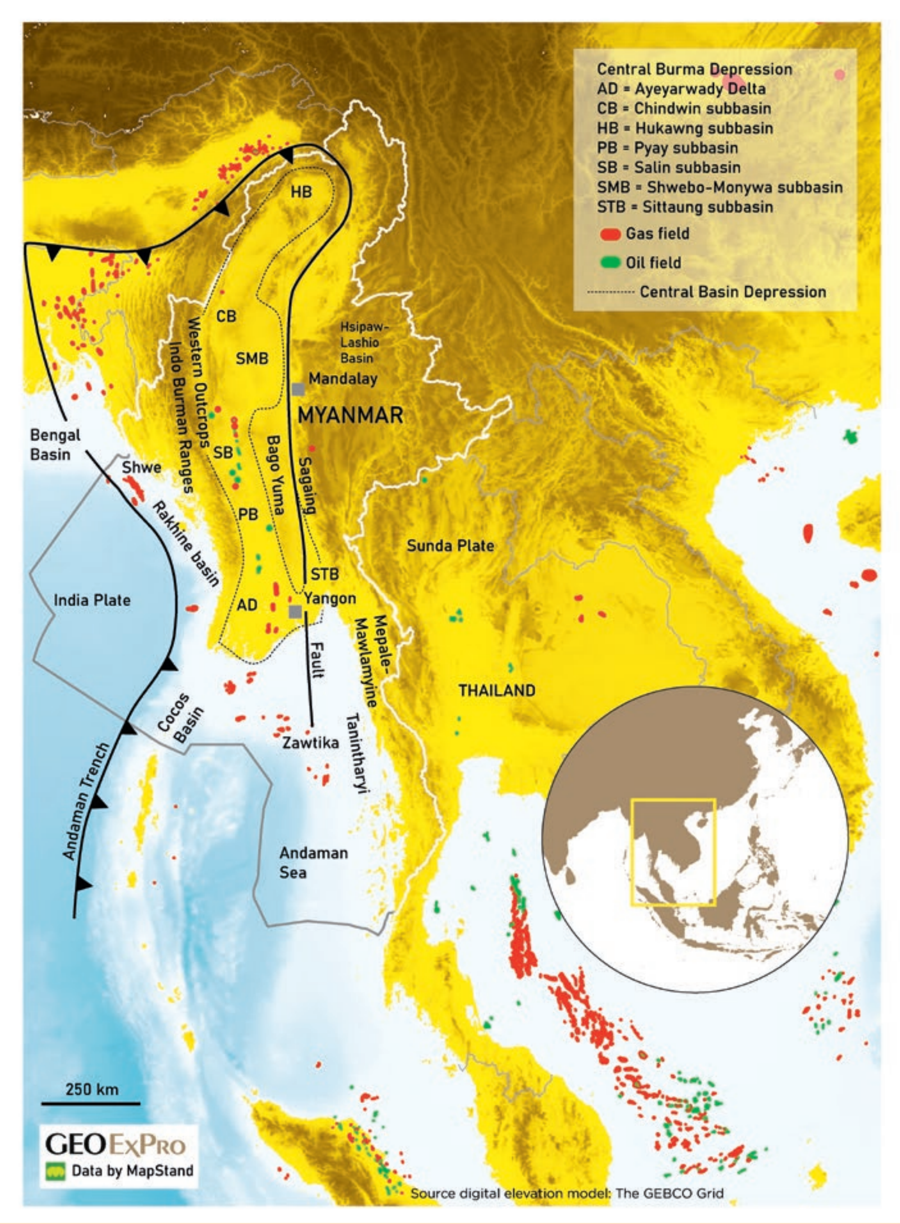


Figure 1: Regional plate tectonic map of Myanmar showing the oil and gas producing Central Burma Depression (CBD) that runs from south to north through the country, oil and gas fields, sedimentary basin names with possible oil and gas accumulations, and major geologic structures. Most of the known oil and gas fields of the CBD are structural traps that are the result of transpression associated with the Sagaing fault plate boundary. Additional untested oil and gas traps and sub-basins are interpreted to lie beneath thrust faults and unconformities but not expressed on the earth's surface as is the case with the known CBD oil fields.

democratic form of government and assisted the flow of technical expertise and knowledge into the oil and gas sector. For instance, the American Association of Petroleum Geologists (AAPG), European Association of Geoscientists and Engineers (EAGE), and the Myanmar Geosciences Society hosted four oil and gas conferences in Yangon from 2014 to 2018 that provided a wealth of knowledge transfer and new contacts.

In 2015, exploration and development interest by foreign companies reached a peak when Myint (2016) reported that thirty-two international companies were operating 65 blocks under production sharing contracts (PSCs, an expression of exploration interest).

COOLING DOWN

By 2022, exploration interest had cooled considerably with only 17 onshore blocks and 18 offshore blocks. Oil and gas production is declining too. From 2012 to 2022, oil production decreased from around 20,000 to 7,500 Bopd (barrels of oil per day; Figure 3).

Myanmar produces, uses, and exports a substantial amount of gas. Marketed gas production increased substantially from 2013-2015, mainly from the offshore gas fields, but it has declined about 10% since 2015. In 2019-2020, around 670,000 Mmscf (million standard cubic feet) was produced, with around 146,000 Mmscf consumed in-country, and the remaining exported to Thailand and China.

Gas sales have supported foreign exchange reserves, but the gas and oil production decline and growing LNG (liquefied natural gas) and crude oil imports are unfavourable trends despite recent higher gas prices. LNG imports are needed for domestic and industrial power (the government wants 2.1 metric tons per annum by 2030) while 7 Mmbo (million barrels) of crude oil were imported in 2020.

BACK TO PRE-2012 LEVELS

Despite popular thinking, several factors negatively impacting exploration and production **pre-date** the 2021 Coup d'état (Figure 3).

1) No important discoveries have been made since the offshore gas fields **Shwe** in 2004 and **Zawtika** in 2007;
2) Unresolved operating and policy constraints between the government and operators with some that have lingered since the 2012 FPL;
3) Onshore operating difficulties in challenging and remote settings with poor infrastructure;
4) A lack of and restricted access to geological and geophysical data in a complex region;
5) Worldwide recognition and condemnation of the government's response to civil strife in Rakhine State starting in 2016 that curtailed private sector investment. By 2018, FDI had collapsed to USD 1.77 billion, a 63.2% decline from 2017 (Figure 2).

The military declared a state of emergency in February 2021, ousted

Source: Macrotrends.net, 2020.

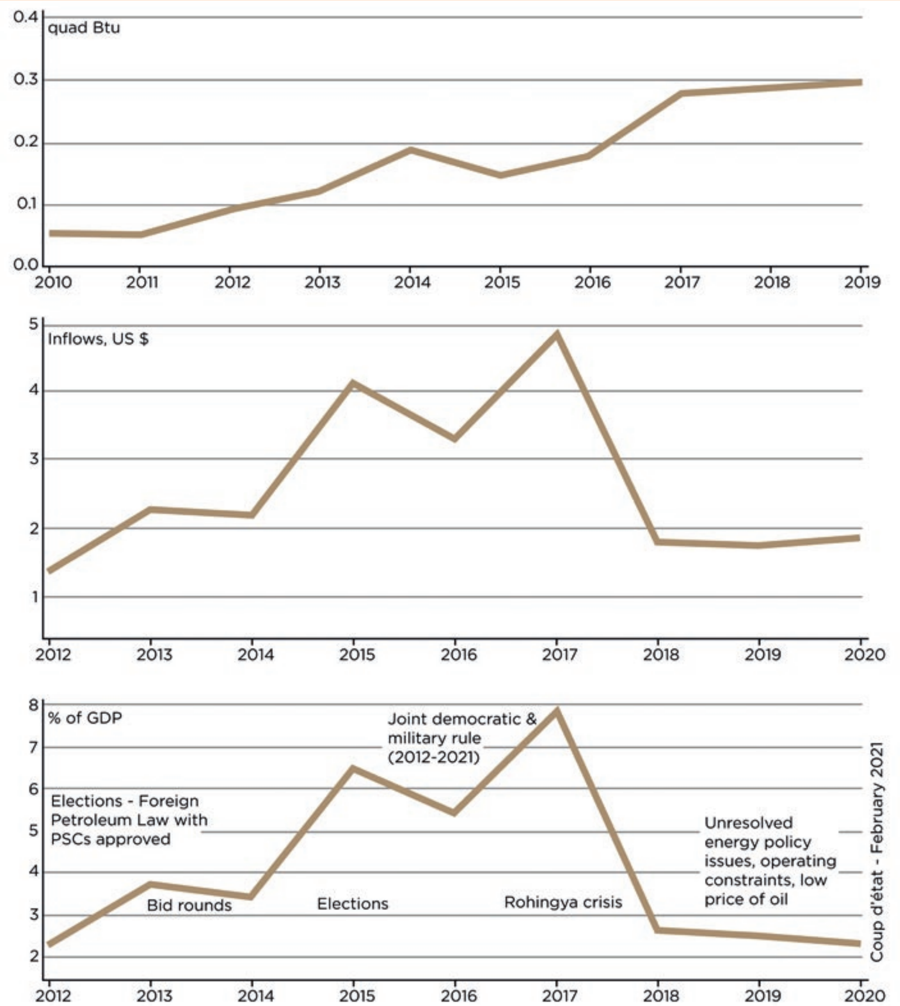


Figure 2: The upper graph shows that Myanmar (Burma) had a nearly 6-fold increase in total energy consumption from petroleum and other liquids from 2012 to 2020 (EIA, 2022). Consumption in quad Btu, that is 1 quadrillion (1015) British thermal units (BTUs). The middle graph shows Foreign Direct Investment (FDI) in USD and the bottom graph % GDP from 2012-2020 with key political and oil and gas sector events added. The graphs show the correlation of oil and gas policy and political events with FDI and GDP.

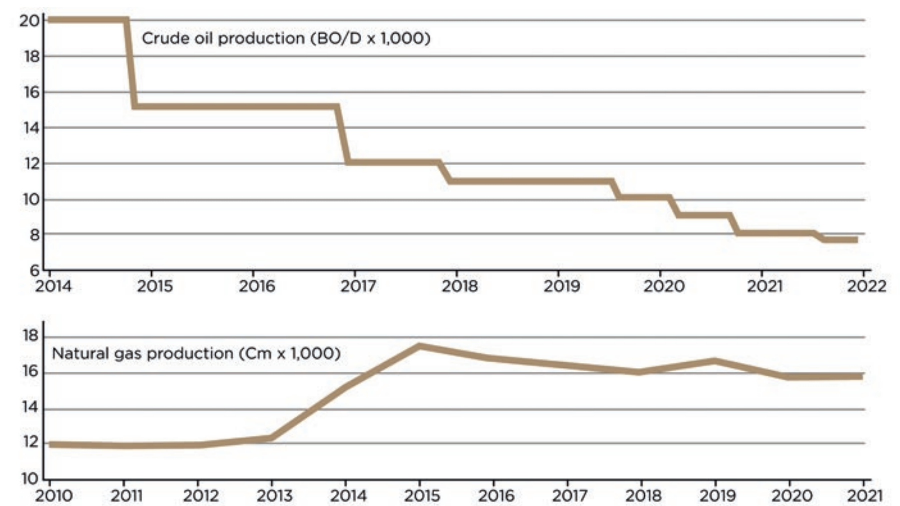


Figure 3: Graph showing the significant decline in daily crude oil production in Myanmar from 2014 to 2022 (Top). Production is in thousand Bopd. Source: TE (2022) and EIA (2022). The bottom graph shows marketed natural gas production in Myanmar from 2010 to 2021. Production is shown in thousand normal cubic metres of gas.

the previous government of the National League for Democracy (NLD), and FDI was back to its meager pre-2012 levels. The military-led government has promised future elections but has not offered a revised energy policy or stated they would honor existing policies, adding to foreign investment uncertainty.

The long-term impact of the 2021 Coup d'état on oil and gas production remains unclear, but being confronted with a decline from 970,513 to 587,060 barrels of oil year on year from just two onshore fields (**Chauk** and **Yenangyang**), there should be some alarm bells ringing.

COLD AND UNCERTAIN

The United States, UK, Canada and the EU have implemented economic sanctions on several entities and individuals in the oil and gas sector in response to the 2021 Coup d'état, the government's role in suppression of the opposition to the coup, plus ethnic cleansing in the Rakhine State.

Export sales of gas are a major source of foreign currency to the government, at risk to further sanctions, and major foreign gas producers such as **Chevron**, **Woodside**, **TotalEnergies**, and **Shell** have departed and turned their operations over to regional operators.

Even though the direct impact of present sanctions is unclear, additional economic sanctions being considered by the USA, UK, EU, and Canada on the sector will be exceedingly harmful to the population, reduce production and government income, and bring in nations not participating in sanctions. Clearly, by the end of 2022, the plan to improve one of the poorest and least developed nations in Asia through increased foreign investment and PSCs in the oil and gas sector has turned cold and uncertain.

FOLD AND THRUST BELT POTENTIAL OF THE OIL-PRODUCING CENTRAL BASIN DEPRESSION

Despite the political problems and associated uncertainties, opportunities remain in the Myanmar oil and gas sector given present-day prices, long-term price forecasts, and continuing demand for fossil fuels both in and out of the country.

Examples of potential growth areas are offshore natural gas in the **Moatama**, **Rakhine**, and **Tanintharyi** areas, exploration in the onshore **Hukawng**, **Hsipaw-Lashio** and **Mawlamyine-Mepale** basins; and gas storage in depleted oil fields near population centers with growing power demands (Figure 1). Here, onshore exploration opportunities in the fold and thrust belt of the Central Basin Depression (CBD) are discussed in more detail.

Nearly all of Myanmar's onshore oil and gas production, historic and present, comes from the CBD (Figure 1), a ~1200 km long, narrow trough with a thick sedimentary section including an active petroleum system of proven reservoir and rich source rocks.

Masters et al. (1998) estimated the mean undiscovered petroleum resources at **1.4 Bbo** for the Burma Basin (primarily composed of the CBD) and they estimated **6.2 Tcfg** for the combined Burma Basin and Andaman Sea.

Wandrey (2006) provides a mean estimate of undiscovered oil and gas reserves for the Central Burma Basin Assessment Unit of **516 Mmbo**; **2,008 Bcfg**; and **99 Mmboe** in natural gas liquids. Myint (2016) estimated **566 Mmbo** cumulative and **85 Mmbo** remaining recoverable for the Central Myanmar Basin (equivalent to the CBD).

Seismic reflection profiles, drilling results, cross sections and geologic mapping show that a significant portion of the undiscovered potential is in the fold and thrust part of the CBD. Such complex belts, even those with rich source rocks, are often resource-underestimated in the early stages of exploration.

Worldwide, oil and gas-prone fold and thrust belts can be enormously rich with giant trapping structures. However, these areas are difficult to explore due to their fault and fold complexity, and often take decades to fully develop through drilling. Likewise, the ultimate potential of fold and thrust belts is difficult to estimate initially without extensive geologic and seismic reflection data and initial drilling results.

The fold and thrust belt of the CBD play is the lowest risk and largest exploration opportunity in onshore Myanmar based on the location of existing oil production, the presence of rich and mature source rocks, and the limited amount of exploration drilling away from the most obvious surface anticlines, e.g., Yenangyaung and Yenangyat-Chauk oil fields (Figure 4).

To assist exploration in such complex structural settings, geologists

MISSED OPPORTUNITIES

The **Central Basin Depression** is in a transpressional tectonic setting along the **Sagaing fault** (SF) plate boundary, displaying convergent and strike-slip crustal movements. The SF shares similarities with the San Andreas fault plate boundary of California: both faults have had around 300 km of right-lateral displacement since the early Miocene with the coeval growth of adjacent fold and thrust belts and sediments overprinted on older structures that provide a variety of oil and gas traps styles.

Both settings are active and prolific petroleum systems, with mature and rich source rock units, and a variety of proven reservoir units. Many transpressional settings have been incorrectly mapped with steepening-with-depth fault patterns, as displayed in cross-sectional view, that forecast very limited sub-fault exploration portions, constraining resource estimates and missing many trapping structures.

For instance, the "flower structure" pattern once used to explain the oil trapping mechanism of the giant oil fields in the oil-rich San Joaquin basin, California, has been shown to be incorrect and thereby limiting resource estimations. Subsequent new field discoveries in the San Joaquin, along with structural mapping and the recognition of strain-partitioning along the San Andreas fault plate boundary, showed that the basin has significant untested oil and gas potential in the sub-fault portions.

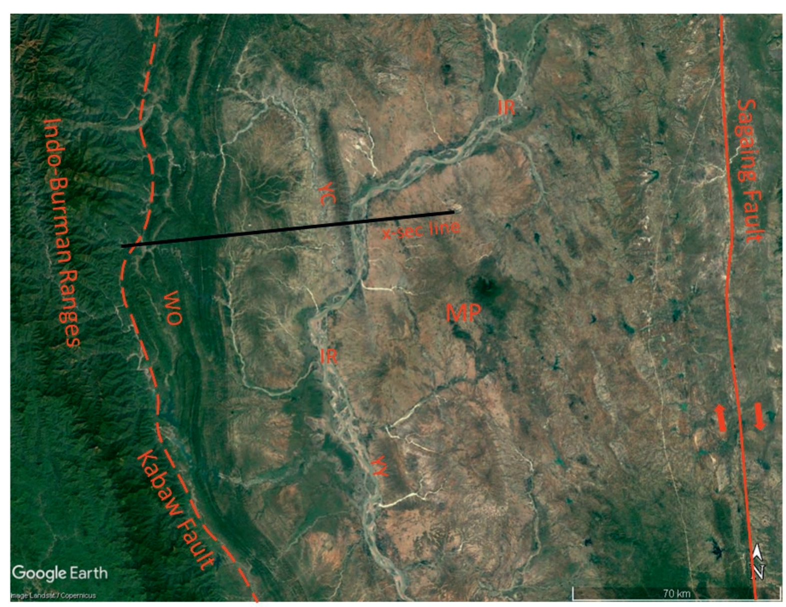


Figure 4: Enhanced satellite image of the Salin sub-basin, Central Basin Depression (CBD). Heavy black line is the location of the cross-sections shown in Figure 6. The west-dipping Kabaw reverse fault and the right-lateral strike-slip Sagaing fault form the west and east edges of the CBD, respectively. Abbreviations: IR = Irrawaddy River, MP = Mount Popa, WO = Western Outcrops (surface expression of the fold and thrust belt structures), YC = Yenangyat-Chauk anticlinal structure and oil fields, YY = Yenangyaung anticlinal structure and oil field.

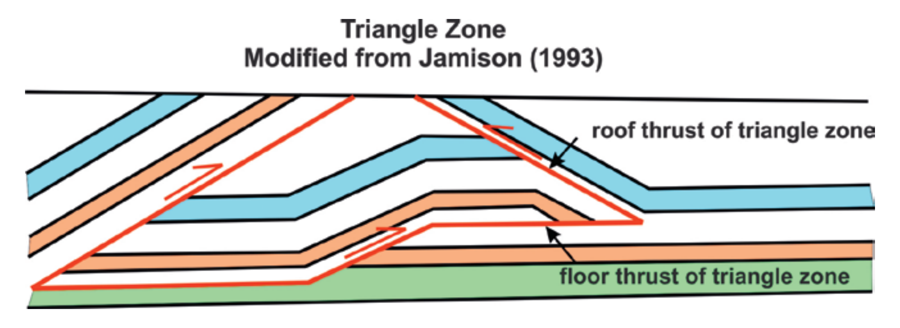


Figure 5: Schematic cross-sectional model of a convergent wedge forming a triangle zone within a fold and thrust belt, illustrating a concealed oil and gas trap (anticline above floor thrust).

have developed models based on observation and theory, with restorable cross-section techniques to assist seismic interpretation and cross-section construction (Figure 5). This has not been done sufficiently in the CBD. Figure 6 is a very generalised application of this approach that illustrates the potential oil and gas trapping areas hidden beneath the faults in the CBD. Exploration in the CBD will require detailed surface geologic mapping using existing well records and seismic reflection profiles. That level of data availability is generally not available or does not exist and geologists must be content with the regional works of Bender (1983), Pivnik et al. (1998) and Racey and Ridd (2015).

PATIENCE REQUIRED

To sum up, the development and further exploration of its offshore gas resources that looked so promising a decade ago are currently stalled in Myanmar. Likewise, onshore oil exploration is now more a dream than a reality. However, the political chaos will end sooner or later, with a new government likely facilitating the return of foreign companies given the attractive opportunities.

In addition, government recognition of and assistance in clearing operational obstacles would be beneficial; making exploration data easily available would cost little and increase foreign interest. The government needs to appreciate that exploration in the CBD will be more demanding, as successful exploration in structurally complex belts requires lots of geological and geophysical data, patience and large investments that will not depart after the first dry hole.

This will require favourable government understanding, policies, and terms that recognise the great financial risk taken by operators in such settings. The costs for even a modest exploration program in a remote fold and thrust belt is probably well north of USD 50 million. For now, the significant oil potential in the fold and thrust belt part of the CBD will remain untested and undeveloped but not forgotten by the world's oil and gas industry.

References provided online. ■

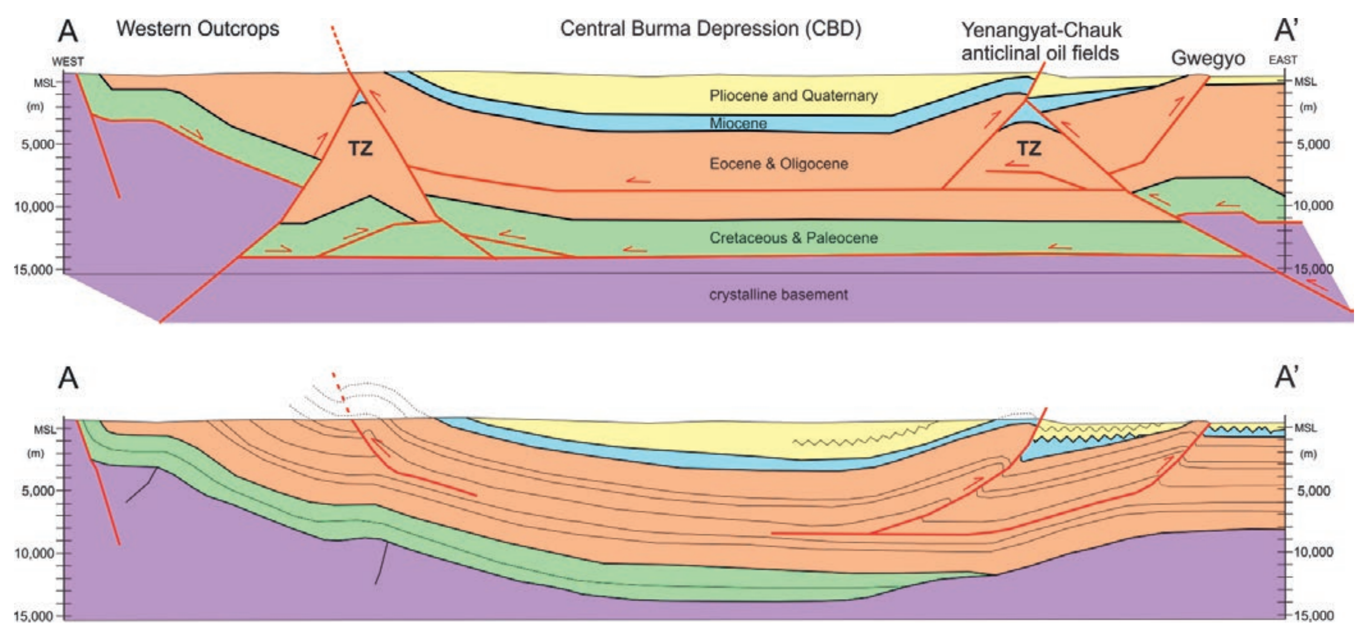
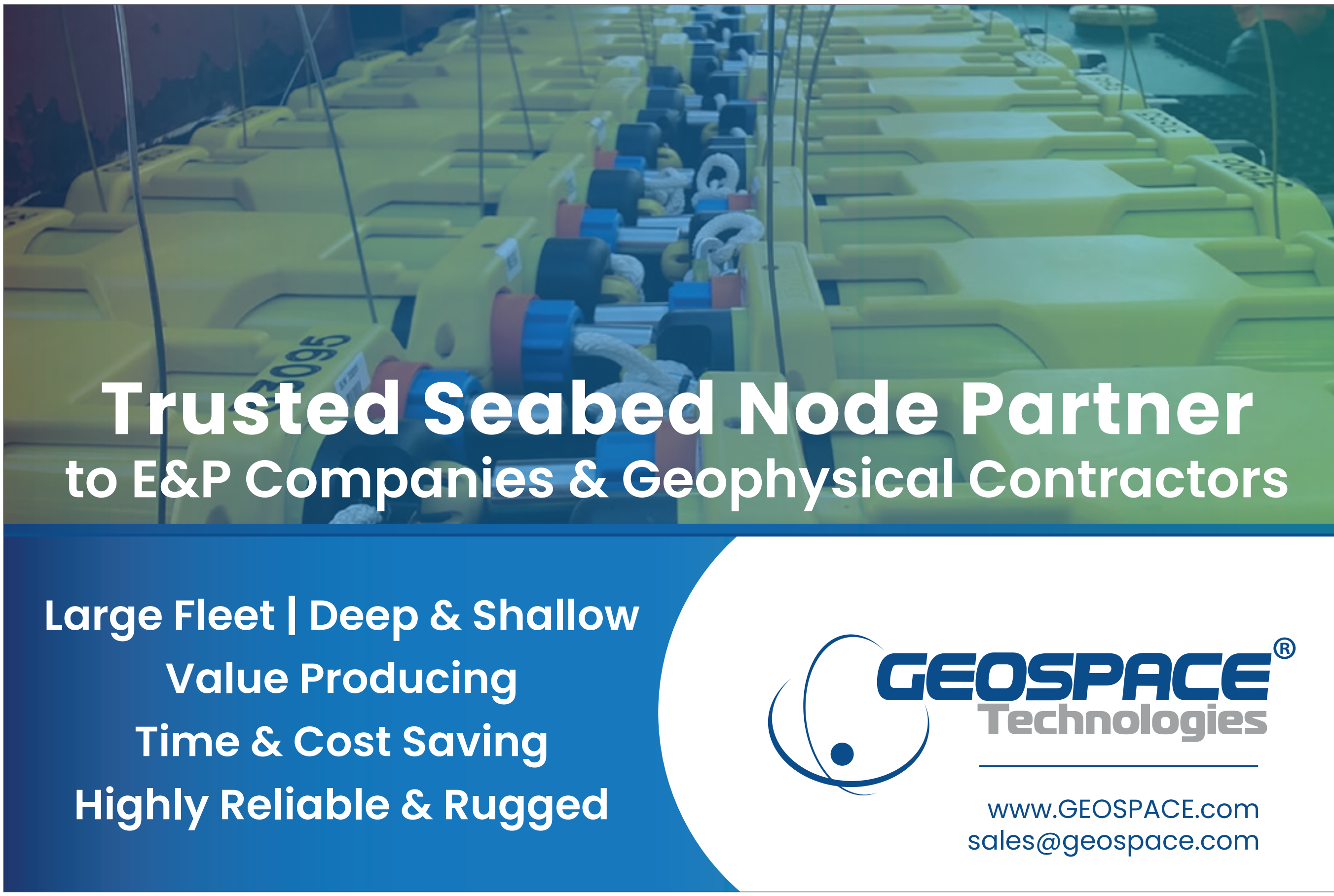


Figure 6: Transpressional deformation along the Sagaing fault plate boundary in Myanmar has produced a fold and thrust belt with untested oil and gas opportunities. These two highly generalized interpretations show the same cross-sectional line of the Salin sub-basin, CBD. Both interpretations show the CBD with a fold and thrust belt structural style. The upper cross section shows untested oil and gas potential in the inferred triangle zone structures (TZ) along the deformed margins of the CBD. The lower cross section is a more resource-conservative interpretation of the fold belt (Pivnik et al.,1988). The location of the cross sections is shown in Figure 4, vertical=horizontal scale and in meters, MSL = mean sea level.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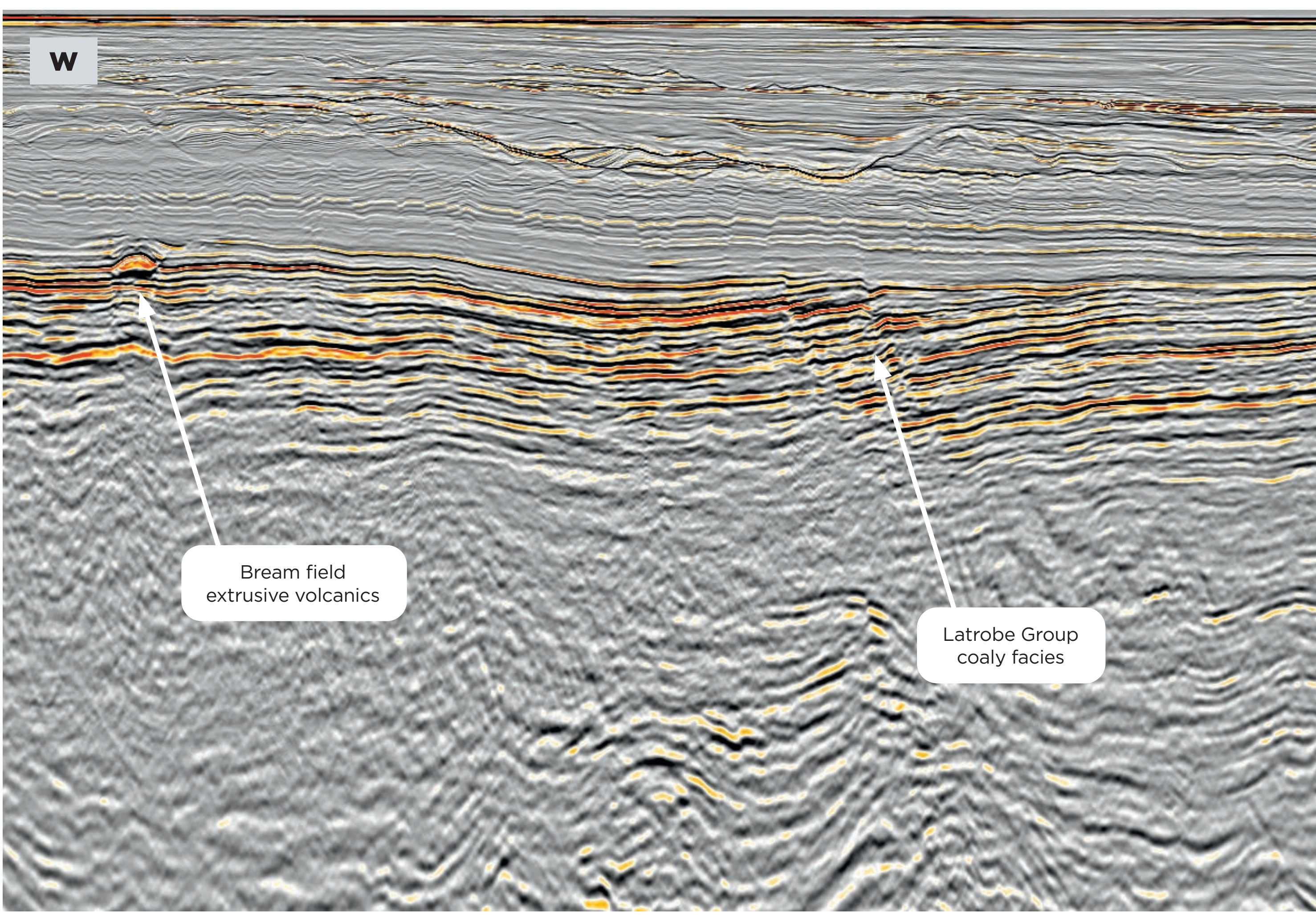
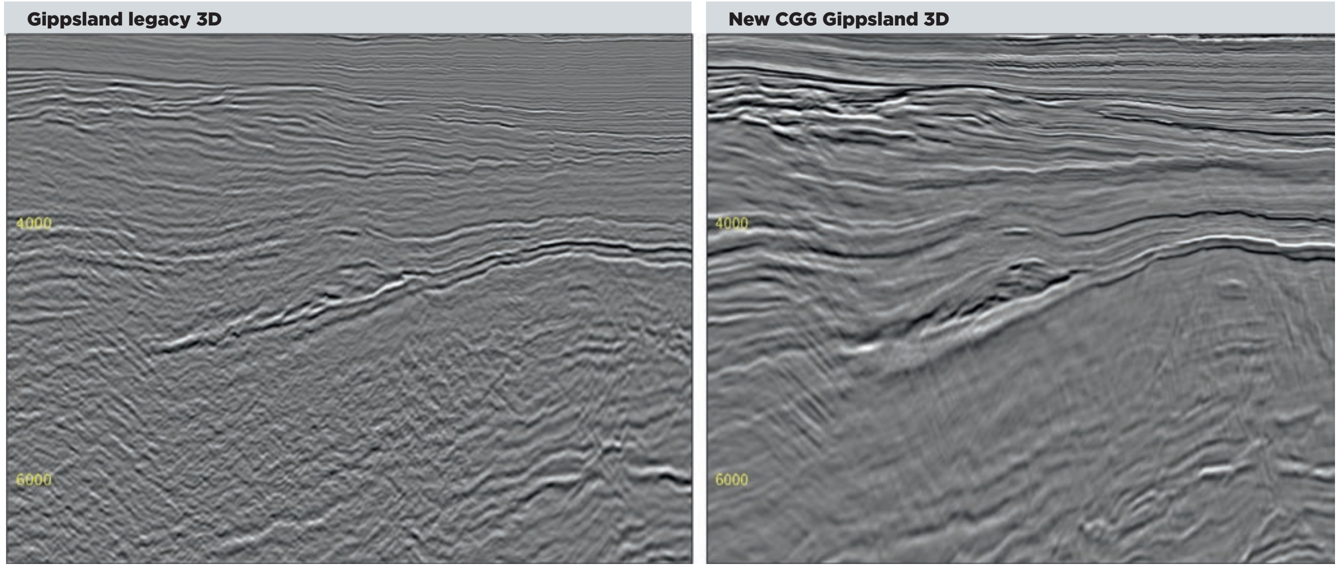
Gippsland Basin, Australia: New Data Provides Compelling Insights in Unexplored Areas

CGG has undertaken a multi-phase, multi-year data enhancement and acquisition project, commencing with a major basin-scale reprocessing initiative and culminating in the completion of a new 3D acquisition and imaging project.

