GEO ExPro
VOL. 19, NO. 3 – 2022
GEOSCIENCE & TECHNOLOGY EXPLAINED

EXPLORATION
California Dreaming

PALAEONTOLOGY
Jurassic Deep Sea Fishing

HISTORY OF OIL
A Time for Reflection

PLANETARY GEOLOGY
The Artemis Project

CCS in Scandinavia

geoexpro.com

CONTENTS

Vol. 19 No. 3
This issue of **GEO ExPro** focuses on North America and Europe; Unconventional Resources; Carbon Capture and Storage.

Previous issues: **www.geoexpro.com**

GEO ExPro
GEOSCIENCE & TECHNOLOGY EXPLAINED

COVER STORY 31

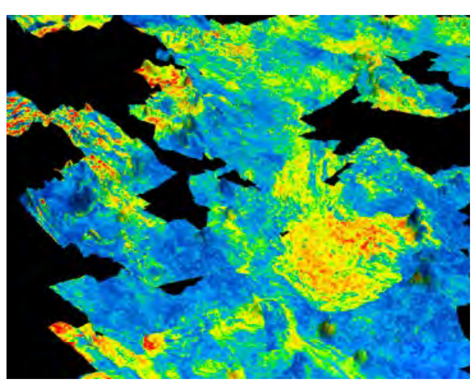
CCS in Scandinavia
With seven CO2 storage sites now either in operation or under evaluation, the Scandinavian countries are accelerating their efforts to roll out CCS technology.

15 MOUNTAINS, MINERALS, AND MAGMA
After compression built the Southern Rocky Mountains, Neogene extension split the range along its axis, opening the 1,000-kilometre-long Rio Grande Rift. Today, a visit will show you dramatic mountains, sand dunes and beautiful landscapes.


NPS/PATRICK MYERS

48 JURASSIC DEEP-SEA FISHING
As dinosaurs reached new heights, creatures such as the pliosaurs became larger, faster, and fiercer, such as 'Predator X', a 15m-long monster with jaws capable of one of the largest bite forces of all the animals in the fossil record!


SHUTTERSTOCK


LYME BAY CONSULTING

38 SEEING THE WHOLE PICTURE
We explore the history around the merging of large, mixed legacy 3D seismic datasets and how they have impacted exploration success in the UK continental shelf. Finally, explorationists could see their exploration blocks in the context of the regional geology.


LICK OBSERVATORY ESA HUBBLE

56 THE ARTEMIS PROJECT
In 1972, the 17th and last Apollo mission put Harrison Schmitt, the only professional geologist ever to have ventured into space, on the surface of the Moon. NASA had been under pressure to put a scientist there and so they sent a geologist. Just take a second to enjoy that sentence!


THE RULES
ARE CHANGING
REGISTER FOR
UPDATES HERE
SHEARWATER
DISCOVERY

GEO ExPro

www.geoexpro.com

GeoPublishing Ltd
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
+ 44 (0) 7909 915513

Managing Director
Tore Karlsson

Editor in Chief
Iain Brown
iain.brown@geoexpro.com

Editorial enquiries
GeoPublishing
Iain Brown
+ 44 (0) 7767 770265
iain.brown@geoexpro.com
www.geoexpro.com

Sales and Marketing Director
Kirsti Karlsson
+ 44 (0) 7909 915513
kirsti.karlsson@geoexpro.com

Subscription
GeoPublishing Ltd
+ 44 (0) 7909 915513
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
kirsti.karlsson@geoexpro.com

GEO ExPro is published bimonthly for a base subscription rate of GBP 60 a year (6 issues).
We encourage readers to alert us to news for possible publication and to submit articles for publication.

Cover Photograph:
Main Image: ©Hufton+Crow
Inset Image: Thomas Davis

Layout: Paul van der Zee

Print: Stephens & George, UK

issn 1744-8743

SHUTTERSTOCK

Iain Brown
Editor in Chief

INTERNSHIPS: TIME TO INVEST!

I asked the question in an earlier issue whether there is really any point in young petroleum geoscientists adversely impacted by the pandemic persevering in their chosen careers. This question is particularly pertinent for those still engaged on postgraduate courses or seeking their first permanent role.

One possible short-term supporting activity by the industry would be paid internships. Yes, there have been huge issues presented by Covid-19, but with the pandemic seemingly in retreat (at least in countries with advanced vaccine programmes) and with the opportunity of providing remote access to software, project data and cloud computing, surely internships should be back on the agenda. Some time ago, Shell announced an initiative called 'Studio X' aimed at increasing collaboration and connecting a network of global geoscientists with remote work opportunities. As part of this initiative Shell is providing access to three core software platforms to support the programme.

Step Recruitment, a specialist provider of paid student and graduate internships (linking students and intern employers), conducted a survey in June of 2020 and discovered that two thirds of interns had their internships cancelled due to the pandemic.

In the current situation, committing to engage interns has genuine challenges, but what I know is that most interns learn extremely quickly and provide the mentoring company with a fantastic opportunity to assess potential future employees. Even if employment is not a likely outcome, it provides invaluable experience for the participants and helps retain competence that would otherwise drift to other sectors. The potential decimation of geoscience talent from the upstream business should not be underestimated. With the 'crew change' having occurred and lack of graduates and postgraduates in this area, paid internships are surely one way to help retain and nurture talent that would otherwise be permanently lost.

Experience has taught me that an internship is only as good as the mentoring which accompanies it. This is an area that is regularly overlooked in the workplace and often absent from formal university curricula, leaving many geoscience professionals unprepared to be effective mentors. Studies show that positive mentoring experiences can help ensure successful degree completion, increase recruitment of underrepresented students into postgraduate courses and research careers and importantly, help reinforce a sense of community and science identity. I'm sure we can all remember at least one teacher, fellow student or colleague who has helped us develop in our careers; perhaps time to think about how we might give something back.

UK UNCONVENTIONALS

Ian Cross
Moyes & Co
icross@moyesco.com

In March 2022 the Oil and Gas Authority (OGA) rebranded to the North Sea Transition Authority (NSTA) to reflect its evolving role in the energy transition. The NSTA is responsible for regulating onshore and offshore exploration and development operations. With the energy crisis gripping Europe, the UK government and industry attention has suddenly been reversed and the UK onshore is being looked at again for oil and gas exploration. In early April 2022 the UK government said that it had commissioned a new study into the latest scientific evidence around shale gas extraction. A report is expected the be available in mid-2022.

As many will be aware there is a highly publicised moratorium in place on 'fracking' in England since November 2019, after an analysis of the environmental impact of work at Cuadrilla Resources' site at Preston New Road in Fylde, Lancashire. Wales and Scotland have similar 'bans' in place, while the situation in Northern Ireland is unclear.

To trace its recent history, interest in unconventional exploration took off in the 1990s in the UK. This was largely in response to onshore successes in the USA, Australia and China. However, the geography of these countries is much different from the UK and most of Europe with vast areas on inhibited prospective areas and, in the case of the USA particularly, wide roads for the large amount of heavy equipment to be moved that is needed for unconventional oil and gas activities.

The UK Onshore Geophysical Library (UKOGL), which is a self-sustaining independent charity which receives limited funding from the government, was established in 1994 to manage and archive landward areas of the UK. If you work through the UKOGL website (ukogl.org.uk) there is a wealth of fascinating information. Browsing through some of the applications and awards can stimulate ideas looking at where the potential has been considered in the past by exploration teams, and maybe in the future.

The main areas which have attracted attention for unconventional plays are the Bowland-Hodder area in north-west England, the Midland Valley in Scotland, the Weald Basin in southern England and the Wessex area also in southern England. In the past we have also seen applications for licences in areas such the coal basins of Gloucestershire, Somerset and South Wales, the Cheshire Basin and the Worcester Graben.

So, what is the future for the onshore UK unconventional oil and gas business, with the slight softening that seems to be happening? Well, very much depends on the outcome of this government-commissioned study. We will never see vast projects, but perhaps smaller well-managed ones could be considered if energy prices continue their upward spiral, and the move to other forms of energy does not reach the ambitious goals that the UK government has targeted. For the industry, an important and promising development in March 2022 was the shift in policy with the NSTA agreeing to a Cuadrilla application to push back a deadline to plug the Lancashire wells.

SOURCE: CUADRILLA RESOURCES

ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand $= 1 \times 10^3$
MM: million $= 1 \times 10^6$
B: billion $= 1 \times 10^9$
T: trillion $= 1 \times 10^{12}$

Time
Ma: Million years ago
Ga: Billion years ago

Liquids
barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day
stoiip: stock-tank oil initially in place

Gas
MMscfg: million ft^3 gas
MMscmg: million m^3 gas
Tcfg: trillion cubic feet of gas

LNG
Liquefied Natural Gas (LNG) is natural gas (primarily methane cooled to a temperature of approximately -260 ºC.

NGL
Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

Reserves and resources
P1 reserves:

Quantity of hydrocarbons believed recoverable with a 90% probability

P2 reserves:

Quantity of hydrocarbons believed recoverable with a 50% probability

P3 reserves:

Quantity of hydrocarbons believed recoverable with a 10% probability

Oilfield glossary:
www.glossary.oilfield.slb.com

REVERSAL IN ALASKA

Trans-Alaska Pipeline System.

The Bureau of Land Management, part of the Department of the Interior, announced on April 25 that the US administration under President Biden is removing almost 50% of the 23-million-acre National Petroleum Reserve in Alaska (NPRA) that's home to wildlife like caribou and polar bears, from oil and gas exploration. This reverses a policy introduced by the Trump administration that permitted oil and gas development on around 80% of the NPRA and comes after the number of permits approved by the Bureau of Land Management for drilling on public lands declined to its lowest number under the Biden administration earlier this year.

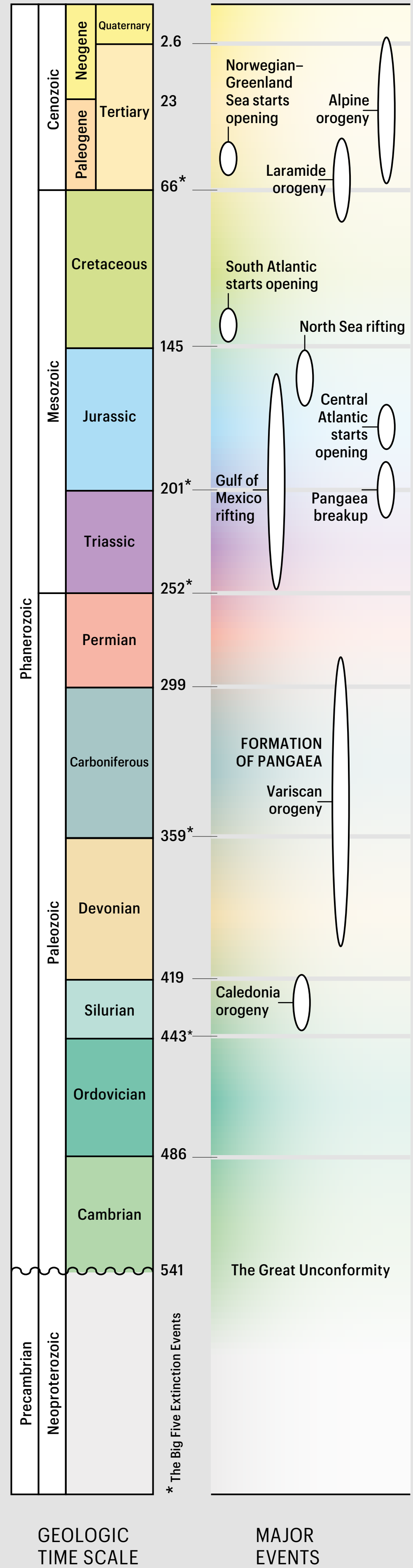
This leaves some 11 million acres, or around 48% of the area, and this remaining land will be closed off to oil and gas leasing. This change in policy effectively means the resurrection of the previous Obama administration plan. That policy allowed oil and gas exploitation in over 50% of the reserve, compared to the Trump administration's plan to open 82% of the land to drilling.

It will also reinstate important environmental protections for designated areas of the reserve, including Teshekpuk Lake, a wetland complex that is uniquely rich with wildlife.

The NPRA constitutes the United States' largest area of public land and is located on the North Slope of Alaska. This extensive area is owned by the US federal government and is managed by the Department of the Interior.

This decision comes at a time when energy security is a key issue in the West, having been further exacerbated by Russia's invasion of Ukraine and increasingly volatile global energy prices.

Estimates by the US Energy Information Administration suggest that oil and gas production on the NPRA has the potential to release over 5 billion metric tons of CO_2 into the atmosphere, roughly equivalent to the amount of carbon released in the entire US in 2019.



Africa's Energy Potential Driving Investment Across the Continent

AOW

The international energy crisis has renewed efforts to explore the potential of Africa as a global supplier, and how its countries can lift themselves out of poverty. From hydrocarbons to green energy, Africa's potential remains largely untapped.

The African continent remains one of the most unexplored places on Earth for oil and gas deposits. Yet, between 2011 and 2020, an estimated 61 billion boe (barrel oil equivalent) of energy resources were discovered, suggesting the continent holds even greater value beneath its surface.

However, according to the United Nations, an estimated half-a-billion Africans live below the poverty line, while at the same time Africa is only responsible for 3.8% of global CO_2 emissions.

Many African countries argue they must be allowed to tap into their natural resources through low-carbon management strategies while developing renewable energy sources at the same time. This will require countries to develop an energy mix suitable to growth and progress.

"We foresee those hydrocarbon as well as renewable energy solutions will be a force multiplier for the continent," says Paul Sinclair, VP Energy for Africa Oil Week and the Green Energy Africa Summit, being hosted alongside each other in Cape Town, South Africa, from 3–7 October.

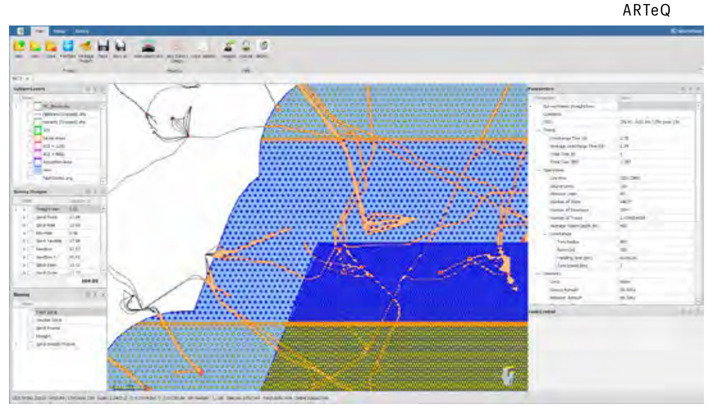
"We expect to see renewed investment opportunities being explored when the industry comes together later this year," he says.

For more information on Africa Oil Week, go to the AOW website.

A HOLISTIC APPROACH TO SURVEY DESIGN AND OPTIMISATION

Developing the optimum survey design requires a holistic view of a wide range of factors. It starts with an understanding of the geology, geophysics and business objectives of the project. Processing techniques such as deblending and full waveform inversion have a significant influence on the selection of the best design. Operational factors such as cost, safety, timing and environmental constraints must also be considered.

ARTeQ



In 2016, ACTeQ was formed when Damian Hite, Dave Ridyard and Dave Monk recognised an industry need for an integrated tool to address these challenges. The company now offers its survey design and optimisation software for seabed, towed streamer, land, transition zone, borehole and hybrid environments. This software incorporates tightly integrated operational and geophysical models. Its modern flexible architecture has allowed rapid adaptation to new acquisition paradigms such as self-guided recording nodes.

The latest release includes two major new features, each developed in collaboration with industry partners – subsurface modelling and illumination study (Z-Terra) and compressive sensing and mutual coherency mapping (In-Depth).

ACTeQ's software is widely used by a range of operators and service providers and the company also offers survey design services for oil and gas exploration and production projects, as well as high-resolution surveys for offshore wind turbine installation and other civil engineering and carbon transition applications.

BRITISH SHALE – **DEMISE OR REPRIEVE?**

Cuadrilla is a British exploration company owned 96% by AJ Lucas, an Australian service provider to the energy sector, which has the ambition to become a key producer of natural gas resources from shale. The company was formed in 2007 and is privately owned, holding onshore exploration licences in the north and south of the UK, located in the counties of Lancashire, Yorkshire and in West Sussex, Surrey and Kent. Cuadrilla has been exploring the Bowland shale in Lancashire for natural gas, but drilling activity which caused micro-earthquakes, meant that all drilling activity ceased in 2020.

Cuadrilla Drill Site, Lancashire, UK.

Although Cuadrilla is most advanced in its attempts to tap into UK unconventional resources, public opinion has been against them. One of the fears of the fracking process is the release of gas or the chemicals used in the fracking process, as well as seismicity (earthquakes). These emissions could be into the atmosphere or the groundwater, possibly contaminating local water supplies. If the correct procedures are followed, particularly the use of properly cemented casing strings and the protection of drill sites from accidental fluid release by containment, then it is very unlikely that the production of shale gas will lead to environmental damage. Many cases cited (notably in the USA) have, after investigation, pointed to pre-existing hazard sources such as shallow biogenic gas being responsible for contamination. The micro-earthquakes caused by the hydraulic fracking process at depth is a more difficult issue to address, although advocates of shale fracking would argue that the magnitude of the tremors at around 2.3–3.0 on the Richter scale are not a danger and that the limit of 0.5 at which operations must cease, is too aggressive.

Such is the pressure of public opinion, both on localised environmental and broader CO2 emissions grounds, that it is becoming increasingly difficult for other countries to follow the North American shale example. In France there is a ban on fracking and more recently the UK, despite initial governmental support, has followed suit.

Earlier this year Cuadrilla said the UK Government's Oil and Gas Authority had ordered the two horizontal shale wells drilled so far in Lancashire to be plugged and abandoned by the end of June this year but since the invasion of Ukraine by Russia and with the new focus on UK domestic energy security, could this situation change?

Robert Jenrick, a vocal supporter of fracking and former Communities Secretary, called for a more pragmatic energy policy that would help address the high cost of energy while the UK progresses to net zero emissions. However, the UK Government has denied suggestions the fracking moratorium could be lifted in response to the Ukraine crisis with energy minister Lord Callanan warning of 'severe environmental problems' with shale gas production, pointing out that Lancashire is much more densely populated than areas such as Texas in the US, where unconventional gas resources are well developed.

Since then, comments from both the UK Prime Minister Boris Johnson and business secretary Kwasi Kwarteng appeared to offer hope for the shale industry, but as the clock ticks down to the 30 June deadline when the Cuadrilla wells must be abandoned, there appears to little concrete progress on a government change of heart.

Whilst Cuadrilla has the most advanced UK projects, other energy companies such as IGas and Egdon have amassed material prospective acreage across Cheshire, Lancashire and Lincolnshire, where IGas has a portfolio of six licences across the East Midlands, the Gainsborough Trough. Egdon has over 600 square kilometres under licence in its unconventional resources portfolio, also focusing on the Gainsborough shale.

The British Geological Survey has pointed out the lack of peer-reviewed research into the environmental impact of fracking as well as the potentially huge gas resources in the shales of the north of England. If the UK authorities decide this is a secure energy resource for the future, it is time to encourage more research and more effort in educating the public so they can be properly informed by all sides of the debate.

CGG JOINS NORWAY'S CENTRE FOR GEOPHYSICAL FORECASTING

In May 2022, CGG announced it had become a member of the Centre for Geophysical Forecasting, a world-leading research and innovation consortium based in the Norwegian University of Science and Technology (NTNU).

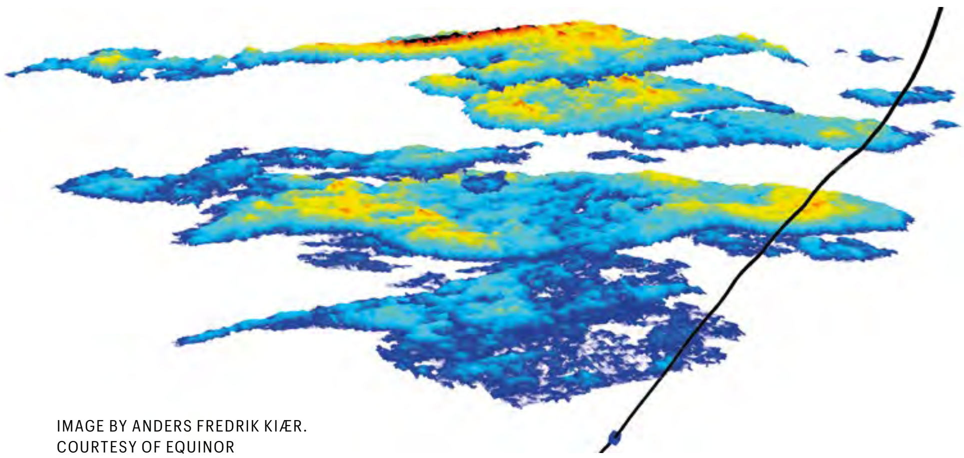


IMAGE BY ANDERS FREDRIK KIÆR.
COURTESY OF EQUINOR

The Centre for Geophysical Forecasting aims to leverage the combined expertise of its 15 members from a wide range of business sectors, both private and public, to promote geophysical capabilities, applying new technologies to new enterprises in the energy transition.

CGG will bring its expertise in seismic modelling and imaging to the work of the consortium. More specifically, it will contribute to the development, modelling, implementation and field testing of a new subsurface imaging and monitoring system designed to support a range of energy transition activities.

Part of the research by the Centre for Geophysical Forecasting will look at the accuracy and effectiveness of CO_2 storage monitoring methods using high-resolution Earth models and seismic imaging.

DISCOVER NEW POSSIBILITIES AT **IMAGE 2022**

AAPG

The Society of Exploration Geophysicists (SEG), the American Association of Petroleum Geologists (AAPG), and in conjunction with the Society for Sedimentary Geology (SEPM) are hosting the second annual International Meeting for Applied Geoscience and Energy (IMAGE), 28 August–1 September in Houston, Texas at the George R. Brown Convention Center.

IMAGE '22 has been designed and built by industry professionals as the place for geoscientists, energy professionals, and thought leaders to meet and shape the future of applied geosciences and energy. It will provide an influential platform for sharing best practices, discovering solutions, and developing new perspectives and strategies to challenge and plan for what's ahead.

A traditional and forward-looking technical programme of more than 750 presentations will inspire and encourage collaboration in areas including: strategic market trends, business of applied geoscience, energy markets and finance, near-surface geophysics, energy transition and sustainability, diversity and inclusion, and government policies and regulation.

The exhibition will bring multiple sectors of geoscience and energy together in one arena to share innovations, network with colleagues, and showcase the latest technologies. A key addition to the 2022 exhibit hall will be three new pavilions focused on carbon management, digitalisation, and the near-surface.

Mark your calendar and start making plans to join us in Houston. Registration is set to open 19 May.

OPTIMISING INDUSTRY DATA MANAGEMENT

Our industry is currently awash with initiatives around data management. Whether it is digital transformation or digitalisation, moving to the cloud, OSDU, or others, it is sometimes hard to chart the correct course. Oil and gas operators are stretched, dealing with day-to-day activities but are being asked to design and implement strategic and transformative projects at the same time. This creates an environment where customers – the geoscientists – are facing delays in accessing the data they need, and these strategic projects are facing delays in implementation. When this happens, it makes good sense to seek outside help and expertise from a company specialising in data management.

When choosing a partner, it's important to seek out key qualities that will enable the relationship to be a successful one. There are several key questions that you should ask yourself:

- ***How much experience do they have in subsurface data management? They may have been around for a while, but where is their real expertise?***
- ***Are they experts in the key initiatives in the industry right now? Have they got experience with deploying sub-surface data management in the cloud, for instance?***
- ***Are they experts, and involved with The Open Group OSDU™?***
- ***Have they managed large digital transformation projects?***


ADOBE STOCK

Getting outside assistance with your data management environment is smart, and in many cases a necessary step to take, that can lead to a cost effective and positive outcome. But it must be done carefully. Be sure to choose a partner that is experienced and capable of helping you navigate to a successful outcome.

For more information go to the Katalyst Data Management website.

RAY-BASED SEISMIC MODELLING ENHANCES EFFICIENCY

Time and budget constraints can jeopardise your seismic projects. Often there are modelling methods which are more efficient than one might expect.

In simplified terms, ray tracing is inherently efficient for two reasons: modelling specific parts of the wavefield means no wasted time generating superfluous data, and smooth macro models allow for simplification, survey decimation, and 'multi-purpose' datasets without degrading results on a seismic scale. Further to the inherent efficiency of ray-based modelling, smart survey setups can make modelling even more expeditious.

Survey Decimation

Shot spacing can be increased without affecting illumination map interpretation by just compensating with a scaling factor. For example, only using every third shot of a flip-flop survey covers the same CMP lines but saves two thirds of the processing time.

Single Shot Equivalents

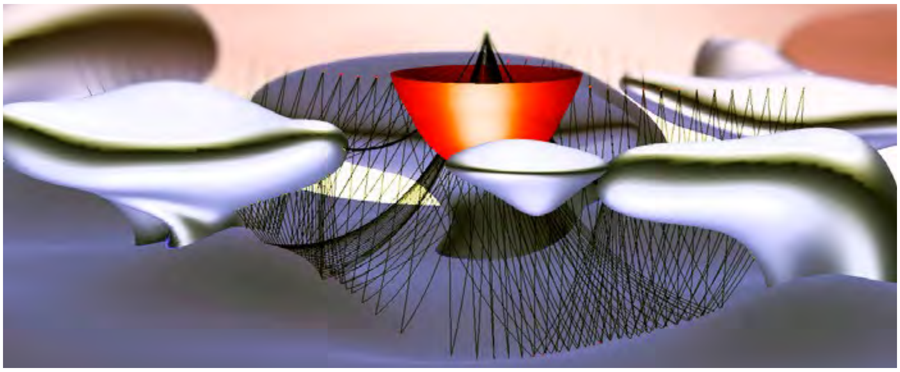
Multi-gun surveys can be replaced by single shot equivalents when adding cables rather than shots. For example, two thirds of the shots of a triple-gun survey can be omitted without changing fold or CMP spacing by adding three times the cables.

Analytic Surveys

Performed correctly, one single modelling run can find all shot and receiver areas, offsets, and azimuths illuminating a target area by combining areal filters, attribute filters, and domain maps. Analytic surveys can be tuned further for minimum fold and maximum speed using coarse shot spacing and exploiting the benefits of a smooth macro model.

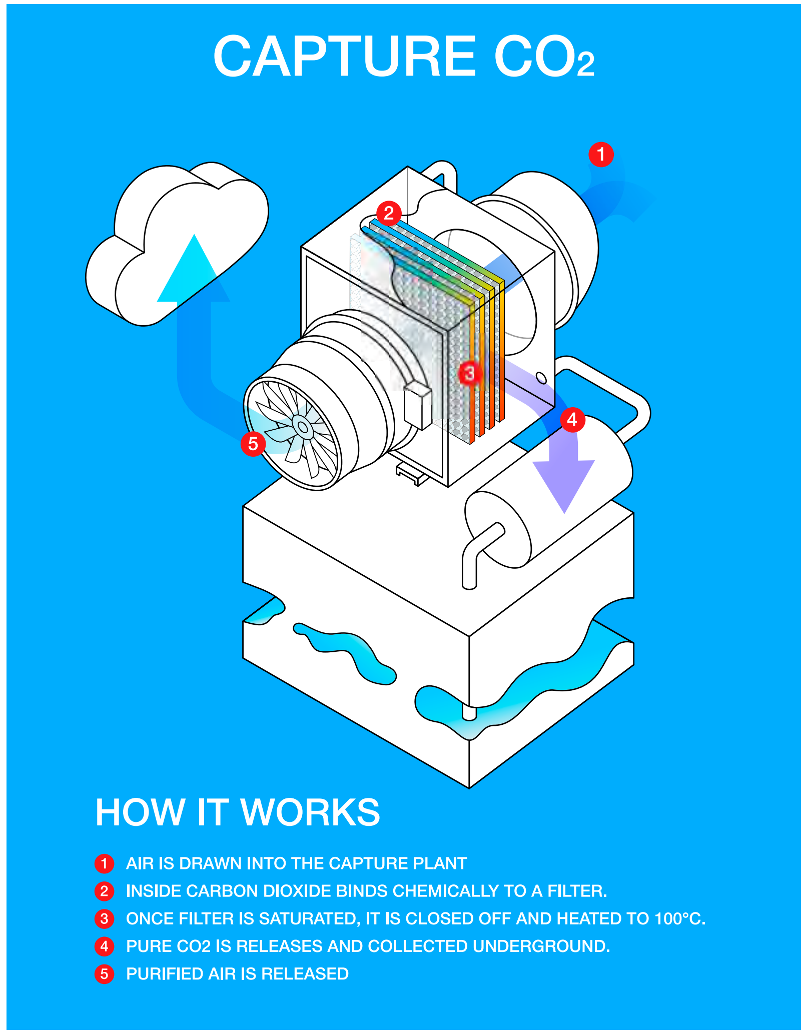
These ray-based modelling methods may not always replace a full setup, but they generate detailed attributes for various survey options. If not sufficient, set up a full modelling run, adding the knowledge gained from these highly efficient methods.

For more information go to the NORSAR Innovation website.


NORSAR INNOVATION

Hot Air or Real Progress?

Usually when we think about CO_2 removal in the oil and gas industry, we think about Carbon Capture and Storage (CCS) or its more advanced cousin, Carbon Capture, Utilisation and Storage (CCUS).



SHUTTERSTOCK

The liquid DACS system.

A newer, more experimental method is Direct Air Carbon Capture and Storage, sometimes also referred to as DAC or DACCS, which is a technology that can remove CO_2 directly from the atmosphere. Unlike other carbon removal technologies that capture CO_2 emissions during the process of extracting oil and gas or generating electricity or heat, DACS can be utilised anywhere in the world where it can access a reliable supply of electricity.

CO_2 emissions reduction and removal are crucial to meeting the international climate goals set by the UN Climate Change Conference (COP21), 2015 Paris Agreement and the more recent COP22 conference. But to achieve 'net zero', it will also be necessary to remove the anthropogenic CO_2 released into the environment by industrialisation. As a technology that removes more CO_2 from the atmosphere than it releases – assuming it is powered by green electricity – DACS has the potential to play a key role in this process.

DACS could very simply be considered as a form of industrial photosynthesis. Just as plants use sunlight to synthesise nutrients from CO_2 and water, DACS systems use electricity to remove CO_2 from the atmosphere using a series of fans and filters.

Air is sucked into the DACS system using large, industrial-scale fans. The liquid DACS system passes the air through a chemical solution which removes the CO_2 and returns the rest of the air back into the atmosphere. The solid DACS system captures CO_2 using filters coated in a chemical agent, where it then forms a compound which is heated, releasing the CO_2 to be captured and separating it from the chemical agent, which can then be recycled. The captured CO_2 can then be compressed under extremely high pressure and pumped into deep geological formations. This permanent storage process is known as carbon sequestration. Alternatively, the CO_2 can be used for commercial processes, such as cement manufacturing.

According to the International Energy Agency, at the end of last year there were some 19 DAC plants operating worldwide, capturing more than 0.01 Mt CO_2 per year, and a 1-Mt CO_2 per year capture plant is in advanced development in the United States. The latest plant to come online, in September 2021, is capturing 4 kt CO_2 per year for storage in basalt formations in Iceland. In the Net Zero Emissions by 2050 Scenario, DAC is scaled up to capture more than 85 Mt CO_2 per year by 2030 and almost 1,000 Mt CO_2 per year by 2050. To achieve this level of extraction will require many more large-scale pilots to refine the technology and reduce costs.

Despite the challenges, this approach is starting to gain more traction, with the US Department of Energy (DOE) announcing in April this year, \$14 million in funding for five front-end engineering design (FEED) studies that will leverage existing zero- or low-carbon energy to supply direct air capture (DAC) projects, combined with dedicated carbon storage.

MOUNTAINS, MINERALS AND MAGMA ALONG NORTH AMERICA'S LARGEST RIFT

An exploration of the 1,000-kilometre-long Rio Grande Rift.

After compression built the Southern Rocky Mountains, Neogene extension split the range along its axis, opening the 1,000-kilometre-long Rio Grande Rift. The rift has been active ever since, creating dramatic mountains, exposing mineral riches, and burying the landscape with volcanic rocks used by the region's native inhabitants to build their settlements.

Lon Abbott and Terri Cook

Although continental rifts are familiar components of plate tectonics, why one rift segment exhibits very different characteristics than another remains puzzling. The Rio Grande Rift, thanks to its convenient location and three subregions displaying distinctive characteristics, has long served as a natural laboratory to study the roles that a variety of diverse factors – including the regional stress field, asthenospheric convection patterns, crustal heterogeneities, and variations in lithospheric thickness – play in rift formation and evolution.

The Rio Grande Rift trends north–south from northern Colorado to southern New Mexico. The Colorado portion, which runs through the heart of the Southern Rockies, constitutes the rift's northern subregion. It consists of a single, dominant half graben, with accommodation zones that transfer extension east or west from one en echelon rift segment to another. An active normal fault bounds one side of each rift valley, and rift-floor volcanism is minimal. But the rift character changes significantly south of the Colorado border. In this central subregion, from Taos to Albuquerque, New Mexico, the Colorado Plateau forms the rift's western border. The central rift is crossed by a north-east–south-west-trending zone of

NPS/PATRICK MYERS

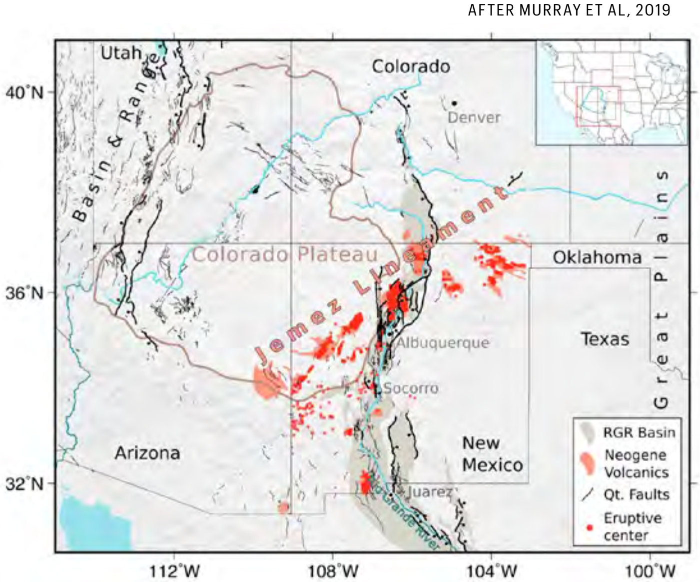
voluminous, bimodal magmatism known as the Jemez Lineament. Here the strain is the highest of the entire rift, and strike-slip faults dominate over normal faults. In the southern subregion, south of Albuquerque, the primacy of north–south-trending normal faults returns, and valley-floor volcanism diminishes. But here, multiple half grabens parallel one another. South of Las Cruces, New Mexico, the Rio Grande Rift is subsumed into the broader Basin and Range province, which exhibits Neogene east–west extension from California eastward to western Texas.

