ROYAL HOLLOWAY UNIVERSITY OF LONDON

MSc Petroleum Geoscience Symposium

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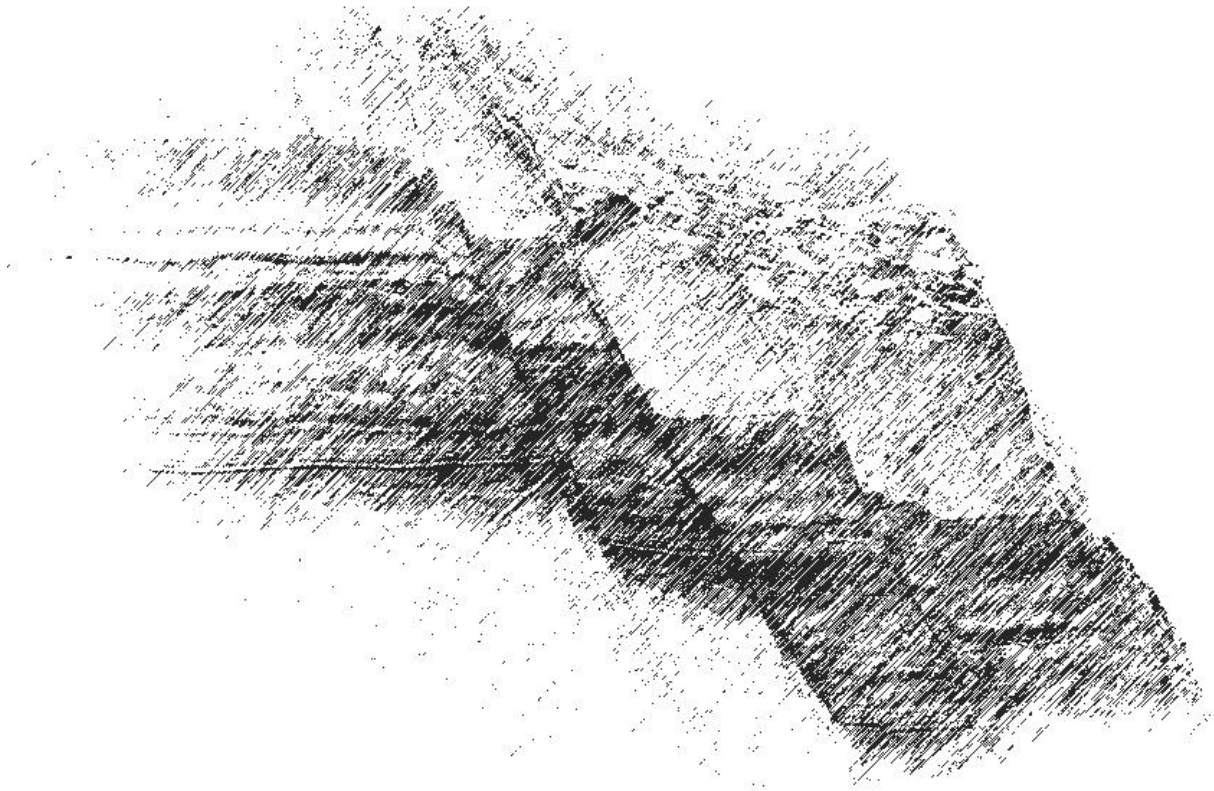

- Acknowledgements -

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Programme
Morning sessions in Queen's Lecture Theatre

