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We gratefully acknowledge the support of the sponsors for making this meeting possible.

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Oral Presentation Abstracts

Exploration – An exciting new Opportunity

Oonagh Werngren MBE
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Exploration activity on the UKCS has been the life blood of the Oil & Gas industry and helped to underpin security of energy supply for the Nation. Over recent years, due to a number of factors ranging from taxation to the price of oil, exploration activity has been in sharp decline. In this talk Oonagh Werngren will discuss the latest figures relating to drilling in the North Sea and highlight the steps that industry is taking to turn them around. The talk will cover collaboration between industry, government and the Treasury to deliver an exciting new seismic acquisition programme in the Rockall Trough and Mid North Sea High that will enable 40,000 km of 2D data to be released to the public at the end of 1Q 2016. She will also discuss how the data is linked to 100 key wells and what this could mean for the academic community. This 2D seismic acquisition project is one of a number of initiatives that have been focused on increasing activity in the UKCS. Additional projects include the study of 100 dry holes in the Central North Sea and Moray Firth, increased understanding of advances in the acquisition and processing of 3D seismic and a detailed study of the potential of the Palaeozoic Plays in Southern and Central North Sea, the Orcadian Basin and Irish Sea. A key aspect of all this work has been to ensure that the data will ultimately end up in the public domain. Going forward the newly established Exploration Board, set up specifically to ensure that we can maximise economic recovery from the North Sea, will drive cross industry collaboration projects of this nature. Oonagh will highlight what is on the agenda for 2016 and how the newly established Oil and Gas Authority hopes to encourage exploration through new licensing rounds.

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Developing and recognising technical excellence in the energy industry

Gary Nichols
Nautilus/RPS Training

"Due to the fall in the price of oil we have had to reduce our workforce, but now that we have fewer people they need to have better technical skills, so we now need more training courses". This is a paraphrased response from a company to an enquiry about their training needs - and it is in stark contrast to other companies who halted all technical training. Rationally we know which approach is likely to be better for the long-term success of a business, but in tough times tough decisions are made.

The oil and gas industry has a good record for Continuing Professional Development but it is now more important than ever to emphasise the value of training at times when some companies are reluctant to pay for it. That value has to be recognised by both the company and the individual. For companies technical training must be targeted and cost-effective: it must satisfy current business needs and be delivered in flexible ways to fit in with project schedules. For the individuals they need to be able to see how the training directly helps them with their current job and at the same time build up knowledge and skills that allow them to further their careers.

There is growing scope for a greater variety of approaches to technical CPD. Classroom events can be mixed with different distance learning modes, including on-line materials, webinars and virtual workshops, to form blended learning packages. These can be more readily tailored to suit the needs of both the individual and the company, can be more flexibly delivered and ensure that the face-to-face element of teaching is most productive. Geoscientists value time spent learning in the field, but field courses are relatively expensive and time-consuming. To get the most out of field time, 3D imagery can be used to create elements of virtual fieldwork that enhance the fieldwork by adding more quantitative learning. Virtual outcrops can also be used to enhance the classroom learning experience and bring aspects of field experience to those who do not get the opportunity to go on field classes. The requirement for CPD will remain as important as ever, but the nature of the training element is evolving to reflect changing individual and business needs.

Individual technical excellence and the collective quality of a team are not easy to quantify, but a combination of experience and effective training is clearly valuable. These can be formally recognised by achievement of a professional status such as Chartership, establishing a benchmark that is demonstrable and transferable. As the energy industry relies even more on the technical excellence of its staff, developing skills and having a means of recognising them has never been more important.

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Hydrocarbon Exploration: The Next Generation – A Royal Holloway Perspective

N. Scarselli, J. Adam, P. Burgess, B. Vining & I. Watkinson
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What is the future of hydrocarbon exploration in a world of climate change debate? This presentation examines predicted global energy needs over the next decades. What proportion of the energy mix is likely to be hydrocarbons, and what types? Will it be driven by a clean environmental agenda and be predominantly gas? What are the petrochemical requirements? In the context of current hydrocarbon production, including improvements in ultimate recovery, and the large volumes of already discovered undeveloped resources, what will be the need for exploration? One thing is certain. This legacy, and the perceived challenges will fall to a new generation of petroleum geoscientists. How can we best develop them for the future? In 2015, Royal Holloway, University of London (RHUL) celebrated 30 years of its highly acclaimed Masters programme in petroleum geoscience and, in addition, are world champions in the prestigious AAPG Imperial Barrel Award in hydrocarbon exploration. This experience, in conjunction with key insights at the forefront of technological geoscience research, well positions RHUL to provide some perspectives into what constitutes this new generation of petroleum geoscientists. Is Wallace E Pratt (1885-1981) right? “Where oil is first found, in the final analysis, is in the minds of men”.

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Social licence to operate: the case of unconventional hydrocarbons in the UK

Zoe Shipton
University of Strathclyde

The term "social licence" refers to the acceptance of a project or a company that is operating that project by a community. It is increasingly recognized that in addition to planning permission and permits, a company requires a social licence to operate within a particular area. In an increasingly globalised economy, a social licence may include gaining social acceptance globally. A company can't grant itself a social licence. Significant investment of time and money is required to attempt to gain a social licence, and it can be lost due to events outwith a company's control.

In the UK, public concern about hydraulic fracturing for shale gas (fracking) was triggered by low magnitude earth tremors induced by exploratory activities in Lancashire in April 2011. The resulting embargo on fracking for shale gas was lifted by DECC in Dec 2012. The Scottish government has since imposed a moratorium pending the result of investigations into the heath and environmental effects of fracking. 'Anti' campaign groups argue that shale gas extraction could produce significant environmental damage and effects on human health, whereas proponents of the shale gas industry argue that an indigenous source of UK gas will enhance energy security and may result in falling household energy bills. In this talk I will use the UK onshore oil and gas industry as a case study into the concept of a social licence, and explore how this is relevant to early career geoscientists.

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Sequence Stratigraphy: A Critical Tool to Encourage Creativity in Exploration

Mike Simmons
Halliburton

Oil companies face ever growing challenges to achieve success in reserves replacement – an essential measure of their performance. Successful frontier exploration is often a critical ingredient in achieving this, yet recent years have seen limited returns from high levels of investment. Moreover, those successes that are reported are typically extensions of known discoveries - no bad thing – but discoveries from entirely new geological concepts – what are referred to as "play openers"– are, with occasional notable exceptions, becoming rarer. So there is a clear challenge – are we running out of ideas to find major new discoveries? One of the oldest clichés in the oil industry is that oil is found in the minds of men and women. This implies that the oil industry geologist needs to be continuously creative and innovative. To add other factors to the mix, the ongoing "big crew change" means that the industry knowledge base is retiring being rapidly replaced by an inexperienced generation at the same time as data volumes and staff workloads increase. The new generation of explorers will take time to learn the skills and gain the experience to be truly creative and ask the "what if" questions that can generate new play ideas.

Sequence stratigraphy and sequence stratigraphy-based technology is a valuable tool in maintaining and improving the creativity of the exploration geologist. They are the key to joining-up vast amounts of disparate geological and geophysical data through a common framework that can be used to predict into "white space" (i.e. areas that are data poor). Making predictions away from data control and that incorporate regional geological thinking are one the greatest challenges an exploration geologist faces, but sequence stratigraphy allied to a whole range of other exploration tools, ensures that predictions are made on a sound geological basis that can be interpreted in terms of confidence. The basis of successful exploration is sound play fairway mapping that expresses risk in the subsurface. Good play fairway mapping is built upon sound palaeogeographic interpretations coupled with an understanding of reservoir, source and seal behaviour in the subsurface. All these parameters can be linked to and better understood from sequence stratigraphic context. Bringing such approaches to bear means that the exploration geologist of tomorrow has the tools at their disposal to find the next game changing discoveries and securing energy supply for several decades to come.

NOTES

Subsurface architecture of fluvio-deltaic deposits in high- and low-accommodation settings

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Combined seismic and well interpretation methods can be used to elucidate detail of the subsurface architecture of fluvial and fluvio-deltaic deposits which can form high quality hydrocarbon reservoirs. Observations made from wireline and core logs, including facies and analysing the relative proportions of architectural elements and facies associations indicative of depositional sub-environments, can be used to interpret changes in local accommodation conditions, and periods of increased seasonal, tidal and marine influence.

Horizon slices, taken from 3D seismic volumes aid in the visualisation of laterally discontinuous, often thinly-bedded, fluvial deposits. Seismic facies, when combined with core and wireline log facies, can be interpreted as a series of 'seismic elements'. The relative proportions of seismic elements mapped out on horizon slices allows the interpretation of depositional environments and accommodation setting; allowing the distinction between fluvial and deltaic settings. A number of data conditioning and seismic interpretation techniques can be used to enhance the visualisation of channelized and non-channelized fluvio-deltaic deposits in the subsurface. Frequency decomposition (and the making of colour-blended volumes) allows the visualisation of the detail of channel belt deposits such as channel belt migration and lateral accretion deposits.

The study uses the Late Triassic Mungaroo Formation, a Mississippi-scale fluvio-deltaic system with a fluvially-dominated, tidally-influenced delta, which accumulated in the Northern Carnarvon Basin, Northwest Shelf, Australia. The study investigates different seismic interpretation techniques and investigates the relative control on fluvio-deltaic deposition of allogenic and autogenic processes.

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The Numidian of Sicily revisited: a thrust-influenced confined turbidite system

Patricia R. Pinter[1], Robert W.H. Butler[1], Adrian J. Hartley[1], Rosanna Maniscalco[2]

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Outcropping turbidite systems of the central Mediterranean-Alpine region are widely used as analogues for a variety of deep-water hydrocarbons reservoirs. Understanding whether the system is unconfined and deposited on relatively unstructured basin floor or confined by actively deformed basins is important for the prediction of sand distribution and therefore the applicability of analogues. Here we consider the Numidian turbidite system (Oligocene-Miocene) of Sicily - for many the type example of thick massive submarine sandstones. The tectonostratigraphic setting of the Numidian is analogous to the Angostura (Trinidad) - Scotland (Barbados) sand systems of the Caribbean and associated ultra-deep water exploration. New mapping and detailed sedimentology in the Nebrodi Mountains (northern Sicily), allied to existing paleontology, challenge conventional ideas on the Numidian system as a whole and how it can be used to inform deep-water hydrocarbon systems. Rather than having being deposited within an unstructured foredeep by relatively unconfined flows, we show that Numidian deposition was strongly confined by active structures. The system was controlled by thrust related folds and their intrabasin submarine slopes, together with basin floor architecture inherited from the underfilled passive continental margin. Thrust-top basins filled diachronously implying a large scale tectonic control both on sand fairways and facies variations along their margins. Existing models wrongly suggest that facies variations between adjacent outcrops on Sicily (and elsewhere) result from long-range stratigraphic variations being juxtaposed by later large-displacement thrusts. Our research reveals a much simpler tectonic structure but a more complex stratigraphic arrangement for the Numidian on Sicily- a characteristic of confined turbidite systems.

