15 - 16 November 2016

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Petroleum Geoscience Collaboration Showcase

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ABSTRACT VOLUME

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University of Aberdeen

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BG Group

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ENI

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ConocoPhilips

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BG Group

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Rocktype

Douglas Paton
University of Leeds

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Statoil

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University of Bergen

Helen Smyth
Halliburton-Landmark

Tom Weight
Statoil

TUESDAY 15 NOVEMBER

CONFERENCE WELCOME
Jonathan Craig, *AAPG President*

KEYNOTE
Prof. John Underhill[1] & Hon. Prof. Keith Gerdes[2], *[1]Heriot-Watt University, [2]Shell*

Sand Injection Research
Prof. A. Hurst, *University of Aberdeen*

Structural Coherence of Fault-Fold Arrays in Salt-Influenced Rifts: Observations from the Halten Terrace, Offshore Norway
A.J. Coleman, *Imperial College London*

A reassessment of the brittle deformation history, age and attribute analysis from the Orcadian Basin, Scotland: implications for offshore Devonian fractured reservoirs
A.M. Dichiarante, *Durham University*

Seismic geomechanics of mud volcanoes: implications on drilling
R. Gulmammadov, *University of Manchester*

The Recognition of Three Types of Seaward-Dipping Reflector (SDR) and Implications for Continental Breakup
C. McDermott, *Imperial College London*

WEDNESDAY 16 NOVEMBER

KEYNOTE
Prof. Bruce Levell, *University of Oxford*

Relationships Between Observed Hydrocarbon Column Heights, Occurrence of Background Overpressure and Seal Capacity within North West Europe
J. Schofield, *Durham University*

Porosity Controls on Devonian Strata of the North Sea: a case study from Ardmore field, Block 30/24, UKCS
L. Tang, *Durham University*

The SAFARI Project -
An online database of reservoir analogue information from outcrops and modern systems
Prof. J. Howell, *University of Aberdeen*

Insights into bottom-currents role in reworking and redistributing turbidites in the Offshore Mozambique: implication for hydrocarbon exploration
A. Thieblemont, *Royal Holloway, University of London*

Turbidite-Contourite Interactions on the Uruguayan Continental Margin: Conceptual Implications
A. Creaser, *Royal Holloway, University of London*

KEYNOTE
O. Martinsen, *Statoil*

Brent Group Petrography and Diagenesis:
Implications for Reservoir Quality and Enhanced Oil Recovery
T. Utley[1] & Prof. R.H. Worden[2], *[1]Durham University, [2] University of Liverpool*

Evolution & Karst Development in a Palaeozoic Carbonate Platform:
A Seismic Interpretation Approach
V.S. Tran, *Royal Holloway, University of London*

Resolving the noble gas fingerprint in UK unconventional gas reservoirs
S. Gilfillan, *University of Edinburgh*

Noble gases in gas shales: Implications for gas retention and thermal maturity
S. Basugupta, *University College London*

The effect of stress-induced porosity and permeability variations on shale gas reservoir performance
S. Mohammed, *University of Aberdeen*

Petroleum Geoscience Collaboration Showcase

15-16 November 2016

Oral Presentation Abstracts

(in presentation order)

Tuesday 15th November

KEYNOTE: The NERC Centre for Doctoral Training (CDT) in Oil and Gas: The Industry Perspective

John Underhill[1] & **Keith Gerdes[2]**
[1] *Heriot-Watt University*
[2] *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 many 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/

Sand Injection Research

Andrew Hurst
University of Aberdeen

This presentation provides an overview of sand injection research done by researchers at the University of Aberdeen in primary collaborations with the universities of Cardiff and Manchester in JIPs sponsored by about 20 oil companies over the past 17 years. Research topics have developed over the years from individual case studies to large-scale field campaigns and basin-scale subsurface framework studies. The sponsor group has also changed significantly from JIP to JIP, with numerous oil companies affected by mergers and with changes of operatorships and smaller oil companies playing an increasing role in the North Sea over the past decade.

Sand injectite research was stimulated by oil industry interest in the late 1990's, specifically associated with the development of the deep-water clastic reservoir in Alba field (UK North Sea). The success of the geological and geophysical evaluation on Alba identified the probable broader significance of sand injectites in the development of deep-water clastic reservoirs, and with support from Chevron UK (Alba operator) a sand injectites research consortium was launched in 2000 with 6 sponsors. Aims of the consortium included each sponsor hosting field/acreage-specific projects on fields to enhance their understanding of sand injectite systems. Case studies included such as Alba, Grane, Jotun, Leadon and the Grieg and Gamma discoveries. A conclusion reached during the first consortium was that very little was known about the detailed geometries of sand injectite networks, partly because there was a lack of detailed outcrop characterization studies. Following on from Phase 1, the first deliberate exploration well targeting injectites was drilled by Marathon who discovered the Volund Field, containing light oil and gas hosted in a large-scale sandstone intrusion complex.

In 2005 the second phase of research began with 7 sponsors supporting the joint goals of developing subsurface identification and mapping of sandstone intrusions, creating an outcrop database and developing predictive models for sand injection. Differentiation of sandstone intrusions from their parent depositional units and creating 3D models from these data using core description supported by outcrop analogues was a major activity. Description of the >350 km^2 exposure of the Panoche Giant Injection Complex (PGIC, Danian) was the first ever detailed logging and mapping of its kind and provide fundamental documentation that supports subsurface applications. Field courses and workshops with sponsor groups became regular activities.

2013 saw commencement of the most recent research consortium with 13 sponsors. A major undertaking of the current project includes description of outcrop of the Tumey Giant Injection Complex (TGIC, late Eocene) and interpretation of seismic data from the TGIC and PGIC from the adjacent subsurface. This included the acquisition of Lidar and photogrammetric surveys of many outcrops for reservoir modelling applications. In addition a basin-wide 3D seismic framework study of the North Sea Giant Injection Province (NSGIP) was undertaken to map the distribution of giant injection complexes in the Tertiary thus providing sponsors with a stratigraphic framework. Use of modern broadband 3D seismic surveys have thrown new light on the complexity and origin of the North Sea sand injection province with implications for continued exploration in this conventionally mature province. Concurrently we have applied novel forward seismic modelling methods to outcrop data, developed and tested mineral-chemical methods for reservoir correlation and provenance, continue to develop bespoke field workshops for sponsors and, are currently developing a reservoir modelling plug-in to facilitate improved mitigation of uncertainty during development drilling and reserve prediction.

We gratefully acknowledge co-workers, colleagues and students who have contributed to the sand injection research over the years. Numerous industry colleagues have shown enthusiasm for the research and contributed data and ideas. The research benefitted from sponsorship and case studies provided by a large number of oil and service companies.

