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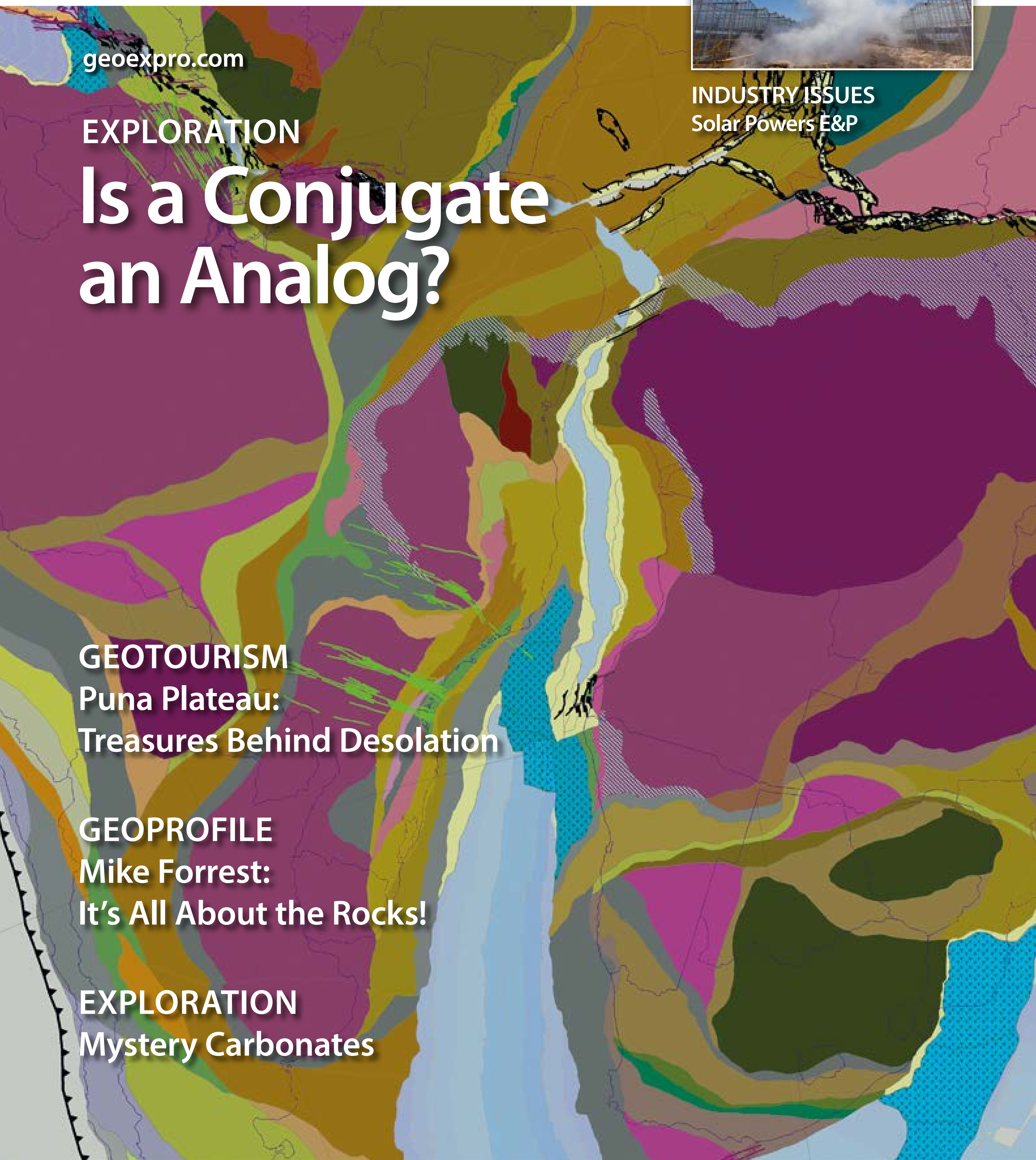

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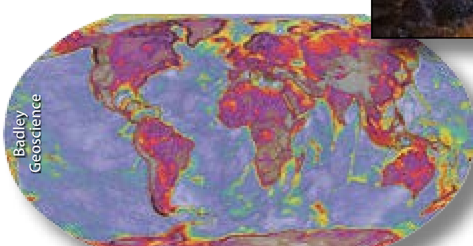

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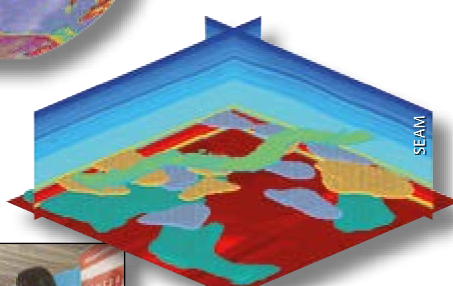

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This edition of *GEO ExPro* focuses on South America and the South Atlantic Margin; Deepwater Exploration; Geophysics; and Alternative Energy

Competitors or Collaborators?

Over the past couple of years, one subject has been gaining increasing prominence among discussion topics at O&G industry meetings: the energy transition. Along with increasing population comes greater demand for energy and the higher quality of life it brings, but at the same time there is a strong shift towards a low carbon future. Solving this dilemma is something that the exploration industry needs to be part of.

Ole Jørgen Bratland/Equinor

Dudgeon wind farm in the North Sea is operated by a subsidiary of Equinor.

Renewables are scaling up fast. According to SolarPower Europe, preliminary global solar installations reached 98.9GW in 2017, a 29.3% increase over the previous year, while module costs are forecast to drop by 40% by 2020. Similar reductions in costs and increase in uptake have been seen in wind power and other renewables. However, as discussed in our Global Resource Management column, this cannot supply anything like the energy we will require; all the forecasts point to a need for hydrocarbons for some time to come. But, as Bob Dudley of BP said recently, "To deliver significantly lower emissions, every type of energy needs to be cleaner and better. A race to renewables will not be enough."

Companies from across the energy sector – whether hydrocarbon-based, traditional non-fossil fuel energy providers like hydroelectric, or the fast-growing new renewables – need to be involved in pushing forward the agenda of a sustainable low carbon energy future. The energy transition has now been understood, and in many cases embraced, by the energy establishment. Data and digitalization have meant that traditional models of business are changing, and multiple business sectors are now working together – take the example of the heavy oil fields in Oman where solar energy is providing the steam required for steam-assisted gravity drainage, as we describe in this issue. Competitors can become collaborators in the move towards transition and convergence in the energy industry.

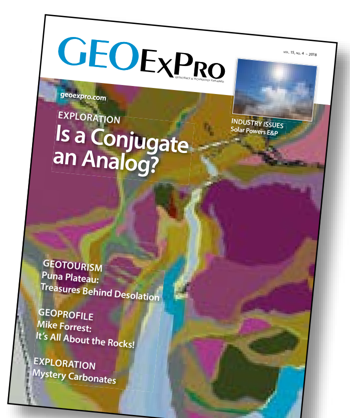
The energy transition is a chance for companies in the oil and gas industry to look at the opportunities that their technologies and expertise offer, embrace change and ensure they are part of the future. ■

Jane Whaley
Editor in Chief

IS A CONJUGATE AN ANALOG?

This End-Aptian reconstruction of the South Atlantic shows the late stages of two competing rift branches in the South Atlantic: a southern branch tipping out west of the Sao Paolo Plateau, and an isolated, salty northern branch between Angola and Gabon. Paleogeographic mapping can be used to attempt to transfer plays and prospects from one conjugate margin to another.

Inset: Vast glasshouses protect the mirrors harnessing the sun's energy to heat water and create steam to help extract heavy oil at the Amal field in Oman.



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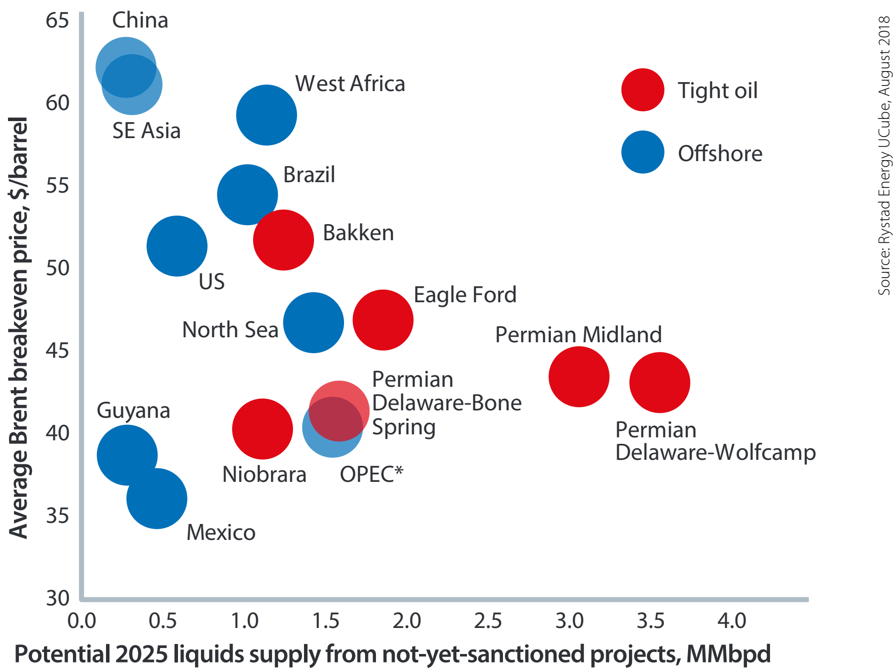
Offshore vs. Tight Oil

Breakeven prices are similar, but tight oil has the largest growth potential.

With the recovery in oil prices and improved free cash flow for E&P companies, Rystad Energy sees a new investment cycle on the horizon. As oil companies start to increase activity again, the question becomes clear: which source of supply will attract most investments and have the strongest production growth?

The chart below shows the average breakeven price for new projects and the total potential liquids production in 2025 for projects for offshore and tight oil that have yet to be sanctioned.



*Average breakeven prices and potential 2025 liquid supply for different offshore and tight oil regions. *Excludes projects in West Africa.*

Wolfcamp in the Permian Delaware is the supply source that has the largest production coming from not-yet-sanctioned projects. Rystad Energy foresees that this formation could add 3.5 MMbpd in 2025 from wells not yet drilled. Offshore Mexico is the source with the lowest breakeven price at an average of ~US$35 per barrel. The projects yet to be sanctioned could add about 0.5 MMbpd by 2025.

Offshore projects in China and South East Asia have, on average, higher breakevens than other offshore regions. Two reasons for this are the tough fiscal regimes in this region, and the fact that the undeveloped discoveries are small.

From the chart we can see that the breakeven prices for tight oil and offshore projects are in the same ball park, at ~US$40–50 per barrel. However, we can observe that in terms of production, tight oil has the largest potential. Wolfcamp in Delaware has more than twice the production potential from not-yet-sanctioned projects in comparison to offshore OPEC.

Another reason for E&P companies to prefer tight oil compared to offshore is the short payback time. Normally, a company can recover its tight oil investments in two to three years, but for investments in new offshore projects the payback time is much longer, normally seven to ten years.

The combination of large growth potential and short payback time has made tight oil a very competitive source of new production. Rystad Energy expects tight oil investments to grow at a yearly rate of ~20% over the next few years. With this growth rate, total investments in tight oil are expected to be at almost the same level as offshore investments in 2019. ■

Espen Erlingsen, Head of Upstream Research, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

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

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

Gas

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

Ma: Million years ago

LNG

Liquified Natural Gas (LNG) is natural gas (primarily methane) cooled to a temperature of approximately -260 °C.

NGL

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

Reserves and resources

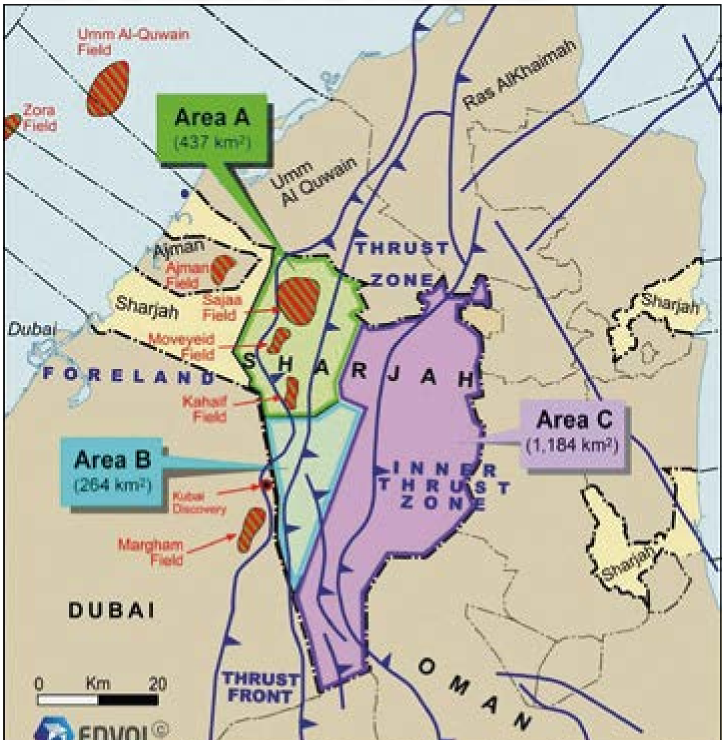
P1 reserves:
Quantity of hydrocarbons believed recoverable with a 90% probability

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

Sharjah:
1st Onshore Round



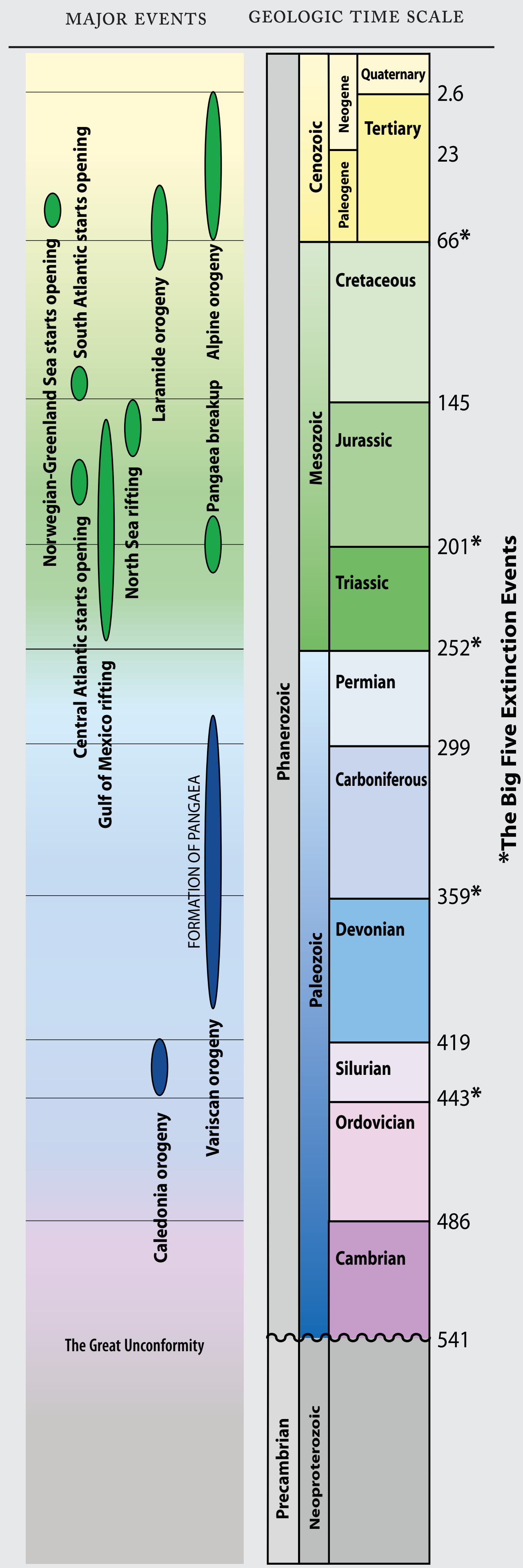
Location of Sharjah Licence Round Concessions

Sharjah's first onshore licensing round opened in late June, offering companies 30-year contracts with a 10-year extension. These cover three concession areas (A, B and C) located in the producing Thrust Zone play trend, including an un-appraised deeper gas discovery below the Sajaa gas-condensate field (Area A). The Emirate's national oil company, SNOC, is currently preparing to drill a well in Area B as operator and is also offering participation in this project. Area A comprises 437 km^2, Area B, 264 km^2 and Area C 1,184 km^2.

Over 5 Tcfg has been proven in existing fields, where production history demonstrates a recovery factor of 90% from naturally fractured carbonates in the Cretaceous Thamama Formation. There is evidence of hydrocarbons in lower horizons and also in shallower Tertiary reservoirs. Newly acquired extensive 3D seismic (shot in 2016 and fully processed in 2017 and early 2018), significantly improved the imaging of the fold thrust belt and early indications are emerging of potentially large, undrilled leads and prospects and untested plays. Interpretation of the seismic is ongoing and volumetric assessments will be made available in the data room, along with well and related data.

Nearby SNOC field infrastructure, gas-condensate processing and export facilities mean that suitable field discoveries can be tied into the existing plants, with SNOC offering to purchase the hydrocarbons. New fiscal terms based on a 'flexible gross split' ensure even modest resources can be commercialized and also generate good returns on larger accumulations.

Bidding closes on November 18 and contracts will be effective from January 2019. ■



OBN : A New Wave in Seismic

Currently, **ocean bottom nodal (OBN)** seismic seems to be riding something of a wave of success in a seismic acquisition market that, contrarily, has been hard hit over recent years. The encroachment of ocean bottom (OB) acquisition on the traditional marine streamer market was highlighted in 2017 when it was reported that there were more vessels deployed on seafloor or OB surveys than marine streamer ones.

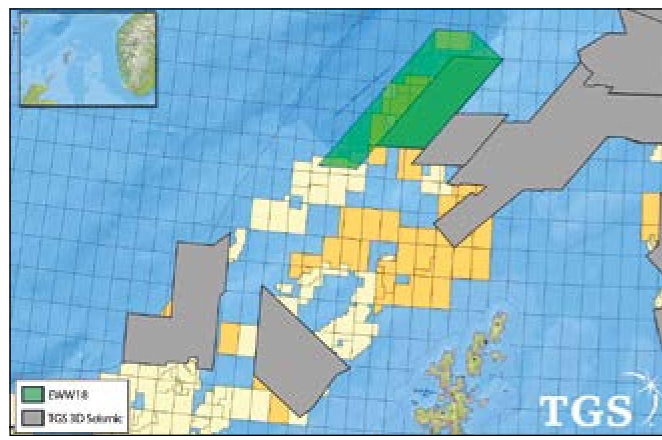
An AGS workboat heading out to the seismic survey vessel.

New companies, like **Axxis Geo Solutions AS**, have been able to form and enter the market even during this downturn, while more traditional marine streamer stalwarts appear to be struggling. Driven by decreasing relative cost to marine streamer and increased oil recovery focus, financial analysts and industry experts are expecting the OBS market to deliver an annual turnover of around US$1 bn in 2018. Further growth expectations suggest annual turnover as high as US$2 bn in 2021 as this unique, scalable and efficient solution for E&P needs develops further. ■

New Multi-Client Project WoS

In early August **TGS** commenced acquisition of a new multi-client **3D survey** on an area about 100 km north-west of the **Shetland Islands**. Known as **Erlend Wild West**, this survey will cover a minimum of 1,000 km². TGS will harness its acquisition and broadband processing expertise in this region, using its Clari-Fi™ broadband technology to deliver high fidelity imaging of the subsurface.

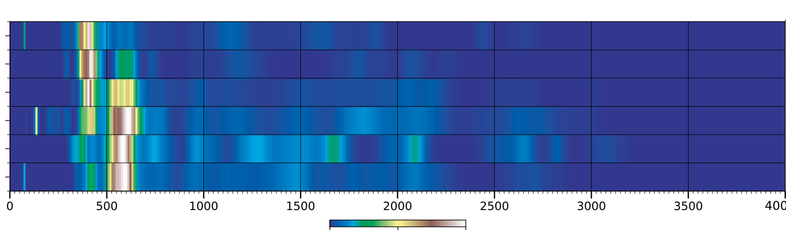
Erland Wild West ties into TGS' existing EW12 3D data, shot in 2012 over 1,580 km² in Quads 208 and 217 of the Faroe Shetland Basin. This was the industry's first 3D survey in this northern area. The new survey will expand TGS' data coverage in this important part of the UK offshore, which includes both open acreage and existing discoveries where high potential prospects have been identified. The new data is highly relevant for exploration in the recently awarded acreage of the UK 30th Offshore Licensing Round. ■

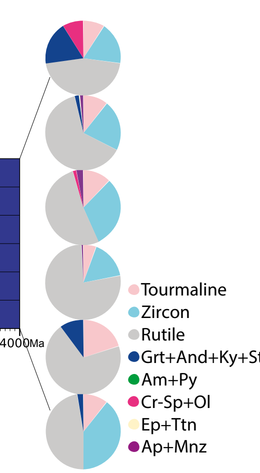


Database for Grand Banks

The sedimentary succession of the **Grand Banks**, offshore **eastern Canada**, is the subject of increasing exploration investment and drilling campaigns, with discoveries in the Flemish Pass and Jeanne d'Arc Basins. However, little is published on the complex sediment provenance of the region, its impact on reservoir quality and on gross depositional environment models. To address these major exploration challenges, **Chemostrat** has created an unrivalled **provenance database** consisting of results of detrital zircon U-Pb geochronology and Raman-heavy mineral analyses performed on samples from different basins of the Grand Banks, including the Orphan Basin, part of upcoming licensing rounds.

Results indicate provenance from multiple terranes, including ultramafic and mafic rocks of the Humber Zone of Newfoundland, and reveal local occurrence of zircon grains compatible either with provenance from Iberia or with recycling of sediment ultimately derived from there. Different basins are interpreted to have different provenance histories and both lateral and stratigraphic provenance changes have been recognized within the sedimentary succession of each basin. ■





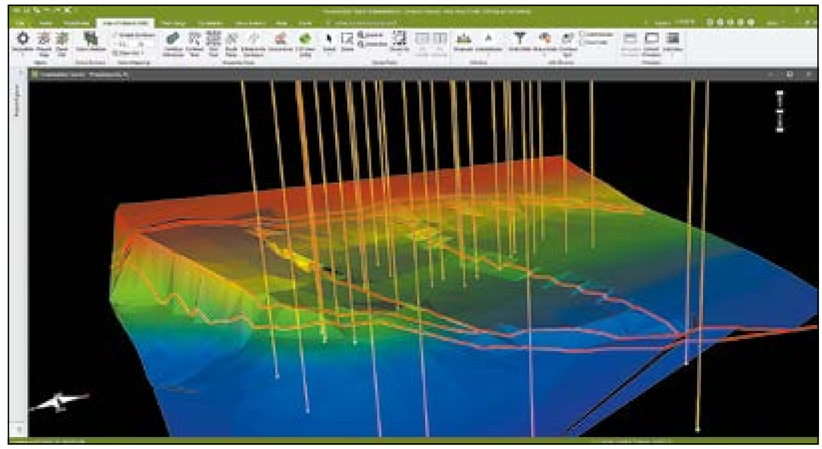
Stratigraphic changes in the provenance of the sandstones in a Grand Banks well shown by heavy mineral assemblages (pie-charts) and zircon U-Pb age populations (heat-map).

NeuraSection Redesigned

For over 25 years **Neuralog** has provided low-cost solutions to capture, organize, and analyze oil and gas data, offering products like the world's only purpose-built well log scanner, plus well log printers, industry-standard automated well log and map digitizing software, and a GIS-based data access and visualization application that seamlessly pulls it all together.

NeuraSection is the only geological interpretation system available with the image quality to truly support raster and digital well log correlation, cross-section creation and analysis. Geoscientists learn from books, of course, but also through pictures, models and diagrams. Over the last year NeuraSection has been redesigned to be more visually intuitive by reducing menu levels, integrating touch screen technology, and prominently placing features to help customers better identify what they are working on. The new graphical interface has been customized so users can create personalized workflows, while the Project Explorer makes it easier to switch between and visualize information across projects without the tediousness of swapping back and forth.

NeuraSection perfectly complements the software and hardware options from Neuralog without stressing the budget. ■



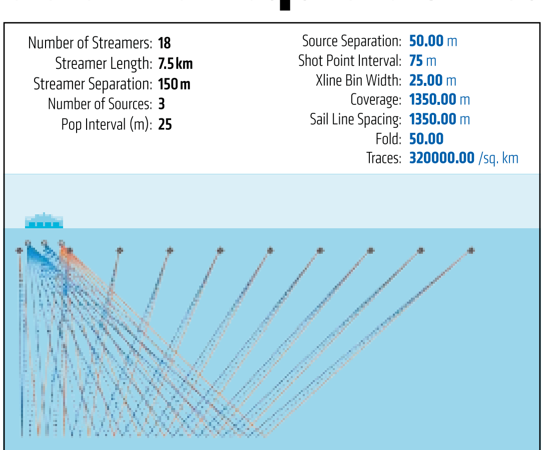
INOVA: Highly Productive Survey

INOVA's Quantum nodal system was recently successfully deployed on a seismic survey in the **Middle East**. The objective was to stress test the performance of Quantum operation on a **high density, high productivity vibroseis survey** in a desert environment, as well as to confirm the system would not constrain source effort, enabling a next level of productivity.

The project area was 82 km^2, with 178 receiver stations and 3,188 vibe points per km^2. Total vibe points were 260,674 and the crew maintained an average source production rate of 37,239 vibe points per day. Quantum's lightweight and extended runtime enabled the field crew to efficiently roll as many as 1,376 nodes to the front of the spread each day, staying ahead of source production and avoiding any impact on the pace of operation. Quantum node management was accomplished using six small pickup trucks, each with a three-person crew. Data download and transcription utilized INOVA's iX1 software and hardware with one operator and three equipment handlers.

The survey demonstrated the operational efficiency of both Quantum and iX1 and the crew achieved a daily production maximum of 52,444 vibe points in a single 24-hour period. ■

Seismic Acquisition Calculator



Tailoring acquisition geometries makes it easier to solve imaging challenges. From single sail line to full-azimuth coverage, illumination and data quality increase with the amount and diversity of data acquired, but that must be balanced by project economics. How can you quickly work out the optimal configuration?

With this in mind, seismic company **PGS** has developed a simple to use interactive acquisition calculator that allows you to quickly tailor the acquisition geometry to figure out the compromises in efficiency versus sampling. By adjusting the input parameters using the slider options on the new **PGS online calculator** you can find that elusive **optimal configuration** to solve your imaging challenge. You can quickly calculate illumination with various streamer and source configurations and thus **tailor the acquisition geometry** to suit each individual project. Check out the calculator on the PGS website. ■

Is a Conjugate an Analog?

Since the discovery of Tupi in Brazil and Jubilee in Ghana in the mid-2000s, the search has been on to prove that discoveries on one side of the Atlantic can be mirrored across the ocean. But is a conjugate an analog?

EDWIGE ZANELLA, HELEN DORAN and JAMIE COLLARD, Westwood Global Energy Group

Figure 1: Map of the South Atlantic, late Albian, 101.3 Ma.

The discoveries of Tupi and Jubilee heralded a decade of 'conjugate chasing', covering 15 basins in the deep waters of the Equatorial and South Atlantic. If we compare the results of this exploration campaign in conjugate basins across the area, can we answer the crucial question: 'if a margin is conjugate is it therefore an analog?'

A Decade of Conjugate Exploration

Exploration of the Cretaceous plays in the deepwater equatorial and southern Atlantic can be traced back to pre- and post-salt discoveries made in the late '90s in the Kwanza and Rio Muni Basins, located in Angola and Equatorial Guinea respectively. The finds that kicked off a decade of intense exploration, however, were undoubtedly Tupi, the Early Cretaceous pre-salt carbonate discovery in the Brazilian Santos Basin in 2006, and the Jubilee discovery, which opened the Late Cretaceous turbidite play in the Tano Basin in Ghana in 2007.

In the four years following the play-opening Jubilee discovery, 1.5 Bboe (70% of the total volume to-date) was discovered in a series of commercial discoveries, including the Tweneboa, Enyenra and Ntomme (TEN) cluster of fields and the Sankofa-Gye Nyame fields. The Tano Basin was emerging as a significant petroleum province. By the end of 2011, four more wells had been drilled further along the West African Margin in the Sierra Leone-Liberia Basin, resulting in three non-commercial discoveries. The first test on its conjugate margin in the Foz do Amazonas Basin was also a discovery at Zaedyus, which initially looked promising, but turned out to be non-commercial after appraisal. These disappointing results were an early indication that commercial success outside the core Tano fairway was not a given.

A breakthrough for the Late Cretaceous turbidite play came with the play-opening Barra discovery in 2011 in the Brazilian Sergipe-Alagoas Basin.

Meanwhile, by the end of 2011 the pre-salt carbonate play had emerged as a major petroleum province with significant discoveries in both the Campos and Santos Basins. The drilling of 41 exploration wells had resulted in 19 commercial discoveries with a total 28 Bboe of resources (Figure 2) – 90% of the total volumes discovered to date in the play on the Brazilian margin.

In 2012 the attention moved from the Campos to its African conjugate off Angola, with the Cameia discovery opening the deepwater pre-salt play in the Kwanza Basin. Cameia was followed by a further 23 exploration wells in the basin and the discovery of 2.6 Bboe of resources but with a lot more gas than had been expected. Meanwhile, the early successes of the turbidite play in the Tano and Sergipe-Alagoas Basins were not repeated in other basins along the margins. In fact, between 2013 and 2017, 40 exploration wells were drilled in the turbidite plays on both sides of the Equatorial and South Atlantic at a cost of $3.5 bn, but delivered only one commercial discovery in the Tano and one in the Sergipe-Alagoas. The play concept was proven successful further west in South America at Liza in the Surinam-Guyana Basin – but that has its conjugate in North America rather than Africa (see Figure 1).

Some conjugates show some symmetry in exploration performance (Figure 3). Both the Foz do Amazonas and Sierra Leone-Liberia Basins, for example, delivered modest-sized, sub-commercial discoveries. The Campos and Kwanza Basins both have a working pre-salt petroleum system, but the Kwanza contains a lot more gas. Successes in the African Tano and South American Santos Basins were not replicated in the Barreirinhas and Namibe Basins, their respective conjugates. The conjugate of the Sergipe-Alagoas in Equatorial Guinea and North Gabon has not yet fully been tested.