9.00			Introduction, welcome and Principal's address
		Queen's Lecture Theatre	
9.15	North Atlantic margins	Adam Kirby	The development of contourites during the Late Cretaceous on the West Iberian margin, and their conceptual application to a petroleum system
9.30		Niamh McGovern	Evaluation of the Cenozoic hydrocarbon prospectivity of FEL 2/13, South Porcupine Basin, offshore Ireland
9.45		Michael Powney	Seismic geomorphological evolution through the Paleocene/Eocene transition in the Faroe Shetland Basin over parts of Quads 204/205 and 6004
10.00		Selcen Yilmaz	Post-rift seismic stratigraphy and evolution of the Hudson Canyon area of the western Atlantic margin
10.15	Americas	Joe Killen	Regional assessment of lithological variation within the Eagle Ford Group, Gulf of Mexico: Implications for unconventional reservoirs
10.30		Alexander Mason	Understanding the impact of diachronous collision on clastic reservoirs along the sub-Andean trend, Colombia and Venezuela
10.45			Coffee & tea with poster session
11.15	South Atlantic margins	Alex Froud	Seismic analysis of the Outeniqua Basin, South Africa
11.30		Melissa Chin	Analysis of potential deep source kitchens within rift basins, offshore Namibia
11.45		Jack Baxter	Rio Muni & Douala Basins: Identifying depositional segments with the best reservoir characteristics
12.00		Nick Reiss	Development of deepwater thrust-related folds, Niger Delta
12.15		Arthur Keep	Seismic characterisation of mass transport complexes and their potential sealing properties, Niger Delta
12.30		William Cranston	Characterisation and distribution of Upper Cretaceous mass flows, deepwater Côte d'Ivoire, West Africa
12.45	Tech	Aizhan Zhakupova	Microstructural characterisation of porosity, elastic moduli and permeability of the Berea Sandstone from synchrotron microtomography

Programme
Afternoon sessions in Queen's Lecture Theatre

13.00			Lunch with poster session
14.00	Barents & Norwegian seas	Robert Batterbury	Halokinetic characteristics, timing and hydrocarbon trapping assessment of resultant salt structures, Nordkapp Basin, SW Barents Sea
14.15		Abigail Taylor	Structural and depositional development of the Loppa High, Barents Sea and implications for hydrocarbon prospectivity
14.30		Billal Nawaz	Cretaceous and Paleogene plays in the Sørvestsnaget Basin, SW Barents Sea
14.45		William Mosdell	Reservoir characterisation of the syn-rift Røgn Formation, Norwegian Sea
15.00		Charles Ross	Sedimentological & reservoir character of the Cret. Kyrre Sst & Agat MB, Maløy slope, Norwegian N. Sea
15:15			Coffee & tea with poster session
15:45	North Sea & UK	Cahyagempita Putri	Reservoir implication of the transition from marine to lacustrine carbonates: A seismic and field-based study, Late Jurassic, Wessex Basin, UK
16.00		Siyuan Wen	Faults and fractures associated with multi-phase emplacement of salt diapirs in the Broad Fourteens Dutch southern North Sea
16.15		Gerardo Gaitan	Structural and kinematic evolution of the Dowsing fault zone, southern North Sea.
16.30		Afiqah Hamir	Seismic characterisation of sand injectites in the Cenozoic section of the central North Sea (Quad 15)
16.45			Award of prizes, closing remarks and reception

Programme
Parallel sessions in room QB170

	Room 170 parallel sessions		
13.00			Lunch with poster session
14.00	Australasia	Grandika Septia Primadani	Tectonostratigraphy of the Asri Basin, SE Sumatera, Indonesia: Unlocking the hidden potential of Oligo-Miocene reservoirs and implications for prospectivity
14.15		Richard Shelton	The prospectivity of the Gippsland Basin, offshore eastern Australia
14.30		Adept Titu Eki	Neogene evolution of offshore eastern Sulawesi, Indonesia
14.45		Herwin Tiranda	Tectonostratigraphic evolution of offshore NW Sulawesi with implications for hydrocarbon prospectivity
15.00			
15:15			Coffee & tea with poster session
15:45	Mediterranean & East Africa	Sophie Evans	Exploration potential of the southern Adriatic Sea Basin
16.00		Zhi Lin Ng	Contourites in the Agios Konstantinos and Petra Tou Romiou sections, Lefkara and Pakhna Formations, Cyprus: Conceptual and economic considerations
16.15		George Peters	Evolution of extensional fault related structures in the Southern Lokichar Basin, Kenya