Total extension diminishes from 50% in the Rio Grande Rift's southern subregion to less than 8–12% in the north. This variation has been used as evidence for northward rift propagation. But recent low temperature thermochronologic data indicates that faulting began simultaneously at about 25 million years ago along the rift's entire length. One potential recipe to produce simultaneous rift onset and northward-diminishing strain is the clockwise rotation of a rigid Colorado Plateau block. But a recent geodetic study reveals that the Colorado Plateau doesn't behave rigidly, indicating that further research is needed to tease out why the Rio Grande Rift formed. Several recent studies agree that the concentration of volcanism in the central rift is caused by small-scale mantle convection triggered by a step in lithospheric thickness at the south-eastern edge of the Colorado Plateau, a step inherited from a Proterozoic suture zone.

Mineral Bounty on the Roof of the Rockies

The 7.5-hour road trip from Denver to Albuquerque provides a tour of the Rio Grande Rift's scenic and historic diversity, from the northern rift's mining legacy to that of native cultures farther south. From Denver, Interstate Highway 70 climbs west into the Southern Rockies. The highway burrows under the Continental Divide, the drainage divide separating

AFTER MURRAY ET AL, 2019



Location and main features of the Rio Grande River Basin (RGRB).

Atlantic-flowing rivers from Pacific-flowing ones, in the Eisenhower Tunnel. From the tunnel's west portal, you enjoy a sweeping view down to the Blue River Valley, the northernmost and narrowest Rio Grande Rift half graben, and the fault-bounded Gore and Tenmile ranges that soar 1,200 metres above its floor.

The highway then descends to Dillon, a ski hub situated on the Blue River, which flows north along the rift to join the Pacific-bound Colorado River. An accommodation zone that transfers extension westward to the Upper Arkansas Valley – the next en echelon rift valley to the south – lies just south of Dillon. To continue your Rio Grande Rift tour, cross this accommodation zone via Colorado Highway 91, which climbs back up to the Continental Divide at Climax, the world's largest molybdenum mine. The Climax ore formed 33–24 million years ago during the transition from compression to Rio Grande Rift extension.

The 20-kilometre descent from Climax brings you to the historic mining town of Leadville, located at the Arkansas River headwaters. Leadville's mining district, among the world's largest lead-zinc-silver deposits, has produced more than $5 billion in ore and is nicknamed 'the richest 12 miles in the world'. Leadville's ore formed 39 million years ago when magmatic fluids interacted with Palaeozoic limestones. Subsequent rifting exposed the ores. Prospectors fortuitously struck a rich silver lode here in 1878, the same year the US Congress passed the Bland–Allison Act, which required the US Treasury to buy large quantities of silver dollars. Leadville's population swelled to 25,000, and the town hosted 100 saloons, a dozen gambling houses and the Tabor Opera House – the largest west of the Mississippi. Wandering through Leadville's National Historic Landmark District of Victorian buildings offers glimpses of the town's glory days. You can tour the mining district east of town and view exhibits at Leadville's National Mining Museum, which traces both local mining history and the broader evolution of mining technology.

Glacial Floods, Wild White-water, and Towering Sand Dunes

Thirty of Colorado's 54 famed '14'ers' (peaks taller than 14,000 feet, or 4,268 metres) line the Rio Grande Rift, including the five highest peaks in the entire 4,800-kilometre-long Rocky Mountain chain, adding immeasurably to the rift's scenic splendour. The Sawatch Range, which hosts 15 of those 14'ers, bounds the active normal fault, west of the Upper Arkansas Valley. This mountain rampart, towering 2,000 metres above the valley floor, is visible on your trip south along the rift axis. The Sawatch Range was heavily glaciated during the Pleistocene; several of its east-flowing glaciers protruded into the south-trending rift valley, depositing impressive moraine complexes on the valley floor. Just south of Mount Elbert, the Rockies' highest peak, the Twin Lakes are cradled by one such complex, and a recessional moraine separates the lakes.

The presence of glaciers and their voluminous outwash gravel on the valley's western side pushed the Arkansas River hard against the eastern wall, where the river incised several narrow canyons into Precambrian granite. Those canyons make the Arkansas the most popular white-water rafting river in the United States, with more than 175,000 visitors annually. The canyons and the surrounding rift-flank uplands, which are popular for mountain biking, were declared Browns Canyon National Monument in 2015. The cutting of these canyons was accelerated by two glacial lake outburst floods 18,000 years ago. The Clear Creek and Pine Creek glaciers, which headed south of Twin Lakes, once extended across the entire rift valley, blocking the Arkansas River and impounding a 23-kilometre-long, 180-metre-deep lake. Twice the glacial dams failed, sending 21,000 m^3/s torrents down the river. The car-size boulders littering the canyons today testify to the power of those floods and add difficulty to the river's famous white-water runs.

After following the axis of the Rio Grande Rift for 100 kilometres, the Arkansas River takes an abrupt eastward turn at Salida, exiting the rift. This is because the Poncha Pass accommodation zone has raised an east–west ridge here. Highway 285 climbs over this ridge and descends south-east into the next en echelon basin, the San Luis Valley, down which the rift's namesake river, the Rio Grande, flows. The active normal fault and its accompanying mountain range, the Sangre de Cristo, bound the San Luis Valley on the east. The range boasts two clusters of 14'ers, connected by a ridge as much as 1,500 metres lower in elevation. Prevailing westerly winds blowing across the valley are funnelled in a venturi through the gap between the 14'ers, depositing the copious sand they carry on the range's west flank to form North America's largest sand dunes. Great Sand Dunes National Park is open year-round, but a visit in late spring, when meltwater from the snow-capped peaks swells the dune-crossing Medano Creek, is especially scenic.


NPS/PATRICK MYERS

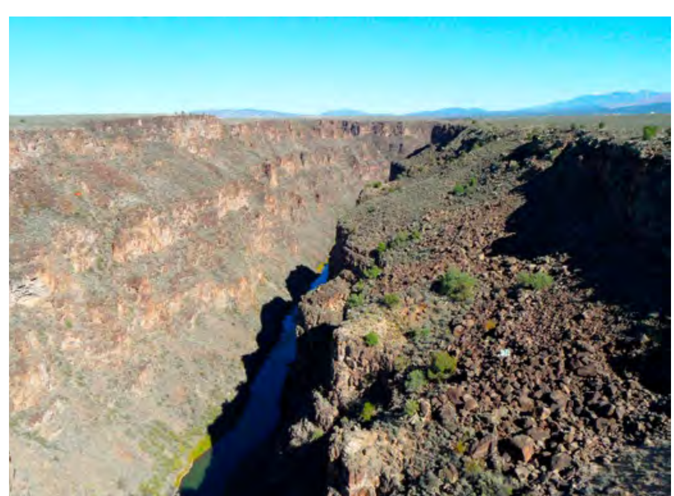
Great Sand Dunes National Park.

Pueblos and Tuff

South of the sand dunes, roads traverse both the east and west sides of the valley. Whichever road you choose, you will spot the first substantial volcanic rift features – basalt lava flows and several cinder cones – near the New Mexico state line. They herald your arrival in the rift's volcanically active central subregion. If travelling the eastern road, Questa is the first significant New Mexico town you pass. Questa hosts a Climax-type molybdenum deposit that was mined from 1916–2014. If you follow the western road, turn east onto U.S. Highway 64 at Tres Piedras, bound for Taos. A worthwhile stop is the highway's crossing of the Rio Grande River on the Gorge Bridge 16 kilometres west of Taos. This area's flat, arid landscape gives no hint that the river has cut an impressive, 180-metre-deep gorge into a stack of basalt flows until you reach the rim.


L. ABBOTT AND T. COOK

Rafting down the granite canyons of the Arkansas River.


L. ABBOTT AND T. COOK

Taos volcanic rift canyon.

A visit to the Taos Pueblo is a quintessential Rio Grande Rift experience. The five-story adobe buildings consist of mudbrick walls several feet thick veneered by mud plaster. Members of the Taos tribe have lived in the Pueblo since about 1000 CE, making it the oldest, continuously inhabited community in the United States. Accounts by Spanish conquistadors who visited the Pueblo in 1540 CE reveal that it has changed little since that time. The conquistadors imagined the Pueblo to be one of the fabled Seven Cities of Cibola; they were disappointed that it lacked the huge troves of gold the story described.


L. ABBOTT AND T. COOK

Taos Pueblo.

Bandelier National Monument, 115 kilometres south-west of Taos, reveals geology's fundamental role in the development of central rift civilisations. The national monument's Frijoles Canyon is lined with tall cliffs of Bandelier Tuff, which erupted from the Valles Caldera 25 kilometres to the west


L. ABBOTT AND T. COOK

Dwellings carved in soft tuff by Ancestral Puebloan people.


SHUTTERSTOCK

Cathedral Basilica of St Francis of Assisi in Santa Fe.

1.25 million years ago. Dwellings carved in the soft tuff by Ancestral Puebloan people between about 1150–1550 CE dot the cliffs, as do circular holes drilled to anchor the roof poles of cliff-side pueblos. Caldera-produced obsidian, used for tools and arrowheads, was a major trade good the inhabitants exchanged with cultures across the American Southwest.

The Urban Rift

Santa Fe, New Mexico's capital, lies 65 kilometres south-east of Bandelier. It is known as one of the world's great art cities, so much so that it belongs to UNESCO's Creative Cities Network, which fosters international collaboration between cities that have invested in creativity to drive sustainable urban development. Santa Fe has been inhabited by Tanoan Pueblo people since 900 CE. The Spanish made it the capital of Nuevo Mexico in 1610, making it the oldest capital city in the US. Santa Fe's mild climate makes it a year-round tourist destination. It is home to many historical buildings including the Cathedral Basilica of Saint Francis of Assisi, built by Archbishop Jean Baptiste Lamy between 1869 and 1886 on the site of an older adobe church. Visiting in September is especially popular because the aspen trees that grow in the flanking Sangre de Cristo Mountains glow orange and gold, adding yet more colours to the city's already rich palette.

New Mexico's largest city, Albuquerque, lies 100 km south-west of Santa Fe and serves as the gateway to the rift's southern subregion. Albuquerque is renowned for its colourful International Balloon Fiesta, the world's largest gathering of hot air balloons, held each October. The aerial tram ascent of the Sandia Mountains, the fault-controlled mountain rampart that rises 1,600 metres above the city's eastern neighbourhoods, provides breathtaking views down to the Rio Grande River. The nearby Petroglyph National Monument protects 24,000 petroglyphs that have been carved into the basalt rimrock on Albuquerque's West Mesa, which marks the Rio Grande Rift–Colorado Plateau transition.

Socorro, 125 kilometres south of Albuquerque and near the rift's end, is home to the New Mexico Institute of Technology, the New Mexico Geological Survey, and the Socorro Magma Body. This latter is a still-molten sill at 20 kilometres depth that triggers frequent, small seismic tremors due to magma inflation and is a potential source of geothermal energy. You reach the southern end of the Rio Grande Rift 100 kilometres farther south at Las Cruces, New Mexico's second-largest city. The Organ Mountains, remnants of a 32-million-year-old caldera formed during the transition from compression to rifting, forms the city's impressive eastern backdrop. It is a fitting culmination to your 1,000-kilometre tour of the impressive scenery and natural resource bounty produced by the tectonic processes that shaped North America's largest rift.

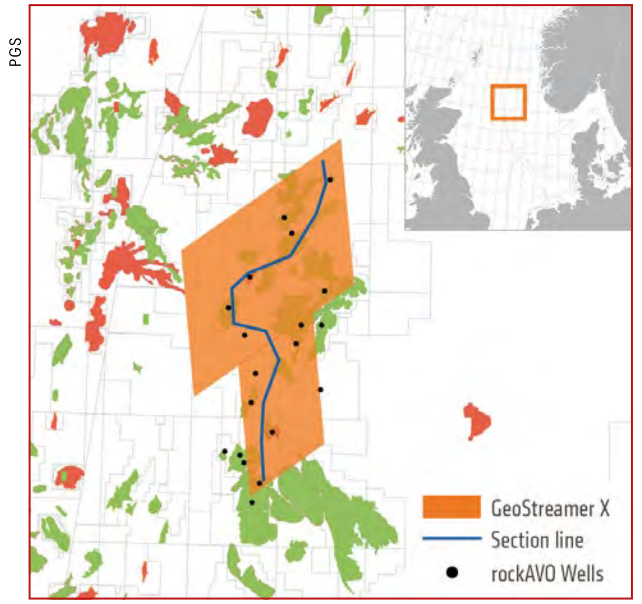
Terri Cook *Lon Abbott*

ACCURATE RESERVOIR ATTRIBUTES DELIVERED WITH GEOSTREAMER X IN THE SOUTH VIKING GRABEN, NORWAY

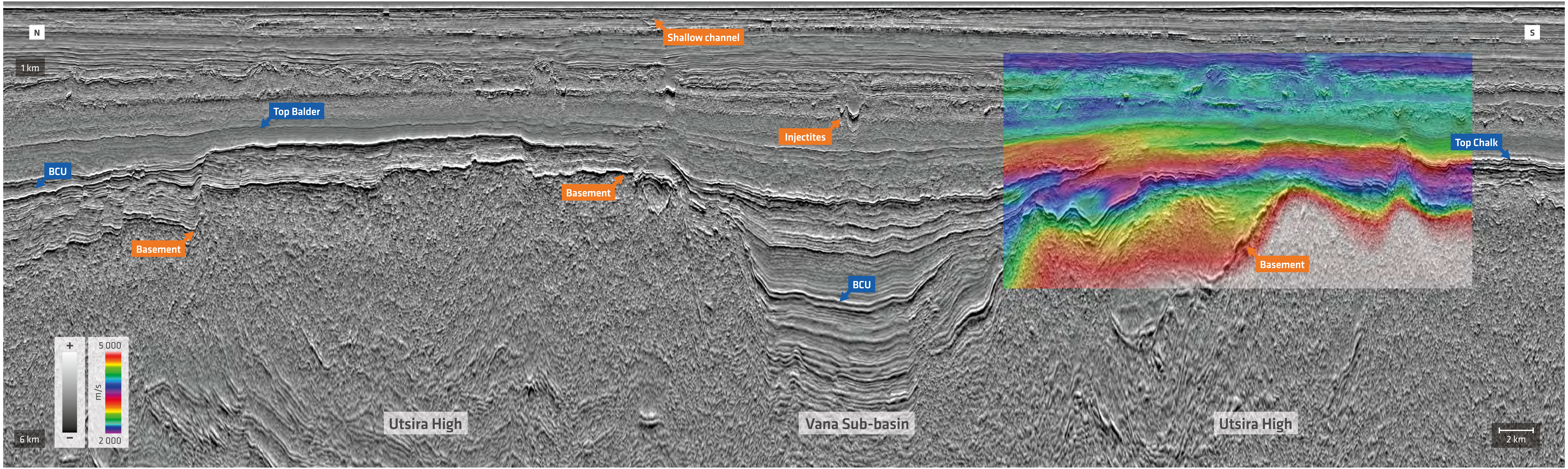
This full stack GeoStreamer X PSDM north to south line transects the two recent multi-azimuth seismic surveys in the South Viking Graben. In addition to the seismic display (in relief grey colour scale), a full waveform inversion (FWI) velocity section is co-rendered. The overall depth range is between 0 and 7 km. This combination of high-resolution velocity data and accurate imaging of the overburden, highlights various geological features such as channels (causing seismic distortion below and correctly picked up by the FWI velocity field), deep imaging and some small gas pockets represented by a very slow velocity (blue colour in the FWI display).

Following a very successful 2019 GeoStreamer X survey in the South Viking Graben, Norway, an additional multi-azimuth survey was acquired further north covering the Utsira High and the Vana Sub-basin. This case study will review the main imaging benefits of various stratigraphic intervals such as the Tertiary and the deeper Jurassic. The implemented technologies and methodologies have enabled the accurate estimation of reservoir properties as well as highlighting the underexplored Vana Sub-basin and near-field opportunities on the Utsira High.

A combination of innovative acquisition, quantitative interpretation, and seismic morphology interpretation delivers enhanced understanding of the main prospective stratigraphic intervals (Tertiary–Jurassic) and an improved assessment of the volumetry of exploration targets.



Illustrated here are the two GeoStreamer X surveys (2019 southern polygon and 2020 northern polygon), the rockAVO wells used in this study and the random line for the main seismic section.



IMPROVING RISK AND UNCERTAINTY ASSESSMENT USING GEOSTREAMER X DATASETS IN THE SOUTH VIKING GRABEN, NORWAY

GeoStreamer X is an integrated broadband multi-azimuth acquisition and state-of-the-art depth imaging solution. Here, we demonstrate the suitability of the dataset for reservoir evaluation by delineating near-field exploration opportunities and providing better trap and reservoir understanding.

Cyrille Reiser, Roberto Ruiz, Eric Mueller and Julien Oukili; PGS

Accurate imaging and evaluation of the main stratigraphic targets has always been a challenge in the South Viking Graben as various geological features, such as shallow channels, gas pockets, and rugose Late Cretaceous Chalk, distort, obscure, and attenuate the image of the subsurface. High fidelity seismic data is required for near-field exploration, appraisal and field development.

The Viking Graben in the North Sea has delivered a significant number of successes across multiple plays ranging from the shallow Tertiary to the deep Permian and is still an area of intense exploration and development. However, accurate identification, imaging, mapping and evaluation of each specific target with seismic technology has required a step change with the objective to estimate and predict elastic and reservoir properties more accurately and reliably.

We build on the previous case study with a similar MAZ dataset to the south, but go a step further by estimating reservoir properties, such as volume of shale (Vsh) and porosity required for volumetric calculations.

Focusing on the Under-explored Vana Basin

The 2019 and 2020 GeoStreamer X surveys are located in the South Viking Graben of the Norwegian sector covering the Utsira High and the adjacent Vana Sub-basin. Major fields in this area include the Balder field discovered in 1967, producing from the Heimdal and Hermod formations (Palaeocene age) as well as some injected sands; the Ringhorne field, part of the Balder complex, which produces from the Hugin (Late Jurassic), Ty (Early Palaeocene) and Hermod formations (Late Palaeocene); the Grane field on the eastern part of the survey produces from the Heimdal Formation (Palaeocene) with very good reservoir quality; and the Jotun field, further north in the survey was producing (currently shut down) from the Heimdal Formation. Few discoveries have been made in the deeper Vana Sub-basin part of the survey: the 25/10-11 well was drilled in 2011, targeting the Early Jurassic interval where minor oil and gas was encountered and the Busta prospect (25/7-7) and well 25/7-2 were drilled by ConocoPhillips targeting the Jurassic Intra-Draupne Formation and discovered gas condensate and light oil.

Innovative Acquisition and Processing Deliver Superior Imaging from Shallow to Deep

The 2020 GeoStreamer X survey has the same configuration as the 2019 survey with minor differences: two new deep-tow (between 25 and 30m) azimuths with 12 streamers 6 km long and spread 93.75m apart, including two 10-km-long streamers for improved Full Waveform Inversion (FWI), and a wide-tow triple source with 250m separation between outer source arrays for more reliable near-offset coverage in the 50–125m range. The benefits of this acquisition set-up are its richer azimuth/offset information and illumination at all depths. The additional acquisition azimuths (two in the 174° and 234° direction) are complementary to the completely reprocessed 2011 narrow-azimuth MultiClient broadband data (114°), creating a homogenous multi-azimuth dataset of around 1,650 sq. km.

A state-of-the-art pre-processing sequence ensures a seamless merge of all the azimuths into a single 5D dataset prior to Kirchhoff Pre-Stack Depth Migration (KPSDM). The velocity model was obtained through comprehensive Velocity Model Building (VMB) which included using both refractions and reflections for FWI in a MAZ setting. This was key for resolving both shallow and deep velocity anomalies such as channels, shallow gas, high velocity injectites and the chalk layer. Figure 1 illustrates the total gain obtained from high-grading existing data with complementary new acquisition and better imaging workflows. The improvements are observed from shallow to deep – higher clarity and resolution and obvious changes in structural geometry, significantly improving interpretability.

Reservoir Property Estimation Using the MAZ Dataset

Based on the above observations, and with the objective to extract reservoir properties such as volume of sand and porosity, instead of estimating absolute elastic attributes, it was decided to use only the pre-stack seismic amplitudes.

A multi-attribute rotation scheme was subsequently implemented to

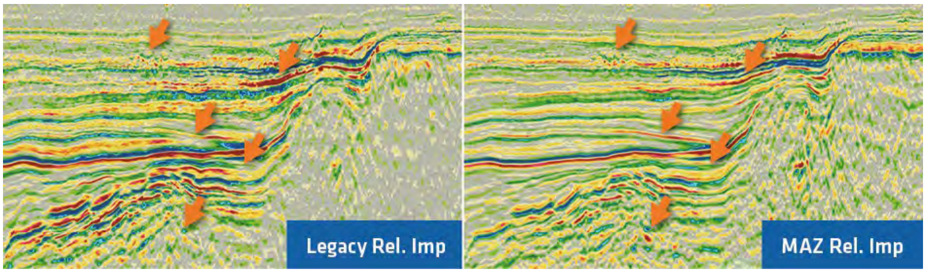


Figure 1: Uplift obtained from high-grading existing data (legacy 2011 or MAZ) with complementary new acquisition and more advanced imaging workflows is illustrated here. The improvements are observed from shallow to deep, in higher contrast, continuity, and resolution of reflectors as well as clear improvements in the interpretability, definition of the faults and structural elements. We illustrate the uplift with the respective relative acoustic impedance inversion of the two datasets.

derive the reservoir properties. This multi-attribute rotation scheme (MARS) is the equivalent of the elastic extended impedance but uses a combination of elastic attributes. The workflow was tested at well locations and then applied to seismically derived elastic attributes. The transforms were used to estimate reservoir properties, porosity and volume of shale based on the derived elastic properties (relative acoustic impedance and Vp/Vs).

MARS methodology has been implemented on the legacy and the new multi-azimuth datasets with the exact same workflow i.e., relative pre-stack seismic inversion followed by the reservoir property transform described above. On the Utsira High, the deeper Jurassic depositional environment is clearly imaged using this combination of pre-stack amplitude and elastic attributes to discern a fluvial channel system (*Figure 2*). It is possible to map and detect untested Jurassic porous sands located in the Utsira High based on the above attribute. These sand geobodies apparently correspond to a channel fill complex. With the porosity (derived independently from the interpretation) draped on the interpretation, the highest porosity (above 30%) is present within the channel. These bodies represent sweet spots of significant porous sands that may be attractive exploration targets.

The same processing workflow was applied in the Vana Sub-basin targeting Jurassic opportunities. Clear differences can be observed between the legacy narrow-azimuth dataset (*Figure 3, left*) and the recently acquired and processed multi-azimuth (*Figure 3, right*). The overall volume using the multi-azimuth dataset appears smaller but is potentially more accurate than using a partial view of the subsurface, thus reducing the uncertainty in the volume estimation.

An Integrated Solution for High Fidelity Subsurface Understanding

We have demonstrated that new opportunities can be found and characterised in a mature basin such as the Norwegian South Viking Graben with a combination of innovative acquisition, and a seismic-driven reservoir property estimation. Seismic morphology interpretation based on enhanced imaging delivers a better understanding of the Jurassic interval using reliable attributes. The integrated workflow allows an improved assessment and higher confidence in the subsurface volume estimation provides a powerful risking and uncertainty assessment tool.

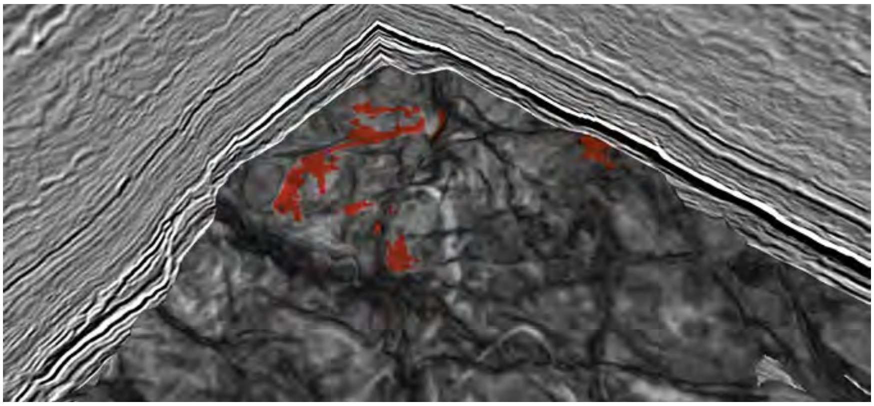


Figure 2: Middle Jurassic fluvial channel complex co-rendered with the amplitude extraction estimated from MARS workflow. Very good porosity (dark red) is predicted within the channel belt.

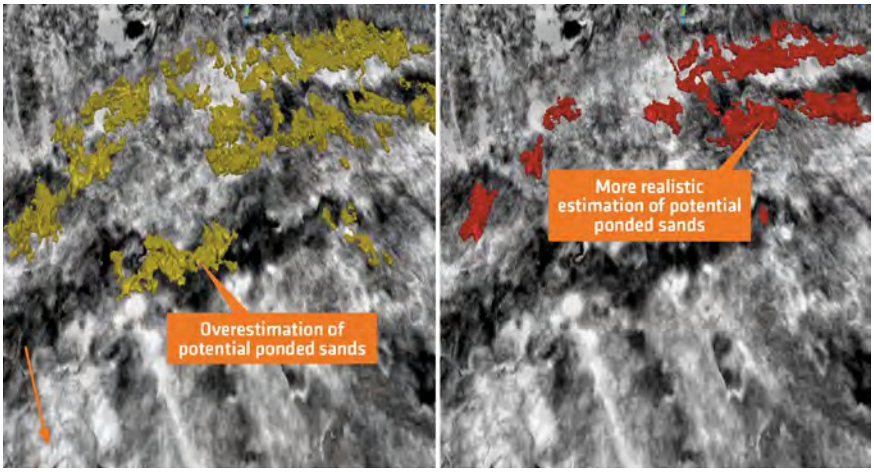


Figure 3: Effective porosity estimation using the reservoir property transform based on data-driven elastic attributes. The above results show the detected geobodies using a cut-off on the volume of shale (below 0.3) and with a porosity above 12%. These geobodies represent the most porous sands. On the left is the result of the porosity estimation using the legacy narrow-azimuth dataset and, on the right, using the newly acquired and processed GeoStreamer X multi-azimuth dataset. The legacy porosity estimation is noisier and less coherent compared to the multi-azimuth dataset leading potentially to an over-estimation of the volume of porous sands. The geobodies are interpreted to be ponded sands associated with mass transport complexes (marine slides). The direction of slide is illustrated with the orange arrow.

GAS RENAISSANCE IN EUROPE

NVENTURES

Brought to you in association with NVentures.

www.nventures.co.uk

Peter Elliott
peter.elliott@ nventures.co.uk

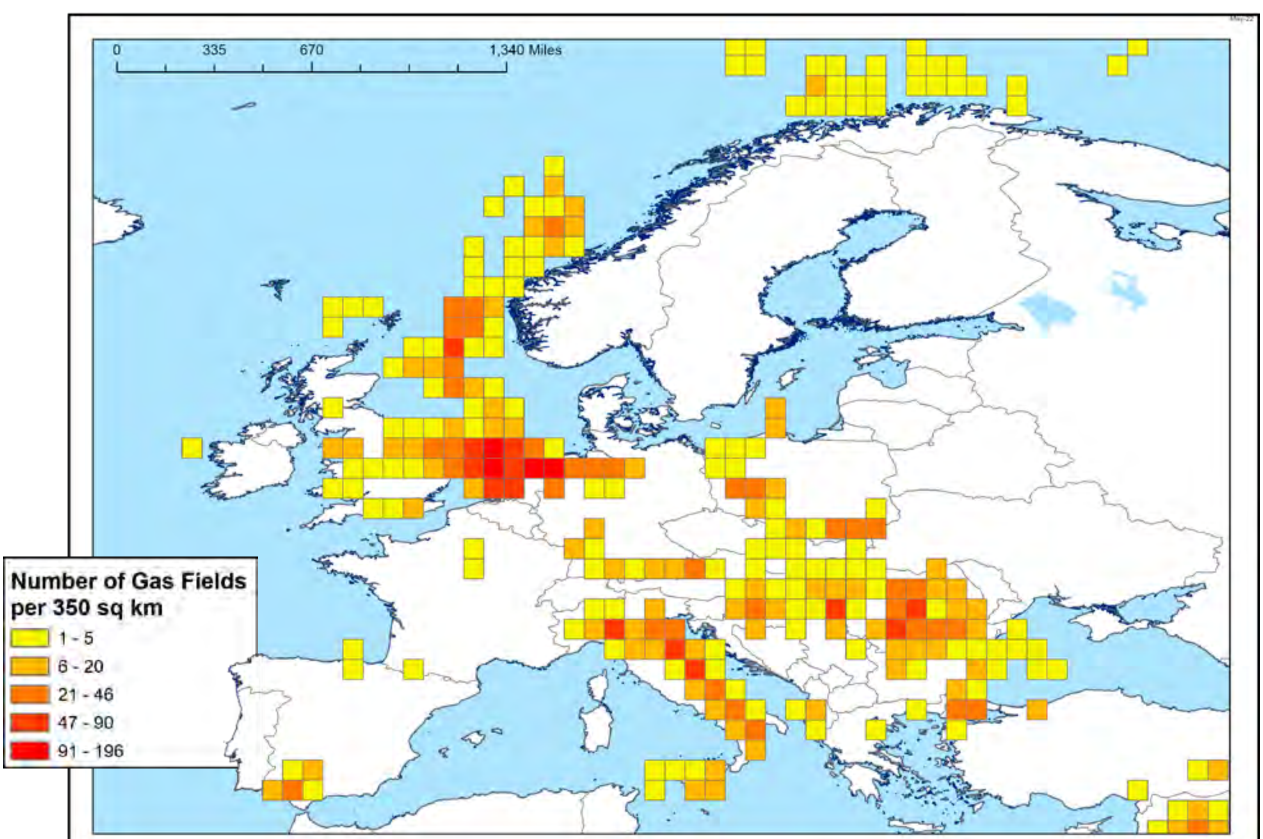
The drive for gas development gathers momentum, as increased energy prices spur on investment; conflict and political instability encourage domestic supply priorities; and post-pandemic macro-economic demands counter global warming hysteria.

Energy demand continues to grow in Europe, where mature gas infrastructure across the region, built over many decades, has created a critical engagement with gas for domestic and industrial usage. Current events have recently led to a significant supply crunch for gas, driven by geo-political problems in Eastern Europe, declining production in mature basins, and environmental regulations and policy designed to discourage investment in new gas developments. As these macro-economic drivers have gathered pace over the last decade, the industry now witnesses new enthusiasm for conventional, home-grown gas production, and it is often the pioneering smaller exploration firms at the vanguard.

A summary tour of North-West Europe reveals that although anti-hydrocarbon legacies are threatening the major economies, there are signs of legislation and policy-making easing to allow a gas renaissance. Germany issued a statement recently explaining plans to re-evaluate their opportunities for gas in the German North Sea. Denmark made clear statements in 2020 regarding a future moratorium on oil and gas, and cancelled a bid round, but in 2022 the Ministry of Energy and Utilities countered this with a package of measures including ramping up gas production. TotalEnergies' Tyra field will be the main beneficiary of this, and of course various green initiatives were announced at the same time. Britain's INEOS will look to benefit at the Siri and Hejre area fields.

In Germany and Austria, the parastatal oil and gas companies of Wintershall and Ruhrgas may show restraint in running down gas production, while smaller firms such as ADX and Terrain are testing new plays in Bavaria and Austria.

The Netherlands is a fascinating example of the current push and pull of environ-



NVENTURES

Map showing gas field density in Europe.

mental policy versus strong socio-economic demand. The main gas producer there, the largest gas field in Europe at Groningen, is due to be shut in within the next four to five years. Production has already been reduced by 70% on the back of environmental concerns and some evidence of subsidence. Whilst the government there has recently said it will increase LNG (regas) capacity to manage the supply crunch in the short term, there are deafening calls to increase domestic gas production. Firms like ONE-DYAS and Kistos are happy to fill the gap in the meantime.

In the UK, where about 40% of gas supply is imported and another 20% from LNG, renewed efforts are being witnessed in the conventional heartland of the Southern North Sea and to some extent onshore England. The UK government announced updated policy guidelines recently, encouraging oil companies to refocus investment on domestic 'energy' production, of which gas is a major element and a relatively low hanging fruit. The business minister explicitly stated full support for the North Sea and challenged 'naïve' environmental activism that might restrict investment in domestic production. Increased investment in natural gas is bound to play a role in environmental initiatives to reduce reliance on coal and oil, and deliver energy and feedstock to blue hydrogen projects – relatively subtle concepts for some activists glued to carbon euphoria.

In the offshore UK, several agile explorers are bucking the trend as supermajors leave the old heartlands. Spirit Energy, Perenco and Harbour currently manage most of the traditional gas fields there, while firms like IOG and Hartshead are bringing new life back to overlooked fields and prospects. Hartshead are targeting development at Anning and Somerville in their first phase of exploration, pursuing resources of over 300 Bcf. IOG have commenced production from Elgood and Blythe, just two years from FDP approval, with 55 MMcfgd and 1 Mbcpd. The firm is chasing several targets in Quad 48 including further drilling at Southwark and appraisal plans for Goddard and Kelham. Shell surprisingly withdrew recently from Egdon's offshore gas basin licences in Quad 41 but remain committed to the Pensacola gas well penned in for 2023 with Deltic.