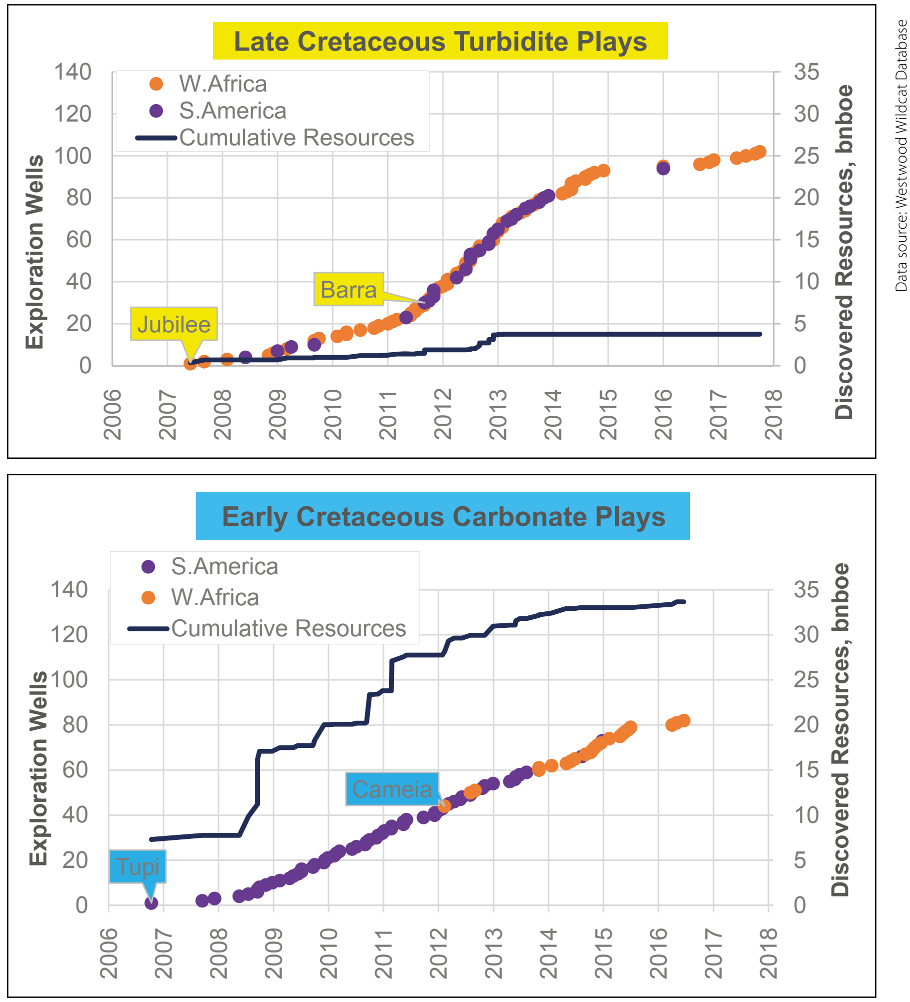


Figure 2: Cumulative exploration wells and commercial resources for the Late Cretaceous turbidite and pre-salt carbonate plays of the Equatorial and South Atlantic.

Why the Asymmetrical Performance?

What are the geological factors driving the asymmetry? To determine these, we need to look in more detail at some of these conjugate margins.

Santos-Namibe conjugates: In total, 26 Bboe have been discovered in the pre-salt carbonate play of the deep water Santos Basin. In contrast, whilst Early Aptian pre-salt carbonates are exposed onshore in the Namibe Basin, the pre-salt play has not been proven offshore there.

The asymmetric rift and breakup dictated the geometry of the basins, creating an asymmetrical play across the conjugates. The Santos Basin is one of the widest basins in the South Atlantic, characterized by a very broad zone of stretched and thinned continental crust. Success in the Santos has been focused around a large, broad topographical feature called the 'Outer High' (Gomes et al., 2009). Its size and position in the basin is the primary control on the scale of the play in Santos, optimal for development of thick carbonate reservoirs and acting as a focus for hydrocarbon migration. In contrast, the Angola-Namibia margin is much narrower and a feature of the scale of the Outer High is simply not present within the Namibe Basin.

Campos-Kwanza conjugates: Moving further north in the South Atlantic, some symmetry can be observed between the Campos and Kwanza Basins. Reservoir quality rocks are deposited on both margins and the traps have comparable size distribution, as shown on the probability of exceedance curves for the two basins, both of which have a P50 of around 260–280 MMboe (Figure 4).

A major difference between the two margins is the nature of the hydrocarbons found. About 80% of the 5.2 Bboe discovered to date in the Campos is oil, while half of the Kwanza Basin's 2.6 Bboe is gas. This asymmetry is believed to be a result of the maturation history, with evidence of variations in heat flow between the two basins. The Angola discoveries are located in an area where the crust is thinned and the rise of the asthenosphere during rifting introduced a high heat flux. The

S. America Conjugate	Performance Symmetry	W. Africa Conjugate
Foz do Amazonas	Some	Sierra Leone - Liberia
Barreirinhas	No	Tano
Sergipe-Alagoas	Not known	Rio-Muni/North Gabon
Campos	Some	Kwanza
Santos	No	Namibe

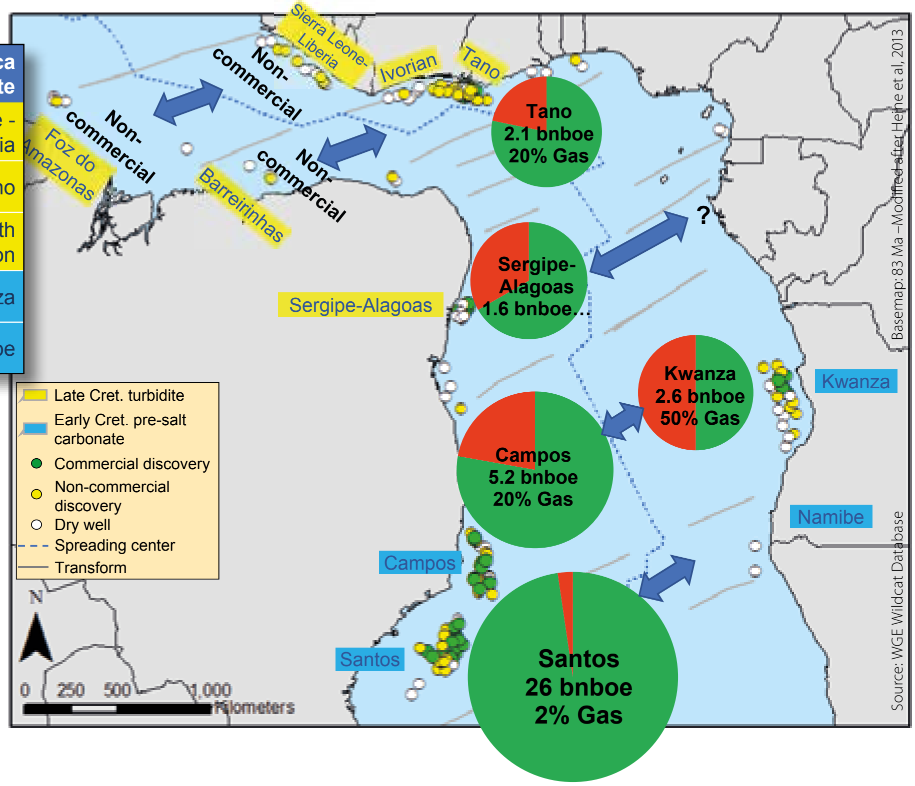


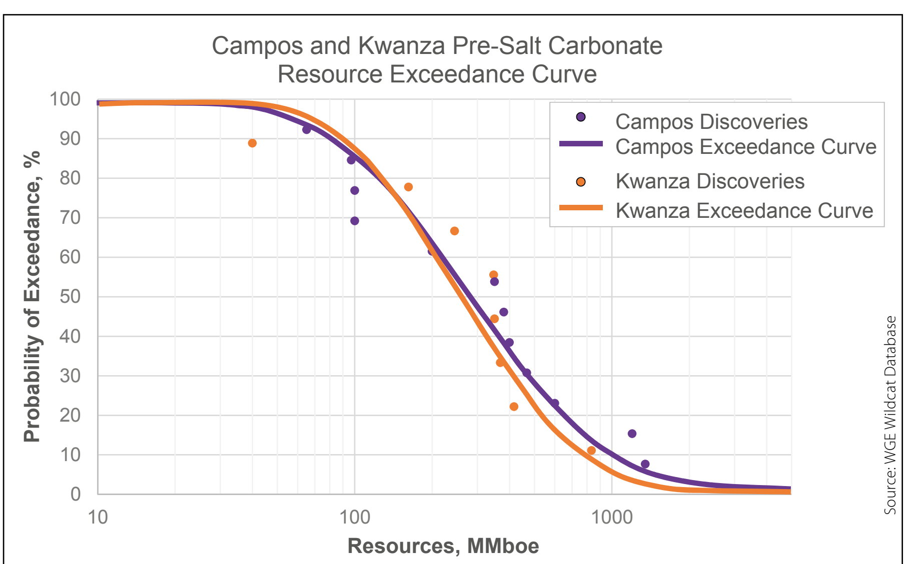
***Figure 3:** Map showing the commercial volume discovered in the basins; (inset) a table describing the symmetry – or lack of it – in exploration performance across conjugate basins.*

syn-rift heat spike was responsible for early maturity of the pre-salt oil-prone source rock. Geochemical modeling, based on Cameia-1 well data, indicates that source rocks located in the pre-salt section have been generating and expelling hydrocarbons since at least 120 million years before present (Cazier, 2014). A Late Cretaceous post-rift volcanic event added additional heat flux, possibly cracking oil present in reservoirs to gas and adding CO_2 to many of the accumulations in the Benguela sub-basin (Baudino, et al., 2018).

Barreirinhas-Tano conjugates: There is a distinct asymmetry in the performance of the Late Cretaceous turbidite plays in the Barreirinhas and Tano conjugates. Between 2007 and 2017, just three wells were drilled in the Barreirinhas, which has delivered only non-commercial gas, whilst 42 were drilled in the Tano resulting in the discovery of 2.1 Bboe of commercial hydrocarbons, 80% of which is oil.

The primary cause of the asymmetry between these conjugates can be attributed to post-rift evolution. A thick Tertiary overburden is present in the Barreirinhas Basin due to the uplift of the Andes in the Miocene. The high volumes of Tertiary sediments deposited into the basin pushed the source rocks deeper into the gas window and also caused extensive gravitational collapse, which has implications on timing of trap formation and preservation. By contrast, in West Africa the Tertiary rivers were diverted away from the Tano area, ultimately creating the Volta and Niger rivers.

***Figure 4:** Exceedance probability curve of the Early Cretaceous pre-salt carbonate plays of the Campos and Kwanza conjugate basins. Key resource probability metrics are summarized in the associated table.*



	Resource Distribution (MMboe)				
Basin	P90	P50	Mean	P10	# Wells
Campos	80	280	460	980	12
Kwanza	90	260	380	760	8

Analogous Play Elements

From this analysis of the Cretaceous plays present in the main South Atlantic basins, it appears that for a conjugate basin to be an analog, all of the play elements must be similar, and this is clearly not the case.

Figure 5 summarizes the elements involved in the Equatorial and South Atlantic Cretaceous plays at difference stages of the rift process and why some prove to be analogs and others do not. Marine source and seal deposition, for example, are usually related to regional scale flooding events and can therefore be present on both sides of the Atlantic, although there might be variation on source quality at a local scale.

The depositional processes involved in creating carbonate and sandstone reservoir rocks are comparable, but the presence and quality are not uniform, due to both the asymmetry of the rift and the different provenance of the sediments. Maturation history, by contrast, is usually not analogous because of local variations in the thickness and composition of the crust, overburden and post-rift heat flux.

✓ Analogous on conjugate ✓ Partly analogous on conjugate X Non-analogous on conjugate

STRUCTURAL EVENT	SOURCE ROCK	SEAL	TRAP	RESERVOIR	MATURATION
Drift		✓ Regional scale events	X Trap preservation due to Tertiary deformation	✓ Deposition process similar. Provenance, presence and quality not uniform	X Variations in overburden thickness and post-rift heat flux events
Sag	✓ Regional scale events	✓ Regional scale events	✓ Trapping mechanism and trap size	✓ Deposition process similar. Provenance, presence and quality not uniform	X Variations in timing and duration
Syn-Rift	✓ Regional scale events	✓ Regional scale events	✓ Trapping mechanism	✓ Deposition process similar. Provenance, presence and quality not uniform due to rift asymmetry	X Variations in heat flux dictated by lithosphere thickness

Figure 5: Elements of the Equatorial and South Atlantic Cretaceous plays can be analogs on conjugates at different stages of the movement from rift to drift, but can also be partially analogs – or not analogs at all.

De-Risking Conjugate Plays

Major discoveries often tempt explorers into extrapolating a play from one flank of a rift into its conjugate margin. The experience in the last decade on the southern and equatorial conjugate margins shows that this must be done with extreme care.

Reconstruction of the regional tectonics and rifting history is necessary to identify the play elements that are common to both sides. Local scale basin evolution makes some play elements unique to a basin, so a conjugate analog would not be valid. Asymmetrical exploration success mirrors the asymmetry of the rift itself.

The key is to understand first what controls success in a play before extrapolating effectively from one side of a rift to its conjugate.

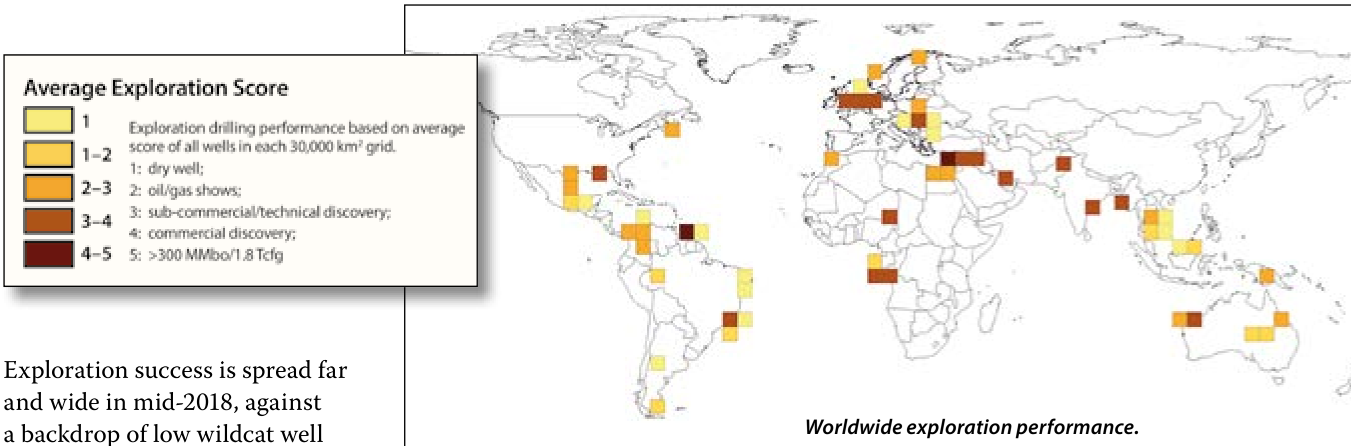
So, the answer to the original question 'is a conjugate an analog?' appears to simply be: 'rarely'.

References available online. ■

Hot Spots Around the World

How successful has 2018 been so far?

PETER ELLIOTT, NVentures



Worldwide exploration performance.

Exploration success is spread far and wide in mid-2018, against a backdrop of low wildcat well counts and mediocre success for some high profile campaigns. Success there certainly has been, however, with major reserves being added by a number of companies, from 'superminors' like Savannnah, Parex, Quadrant and Carnarvon, to the supermajors. With recent industry debate echoing 'peak oil' premonitions of the '90s, the current mood amongst the hydrocarbon eschatologists is set starkly against the inescapable trend of rising demand for oil, the local market imperative for cheap energy, and the inexorable rise of gas in the energy mix. Organic conventional reserves additions at the drill bit is therefore a welcome trend, with discoveries being notched up in Africa, South America, Asia and Australia, amongst other places.

Across the South Atlantic

In Niger AIM-listed junior Savannah Petroleum has racked up three oil discoveries on the southern edge of the Agadem Graben, with between two and five more prospects to test.

The discovery map is still predominantly littoral, however. Offshore Gabon Petronas, Woodside and Repsol have been successful in opening up the Lower Cretaceous/Barremian pre-salt clastic play, a major new trend with equal measures of challenges and rewards. Further south in Angola, Total has kick-started the first of two Kaombo FPSO developments in ultra-deepwater Block 32, which is bound to pave the way for a number of previously isolated tie-back developments in the distal Lower Congo Basin.

Across the Atlantic in similar aged rocks, the Brazilian sector is benefiting from numerous wells and developments. Equinor's Guanxuma 1 in the Santos Basin (with ExxonMobil, Galp and Barra) may contribute over 500 MMbo to its inventory.

The Upper Cretaceous still holds fascination, with high quality marine clastics providing reasonable results on the South American eastern seaboard, although the same play in the African Transform Margin failed. ExxonMobil (with Hess and CNOOC) are chasing their seventh discovery with Hammerhead, having proved up over 4 Bbo on the Starbroek block in Guyana.

Colombia continues to see high levels of activity, with almost 30 wells being drilled so far in 2018 in the Llanos and Magdalenas Basins by the likes of Geopark, Parex, Frontera and of course Ecopetrol. Likewise Trinidad and Tobago continues a long tradition of exploration and development, with BHP and Shell testing Victoria 1, while BP moves the Angelin FPSO into place.

Supermajors like Shell, Total, ExxonMobil and Equinor are teaming with YPF in the Neuquen Basin's Vaca Muerta Shale in world-class gas developments in what is by far the largest unconventional play outside North America.

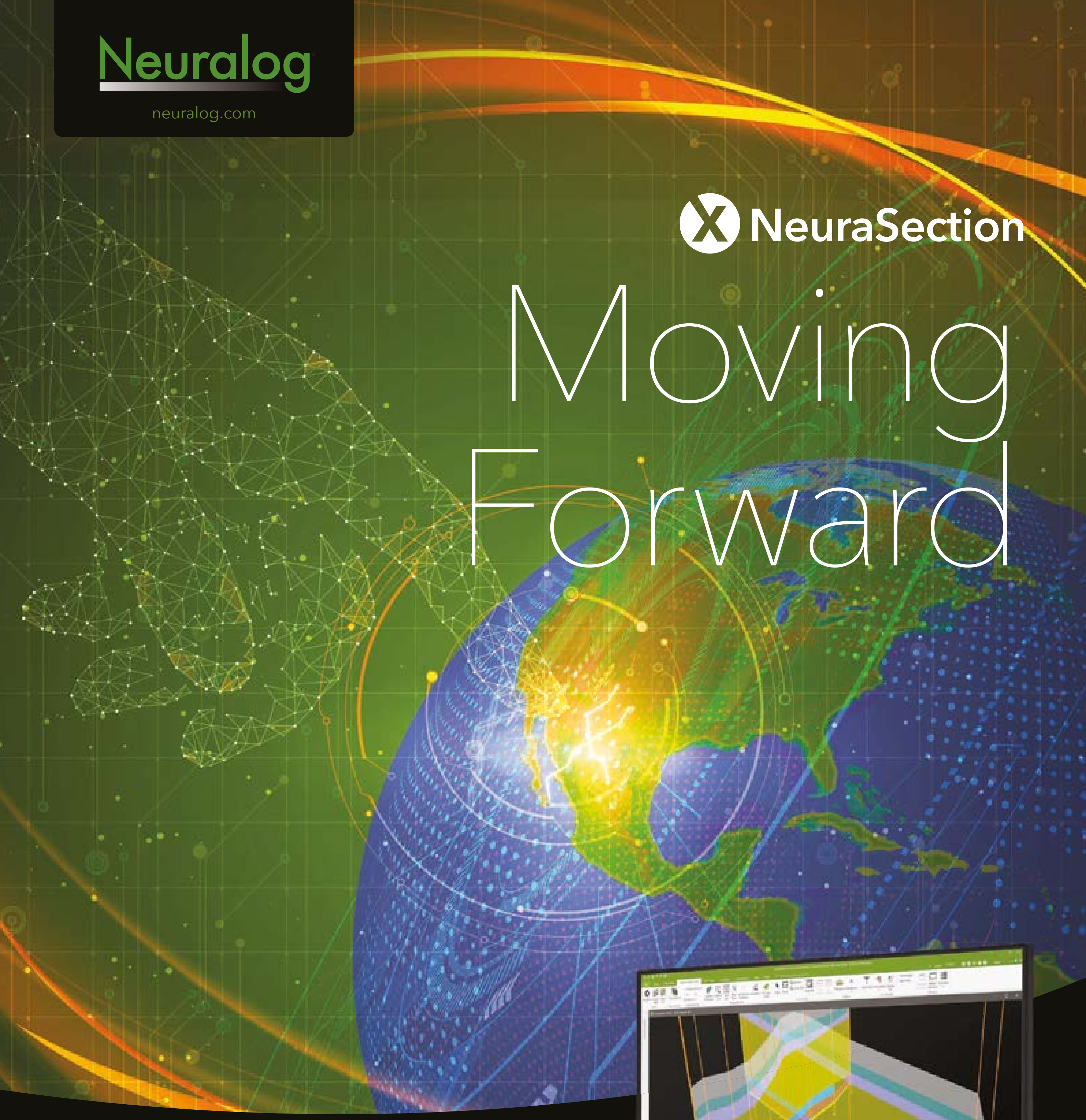
Mexico will be under scrutiny in the next few months as the new political leaders get established, but there is certainly a great deal of early success plus committed drilling to keep this area in the spotlight.

Ready to Drill

Notwithstanding the low oil price inertia, several important wells are sanctioned and ready to deliver, including offshore Portugal, where Eni and Galp are targeting the Jurassic Santola prospect, with close analogies to the eastern Canadian Lower Mesozoic play.

Brazil will host Premier's attempts to develop the Cretaceous rift basin play around Pecem, with a dual-target well to test the Maraca and Berimbau prospects in the Ceara Basin, while Shell and Total plan a well in Q1 2019 in the Gato de Mato block. This is one of many high impact pre-salt wells planned after the hugely successful 2018 pre-salt bid round organized by ANP.

Offshore Namibia and South Africa will also host important wildcats. In the Walvis Basin, Tullow and Chariot Oil & Gas will drill Cormorant and Prospect S respectively. The Orange Basin Namibia will be tested in earnest with Shell targeting isolated reefal targets (Cullinan) and Total choosing to test major deep marine fans in water depths of over 2,500m. Total will also revisit its Bulpradda prospect in the Padavissie fan system in South Africa this year, while Eni and Sasol have up to five wells planned in their deepwater Durban Basin block. ■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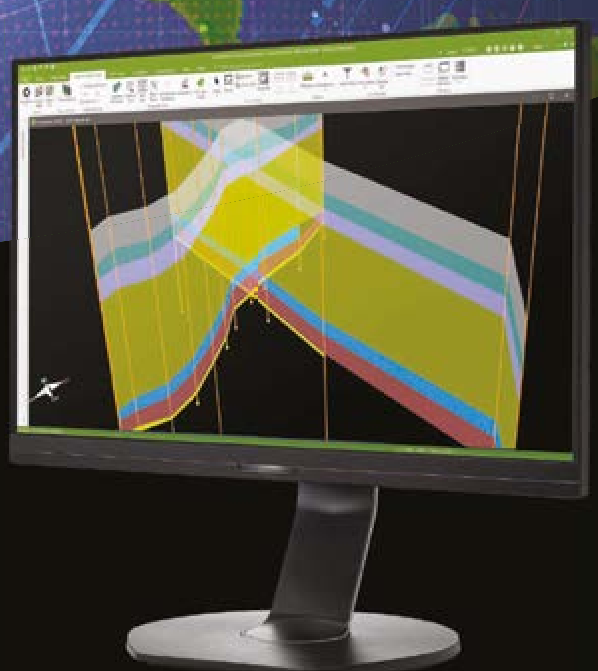


Pre-Salt: The Brazilian Shining Star

The next phase for Santos Basin appraisal and development will require new seismic data that captures the pre-salt accurately.

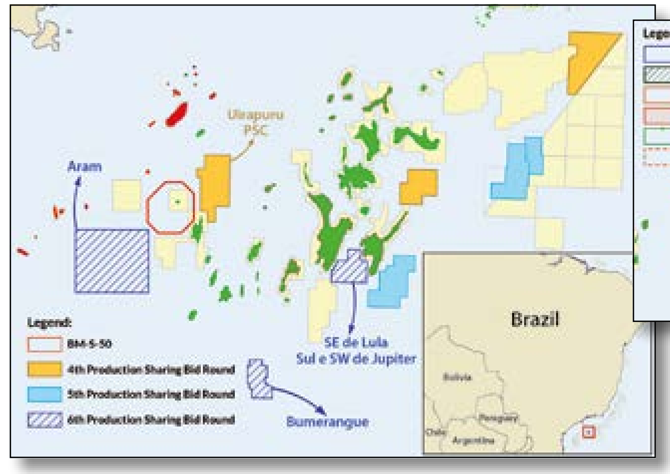
Seismic section over the Sagitario light oil discovery, portraying the detailed BM-S-50's velocity model. Isotropic and anisotropic tomography was applied in both the post- and pre-salt sequences. The comprehensive processing workflow captured complex lateral velocity contrasts in post-salt mini-basins that register fast carbonate layers. The resulting imaging correctly depicts the salt geometries, the base of salt, and most importantly, the pre-salt sequence.

In recent years, the geophysical, commercial and HSE benefits of multiple source acquisition, and the multi-azimuth uplift in pre-salt illumination and velocity model building have become renowned within the industry. Utilizing this combined multi-source and multi-azimuth approach offers a safe, cost-effective and technically robust solution to further optimize the exploration of the Santos Basin.

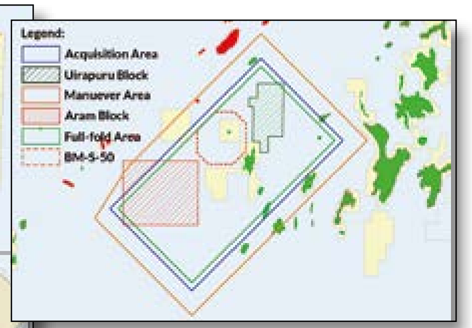
Formation tests over the Sagitario pre-salt prospect (below) in 2014 confirmed that the region had excellent carbonate reservoirs bearing high quality oil at a depth of 6,144m.

Polarcus has received a full environmental permit from IBAMA for an XArray™ Triple Source, long-offset project in the Santos Basin, which is designed to provide exceptional operational efficiency without compromising the pre-salt imaging. The permit for the ACU survey covers the Aram prospect, the unitized BM-S-8 and North of Carcará blocks, and the newly awarded Uirapuru block, as shown on the map. Further information can be provided on request.

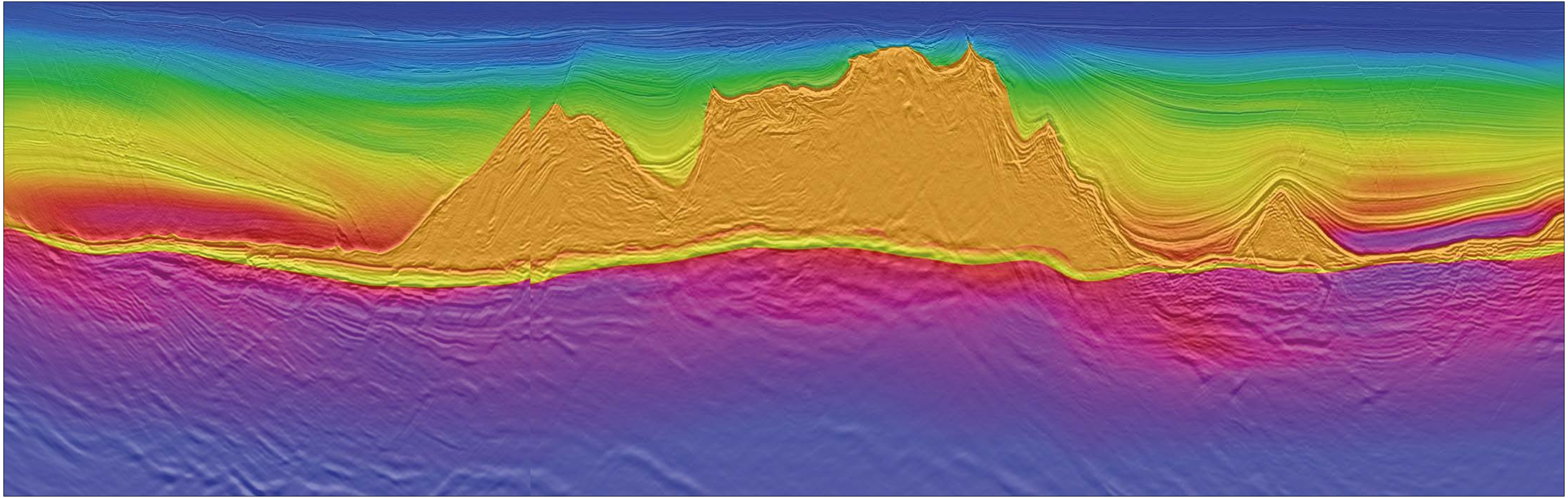
Polarcus®



Map showing fields and location of newly awarded acreage (Uirapuru) and the Aram, Bumerangue and Sul de Lula prospects that will be offered in the sixth Pre-Salt Round.



Location of the XArray Triple Source project which will cover the Aram, Carcará and Uirapuru areas.



A Game Changer Dataset

Combining forces in the Santos pre-salt: a multi-azimuth and multi-source approach brings benefits to understanding pre-salt Brazil.

DAVID CONTRERAS DIAZ and MARC ROCKE, Polarcus

Despite political uncertainty following October's presidential election, the Brazilian regulatory body (ANP) remains committed to developing a re-energized oil and gas industry, proactively encouraging more foreign investment and synergies between international and local oil players.

The results are significant. In the past nine months, the ANP has hosted five successful bid rounds that generated up to $5.45 billion in signature bonuses for the Brazilian government. Most recently, the ANP hosted the fourth Pre-Salt Round in June, approved blocks for the fifth round and designed the licensing calendar all the way to 2021. The attractive terms that are now offered to the industry, the volumes in place and the visibility and transparency of the entire licensing process makes offshore Brazil a prime location for hydrocarbon exploration. Not surprisingly, the supermajors have doubled their efforts to acquire new blocks and enter into new agreements with Petrobras to gain access to already discovered resources, such as Equinor's 25% stake in the Roncador field, the largest producing field in Brazil with 210 Mbpd output.

Zooming in to the Santos Basin, three companies stand out from the crowd: Equinor, ExxonMobil and Galp. The trio submitted the winning bid for the Uirapuru block during the 4th Pre-Salt Round, beating the Petrobras-led JV (with Total and BP) and two other consortiums. Petrobras did exercise its preferential right to enter the block and will be the operator with a 30% stake, while Exxon and Equinor will keep 28% each and Galp the remaining 14%. Just south-west of Uirapuru, the trio also holds very valuable pre-salt acreage in the North of Carcará and BM-S-8 blocks with a 40-40-20 split respectively. In late July, *Upstream* reported that the results of the pre-salt Guanxuma prospect drilled in BM-S-8 are promising, according to Equinor CFO, Hans Jakob Hegge.