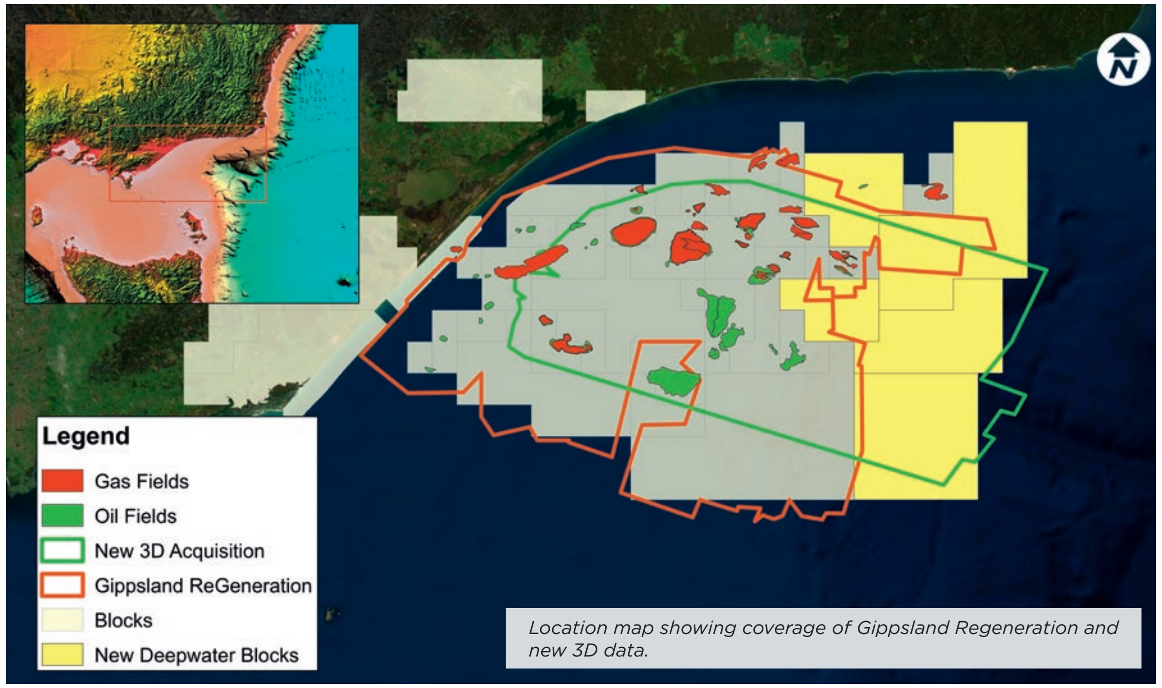
The new survey has provided expanded data coverage from the inboard shallow water areas, throughout the Central Deep, and into the previously unexplored deep-water areas. Preliminary interpretation of the final data processed with CGG's latest proprietary imaging technology has yielded several key insights which further enhance understanding of paleo-depositional environments and prospectivity of the deep-water areas.

The new data is already unlocking previously unseen depositional elements, with strong implications for petroleum system understanding.

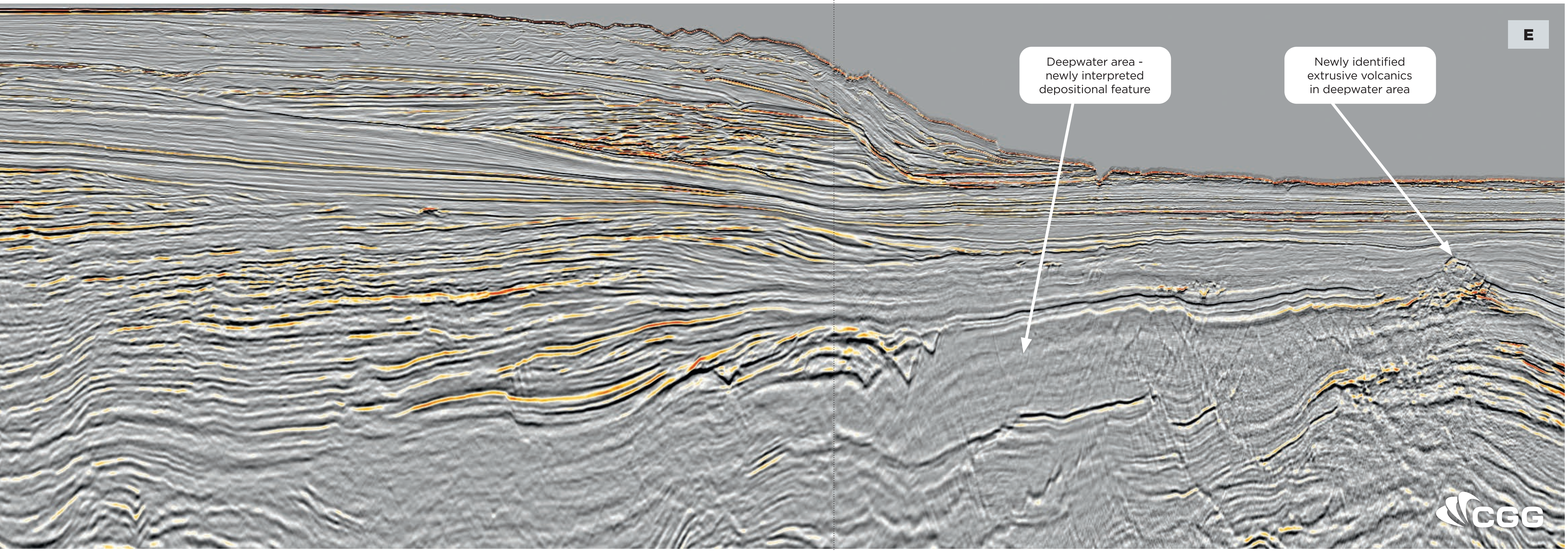




Gippsland legacy data comparison with CGG's newly acquired and imaged 3D data. Example from deep-water area demonstrates significant uplift with longer cable lengths, utilizing P/Z components and the latest proprietary imaging technologies.



Location map showing coverage of Gippsland Regeneration and new 3D data.



Gippsland Basin - Enhanced Understanding Unlocks New Deepwater Opportunities

A new high-quality 3D data set imaged with the latest technologies reveals previously unseen depositional elements, with strong implications for petroleum system presence.

Text: Jarrad Grahame, CGG

The **Gippsland Basin** is Australia's premier oil-producing basin covering approximately 46,000 km^2, primarily **offshore Victoria**. Over the past four years, CGG has undertaken a multi-phase data enhancement and acquisition project, commencing with a major basin-scale reprocessing initiative, and culminating in the completion of a new 3D acquisition and imaging project.

The Gippsland **ReGeneration reprocessing project,** undertaken in 2018, demonstrated the enhanced potential for new CGG imaging technologies to generate important new insights, particularly throughout underexplored areas beyond the present-day shelf break.

These insights highlighted the need for new and expanded data coverage beyond the existing shallow water exploration areas. Correspondingly, CGG developed the new expanded 3D seismic acquisition project. This multi-client survey was acquired in 2020 and final data processing, with CGG's latest proprietary imaging technologies, reached completion in 2021.

The new survey has provided expanded data coverage from the inboard shallow water areas, through the **Central Deep**, and into the previously unexplored deep-water areas. Preliminary interpretation of the final processed data has yielded key insights that further enhance the understanding of petroleum system elements and the prospectivity of the deep-water areas.

GIPPSLAND BASIN GEOLOGICAL SETTING

The Gippsland Basin is part of a series of west-east trending southern margin basins, including the **Bass and Otway Basins** that formed contemporaneously throughout multiple rift and drift phases (Tosolini et al, 1999).

The first of the main rift phases was associated with the **Early Cretaceous** continental breakup of Australia and Antarctica. This was followed by the opening of the **Tasman Sea** along a NNE-SSW axis during the Late Cretaceous (Yang et al, 2019). An episode of compression occurred during the **Early Eocene** to **Early Miocene**, as a result of the convergence of the Australian and Southeast Asian plates, and seafloor spreading within the Southern Ocean (Power et al, 2001).

The main stratigraphic subdivisions of the basin are the early rift **Strzelecki Group**, the Late Cretaceous to Oligocene **Latrobe Group**, and the Oligocene to Miocene **Seaspray Group**. The Latrobe Group has historically been the primary exploration target and represents the main exploration focus within the offshore areas (Bernecker et al, 2001). The Latrobe Formation reservoir targets have been charged primarily by coal-derived source rocks, deposited in upper coastal plain settings (Bishop, 2000).

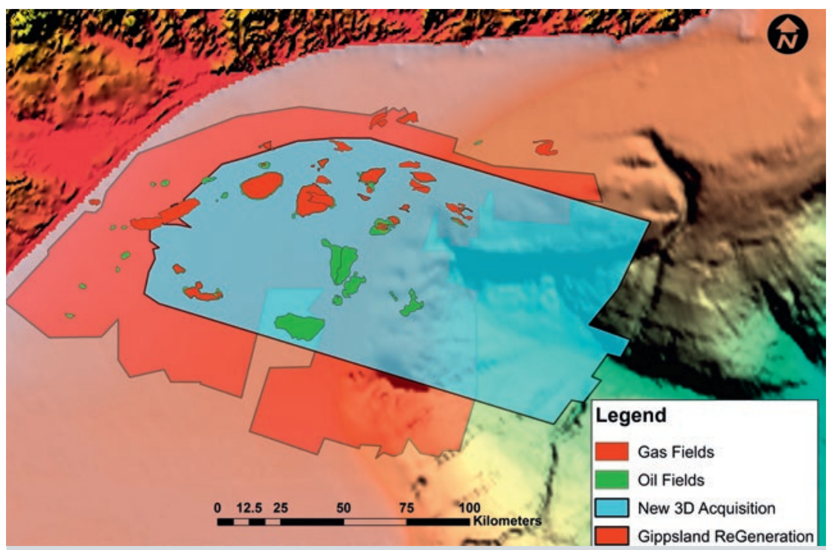


Figure 1: Gippsland Basin – ReGeneration reprocessing (red) and new 3D acquisition coverage (blue).

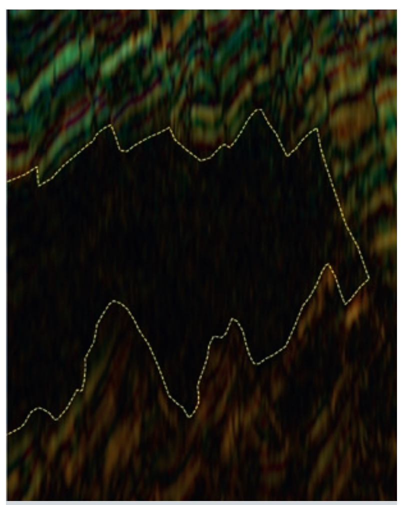


Figure 2: Spectral decomposition - North-South line through the deep-water area – Intra-Latrobe Group depositional feature.

RE-IMAGING THE GIPPSLAND BASIN

For CGG's initial ReGeneration reprocessing project, several key technologies were applied to the pre-existing 16 vintages of 3D data. These included 3D joint source and receiver deghosting, the latest full-waveform inversion and least-squares Q pre-stack depth migration (QPSDM).

The resulting uplift in data quality achieved for ReGeneration was pivotal for enhancing interpretation capabilities and generating new insights, in particular for the deep water. These insights led to the development of the new 3D acquisition project, which further leveraged the ReGeneration data results for the optimization of velocity model building, filling areas without data coverage, and as an additional azimuth for the final stack.

To further enhance interpretation capabilities of the data, the new multi-client 3D survey was acquired utilising P/Z components, longer cable lengths, and the latest imaging technologies. These included time-lag full-waveform inversion (TLFWI) with 15-Hz maximum frequency, 3D P-Z joint de-ghosting and de-signature, 3D interbed multiple attenuation, Q tomography, and Least-Squares QPSDM dual-azimuth optimized stack.

The new imaging flow generated significant benefits for the Gippsland Basin data, including:

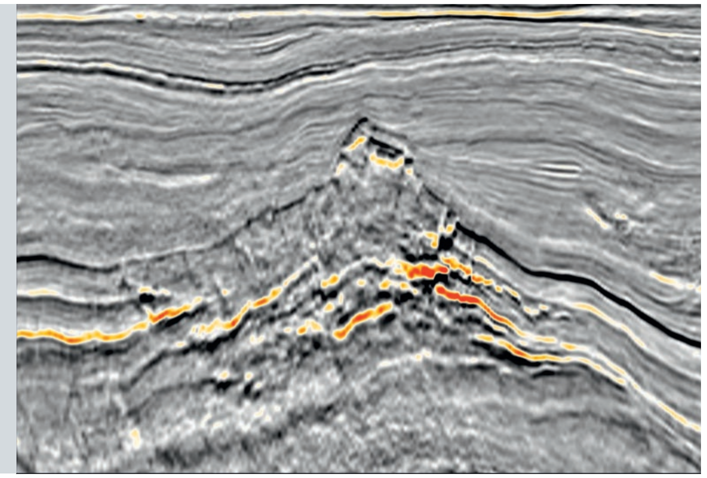
- High-resolution velocity and well-tie across the whole survey
- High signal-to-noise ratio and coherency of events, from shallow overburden, to deeper, sub-carbonate successions
- A sharper image from the shallow-water to new deep-water coverage areas throughout the Gippsland Basin.

NEW 3D DATA – INSIGHTS & OPPORTUNITIES

For both the ReGeneration and new 3D volumes, CGG undertook interpretation, both throughout and after completion of the processing sequence. The main objectives were to assist with velocity model building and develop a framework for detailed interpretation of the final processed data.

The resulting interpretation of the ReGeneration volumes provided a strong foundation for preliminary interpretation of the newly acquired 3D data, particularly for the expanded deep-water coverage.

Figure 3: Previously unseen extrusive volcanics, located in the present-day deep-water area of the Gippsland Basin. This has implications for early rift depositional environments.



This provided a unique opportunity to test and expand upon pre-existing insights and develop new concepts for prospectivity. These included an enhanced structural understanding and identification of previously unknown, or poorly understood, depositional systems and features.

One of the key interpretation techniques applied to both the ReGeneration and new 3D volumes was the generation and analysis of seismic attribute volumes, including spectral decomposition and amplitude attribute volumes. The following examples demonstrate some of the interpretation capabilities and opportunities made possible by the new data.

The example in Figure 2 is a spectral decomposition colour-blend image generated using a third-party interpretation software. The example highlights a newly observed, thick depositional feature, with distinctly different seismic characteristics to the overlying and underlying successions. This contrasting lack of internal reflectivity is consistent with massive, very fine-grained depositional facies, such as shale or mudstone.

The feature identified and mapped within the deep-water area is located immediately below the Longtom Unconformity which separates the Late Cretaceous Golden Beach and Emperor Sub-groups. The distinguishing seismic characteristics and stratigraphic level of this feature suggest a possible correlation with early rift, intra-cratonic lacustrine shale deposition (Emperor Sub-group Kipper Shale), or a marine shale time-equivalent. These lacustrine shales typically have high levels of organic, terrestrial input and have been identified as widespread with good source rock potential in other parts of the basin.

Importantly, this feature could not be mapped to its full extent with pre-existing data quality and coverage beyond the present-day shelf break. This demonstrates potential within the present-day, deep-water areas of the basin for widespread deposition of source rock facies within early rift, intra-cratonic depocenters.

Another key example of newly identified features within the deep-water areas can be seen in Figure 3. It is also highlighted on the main foldout seismic line. This example shows an extrusive volcanic edifice that was never seen before, interpreted as a well-preserved cinder cone within the present-day deep-water area.

While extrusive volcanics are not typically associated with petroleum system elements, the presence of this feature in association and potentially coeval with the interpreted shale body, strongly validates the proposed depositional environment concepts.

These new insights have only been made possible through the acquisition of expanded 3D data coverage and the application of the latest, advanced processing techniques. The features observed and discussed herein highlight the presence of previously unknown or poorly understood depositional systems in the deep water, and advance our understanding of the distribution and interplay of these elements.

While the full exploration potential of the deep-water Gippsland Basin is yet to be revealed, the new data is already unlocking previously unseen depositional elements, with strong implications for petroleum system presence.

ACKNOWLEDGEMENTS

The author wishes to thank CGG Subsurface Imaging for their significant contribution to these results.

"All the Beautiful Domes": Oil in Indonesia, 1871-1949

Royal Dutch Shell owed its origins to Indonesia, formerly known as the Dutch East Indies. Comprising over 17,000 islands, including Sumatra, Sulawesi, Java, and parts of Borneo (Kalimantan) and New Guinea, Indonesia has a long history of oil exploration and development.

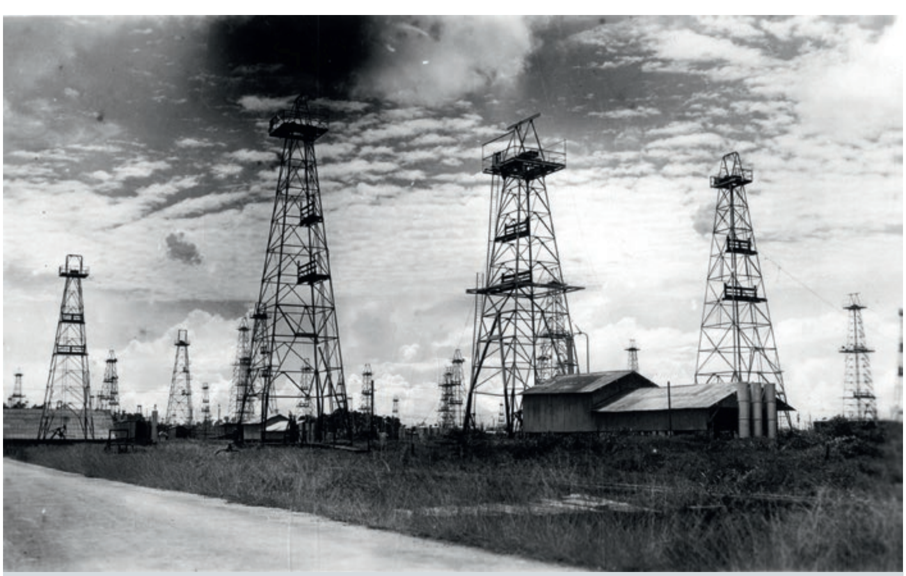
Text: Quentin Morton

On 21 January 2022, Shell officially dropped 'Royal Dutch' from its title, following plans to move its headquarters from The Hague to London. It was the end of an era, since the combination of the Royal Dutch and Shell Transport and Trading Company in 1907 had triggered the birth of the global oil company we recognise as Shell Plc today.

Source: Tropen Museum

The Royal Dutch Shell dock on Tarakan Island, Kalimantan, c. 1925.

Source: University of Leiden



Oil derricks on Tarakan Island, c. 1940.

THE DUTCH EAST INDIES

In medieval times, the sight of oil-soaked fireballs raining from the sky as Acehnese fishermen bombarded their enemies was an early indication of the region's petroleum resources. The modern story of Indonesian oil began in a less dramatic fashion, however, when the Dutch Indies government drilled a modest well in West Java in 1871. The existence of oil seepages and shallow pits was well known by then, and it fell to a 20-year-old tobacco planter named Aeilko Jans Zijklert to start the first commercial venture, a drilling operation powered by mules, in North West Sumatra in 1885. He subsequently struck oil at Telaga Tunggal I in Langkat. This find, together with the discovery of other oil seepages elsewhere in Sumatra, Java and Kalimantan, indicated the region's petroleum potential.

The death of Zijklert of a tropical disease in 1890 paved the way for the "Royal Dutch Company for the Working of Petroleum Wells in the Dutch-Indies" to continue the development of the Telaga field and build an oil shipping harbour nearby. Despite early disappointments, the new company broadened its scope, constructed a refinery and, in 1898, employed a team of European geologists to survey the wider region.

It seems that the inclusion of 'Dutch' in the company's title was a slip of the pen by the Dutch King's secretary in signing the company's royal warrant, rather than a deliberate attempt to bestow nationalistic qualities on the new company. However, its colonial associations were plain enough. The Dutch had established trading posts in Indonesia from the seventeenth century and these came under the rule of the Dutch government in 1800. The area was known to Europeans as the Dutch East Indies and, by 1900, only companies registered in the Netherlands were allowed to operate in there. British commercial interests were represented by the Shell Transport and Trading Company, among others.

The merger of Royal Dutch and Shell is a story in itself, and has the Rothschild Bank of Paris at its heart. Rothschild engaged Samuel & Co headed by Marcus Samuel to transport their shipments of kerosene from its Caspian oilfields for use as lamp oil in the Far East. Samuel formed the Shell Transport and Trading Company and revolutionized oil transport with a fleet of specially designed ships to carry crude through the Suez Canal; the Murex was the first oil tanker to pass through the canal. Shell also obtained an oil exploration permit for Sangasanga in Eastern Borneo (Kalimantan). Royal Dutch struck its first oil in 1892, shortly before the first consignment of Russian oil arrived in Singapore. Headed by the volatile Henri Deterding, who was determined that his company should rival Rockefeller's Standard Oil, Royal Dutch soon became a major supplier of kerosene to the Asian market. In 1893, after obtaining the rights to explore Sangasanga, Shell built a refinery at Balikpapan.

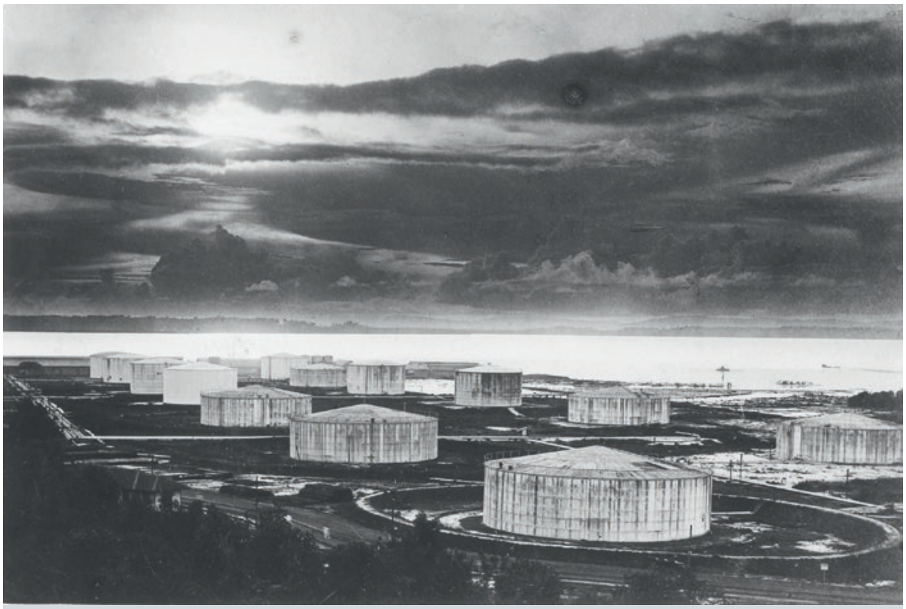
Shell's shipping interests in the Far East brought it into contact with Royal Dutch, and merging was a logical move. As Royal Dutch's main strength lay in oil production and Shell's expertise was transport, it would bring together two companies with different but complementary strengths. Indeed, it laid the foundations for the global oil company that became known as Royal Dutch Shell. The following decades saw an impressive phase of worldwide exploration, taking in countries as far afield as Egypt, Romania, Russia, Venezuela, Mexico and the United States.

Shell never forgot its roots, and its distinctive logo – a scallop shell – referencing the time when importing seashells to Europe from the Far East was an important part of its progenitor's import-export business. The Bataafsche Petroleum Maatschappij (the Batavian Oil Company or BPM for short) was Royal Dutch and Shell's vehicle for exploring and developing the oil resources of Indonesia with the two companies owning shares in a 60/40 split.

THE RIVALS

Exploration geologists faced many challenges in the jungles of Indonesia. One tried and trusted method of field work was to follow stream courses inland and examine exposed outcrops along the way. In those areas where oil seepages or favorable structures were present, a track was hacked through the undergrowth and pits were dug to a depth of 15 to 25 feet so that the geologist could clamber down and determine the dip and strike of the strata. Local labourers were employed for this purpose, supervised by young Dutchmen who had grown up in the Indies and were fluent in their language. Dr. Hans Cloos, a German geologist employed to examine concessions in the area, described his frustration at working in the conditions, noting that **'all the beautiful, rounded, layered domes which we discovered in Java and Borneo turned out to belong to competitors!'**

The producing wells were near the Chinese kerosene market, which was most useful when lamp oil was in high demand. The fact that oil from Sumatra was low in sulphur was a boon so far as refining was concerned but, with the advent of the motor car, Indonesian oil was not particularly advantageous because of the presence of aromatics, especially gum. It was only later, in the 1920s, that the value of aromatics in preventing 'knocking' in petrol engines was recognised.



Source: University of Leiden

Oil storage tanks in Balikpapan, Kalimantan, c. 1910.

ource: Alamy

Henri Deterding.

ource: Alamy

Sir Marcus Samuel .

Source: Tropen Museum

Socony petrol station Dutch East Indies.

Moeara Enim, but this broke down after the Dutch minister of colonies questioned the renewal of their five-year concession.

Underlying these events was an anti-Standard sentiment and a desire to keep foreign investment out of the colony. Without US government backing, Standard was destined to support its markets in the Far East from oilfields much farther afield. By 1912, Royal Dutch Shell had virtually secured a monopoly of the Indonesian oilfields when it acquired its last real competitor, the Dordtsche Petroleum Company. By 1920 it controlled about 95 percent of crude oil production and operated oilfields in Borneo, Java and Sumatra, and the Plaju refinery in south Sumatra, which at one time was the largest refinery in South-East Asia.

To comply with the requirement that all companies operating in Indonesia should be registered in the Netherlands, Jersey Standard set up the Dutch-registered and managed NKPM (Nederlandsche Koloniale Petroleum Maatschappij) with its headquarters in The Hague. NKPM applied for an oil concession for the promising Djambi field in central Sumatra, but Royal Dutch Shell intervened and made a higher offer, and then the Dutch authorities suspended all mining operations. For the next five years, NKPM was effectively barred from exploring and drilling for oil. A new Dutch mining law was passed in 1917 which gave the government at least half a share of future oil concessions and enabled it to take over a promising area upon the prospecting company being reimbursed for their expenses.

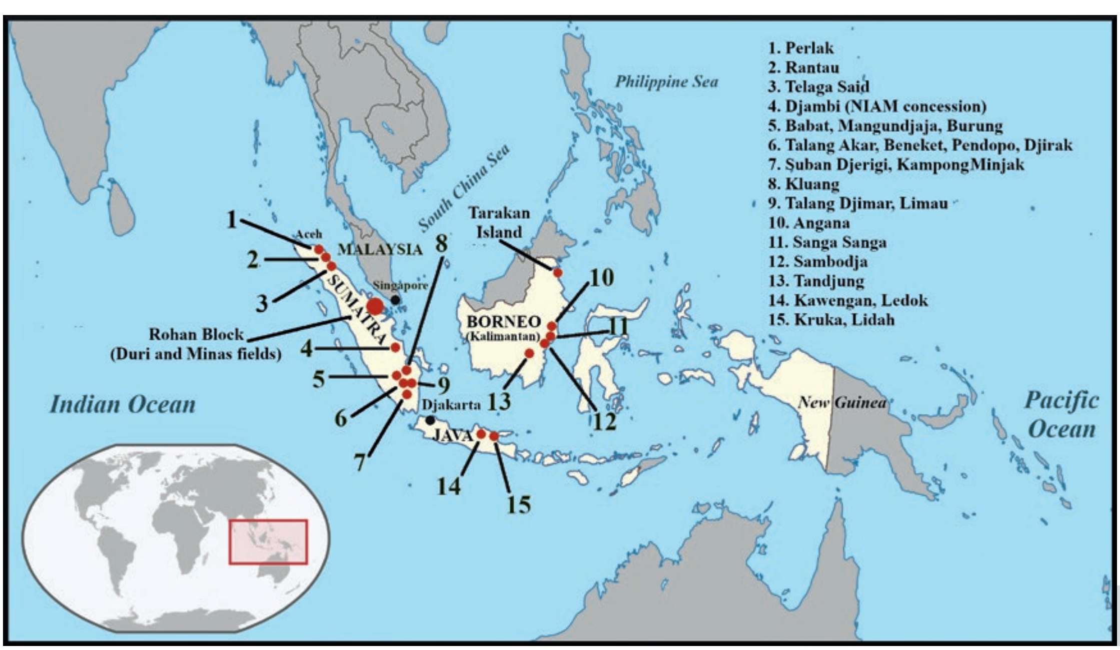
A MONOPOLY

Since Indonesia became one of the largest producers of high-quality crude oil outside the United States, it was inevitable that it should attract the interest of international oil companies, particularly those from the United States. Standard Oil's interest began in the days when AJ Zijklert was making a name for himself in the Sumatran jungle. But progress was slow – the US State Department was reluctant to become involved in the commercial activities of US companies abroad with the result that Standard was left to fend for itself in its dealings with the Dutch authorities. To meet the requirements of Dutch law, Standard formed a partnership with

OIL RUNNING OUT?