Traditional gas exploration onshore is not being ignored, with INEOS, UKOG and Egdon heeding the call for more gas. UKOG has small production in the Weald Basin in southern England, with significant potential at Horse Hill. INEOS accounts for 26 Mboepd in the major producing basins onshore UK, while IGas contribute around 2 Mboepd. Major potential for over 200 Bcf of untapped reserves has been revealed at West Newton, north of Hull. Junior explorers Rathlin, Reabold and Union Jack Oil have been working up this western edge of the European Permian basin for a number of years, and planning permission appears to be in place for imminent development. This could be the largest gas development onshore UK, one that will rely heavily on positive investment sentiment and clear policy direction from central and local government. Long-time onshore operator Egdon have reported a 'step change' in production and revenue, mainly from small gas-producing assets.

Whilst indications are strong for a renaissance in conventional gas in the UK and North-West Europe, shale gas may yet play a role, although public and technical barriers remain. In the UK for example the Business Secretary asked the British Geological Survey (BGS) to carry out a review on the impacts of fracking in 2022. Cuadrilla in the meantime has been asked not to fully abandon their shale gas wells in Lancashire. Large energy firms like INEOS, IGas and Centrica have substantial legacy shale gas licences, and all have started lobbying government to allow well testing and reconsider the current UK moratorium on shale gas fracking.

ARTIFICIAL INTELLIGENCE – ITS USE IN EXPLORATION AND PRODUCTION

PART 3 Are we finally seeing AI fulfil its potential in oil and gas exploration?

Dr Barrie Wells
Conwy Valley Systems
Barrie.Wells@ConwyValley.com

SHUTTERSTOCK

Electrical and instrument site service temperature transmitter on offshore oil and gas wellhead platform to monitor and record gas and oil temperature inside flowline pipe.

In this series of articles, we are attempting to establish the background to the current resurgence in interest in Artificial Intelligence (AI), enabling us to have the best opportunity to use the technology to advantage. We have looked at how AI has evolved and at how Neural Networks (NN) work. Crucial to understanding the current resurgence of interest, this latest 'Spring' in the seasonal cycle of AI development, is what distinguishes Deep Learning from earlier implementations of NN.

In the mid-1990s Bertrand Braunschweig co-edited reviews of AI in oil exploration and production (E&P), consisting of papers presented at the CAIPEP, Euro-CAIPEP and AI Petro conferences. This may be taken as the state of the art at that time. Fuzzy logic and Expert Systems were still being discussed, but by consensus the tool of choice was NN and the papers primarily described applications of NN to problems in petrophysics, geochemistry, seismic geophysics, stratigraphy and others. Given that the Massachusetts Institute of Technology (MIT) describes Machine Learning (ML) and Deep Learning as developments of NN, we might usefully look at those reviews and ask what is different nearly 30 years later.

One obvious difference is a change of emphasis, from describing the technology to describing the results. The 1990s papers would start by both describing and justifying the choice of NN method (Multi-Layer Perceptrons, Radial Basis Function, Self-Organising Feature Map, Adaptive Resonance Theory, etc.) and the activation functions applied in the nodes (e.g., tangent hyperbolic, IMQE, Gaussian, Sigmoidal). Whilst the availability of methods has increased, the perceived need to explain has diminished. Nowadays, authors treat the underlying technology as just that, a technology on a par perhaps with choice of programming language or operating system.

Oily Fingerprints

A more useful comparison is with the applications. One from 1995 with which I am more familiar than most was a NN application for identifying oils from fluorescence spectra. It could learn to recognise 'oily fingerprints' by being taught on a training set. It is AI, it is a NN, and it learns, so how does this differ from what we now refer to as Machine Learning or Deep Learning (DL)?

The principal differences are in the size of the dataset and the number of parameters that characterise the data. The four factors listed earlier as driving the current interest in AI are access to data, computing power, development of the mathematical basis and commercial drive. Access to data is most commonly thought of as the internet but can also mean data accumulated by monitoring devices, such as those on production platforms. Increased computing power allows the processing of larger datasets and analysis of more characterising parameters.

Image Analysis Applications Dominate

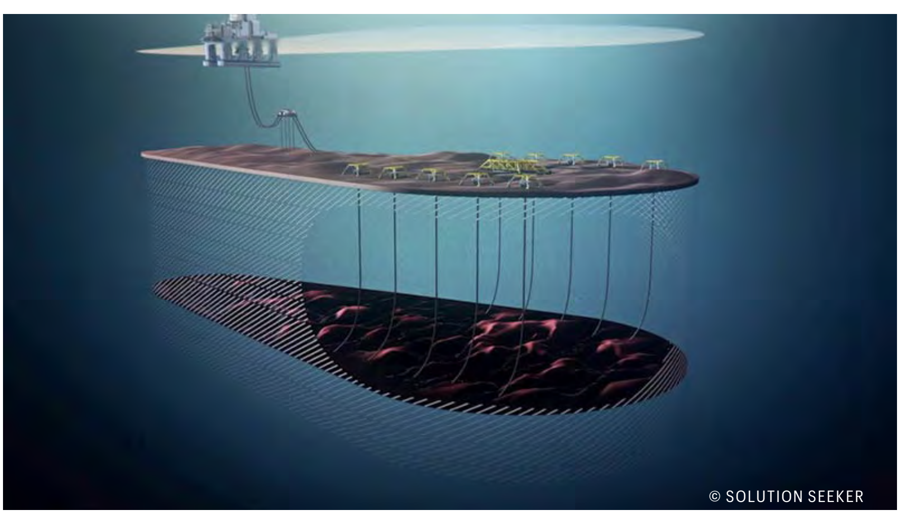
If Braunschweig were to undertake his survey today, it would be dominated by image analysis applications, which were absent 30 years ago. One reason for this is that creating large datasets of images is now an integral part of many of the applications in routine use in E&P companies. For example, a petrographic data analysis application will collect up to 1,000 images each day of use, with detailed data and metadata going far beyond the simple classifications in facial recognition systems. The ML and DL frameworks provided by, for example, TensorFlow, MLFlow or PyTorch, then allow petrographers to perform their own AI investigations without needing a collaborating university research group.

However, more instructive in understanding how AI has progressed would be the applications that are not based on image analysis. Previous articles in *GEO ExPro* have discussed ML by analogy with cat/dog classification and facial recognition but we can gain a better understanding of how ML works if we look at an application that is more nearly a next generation (or even the one after next) from those showcased by Braunschweig. For this we can seek help from Solution Seeker, showcased in *GEO ExPro* Vol. 15, No. 3, 2018.

With excellent academic credentials, a spin-off from the University of Science and Technology (NTNU), Norway, and a track record going back almost into prehistory in Deep Learning terms (founded in 2013) they have applied Deep Learning to production data: actual data from databases, rather than abstract information extracted from images.

level neural networks. Some popular examples of Deep Learning substitute a rule, a way to specify an objective function, for the large database of training examples. In this category are game-playing AIs that train themselves by playing games and revising strategies based on outcome, still with fast computing and sophisticated software. It is difficult to think of applications for this approach within E&P, as geology does not follow an arbitrary set of printed rules. We therefore need to identify large datasets on which our DL will operate. The most obvious sources are the large sets of tagged images, such as in the PETROG automated petrophysical solution. Additional software may be needed to turn these datasets into reliable exemplars, for example compensating for lighting, angle, scale, etc.

Solution Seeker's approach is to turn commonly available datasets, such as historic monitoring data, into reliable exemplars and thus provide the first pillar of the DL paradigm. Indeed, as an example of how technologies advance



The huge quantities of raw data generated during production can be used to optimise the process.

at increasing speed due to their ability to feed on themselves, the Solution Seeker algorithms for preparing the data, and hence providing this first pillar, are themselves AI applications.

Considering Solution Seeker's products lets us see how the Deep Learning paradigm is both a natural progression from the earlier NN applications and a step-change in the application of AI to E&P workflows.

Deep Learning is based on access to large datasets, fast computing, and multi-

The Image Conundrum

The availability of large datasets may be questionable in many practical examples. A dataset consisting of a large number of images, for example, may require extensive preparation and cleaning in order to make it suitable for use by an image recognition application: an archive picture of a face and a specimen for comparison are unlikely to have been taken from the same angle, been captured under the same lighting conditions, posed with the same facial expression, etc. Fortunately for those in the business of matching images, there is a vast amount of experience on which to draw, not least from the gaming and film industries: CGI is now able to complete films in which an actor has died during filming or extend the oeuvre of long-dead film stars.

A similar challenge faced Solution Seeker: although large oil and gas production datasets have been accumulated, data volume is typically low for individual wells. A key component of the step-change from AI in the 1990s to state-of-the-art ML and DL is the ability to prepare data for the machine. Solution Seeker has developed a transfer learning model that is able to learn continuously across thousands of wells, utilising the resulting dataset as its exemplars. This modelling approach enables, for instance, a cost-efficient and high-quality Virtual Flow Meter.

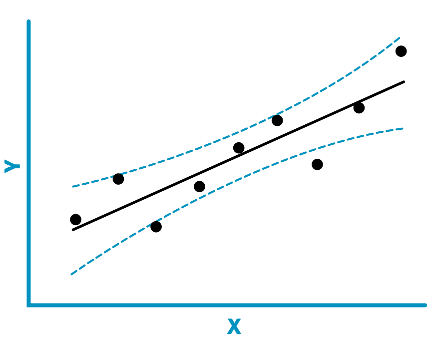
The 'Long and Wide' of It

Bzdok et al. in their paper 'Statistics versus Machine Learning' characterise the difference between AI, or specifically Machine Learning, and classical statistical methods, as ML methods are particularly helpful when one is dealing with 'wide data', where the number of input variables exceeds the number of subjects, in contrast to 'long data', where the number of subjects is greater than that of input variables. This is another way to think of the dependence of ML and DL on greatly increased computing power. In the 1990s, there was insufficient computing power available to look at all the possible interactions between the parameters in a very large input dataset. NN were therefore necessarily used in a more classical statistical sense and indeed NN methods were often taught as just another multivariate statistical technique alongside Cluster Analysis, Principal Components Analysis and Factor Analysis. It is therefore, in part, the way in which NN are now used that provides a step-change from the 1990s to applications such as Solution Seeker.

AI pillar	1995: 'oily fingerprints'	2022: Solution Seeker
Access to data	Individual spectra manually prepared from spectrograph output	Real-time sensor data automatically labelled and categorised to increase data quality
Computing power	Speed of algorithm was considered important in choice of NN method	'Unlimited' capacity available. Dataset preparation and model architecture more important
Mathematical basis for AI	Complex multi-level networks still under development	Conventional DL architecture, tailored to learn the behaviour of oil and gas production systems
Commercial drive	Primarily from the perceived need to retain expertise in the 'Big Crew Change' (large number of geoscientists due for retirement)	Increasing amounts of sensors and available data

Table: AI: Then and Now

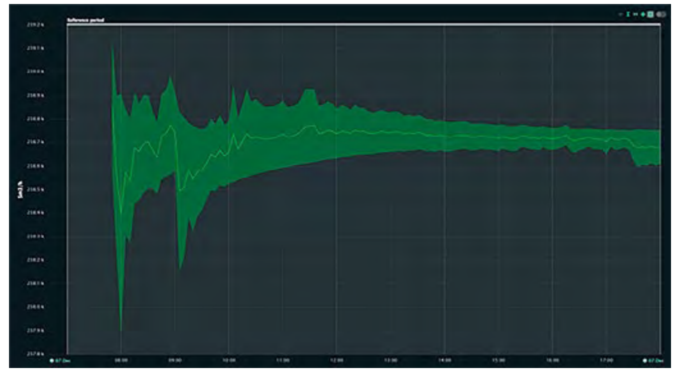
With this step-change we have moved further from being able to ask the NN the crucial question "Why?": why a prediction was made, what were the reasons. We are, however, now better able to ask how good the prediction is, in a similar way to placing predicted error bounds on methods from mathematical statistics. It is routine to predict permeability from porosity using linear regression, a practice necessitated by the comparative ease of obtaining porosity estimates, relative to the difficulty and expense of obtaining permeability measurements. Linear regression has an associated error estimate, which allows confidence bounds to be placed on a predicted value of permeability (assuming, of course, absolute accuracy in the inputs).



Error bounds on linear regression prediction.

DR BARRIE WELLS

Similarly, a method to estimate or predict flow rates, such as that of Solution Seeker, is predicated on the relative ease of obtaining measurements which may then be used to model flow rates. At present, such predictions are not used routinely. Confidence in their use should increase with availability of reliable error bounds. Probabilistic error bounds may be



SOLUTION SEEKER

Uncertainty based on a data-driven ML (Virtual Flow Rate).

calculated, by treating the weights in the NN as random variables for generating probabilities.

AI – A Tool for the Geoscientist, not a Replacement

Machine Learning and Deep Learning are terms that are used to describe new ways of taking advantage of the implementations of mathematics and mathematical statistics comprising the methods under the umbrella of Artificial Neural Networks. They are capable of providing surprising results and are sufficiently far advanced technologically to sometimes appear to be indistinguishable from magic, if we do not appreciate the simple building blocks of NN and the addition of large datasets for training or learning.

It has taken a while for ML / DL to attain a level of usefulness in E&P, but now we expect to see a rapid expansion in deployment, based on the relative simplicity to scale across assets.

The main drawback of ML and DL is that we currently have no way to interrogate the engine, to ask why a certain conclusion was reached or on what basis certain inputs are considered to be similar. This places even greater importance on the role of the domain expert, the geoscientist, and means that, for the foreseeable future, AI will not replace good geoscientists; it should instead enhance their capabilities.

References

Braunschweig, B. and Bremdal, B. 1995 and 1996. *Artificial Intelligence in the Petroleum Industry: Symbolic and Computational Applications.* Vols 1 (ISBN: 9782710806882) and 2 (ISBN: 9782710807032). Editions Technip.

Hatton, R., Duller, A., Wells, B. and Barwise, A. 1995. *Application of Neural Networks in Crude Oil Fluorescence Fingerprinting.* 'Best Paper' at AI Petro, Lillehammer, Norway, September 1995.

Bzdok, D., Altman, N. and Krzywinsk, M. 2018. Statistics versus Machine Learning. *Nature Methods,* 15(4), pp.233–234.

https://www.ntnu.edu/subpro/enhanced-virtual-flow-metering

https://www.solutionseeker.no/products-and-solutions/flow-rates/neuralcompass-dd-vfm/

https://www.petrog.com

CCS IN SCANDINAVIA

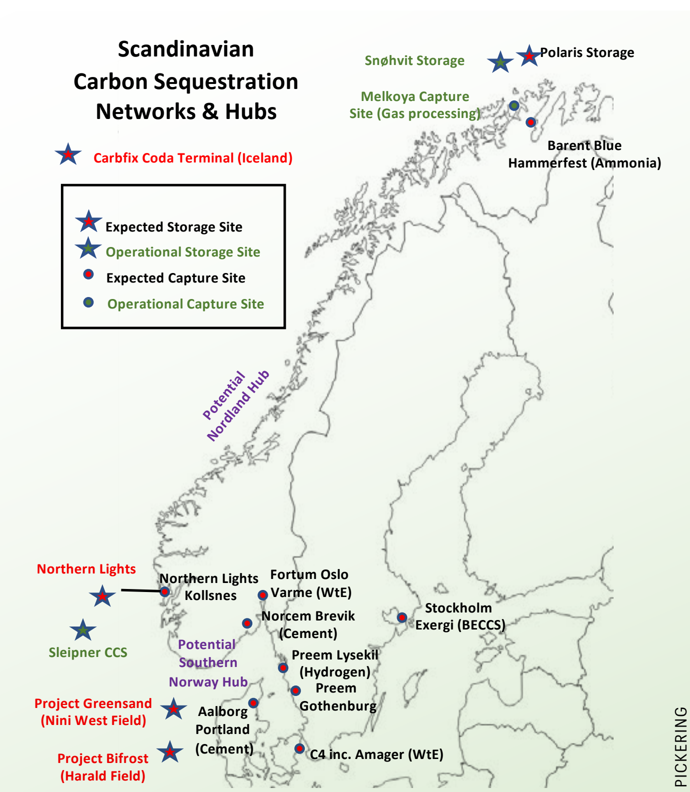
David Pickering

Pickering Geoscience
davidcpickering@googlemail.com

The deployment of carbon capture and storage (CCS) in Scandinavia accelerates.

Norway has led the way in carbon capture and storage (CCS) for many years, underpinned by its leading role in oil and gas production in the Norwegian, Barents and North Seas over the past half century, but there has been significant recent CCS activity in Denmark, Iceland and Sweden too. In the past couple of years, a critical mass of activity and collective will may have been reached, suggesting that the mass rollout of CCS will happen in the coming years.

At least seven CO_2 storage sites are now either in operation or being evaluated. Hard-to-decarbonise industries are looking at capturing their emissions and utilising networks and hubs to share efficiencies for dehydration, compression, intermediate storage and transport to sequestration sites. Power-to-X, Energy-from-Waste (EfW), District Heating and Hybrid Energy Solutions are all big topics of discussion, supported by Scandinavia's abundant and continuously expanding renewable energy sector.



DAVID PICKERING

Scandinavian CCS networks and hubs.

HUFTON+CROW

Efforts are being made to actively decarbonise industrial emissions by removing legislative and commercial hurdles, whilst simultaneously utilising a highly experienced offshore workforce, specialised academic centres of excellence and the current political will to implement change. Given the modest scale of their emissions compared to their more populous European neighbours, and some favourable geology, it is likely that the Danish, Norwegian and even Icelandic storage sites will be able to provide 'storage as a service' in the not-too-distant future.

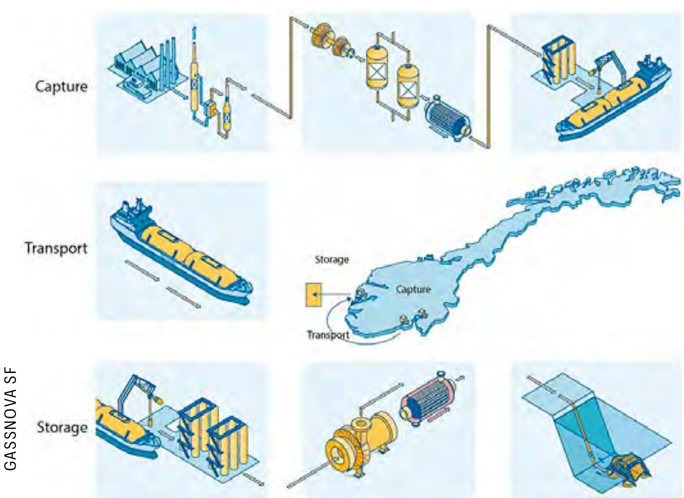
Norway Leads the Way

The Sleipner project was the world's first commercial CO_2 project, originally motivated by the implementation of a CO_2 tax in Norway. Since Statoil brought the facility online in 1996, more than 18 million tonnes of CO_2 have been injected to a depth 800–1000m into the saline aquifers of the Utsira Formation. Capturing the CO_2 emitted from the natural gas production (up to 9%), it is reinjected on location.

This development was followed in 2008 by the Equinor-operated Snøhvit project, this time driven by both regulatory requirements and a carbon tax. The CCS-equipped LNG processing plant on Melkoya island, near Hammerfest, strips the 5–8% CO_2 piped ashore from the Snøhvit field in the Barents Sea. Up to 0.7 million tonnes per year (Mtpa) are captured and sent back offshore, via a 150 km pipeline, and sequestered within the saline Tubasan Formation, some 2.6 km below the seabed.

Inside the Amager Bakke Waste-to-Energy plant.

Recently, there has been a lot of focus on the development of open access, full value chain projects and networks. The Langskib (Longship) project is a full-scale CCS project designed to capture CO_2 from industrial polluters in onshore Norway and beyond. Industrial emissions will be captured at the Heidelberg Cement's Norcem cement factory in Brevik and Fortum Oslo Varme's waste incineration facility in Oslo Fjord. Ships will transport the CO_2 to an onshore terminal on the Norwegian coast, before it is piped offshore and then stored in the Cook and Johansen Formations, some 2.5 km below the Norwegian Sea. The transport and storage elements of this project are called Northern Lights and start-up is expected in 2023–2024. With imports from additional emission sources, this will increase to c. 1.5 Mtpa then potentially 5 Mtpa.



Norwegian Longship CCS networks and hubs.

Horisont Energi, Equinor and Vår Energi have very recently been awarded a CO_2 storage licence for a site in the Barents Sea with storage capacity in excess of 100 Mt. The Polaris CCS project is being matured off the coast of Finnmark and is linked to the Barents Blue project, which will be Europe's first world-scale carbon-neutral ammonia production plant. Natural gas will be converted into blue ammonia, with CO_2 being stored in the Polaris reservoir.

Denmark's Use of Depleted Oil and Gas Fields

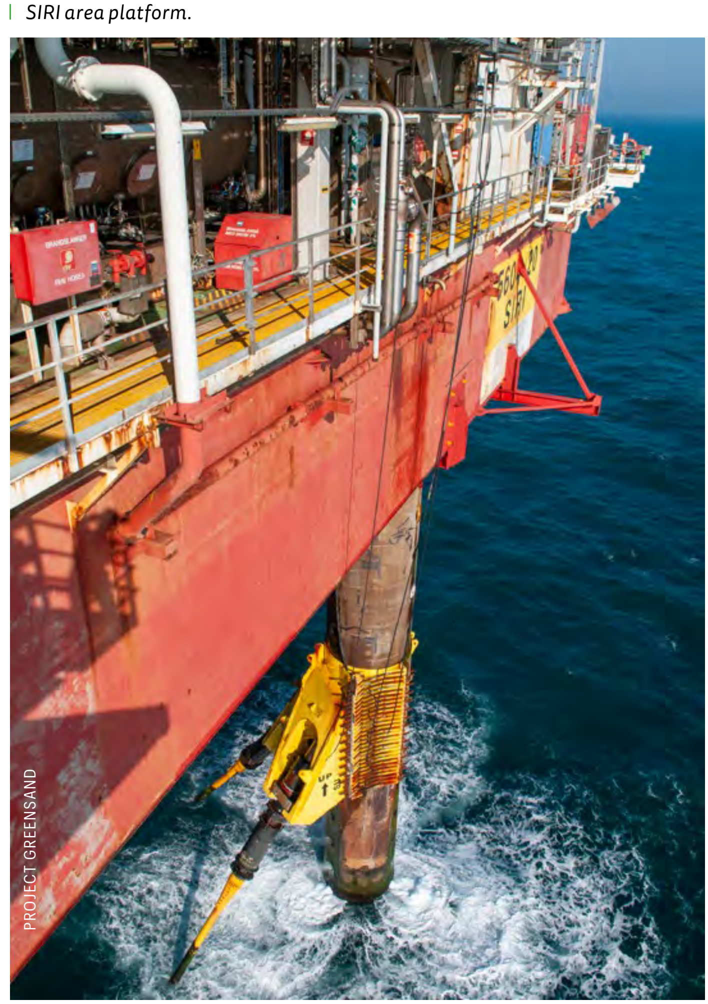
Denmark has proven subsurface storage potential. With the fall in oil and gas production in the offshore Danish sector, the country has been advancing its plans to repurpose its oil and gas fields and infrastructure for carbon sequestration. Oil production is now less than 70,000 bopd in the country, with gas at around 135 MMscfd. With their significant and well-described storage capacity, along with decades of understanding of the subsurface performance, many see a distinct advantage to using oil and gas assets for CO_2 storage over saline aquifers.

There are benefits to using existing infrastructure too, including the deferral of some abandonment liabilities and the acceleration of the timeline to first sequestration. Offshore locations are deemed to be less contentious with the public at present, although potential structures closer to shore have been identified. The counter argument to the use of depleted oil and gas fields is primarily around storage capacity and efficiency, as well as the potential for the legacy well stock to act as leak points.

There are two major sequestration projects currently in the planning stages. The first, Project Greensand, is a consortium led by INEOS, in partnership with 22 other companies including Wintershall Dea, Maersk Drilling and Geological Survey of Denmark and Greenland (GEUS). The strategy is centred around the depleted Siri area oil fields on the border between Norway and Denmark, in the Permian Basin, and the plan to store carbon dioxide in these assets. The project is named after the distinctive colour of the target for CO_2 injection – the green-coloured, glauconitic Tertiary sands that originate from the Stavanger Platform in Norway and are present throughout the region.

The partnership is estimating in the region of 4–8 Mtpa storage potential in the wider Siri area, primarily into the old oil fields at depths of up to 2 km. The project aims will begin with a pilot phase before first ramping up in 2023 to a demonstration

SIRI area platform.




HUFTON+CROW

Amager Resource Centre (ARC). (There is even a cable snowboarding slope on the roof of the facility!).

phase on Nini West (0.45 Mtpa) and then to a full-scale development beyond Nini in 2025 (3–4 Mtpa). Shuttle tankers will offload CO_2 captured at onshore industrial facilities.

The second sequestration project is called Bifrost and is a partnership of the Danish Underground Consortium (DUC), Ørsted and DTU. This group are evaluating the potential for CO_2 transport and storage at the Harald field in the Danish North Sea, with a start-up capacity of 3 Mtpa. Initially, Harald West will be utilised, with its sandstone reservoir targeted for first sequestration in 2027. To achieve the scalability and longevity, there is however a need to unlock the chalk storage potential, starting with Harald East. Research in this area is ongoing.

In Copenhagen, there is a focus on making the Danish capital the world's first carbon neutral capital city. This is led by C4 (Carbon Capture Cluster Copenhagen) which brings together large industrial power producers who are now collaborating on shared infrastructure and storage options. Whilst the country leads the world in renewable energy deployment, Denmark produces some of the highest levels of municipal waste (per capita) in the European Union and has a long history of burning that material. Recovering the energy from waste, capturing the CO_2 emissions and storing the CO_2 in repurposed offshore assets seems like a great example of the circular economy in action.

The largest project to date is led by Amager Resource Centre (ARC), the owner of the Amager Bakke Waste-to-Energy plant. Its facility supplies low-carbon electricity to over 500,000 people and district heating to 140,000 households. They plan to capture 0.5 Mtpa, helping the municipality of Copenhagen to become carbon neutral by 2025.

The Amager Bakke Waste-to-Energy facility opened in 2017 and is playing a key role in the circular economy. It is a combined heat and power complex and one of the largest waste-to-energy (WtE) projects in northern Europe. Owned by the local municipalities, it incinerates 450,000 tonnes of residential and commercial waste each year, generating steam at 440°C / 70 bar. This energy is recovered for households in the surrounding area, supplying both district heating and power. Between 0–60 MW electricity and 157–247 MW district heating are generated, dependent on local demand and power prices. WtE will become a big industry in the coming years.

A pilot CO_2 capture project has been kicked off at the site, with the ultimate aim of being upscaled to capture and store 90–95% of the 500,000 tonnes of CO_2 emissions annually emitted by the new facility. The captured CO_2 will be liquefied and transported by pipeline to the terminal on nearby Prøvestenen. From there, it can be shipped to several possible depleted oil and gas field sequestration sites under development in the Danish offshore.

Iceland Leverages its Geology

85% of Iceland's primary energy is derived from renewables. Electricity is almost entirely generated from a mix of hydropower (c. 70%) and geothermal (c. 30%). Geothermal has been used for industrial purposes in Iceland for decades. Recently, the abundance of renewable energy is behind a push for Power-to-X, Green Hydrogen and other eFuels. And the abundant basalt could store large volumes of CO_2 meaning that carbon sequestration is making progress too.

Geothermal wells can have greenhouse gas emissions (GHG) too. Landsvirkjun's newest geothermal power plant, Þeistareykir, is located in north-east Iceland. With an installed capacity of 90 MW, it emits around 6.5 kilotons of CO_2 per year. Project 'Koldis' aims to reduce CO_2 emissions by over 90% by capturing emissions and reinjecting on site. The plant is expected to be onstream by 2025.


CARBFIX

Precipitated carbonates in cored basalt from the Carbfix CO2 injection site.

Climeworks have collocated their facility with the Hellisheidi geothermal plant. Orca is the world's first large-scale direct air capture (DAC) and storage facility, with plans to expand to 0.5 Mtpa by 2030. Geothermal is used to power fans, filters and heaters. The DAC CO_2 is reinjected into the subsurface onsite at Carbfix's mineral storage facility, along with CO_2 and H_2S emissions from Hellisheidi.

Carbfix's Icelandic injection site.

Carbfix are also constructing the Coda terminal at Straumsvik. CO_2 shipments from across northern Europe will be able to dispatch to the terminal. CO_2 is then dissolved in water before being injected into highly reactive basaltic rock. Within two years, much of the CO_2 will have formed solid carbonate minerals, permanently and safely locking it away.

Sweden Focuses on Capture

With a population greater than that of Norway, Denmark and Iceland combined, there is significant emissions capture potential in Sweden. Although the industrial emitters tend to be small and far apart, they are mainly present on the east coast of the country, allowing for potential evacuation by ship.

Most of the country is underlain by Precambrian craton (crystalline basement rock), which poses a significant challenge to finding suitable sites for CO_2 sequestration within the country itself. There are small sedimentary basins close to the Danish border in the county of Skåne in the south-west of the country, as well as in the southern portion of the Baltic Sea, and some research is ongoing to examine the potential for sequestration within fractured basement. However, it seems likely that Swedish hard-to-decarbonise industries will initially look to export captured carbon eastwards to Norway, Denmark and the UK.

Activity, therefore, is focused on capture and intermediate storage, rather than the development of long-term sequestration sites. By way of example, the CinfraCap project (Carbon Infrastructure Capture) is focused on the cost-effective transport of CO_2. It is examining ways of improving efficiencies in the logistics chain: liquefaction, intermediate storage etc. Göteborg Energi, Nordion Energi, Preem and several other industrial facility owners in western Sweden are participating in this research.

The Preem project is a test facility that commenced operations in 2020. It aims to capture CO_2 from flue gases from Preem's hydrogen gas plant at the Lysekil refinery. This project is being carried out in collaboration with Aker Solutions, Chalmers University of Technology, Equinor and the Norwegian research institute SINTEF. Funding support is coming from the Swedish Energy Agency and a Norwegian research programme called CLIMIT. Initially 0.5 Mtpa are being targeted; however the combined emissions of the Lysekil and Gothenburg refineries are c. 2 Mtpa. It seems likely the Norwegian Northern Lights could be the destination for the captured CO_2.

Northern Lights template on the Edda Freya supply ship.

Slite Cement is a factory on the island of Götland, owned by Heidelberg Cement. It aims to be the world's first carbon neutral cement works and is targeting the capture of all 1.8 Mtpa of CO_2 emissions. Heidelberg are already working on the Brevik site in Norway, working to capture emissions with Aker Carbon Capture, as part of the Northern Lights project.

The municipal energy company Stockholm Exergi has installed a test facility at the Värtaverket bio-cogeneration plant in Stockholm. The project is looking at bioenergy with CCS (BECCS) and has the potential to capture 800 ktpa.

EVALUATING FLUID DRAINAGE DYNAMICS IN RESOURCE PLAYS

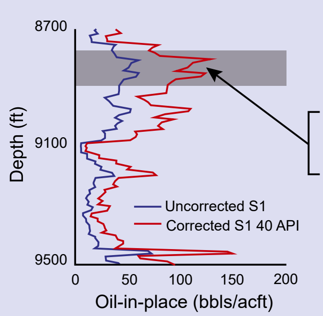
Geochemistry provides significant benefits when optimising developments.

Hydrocarbon production from resource plays (those in which the source rock and reservoir are the same unit) requires hydraulic fracturing of stacked horizontal wells. To ensure economic production across these wells, operators look to optimise spacing, stacking and completions across their acreage. In this article we discuss how fluid chemistry can be deployed to directly confirm or refine the assumptions made when optimising these developments.

Craig D. Barrie and Eric Michael, APT USA

Targeting the Right Zones

Evaluation of hydrocarbon richness and production potential across an operator's acreage is a key early phase, prior to production and development. This evaluation can be done using a variety of toolkits, but few are direct measurements of the hydrocarbons within target zones themselves. To directly evaluate in-situ fluids you need access to core or cuttings. Analyses of these samples via pyrolysis methods (e.g., S1, S2, S3, where S1 = the amount of free hydrocarbons (gas and oil) in the sample, S2 = the amount of hydrocarbons generated through thermal cracking of non-volatile organic matter and S3 = the amount of CO_2 (in milligrams CO_2 per gram of rock) produced during pyrolysis of kerogen) allows rapid, inexpensive assessment of the character of the source rocks (e.g., richness, kerogen type, etc.) and insight into fluid mobility and physical properties (e.g., petroleum yield, API gravity, etc.). Three of the most important parameters are oil in place (OIP), oil saturation and oil mobility, all of which can be estimated from pyrolysis data. These factors all play a role in defining whether a pay zone is sufficiently rich in mobile hydrocarbons to be landed in. In Figure 1 a zone of interest has been identified and the goal is to assess saturation and mobility. The depth plot shows uncorrected mobile OIP (blue) and corrected OIP assuming an API value of 40 (red). In this example we can take determined OIP, from the zone of interest, and assuming standard rock and oil densities, and a range of porosities, calculate total oil saturation (So), from which mobile oil will be lower, the extent of which is dependent on oil maturity. This screening workflow is the first stage in ensuring production is optimised, in this case landing zone optimisation, across stacked plays.



Comparison of Pyrolysis OIP to Saturations

Depth	porosity	Rock Bulk density g/cm3	uncorrected S1	oil density g/cm3	API Gravity	Total So
8815	4.0	2.50	2.43	0.835	38.0	67.5
8815	6.0	2.50	2.43	0.835	38.0	45.0
8815	8.0	2.50	2.43	0.835	38.0	33.7

Figure 1: Geochemical oil-in-place (OIP) determined from pyrolysis data (bbls/acft) from pilot hole WBM cuttings. Blue line = uncorrected data. Red line = corrected S1 data assuming an API value of 40. The table shows conversion of geochemical OIP data to total saturation (So) using a range of porosity values.