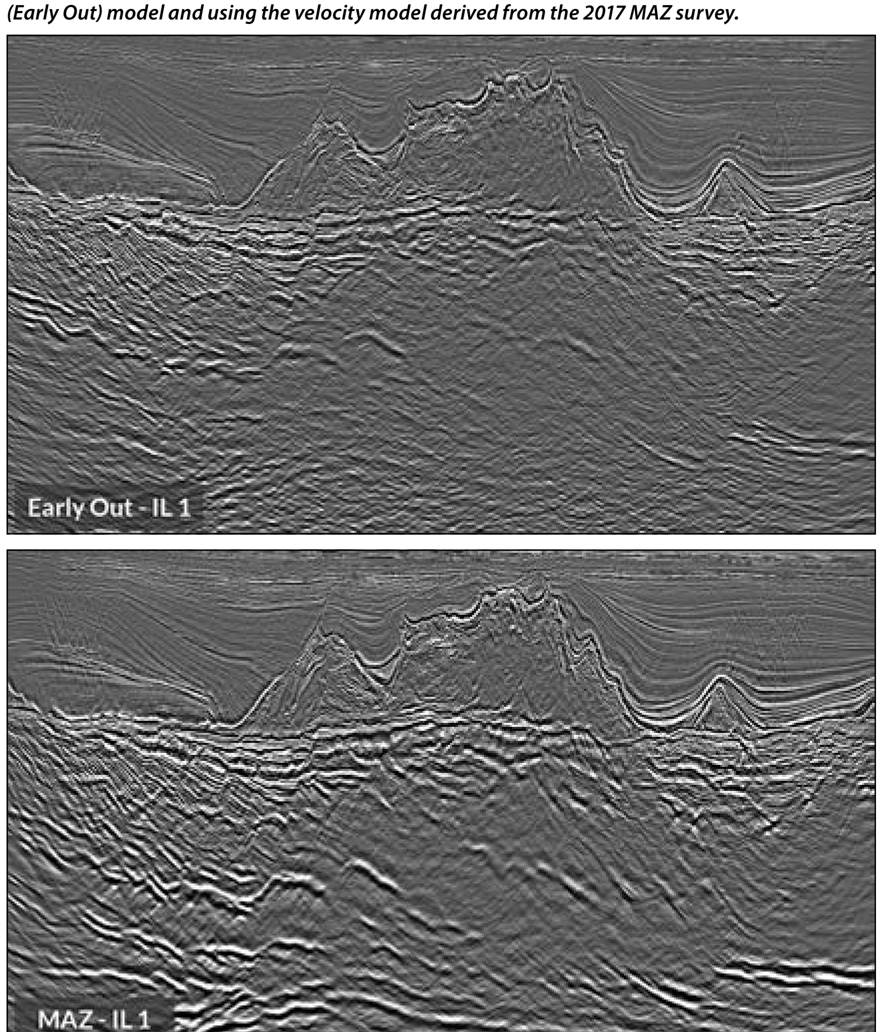
But although vintage seismic data might be enough to drill exploration wells, the next phase for the Santos appraisal and development will require new seismic data that captures the pre-salt accurately.

Illuminating the Pre-Salt

The geophysical challenge in the Santos Basin, as in any other pre-salt province, is to come up with a cost-effective solution that optimizes the illumination of the prolific pre-salt targets, accurately positions the main events correctly in depth while also respecting their continuity and character, and that captures the complexity of lateral velocity contrasts in the post-salt.

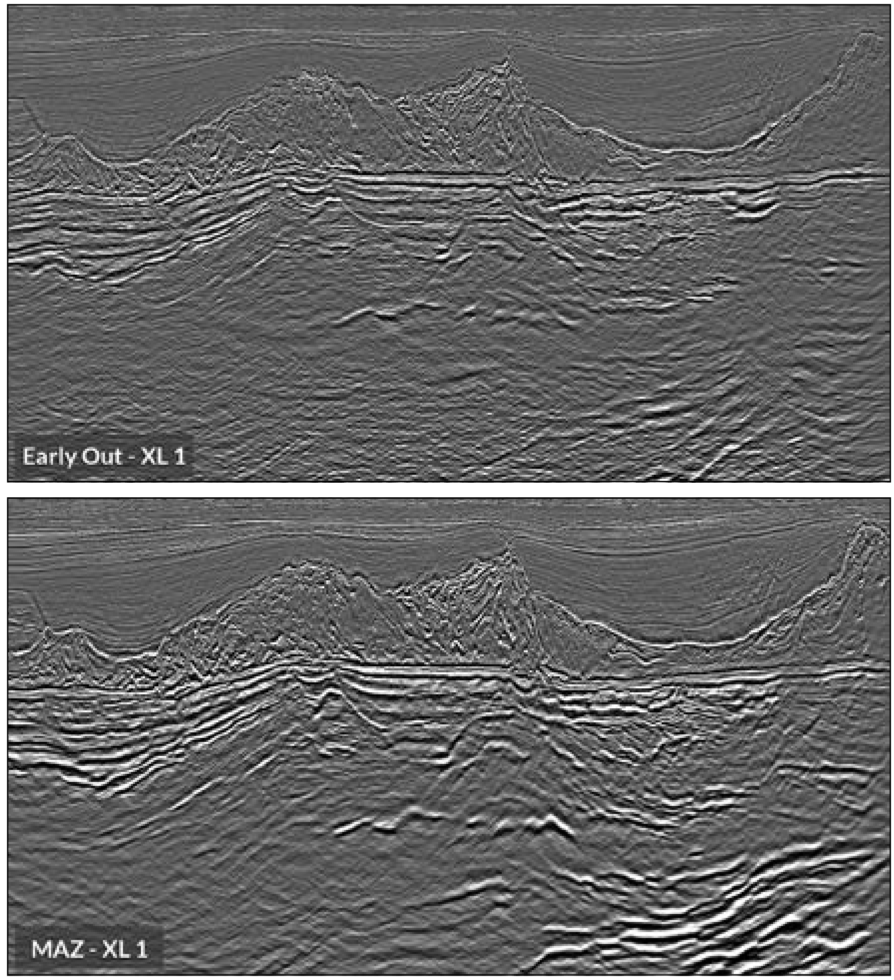
Many seismic acquisition technologies have been

Comparison between new data migrated using a 2012 legacy regional velocity single azimuth (Early Out) model and using the velocity model derived from the 2017 MAZ survey.



developed to address these challenges, from Multi-Azimuth (MAZ) to Wide-Azimuth (WAZ), and going all the way to Full-Azimuth (FAZ) surveys. These techniques are considerably more expensive than conventional acquisition due to the increase in vessel time required for multi-azimuth solutions and the use of additional source vessels for wide-azimuth projects. The ultimate FAZ solution might come from the use of ocean bottom seismic, but that is considerably more expensive and time-consuming. Thus, the use of these techniques for exploration surveys has been limited to date.

The 1,600 km^2 BM-S-50 MAZ survey acquired for the Petrobras-led consortium, in which Shell and Repsol-Sinopec each individually hold a 20% stake, was designed to better delineate the 2014 Sagitario oil discovery and to assess the hydrocarbon potential of the surrounding area. The survey was shot in late 2016 through to early 2017, using a 12 x 75 x 8,100m streamer configuration. Azimuths of 45° and 135° were selected after a thorough illumination study indicated that these were the optimal acquisition directions to obtain complementary illumination of the pre-salt sequence. Explorationists with extensive knowledge of the area have indicated that the vintage datasets acquired east-west and north-south have been found to either be suitable for mapping the complex faulting of the pre-salt, or for tracking the main horizon events, but never for both.



Comparison between Early Out and MAZ processing. The latter better delineates the structural complexity of an untested pre-salt prospect west of BM-S-50 block.

Multi-Azimuth Benefits in Pre-Salt Brazil

The images here illustrate the uplift in illumination and accuracy of the velocity modeling gained from the use of two azimuths over the BM-S-50 survey. The comparisons are made between the new data depth-migrated using a 2012 legacy regional velocity model (Early Out) derived from a single azimuth, short-offset survey, and the new data migrated using the velocity model derived from the 2017 MAZ acquisition and processing. As demonstrated on these pages, the pre-salt imaging improvements using the multi-azimuth approach are significant.

In these figures, the MAZ processing results in much better imaging of the deep pre-salt section, an improvement in the Base of Salt (BoS) identification, and better depth positioning of the pre-salt sequence. The imaging uplifts noted can be attributed in large part to the complementary azimuths contributing to a more constrained tomography solution in velocity model building, as well as providing additional illumination of structurally complex features such as faults and salt overhangs.

From a New Ventures perspective, the BM-S-50 survey highlights further potential in the pre-salt prospectivity just west of the block, as illustrated in the data comparison above. This new multi-azimuth dataset, which includes Kirchhoff, Beam and RTM volumes, provides an opportunity for some important basin insights to be extracted, enabling evaluation of the adjacent Aram prospect, which the ANP is planning to offer to the industry in the sixth Pre-Salt Round during the second half of 2019.

Multi-Azimuth, Multi-Source Approach

A further step-change in pre-salt imaging may be achieved by combining the high fold and dense cross-line sampling delivered by multiple source acquisition with the uplifts gained using the multi-azimuth acquisition technique, illustrated above. The velocity model resulting from such a survey will be even more robust in the post-salt sequence, and the pre-salt imaging will therefore have either the same or higher resolution than that of conventional dual source acquisition, depending on the operational efficiencies that are sought in the survey design stage. This geophysically and geologically driven approach offers a cost-effective solution for pre-salt exploration programs to oil and gas companies in the Santos, Campos and Espirito Santo Basins. ■

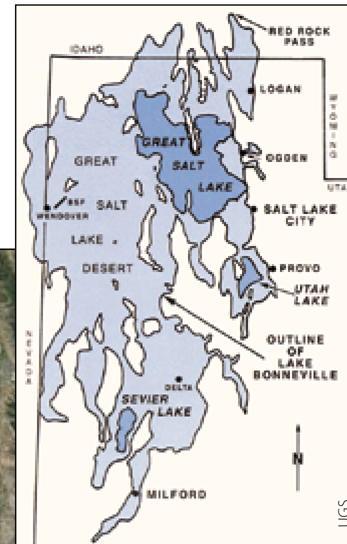
Mystery Carbonates

The 2006 discovery at Tupi, offshore Brazil, opened up a new chapter for petroleum reservoirs: lacustrine carbonates capable of producing hydrocarbons at extremely high rates. Several recent studies have started to unravel the mystery of these poorly understood and highly varied reservoirs; however, many questions remain.

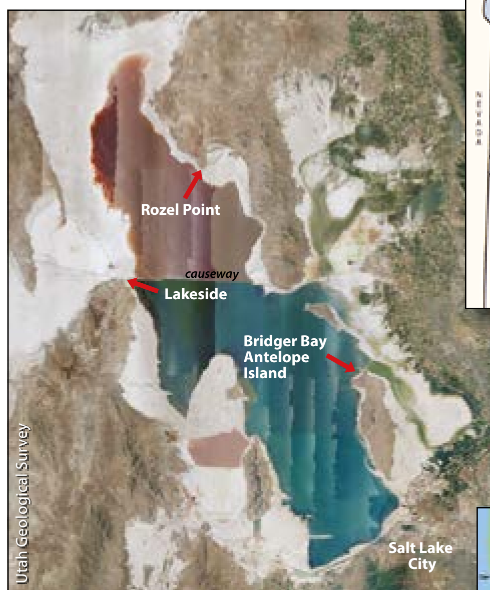
THOMAS SMITH

Since the Tupi (now called Lula) discovery, Lower Cretaceous, pre-salt lacustrine carbonates have been found to host giant petroleum discoveries in the South Atlantic rift basins on both sides of the Atlantic. Early in the rifting event when South America and Africa parted ways, much of the area was covered by extensive lakes. Successions of varied lacustrine carbonates were deposited along what is now the South Atlantic margins off Brazil and West Africa.

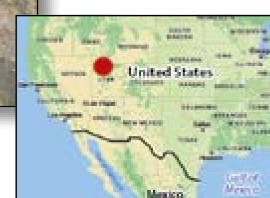
Coquina reservoirs, consisting of shell fragments accumulated on lake margins, have been found in small fields in shallow water off Brazil. However, the pre-salt reservoirs, particularly in the Santos Basin deepwater, are very different. Referred to as 'microbialites' when first discovered, their origin has recently come into question. There is good evidence that these carbonates formed in shallow basins abiotically and the 'microbialites' do occur but

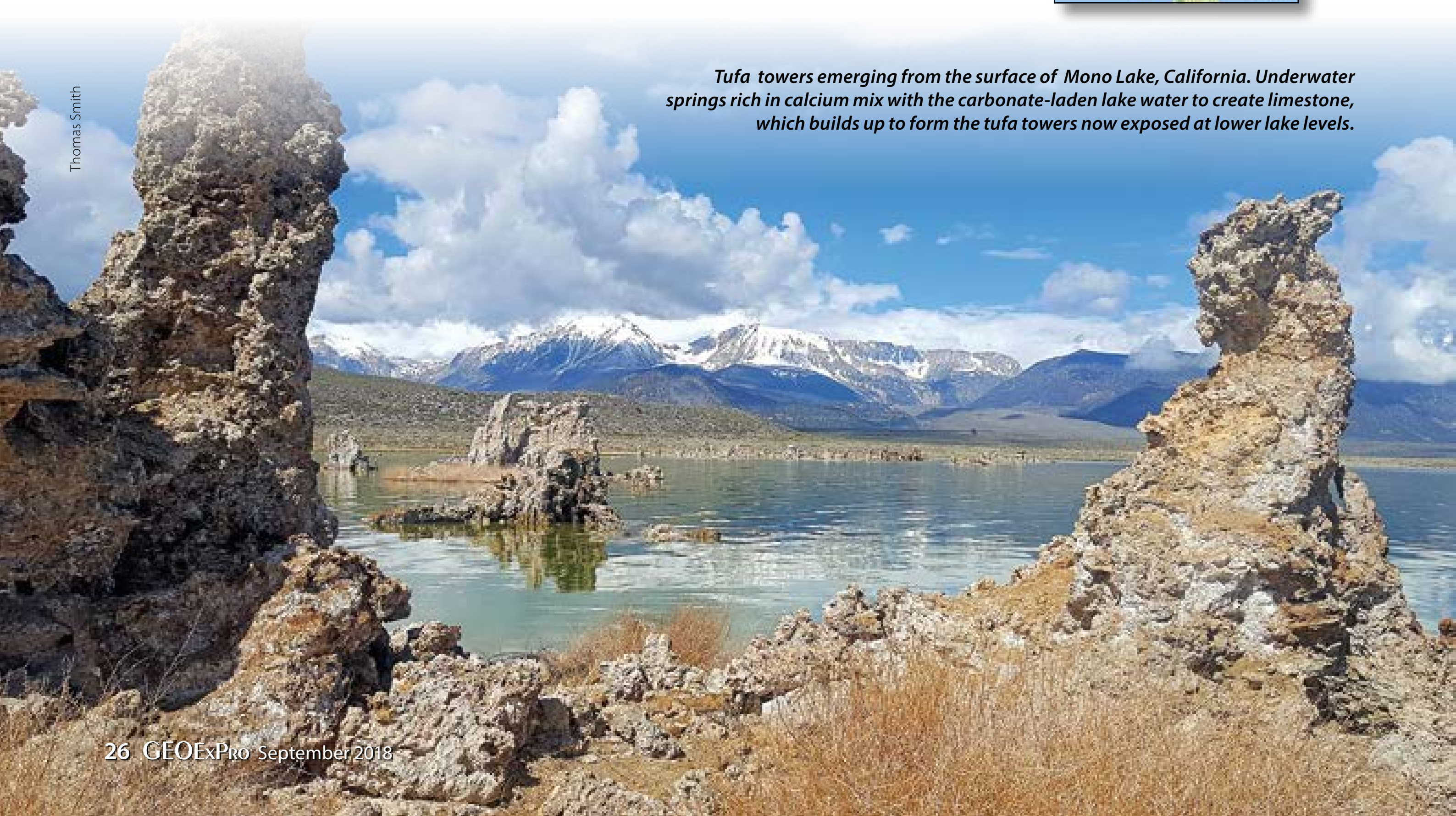


Map (above) showing location of Great Salt Lake, the outline of Pleistocene Lake Bonneville, and some of the towns and cities including Salt Lake City.



Satellite image of Great Salt Lake with the location of Rozel Point, Bridger Bay, and Lakeside. National Agriculture Imagery Program, 2016.





Tufa towers emerging from the surface of Mono Lake, California. Underwater springs rich in calcium mix with the carbonate-laden lake water to create limestone, which builds up to form the tufa towers now exposed at lower lake levels.

make up a less important portion of these carbonates. While there are similarities in these reservoirs both across the South Atlantic and north-south along the margins, there is much variation between them as well. From area to area they exhibit distinct stratigraphic patterns and diagenetic histories, with modes of formation varying from distinctly biotic to abiotic. These differences may be explained by the variability in climate, geology, and chemistry of the lakes where the carbonates were deposited.

Knowing the depositional settings for contrasting lacustrine facies is necessary to help interpret and model these important reservoirs. Lacustrine deposits, both modern and ancient, can be found all over the world (western Australia, Oman, Namibe, Italy, Turkey, east Africa, Argentina, and Spain), but some of the best-documented are located in the western United States and include the modern Great Salt Lake, Mono Lake, Pyramid Lake and the Eocene Green River Formation. Utah and surrounding states have become one of the many destinations for several international groups looking to better understand lacustrine reservoirs.

Great Salt Lake Study Areas

At times during the Pleistocene, a large, freshwater lake covered north-western Utah and extended into the adjacent states of Nevada and Idaho. The ancient Lake Bonneville covered over 52,000 km^2. All that remains is the 4,190 km^2 Great Salt Lake, the largest lake in the US outside the northern Great Lakes.

"Great Salt Lake is an excellent locale to study recent microbialite formation as well as abiotic carbonate deposits," says Michael Vanden Berg, Energy and Minerals Program Manager for the Utah Geologic Survey. "Microbialite domes, mats and ridges, as well as spring deposits, coated grains and shoreline tufas are widespread in and around Great Salt Lake. Two readily accessible areas for study are Rozel Point in the northern portion of the lake and Bridger Bay located at the northern tip of Antelope Island, in the south arm of the lake. The early Great Salt Lake shoreline deposits at Lakeside also provide accessible meter-scale travertine mounds and associated microbialites from past higher lake levels."

Lacustrine and mineral spring-deposited carbonates can form in a great variety of environments and take shape in unusual ways: from abiotic formation in geothermal springs to microbial mats and reefs. Photos from top to bottom: travertine terraces at Mammoth Hot Springs, Yellowstone National Park, Wyoming; Pleistocene Monk's head bioherm reef, now exposed along the shoreline of Great Salt Lake, Utah ; Holocene microbialite domes along the current margin of Great Salt Lake, Utah.

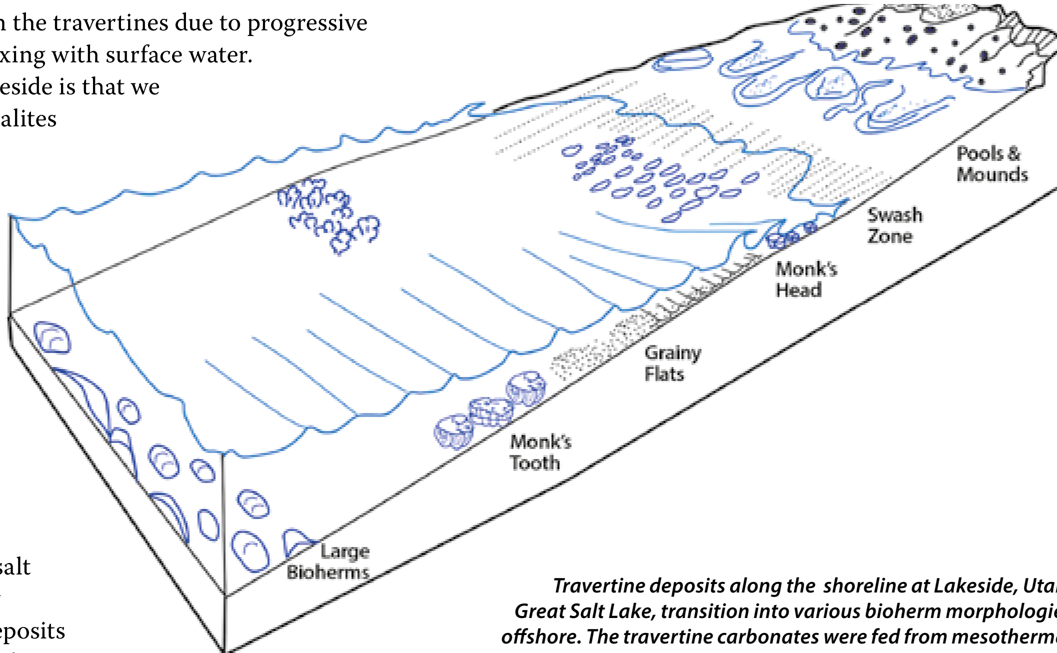
The Lakeside Outcrops

"The Lakeside area provides field-based data that show how highly porous facies can be linked together within travertine and microbialites," says Peter Homewood of Geosolutions TRD, France. "These carbonates are composed of site-specific minerals deposited before diagenesis, and demonstrate that the travertine and microbialite scenarios can be intimately associated rather than mutually exclusive for interpreting pre-salt reservoirs."

Offshore from the travertine deposits are the various forms of the microbialites, such as those shown in the introductory photographs.

"The alkaline groundwater can promote growth of both onshore travertine and lacustrine microbialites in the same depositional system," says Dr. Homewood. Researchers also discovered that different carbonate minerals are closely linked with specific depositional environments, water temperature and chemistry. Major lake level changes drove the geothermal alkaline groundwater systems, with a wide range of temperatures recorded from the travertines due to progressive flushing from depth and mixing with surface water.

"The real tale here at Lakeside is that we have travertine and microbialites that were deposited adjacent to each other and during the same intervals, showing that they are not mutually exclusive," concludes Dr. Homewood. "Travertines and microbialites compete in opposing scenarios that are commonly used for interpreting reservoir facies observed in South Atlantic late sag phase pre-salt lacustrine carbonates. Early Great Salt Lake shoreline deposits at Lakeside provide spectacular outcrop analogs for these reservoir facies."



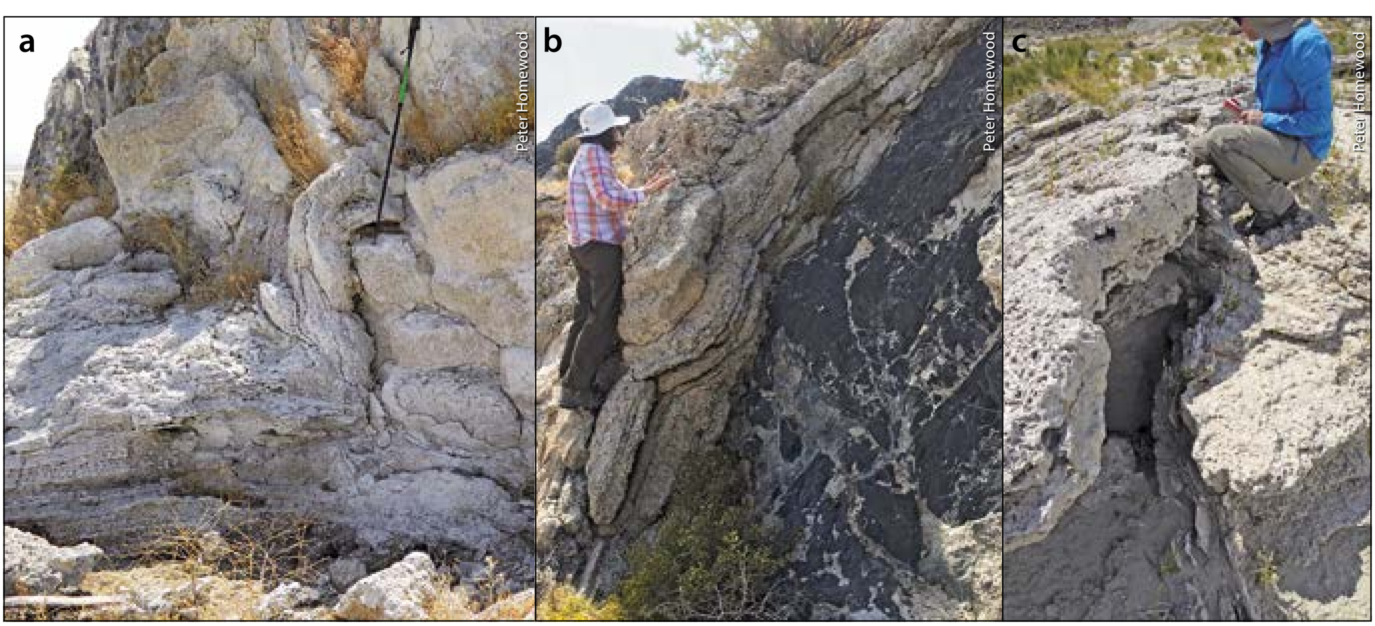
Travertine deposits along the shoreline at Lakeside, Utah, Great Salt Lake, transition into various bioherm morphologies offshore. The travertine carbonates were fed from mesothermal springs and formed terraces, cascades and mounds, draped bedrock and coated boulders.

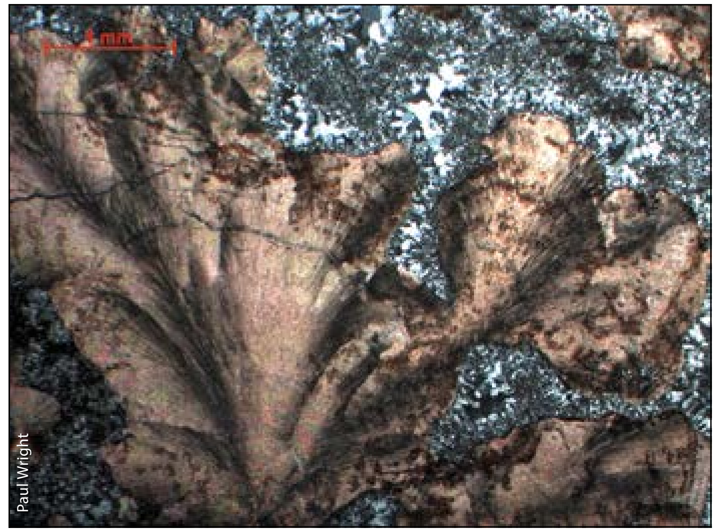
Analog or Not?

"Microbialites have been forming in diverse basin types from the Neoproterozoic to the Recent," says Webster Mohriak, researcher at the State University of Rio de Janeiro and South Atlantic margins expert. "During periods of sea-level rises in a desiccating basin, carbonate buildups (stromatolites) and reefs are commonly found. In basins affected by volcanic or hydrothermal episodes, chemical abiotic precipitation of carbonates occurs in the form of travertine and tufa deposits with secondary biogenic growth. These carbonates are commonly reworked in higher energy environments leading to the deposition of detrital carbonates. All these types can be found in the pre-salt reservoirs offshore Brazil."

Webster's observations are backed up by recent publications of the National Agency of Petroleum (ANP) for Brazil on Brazil's pre-salt reservoirs. In a 2013 Geological Assessment, they identify the Itapema and Barra Velha formations in the Santos Basin as "carbonate rocks formed by coquinas and /or microbialites." Petrobras used the present-day carbonate rocks deposited at Lagoa Salgada (Salty Lake) in Rio de Janeiro State as analogs to the reservoirs in the Santos Basin. The microbial carbonates are found in both the Santos and Campos basins, just below the salt layer, on the sag (post-rift) and upper rift layers. They identify a variety of coquinas, graded and closely packed spherulites, and laminated to massive calcilutites.

Travertine examples from Lakeside, Great Salt Lake: (a) travertine cascade coating stepped mini-terracettes; (b) travertine encrusting a bedrock cliff; (c) vents propagated from bedrock through mounds to feed travertine layers.





The best reservoir facies in the Barra Velha Formation consist of in-situ cm-sized crystal shrubs made of radiating fibrous calcites and resembling abiotic travertines.

New Modeling

Contrasting with past microbialite interpretations for much of the pre-salt carbonates, V. Paul Wright of PW Carbonate Geoscience, Cardiff, UK and Nick Tosca at the University of Oxford, UK published a 2016 paper presenting an evaporitic geochemical model for the Aptian Barra Velha Formation pre-salt reservoirs in the Santos Basin, offshore Brazil. The authors have observed similar carbonate precipitation in Lake Chad (central Africa) leading to the growth of spherulites. They do admit in their paper "that there are several different reservoir types in the South Atlantic pre-salt". Their model for the Barra Velha "invokes shallow evaporitic lakes, with the carbonates of largely abiotic origin produced with magnesium-silicate gels, which later formed clay matrices, and consequently dissolved, creating much of the porosity and impacting later diagenetic events."

Dr. Wright has authored several more recent papers on the pre-salt lacustrine carbonates and also has studied some of the Utah 'analogs'. "What we have found is that there are different reservoir types in the South Atlantic pre-salt," says Dr. Wright. "Lake deposystems are controlled by often highly complex hydrological factors reflecting the interaction of local climate, tectonics and the composition of the catchment geology. We have a much clearer picture now of their diversity and what was controlling their compositions, architectures, porosity types and diagenesis.

"The Barra Velha reservoirs are remarkably uniform in terms of their composition," continues Dr. Wright. "Their two main grain types are either in-situ or reworked. The best reservoir facies consist of in-situ centimeter-sized crystal shrubs made of radiating fibrous calcites and resembling abiotic travertines." Currently, most experienced sedimentologists who have seen the Barra Velha or its equivalents generally agree on the abiotic generation of these carbonate facies.

For the pre-salt South Atlantic reservoirs, it would seem that analogs abound around the world and greatly vary in ways we are only beginning to understand. Great Salt Lake provides one place where some of this variety comes together, from abiotic travertine deposits to bioherms in the form of reefs and carbonate buildups. It has become important to properly characterize the environment that led to carbonate deposition in order to explore these carbonate reservoirs. The Barra Velha Formation and its equivalents, "represent shallow lake deposits with the potential for similar facies present off the main structural blocks," Dr. Wright points out. "The same facies can be found in the West African basins and may extend well east of the explored areas in both the Santos and Campos Basins.

"The problem is there is no direct analog for these complex and highly productive reservoirs and that has caused a controversy over their interpretation," adds Dr Wright. "Conditions in the Cretaceous were unique to that period in creating vast, hyper-alkaline lakes, probably due to CO_2 derived from the mantle."

However, as Michael Vanden Berg points out "Even though there may be no direct analogs, the general study of lacustrine deposits is still very important to the understanding of all lacustrine reservoirs, including the Cretaceous pre-salt reservoirs found offshore Brazil." ■

Holocene microbialite domes covered with living microbial mat, Bridger Bay, Antelope Island, Great Salt Lake.

Geothermal in the Future Energy Mix

Geothermal energy is still a marginal player in the energy mix, but geoscientists will be needed to help it play its part in the energy transition.