In 1919, the US Geological Survey estimated that oil supplies would run out in ten years, bringing an oil scare to Washington and a new determination to seek foreign oil concessions which was fanned by a perception that American firms were not receiving equal treatment abroad. In 1920 the Mineral Leasing Act was passed to allow the US government to withdraw the mining rights of foreign companies on home

Modified from Wikipedia Commons



Indonesian oilfields discovered pre-1945.

soil if their governments did not allow reciprocal rights to US firms. This was the start of the so-called 'Open Door' policy, which represented a push by the US government and firms to gain equal access to commercial opportunities abroad.

In 1921 BPM went into partnership with the Dutch East Indies government and set up Nederlands Indische Aardolie Maatschappij (NIAM) to operate the oilfields around Djambi. In the same year, NKPM discovered oil in the Pendopo/Talang Akar field in South Sumatra, and new discoveries followed. The company built a new refinery and changed its name to the Standard-Vacuum Petroleum Maatschappij or SVPM. In 1934 the company obtained its first concession for central Sumatra and went on to strike oil at several locations.

Celebrations after the first transfer of oil from Pendopo/Talang Akar to the refinery at Palembang, Sumatra, 1947.

Source: Nationaal Archief

A late arrival on the scene was the California Texas Oil Company (Caltex) which, as its name suggests, was a merger between Standard Oil of California and the Texas Company. In 1930, Caltex established NPPM (Nederlandsche Pacific Petroleum Maatschappij), also registered in the Netherlands and headquartered in The Hague. Caltex soon struck oil in Central Sumatra and in 1941 discovered the Duri oilfield at a depth of 400 feet. Operations were interrupted by World War II and production did not commence until February 1954. The oilfield measures 10 km by 18 km and is part of the productive Rokan block, which includes the giant Minas field discovered in 1944. The Duri and Minas fields became Indonesia's most productive fields in the post-war years.

THE END OF THE COLONIAL ERA

By 1938, production had reached 7.4 million tons, all processed by local refineries. But success brought danger. For many years, Dutch officials had suspected that the Japanese coveted the Indonesian oilfields; in fact this was often cited as one of their reasons for excluding foreign oil companies from the area. When war broke out, the oilfields were a primary target for the Japanese, who lacked their own sources of crude and needed vast quantities of petroleum to fuel their war effort. As Japanese forces invaded the Dutch Indies from February 1942, the oil companies set about destroying their installations, but this was only partially successful. Nevertheless, oil production under Japanese control never achieved the same level as during the pre-war years. The Balikpapan refinery, which the Japanese used to supply their navy, was bombed by the Allies, together with other targets. The result was that, by 1945, production had dropped to 845,000 tons.

At the end of the war, nationalist leader Sukarno returned to Indonesia from internal exile and declared independence on 17 August 1945, three days after news broke of the Japanese surrender to the Allies, but it was not until 1949 that the Dutch recognised Indonesian sovereignty. The post-war years were characterized by a drive for economic independence and the activities of the state-owned oil company, nowadays known as Pertamina. Nevertheless, ExxonMobil and Chevron (the successor to Caltex) still maintain a presence in the country, being among its main oil producers – Shell withdrew in 1965. In more recent years, declining output has seen Indonesia, which was once among the leading oil producers, dropping to the rank of 25th in the world.

Acknowledgement: many thanks to Peter Morton for his kind assistance. ■

Illuminating the Complex Geology of the UK Faroe Shetland Basin

Through the integration of legacy seismic data, PGS' Faroe Shetland Basin Vision product assists companies in their UK 33rd Round applications.

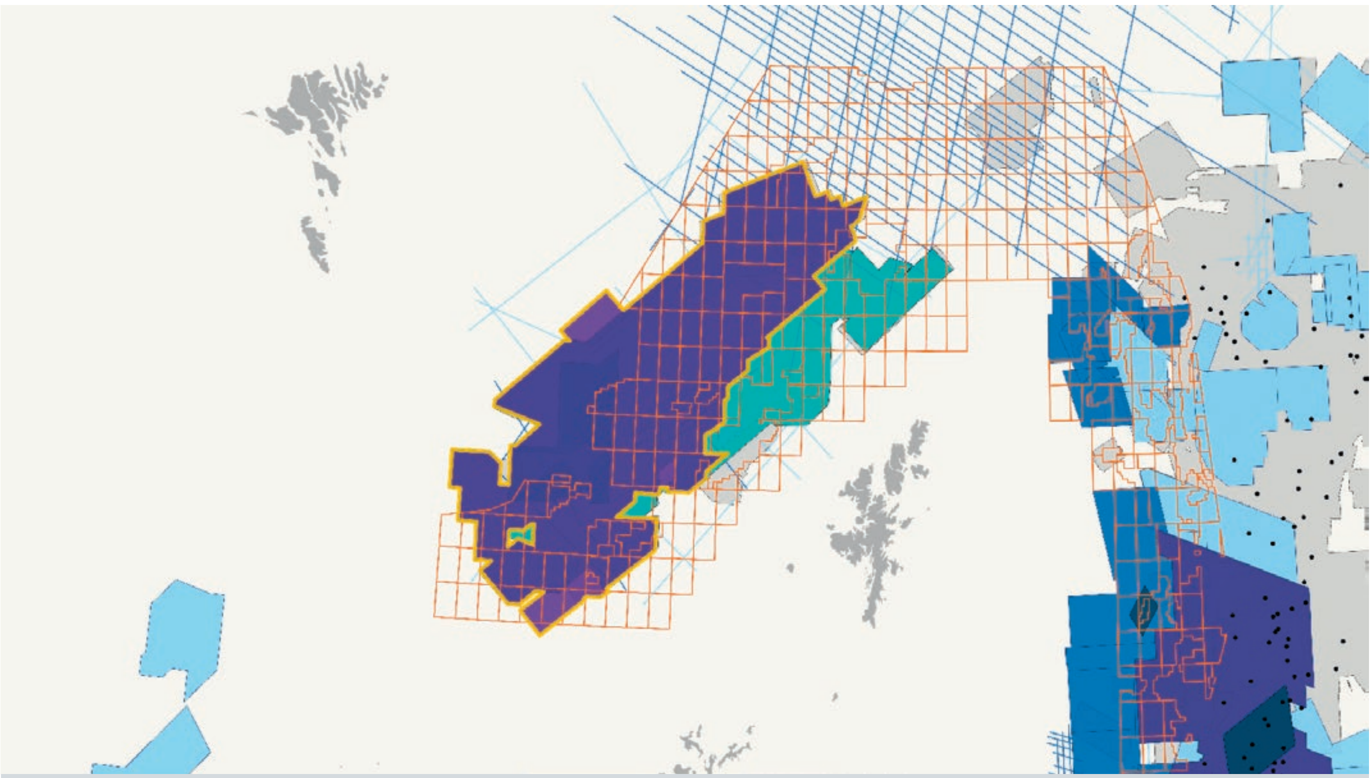


Figure 1: FSB Vision (yellow outline) with UK 33rd Licensing Round blocks overlaid in orange.

Text: Antonio Castiello, Gareth Venfield, Jens Beenfeldt, PGS

In the current economic climate, reprocessing of legacy data can provide an attractive tool for exploration, infrastructure-led exploration (ILX) and even for production. In combination with state-of-the-art processing flows, legacy datasets may be revitalized to produce high quality imaging products, which may be used for field identification, planning and development. The new **FSB Vision product** (Figure 1) is a powerful tool for operators to use in preparation for the **UK 33rd Licensing Round**, as well as for work programs after the award.

The benefits of reprocessing a large number of legacy surveys on a regional scale using an advanced processing sequence is presented here. The data, taken from the **Faroe-Shetland Basin** (FSB), West of Shetland, UK, comprises several input surveys covering over 24 000 sq. km, reprocessed through four phases, to provide a single, high quality and seamless regional dataset. The vintages of the surveys and their acquisition parameters vary greatly, with differing numbers and lengths of streamers, both single component and multi-sensor data, as well as various acquisition azimuths.

The FSB is known for having large lateral and vertical velocity gradients due to shallow injectites, alluvial deposits and intrusive and extrusive volcanics. As a result, high-end and robust velocity model building (VMB) is required to capture these variations and image them precisely. The VMB employed in this project is a combination of high-resolution Full Waveform Inversion (FWI) and reflection tomography, constrained by both geological interpretation and well data. We demonstrate the results of this integrated model building scheme from the initial phases of reprocessing.

THE GEOLOGICAL HISTORY SUGGESTS MULTIPLE TARGET POSSIBILITIES

The FSB is a NW-SE orientated deep-water rift basin, consisting of several ridges and sub-basins, located between the Faroe and Shetland islands on the north-western European Atlantic margin. The basin has a long and complex tectonic history and has experienced several periods of rifting in Permian-Triassic, Jurassic, Cretaceous and Paleocene, followed by thermal subsidence.

The basin was subjected to extensive igneous activity associated with the proto-Icelandic plume and seafloor spreading in the North-Atlantic during the Paleocene to Early Eocene. Thick sequences of basaltic lava flows were deposited, along with extensive emplacement of subsurface intrusive sill complexes. The Cenozoic period is signified by post-rift thermal subsidence and minor episodes of rifting, uplift and compressional events. The most promising targets are turbiditic or marine slope fan sandstones of Paleocene-Eocene age, fluvial systems and slope fans of Jurassic-Early Cretaceous age and Palaeozoic sandstones around the ridges.

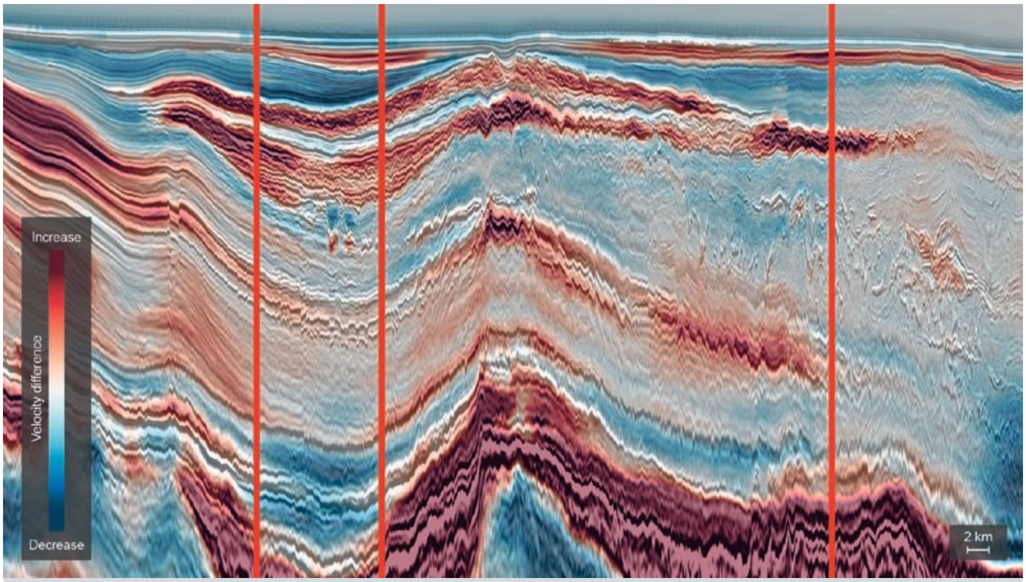


Figure 2: Velocity difference from FWI extracted along a line from which single component and multisensor field data contribute. The section highlights the uniform update, despite the differences in acquisition configurations. Red lines highlight boundaries between different surveys that have jointly contributed to the FWI inversion.

COMPENSATING FOR DIFFERENT ACQUISITION CONFIGURATIONS

To date, 23 (of the 38) legacy streamer surveys have been processed and incorporated into the study. These include multi-sensor and conventional data acquired between 1995 and 2013, consisting of variable acquisition parameters including azimuth and streamer number and length (varying between 3 and 8 km).

The water depth over the area varies between 500 – 1500 m, and the overburden is characterized by high-velocity Eocene fan deposits, sand injectites, polygonal faults, turbidite deposits and hydrothermal vents. Intra-volcanic reservoirs are encased in high-contrast flood plain basalts which provide a challenge for tomographic model building. Intermittent periods of volcanic activity produced varying quantities of intrusive complexes, basaltic lava and volcaniclastic material, with a large range of seismic velocities.

Due to the complexity in the overburden and the upper Tertiary (extrusive volcanics), obtaining an accurate high-resolution velocity model is beyond conventional tomographic techniques. As a result, FWI has been used to capture this complexity. We implement a classical multi-scale approach: moving from low to high frequencies and gradually growing the data selection based on the match between the observed and modeled response until most of the data was input to the inversion.

We use a unique imaging condition that separates the tomography from the impedance kernel in order to reduce the traditional dominance of high wavenumbers when reflections are involved in the inversion. As a result, the full wavefield contributed to the cost function and computed gradient, allowing for deeper updates and more consistent coverage, given the streamer numbers and length.

FWI was completed by inverting all surveys simultaneously in several passes to update a common model, progressively increasing the frequency of the update to 12 Hz. The result of this approach is displayed in Figure 2 and shows the velocity perturbations superimposed on the stack.

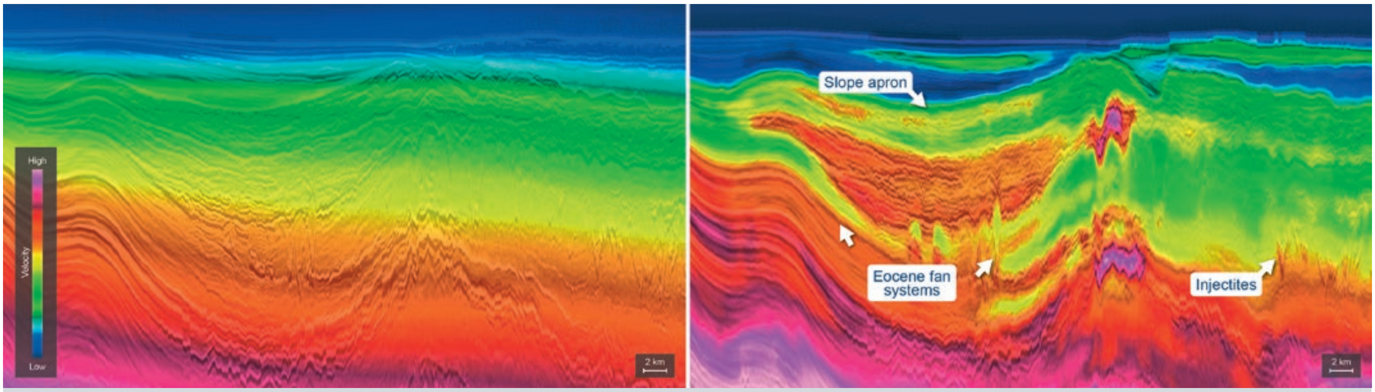


Figure 3: Simple input model to FWI shown (left) and the updated FSB Vision FWI model (right). The resultant model is geologically conformable, resolving the vertical and lateral velocity variation in the image.

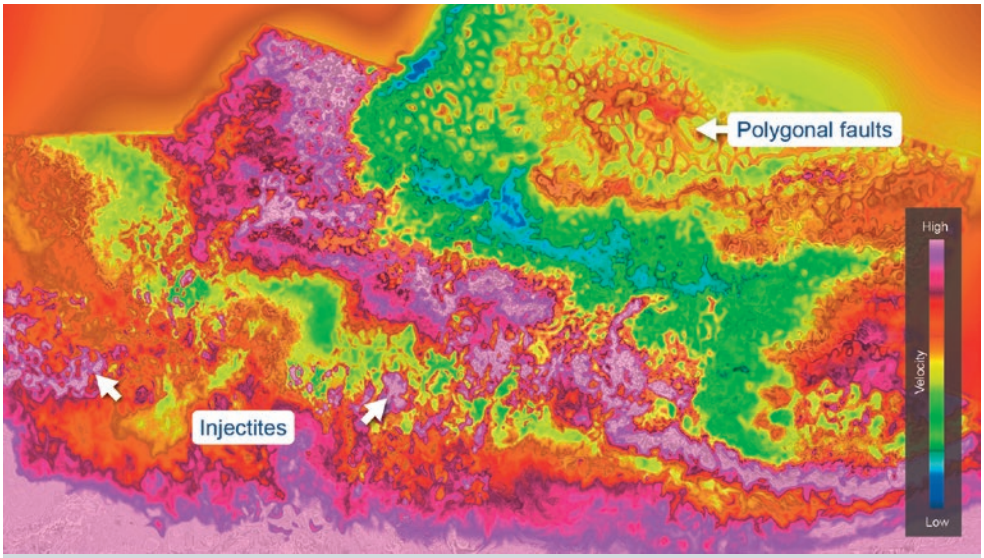


Figure 4: Depth slice taken through the overburden. The final velocity model from FWI is overlain onto the Kirchhoff PSDM stack and highlights the level of resolution achievable enabling a clear image of polygonal faulting and injectites.

This line transects both short offset single-sensor and longer offset multi-sensor data, shot with approximately 45o difference in azimuth. Despite these differences, the section is extremely well balanced, the depth of update is consistent, as is the magnitude within the different geological packages.

Figure 3 shows the long wavelength velocity model input to FWI and the final FWI velocity model. The new model is highly conformable with the geology, capturing the vertical layering present in the overburden and the small-scale features such as injectites. Figure 4 shows a depth slice through the overburden of the velocity model after FWI. It captures the strong lateral velocity variations caused by the polygonal faulting, injectites and alluvial deposits. The resolution is high across the area and there are no apparent survey boundaries, despite the differences in acquisition configurations.

AUTOMATIC PICKING OF GEOBODIES FOR VELOCITY MODEL CONSTRAINT

Following FWI, the model build moved to the Mid-Tertiary and Cretaceous sections. The workflow adopted for the intra-volcanic interval included the automatic picking of the volcanics and intrusions as geobodies. The use of geobodies was suitable as it was fast, accurate and allowed for an iterative picking approach to ensure an optimal result. Following this picking, the geobody volume was sculpted using the regional horizons to remove any errant picks.

The geobody volume, once finalized, was used during the subsequent tomographic updates to constrain the model and allow both a targeted high-resolution velocity variation within the intrusions/volcanics whilst preventing any leakage into the background model. Several iterations of the update were completed and resulted in a geologically conformable model that flattened the gathers and improved the stack response significantly. An example of the updated model is shown in Figure 5. The volcanics have been effectively updated using the geobody picking, they are well-defined with no apparent leakage into the background velocity model.

THE VALUE OF (FSB) VISION

We demonstrated that applying advanced state-of-the-art processing solutions to a large number of vintage surveys results in highly detailed and accurate models that are consistent on a regional scale. We used a robust velocity model building workflow that leverages FWI updates and geologically constrained reflection tomography to resolve the large lateral and vertical velocity variations in the overburden and defined the sharp contrast geobodies in the mid and deeper sections. By doing this, we produced the FSB Vision product that has a highly conformable model with regards to the geology and that is validated by well data. As such, this project provides clear, regional broadband images of the Faroe-Shetland Basin, West of Shetland, ready to be used for UK 33rd Licensing Round assessments and work programs.

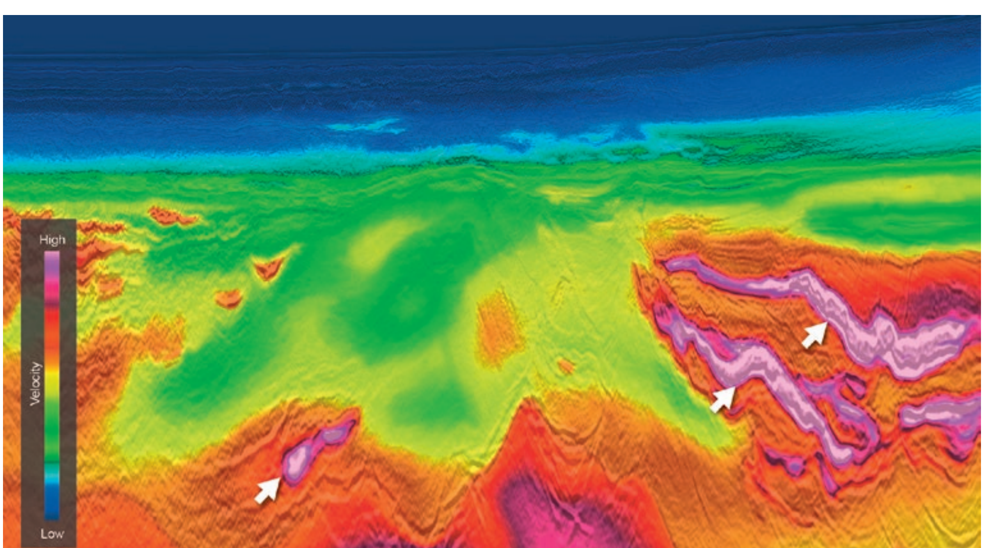


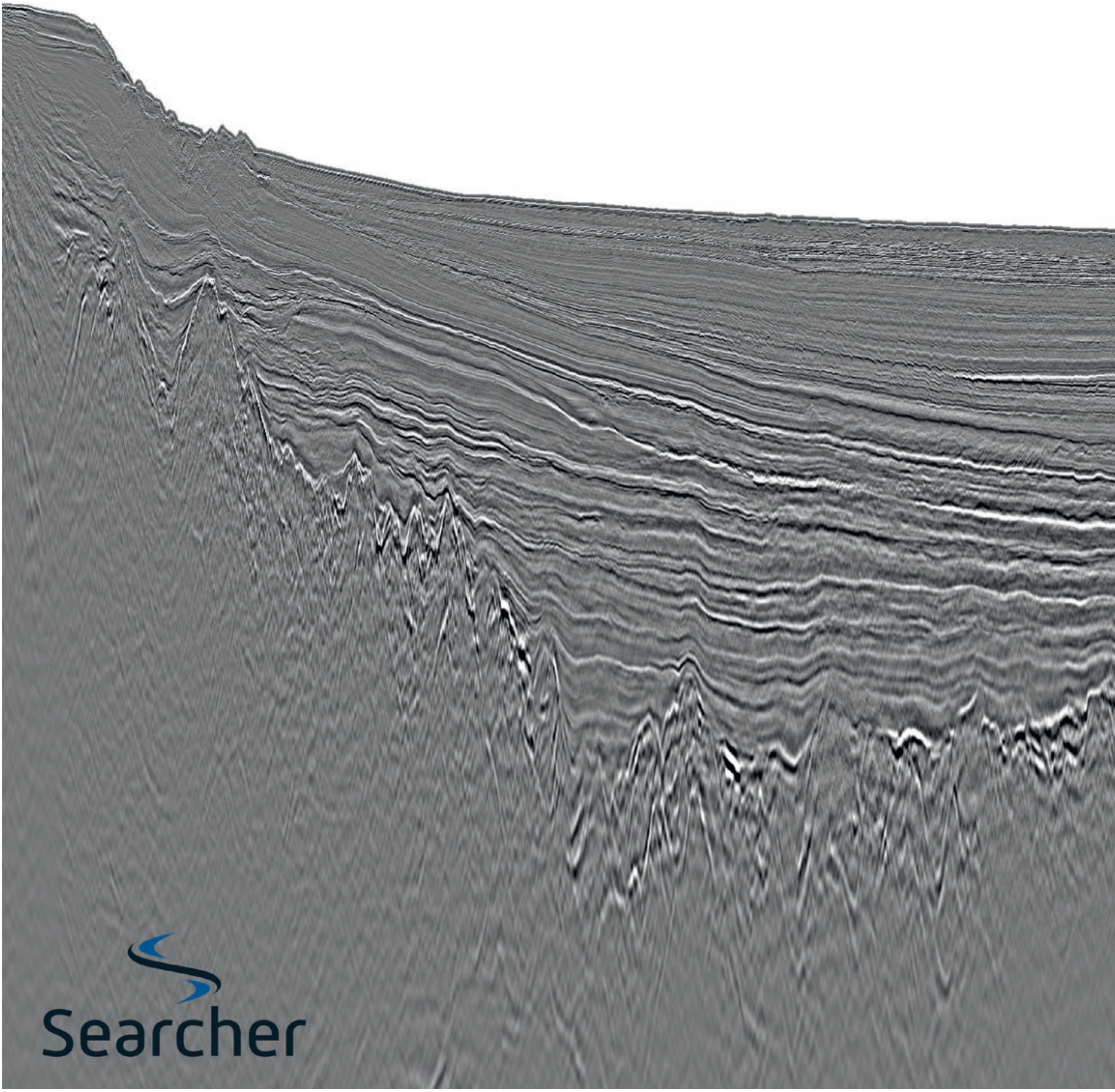
Figure 5: Resultant model from targeted tomographic updates within the volcanics (white arrows) and longer wavelength updates in the complex background model.

ACKNOWLEDGEMENTS

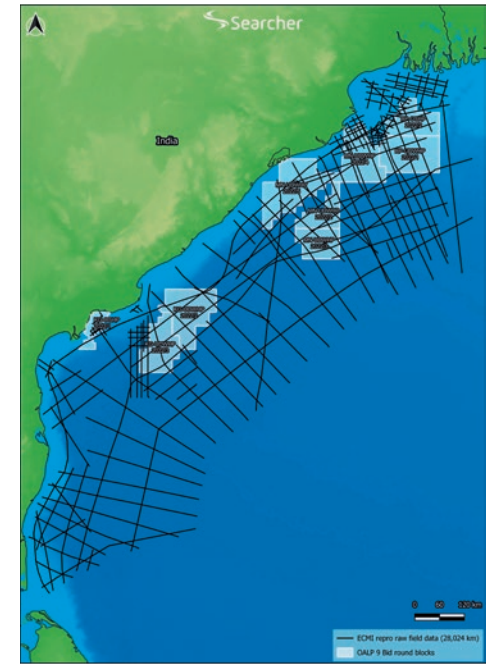
We thank PGS MultiClient for the permission to present this work.

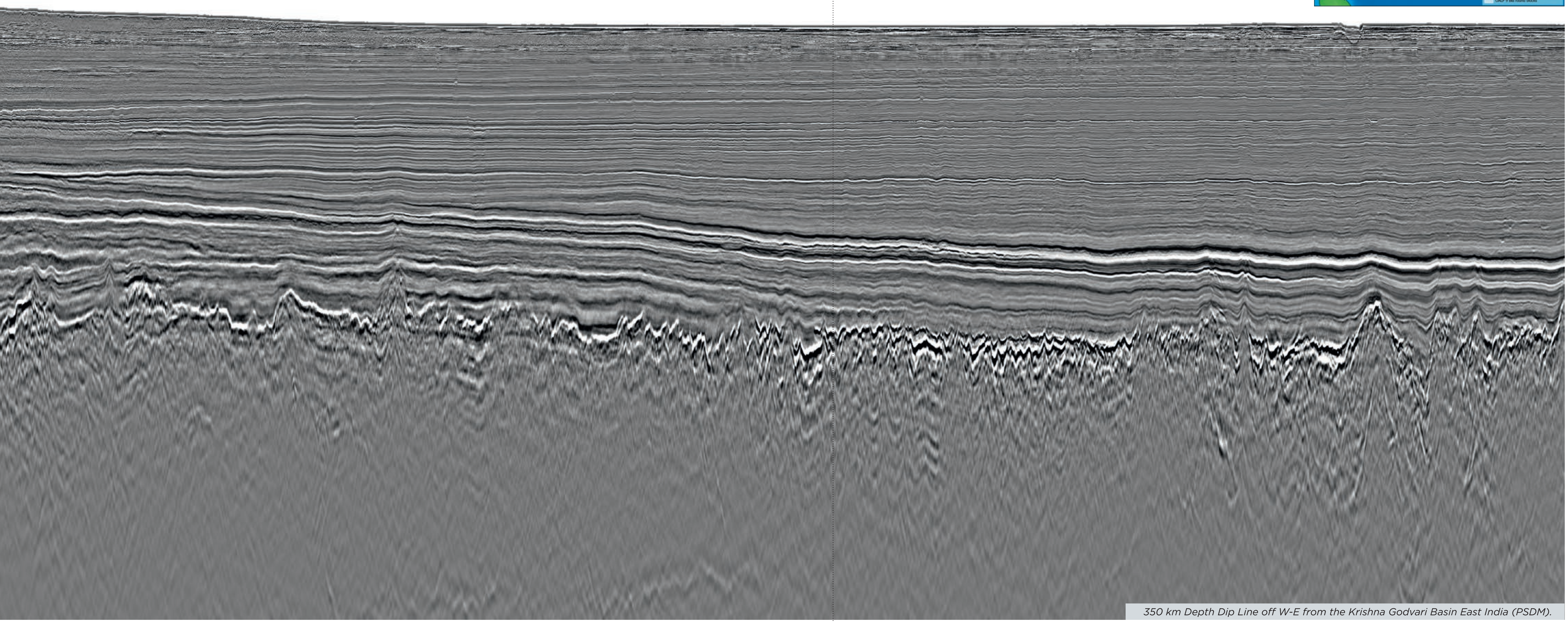
References provided online.

The Gateway to India: OALP-IX Offers Industry Access to East India's Extraordinary Hydrocarbon Basins



Searcher is reprocessing 10,000 km of regional 2D data offshore East India, bringing 2022 processing technology to bear in the hunt for source rock and sedimentology sweet spots. There is a dire need for additional low-carbon energy on the eastern margin of the largest nation (by population), with one of the fastest-growing economies on earth.





350 km Depth Dip Line off W-E from the Krishna Godvari Basin East India (PSDM).

Accessing a Seat at the Low-Carbon Energy Table on India's Eastern Margin

In June 2022, the DGH India announced the OALP Bid Round IX (2022/3) Licence Round which includes 9 blocks East of India in the Krishna Godavari, Mahanadi and Bengal Basins. These blocks cover both shallow and deep water, they are by any standards huge (2,800-14,000 sq km) and largely or completely unexplored.

Text: Neil Hodgson, Peter Hoiles and Karyna Rodriguez; Searcher

Situated close to one of the world's fastest-growing economies, where a population of 1.2 billion is eager for low-carbon energy provided by domestic production, the **OALP Bid Round IX** will certainly draw the attention of investors all around the world. Large commercial oil and gas discoveries and the industry's progression in deep-water drilling records should cause serious interest in accessing acreage in these three basins.

SUCCESS ON THE SHOULDERS OF GIANTS

Success offshore **East India** will be found by standing on the shoulders of previous explorers and looking through a lens of improved seismic data to see further than was previously possible. It starts with a regional play understanding as both the margin and the blocks on offer in OALP-IX are so large.