Structural Coherence of Fault-Fold Arrays in Salt-Influenced Rifts: Observations from the Halten Terrace, Offshore Norway

Alexander Coleman
Imperial College London

The structural style and evolution of salt-influenced rifts significantly differs from those developed in simple, homogeneous and brittle crust. For example, ductile, evaporite-rich units can effectively decouple brittle deformation in supra- and sub-salt strata, leading to the development of contrasting structural styles at these two stratigraphic levels, which may not be geometrically connected. However, the kinematic link or 'coherence' between supra- and sub-salt fault populations i.e. the transmission of strain through the salt, and the relative contributions of thin-skinned gravity-driven and thick-skinned, whole plate stretching-driven deformation remains poorly constrained. This variability in structural style ultimately has implications for future exploration within hydrocarbon provinces, controlling the timing of trap formation and reservoir distribution in time and space.
Here, we address these issues and seek to understand how extensional strain is partitioned between faulting and folding using high quality 2D and 3D seismic and well data from the Halten Terrace, offshore Norway. Given that the salt in this location is relatively thin and immobile compared to other salt-influenced basins in the North Sea, diapirism is minimal and no allochthonous salt bodies are developed, thereby permitting the study of salt-influenced rift structures without significant structural overprinting.
In this study, we: (1) describe the structural style and evolution of the supra- and sub-salt fault populations, (2) apply structural restoration methods to determine the degree of kinematic coherence between supra- and sub-salt fault populations, and (3) deconvolve the contributions of purely thin- and thick-skinned strain in deforming the cover. We find that despite similar amounts of extension in sub- and supra-salt strata, the supra-salt strata preferentially accommodate strain by folding, whereas sub-salt strata tend to fault. This suggests that, while the system is kinematically coherent, strain is expressed differently above and below the salt. These results highlight that kinematic coherence does not necessitate similar structural styles, and fault-fold arrays that are stratigraphically-separated by salt should not be interpreted as isolated systems.

Wednesday 16th November

KEYNOTE: Collaboration, the Underground and the Resistance

Prof. Bryan Lovell
University of Oxford

Current Industry priorities include: cost reduction, standardisation, work force productivity improvements, and maintaining licence to operate in a broadly hostile social environment.

Typical academic priorities include: addressing “Big Science Questions”, exploiting new analytical capabilities, developing non fossil fuel based energy systems, and, at a more personal level, publishing in high impact journals. Given this the basis for collaboration could seem slight. A recent survey by DNV showed that only 16% of the more than 900 executives interviewed were looking to academic collaboration to maintain innovation. Taking examples from the Geosciences I will argue that this view is too pessimistic.

Future exploration in the medium term, driven by “lower for longer” is likely to be in: proven basins, areas near existing facilities, select DW frontiers, and select onshore unconventional plays, with avoidance of above-ground political and reputational risk in areas such as the Arctic, Russia, Europe, and the Middle East. This focus will logically put a premium on *detailed* understanding of: migration paths, pressures, fault and top seal and secondary petroleum systems. The necessity for a detailed understanding but with reduced experience levels will drive improved data retrieval, software that supports the user’s education, and better integration tools such as constrained seismic inversion.

This sets of “Business Pulls” can match reasonably well with some “Big Science Questions” : e.g. subsurface fluid flow from the mantle through the crust, exploitation of new levels of accuracy in isotopic measurements for unravelling aqueous geochemistry and investigation of palaeoclimates. Exploration of DW (and some onshore) frontiers raises some embarrassingly fundamental questions about geodynamics and basin formation. And the productivity needs of the industry possibly map onto the Big Science areas of machine learning and data analytics. Scope for collaboration is certainly there. The extent of the collaboration will perhaps depend more on how many choose to be “fast followers” rather than true innovators.

The drive for transparency and societal acceptance will also bring industry and academia together. Continuous, transparent, independent ,monitoring of the environment (biosphere, geosphere, hydrosphere, atmosphere) will be a requirement whether or not it is regulated. Industry data on seismicity, water quality, emissions, etc are of great attractiveness to academia for several Big Environmental Questions and industry’s willing cooperation in making data freely available may offer it a little redemption at least among some audiences. Resistance will be futile.

Relationships Between Observed Hydrocarbon Column Heights, Occurrence of Background Overpressure and Seal Capacity within North West Europe

J. Schofield[1], A. Aplin[1], R. Swarbrick[2] and J. Streit[3]
[1]*Durham University, Earth Sciences (UK),*
[2] *Swarbrick GeoPressure Consultant Ltd. (UK),*
[3]*Woodside Energy Ltd. (Australia).*

When reservoir pore pressures approach the fracture pressure the risk of hydrocarbon leakage increases as a result of mechanical failure. Here, relationships between overpressure, hydrocarbon column heights and seal capacities (fracture pressure – pore/aquifer pressure) will be explored and best practice criteria for assessing seal capacity is discussed.

The term overpressure (OP) can be applied to any formation with pore pressures higher than the hydrostatic pressure. Mechanical caprock failure (tensile failure, shear failure and re-activation of pre-existing faults) is arguably the hardest failure criterion to constrain. From a 129 field database, critical shear failure pressures, fault reactivation pressures and tensile failure pressures were derived. Calculating the difference between such pressures and the aquifer pressures at structural crests within fields, allows quantification of the envelope between the reservoir pressure and failure pressure, a term coined by Swarbrick et al. (2010) as "aquifer seal capacity" (ASC).

Conventional approaches suggest that fractures will form when the pore fluid pressure equals that of σ_3 plus the tensile strength of the rock. However, there remains the distinct possibility that it is aquifer pressure that governs failure, and that the hydrocarbon phase is not involved (Swarbrick et al. 2010). The dilemma is shown in Figure 1 – i.e. (a) hydrocarbon column heights (HCH) limited by fracture pressure, (b & c) uppermost pressure defined by Pwater = Pfrac, and hydrocarbon column height is independently controlled.

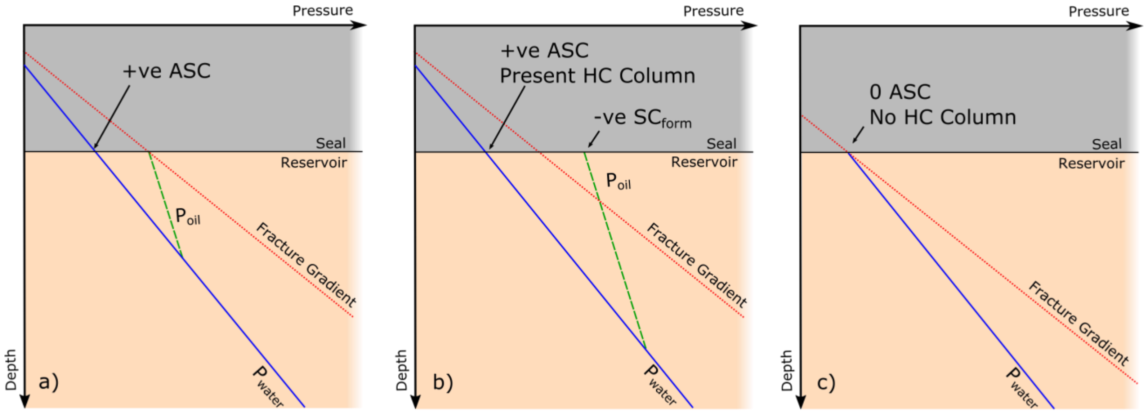

Figure 1. Schematic pressure-depth plot indicating the 'conventional' route for mode 1 failure (a) and the new approach (b & c) suggested by Swarbrick et al. (2010)

This research suggests a convergence of the fracture pressure gradient and σ_v, resulting from P_p/σ_h coupling, at 14,500 ft, within the range suggested by the literature. Furthermore, a general reduction in HCH is observed with a) increasing aquifer OP and b) a reduction in ASC. The possibility of applying upper bound cutoff lines is explored, i.e. column heights are not expected greater than χ ft given an aquifer OP. By comparing aquifer OP to derived fracture pressures & fault reactivation pressures, theoretical maximum aquifer OP of the Central and Northern North Sea are suggested.