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Using Spectral Decomposition to Better Define Reservoir Architecture and Prospectivity in the West of Shetland

Kirstie Wright, Alwyn Ross and Neal Baker
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Exploration in the West of Shetland has largely been focused on amplitude driven prospectivity, which has led to a number of significant discoveries. However, with many of these prospects having now been identified, the industry's attention is now turning to more challenging play types and deeper stratigraphic intervals to deliver future reserves. At DONG we have been using spectral decomposition, in addition to conventional seismic interpretation methodologies, such as amplitude extraction and attribute analysis, to enhance our subsurface understanding and de-risk exploration and development well planning activities. Spectral decomposition analyses seismic reflectivity data in the frequency domain, providing enhanced images of the subsurface that compliment conventional seismic interpretation. It is a highly visual tool that helps the user to better identify critical elements of reservoir architecture that may otherwise be missed such as depositional patterns, channels, faults, barriers and baffles.

Within DONG Energy, spectral decomposition has become an integral part of our standard G&G work flow and has been applied to a number of leads, prospects and discovered hydrocarbon fields in and around the West of Shetland. We provide specific examples that demonstrate the insights spectral decomposition can offer, from intra-volcanic, to stratigraphic, to combined structural-stratigraphic plays. By using this technology to optimise information provided by seismic data, a greater understanding of the subsurface can be gained and can aid future hydrocarbon exploration. As an early career geoscientist, the presenting author has experience of both academia and industry, and the benefits of working in partnership with both. This has provided her with a unique perspective on adapting to a constantly evolving industry and the use of new techniques and approaches to solve the challenge of exploration.

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Global trends in exploration, the Great Australian Bight and reaching out to new frontiers

Dr Bryan Ritchie
BP plc.

The challenges of discovering conventional oil and gas are increasing. Deepwater exploration will continue to be important, but the sector is maturing in established areas such as the Gulf of Mexico and West Africa. Conventional opportunities outside deep-water are more limited although there are a rich set of gas options and 'new geographies' that will potentially become available. Unconventional plays have transformed North American energy supply but sustainability at lower commodity prices is relatively untested and challenges remain to replicate this success internationally.

After the opening of several new deep-water provinces in the last decade like the Santos pre-salt and East Africa gas, the world is now looking for the next new province. BP is exploring for this and one of the interesting opportunities is the Great Australian Bight. BP was awarded four deep-water offshore blocks covering an area of 24,000 km^2 in 2011 and a 12,000km^2 3D seismic survey was completed in 2012. We hope that our exploration activities in the relatively unexplored waters of the Great Australian Bight will lead to the opening up of a new oil and gas province.

Technology will continue to be a key enabler in further unlocking resources. It underpins everything we do in the oil and gas business, right across the value chain. It enables us to discover, recover, process and market energy safely and efficiently to provide heat, light and power to communities around the world and drive economic growth.

NOTES

Gravity for hydrocarbon exploration - a new look at an established tool

Tim Archer
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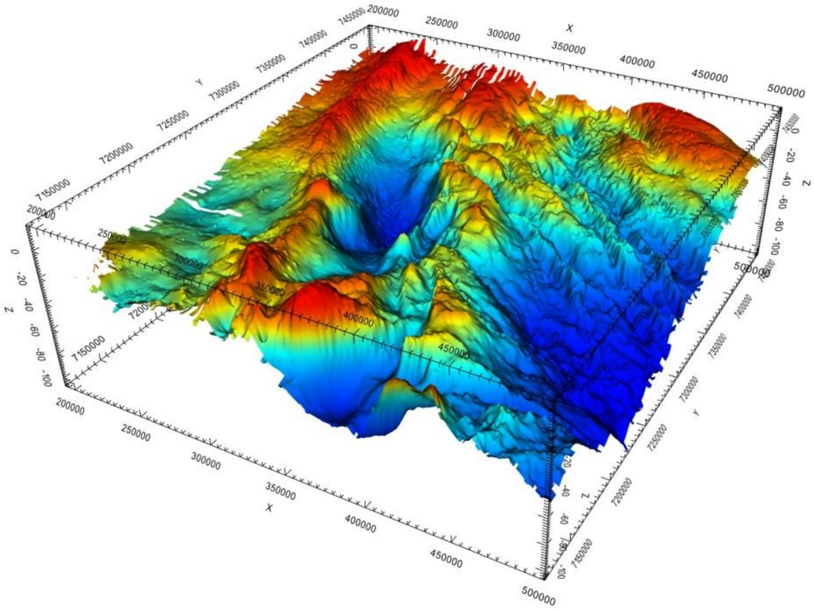
The gravity method was the first geophysical technique to be used in hydrocarbon exploration, and in 1924 resulted in the first geophysical oil and gas discovery, namely the Nash Salt Dome in coastal Texas (Nabighian et al, 2005).
Seismology now holds centre stage in geophysical hydrocarbon exploration, but the gravity method remains an extremely cost-effective tool in the exploration tool box, particularly for:

- Identifying sedimentary basins within a regional framework
- Determining structural controls on basin formation and possible hydrocarbon accumulation
- Planning the layout of 2D and 3D seismic surveys
- Informing geological interpretation where seismic information breaks down eg sub-salt, sub-basalt and in areas of complex shallow structure
- Confirming and constraining seismic interpretations and velocity models



Bouguer gravity anomaly over the Merlinleigh Sub-basin, Western Australia (Burney & Sumpton, 2013)

Although the gravity method has been used for over a century, field equipment and processing techniques are constantly being adapted to enhance exploration potential and reduce survey cost. Improved positional accuracy, faster sampling rates and clever software algorithms have been combined to produce datasets that would have been impossible to collect twenty years ago. For example, airborne gravity and gravity gradiometry systems are now capable of collecting hundreds of line kilometres of data per day, with preliminary results often available to clients within less than a week.
With this undoubtedly exciting explosion in technology, it is sometimes easy to lose track of the physical limitations which modern gravity techniques (in common with all other geophysical techniques) inherently possess, and how these limitations can best be overcome (or at least mitigated).

This paper seeks to highlight to early-career hydrocarbon explorers some of the recent developments in the gravity method (and some of the physical limitations to watch out for) by comparing:

- airborne gravity with ground gravity
- airborne gravity with airborne gravity gradiometry
- different airborne gravity gradiometry system configurations

Gravity data can be extremely important to an exploration programme. They need to be carefully handled if they are to provide information that is geologically sensible and commercially advantageous.

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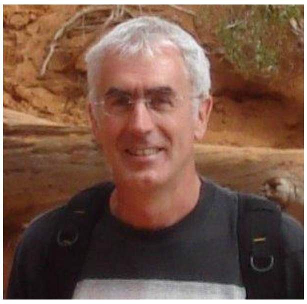
Structural tools and workflows for Hydrocarbon Exploration of Faulted Reservoirs



G.Yielding, B.Freeman, P.Bretan, D.Quinn.
Badley Geoscience Ltd.

Conventional discoveries have decreased in volume but increased in complexity over recent years. More than ever, it is critical for exploration teams to have a clear three-dimensional understanding of the subsurface. The reservoir map of old is now replaced by computer models of many different types. However, a key requirement for any credible trap appraisal is a robust structural framework model.

A framework model comprises an assemblage of surfaces – horizons and faults from seismic interpretation – which fit together correctly in the three-dimensional subsurface. Critical elements in a framework model are the intersection lines between the surfaces, namely fault-fault intersections (branch lines) and horizon-fault intersections (3D fault polygons). Structurally-informed methods should be employed to build these geometries from seismic interpretation, to generate a robust framework model which is essential for assessing trap integrity and volumetrics, and also much subsequent reservoir characterization.

The integrity of faulted traps can now be assessed with the benefit of 20 years R&D in fault seal. Multi-fault trap analysis can now be performed in both siliciclastic and carbonate reservoirs, providing an automatic synthesis of multiple leak points in complex traps in order to determine the extent of trap fill for volumetric studies. Fault-displacement backstripping can be incorporated, to show the impact of changing fault-seal capacity through time in those traps where charge overlapped with structural development.

In tight faulted reservoirs, fracture prediction methods can provide the key input for an economic development. A high-quality framework model, with geologically valid fault displacements, permits the calculation of fault-related strain throughout the reservoir. At each point, fracture orientations and intensity can be computed, based on the local strain tensor. Corresponding fracture conductivities can then be determined in response to present-day stress.

The future of exploration, particularly in the North Sea, depends on our ability as an industry to ensure that every geoscientist has the correct tools at their disposal and the ability to use them effectively. This not only involves software training, but an appreciation of the principles and techniques required to create geologically meaningful models.

NOTES

Integrated Overburden Fluid & Heat-Flow Characterization Offshore Uruguay

Owain Lavis, [1] Dr Mads Huuse[2], Richard Walker[3], Dr Phil Thompson[3]
(BG Group & ANCAP sponsored MSc project*).*

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Frontier exploration interests in South Atlantic margins are surging with investment, with expectations that these passive margins, particularly offshore Uruguay, retain the key to the next generation of petroleum discoveries. Innovative exploration techniques in fluid and heat-flow characterization deliver cost-effective results prior to drilling, enabling an integrated basin analysis. High-quality 3D seismic coverage of three licence blocks (13,000 km^2), offshore Uruguay exhibit a gas hydrate-related bottom simulating reflection (BSR). Sensitive to pressure and temperature, this subsurface BSR enables geothermal gradient and heat flow derivation, providing a modern day calibration point to test basin models and assess source rock maturation. This research provides an integrated fluid and heat-flow analysis using non-invasive techniques to create and utilise a seismic only workflow to estimate geothermal parameters in a frontier basin.

A broadly distributed gas hydrate-related BSR is recognised within the shallow subsurface offshore Uruguay (< 500 mbsf) covering a total expanse of 3750 km^2. Thickness of the gas hydrate stability zone (GHSZ) between BSR and seabed is intrinsically related to sea floor depth, increasing thickness through to ultra-deep waters. The spatial distribution, continuity, and prevalence of the BSR are properties inherently associated with seismic facies, presence of free gas, and seafloor geometry. Geothermal gradient and heat flow are derived utilising this subsurface fluid phenomena, whilst thermal conductivity of sediments within the GHSZ are calculated using experimental seismic processing velocity conversion techniques. Heat flow increases from the basin floor to the upper slope, ranging between 40.4–68.0 mW/m^2, with an average geothermal gradient of 50ºC/km. These results from BSR-derived non-invasive techniques remain comparable to global heat flow modelling, whilst parameter uncertainties are expected to remain below 20%.

Extrapolation of BSR-derived heat flow within integrated basin models will deliver greater understanding of the basin petroleum system offshore Uruguay; an oil window depth predicted with this technique is at *c.* 2250 mbsf. Further work utilising techniques used in this study beneath the BSR, whilst acknowledging basement structure, sediment thickness, and sediment thermal conductivity, can apply further constraints on the petroleum system, influencing the next phase of exploration in this frontier basin.

NOTES

KEYNOTE: The NERC Centre for Doctoral Training (CDT) in oil and gas: A new model for academic partnership and industry engagement

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The Natural Environment Research Council (NERC) Centre for Doctoral Training (CDT) is an exciting and innovative initiative to train the next generation of industry, academic and government policy leaders. Set up in 2014 after a NERC completion, the CDT is run out of Heriot-Watt University (HWU) and consists of a collaboration between 7 core academic partners (Aberdeen, Durham, Heriot-Watt, Imperial College London, Manchester and Oxford universities and the British Geological Survey), 12 associate academic partners (the universities of Birmingham, Cardiff, Dundee, Exeter (Camborne), Glasgow, Keele, Newcastle, Nottingham, Royal Holloway, Southampton and Strathclyde and the National Oceanography Centre), 9 core industry sponsors (BP, Cairn Energy, ConocoPhilips, E.On, OMV, Shell, Statoil, Total and Woodside Energy) and 5 associate industry sponsors providing support 'in kind', Halliburton/Neftex, Nautilus, PGS, Schlumberger and Spectrum.