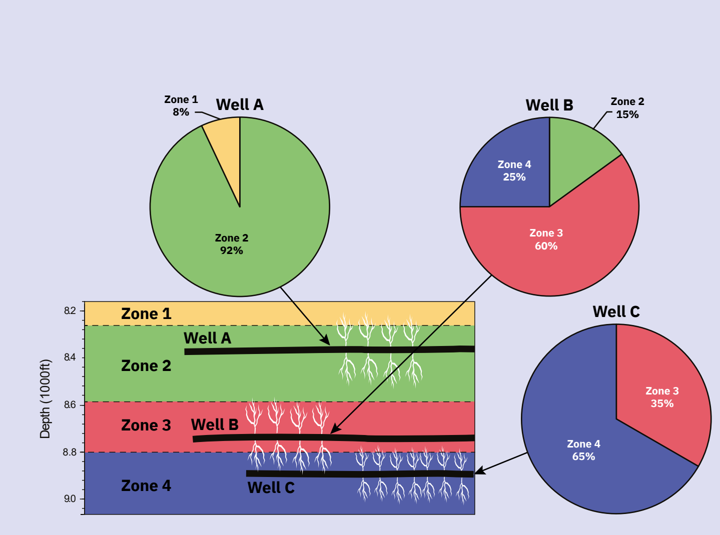
APT

Understanding Your Drainage Network

Hydraulic fracturing is the process by which fluids are produced in resource plays. The hydraulic fracture network consists of stimulated rock volume (SRV), the total extent of the fracture network, and drained rock volume (DRV), the extent of the network which drains fluids. DRV cannot be larger than SRV, but the DRV is also rarely static and changes through time, often reducing as fractures heal. Furthermore, these networks do not necessarily drain equally; lithology and associated permeability also play an important role in which formations are preferentially drained. For example, while rich shale zones are often targeted, these are juxtaposed against silt or sandstone layers which are more permeable and may be the dominant production fluid, even where the landing zone is a shale. There are numerous methods to infer where production is coming from, especially if you have at least a baseline understanding of fluid saturation and mobility. But, given the caveats discussed, the only direct way to assess and understand active DRV is to analyse the chemistry of the production fluids. In Figure 2, we have already characterised the end member (EM) fluid signatures from the four identified production zones from cuttings. The produced oils from the three horizontal wells can then be compared back to these EMs and source contributions to production can be defined. This allows rapid, direct evaluation of whether these source contributions match modelled expectations and what the results indicate about individual well production lifetimes.

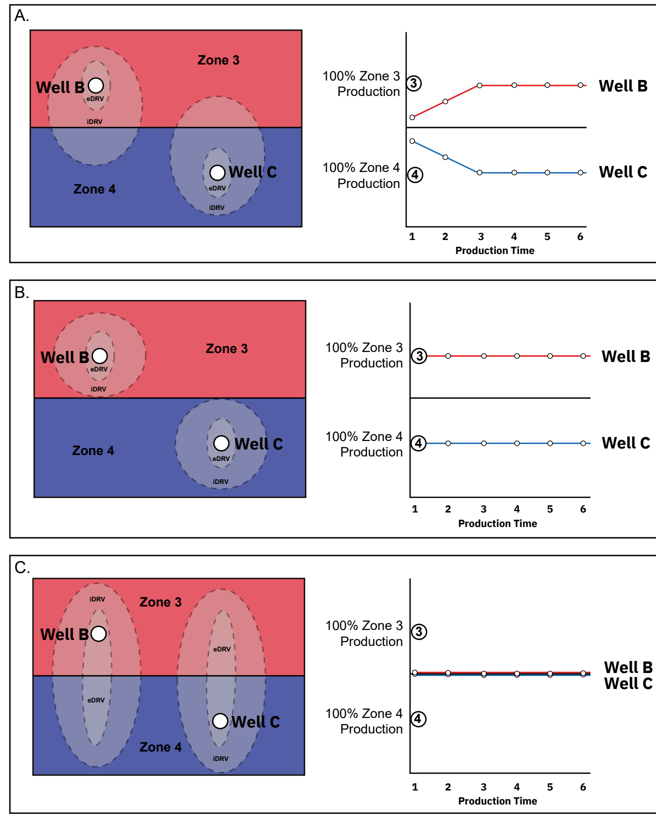
Monitoring Through Time

Source contributions are generally measured at a single snapshot in time. These contributions, as indicated above, will potentially change as DRV refines



APT

Figure 2: Schematic showing the production contributions of four distinct production compartments across three horizontal wells landed in adjacent formations to one another, at a single point in time. Wells A and C are producing from their landing and overlying zones, while Well B is producing across three zones. Dominant production in each well is from the landing zone.



APT

Figure 3: Schematic showing variation in initial drained rock volume (iDRV) and established drained rock volume (eDRV) across two unique production compartments through time. A) iDRVs in the two wells overlap production compartments ensuring fluid chemistry in the wells is similar but, not identical. As we shift to eDRV, fluid chemistry becomes increasingly unique until the wells match their own production compartments. B) iDRVs in both wells are within their unique production compartments ensuring fluid chemistry of the wells match the production zones with minimal change in eDRV. C) iDRVs in both wells cover both production compartments with both wells producing identical fluids. eDRV shrinks in both wells but, coverage is the same ensuring fluid chemistry remains the same.

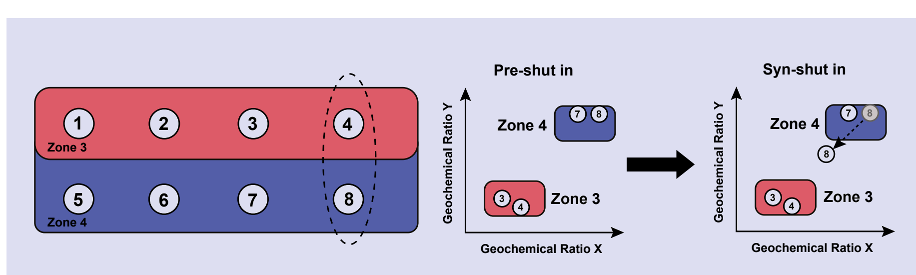
from its initial state (iDRV) to its stable, established state (eDRV). Figure 3 is a generalised schematic showing how production signatures, monitored via fluid chemistry, change through time based upon differing fracture geometries. Monitoring of fluid chemistry through time is essential to understand drainage behaviour and evaluate long-term viability of stacking, spacing and completion designs. However, source contributions do not only change because of refinement of the DRV and therefore fluid chemistry results should be coupled with additional complementary datasets to further understand changes in DRV and whether these will be an issue for the economic health of currently producing and/or future planned wells.

Complementary Datasets

Even standalone, geochemistry offers the best chance to directly understand subsurface drainage dynamics. However, as noted, it is more powerful when coupled with additional complementary datasets. One complementary method, shown in Figure 4, is interference testing. In this example a well will be shut in and the offset wells are being geochemically monitored. Pre-shut in the geochemistry of the shut in well (4) and the lateral offset (3) are identical and measurably different from the underlying offset wells (7 and 8).

During shut in, pressure and production monitoring indicates no change in the lateral offset wells 3 and 7, but well 8 shows an increase. The fluid chemistry of the wells also shows no change in 3 and 7, but in well 8 fluid chemistry has shifted towards the overlying zone and looks increasingly like well 4. Production data confirmed there was an issue and fluid chemistry data indicated where that issue was stemming from. The results suggest communication across the two zones during shut in and that vertical spacing is potentially destructive and therefore the stacking and spacing pattern is not optimised.

This article highlights the value and utility of fluid chemistry data, from landing to completion optimisation, for directly understanding and evaluating drainage dynamics in resource plays.



APT

Figure 4: Schematic showing how combining geochemical data with interference testing can provide insight on the viability of stacking and spacing patterns. During shut in of well number 4 in Zone 3, pressure and production increases in well number 8. Geochemical analysis of the fluid from the underlying well 8 in Zone 4 indicates the DRV has moved up and well 8 is now communicating across both zones.

SEEING THE WHOLE PICTURE

The merging of large, mixed legacy 3D seismic datasets, its history and why it makes sense in the UKCS.

During the pandemic, Lyme Bay Consulting took the opportunity to download all the Operator-released 3D seismic data in the UKCS to produce a series of Post-Stack Merged Seismic Volumes covering the Central North Sea (CNS), Outer Moray Firth (OMF), Northern North Sea (NNS) and Faroe-Shetlands Basin (FSB).

Steve Morse and Gerrard Spear,
Lyme Bay Consulting

Given the current energy security risks and increasing effort and research into energy transition and CCS, we are pleased to announce, subject to completion of contracts, that this data will be handed over to the North Sea Transition Authority (NSTA) and be available for free public distribution via the National Data Repository (NDR).

This will allow unconditional access to the data for research institutions and large and small companies alike in both the oil and gas sector as well as carbon capture and storage (CCS) and renewables.

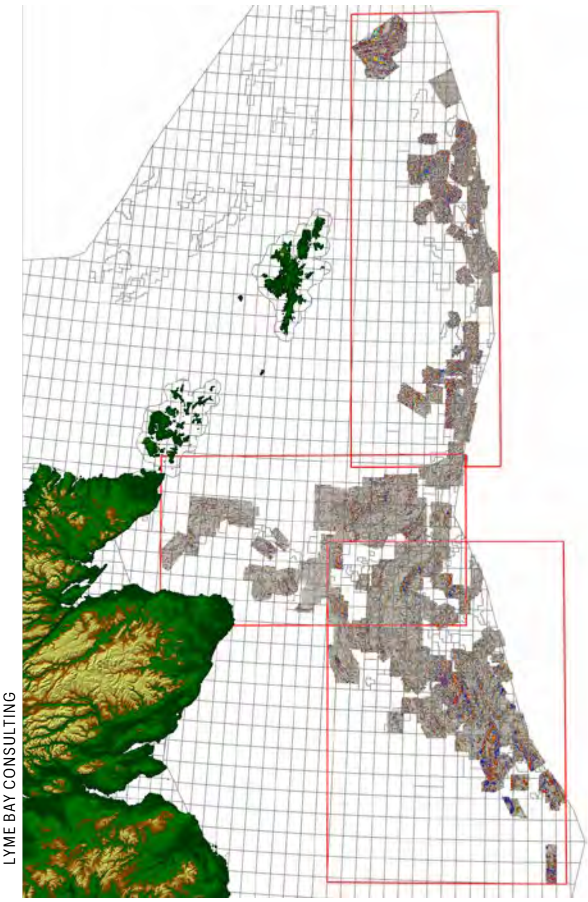
With this exciting news, we felt it timely to reflect on the history of large-scale regional merged seismic data and its many advantages.

Merged Datasets, Why Bother?

It is more than 20 years since the concept of large-scale merged seismic projects was brought to life by a leading seismic company with a multi-client (MC) seismic division. These merged datasets are now commonplace in many basins the world over and an integral component of oil company seismic data portfolios.

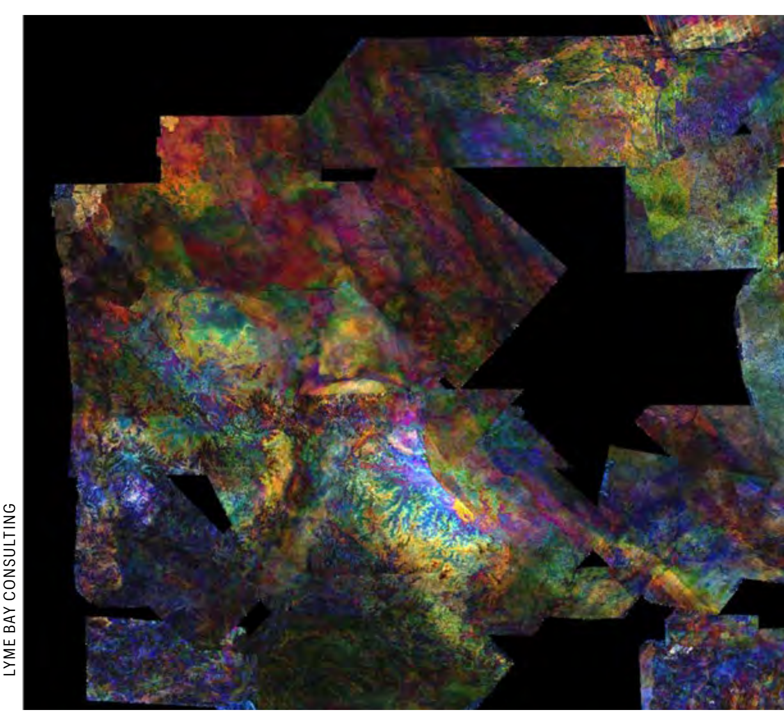
For some of us who have worked in the industry for many years, the early days of these merged projects is relatively well known. To those with a few less years under the belt, they are 'part of the furniture' and are rarely given a second thought and the trials and tribulations of getting these projects off the ground at the turn of the century are perhaps less well known.

LYME BAY CONSULTING



Merged seismic data coverage – CNS, OMF and NNS.

LYME BAY CONSULTING



FSB merged seismic data – spectral decomposition.

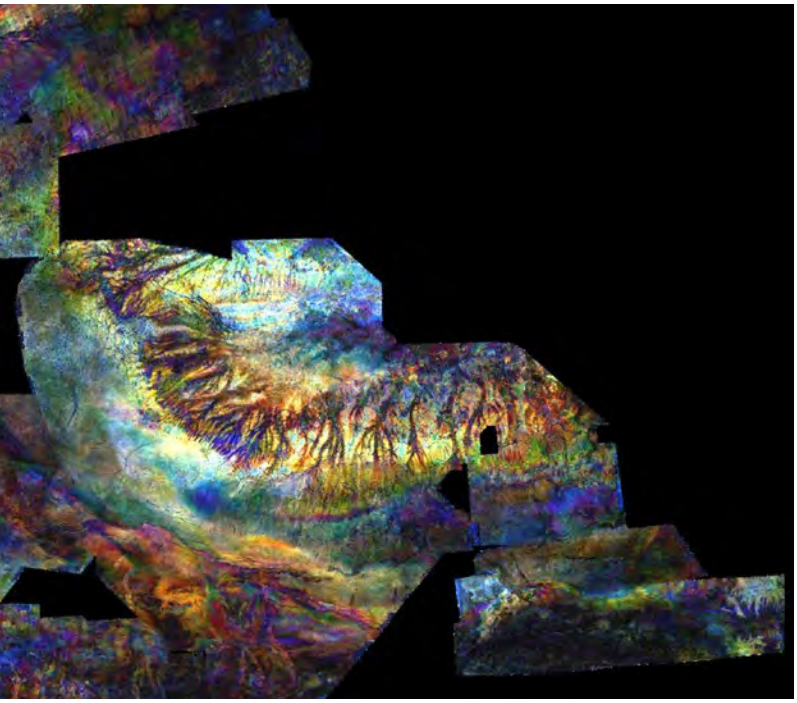
The original concept was established around the inconvenience of the patchwork quilt of available 3D surveys covering the UKCS Central Graben. These surveys had different orientations, bin sizes, amplitude, polarity and phase. Loaded as individual surveys and viewed together on an interpretation workstation (not a simple task in the 1990s) they provided a poor visual image of the subsurface and required significant balancing and adjustment to produce a consistent section, which was complex, time consuming and rarely successfully achieved.

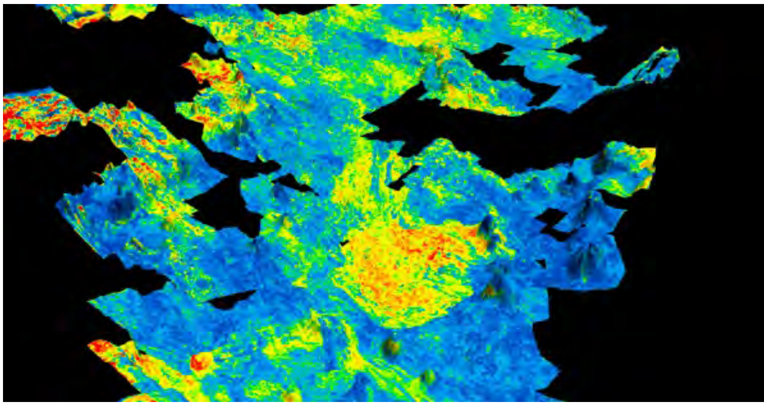
If these surveys could be integrated and merged on the same super grid and balanced in amplitude and phase, then there were major advantages over the numerous and disparate individual surveys.

Seeing the Big Picture

One big advantage, marketed in the early days using the famous Maureen Fan image, was the ability to extend interpretation seamlessly across large areas, removing the 'postage stamp' interpretation approach allowing both explorationists and developers to view their area of interest with adjacent geology and see it in proper regional and sedimentological context.

Whether placing a prospect within a regional play-fairway or obtaining a better understanding of the depositional environment for a discovery or development, this ability to map outside the immediate area of interest was, and still is, of great value. Seeing the geology within a company's licence area in a regional context and tying formations to wells across multiple licence blocks and even much larger UKCS quadrants, allowed the early establishment of play models within an exploration team and became a vital aid in identifying new or missed prospects.





CNS merged seismic data –Maureen Fan (RMS 3D oblique view from south).

This ability to derive relevant and detailed regional play fairway maps directly from seismic, calibrated to well data, provides a far better understanding of sediment distribution and of prospectivity concepts. The ability to map them directly from distal analogues of offset field and well data to a prospect or discovery allows one to understand and quantify risk with more detailed observations.

There is a clear commercial benefit too. The ability to independently review farm-in opportunities or open acreage prior to third party discussions, promotes improved early understanding and allows for increased relevance and understanding when attending farm-out data rooms.

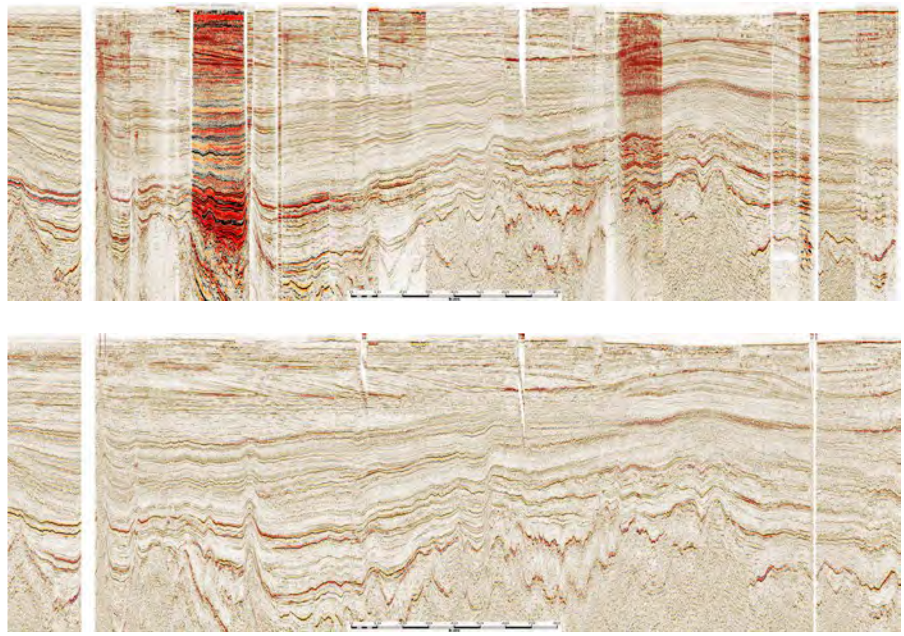
How it Started and the Early Reality

To readers brought up on multi-terabyte disks, high CPU clock speeds, numerous gigabytes of RAM and high-end graphics cards, the challenge of loading and interpreting regional merged datasets must seem trivial.

However, to put the challenge in perspective, my first interpretation workstation, an IBM RT with five 300 MB SCSI (Small Computer System Interface) disks and a tie wrap to keep the A4-sized graphics card in its slot, was cutting edge in 1988. Just over a decade later, in 1999, I was blessed with a Sun Sparc 60 workstation and a RAID (Redundant Arrays of Independent Disks) containing twenty 9 GB SCSI disks which were full to the brim with ongoing client and MC interpretation projects. It was at this time that the Geoscience Director approached me and asked me to look at the feasibility of loading and interpreting the entire merged Central North Sea seismic volume.

The Scale of the Challenge

The first issue was that the dataset size was far too large for the interpretation software and hardware technologies available at the time. One of the interpretation software packages even had a 16-bit number limitation (32767) on the



LYME BAY CONSULTING

Upper Image – original operator seismic.
Lower Image – LBC merged seismic.

number of seismic lines and number of crosslines in any given survey and an upper limit on the size of the loaded volumes. Interpretation of modest seismic volumes was already difficult as most software and hardware was limited to 2 GB of RAM and, if pushed, paging memory in and out of disk-partitioned swap space.

Due to tape capacity limitations, the first SEGY data was delivered in 1000x1000 volumes or tiles that fitted on an IBM 3590 cartridge. The first tile was loaded at full resolution, but it was quickly established that to have any hope of success, the data had to be sub-sampled. Comparison tests were carried out comparing the 12.5m binned data to sub-sampled 25m, 50m and 100m versions. 50m bin size was chosen as the level of seismic aliasing was only an issue on very steep flanks of salt diapirs. This gave a volume that was 1/16th of the size of the original SEGY data.

Following on from this, the 50m volume was then tested at 8 bit, 16 bit and 32 bit. The space-saving 8-bit was really the only option at this point as this reduced the data again to ¼ of its 50m volume size, an overall reduction of 1/64th of the size of the original SEGY. The 8-bit data however was deemed unacceptable as the scaling and clipping required reduced the dynamic range of the amplitudes and created unwanted fingerprint effects on auto-tracked horizons and subsequent attribute maps.

Just as we were about to throw in the towel, along came workstation compressed format seismic which radically changed our approach. With a compression fidelity of 85, a 50x50m volume at 32-bit resolution shrank to as little as 300 MB per tile. This allowed us to load the data at 32 bit and create locally stored 8-bit RAM friendly, auto-track volumes as and when required.

The irony of merging all the UKCS seismic 3D datasets into large regional volumes and then breaking them apart into over 100 tiled projects was not lost on us. However, it would not be for another 10 years or so before hardware and some interpretation software would catch up and allow for the full merged data to be loaded into one contiguous data cube.

With over 20 interpreters working on the data at any one time, the advantage of the tiled projects became evident as it allowed for focused and easily managed interpretation and QC. Additionally, when new data was released, the tiles were easily updated without having to replace the entire volume. If a tile was corrupted or data accidentally deleted, it was easily restored with minimal downtime. As for 'gluing' it all back together again, all of the data management, exports, imports and mapping were command-line scripted and automated, driven by a strict regime of project, horizon and user naming conventions.

And so, to the Present Day

Since then, the situation has changed dramatically, mostly due to the exponential improvements in computing hardware and its reduced cost. We now have access to superfast PCs, larger capacity and spectacularly cheaper and faster disk space, Gigabit local area networks and vast amounts of RAM as standard. This means that regional seismic projects can be loaded, as originally intended, in one cube at 32-bit resolution and at 12.5m or 25m bin size. There are still some software platforms that struggle with large volumes, large horizon files, or both, but generally the ability to use and capitalise on large regional seismic volumes has improved to the point that it should be standard practice for any interpreter and/or exploration or development team to review regional data and offset analogues in any subsurface workflow.

UKCS Merged Volume Improvements

Above is an example of the uplift the Lyme Bay (LBC) merged UKCS has over a raw merge of released NDR 3D data. Our conditioning approach has produced a balanced volume that is far superior for both regional interpretation and prospectivity mapping given the noise reduction, amplitude and phase matching, and improvements in reflector continuity.

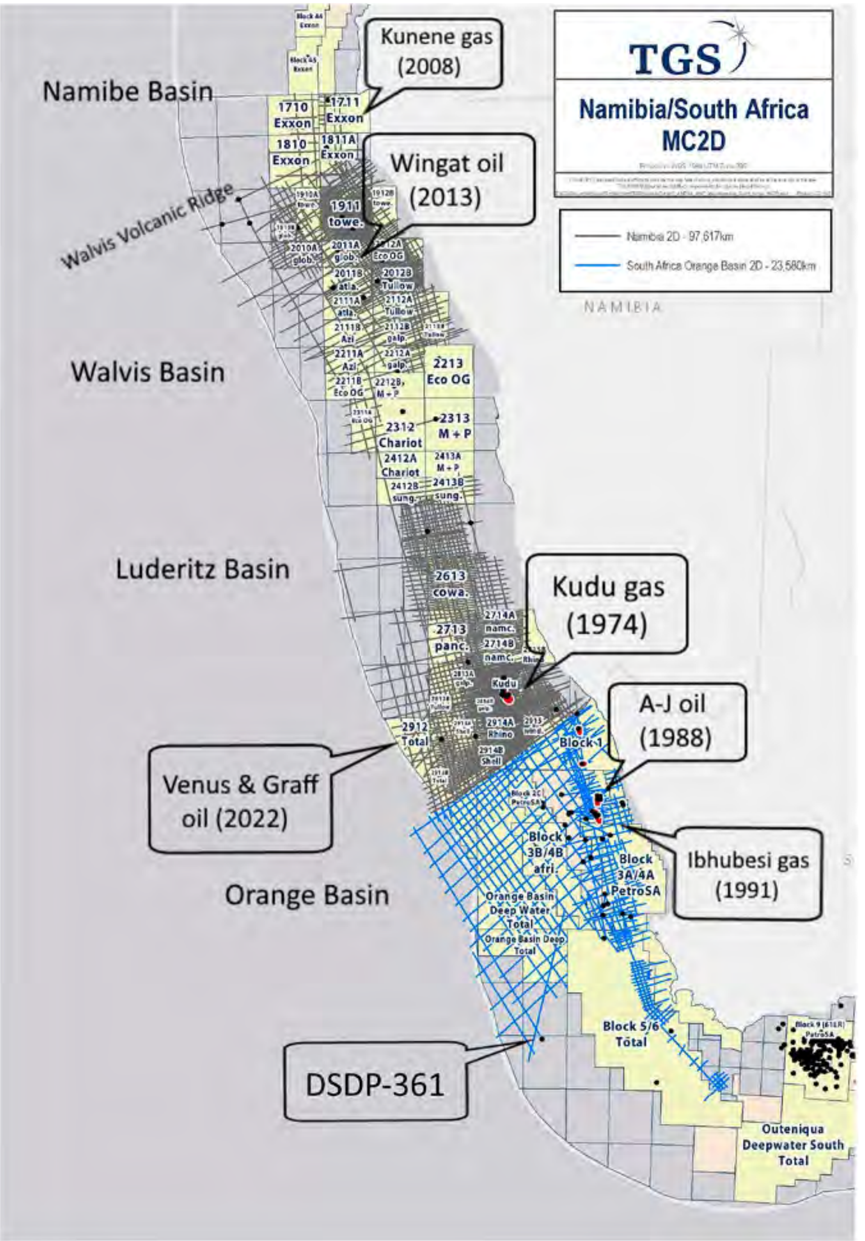
In addition to the LBC Merged Volumes for the CNS, OMF, NNS and FSB areas, the 130+ corrected individual input volumes will also be made available via the NDR. These have been corrected for navigation and CRS issues, the byte locations standardised, true live-trace polygons created and data re-binned to a common grid. This will allow users the ability to remerge surveys using their own phase and shift parameters, without the need for re-binning the legacy 3D survey if desired.

SEISMIC FOLDOUT

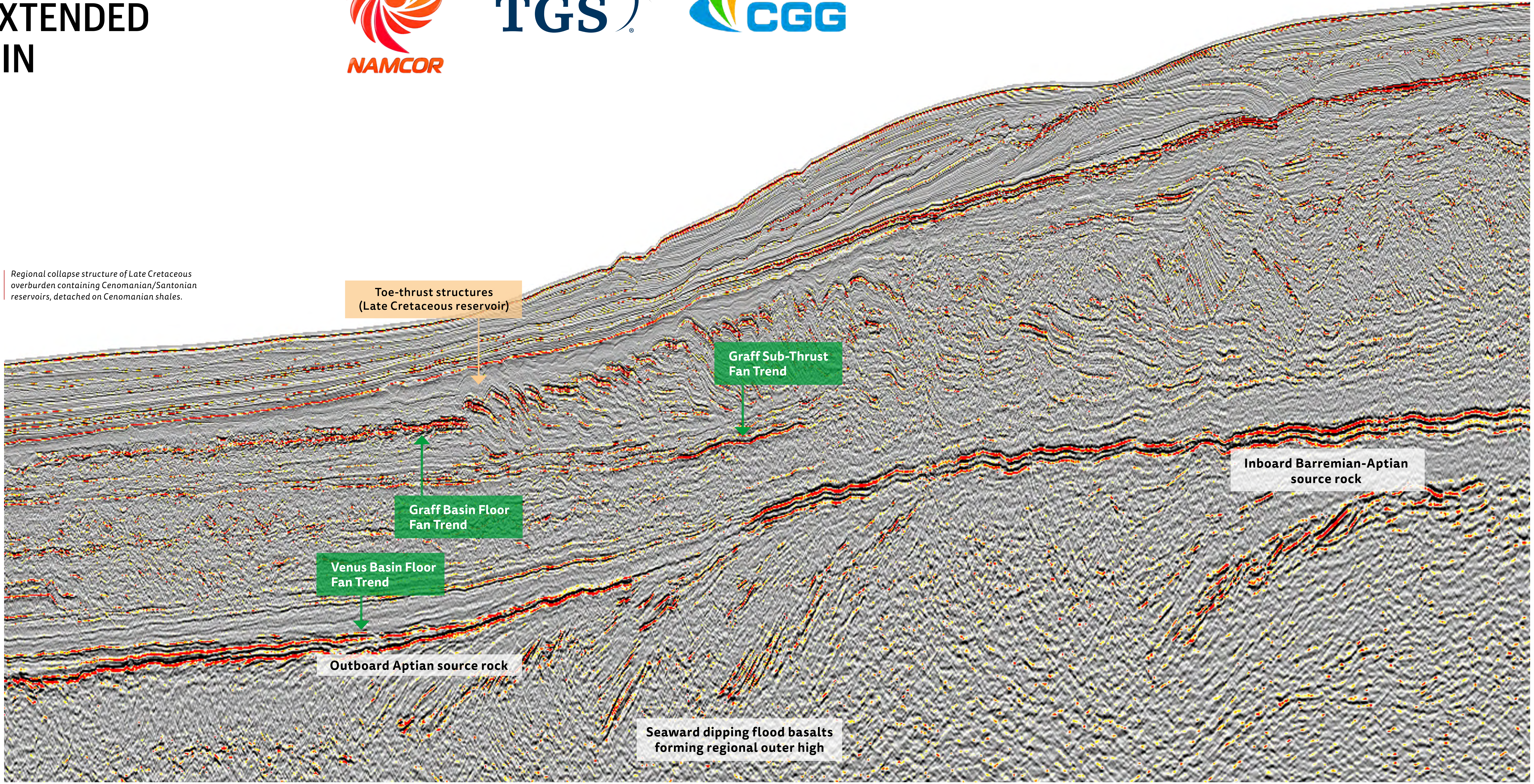
NAMCOR TGS CGG

NEW LIFE FOR THE EXTENDED ORANGE BASIN

The recent Venus and Graff oil discoveries have renewed interest in the prospectivity of the Orange Basin, offshore Namibia and South Africa. These two new proven plays calibrate the deepwater source rock story and help guide the identification of analogues along the margin with equivalent reservoir, traps, and charge scenarios.



Regional collapse structure of Late Cretaceous overburden containing Cenomanian/Santonian reservoirs, detached on Cenomanian shales.



TGS

THE ORANGE BASIN – AN UNDEREXPLORED OIL GIANT?

Felicia Winter, Anongporn Intawong and Jason Robinson, TGS UK

The Orange Basin Offshore Namibia and South Africa

The Orange Basin is part of the volcanic-rifted passive margin south of the Walvis Volcanic Ridge along the southern South Atlantic coast of Namibia and South Africa. The basin formed in the Late Jurassic to Early Cretaceous period, as South America and Africa started to rift apart, forming continental syn-rift half-graben. The Orange Basin can be divided into two major sub-basins separated by the Outer High basement ridge (Foldout), thick subaerial flood basalts that form a large area of Seaward Dipping Reflectors (SDRs) measuring more than 5 km thickness. The inner sub-basin formed first, in a NW–SE direction, possibly in the Neocomian era. The outer sub-basin formed later, during the Aptian, with the submersion of the SDRs. The rifting provided an environment for the young South Atlantic Ocean where circulation was restricted creating anoxic marine conditions in the Barremian to Aptian eras, allowing good quality source rock facies to develop and deposit under anaerobic conditions. In the inner sub-basin, they are referred to as the Kudu Shale Formation.

Hydrocarbon Play Concepts Offshore Namibia and South Africa

The Venus discovery is in the outer sub-basin, as shown in a seismic dip line in Figure 1. The trapping mechanism of Venus is the basin floor fan fairway onlapping onto the Outer High. The Outer High plays an important part in controlling reservoir and source rock distribution and deposition and is also responsible for generating many other trapping configurations. Barremian-aged carbonates inboard drowned out during the sag phase but formed carbonate platforms on the Outer High. These can also be reservoirs in the form of shallow marine bioclastic limestones, build-ups, and shoals. The Venus reservoir Aptian sands were probably sourced from the inboard basin in the east and transported across the carbonate platform on the Outer High, to be deposited in the outer sub-basin, ponding in the accommodation space down-dip. The Shell-operated

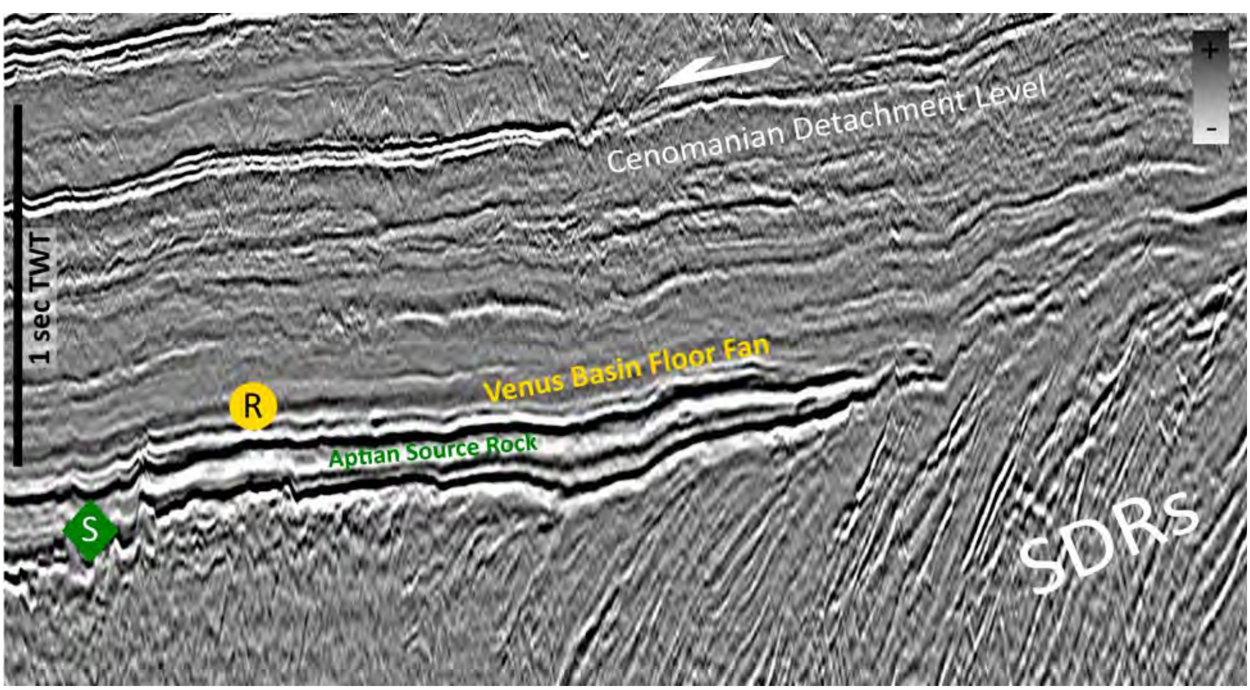


Figure 1: SW–NE dip line through the Venus-1 structure; basin floor fan fairway sitting on Aptian source rock in the outer sub-basin west of the SDR basement high. The reservoir is onlapping onto the high, creating the Venus trap, which trapped the light oil discovered in 2022 by TotalEnergies.