The HPHT Shearwater field is an exception for all trends within the research. The concept of a protected trap is suggested as an explanation for this apparently anomalous trap integrity.

Porosity Controls on Devonian Strata of the North Sea: a case study from Ardmore field, Block 30/24, UKCS

Longxun Tang[1], Jon Gluyas, Stuart Jones
[1]*Durham University*

The Devonian strata are widely distributed in the North Sea area but rarely regarded as effective petroleum reservoirs. Several oil fields (UK: Ardmore, Auk, Buchan, Stirling; Norway: Embla) proved that Devonian formations can be porous, permeable and productive. Ardmore field (previous name 'Argyll') was selected as the main research target because it was extensively cored when first discovered and produced. It has both high quality Devonian sandstones with around 1 Darcie permeability interbedded with 'white rock', sandstones which have near zero porosity and immeasurably low permeability and the origin of this heterogeneity of reservoir quality was not understood. This study aims to reveal the controls on Devonian reservoir quality from perspectives of sedimentology, petrography and diagenesis, using both Ardmore Field cores and comparable Devonian outcrops in Dunnet Head and Orkney Islands and offshore Northern Scotland.

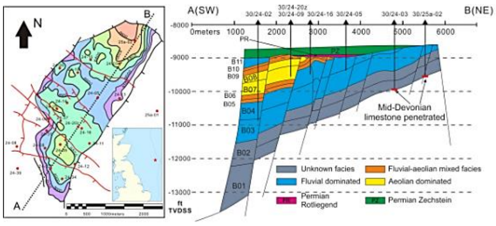

Fig1: Location, contour map and vertical profile of Ardmore Field

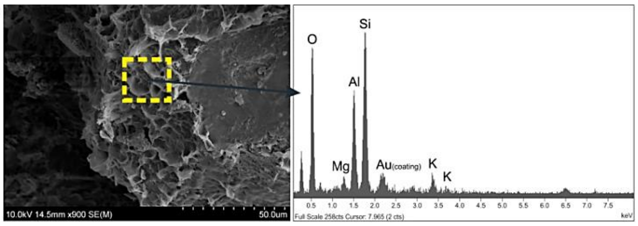

Fig2: SEM image and EDX spectrum of grain coating smectite (with partial illitization)

Our research, from macro outcrop to micro pore scale, suggests that the Upper Devonian formation shows an upward fluvial-aeolian-fluvial cycle deposited under a generally hot and semi-arid to arid circumstance, different depositional facies and resulting mineralogy exerted a powerful influence on the subsequent diagenesis. For the fluvial sandstone, the lack of rooted vegetation in Devonian age led the frequent combination and bifurcation of fluvial morphology, thus the complex mineral composition and immature grain texture are responsible for low primary porosity, the later compaction, quartz overgrowth and carbonate cementation worsened the situation and the reservoir was limitedly improved by dissolutions on feldspar and dolomite cement. For the aeolian sandstone, the natural deposition property of aeolian transportation led very good sorting and roundness, and high percentage of rigid grains, these are favourable on preserving primary porosity. Another important discovery in this project is the thick and continuous grain coating clay, which effectively inhibited the quartz overgrowth, was confirmed as detrital smectite (with partial illitization) by thin section, SEM and EDX spectrum. It is only found in aeolian sandstone but believed as fluvial origin. The suspended smectite aggregates, deposited in remote part of fluvial system the distal sandflat, will automatically flow into the dry, porous and permeable aeolian sediments by infiltration mechanism once encountered, and precipitated as grain coating and pore-filled clays. In the short future fluid inclusion and stable isotopes will be added for quantitative description of diagenesis events, and try to draw a whole picture of porosity evolution. The outcomes will be a useful reference for future Devonian explorations in the North Sea.

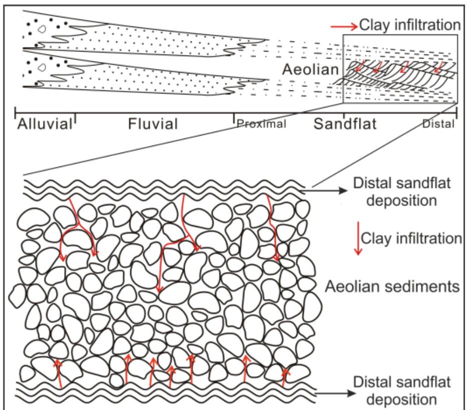

Fig3: smectite infiltration mechanism

Poster Presentation Abstracts

Tuesday 15th November Poster Session one

A reassessment of the brittle deformation history, age and attribute analysis from the Orcadian Basin, Scotland: implications for offshore Devonian fractured reservoirs

Dichiarante A.M.[1], Holdsworth R.E.[1], McCaffrey K.J.W.[1], Dempsey E.D[1], Selby D.[1], Conway A[2]. and Wilson R.[3]
[1] *University of Durham*
[2] *ConocoPhillips (UK) Ltd*
[3] *BP Sunbury.*

The onshore Devonian sedimentary rocks of the Orcadian basin host significant localized zones of fracturing, faulting and some folding on all scales. New field and microstructural analyses carried out within the Devonian cover sequences in Scotland and Orkney reveal 3 main groups of structures based on orientation, kinematics and infill.

<u>Group 1</u> faults trend N-S and NW-SE and display predominantly sinistral strike-slip to dip-slip extensional movements. They form the dominant structures in the eastern part of Caithness, and to a lesser extent on Orkney. Gouges/breccias associated with these faults display little or no mineralization or veining. It is suggested that these structures are related to Devonian ENE-WSW transtension associated with sinistral shear along the Great Glen Fault (GGF) during Orcadian and proto-West Orkney basin formation.

<u>Group 2</u> structures are closely associated systems of metre- to kilometre-scale N-S trending folds and thrusts related to a highly heterogenous regional inversion event recognized locally throughout the field area, but especially on Orkney. Once again, fault rocks associated with these structures display little or no mineralization or veining. Group 2 features are likely related to late Carboniferous – early Permian E-W shortening associated with dextral reactivation of the GGF.