The CDT currently comprises two cohorts of PhD students, who are undertaking their degrees at one of the 19 academic institutes. As part of their PhDs, the Centre provides them with a total of 20 weeks' joint training during the first three years of their 4 year degrees. The program is delivered by academic, governmental and industry experts from the Earth, Environment and Applied Business sectors. There is also an annual graduate school conference held at HWU, at which students will present their results and showcase the best academic research in oil and gas to the industry, government and academic peers.

The PhD research topics being undertaken are focussed on four areas:

- Environmental Impact & Regulation
- Extending the Life of Mature Basins (e.g. North Sea)
- Exploration in Challenging Environments
- Unconventional Oil & Gas Resources

The Centre aims to create a highly skilled workforce with expertise that can be used across the wider energy and environmental sectors. It will equip industry with the skills needed to explore, sustain and reduce the environmental impact of oil and gas exploration and extraction at a time of economic challenge and pressure for responsible environmental management.

The academy of talent currently comprises 28 4-year PhD studentships based in the 17 HEI partners in the 2014/15 entry cohort and 30 students in the 2015 cohort. The CDT is currently recruiting a further 35 PhD students for entry in October 2016 taking the CDT numbers up to 93.

NERC also announced on 16th December 2015 that the Research Council will provide a further £1Million funding for a fourth annual student intake in October 2017 to allow time for a re-commissioning process to be agreed that will apply to all NERC's CDT/DTP partnerships.

The CDT is now a >£10M investment funded by £3.7m from NERC, £5.3m from the host higher education institutions and with over £1m already pledged to the CDT training Academy by the industry sponsor companies. Website details: http://www.nerc-cdt-oil-and-gas.ac.uk

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KEYNOTE: The NERC Centre for Doctoral Training (CDT) in oil and gas: The Industry Perspective

Keith Gerdes
Chair of the NERC CDT Industry Advisory Board; Exploration Excellence & External Affairs, Shell

Industry involvement was identified as one of the key measures of success for the UK CDT for Oil and Gas. It is well recognised within the industry that energy transition will remain one of the major challenges in the future. The potential solutions to this challenge will require bright, creative individuals who have benefited from a broadly based, multi-disciplinary education in the geosciences and who are capable of engaging with all stakeholders to ensure solutions are sustainable and safe for both the public and the environment. The loss of expertise from the industry (the "Great Crew Change") has been accelerated by recent geo-political events making this initiative even more timely.

The formation of a cohort of PhD students following postgraduate studies over four years in a range of geoscience, environmental and regulatory disciplines creates a multi-disciplinary network which has the potential to develop the leaders of the future. The combination of 20 weeks of formal training by subject matter experts from both academia and industry with the intellectual independence of a PhD is a powerful combination for future careers in academia, regulation, industry and research.

It was a bold visionary move at the outset to propose a Training Academy fully funded by industry. The response of industry to this call, however, both in financial support and by providing staff to present training modules, not only justified this bold move but has created a key differentiator for this initiative.

The UK CDT in Oil and Gas is an exemplar of successful academic-industry collaboration and is tailored to prepare gifted students to meet the challenges of the future.
Website details: http://www.nerc-cdt-oil-and-gas.ac.uk/

NOTES

Tectonics of SE Asia and Australia–Asia collision: 30+ years of working with industry to drive forward geological knowledge

Robert Hall
SE Asia Research Group, Royal Holloway University of London

SE Asia is one of the planet's most tectonically active regions. Since the Palaeozoic the region has been largely surrounded by subduction zones and subduction has driven the growth of SE Asia by collision and accretion of numerous continental fragments. Australia–SE Asia collision began in eastern Indonesia in the Neogene and in the past few million years there have been episodes of dramatic uplift and subsidence within this convergent zone which have changed the palaeogeography of the region and influenced its biogeography. The region has long been one where new ideas about tectonics and evolution have developed and this continues today as new techniques and data, combined with traditional field-based studies, have changed our understanding of processes and rates of tectonic change. Field-based studies remain essential in this remote and challenging region but have generally declined in the last 30 years as research budgets have diminished and perceived priorities have changed. In the same interval there have also been major changes in funding of universities and assessment of research costs. The SE Asia Research Group, based at Royal Holloway University of London, has been able to continue major campaigns of field-based studies, accompanied by laboratory work involving collaborations between UK, international and SE Asian universities, government institutions and professional organisations, with the support of industry. In the last decade this work has included projects investigating the Sorong Fault Zone in east Indonesia, the Sumatran Fault Zone, arc development in Java, isotopic dating in Borneo, Cenozoic exhumation in Malaysia, the complex uplift and subsidence history of Sulawesi, studies of the Banda Arc collision, and regional sediment provenance studies. The research group has a long and successful history, with much of its work funded through industrial consortia. By combining the, at times conflicting, desires of academia and industry, it has been possible to carry out high-quality cutting edge geological studies that are mutually beneficial to both parties.

NOTES

Deep-water margins hold the key to the future oil-to-gas energy shift: Examples from recent industry consortia

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A major paradigm shift has happened in E&P in the past few years: a) hydraulic fracturing and EOR techniques led to the markets' perception that vast untapped reserves are now at reach of the major industry players; b) relatively cheap gas is increasingly seen as the main energy source for the 22nd Century, in part due to its abundance on continental margins. However, energy forecasts advocate that oil and gas production will steadily rise as share of the total energy demand, whereas the production of renewable sources has a maximum plateau at ~500 EJ. Hence, what is the reason for reductions in oil and gas E&P as of late? Is the relinquishment of 'mature' prospects a mistake, or are we witnessing a sustained period of 'cheap' energy? Were oil and gas prices primed by quantitative easing in the USA until the summer 2014, leading to over-capacity in the E&P industry?

This presentation will present the idea that increasing environmental regulation and future CO_2 targets will radically transform the E&P sector. Examples will be given in this talk of industrial and European consortia recently completed, or in development. In the North Sea, the increasing use of EOR techniques in 'mature' fields has led to multiple projects on the characterisation of sub-surface fluid flow. Of interest to industry is the recognition of the timings that led to the formation of fluid pipes in areas considered for reservoir stimulation, EOR techniques and further exploration campaigns. In Canada, vast deep-water areas spanning from the Flemish Cap to the Labrador Sea are being explored for oil and gas. West Iberia and Greece are being used as an analogue for sedimentary basins in Canada, and other Atlantic rift basins. In West Africa, stringent environmental regulations require the 'de-risking' of prospects in Albian and pre-salt units. Similar problems have been faced in new prospects offshore SE Brazil, China and Japan.

Future E&P will require sophisticated methods. We will see a rise in FPSOs, with inherent risks in terms of oil spills and maritime accidents. This shift will contribute to a 'near-CO_2 neutral' production of hydrocarbons. We are therefore heading towards a new exploration paradigm - one in which energy and environmental budgets are taken in consideration before oil and gas are produced. This will eventually keep production rates under control and will contribute to a gradual rise in energy prices.

NOTES

Source rock maturity modelling offshore Namibia –a successful Industry, Academia and Government collaborative project.

Karyna Rodriguez, Anna Marszalek, Anongporn Intawong
Spectrum Multi-Client UK

Spectrum has established a close collaboration scheme with Academia and Governments on a global scale. We provide support to postgraduate and research group projects at universities and government research institutes by sharing 2D and 3D seismic datasets from our vast global data library made up of 3.3 million km of 2D and 160,000 km2 of 3D. Some of the universities Spectrum cooperates with include Royal Holloway, Manchester, Heriot- Watt, Aberdeen, Leeds, Oxford and Imperial College. We also support Natural Environmental Research Council (NERC) Postgraduate Centre of Doctoral Training (CDT) in Oil and Gas. The projects cover a wide range of topics from regional studies, basin hydrocarbon prospectivity evaluation, structure- volcanic interactions, structural geology, and processing geophysics to earthquake and tsunami prediction studies.

An example of a successful joint Industry, Academia and Government project is a basin modelling study in the Lüderitz Basin, offshore Namibia conducted by Spectrum with assistance from Manchester University and the National Petroleum Corporation of Namibia (NAMCOR). The aim of the project was to de-risk the presence and maturity of the Aptian source rock. Source rock maturity modelling involved geothermal gradient calculations based on the Bottom Stimulating Reflectors (BSRs) mapped on 2D seismic data offshore Namibia and 2D basin modelling. The data was acquired by Spectrum as a joint venture with NAMCOR. Manchester University provided their in-house expertise in geothermal gradient calculations and basin modelling. The study not only achieved the objective of de-risking source rock presence and maturity in the Lüderitz Basin but also showed that seismic can be used as tool to de-risk source rock maturity in unexplored basins.

The Industry Academia and government collaboration model used by Spectrum promotes ideas and skills transfer between the institutions. During joint seismic acquisition projects, technical training is often provided by Spectrum to the country government's representatives. Likewise, when supporting academic research, universities share their expertise with Spectrum by providing training courses, geological fieldtrips or academically proven methodologies. Sharing seismic data gives researchers an opportunity to work on the high quality seismic data in many basins around the world and while new findings from these studies add value to our datasets they also provide a valuable contribution to the better understanding of petroleum systems and the geology of basins around the world.

NOTES

How convective circulation of the Earth's mantle affects hydrocarbon exploration potential at continental margins.

Professor Nicky White
Cambridge University

It is generally agreed that convective circulation of the deep interior causes vertical displacements at the Earth's surface. These displacements, referred to as dynamic topography, occur on a large variety of length and time scales and have the potential to impact exploration risk (e.g. heatflow and maturation, source to sink, reservoir leakage). Analysis of age-depth anomalies of old oceanic crust using high quality regional seismic surveys has played a key role in helping to resolve the size and shape of dynamic topographic anomalies. These anomalies help to inform our understanding of the sequence stratigraphy and thermal structure of adjacent passive margins. A series of case histories will be presented that illustrate how these new observations link deep and shallow phenomena and guide exploration strategies.

NOTES

Oil & Gas Exploration in the Arctic

Prof. Alastair Fraser
Imperial College London

In overcoming the technical challenges of oil production in the Arctic, are we making the most of a strategic resource or heading for an environmental and political minefield?

The vast Arctic region is probably the last remaining unexplored source of conventional hydrocarbons on the planet.

In the past three decades of oil exploration in the Arctic, more than 200 billion barrels of oil have been discovered. Ultimate resources are estimated at 114 billion barrels of undiscovered oil and 2000 trillion cubic feet of natural gas. If these estimates are correct, these hydrocarbons would account for more than a fifth of the world's undiscovered reserves. This great prize, in a world of diminishing resources, has stimulated both governmental and industry interest in areas such as the US and Canadian Beaufort Sea, East and West Greenland and the Kara Sea.

Balanced against this are the considerable technical challenges of exploring and producing hydrocarbons in areas where sea ice is present for more than half the year as well as the underlying threat of damage to a pristine Arctic environment.