MARIT BROMMER, International Geothermal Association

The Energy Transition is well underway and is here to stay. Although fossil fuels provide 80% of the world's energy demand and are forecasted to remain an important player in the coming decades, alternative sources of energy have taken off and are on the radar of countries wishing to develop economies less dependent on fossil fuels. The past decade has seen a steady increase in the uptake of renewable energy sources, mainly in solar and wind, as the energy transition has been focusing on ´electrification´, meaning that policy measures encouraged investment in projects involving these technologies worldwide. As a result, technology costs for predominantly solar (solar thermal and PhotoVoltaics) have been going down, spurring an even higher level of investment interest.

However, demand for power accounts for only 20% of global energy consumption. Despite the focus on electricity, the real game changers in the Energy Transition will be alternative fuels for transport, which accounts for 30% of total energy consumption, and for heating and cooling (50%).

Global Potential

In today´s renewable energy mix, geothermal energy is still a marginal player, providing a little over 1% to the worldwide power demand and about 3% to the heat demand[1]. The potential of geothermal, on the other hand, is huge as there is a phenomenal amount of heat stored under our feet[2] – but tapping into this, exploiting geothermal energy as a cleaner and greener alternative to coal, oil or gas is another thing. As a geologist myself, and having built my career in the oil and gas industry prior to joining the International Geothermal Association as its executive director, I am passionate about advocating geothermal as a reliable, affordable, alternative source of energy. In order to create space in the future energy mix there is a need for keen passionate subsurface professionals, who are not averse to taking risks but also understand that when dealing with a natural resource almost anything can happen. In this article, I will focus on two sides of the story. Firstly, I will look at enhanced geothermal systems technology, and then I will discuss the need to train geoscientists on geothermal reserves definitions and resource classifications.

Areas with the highest subsurface temperatures are found in regions

The Monterotondo Marittimo geothermal power plant in Tuscany, Italy dates back to early in the 20th century.

Fabio Sartori

with active volcanoes close to tectonic plate boundaries, or where the crust is thin and heat can rise easily. These plate boundaries, often referred to as the ‘Ring of Fire’, have volcanoes associated with them: hot spots which are seismically active, meaning that temperatures between 200° and 500°C are relatively easily reached. The first countries to pioneer harnessing the high temperature or high-enthalpy resources of the naturally occurring hot spots were Italy, which established a geothermal powerplant in 1904, New Zealand (Wairakei, celebrating 60 years in 2018) and Iceland, which is particularly strong in geothermal project development, having transformed its fossil-fuel-dependent economy to a 90% renewable-based one sourced by hydro and geothermal. Iceland is also forward-looking regarding creating additional revenues from the geothermal power plants, the best known example of which is the Blue Lagoon. In addition, recent initiatives around the production of hydrogen and methanol is certainly an interesting way of making multiple use of the geothermal brines.

Iceland’s Blue Lagoon: swimming in silica, the run-off from the Reykjanes Geothermal Power plant.

Beyond the Ring of Fire

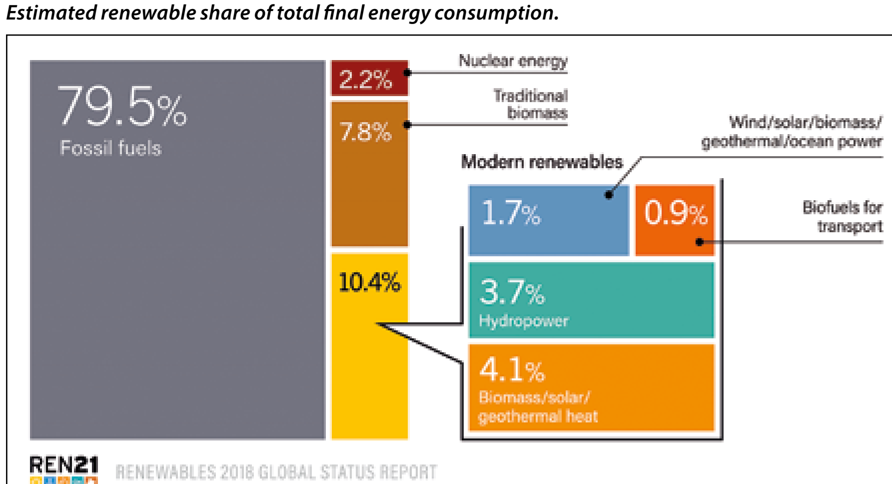
Although hot spots have been the incubator, they are certainly not the only areas where geothermal energy can be tapped – good news for those countries not situated on top of a volcano. Geothermal resources can be developed from basement rock such as the granites in Soultz, France (Electricité de Strasbourg) and Espoo, Finland (ST1) and from deeply buried sedimentary basins (Triassic) at various depths between 3 and 6.4 km, as has been done in Netherlands, France and Finland. These deeply buried reservoirs are in some cases hydrothermal (water-bearing reservoirs) or petrothermal (so-called Hot Dry Rock), but both need stimulation and enhancement techniques in order to create flow in the wells, as these reservoirs are typically tight with little permeability.

In addition, hot dry rock reservoirs require cold water to be injected which, once heated, is pumped back to surface by the producing wells. Both geothermal developments fall under the category of Engineered or Enhanced Geothermal Systems (EGS) and it is this EGS technology that attracts most of the R&D attention in the geothermal space globally, as it is considered to be the game-changer for geothermal development especially in low temperature (low-enthalpy) environments, i.e. bottom-hole temperatures of up to 150°C.

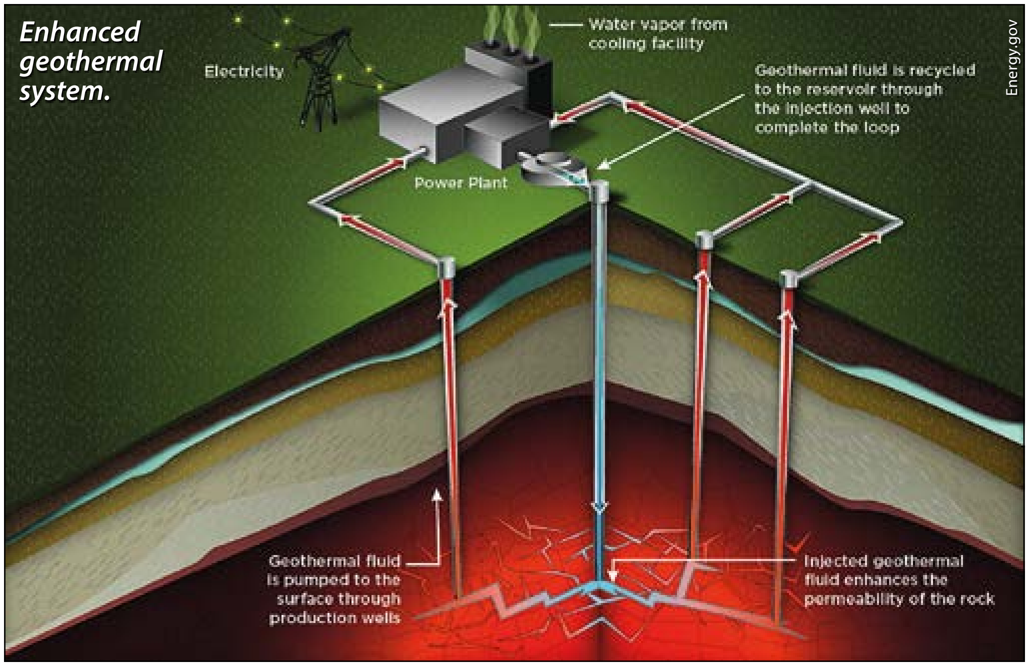
Why focus on EGS and how come this may be the game-changer for geothermal uptake? As countries adhere to the Paris Agreement, they will want to offer their citizens clean, green and affordable energy, so they will need to set policies on heating and cooling, amongst other things[3]. The first option for geothermal to come into play is for it to become competitive in firing up combined heat and power (CHP) plants to co-produce electricity and heat. Worldwide, coal-based power plants are the most widely used, but it is expected that countries will shy away from coal in the coming decade, according to the World Bank, which announced early in 2018 that it will discontinue investing in coal-based power plants[4].

As the demand for power and especially heat will come from cities for district heating networks and industrial purposes such as the food processing industry, the geographic location of a geothermal power plant becomes a strategic investment decision. Hence, having the right production

Estimated renewable share of total final energy consumption.



technology in place to stimulate and enhance those potential reservoirs close to the strategic locations of future CHP plants, and in some cases repurposing existing fossil fuel-based CHP plants, is crucial for geothermal success. Being competitive therefore means that costs need to go down for geothermal projects. According to the US Energy Information Administration projections for 2040, geothermal power plants will be one of the cheapest options, with a projected levelized cost of electricity of around US$ 0.05 per kWh[5].

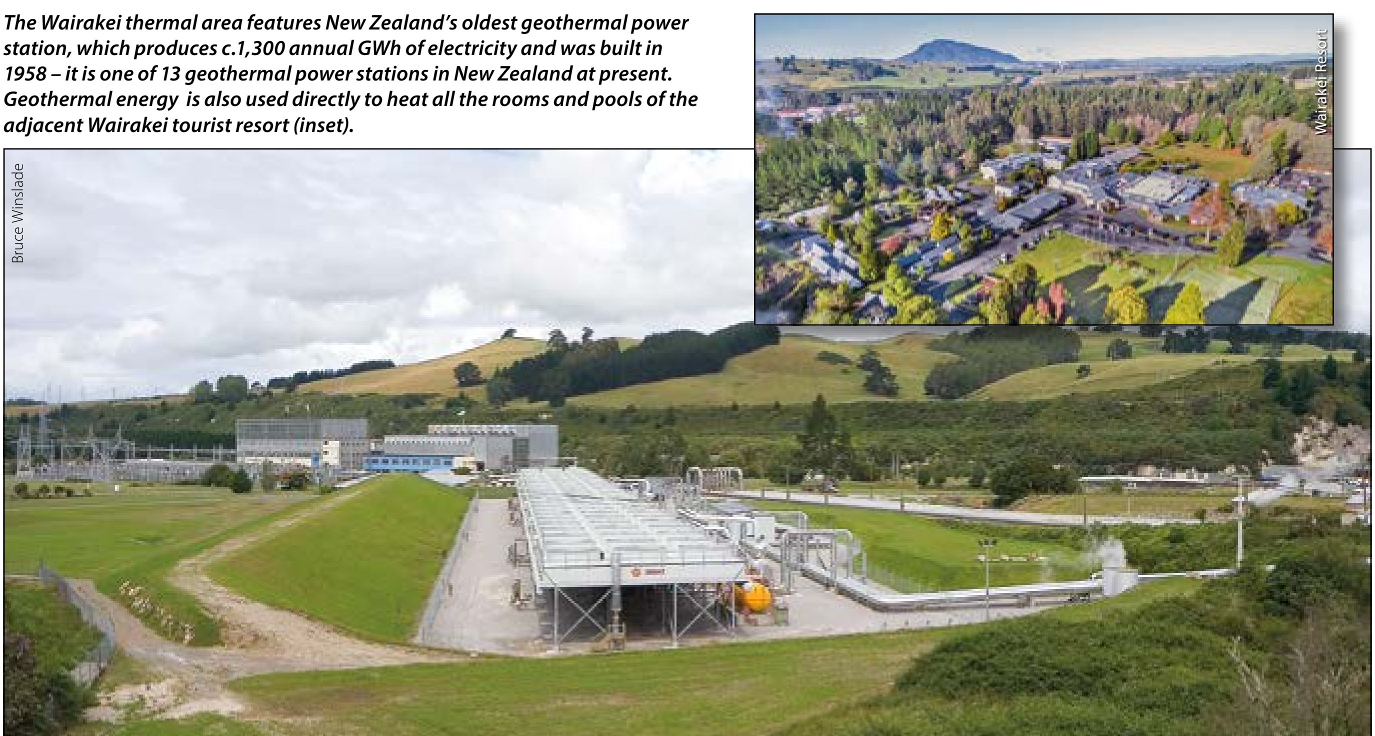


Skillsets of the Geoscience Subsurface Professional

Geoscientists and reservoir engineers working in the oil and gas industry are trained to report the quantities of their reserves and the resources of their prospects, projects and assets, according to industry recognized standards. These are key metrics in order to facilitate comparative valuations of the reported reserve and resource assets of different companies, which in turn provide investors with confidence to invest and allow the firms to raise equity on the stock markets.

In the geothermal community, however, there is a lack of clear global guidelines and standards, which is significantly holding back the assessment and development of geothermal energy as a viable option at a global scale. The planning and funding of energy infrastructure is based, to a large extent, on the comparative potential of different energy options in different locations. A proper comparison of those possibilities requires globally consistent methods of assessing and classifying energy potential. National agencies in many parts of the world have no experience or guidelines as to how to assess, quantify and classify their local geothermal potential. In addition, those agencies that have assessed geothermal potential within their jurisdictions have developed and used their own

The Wairakei thermal area features New Zealand's oldest geothermal power station, which produces c.1,300 annual GWh of electricity and was built in 1958 – it is one of 13 geothermal power stations in New Zealand at present. Geothermal energy is also used directly to heat all the rooms and pools of the adjacent Wairakei tourist resort (inset).



local methodologies and terminologies, which are not necessarily comparable with other jurisdictions[6]. The United Nations Economic Commission for Europe has led an effort to develop a harmonized methodology for classifying and reporting fossil and renewable energy resources under the United Nations Framework Classification for Resources (UNFC, formerly UNFC2009). This was finalized in 2016 and includes 14 case studies[7].

The International Geothermal Association is working with the International Renewable Energy Agency and the World Bank to deploy the UNFC code in a pilot project targeting four different countries. Work started in Indonesia (Flores Island, Bandung) in March 2018 and the committee is now looking into Ethiopia, a cluster of Small Island States in the Caribbean, and the Central American region. The pilot project is about raising awareness of the code itself and the value of adopting a standardized guideline, and emphasis is on training regional geoscientists and engineers in the four pilot regions. Given the importance of having a unified reporting standard for both reserve definitions and resource classification, it is highly probable that more countries will adopt the new guidelines. Understanding the UNFC code and its application to prospects, fields and assets will be a fantastic competence for the geothermal professional to have in the coming decade.

Future Outlook

Geothermal, albeit a marginal player today, has the potential to become a strong actor in the global energy transition. The IGA is working with leading oil and gas associations such as the EAGE, AAPG, and the IADC to jointly work on cross-over initiatives around co-production of electricity and heat in dual plays, on novel drilling tools able to withstand high temperatures, and on setting global standards and certifications both for geothermal well designs and production strategies in low-enthalpy environments. There is a wealth of knowledge, strong leadership and a thriving safety culture in both industries. Stimulating interactions between the two communities and jointly tackling some of the required technology breakthroughs will be inspirational for both the seasoned industry professional and for the recent geology graduate on the outlook for a sustainable energy career. ■

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The Puna Plateau: Treasures Behind Desolation

The Puna Plateau in northern Argentina and Chile is a harsh desert, spreading over a large area, much of which is more than 4,000m above sea level. This desolation, however, hides geological treasures among its vast landscapes, where the Earth's history meets the human story.

OLIVIER GALLAND, Department of Geosciences, University of Oslo; and **CAROLINE SASSIER**

Continuing Olivier and Caroline's epic cycle journey through South America

"What's the altitude?" I look at the altimeter: 4,840m above sea level. "Higher than Mont Blanc!", and we burst into tears together. What a surprise: this pass, the highest point of the crossing of the Puna Plateau between San Salvador de Jujuy, Argentina, and San Pedro de Atacama, Chile, is not even indicated on our map! Exhausted, cold and out of breath, we start cycling down the pass toward Atacama, the driest desert in the world. A lunar landscape opens: a desolate desert stretching between stratovolcano peaks which rise out of the high plateau. In the distance, steam from the Lascar volcano rises through the deep blue sunset, seeming to greet us with an ironic welcome.

The Puna Plateau

The Puna Plateau is easily accessible via the asphalted national road N°52. The geomorphology of the Puna Plateau consists of a series of flat basins separated by low hills, quite different from the wide, perfectly flat Altiplano Plateau further north. The most spectacular of these high-altitude basins is the Salinas Grandes, a vast salt flat that extends over 120 km^2.

The Puna Plateau is itself a geological curiosity. Together with the Altiplano, it is the second largest high plateau after Tibet. It extends over 180,000 km^2 between northern Argentina and Chile and has an average altitude of more than 4,200m. This exceptional elevation is due to an anomalously thick crust (~80 km), the result of Cenozoic shortening of the western margin of South America. The detailed geological processes leading to the development of the plateau are not known, but it probably results from complex interactions between tectonics, arc magmatism, and crustal melting, coupled with geomorphological processes specific to dry climates.

Olivier Galland

Volcanic landscapes of the Puna Plateau, near the Jama Pass, Argentina-Chile border.

The Quebrada de Humahuaca

The Quebrada de Humahuaca is a deep canyon that extends at the eastern foot of the Puna Plateau, in the Jujuy province in north-western Argentina. It is a UNESCO World Heritage Site, thanks to its spectacular scenery and archeological remnants.

What make the landscape so stunning are the numerous outcrops of colorful red geological formations. The most spectacular and famous one can be seen at the Cerro de los Siete Colores (Hill of the Seven Colors), behind the village of Purmamarca at the beginning of national road N°52. There, a combination of sedimentary and tectonic processes have brought into contact geological formations of distinct ages, spanning from Precambrian to Tertiary, and of contrasting colors due to copper oxides (green), copper sulfides (blue) and iron oxides (red).

The Hill of the Seven Colors at Purmamarca, Quebrada de Humahuaca, Argentina. From background to foreground: (1) light brown mountain – Ordovician sand-clay deposits; (2) green with purple stripes – Precambrian marine sedimentary rocks; (3) red-pink top of the foreground hill – Tertiary sand-clay deposits; (4) striped white, pink and purple bottom of the foreground hill – Upper Cambrian marine sandy deposits, partly quartzitic.

Another spectacular locality is the Paleta del Pintor (Painter's palette) in front of the village of Maimará, a few kilometers north of Purmamarca. The landscape offers a spectacular view over steeply tilted geological formations of contrasting colors, evoking the diversity of a painter's palette. Here, the north-north-east to south-south-west-trending gorge follows a basement fault that allows the exposure of dark red Upper Cambrian quartzite, covered by yellow to red continental Cretaceous to Paleogene deposits. The interaction between the steeply dipping strata and erosion reveals an astonishing landscape of successive characteristic rule-of-V features.

The Quebrada de Humahuaca hosts numerous archeological treasures that bear witness to more than 10,000 years of human presence. There is evidence that the valley has been a major trading path for successive civilizations, including prehistoric hunter/gatherers, flourishing pre-Hispanic towns and fortresses, the Inca empire, Spanish villages and traces of republican fights for independence. Given that the geological landscapes amaze tourists from all over the world, their esthetical power has doubtless deeply inspired the life, art and spirituality of indigenous populations through time.

The Chuquicamata Copper Mine

The Chilean flank of the Puna Plateau corresponds to the Atacama region, which displays several remarkable geological sites that can be visited. One of them is the Chuquicamata mine, the largest open pit copper mine in the world by excavated volume. The dimensions of this huge hole are gigantic: 4.3 km long, 3 km wide and 900m deep! Actually, this is the mine of superlatives: it represents one of the largest known copper resources (13%); it is the mine with the largest total production (29 million tons in 2007); and it represents more than one third of Chile's foreign trade. Chuquicamata is also a significant producer of molybdenum – but it is also probably the largest polluter in South America. Note that Ernesto Guevara visited Chuquicamata when he was young in 1952. This visit opened his eyes to working conditions, and greatly contributed to the development of the revolutionary leader 'Che' Guevara.

The Chuquicamata ore deposit is a typical porphyry copper, and is part of the broader Chuqui Porphyry Complex. It consists of a magmatic intrusive complex of dioritic to granodioritic compositions. After their emplacement in the shallow

The Chuquicamata copper mine, a 4.3-km long, 3-km wide and 1-km deep hole. In the shaded part of the mine, between the white dust cloud and the right flank, a darker steeply-dipping track, ending up in collapse deposits near the bottom of the mine, is visible: it is the trace of the fault that controlled the emplacement of the magmatic intrusions and the ore.

Earth's crust, these intrusions cooled down and liberated large volumes of fluids rich in dissolved minerals, leading to a kilometer-scale hydrothermal zone where copper and molybdenum minerals, among others, precipitated along veins. The Chuquicamata porphyry was emplaced during the Eocene-Oligocene along a regional north-south striking fault, the trace of which is visible in the open pit mine.

The El Tatio Geyser Field

A journey to the El Tatio geyser field is unforgettable, not only for the beauty of the spectacular manifestations of the active earth, but also for the body: the spectacle is best at the coldest hours of the day, meaning -10°C to -15°C! Indeed, the extreme temperature contrast between the air and the steaming ground give rise to the dramatic view of white steam columns rising over a vast, high altitude (4,300m above sea level) flat plateau surrounded by a string of dormant stratovolcanoes, the peaks of which are illuminated by the burning colors of the sunrise. With a total area of 10 km^2, El Tatio is the third largest geyser field in the world, and the largest in the southern hemisphere. It displays boiling water fountains, hot springs (60–80°C), small geysers, mud pools, mud volcanoes and sinter terraces.

The El Tatio geothermal field is located around a large caldera complex, which is part of the regional-scale Altiplano-Puna Volcanic Complex. The collapse of the caldera was coeval with the Quaternary eruption of a large ignimbrite, i.e. an immense volcanic explosion of pyroclastic ash, lapilli and molten blocks flowing down the volcano flanks as pyroclastic density currents. The current geothermal activity strongly suggests that a body of hot magma remains under the caldera, heating up ground water.

The El Tatio geothermal field represents promising potential for geothermal energy. Geothermal energy projects at El Tatio were initiated as far back as the 1920s, but drilling considerably impacted the natural geyser activity, and several technical and economic challenges prevented the development of profitable geothermal power production. The last attempt was dramatically abandoned after the blow-out of a drilling well in September 2009, generating a 60m-high steam fountain and creating negative publicity for geothermal energy in Chile – much to the satisfaction of tourists and the relief of indigenous populations.

The Atacama Lithium Deposit

A remarkable geomorphological feature of the Atacama region is a large salt flat, the Salar de Atacama. It lies at an elevation of 2,300m and is confined between the western flank of the Puna Plateau and the moderately high Cordillera de Domeyko. It is covered by a salt crust, where nothing grows, and the sun's radiation can damage exposed skin in minutes. Humans would keep clear of this hostile area, if it did not hide the precious brine that contains an element that has become more and more essential in our modern world: lithium. The Atacama is one of the largest and purest active sources of lithium, containing 27% of the world's known reserves. In 2008, Salar de Atacama provided 30% of the world lithium supply, produced as lithium carbonate and lithium chloride salts.

This lithium deposit is the result of

Licancabur volcano, the sentinel dominating the Salar de Atacama.

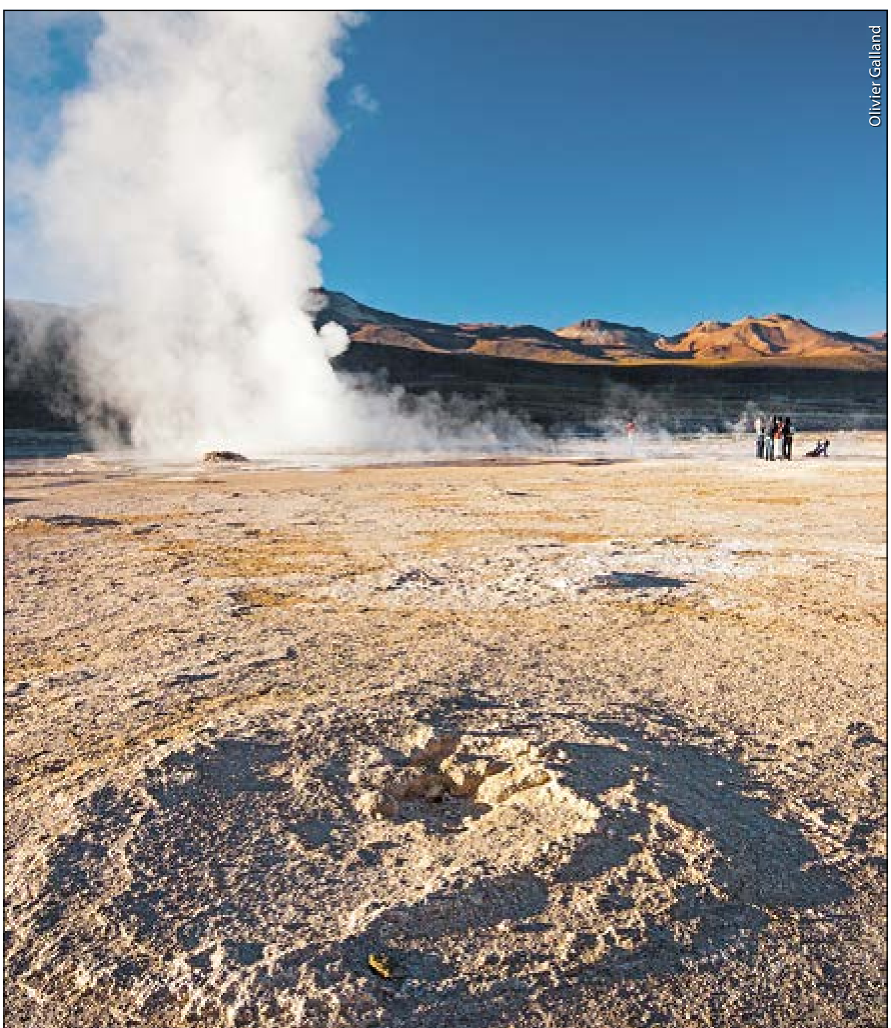
an optimal geological, geographical and climatic combination. The geothermal fields associated with active volcanism produce waters rich in various salts, including lithium; brines from the El Tatio geyser field are, for instance, considered to be the major source of lithium in Atacama. Once liberated in the rivers, the brines flow down to the Salar, where they remain trapped. Indeed, the Salar de Atacama depression is an endorheic basin, i.e. there is no outlet to the sea. Consequently, the salts brought by the surrounding rivers accumulate through time. Finally, the extremely arid climate evaporates the water, and concentrates the salts in the brines to form the hostile salt crust at the surface. The exceptional lithium concentration of 2 g/L in Atacama is unique.

The production of lithium utilizes the sun as the main processing energy source. The brines are pumped out of their host aquifer into evaporation ponds, where lithium is concentrated by evaporation. During the process, several salts precipitate successively in distinct ponds: calcium sulfate (gypsum), sodium chloride (halite), potassium chloride (sylvite) and eventually lithium chloride and carbonate.

Pachamama: Mother Earth

Contemplating such geological marvels naturally generates a great respect for the planet. Such respect is very much present among indigenous populations through the Pachamama divinity, or Mother Earth in Aymara and Quechua languages. More than a goddess, Pachamama represents a mindset of gratitude to the Earth for fertility over planting and harvesting, and for sustaining life in harmony. People in western countries have been unplugged from this direct connection to the Earth, and a journey to the Puna region has the potential to re-establish it. ■

Part of the El Tatio geyser field.



Deepwater Exploration:
The Importance of Crustal Structure

ANDY ALVEY,
ALAN ROBERTS and
NICK KUSZNIR,
Badley Geoscience Ltd.

Cost-effective screening of frontier acreage is an essential early part of any deepwater exploration strategy at continental margins.

Screening of deepwater frontier acreage requires an understanding of crustal structure and crustal type within the ocean-continent transition of the associated rifted margin, with a view to addressing the question of whether the basement is likely to support a viable petroleum system within the overlying sedimentary basins.

The gravity inversion method described by Alvey et al. (2008), Chappell and Kusznir (2008), and Kusznir et al. (2018) can be used to map and characterize the regional crustal structure of many of the world's continental margins and their associated sedimentary basins. Key to this method are two corrections that must be made in order to account for the highly attenuated nature of the continental crust in deepwater basins and rifted margins. Firstly, an adjustment is made for the lithosphere thermal-gravity anomaly associated with the elevated geotherm produced by rifting and breakup. A prediction of magmatic addition to the crust at high stretching factors can then be made, following the decompression melting model (White and McKenzie, 1989).

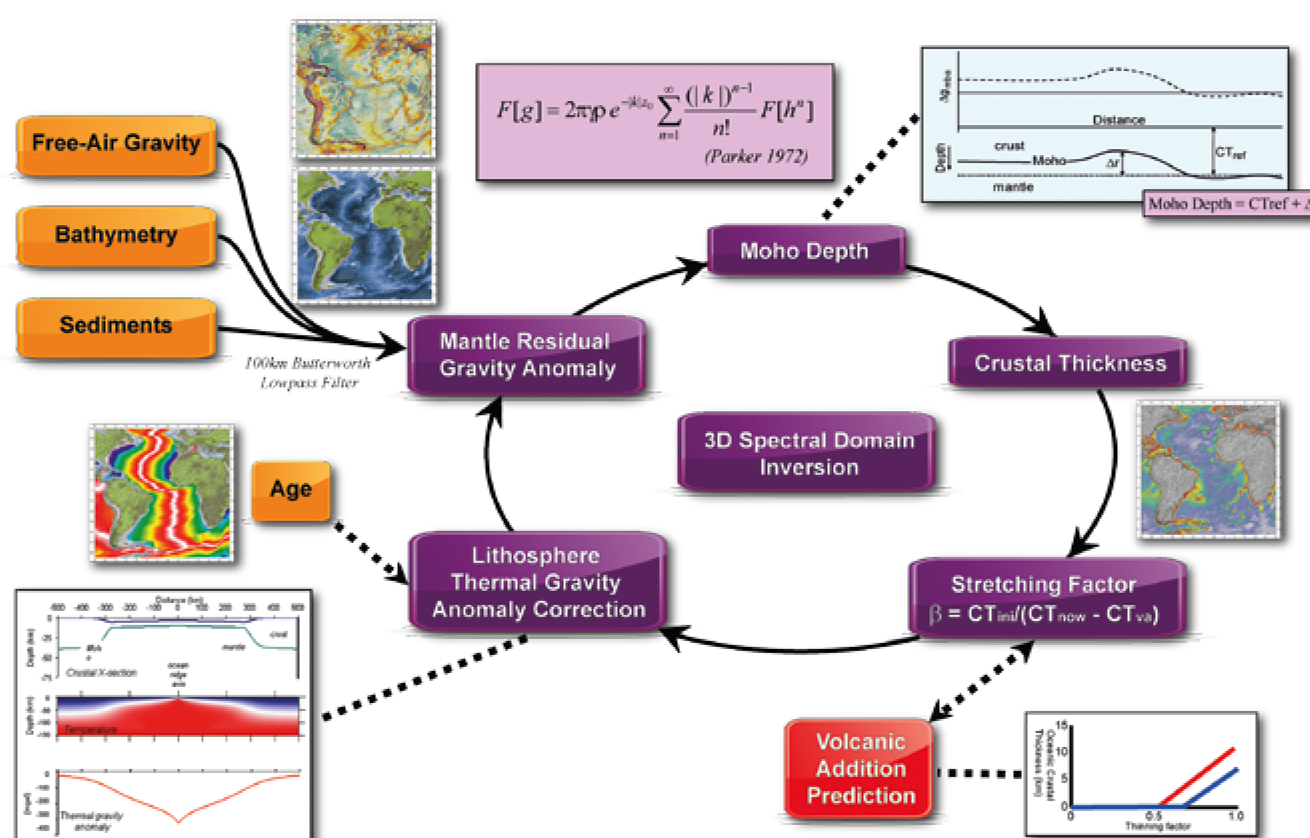
These corrections are required in order to produce reliable estimates of the thickness of hot, thin crust at continental margins. Consultants Badley Geoscience, in collaboration with the University of Liverpool, have developed this method, known as OCTek, to characterize whether crust is continental, oceanic or transitional, and to quantify both total crustal thickness and radiogenic continental crustal thickness, along with the lithosphere stretching/thinning factor, across most of the world's prospective margins.