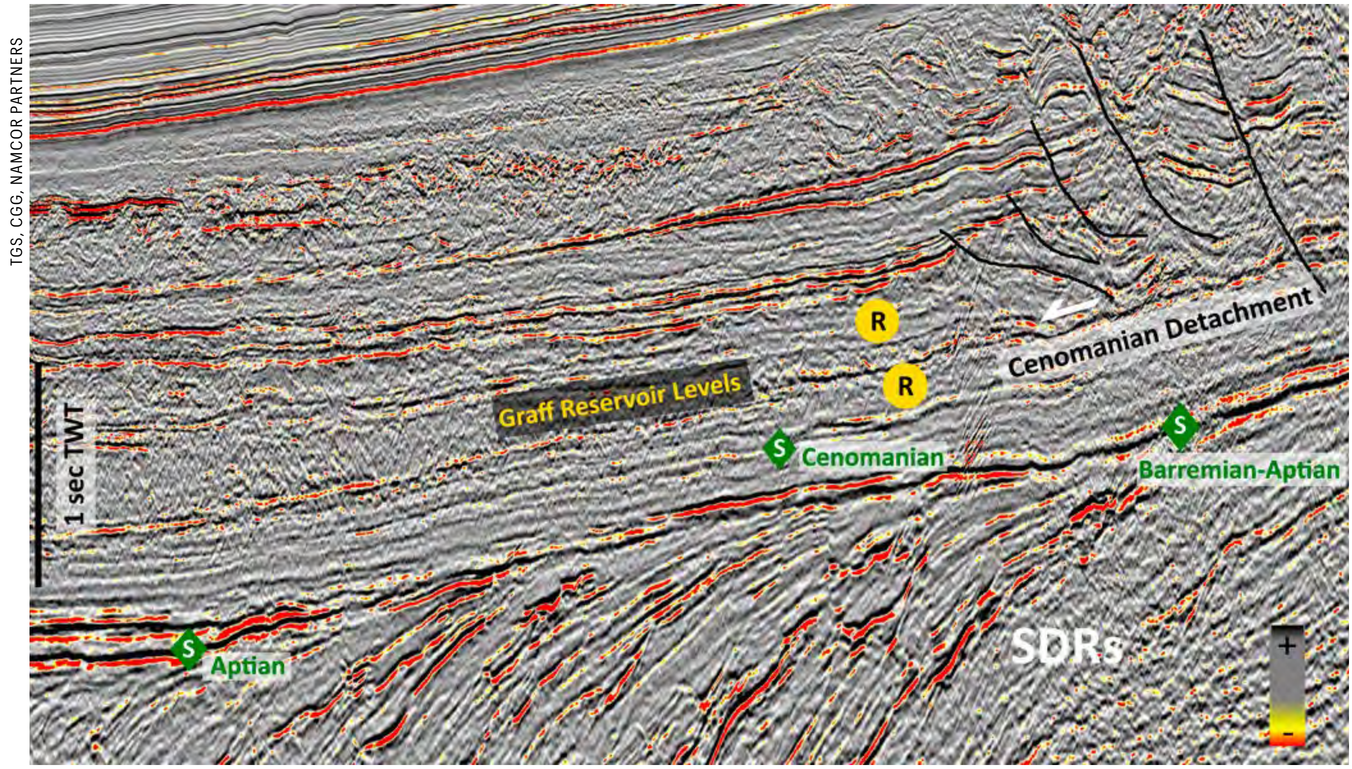
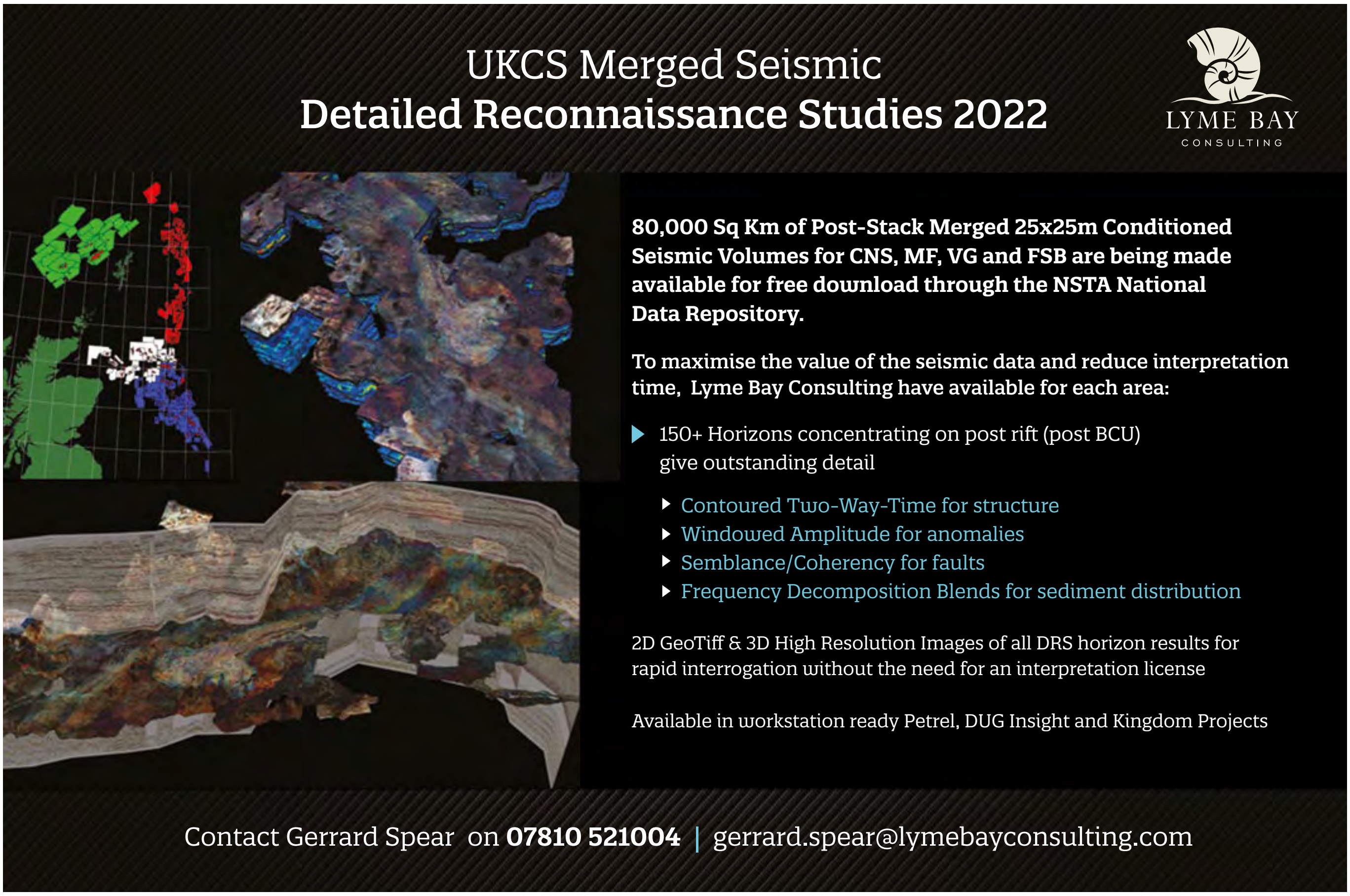


Figure 2: SW–NE dip line through the Graff light oil discovery trend at the western end of the toe-thrust system and the base of the collapse structures. The Santonian–Campanian turbidites have been trapped above the outer high, which likely acts as a backstop for the reservoir influx from the east. Light oil in two different reservoir levels has been discovered by Shell in 2022.

Graff-1 discovery in the inner sub-basin, shown on Figure 2, is of Late Cretaceous age (possibly Campanian to Santonian) and is buried approximately 2.5 km below mudline. The trap appears to be a stratigraphic sub-thrust trap developed at the outboard extent of the Late Cretaceous toe-thrust structures – which developed due to episodic gravitational collapse along the margin. The Outer High has probably played an important role for this trap, acting as a backstop causing turbidite sands to pond east of the High. The Outer High also seems to control the westerly extent of the Late Cretaceous toe-thrust imbricates. Some untested plays are the compressional toe-thrust structures of the Orange Basin's gravitationally driven system and the large roll-over structures of the extensional domain inboard of the same gravity-driven system (Foldout).

Source Rock Presence and Maturation Modelling

Interpretation of regional seismic data and well information along the Namibia and South Africa margin suggests that the Barremian–Aptian source rock is distributed over wide parts of offshore Namibia, as far north as the Walvis Ridge, and southwards into South Africa. The source rock thickness is varying across the two main sub-basin depocentres, which are divided by the Outer High. The Barremian–Aptian restricted marine source rock which was encountered in previous exploration wells has a varied Total Organic Carbon between 1% and 14%, the control of which is suggested to be the dilution with differing clastics inboard and better distal organic content outboard. Overall, based on the available data, the best oil-prone source rock seems most likely to be present in the outer sub-basin and at the western edge of the inner sub-basin where it is less likely to be diluted with shelf-derived clastics. 1D basin modelling at several well and pseudo-well locations offshore Namibia and South Africa based on regional well-tied seismic surfaces, a continental crust rift temperature model and a Miocene heating event in the Orange Basin (Vema hotspot) corroborate a Late Cretaceous start of oil generation on the western flanks with most of the kerogen converted to oil by mid-Tertiary times. The wider basin modelling study, now tied in with the oil window from the Venus discovery, indicates favourable burial history for oil expulsion in the outboard, not only for the Orange Basin, but in the Lüderitz and Walvis basins along the equivalent fairway trend. Mapping the kitchens and the discoveries' amplitude versus offset anomalies is key to understanding the play fairways of the recent discoveries, and more importantly how each play concept works. Important next steps are mapping the Aptian interval west of the Outer High for fan geometries and finding channels that cut across the carbonate platform to identify where Venus lookalikes may exist in other parts of Namibia, as well as mapping out and modelling the maturity of the underlying Barremian–Aptian and Cenomanian–Turonian source rocks outboard and inboard of the Outer High. There will be many prospective ponded sand bodies equivalent to the Venus trap type and Graff lookalikes found along the length of the Namibian and South African outboard fairway, surrounded by Aptian source rock, which is likely in the oil window.


UKCS Merged Seismic
Detailed Reconnaissance Studies 2022
LYME BAY
CONSULTING
80,000 Sq Km of Post-Stack Merged 25x25m Conditioned Seismic Volumes for CNS, MF, VG and FSB are being made available for free download through the NSTA National Data Repository.
To maximise the value of the seismic data and reduce interpretation time, Lyme Bay Consulting have available for each area:
150+ Horizons concentrating on post rift (post BCU) give outstanding detail
Contoured Two-Way-Time for structure
Windowed Amplitude for anomalies
Semblance/Coherency for faults
Frequency Decomposition Blends for sediment distribution
2D GeoTiff & 3D High Resolution Images of all DRS horizon results for rapid interrogation without the need for an interpretation license
Available in workstation ready Petrel, DUG Insight and Kingdom Projects
Contact Gerrard Spear on 07810 521004 | gerrard.spear@lymebayconsulting.com


GEOPUBLISHING
NCS Exploration Strategy
SAVE THE DATES
23-24 November 2022
Stavanger / Scandic Forus
ncs-strategy.no

Dr James Etienne
james.etienne@halliburton.com

PALAEONTOLOGY

JURASSIC DEEP-SEA FISHING

Apex predators of the Jurassic seas.

This month a statue is being unveiled on the Jurassic Coast of southern Britain to commemorate the life and contributions of Mary Anning to palaeontology. Mary is remarkable in many ways, but most importantly for the insights that she developed and shared on the many fossil discoveries she made during her lifetime including ichthyosaurs, plesiosaurs, fish, sharks, squid, rays and even pterosaurs. Her finds adorn the walls of museums around the world, so I felt it fitting that this fourth article in the series touches upon some of the great marine reptiles that she was famed for – the apex predators of the Jurassic seas!

You could be forgiven for thinking Mary was the first to discover ichthyosaur and plesiosaur fossils, but specimens of ichthyosaur vertebrae and propodial (limb) bones and pliosaur vertebral centra were in the Ashmolean Museum in Oxford over 100 years before Mary was born, as illustrated in Edward Lhwyd's 1699 contribution *Lithophylacii Britannici Ichnographia*, published during his tenure as Keeper of the collection. Some of those illustrated specimens came from localities within reasonable walking distance of where I live, an area where the Tithonian part of the Kimmeridge Clay has yielded abundant ichthyosaur, plesiosaur and pliosaur remains, crocodylomorphs (thalattosuchians), turtle, fish, shark and even dinosaur fossils! While isolated bones had been collected during the 1600s (and quite probably earlier), their significance wasn't really recognised until more complete skeletons started to be unearthed in the early 1800s. The Temnodontosaurus skull and torso discovered by Joseph and Mary Anning rocked the world even though fairly

Figure 1: Stunning ichthyosaur skull found by Christopher Moore Fossils in a birchi nodule on the Jurassic Coast of southern England. Craig Chivers supported the preparation of this specimen. This is the underside of the skull. Check out the teeth in the rostrum and the ammonite shells washed up against the skull! The ammonites are important for constraining the age of this beast from the Lower Lias. Note the ichthyosaur pieces in the background from other specimens!

Figure 2: Some scattered vertebral centra from a scavenged ichthyosaur carcass in the Kimmeridge Clay. Most likely from an opthalmosaurid ichthyosaur although diagnostic features such as the teeth, skull and propodial (limb) and paddle bones are missing.

complete skeletal material had already been collected elsewhere in the UK and Europe. Stunning specimens of ichthyosaurs continue to be collected to this day on the Jurassic Coast, often turning up in the workshop of Christopher Moore (*Figure 1*).

The 'Fish Lizards'

Appearing in the Triassic, and surviving most of the Mesozoic, ichthyosaurs were cosmopolitan, with fossils recorded all over the world, from the Berlin-Ichthyosaur State Park in Nevada USA to the Eromanga Basin in Australia. Complete skeletons are not uncommon, so their anatomy is well-understood, but the taxonomy is a bit of a mess and is currently being overhauled by the academic community. A lot of genera and species level designations were introduced (particularly by early workers) on insubstantive material such as isolated vertebral centra which may not be sufficiently diagnostic for species recognition (e.g., *Figure 2*).

Ichthyosaurs (named after the Greek words for fish and lizard) ranged in size from small taxa, typically a few feet in length, to enormous beasts such as Temnodontosaurus – a fearsome-looking animal with the largest eyes recorded for any organism that ever lived on Earth. In exceptional cases, their eyes could literally be the size of footballs, although they weren't perfectly spherical in shape. Temnodontosaurus also had one of the greatest bite forces ever calculated – what a predator!

Some exceptional specimens are preserved that tell us a lot more about ichthyosaurs (notably from localities like Holzmaden in Germany, and Dorset and Yorkshire in the UK). From fossilised skin we know that some were counter-shaded like sharks (dark on the back with a lighter underbelly), they had blubber, they carried embryos and gave birth to live young and fed on a diet of fish and squid (belemnites) and occasionally even ate each other, as evidenced from coprolites containing ichthyosaur teeth and vertebrae (*Figure 3*)!

Figure 3: An ichthyosaur coprolite containing around a dozen vertebrae probably from a juvenile ichthyosaur.

Monsters of the Deep

Ichthyosaurs weren't the only large marine reptiles comprising the upper echelons of the food chain. Plesiosaurians (plesiosaurs, pliosaurs) also arose during the Triassic, living throughout the Mesozoic before extinction of the elasmosaurs at the K–T boundary (this boundary marks the end of the Mesozoic Era, and the beginning of the Cenozoic Era, and is associated with the Cretaceous–Tertiary mass extinction event).

Unlike the ichthyosaurs, complete skeletons of Jurassic plesiosaurs (long-necked, small skulls) and pliosaurs (short-necked, large skulls) are far less common. Many taxa are based on bones from the torso, limbs and paddles, or from teeth, mandibles or skull material. It is unusual to find very complete specimens.

Plesiosaurs have gripped the imagination of the general public for 200 years, from the discoveries of Mary Anning in the early 1800s, to the legend of 'Nessie' the Loch Ness monster, often portrayed as a plesiosaur. Some iconic pictures of Nessie (including the 'surgeons photograph') are now widely recognised as hoaxes.


SHUTTERSTOCK

Figure 4: Scary stuff – an artist's impression of a Late Jurassic monster – what the pliosaur Predator X may have looked like. While I love collecting fossil bones from these creatures I would not want to encounter one swimming in the sea!

More recently, documentary coverage of some enormous Pliosaur skeletons have recaptured the attention of the general public, with specimens collected from the upper Agardhfjellet Formation in Svalbard being dubbed 'The Monster' and 'Predator X' (now formally described as *Pliosaurus funkei; Figure 4*), and from Mexico, the 'Monster of Aramberri' from the broadly age-equivalent La Casita Formation. Realistic estimates place these specimens in the range of 13–15 metres in length. Other very large pliosaurs include the >2m skull of the Weymouth Bay *Pliosaurus kevani* thought to have had the bite force to crush a small car, and of course the iconic *Liopleurodon ferox*. Both *P. funkei* and *P. kevani* are named after the original finders of the specimens. The reality of most of these large finds is that they can take many years, a lot of dedication, and sometimes a large team to retrieve the specimen. It is common for skeletons


JAMES ETIENNE

Figure 5: The ultimate jigsaw puzzle – a partial plesiosaurian skeleton I am in the process of preparing. Many vertebrate fossils are found in pieces like this, and it can take a lot of time and effort to collect the fragments of bone (sometimes over periods of weeks to months to years), to put them back together again. Left: material collected on day 1, some 200+ pieces of bone; centre: back ribs and gastralia starting to be re-assembled; right: part of a paddle including phalanges starting to be identified.

to be gradually exposed, often in hundreds or even thousands of pieces (e.g., *Figure 5*). In the case of Predator X, the skeleton is thought to comprise an incredible 20,000 pieces! The Svalbard locality has yielded material from around another 40 plesiosaurian skeletons – a very important site which will no doubt yield some more sensational fossils.

Like the ichthyosaurs, plesiosaurians had a taste for squid (belemnites) and fish but have also been found with other marine reptile and even dinosaur remains in their stomach contents. Assemblages of marine reptile bones from the Kimmeridge Clay and its equivalents typically show extensive predation and scavenger bitemarks on bones (e.g., *Figure 6*), some of which can be directly related to plesiosaurians. It is not uncommon to find Hybodont and Sphenodus teeth lying in the matrix on top of large plesiosaurian bones. A single specimen of a polycotylid plesiosaur from the Cretaceous of Japan has stomach contents preserved that contains an abundance of ammonite aptychi. The aptychi are hard calcite opercula or part of the mandible apparatus of ammonites which otherwise had soft aragonitic shells (hence their selective preservation in the gut). Little other evidence exists to suggest that ammonites were an important part of the diet of plesiosaurians, but they were plentiful in Mesozoic ecosystems and must have formed part of the food chain.

Figure 7: A near-complete plesiosaur paddle, with humerus and phalange bones. From one of two spectacular plesiosaurian skeletons in the collection of the Oxford University Museum of Natural History. This specimen is from a long-necked plesiosaur with a small skull. These specimens are just a small part of an outstanding collection well worth visiting!

Mobility

One interesting area of research in the life habitat of the plesiosaurians has been evaluation of how they swam or moved through the water. A number of different approaches has been taken, including physical experiments (swimmers in a pool, robotic limbs with dye tracing experiments) and computer simulations. A broad consensus seems to be that plesiosaurians 'flew' underwater in a style similar to modern penguins, with other potential analogues (underwater 'rowing' like a duck or an intermediate motion more like that of a modern sea lion) having been largely rejected. One thing is clear – plesiosaurians developed very large and powerful limbs with shoulder joints that would have enabled the kind of movement required for underwater 'flight' (e.g., *Figure 7*).

Other Notable Marine Organisms

As always, there is a rich literature on Jurassic marine reptiles and other organisms such as fish and sharks and I encourage anyone interested to delve deeper and also to visit the important museum collections. Sharks tend to be known from their teeth and fin spines, as their cartilaginous bones are rarely preserved (although some spectacular specimens do exist). Thalattosuchians (crocodylomorphs) were also common, with small elongate vertebrae that look a little like cotton spindles, and distinctive dermal plates referred to as 'scutes'. Turtles grew to some significant sizes, including the Late Jurassic eucryptodiran turtle *Thalassemys hugii* although nothing that quite rivals Archelon from the Late Cretaceous… at least not yet!

In the next article in this series on fossils I will focus on the scientific value of fossils, how they impact dating and correlation of rocks, event stratigraphy, understanding evolution and the impact of species radiation on regional geological models, insights from palaeobiology and palaeoclimatology and utility in burial modelling and thermal maturity analysis.

Figure 6: Ouch! That had to hurt. Just look at the bite mark on this bone! Predatory marks like this are very common on Jurassic marine reptile bones in the Kimmeridge Clay and its equivalents. In some cases, bite marks go right through the bone. Some examples can also be found where the bone has annealed around bite marks, demonstrating that the predatory attack didn't kill the animal. Plesiosaurian limb bones with predation marks (including from crocodylomorphs) are well recorded in the Etches Collection and I have also collected at least one large pliosaur propodial that looks like it may have been bitten clean in half by another pliosaur!

A TIME FOR REFLECTION


LESLI J. ELLIS, USGS

Vibroseis trucks deployed in Nevada in 2012.

Geophysics and Petroleum Exploration in North America

M. Quentin Morton


DEGOLYER LIBRARY, SMU

A GSI crew in South Louisiana in the early 1930s.

Prospecting for oil in the the early 20th century had come a long way from the days of riding around the prairie on a horse and drilling wherever your hat fell off. Even so, however you looked at it, the extent to which a geologist could predict the subsurface structure was limited. Anticlines might have been the classic indicator of an oil-bearing structure, but only drilling could prove its presence and then often by chance. The advent of 'remote' sensing fundamentally changed this.

Salt domes were often associated with oil fields. In 1924 Everette deGolyer discovered the Nash Salt Dome in Texas using an Eötvös torsion balance, a device for measuring anomalies in local gravity – the first time that a significant oil field was located by geophysical means in the United States. Gravimeters and magnetometers were subsequently developed, and the Schlumberger brothers pioneered electrical surveying in Europe, but none of these methods could supplant seismology which arrived on the scene in the 1920s.

Seismology originated from the study of earthquakes many years before it was applied to petroleum exploration. It was understood that sound waves passed through the ground at different velocities according to the density of the rock they encountered and, by recording them, the subsurface structure could be delineated. During World War I, German mining engineer Ludger Mintrop developed a portable seismic device for locating enemy gun emplacements. In 1921 he formed a company named Seismos, and three years later a Seismos crew was hired by Gulf Oil to search for shallow salt domes in Texas using the refraction method.

Seismology – the Turning Point

However, experiments in reflection seismology marked a turning point. While the refraction method sent sound waves down and then laterally through the Earth, the more powerful but expensive reflection method measured waves reflected directly from below. The original research was carried out by Canadian radio pioneer Reginald Fessenden. In September 1917 he patented his 'Method and Apparatus for Locating Ore Bodies', a design for sound-generating equipment to be used in geophysical prospecting.

American physicist John C. Karcher, who worked for the Sound Section of the US Bureau of Standards on artillery detection, was aware of Fessenden's work on reflection seismology. After the war, he researched its possible use in petroleum exploration. In December 1928, based on his earlier findings, the Amerada Petroleum Corporation drilled into the Viola limestone formation in Oklahoma and discovered oil – the first well to be drilled in a structure discovered by the reflection method. Karcher's work earned him the sobriquet 'Father of Reflection Seismology'.


GERHARD KEPPNER

A Seismos convoy in Louisiana in 1926.

By now DeGolyer, vice president and general manager of Amerada, was closely involved with Karcher through a subsidiary, the Geophysical Research Corporation. In 1930, with Eugene McDermott and the backing of DeGolyer, Karcher launched Geophysical Service Incorporated (GSI) which would later become Texas Instruments with GSI as a subsidiary. The reflection method, more suited to greater depths and marine environments than refraction, became a primary means of petroleum exploration, although the latter still had a role to play.

Out in the Field

> *Deep in the southern tip of Canada's vast coniferous belt, dotted with innumerable muskeg, haunted by wails of coyote and wolf, Western F-53 maintains the company colors in this wild and rugged no man's land 300 miles northwest of the provincial capital city of Edmonton.*

By the 1950s, seismic crews were operating across the continent, albeit with differences in working conditions between prairie, mountain, desert, or sea; it was not all camping in the wilderness, but in some cases a question of finding accommodation in a nearby town. We can imagine the scene when a survey party set off in convoy for a new location. At times, they would leave town in multiple convoys in order to throw oil scouts off the scent and prevent them from discovering their new survey locations.

Research included published literature and work on theoretical mathematics. Dr Milton Dobrin's *Introduction to Geophysical Prospecting* was the most influential textbook of its day. But essentially it was field work that kept the wheels of the industry turning. By the 1960s, the cost of geophysical and geological surveys could vary considerably, sometimes exceeding the drilling costs of a well, ranging over several months or years from between $20,000 to $50,000 ($425,000 today) a month with only a few prospects in return. Nevertheless, it often made sense to drill since the additional costs would only be nominal when compared with those that had gone before.

Often it took years before there were results to drill upon.

Exploration was a lengthy business: there was the time needed to plan, contract a seismic crew and a company to acquire and process the data, perhaps within a weather window, and then finally to interpret it, which often took years before there were results to drill upon. What was acquired, processed, and reprocessed depended on the cost of drilling a well, the requirements of governments, and the type and duration of a concession.


DEGOLYER LIBRARY, SMU

A worker placing explosives for seismic testing, 1940.

Seismic is King

After World War II, innovations such as the airborne magnetometer, computers and magnetic tape were increasingly used. The mid-1950s saw the introduction of sonic logs, which brought greater precision to measuring the depth of structures identified by seismology. Since seismic data is usually measured in time, and geophysicists, geologists, and drillers work in depth, the process of depth conversion to produce maps and make drilling progress was an important part of exploration and development. If a depth conversion was incorrect, expected reservoir levels could be hundreds of metres too deep or too shallow, bringing increased exploration costs and risk.

Magnetic tape allowed relatively large amounts of data to be recorded and analysed, and seismic reflections to be manipulated to cut out extraneous 'noise' and enhance the essential signal. In an Alaskan summer, for example, the sound of ice thawing, vegetation moving and the wind blowing could interfere with seismic surveys, while in the winter the freezing of the ice had a similar effect. But that was in the days of old-style single-fold shooting, which was replaced by common depth shooting (CDP), a technique invented by Harry Mayne of the Petty Geophysical Engineering Company that cancelled much of the 'noise' around seismic readings. With magnetic tape, companies could process the extra data in a cost-effective way.

Computing Power

By 1972 the power of computers and the range of data acquisition were such that 3D imaging was technically possible. After a brainstorming session at GSI headquarters in Dallas, and with the support of six major oil companies, Bell Lake field in New Mexico was chosen as the test site. The results were remarkable: now seismic sections of the subsurface could be displayed in any orientation. However, it took time to catch on. Until the arrival of workstations in the 1980s, seismic was still interpreted on paper with coloured crayons, stratigraphic horizons and faults were picked by an interpreter and digitised, and maps were contoured by hand.

The innovations went on. It became possible to measure relative wave amplitudes and directly identify the presence of hydrocarbons, or so-called 'bright spots'. With the addition of time, 3D surveys became 4D and could show how reservoirs changed over a period. Pre-stack depth migrated seismic (PSDM) was used for imaging complex features adjacent to or beneath salt in the Gulf of Mexico. In post-seismic processing, many things could be done to present the data by emphasising or filtering features to clarify the image or subsurface prospects, the connectivity of faults and the like. An application named the coherence cube focused on 3D seismic discontinuities and revealed stratigraphic features and faults that were not immediately visible in other seismic programmes.

With the shale revolution, there was a rush to reprocess older seismic surveys, and many operators seeking partners and money to do new 3D surveys taking advantage of the latest upgrades in recording and processing technologies. Microseismic technology was used to review and guide the effectiveness of fracking operations and assist in locating adjacent wells. These days there are only a few seismic companies operating onshore, although the new technologies have given rise to a small market for reshooting areas that were considered poor quality seismic areas.

Making Waves

In 1936 geophysicist Maurice Ewing, whose ground-breaking work on ocean basins opened a new field of marine seismology, approached an executive of a large oil company for support and was told they were not interested in searching for oil at sea. It has since transpired that the sedimentary basins of the kind investigated by Ewing are the source of vast deposits of oil. Nearly all the marine discoveries have been made with seismic devices.

Dynamite, the seismic source of choice in the past, has been replaced by more environmentally friendly methods. 'Thumper' trucks which drop a weight on the ground were introduced in 1953 as an alternative to dynamite. However, since Conoco introduced hydraulic vibrators in the mid-1950s, vibroseis trucks have become the most common seismic method on land, providing a continuous signal and being less destructive than other methods. The seismic air-gun was invented in the 1960s and is often used as the seismic source at sea. Towed behind seismic survey vessels, arrays of air-guns release high pressure air pulses that penetrate the ocean floor.

DEGOLYER LIBRARY, SMU

Texas Instruments computers for digital seismic processing, 1964.

Whatever their source, seismic signals create compression waves (P waves) and shear waves (Sh and Sv). Typically, geophones record these modes using three components (3C recording or 4C recording in the sea where an extra hydrophone is used). Accelerometers, which measure acceleration as opposed to velocity, have a greater range than geophones and

GETTY IMAGES

A seismic survey ship trailing cables (streamers) in its wake.

are often used in 3C and 4C recording. While P waves propagate through water, collecting data with a marine cable containing geophones (a 'streamer') towed behind a vessel is fraught.

The slightest motion generates 'noise' so the offshore industry uses hydrophones, these being detectors that respond to pressure changes in the surrounding medium. Ocean-bottom recording is used to record shear wave data, which cannot travel through water. Broadband seismic allows deeper imaging, and towing streamers at different depths and using sampling pairs, such as pressure and velocity fields, reduces reflections from the sea surface ('ghosting').

Emerging technologies

Today, the purpose of seismology in petroleum exploration remains essentially the same, to identify oil and gas prospects, and to assist the development of discoveries. But the technologies, and the acquisition, processing and interpretation of seismic data have evolved with the development of computing power and workstations, making it possible to develop deeper and clearer images of the subsurface, and beneath salt and basalts.

The geophysicist can image hydrocarbons from Direct Hydrocarbon Indicators (DHIs) and fluid contacts and movement via time-lapse surveys. Fibre optics are in vogue instead of geophones in boreholes where information is derived from the deformation in a fibre optic cable caused by seismic waves – a recent development is to make the fibre optics biodegradable.

There are plenty of derivatives of good quality offshore data worldwide like Exxon's model for oil exploration based on seismic stratigraphy and global sea level change. This was of particular interest to the oil industry because it enabled sequences to be predicted and thus be correlated on a regional scale and represented a paradigm shift in geology. Technology is improving all the time and it is common to reshoot time-lapse surveys every few years, particularly over producing assets.

The upshot of these innovations has been to lower the element of risk in petroleum exploration. Since it is possible to predict the presence of hydrocarbons more accurately than by simply delineating structures and traps, the uncertainty and cost of drilling for oil are greatly reduced. This in turn has allowed companies to invest in new technologies, such as larger deepwater platforms that take petroleum exploration to new frontiers.

Acknowledgements
Thanks to Peter Morton and Alan Heward for their kind assistance.

THE ARTEMIS PROJECT

Geology's gateway to the stars.

NASA

NASA's Artemis I patch

In December 1972, the 17th and last Apollo mission put Harrison Schmitt, the only professional geologist ever to have ventured into space, on the surface of the Moon. NASA had been under pressure to put a scientist on the Moon – and so they sent a geologist. Just take a second to enjoy that sentence.

Neil Hodgson and Iain Brown

However, since his return to Earth in 1972, no human has been out of Low Earth Orbit (LEO) until now. After 50 years of robotic exploration, 20 years of continuous habitation of the International Space Station (ISS) and many unmanned science missions – NASA are going back to the Moon; and this time, the ambition is immense. If putting the first women and man back on the Moon in just three years' time (2025) wasn't enough – this mission is beta testing the necessary systems to survive deep space travel and so preparing the way for the first manned journey to Mars.

It is fair to say that lunar geology was an unwitting beneficiary of John F. Kennedy's declaration in May 1961 to put a man on the Moon before the end of the decade. In the 1960s there were many gaps in our knowledge about lunar geology which were filled quickly by samples returned from the Apollo missions from 1969 to 1972, and the scientific equipment (including seismometers) left on the surface.