The path to ensure that the offered acreage is high-graded starts by using a regional seismic dataset to better understand the distribution of source rocks through the analysis of carefully processed gathers. Then, the distribution of reservoirs through de-ghosting data and an assessment of the true nature of plays and traps is carried out.

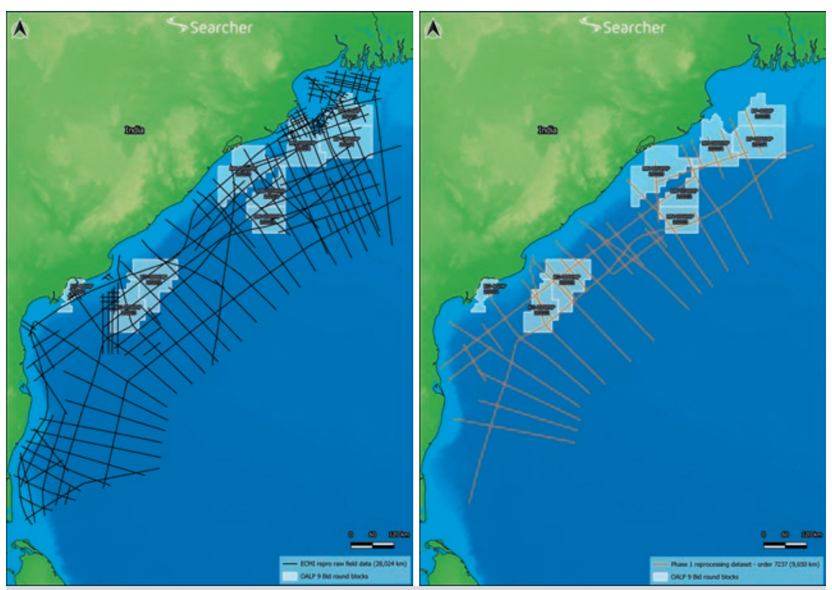


Figure 1: Left: Searcher's 28,000 km sAIsmic rectified regional dataset. Right: Searcher's 10,000 km 2022 reprocessed dataset.

To support the Licence Round, **Searcher** has rectified (post-stack equalization, navigation verification) a large 28,000 km 2D legacy regional dataset across the **Krishna-Godavari**, **Mahanadi** and **Bengal basins**. Based on data acquired between 1995 and 2006, the company also reprocessed a strategically selected regional 10,000 km subset through a modern de-ghosting PSTM sequence (Figure 1 and Foldout line (PSDM)). The regional reprocessed grid is specifically designed to allow high grading of the Licence Blocks on offer in OALP-IX.

SOURCE ROCK GEOLOGY

The **Eastern Margin of India** formed in the Early Cretaceous when a Karoo-fabric-following rift allowed India and Antarctica to separate. **Aptian source rocks** are found in wells drilled on the shelf in syn-rift lacustrine rifted half-grabens. These lacustrine source rocks were inundated at the start of drift by marine incursions, depositing a restricted marine source rock.

In the Seaward Dipping Reflector (SDR) domain in the northern **Mahanadi** and **Bengal basins**, such a "first-flood" source rock was deposited after the first marine transgression had peneplained irregularities off the upper SDR surface. Continuous loading caused by **Ganges** and **Brahmaputra** sediments subsequently created a succession of counter-regional dip geometries of onlapping Upper Cretaceous clastics (Figure 2).

This counter-regional geometry, directly below onlapping pro-delta fans, is similar to the play system

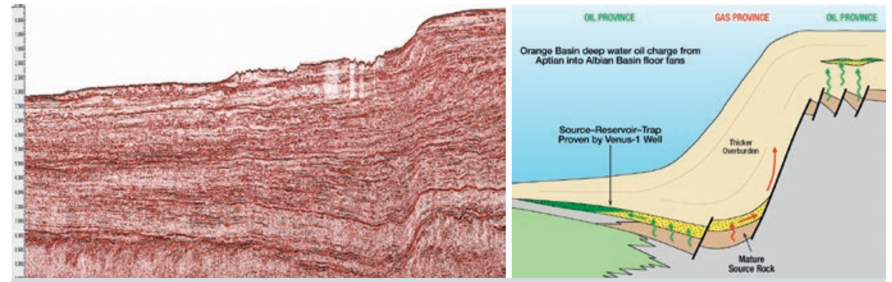


Figure 2: 400 km N-S legacy section from the Bengal basin showing the counter-regional dip play against Seaward Dipping Reflectors (SDR) and multiple soft kicks up-dip onlap within the succeeding Upper Cretaceous section. Reprocessing reveals the extraordinary sedimentology and stratigraphic traps on this line.

recently proven by the **Venus-1** well in **Namibia**. Such plays are low risk because the up-dip pinch-out of sands is a certainty and prospects are typically game-changingly huge. This play is to date untested in East India although it is developed extensively on the Bengal Basin to Mahanadi margin.

To the southwest, in the non-magmatic part of the rift (Nemcok, et. al., 2013), source rocks in syn-rift half grabens and the overlying thick Upper Cretaceous sequence are unexplored as is much of the overlying Tertiary (see Foldout line). Beyond the extended crust on this part of the margin, it is also likely that restricted marine Aptian-Albian source rocks will be encountered, in addition to several Cretaceous and Lower Tertiary global Ocean Anoxic Event (OAE) source rocks (Singh, et al 2022).

Reprocessed lines over the **Krishna Godavari** syn-rift show the potential for a working hydrocarbon system with deeply buried Lower Cretaceous source rocks in extraordinary detail (Figure 3).

The secret to identifying source rocks on seismic, which has been revealed by many global studies that have validated the technique, relies on the presence of seismic intervals that are:

- Soft compared to the underlying and overlying sequences;
- Relatively high-amplitude but lower frequency (see Figure 3) and
- Exhibiting a dramatic reduction in amplitude with offset (a Class IV AVO anomaly).

Developed using the **UKCS Kimmeridge Clay Formation** (Loseth et. al., 2011) and employed in **Namibia's Orange Basin** and its **conjugate Pelotas Basin** (Eastwell et. al., 2016, Rodriguez et. al., 2016) this was a major de-risking tool in the validation of the source rock for the super-giant Venus-1 discovery in 2022.

UNCERTAINTY COLLAPSE

Identifying sweet spots within the extent of source rock distribution is key on this margin. By analogy, the source rock in both deep-water Guyana and deep-water Namibia was identified, but considered a pre-drill risk before Liza and Venus were drilled, simply because no wells had been drilled in those specific areas to prove presence and effectiveness.

Looking back, it is easy to separate the uncertainty from any negative evidence, but prior to exploration drilling, this was not the case. On the east coast of India, the situation is similar as source rocks can be identified on seismic and once the presence of mature generative source rock is proven the uncertainty collapse will allow exploration prospect risk to be viewed as solely trap dependent. In the presence of counter-regional dip stratigraphic plays (Venus-1 Namibia and Figure 2), or regional channel truncation (deep-water Guyana), such trap styles allow prospect risks to become very low ensuring repeatability of success.

Offshore East India, the uncertainty in Lower and Mid-Cretaceous source rock distribution can be rapidly reduced by mapping the AVO response at these undrilled stratigraphic horizons. To do this, however, the re-processing of the raw data using a modern processing flow to produce accurate, flat gathers from long offset datasets is imperative, as legacy datasets and extrapolative datasets do not offer reliable indicators of variations in AVO Class IV anomalies.

THE FASTEST GROWING ENERGY MARKET

Exploration for domestic gas resources in the world's hungriest and fastest-growing energy market that otherwise would be reliant on utilisation of its native coal reserves is seen as a critical step in the human race's journey to low-carbon energy sustainability. The OALP-IX Licence round allows international investors to access Searcher's reprocessed regional dataset to high-grade and cherry-pick the most prospective blocks on this super-margin.

We would like to thank our colleagues at Shearwater Geoservices for producing the amazing seismic images utilised in this article.

References provided online.

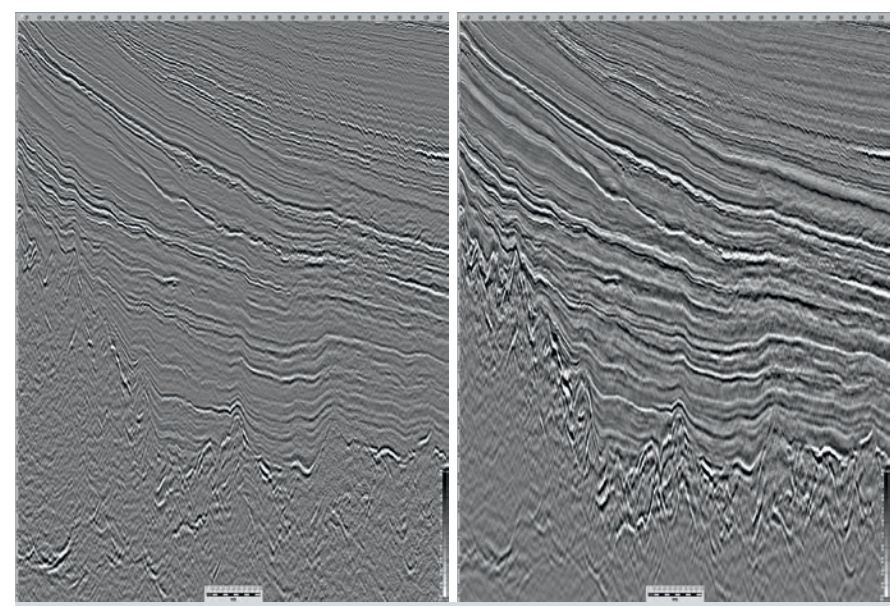


Figure 3: 2D TWT Legacy (LHS) versus 2020 Reprocessed Syn-rift section from deep-water Krishna Godavari Basin – see also Foldout line PSDM.

Leeuwarden Geothermal Project to Continue

Even though the first well disappointed, the partnership has decided to drill a second well.

In the north of the **Netherlands**, a group of companies including **Shell** and **EBN** drilled a well in 2021 to test the quality of the **Upper Permian Rotliegend reservoir** for geothermal purposes. Despite the presence of quite a few offset wells that were drilled for conventional gas exploration, the results of the well were reported to be below expectations. This kickstarted a long period of work-overs and additional studies, which unfortunately did not result in an improvement of the reservoir's flow properties.

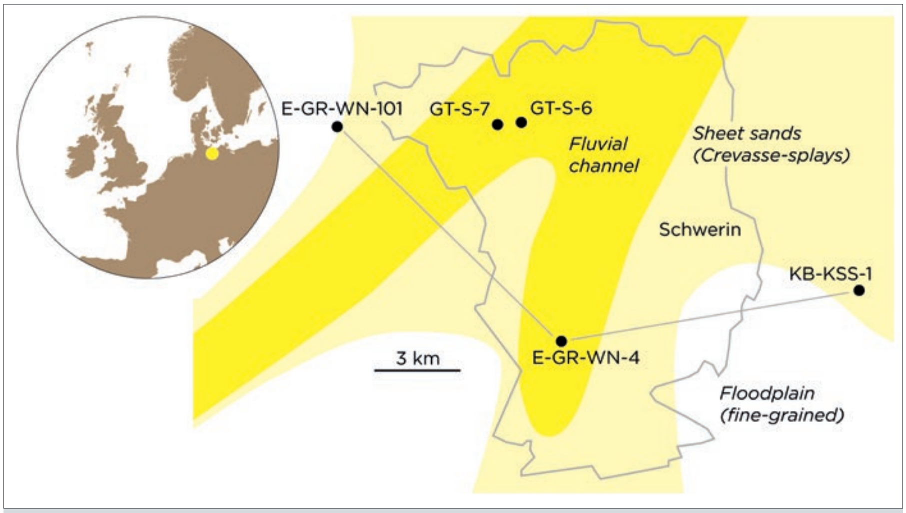
Nevertheless, the partnership has now decided to go ahead with the project and drill the second well, which is required for the open loop doublet. As **Ivar Nijenhuis,** director of the project partnership, writes in a blog on the project website: "The project is very important for the development of geothermal energy and the integration with district heating networks in the Netherlands."

So far, most geothermal doublets in the Netherlands were drilled to heat greenhouse complexes, which must form the background behind the statement regarding the importance of the Leeuwarden well.

In order to guarantee the same level of energy delivered by the geothermal project as originally planned, the partnership is now aiming to include a heat pump to increase the temperature of the produced water. In addition, a shallow borehole will also be drilled to investigate the potential for seasonal heat storage. ■

The Schwerin Sweet Spot

Geothermal project in northern Germany should be used as a template for getting it right.



The paleogeographic setting of the targeted Rhaetian fluvial system in and around Schwerin.

The current energy situation, together with a favourable geological setting and recent technical advances, have put the **Schwerin geothermal project** back on the radar big time.

Schwerin, the capital of **Mecklenburg-Vorpommern**, is a medium-sized town in northern Germany, situated in the North German Basin. As in many places in this part of the world, district heating systems have been in operation for decades, providing a good starting point to benefit from local geothermal energy production.

Why is geothermal energy not being used more already then? The large upfront investment, together with the exploration risks and maintenance costs have hindered the large-scale implementation of this energy resource to date, despite a range of pilot projects that have been carried out in the region over the years. Until recently, Germany's energy policy has also meant that the import of cheap gas from Russia formed too much of a damper on developing local initiatives. That has now all changed.

GOOD PERMEABILITIES

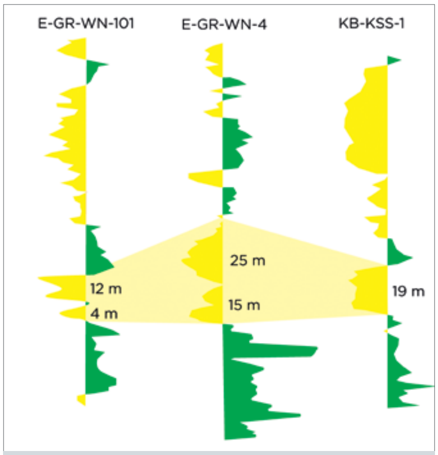
Even though large upfront investments are still needed to drill the required boreholes, the economics of geothermal projects such as Schwerin have improved significantly. And the geology plays a role too.

In contrast to places like Hamburg, where a recently drilled geothermal well demonstrated that the Upper Triassic Rhaetian reservoir target did not live up to expectations – permeabilities were too low – the same Rhaetian reservoir displays much better characteristics in the Schwerin area.

The **fluvial reservoir** is not as deeply buried as in Hamburg (1,300 m versus 3,000 m) but with a porosity varying between 23 to 31% and a permeability of around 6 Darcy, the properties of the Rhaetian sandstone in this area are very promising.

Yet, careful mapping is required to drill wells in the right locations. Again, as recently shown by the Hamburg geothermal

Modified after: Thiem et al. (2022).



Cross-section showing the gamma-ray log of three wells drilled in the Schwerin area and how the targeted sandstones correlate.

well, drilling outside the sandy fairway has detrimental effects on the flow properties of the reservoir.

The Rhaetian reservoirs have been mapped across the entire North German Basin. Schwerin is situated in a genuine sweet spot; right beneath the perimeter of the town lies a complex of branching fluvial channels. It is these channels that generally show the best reservoir characteristics. As **René Tilsen**, who works for **Schwerin City Council** and is partly responsible for the geothermal project, stated: "We have a river beneath our feet."

The thickness of the individual sandstones, next to permeability, is another key factor in

> We have a river beneath our feet.

the success of a geothermal development. Of the six reservoirs known to occur in the Rhaetian, two were targeted in the subsurface of Schwerin. In general, a thickness of 15-20 m is required for individual sandstones to be a suitable candidate for development. With 35 m thick fluvial channels proven in the central parts of the system within one of the mapped successions, this prerequisite has also been met.

DRILLING SUCCESSFUL

So far, the first two wells for the geothermal project have successfully been drilled (Gt-S-6 and Gt-S-7). The 6 well will be the production well, the 7 well is going to be the injector.

The aim is to supply between 75 to 80% of heat demand in Schwerin from its geothermal resource. To that end, the first doublet is aimed to be operational in the first quarter of 2023. To scale up to reach the desired output, a total of around 10 doublets will be required. In addition, 3D seismic will be needed such that the wells, which require a spacing of around 1,200 m, are placed in the most optimal configuration with respect to other doublets and the local geology.

When everything goes to plan, Schwerin can become **the example** of a successful geothermal project. All the ingredients thus far seem to be in place. And with plenty of potential across the North German Basin, there will now hopefully be momentum to expand the rollout of this concept to many more places across this part of the country.

In most of northern Germany, district heating systems operate at temperatures between 80°C and 130°C. As the produced temperature of the Triassic brines is only 55°C at Schwerin, until recently this prevented the full-scale implementation of geothermal energy. Heat pump technology was not able to boost the temperature to the desired level. However, recent technological advances in heat pump technology have meant that this is now feasible.

The heat pumps currently in operation in Schwerin have an output of 6.9 MW at full load, with 5.3 provided through the geothermal resource. This heats the district heating grid fluid from 55 to 80°C, while the brine is cooled from 55 to 20°C. Through connecting the heat pumps in series, the efficiency has been further improved, arriving at a coefficiency of performance of approximately 4.35.

The Tyranny of Distance

Even though geothermal sweet spots are not always where demand is, Australia has potential to tap into this subsurface resource.

An essential element of developing geothermal energy resources is having a market close by. That is one of the main challenges in **Australia**, where most people live on the southeast coast in an area where geothermal gradients are quite low.

That does not mean that there are no ways geothermal energy can be part of Australia's energy mix, as **Trey Meckel** explained during a webinar held for the **Petroleum Exploration Society of Australia** recently. Amongst other roles, Meckel is the founder of **Monteverde Energy**, where he is involved in geothermal projects in **Western Australia** and the **USA**.

Meckel showed that the main way of tapping into Australia's geothermal potential is by producing water from so-called Hot Sedimentary Aquifers at depths of around 1.5 to 5 kilometres. There are a few hotspots across the continent where elevated geothermal gradients (up to 300°C at 5 km depth) exist, such as the **Cooper Basin** which straddles the boundary between Queensland and South Australia.

There are currently around **15 geothermal projects** in operation across Australia. These all classify as **Direct Use projects,** where the energy is used for local heating. Temperatures of the produced fluids do not exceed 71°C and depths of production are generally between 1,000 and 1,500 m, producing around **1 MW per project**. In other words, these are fairly small-scale and shallow projects.

Electricity production from geothermal resources has also taken place in Australia but has seen some setbacks as well. As Meckel explained, a number of so-called

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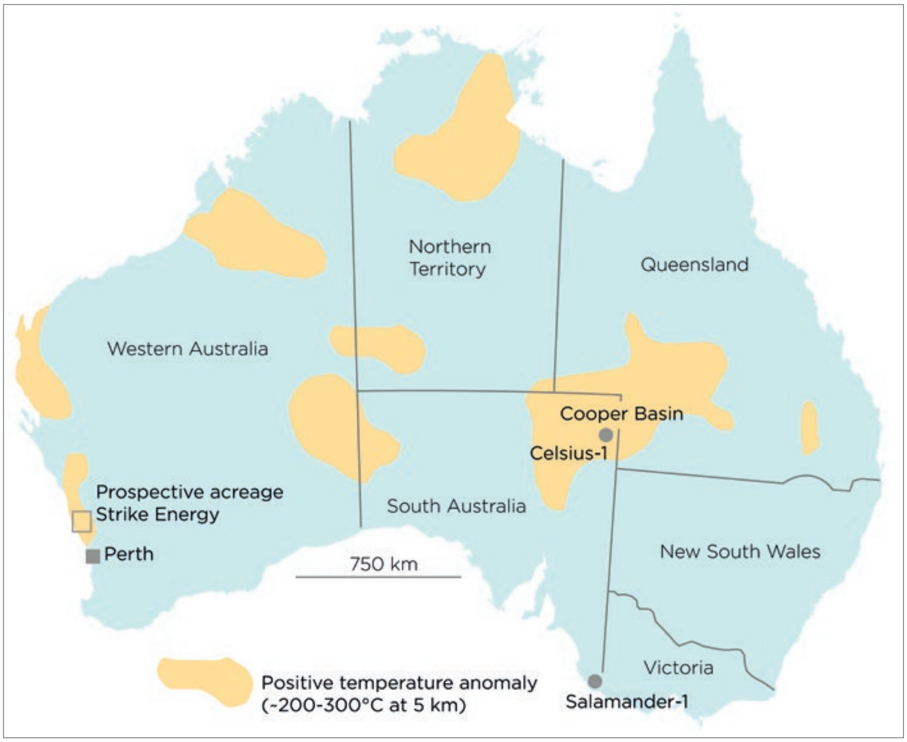
Twelve Apostles, Australia.

"dry" wells have been drilled in attempts to tap into these higher-temperature reservoirs that could form a source for electricity production. Examples include two high-impact exploration wells in South Australia, **Salamander-1** and **Celsius-1**, where reservoir permeability turned out to be the main limiting factor. At the moment, there is no electricity production taking place using geothermal energy in Australia.



PERMIAN SANDSTONES

One of the areas that are currently on the radar for geothermal power generation is the area north of Perth along the west coast. It is characterised by higher geothermal gradients combined with the presence of a nearby market such as a fertiliser plant.

In this area, **Strike Energy** is currently looking at the geothermal potential of the **Kingia Sandstone**. This is a Lower Permian shallow marine sandstone succession that was deposited in the **Perth Basin**, which currently has an average geothermal gradient of **3.6°C/100 m**. That means that temperatures of >100°C can be reached at depths of 2,500 m. The porosity and permeability of the Kingia Sandstone are also promising, with the higher quality reservoir displaying >16% porosity and permeabilities of >100 mD.

One of the reasons why the Kingia Sandstone displays such good reservoir characteristics is the fact that the sands are coated with clay, which has limited the extent to which quartz overgrowth could occur. Strike Energy estimates that the P50 geothermal resource in their Kingia Sandstone area stands at **202 PJ**, which is equivalent to a **192 Bcf** or **5.4 Bcm** gas field.

The Two Options for Calypso

Neptune and partners prove hydrocarbons in the Calypso prospect. If the find is commercial, there could be two possible export routes.

In what is **Neptune's** third discovery in six months, following on from **Ofelia** and **Hamlet** in the greater **Gjøa area**, this time oil has been found in the **Calypso** prospect in the Norwegian Sea a little further north.

According to documents available through the Environmental Agency, the 6407/8-8S Calypso well targets a **Middle Jurassic Garn** or slightly deeper reservoir at a depth of around 3,000 m. Partner **Vår Energi** (20%) estimated that **Calypso** could hold **34 MMboe**, whilst partner **OKEA** (30%) is a bit more conservative and states a potential volume of **22 MMboe**.

Even though it is too early to conclude that the discovery is commercial, the well results must raise hopes for the possibility of a tie-back. But a tie-back where to?

TWO OPTIONS

For partner OKEA, an export route via the **Draugen platform** is the most favourable option. It will extend the life of this maturing asset a little longer.

However, there is another possible export route, and that is to **Njord**. Production from Njord was suspended in 2016 due to structural integrity issues to the platform, but thanks to an upgraded facility, production is expected to resume soon. The expectation is that Njord will be able to handle hydrocarbons up to 2040.

At the same time, Neptune is developing the **Fenja field**, the oil of which is also going to be exported through Njord. The **Bauge** discovery, adjacent to **Hyme**, is under development too and will be directed to Njord as well.

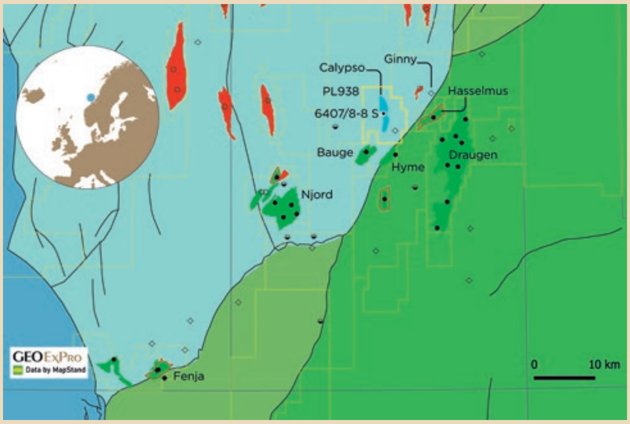
With Neptune being a partner in Njord (22.5%) and not in Draugen, it remains to be seen which export route the company and its partners ultimately prefer.

RUMPELDUNK

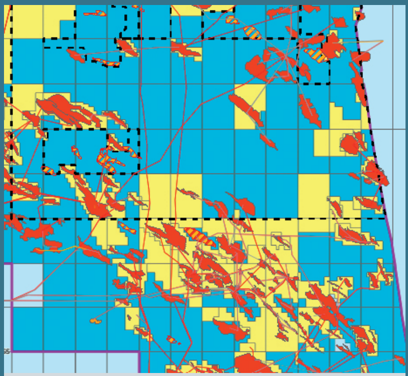
Licence PL938, in which Calypso lies, was awarded to Neptune in 2018. Before that, **Statoil** (Equinor) operated the area under licence PL348C, which was relinquished in 2016. In the area where the current well is being drilled, Statoil defined a prospect under the name **Rumpeldunk**, with an outline fairly similar to Neptune's Calypso prospect.

The difference between the Rumpeldunk and Calypso prospects is that Statoil defined the former as an Upper Jurassic target, whilst Neptune supposedly drills a Middle Jurassic closure. Whether Calypso is in fact a re-interpretation and revision of the Upper Jurassic Rympeldunk prospect remains to be seen. Statoil's estimated volume for Rumpeldunk was **20 MMboe** in place.

HASSELMUS



Recent exploration in the Draugen area has not been very successful, with the **Ginny** well (6407/9-13) completed dry earlier this year. However, OKEA drilled a development well onto the **Hasselmus** discovery just north of Draugen this summer, which will bring in additional gas to power the platform.



Source: NSTA.

UK Southern North with current licences in yellow and acreage available for bids in blue.

A Licensing Round with Urgency

Two years ago, the prospect of another UK Offshore petroleum licensing round was not a given. The COP26 Conference in Glasgow made any announcement in this regard too hot a political topic. With the need for domestic oil and gas production being escalated to the top of the political agenda though, the North Sea Transition Authority (NSTA) has now launched the 33rd Round.

A total of almost 900 blocks are on offer, which could lead to the award of more than 100 licences, according to the NSTA.

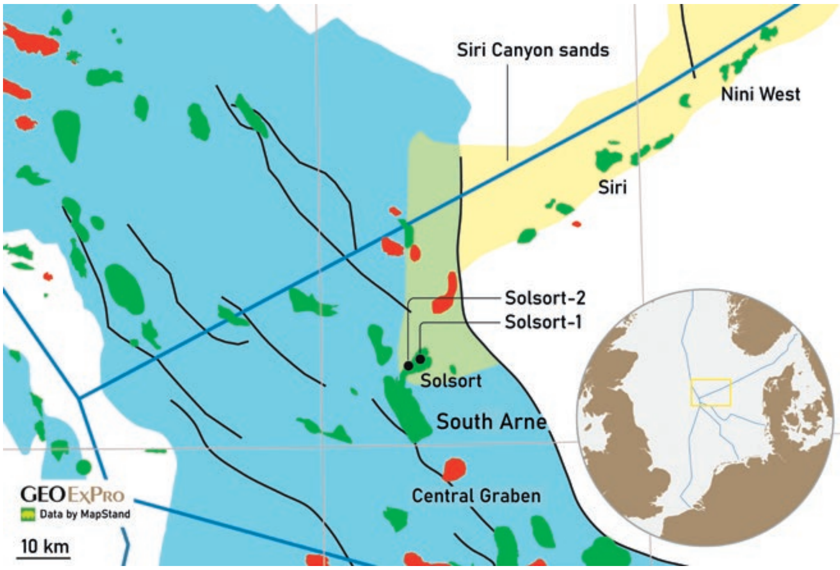
It even offers some priority clusters, all situated in the gas-prone Southern North Sea. It is a clear expression of the urgency and pressure the Authority is now experiencing from Westminster.

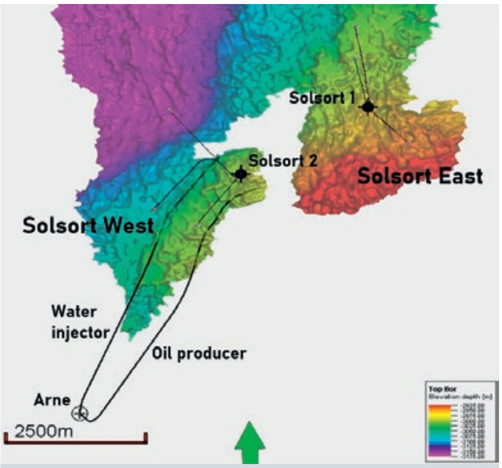
"The priority clusters are known to have hydrocarbons, are close to infrastructure and have the potential to be developed quickly," reads the press release. The NSTA will prioritise licensing these applications prior to others, such that they can go into production as soon as possible.

It again shows the pressure exerted by Westminster to make the UK less dependent on oil and gas import. With the UKCS being more creamed than neighbouring Norway, and with the low number of exploration wells being drilled in recent years, it remains to be seen if an uptick in drilling, developing and production is a real prospect.

The Last Field Development of the Danish Offshore?

With Ineos' plans to develop the Solsort discovery being approved by the Danish Energy Authority, the westernmost accumulation of the Paleocene Siri Canyon Play will now be developed.





Map showing the Solsort East and West accumulations, the exploration wells drilled (Solsort 1 and 2) and the projected trajectories of the development wells.

Source: ens.dk

When **Ineos** acquired Hess' **South Arne** assets last year, the opportunity to develop the nearby **Solsort discovery** – already in Ineos' hands – became a logical next step. So, it is not a huge surprise to see that the **Danish Energy Authority** has approved Ineos' plans to develop Solsort.

Yet, it is the first time since 2017 that a field is being approved for development in the Danish sector. Solsort will also be the first field development after the decision taken in 2020 by the Danish government to stop production of oil and gas from the Danish sector in 2050 altogether.

LONG-OFFSET WELLS

As expected, Solsort will be developed as a tie-back to the North Platform of the South Arne field. Ineos aims to drill two wells; a water injector placed in the northwest of the accumulation and an oil producer along the southeastern edge.

The decision to develop the discovery through the drilling of long-offset wells has probably meant that only the western compartment can be developed; Solsort consists of two separate accumulations (see map).

Solsort (East) was discovered in 2010 through drilling Solsort-1 (5504/26-5) by **Dong Energy**. The oil discovery was further appraised by three side tracks drilled from the parent well, radiating in different directions. One had a step-out of almost 5000 ft. Solsort (West) was drilled in 2013 through Solsort-2 (5604/26-6) by Ineos – approximately 2.5 km to the southwest of Solsort-1. Although the parent well did encounter oil, the two side tracks were dry.

In the published environmental impact assessment, a production profile for Solsort (West) shows that the operator expects a peak oil production of 1**4,000 barrels/day**, declining to less than 2,000 barrels/day after four years of production.