Global Crustal Basement Thickness Map

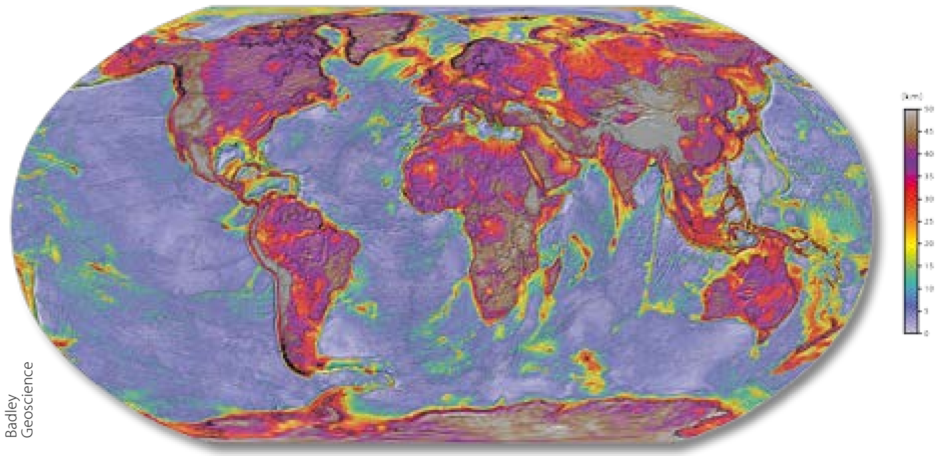
Using public domain free-air gravity, bathymetry and topography data, along with sediment thickness information, crustal thickness mapping has now been expanded to provide global coverage in a single map (Figure 2), extending the mapping onshore (see online for full data source details).

The use of public domain data is both a strength and weakness; its availability allows the global mapping to be performed, but its resolution and accuracy is an accepted compromise because of the scale of coverage. For this reason, local application of the method using optimized or proprietary sediment thickness data will always provide more accurate results than the global data.

Figure 1: Schematic outline of the OCTek gravity inversion method to determine Moho depth, crustal-basement thickness and lithosphere thinning factor, using gravity anomaly inversion incorporating a lithosphere thermal correction and decompression-melt prediction.



Adapted from Roberts et al (2013) and Kusznir et al (2018)



Badley Geoscience

Figure 2: Global map of total crustal basement thickness (continental and oceanic) from gravity inversion, overlain by a display of the shaded relief free-air gravity anomaly which enhances the underlying tectonic features (Robinson projection).

Notwithstanding this, it is believed that the first-order results of the global mapping, in terms of identifying areas of thick or thin crust and the transition in between, will be correct in both onshore and offshore areas, although for the former, in particular, the scale (in kilometers) should be taken as a guide rather than an absolute value.

The global map resolves the majority of known oceanic areas with a crustal thickness of about 5–7 km (i.e. normal thickness oceanic crust). Exceptions are known volcanic plateaus such as Iceland, Kerguelen and Ontong-Java, hotspot trails like those in the Pacific and the Walvis Ridge in the Atlantic, and microcontinental blocks including Jan Mayen, the Seychelles-Mascarenes and several others.

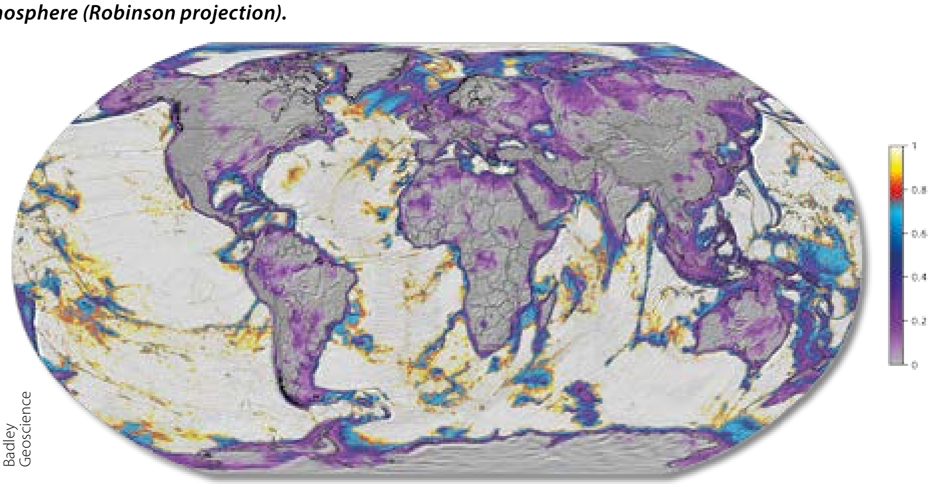
Onshore crustal thickness has a 'typical' value of ~37.5 km, with thicker crust delineating the major orogenic belts and the thick cratonic crust of Africa. Thinner onshore crust typically delineates intra-continental rift basins, many of which also extend offshore and link into the thinned crust of continental margins.

Continental Lithosphere Thinning Factor

Figure 3 illustrates another outcome of the OCTek global mapping: the calculation of continental lithosphere thinning factor (= $1–1/\beta$ where β is the more traditionally used stretching factor). A thinning factor value of 0 represents no thinning, or even crustal thickening in the case of the orogenic belts, while 1 denotes complete thinning and removal of the continental crust and lithosphere and its replacement by oceanic crust and lithosphere, or in some localized cases by exhumed mantle. This map was produced by taking the total crustal thickness map of Figure 2, subtracting the predicted magmatic addition by decompression melting (including 7 km of oceanic crust in oceanic areas) and referencing the remaining thickness of continental crust to an initial thickness of 37.5 km.

On a global scale the known oceanic areas 'clean up' nicely with a thinning factor of 1 (white). The anomalous oceanic areas of volcanic plateaus, hotspot trails and microcontinents all stand out with a lower thinning factor. Note that this map not only identifies the main ocean basins, it also recognizes smaller (often older and land-locked) ocean basins such as the Gulf of Mexico, Baffin Bay, the Mediterranean and the Black Sea.

Figure 3: Global map of continental-lithosphere thinning factor overlain by a display of the shaded relief free-air gravity anomaly to enhance underlying tectonic features. A thinning factor of 0 represents no thinning, in comparison to 1 which signifies complete thinning and removal of the continental crust and lithosphere (Robinson projection).



Badley Geoscience

The stretched and thinned continental margins, which are so important for frontier exploration, are delineated by the (colored) narrow zones of rapid thinning between unthinned continental crust onshore and oceanic crust offshore.

Within the onshore areas intra-continental rifts typically show up with a thinning factor of ~0.2–0.3 (e.g. the Amazon, Newark (USA), West Siberia and the North African Basins). Intra-continental rifts extending offshore may have a higher axial thinning factor of ~0.5 (e.g. the North Sea, Kara Sea and Canning (Australia) Basins).

Understanding the thinning/stretching factor within rifts and across margins is important, because this helps us quantify the transient thermal anomaly which results from lithosphere thinning, which in turn is a key input to any petroleum systems model in these basins.

Predicting Top-Basement Heat-Flow History

The use of these gravity inversion results as input to petroleum systems models can be extended still further by using them to make predictions of top-basement heat-flow history (Cowie and Kusznir, 2012; Roberts et al., 2018).

Top-basement heat-flow within a rift basin or margin results primarily from a combination of three heat sources: (i) radiogenic heat input from the continental basement, which following rifting is thinned from its initial pre-rift thickness and can be quantified from a map of crustal basement thickness; (ii) heat input from the transient elevated geotherm resulting from lithosphere stretching and thinning, which can be quantified from a map of continental-lithosphere thinning factor; and (iii) long term, steady-state heat loss from the mantle (~30mW/m^2). Figure 4 shows the application of this technique to the offshore Arctic.

The principal uncertainty in the prediction of heat-flow is calibrating how radioactive the basement is. The global average value for radiogenic heat input from unstretched continental basement is ~30 mW/m^2. The three examples illustrated in Figure 4c capture this value as the central case, with an uncertainty (in the absence of direct calibration) of +/- 50% on either side.

On all three heat-flow maps the active Atlantic/Eurasia spreading center stands out as a band of high heat-flow, while the old oceanic crust of the Canada Basin is cold. Top-basement heat-flow within the areas of thinned continental crust is seen to be dependent on the value of initial radiogenic heat used, reinforcing the importance of understanding the uncertainty within this parameter if no calibration is available.

The maps in Figure 4c all show a possible present-day case. A full heat-flow history, back through time to rifting/breakup, can also be produced using the same methodology (Roberts et al. 2018).

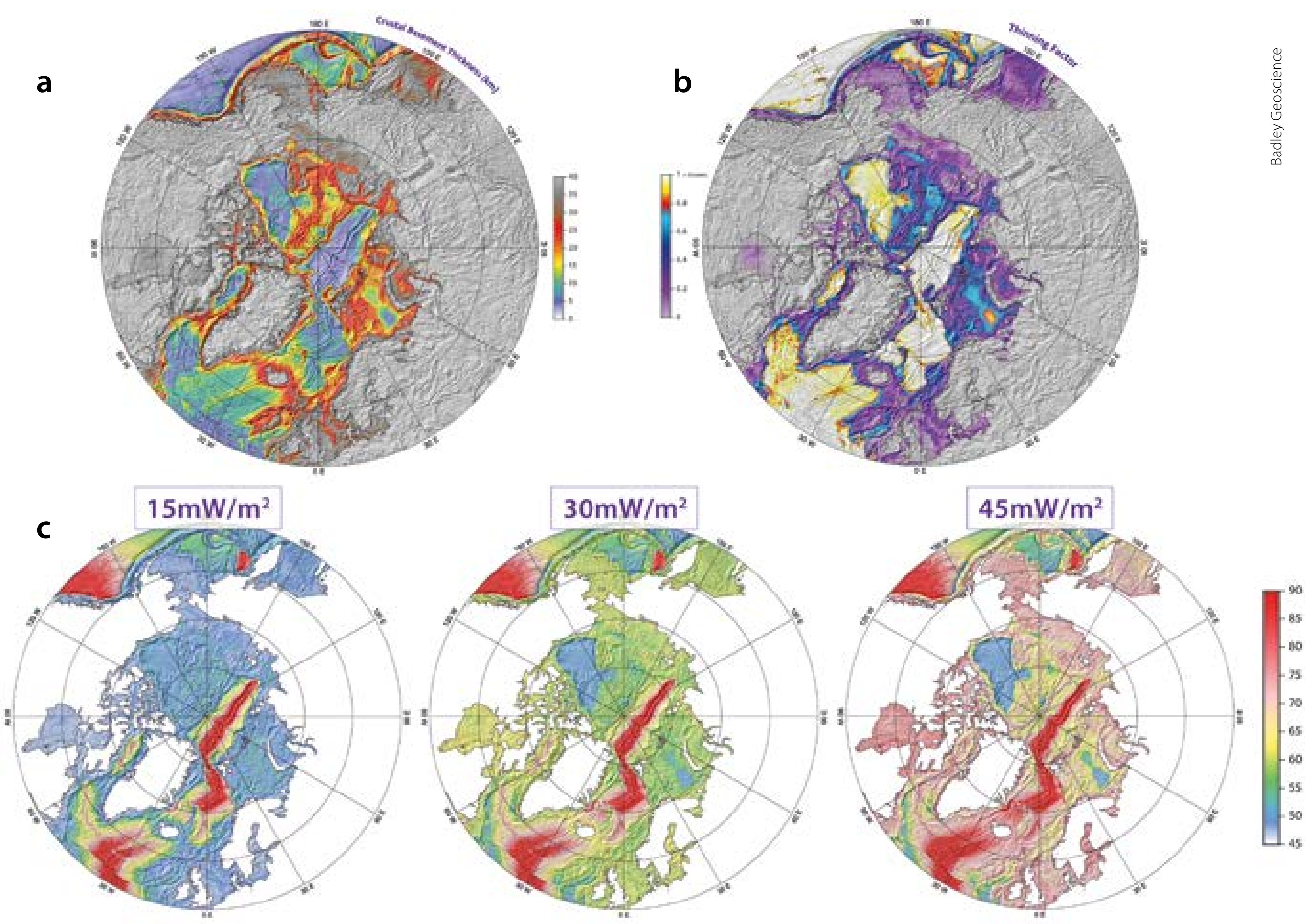
Understanding Crustal Structure

We hope this article has shown how a first-order understanding of crustal structure at a regional and global scale can be produced by using data which are freely available in the public domain. Quantified crustal structure, thinning factor and heat-flow history are all important contributions to any screening study of offshore frontier acreage, particularly in deep water. Maps of crustal thickness and thinning factor can also be used to provide constraints on plate reconstructions (Alvey et al., 2008; Kusznir et al., 2018).

The results presented here all contain some element of compromise as a consequence of the scale at which the mapping has been performed. The outcomes can, however, be refined and improved by focusing on smaller areas with bespoke parameterization of the gravity inversion and with the use of improved local sediment thickness information, where available.

References available online. ■

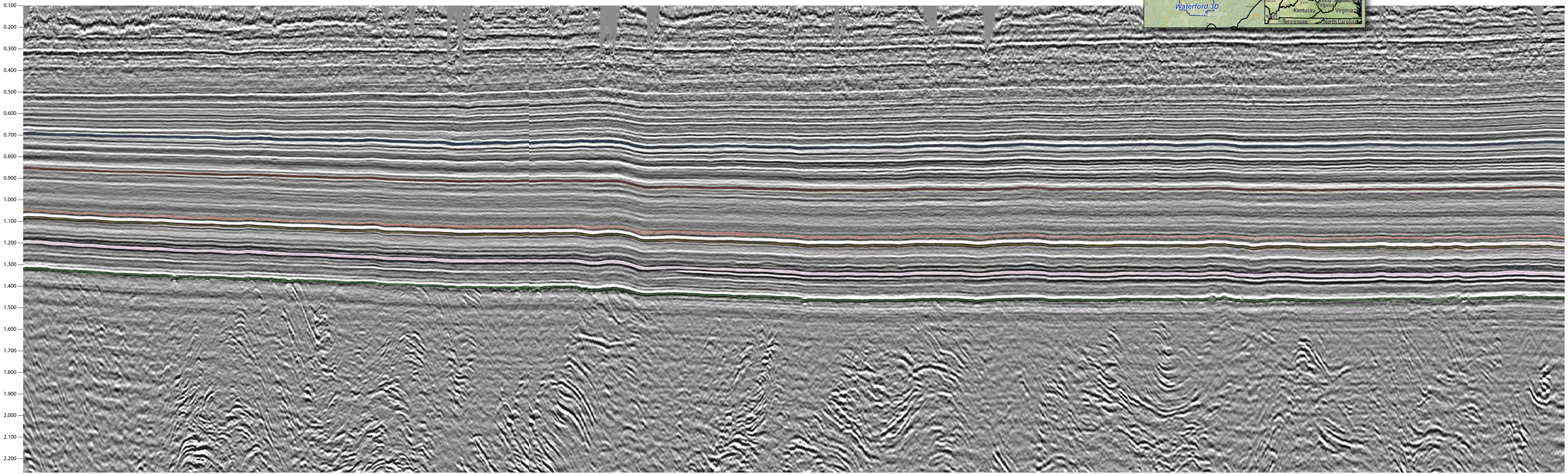
***Figure 4:** (a) Map of total crustal basement thickness (continental and oceanic) for the offshore Arctic, overlain by shaded relief free-air gravity anomaly; (b) Corresponding map of continental lithosphere thinning factor for the offshore Arctic, with oceanic areas picked out by a thinning factor of 1; (c) Three maps of present-day top-basement heat-flow for the offshore Arctic, derived from the results of the gravity inversion (without including the effects of sediment blanketing). Each is conditioned by a different value of initial crustal radiogenic heat-productivity: respectively 15, 30 (global average) and 45 mW/m^2.*



The Utica – Point Pleasant Shale

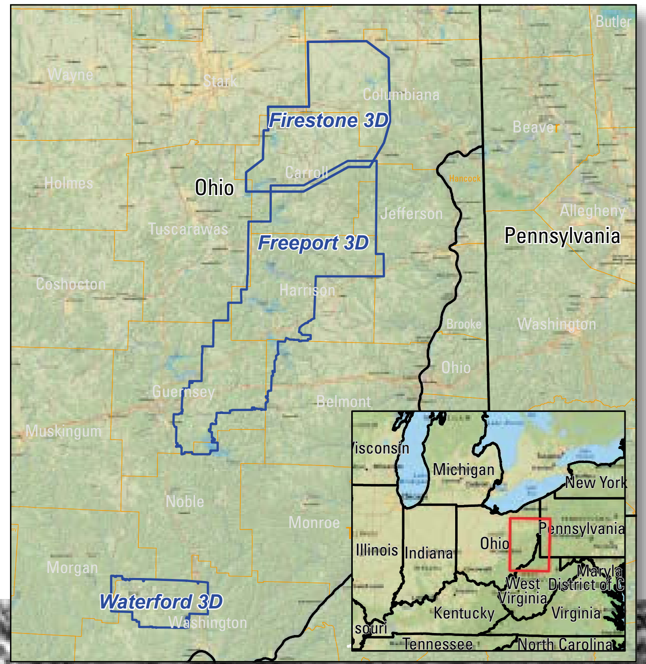
Using seismic reservoir characterization techniques is essential in the identification of sweet spots that represent the most favorable drilling areas such as the Utica Shale in eastern Ohio.

This south-west to north-east view along the TGS Freeport 3D seismic survey, Central Ohio, is oriented subparallel to structural strike along the west flank of the Appalachian Basin. The survey images some major regional faults, which appear as subtle rolls and deflections in the events at this scale. The line highlights the Devonian Onandaga (blue) to the Basement (green) with exceptional resolution. The Point Pleasant is the strong trough above the Trenton/Black River peak highlighted in yellow. Prospective zones in this view include the Utica (light red), Point Pleasant, Trenton Black River, Knox (pink) and Rose Run sands.



The Marcellus Shale, which has become widely known as a source of natural gas in the eastern United States, is a thick formation that covers 95,000 mi² (246,050 km²) across the Appalachian Basin. Approximately 2,000–7,000 ft (610–2,133m) below the Marcellus sits a geographically even more massive formation, the Utica Shale. Its areal extent is larger in that it spans more than 170,000 mi² (440,300 km²) over portions of seven U.S. states (Pennsylvania, Ohio, West Virginia, New York, Virginia, Kentucky, and Tennessee) and across the border into Canada (Ontario) (EIA Report, 2017). The Utica Shale is considered a source rock for oil and natural gas, and it has been produced by conventional means in the overlying rock formations. According to a 2012 USGS report, the formation holds 940 MMbo and approximately 38 Tcf of natural gas (Kirschbaum et al., 2012), but with more drilling and production, these estimates have been revised and now stand at 2 Bbo and 782 Tcfg (Cocklin, 2015).

The acquisition by TGS of a 702 mi² (1,818 km²) 3D seismic survey spread over Carroll, Tuscarawas, Guernsey, Noble, Belmont, Harrison and Jefferson counties of eastern Ohio was completed in late 2015. The processing of this large data volume was finalized in June 2016, with anisotropic pre-stack time migration gathers and stacked volume with 5D interpolation made available for reservoir characterization and quantitative interpretation.



Location of the TGS 3D surveys in eastern Ohio

Seismic reservoir characterization with efforts at quantitative interpretation: a case study

SATINDER CHOPRA, RITESH KUMAR SHARMA, HOSSEIN NEMATI, and JAMES KEAY; TGS

Eastern Ohio has become a new drilling target and the focus of development activity in the Utica Shale play.

Thermal maturity studies of the Utica Play Shales have indicated a north-east to south-west trend over eastern Ohio and western Pennsylvania, with a western oil phase window, (Mariani, 2013). The Utica Play thins to the west in Ohio and becomes deeper and thicker as its dips to the east and south-east of the Appalachian Basin (Antoine and Frederic, 2016). In eastern Ohio, therefore, the Utica Play is the preferred target (over the Marcellus) due to its increased thickness within the oil and wet gas windows and the higher reservoir pressures present because of the extra 2,000–6,000 ft (610–1,830m) of burial.

In this case study, we present our attempts at reservoir characterization of the Utica–Point Pleasant package in eastern Ohio, with the goal of identifying sweet spots. Such an exercise entails understanding the elastic properties, lithology, fluid content and areal distribution of the reservoir intervals. A good starting point for this is to use well data and understand the parameters that populate the reservoir intervals at the well locations, so sonic, density, gamma ray, resistivity, and porosity log curves were sought for the available wells within the 3D seismic volume. Core analysis results, geochemical as well as geomechanical data, were available for one well.

Preparing and Preconditioning Data

As we started compiling well data for our study, we realized that the wells with density logs were located in a cluster to the northern part of the survey, and very few wells had sonic and density curves, which is unfortunately a frequently encountered situation. It is always desirable to have a uniform distribution of wells with sonic, density, and other curves, even if sparse, because it helps the generation of a reliable low-frequency impedance model for impedance inversion, as well as for carrying out any neural network analysis for computation of a reservoir property. Once the final seismic data were loaded on the workstation, we assessed the quality and frequency content. The data were preconditioned for random noise attenuation by applying structure-oriented filtering (Marfurt, 2006; Chopra and Marfurt, 2007).

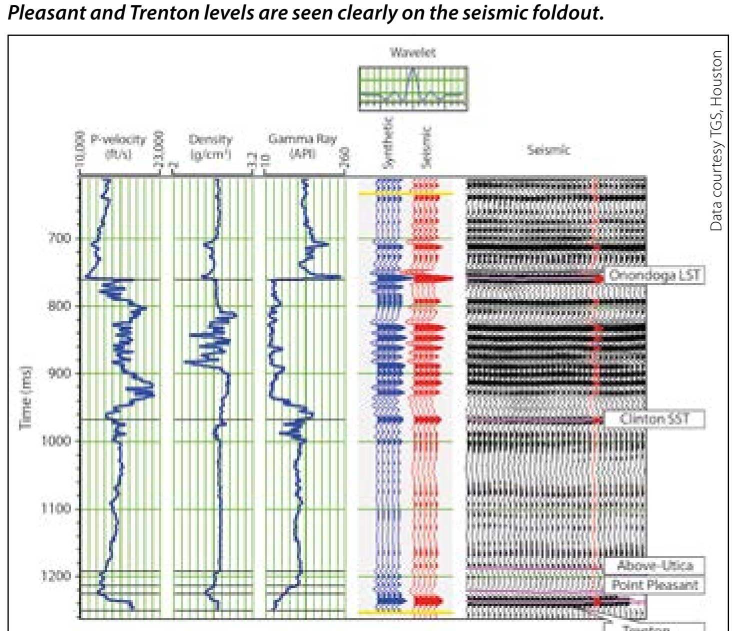
The pre-stack seismic data were preconditioned carefully, making sure that amplitudes were preserved. This entailed supergathering (3 × 3), bandpass filtering, random noise attenuation, and trim statics processes, with difference plots taken at each step to ensure that no useful signal leaked through the processes. The angle of incidence information was extracted from the velocity model generated for carrying out simultaneous inversion and overlaid on the offset gathers (below) to help quality control the range of angles that can be meaningfully used in the inversion process. We found that the usable angle range for simultaneous inversion was 34°.

In simultaneous pre-stack impedance inversion, multiple partial angle sub-stacks are inverted simultaneously. For each angle stack, a unique wavelet is estimated. Subsurface low-frequency models for P-impedance, S-impedance, and density-constrained with appropriate horizons in the broad zone of interest are constructed. The models, wavelets and partial stacks were used as input in the inversion, and the output was P-impedance and S-impedance. Because the usable angle range was only 34°, the density attribute could not be determined with simultaneous inversion, which requires angles beyond 40°.

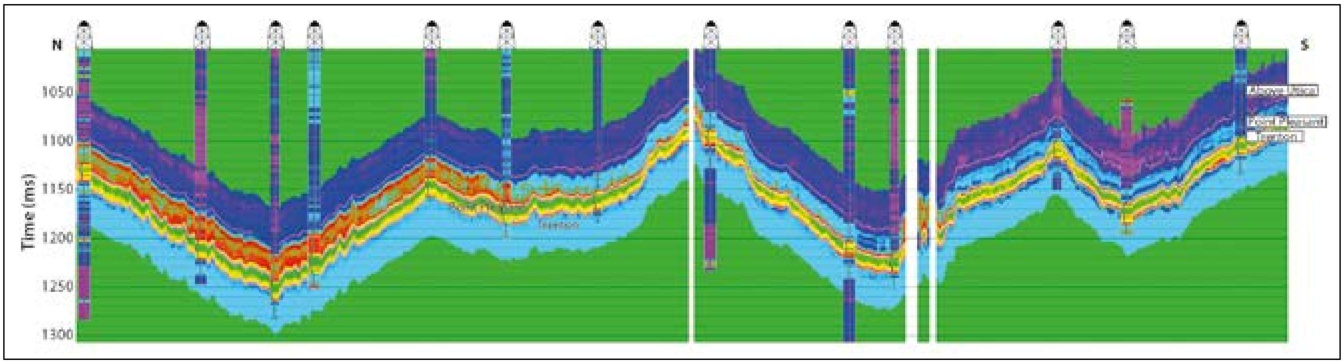
Sweet-Spot Determination

The main goal for shale resource characterization is usually the identification of sweet spots – pockets in the target formation that exhibit high TOC content, porosity and brittleness, thus representing the most favorable drilling targets. The organic richness in the shales influences properties such as P- and S-wave velocities and density (Chopra et al., 2012). In this study, we have tried to bring in data from core analysis, as well as geochemical

Correlation of well W-3 P-wave velocity, density and gamma ray curves with seismic data. Notice the sharp impedance contrast seen at the Onondaga Limestone and Trenton Formation levels giving rise to strong reflections. The horizons corresponding to Onondaga Limestone, 'Clinton' Sandstone and Point Pleasant and Trenton levels are seen clearly on the seismic foldout.



Data courtesy TGS, Houston



An arbitrary line passing through different wells in the density volume generated using neural network approach. The measured density logs have been inserted as variable density color log. A variation of density can be seen vertically as we go from Utica interval to Trenton. Additionally, lateral variation of density can be noticed within the individual intervals.

and geomechanical analysis, and integrate that with surface seismic data. When density and TOC measurements made on the core samples were cross-plotted, a strong linear relationship was seen in the Point Pleasant interval, suggesting that the density attribute would be required if the organic-rich zones in this interval are to be determined from seismic data.

In addition, as the angle range was not favorable for computing density from seismic data through simultaneous inversion, we turned to neural network analysis for this task. We decided to determine density with probabilistic neural network analysis using some of the attributes determined from simultaneous inversion (for further details see http://info.tgs.com/utica-pointpleasant_casestudy). Once the density volume was quality checked and determined, the relationship between density and TOC determined from core data was used to transform the predicted density volume into a TOC volume.

Realizing that the Point Pleasant interval has high calcite content (Patchen and Carter, 2012), meaning its ability to fail under stress and sustain fractures must be high, we extracted the P- and S-wave impedance derived from simultaneous inversion and density derived from probabilistic neural network analysis to compute the Young's modulus and Poisson's ratio attributes for the seismic volume. These were then cross-plotted for just the Utica to Trenton interval, which we interpret as prone to fracturing under stress. Its ability to sustain fractures in a relative sense can be examined based on the Young's modulus attribute.

To examine the lateral variation in the Young's modulus, we extracted a horizon slice from the Young's modulus volume. Thus, by restricting the values of the Poisson's ratio and examining the variation of the Young's modulus, we were able to determine the variation in the brittleness of the Point Pleasant interval.

Examination of the available XRD data showed that quartz, calcite and clay are the main minerals present in the Utica play. Additionally, regional petrophysical modeling carried out for the condensate region revealed a strong relationship between clay volume (Vclay) and the neutron porosity minus density porosity (NMD) data. Furthermore, the quartz and carbonates groups showed a strong relationship with the neutron porosity curve (NPHI). Thus, if we are able to compute the volumes of neutron porosity and density porosity (DPHI) we should be able to compute the mineralogical content of the Utica play.

We therefore crossplotted both neutron porosity and density porosity with those attributes from well log data that could be seismically derived, e.g. P-impedance, S-impedance and density. We found a good correlation between P-impedance and NPHI and density as well as DPHI and we can use these respective relationships for deriving both NPHI and DPHI volumes from P-impedance and density volumes.

A similar analysis was carried out for the Utica interval and we noticed a good correlation between DPHI and density, but a better correlation for S-impedance and NPHI. These determined relationships were then used for deriving NPHI and DPHI volumes from inverted P- and S-impedance and density and to transform the inverted volumes (P-impedance, S-impedance and density) into individual mineral content volumes. It was noticed that more than 40% clay content exists in the Utica interval, decreasing as we go from Utica to Trenton. Quartz group content varies from 20 – 40% for Utica and Point Pleasant intervals, being higher in the former than the latter. Additionally, carbonate content decreases moving from the Trenton to Utica interval. Considering the importance of brittleness and its association with mineralogical content of a formation, we also concluded that mineralogical BI proposed by Jin et al. (2014), would be a useful area of study due to high carbonate content in the target formation.

Characterizing Formations

Having characterized the Point Pleasant Formation in eastern Ohio using 3D surface seismic and its integration with core, geochemical, and geomechanical data, we found that it does not seem to follow the commonly found variation in terms of low Poisson's ratio and high Young's modulus for brittle pockets. By restricting the values of the Poisson's ratio and examining the variation of the Young's modulus, we could determine the brittleness behavior within the Utica and the Point Pleasant intervals based on the mineral content within these formations. Combining the brittleness behavior with the organic richness determined through the TOC content, we could pick sweet spots in the Point Pleasant interval that match production data.

This case study demonstrates that the integration of 3D surface seismic data with all other relevant data can be used to accurately characterize reservoir features.