NASA's Space Launch System (SLS) rocket with the Orion spacecraft aboard is seen atop a mobile launcher at Launch Complex 39B.

NASA/JOEL KOWSKY

Schmitt's out-of-this-world field trip on Apollo 17 to the Taurus-Littrow Valley of Mare Serenitatis, resulted in the sampling of both old impact melts (3.89 Ga) (i.e., the lunar highland material), and younger Mare volcanic flows (3.7 Ga). However, they also sampled 4.2 to 4.5-billion-year-old dunites and troctolites formed some 25 km below the surface of the Moon and subsequently exposed after a major meteorite impact event. Our model for the formation of the Moon in a titanic collision between the early Earth and an unidentified actor (perhaps a Mars-sized world called Theia) 4.51 billion years ago comes from studies of these, and the other Apollo mission Moon rock samples.

The Apollo missions 12, 14, 15 and 16 all left seismology instruments on the Moon which recorded data until 1977. Hundreds of Moonquakes were recorded, both tectonic shallow quakes and deeper quakes that may be caused by Earth's tidal forces. The recordings also discovered a small 500-km-wide core with a partial melt layer near the base of the mantle. One issue with the data is 'selenographical distribution' – i.e., all the receivers were placed on the near side of the Moon, the side facing Earth and frozen by tidal forces, which may explain why there are few quakes observed with epicentres on the far side of the Moon.

Moon Samples – The Weird and Wonderful

Schmitt returned to Earth with 115 kg of material which spawned a raft of scientific studies – work that is still continuing with the opening in March of 2022 of a vacuum-sealed sample Schmitt collected by hammering a 14-inch tube into the lunar surface 50 years ago. This gives a unique opportunity to study volatiles in Moon rock and soil, using technology that was just not thought of in the 1970s. The Moon rock samples also spawned a genre of non-fiction pulp-science literature about the final destination of the material brought back including the less interesting than you may think, 2011 'Sex on the Moon' book title (Mezrich, 2011). Yet perhaps the weirdest rock to have been collected on the Moon was a breccia sampled by Alan Sheppard in the 1971 Apollo 14 mission. A clast in this breccia (formed by meteorite impact) is particularly exciting because it is zircon-bearing, 4.05 billion years old and most likely originated on Earth. The Moon though, is likely to be covered in fragments of meteorites from the inner planets, forming the 'solar-system's library' and just awaiting geologists working from a Lunar Habitation System (LHS) to discover and sample them using AI-driven robots.

Lunar Sample 76015 143 Moon rock on display in the Oval Office, White House. Apollo 17 astronauts, including Harrison Schmitt, chipped this sample from a large boulder at the base of the North Massif in the Taurus-Littrow Valley. This 332-gram piece of the Moon (less than a pound), collected in 1972, is a 3.9-billion-year-old sample formed during the last large impact event on the nearside of the Moon, the Imbrium Impact Basin, which is 1,145 km or 711.5 miles in diameter.

Lunar Habitation

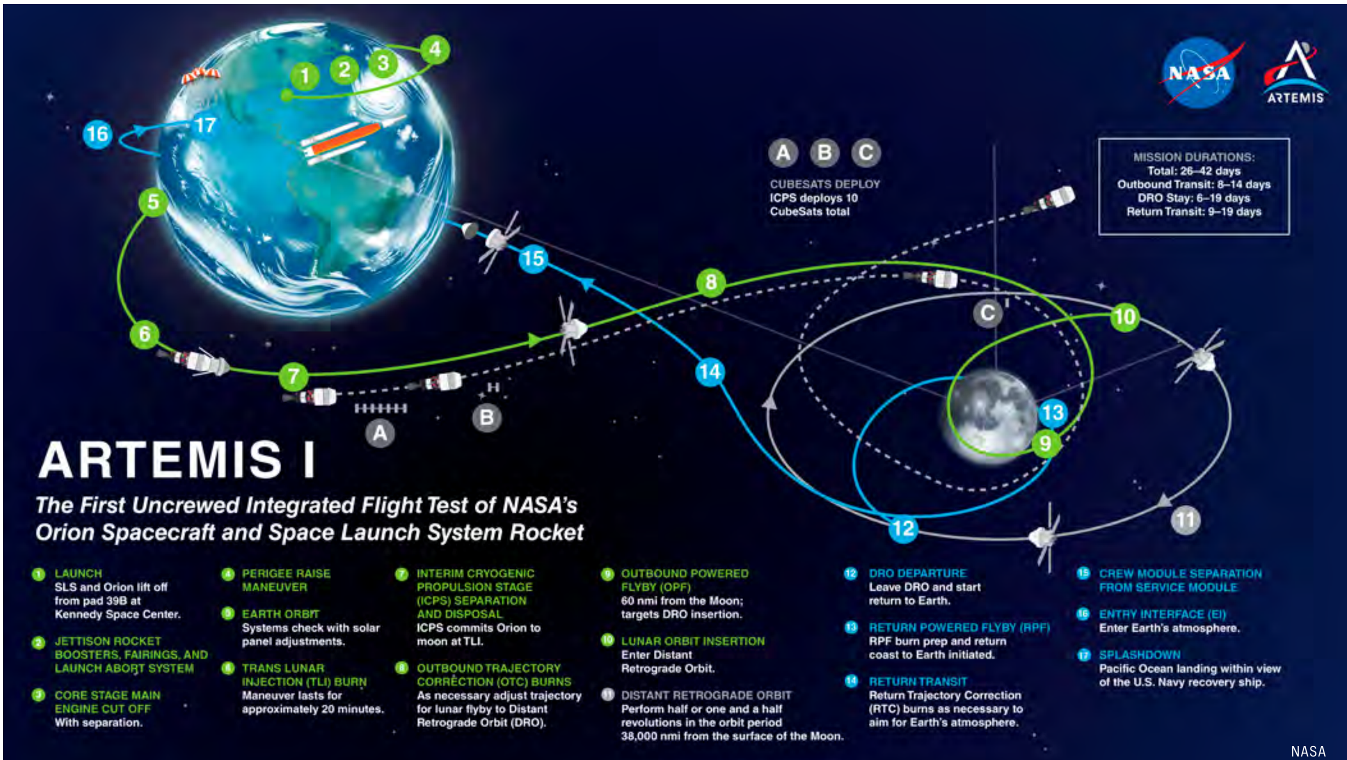
The Apollo missions to the Moon (commissioned initially perhaps for political and ideological reasons) targeted geological objectives to better understand the formation of the Moon and therefore the Earth. The new adventure – the Artemis missions, are focused on establishing a habitation unit (yes – a Moon base!) where we can learn how living and researching on the Moon can be efficient and supportable. Beyond this the Artemis missions (starting with Artemis IV) will place a 'gateway' space station up in lunar orbit as a staging post for Martian exploration.

In order to launch the Artemis project, NASA has had to mine a significant portion of the world's acronym reserves. So, let's identify the key parts upfront that make up the project. The Space Launch System (SLS) is the big powerful launching rocket that is needed to push the Orion spaceship into Low Earth Orbit (LEO), where it will fire the interim cryogenic propulsion stage (ICPS) pushing Orion into High Earth Orbit (HEO), and then on to the Moon where the Human Landing System (HLS) will be deployed on the Artemis III mission. After the Moon landing mission, Artemis IV will set up some of the first components of 'Gateway' – a small space station in lunar orbit from which future astronauts will transit in the Human Landing System (HLS) to and from the Lunar Habitation Unit (LHU), and they will also prep for the journey to Mars.

So that's the plan at high level. If you want to access some cool graphics and animations, head over to the NASA website:
https://www.nasa.gov/specials/artemis-i/

A New Commercial Model

Note also that there is some interest in the way the project has been contracted out through competitive tender – not just the construction of the various components, but also the design creativity for the solution set for the various stages involved. Numerous companies are involved for not only the main mission but the support, delivery and resupply for the various components of the mission. This is a complex and multi-faceted, ambitious programme, and NASA won't jump straight to the next Moon landing – there is a lot of development and safety checking to be done first. So, we will see two Artemis launches before the Moonshot in 2025, and another will follow with the gateway and others with the Moon base.



Flight Plan for Artemis I – the first integrated flight test of NASA's deep space exploration system.

Apollo's Twin

So, 50 years after the original spurt of human Moon landings – NASA is preparing to send humans back to the Moon in 2025. The missions will make another of Zeus's children and Apollo's twin sister – 'Artemis' – a household name. We need to know who Artemis was as she will become synonymous with the Moon, journeys through the heavens and NASA space magic. Well, this is all good as that's pretty much what the Ancient Greeks thought too. Artemis was one of the triad of goddesses conflated together to represent the Moon goddess. She was the patron deity of the Moon as well as hunting and the protector of women. The Romans later worshipped her as Diana, and Hollywood as Wonder Woman. This is useful as Artemis III will have the first woman moonwalker on board. Selene was another lunar deity the Ancient Greeks worshipped as a Moon goddess, believing that although of Titan heritage she would drive her silver chariot across the night sky, representing the Moon. Hecate, who may have been a Chthonic goddess of non-Greek origin, is the darker third of the Artemis triad – she was also associated with the night and witchcraft. All this symbolism seems far-fetched to modern eyes, yet, compared to premise of 'Who Built the Moon?' (Knight and Butler, 2007), a contender to be the daftest non-fiction book ever written, it makes comparative sense. The 'Built Moon Theory' is based (solely) on the observation that from Earth, the Moon looks to be exactly the same size as the Sun, therefore it has to have been built by time-travelling future humans – an argument for book burning if ever there was one!

Return to the Moon in Stages

What you will see next on the timeline is NASA launching Artemis I. This will be an unmanned launch to test the SLS system demonstrating its capability to slingshot the uncrewed Orion capsule around the Moon and back. This remote-operated mission will test the rocket systems, the habitation system robustness and deploy 10 satellites 'cubesats' for deep space navigation and experiments.

On return to Earth, Artemis I will test the capability of the heat shield system to withstand 5,000°F temperatures on re-entry.

The second planned Artemis flight comprises a manned mission to orbit the Moon and test the habitation systems. This will be the Artemis Generation's 'Apollo 8 moment', when the astronauts aboard Orion will

Artist's concept of the Orion Service Module.

Gateway space station in Lunar Orbit.

photograph the full globe of the Earth as a backdrop to the Moon.

The Artemis II crew onboard Orion will have a 10-day mission to test the habitation system, although the flight will ultimately carve a figure-of-eight path extending more than 230,000 miles from Earth on a fuel-efficient gravity-controlled trajectory where the Orion craft will be guided back naturally by Earth's gravity, with no propulsive moves required. In orbital mechanics this is called a 'free-return trajectory'; the only other spacecraft that has achieved this was Apollo 13 in 1970. During re-entry, the Orion spacecraft on the Artemis II mission will be travelling at nearly 25,000 mph as it re-enters the Earth's atmosphere, which will slow it down to 325 mph before parachutes are deployed for splashdown in the Pacific.

Target – 2025 Landing

And then in 2025, the Artemis III mission will land humans on the Moon: giving us the first new moonwalkers for 50 years. It's a shock that only four of the original moonwalkers remain alive today on Earth – and it's time for this to be addressed. Of the four Orion astronauts, two will land on the Moon and one of those will be a woman. The following Artemis missions will establish the Gateway station, and the Gateway-to-Moon human delivery system and habitation module, which will provide a staging point for human and robotic lunar missions.

The orbiting Gateway will support longer expeditions on the Moon, and potentially multiple trips to the surface during a single Artemis mission.

It will be important to gain operational confidence in this system on the Moon before the first human missions to Mars. The Human Landing System (HLS) will land astronauts on the Moon and then safely return them to lunar orbit before their trip back to Earth on Orion.

All this may sound complex, but this will be considered, planned and executed to NASA's extraordinary standards of safety and technical oversight, in concert with the most competent contractors and partners.

Currently the Artemis 1 SLS has undergone a 'wet dress rehearsal' on the launch pad in Cape Canaveral, where testing of the loading of the rocket fuel systems has indicated that changes need to be made to the hydrogen and nitrogen supply systems to make them safer and more effective. These changes learning will be quickly implemented, such that an autumn 2022 launch for Artemis 1 is still likely.

Looking back at the Apollo missions 50 years ago, they were incredibly brave but risky adventures. As Andrew Chaikin wrote in 1994, "...Apollo has nested risks: You get on top of a Saturn V rocket with enough chemical energy to be the equivalent of a small atomic bomb. Then you throw away levels of safety by going to the Moon."

NASA has had to learn the hard way that risks in space exploration can be painful as well as fulfilling when a mission is successful. A new balance has been struck and looking forward to Artemis, with the technology, complexity understanding and risk management processes of NASA today, the Artemis project is very different. The risk is lower, but it is an even more ambitious and courageous project. Very 21st century. I just hope they remember to bring back some more rocks...

References

Chaikin, Andrew. 1994. *A Man on the Moon*. Penguin Books. https://www.space.com/26558-apollo-11-anniversary-complete-coverage.html

Knight and Butler, 2007

Mezrich, Ben. 2011. *Sex on the Moon*. Doubleday.

https://en.wikipedia.org/wiki/Artemis_program

Illustration of Artemis astronaut activities on the Moon.

FROM ARRHENIUS TO CO_2 STORAGE

Part XVI A Greenhouse Model for Stratospheric Cooling – 2

NASA'S EARTH OBSERVATORY

Figure 1: Polar mesospheric clouds (PMCs) appear as shining threads against the darkness of space – hence their other names of 'noctilucent' or 'night-shining' clouds. They form 76–85 km above Earth's surface when there is sufficient water vapour to freeze into ice crystals. The clouds are illuminated by the Sun when it is just below the visible horizon, lending them their night-shining properties. In addition to the PMCs seen across the centre of the image, the stratosphere is clearly visible by dim orange and red tones near the horizon.

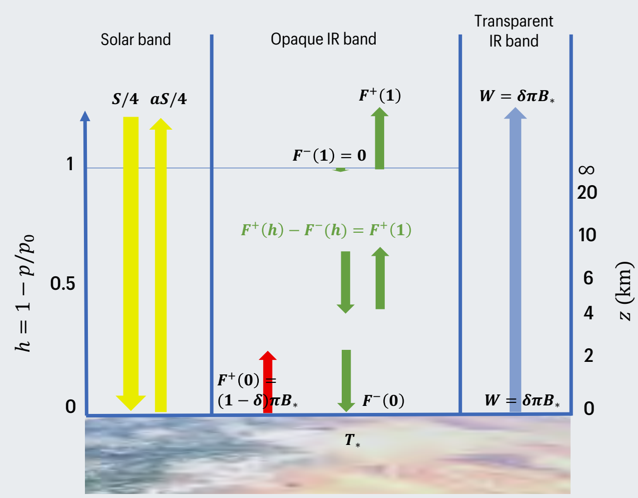
Nothing in life is to be feared,
it is only to be understood.
Now is the time to understand more,
so that we may fear less.
– MARIE CURIE (1867–1934),
POLISH-BORN FRENCH PHYSICIST,
TWICE A WINNER OF THE NOBEL PRIZE

Increased concentrations of greenhouse gases are warming Earth's surface and troposphere while cooling the mid to upper atmosphere. We introduce you to the 1D window-grey radiation model of the atmosphere, which illustrates the physical essence of the mechanism by which a CO_2 increase cools the stratosphere and mesosphere.

Lasse Amundsen* and Martin Landrø,
NTNU/Bivrost Geo

In the early 1960s, mathematical models of the climate system showed that increases in CO_2 would be expected to lead to gradual warming of the Earth's surface and the troposphere and cooling of the stratosphere. Later, temperature measurements from satellites confirmed these early forecasts. Today, the observed pattern of tropospheric warming and stratospheric cooling is supported by global-scale computer model simulations although there are some differences between models and observations. In the tropics, models show more warming in the troposphere than has been observed. In the Arctic, most models underpredict the observed warming of the troposphere.

The educational grey radiation model cannot explain cooling of the stratosphere. Therefore, it has to be extended to the window-grey model (see *Figure 2*).



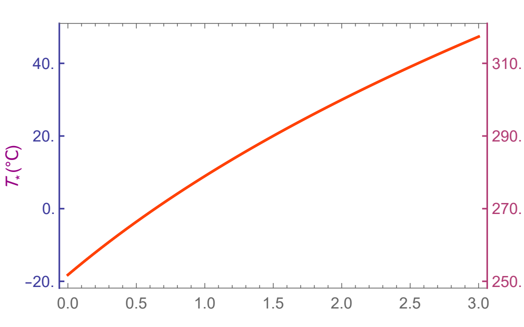
LASSE AMUNDSEN

Figure 2: Sketch of the window-grey radiation model introduced by Goessling and Bathiany (2016). The atmosphere is transparent to the Sun's shortwave radiation in the solar band. The Earth heats and sends upwards longwave, infrared (IR) radiation. Part of the radiation goes upward in Earth's atmospheric IR window, being transparent to radiation. The rest radiates in the grey atmosphere (see Part XIII, GEO ExPro Vol. 18, No. 6) where IR radiation is absorbed by thin layers in the atmosphere. The layers heat and re-radiate energy to space and back to the surface. F+ and F- denote upward and downward fluxes, respectively. Earth's surface at level z=0 radiates as a blackbody with flux F+(0)+W=πB. At the top of the grey atmosphere there is no downgoing IR radiation, F-(1)=0. The Earth is in energetic equilibrium between the radiation it receives from the Sun and the radiation it emits to outer space. The condition of radiative equilibrium requires that the net flux at any given depth, F+(h)- F-(h), remains constant. The grey radiation model is the special case of no transparent IR band (δ=0).*

Revisiting the Grey Radiation Model

In Part XIII of this series (*GEO ExPro* Vol. 18, No. 6) we derived the differential equations for upward and downward fluxes in the grey atmosphere model and derived temperature profiles for an Earth (atmosphere and surface) in thermal equilibrium. The single parameter of the grey model is the absorption coefficient β which describes the atmospheric opacity in the IR band. Earth's surface temperature T^* and the atmospheric temperature $T(h)$ are functions of β. The atmosphere's altitude was given in terms of the vertical coordinate h being the relative pressure deficit. The key results of this model are collected in Table 1.

Let's see what happens if the absorption factor increases, say, as a result of an increase in the CO_2 level. The equilibrium temperature equations in Table 1 show that when the absorption coefficient β increases, then the atmospheric temperature (except at top of atmosphere, TOA) and the surface temperature both will have increased, after a new equilibrium is achieved. The grey model thus is not able to explain why temperature is decreasing in the mid-atmosphere when the absorption level increases. In Figure 3 we show the relation between the surface temperature and the absorption coefficient. Figure 4 (left) illustrates that the grey model predicts an increase in temperature everywhere in the atmosphere (except at TOA) for an increase in absorption factor from β=1.31 (the yellow line) to 1.5 (the red line).



LASSE AMUNDSEN

Figure 3: Surface temperature as function of absorption coefficient in the grey radiation model. Today's surface temperature T=289K (16°C) is obtained when β=1.31.*

The Window-Grey Radiation Model

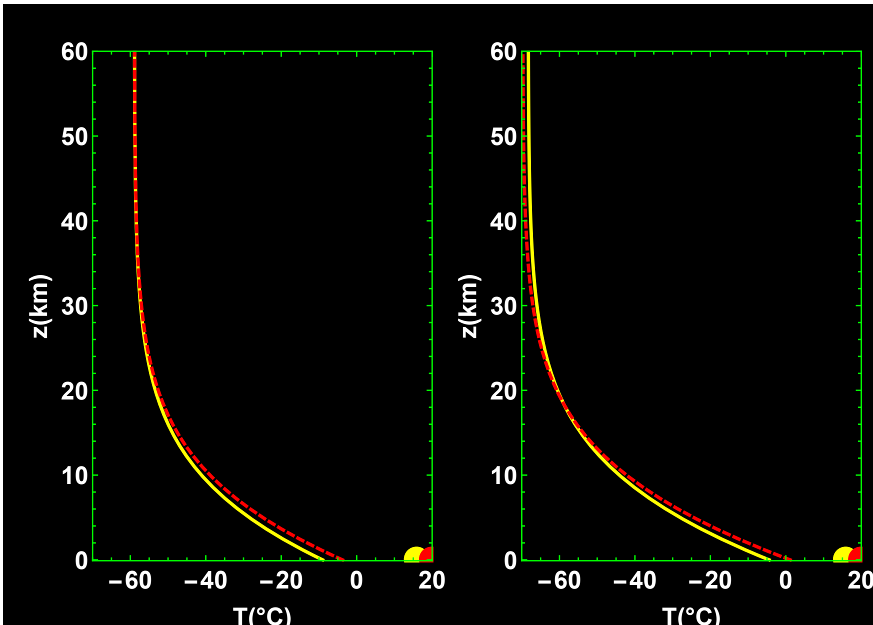
Goessling and Bathiany (2016) suggest extending the grey model to the simple case of two IR bands, as shown in Figure 2. The first band is fully transparent and corresponds to the atmospheric IR window. The second band is the grey IR band which we have thoroughly discussed in Part XIII. It is straightforward to generalise the differential equations presented in Part XIII to take into account the atmospheric window part. The Earth acts as a blackbody in the IR region, radiating according to its surface temperature T^* the flux πB^* upwards. Part of this flux, $W=\delta\pi B^*$, radiates in the atmospheric window. The rest $F+(0)=(1-\delta)\pi B^*$, radiates in the grey window. Assume that the absorption coefficient is β_0. The source term in the differential equation for the upward flux in the window-grey model is reduced by the factor $1-\delta$ compared to the grey model case. The differential equations that govern the flux transport now become

$$\frac{dF^+}{dh} = -\beta_0\left(F^+ - \pi B(1-\delta)\right) \qquad (1a)$$

$$\frac{dF^-}{dh} = \beta_0(F^- - \pi B) \qquad (1b)$$

These equations can be solved, given two boundary conditions: at the top of the atmosphere there is no downgoing flux, $F-(1)=0$, and the upward flux at Earth's surface is $F+(0)$.

The derivation is beyond the scope of this document, but the reader can learn more about the topic by visiting www.bivrost-geo.no. The window-grey temperature equations which follow by solving equations 1a and 1b are listed in Table 1. The window-grey model reduces to the grey model by setting δ=0 whereby $\beta_0 \rightarrow \beta$.



LASSE AMUNDSEN

Figure 4: Left: The grey model predicts an increase in temperature everywhere in the atmosphere (except at TOA) for an increase in absorption factor from β=1.31 (the yellow line) to 1.5 (the red line). Right: The window-grey model predicts an increase in temperature in the lower atmosphere but cooling in the mid to top atmosphere for an increase in absorption factor from β0 =1.96 (the yellow line) to 2.32 (the red line). The parameter δ=0.2 describes the fraction of IR radiation from the surface which is directly emitted to space. The two cases have surface temperatures T=289K (16°C) (yellow dot) and T*=293K (20°C) (red dot). The vertical coordinate z is only approximate height, calculated from h with a constant scale height L=8 km such that h=1−exp(−z/L). The discontinuity in temperature at Earth's surface, where the atmospheric temperature just above is always lower: T(h = 0)<T*, is a result of the negligence of all mechanisms of energy transfer other than radiation in the model; in the real atmosphere, diffusion of heat removes the discontinuity.*

Temperatures	Grey model	Window-grey model
T_*	$T_* = T_0 \left(\frac{\beta + 2}{2}\right)^{1/4}$	$T_* = T_0 \left(\frac{\beta_0 + 2}{\delta\beta_0 + 2}\right)^{1/4}$
$T(h)$	$T(h) = T_0 \left(\frac{\beta(1-h) + 1}{2}\right)^{1/4}$	$T(h) = T_0 \left(\frac{\beta_0(1-h) + 1}{\delta\beta_0 + 2}\right)^{1/4}$
$T(h = 0)$	$T(0) = T_0 \left(\frac{\beta + 1}{2}\right)^{1/4}$	$T(0) = T_0 \left(\frac{\beta_0 + 1}{\delta\beta_0 + 2}\right)^{1/4}$
$T(h = 1)$	$T(1) = T_0 \left(\frac{1}{2}\right)^{1/4}$	$T(1) = T_0 \left(\frac{1}{\delta\beta_0 + 2}\right)^{1/4}$

Table 1: Temperatures. Here, h is zero at sea-level and one where pressure is zero, in outer space. Further, T_0=255K (-18°C) is Earth's temperature in the reference case of no atmosphere. See main body of text for definitions. At the top of atmosphere, h=1, the temperature in the grey model is independent of the absorption.

The parameter δ describes the fraction of IR radiation from the surface which is directly emitted to space. Our interest is to get a feeling for how a CO_2 increase – described by an increase in the absorption factor β_0 – affects the temperatures. Since a CO_2 increase introduces no effect in the atmospheric window, we can keep δ constant. Given δ, we can determine the absorption factor β_0 that produces today's surface temperature T^*=289*K* (16°C). Figure 5 shows contours of (δ,β_0) combinations that fix the surface temperature. The solid white line has today's surface temperature. The choice δ=0 corresponds to the grey radiation model. For our temperature calculations we choose δ=0.2 and investigate the temperature behaviour when β_0 is increased from 1.96 to 2.32.

The temperature profiles are shown in Figure 4 (right). We observe that the surface temperature rises from T^*=289*K* (16°C) to T^*=293*K* (20°C), in agreement with the surface temperature equation in Table 1 which shows that the numerator increases more than the denominator with the β_0 increase.

The atmospheric temperature at the surface, *T*(0), given in Table 1, also has to increase with increasing β_0.

Now, look at the atmospheric temperature at outer space, *T*(1), given in Table 1. In the grey radiation model *T*(1) never changes. It is constant, independent of any change in absorption of radiation in the atmosphere. In contrast, in the window-grey radiation model *T*(1) decreases with increasing absorption in the opaque part of the model.

This result is not only a mathematical result. It has a physical explanation when we allow the atmosphere in the infrared to have two bands. The important observation to make is that the transparent band is the atmospheric window, outside the wavenumber range where CO_2 absorbs radiation. Therefore, the window part is not affected by any increase in CO_2 concentration. However, as we know and have seen, Earth's surface temperature increases when the Earth-atmosphere system attains equilibrium after a CO_2 increase.

We have the result that the atmospheric surface temperature increases whereas the TOA temperature decreases. Then, the atmospheric temperature profile *T(h)* in the window-grey radiation model must have a crossover at some height h_c where the absorption increase leads to heating below and cooling above. This crossover altitude one may interpret as the altitude from the troposphere to the stratosphere based on the discussion in Part XV (*GEO ExPro* Vol. 19, No. 2): increased concentrations of CO_2 are warming Earth's surface and troposphere while cooling the mid to upper atmosphere.

In Figure 4 (right) we display the window-grey temperature profiles for the selected parameters given above. The crossover point is h_c =1-δ/2 (Goessling and Bathiany, 2016).

In summary, we see that the window-grey model accounts for temperature cooling in the mid to upper atmosphere when the absorption factor is increased. The lower atmosphere experiences warming as in the grey model.

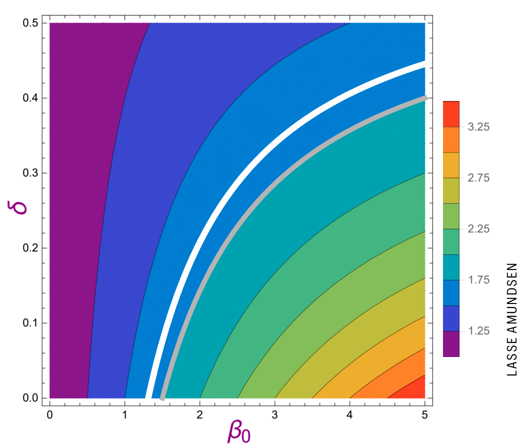


Figure 5: The dependence of the equilibrium surface temperature on the parameters β_0 and δ in the window-grey model. δ=0 corresponds to the grey case. The temperature which is constant on contour lines is T^*=289K (16°C) on the white line and T^*=293K (20°C) on the grey line.

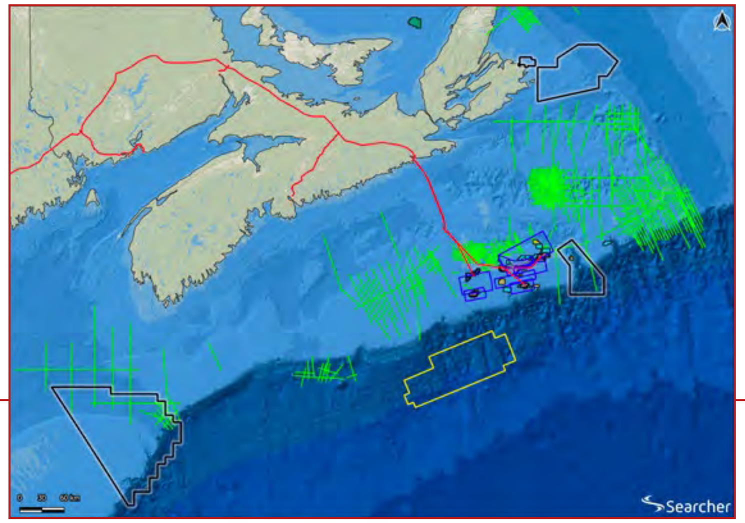
* *Lasse Amundsen is a full-time employee of Equinor.*

References

Goessling, H.F. and Bathiany, S. 2016. Why CO_2 cools the middle atmosphere – a consolidating model perspective. *Earth System Dynamics, 7, pp.697–715.*

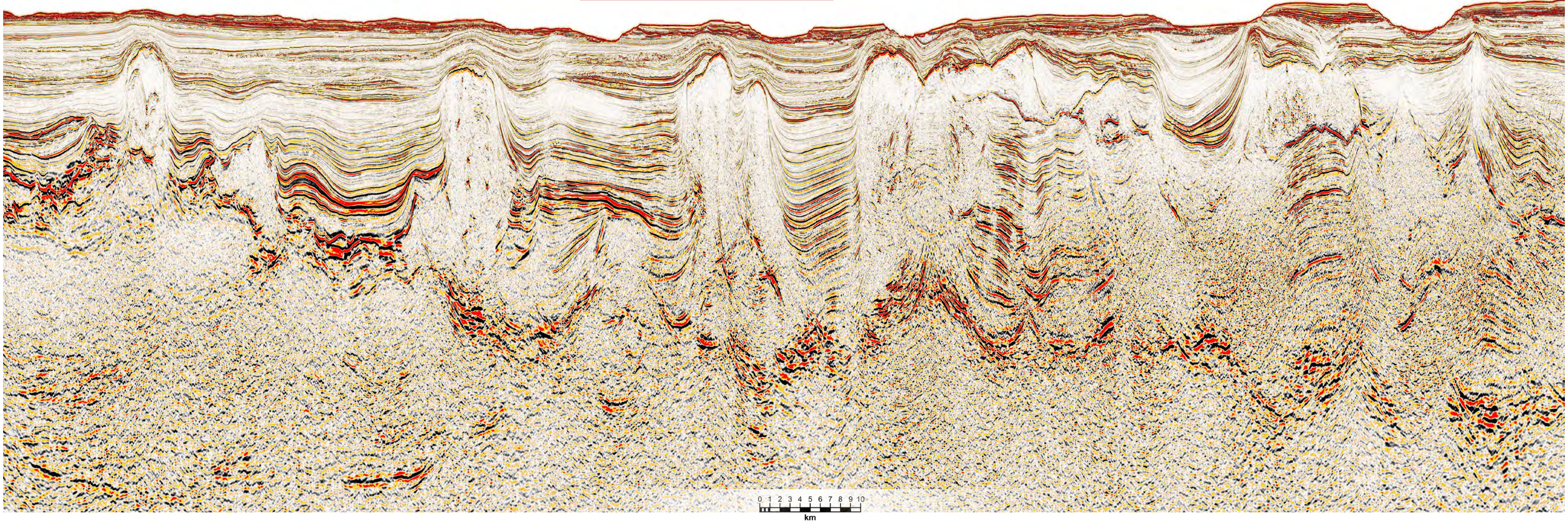
A NEW ARCADIA: SEISMIC ACCELERATION OF THE NOVA SCOTIAN MARGIN

Playing the Nova Scotian margin is a game of two halves. On the shelf lies an exciting exploration ground where 20 years ago fortunes were made discovering oil and gas in shallow water, syn-rift plays. For 20 years though, exploration has neglected the shelf. On the slope and basin floor, new hyper-modern seismic has revealed a fantastic salt basin with new play fairways where the little exploration to date has clarified the key uncertainties that seismic can now resolve.



150 km West–East section from the Tangier 3D offshore Nova Scotia. PSDM in Depth (m).

Arbitrary line. Arrows mark locations of oil seeps on sea surface and seabed coring site 41.



SEARCHER

RE-IMAGINING THE PROVEN HYDROCARBON BASINS OFFSHORE NOVA SCOTIA

In 1958 Parke Dickey wrote, "We usually find oil in new places with old ideas. Sometimes, also, we find oil in an old place with a new idea, but we seldom find much oil in an old place with an old idea." However, in 1958, modern seismic imaging was not even science fiction yet. Now, with modern processing techniques, you can re-image the subsurface (or image it for the first time more likely) by reprocessing the legacy data from almost any 'old place' and oil and gas will fall out of the data at you.

Neil Hodgson, Karyna Rodriguez, Peter Hoiles, Julia Davies and George Kovacic; *Searcher Geodata UK Ltd*

Geological thinking hasn't progressed much since the concepts of sequence stratigraphy were developed in the 1980s, so new exploration ideas now come largely from new or reprocessed seismic data. In this century perhaps the greatest collective advance in our industry's science, arguably to the greatest scientific benefit for all mankind, has been in the field of seismic processing. Tools such as SRME (Surface Related Multiple Elimination), shallow water de-multiple and de-ghosting (removing source and receiver notches/ghosts) which are now standard, have revolutionised imaging of sedimentology, structure, DHIs (Direct Hydrocarbon Indicators) and source rocks over the last 20 years. Reprocessing legacy data can now unleash idea-tsunamis in old basins. And in some basins, where the original seismic just wasn't up to the job, old ideas in an old place – will work just fine. Offshore Nova Scotia is one such basin.