Solsort is the westernmost accumulation in the **Siri Canyon play**, where Ineos has got a significant stake already. This includes the Nini West field that is in the process of being converted to a CO2 storage site (Greensands project) and where a test injection phase will soon kick off. Now that Solsort (West) is going to be developed, it may be the last discovery in the Siri Canyon to see first oil, and maybe the last one in the Danish sector altogether? ■

SOUTH ARNE

The South Arne field is an Upper Cretaceous Chalk oil field that was discovered in 1969 but it took about 30 years before first oil from this 125 MMboe accumulation came to market. Similar to Ekofisk, imaging of the reservoir was hampered by a gas cloud, but the wells drilled through it in the 1990s proved a much thicker Chalk section than had previously thought. In 2010, Hess and partners sanctioned the Phase III development whereby 11 new wells were drilled and two new wellhead platforms were installed, aiming to extract an additional 15 MMboe.

NCS not yet Creaming

Despite a trend of ILX-driven exploration and increasingly smaller volumes, the Norwegian sector is still worth exploring.

Whilst the call for more frontier exploration and the associated likelihood that bigger fields are being found is getting louder, it is important not to forget that infrastructure-led exploration is also very worthwhile on the **Norwegian Continental Shelf**.

Anders Wittemann showed a series of creaming curves during his presentation at the **NCS Exploration Strategy Conference** in Stavanger recently that clearly showed an ongoing upward trend, even when including all major discoveries made from the start of exploration in the area (plot on the left).

In the plot on the right, discovered volumes have been split per licence type since 2010. This shows that a lot more wells have been drilled in licences awarded in APA rounds than in the traditional and more frontier licence rounds. The "APA graph" also illustrates that more wells were required to discover the same volume as drilling in acreage that was awarded during the traditional licensing rounds. This is no big surprise though, as the APA rounds are focusing on the more mature and near-infrastructure areas of the NCS.

Comparing the two "Rounds" creaming curves, both trend in the same direction, despite the differences in lengths of time acreage has been held. The more recently awarded blocks have delivered slightly more - Round 16 took place in 1999 - primarily thanks to the Wisting discovery. It also shows that exploration in long-held acreage is still paying off, as the King-Prince discovery made in one of the oldest licences on the NCS has illustrated quite recently.

Despite the higher number of wells required in the APA blocks, this creaming curve also shows that exploration in the more mature areas has been the most dominant way of adding reserves since 2010. One of the biggest advantages of ILX-driven exploration is that newly discovered volumes can be put on production quickly, enabling companies to rapidly recover exploration costs.

DEVELOPMENT OR EXPLORATION?

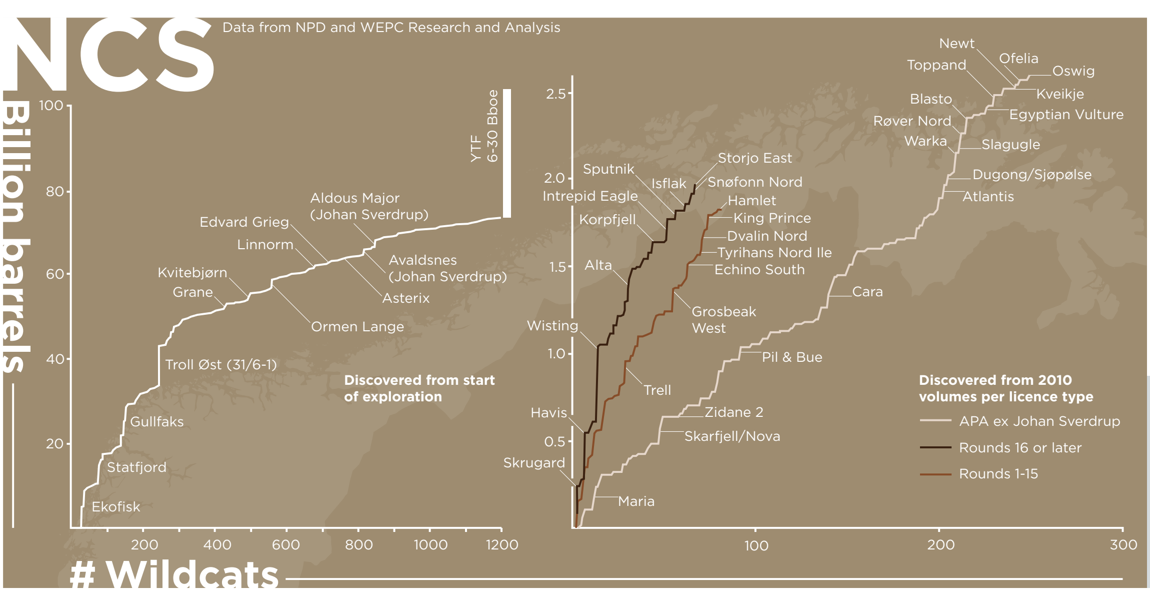
Due to the dominance of ILX-driven exploration, the boundary between what can be regarded as exploration and what is infill drilling may sometimes get a bit opaque. Wittemann showed that the most valuable discovery on the NCS since 2019 is **Tyrihans Nord Ile** in the **Norwegian Sea**. This compartment below the main Garn reservoir of the **Tyrihans Nord** field was drilled by well **6407/1-A-3 BH**. The NPD carried the well as a development well. Against this backdrop, Wittemann said that some may argue for Tyrihans Nord Ile to be regarded as a further development of an existing field instead of a new discovery. Yet, **Patrick Stinson** from **TotalEnergies**, keen to support his company's exploration strategy, noted that the well was drilled updip of a dry hole, making a case for an audacious exploration effort.

Looking at a bit more detail to the results this year, it must be said that 2022 is probably not going to be a record-breaking one. In total, **233 MMboe** has so far been proven, which is significantly less than the **457 MMboe** discovered last year. **Aker BP's Storjo East** in the Norwegian Sea is the biggest find one to date this year, with an estimated recoverable gas volume of between **25 and 80 MMboe.** Appraisal drilling is now planned for 2023.

YET TO FIND

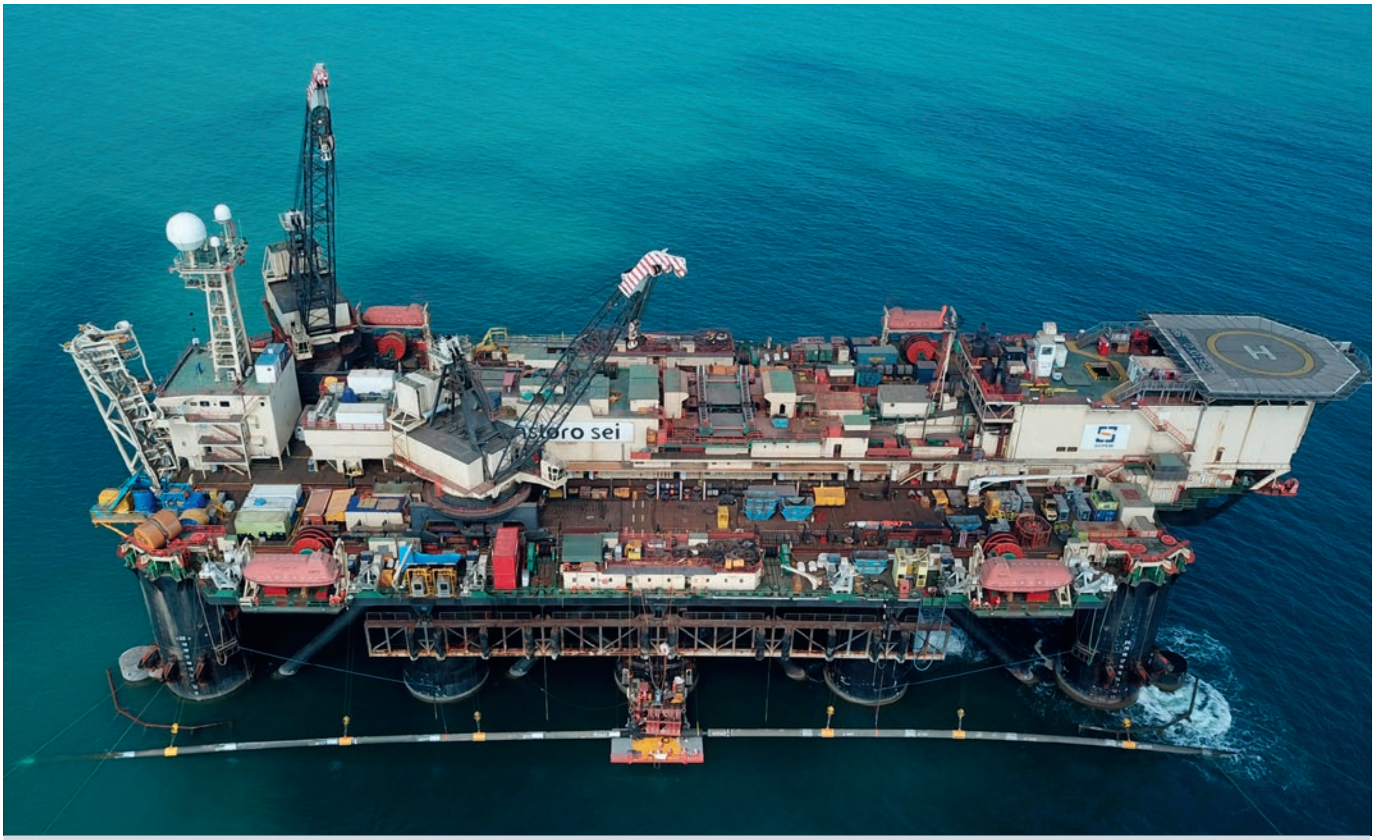
With between **6 to 30 billion barrels** yet to be found on the NCS, there is still room for exploration in the years to come. And as **Kjersti Dahle** from the **NPD** reiterated, there are almost **1,300 leads** and **1,200 prospects** in NPD's Treasure Chest waiting to be worked up to drilling targets. Expected volumes for the majority of these prospects are modest though, with most prospects falling into the **13-31 MMboe** bracket. ■

Redrafted from: NPD and WEPC Research and Analysis.



Creaming curves for the Norwegian Continental Shelf from the start of exploration (left) and for discoveries made from 2010 onwards.

Photo: baltic-pipe.eu



Pipeline vessel Castoro 6 laying the Baltic Pipeline.

The Poles Were Bang on Time

With the gas crisis unfolding this year, the Baltic pipeline exporting Norwegian gas to Poland came online at exactly the right moment.

It must have been a good moment for **PGNiG** Norway's Subsurface and Exploration manager **Chris Dart** to present his company's business outlook at the recent **NCS Exploration Strategy Conference** in Stavanger.

In 2018, he stood on the same stage, explaining how the investment decision for the pipeline connecting Poland to North Sea infrastructure had just been made the year before. At the time, he said that 2022 was going to be a key year for the company.

Now, as we have arrived in 2022, the pipeline has started to transport gas to Poland, while imports from Russia have come down. The timing could not have been much better than that, even though the circumstances are nothing to be upbeat about. It shows a degree of foresight many people did probably not credit the Poles sufficiently for when the project was sanctioned.

AN INCENTIVE TO EXPLORE

The Baltic pipeline is able to transport up to **10 Bcm** of gas to Poland a year. That means PGNiG Norway is constantly looking for ways to add volumes to its portfolio which currently sits at **309 MMboe** of proven reserves plus contingent 2P and 2C resources - this would equate to **50 Bcm** if the entire portfolio would have been gas. Current gas production capacity sits at **3 Bcm** for 2022.

Since the establishment of the Norway PGNiG office in 2007, the company has been building up its portfolio both through acquisitions and through the drill bit – operated and non-operated. A major transaction was the acquisition of **Ineos**' Norway assets in 2021, which came with a 14% stake in the **Ormen Lange** gas field, 15% in **Alve** and 30% in **Marulk**. This year,

Photo: baltic-pipe.eu

Opening ceremony of Baltic Pipe project, 27th September 2022.

"This company is all about getting gas to Poland"

Chris Dart, PGNiG Norway's Subsurface and Exploration manager

the company acquired a 40% stake in the **Ørn** gas discovery from **Wellesley**, adding an estimated **7 Bcm** to its portfolio.

The Norwegian Sea is the core area for the company, also when it comes to exploration. For instance, it was PGNiG that mapped the **Warka** prospect in PL1009, which was ultimately drilled with **ConocoPhillips** as the operator in 2020. Well 6507/4-1 proved a 27 m gas column in Lower Cretaceous sandstones of the **Lange Fm** and with an estimated volume of between **50 and 189 MMboe** of recoverable gas. A decision to further appraise Warka is now awaited.

Exploration results do come with surprises though. An example is the **Copernicus** well (6608/1-1) recently completed by PGNiG as the operator in a remote part of the Norwegian Sea to the east of the **Aasta Hansteen** field. Pre-drill volumes for Copernicus were reported to be **254 MMboe** by partner Longboat, but the well came in dry. The prospect consisted of **Miocene-Pliocene** lowstand wedge sandstones that showed a clear amplitude anomaly on seismic data. However, the well failed to prove any effective reservoir according to Longboat.

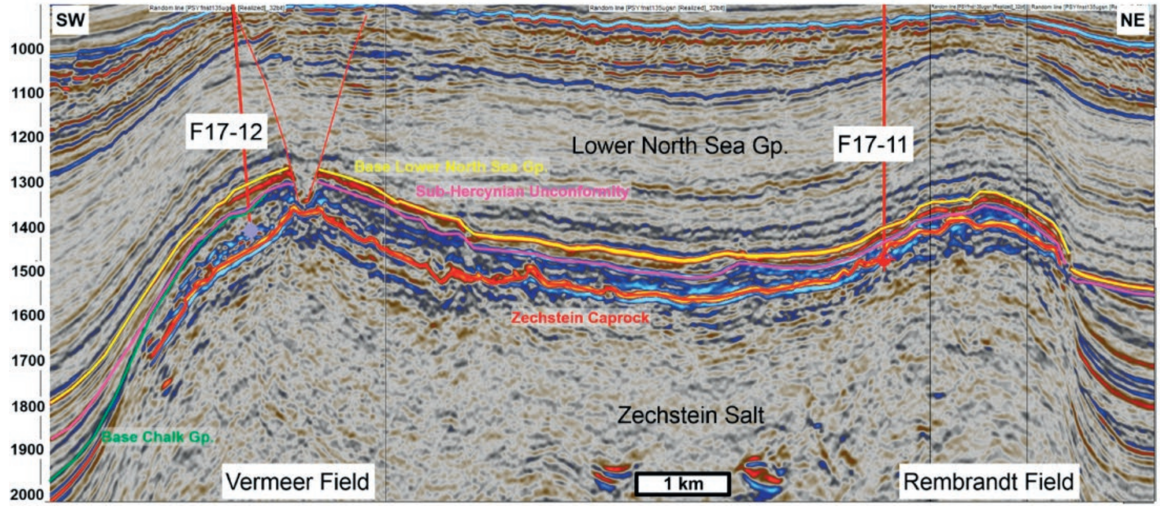
In a way, PGNiG's efforts in the Norwegian sector clearly show what it takes to explore for gas in a relatively mature basin; it takes a diversified strategy to build up a portfolio and it takes time. Having a pipeline in place this year has turned out to be a crucial decision though, a foresight for which the company should be credited. ■

AN EXAMPLE FOR NORWAY?

At the **NCS Exploration Strategy Conference** in Stavanger, several talks addressed energy security in Europe. It was clearly shown by **Simon Sjøtun** from Rystad that in the case of a total stop of gas import from Russia, Norway cannot fill the supply gap on its own. Europe consumes around **500 Bcm** per year, of which **110 Bcm** is being supplied by Norway. However, without significant new discoveries being made, Norway is expected to come off the current gas "plateau" in 2030.

One thing that was discussed by several presenters at the conference was the idea to build a gas pipeline to the Barents Sea. That would be the only way to unlock the area for more gas-focused exploration, as the only gas-processing facility (**Melkøya LNG plant**) is at capacity with gas coming in from the Snøhvit field for years to come. The challenge with the Barents Sea however is that most undeveloped gas discoveries sit in relatively tight reservoirs and are not large. That is the reason why building a pipeline is seen as extremely risky. At the same time, there are voices in Norway saying that the government should take more risks if it wants to secure a longer future as an oil and gas-producing nation. At least Poland has shown that building new infrastructure can pay off.

From: Van Lochem et al. (2018).

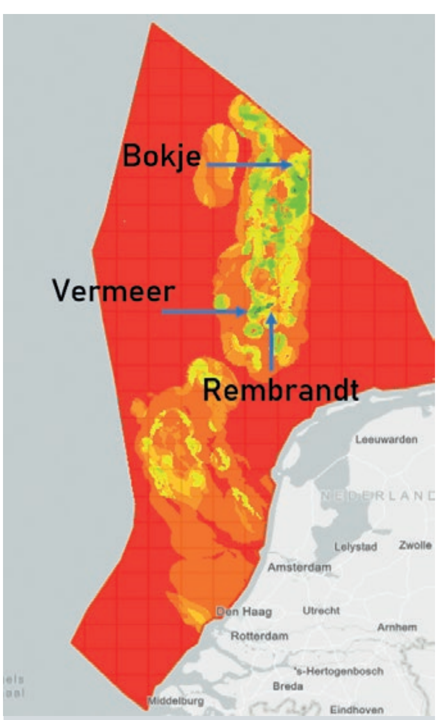


Interpreted TWT seismic section across the Vermeer and Rembrandt discoveries, showing the thin development of the Maastrichtian Chalk.

Where to Explore in the Dutch Offshore?

Online platform aims to provide more information on exploration potential of mature Dutch North Sea sector.

Source: Geode platform.



Composite Common Risk Segment map for the Chalk oil play, showing the probability of finding all mapped play elements ranging from red (no chance) to green (very likely).

How to encourage exploration in the Dutch offshore? Against a backdrop of a dramatic decline in number of wells drilled in recent years (only 2 exploration wells were completed in 2021), in addition to lengthy approval procedures for newly proposed projects, the dependency on import of oil and gas for the Netherlands is set to further increase in the years to come.

The closure of the **Groningen field** is only part of this story. Maybe even more important in this context is the decline in production from the numerous offshore fields. And it is the offshore where any growth in production should come from because onshore operations are met with even more red tape than offshore.

To ease access to subsurface data, **EBN** and **TNO** – **Geological Survey of the Netherlands** – have launched an online portal under the name **GEODE** (geodeatlas.nl) where all known hydrocarbon plays in the Dutch sector are presented. For each play, reservoir presence, effectiveness, seal presence and charge & migration have been mapped. These were subsequently combined into play risk maps, which present the user with a better understanding of the areas where future exploration potential exists.

The platform also hosts a range of other datasets and studies such as a hydrocarbon show database, a missed play study performed by **Panterra**, gas composition data and much more.

THE UPPER CRETACEOUS PLAY

One of the relatively underexplored plays in the Netherlands is the **Upper Cretaceous Chalk play**. In the hunt for gas in the deeper Rotliegend succession, the Chalk has often been ignored, but in recent years some interesting oil discoveries were made in the offshore Chalk by **Wintershall Noordzee** (see seismic line); **Rembrandt** and Vermeer. Even more recently, **Dana** seems to have successfully completed an exploration well on another Chalk prospect in the northern offshore (**Bokje**).

With a play risk map now available for the Upper Cretaceous play, which shows that there are quite some more areas where the play may work (green shades), will there be an uptick in activity in the Dutch offshore soon? ■

An Onshore CCS Debacle

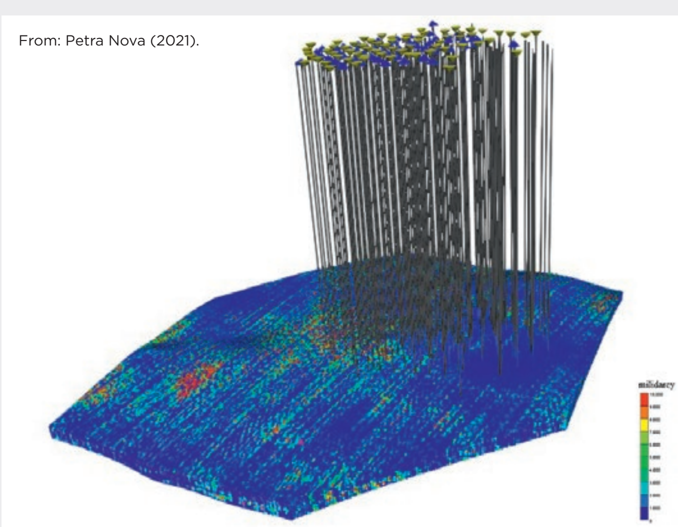
Sale of stake in carbon capture plant at huge loss leaves taxpayer exposed.

The owners of the **Petra Nova** CO_2 capture plant, built at a Coal Power Station in **Texas**, went for it. Rather than constructing a 60 Mwe facility according to the first design, a unit four times that size was ultimately built. The reason? Modelling studies had shown that the oil field where the CO_2 was going to be injected in for EOR purposes needed at least that amount in order to be effective.

Now, five years after the first CO_2 was transported through a 130 km long pipeline, the facility has ceased operating. One of the owners (**NRG Energy**) has sold its 50% stake in the carbon capture plant for a value representing less than 0.5% of its roughly 1 billion USD construction costs. The facility was heavily subsidised by the US government.

> Recommendation: Stop taking U.S. taxpayers for a ride on a CCS money guzzler.

The **Institute for Energy Economics and Financial Analysis** wrote a very critical account on its website, detailing a lack of transparency in the reporting of numbers and poor plant performance. It concluded that the US government must sharply scrutinise all claims made by applicants for federal dollars to promote CCS technology.



Location of EOR operation wells and horizontal permeability into the West Ranch numerical simulation model.

AN ONSHORE FIELD

The transported CO_2 was injected into the onshore **West Ranch** oil field about 100 km to the southwest of Houston. A simple four-way anticlinal structure, the **Oligocene** barrier sandstone reservoirs of the **Frio Formation** are situated at a depth of around **1,700 m**.

The field was discovered in 1938 and had **925 wells** drilled into it in December 2020. This exposes another intriguing aspect of this CO_2 injection project.

Given the large number of wells and the period over which these were drilled and subsequently abandoned, it is interesting to see that this part of the project could go ahead. Even though a report on the feasibility of CO_2 injection into West Ranch describes that all well completions had been inspected prior to injection, it is still showing a large contrast in acceptance of CO_2 injection between North America and Europe.

Following heavy protests, **Shell** had to abandon plans to store CO_2 in the onshore **Barendrecht field** in the Netherlands around 2012. This led to a focus on offshore storage only, while Barendrecht only had **two production wells** drilled. Even though Texas has a lower population density than the **Barendrecht** area, this still exposes the difference in approach between the US and Europe.

All in all, just over **3 million tonnes** of CO_2 was injected into West Ranch over the project's lifetime. ■

UK Gas Storage Facility Reopens

Mothballed in 2017, the former gas field in the Southern North Sea will be operational this winter at about 20% of its previous capacity.

At full capacity, the **Rough storage reservoir** would have been able to deliver more than **5.5 Bcm** of gas during peak demand in wintertime. As such, it was one of the bigger gas storage sites across Western Europe.

However, the site became unprofitable following technical and maintenance issues and was closed in 2017. For years, no serious concerns were raised as the UK became more dependent on uninterrupted gas import. The UK now buys around 60% of its gas abroad.

When discovered by **Gulf** in 1968, the Rough field held slightly more than **10 Bcm** in gas reserves. This was produced through six development wells from 1975 through to the early 1980's.

The reservoir consists – as many fields in the UK Southern North Sea – of **Permian** dryland sediments, showing an alternation between aeolian and intra-dune deposits that together attain a thickness of around 29 m.

The conversion to a storage site, which already took place in the 1980's, has meant that **23 further wells** had to be drilled in order to ensure rapid filling during the summer months and rapid production during winter. First injection took place in 1985.

Given this number of wells, and the site being offshore, it is no surprise that the maintenance costs of such a facility are high. ■

Aerial picture of Epe landscape, Germany. A cavern site can be seen on the left and a peat bog to the right.

The Deep Subsurface is Not Always to Blame

Solution mining in Germany leads to subsidence, but cannot solely be held responsible for damage to property, study shows.

When data on land subsidence in the Epe area (Germany) was made public, Pandora's box opened. Those who looked at the data were quick to point their finger at the party responsible for this: the company mining salt from Zechstein salt domes through solution mining – **Salzgewinnungsgesellschaft Westfalen** (SWG) and the companies currently storing gas in the caverns where solution mining has ceased.

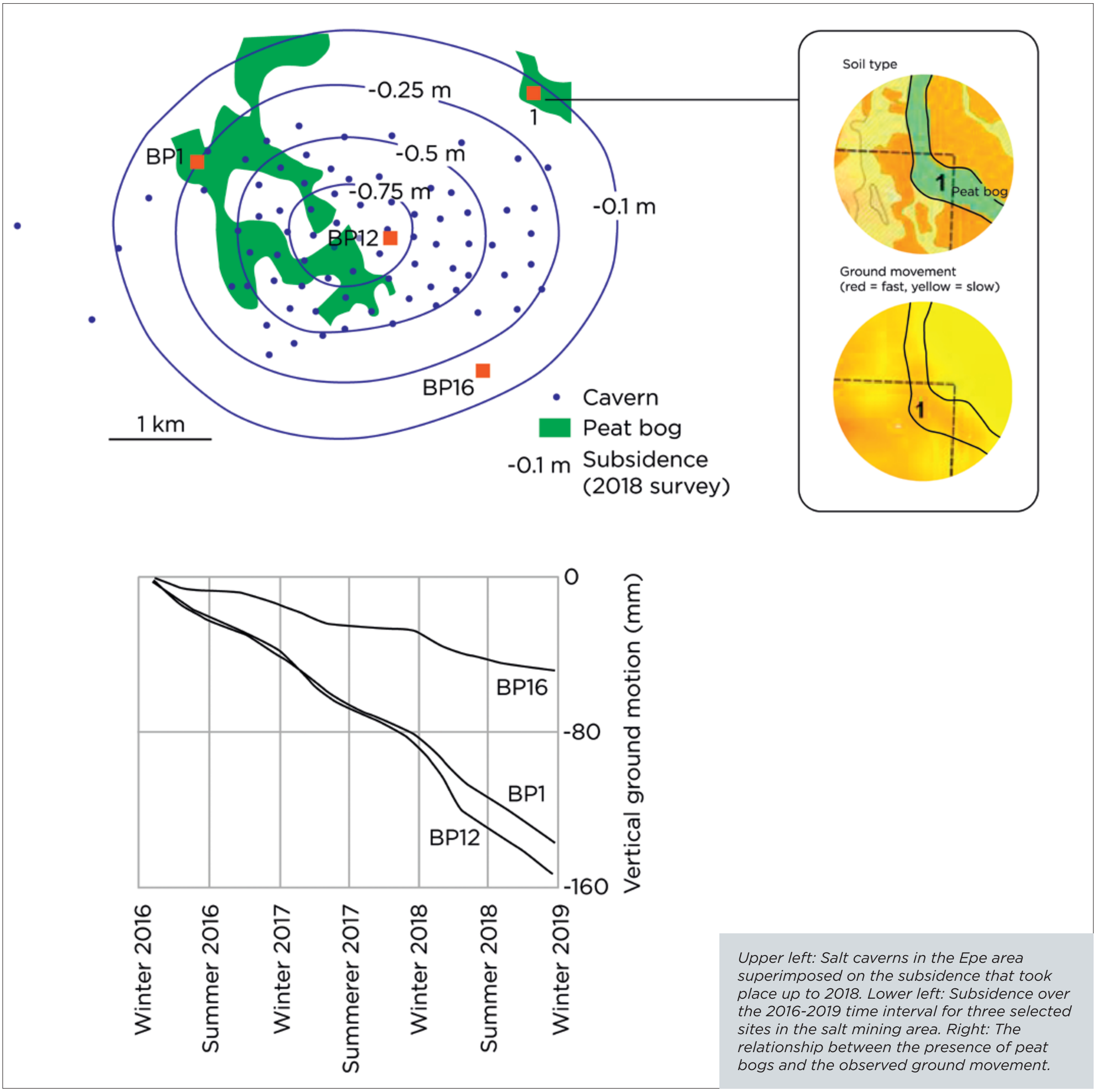
As damage to property in the area occurred, the issue quickly escalated to the national news, which prompted local authorities to investigate the matter further. This led to the foundation of a research consortium that aims to further investigate the root causes of subsidence. The consortium consists of the Technische Hochschule Georg Agricola (Research Center of Post-Mining), Remote Sensing Technology Transfer (EFTAS GmbH), the City of Gronau and a local Citizen Initiative.

Presented at **EAGE's Global Energy Conference** (GET) in the Hague in November, **Tobias Rudolph** from the **Technische Hochschule** gave an account of what followed.

A SUBSIDENCE BOWL

At first glance, it seemed plausible that solution mining and the related subsidence at surface were the root cause for the damage observed. It is well-known that the caverns that formed in the Zechstein salt as a result of solution mining cause a broader area to subside at surface (see map). In the Epe area, where more than 100 of those caverns now exist, a total

Figures adapted from: Rudolph et al. (2022), EAGE GET Conference Extended Abstract.



Upper left: Salt caverns in the Epe area superimposed on the subsidence that took place up to 2018. Lower left: Subsidence over the 2016-2019 time interval for three selected sites in the salt mining area. Right: The relationship between the presence of peat bogs and the observed ground movement.

A SERENDIPITOUS DISCOVERY

In 1964, the Epe-1 well was drilled. Rather than hitting gas, the primary target of the well, halite was found at a relatively shallow depth (1,300 m). Thanks to the purity of the halite, its value was soon recognised for many industrial processes, and therefore solution mining started in the 1970s. Thus far, more than 100 caverns have been created in an area measuring approximately 4 square km. One cavern has an approximate height of 300 m and a width of 200 m.

Many of the salt caverns are currently in use to store gas, with a variety of companies involved. During the summer months, surplus gas is injected, with subsequent production during the winter months.

subsidence of around 90 cm has already taken place in the middle of the so-called subsidence bowl. Most of this subsidence is likely to be due to salt mining.

However, the link between subsidence due to salt mining and damage to property is more complex, as Rudolph showed in his talk.

AN ACTIVE PEAT BOG

Part of the area where solution mining is taking place also hosts an active peat bog and associated organic-rich soils. It now happens to be that due to the past summers, some of which were characterised by long spells of hot and dry weather, the water table supporting the peat bog lowered by around 2 metres. That is a significant change, resulting in the degradation and oxidation of peat.

When he subsequently overlaid a geological map of the area onto the subsidence pattern, some relationships started the emerge. In areas where the peat showed elevated thicknesses, subsidence showed a more pronounced value. In contrast, in areas where no peat occurs but Pleistocene sand instead, subsidence was much lower.

This can be illustrated further by looking at the subsidence data from three sites across the monitored area. Site BP1, which is located in the bog area but further towards the perimeter of the subsidence bowl, shows a total subsidence in the period 2016-2019 of almost the same amount as BP12 (~ 150 mm), which is in the centre of the subsidence bowl.

In contrast, BP16, which is located in the southeastern part of the subsidence bowl, only shows subsidence around 50 mm of subsidence over the same period. Even though BP1 and BP16 are in similar positions with respect to their location in the subsidence bowl, i.e. the amount of subsidence based on the effect of solution mining would be expected to be similar, it is probably the soil type that has got a major influence on the total amount of subsidence that is taking place.

And because soil types are rapidly changing across the area, so is the total amount of subsidence per location. This can be seen at location 1 on the map. This location is situated at the very margin of the subsidence bowl, where only 0.1 m of total subsidence should have occurred as a result of mining-induced subsidence. However, it can clearly be seen that the observed subsidence pattern lines up with the occurrence of a peaty soil.