References available online. ■

Advancing Geophysics Through Cooperation

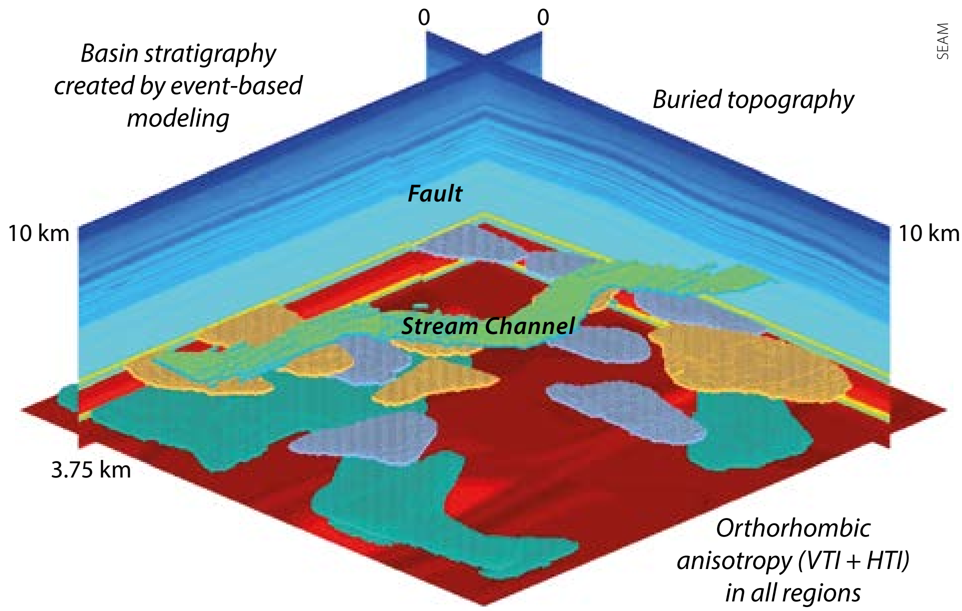
Propelling the science of geophysics to meet the grand challenges of tomorrow.

JOSEF PAFFENHOLZ, Chair SEAM Board of Directors

Geophysical research needs to continue to forge ahead to ensure that the acquisition, processing and imaging of seismic data reveals the maximum amount of information to facilitate the understanding of the sub-surface for resource extraction, ground water management, carbon storage and sequestration. The SEG Advanced Modeling Corporation (SEAM) was established in 2007 as a conduit to facilitate inter-company collaboration by working on projects too daunting and expensive for any one company. The SEAM projects so far have worked on large-scale, leading edge model building and numerical modeling. The resulting datasets are constructed around problems of importance to the resource-extraction industry and serve as research tools, benchmarks and educational tools. SEAM provides opportunities for companies to share the high cost of substantial model design, generation and data simulation. Participant companies can address large-scale modeling issues at a fraction of the cost of companies doing this alone, thus giving a substantial boost to advancing the art of modeling and computation.

SEAM projects typically are conducted in phases, each lasting approximately two to three years, by an industry consortium assembled around a geophysical challenge of great current relevance. The technical detail of the project work is directed by the participating companies, while SEAM provides logistical support by handling financial and legal matters as well as the long-term preservation and storage of data.

It is important that these results are accessible to the wider research and extractive industry so, after an initial two years of confidentiality, they enter the public domain. SEAM projects thus provide the geophysical exploration and training community with model data at a level of complexity and size that cannot be funded or computed by any single company or organization.



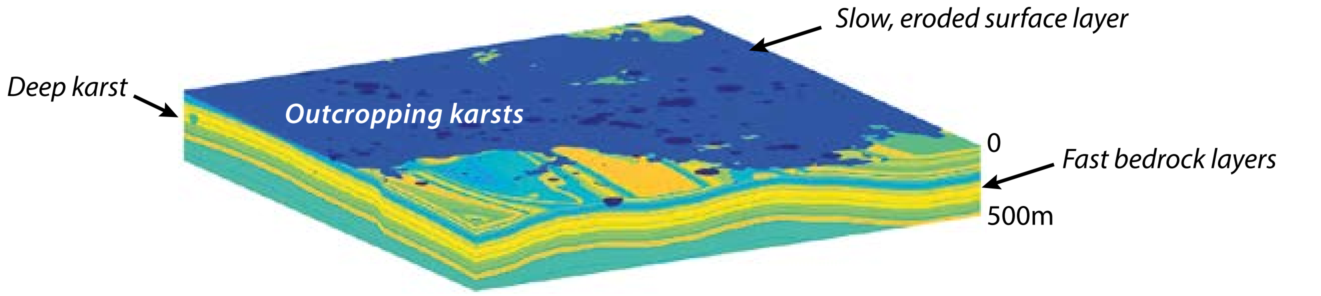
The Barrett Unconventional model includes the characterization of finely laminated and fractured shale reservoirs by their full seismic anisotropy. Geobodies like this represent sweet spots in shale layers based on Eagle Ford and Woodford Formations of Oklahoma and Texas.

Complex Imaging Challenges

One of SEAM's primary objectives is to design and generate synthetic models of 2D and 3D seismic data. One of the first issues tackled, in SEAM Phase I in 2007, was subsalt imaging in Tertiary basins. This entailed the construction of the SEAM Earth Model with the simulation of approximately 65,000 shot records, containing as many as 450,000 traces each for an acoustic dataset. Although this was representative of a 60-block area of the deepwater Gulf of Mexico, it was developed in a form that easily enables extension to other complex imaging challenges by adding the rock properties necessary for elastic, non-seismic, anisotropic and viscoelastic. The project was considered a resounding success, with data from it being used for a number of presentations at the 2011 SEG Annual Meeting.

This was followed by Phase II, which ran from 2011 to 2016 and looked at the specific challenges in the exploration and characterization of petroleum reservoirs on land. For this, three models were built: the Barrett Unconventional model, which focused on features of unconventional hydrocarbon reservoirs; the Arid model, looking at desert environments; and the Foothills model, focusing on features of mountainous regions. Phase II was a collaboration of 22 oil and oilfield service companies and more than 100,000 seismic shots were simulated over the three SEAM land models.

Ongoing projects include a study to evaluate and advance current methodologies for pre-drill pressure prediction and hazard avoidance through improved seismic imaging. While this project has concentrated on predicting pore pressure using surface seismic and EM data, a separately funded pilot (TimeLapse) looked at 4D pressure prediction, focusing on understanding the evolution of pore



The Phase II Arid model focused on features present in arid or desert environments and models karst structures and the extreme contrasts between unconsolidated near-surface sediments and bedrock, which often obscure deeper imaging targets.

pressure during production using time-lapse seismic data and reservoir characterization. This represents a significant advancement in the state of the art of geophysical numerical modeling by proving that time-lapse seismic for reservoir monitoring can be successfully simulated. This opens the door for using synthetic data to address problems and explore solutions for reservoir characterization during the life of the field.

The most recent SEAM project, which commenced late in 2015, looks at Life of Field workflows, including simulations of reservoir dynamics based on a realistic production scenario using complex geology, reservoir description and seismic data. The simulations will help participants to understand the value (or lack of value) of frequent 4D re-shoots.

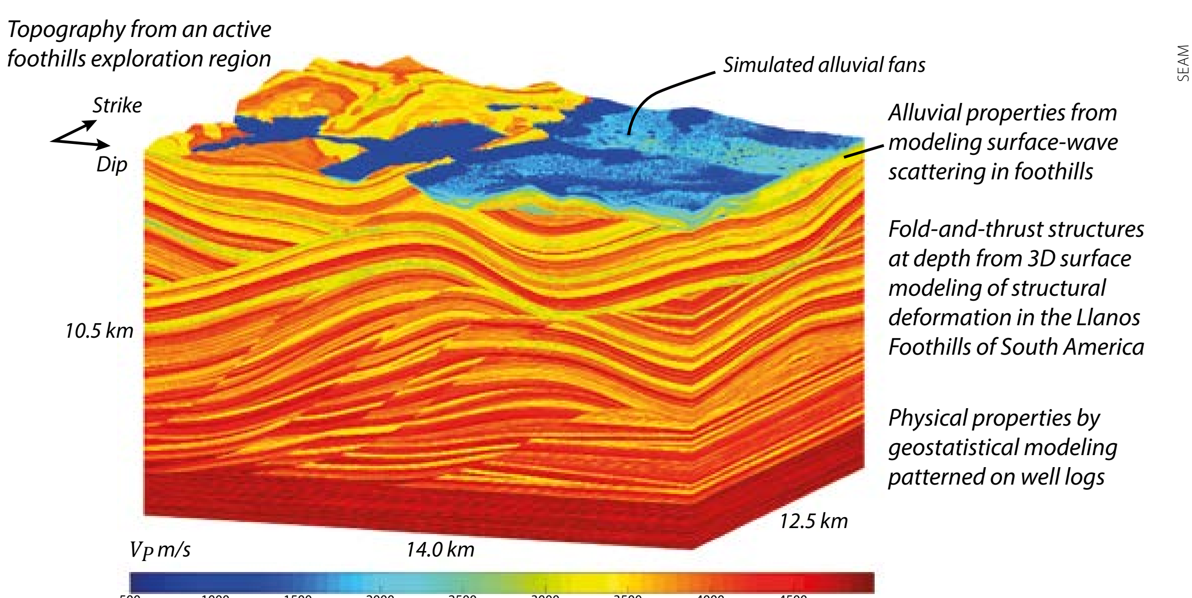
Building on the success of the modeling projects, SEAM is currently working to establish new projects to collaboratively advance the technology in areas of common interests. Two projects under consideration would look at issues around Full Waveform Inversion and at Artificial Intelligence. Both projects would expand collaboration beyond model building and data generation. They are scheduled for launch in early 2019.

Achieving Goals

The primary goals of SEAM are to provide a forum to discuss geophysical problems of interest and to advance the art of modeling and computation, while accelerating the pace of innovation and maintaining a constant stream of research activity. Progress in the 11 years since its inception suggest that it would appear to be successfully achieving those aims. Participants are very satisfied with the project and its results, with seismic companies, for example, saying that they see tremendous value in testing survey design methods and forward modeling and depth imaging algorithms, particularly taking advantage of the diverse experience of the contributors.

One of the most important aims of SEAM is to ensure that the data and learning gained through the projects is available to the wider industry, in order to provide vital benchmarking tools, as well as material to help educate the next generation of seismic processing and image experts. Therefore, small proprietary datasets are available free of charge to advance research and innovation in geophysics. These include 2D datasets from SEAM Phase I and samples of the model and other material from the Time Lapse project. These data can be downloaded from the SEG website, where, for a fee, the full datasets of all the SEAM projects are also available. ■

For the SEAM Foothills Model the complete wavefield was recorded at a dense array of three component receivers to test data interpolation and extrapolation algorithms in regions of rapidly varying and sharp topography, with alluvial fill at the surface and deep complex structures caused by compressive fold and thrust tectonics.



Solar Powers E&P

JANE WHALEY

A revolution is underway in the Omani desert: a renewable energy source is being used to help produce oil.

In the vast empty spaces of Oman's desert, about 300 km north-west of the southern city of Salalah, lies the Amal field. In common with many other fields in the country, Amal has considerable reserves of heavy oil – liquid petroleum with an API gravity of less than 20°. Heavy oil is highly viscous and does not flow easily, so the usual techniques for extracting the oil from reservoirs are not effective, and steam-assisted gravity drainage is used to induce it to flow to the surface. In this technique a pair of horizontal wells are drilled into the reservoir, one a few meters above the other, and high pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is produced. This is highly effective, but uses vast amounts of steam, which in Oman has been generated by burning natural gas, and now accounts for about 20% of the country's total gas use. With gas reserves depleting in the country and demand for domestic consumption increasing, however, using gas for enhanced oil recovery (EOR) is becoming unsustainable. It is also expensive: it is estimated that in a typical heavy oilfield, between 60% and 80% of the operating cost is fuel purchase for steam generation.

Steam and Mirrors

One commodity which is not in short supply in Oman is sunshine, so for a number of years Petroleum Development Oman (PDO) have been looking into ways of harnessing solar power to help produce heavy oil. In 2011 the company began collaborating with solar energy supplier GlassPoint, and in 2013 Alam West, the first solar EOR project in the Middle East, was commissioned. The 7 MWt pilot project delivered 50 tonnes of solar-generated steam a day, proving the effectiveness and cost-efficiency of the technology.

This paved the way for the development of a full scale solar-powered enhanced oil recovery (EOR) plant on the Amal field, with construction beginning in 2015. Unlike the solar panels that are used to generate electricity, GlassPoint's solution uses large mirrors which are curved, so they focus sunlight directly onto a pipe filled with water, which boils and is converted into steam. The mirrors are very simple curved sheets of aluminum foil, suspended by wires from the ceiling, and as the sun moves across the sky, small motors pull the wires to adjust the angle of the mirrors. The steam generated is exactly the same quality, temperature and pressure as that produced by burning natural gas, and can be fed directly into the oilfield's existing steam distribution network.

The arrays of mirrors are protected from the harsh desert winds and dust storms by greenhouses, which means that the components of the mirrors themselves can be lightweight and inexpensive. In February 2018 the first four greenhouse blocks of the project were inaugurated; these can deliver 660 tonnes

Curved mirrors focus the sun's rays at the Amal field.

GlassPoint

Huge greenhouses protect the steam-generating mirrors in the Miraah project.

of steam per day, with a total capacity of over 100 MWt, and the project is on track to deliver an additional eight blocks by early 2019.

Once completed the project, which is called Miraah (Arabic for mirror), will consist of 36 blocks, will cover 3 km^2 (an area equivalent to more than 360 football pitches) and will generate an average of 6,000 tons of solar steam each day, with a total capacity of one gigawatt. In fact, Miraah will be one of the world's biggest solar plants and will deliver the largest peak energy output – 1,021 MW – of any solar plant in the world at present.

Economic Benefits

For PDO, using solar power to create steam will significantly reduce operating costs for the Amal field, where it is estimated that the Miraah project will produce enough steam to extract about 35,000 bpd of heavy oil. The use of solar for EOR has therefore become a long-term strategic solution for PDO to develop its heavy oil portfolio and reduce consumption of natural gas.

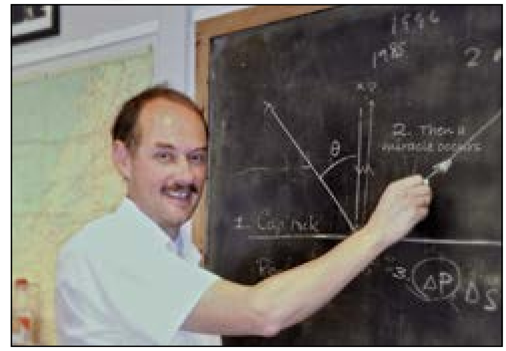
There are also major economic benefits to be gained by Oman through the use of solar energy for EOR. It is estimated that when the project is running at full capacity solar energy will replace the use of 5.6 BTU of natural gas a year – enough to provide electricity for more than 200,000 Omanis, or which could be used for industrial development or exported as LNG. The pioneering technology will also help diversify Oman's oil-based economy by establishing a new solar power industry, while creating much needed jobs and training in engineering, construction, operations and administration; over 60% of employees at GlassPoint's Oman subsidiary, established for this project, are Omani nationals. The vast majority of the materials needed to manufacture the Miraah steam generators can be sourced locally within the Sultanate, which helps generate in-country value through local supply chain development. And as a clean energy source, Miraah will reduce carbon emissions by over 300,000 tons annually, the equivalent of taking 63,000 cars permanently off the roads.

With the success of Miraah and other EOR solar projects, Oman is considered to be the Middle East regional leader in energy convergence, uniting renewable and conventional energy industries to demonstrate a significant and lasting economic benefit for the Sultanate. It is showing the way – and the industry is following. GlassPoint recently announced a project with oil and gas producer Aera Energy to build the largest solar plant in California, USA, which will be the first of its kind in the world to use solar steam and solar electricity to power oilfield operations. ■

Finite Difference Modeling: Part II

How to clean numeric time dispersion

"What you learn from others you can use to follow. What you learn for yourself you can use to lead."
Richard Hamming (1915–1998)
The Art of Doing Science and Engineering: Learning to Learn



Student: "I think you should be more explicit here in step two."

LASSE AMUNDSEN, ØRJAN PEDERSEN and MARTIN LANDRØ

Continuing the discussion that was started in GEO ExPro Vol. 15, No. 2.

The wave equation is the partial differential equation that governs the wavefield that geophysicists want to solve for advanced seismic imaging of the subsurface. The finite difference (FD) approximation gives us another partial differential equation – the one that we are actually solving in the computer for the wavefield. This approximation to time-stepping the wavefield produces a wavefield contaminated with temporal dispersion – a numerical error which is more pronounced towards higher frequencies or at longer wave propagation distances, and this error is accumulated over time. Time dispersion implies that the higher frequency components of the signal propagate at the wrong speed. Here we show how the Fourier transform can be used to relate the two partial differential equations and their solutions. Each of the two wavefields is then a time-frequency transformation of the other. Therefore, numerical time dispersion can be cleaned from FD modeled data post-modeling.

Finite difference (FD) modeling is the work horse of seismic imaging and inversion in our industry. FD-based Reverse Time Migration (RTM) and Full Waveform Inversion (FWI) are industry standard algorithms used to generate accurate images of the subsurface in complex geology. The bulk of the computational cost of RTM and FWI stems from simulating the propagation of waves inside the earth, a process that involves solving differential equations that describe the wave propagation under a set of initial, final and boundary conditions.

To solve the wave equation by the FD method one discretizes the equation in time and space, and time-steps the wavefield in small incremental time intervals. In this article we will not consider the spatial discretization of the model. We only note that pseudo-spectral or optimized operators can be used for spatial derivatives to keep the spatial errors at a minimum.

When time-stepping the wavefield forward in time increments Δt, the geophysicist needs to ensure that the numerical errors due to the time discretization – known as numerical time dispersion – do not become too large. This is done by selecting values of Δt that are sufficiently small enough for the numerical time dispersion to be minimized. .

Time Dispersion Leads the Signal

Numerical dispersion is the separation of different Fourier components of a FD approximation to a wavefield into a train of oscillations that travel at different speeds. Mathematically, it can be shown that when the physical velocity is constant equal to c, then the numerical waves travel with frequency (f)-dependent phase velocity

$$\hat{c}(f) = c/\,\mathrm{sinc}(\pi f \Delta t)\,,$$

where $sinc(a) = sin(a)/a$ is the sinc-function – which geophysicists will recognize as the Fourier transform of the rectangular function. The sinc is unity for $f = 0$ Hz, and decays gently with increasing frequency. Therefore, the effect of temporal discretization leads to numerical dispersion due to velocity increasing with frequency. The higher frequency components of the signal thus travel faster than the lower frequency components do. For the physical wavefield, all frequency components will travel with the same velocity.

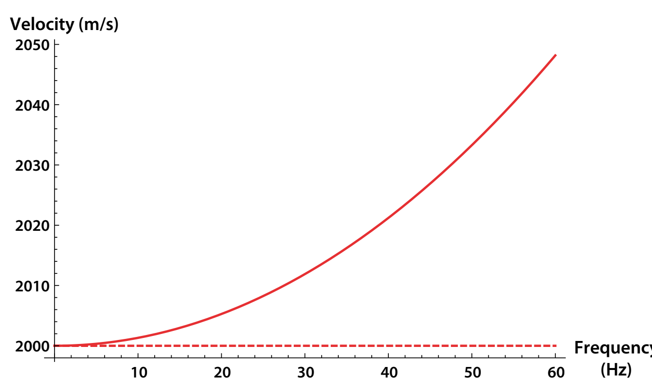


Figure 1: The wave speed in the physical medium is 2,000 m/s for all frequencies (dashed line). Due to time discretization of the wave equation (in this example Δt = 2 ms) the higher frequency components of the signal will travel with increasingly higher speed (solid line).

In Figure 2 we display the effect of time dispersion when solving the 1D wave equation in the same model as that used in Part 1 of this series. The non-red signals are the exact d'Alembert solutions to the wave equation at offsets 1, 2, 3, 4 and 5 km away from the source, which emits a Mexican hat wavelet into a homogeneous medium. However, when we solve the wave equation with too large a time step, as in the example of $\Delta t = 2\ ms$ in Figure 1, the frequency components of the source signal travel at a speed which increases with the increasing frequency. This is, as stated, a non-physical dispersive effect, and is shown by the red signals in Figure 2.

The good news is that the dispersion effect can be eliminated post-modeling. The not so good news, perhaps, is that to show how this can be done, we need to take you to the frequency domain by using Fourier transforms. The Fourier transform is useful in disciplines varying from geophysics, oceanography, signal and image processing, to speech recognition. In medical areas, it has helped in analyzing bio-signals such as heart rate variation and in interpreting X-ray computed tomography images. Fourier transforms can also be used to analyze and solve differential equations.

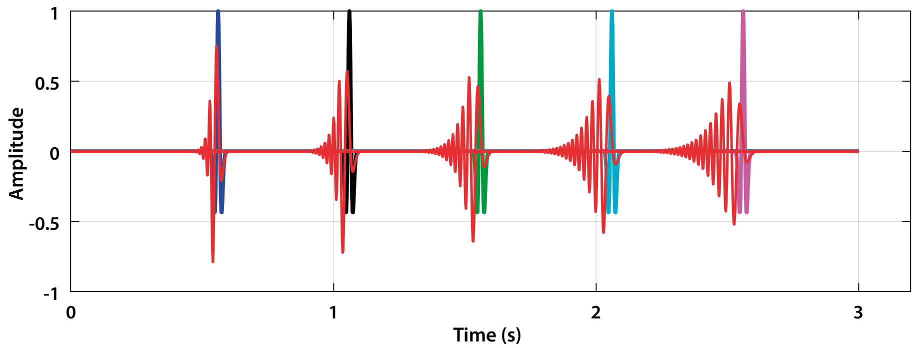


Figure 2: Mexican hat wavelets recorded at offsets 1, 2, 3, 4 and 5 km, in colors blue, black, green, cyan and magenta, respectively. FD modeling with time-stepping of 2 ms yields the red, dispersed signals, plotted together with the Mexican hats. Observe that time dispersion grows with increasing time or traveled distance, but can be cleaned by the procedure shown in this article.

Fourier Transforms

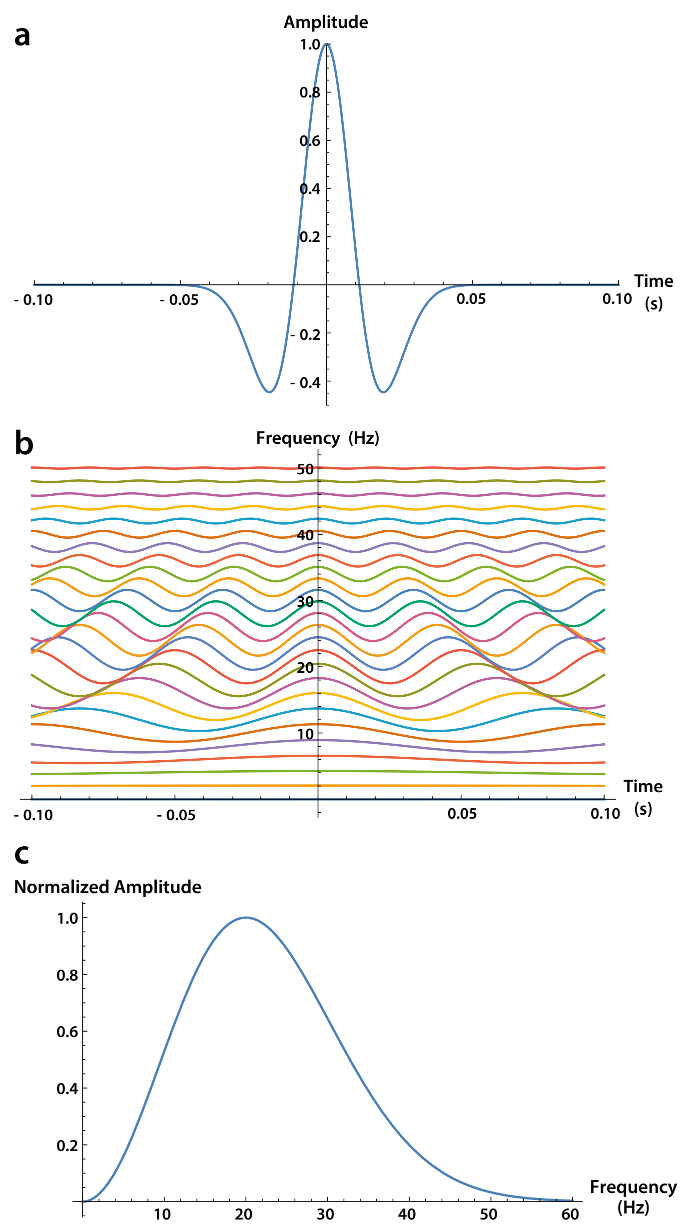
All waveforms or signals – functions of time or space – that you observe in the universe are just the sum of simple sinusoids of different frequencies. To calculate the signal's frequencies, amplitude and phase, the Fourier transform is often used. Making a graph of the Fourier transform of the signal – with the frequency on the x-axis and the amplitude or intensity on the y-axis – will show the strength of each frequency which corresponds with the signal. (If you want to learn more read the just-published text book by Ikelle and Amundsen, 2018).

As an example, let's break down the Mexican hat wavelet, shown in time in Figure 3a, into its 'building blocks', or constituent frequencies. The break-down or decomposition can be done with a Fourier transform, and is displayed in Figure 3b. When we sum (integrate) the breakdowns of the sinusoids shown in Figure 3b which the Mexican hat consists of, by using an inverse Fourier transform, we get back the Mexican hat signal.

Numerical Time Dispersion: History and Progress

It is well known that the numerical time dispersion is independent of any spatial dispersion (Dablain, 1986). Moreover, we know that the numerical time dispersion is independent of the wavefield's propagation path, the kind of elastic medium and any spatial modeling errors. Stork (2013) and others pointed out that the numerical time dispersion in FD-modeling can be filtered from seismograms post-modeling using time-variable filter banks. Zhang et al. (2013) and Wang and Xu (2015) proposed using a frequency-time transform to seismograms post-modeling to eliminate the time-stepping dispersion. Anderson et al. (2015) showed that these procedures require a pre-filtering of the source time wavelet before the modeling starts. The approach was redesigned in Qin et al. (2017), Xu et al. (2017), and extended by Koene et al. (2017). Mittet (2017, 2018) developed a general analysis of the temporal dispersion problem for

Figure 3. The Mexican hat time wavelet (a) can be broken down into sinusoids with frequencies between 0–50 Hz, shown in (b). The sum of sinusoids reproduces the time signal in (a). (c) shows the relative amplitude strengths of each of the sinusoids up to 60 Hz. Geophysicists use the Fourier transform to show what frequencies are in a signal. They also use the Fourier transform to analyze the wave equation.



various kinds of source terms. Amundsen and Pedersen (2018) showed how numerical time dispersion can be corrected also for waves traveling in media with absorption.

To be more explicit, consider the generic formula for the wave equation in time-space expressed as:

$$\mathcal{L}(x,t)u(x,t) = s(x,t);\;\; \mathcal{L} = \left(\frac{\partial^2}{\partial t^2} - L(x)\right) \quad (1)$$

where $L(x)$ is the system operator that contains material parameters and spatial derivatives, and s is the source term. For acoustic wave propagation, $L = c^2\nabla^2$, where $c = c(x)$ is the velocity and ∇^2 is the Laplacian. The FD solution of the wave equation (1), discretized in time, becomes:

$$\hat{\mathcal{L}}(x,t)\hat{u}(x,t) = \hat{s}(x,t);\;\; \hat{\mathcal{L}} = \left(\frac{D^2}{Dt^2} - L(x)\right) \quad (2a)$$

with the classic second-order accurate temporal discretization:

$$\frac{D^2\hat{u}(x,t)}{Dt^2} = \frac{\hat{u}(x,t+\Delta t) - 2\hat{u}(x,t) + \hat{u}(x,t-\Delta t)}{(\Delta t)^2}\,. \quad (2b)$$

(Observe that we use the hat-accent to indicate FD wavefields.)

By inserting equation 2b into 2a, and reordering the terms, we obtain the famous FD time-marching scheme which calculates the next value of the wavefield at the discrete time $t + \Delta t$ from current values known at time t and the previous time $t - \Delta t$ through the formula:

$$\hat{u}(x,t+\Delta t) = \left(2 + (\Delta t)^2 L(x)\right)\hat{u}(x,t) - \hat{u}(x,t-\Delta t) + (\Delta t)^2\hat{s}(x,t)\,. \quad (3)$$

Modeling by use of computers starts at time zero, and the time-stepping continues until the desired recording time is met.

Obviously, the exact wavefield and the FD wavefield are not equal, $u(x,t) \neq \hat{u}(x,t)$, since the differential operators for the wavefields differ, $L(x,t) \neq \hat{L}(x,t)$. The problem at hand is: we would like to know the solution $u(x,t)$ to the physical wave equation (1), but with the temporal discretization in equation 2 we obtain the FD wavefield $\hat{u}(x,t)$. Is there an exact relationship between the physical and FD wavefields?

A Miracle Occurs!

Yes! It is straightforward to show (see Amundsen and Pedersen, 2018) that when we Fourier transform the exact wave equation 1 to the frequency

$$\hat{f} = f\,\mathrm{sinc}(\pi f \Delta t)$$

but transform the FD wave equation 2a to the frequency f, then the differential operators of the two systems in frequency-space domain become equal: $L(x,\hat{f}) = \hat{L}(x,f)$. Then, the miracle occurs: since the differential operators are equal, the wavefields must be equal! Therefore, the exact wavefield and the FD wavefield obey the relation

$$u(\hat{f}) = \hat{u}(f)\,.$$

This is the key result. We have arrived at the point where, given a time-domain solution to one of the wave equations, we can derive the solution to the other wave equation by employing the Fourier transformation. Recall that $\hat{u}$ is the FD wavefield in time and space. Thus, since $\hat{u}$ is known for all times, we can Fourier transform $\hat{u}$ to the frequency domain at frequency f. At this point this wavefield u equals the temporally dispersion-free wavefield at frequency $\hat{f}$. Finally, an inverse Fourier transform gives the temporally dispersion-free wavefield in time.

Digital Filtering

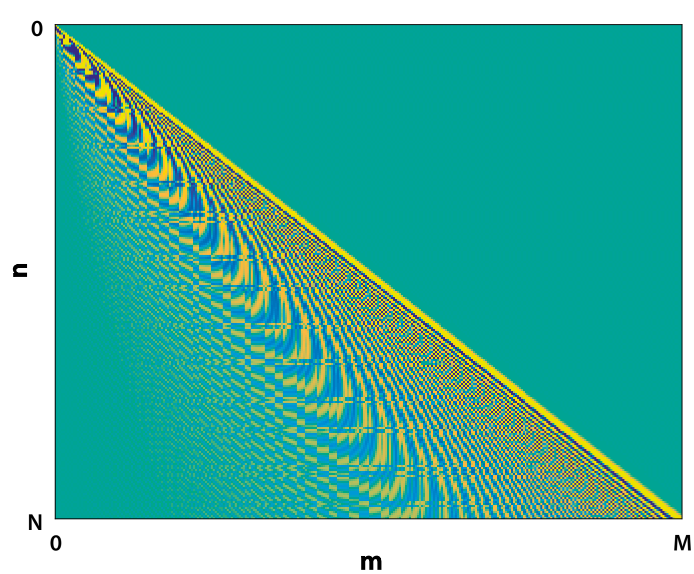
Mittet (2018) and Amundsen and Pedersen (2018) have shown that the dispersion elimination can be implemented by applying time-step independent digital filters to the FD-modeled data. The filters can be pre-computed and applied to any FD data modeled with second-order time integration (equation 2b) of the wave equation. Since the filters are independent of the time-step interval Δt, the geophysicist needs to compute the filters only once in his or her career.