The Proven Shelf of Nova Scotia

On the shallow water shelf (mostly below 100m water depth), proven Jurassic source rocks charge proven Jurassic and Cretaceous reservoirs. A number of gas discoveries made around Sable Island in the late 1990s and early 2000s were developed and produced. Now these fields are depleted and most of the infrastructure decommissioned. Prior to development, 3D data was acquired over these discoveries allowing some infill exploration success. Yet, these 3D surveys have never been reprocessed. Recent analyses by CNSOPB (Canada Nova Scotia Offshore Petroleum Board) (Smith et al., 2014, 2018) have shown that even on these ancient datasets, ca. 1.3 Tcf of discovered but not developed potential reserves remain. When the reprocessing of the Sable Island 3Ds is complete, they will not only reduce imaging uncertainty on the existing unproduced discoveries, but also reveal additional targets and new plays to chase, allowing for a rejuvenation of exploration, reutilisation of some of the infrastructure and the renewal of production of advantaged hydrocarbons on this shelf.

SEARCHER

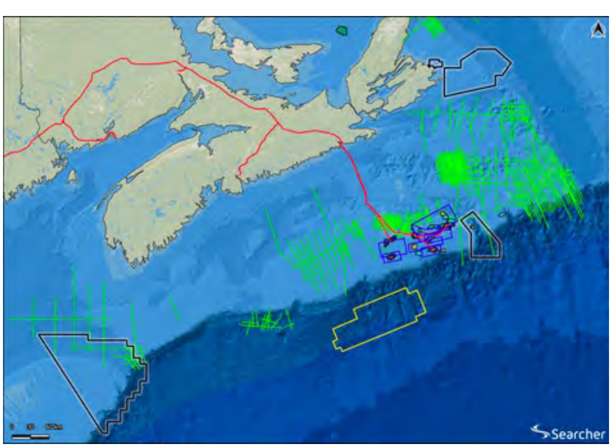


Figure 1: Searcher's data library, Nova Scotia. Green lines: legacy 2D. Blue polygons: 3D volumes around Sable Island gas fields. (green and blue being reprocessed). Yellow polygon: Tangier 3D. Grey and purple polygons: protected areas. Red lines: infrastructure.

Ultimately, when all the possible commercial reserves have been discovered and developed in any basin it becomes over-mature so that depleted fields will be decommissioned and abandoned. Yet how do we know when this point has been reached? The exploration of almost every basin tells us that when a basin looks to be exhausted, it is only the explorers who are exhausted – and with new data and new imaging of the subsurface, then new plays and missed traps in old plays are found so a new creaming curve of exploration value creation erupts. New plays for new times on the shelf also include the only potential for developing Carbon Capture Utilisation and Storage (CCUS) in Eastern Canada.

The Slope and Basin Floor Salt Play

Off the shelf into the slope and basin floor domain – a whole different adventure awaits the explorer. Slope channels can be mapped bringing coarse clastics off the Scotian slope into a glorious salt basin. To the south and west this salt basin is categorised by salt diapirs and walls that separate sediment pods of Jurassic to Cretaceous age. Above the migration-focusing diapirs, shallow fluid escape features link to both repeat satellite slick clusters, and oil recovered from seabed cores (see Foldout line) (Fowler and Hubert, 2020). To the north and east, salt

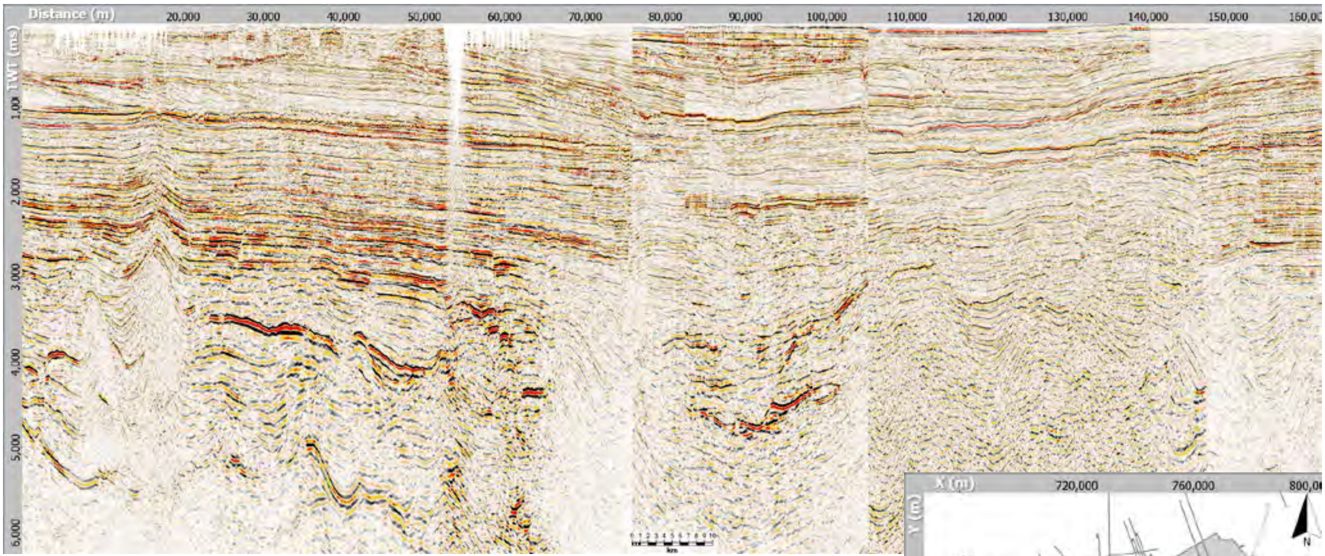


Figure 2: Arbitrary line through the legacy Sable Island 3Ds being reprocessed.

lavas extruded on the seabed at the end of the Cretaceous have formed a salt canopy, in places wrapping the underlying pods up like Beef Wellington, generating potentially perfect top and side seals to thick grounded Jurassic to Late Cretaceous sediment pods. Over such simple geology with complex imaging challenges, one of the world's most exciting Wide Azimuth (WAZ) seismic surveys has been acquired (*Tangier 3D, Foldout line and Figure 3*) that has allowed for astonishing imaging beneath the canopy.

The recently drilled Aspy-1 well proved a working hydrocarbon system, finding good oil shows in silts that were in closure under a salt canopy (Nova Scotia, Aspy D-11, Subsurface Well History Report for CNSOPB). This is the play opening observation that will ignite exploration on the slope and basin floor of this margin. The next stage of exploration can focus on the pursuit of the coarse clastic sand systems that poured off the shelf into the salt topology. These sands systems can be mapped and conflated with seismic characterisation of source rocks in this basin.

Advantaged Hydrocarbons: Nova Scotia is the New Downton Abbey

The first European settlers in Nova Scotia in the 17th century were French Acadians who were forced to leave the area after 1755 by the British (in 'Le Grand Derangement') and migrated south to found the 'Cajun' communities in the southern United States. From bleak times to future fortune – so stands the neglected shelf of Nova Scotia today. A shelf blessed with hydrocarbon reserves discovered and developed in the 20th century looked privileged enough but has been neglected for 20 years. We now have the technology to re-image the geology near to the discoveries (a version of in-field exploration), re-evaluate the discoveries in hand, resolve the plays that could not be imaged before and image entirely new plays. On a grander scale the slope and deepwater salt basin are poised for success with a newly proven hydrocarbon system and some of the most amazing seismic ever acquired on planet Earth with which to chase reservoirs, source rocks and traps.

Nova Scotia has encouraging new commercial terms that have just got better through supportive regulator and government legislation that provides a clear path to acreage access and operational stability. Nova Scotia has the pedigree of advantaged aristocracy – and is ready in the 21st century for a new technology-led future.

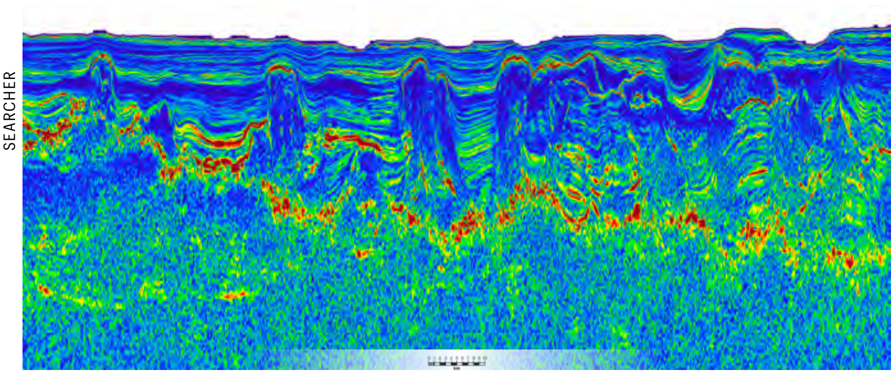


Figure 3: RTM Sweetness Blend: high values (red) associated with source rocks and reservoirs. Tangier 3D.

References

Smith, B.M., Makrides, C., Altheim, B. and Kendell, K. 2014. Resource Assessment of Undeveloped Significant Discoveries on the Scotian Shelf, CNSOPB Geoscience Open File Report.

Smith, B.M., Kendell, K., Brown, D., Makrides, C. and Altheim, B. 2018. Call for bids NS1-3 – Seismic interpretation, well summaries, source rock, and exploration leads in the Central Scotian Shelf. Sable Subbasin. CNSOPB Geoscience Openfile Report 2018-0002MF.

Fowler, M. and Hubert, C. 2020. Geochemistry and Microbiology in Seep Prospecting. GeoExPro Vol. 17, No. 2, pp.56–58.

WHAT IS THE **U** IN CCUS?

Jane Whaley
Associate Editor
jane.whaley@geoexpro.com

It is generally accepted that it will be impossible to keep global temperature increases below 1.5°C without capturing carbon from emitting sources and the atmosphere and storing it in underground reservoirs, a process known as carbon capture and storage, or CCS. Another commonly used acronym is CCUS, where the U stands for utilisation or usage, in which, instead of storing captured CO_2, it is reused, ideally in ways that lock the carbon into the resultant material.

While there is a strong push towards replacing fossil fuels with renewable energy in areas like electricity generation and personal transport, some industry sectors remain 'difficult to decarbonise', such as cement manufacture and aviation fuel (see *GEO ExPro* Vol. 19, No. 2). CO_2 is one of few alternatives to fossil fuels as a source of carbon and CCUS will be a vital component in making these 'difficult' processes greener.

Carbon dioxide has been captured at the point of emission and then reused for many years, primarily in enhanced oil recovery and in the production of fertilisers. Annual global consumption of CO_2 was reported by IHS Markit in 2018 to be around 230 Mt – a figure that needs to increase dramatically if we are to reach our climate goals. A number of exciting new developments suggest we could increase our use of captured CO_2. Some of these make use of the gas directly, while others convert it to other forms of carbon before use.

Let's look in a bit more detail at ways in which CO_2 is being and could be used.

CO_2	
DIRECT USE	**CONVERSION**
Yield boosting: • greenhouses • algae • urea/fertilisers	**Building Materials:** • aggregates (filling materials) • cement • concrete
Solvents: • EOR • decaffeination • dry cleaning	**Fuels:** • methane • methanol • gasoline, diesel, aviation fuel
Heat Transfer Fluid: • refrigeration • supercritical power system	**Chemicals:** • chemical intermediates (methane, methanol) • polymers (plastic)
Other: • food and beverages • welding • medical	

Ways of using captured CO_2 (modified from IEA).

Traditional CO_2 Uses

Injecting CO_2 has been used for many years to improve recovery from oil wells and the oil industry is the largest consumer of externally sourced CO_2, with an estimated annual global consumption of around 80 Mt. When natural reservoir pressure is no longer strong enough to drive oil to the surface, as much as 65% of it may remain in place. This can be extracted by pumping CO_2 into the reservoir, because at high temperature and pressure the gas combines with oil and helps it move through the pore spaces and into the well bore. During this process, known as enhanced oil recovery (EOR), some of the CO_2 remains below ground, the remainder returning to the surface with the extracted oil. Most CO_2-EOR projects recycle the returning gas, resulting in over 99% of the injected CO_2 being permanently stored over the life of the project.

Over 125 Mt/y of CO_2 is used annually to manufacture fertilisers by producing calcium ammonium nitrate from ammonia, using the CO_2 produced in the initial ammonia manufacturing process rather than traditional limestone, thus reducing the total emissions of the process. There are plans to further decarbonise the procedure using, for example, green energy electrolysis, but the technology needs further development.

Permanent Carbon Retention

One of the most important features of using CO_2 is knowing how permanently the gas will be stored; this can range from less than a year for fuels to millions of years in building materials. CO_2 from ammonia plants, fertiliser producers and other emitters can be used in various industrial processes to create substances such as melamine, glues and resins that capture the carbon in the product for a long time. It is estimated that one tonne of melamine actually stores a tonne of CO_2, although there is an issue as to the recycling and disposal of melamine once the product is no longer required. Similarly, use of the gas in glues binds the CO_2 for the lifetime of the product it is used for.

A particularly effective use of CO_2 that offers long-term carbon retention is in building materials. One of the most mature and promising applications so far is CO_2 curing, where the gas replaces water in making concrete, reacting with cement to form nano-sized particles that become

CARBONCURE TECHNOLOGIES

A CarbonCure truck carrying CO2-cured concrete.

permanently embedded in the material. As well as having a lower carbon footprint, concrete made this way can be cheaper to produce; American company CarbonCure reports that CO_2 curing results in an 80% reduction in the CO_2 footprint of cement. Further testing is required to confirm the mechanical strength of CO_2-cured concrete, but for the moment it could be used in areas like road construction where this is not so vital.

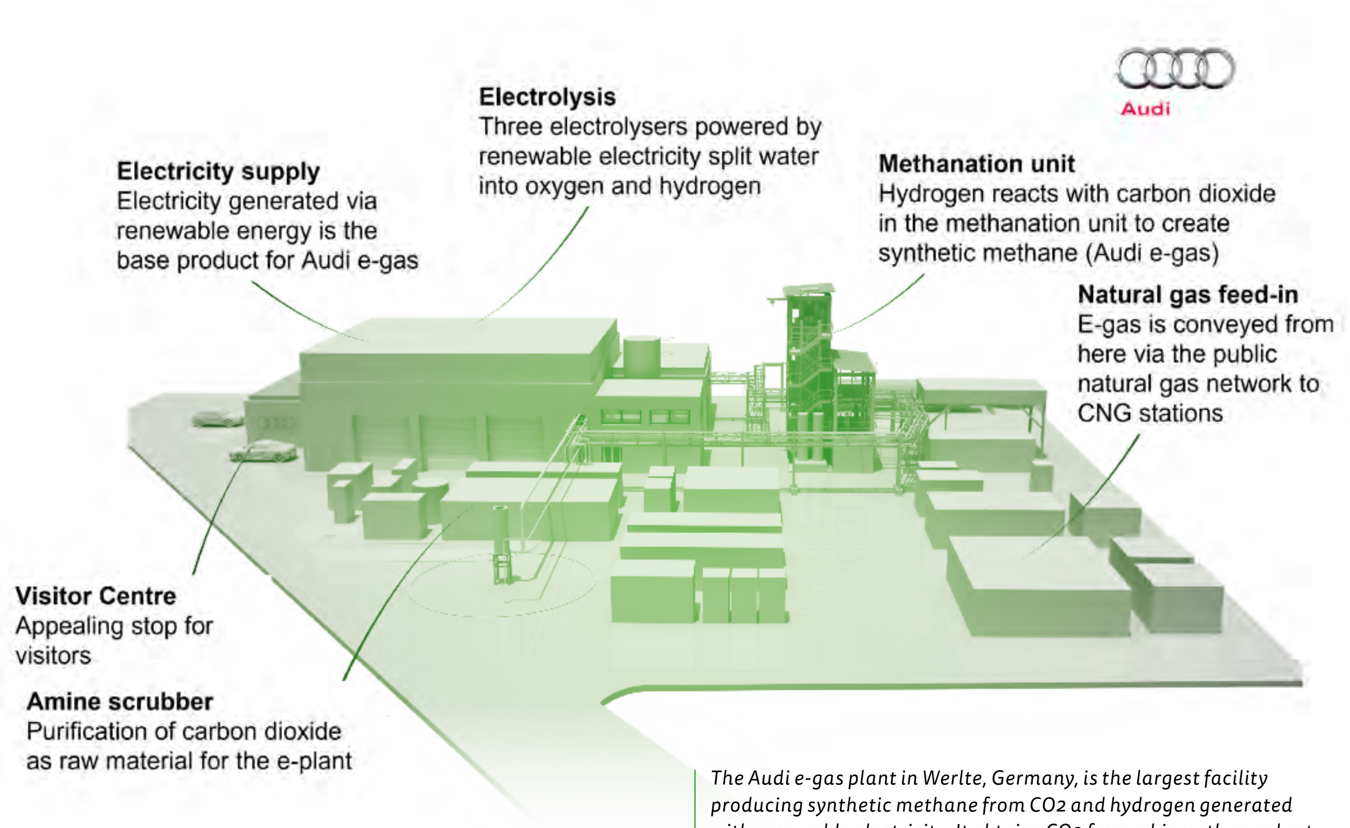
Carbon dioxide can also be used as a raw ingredient in building materials, replacing cement or construction aggregates, by reacting with waste materials from power plants or industrial processes, such as iron slag and coal fly ash; hazardous waste material can even be used. British company Carbon8 uses this process to convert waste and high emission residues into lightweight aggregates for use as a component of building materials and for fertilisers. Although some of the methods used to create cement this way are energy intensive, the company claims that their process is carbon-negative, as more carbon is permanently stored than emitted in its manufacture. This technique effectively diverts waste from landfill, replaces carbon intensive products with low carbon, sustainable alternatives, and locks CO_2 into material for potentially millions of years.

Fuels and Chemicals

Combining hydrogen with CO_2 allows us to access the carbon to create fuels such as methane, methanol and gasoline, resulting in a fuel that is easier to handle and use than pure hydrogen. At the moment, fuels created this way are much more expensive than their fossil fuel alternatives, and the green credentials of the resulting fuel does depend on the source of electricity used to create the hydrogen. It works best where both low-cost renewable energy and CO_2 are available, such as in Iceland, where the George Olah facility takes around 5,600 tonnes of CO_2 emissions a year from the Svartsengi Geothermal Power Plant, as well as water waste, and, using electricity generated from hydro and geothermal sources, creates 4,000 tonnes of methanol. However, the carbon retention of CO_2 in fuels is low, as mentioned above.

CARBON RECYCLING INTERNATIONAL

The George Olah plant in Iceland creates methanol from geothermal power plant emissions.



AUDI AG

The Audi e-gas plant in Werlte, Germany, is the largest facility producing synthetic methane from CO2 and hydrogen generated with renewable electricity. It obtains CO2 from a biomethane plant and feeds synthetic methane into the local gas grid.

CO_2-derived methane and methanol can be subsequently converted into other carbon-containing high-value chemical intermediates such as olefins, used to manufacture plastics, and aromatics, utilised in health and hygiene and food production and processing. Using CO_2 to create the polymers needed in making plastics, foams and resins requires little energy input, because the gas is converted into carbonate, which has a lower energy state, so this process can be competitively priced and potentially cost less than fossil fuel counterparts. Up to 50% of the resultant polymer comprises CO_2, which is effectively stored away from the atmosphere for possibly hundreds of years.

In addition to EOR, CO_2 is used directly in a number of ways, including to enhance yield in greenhouses. Putting many plants together in one place reduces the amount of CO_2 available for photosynthesis, so adding more CO_2, combined with low-temperature heat, increases yields by up to 30%. The Netherlands is the leader in this technology, but much of the gas comes from on-site gas-fired boilers; increased use of industrial sources or air capture would be more advantageous to the climate.

Carbon dioxide is a critical ingredient in beer, soft drinks and other beverages. The CO_2 is usually sourced as a by-product from the fertiliser industry using natural gas but there are greener alternatives, such as using the CO_2 produced in making bioethanol or from anaerobic digesters. Swiss company Climeworks concentrates on extracting CO_2 from the atmosphere and while most of it is stored underground, some is used in a Coca Cola factory.

Important Role to Play

There are a number of points to consider when assessing the climate benefits of CCUS. These include the source of the CO_2; the life-cycle emissions of the product or service the CO_2-based product is replacing; how much energy is required to convert the gas and what has sourced that energy; how long the carbon is retained in the product; and the scalability of the process.

As one of the few ways of tackling emissions from heavy industry and removing carbon from the atmosphere, CCUS technologies are attracting the attention of governments. These technologies have a role to play in reaching net zero and achieving a circular economy, but many techniques will need both financial and regulatory help to scale up from start-up idea to commercial reality.

It is important to note that using CO_2 is not the same as avoiding producing CO_2. In addition, it is complementary, not an alternative, to CCS and will not reduce emissions at the same scale as storing the gas underground. However, CCUS can support the development of products with a lower carbon footprint and provide climate benefits, ideally with the CO_2 being sourced from biomass or the air, but the whole life-cycle emissions need to be carefully analysed.

References available online.

CALIFORNIA DREAMING

Revisiting the oil-rich San Joaquin Basin, California.

New potential unveiled in the San Joaquin Basin, California (CA) where reprocessed 3D seismic surveys and structural geology provide new oil opportunities in an exploration-mature and prolific oil basin.

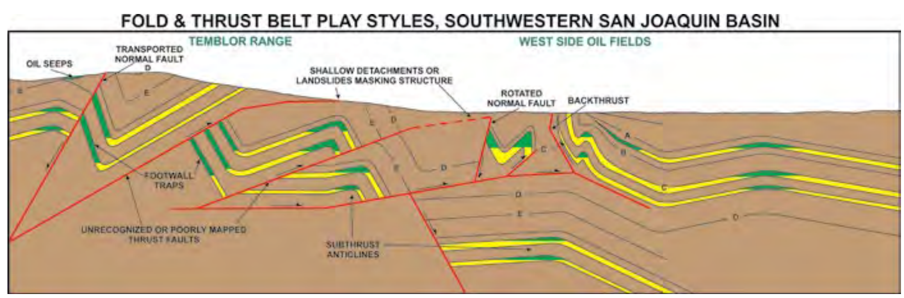
Thomas L. Davis and Geoff Gallant, *Ventura, CA*

West-Side Fold Belt (WSFB)

Images from reprocessed 3D seismic surveys integrated with structural models of convergence yield untested conventional oil prospects and explain dry holes. Exploration risk is generally lower in basins with giant oil fields while complex geology can increase risk and the San Joaquin Basin (SJB, *Figure 1*) has both. Explored and produced for over 140 years, the SJB has yielded ~17 billion barrels of oil equivalent (Bboe) with at least 5 Bboe yet to be produced (Neher, 2018).

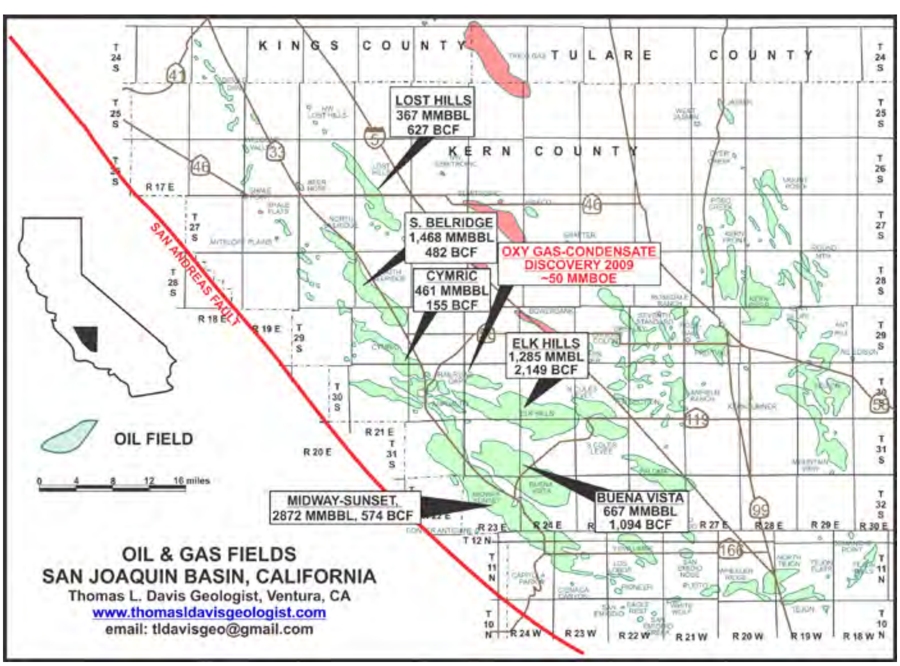
Here, we focus on new exploration opportunities, in the tens of millions barrel range, along the WSFB using a recently reprocessed 3D seismic survey (TRICON 5, 2022) and structural geology-based mapping. Most oil discoveries of the last five decades in the SJB have occurred in the WSFB. The WSFB developed along and contemporaneously with the San Andreas fault (SAF) plate-boundary and its true structural style, a fold and thrust belt (F&TB), has been recognised only during the last four decades (Namson and Davis, 1988; Davis and Namson, 2017). Use of the F&TB structural style in seismic mapping reveals untested prospects and explains many dry holes. However, the F&TB concept arrived late in the basin's long exploration history and remains underutilised. Within the WSFB are several giant oil fields and numerous large to medium-sized oil fields with a wide array of anticlinal, fault, and stratigraphic-trapping mechanisms (*Figure 2*) that have resulted from nearly non-stop deformation and deposition during the Neogene.

Geologic complexity is both an exploration challenge and an opportunity where smaller traps can be poorly imaged, overlooked, and difficult to pinpoint. Improved seismic imaging and structural mapping are key to future success. In the WSFB there are numerous oil fields with 1–50 MMbo recoverable with only 10s to 100s of acres of extent, yet these small areas yield large volumes due to multiple, stacked reservoirs and seals (*Figure 3*).



AFTER MOUSTAFA, A.R. AND KHALIL, S.M. 2016

Figure 2: Diagrammatic cross-section showing the various oil trapping mechanisms encountered in the WSFB of the SJB. Most of these traps are associated with development of the fold and thrust belt (F&TB). Underexplored and previously poorly imaged synclinal areas with sub-thrust and sub-detachment anticlinal traps are of primary interest. These areas are more extensive than previously thought and have concealed oil traps and sub-basins with known oil source and reservoir rocks (Davis et al., 1988; Davis, 2015; Davis and Namson, 2017).



THOMAS L. DAVIS AND GEOFF GALLANT, UNPUBLISHED

Figure 1: Oil field map of the San Joaquin Basin showing cumulative oil production for the largest oil fields in the West-Side Fold Belt (WSFB). Trapping mechanisms for the largest fields are anticlinal at this scale but at a more detailed look are multi-pool structural and stratigraphic traps along the anticlinal crests and occasionally along the anticlinal limbs.

AFTER MOUSTAFA, A.R. AND KHALIL, S.M. 2016

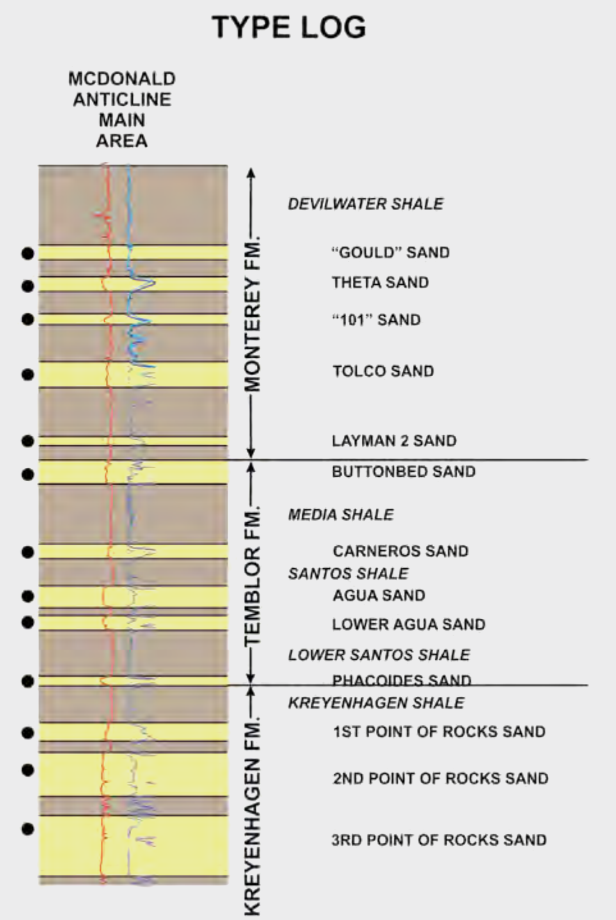


Figure 3: Type log for the Main Area Pool (aka Layman) of the ~22 MMbo McDonald Anticline oil field that is near the seismic displays in Figures 4–6. Discovered in 1945, the field reached peak annual oil production of 750,000 barrels in 1969. The field has a very long production history that is common to many SJB oil fields. The field is now producing from 2,000–4,000 barrels/month. The black dots show the 13 oil-producing reservoirs that are sandstone dominant. Initial yields for the various reservoirs range from 500–2,000 STB/ac-ft and the reservoirs are separated by claystone and siltstone dominated seals. Stacked reservoirs and seals are common in the WSFB oil fields and cumulative yields over a small area can be very high. * https://thomasldavisgeologist.com/oil-field-production-injection-data/*

San Joaquin Super Basin

The American Association of Petroleum Geologists (AAPG) classify the SJB as a Super Basin i.e., >5 Bboe (Neher, 2018). A USGS, 2003, assessment of undiscovered, recoverable, conventional hydrocarbons in the SJB has an estimated mean of 1.8 trillion cubic feet of gas, 393 million barrels of oil, and 86 million barrels of natural gas liquids. The SJB has several organic-rich and thermally mature source rock intervals that include the Monterey Formation, a world-class oil source rock that provides 86% of the estimated ultimate oil recovery in the basin (Neher, 2018; Isaacs and Rullkoetter, 2001). Numerous, highly productive clastic and fractured shale reservoirs span the geologic column from Cretaceous to the Quaternary. Within the WSFB are six of the nation's top 100 producing oil fields: Coalinga, Lost Hills, South Belridge, Cymric, Midway-Sunset, Elk Hills, plus numerous lesser oil fields.

Structural Models, a Key Interpretation Tool

Fault-related fold models that illustrate the development of petroleum traps and structures are frequently used to assist seismic and cross-section mapping and interpretations in structurally complex F&TBs (Namson and Davis, 1988). Worldwide, numerous petroleum-rich provinces are situated in convergent strike-slip belts with giant petroleum traps such as the WSFB (Davis and Namson, 2017). Before the 1980s the WSFB's structural style was attributed to wrench faulting that produced steepening-with-depth fault patterns in cross-section with limited sub-fault exploration areas. Subsequent efforts by the Atlantic-Richfield Company (ARCO) in the Cuyama Basin, CA (Davis et al., 1988), the 1983 Coalinga earthquake (Namson and Davis, 1988), and the discovery of strain-partitioning adjacent to the SAF plate-boundary (Mount and Suppe, 1987; Zoback et al., 1987) show the WSFB and other CA oil basins have a F&TB structural style. Thus, the WSFB and other CA oil basins have extensive under-explored areas, with known oil source and reservoir rocks, where detachments and thrust sheets conceal footwalls with untested traps (*Figure 2*; Davis, 2015) and in Cuyama, a previously unknown oil and gas sub-basin proven by deep drilling (Davis et al., 1988). Here, we show a 2D seismic line with dry holes (*Figure 4*) and contrast its trap image with the TRICON 5's 3D images that are integrated with the F&TB structural-style mapping (*Figures 5 & 6*). This approach accounts for previous exploration failures and identifies an untested prospect. The significant improvement in the reprocessed data quality is a result of a new term noise attenuation workflow where the data are sorted in five different domains with noise attenuation applied in each domain.

PACSEIS, INC. AND TRICON GEOPHYSICS, INC.

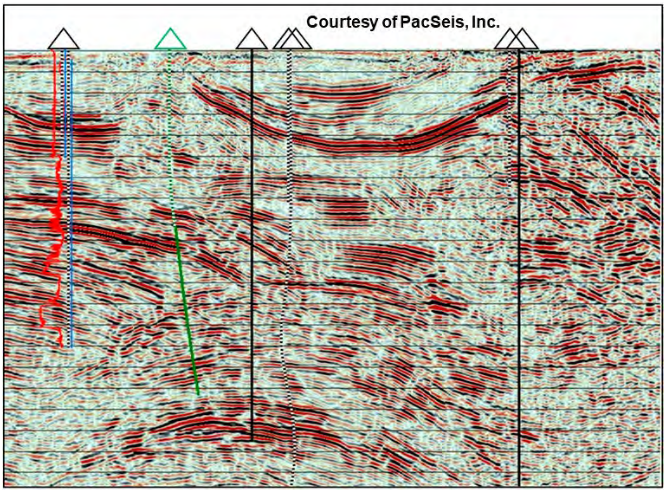
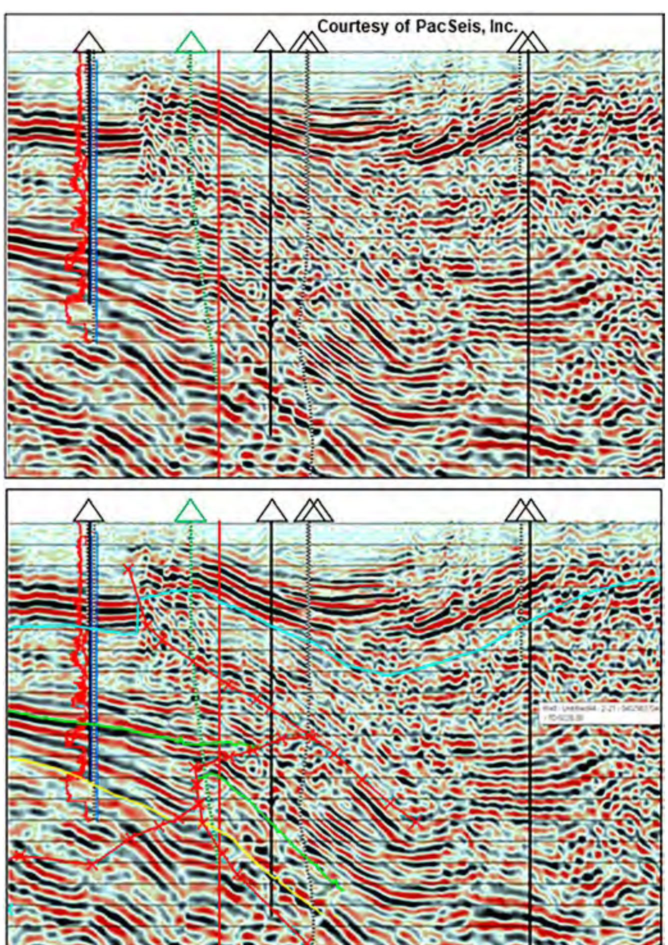


Figure 4: A migrated 2D seismic line within and pre-dating a 3D seismic survey that was recently reprocessed. The 2D line lies along the 3D survey profile shown in Figure 5 and comparison of the images is instructive. Black triangles show noncommercial exploration wells (dry holes) adjacent to the line. The large roll-over imaged in the centre of the 2D line was tested by two wells that had oil shows but were noncommercial. The green triangle shows a proposed test well.