Harnessing the considerable resources of the 'Final Frontier' is going to be fraught with many technical, political and environmental challenges that will engage many minds, both scientific and political over the next half century.

NOTES

The Future of Exploration: Challenges and Advances in Applied Geosciences

Dirk Smit
Shell

Climate Change and increased operational efficiency will require smaller environmental footprint and greater predictability of subsurface asset performance to increase effective management of hydrocarbon production and environmental footprint – already at the exploration stage. This is a formidable challenge and requires new geosciences insights and technologies.

Advances in Geosciences has always been triggered by either the ability to acquire more and better data and, or by lowering computing costs to process data faster. Indeed we still under-sample the subsurface compared, say, to the medical industry hence by simply being able to measure more we are able to see more of the subsurface and more accurately. However, recent breakthroughs in both computing as well as in sensor technology and technologies like the “internet of Things” allow for a more radical change on how to interpret and manage subsurface resources. Apart from being able to recognize and interpret ever more refined geological conditions it may also become feasible in the near future to understand and even predict the dynamics of the subsurface during the production of resources. This will however require changes in the traditional way we acquire, process/image and interpret data in a sequential pipe-line process. In this talk I will outline this by way of a few examples of new technologies. Indeed, it will allow for more efficient and possibly more predictive asset performance than currently possible.

NOTES

The Future of Oil Exploration.

Neil Hodgson and Karyna Rodriguez
Spectrum Geo.

Oil exploration in the 21st Century has been a journey into ever deeper water to seek the reserves that will prevent our civilization from collapsing into energy starved chaos. Increasing competition for an ever smaller prize in the accessible shelf or failed rift basins, has compelled a courageous few companies to creep down the continental slopes looking for new plays and resources. Yet on these continental slopes, success has been episodic because the targets have predominantly been stratigraphic channel plays which cannot be fully de-risked pre-drill. We now need to complete the journey to the deep water abyssal plains to explore the super-giant low risk apron fan prospects that lie there.

To complete this journey we must seize a future that works ONLY because oil is at $50/bbl, we must complete the technological journey that operates safely between 3000 and 4000m of water, and we must find truly giant prospects to drill.

The NOAA sediment thickness maps constraining first order models for source rock maturity along the Atlantic margin, can be coupled to a model of sediment loading and plate cooling that generates huge trapping geometries at depth along all the Atlantic margins. Intriguingly the stratigraphic apron fan traps that dip landward are also more oil prone due to less burial of the source rock in the out-board setting. Modern long streamer ultra-deep water 2D seismic from the coast of Uruguay, Brazil, Eastern USA, Namibia/ South Africa, Gabon, Senegal and Mauritania, indicates where these giant prospects lie and what their associated resource potential might be. The potential of Senegal and Mauritania out-board of recent drilling success will be particularly illustrated. We will also review settings in SE Asia with similar potential but subtly different play systematics, to indicate how these systems might work in ultra-deep water on broadly destructive margins.

Whilst it is clear that Ultra-Deep Water has the potential to transform global energy supply, good-data and clear vision are required to complete the journey and claim the prize. The journey to deep water through an unpromising slope setting is nearly over, and just ahead of us lie low-risk apron fan oil prospects, that trap on a plate scale. Keeping the vision for deep water exploration is our responsibility that will soon return huge rewards, just when the world needs them.

NOTES

Is biogas production from heavily degraded crude oil a viable option for energy recovery?

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Most of the oil in low temperature, non-uplifted reservoirs has been biodegraded by millions of years of microbial activity. Understanding the limiting factors of microbial degradation of crude oil could open opportunities to bioengineer heavy oil reservoirs for energy recovery in novel ways – e.g. by stimulating biogenic methane production *in situ*. This idea has been proposed in recent years as a 'greener' alternative for exploiting heavy oil deposits. In this study, we performed long-term microcosm experiments to investigate whether addition of inorganic nutrients and different electron acceptors could stimulate further biodegradation of already severely biodegraded Athabasca oil sands bitumen (Alberta, Canada) for the production of methane. We combined basal water and surface-mined bitumen in microcosms that were incubated for 3000 days under different redox conditions, without any additional substrate. Biogenic methane production was observed in both replicates for three out of five treatments. This corresponded with enrichment of methanogenic *Archaea* and several potential syntrophic bacterial partners. However rates of methanogenesis were below 15 nmol/day/g oil sands, which is 10 to 1000x lower than published reports of methanogenesis from lighter crude oils. The organic composition of the bitumen before and after 3000 days of incubation was analysed by gas chromatography-mass spectrometry (GC-MS) and Fourier transform ion cyclotron resonance-mass spectrometry (FTICR-MS). No significant degradation was observed for any compound or compound class, suggesting that degradation may have occurred at low rates and in an unspecific manner. These results demonstrate that microbial communities in Athabasca oil sands are capable of accessing a limited pool of organic carbon present in severely biodegraded heavy oil as substrates for methanogenic biodegradation, but at very low rates. This highlights the challenge of bioengineering heavy oil reservoirs in this way, and suggests that less-heavy oils may represent better targets for *in situ* biogasification strategies.

NOTES

Evaluation of shale gas resources using a high pressure water laboratory maturation method: application to the UK Bowland shale

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The study by Andrews (2013) estimated that the shale gas resources of the UK Carboniferous Bowland Shale is significant, containing 822-2281 tcf (trillion cubic feet) of gas. However, this resource estimation was based on screening geochemistry and source rock potential. Shale gas is often relatively dry (composed mainly of methane), implying that it is largely generated at high maturities, yet the study by Andrews (2013), and others carried out so far on UK shale gas systems did not directly address the fundamental science questions of what the composition of a typical UK shale gas will be, how much methane is in the gas, and what was the source rock thermal maturity range at which gas enriched in methane is generated, and how the amount of generated gas varies with source rock maturity. To properly estimate the UK shale gas resources in the absence of producing well data, we have used a novel high water pressure sequential pyrolysis method that simulates conditions in geological basins to investigate gas generation in shale gas reservoirs, as a function of both temperature and pressure to address these issues. In this method, a relatively immature source rock (TOC of 6.69%, HI of 410 mg/g, VR of 0.58% Ro) from the upper Bowland Shale unit within the Rempstone-1 well was successively heated (using a 25 ml autoclave Hastalloy vessel at 180-800 bar pressure range, at 350-420 °C for periods of 24-120 hr) to archive source rock thermal maturity stages equivalent to the oil window, the wet gas window and the dry gas window. After each maturity stage, the experiment was stopped and the expelled oil and gas generated recovered and the gas analysed.

This study concludes that shale gas (> 80% methane as found in US shale plays) will only be generated at high maturity (VR > 2.0% Ro), and that the gas yield will be less due to very little generative potential remaining at this maturity. Although more gas will be generated at lower maturity (VR > 1.2% Ro), the gas will certainly be wet (< 50% methane) and not dry. The implications of this study to the Bowland Shale are that the thermal maturity range (1.1-1.9% Ro) suggested by Andrews (2013) for extensive gas generation, is actually insufficient for extensive dry gas generation. Therefore Bowland Shale source rocks with a higher maturity need to be targeted for shale gas exploration. The decreasing gas yield with increasing thermal maturity observed here suggests that the study by Andrews (2013) may have overestimated the UK Bowland Shale gas resource (based on the assumption that a typical shale gas generation starts at a VR of 1.1% Ro), and a re-evaluation is required that will need to include a more reliable laboratory data set.

Reference

Andrews, I.J., 2013. The Carboniferous Bowland Shale: Geology and resource estimate. British Geological Survey for Department of Energy and Climate Change, London, UK.

NOTES

QEMSCAN: rock characterization for the digital age

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The hydrocarbon industry uses advanced software packages to model reservoir behavior. A model can only be as good as the data that underpins it. Traditional techniques to calibrate logs and quantify rock properties, such as XRD, XRF, optical petrography and core analysis, and newer techniques such as QEMSCAN and microCT, are generally carried out on a small subset of available material, such that upscaling introduces great uncertainty.

At Rocktype, we are developing ways to provide significantly larger (Big Data) rock properties datasets to support reservoir modeling. The challenge is not technical, but one of scale, processes and pricing.

We can look to companies that have led revolutions in their own industries, for example Amazon, Easyjet, Netflix and Uber. We are all familiar with the changes companies like this bring to our daily lives, but few are aware of the processes they use to create change and the thinking and implementation principles that underlie it.

The hydrocarbon industry has largely been unaffected by this trend to date. However, with the sharp change in oil price we are likely entering a period of strong innovation and disruption. Lower profits require new thinking.

This talk will outline the theories and methods employed by disruptive companies such as ours. We hope it will inspire the listener to think about their own working practices and ask if they too can lead innovation to help our industry thrive in this low oil price environment.

NOTES

The clumped isotope palaeothermometer as a reservoir characterisation tool in deeply buried carbonate reservoirs

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Dolostones will often form excellent reservoirs due to enhanced porosity after the dolomitisation process. Characterising the temperatures of dolomitisation and recrystallisation is therefore key to understanding reservoir quality and minimising exploration risk. The novel 'clumped' isotope palaeothermometer has great potential as a new way of accessing this rich record of geological processes. This study investigates what geological processes clumped isotope temperatures record in dolomite in sedimentary carbonates buried to >~1km.

The Albian Pinda Formation is a major hydrocarbon reservoir in the Lower Congo basin, northern offshore Angola. Temperatures derived from clumped isotope thermometry of dolostone drill cuttings from ~2-4 km depth are ~30-50 °C lower than fluid inclusion and present-day temperatures recorded at any given depth. They range from 65 °C to 122 °C and cluster at about 110±10 °C in the deeper samples. This suggests massive burial dolomitization occurred at ~110 °C and did not continue on to the present-day burial temperature (~150°C). The reconstructed $\delta^{18}O$ value of the dolomitization water is between 4 and 6‰ SMOW, in good agreement with the $\delta^{18}O$ value of 5 ‰ measured for present-day formation water in a nearby well.

Dolostone samples from the Upper Jurassic Mano and Meillon dolomite formations from the Aquitaine Basin, Southwest France, from ~2.5-5.5 km depth, also record burial recrystallisation temperatures of ~60-100 °C in their clumped isotopes. A particularly coarse dolostone sample records a much higher clumped isotope temperature of 144±7 °C, interpreted to represent recrystallisation in the presence of a fault-related hydrothermal fluid.

Despite relatively deep burial, the clumped isotopes are recording the temperatures of discrete recrystallisation events in dolomite in these samples. Signals of these events are being preserved despite subsequent increases in ambient temperature. This indicates that at temperatures of at least ~150 °C and burial depths of at least 5.5 km, clumped isotopes in dolomite will preserve the temperature of open-system recrystallisation events. This suggests that clumped isotopes can be a valuable tool in characterising the temperatures of deeply-buried diagenetic dolomite and therefore the thermal history of carbonate hydrocarbon reservoirs.