Adam Kirby

The development of contourites during the Late Cretaceous on the West Iberian Margin, and their conceptual application to a petroleum system

Contourites and the processes that form them have recently become of interest in hydrocarbon exploration as companies move further offshore and explore deeper marine environments. Here, 2-D seismic and Deep Sea Drilling Project borehole data has been used with published literature to define, categorise and understand contourites and their development during the Late Cretaceous along the West Iberian margin. Observed contourites have been applied to a conceptual petroleum system with the aim of better understanding the various roles they can play and the economic significance they could have in exploration. Evidence for strong bottom currents across the North Atlantic basin has been found with the identification of large contourite drifts and erosional features across the margin and in other parts of the Atlantic. Potentially very large deposits have been observed on the lower slope in a confined seaway, here bottom current velocities were capable of reworking coarse grained sediments and mass-transport deposits on the paleo-seafloor. Based on seismic character alone, two post-Cenomanian drifts have been identified with internal seismic character and external geometries that suggest they could act as a reservoir, seal and trap simultaneously in a petroleum system, thus strengthening the argument for the significance of contourites in hydrocarbon exploration. To conclude, this work is improves our understanding of the development and prospective significance of Late Cretaceous contourites on passive margins across the Atlantic, and potentially globally.

Supervisor: *F. Javier Hernández-Molina (RHUL)*

Data provided by: *TGS and Repsol*

Niámh McGovern

Evaluation of the Cenozoic hydrocarbon prospectivity of FEL 2/13, South Porcupine Basin, offshore Ireland

Frontier Exploration Licence 2/13 is located within the South Porcupine Basin, ~200 km off the west coast of Ireland. The Porcupine Basin developed from the NE Atlantic Conjugate margin, consisting of sediments from Mesozoic to Cenozoic age, with phases of extension and thermal subsidence. The Cenozoic interval has been under-developed throughout the basin. This project utilised anisotropic pre-stack time migrated seismic data and integrated 43/13-1 well data. Unconformities mapped and identified throughout the dataset established submarine fan system environments and were associated with major unconformities across the basin. Contourite drifts are confined to the thick Miocene sediments and are associated with bottom ocean circulation. These drifts need to be further investigated and applied to other licenses throughout the basin in order to be fully evaluated. Early Oligocene and Middle Eocene channel features are NW-orientated, correlating with the Porcupine High as a sediment source. Attribute maps establish a NW-orientated channel with low amplitudes indicative of potential sand areas. The isochore and isochron maps of the Early Oligocene and Middle Eocene illustrate a sediment supply from the NW. An intra-Paleocene sand unit onlaps Early Paleocene basalts. The intra-Paleocene unit was sand prone, identified by its high amplitudes across the dataset. This intra-Paleocene sand unit could be a potential reservoir for FEL 2/13 and indicates stratigraphic and structural traps. The stratigraphic up-dip pinchout is higher risk than the small two-dip closure trap. The Middle Eocene mudstone sequence is predicted to be a potential sealing unit. Direct hydrocarbon indicators are abundant throughout the dataset and are associated with gas chimneys. These bright spots are trapped and sealed by the intra-Late Oligocene unconformity, indicative of a pre-Cenozoic source rock. However, the well data suggests an immature Jurassic source rock. There is evidence of vertical migration associated with the gas chimneys and potential for lateral migration. Paleocene sills were identified within and associated with FEL 2/13. There is potential for these igneous intrusions to act as migration pathways, which could affect the reservoir quality of the overlying intra-Paleocene reservoir. Three main leads were identified within the intra-Paleocene, along with two smaller leads.