<u>Group 3</u> structures are dextral oblique NE-SW trending faults and sinistral E-W trending faults with widespread syn-deformational carbonate mineralisation (± pyrite and bitumen) both along faults and in associated mineral veins. In a few localities (e.g. Brough, Scarfskerry, East Scapa faults) oblique reactivation of large pre-existing Group 1 faults has led to complex zones of localized transpression or transtensional folding, faulting and inversion synchronous with the carbonate and associated mineralisation events. Re-Os model ages of syn-deformational fault hosted pyrite in Caithness yield Permian ages (ca. 267Ma). This is consistent with the field observation that Group 3 deformation is synchronous with the emplacement of ENE-WSW-trending lamprophyres east of Thurso (ca 268-249 based on K-Ar dating). Stress inversion of fault slickenline data associated with mineralization suggest NW-SE regional rifting, an episode also recognized farther west in the Caledonian basement of Sutherland. Thus from St John’s Point to Cape Wrath, Permian age brittle faults dominate the north coast of Scotland, forming part of a regional-scale North Coast Transfer Zone translating extension from the offshore West Orkney Basin westwards into the North Minch Basin.

We investigated fault size scaling in Caithness across 8 orders of magnitude using a combination of 1D and 2D methods. Fracture length was quantified from 10^{-4} to 10^{4} m scales using remote sensing, outcrop and thin section datasets. The lengths are well described by a power-law distribution with an average exponent value of ~ -1. Results are consistent with previous fracture analyses in similar lithologies from Norway (mesoscale) and offshore datasets in the North Sea (seismic/regional scale). Fracture aperture/width, constrained from 10^{-6} to 10^{-2} m scales, shows a similar -1 scaling exponent. Results from 2D box counting and topology analysis on regional to mesoscales confirm self-similarity and reveal locally high fracture connectivity at fault intersections.

Seismic geomechanics of mud volcanoes: implications on drilling

Rashad Gulmammadov[1], Stephen Covey-Crump[1], Mads Huuse[1]
[1]*University of Manchester*

Mud volcanoes are considered a significant hazard for field development, particularly with reference to well planning and siting of the facilities. To date numerous multi-scale near-surface geological studies have been performed in offshore areas for risk mitigation in seabed facilities linked with mud volcano activity and associated hazardous phenomena. Nevertheless, the extent to which drilling in such zones has to be avoided because of mud volcano related risks remains unclear. The principal challenge posed by the complicated geology in and around mud volcanoes concerns the prediction of local pore pressures because this has significant implications for development drilling (e.g. borehole blowouts and instability).

A P-wave velocity dataset digitized from a publicly available Full Waveform Inversion image from across the Azeri-Chirag-Guneshly field, has been used to develop a geomechanical model of mud volcanoes in the South Caspian Basin. The principal objective of the study was to explore the extent to which P-wave velocity datasets can be used to provide sufficient geomechanical information to help guide development drilling strategies in regions close to mud volcanoes. As an initial feasibility test, generic P- and S-wave velocity vs. depth curves for marine sediments together with a compaction curve from the northwest South Caspian Basin, were used to calculate (using a number of analytic and empirical relationships) the mechanical properties and stresses at two locations on a South Caspian Basin mud volcano. Having established that realistic values for those properties and stresses could be obtained, the modelling was extended to calculate properties and stresses on a 2D vertical section across the Azeri-Chirag-Guneshly field using P-wave velocity data alone. From this 2D modelling we obtain spatial variations in pore fluid and fracture pressure gradients that allow a safe drilling window to be defined. We find that P-wave velocity datasets contain a remarkable amount of usable reconnaissance level geomechanical information although, naturally, additional petrophysical data are required if the geomechanical characterization is to be more comprehensive.

The recognition of three types of seaward-dipping reflector (SDR) and implications for continental breakup

Carl McDermott
Imperial College London

The recent pre-salt lacustrine discoveries offshore Brazil, and the Kudu gas field offshore Namibia are driving hydrocarbon exploration south, onto the continental margins of the South Atlantic Ocean. Unlike offshore Brazil, the southern segment of the South Atlantic Ocean is a magma-rich margin (volcanic). Such margins are characterised by significant volumes of extrusive volcanic material, known as seaward dipping reflectors (SDRs). SDRs are erupted during the final stages of breakup and record the transition between continental rifting and seafloor spreading. SDRs are composed of packages of thick sub-aerial tholeittic lavas and tuffs interbedded with thin layers of terrestrial sediment. The thick layers of basalt and sedimentary rocks impede conventional seismic imaging, refracting seismic energy to long-offsets, resulting in a loss of internal and sub-basalt imaging. Here, using deep-towed long-offset seismic data, we define three types of SDR. Each type is characterised by their reflection geometry, interval velocity and their spatial relationship with anomalously high-velocity bodies. Further, we outline a new model for rifting in a magma-rich setting using the development of our type SDRs as “snapshots” into the phase of lithospheric breakup.

Our model is based on seismic observations of ~18,000 km of long-offset (10,200 m), pre-stack time and depth migrated, 2D seismic reflection data. These data were acquired between 2009 and 2012 by ION-GXT along the South American margin and images the deep crustal structure of the margin. We integrate our whole crust observations with interval velocities calculated from detailed velocity analysis of high-quality pre-stack seismic gathers. The analysis was completed on three dip-lines, each spaced ~1000 km apart along the South American margin.

Of our three SDR types, “Type I” is the most landward and therefore oldest. They are fault-bounded and are associated with high-velocity bodies (6.5-7 km/s) both beneath, and at the down-dip end of their diverging wedges. “Type I” SDRs are observed on all seismic surveys and are onlapped by either “Type II or III”. “Type II” reflections are shorter (< 30 km) and shallower (~10°) than both “Type I & III”. “Type III” SDRs have the longest reflections (>100 km) of the three types and are the most similar to the “classic” geometry commonly described as “SDR trains” (Hinz 1981). Unlike “Type I”, “Type II & III” SDRs are not fault-bounded and are not associated with high-velocity anomalies.

We interpret “Type I” as the earliest SDRs, confined within landward-dipping continental rift basins and sourced from mafic intrusive complexes. They are often capped or pass distally into “Type II and/or III”. We suggest that “Type II” SDRs are lava flows that were erupted close to ephemeral lakes or marine incursions which restricted flows when they hit standing water. Conversely, “Type III” SDRs are lavas erupted without water level restrictions on flow. The development of non-fault-bounded “Type II or III” SDRs, marks the transition between mechanical thinning of the crust and extension via intense dyking. This transition constructs a dense dominantly mafic crust which immediately precedes lithospheric breakup. “Type II” SDRs are observed along the southern margin while “Type III” are mapped to the north. We suggest that their development is linked to the northern impact point of the Tristan de Cunha hotspot. Proximal to the hotspot, unrestricted “Type III” flows erupt from an elevated rift-axis, while distally, restricted “Type II” flows erupt on a shallower rift-axis. Based on our seismic and velocity analysis we present a tectonic and magmatic model for the breakup of the South Atlantic magma-rich margins. Our new model has further implications for regional heatflow modelling and predictive source and reservoir mapping.