NOTES

Detailed reservoir characterization using 3D CT scans, borehole imaging (BHI) and core

Beatriz Serrano-Suarez[1] and **Adrian Neal**[2]
[1]BP America
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Computer Axial Tomography (CAT or CT scanning), is an X-ray based technique first developed in the late 1960s for medical '3D' imaging purposes. However, it has increasingly found applications in the earth sciences due to its ability to provide both quantitiative and qualititaive data regarding the internal structure of rocks and sediments, as determined by contrasts in density and atomic composition. The integration of 3D CT Scans from core with more traditional core description techniques, and other technologies such as borehole imaging (BHI), offers a powerful way of characterising sedimentological and structural features in a reservoir. With borehole images it is possible to identify and orient geologic features over relatively long well sections (100s - 1000s of feet). However, BHI resolution is still very coarse compared to what can be observed in a core, which offer a very detailed picture of the reservoir rock. Despite this, subtle sedimentary and structural features can be difficult to see with the naked eye, especially if the core is oil stained. In these cases the use of 3D CT scans offers a very high resolution image of the structures in the rock, which can be used to enhance the core description. The study we present here shows a detailed interpretation combining 3D CT scans, BHI and core from a deepwater turbidite reservoir. Firstly, the 3D CT scans allowed more detailed recognition of sedimentary facies; commonly sandstones that seemed structureless in the slabbed core were shown to be space-laminated or dewatered in the CT scans. Secondly, by using bedding features common to both the BHI and core data sets, it was possible to orient the 3D CT scans and demonstrate that interpreted fractures in the BHI corresponded to deformation band sets in the core. Using the CT scans it was possible to identify more deformation bands than with the BHI. However, most of the fractures identified with the BHI matched both in orientation and location those interpreted in the CT scans. Thus by combining CT scans and BHI it is possible to orient sedimentological and structural features to provide a more complete picture of the reservoir at a particular well location, and provide calibration for wells where only BHI are available.

NOTES

Extrusive igneous reservoirs in hydrocarbon exploration

Andrew Racey
Andy Racey Geoscience Ltd

Reductions in the volume of discovered and produced hydrocarbons will ultimately drive exploration companies to further assess the economic viability of unconventional lithologies including extrusive volcanic rocks as potential reservoirs. Currently around 60% of the worlds conventional hydrocarbon resources are in sandstones, 40% in carbonates and <1% in volcanics.

Extrusive volcanic rocks occur in most geological settings and over the entire geological column and can host hydrocarbons in a broad range of volcanic rock types. They are especially common in rifts, back-arcs, fore-arcs and even foreland basins forming an average of 25% of basin fill. Commercially producing volcanic reservoirs are geographically and stratigraphically widespread and include: Upper Carboniferous to Palaeogene of China (Songliao, Junggar, Erlian, Sichuan, Santanghu and Bohai Bay basins); Cretaceous Campos Basin of Brazil; Permo-Triassic and Jurassic of the Neuquen and Austral basins of Argentina; Palaeocene of the Cambay Basin, India; Miocene-Pliocene of the Nigata and Akita basins of Japan; Miocene Petchabun Basin of Thailand; Kura Basin of Azerbaijan and Georgia and also in the USA (Pliocene of Utah and Oligocene of Nevada). To date there are over 300 global records of hydrocarbon discoveries and significant shows in volcanic rocks of which around 170 have proven reserves.

Volcanic rocks are less affected by compactional porosity loss than typical sandstone and carbonate reservoirs due to their greater mechanical strength and, can therefore form potential reservoirs in the deeper parts of basins where more conventional sandstone and carbonate reservoirs are unproductive. Hydrocarbons are produced from acidic, andesitic and basic (basaltic) lavas and volcaniclastics with most of the production coming from onshore fields. These reservoirs often show a high degree of variation in terms of porosity (1 - 35%) and permeability (0.1 - 250 mD and rarely > 1 Darcy). Volcanic rocks are often highly heterogeneous in terms of their rock fabric and commonly possess complex pore architectures which are controlled by a range of primary and secondary processes. The dominant controls on igneous porosity are primary degassing structures (such as lava tunnels, caves, vesicles and pipes) which are typically concentrated towards the flow tops; fractures (both primary i.e. cooling joints or quench fractures and secondary tectonic fractures) and subsequent secondary dissolution and alteration during weathering and/or burial. Reservoir development is complex and also depends on the original silica and volatile contents of the magma which affect viscosity and degree of subsequent alteration/fracturing especially if rapidly quenched by water and the degree of primary vesicle and vug development respectively.

NOTES

On the road to a global dynamic subsurface model: synergy between content and technology in DecisionSpace® Geology

Rachel Zaborski
Halliburton

With the global oil market predicted to be oversupplied for the duration of 2016, the industry faces an uncertain future. To increase efficiency within exploration workflows, the 4D Global Earth Model (GEM) in DecisionSpace® Geology leverages both content and technology in a derivation of a collaborative and integrated global description of the subsurface.

Regional 3D isochronous depth grids have been built for key stratigraphic surfaces and provide the geological foundation for 4D GEM. These are built using publically available data that is collected, standardised, and digitised, then interpreted in accordance with the Neftex sequence stratigraphic model. This data is stored in a comprehensive portable database, and accessed by DecisionSpace Geology during model building and play analysis.

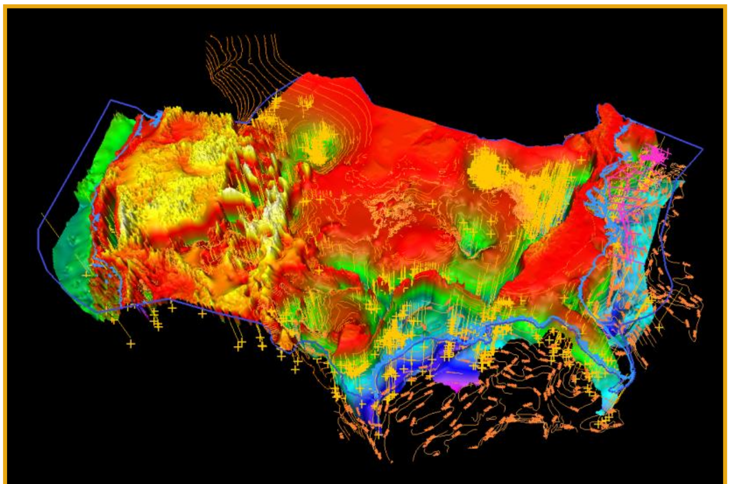
The development of the 4D GEM has vast potential, and in the age of big data, it offers dynamically updatable, data-derived solutions. In this way, knowledge is preserved, data is easily coordinated, and effort is not duplicated. It serves as a geologically constrained starting point of any new venture project.

Presented here are some highlights of building the 4D GEM over the last year covering both content and technology:

- A continental-scale framework model of the lower 48 states of the US (*see image*) was generated comprising surfaces defined by the regionally significant Sloss sequences. Within this sequence stratigraphic framework, regional and local trends in sedimentation can be seen. By integrating a wide variety of disparate data and interpretations of the depositional environments, rapid and iterative regional screening can be achieved.

- The Chronostratigraphic Manager is a unique tool that allows the global integration of stratigraphic data between third party vendors and legacy and proprietary datasets and interpretations.

Finally, the vision for the future is collaboration between academic and industry organizations to improve the versatility, accessibility, and progressive nature of the software and content.



L48 Basement surface with constraining basement contours, wells and Atlantic seismic

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NOTES

Belinda and Evelyn – New seismic insights for near field exploration

Stacey Emmerton, Jaume Hernandez Casado, Arfan Ali, Robert Broos, Lin Li
Shell

Evelyn & Belinda are two fields south of the Gannet cluster, discovered in 1984 and 1990 respectively. Their proximity to nearby infrastructure and the advent of Small Field Allowance has renewed interest in a quick development of these stranded hydrocarbon volumes.
Both fields consist of oil rims and associated gas caps within the Tay reservoir, part of a small Tay fan system from the West. Belinda is a four way dip/fault closure with Middle Tay sand lobes. Evelyn is more complex due to the presence of Upper Tay channels pinching out over Middle Tay channelized lobes. The specific development challenge is to identify firstly the sand distribution across the field and then the optimal well placement for effective oil recovery of these small accumulations.

Using new multi-client broadband seismic data acquired by CGG, the fields have shown a very complex seismic signal response due to different fluids as well as the presence of soft and hard sandstones. Understanding the seismic signature through rock physics analysis and synthetic modelling has allowed us to separate the Upper & Middle Tay to further understand the depositional model. Further evaluation with a probabilistic inverted seismic volume has allowed us to delineate the fields in much more detail revealing 1) a larger sand distribution over Belinda with individual sand lobes identified and 2) a lack of connected sand bodies over Evelyn.

Through detailed quantitative interpretation (QI) of new broadband seismic we have advanced our understanding of the reservoir architecture over these fields as well as the surrounding area, allowing us to continue plans to develop Belinda and characterise additional potential targets. For near field exploration it has identified the need to maximise current data with advances in technologies/software to better understand detailed sand distribution and help de-risk further activities. Advanced QI techniques are rarely applied to an exploration setting and could help unlock future opportunities near existing field infrastructure allowing companies to maximise facility capacity and bring additional growth to producing basins.

NOTES

Collaboration – a cloud on the horizon

James Selvage, Charles Jones and Andrew McVey

In a world where oil prices have dropped by more than half and budgets are dramatically cut, we need to look at our current practices. We need to focus on doing things differently and doing different things. In 2015 BG Group identified cloud computing as a viable alternative to owning an internal seismic storage and compute environment. The business case for such a change is strong: with an opportunity to offer a more secure storage and flexible compute environment that can respond to business needs combined with a cost saving estimated at 50%.

Whilst these benefits are compelling we recognise that business value is delivered from the analysis and interpretation of seismic data not the storage of the data itself. Therefore, we conducted a pilot project to demonstrate that analysis and interpretation of seismic data could be performed using standardised cloud components.

BG Group's standard interpretation workflows have evolved to incorporate various types of pre-stack seismic data (Table below). These volumes are typically 50 times larger than their traditional stacked equivalents.

Analysis	**Pre-stack seismic used**	**Typical volume (TB)**
Imaging uncertainty	Pre-migration common midpoint	10 – 30
Amplitude-versus-angle	Final Common Image Point Angle Gathers	10 – 20
Gather conditioning (*e.g. trim statics*)	Raw Common Image Point Angle Gathers	10 – 20

To process these datasets, within a timeframe to make meaningful business decisions, requires significant storage and compute capacity. Typically, this capacity is scaled to meet the peak load of medium-term business needs. This commonly results in the storage only being filled by the end of its intended requirements and compute resources often only average 20% usage. Long lead times (3 – 6 months) also make these systems inflexible to changing business demands.

In contrast cloud computing technology has the ability to provide storage and compute on a pay-as-you-go basis which scale in response to business demand. The pilot demonstrated that cloud computing provides a flexible compute platform for BG Group. During this pilot the following tasks were undertaken "in the cloud":

- Upload of a multi-terabyte seismic datasets (storage solutions)
- Processing using internally developed code in MATLAB (high performance access to large data sets)
- 3D visualisation and interpretation in OpendTect (to test 3D graphics and memory requirements)

The main concerns that were encountered during the project framing were not technical, but the legal and security compliance of a public cloud environment. To address these we worked with legal and security stakeholders to identify the main risks and mitigate them in the cloud pilot.

BG Group has geoscientists deployed globally, all of whom need access to a core set of tools and data running on a consistent architecture. It can be difficult to deliver a consistent and scalable infrastructure in some of the locations and over the timeframes in which we operate, with variations leading to frustration and the risk of missed opportunities. The cloud pilot demonstrated that it is possible to offer a secure, consistent and repeatable platform in geographies close to where we operate.