Supervisors: *Domenico Chiarella & F. Javier Hernández-Molina (RHUL); Rowland Thomas & Neil Parkinson (Europa Oil and Gas)*

Data provided by: *Europa Oil and Gas*

Michael Powney

Seismic geomorphological evolution through the Paleocene / Eocene transition in the Faroe Shetland Basin over parts of quads 204/205 & 6004

The evolution of the Faroe-Shetland basin involved a complex rifting and inversion history. The transition through the Paleocene/Eocene poses many questions in regards to how the Icelandic Plume, thermal maximum and tectonic events influenced the basin. By analysing the FSB2011/2012 survey, clear geomorphologies observed allow for a more succinct interpretation of the basin's evolution. Using state of the art 3-D seismic interpretation, it is concluded that the Lamba T38 sequence saw a retrogradation of the northerly shelf feature disrupting a deltaic sequence. A series of alternating braided and meandering systems are clearly observed throughout the south of the basin, depending on the energy within the key horizons. The sedimentary direction changed throughout the Upper Flett, creating a linear coastline across the study area. Retrogradation of this feature was then observed until the Upper Stronsay (T60). This sequence represented a highstand systems tract with a change of sediment supply from a SE direction. This created a series of sub-aqueous, delta slope clinoform features trending at a very shallow angle. Analogues were then created to display real world examples of the features observed for comparisons. Using the completed analysis and analogues, facies were predicted within the basin in regards to sands, clays and muds, this would have been better analysed by using a two term inversion to restrain lithologies further. Given the clear hinterland to basin relationship observed within various analyses and facies predicted, a potential petroleum system was analysed. A variance cube was created to better constrain locations of secondary migration for hydrocarbons as well as contour analysis to understand potential trapping geometries. Although potential accumulations within the study area are too small for commercial interest, the methodology utilised here provides an important process in frontier exploration where well ties are scarce and lithologies are largely predicted.

Supervisors: *Jürgen Adam (RHUL); Steve Morse (PGS)*

Data provided by: *PGS*

Selcen Yilmaz

Post-rift seismic stratigraphy and evolution of the Hudson Canyon area of the western Atlantic margin

The western Atlantic passive margin is buried by a set of clinoforms, well defined in seismic data, which prograded basinward during the Miocene. The prograding slope clinoform succession comprise six seismic facies, based on the geometry of reflectors, reflection configuration and reflection terminations. This study is centred on a sequence stratigraphic analysis of the Paleogene-Miocene sequence on the continental slope of Hudson Canyon area. Sequence stratigraphy is based on recognising unconformity-bounded sedimentary units in seismic profiles. The analysed interval comprises four stratigraphic sequences; sequence SS is characterized by a transgression overlying a highstand progradational pattern. Sequence SS1 was deposited during a highstand forced regression. Sequence SS2 is characterized by the development of complex sigmoid oblique clinoforms during the transgressive system tract between Oligocene and Early Miocene times. Sequence SS3 is defined as a lowstand systems tract. Consequently, the depositional sequences are unconformity bounded and they are corellated to regional unconformities and controlled by numerous relative sea level changes. Potential reservoirs defined within the sequences include mass transport depositss, turbidites and contourites.

Supervisors: *Saswata Hier-Majumder & Ian M. Watkinson (RHUL); Raffaele Di Cuia (G.E.Plan Consulting)*

Data provided by: *G.E.Plan Consulting*

Joe Killen

Regional assessment of lithological variation within the Eagle Ford Group, Gulf of Mexico: Implications for unconventional reservoirs

The Eagle Ford Shale in southern Texas is one of the most prolific unconventional reservoirs in the world; however understanding of reservoir variations and the controls on production is limited. This study uses petrophysical and production data to analyse the lithological variations of the Eagle Ford Shale at a range of resolutions to identify the relationship between lithological properties and hydrocarbon production, and then outline the geological mechanisms behind these relationships.