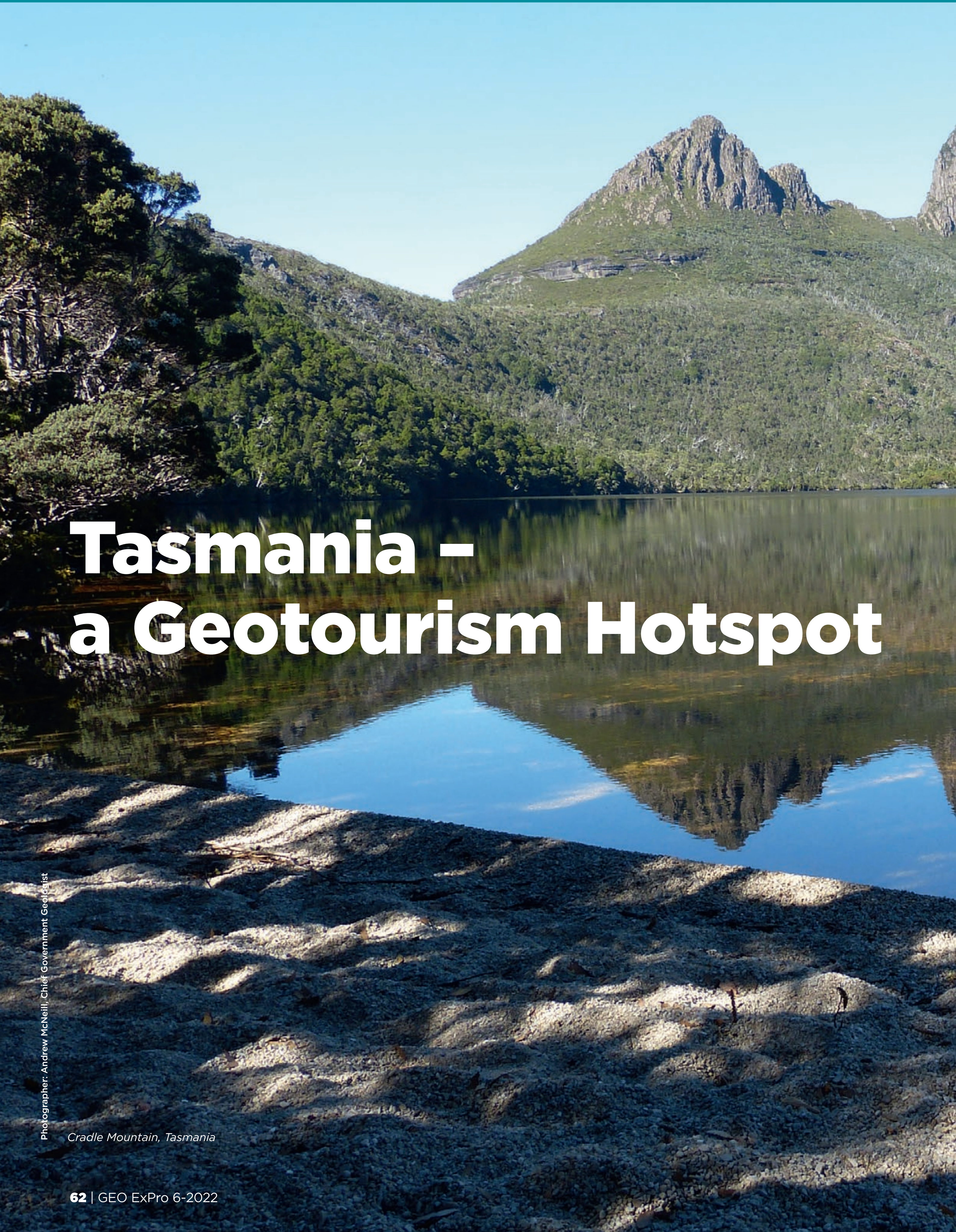
A MORE COMPLEX SITUATION THAN FORESEEN

The above observations suggest a more complex relationship between subsidence and solution mining. The results do not line up with the more straightforward bowl-shaped subsidence patterns one would expect when the salt caverns would have been the only factor at play.

Rudolph, therefore, concluded that peat degradation as a result of warm and dry summers is a significant factor explaining the observed subsidence patterns. Damage to buildings only seems to occur where a peaty subsoil exists, casting further doubt on the effects of solution mining.

The study demonstrates the need for proper geological investigation and explanation to be provided along with raw data such that non-specialists are also in the position to make correct inferences on the relative contribution of multiple factors that can contribute to one phenomenon. ■

Tasmania – a Geotourism Hotspot



Photographer: Andrew McNeill, Chief Government Geologist

Cradle Mountain, Tasmania

The island of Tasmania is one of Australia's outstanding National Landscapes. In a 14-day journey around this state, geotourists can explore unique Gondwanan flora and fauna, and a distinctive Aboriginal and post-settlement culture unique from Australia and the world.

■ **Text:** **Dr Melinda McHenry, Mark Williams, Violet Harrison-Day, Tzigane Scholz-Talbot, University of Tasmania, School of Geography, Planning & Spatial Science; Angus M Robinson, Leisure Solutions®**

Tasmania's geodiversity is remarkable, representing every past geological period and climatic event. A journey by coach or car will immerse a visitor in one of the most mountainous places in the world and can be augmented with any number of short to multi-day walks, boat and kayaking adventures, mountain biking, strenuous climbing, caving or luxurious food and wine adventures.

Our journey starts in the north-west – flying over spectacular King Island to Burnie-Wynyard. Heading out of the airport along the Bass Highway towards Rocky Cape will reveal a spectacular vista of the Bass Strait, which separates Tasmania from mainland Australia. The far northwest Rocky Cape marine sediments are Precambrian, and feature monazites, zircons and fossils over a billion years old (1,350 -1,450 Mya). Before arriving, however, a visitor might want to stop off at 'The Nut' – a Tertiary basaltic tabletop monument that is but one feature of the more recent development of rocky shorelines along the north coast. At any time, a diversion south off the highway allows visitors to travel through ancient times through a spectacular Gondwanan rainforest. This forest features some of the oldest living plants on earth such as the 10,000-year-old endemic Huon pine trees and alpine pines.

THE 99 BEND ROAD

Western and Central Tasmania began forming 1250 Mya. A trip down towards Strahan reveals the long chaotic history in seas, estuaries, lakes and rivers punctuated by mountain uplift, past glaciation, and faulting. The mining townships between Tullah and Queenstown reveal insights from the Cambrian and subsequent Ordovician periods of intense volcanism and sedimentation.

The Mt Read Volcanics are economically significant and have sustained a 120-year history of polymetallic mining and exploration near Rosebery. This complex volcanic belt has undergone numerous tectonic metamorphic events, with gold-bearing gossans near Mt Lyell and Queenstown, and metamorphosed gabbro and other mafic magmas into serpentine exposures near Zeehan. This landscape features spectacular lakes, incredible flora, and mountain vistas.

Turning inland along the affectionately named '99 bend road' (Lyell Highway) from the stark, but colourful, denuded Queenstown hills towards the south will reveal further evidence of past climates in the mountains, rivers, and cave systems. A short trip off-road near Mt Field reveals some of the substantial Ordovician limestone karst complexes of Tasmania, including the deepest (over 400 m) and some of the longest caves mapped in Australia. Further along the road, a turn south will reveal some very ancient landscapes, and contemporary peat bogs. The best-known expression of the old Cambrian quartzites and glacial features in the region is in the Arthur Range, culminating in the impressive rocky crag of Federation Peak.

DOLERITES AND DUNES

Turning south towards Hobart reveals three charismatic geological settings for which Tasmania is well known – Jurassic Dolerite (diabase), Triassic Sandstones (found in many buildings of convict heritage and outcropping along the Lyell Highway) and Permian, fossil-bearing mudstones. Many short-day trips can be undertaken in Hobart – up the mudstone Kunanyi/Mount Wellington with its characteristic dolerite 'organ pipe' dikes and down along the mudstone Derwent River estuary. Travelling across to the south-east will reveal more sandstones in buildings and the Tasman Peninsula, where dramatic dolerite coastal cliffs also rise from the rough surf at Capes Raoul, Pillar with sharp outcrops protruding from the water, showcasing spectacular jointing and fault control.

Eastern Tasmania's sandstones and Devonian granites are spectacular. In the southeast, sandstones can be found in old convict constructed built heritage, on the Tasman Peninsula and on Maria Island. The first glimpse of granite is found at The Hazards – a pink feldspathic granite range, and the spectacular white 'Friendly Beaches' on the Freycinet Peninsula. The famous Bay of Fires on the north-east coast, with its bright orange lichen cover, is a series of I- and S-type granodiorite plumes that dip into the Bass Strait and South Pacific Ocean. Heading a few kilometres inland towards Mount Cameron reveals the remnants of an

Photos by: the authors

Just some of the incredible Tasmanian landscapes. Clockwise from top left: Mt Read (1,123 m/3,684 ft) volcanics and remnants of past glaciations throughout the Tasmanian Wilderness World Heritage Area in the distance; Growling Swallet – a 360 m (1,118 ft) deep limestone cave containing parts of the Junee River and waterfalls that suddenly 'vanish' from the surface near the Junee Cave; Eastern Granites and coasts at the Bay of Fires and Wineglass Bay; and some of Tasmania's unique dolerite expressions at Cradle Mountain and Cape Hauy.

old tin mine, which has stained waters with copper sulphates, aptly named 'Blue Lake'.

The remaining trip winds back via the spectacular dunes of the north-coast Bass Strait towards Launceston, to celebrate the world's largest expressions of dolerite across the central north. Cataract Gorge is a great place to picnic and easily traverse a dolerite riverside track. Nearby Ben Lomond features 100 sq km of alpine plateau atop spectacular dolerite vistas and Central Plateau – the largest exposure of dolerite in the world.

A visit 'Down Under' is incomplete without experiencing Tasmania's truly diverse and outstanding landforms, geology, flora, and plentiful and diverse native wildlife, all within a cultural landscape which completes an outstanding geotourism experience. ■

Edited by: Ronny Setså

Source: Impossible Metals

New designs and technological advances may contribute to reducing or even eliminating plume generation.

The Complexity of Plumes

The complex behaviour of seafloor plumes needs to be understood before deep-sea mining can become a reality.

How far will a sediment plume travel from a seabed mining site, and in what concentrations? This is a first-order problem the industry needs to solve, argued **MIT** professor **Thomas Peacock**. Peacock spoke at the **Deep Sea Minerals** conference in Bergen last October.

Peacock said that plume generation is highly dependent on the type of mining operation in question; where the locality is (such as abyssal plains or seamounts) and what extractive technology is being used (picking, vacuuming, drilling, blasting etc.). Last year, a team of researchers from MIT and Scripps Institution of Oceanography conducted a study whereby sediment was stirred up from the seabed. The results, recently published in **Science Advances**, were somewhat surprising.

The vehicle created a dense plume behind it, as expected. However, only a small fraction of the sediments was detected above 2 meters above the seafloor, while the majority of the plume (92-98%) stayed below 2 meters. These observations contrast the general belief that the sediment plumes rise higher into the water column, and that the plumes may travel far.

However, before concluding that there is no issue, Peacock stressed that the total area impacted by a plume is highly dependent on grain size distribution and that modelling and monitoring will always be required. ■

Be Transparent!

The deep-sea mining industry is facing criticism, opponency and misconceptions. The Metals Company is confronting public mistrust with honesty, by improving technology and investing in independent research.

Erika Ilves, Chief Strategy Officer at The Metals Company.• Photo: Halfdan Carstens

As an inexperienced, nascent industry, we need to deal with the elephant in the room, which is the public perception of our industry, **Erika Ilves** remarked during her talk at the Deep Sea Minerals 2022 conference in Bergen in October.

Ilves is the Chief Strategy Officer at **The Metals Company**, an exploration-stage marine mining company with licences in the Pacific Ocean.

She started off her talk by taking us back to the glorious 1960s and the beginning of the American space age. Contrary to what many may believe, the **Apollo program** was not at all supported by the public. Even when Neil Armstrong set foot on the surface of the Moon, only 53 percent of Americans were in support of governmental spending on space exploration.

Now the industry is on the rise again. But so is opposition. As an example, Ilves showed an image circulated among anti-DSM organizations depicting a turquoise shallow sea with corals and marine life. "What is wrong with this image," she asked rhetorically, knowing that most in the audience understood that deep-sea mining won't happen in the photic zone, but rather in much deeper waters with significantly less diversity and overall biomass.

"We have investigated how the anti-DSM campaign operates and the tactics they use. It is not that much different from the anti-nuclear power playbook," she claimed.

As an example of the tactics used, she stated that every single company that The Metals Company has had business relations with, has later been approached by members of the anti-DSM campaign – several times.

> "The anti-DSM campaign, including the moratorium to stop seabed mining, is supported by more than 100 organizations and is well funded. However, it is also founded by a lot of misconceptions that we need to deal with."

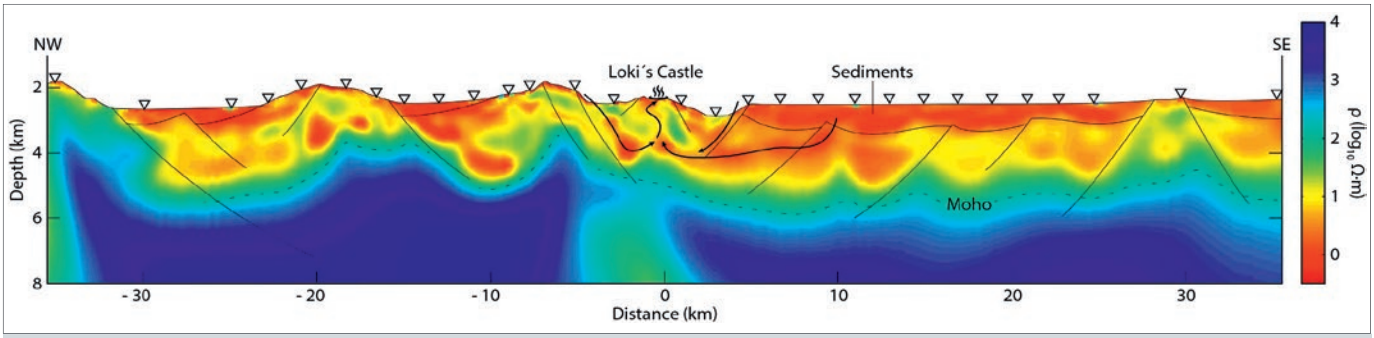
It can be argued, according to Ilves, that the deep-sea mining industry is a well-established industry.

Deep sea minerals (nodules) were first discovered by **HMS Challenger** almost 150 years ago, although efforts to extract minerals from the sea floor didn't start until the 1970s after many decades of offshore technological development. At that time, however, the industry fizzled out, mainly because of decreased commercial interest and falling metal prices.

"I guess the tactic is to make it difficult for those that are in contact with us to continue doing business with us, and thereby also making it difficult for us to operate," Ilves said.

Given this situation, Ilves reiterated that the deep-sea mining industry players need to be aware of the opposition and do their best to improve public perception in constructive ways. ■

Illustration: ATLAB/Ståle Johansen



Measured resistivity versus depth across the Mohns' Ridge at Loki's Castle. The colors show resistivity in the horizontal direction.

Deep Imaging at the Ridge

Through geophysical imaging, the ATLAB consortium is seeking to increase knowledge of the geological processes taking place at spreading ridges. Marine minerals players are paying attention.

"Our focus is increasing our knowledge on the geological development of spreading ridges, including the formation of natural resources," said **Ståle Emil Johansen**, professor at **NTNU**, at the **Deep Sea Minerals 2022** conference in Bergen in October.

Johansen presented the research being carried out by the NTNU and industry-founded ATLAB consortium. The objective of the consortium is to collect a broad range of scientific data at the Mohn's and Knipovich ridges located in the North Atlantic Ocean between Norway and Greenland, using a range of geophysical methods.

The natural resources Johansen referred to are marine mineral deposits. Hydrothermal circulation along the ridges around the world leads to vent formations that spew out boiling hot, mineral-rich water. The minerals precipitate around the vents, forming seafloor massive sulphide (SMS) deposits.

Foto: Halfdan Carstens

Ståle Emil Johansen - Professor in applied geophysics at NTNU.

Such deposits are often enriched in copper, zinc, lead, iron, gold and silver, with grades far exceeding what we find in terrestrial deposits.

ATLAB has so far completed three cruises and are planning a fourth next year. The first cruise took place at the Mohn's Ridge where several geophysical measurements were done. The survey gave the scientists insight into the plumbing system in the crust below the hydrothermal fields on the ridge, including the Loki's Castle vent field, in addition to images of the mantle down to a depth of 120 kilometres.

"Analysing the acquired conductivity data, we could see how cold sea water is seeping into the system at the edges, and then being heated up and venting out at Loki's Castle. The heat is supplied from below, from what we interpret as partly melted rocks," Johansen explained.

Last year's cruise collected a combination of electromagnetic (EM) and seismic data revealing the distribution of melt below the ridge in more detail. The researchers learned that some areas are more prone to melting and hydrothermal circulation than other areas. This year, a number of new members joined the project, which also helped fund the cruise.

"As a larger team, we were able to collect even more data from the ridges. We did seismic, CSEM, towed EM, deep MT, as well as environmental data," Johansen said.

The environmental data program included measurements of water currents, pressure, turbidity, conductivity, O_2, CO_2 and CH_4 content, environmental DNA and whale observations.

This year's data is still being processed, and results will be published next year.

"With more data from Loki's Castle, we'll be able to get a three-dimensional overview of the vent field and its plumbing system. If we can collect such data, we will be able to get more details and can start identifying what the petroleum industry refers to as plays and prospects," Johansen concluded.

Next year, ATLAB plans to collect more EM, environmental and seismic data at the ridge, both 2D and 3D. Growing from a small university project to a full-fledged consortium is paying off. ■

The **ATLAB (Atlantic Laboratory)** consortium for the acquisition of geophysical research data started as an internally funded project at NTNU in 2016. ATLAB's primary aim is to research the nature, dynamics and diversities of mid-ocean ridges and oceanic plates using state-of-the-art equipment and methodology. Previous expeditions have collected ultradeep passive magneto-telluric (MT) and controlled-source electromagnetic (CSEM) data.

The consortium members include Aker BP, Allton, CGG, EMGS, Equinor, InApril, Norce, NTNU, OFG, NPD, PGS, Shearwater and TGS.

Oil Companies are Actively Looking at Deep-Sea Minerals

Aker BP sees potential in deep-sea mining, even though the business case is not as strong as in oil and gas production.

"All extractive activity comes with costs, both in terms of money and in terms of environmental impact. Many terrestrial mines have to blast and move huge amounts of waste rock to reach the ore. **Ten percent** of our CO_2 emissions come from the extraction and crushing of rock," said **Ebbe Hartz**, Lead Geologist at **Aker BP** during the Deep Sea Minerals conference in Bergen on October 27.

Hartz pointed out that deep-sea minerals occur with far **higher grades** than the mineral deposits we find on land. That offers several advantages, including lower costs of extraction. It also means that we need a much smaller area to operate on per kg of metal we want to extract, the geologist claimed.

During his talk, he presented several diagrams that illustrate what this could mean for Norway. This country is potentially approaching the end of the opening process first set out by the former government in 2019. In the Norwegian exclusive economic zone, which includes the Atlantic spreading ridges, we find both seafloor massive sulphide (SMS) deposits and cobalt-rich crusts.

AN FPSO FOR DEEP-SEA MINING

Aker BP's calculations are based on the use of floating production, storage and offloading vessels (FPSO), which can turn round two million tonnes per year. "One mine on the seafloor, producing two million tonnes of ore per year, will occupy far less than one square kilometre. This is in stark contrast to many mines on land, which consume much larger areas," says Hartz.

According to Hartz, a potential deep-sea mine at a sulphide deposit on the Mohn's Ridge could make Norway **more than self-sufficient** for cobalt, copper, zinc, silver and gold. Of these metals, cobalt is the most important if we consider the EU's definition of supply risk, while gold could contribute the highest value per tonne of ore.

SELF-SUFFICIENT

For a Norwegian mining operation based on the extraction of crusts, Norway can be self-sufficient in as many as ten metals. "Of these metals, scandium will be the one we can export the highest share of; Norwegian scandium production based on a small mining operation (a quarter of a million tonnes per year) can cover almost the entire global demand," Hartz mentioned.

ENVIRONMENTAL CONCERNS

The Aker BP geologist reiterated that mining operations in the deep sea have negative environmental consequences but maintained that many of these can be handled with the right choice of design and technology. He explained that the company spends a lot of resources on modelling plumes (sediment clouds) that are swirled up when activities take place on the seabed.

Another impact is noise, but the geologist claimed that this too is fully manageable, for example by placing the pump that will retrieve the material from the seabed on the production ship instead of in the water.

In conclusion, the geologist said that **Norway has everything needed** to start mineral extraction on the seabed, including an industry that cooperates well with the authorities, and that what remains is for the government to open a licensing round for exploration. This could potentially happen next year, as the impact assessment in connection with the opening process was recently put forward for public consultation with deadline in January 2023.

Aker BP sees mining of deep-sea minerals as a profitable line of business, albeit not to the same extent as the oil and gas activities. ■

Photo: Halfdan Carstens

Ebbe Hartz, Lead Geologist at Aker BP.

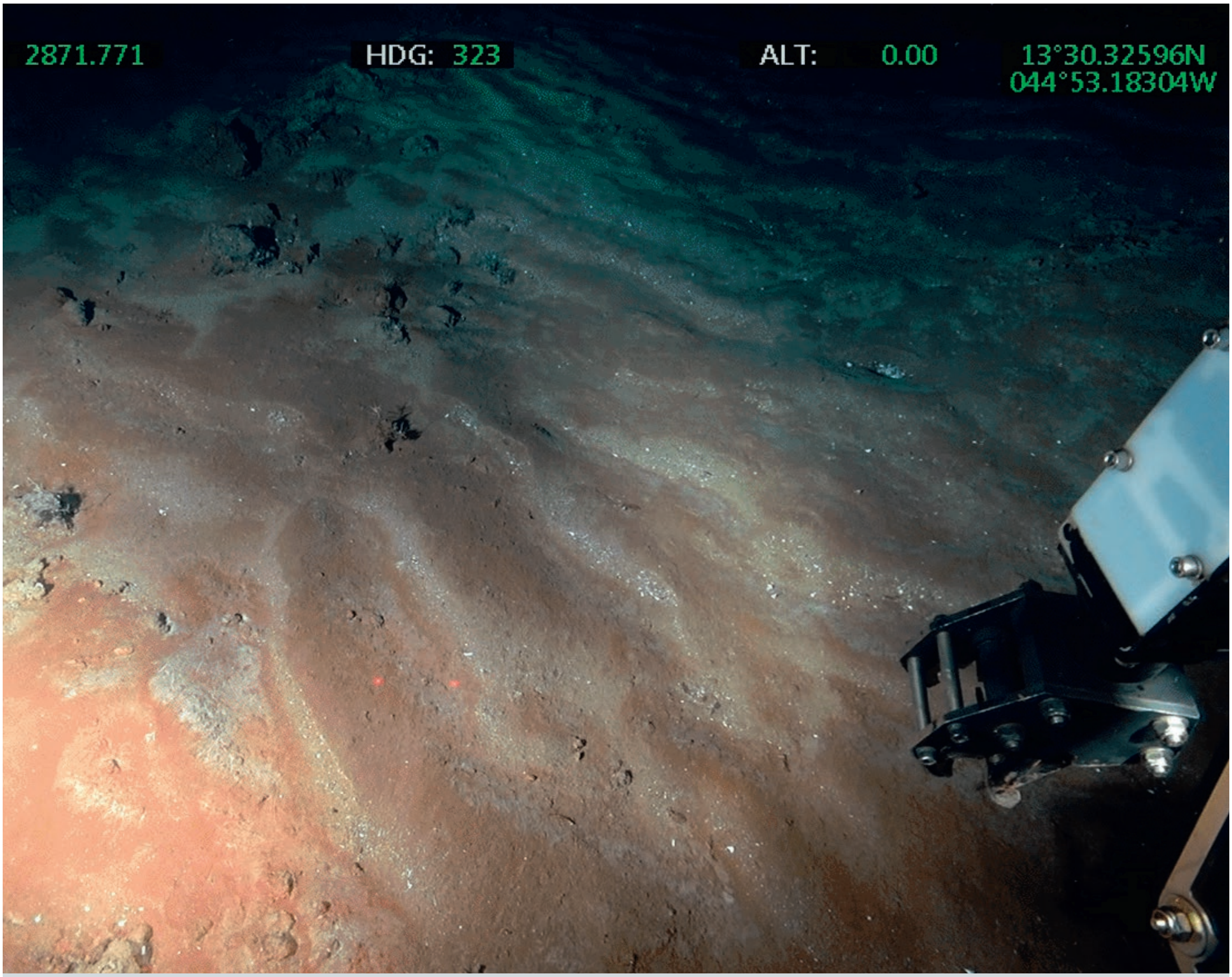
This piece of crust was collected by the Norwegian Petroleum Directorate during a cruise to the Jan Mayen Ridge.

Photo: Ronny Setsaå.

Finding Hidden SMS Deposits

The presence of metalliferous sediments is often indicative of nearby sulphide deposits. Signatures in the sediments may also indicate the deposit's tonnage.

Photo: Acer Figueroa - Project ULTRA



Sediments displaying a brown-red tint caused by the presence of certain metals.

"Metalliferous sediments are important deep-sea exploration markers," said **Acer Figueroa**, PhD student at the **National Oceanography Centre** (University of Southampton) during the **Deep Sea Minerals** conference in Bergen in October.

During his talk, Figueroa made the case that mapping these sediments may be a useful method for finding hidden seafloor massive sulphide (SMS) deposits.

SMS deposits are one of three types of deep-sea mineral occurrences which contain several of the metals that are required to succeed with the energy transition, including copper, nickel, zinc, manganese and rare earth elements (REE).

Active hydrothermal fields can be located by identifying the plumes in the water column. Inactive fields are harder to locate as they no longer spew out water with detectable geochemical signatures. In addition, inactive vents are often buried by sediments.

However, from a resource and mining perspective, buried vents are preferred over active ones as one avoids challenging high-temperature fluids and disturbing vulnerable fauna.

The PhD student explained that metalliferous sediments are formed generally by two processes.

1. They can be created by the fallout from hydrothermal plumes sourced from vents. These plumes can travel far, and the sediments will typically be well-sorted and fine-grained.
2. They can also be created by mass flows. These deposits are located close to the hydrothermal vents and are generally poorly sorted consisting of coarser grains.

Figueroa presented some results from the research that he and his colleagues did when they went on a cruise to the **Semenov hydrothermal field** cluster on the Mid-Atlantic Ridge (13º30'N, approximately the same latitude as Senegal and Nicaragua) earlier this year as a part of the **ULTRA project.**

The project, which will return to the ridge next year, has and will collect a variety of data from the sites of mineralization, including drilling and coring, rock collecting, mapping the seafloor and using ocean-bottom seismometers.

"The cores closest to the hydrothermal vents displayed higher concentrations of certain metals, such as iron, zinc, lead and copper," Figueroa explained. It thus seems that mapping these sediments can be used as a method for locating nearby buried hydrothermal deposits.

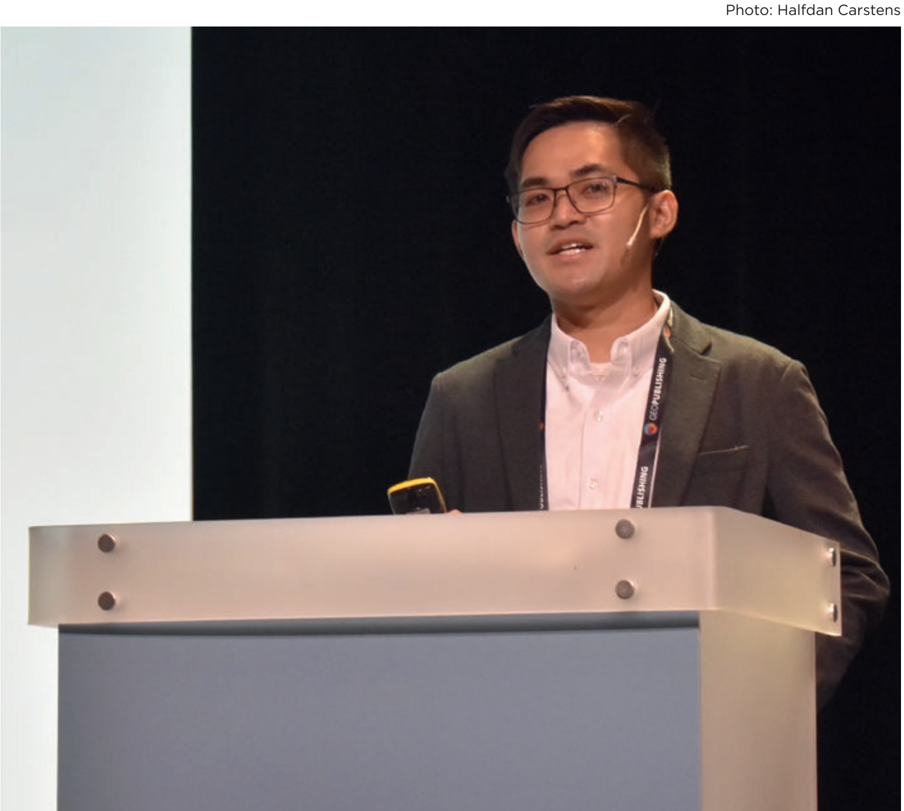
He also pointed out that discovering mass flow products within the sediments would be a good find, as they indicate that a deposit will be very close by.

Mapping metalliferous sediments in a grid will give a spatial distribution of the metal content in the sediments that provide vectors to hidden deposits. It could be an important tool in the exploration toolbox. Figueroa also said that his upcoming work will include dating the sediments. This will give insight into the longevity of a hydrothermal area.

"If we can determine how long a hydrothermal vent area has been active, then we will also know more about the potential tonnage of the deposit. Longer periods of hydrothermal activity typically yield larger deposits," Figueroa concluded.

Partners in Project ULTRA include the universities of **Cardiff**, **Southampton**, **Leeds** and the **Memorial University** (Canada), as well as **GEOMAR** (Germany). Norwegian project participants are the **University of Bergen**, **Equinor** and **Green Minerals**. ■

Photo: Halfdan Carstens



PhD student Acer Figueroa explained how sediment mapping could be used as an exploration tool in the deep sea.

Maximising the Potential of Seismic Expressions by Surgical Geological Modelling and Spectral Decomposition

One of the ultimate goals of seismic interpretation is to accurately delineate geological objects. The process of spectral decomposition reveals the distinctive frequencies encompassing an energetic maximum relative to a geological target, to be extracted and mapped through a red-green-blue viewer.