Hinz (1981). "A Hypothesis on Terrestrial Catastrophes Wedges of very thick Oceanward Dipping Layers beneath Passive Continental Margins."

Wednesday 16th November Poster Session two

The SAFARI Project – An online database of reservoir analogue information from outcrops and modern systems

John Howell
University of Aberdeen

SAFARI is an on-going JIP at Uni Research CIPR in Bergen and the University of Aberdeen in collaboration with 14 Oil Companies, the Research Council of Norway and the Norwegian Petroleum Directorate. The project has been running since 2007 and is currently in its third phase. The SAFARI Project is developing a fully searchable repository of geological analogue data for clastic depositional systems for use in reservoir modelling and exploration. Data within SAFARI include information from 164 geological outcrops and a series of webtools for locating suitable modern analogues to ancient systems. The key goal is to make geological knowledge readily available for professional users who do not have ready access to outcrop data.

SAFARI is accessed through the web-portal www.safaridb.com. Data within the database come from students who have worked on PhDs (9) and Masters (12) during the course of the project; from previous students who worked on similar projects in the past; from partner institutions who share data with SAFARI and from published literature. A key aspect of the project has been the development of a schema to describe all aspects of the depositional system, the data types and quality, stratigraphy, outcrop quality etc. This facilitates the sorting, accessing and comparisons of data from the numerous different sources and is fully documented in an online encyclopaedia.

SafariDB includes a fully searchable (by depositional setting, climate, basin type) database of geological outcrops, including descriptions and locations for all and various data such as photo-panels, logs, correlations, thesis, as available. Eighty of the outcrops are supplemented with Virtual Outcrops which were specifically collected for this study. The Virtual Outcrop is a photo-realistic 3D model of the outcrop which can be viewed via a purpose built webviewer. These models allow geoscientists and engineers to take mini-field trips from their desk to to address questions that arise during their efforts to understand the subsurface. Virtual Outcrops can also be used as a useful supplement to conventional fieldwork, either pre- or post trip.

The advent of free desktop remote sensing data (GoogleEarth and similar) has made it possible to access data on modern analogues very rapidly, the key challenge is to find the appropriate area. The SafariDB “modern analogue finder” allows the user to search the Earth for suitable analogues for ongoing reservoir studies based on depositional environment, climate and tectonic setting. The tool is based upon the results of a PhD by Bjorn Nyberg who mapped the distribution of the present depositional areas on the Earth’s surface (Nyberg and Howell 2015); classified the World’s coastline into 5km intervals (Nyberg and Howell 2016) and mapped the continental systems at 1 degree spacing.

The final aspect of the database is geometric data. There are 6500 unique measurements from architectural elements (such as channel bodies, intra shoreface shales, mouthbars etc) which are all fully searchable. These can be filtered by climate, depositional system and tectonic setting, so it is possible to obtain data for object based modelling that is robust, repeatable and auditable.

In addition to providing data that is invaluable for industry professionals, SafariDB provides a unique tool for examining fundamental questions in the geosciences. To date these have included the recognition and quantification of very large scale Distributive Fluvial Systems in classic sections from the Book Cliffs of Utah (Rittersbacher et al 2015); new models for the formation and distribution of intra-shoreface shales (Eide et al 2014) and, a global mapping of modern depositional systems (Nyberg and Howell 2014). During the course of the project we have developed new methods for the acquisition of Virtual Outcrops using ground based and helicopter mounted laser scanners. Most recently we have implemented the use of drones for optimising VO acquisition.

The current phase of the project is due to run until 2018. In that we are adding significant volumes of new virtual outcrop data to the database; collecting data from shallow seismic volumes; developing methods to use Virtual Outcrops as MPS training images and developing tools to view and collect virtual outcrop data on tablets. While much of the data in SafariDB currently lies behind the sponsor pay-wall we are in the process of making parts of it, such as the outcrop descriptions, public. The goal of this is to then crowd source outcrop descriptions and data so that SafariDB becomes “the” place to search for and upload information on geological outcrops.

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Insights into bottom-currents role in reworking and redistributing turbidites in the Offshore Mozambique: implication for hydrocarbon exploration

Antoine Thiéblemont[1], F.Javier Hernández-Molina[1] and François Raisson[2]
[1]*Royal Holloway, University of London*
[2]*TOTAL S.A*

Since the giant gas discoveries off the coasts of Mozambique and Tanzania (e.g., Mamba, Windjammer, Barquentine, Lagosta, Pweza, Ironclad), the East African margin has proved to be a hotspot for hydrocarbons deepwater exploration activity. The high quality sandstones reservoirs within the Cretaceous and Tertiary sedimentary sections can be related to the presence of vigorous, deep-water bottom currents that influenced the deposition of gravity flows and /or later rework its deposits on the sea-floor. On the other hand, bottom currents can redistribute fine deposits, which can be good seal rocks. It is essential to understand the control factors for these deposits to predict where and when they occur. Along the present-day East African margin, water masses circulation is mainly driven by thermohaline circulation (THC) but deeply affected by both regional continental margin configuration and local sea-floor topography. Contourites are generated by the northward flow of AAIW (Antarctic Intermediate Water) and NADW (North Atlantic Deep Water) that form the Mozambique Undercurrent (MUC) but can be affected by a train of large anti-cyclonic eddies that can reach the channel bottom and propagate southward. In past-time, such currents can only occurred with a marine connection between the pole and the equator by a continental break-up and spreading along the East African margin. Initial rifting began between East Gondwana (i.e. Madagascar, India, Antarctica and Australia) and West Gondwana (i.e. Africa and South America) at around 157-190Ma. This stage is followed by a N-S to NNW-SSE rifting and early drifting of East Antarctica from Mozambique between 148.16Ma and 155.6 Ma with the offset of the Mozambique basin and the conjugate Riiser-Larsen Sea. The complete marine connection occurred in the Early Cretaceous (i.e. 120-130 Ma) with the end of Madagascar movement. Seismic evidence indicates that the currents velocities have significantly increased around the Eocene-Oligocene transition, probably due to the opening of the Drake and Tasmanian Passage (i.e. South-America/Antarctica and Australia/Antarctica) and the final onset of the Antarctica Bottom Water (AABW). Turbidite flows are captured and diverted by structural elements related to the tectonic of the margin (e.g., Davie Fracture Zone, Beria High) and redistributed by the bottom currents, which mainly flow parallel to these structures. The objective of this work is to characterized contourites and mixed (i.e. coutourite-turbidite) depositional systems offshore Mozambique and Rovuma basin. A detailed seismic interpretation of these deposits was carried out over time and factors controlling sediments distribution are discussed. This study is based on an extensive deep-water exploration dataset comprises high quality 2D and 3D seismic data with a set of exploration wells.