Regional screening identified clear trends in the Eagle Ford Group. This method demonstrates that areas of highest production are well constrained by thermal maturity, gross thickness, and depth of the Eagle Ford Shale. At a higher resolution, as part of a 3-D petrophysical modelling workflow, a reservoir quality index composed of four factors has been created using multivariate analysis, 3-D modelling, and factor analysis to identify sweet spots within the Eagle Ford Shale. From these regional screening and petrophysical results, it has been interpreted that the San Marcos Arch acted as a barrier to terrigenous sediments from the Woodbine Delta system, and prevented dilution of the organic shale to the SW of the Arch.

As part of the petrophysical modelling, classification and regression tree (CART) analysis was run to determine the relationship between production and factor scores. Using this CART analysis, a model for predicting production volumes has been created, and it may now be possible to predict production volumes for planned wells within the Eagle Ford Shale based solely on factor scores derived from petrophysical properties. The workflow used within the study may be transferable to any unconventional reservoir, both frontier or mature. The methods described in the study will allow rapid identification of the most prospective areas, and help maximise recovery rates and production volumes.

Supervisors: *F. Javier Hernández-Molina (RHUL); Helen Smyth, Alex Bromhead & Jeffrey Yarus (Halliburton)*

Data provided by: *Halliburton (Neftex Exploration Insights)*

Alexander Mason

Understanding the impact of diachronous collision on clastic reservoirs along the sub-Andean trend, Colombia and Venezuela

The northern sub-Andean basins of Colombia and Venezuela comprise a series of linked sedimentary basins, which record the diachronous collision of allochthonous material with the NW margin of the South American plate, during the Late Cretaceous and Cenozoic. The affected area encompasses a series of foreland basins that include some of the most important petroleum basins in Latin America. Many of the key hydrocarbon reservoir horizons within these basins were deposited as a direct result of inversion along their margins and the transition from passive margin to foreland basin deposition. Using a synthesis of geochronological, thermochronological and 1-D basin modelling data, this research proposes a high resolution timing of uplift events within the Colombian Cordillera and northern Venezuela. The Central Cordillera of Colombia has been identified as initially uplifting from the Paleocene, with unroofing and continued uplift through to Oligocene times. Inversion of the Eastern Cordillera of Colombia has been shown to have occurred diachronously through the Eocene; accretion and uplift of the Caribbean Coastal Ranges has been isolated to latest Oligocene times.

These events have been found to have had a profound impact on palaeo-drainage networks, based on detrital geochronology derived from Cretaceous and younger sediments. Deformation associated with the Central Cordillera initially formed the Ecuador-Colombia foreland drainage routes (Oriente & Llanos Basins) in contrast to the Cretaceous passive margin. Segregation of the Magdalena Valley Basins of Colombia is proposed in response to complete inversion of the Eastern Cordillera, achieved by latest Eocene times. Initial Caribbean Coastal Range accretion, coupled with uplift of the Venezuelan Merida Andes range, resulted in a pronounced switch in drainage of the palaeo-Orinoco River, diverting this iconic drainage pathway to the east during the Miocene, as seen at Present day. As a result of drainage analysis and reservoir prediction, three new prospective levels have been identified as potential commercial reservoirs, especially within the under-explored Barinas-Apure Basin of Venezuela, at Turonian-Santonian, Paleocene and Oligocene stratigraphic levels. This study shows how diverse geological datasets can be synthesized to provide a first-pass regional appraisal of reservoir sequences in a collisional setting.

Supervisors: *Ian M. Watkinson & Jürgen Adam (RHUL); Richard James, Graeme Nicoll & Fabian Kohlmann (Halliburton)*

Data provided by: *Halliburton (Neftex Exploration Insights)*

Leona Hyslop

Gravitational processes and products along contourite terraces of the Uruguayan margin during the Cenozoic: Theoretical implications for hydrocarbon exploration

Contourites are sediments deposited or substantially reworked by the persistent action of bottom currents, found in water depths of 500 m to 5000 m and are known to transport sediment over thousands of kilometres, producing sediment drifts. Bottom current processes such as contourites are known to winnow turbidite sands, resulting in the production of a sandy facies composed of differing grain size. Sandy contourite facies are rare in modern oceans but are thought to occur where there is an increase in the velocity of the current. This project investigates how bottom current morphology can influence turbiditic deposition and where sand can be deposited under these conditions.