For all oil and gas industry stakeholders exploration activities present a “data gravity” problem. A large amount of time is spent moving datasets between other operators, contractors, regulators and academia. Therefore, we see a benefit in cloud computing providing an opportunity for standardisation amongst these stakeholders. The scale of the storage and compute enables each stakeholder to have their bespoke Virtual Private Cloud (VPC) and control access to share datasets. For example, instead of a new dataset being stored by each individual operating partner it could be stored in the cloud and be shared into each partner’s VPC.

In times of low oil price, we need to question whether we should continue with old ways of working or move to a new framework? Other industries already benefit: it is now time for the oil and gas industry to catch up. Rather than individual oil and gas industry stakeholders performing their own pilots we suggest that a Joint Industry Project could facilitate the adoption of cloud computing for the industry as a whole.

NOTES

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Poster Presentation Abstracts

Electrification of Road Transport and its Impact on Oil Demand and Hydrocarbon Exploration.

Dr. Matthew Brown

The author believes that within the working lifetime (30-40 years) of current early-years geoscientists the internal combustion engine (ICE) will cease to exist as a significant power source. For over a century it has been the dominant form of power for road transport burning petrol or diesel refined from oil. Today 44% of produced oil is burnt in internal combustion engines (World Oil Outlook, 2015).

In recent decades the recognition of the local and global environmental damage caused by burning fossil fuels has led to increased efficiencies in internal combustion engines and the development of hybrid engines and pure Battery Electric Vehicles (BEV's). One company, Tesla, has demonstrated that BEV's can exceed the capabilities of ICE powered cars in almost every metric. The realisation that this is possible and that there is a demand for these vehicles is spurring major car manufacturers to start and accelerate production of their own BEV's.

Total BEV numbers are currently very low, around 0.01% of global vehicles; however growth is rapid and accelerating. In several markets around the world they outsell comparable ICE powered vehicles. There can be no doubt that the ICE will become redundant in the future. The only question is how far away that future is.

This poster aims to justify the assertion that the ICE is now in terminal decline and reminds us why this is a good thing for the world in general. However given that 44% of oil production (op. cit.) is currently burnt for road transport the effect on our business of hydrocarbon exploration and production can be expected to be significant and negative. The poster attempts to consider the magnitude and timescale of this change and the effect on our industry. In doing so it will touch upon a far wider discussion around electricity generation. Finally it considers how we as an industry might start to think about adapting to a future without our largest customer, the internal combustion engine.

The New Energy Rush: Shale Gas Development vs. the Environment

Deji Kolawole

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Shale gas has become a major talking point in terms of its potential as a future global energy source. The term "*fracking*" was relatively unknown at the turn of the millennium; this has changed due to the recent publicity the shale gas industry has received. The possibility of energy independence and security, coupled with the major technological advances made over the years, has made the shale gas industry economically viable and attractive, especially in countries like the US where it has flourished. This study will provide an insight into the impact of shale gas development in relation to: 1) national energy security; 2) the environment; and 3) the environmental challenges associated with shale gas extraction.

For the purpose of this study, technical data from shale gas analysis, studies carried out by governments, academic organisations and green groups, articles and peer-reviewed articles from academia various media outlets and books related to fracking and shale gas exploration will be critically reviewed.

The investigation into the potential correlation between shale gas development and national energy security indicates that the rise in shale gas production has significantly reduced the U.S. reliance on foreign gas imports. However, with regards to research in relation to the environmental impacts of shale gas development, the findings establish that there are some potentially harmful impacts on the environment which begs the question: are the positives worth all the negatives that come with the process? These impacts have also posed various environmental challenges resulting in the need for improvements in aspects of exploration and drilling, hydraulic fracturing, water and land-use, and environmental health and safety.

The relative infancy of the global shale gas extraction industry leaves room for the formation of a standard global regulatory framework and scope for further research in relation to: 1) the greenhouse-gas footprint of shale gas extraction; 2) the water requirements of shale gas extraction; 3) the associated environmental risks of shale gas extraction; and 4) the viability of shale gas development on a global scale

Volumetric estimates of a thin CO2-filled layer at the Sleipner Field, North Sea.

Laurence Cowton
University of Cambridge

Migration of sequestered CO_2 through offshore storage reservoirs can be monitored using time-lapse seismic reflection surveys. At the Sleipner Carbon Dioxide Storage Field, injected CO_2 is distributed throughout 9 discrete layers within the reservoir. These layers are too thin to be resolved by direct measurement of the separation between reflections from the top and bottom of each CO_2-filled layer. Thus, monitoring CO_2 injection has been restricted to measuring changes in the areal planform of each layer. Here, we develop and apply a method for measuring thickness changes of the shallowest layer. My approach exploits time-lapse seismic surveys by comparing the two-way travel time down to the reflection from the top of this layer from survey to survey. Changes in travel time are combined with amplitude measurements to determine the optimal layer thickness by inversion. A series of synthetic forward models, to which different amounts of ambient noise were added, were used to test the robustness of our inverse algorithm and to quantify trade-off and uncertainty. In the absence of ambient noise, the algorithm can perfectly resolve layer thickness. When a realistic ambient noise distribution is included, layer thicknesses of 1-6 m can be accurately retrieved with an uncertainty of +/- 0.5 m. We used this approach to generate an isopach map of the shallowest layer at the Sleipner Field. The fidelity of this map was tested using direct measurements of layer thickness from the 2010 broadband seismic survey. My results suggest that the shallowest layer is growing rapidly and at the expense of the lower layers. Finally, the relationship between caprock topography and layer thickness is explored and potential migration pathways that charge this layer are identified.

The Impact of Palaeogene Tuffs on the Petroleum System in the Faroe-Shetland Basin

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A number of tuffaceous horizons are preserved within the Lower Palaeogene stratigraphy of the FaroeShetland Basin (FSB). Of the thicker sequences, the Kettla Tuff contributes to the regional pressure seal in the Flett Sub-basin, and the Balder Tuff forms the prominent seismic “ash marker” in the North Sea and Atlantic Margin. These Palaeogene tuffs are rarely cored, their petrophysical character is frequently misinterpreted and their overall number is likely underestimated due to their thickness often being below the vertical resolution of downhole tools. In this study we utilised the PGS FSB MegaSurvey Plus 3D regional seismic dataset and released well logs and core, to investigate the distribution and character of all the seismically and petrophysically resolvable tuffaceous horizons. We examined the nature of the sedimentary units directly above and below these tuffs, mainly their petrophysical and drilling properties, to determine impact on the petroleum system.

Tuffs are commonly recognised as stratigraphic markers and potential top seals, however, we also recognise the impact interbedded tuffs have on reservoir material. In particular, the alteration of degraded tuffaceous material maybe be critical to preserving the porosity within the Laggan-Tormore Fields. We also show that tuffaceous material is best preserved in low energy settings such as below the wave base, and in isolated swampy pods in terrestrial settings. This relationship is crucial as interbedded tuffs and sands can produce Amplitude Versus Offset (AVO) anomalies, which have been misinterpreted and drilled (e.g. the Longan & Fleet North prospects). Understanding where tuffs are winnowed out can help de-risk the prospectivity of high energy marginal marine and fluvial sands which are deposited during known periods of tuff deposition. The interaction of tuffaceous material with reservoir quality sands is crucial, not only to the prospectivity of tuff-dominated intervals in the FSB, but in de-risking reservoir material from similar prospects in rifted margins globally.

Seismic expression of blow out pipes and their root zones using time lapse surveys: the case of the Loyal field (West Shetland, North Sea)

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Most of the available knowledge for fluid escape and blow-out pipes (Cartwright et al., 2007) has been inferred from high resolution marine seismic studies. On seismic data fluid escape pipes are recognizable as columnar zones of disrupted reflection continuity, commonly associated with amplitude and velocity anomalies, and scattering, attenuation and transmission artifacts (Loseth, et al 2009, Cartwright and Santamarina, 2015). In some cases, pipes consist of zones of deformed reflections related to minor folding and faulting. In others, they simply appear to consist of stacked pockmark craters or stacked localized amplitude anomalies that are likely to be small gas accumulations or zones of cementation. In most cases, they tend to be localized at natural leak-off points for over pressured pore fluids, for example at the crests of structures, above gas reservoirs, or at the up-dip limits of aquifers. However the detailed structure of pipes is still poorly understood and may be highly variable. Here we report on a detailed analysis of the seismic expression of some blow-out pipes from the Loyal field affecting the late Paleogene-Neogene overburden units, focusing on the root zones and potential source layer of those structures. The Loyal field in the UK North Sea is an oil and gas producing field located in Quadrant 204 and 205 of the UKCS, 130 km west of Shetland and is characterized by siliciclastic turbidite sandstones, derived from the uplifted Scottish Massif to the southeast. In order to investigate the internal structure and distribution of the root zone structures the major Cretaceous to Neogene formations have been systematically mapped and interpreted to outline the source-overburden strength heterogeneity. Initial results suggest that most of the pipe roots are triggered or from the over-pressured units of the Montrose Group and Lista Formation. (the smallest) or from the T31-T36 Paleocene reservoir units (the largest structures). The internal structure of the root are imaged differently across the near to far offset dataset and are often characterized by low signal/noise and a more diffuse geometry with depth. The majority of the Lista Formation related blow-out pipes show localized root structures (across both the near to far offset seismic dataset) confined to the upper part of the sloping basin structure, in some case exploiting pre-existing faults. The largest and deepest fluid pipes are instead scattered across the basin slope, apparently associated with the main reservoirs currently under production. The fact that they have been observed to ascend across more than 2000 m of highly impermeable units and deflect upward the main refelctors csuggests that the driving processes involved in pipe development are extremely energetic. The use of full, near, medium and far offset seismic datasets to analyse internal seismic texture of root and main conduit zones suggest the largest pipe blow out zones are associated to flux of gas-saturated mud that in some case reach the surface and build pockmark structures.

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The impact of Igneous Intrusions on the Petroleum System: Implications on Reservoir Quality, Source Rock and Exploration.

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Exploration in volcanic rifted margins can be complicated by the presence of extensive intrusive igneous complexes into the sedimentary succession. These intrusions can provide a potential hazard during drilling and can have profound impacts on the host rock properties such as reservoir quality, source maturation, and hydrocarbon migration. Intrusions in petroliferous basins can pose significant challenges from exploration through to appraisal and production, with potential for tight reservoirs, reduced production and reservoir compartmentalisation (Holford et al., 2013).

Applied petroleum research focused on volcanic rifted continental margins is currently undergoing resurgence due to the potential untapped hydrocarbon resources that may be found in volcanic rifted margins worldwide. The Faroe-Shetland Basin (FSB) is one such basin, and despite several significant discoveries (e.g. Clair, Rosebank, Schiehallion), exploration success has been mixed (Austin et al., 2014). In recent years, it has been suggested that the Faroe-Shetland Sill Complex (FSSC), which intrudes pervasively through the Cenozoic and Mesozoic sequences of the FSB may have had a profound effect on the petroleum system (Schofield et al. 2015). Intrusions have the potential to act as barriers and baffles within the subsurface, alongside the potential to act as conduits to hydrocarbon migration (Rateau et al., 2013; Schofield et al., 2015). However, many of these relationships, though founded on good interpretation of seismic and well data, lack the detailed knowledge and physical constraints to make a quantitative assessment about the interaction of intrusions in relation to reservoir quality, source maturation and hydrocarbon migration. In the FSB many wells have drilled intrusions with over 200 individual intrusions encountered in the FSB alone. Wells that have encountered intrusions whilst drilling had problems such as loss of circulation, downhole instability, downtime and in some cases significant overpressure resulting in a kick.