When we discretize the time variables, $t = n\Delta t$, $t' = m\Delta t$, we obtain the result:

$$u(n) = \sum_m F(n,m)\hat{u}(m)$$

where $F(n,m)$ is the digital filter matrix. To remove time dispersion on sample n of the FD data, one simply computes a weighted sum over all samples m of the FD data. Figure 4 displays the filter matrix $F(n,m)$ in color. By applying this filter matrix to each of the dispersive signals in Figure 2 (which are recorded at different source-receiver distances), we map them back onto the Mexican hat wavelets that d'Alembert showed in 1746 to be the solutions of the 1D wave equation. ■

***Figure 4. Plot of the digital filter matrix** F(n,m), N = M = 1001 **that eliminates temporal numerical dispersion from dispersion-contaminated FD wave-equation seismograms.** F(n,m), **applied to the dispersion-contaminated data** $\hat{u}(m)$ **over all time samples** m, **predicts the dispersion-free data at time sample** n.*



Diversity: It's Up to Us All

Ask not what the energy industry can do for you, but what you can do for the energy industry.

FRANCIS GUGEN

Why am I interested in diversity? Because the energy industry has a problem. When I started in the oil and gas sector more than 40 years ago – yes, I have been around that long – few would have predicted that hydrocarbons would be thought of as evil. Nowadays, there is little understanding of how much good the energy industry has done for humanity, freeing people from spending their working lives toiling every waking hour on the land. Today, most of us would need at least 200 energy slaves, pedaling furiously, to provide us with our daily ration. Put simply, the energy industry has made us all pharaohs!

And this energy source is intensely concentrated. It may surprise many to learn there is eight times more energy in a pound of oil than in a pound of TNT! Finally, this power is cheap; a pint of crude oil costs about the same as a third of a pint of milk. So today much of our energy is incredibly ubiquitous, incredibly concentrated, and incredibly cheap!

Losing Talent

Does this mean we should accept climate change as an inevitable price to pay? Of course not. But it does mean we need serious solutions to a significant challenge. And for serious solutions we need: creativity; social license to operate (so that incumbent energy companies can be part of the solution and not excluded as part of the problem); and enough high quality skills and labor to work the problem. We cannot do this without diversity. If you are serious about tackling climate change you need to be serious about attracting more women into the energy sector.

Why do I say this? There are endless studies and examples of successful businesses, principally in other sectors, that show creativity is greatly increased with gender diversity. More women on boards correlates with higher share prices and return on capital, for example. What about social license to operate? Around 70% of energy-related purchasing decisions in the UK are made by women, but in the energy sector at present less than 5% of the executive directors are women. If you do not look like, sound like and maybe even truly understand your customers, how do you stand a chance of being able to work with them to find socially acceptable solutions that move us from where we are to where we need to be?

POWERful Women

Also, where are the people going to come from to create this new energy infrastructure and to remodel the industry? The attrition of energy industry joiners is much higher for women than it is for men. The industry cannot afford to train and then lose such significant numbers of talented people. The cost in staff recruitment and training is bad enough, but when we add the opportunity cost of lost talent, how do incumbents expect to compete against new players already forming part of the industry's transformation if they cannot crack this problem?

Women are substantially underrepresented in the oil and gas industry worldwide.

Diversity = Success

What are my credentials for talking about diversity as a pale, stale, male, industry veteran of over 40 years standing? Probably number one is that I have a daughter – it helps, at least for these purposes! I have also made considerable efforts in recent years to create more diverse teams, with some – but not universal – success. Why have I been keen to do so? Put simply – to make more money. I have been part of starting many businesses from a clean sheet of paper, all of which have needed ingenuity, creativity and in some cases a social license to be able to succeed. I can state without a shadow of a doubt that diversity has been an important factor in my business successes – and has made it a lot more fun. However, I felt sufficiently exercised about the lack of progress in the energy sector as a whole that I helped found POWERful Women and I continue to be actively involved in delivering our target, which is 40% of middle management, and 30% of executive board positions, to be female in the UK energy sector by 2030.

Can these targets be reached? The answer is yes, but not without concerted and continuous effort, given the size of the challenge we face. Of the top 80 UK energy companies, for example, only 30% have two or more women on their boards and 50% have no women at all. Turning to executive board seats, in these same companies only 4% have two or more female executive directors, with 8% having a single executive director, leaving a whopping 86% with all-male executive directors. Recent gender pay gap data only reinforces these same findings.

With such a poor starting point how can I say the targets can be reached? Simply because they *must* be reached if current energy incumbents are going to be part of the solution. A step change in gender diversity is essential if they are going to be able to transform themselves to meet the challenges that society, their customers and many shareholders are demanding. One only has to look at the growing number of institutions that will no longer invest in hydrocarbon-related businesses for evidence of such stakeholder pressure.

To me, the challenge is similar to safety. When I joined the industry we were perhaps too ready to find excuses for safety failures and in some cases even to accept that deaths were inevitable. But these attitudes have been completely transformed through leadership and a refusal to accept the status quo. Today you are many times safer working on a North Sea rig than you are in your own home! It is interesting that, according to some, the best way to get the next step change in safety performance is to have more women in the workforce, making it easier to improve behaviors. So the seemingly impossible can be done – it is largely a question of leadership.

Start With Yourself

And if it is behavior that makes the difference, then, whether male or female, the right place to start is with yourself!

If you are a male leader, make improving female

Women's networking groups and organizations can help push the diversity agenda.

representation one of your key priorities. Which women in your organization can you mentor? Do you know what your unconscious biases might be? (By definition no, so ask.) I remember a story told to me by one of the most able board colleagues I have ever had, about a woman who wanted a posting as manager of a country where at the time much business was done in none too salubrious evening establishments. Her then boss did not want to put her up for the role because he was reluctant to expose her to inappropriate practices: the reaction of a man brought up to protect women. But, as she rightfully said, this was not his decision to make, it was hers. He realized he had an unconscious bias and dropped his objection; she got the job and proved to be one of the most successful country managers they had ever had. As a man, if you are in a position of leadership in your organization, make female contribution and diversity as important as safety, and watch your company's results improve. What did we in the energy industry do with safety to make a real difference? We improved measurement, but crucially we recognized it was about behavior and leadership.

Francis (in grey suit) and others listening to Baroness Verma, co-founder of POWERful Women.

As a woman, there are things you can do too. Research by Accenture has shown three things make a real difference: firstly, improve your digital fluency (the extent to which you use digital technologies to connect, learn and work); secondly, have a career strategy – aim high, make informed choices and proactively manage your career , such as having a mentor and working for a company that supports women; and thirdly, improve your tech immersion (take opportunities to acquire greater and stronger digital skills and experience adapting quickly to new technology).

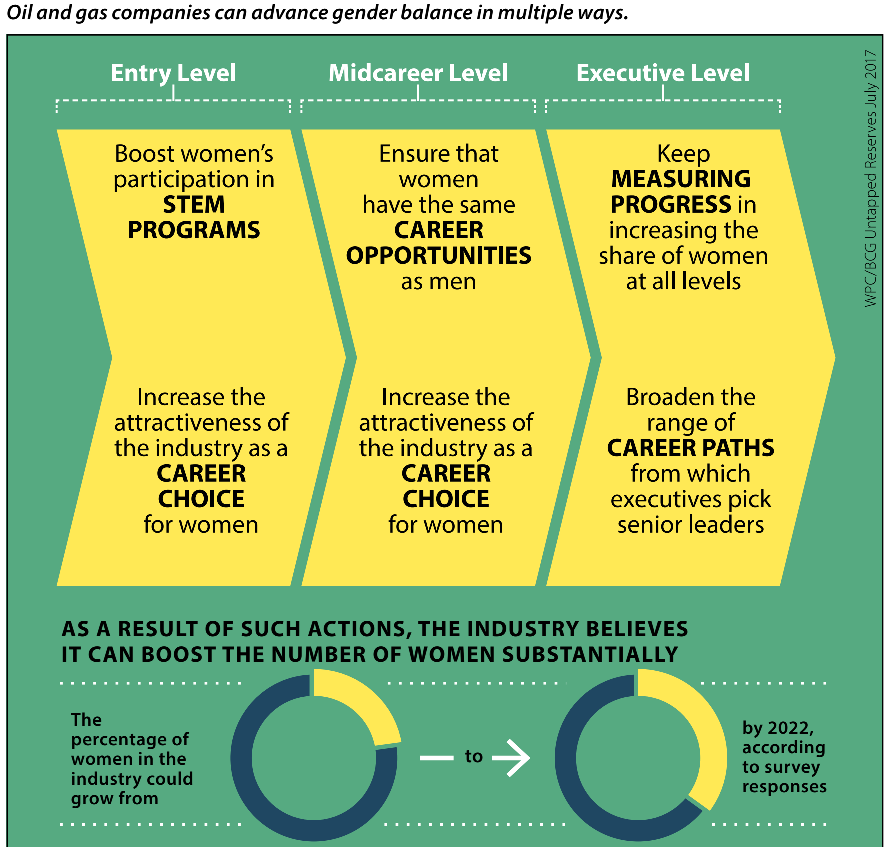
How can initiatives like POWERful Women help and how do they affect you? The organization works in a number of ways, including:

- Mentoring and advice for aspiring women; both men and women are encouraged to become mentors and mentees;
- Reporting on board statistics and the gender pay gap, to help show what progress is being made; these are statistics that can and should be tracked in your own organization;
- Corporate leadership: energy companies aiming high and committed to improving;
- Encouraging company pledges towards diversity: is your organization already involved and, if not, could it be?
- Leadership from government: involved from the very start, the UK government continues to play a vital role in driving the campaign forward.

Leadership Vital

If you take away one message, it should be the vital role of leadership. In May, POWERful Women announced the

Oil and gas companies can advance gender balance in multiple ways.



formation of the Energy Leaders' Coalition, comprising eight leading CEOs from the UK's energy sector who have made a public declaration to improve gender diversity in their companies and in the sector as a whole. Each recognizes that there is a rich pool of talented women in the sector who can make a significant contribution to the growth of their business and to the transformation of the energy sector to meet the challenges of the coming decades. The members are at different stages of the journey to meeting government and industry targets, but all are honest that they have a way to go and will benefit from the experience and support of their fellow CEOs. The Coalition will meet regularly to review progress, share evidence of what works and plan actions to improve. They will act as 'ambassadors' to encourage others in the sector to accelerate change by demonstrating the benefits to their business.

In summary, is there a need for more women at senior levels in the energy sector? Absolutely. Are our goals achievable? Yes. What will it take? Leadership. Whose leadership? Yours!

So, ask not what the energy industry can do for you, but what you can do for the energy industry. No matter what level you are at in your organization, it all counts.
References available online. ■

Francis Gugen is a Founding Board member of POWERful Women and an oil industry veteran. Read his GEO Profile in *GEO ExPro* Vol. 14, No. 2.

It's All About the Rocks!

The Sidney Powers Memorial Award is the AAPG's most prestigious award, given in recognition of outstanding contributions to, or achievements in, petroleum geology. In 2018 it was awarded for the first time to a geophysicist, Michael Forrest, known as the 'Father of Bright Spots' from his work with Shell during the late 1960s and early '70s.

JANE WHALEY

Mike Forrest was responsible for recognizing and helping develop the use of seismic amplitude anomalies, or 'bright spots', in petroleum exploration. After a 37-year career with Shell and five years with Maxus Energy, he led the Rose & Associates DHI Risk Analysis consortium and, now in his eighties, still travels the world promoting and researching the concept.

Learning Geophysics

"I had an interesting route into oil exploration," Mike explains. "Growing up in St Louis, Missouri, my high school was strong in science and math. I went to St. Louis University, which had a good geophysics program and the course curriculum fitted my interests, even though I knew very little about geophysics at the time. During the first couple of years you take general subjects, so to learn more I wrote to oil companies looking for a summer job and was offered one by Shell. I worked three months on a seismic crew in the Hill Country of Texas, planting geophones, helping the survey crew, watching the seismic recording – that was back in the days when we had paper records. I learned the basics of seismic acquisition that summer. Shell hired me back the following year which helped me whiz the geophysics courses at school!"

After finishing his degree in Geophysical Engineering, Mike joined Shell full time to work on a seismic crew in South Louisiana. A couple of years later, they moved him to the Offshore Division in New Orleans – a whole different scenario. "All of a sudden, I was asked to interpret many miles of 2D seismic!", he says. "Onshore seismic acquisition is very slow compared to offshore: permitting can be difficult, there are gaps in the data, and other issues. Shell had its own seismic boats, so we could shoot one-mile grids and have loads of data. I loved offshore seismic interpretation and learned the basic geology of the Gulf of Mexico. I must have had a knack for geology because my co-workers told me my maps 'looked geological'!

Patsy Alexander

Seeing Bright Spots

Mike progressed through Shell and began working on offshore seismic data for lease sales.

"In 1967 I was assigned a

project in an offshore Louisiana sale concentrating on a deep structure when I noticed a curious, strong, shallower seismic reflector which seemed to run parallel to the structural contours and was interpreted as a hard, calcareous zone. The deep structure was dry – but the shallow 'bright spot' proved to be a 30 ft gas sand. No one was interested in shallow gas at the time – this was 1968 and the gas price was very low; the emphasis was exploring for oil.

"Shortly afterwards, I was asked to lead a project looking for Gulf of Mexico Plio-Pleistocene prospects," Mike continues. "I observed many bright spots on structural closures but there was essentially no well control for calibration. In another area, a strong reflection matched a thick pay sand on the south flank of the large Bay Marchand salt dome field. I continued mapping these anomalies but my co-workers were very sceptical. At the time, seismic was used to map subsurface structure, not for direct detection of hydrocarbons – I was the joke of the office!"

Undeterred, Mike began comparing well logs and seismic in areas where he had spotted amplitudes, and in early 1969 his regional geophysical manager suggested that he document his ideas.

"I gathered data on several oil and gas fields in the shallow water Louisiana shelf area. I looked at the maps, well logs and seismic data and tied it all together – integration, we call it today – and was able to show how both gas and oil pays were related to amplitude anomalies on seismic data and calibrated to low impedance intervals on well logs. Shell management were very excited and formed an operations/research team for detailed studies. I went to Houston to meet with research staff, who shook their heads, wondering why it had not been previously studied. It goes to show that good ideas don't always come from research. Operations people can generate ideas, but they need researchers to quantify and refine them.

"I'm often described as 'the father of bright spots' by my Shell co-workers – but I didn't coin the expression," he adds. "A colleague looked over my shoulder one day and said, 'Those strong reflections look like bright spots' and the term stuck."

Mike (second from right) worked on Shell seismic crews during the summers of 1953 and 1954.

Testing the Concept

Shell's bids in the 1970 Gulf of Mexico lease sale were mostly based on seismic amplitudes, coupled with a simple software program which helped quantify the amplitude changes and pay thickness. "We won a number of blocks and all but one of the prospects found gas or oil."

Shell organized a key team of geologists, geophysicists and petrophysicists to work on a database of seismic, well logs and drilling results in order to, among other things, determine how different rock types and hydrocarbons would appear on seismic. "This was revolutionary," Mike continues, "an integrated exploration and production team working together. Not everyone thought bright spots work to identify oil pays, though.

"I emphasize that you can't just rely on amplitudes, you have to keep the geology in mind. I remember a promising prospect with a good bright spot, but the trap was questionable. We drilled the prospect and found a low gas saturation wet sand; we've since realized that seismic cannot tell the difference between a sand with 20% gas saturation and one with 80% gas saturation. Geology, petrophysics and seismic studies are all needed for bright spot technology to be successful in oil and gas exploration."

Shell tried to keep bright spots confidential, but by 1973 the theory and application were common knowledge in the industry.

Moving into Deep Water

In 1978 Mike was appointed Manager of Shell's Alaskan operations. Although still based in Houston, he made frequent visits to Anchorage and has fond memories of his time there. "The office had a closet full of coats, furs and boots for the winter seismic and drilling season. Unfortunately, we didn't find enough oil to be economic. I also managed Bering Sea exploration operations, then California, and other places onshore USA – but never the Rocky Mountains."

In 1984 he became General Manager for Shell's Gulf of Mexico Exploration Division, where much of the exploration was based on identifying and drilling amplitudes. Mike's experience of the Bering Sea frontier exploration encouraged him and his staff to review prospects in water depths of 2,000 to 6,000 feet. The use of bright spots, coupled with a change in the bidding system, meant Shell became very successful in deepwater exploration in the Gulf.

"Previous lease rounds were based on competitive cash bidding and economic analysis of relatively small areas," he explains. "In 1983 area-wide leasing was introduced and companies could identify their own prospects, which spread competition and encouraged more drilling. We were in a whole new world. We didn't know if the development of exploration discoveries using tension leg platforms and other technologies would be economic in very deep water. Also, the geology was different as the sands were deepwater turbidites, in contrast to shallow-water marine sands on the Gulf of Mexico Shelf.

"Shell was one of the first to explore in water depths greater than 2,000 feet and although we could see excellent amplitude anomalies, it was very speculative at the time. The drilling program had some successes but then a string of dry holes. Finally, in late '88, after I had moved to another assignment, Shell decided to drill a prospect that was a last-minute addition to the bids at the 1985 lease sale – and discovered the 1.5 billion-barrel Mars field with many oil and gas pay sands. This changed the whole deepwater scenario."

On a trip to Sanaa, the capital city of Yemen, to celebrate an oil discovery in South Yemen.

The DHI Consortium

In 1992, Mike Forrest retired from Shell, worked with Maxus Energy in Dallas for five years and then moved to consulting. During late 2000, he met with an old colleague, Pete Rose.

"Pete explained that a number of Houston oil companies wanted to work together to investigate bright spots and AVO (Amplitude vs. Offset) analysis," Mike says. "Roger Holeywell, a geologist/programmer, and I formed the Rose & Associates DHI (Direct Hydrocarbon Indicator) Risk Analysis Consortium in January 2001 and geophysicist Rocky Roden joined us a few months later. We built software to help interpret the seismic and geology data, and the DHI Consortium grew, expanding into Europe in 2007. We now have ten companies in Houston and 22 in Europe.

"We have five one-day meetings in Houston and three two-day meetings in Europe every year; about 40 people from up to 20 companies attend each gathering. Companies show prospects with a DHI (Direct Hydrocarbon Indicator, the industry accepted name for a bright spot), along with the data they had presented to their management in a drilling recommendation – but don't tell us the result! We study several prospects each meeting, starting with the geology, then geophysics, maps and petrophysics. The group risks each prospect, considering petroleum system elements such as trap and seal and a number of seismic amplitude anomaly characteristics, and end up with a number that represents the geologic chance of success of the prospect – and then we say 'tell us the drilling results'. It's very interesting, as companies think in different ways and the attendees learn a lot from each other. We now have 318 prospects in our database, graded as to the probability of geologic success mostly using the calculated 'DHI index' in our SAAM (Seismic Amplitude Analysis Module), and we occasionally publish papers on the topic.

"We also have a lot of fun, with trips, dinners, even field trips, including an excellent one in Bordeaux, which, of course, included visits to a couple of vineyards."

Keeping Active

Mike admits he has reached an age when many men would be sitting back and taking it easy, but says: "I keep busy because it's fun! I love looking at seismic lines; at my retirement party from Shell they plastered the walls with seismic – all prospects that I had worked on. I never forget a seismic line – looking at them is really like a hobby for me.

"DHI studies are great, but geology must always come first in a prospect review – and I have found that geology is always much more complicated than an interpreter originally envisions. Geophysics has made huge advancements in seismic imaging technology during the past 50 years, but in the end, it's about understanding the rocks; that's what we do," he adds.

Mike is enthusiastic about the industry's charitable outlets. He has been a member of the SEG Foundation board for 10 years, including Chair for four years, and is now focusing on fund raising for the SEG Geoscientists Without Borders program which supports humanitarian applications of geoscience around the world, as well as a student program. He is very interested in the Foundation and the changes it can make.

"Being active keeps me healthy," he laughs. "Also travelling – though I still haven't made it to New Zealand but I hope to get there soon."

How did he feel about being given the Sidney Powers Medal? "When I first heard about it, I was in shock," Mike replies. "I heard that one of the people who nominated me was Marlan Downey, past Sidney Powers Awardee who sadly passed away in May, 2017 (see *GEO ExPro*, Vol. 8, No. 6). Marlan, also retired from Shell, was a brilliant geologist, and I was very honored by his recommendation, especially as the first geophysicist to have received the award."

A very well-deserved award indeed! ■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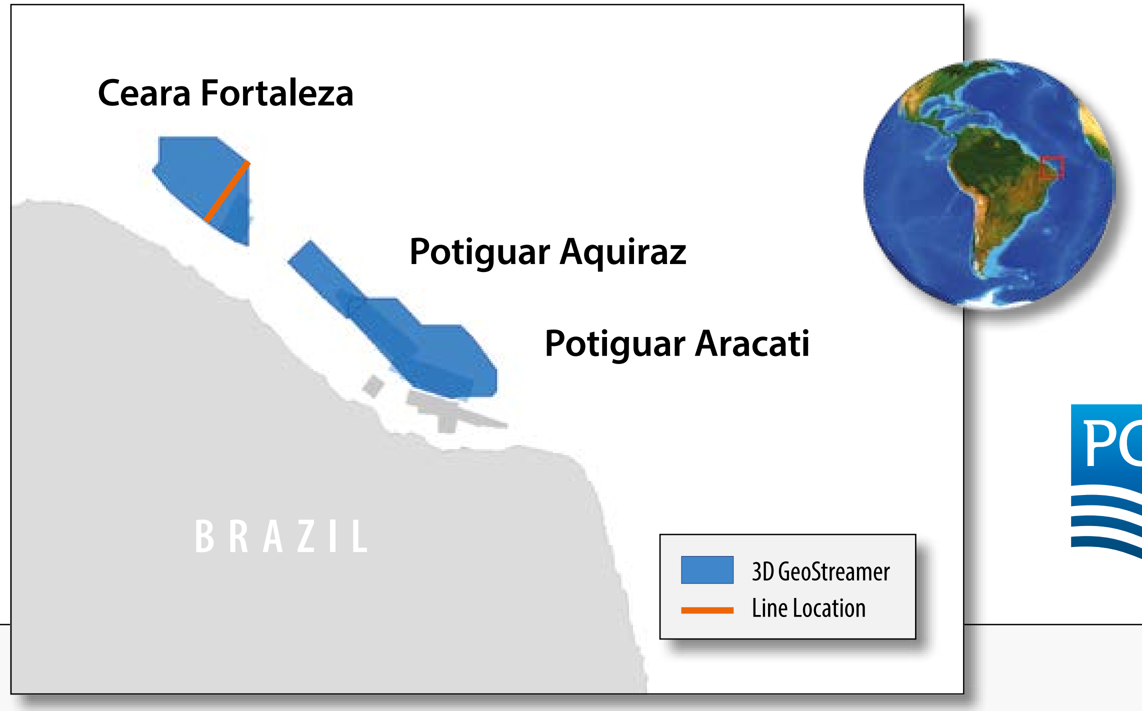
Ceará to Potiguar:

New Insights into an Underexplored Hydrocarbon Province

The Ceará and Potiguar Basins on the equatorial margin of Brazil are two deepwater underexplored basins. Both have geological exploration successes, indicating working petroleum systems and potential deepwater reservoirs.

PGS has undertaken an extensive series of broadband multi-sensor GeoStreamer 3D surveys to address exploration concerns and de-risk play elements in the Potiguar and Ceará Basins. In 2015, the company acquired the Ceará Fortaleza survey, followed by Potiguar Aquiraz in 2016 and Potiguar Aracati in 2017, covering over 18,000 km² in total. Potiguar Touros is currently being permitted and is scheduled for acquisition in 2019.

Several major E&P companies, including Petrobras, BP and Devon, have investigated the potential on the equatorial margin in recent years. Pecem and Pitu, discovered by Petrobras in the Ceará and Potiguar Basins respectively, are the two deepwater discoveries that have given life to the exploration programs of subsequent leaseholders like Total, Wintershall and Shell.



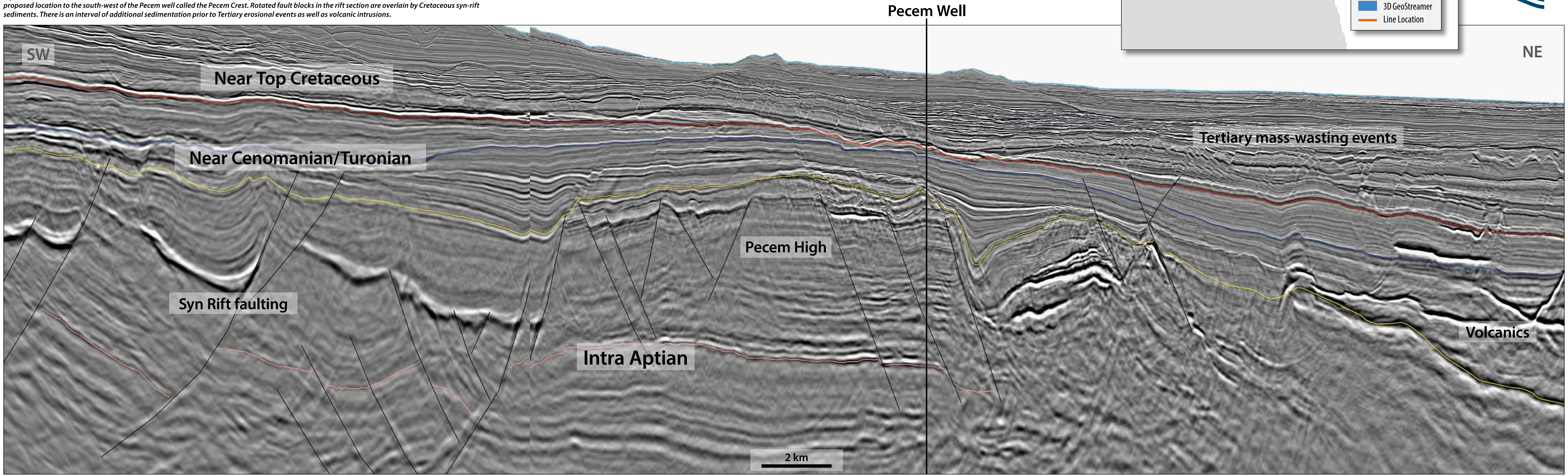


Figure 1: This Ceará Fortaleza dip seismic section demonstrates some of the significant surfaces in the area of the Pecem discovery well. Premier has a proposed location to the south-west of the Pecem well called the Pecem Crest. Rotated fault blocks in the rift section are overlain by Cretaceous syn-rift sediments. There is an interval of additional sedimentation prior to Tertiary erosional events as well as volcanic intrusions.

GeoStreamer Data Reveals Exploration Potential

PGS GeoStreamer 3D datasets are positioned to give explorers in Ceará and Potiguar the best opportunity to de-risk these play fairways and prospects.

SCOTT OPDYKE AND YERMEK BALABEKOV, PGS

Significant shallow water discoveries have been made in both the Ceará and Potiguar Basins, while the largest oil-producing region in Equatorial Brazil is the onshore portion of the Potiguar Basin, where production is from the syn-rift to transitional successions. However, only a few deepwater exploration wells have been drilled in the Equatorial Margin from the Amazonas Cone to the Potiguar Basin.

The offshore plays are structural and stratigraphic traps in the Upper Cretaceous reservoir section. Tests of these reservoirs along the conjugate margin in West Africa have precipitated a move by explorers to examine the Equatorial Margin from Brazil to Guyana from a new perspective. Zaedyus in French Guiana was an early geologic success and Liza and associated prospects in Guyana have become the poster child for economic success in these play fairways on the South America Equatorial Margin.

Structural Setting and Significant Wells

The dip seismic line in the foldout (Figure 1) shows rotated fault blocks in the rift section, overlain by Cretaceous syn-rift sediments, which in turn transition to post-rift turbidite onlap facies. There is an interval of additional sedimentation prior to Tertiary erosional events as well as volcanic intrusions. In the strike direction (Figure 2), there is a highly faulted and folded zone associated with the Romanche Fracture Zone to the north-west.

Spectral decomposition is a useful tool for showing geomorphology and depositional system components on high quality seismic data. Figure 3 shows some of the details of a channel system as it meanders down dip to the basin floor.

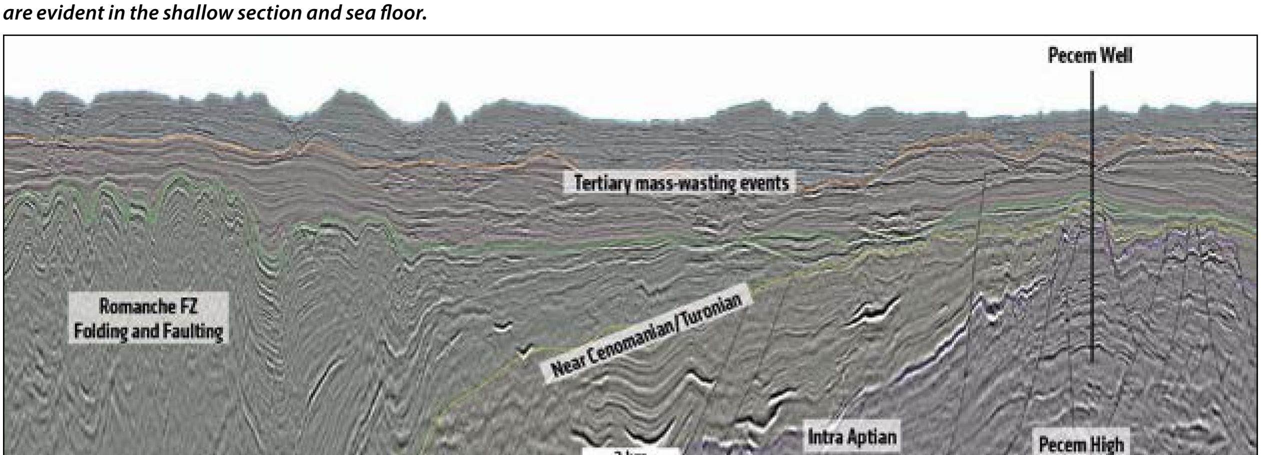
The late Cretaceous reservoir play fairway has been penetrated by the Pitu and Pecem wells.

The Pitu well in the Potiguar Basin found oil, gas and condensate at depths of 4,150m to 4,450m in Upper Aptian sands in the Pescada Formation. The discovery well was spudded in 2013 in 1,731m of water, 55 km offshore Brazil's Rio Grande do Norte and the prospect is still considered to be in appraisal. It reached a total depth of 5,353m and discovered a 188m column of intermediate 24° API gravity oil.