PACSEIS, INC. AND TRICON GEOPHYSICS, INC.



PACSEIS, INC. AND TRICON GEOPHYSICS, INC.

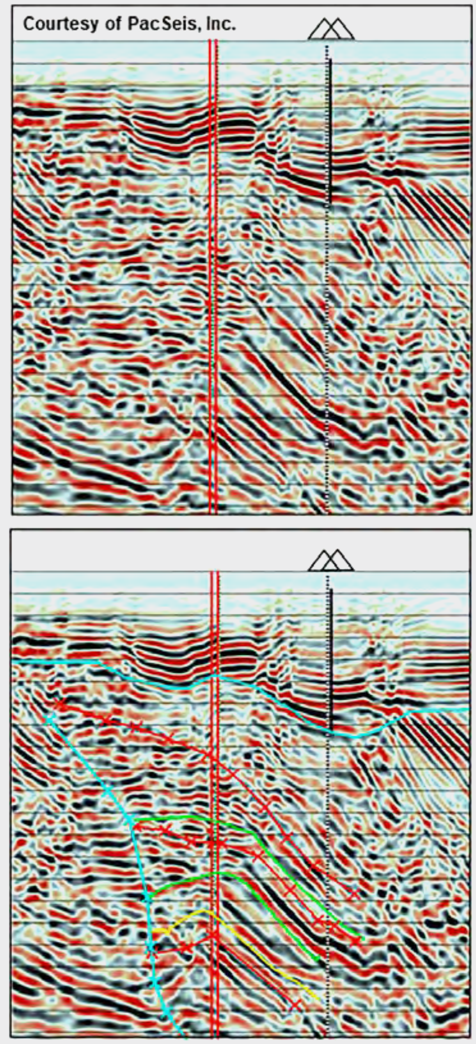


Figure 6: Upper image – uninterpreted 3D seismic profile (inline). Lower image – geologic interpretation of the upper image that shows the untested shallow anticlinal trap and the untested deeper, faulted-anticlinal trap. Red and light-blue curved lines with Xs are faults, shallow light-blue curved line is the top of the Monterey Formation, green curved line is the top of the Buttonbed sandstone, and the yellow curved line is the top of the Agua sandstone (see Figure 3 for more stratigraphic and reservoir detail). Black triangles show the noncommercial exploration wells (dry holes) adjacent to the profile. The inline profile is perpendicular to the crossline shown in Figure 5 and the 2D line shown in Figure 4 (intersections are vertical red lines).

Figure 5: Upper image – uninterpreted 3D seismic profile (crossline) along the 2D line shown in Figure 4. Lower image is a geologic interpretation of the upper image that shows an untested shallow anticlinal trap (fault-propagation fold) and an untested deeper, faulted-anticlinal trap above a triangle zone. Red curved lines with Xs are faults, shallow light-blue curved line is the top of the Monterey Formation, green curved line is top of the Buttonbed sandstone, and yellow curved line is top of Agua sandstone (see Figure 3 for more stratigraphic and reservoir detail). Black triangles show the noncommercial exploration wells (dry holes) adjacent to the profile and the green triangle shows a proposed test well. Red vertical line is intersection of the inline shown in Figure 6. The seismic profiles in Figures 5 and 6 are from a reprocessed 3D survey and the improved image quality is due to the TRICON 5 (2022) workflow.

Future of Oil in California and CO_2 Emissions

California oil demand has remained constant over nearly four decades (*Figure* 7), it is the second-largest consumer of petroleum products in the nation, and the largest consumer of gasoline and jet fuel (EIA, 2021). The SJB and CA's other oil-rich basins remain an important crude oil source to CA's refineries despite declining in-state production. For at least the next several decades CA will remain a sizeable oil market and the SJB will be its most important domestic source despite concerns and policies to address climate change.

This market has an indispensable role in CA's energy mix and has decades of high demand that show no sign of decreasing (*Figure* 7). Counter-intuitively, CA's present anti-fossil fuel politics and policies have increased its per-barrel CO_2 emissions by reliance on an ever-increasing supply of maritime-transported oil (*Figure* 7, Olmer et al., 2017), plus raising the risk of oil spills at sea and onshore oil leakage at foreign sources with questionable environmental records. It is politically unlikely that CA's public and businesses, while concerned about climate change, will support a dramatic oil supply reduction with its negative economic impact and life-style restrictions while also becoming a national security risk (Rapier, 2019). CA will need to adjust its counter-productive policies by allowing more in-state oil production and exploration that will support a smoother, more practical energy transition over the next four or five decades.

OLMER ET AL., 2017

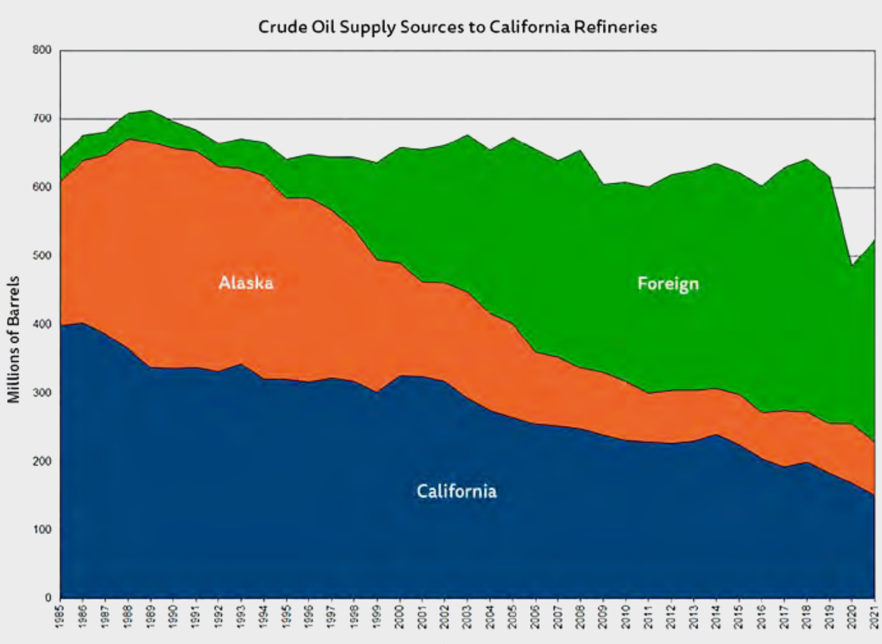


Figure 7: California (CA) has a sizeable crude oil market. Graph shows CA's imports of crude oil from foreign sources have increased from 6% in 1985 to 56% in 2021. In 1985 CA produced ~60% of its consumption from in-state sources and by 2021 this had decreased to ~29% (CAEC, 2021). CA oil demand has been roughly constant over nearly four decades: 600–700 MMbo/yr, mostly, because of improved energy efficiency as the population of CA has increased significantly since 1985. During this period CA has increased its per oil barrel emissions of CO_2 by over-reliance on maritime transport of oil from foreign sources.

References

CAEC, 2021, California Energy Commission, https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/oil-supply-sources-california-refineries

EIA, 2021, California State Energy Profile, US Energy Information Administration, https://www.eia.gov/state/print.php?sid=CA

Davis, T. L., M. B. Lagoe, W. J. M. Bazeley, S. Gordon, K. McIntosh, and J. S. Namson, 1988, Structure of the Cuyama Valley, Caliente Range, and Carrizo Plain and its significance to the structural style of the southern Coast Ranges and western Transverse Ranges, in W. J.M. Bazeley ed., Tertiary tectonics and sedimentation in the Cuyama basin, San Luis Obispo, Santa Barbara, and Ventura Counties, California, Pacific Section SEPM, v. 59, p. 141–158.

Davis, T. L., 2015, Study shows evidence for untested large traps, San Joaquin basin, California: Oil & Gas Journal, v. 113, no. 10, p. 42–50.

Davis, T.L., and J.S. Namson, 2017, Field excursion: Petroleum traps and structures along the San Andreas convergent strike-slip plate boundary, California: AAPG Bulletin, v. 101, No.4, p. 607-615.

Isaacs, C. M., and Rullkoetter, J., eds., 2001, The Monterey Formation: From rocks to

molecules: Columbia University Press, New York, NY, United States: 553 pp

Mount, V. S., and J. Suppe, 1987, State of stress near the San Andreas fault: Implications for wrench tectonics: Geology, v. 15, p. 1143–1146, doi:10.1130/0091-7613(1987) 15<1143:SOSNTS>2.0.CO;2

Namson, J. S., and T. L. Davis, 1988, Seismically active fold and thrust belt in the San Joaquin Valley, central California: Geological Society of America Bulletin, v. 100, p. 257–273,

doi:10.1130/0016-7606(1988)100<0257:SAFATB>2.3.CO;2.

Neher, K. 2018, San Joaquin Basin, California, Super Basin: Past, Present and Future San Joaquin Geological Society December 2018, SJGS Meeting & Presentation: https://www.searchanddiscovery.com/abstracts/html/2019/longbeach-90339/abstracts/2019.PS.15.html

Olmer, N., Comer, B., Roy, B., Mao, X., Rutherford, D., 2017, Greenhouse Gas Emissions from Global Shipping, 2013-2015, International Council on Clean Transportation (ICCT),

https://theicct.org/sites/default/files/publications/Global-shipping-GHG-emissions-2013-2015_ICCT-Report_17102017_vF.pdf

Rapier, R., 2019, California's Oil Hypocrisy Presents A National Security Risk

https://www.forbes.com/sites/rrapier/2019/06/21/californias-oil-hypocrisy-presents-a-national-security-risk/?sh=2d9c2839252a

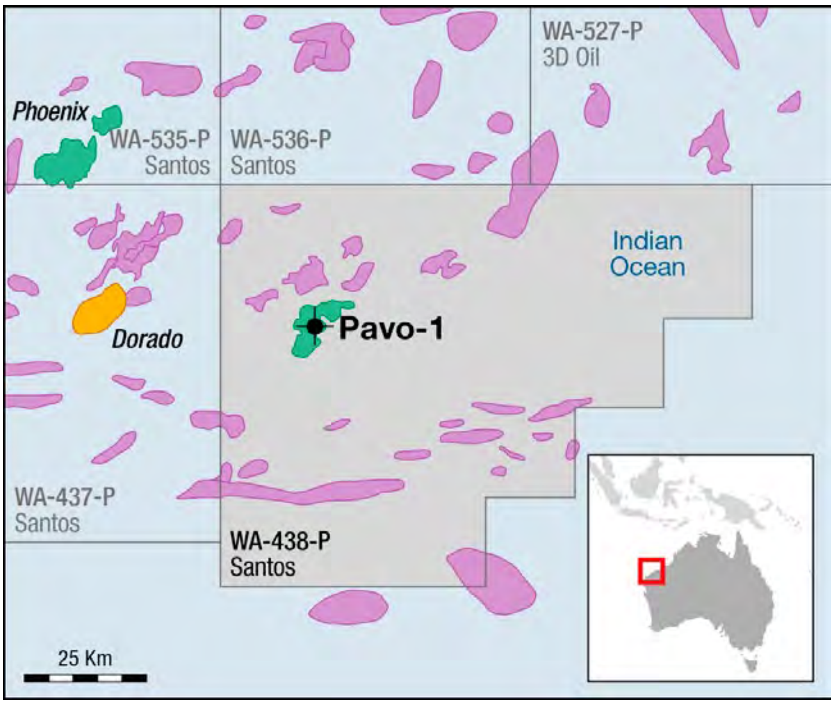
TRICON 5, 2022, Tricon Geophysics, Inc., http://tricongeophysics.com/products-and-services/time-processing/

United States Geological Survey (USGS), 2003, Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, Professional Paper 1713,

https://pubs.usgs.gov/pp/pp1713/01/pp1713_ch01.pdf

Zoback, M. D., M. L. Zoback, V. S. Mount, J. Suppe, J. P. Eaton, J. H. Healy, D. Oppenheimer, et al., 1987, New evidence on the state of stress of the San Andreas fault system: Science, v. 238, p. 1105–1111, doi:10.1126/science.238.4830.1105.

PAVO TENTATIVELY EXTENDS THE DORADO PLAY IN WESTERN AUSTRALIA



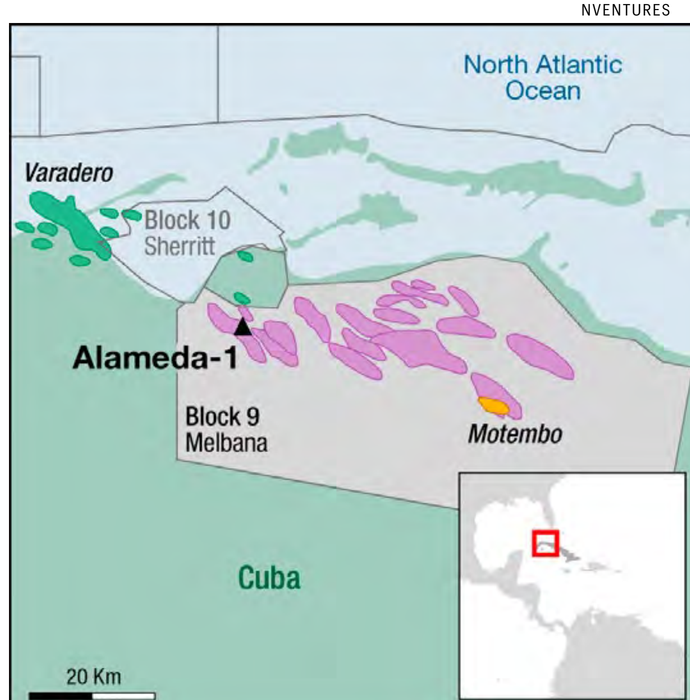
NVENTURES

Santos (with partner Carnarvon Energy) recently announced the offshore Pavo-1 well as a significant oil discovery. The well, which was drilled on the northern culmination of the Pavo structure, is 46 km east of the Dorado field in the Bedout Sub-basin, Western Australia. Drilled between February and March 2022 in Licence WA-438-P to 4,235m TD, the well encountered 46m of net oil pay in the Lower Triassic primary Caley member reservoir target. Reservoir and prospect geometry are very similar to Dorado, improving chances for several prospects in the Bedout basin. Excellent reservoir quality is interpreted from logs with 19% average porosity, permeabilities in the 100–1,000 mD range and hydrocarbon saturations averaging 80%, similar to those encountered in the Dorado field. The crude is a light, sweet oil (~52 degrees API) with a low gas–oil ratio. A 2C contingent resource for the northern culmination is assessed at 43 MMbo gross, with an estimated 55 MMbo gross in the Pavo South structure (yet to be drilled). Unfortunately, the following well, Apus-1, in a similar play, disappointed. Although reservoir qualities were good, the prospect may have failed due to insufficient charge, or seal failure in the structure.

INTERNATIONAL JV REPORTS SUCCESSFUL OIL WELL ONSHORE CUBA

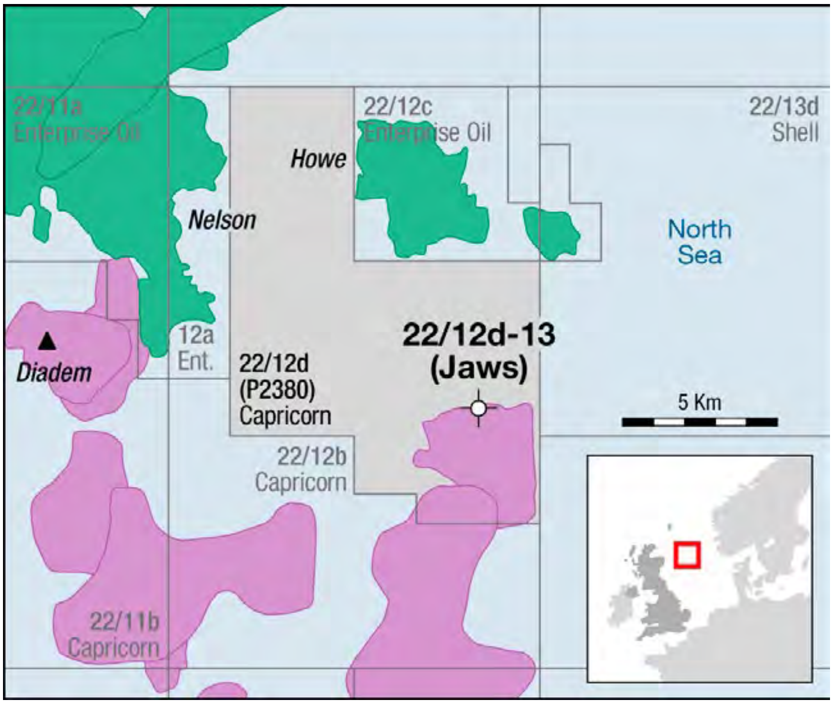
A joint venture between Melbana Energy of Australia (operator) and Sonangol, the state oil company of Angola, have met with early success on Block 9 onshore northern Cuba, with an oil discovery at Alameda-1. The well was drilled between September 2021 and March 2022, reaching a TD of 3,916m. Good oil shows were encountered over 300m, and the well was TD'd early after one or more kicks, resulting in well control and 'safe containment' of the well. Testing has been delayed for now, while the group drill their second well in the campaign, Zapato-1. Block 9 is very large, over 2,300 sq km, with good follow-on potential albeit in a high-pressure thrusted basin. Alameda itself targeted 161 MMbo mean unrisked reserves, pre-drill, over three thrusted fault blocks. Logging results suggest net pay within the Marti, Amistad and Alameda structures. Nearby Zapato-1 will target 114 MMbo mean unrisked reserves. Melbana was awarded the block in 2015, with the Santa Cruz Block, and Sonangol entered in 2020. Ascent Resources will be following the news here, having options on onshore blocks nearby.

NVENTURES



Ian Blakeley
ian.blakeley@nventures.co.uk

DRY WELL AT JAWS, UK QUAD 22



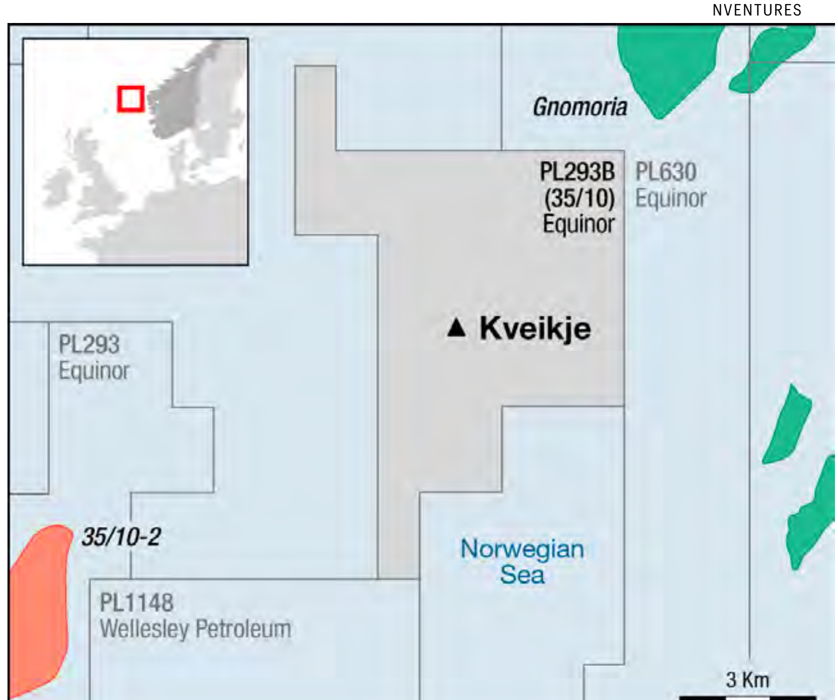
NVENTURES

Shell and Capricorn (50/50 co-venturers) have reported a dry well at 22/12d-13, called the Jaws prospect. The well was spudded on UK North Sea Licence P2380 in November 2021 and reached TD in late January 2022, after encountering 31m of fair to good quality Jurassic reservoir sandstones, but these were water-bearing. The well will be permanently plugged and abandoned. Preparations continue to drill on the Diadem prospect in the neighbouring P2379 licence area (Capricorn 50% WI, operator), with an expected spud in Q2 2022. The prospect was mapped as a rotated fault block with three-way dip closure. It has a significant seabed expression; this and the onlapping nature of the shallower sediments of the high indicate that this may be recently active and the structure has undergone recent deformation. Jaws and Diadem lie between the main Forties Montrose Paleogene trend but target the Upper Jurassic Fulmar Sandstone in the interpod play on the Forties Montrose High. In 2020, Shell and Capricorn swapped 50% interest in Permits 2380 and 2379, hoping to target 'high NPV' barrels with rapid tie-back in the Nelson area.

DRUM ROLL TO SUCCESS AT KVEIKJE

Equinor (51%, operator) has reported a significant oil discovery at well 35/10-8, the Kveikje prospect, on Licence PL293B. DNO are partners with 29%, Idemitsu 10% and Longboat 10%. A preliminary estimate of recoverable resources in Kveikje Main, being the primary target of the exploration well, is 28 to 48 MMboe (gross), above the pre-drill expectation. The discovery has excellent reservoir quality and is close to existing infrastructure allowing for a simple development through multiple export options, possibly to Troll B nearby. The primary target was the Eocene Hordaland Formation, a sand injectite at this location. The top of the main reservoir was reached at 1,757m TVD with 18.4m of net sand in a 24m oil-filled gross interval with porosities in the order of 30%. A shallower interval has 2.7m net sand reservoir, while deeper targets Rokke and N'Roll both encountered indications of sand with hydrocarbons with further analysis required to determine potential.

NVENTURES



THE GEOLOGIST'S HAMMER

The most emblematic geologist's tool.


SHUTTERSTOCK

Of all the equipment hauled around the field by geologists, the geological hammer must be the most essential and emblematic. From the cheaper, wooden-handled tools bought by most undergraduates to the special edition, drop forged Estwings, they all, over time, develop their own personalities and patinas.

Iain Brown

Few of us today are fortunate enough to have had careers as field geologists (see *GEO ExPro* Vol. 19, No. 1, page 72), but almost all geologists will have undertaken fieldwork and mapping as a key part of their training and will know that hammers are a necessity. Specially manufactured for breaking or picking at rock in a variety of ways, whether using the hammer to expose fresh rock surfaces or to extract samples for further analysis, they are of critical importance to the geologist.

All geological hammers come with at least one flat face which is primarily for breaking rock where less accuracy is required or to break down larger pieces into smaller fragments. Most modern hammers will also have a pointed tip or pick at one end for more accurate, delicate work or extraction of crystals, clasts, or fossils. A chisel end comes in handy when prying apart layers.

Hammers vary in two key respects: the head, and the forging. The head's weight is an important consideration – 16 oz (453g) is suitable for almost all every-day use but someone with an interest in metamorphic rocks, or minerals, may prefer a larger head. Casual users may favour something lighter, though these are increasingly hard to source. Light hammers will suffice for most sediments and are therefore handy for fossil hunters – but will be less effective when confronted with a granite or marble.


SHUTTERSTOCK

Long-shafted hammers used for heavier work.


SHUTTERSTOCK

Lightweight hammer – ideal for more delicate fossil extraction.

The Forging is Key

The crème de la crème is a one-piece drop forged hammer, such as those manufactured by Estwing. These are made of one piece of metal and less prone to fracturing!

A solid or tubular shaft hammer comprises a separate handle and head, joined together – this joint provides a point of weakness which may eventually fail. Most hammers should last for a long time before this becomes an issue, but as failure is often unpredictable, it may cause a hazard. A tubular shaft is hollow, and thus lighter, and it also allows the hammer to be better weighted; a solid shaft is more durable.

A wooden-shaft hammer has the shortest life, even if extreme care is taken when hammering, since the wood always tends to strike rock at some point, causing the handle to wear and splinter. However, you can at least see when the time is coming to replace the implement!

The length of the handle is a consideration for some – extra-long handles being available, allowing a more powerful blow, and greater distance to be maintained from the rock – protecting the user from rock 'shrapnel'. This leads me nicely to the safety warning. To avoid the danger of fragments of rock hitting you in the eyes, it's advisable to always wear goggles when hammering – especially when hitting harder rocks. As always, common sense should always prevail!

Pride and Joy

I am the lucky owner of an Estwing special edition E30SE, given to me as a birthday present by my wife after she had clearly become fed up with me bemoaning the fate of my old student hammer (left on a coach on an Easter field trip to Spain in 1982!). This relative newcomer is a 22 oz (624g) 'head and pick' hammer forged from a single piece of steel, designed to reduce impact shock and limit the risk of breakage. It has a lovely lacquered, bound leather grip and I am ashamed to admit, has so far only been used for fossil hunting on the Jurassic Coast of southern England. It does, however, take centre stage in my office and reminds me that the best geologists are the ones that have seen (and chipped away at) the most rocks.


IAIN BROWN

Estwing special edition E30SE.

KEEPING DISRUPTION AT BAY

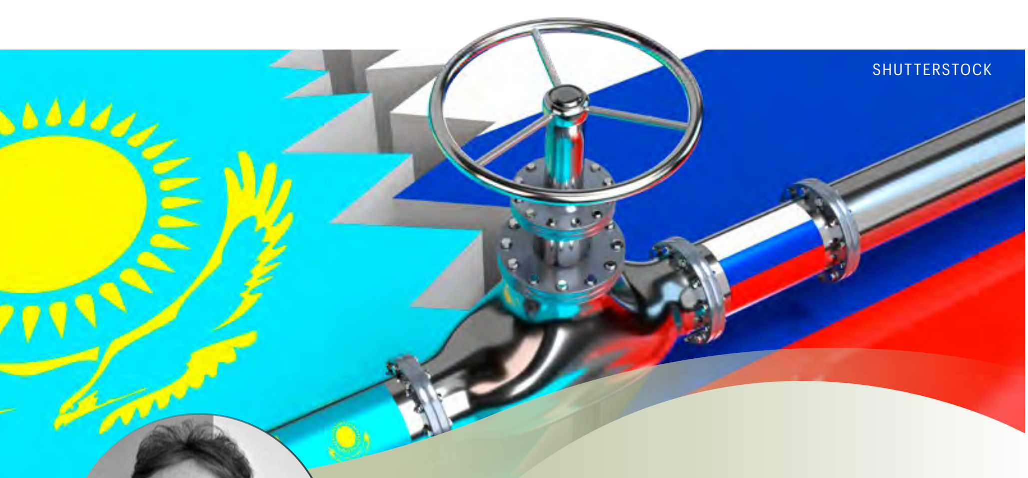
Vagit Alekperov is worried about investment in the oil and gas sector. At a time when his country is waging war in Ukraine, the president of Lukoil, Russia's leading privately held oil and gas producer, has highlighted the lack of funding for "greenfield and exploration projects to identify new reserves".

As the tanks roll and large parts of the world put Covid restrictions on the back burner, Alekperov warns that there is a risk of global oil and gas supply shortages in just five years if the current trend of limiting industry investment persists. Even if wind and solar account for 40% of global energy consumption by 2050, he notes, the lack of sufficient available capital for oil and gas projects will see supply struggling to meet demand.

Lukoil, like other Russian companies might well be feeling the pinch on investment at the moment – or at least be worried about the response to its next foray into the market. The pinch for Germany and other EU countries is just as urgent: where do we find alternative, non-Russian supplies of gas. Two different sides of a fossil fuel conundrum in a convoluted, disrupted energy market.

Here's another example. The authorities in Kazakhstan plan to sell exploration and production licences for a record number of blocks across the country. The target for an offering amounting to 60 blocks in total, say the Kazakh authorities, is international investment which it is claimed will be more suited to the large acreages involved. One caveat to this enthusiastic flash of foreign credit cards: the country relies on Russia to transit its energy exports. Any perception that the tankers might not be able to dock when supplies start flowing (for whatever reason) might just unsettle those potential investors.

For his part, Vagit Alekperov makes a case for oil and gas in the face of transition, not sanctions. The world wants more renewable energy but not quite yet, he argues, and in the short term no-one wants the fossil fuel tap turned off too quickly for whatever reason. If indeed Europe ramps up sanctions on Russia, Lukoil will take comfort in continuing demand from the likes of China and India. Recovery for the company in 2021 was strongest for its acreage outside Russia, especially Uzbekistan, where output jumped by 40% due to stronger demand from - you've guessed it - China.



SHUTTERSTOCK

Nick Cottam
nick@nickcottam.com

Finally news from the US that the Biden administration is reversing its decision to suspend new licences for oil and gas drilling on public land. Vagit Alekperov would surely approve.

CONVERSION FACTORS

Crude oil
1 m³ = 6.29 barrels
1 barrel = 0.159 m³
1 tonne = 7.49 barrels

Natural gas
1 m³ = 35.3 ft³
1 ft³ = 0.028 m³

Energy
1000 m³ gas = 1 m³ o.e.
1 tonne NGL = 1.9 m³ o.e.

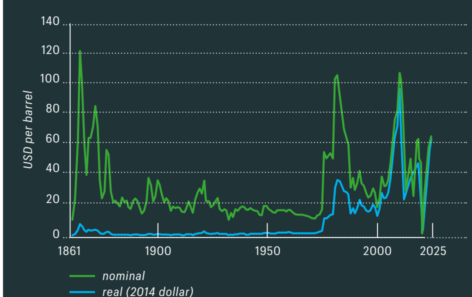
Numbers
Million = 1 x 106
Billion = 1 x 109
Trillion = 1 x 1012

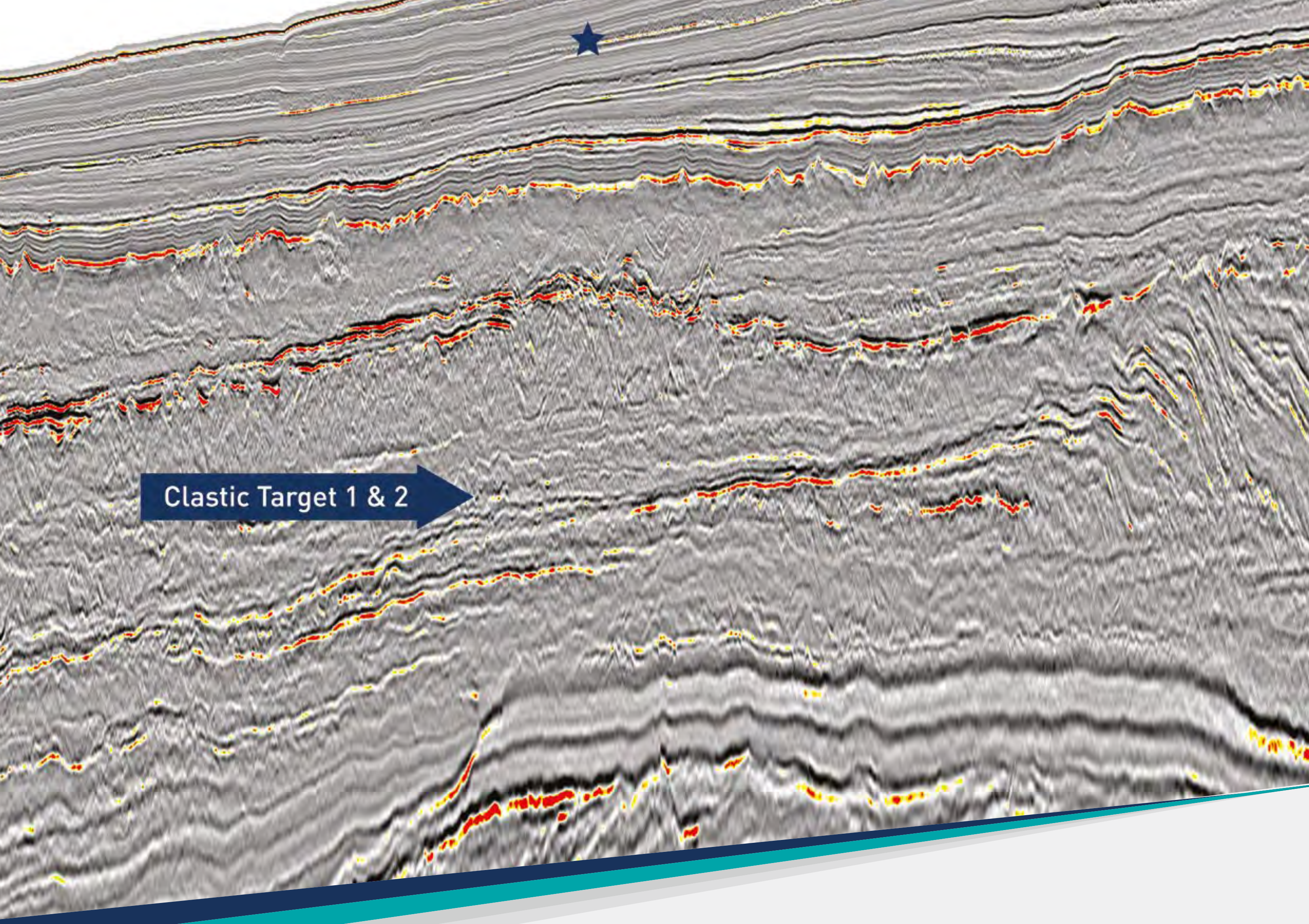
Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm³) of oil equivalents

Giant field
Recoverable reserves > 500 million barrels (80 million Sm³) of oil equivalents

Major field
Recoverable reserves > 100 million barrels (16 million Sm³) of oil equivalents

Historic oil price
Crude Oil Prices Since 1861




Clastic Target 1 & 2