Through carrying out a combination of fieldwork, seismic interpretation and well analysis this poster will illustrate the impact igneous intrusions have on the host rock sediments. This will highlight the implications this has for the petroleum system with a focus on the FSB and ongoing exploration there. This poster will also illustrate with examples how sills can present a potential drilling hazard in the FSB and how it is possible to understand and mitigate this risk during exploration.

Is there any relationship between Oceanic Anoxic Events of the Aptian-Albian interval and the opening of central segment of the South Atlantic during the Early Cretaceous

Leonardo R. Tedeschi*, Hugh C. Jenkyns and Stuart A. Robinson

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The Aptian and Albian stages represent a critical time interval for global palaeoceanography because fundamental changes took place in the ocean–atmosphere system. The possible relationship between the opening of the central segment of the South Atlantic (CSSA), and periods when unusually large amounts of organic matter were preserved as marine 'black shales' during Oceanic Anoxic Events (OAEs 1a to 1d), is not well constrained. The main aim of this study is to examine the possible correlation between OAEs and the opening of the CSSA. Carbon-isotope profiles ($\delta^{13}C$) from wells in the CSSA can be compared with those from stratigraphically well-calibrated open-marine sediments. In addition, a high-resolution strontium-isotope stratigraphy ($^{87}Sr/^{86}Sr$) from one offshore well has also been generated. $\delta^{13}C$ profiles and $^{87}Sr/^{86}Sr$ profiles from shallow-water carbonate sequences, lying stratigraphically just above the evaporites from offshore wells in the Campos and Santos Basins, constrain major evaporite deposition in the CSSA to be no younger than Early Aptian (*L. cabri* Zone). Consequently, the data permit possible links between OAE 1a and the opening of the CSSA. The unusually extensive evaporite deposition would have reduced the global dissolved sulphate inventory, which could help in explaining the coincidence in timing between OAE 1a and the dramatic negative sulphur-isotope excursion over this interval. Deposition of evaporites, by decreasing the sulphate content of the oceans and reducing pyrite formation and oxidation of marine organic matter, could explain these associations. Hence, not only the contemporaneous volcanism from formation of the Ontong Java and Kerguelen Plateaus, but also the opening of the CSSA, may have played an important role in the genesis of OAE 1a.

Characterising the Balder Formation (T50) in the North Sea and Faroe-Shetland Basin; implications for the petroleum industry.

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The Balder Formation (T50) is an important stratigraphic horizon deposited *ca*. 54.5Ma and found throughout the North Sea and Faroe-Shetland Basin (FSB), where it is mainly composed of interbedded claystone, siltstone and sandstone with variable amounts of volcanic material (Pedersen et al. 1975; Roberts et al. 1984). The Formation has been described in detail for the North Sea where core is more widely available, although these observations would benefit from re-investigation, due to improvement of characterisation and analytical techniques. Limited core availability has resulted in only provisional studies of the Balder Formation within the FSB. The importance of this Formation within the FSB with regards to its suitability as a seal or reservoir, and the expensive, time-consuming problems related to mud-loss and cavings during drilling, means that it deserves to be the focus of further study. In this study initial logging of core from the North Sea shows that the Balder Formation contains a more variable sequence of finely interbedded strata with carbonate cement, micro-faults and slumping features not predicted in wireline and seismic data. The volcanic component of the strata is unclear but has been previously attributed to large-scale (>400,000km^2) explosive basaltic eruptions that occurred during initiation of sea floor spreading in the North Atlantic (Jacqué & Thouvenin 1975; Knox 1984). The source, abundance and true extent of this volcanic material is uncertain. Initial thin-section studies suggest that volcanic material may have originally been a major component of the Formation in the North Sea; however, the material is now present as secondary mineral phases due to extensive alteration. The Formation varies in the FSB and it may not contain an abundance of volcanic material. These conclusions are important for improving our understanding of the early-Palaeogene stratigraphy of the North Atlantic Margin and treatment of the Balder Formation during exploration and drilling. Future study will involve multi-component analysis of this Formation via comparison of stratigraphic logs of core and SEM studies to understand the composition and provenance of the rocks. These will be integrated with the study of wireline and seismic data provided by OMV to allow wider scale investigation into the characteristics of the Balder Formation.

Industry & IODP

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The International Ocean Discovery Program (IODP) and its predecessors form a global collaborative research and exploration effort with a 50-year history that has facilitated ocean research drilling and in so doing, helped explore Earth's history and dynamics. In this time, the IODP has collected a broad range of data types ranging from petrology to paleomagnetism, from paleontology to petrophysics, and beyond. An equally wide variety of geological environments have been sampled by the IODP across the world's oceans, including sequences familiar to the hydrocarbon industry, such as siliciclastic sedimentary deposits, but also those which are perhaps more unfamiliar, including ocean crust formations.

The poster will explore how industry and IODP communities can better engage in order to prevent duplication of data acquisition and research, and forge new productive collaborations. The main IODP legacy datasets that may be relevant to industry include petrophysical, biostratigraphic and stratigraphic data and novel applications of these and other data will be discussed. Case studies of existing UK industry uses of the databank will be presented as well as details of how researchers and industry can access the various IODP databanks.

As the energy and extractive industries move into more marginal environments, this breadth in geography, geology and data in the open-source IODP databank, in combination with the scientific expertise of the UK IODP researchers, makes an unrivalled resource for UK industry as they push the frontiers.

CGG – Collaborating with Universities and Utilising New Technologies to Ensure the Future of Hydrocarbon Exploration

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In an increasingly complex and challenging environment, CGG is building effective links between academia and industry and utilising new techniques whilst adapting current ones to enhance hydrocarbon exploration success in a world where oil prices are highly volatile. In this environment there is increasing focus on risk reduction and increased exploration efficiency. In synergising the use of newly available technologies, research and an integrated geoscience approach, CGG is ensuring the future of hydrocarbon exploration. We present here the main technical highlights of an early-career geoscientist.

One of these key technologies CGG has utilised to enhance exploration is its broadband acquisition technique, BroadSeis™ and BroadSource™. This state of the art technology brings together a variable depth streamer profile and synchronised multi-level source in one seamless package to deliver a ghost-free broadband solution, with the widest available bandwidth at 2.5-200Hz. This technology is actively enhancing exploration by better defining vertical resolution of subtle stratigraphic traps and pinch-outs, with additional high and low frequencies reducing tuning thickness and wavelet side lobes respectively. Furthermore, the addition of ultra-low frequencies is allowing improved imaging of deep targets, something key in mature basins such as the Central North Sea. This high spec seismic data is then used for research in integrated geoscience projects to enhance exploration.

In addition, CGG brings technical experts together through its collaboration with academic institutes to improve geoscientific knowledge and increase hydrocarbon exploration success. This is commonly concretised by giving access to the latest data for MSc and PhD projects. Such sponsorship ensures academic research is helped by having access to these latest seismic technologies. Furthermore, data provided and project scope is kept in line with industry interest. This year CGG worked with Royal Holloway University of London, providing 3D broadband seismic data for an MSc project. In this case, investigation of the structural evolution of the Mid-North Sea High northern margin and how it relates to hydrocarbon prospectivity, complements current focus of industry bodies such as the OGA's initiatives and the 21st Century Exploration Roadmap project. Complementary to this, a recent project involved PSDM processing and geological interpretation of CGG's Lodestone multi-client dataset in the Southern North Sea, in which seismic, well and gravity data were combined with the latest processing techniques in an integrated geoscience approach to provide as much value as possible and to enhance hydrocarbon exploration in this mature basin.

Dynamic Corrections Applied to Surface Gas Extraction

David K. Muiread
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During drilling operations, the approach to formation gas extraction at surface is often flawed through the use of extraction efficiencies. Applying a control value from a specific volume of fluid or gas to further discrete extractions can lead to erroneous results and inaccuracies in calculated species. This study has involved significant interaction between established industry practices from the service sector and a more academic approach to processing an under-utilized source of data.

Here we present a dynamic system of corrections developed to take into account the subtleties of extraction as a function of time, chemical composition, and physical properties of the fluid. For any extraction system, this set of equations must change to accurately characterize the fluids and can be used to correct between different extraction systems. This approach removes errors often encountered in data from surface gas extraction and leads to accurate data compensation over whole well bores. Furthermore, we provide a proof of concept to this correction that can reduce the need for additional sampling, reducing operational time and cost whilst improving on the decision-making process.

Correlation of Fluvio-Lacustrine Strata Using Volcanic Tuffs in the Jurassic Walloon Coal Measures, Surat Basin, Australia: A New Technique in the Exploration Tool Box

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Correlating nonmarine strata is a major challenge for the petroleum sector. Fluvial and lacustrine facies are often laterally discontinuous and without reliable stratigraphic markers in these settings, predictions on the distribution of facies and subsequent volumetric calculations are often prone to error. Traditional techniques of correlating nonmarine strata, from stacking patterns to biostratigraphy, make geologic assumptions that may not be applicable on a regional level. The Jurassic Walloon Coal Measures of the Surat Basin, Australia is a classic example of where many correlation techniques have been applied, yet the construction of a robust stratigraphic framework remains a challenge for industry. The Walloon Coal Measures comprise a 500m thick succession of fluvio-lacustrine strata, with abundant coal beds representing 5.8% of the sedimentary sequence. Many coal beds are thin (<0.4m) and discontinuous (<5km), leading to complications for both geoscientists and engineers. The abundance of volcanic ash fall tuffs interbedded within coals and lacustrine beds provides a unique opportunity to examine chronostratigraphic relationships on a regional basis. Using the CA-TIMS technique, zircon crystals from twenty nine tuff beds in nine wells across the basin have been successfully dated and correlated over hundreds of kilometers. These dates substantially modify existing stratigraphic frameworks. Variable tectonic subsidence rates, between 6.7m/Myr and 23.3m/Myr through this interval, contributed to the evolution of facies patterns in the basin through time. Applying the high resolution CA-TIMS technique may help in the construction of reliable stratigraphic frameworks of other nonmarine strata worldwide.

Enhanced hydrocarbon system evalution from new improvements of source rock potential analysis by Optical Kerogen Analysis

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Hydrocarbon exploration is strongly focused on reservoir analysis mostly. Compared to the intensity and detail of reservoir studies, the source rock potential is much less explored in most systems, often limited to standard geochemical analysis. Working well in many systems, in several potential hydrocarbon systems, particularly also unconventional shale plays, the established source rock analysis workflows are misleading producing a major misfit between primary expectations and exploration results. This shows a need for new workflows for detailed analysis of the source rock potential. A promising approach for enhanced analysis of source rock potential is Optical Kerogen Analysis, based on optical analysis of the composition, preservation and maturation of the kerogen, combined with lithofacies based analysis of the depositional setting and basin development.