The Pecem well in the Ceará Basin (Mundau Sub-basin), 76 km offshore from the county of Paracuru, spudded in 2012 in a water depth of 2,129m and found a hydrocarbon column estimated to be 290m. The oil-bearing sands are Aptian age in the Paracuru Formation. The oil discovered in this well indicates a transitional environment source but could also include a contribution from the same Albian-Cenomanian source rock system present in the equatorial margin of West Africa. The dip seismic line through the Pecem well location (Figure 1) illustrates the Pecem High and onlapping intervals above it.

The deepwater seals for both the Ceará and Potiguar Basins are regional shales from the Cretaceous to the Tertiary. Mass-wasting events in the Upper Tertiary

Figure 2: This Ceará Fortaleza strike seismic line runs from the Romanche Fracture Zone in the north-west to the Pecem High in the south-east. The syn-rift section is overlain by compression associated with the fracture zone. Tertiary erosion, mass-wasting events and canyons are evident in the shallow section and sea floor.



could cause seal failure for younger stratigraphic intervals.

PGS GeoStreamer 3D data improves attribute computations and reduces risk with more precise reservoir estimates than conventional streamer data. An arbitrary well tie line (Figure 4) shows the Amontada, Canoa Quebrada and Pecem wells. The Albian/Cenomanian section contains turbidite fan/channel systems penetrated by the wells and illustrated on the full stack and Vp/Vs seismic data.

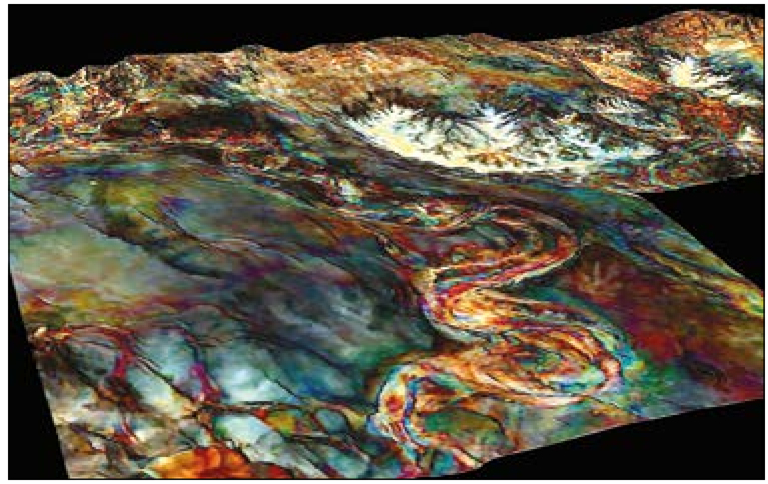


Figure 3: Frequency decomposition cube looking south-west towards the coast. Channel/canyon systems feed downdip to deepwater fan and channel systems.

Great Potential with Four Source Intervals

The Equatorial Margin of Brazil has four potential sources for exploration prospects and play fairways.

The oldest source system in the Aptian/Barremian is characterized by highly cracked, very mature oils and condensates sourced by a saline to alkaline, calcareous black shale deposited in a lacustrine brackish to saline anoxic environment. This petroleum system sources the majority of current production offshore Brazil.

The second oil system is characterized by transitional environments, as found in the Ceará and Potiguar Basins, with the Late Aptian source rocks in the early to peak oil window stage. Most of the Equatorial Brazilian continental margin basins have little salt in the transition from continental to marine environments. The Ceará Basin may be the exception, as a few boreholes encountered evaporites in the Late Aptian stratigraphic interval, indicating a restricted depositional environment. Geochemical data from hydrocarbons recovered from oil fields in the Ceará and Potiguar Basins in northern Brazil indicate the presence of oil types similar to the ones that are present in the salt basins south of the equatorial transform fault zones. Consequently, the transform margin basins may share similar source rock systems.

The third petroleum source consists of Albian/Cenomanian/Turonian marine black shales, which are a major source for the oils in the West African salt basins. Similar oils have also been recovered in the Amazonas Cone and Pará-Maranhão Basins and in five ultra-deepwater discoveries in the Sergipe Basin. The origin of the marine hydrocarbons in these systems is related to Late Cretaceous global Oceanic Anoxic Events, which occurred when the two plates were totally separated and the basins were influenced by worldwide sea level rises and falls.

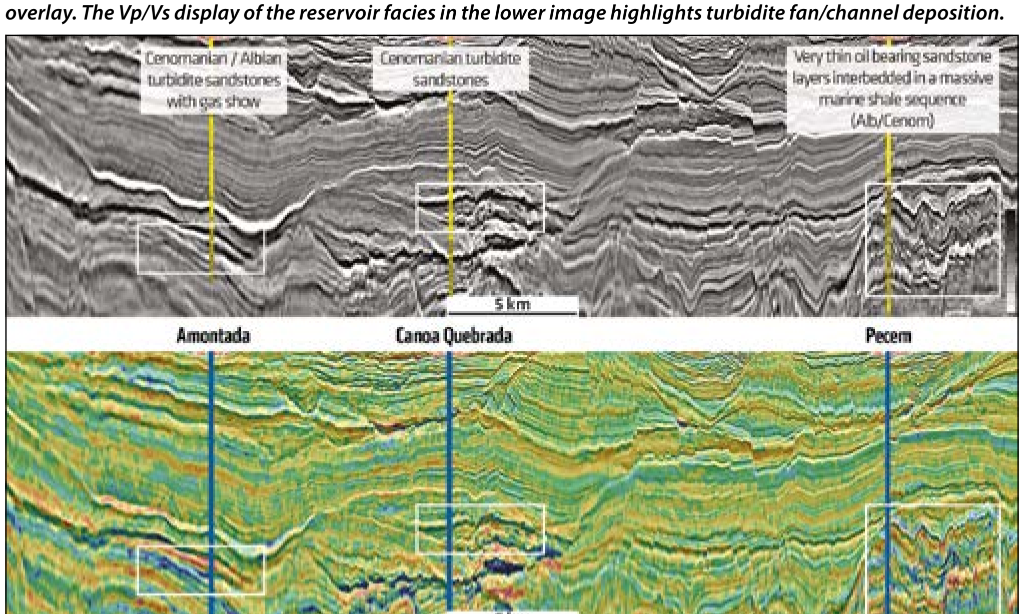
The fourth source system consists of Tertiary source rocks deposited in deltaic environments in the Pará-Maranhão Basin. The 1-PAS-9 and 1-PAS-11 sub-commercial discoveries, as well as the gas accumulations in a number of wells drilled in past decades, were sourced by these Tertiary source systems.

Exploration Potential Revealed

The current play fairways, demonstrated by recent drilling and seismic stratigraphy combined with seismic attributes from high quality GeoStreamer data, are generally underexplored on the Brazilian Equatorial Margin. Since 2015 PGS has undertaken an extensive series of GeoStreamer 3D surveys to address exploration concerns and de-risk play elements in the Potiguar and Ceará Basins.

Future exploration using these excellent 3D seismic datasets should lead to continued successes for the oil and gas industry in Brazil. ■

Figure 4: An arbitrary well tie line through the Amontada, Canoa Quebrada and Pecem wells. The upper display is a -90 degree phase rotation of the full stack and the lower display is a rotated full stack with a relative Vp/Vs overlay. The Vp/Vs display of the reservoir facies in the lower image highlights turbidite fan/channel deposition.



A Fine Book

Introduction to Exploration Geophysics – with Recent Advances

By Martin Landrø and Lasse Amundsen. Bivrostgeo, 2018

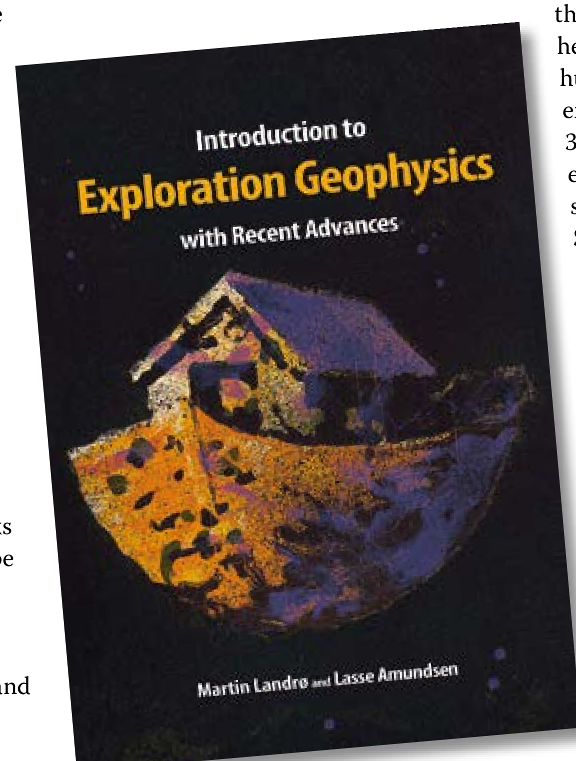
ANTON ZIOLKOWSKI

In 2007 Halfdan Carstens, then editor of *GEO ExPro* , asked Martin Landrø to write a short technical article on the new GeoStreamer® technology, which had been launched by PGS earlier that year. Martin accepted on condition a co-author could be found. Under what is described as 'mild pressure,' Lasse Amundsen accepted that role. The paper was published in the September 2007 issue of *GEO ExPro*, and since then Martin and Lasse have contributed to every single issue: a total of 62 articles in ten years. These articles form the basis of the book *Introduction to Exploration Geophysics – with Recent Advances*, which is even greater than the sum of its parts. This is a fine book.

Exploration geophysics is the application of physics to explore the physical properties of the Earth's interior and map the subsurface rocks and their fluids at all scales. The scope of the book is broadly defined by the titles of its nine chapters: Looking into the Earth; Elements of Seismic Surveying; Marine Seismic Sources and Sounds at Sea; Reservoir Monitoring Technology; Broadband Seismic Technology and Beyond; Gravity and Magnetics for Hydrocarbon Exploration; Supercomputers for Beginners; Gas Hydrates; Dwelling on the Mysteries of Space. Chapter 6 was written by guest author Christine Fichler and Chapter 9 has major contributions from guest authors Christine and Birgitte Reisæter Amundsen, Lasse's twin daughters. The chapter titles are perfectly reasonable in a book about exploration geophysics – but give no indication of the exciting things you find when you open this book.

Careful Research

The first thing that struck me is the excellent quality of the more than 600 graphs, diagrams, photographs and cartoons which illustrate almost every one of the 327 pages. Martin Landrø and Lasse Amundsen are two outstanding geophysicists who research everything very carefully before writing about it. What is special about this book is not the excellent quality of the technical



content, which one would expect from two such distinguished authors, but the sheer scope of each topic. It is full of interesting complementary information. You can certainly learn a great deal about exploration geophysics by reading it, but that seems almost incidental. It is everything else you pick up along the way that makes you want to read on, especially as the writing style is simple, clear and convincing. Figure 1.32, for example, shows that 'The Mexican wave is an illustration of a shear wave propagating perpendicular to the movement of each spectator'. Figure 2.53 is an engraving of Newton's decomposition of white light into a band of colors with a prism; the caption gives Newton's introduction of the word 'spectrum', from the Latin word 'spectre', meaning 'ghostly apparition'.

Chapter 3 on seismic sources and sounds at sea is rich in sound generation and acoustics and gives, for example, the sound range from the threshold of hearing at 20μPa (0 dB) for undamaged human ears to the 1883 Krakatoa eruption with a sound pressure level of 310 dB. It also connects marine seismic exploration to marine life by including sections on Marine Mammals and Seismic Surveys; Fish are Big Talkers; and the Effect of Seismic on Crabs.

The subtitle 'with Recent Advances' is right. This book is up-to-date and Martin and Lasse have included contributions from many expert friends and colleagues to ensure that it is. For example, use of codes and decoding and simultaneous source separation is covered in two sections of Chapter 2, written by guest contributors Dirk-Jan van Manen and Johan Robertsson. Section 9.4 describes gravitational waves and the recent successful detection of a gravitational wave on the Earth, which, on this scale, is merely a point diffractor in the universe.

Appeals at All Levels

The book does not have an index, but is organized so clearly and logically that it is straightforward to find what you want – although you can easily be diverted to more interesting things. And it has a very comprehensive list of references. The authors have generously made the e-version of the book freely available; an important point, as it will appeal to students of all academic levels, including those at high school, college and university, as well as those who plan to study exploration geophysics and professionals interested in learning more. ■

Exploration Update

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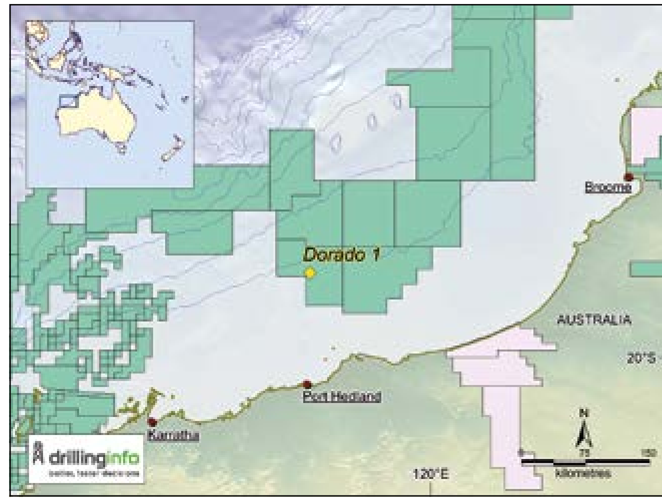
Australia: More Oil in Dorado

Originally spudded in early June 2018, the **Dorado-1** well on block **WA-437-P** off north-west **Australia** has discovered oil at a number of levels. In July it was reported to have intersected approximately 80m net (96m gross) of light oil pay in highly porous and permeable sands in the Triassic Caley Sandstone and over 21m of gross interval (10.5m net pay) of gas and condensate reservoir in the top of the Baxter Member. Further drilling to a TD of approximately 4,650m has now discovered more oil in the secondary objective of the deeper Crespin and Milne Members, bringing the total net hydrocarbons pay encountered in Dorado-1 to 132m. The Crespin Member sandstone reservoir contains a gross interval of 50m with a net pay thickness of 22m and average porosities of 14%. The Milne Member sandstone reservoir contains a gross interval of 30m with net pay thickness of 18m with average porosity of 13%.

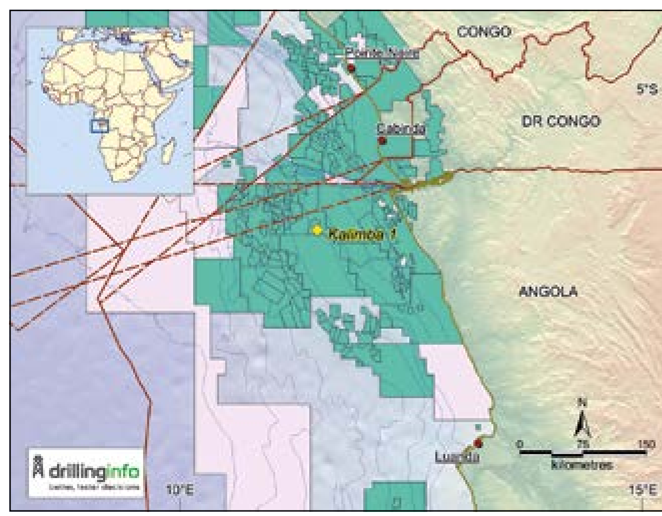
The well, operated by **Quadrant Energy Pty Ltd.**, lies about 100 km north of Port Hedland in about 3,000m of water. Quadrant hold 80% of the license and Carnarvon Petroleum Ltd. 20%. ■



Angola: Oil Discovery

Eni has made a new offshore oil discovery in **Angola block 15/06** with the **Kalimba-1** new field wildcat, which encountered 23m net oil pay in an Upper Miocene sandstone target. Eni believes the field could contain some **230–300 MMbo** light oil in place (33° API) and estimates production capacity could be more than 5,000 bopd.

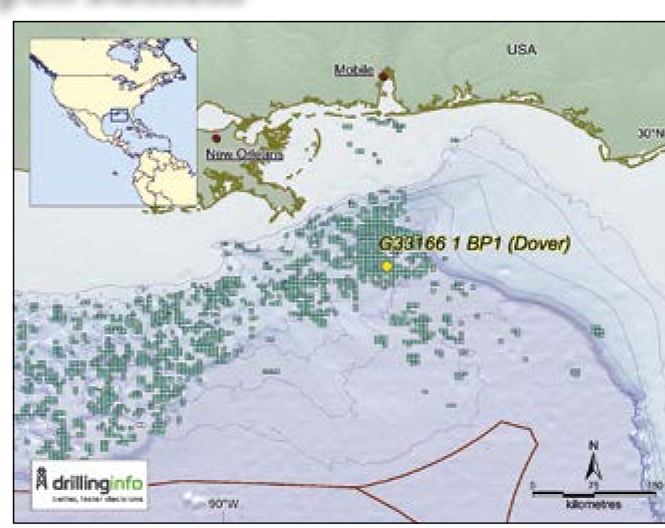
Kalimba-1 was drilled in 458m of water by the Seadrill *West Gemini* drillship and reached a TD of 1,901m in mid June, 2018, having spudded a month earlier. Eni Angola acquired the operatorship of 15/06 in 2006 and made the first discovery on the block in 2008 (Sangos-1) followed by Cinguvu-1 in 2009 and Mpungi-1 in 2010, as a result of which the **West Hub FPSO Project** was developed to exploit these discoveries. Equity in the block is split between Eni (36.84%), Sonangol Sinopec (26.32%) and Sonangol (36.84%). ■



United States: Mississippi Canyon Success

Shell encountered more than 244m of net hydrocarbon pay in bypassed **G33166 1 BP1**, a new field wildcat which was targeting the **Dover** prospect in the Norphlet play, according to reports in late May 2018. The bypass, which was kicked off on March 23, 2018, is located about 21 km from the **Appomattox** host, which is expected to start production before the end of 2019, and is considered an attractive potential tieback to it. The original wellbore, G33166 1, was spudded in late February 2018 and drilled to a final TD on March 11, 2018. Both wellbores were drilling from a surface location in the eastern portion of **Mississippi Canyon Block MC 612** in the **Gulf of Mexico Basin** in water depths of about 2,500m. The Dover discovery is Shell's sixth in the Norphlet.

In early March 2016, Shell had submitted plans to drill a total of four exploration wells in Mississippi Canyon Block 612. The lease was awarded to Shell as operator and sole interest-holder in August 2009. ■



Plenty of Potential off Namibia

David Sturt, Managing Director of Azinam Limited, a Namibia-focused exploration company, will be speaking at Africa Oil Week in Cape Town in November. He tells us why he is so excited to be exploring in the region.

Why Namibia?
Surrounded by the resource-rich countries of South Africa, Angola and Botswana, Namibia is ideally placed to be the next great African frontier. The country has increasingly attracted supermajor attention thanks to its attractive fiscal regime and political stability, and the Ministry of Mines and Energy are unceasing in their support of operating companies such as Azinam. Namibia has an excellent infrastructure: developed and well-maintained roadways and telecommunications channels, an exclusive modern electricity distribution grid, modern ports, banking and all the key support services required in modern business. In fact, Namibia's infrastructure stands out among the best in the continent of Africa.

What excites you about the potential of deepwater Namibia?
The significant oil potential in the deepwater areas offshore Namibia! HRT's 2013 Wingat-1 well on neighboring acreage to two of our blocks has demonstrated that there is a working petroleum system. Since then, consolidating technical work and high resolution seismic surveys have enabled us to de-risk our exciting prospects.

Is exploring in Namibia challenging from the administrative viewpoint?
No, not at all; the Namibian government has developed 'open-door' policy systems. They listen carefully to the operators with an effort to try and provide solutions to any challenges faced. The data rooms at the National Petroleum Corporation of Namibia (NAMCOR) are well managed and they have access to abundant information to make decisions which benefit both the country and the operating companies.

Are there geological or technological challenges?
The geological conditions are excellent and there are discoveries with proven petroleum systems. Namibia, through the Kudu discovery, was seen as a primarily gas play, which has been a challenge to materialize. But now, since the wildcat (Wingat-1), we have proven Aptian source rocks. There is good local technology and no barriers to companies importing additional technology and support if and when required. Namibia's supply chain, like the rest of the world, is now at a much lower cost base. From a technical perspective Azinam are chasing significant liquid plays, so the timing is right to unlock this next great frontier.

You will be speaking at Africa Oil Week. What do you hope to gain from the conference?
We are very excited to be hosting the Namibian exploration spotlight panel at this year's Africa Oil Week. The panel is an excellent mix of operating companies and government representatives that will create a lively discussion focused on deepwater exploration. We hope to share our insights about what we know about the potential for oil and gas in Namibia and also learn more from our fellow operators and government partners, based on their experiences and understanding.

What would you say to someone considering exploring the deepwater off southern Africa?
We encourage companies to join us (Tullow Oil, GALP, ONGC, Total, Shell and new players ExxonMobil as well as a host of key junior explorers) in deepwater exploration off southern Africa. The fiscal regimes are highly attractive, and the scale of opportunity is tremendous. ■

Azimuth Group

David Sturt holds an MSc in Exploration Geophysics from the University of Leeds. He joined Azimuth Group in April 2012, and as well as being Managing Director of Azinam he is also SVP – Technical of the Azimuth Group (Indonesia, UK, Norway, Ireland, Namibia, Brazil and Honduras). David has over 30 years of exploration and production experience, gained from working for a number of companies throughout the world, including in West Africa, South East Asia, Central Asia and Russia.

The Future Belongs to Oil

Primary energy consumption grew by 2.2% in 2017. That is the fastest growth rate since 2013, as BP observes in their recently published *Statistical Review of World Energy 2018*. Only a fraction of that growth was covered by new renewables (wind and solar), despite renewable power growing by a stunning 17%: 'the largest ever contribution in terms of overall power generation'. Wind provided more than half of the growth in renewables, while solar contributed more than a third, the big driver being 'the falls we have seen in solar costs', according to BP.

This rise in primary energy consumption means that oil consumption also grew last year: **1.7 MMbopd** higher in 2017 than the year before, totalling **92.6 MMbopd**. China, with an additional 500,000 bopd, was the largest contributor to this increase. US tight oil also grew rapidly, increasing by **1.5 MMbopd** from the end of 2016 through to the spring of this year. The biggest spender was, as expected, the US with **19.9 MMbopd**.

For oil companies that still actually explore for oil, it must be good to learn from Equinor's recently released *Energy Perspectives 2018* that the company estimates the need for oil will grow substantially over the next 35 years. According to their *Reform* scenario, the world will need some **111 MMbopd** in 2030 and **105 MMbopd** in 2050 – meaning that, if we trust these figures, we will reach 'peak demand' in the foreseeable future.

Equinor has arrived at approximately the same conclusion for gas. Demand will be higher in 2030 than in 2015 (the reference year), and even higher in 2050.

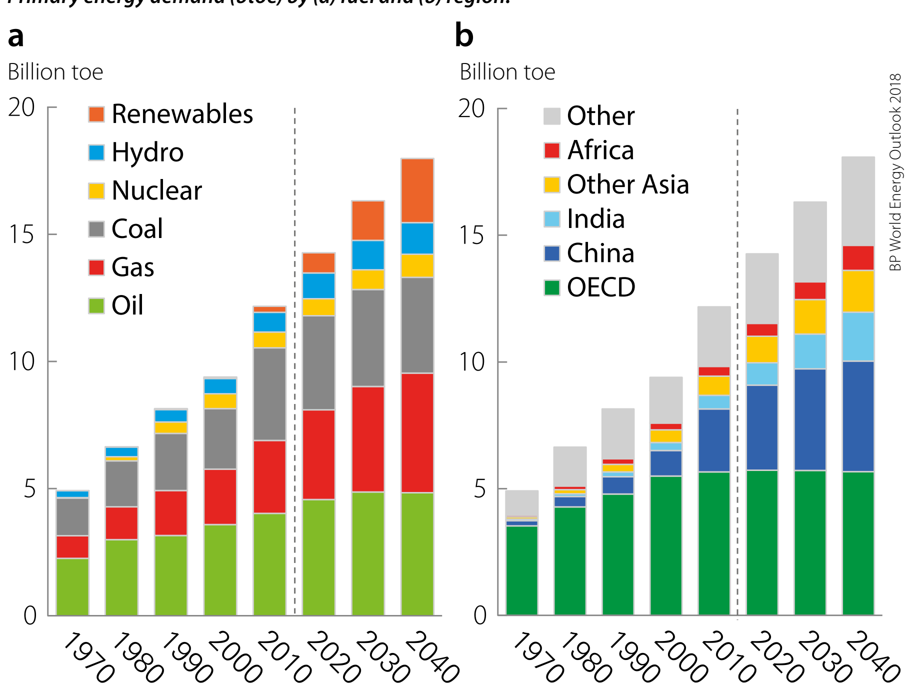
In 2015 Equinor (then known as Statoil) concluded in their *Energy Perspectives 2016* that 'oil is here to stay'. As evident from the above, this statement is still true, at least for another 30 or more years, and we can comfortably add that the same is true for gas. Equinor, however, emphasizes that large investments are needed in the oil industry, as half of the required volumes will be sourced from existing fields. The million-dollar question is, of course, where all that oil will come from and where the investments will take place, as the oil companies seem to find less oil every year.

In conclusion: there is a necessity (1) for continued exploration on a global scale to find additional resources; (2) to convert resources into reserves; and (3) to improve recovery from existing fields and thereby prolong tail-end production.

Petroleum geologists and geophysicists will be busy for at least another two generations. ■

Halfdan Carstens

Primary energy demand (btoe) by (a) fuel and (b) region.



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 10^6

Billion = 1 x 10^9

Trillion = 1 x 10^{12}

Supergiant field

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

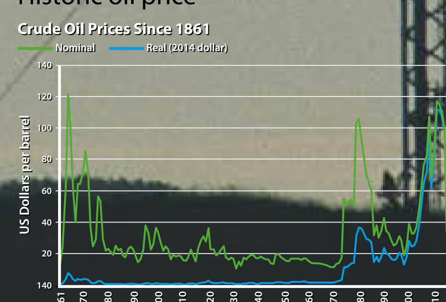
Giant field

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

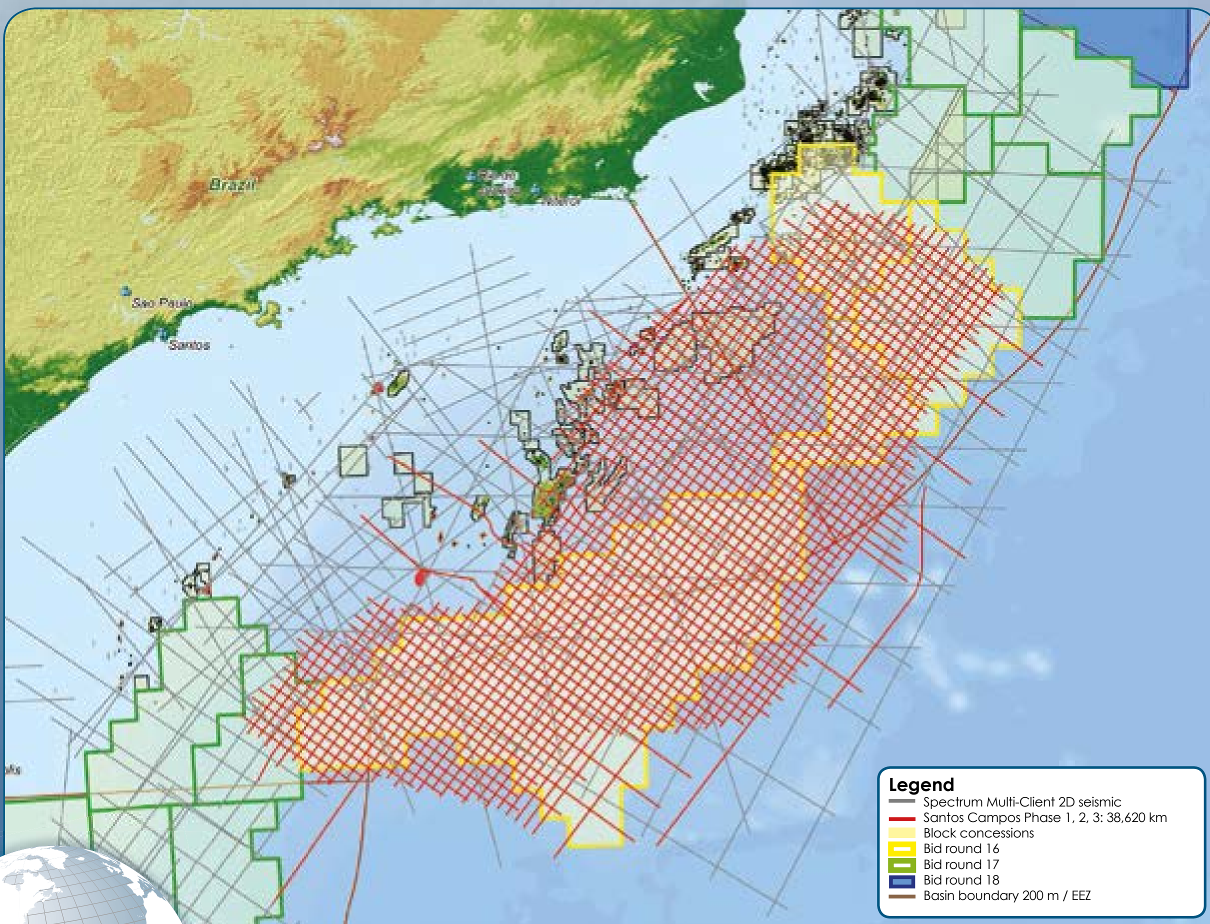


multi-client seismic

BRAZIL

Brazil: Santos Campos 2D

Multi-Client 2D Seismic for the Exploration Journey to Giant Oil



Spectrum holds more than 38,000 km of long offset 2D seismic data in the Santos-Campos basin over some of the most exciting open exploration acreage in the world. These surveys, acquired between 2012 to 2018, have now been de-ghosted and are available in both Pre-Stack Time and Depth Migration (Kirchoff & RTM).

This seismic covers a vast area where the prolific pre-salt play is confirmed to extend out from giant discoveries into the16th Round Sector area. The 2D data, acquired in a 10 km x 10 km grid, allows crustal structure to be defined, thereby enhancing thermal maturity modelling and imaging of base salt and syn-rift source rock sequences. The prolific Barra Velha sequence is now mappable from Tupi, Jupiter and Libra into open acreage.

Multiple giant structures with billion barrel low-risk oil potential are mapped within Brazil's 16th Round Sector. This regional seismic data allows prioritization of the main play fairways, structural trends and oil prone areas, as well as deep crustal fault distribution mapping for CO_2 risk mitigation. Yet-to-find analysis of the area covered by this dataset exceeds the 60 billion barrel potential resource already discovered in the pre-salt play.

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