Turbidite-Contourite Interactions on the Uruguayan Continental Margin: Conceptual Implications

Adam Creaser
Royal Holloway, University of London

Historically, geologists have relied heavily on the theory that sedimentary systems conform to end-member models. While depositional architectures may host characteristics of one depositional system, more commonly, deposits lie on a spectrum of interstitial models, which can show characteristics of two or more depositional processes. These “mixed-systems” form a fairly new addition to the geological lexicon, occurring due to the spatial and temporal interaction of two or more depositional processes, of varying intensity.

With an increasing catalogue of turbidite reservoirs worldwide hosting anomalous reservoir qualities and geometries, the synthesis of both contourite and turbidite models are now used to better represent all processes occurring within deep-marine systems. Using a 2D and 3D dataset we aim to: (1) characterise the Cretaceous mixed-drift system recognised across the Uruguayan Margin and (2) evaluate the conceptual implications for the interaction of deep-marine sedimentary processes.

Four large (>25 km wide and up to 100 km long) asymmetrical contouritic drifts have been identified propagating obliquely from slope. Drifts have over 1 km of local relief over adjacent channels (canyons?), which amalgamate towards the SE following underlying basement topographic features. Internally, drifts are characterised by a series of convex-up, low to medium amplitude reflections which prograde away from the slope, and prograde/aggrade laterally towards the south-west. Basal reflections can be traced across multiple drifts, though later, these terminate into adjacent channels or pinch-out against internal discontinuities. Along steeper slopes (SW), slumps displace sediment down into depressions, prior to reworking by gravity flows.

Sediment availability appears fundamental in controlling the growth of channel-drifts. Prominent drifts growth coincides with highly active down-slope systems and deltaic progradation along the continental shelf, but also with the onset and enhance of bottom currents. This period is following the opening of tectonic gateways (e.g. Falkland-Agulhas Seaway, Walvis Ridge/Rio-Grande Rise) and Cretaceous Thermal Maximum. In these periods, vigorous bottom current have the potential to actively pirate material from turbidite plumes to build a channel-drifts system and potentially leave cleaner channel-sands, or rework sediments across on the sea floor. A similar channel-drift depositional model has been previously proposed for glacial areas including the Weddell Sea, Antarctic Peninsula and Eastern Greenland, where both sediment availability and bottom-current velocities are high. More recently, this has now been applied to more siliciclastic margins including the Mamba Complex, offshore Mozambique where cores and primary sedimentary data is available highlight a significant lacking of mud within channels, producing thick, clean, homogenous sandy packages within channels.

The nature and consequences of interactions between both along- and down-slope depositional systems are still significantly understudied. Across the Uruguayan margin, the development of a channel-drift system rather than a bi-lateral levee complex highlights the potential role of bottom-currents in controlling deposit architectures. While mixed-systems have been identified in a variety of environments, the fundamental mechanics behind their depositional processes, and associated sedimentological consequences are still relatively unknown. Significant work is still required to develop new conceptual models is required to fully and accurately understand their role in deep-water environments.

Wednesday 16th November
Poster Session three

KEYNOTE: Sustained industry-academia collaboration: scientific advances driving successful subsurface analysis

O. Martinsen
Statoil

Introduction

Since the advent of exploration in the North Sea in the 1960's, there has been sustained collaboration between academia and the oil and gas industry in and between the countries surrounding the North Sea Basin, not least to produce qualified recruits for industry employment. However, despite being a major driver for industry support of academic research, collaboration extends far beyond the human factor. Major scientific advances have been made as a result of the cooperation, both within geology and geophysics.

Collaboration – not competition to achieve scientific breakthroughs

Major scientific breakthroughs in the subsurface sciences geology and geophysics have been generated by industry supported by academic research in universities and other research institutions. These breakthroughs include seismic and sequence stratigraphy and source-to-sink (S2S). Time pressure in industry to deliver material results requires rapid development of applicable research products. This not negative to basic scientific, because it leads industry to focus research activities. However, the possibility to explore basic scientific principles is much less compared to academia. Yet such principles, often derived from outcrops or other data sets are important foundations for successful subsurface analysis. This is a major role of universities and research institutions.

Sustained cooperation across the North Sea rift basin

The dominant play in the North Sea are extensional fault blocks formed during Permo-Triassic and late Jurassic rifting, sourced by upper Jurassic source rock deposited in intervening half grabens. In the early 1990's, projects were formed between UK universities and Norsk/Statoil to jointly study the geology of major fields such as Statfjord, Oseberg and Troll, as well as outcrop analogues in Sinai (Fig. 1) and Corinth. Complementary strengths were developed between key universities such Manchester, Imperial College, Edinburgh and Durham and Norwegian oil company research laboratories. Key benefits for the universities included long-term funding and sustained focus on new, globally applicable research themes such as tectonics and sedimentation in extensional settings. The oil companies benefitted substantially from direct hiring of students trained in both outcrop and subsurface analysis of seismic and core data. Some of these students have made impressive careers in industry and based on their rigorous training and experience have developed senior technical and management careers.

Even more importantly, the companies have developed new and more confident play and prospect models from the cooperation that have led to significant discoveries. The focus by cooperating academia on applied aspects of the research rather pure academic and theoretical concepts have contributed to substantial production from oil and gas fields. A final benefit has been the cooperation on field training in key places such as Corinth and Sinai and elsewhere.

Increased global scope, new challenges and continued cooperation

Over the last 10-15 years, Norwegian oil companies have extended their work to many basins globally, particularly deep-water clastic basins along Atlantic margins. New geological challenges beyond the classic rift play have emerged. Nevertheless, in addition to the core collaboration with Norwegian universities, the companies have sustained their collaboration with UK and Irish based universities due to the quality of research work. Key cooperating institutions to those mentioned earlier include Leeds, University College Dublin and Herriot-Watt University. An interesting effect in later years is the return of initially recruited staff to the companies back to senior positions in academia. This has strengthened the university staff and contributed to making and sustaining the key universities as centres of excellence for geoscience education.