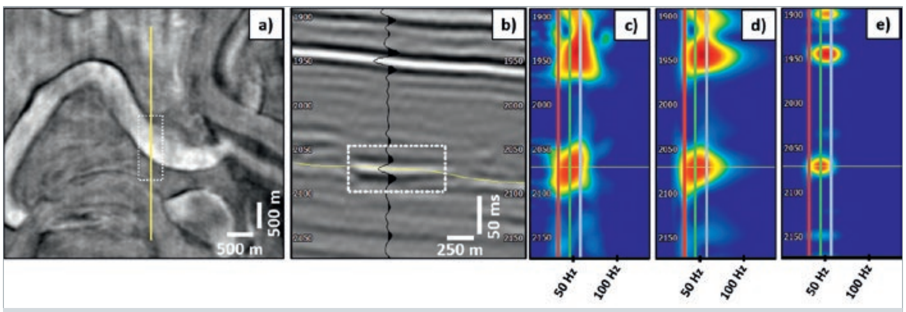


Figure 1: Turbidite channel observed on a) an RGT isochrone with mapped seismic amplitudes and b) a vertical seismic section. Three different spectrograms of a single trace intersecting the channel: computed from c) STFT, d) CWT and e) MP. (MAUI dataset, courtesy of Government of New Zealand).

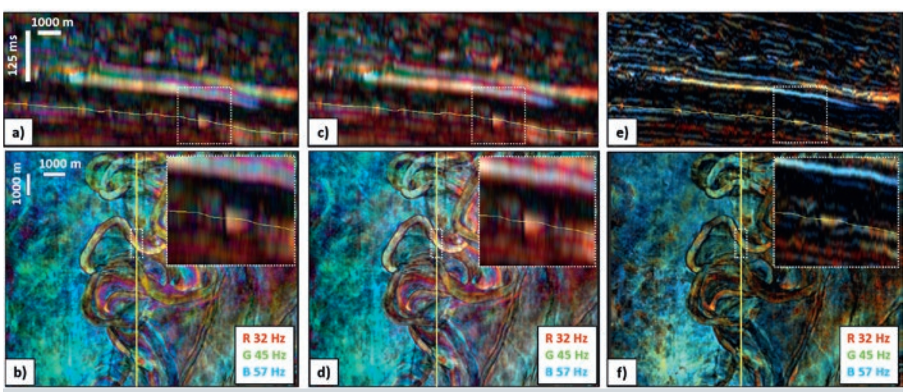


Figure 2: Red-green-blue inline and horizon views of spectral decomposition from STFT (a-b), CWT (c-d) and MP (e-f) at 32Hz, 45Hz and 57Hz.

Text: **Lory Evano and Fabien Cubizolle; Eliis**

Spectral decomposition methods are widely used to highlight geological features according to their frequency content. However, the frequencies characterising the targeted event might vary spatially, which complicates their extraction as 3D geological objects.

Generally, the picking of the frequencies representative of the targeted event is performed by selecting one specific trace directly from seismic lines. The picked frequencies may not be fully representative of the tracked object, which may reduce confidence in the process. On top of that, the spectrogram's accuracy varies according to the spectral decomposition method and its parameters. All these limitations give rise to a high level of uncertainty and therefore risks.

COMBINING SPECTRAL DECOMPOSITION WITH GEOLOGICAL MODELLING

To assess geological targets, the traditional interpretation method consists of tracking the target object by scanning the seismic volume spatially and temporally (inlines/cross-lines vs time slices). However, a single object generally lies on several lines and geoscientists tend to have a hard time juggling spatial distribution in three dimensions.

To overcome this issue, a **Relative Geological Time** (RGT) model, where a relative geological age is assigned to each voxel belonging to the same depositional surface, can be calculated from a comprehensive seismic interpretation method. Seismic amplitudes and derived attributes are mapped on a dense stack of isochronous surfaces extracted from the RGT model, allowing an interactive scanning of the seismic data and, thus, facilitating the spectral signatures emphasis and subsequent 3D delineation of the targeted object. Finally, this high density of horizons enables a thorough selection of the tracked object's most representative frequencies (Figure 1).

IDENTIFICATION OF TURBIDITE CHANNELS

The three spectral decomposition methods have been applied to a turbidite system from the MAUI dataset located offshore New Zealand in the Taranaki Basin. For this dataset, the visualisation of the turbidite system is challenging because of entangled geometries. The 32Hz, 45Hz and 57Hz frequencies were selected to display an optimum contrast for revealing the geometrical details and features of the sedimentary system such as the contour, thickness and connectivity of its constitutive elements.

A vertical window of 21ms is performed for the STFT and Morlet wavelets are used for the CWT and MP algorithms. The frequency-decomposed amplitudes are mapped into a red-green-blue viewer (Figure 2). The low-vertical resolution of the STFT and the CWT displays the energy of the stacked channels on more horizons than the MP. As a consequence, multiple events can overlap, which creates uncertainty with regards to the independent delineation of

SPECTRAL DECOMPOSITION ALGORITHMS

The **Short Time Fourier Transform** (STFT) and the **Continuous Wavelet Transform** (CWT) are the main spectral decomposition algorithms used for seismic interpretation.

STFT method consists of performing a Fourier transform inside a sliding window, implying a time-frequency resolution dependent on the window length. Indeed, the larger the sliding window, the greater the frequency accuracy will be. However, this is at the expense of vertical resolution. Reciprocally, the smaller the sliding window, the greater the vertical resolution will be. In this case, a loss of frequency resolution takes place.

The CWT convolves the seismic signal with different compressed-dilated wavelets, allowing a multi-resolution analysis of the signal, not available with the STFT. It generates high temporal resolution at high frequencies and high-frequency resolution at low frequencies.

MATCHING PURSUIT IMPROVES SEISMIC INTERPRETATION

Matching Pursuit (MP) is a third method that offers better temporal as well as frequency resolutions compared to the STFT and the CWT (Figure 1 c-e). Its resolution is similar to seismic data, but its iterative process lengthens the computation time. Indeed, each seismic trace is decomposed in a linear combination of wavelets that locally match the seismic data. The best wavelets are identified by correlation in varying their frequency, phase, scale and time delay. The high-resolution accuracy of the MP combined with the horizons generated from the RGT model results in the emphasis on geological feature delineation.

For the tree methods described above, a spectrogram can be computed along a trace chosen from the interactive scanning of the seismic lines and the dense isochronous surfaces obtained from the RGT model. The spectrogram corresponds to the trace time-frequency spectrum and helps pick the most representative frequencies of the tracked geological object. Once the iso-frequency volumes are computed, they can be blended in a Red-Green-Blue (RGB) viewer and mapped on the dense stack of horizons for further analysis.

individual channels. In turn, this can lead to wrong volumetrics estimations.

Thus, the high vertical resolution of the MP combined with the high number of horizons extracted from the RGT model enables a better delineation of geological objects, improving their modelling and then their interpretation (Figure 3).

LEVERAGING THE RGT MODEL TO GUIDE MATCHING PURSUIT

In addition to being time-consuming, the Matching Pursuit method is sensitive to small changes in seismic amplitudes, leading to lateral discontinuities in the extracted iso-frequencies. To solve this issue, the lateral coherence of seismic traces can be used as a constraint during the decomposition.

Indeed, by assuming that the waveforms along a reflection are continuous to a certain extent, a 3D structural constraint is added to the Matching Pursuit decomposition through the use of the RGT model. From a picked seed trace, wavelets are extracted using the Matching Pursuit and iteratively propagated laterally along the RGT model iso-values to reconstruct seismic reflectors (Figure 4a).

The RGT model helps identify at which time the wavelets need to be propagated and extracted to the neighboring traces. The waveforms along a seismic reflection change progressively when moving away from the trace where the wavelet has been extracted. Consequently, the propagation of the extracted wavelets must be stopped when the waveforms on the neighbouring traces are too different from the initial wavelet.

In summary, the method described here avoids going through the computation-heavy and time-consuming Matching Pursuit process where each trace is processed independently. In addition, the extracted iso-frequencies are less sensitive to noise and are more geologically consistent with better lateral continuity (Figure 4b & 4c).

ACKNOWLEDGMENTS

The presented workflow was obtained using PaleoScan™, software developed by Eliis. The authors would like to thank New Zealand Petroleum & Minerals and the New Zealand government for their permission to use and publish the MAUI dataset.

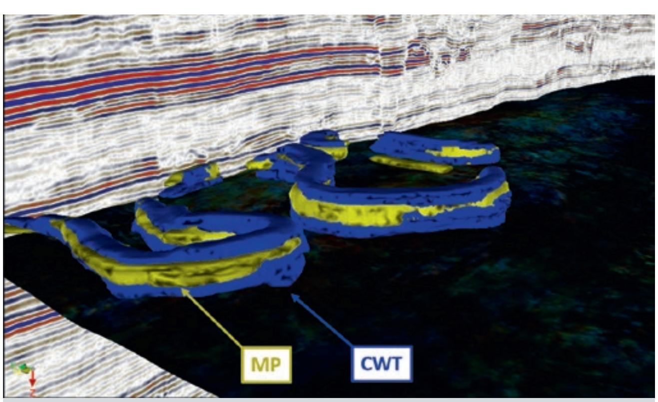


Figure 3: 3D manual extractions of the turbidite channel based on CWT and MP spectral decomposition.

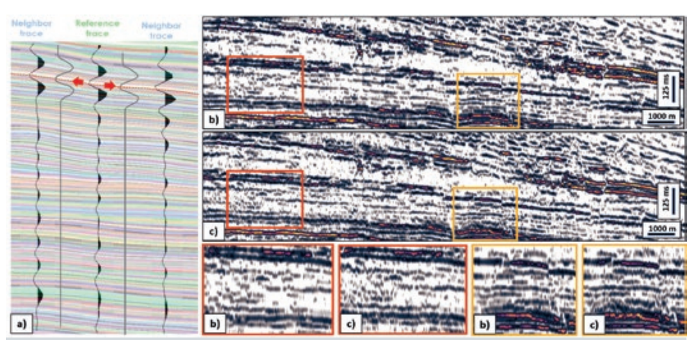


Figure 4: a) Multichannel Matching Pursuit based on the propagation of the extracted wavelet from a reference trace to neighbouring traces guided by an RGT model. 45 Hz iso-frequency extracted using b) the RGT model-based multichannel and c) the classical matching pursuit algorithms.

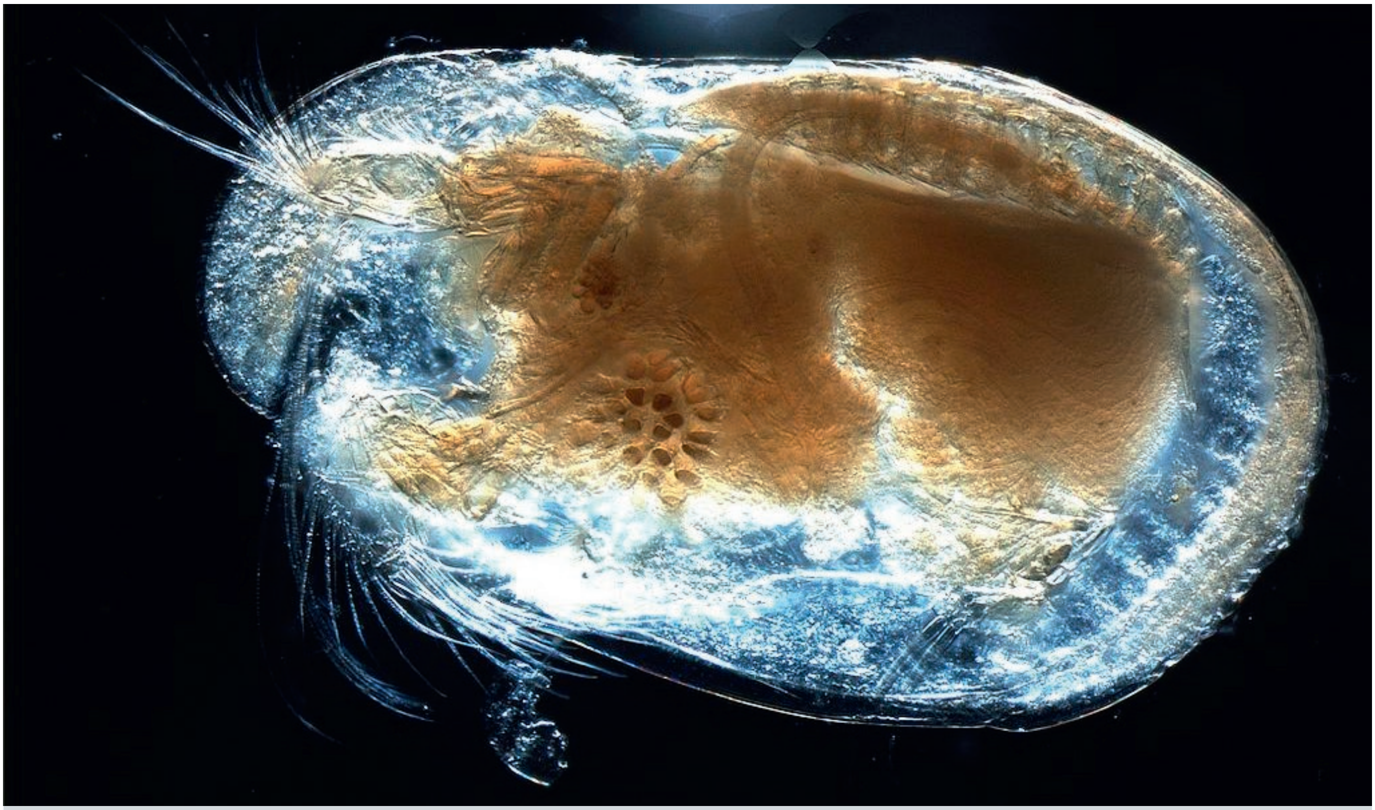


Figure 1. Microscopic image of an extant ostracod. These tiny crustaceans are known to have appeared in the fossil record at least as early as the early Ordovician and are remarkably adaptive, living everywhere from marine to terrestrial aquatic environments.

Microfossils and the World of Chalk and Chert

In this article, James Etienne touches on the importance of microfossils and takes us on a journey from North Africa, via Ekofisk in the North Sea, to California in the USA.

Text: Dr James Etienne
james.etienne@halliburton.com

Dr James Etienne

Microfossils are those fossils that require a microscope to carry out fundamental identification. They are the fossils of a biologically diverse group of organisms, including microscopic algae, protists, and invertebrates, and are noted for their geological utility.

Many groups of microfossils exhibit a rapid evolution rate as a result of sensitivity to palaeoenvironmental conditions. As a consequence, they often include short-lived species that have excellent value in calibrating age, correlation and assessing palaeoenvironmental conditions.

Microfossils are therefore essential to biostratigraphy and for several intervals of geological time they are ***the*** diagnostic zone fossils. Microfossils are abundant in most sedimentary rocks, and because of their small size are more likely to be preserved and recovered from well cuttings and core than macrofossils are (see also: GeoExpro 2022-5, 72-75).

They provide a basis for subsurface correlation, geochemical studies, understanding of palaeoenvironments, and even source rock maturity. Under the right palaeoceanographic conditions, microfossils have also been deposited in such vast numbers that they are the primary material for the accumulation of some extremely economically important types of rock, including chalk and siliceous rocks such as chert and porcelanite.

VARIED HABITATS

Microfossils include some groups of organisms which remain extant today (for example **dinoflagellates**, **ostracods** (Figure 1) and **foraminifera**) and others that are now extinct (for example **chitinozoans** and **conodonts**). Extant taxa are particularly useful, as a sound understanding of their biology and ecological niches can be used to drive palaeoenvironmental interpretation and reconstruction from fossil occurrences.

Microfossils represent a very diverse suite of zoological and botanical groups of organisms from single-celled to multicellular organisms and larger animals that we only find fragmentary remains of (e.g. conodonts). Like macrofossils, microfossils represent flora and fauna from varied habitats, from marine to terrestrial environments, and across the full aquatic realm from the photic zone to the benthos on the sea floor and across all water depths.

Ostracods, such as the example in Figure 1, are the fossils of tiny **crustaceans** (arthropods). They are remarkably well adapted to aquatic environments including a variety of marine, brackish and freshwater habitats and can even survive on land provided there is sufficient moisture.

By contrast, the foraminifera ("forams") are the fossil remains of protists that represent a component of both the marine zooplankton (*Globigerinina* suborder) and the benthos (11 suborders including the agglutinated forams from the suborder *Textulariina*). Benthic forms adapted to live on, and in, the top layer of the seafloor substrate and are very sensitive to seawater temperature, salinity and other environmental conditions. This makes them excellent indicators for palaeoenvironmental reconstruction. Care is needed in foram identification – in the *Globigerinina* alone, of the 2000+ described planktonic foraminifera as many as half probably represent synonyms of already described species.

Other groups like the **acritarchs** include more than 10,000 described fossils that are of poorly resolved affinity. Then there are the **radiolaria**, the **calpionellids**, the **chitinozoans**, **dinoflagellates**, **silicoflagellates**, **diatoms**, **palynomorphs** (spores and pollen) and many more. It is impossible to cover everything in this short article, so if you fancy a bit of further reading check out Howard Armstrong and Martin Brasier's classic textbook "Microfossils" or Marius Dan Georgescu's "Microfossils through time: an introduction."

Photo: James Etienne.

Figure 2. Some foraminifera grew so large that they are effectively macrofossils, even though a microscope is still required to observe the internal morphological details critical for identification. I collected this specimen 28 years ago from the Eocene Bracklesham Group in Bracklesham Bay on the south coast of England. The large round discs are the fossilised tests of the foraminifer Nummulites laevigatus. They are so common, you can find them eroded out of the formation, littered all over the beach at low tide.

GIANT FORAMS FOR GIANT FIELDS

Some foraminifera grew so big that they could be regarded as macrofossils (Figure 2). They are an important component in the formation of nummulitic limestones which take their name from the ***Nummulites*** foraminifera that are the dominant bioclastic grains in those rocks. One such accumulation of nummulitic limestones is the Eocene (Ypresian) El Garia Formation, a prolific hydrocarbon play along the North African margin.

Numerous discoveries have been made in these limestones offshore Tunisia (including the **Ashtart** and **Zarat** fields amongst others), and in offshore Libya where the Giant **Bouri field** in concession NC-41 is the largest producing oil field in the Mediterranean Sea. In Bouri, banks of *Nummulites* foraminifera were accumulated as a result of hydrodynamic reworking and comprise the primary reservoir facies in the field.

CHALK AND EKOFISK

Last year, the **Ekofisk** field (Figure 3) in the Norwegian sector of the North Sea celebrated 50 years and over **3 billion barrels** of cumulative oil production. The field was discovered in 1969 by **Phillips Petroleum Company** and produces from a 300 m thick oil column 3 km below the modern sea bed in Chalk reservoirs of the Paleocene **Ekofisk Formation** and the late Campanian to Maastrichtian **Tor Formation**. Both formations vary in thickness up to 150 m across the Ekofisk area. The Cretaceous Chalk is regionally extensive (Figure 4)

Photo: BoH under CC BY-SA 3.0.

Figure 3. The Ekofisk platform complex in the Norwegian sector of the North Sea. It acts as a major transportation hub for surrounding fields including Valhall, Statfjord and Gullfaks.

and can reach thicknesses of up to 400 m.

Chalk is essentially a fine-grained limestone composed dominantly of the calcified skeletal debris of haptophyte algae called coccolithophores (Figure 5). Other microfossil grains include planktonic foraminifera and sponge spicules and other minor components (debris from echinoderms for example).

In the Ekofisk area, reservoir properties are excellent with 30-48% interparticle microporosity. Up close, there is a surprising amount of stratigraphic and facies variability in Chalk successions, but from a reservoir perspective the critical factors are pore throat size and tortuosity. Permeability is tight at 1-5 mD but is significantly enhanced by natural fractures (up to 100 mD in places).

Fracture porosity does not contribute much in terms of pore volume but greatly enhances horizontal and vertical permeabilities. A significant body of literature exists on the Chalk with extensive case studies available from numerous fields. It is clear that reservoir quality is impacted by the original depositional facies, burial diagenesis and the timing of oil migration and saturation.

Ekofisk was a ground-breaking discovery and highlighted the significance of the Chalk as an important hydrocarbon reservoir in the North Sea – tens of billions of barrels of oil-equivalent hydrocarbon resources in place have subsequently been identified in North Sea Chalk reservoirs, and with modern stimulation and enhanced oil recovery methods will continue to provide important production.

Optimised well placement in Chalk reservoirs has been facilitated by biosteering using detailed zonation schemes for microfossil assemblages. Some of the higher porosity zones in the Ekofisk Formation are related to debrites which include reworked Cretaceous microfossils mixed with in situ Danian (Paleocene) taxa. The proportions of reworked taxa versus those in situ are sufficiently diagnostic to identify which debris flow unit is being drilled and ensure wells are landed and maintained in-zone to maximise reservoir contact. This approach has kept many Chalk fields profitable beyond original expectations.

PALAEOCLIMATOLOGY

Because of their sensitivity to palaeo-environmental conditions, many groups of microfossils are incredibly useful as palaeoclimatic indicators. Palynomorph assemblages are important indicators in terrestrial environments where floral assemblages react very quickly to changes in temperature and aridity. Foraminifera, along with ostracods are arguably the most important groups for such analysis in the marine realm, with specific indicator species, certain morphotypes, composition of microfossil assemblages and preservation styles all relevant to deducing palaeoenvironmental conditions. A number of statistical techniques are used to assist in the analysis of assemblage data.

Foraminifera can provide proxy data for water depth, temperature, salinity, bulk water chemistry, pH, degree of mixing, oxygenation levels of bottom waters and more. These trends can also be related to broader changes in eustacy, oceanic circulation and the opening and closure of oceanic gateways resulting from geodynamic events. Under the right conditions, extremely high rates of organic matter burial can even perturb the carbon cycle.

DIATOMITES, CHERT AND PORCELANITE

One such event is thought to have occurred during the middle to late Miocene where a change in thermohaline circulation drove the intensification of upwelling around the Pacific Rim, reflected by the widespread deposition of diatomites. Diatoms are photosynthesising green algae that have a siliceous frustule or skeleton and are the primary producers in the world's oceans today. Diatomite sedimentation was broadly coincident with significant cooling and expansion of the West Antarctic ice sheet and a positive carbon isotope excursion reflecting rapid global drawdown of carbon.

At least some contribution to this event is thought to be associated with the deposition of the **Monterey Formation** in **California**. The Miocene Monterey Formation is a thick and organic-rich succession of rocks including mudstones, dolomites, limestones, diatomites, chert and porcelanite. These rocks are the source of most of the conventional oil in California (nearly **40 billion barrels**), a succession that is particularly rich in biogenic silica derived from diatoms, silicoflagellates and radiolaria.

In the Monterey Formation, diagenesis of biogenic silica (Opal A) has led to both Opal CT and stable diagenetic quartz cementation, which vary depending on temperature as a function of burial depth. Some fields produce directly from these chert and porcelanite beds, including two reservoirs in the **Elk Hills** field (onshore) which have delivered cumulative production of more than **80 million barrels** from laminated porcelanites with quartz-phase mineralogy. The rocks are tight (0.8 mD) but are enhanced by natural fractures. Elsewhere, in the offshore, production from the Monterey comes from matrix porosity associated with rocks in the Opal CT phase (also enhanced by natural fractures, e.g. Figure 6).

In the Monterey, as with Chalk reservoirs, the timing of hydrocarbon generation and reservoir saturation also plays a role in how porosity is distributed in the resulting diagenetic cements. Natural fractures are known to enhance reservoir characteristics for these otherwise tight rocks, but with additional structural complexity this is not a simple unconventional resource target. Understanding the role microfossils play in the formation and diagenesis of these rocks has been key to understanding reservoir characterisation – a lesson learned as the Monterey is applied as an analogue to siliceous reservoirs elsewhere in the world.

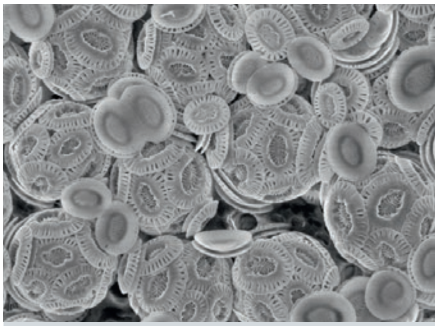
Photo: Ian Stannard under CC BY-SA 2.0.

Figure 4. Turonian-Santonian Chalk viewed from the air at Beachy Head in England. Standing at 162 m tall, this spectacular exposure gives a good sense of the thickness of the stratigraphically younger Chalk in the Tor Formation and Ekofisk Formation reservoirs in the Ekofisk area of the Norwegian North Sea. At Ekofisk the total oil column height is 300 m – so the reservoir interval is nearly double this thickness.

FROM LUCA TO LUCY

In summary, microfossils represent a remarkably diverse suite of zoological and palaeobotanical groups. They are incredibly important for subsurface interpretation, facilitating correlation, palaeoenvironmental interpretation, thermal maturity assessments and many other industrially and academically important uses. They have also led to the generation and accumulation of significant volumes of hydrocarbons, and will no doubt influence our understanding of the storage potential (and challenges) associated with depleted fields and saline aquifers for CO_2 storage.

This article wraps up this year's series of contributions on fossils. Over the year, we have looked at the fascinating world of fossils from folklore and culture to trade, complexities of ownership, considerations for collection, preparation and preservation of fossils, evolutionary traits from LUCA to LUCY, apex marine predators of the Jurassic and the many ways in which fossils help decode the subsurface. Whatever your interest in fossils, I am sure you will agree that they offer a fascinating insight into the world beneath our feet and the history of our planet!



Credit: Robin Mejia. Image Courtesy Dr. Alison Taylor under CC BY-SA 4.0.

Figure 5. Scanning electron microscope image of the calcified debris of coccolithophores that make up Chalk. There is evidence that a lot of this material was eaten and excreted by marine zooplankton as faecal pellets. Gallois calculated it would take 400 million of these to cover the surface of a coin. Just think how many of these algae bloomed to create the great thickness of chalk formations in the Cretaceous and Paleogene.

Photo: Professor Richard J. Behl, California State University Long Beach.

Figure 6. Intensely fractured Opal CT chert in outcrop, Monterey Formation. In the subsurface, natural fractures enhance the permeability of these rocks allowing them to be productive hydrocarbon reservoirs. For more information on the Monterey, including some of the latest research check out the incredible MARS project (Monterey And Related Sediments).

Angolan Kwanza Basin – Expanding Proven Opportunities

Overcoming Pre-Salt imaging challenges by leveraging high-end technologies to enhance imaging of existing seismic data.

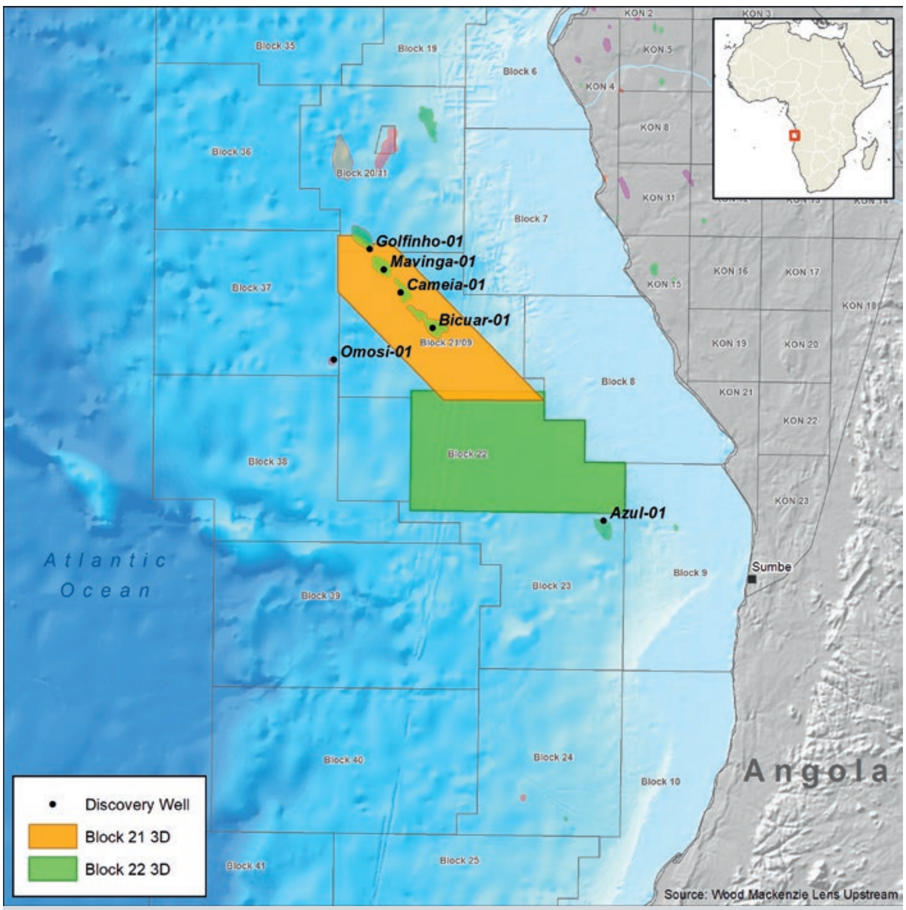


Figure 1: Map showing the location of Blocks 21 and 22 multi-client survey in the Outer Kwanza Basin, Angola.

LEGACY DATASET

CGG's Block 21 and 22 broadband 3D multi-client surveys (Figure 1) were acquired in the deep-water Outer Kwanza Basin with a total data coverage of over 7,000 km². The Block 21 survey is located on the exploration trends of the Cameia, Mavinga and Bicuar discoveries. These two datasets are currently being re-processed, and the first phase has now been completed with the re-processing of a sub-set of the Block 21 survey.

Advanced imaging techniques were applied as part of the processing sequence. These included machine learning algorithms for denoise and seismic interference removal, interpretation by fault extraction, and time-lag full-waveform inversion (TLFWI) to produce a more accurate velocity model. The net result is enhanced Pre-Salt imaging and better-defined salt boundaries on the RTM image.

Text: Madhurima Bhattacharya and Harrison Moore, CGG

Seismic imaging in the **Kwanza Basin** in **Angola** has historically proven challenging owing to complex geology and the presence of deep Pre-Salt targets. **CGG** has recently started a program to re-image its Kwanza Basin multi-client data portfolio in order to benefit from new insights made possible by advanced proprietary imaging techniques that have already been proven in other Pre-Salt basins. The newly re-processed data will enable interpreters to produce meaningful interpretations to reveal new exploration targets.

KWANZA BASIN – A PRE-SALT SUCCESS STORY?

Historically, exploration activity has focused on the prolific **Lower Congo Basin** in **Northern Angola**, concentrating on the post-salt **Upper Cretaceous** and **Tertiary** reservoirs. The resounding success of **Lower Cretaceous** Pre-Salt reservoirs in the **Santos** and **Campos Basins** of **Brazil** forced explorers to look at the conjugate West African Kwanza Basin, which shares promising geological similarities across the margin.

Thirteen significant Pre-Salt discoveries were made in the early 2010's in the Kwanza basin. In Block 21, five exploration wells have been drilled so far. These wells have confirmed the existence of approximately **780-800 MMboe** of recoverable reserves. The most significant of these discoveries (Figure 1) was the light oil **Cameia-1** discovery in a four-way dip-closed structural trap in an **Aptian reservoir** with at least 500 meters of closure (Cazier et al., 2014). The well encountered approximately 300 m of gross oil column with over 270 m of net pay in a Pre-Salt carbonate reservoir which is a mixture of chert, dolomite and limestone.