Optical Kerogen Analysis identifies mixed kerogens, mixed regarding composition, preservation and maturation. Kerogen composition indicates the type of primary generated hydrocarbons, kerogen preservation indicates the level of hydrocarbon generation and the level of kerogen microporosity, which is of particular interest as major gas storage capacity in unconventional hydrocarbon systems. Integrated optical organic maturation analysis provides highly reliable maturation data. Major benefits for hydrocarbon exploration are: quantification of productive vs. unproductive proportions of the total kerogen (=**net-TOC)**; quantification of oil-prone vs. gas-prone kerogen within the productive kerogen; detailed analysis of preservation of each kerogen type for the estimation of HC generation from oil-prone and gas-prone parts of kerogen; high resolution analysis of organic maturation by two independent methods for highly reliable analysis of in-situ basin maturation, identification of different kerogens with different hydrocarbon potential mixed within the total kerogen; identification of effective source rock thickness (=**net-source-rock unit)** in potential source rock formations. This enhances significantly the resolution and reliability of kerogen analysis and the evaluation of primary generated types of hydrocarbons compared to bulk-rock geochemical analysis.

Two case studies are presented, showing the impact of optical kerogen analysis in recent exploration campaigns in two mature hydrocarbon systems of Germany: the highly mature gas system in the Carboniferous of the North German Basin and the less mature oil system in the lower Jurassic of SW-Germany. In both systems optical kerogen analysis led to significant changes in the understanding of the kerogen composition and basin maturation, compared to previous exploration studies, which led to a major change in the type and productivity of hydrocarbons, totally changing the evaluation and prospectivity of both systems.

Unlocking Intra-Volcanic Prospectivity, West of Shetland

Jonathan Hardman
University of Aberdeen

The volcanic dominated Atlantic Margin is one of the last frontiers of hydrocarbon exploration within the UKCS. In 2004, a major oil and gas discovery (Rosebank) was made within Palaeocene and Eocene age lavas in the Faroe-Shetland Basin. Consisting of terrestrial to marginal marine reservoir sequences, the Rosebank Field consists of intra-basaltic sediments separated by basaltic lava flows and volcaniclastics. These sequences contain interbedded sediments of the Flett Formation, sourced from within and outwith the lava field, equivalent to the Dornoch Delta of the North Sea. Despite the identification of a major intra-lava incised drainage system running parallel to the Rosebank Fields (Schofield & Jolley, 2013), the play fairway remains poorly understood, in part due to the difficulties that volcanic sequences pose to seismic acquisition and processing. The recently acquired FSB2011/12 MultiClient GeoStreamer® survey aids better identification of geological units within and below the volcanic succession, especially at the lower frequencies required to image within and below the basalts. In addition to well and seismic analysis, enchanced seismic interpretation tools within Geoteric have been used to differentiate between volcanic and sedimentary facies within the volcanic sequence.

This study has found that the structure and the lithology of the basement strongly influence the distribution of sediments and volcanics within the Flett Formation. Interpretation of wells and seismic data covering the Cambo and Rosebank fields suggest that the Corona Ridge and the Cambo High were part of a linear, SW-NE trending feature that influenced the distribution of volcanics throughout the Upper Palaeocene and Lower Eocene and may have been a possible source of intra-basaltic sediments. South of the Cambo field, the presence of an incised drainage network centred on the Judd basin, opens up the possibility that other sources of reservoir material may exist extending the play into other areas of the basin.

Composite model to reproduce the mechanical response of methane hydrate bearing soils

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Methane Hydrate Bearing Sediments (MHBS) are natural soils characterized by containing methane hydrate in its pore space. This type of sediments store a vast amount of mobile organic carbon and are a potential future energy resource that exist at many sites along permafrost regions of the Arctic and in continental slopes and deep water setting of most continental margins worldwide.   The different components contained at the pore space can suffer phase changes under relative small temperature and pressure variations for conditions typically prevailing a few hundreds of meters below sea level. Hydrate dissociation may be a significant geohazard triggering factor, having an important bearing on flow assurance and safety issues in oil and gas pipelines. The complex modelling of methane hydrate deposits needs to account for heat and mass balance equations of the different components, and several strategies already exist to combine them. These equations have to be completed by restrictions and constitutive laws reproducing the phenomenology of heat and fluid flows, phase change conditions and mechanical response. While the formulation of the non-mechanical laws generally includes explicitly the mass fraction of methane in each phase, which allows for a natural update of parameters during phase changes, mechanical laws are, in most cases, stated for the whole solid skeleton. This poster describe the fundamental hypothesis of a new mechanical model proposed to cope with the response of MHBS. It is based on a composite approach that allows defining the thermo-hydromechanical response of mineral skeleton and solid hydrates independently. The global stress-straintemperature response of the solid phase (grains + hydrate) is then obtained by combining both responses according to energy principles. In this way, dissociation of MH can be assessed on the basis of the stress state and temperature prevailing locally within the hydrate component. Besides, its structuring effect is naturally accounted for by the model according to patterns of methane hydrate inclusions within soil pores.

Collaboration – a cloud on the horizon

James Selvage, Charles Jones and Andrew McVey

In a world where oil prices have dropped by more than half and budgets are dramatically cut, we need to look at our current practices. We need to focus on doing things differently and doing different things. In 2015 BG Group identified cloud computing as a viable alternative to owning an internal seismic storage and compute environment. The business case for such a change is strong: with an opportunity to offer a more secure storage and flexible compute environment that can respond to business needs combined with a cost saving estimated at 50%.

Whilst these benefits are compelling we recognise that business value is delivered from the analysis and interpretation of seismic data not the storage of the data itself. Therefore, we conducted a pilot project to demonstrate that analysis and interpretation of seismic data could be performed using standardised cloud components. The main concerns that were encountered during the project framing were not technical, but the legal and security compliance of a public cloud environment. To address these we worked with legal and security stakeholders to identify the main risks and mitigate them in the cloud pilot.

For all oil and gas industry stakeholders exploration activities present a “data gravity” problem. A large amount of time is spent moving datasets between other operators, contractors, regulators and academia. Therefore, we see a benefit in cloud computing providing an opportunity for standardisation amongst these stakeholders. The scale of the storage and compute enables each stakeholder to have their bespoke Virtual Private Cloud (VPC) and control access to share datasets. For example, instead of a new dataset being stored by each individual operating partner it could be stored in the cloud and be shared into each partner’s VPC.

In times of low oil price, we need to question whether we should continue with old ways of working or move to a new framework? Other industries already benefit: it is now time for the oil and gas industry to catch up. Rather than individual oil and gas industry stakeholders performing their own pilots we suggest that a Joint Industry Project (or Forum) could facilitate the adoption of cloud computing for the industry as a whole. References for how such a project (or forum) could be structured can be found at:

- PCI Security Standards Council (https://www.pcisecuritystandards.org/)
- Open Compute Project Foundation (http://www.opencompute.org/)

As a stakeholder in the oil & gas industry we would like to hear your thoughts and gain your feedback.

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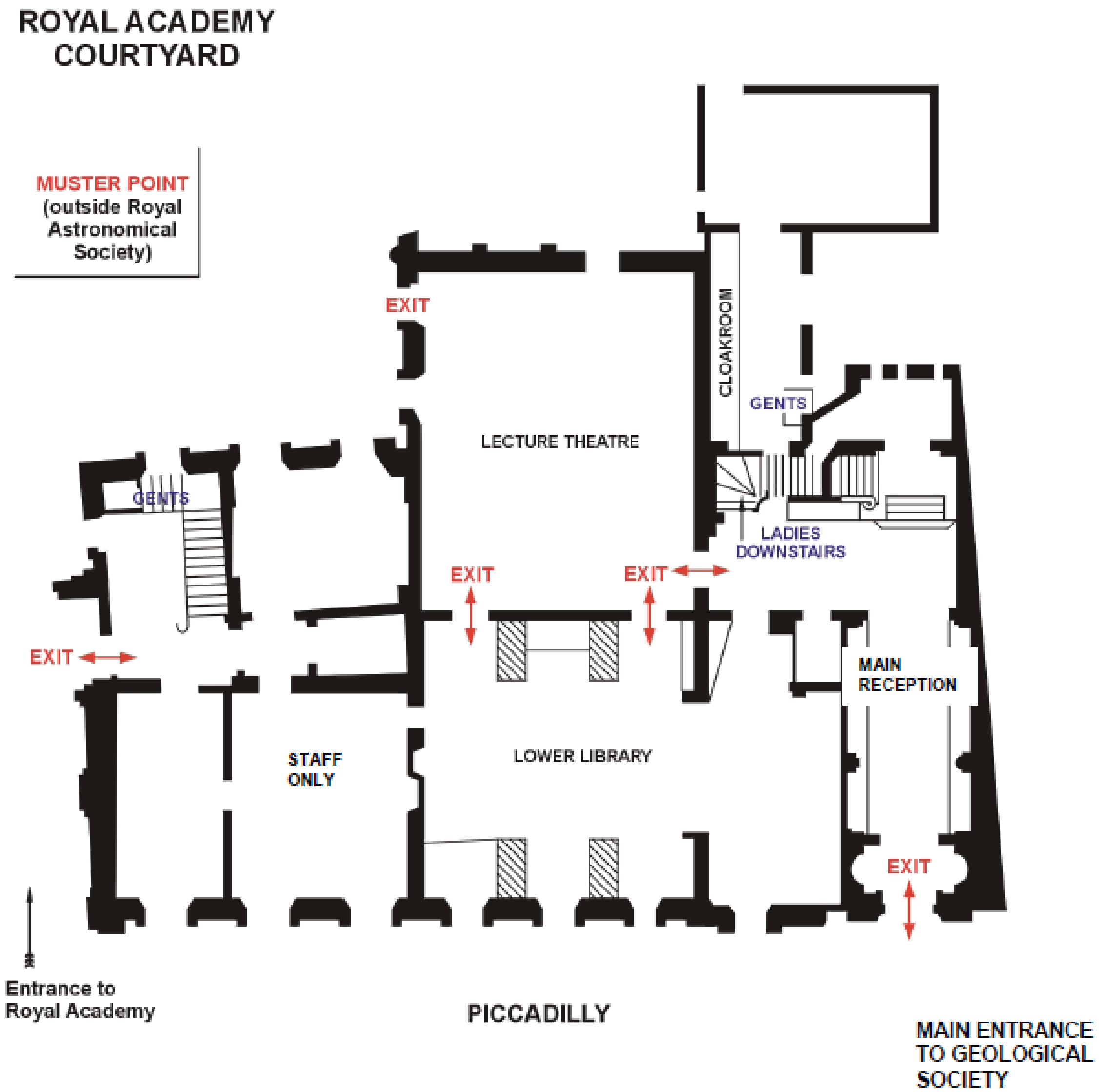
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2016 Geological Society Conferences

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7-9 September	Mesozoic Resource Potential in the Southern Permian Basin	Burlington House
14 September	GSL London Lecture: A little goes a long way: researching ash clouds and abrupt climate change	Burlington House
27-29 September	Rain, Rivers and Reservoirs	Burlington House
12 October	GSL London Lecture – Water on Mars	Burlington House
2-3 November	Operations Geology Conference: Bridging the Gaps	Burlington House
9 November	GSL London Lecture – Climate Change and Antarctica: the great ice sheet in the past, present and future	Burlington House
9 November	GSL Nottingham Careers Day	British Geological Survey, Nottingham
23 November	GSL Edinburgh Careers Day	Our Dynamic Earth, Edinburgh
7 December	GSL London Lecture – Waking the Giant: how a changing climate triggers earthquakes, tsunamis and volcanoes	Burlington House

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