Seismic packages at the Uruguayan margin were interpreted chronostratigraphically, then horizons picked for the contourite terraces and high amplitude bodies present on them. This analysis revealed multiple targets potentially viable as good quality reservoir rocks. These deposits are composed of both bottom currents infering with gravitational processes such as turbiditic channels and levees. These are given the moniker “mixed system” deposits. From AVO, velocity, density, porosity and multiple horizon stack analysis, it became clear that three key seismic horizons represented good potential reservoir rocks.

These horizons are all classified as mixed systems deposits all of which lean towards a slightly greater inference from the bottom current. It is proposed that bottom currents can enhance the quality of turbiditic reservoir rocks, under the right conditions.

Supervisors: *F. Javier Hernández-Molina (RHUL); Gideon Lopes-Cardozo (Shell)*

Data provided by: *Shell, ANCAP*

Alex Froud

Seismic analysis of the Outeniqua Basin, South Africa

The Outeniqua basin situated off the Southern coast of South Africa is an area that has seen all previous exploration focus on the continental shelf, with treacherous drilling condition out into the deeper parts of the basin leaving the continental shelf edge and deeper water of the basin unexplored. With many recent discoveries being only contingent reserves with sub-economic volumes, and with production from existing fields in decline, exploration for further domestic reserves is imperative in South Africa. With drilling on the continental shelf exhausted, companies are starting to explore new play concepts in the deeper Southern Outeniqua basin. A petroleum systems analysis of the Southern Outeniqua basin shows that similarities can be drawn from the proven hydrocarbon system on the shelf and into the deep-water basin, as well as the development of new play concepts. Significant factors for discussion are source rock presence in the Southern Outeniqua basin and its deposition in relation to tectonic reconstructions, as well as the implications of reservoir provenance on the quality of sands in the basin, with competing models suggesting a provenance from the continent to the north or from the Diaz Marginal Ridge to the south. With no successful drilling so far in the Southern Outeniqua basin Block 11b/12b, seismic stratigraphic analysis forms the bedrock of these key discussions.

Supervisors: *Dan Le Heron & Nicola Scarselli (RHUL); Mike Cottam (BP)*

Data provided by: *BP*

Melissa Chin

Analysis of potential deep source kitchens within rift basins, offshore Namibia

The recent identification of an early to middle mature oil source in Namibia's Walvis Basin reignited interest in the potential of viable charge in the drift section since the 1974 Kudu gas discovery. However, the objective of this project is to demonstrate that these excellent quality Aptian shales are the youngest member of three prospective source kitchens offshore Namibia. Through interpretation of regional seismic data, the extent of Mesozoic rifting was mapped across the margin and prospective source rock intervals were identified to determine the potential for kitchens in the deeper section. Using 1-D and 2-D basin modelling techniques, these source kitchens were analysed to determine likely maturity and migration capability.

This project concludes that there are in fact two separate kitchens that form the base for two new play systems in the deep section offshore Namibia: the "Rift" Play and the "Sag" Play. The Mesozoic syn-rift basins, which were the original focus for the study and host the Upper Jurassic lacustrine shale source of the "Rift" Play are currently over mature, likely filling syn-rift traps with gas. In the process of determining the presence of this "Rift" Play, the evolutionary model revealed the likelihood of a second candidate source in the transitional (early post-rift) section. This Hauterivian, shallow marine shale source has the potential to charge the transitional section and the younger drift section with middle to peak maturity oil. These plays broaden the horizon for both deep water and shallow water exploration offshore Namibia, with multi-billion barrel expulsion potential over vast areas capable of charging a variety of viable reservoirs and traps – a discovery in which would catapult Namibia into the higher ranks of frontier exploration.