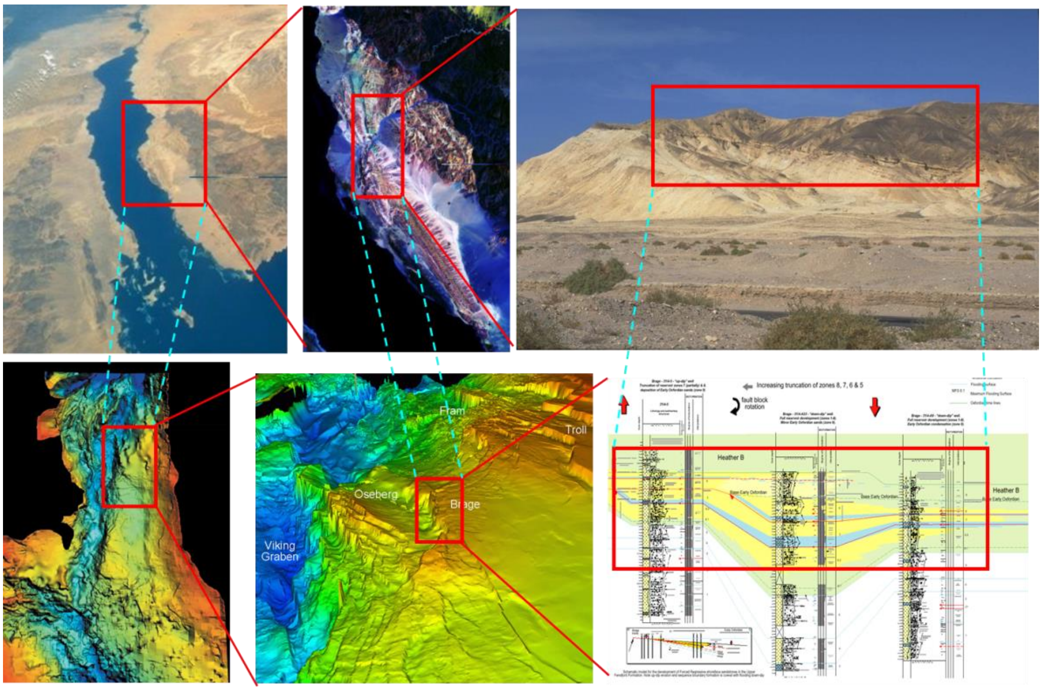

Fig 1. A major reason for the development of the sustained cooperation between Norwegian companies and British universities was the complementary competences developed for understanding rift basin plays, the major exploration and production target in the Northern North Sea. Over the years, much work has taken place to establish the understanding for this target through subsurface work and field work in the Gulf of Suez.

Acknowledgements

The author acknowledges important input from Robert Gawthorpe (University of Bergen), Chris Jackson (Imperial College), Ian Kane (University of Manchester) as well Tony Doré, Ian Sharp and Tom Dreyer (all Statoil).

Brent Group Petrography and Diagenesis: Implications for Reservoir Quality and Enhanced Oil Recovery

Thomas A. G. Utley[1, 2] and Richard H. Worden[1]
[1] *University of Liverpool*
[2] *Durham University*

Despite many decades of exploration and oil production there has been no regional assessment of detrital and diagenetic mineralogy and the controls on reservoir quality of the prolific Middle Jurassic Brent Group, Viking Graben, UK. Here we have integrated, evaluated and synthesised a combination of proprietary and publically-available core analysis data and petrographic mineralogical data from the Brent Group. The aim to better understand the regional mineral and petrographic properties of the Brent reservoir units, the distribution of detrital and diagenetic minerals, and how these influence reservoir quality and options for enhanced and improved oil recovery.

Despite the Brent Group being the focus of many studies into sandstone diagenesis in the 80's and 90's, there have been no published reviews of the regional patterns of diagenesis. Furthermore little effort has been made to develop an overview of how the Brent Group changes both spatially and with depth across the Viking Graben.

Using data supplied by four industry partners, together with published data, a data set of over 2500 samples was collated from 169 different wells, representing 27 different fields that are producing or have produced oil from Brent Group reservoirs over the last 40 years. This data set, the largest produced on the Brent, has allowed us to generate and analyse maps of the distribution of the diagenetic minerals that control reservoir quality (quartz, calcite, illite, kaolinite, siderite, etc). We have also compared cement abundances in the various Brent Group formations, and examined the effects of depth of burial and different fluid type on cement abundance patterns.

A greater understanding of how the Brent Group varies, spatially, with depth, and between formations, will help in the management of Northern North Sea assets, and in any potential exploration on deeper or satellite structures in the area. A regional understanding of Brent mineralogy will help in appraising the possible effectiveness of EOR approaches such as low salinity water injection. With a drive to reduce costs and maximise economic recovery from the UK Continental Shelf, the encouragement of operators to share information with one another and work more closely with academia, together with the re-examining of legacy data may be the key to future success both in this basin and elsewhere.

Evolution and Karst Development in a Palaeozoic Carbonate Platform: A Seismic Interpretation Approach

Viet Son Tran[1], Nicola Scarselli[1], Alberto Riva[2], Raffaele Di Cuia[2], Paolo Pace[2]
[1] *Royal Holloway, University of London*
[2] *G.E. Plan Consulting*

This MSc collaborative study between Royal Holloway Department of Earth Sciences and GEPlan Consulting focuses on the Pre-Caspian Basin (PCB), an elliptical-shaped palaeo-depression located in the western part of Kazakhstan and Russia. This basin is one of the largest oil-producing regions in central Asia. The Permo-Carboniferous carbonate platforms surrounding the PCB represent one of the main exploration targets as they are excellent hydrocarbon reservoirs.

The PCB originated as a pericratonic basin due to pre-late Devonian rifting, the precise timing of which is still poorly understood. The basin is bounded by the Palaeozoic carbonate platform of the Volga-Ural province to the north and west, and by Hercynian fold belts to the east and south. The basin infill, which can exceed 20 km in thickness, is divided into two main sequences by the regionally extensive Kungurian evaporites. The pre-salt Devonian-Early Permian section principally comprises shallow-water carbonates, intensely karstified at certain stratigraphic intervals, on the basin margins, whereas siliciclastic deep-water facies are found in the basin centre. The post-salt succession is dominated by Mesozoic-Cenozoic clastic rocks and is strongly affected by halokinesis, which also resulted in variable evaporite thicknesses in the basin.

The aim of this study is to understand the evolution of a carbonate platform in the northern portion of the PCB with particular attention on the processes of karstification that, whilst enhancing the characteristics of potential carbonate reservoirs, may also result in complex fluid flow regimes more difficult to predict. The controls on karst development are addressed through a sequence stratigraphic approach, in order to construct a geological and geometrical model of the evolution of the karst geometries. The 3D seismic data available allows the implementation of a multi-attribute approach in characterising structures and morphologies of interest. The results of this study have a positive impact on the understanding and reduction of the uncertainty associated with behaviours of fluid flow within karst-related structures. Our results and methodology are also applicable to analogues fields in the PCB and other regions having hydrocarbon potential within karstified carbonate reservoir.

Resolving the noble gas fingerprint in UK unconventional gas reservoirs Introduction

Stuart Gilfillan
University of Edinburgh

In the last decade, there has been an unprecedented expansion in the development of unconventional hydrocarbon resources. Concerns have arisen about the effect of this new industry on water groundwater quality have abounded, particularly focussing on the process of “Fracking”, or “hydraulic fracturing”, the process technique used to increase the permeability of a geological the targeted tight shale formations.