This was followed by further discoveries in the block such as Mavinga and **Bicuar**. Bicuar was the first syn-rift discovery in the deep-water Kwanza Basin and encountered

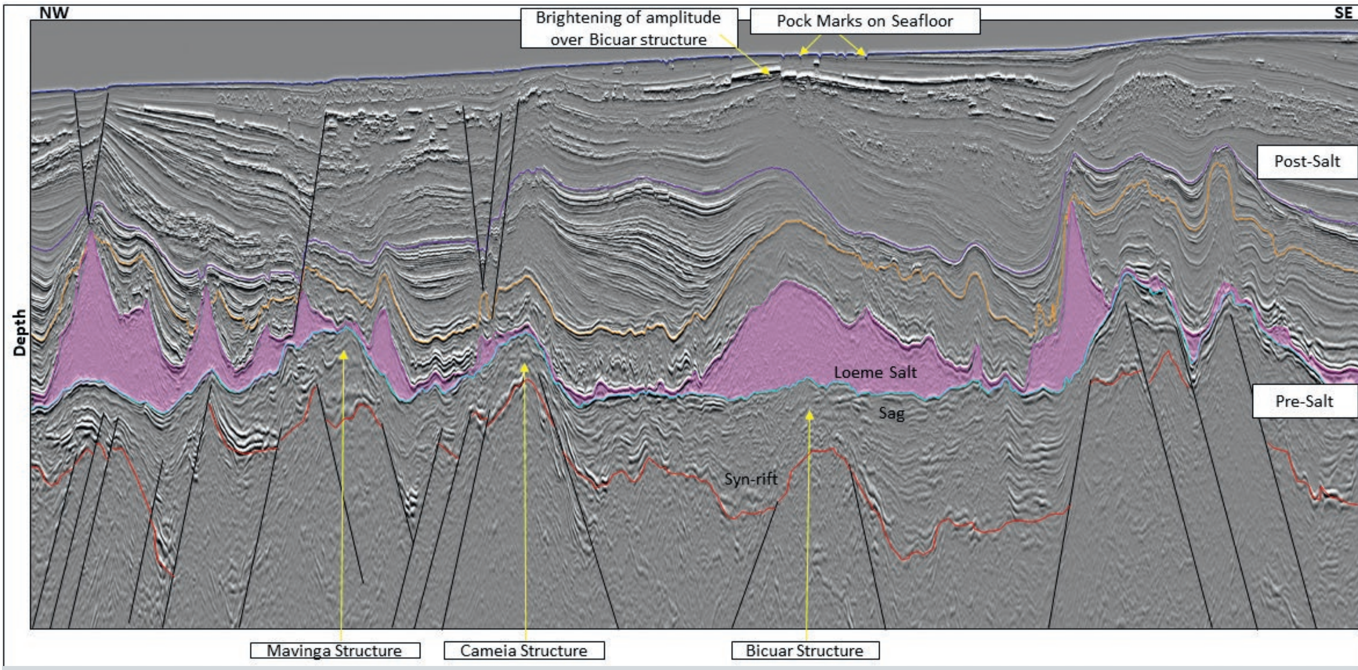


Figure 2: A regional interpreted seismic section (displayed with a pseudo-relief seismic attribute) through the legacy Block 21 survey highlighting the Mavinga, Cameia and Bicuar structures. Note the large shallow direct hydrocarbon indicator (DHI) as a result of fluid accumulation seen over the Bicuar structure.

56 m of net pay. Currently, the Cameia discovery is expected to start production in 2025, and development will involve the drilling of approximately five wells, including an FPSO and subsea trees.

THE PRE-SALT PLAY OF KWANZA BASIN

All the key elements of a working petroleum system are present within the Pre-Salt (Figure 2). The play consists of **Barremian** type I oil-prone source rocks of the **Bucomazi Formation** which were deposited in deep anoxic lakes charging the Pre-Salt reservoirs. The sag interval is characterised by carbonate deposition in restricted alkaline lacustrine settings. These excellent reservoirs have been proven in both the Cameia and Mavinga discoveries. Oil generation probably began in the deeper parts of the syn-rift graben during or after late sag deposition (Saller et al., 2016). The regional **Loeme salt** along with tight carbonate layers deposited over the Pre-Salt unit act as an excellent vertical regional seal. In addition to these carbonate reservoirs, deeper sag and syn-rift sands of the **Cuvo Formation** act as the secondary reservoirs within the Pre-Salt section.

SEISMIC IMAGING CHALLENGES

The latest proprietary pre-processing, velocity model building and imaging algorithms were applied to generate a high-quality image for improved prospect mapping. Starting from raw vintage data allowed for the implementation of the latest advances in pre-processing technology to tackle existing challenges at the source, most notably high-frequency multiple suppression using a targeted de-multiple modelling and subtraction workflow, as well as attenuation of the complex receiver ghost from the variable-depth streamer with 3D de-ghosting algorithms.

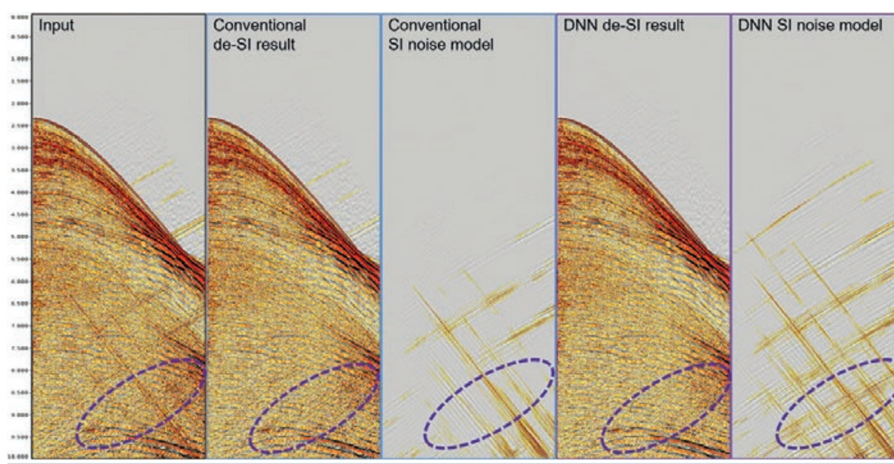


Figure 3: A comparison on a shot gather of a conventional (G2) de-SI method and the designed Deep Neural Network (DNN) based method. The DNN algorithm attenuates significantly more SI noise, particularly in areas of lower amplitude discrepancy with primary data.

An additional requirement was fully addressing the seismic interference (SI) noise caused by other seismic vessels conducting acquisition in the area as well as coherent noise from numerous and unchecked local fishing vessels, an ever-present issue offshore Angola. To attenuate this noise, an innovative machine-learning algorithm was designed using a trained **Deep Neural Network** (DNN). The DNN flow (Sun et al., 2022) outperformed conventional de-noise methods, particularly in areas of comparable amplitude between primary signal and noise (Figure 3).

With the newly pre-processed data available, the biggest challenge still had to

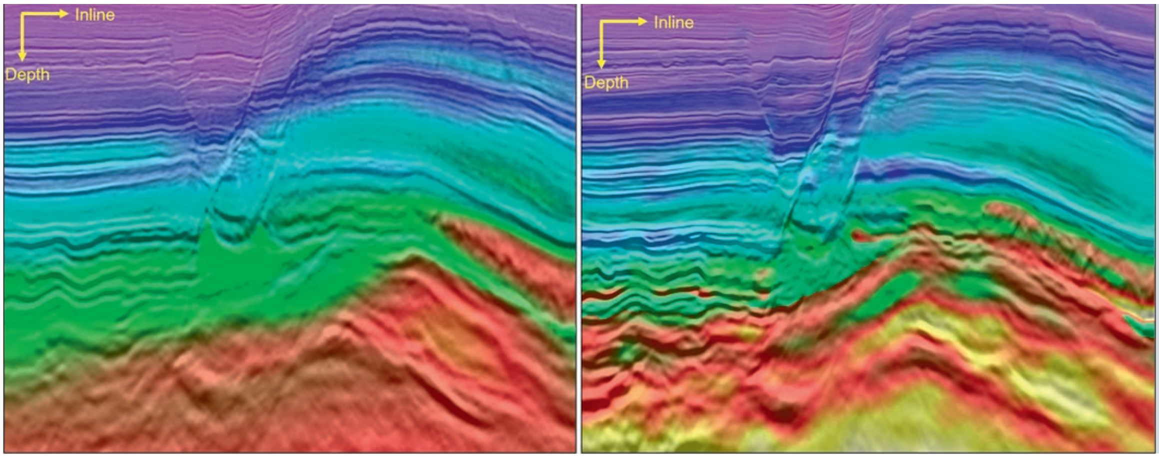


Figure 4: A comparison of the legacy stack (left) and newly imaged re-processing (right). The velocity model overlay highlights the improved detail achieved with TLFWI whilst the underlying seismic highlights the opportunity for a new analysis of the reservoir package.

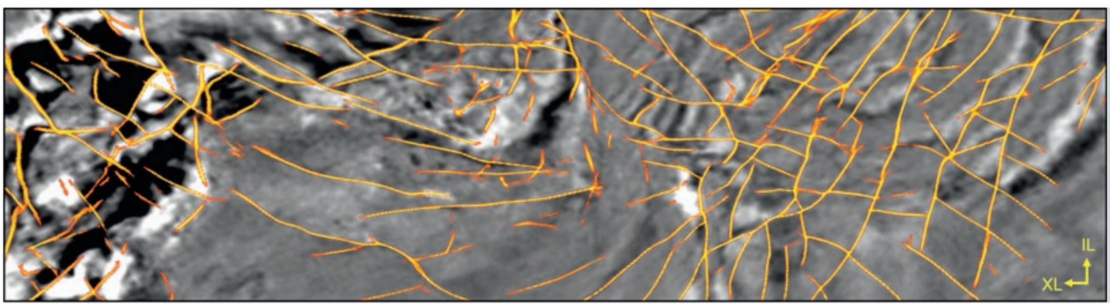


Figure 5: Machine Learning fault extraction algorithm provides a robust interpretation of the complex polygonal faulting. The colour intensity defines the probability of a recognized fault on this depth slice according to a trained Deep Neural Network.

be overcome: generating a detailed velocity model for final imaging in a geological setting with strong fault-bounded velocity contrasts from layered carbonates and salt. To this end, **TLFWI** (Wang et al,. 2019) was utilised as the main model-building tool. The algorithm employs a cross-correlation-based cost function to measure travel time differences between real and synthetic data. This allows it to mitigate the amplitude and cycle-skipping issues plaguing conventional FWI algorithms at strong impedance contrasts, e.g. salt-sediment and carbonate-sediment boundaries.

The TLFWI update provided both the layered and localized detail required to represent this geological setting (Figure 4). It proved particularly effective in resolving the velocity contrasts arising between the layered carbonate sequences, even in areas with a contrast greater than 1500 m/s over 50 m between layers. In addition, the use of reflections as part of the full wavefield in TLFWI allowed for an accurate update of velocities in the Pre-Salt, capturing both the sag sequences and reservoir packages in the velocity field. Final depth imaging gave an improved structural understanding of the base salt and deeper faulted structures (Figure 5), with well-tie analysis showing notable improvements in reservoir depth position.

NEW EXPLORATION OPPORTUNITIES

This newly re-imaged dataset opens the door for a fundamental re-assessment of the Pre-Salt system present in the Kwanza Basin. An arbitrary line through the Mavinga and Cameia wells in the area (shown in Figure 6) highlights the improved resolution of the sag carbonate reservoirs. The base salt is better focused and more easily trackable. In addition, previously weak and fragmented syn-rift sands were revealed. The re-processing now allows for a re-assessment of this deeper secondary reservoir in the promising Kwanza basin. ■

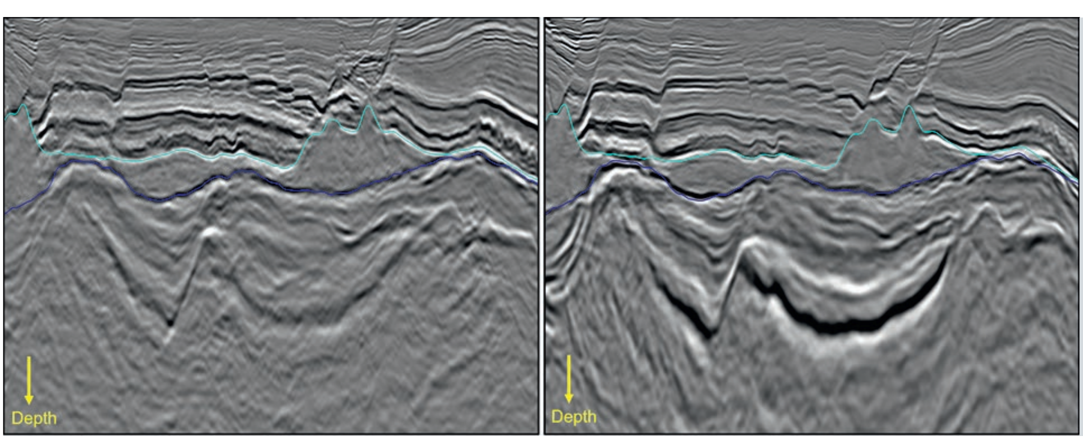


Figure 6: A comparison of the legacy stack (left) and newly imaged re-processing (right). Legacy horizon overlays of Top Salt (cyan) and Base Salt (blue) give an indication of the structural highs in the area. Potential re-interpretation of these legacy horizons with increased confidence is now achievable to map out the deeper syn-rift packages as well as re-define the prospective reservoir intervals across the wider Block 21 area.

NVENTURES

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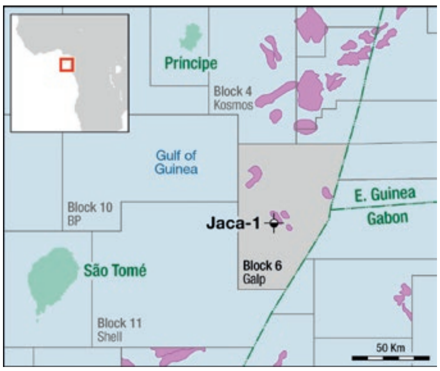
Edited by Ian Blakeley ian.blakeley@nventures.co.uk

Promising Results in the New São Tomé & Principe Frontier

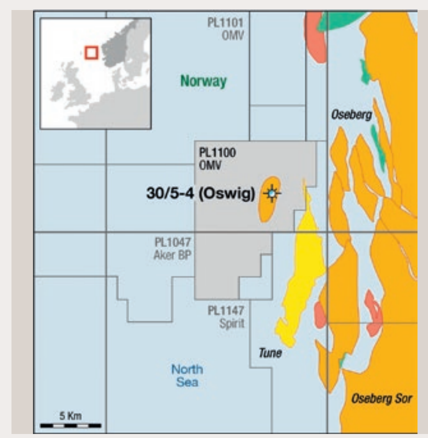


NVentures

Shell and **Galp Energia** have completed drilling the **Jaca 1** wildcat in Block 6, offshore **São Tomé & Principe**, with promising results for an oil-rich petroleum system. Whilst the operating group have not yet made any substantial announcement (apart from on time and on budget), **ANP** (the government regulator) has said the well found thin oil pay in the **Upper Cretaceous** clastic targets. This is significant for the first well in this large deep-water basin, distal to both the **Rio Muni** and **North Gabon** basins. Light movable oil is often elusive to the first wildcat campaigns in these frontier basins, so an early indication of an oil source and migration will lift the chances of success here. There are also some industry rumours that the Upper Cretaceous reservoirs are of good quality, and having sand reservoirs this far from the provenance is also a good sign for the future. The well was drilled in 2,500 m water, between April and May 2022. **Shell**, **Kosmos**, Oando, **TotalEnergies** and **Galp Energia** have similar acreage adjacent and on trend, and further drilling can be expected in this frontier basin, where large structural traps can be found over the transform faults sweeping through the area.

Oswig

OMV's Oswig well (30/5-4 and sidetrack 30/5-4A) encountered gas and condensate in the **Tarbert Formation**, but is currently suspended pending follow-up. Presence of hydrocarbons in the deeper Ness formation is inconclusive at the well location. The well was drilled to a vertical depth of 5,003 m. **Longboat Energy, Source** and **Wintershall** all have 20% working interest in the licence. The sidetrack well (30/5-4A) was successfully tested at an average production rate from the Tarbert Formation of around 60,000 m^3 of gas and 45 m^3 of condensate per flow day. The well is located west of the **Tune** and **Oseberg** fields in 95 m water, and was targeting an HPHT Jurassic fault block with **93 MMboe** unrisked reserves. Several similar rotated fault blocks are mapped nearby, ready to be drilled.



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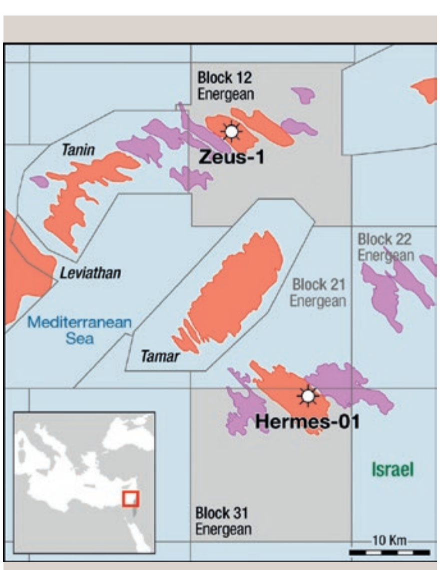


NVentures

Hermes 1 and Zeus 1 – Gas Prospectivity Rising in the Levant

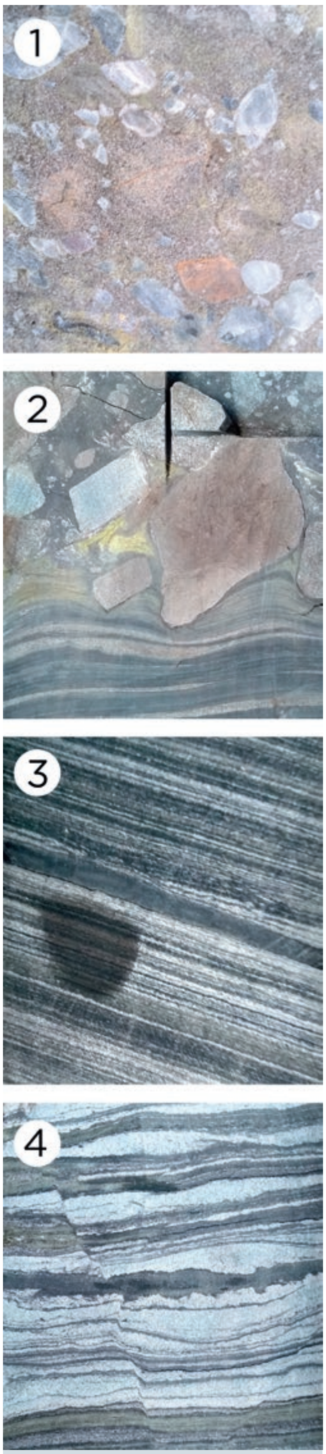
Energean have reported gas discoveries at the Hermes 1 and **Zeus 1** wells **offshore Israel**, with volumes ranging from **245 to 525 Bcf** gas for Hermes and **470 Bcf** gas at Zeus. The wells targeted the Tamar A to D sands in the Miocene, in what is recognised as a prolific gas basin in the Levant Basin. The wells were drilled in around 1620 m water. The wells are option wells taken by Energean when they were awarded the acreage in 2017. Hermes is one of around 6 prospects in a cluster of Tamar structures in Block 31, similar to the **Tamar Field** immediately to the northwest, which is already in production (Chevron and partners). Zeus is one of 6 similar age prospects in Bock 12 referred to as the **Olympus area. Leviathan** and **Tamar** were the first major gas discoveries in the basin (2010) after which Karish and Tanin were discovered by **Delek** in 2011. Energean purchased the Karish and Tarin gas fields from Delek and Avner in 2016. The Karish Field started producing gas on 26 October 2022.

The Stena rig contract was extended this year after successful wells at **KM4** (Karish) and the new field discovery **Athena 1** in Block 12. Energean have mobilised the IceMax to Block 23 to drill the **Hercules** prospect.

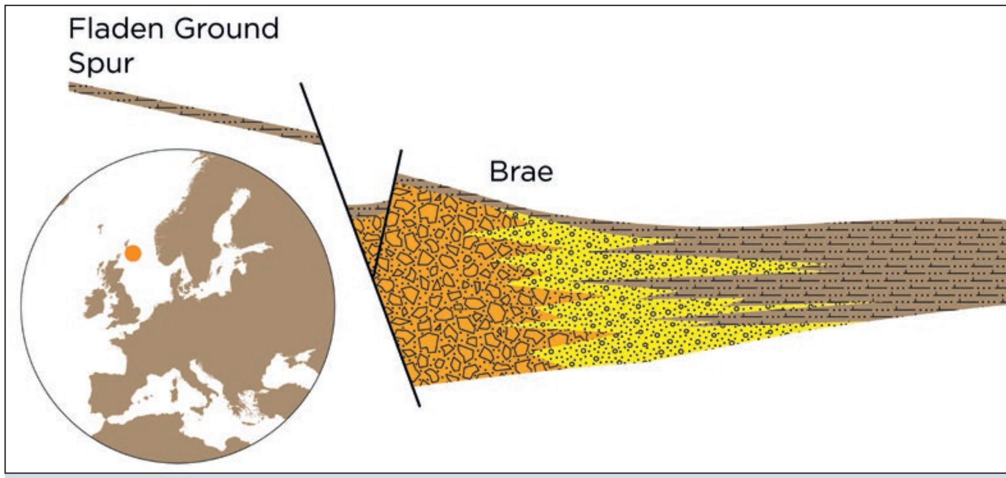
The Best of Brae

Upper Jurassic submarine fans from the UK South Viking Graben display a large variety of depositional systems.

Photos: Henk Kombrink.



Photos from typical Brae core hand samples. Further explanation in text.



Generalised cross-section through a Brae submarine fan system in the South Viking Graben, UK North Sea. Modified after: Raji et al. (2015).

In Late Jurassic times, an overall north-south trending graben system transected the North Sea as a response to tensional stresses building up in the wider area. The grabens were connected to the open oceans further north, whilst the faulted margins and the adjacent footwalls were subaerially exposed.

This setting of steep topographical gradients from land to sea created the perfect template for the deposition of submarine fans. The Brae field complex in the UK South Viking Graben is situated in one of these major submarine fan complexes derived from the adjacent Fladen Ground Spur.

The Brae fields are best known for the thick successions of sand-matrix conglomerates (Photo 1) deposited as submarine fans right across the faulted basin margin. This succession can attain a thickness of up to 4 km in places. Core porosity in the sand-matrix conglomerates can be up to 16%, with permeability up to 300 mD.

The spectacular core sample in Photo 2 shows how a more distal part of the depositional system, where sedimentation of mostly finer-grained lithologies took place, was rudely interrupted by a debris flow that carried large angular clasts in a muddy matrix. In other areas more distal to the main axis of the submarine fans, a more regular alternation of mud and sand deposition took place, as Photos 3 and 4 demonstrate. Subsequent small-scale faulting (Photo 4), folding and sand remobilisation are features commonly observed in the more distal Brae depositional facies.

A RETURN TO HOUSTON

The cores pictured here were cut by Marathon Oil. For some reason some years ago, the company decided that it would be better to transport the core material to Houston and store it there, rather than keeping it in the UK where most of the cores from the North Sea are being stored. Now that operator TAQA is decommissioning the Brae fields, the core selected by the British Geological Survey as a replacement for the Brae core already in stock and by North Sea Core CIC for further distribution amongst the geological community was shipped on pallets back to the UK recently. Full circle for the best of Brae.

Henk Kombrink

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

NORTH SEA CORE

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
- Speed to be able to seize opportunities and mitigate risks

Intelligent Connections for the Energy Industry

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.

This is what we call Intelligent Connections: empowering your company to discover previously unseen insights and opportunities, act fast, and deliver extraordinary outcomes.

A Technology Partner for the Future

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.

Over 300 financial institutions and 5000+ energy companies rely on our analytics, intelligence, and technology to make capital investment decisions and increase investor ROI.

Our platform is built both by, and for, our industry. Our source is our own connections; with direct access to over 98% of US producers, and over 35,000 suppliers, we inform more efficient production and distribution, capital allocation, renewable energy development, investment, and sourcing.

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

ENVERUS

An Exposed Salt Dome

The combination of an arid climate and a diverse geology means that Oman is a popular destination for geoscientists. Here, we feature an exposed salt dome, Qarat Kibrit, to the northwest of the Huqf Uplift in the middle of the country, providing a spectacular example of the effects of halokinesis.

The salt exposed here consists of halites of the Ara Salt, which was deposited around 540 million years ago during the earliest Cambrian. The core of the dome, where the halites are found, can be seen on the right-hand side of the photo.

Despite the arid conditions, the salt at surface suffers from dissolution. The remnant residual strata (above the cars) consist of rafted carbonate stringers and black organic-rich shales, where good visible pinpoint porosity is present in the former, especially in wavy-bedded dolostones.

The carbonate stringers (see inset photo for more detail) are considered to be rafted into the salt basins from surrounding platform areas, which is particularly evident from subsurface interpretation. The early discoveries of oil in Oman reservoired in these carbonate rafts within the salt must have come as a bit of a surprise when drilling through them.

With improved seismic interpretation techniques and in particular 3D acquisition and processing, the identification of stringers became easier over time. On seismic, the high amplitude stringers give the appearance of a string of sausages encased in the more amorphous Ara Salt.

A longer article describing the (petroleum) geology of Southern Oman will appear on our website soon.

Photo and text:
Stuart Harker – MPG Consultancy

In this series, we feature a range of outcrops to give more context to what “1D” core interpretation typically allows.

Do you have a suggestion for an outcrop feature? Please get in touch with Henk Kombrink (henk.kombrink@geoexpro.com).

Western Australia – Looking Towards a Busy Year in 2023

NVENTURES

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

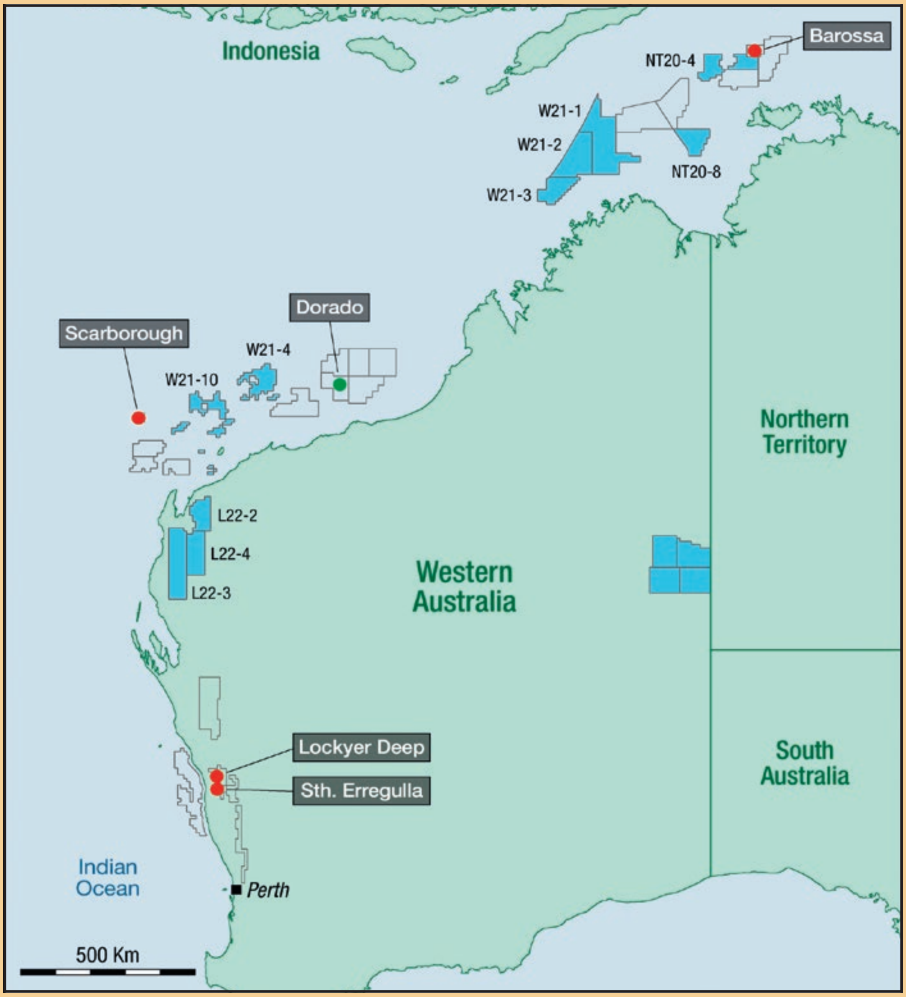
Against the backdrop of a discussion on "Licence to operate," Western Australia is still boasting of opportunities.

For Western Australia, the year 2022 saw two sides. On one hand, there was hesitance when it comes to developments offshore, further marked by a court case, but on the other hand, looking at onshore activities, there is significant activity with a lot of plans in the pipeline as well.

A setback for **Santos** and partner **Carnarvon** was the decision to delay FID of the **Dorado discovery** in the Bedout subbasin. Development of Dorado also comes with further near-field opportunities, so a go-ahead is important for the area.

At the same time, **Woodside** decided to go ahead with the development of the **Scarborough gas field** in the Carnarvon Basin, which entails the drilling of 21 wells in total. Already proven in 1979, it took a long time to get this development over the line.

A significant moment for the industry this year was the overturning of the decision to approve the environmental plan for drilling that was filed by **Santos**. Initiated by **Tipakalippa**, the appeal from Santos has now been heard and a final judgement is awaited. This has had a knock-on effect on the investment climate, with uncertainty around how to get environmental plans accepted in the future. To an extent, the industry has partly lost its licence to operate, which is a trend seen in many other parts of the world.



CARBON STORAGE

The offshore of Western Australia also saw the award of a **CCS licence** to Woodside Energy in the **Browse Basin** while the industry has until May next year to apply for acreage in the currently open petroleum licensing round. At the same time, despite the overall positive reception of the news on the CCS licences, the government withdrew grants enabling CCS feasibility studies after initially issuing those. Onshore CCS is also currently looked at by the WA Government in terms of getting the legal framework in place.

BUSY ONSHORE

Whilst the offshore sector is awaiting further directions from the court, onshore Western Australia has shown to be a busy place this year. In the Perth Basin, **Strike Energy** is currently evaluating the **West Erregulla-3** well, which tested at **90 mmscf/d** from the Permian Kingia sandstone reservoir. At the same time, the company is developing the **Walyering** Cattamarra Coal Measures discovery by drilling the Walyering-5 and -6 wells.

Mineral Resources, the company behind the 2021 **Lockyer Deep** discovery, is shaping up plans to appraise the extent of the **Kingia sandstone** gas reservoir in which a 34 m gross pay interval was proven. In the meantime, **Buru Energy** announced the discovery of potentially **1 Tcf** of wet gas in the **Ungani Dolomite** of the Canning Basin following the completion of the **Rafael-1** well this year.

Next year promises to be another big year for drilling in WA. Testament to that is the increased activity in the Canning Basin where **Black Mountain** is progressing towards seismic acquisition and drilling on their multi-Tcf **Valhalla** tight gas prospect. ■

*Henk Kombrink, with valuable input from **Simon Molyneux** from **Molyneux Advisors***