Methane contamination of groundwater has been documented in areas of gas production[1] but conclusively linking this to fugitive emissions from unconventional hydrocarbon production has been controversial[2]. A lack of baseline measurements taken before drilling, and the equivocal interpretation of geochemical data hamper the determination of possible contamination.

Fingerprinting methane sources

Common techniques for “fingerprinting” gas from discrete sources rely on gas composition and isotopic ratios of elements within hydrocarbons (e.g. $\delta^{13}C_{CH4}$), but the original signatures can be masked by biological and gas transport processes. The noble gases (He, Ne, Ar, Kr, Xe) are inert and controlled only by their physical properties. They exist in trace quantities in natural gases and are sourced from 3 isotopically distinct environments (atmosphere, crust and mantle)[3]. They are decoupled from the biosphere, and provide a separate toolbox to investigate the numerous sources and migration pathways of natural gases, and have found recent utility in the CCS[4] and unconventional gas[5] industries.

Fingerprinting UK unconventional gases

Here we present a brief overview of noble gas data obtained from a new coal bed methane (CBM) field, Central Scotland. We show that the high concentration of helium is an ideal fingerprint for tracing fugitive gas migration to a shallow groundwater. The wells show variation in the noble gas signatures that can be attributed to differences in formation water pumping from the coal seams as the field has been explored for future commercial development. Dewatering the seams alters the gas/water ratio and the degree to which noble gases degas from the formation water. Additionally the helium and neon isotopic signatures exhibit a small but resolvable mantle input previously unseen onshore in the United Kingdom. We will outline the potential sources of this mantle input.

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Noble gases in gas shales: Implications for gas retention and thermal maturity

S. Basugupta, A.P. Jones[1], A.B. Verchovsky[2] & J. McQuilken[3]
[1]*University College London*
[2]*Open University*
[3]*BG Group*

Gas shales from three cores of the Haynesville-Bossier formation have been analysed simultaneously for carbon, nitrogen and noble gases (He, Ne, Ar, and Xe) to constrain their source compositions and identify signatures associated with high gas retention. Ten samples from varying depths of 11785 to 12223 feet from each core, retrieved from their centres, have been combusted from 200-1200°C in incremental steps of 100°C, using 5 – 10 mg of each sample.

Typically, Xe is released at 200°C and is largely adsorbed, observed in two of the three cores and can be used to identify shales with high adsorption capacity. The third core lacked any measureable Xe and its low adsorption efficiency is in agreement with observed clay type (illite) having low adsorption capacity and, thin sections indicating burrowing activities that can destruct micro and nano pores associated with organic matter that can potentially host adsorbed gases. High $^{40}Ar/^{36}Ar$ ratio up to 8000, is associated with peak release of nitrogen with distinctive isotopic signature, related to breakdown of clay minerals at 500°C. He and Ne are also mostly released at the same temperature step and predominantly hosted in the pore spaces of the organic matter associated with the clay. He may be produced from the uranium related to the organic matter. The enrichment factors of noble gases defined as $(^{i}X/^{36}Ar)_{sample}/(^{i}X/^{36}Ar)_{air}$ where ^{i}X denotes any noble gas isotope, show Ne and Xe enrichment observed commonly in sedimentary rocks including shales (Podosek et al., 1980; Bernatowicz et al., 1984). This can be related to interaction of the shales with circulating fluids and diffusive separation of gases (Torgersen and Kennedy, 1999), implying the possibility of loss of gases from these shales. Interaction with circulating fluids (e.g. crustal fluids) have been further confirmed using $^{20}Ne/N_2$, $^{36}Ar/N_2$ and $^{4}He/N_2$ ratios. Deviations of measured $^{4}He/^{40}Ar^*$ (where $^{40}Ar^*$ represents radiogenic ^{40}Ar after correcting for contribution from atmospheric Ar) from expected values has been used to monitor gas thermal maturity. Deviation from expected Ne/Ar ratios after modelling for diffusive and solubility controlled processes, suggests that 2 to 50% of Ar has been degassed from the samples at ~50°C from different intervals by solubility controlled process. This is not directly correlated to the depth level of samples implying variation in porosity, permeability and presence/absence of fractures at different levels facilitating circulation of fluids played the major role. Given that the solubility of Ar and CH_4 in water are comparable, we can conclude similar losses of natural gas from the different intervals of the shales.

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The Effect of Stress-Induced Porosity and Permeability Variations on Shale Gas Reservoir Performance

Shaibu Mohammed
University of Aberdeen

In shale gas reservoirs, porosity and intrinsic permeability are sensitive to changes in effective stress. Conventionally, pore volume compressility - as derived from dry gas continuity equation - is defined as the fractional change in pore volume per unit pore pressure. This definition, unfortunately, only considers the effect of pore pressure variations on porosity; consequently, the effect of stress (and hence effective stress) on porosity and intrinsic permeability during shale gas production is not accounted for. Further, as opposed to competent formations such as sandstone reservoirs, the coupling between gas desorption and rock matrix deformation must be accounted for in poroelastic response of gas shale. Also, due to the extremely low permeability of shale gas reservoirs, the physics of gas flow is very complex, and involve more than one transport mechanism. The primary purpose of this paper is to model the coupled processes between matrix deformation and fluid flow in fractured reservoirs such as gas shale by taking into account the influence of effective stress on porosity and intrinsic permeability. Furthermore, the effects of these coupled processes on shale gas reservoir production behaviour is investigated. For these purposes, a continuity equation of dry gas that considers the mass conservation including both free and adsorbed phases and stresses-induced intrinsic permeability and porosity variations, is developed. The adsorbed gas content, which is incorporated in the proposed continuity equation as an effective porosity term, is described through a Langmuir-type equation. In addition, a stress-induced porosity variation is incorporated in the proposed continuity equation to improve upon the conventional method. In particular, the pore volume compressibility is expressed as the fractional change in pore volume per unit effective stress as opposed to pore pressure. The model for the variations in porosity with respect to the effective stress is modelled using the equation proposed by Cheng (2016) while the stress-induced intrinsic permeability is modelled using the equation proposed by Kozeny and Carmah. The apparent permeability, which is a function of intrinsic permeability and accounts for the diverse transport mechanisms in shale gas reservoirs, is also modelled using the equation proposed by Karniadakis et al. Due to the nonlinearity of the resulting field equations, a finite difference scheme is implemented as the solution based approach. The model is then used to investigate coupled desorption/diffusion-rock deformation phenomena, and its impact on gas flow in shale gas reservoir. Simulation results show that the time evolution of gas pressure, effective stresses and intrinsic permeability are not strong functions of gas desorption during early-time production, but may have a significant effect at late time production. Gas desorption retards the influence of the effective stress increase associated with pore pressure reduction at late time production. The combination of in-situ stress condition and gas desorption mechanism governs the pore deformation behaviour in gas shale reservoirs. Stress-induced porosity and intrinsic permeability changes cause a sudden decrease in shale gas production. The results of this work may aid to understand the reason behind the steep fall from a peak value that is an inherent behaviour of shale gas production.