Supervisors: *Ian M. Watkinson (RHUL); Duncan Wallace (Chariot Oil and Gas)*

Data provided by: *Chariot Oil and Gas*

Jack Baxter

Rio Muni and Douala Basins: Identifying depositional segments with the best reservoir characteristics

The Douala and Rio Muni Basins are two rift basins that lie within the West-Central Coastal Province, offshore of Cameroon and Equatorial Guinea. Both are regions of proven petroleum, but neither have seen the success achieved by the Niger Delta or Gabon Basin to date. In an effort to identify the best depositional segments for reservoirs, gross depositional environment (GDE) maps were constructed for eleven timeslices throughout the Cretaceous to show the major changes in sedimentary deposits and the deposition of sand-rich intervals. Using these GDE maps, five main time periods for reservoir deposition were identified: The early Barremian, Albian-Cenomanian, late Turonian, Santonian-Campanian and Maastrichtian. Geochronology data (lithology and age) from the hinterland allowed compositional estimations for these five intervals. Well data from the Benito_1, East Eviondo_1, And Matondo_1 wells, in the Rio Muni Basin, contained stratigraphic thicknesses, top depths and lithology. By creating 1-D basin models from well data and comparing to the five reservoir intervals proposed, burial temperatures and porosities were estimated. Preliminary results showed that mainly felsic to intermediate Precambrian basement will have likely supplied quartz-feldspar rich grains leading to good quality reservoir development. However, mafic and meta-mafic constituents on the hinterland will have potentially reduced reservoir quality. By comparing with published geochemical studies of Cretaceous rock samples, a largely felsic-intermediate hinterland signature was confirmed. From 1-D basin modelling, estimated porosities for the Albian-Cenomanian interval ranged from 5-17%, 20-30% for the late Santonian, and 25-35% for the Maastrichtian. Using the Sanaga Sud field as an analogue for the Douala Basin, other Albian-Cenomanian reservoirs are inferred to reach average porosities of 23%. The Ceiba field also provides a useful analogue for the Rio Muni Basin, high quality sands and porosities of 26% are seen in the late Santonian to Campanian interval, so one would expect similar values for equivalent aged reservoirs within this basin. Further 1-D basin models were used to estimate maturities of source rocks in the Rio Muni Basin; those source rocks ≥109 Ma (Albian) are presently mature and likely to be oil producing. Public domain seismic was used to constrain potential frontier plays in both basins based on the five reservoir intervals and source rocks in the 1-D basin models. In conclusion, the hinterland provenance of the reservoir intervals through the Cretaceous has resulted in good quality sands with high porosities.

Supervisors: *Domenico Chiarella (RHUL); Colin Saunders (Halliburton (Neftex))*

Data provided by: *Halliburton (Neftex Exploration Insights)*

Nicholas Reiss

Development of deepwater thrust-related folds, Niger Delta

A suite of geophysical data including 3-D seismic and well data from the outer thrust belt zone, Eastern Lobe, Niger Delta, reveals growth packages, unconformities, and fault geometries that record fault growth. The conventional view of how shortening is accommodated is revisited by detailed kink band mapping and analysis of fault propagation fold and fault bend fold geometry. Results show contradictory evolutionary styles, which include out-of-sequence forward and backward stepping thrusts. Palynspastic reconstructions suggest that thrusts on the eastern side of transfer structures are less active than those on the western side. Transfer structures correspond to a ramp at detachment level that is controlled by pre-existing basement elements and accommodates differential velocities in the outer toe thrust front. A cumulative 18.2 km of shortening, east of the transfer structures, is restored on multiple detachments and accommodated in the Miocene through to the Pliocene. The methods used in this study can be applied to conventional seismic interpretation to constrain trap timing, initiation of thrust related folding and become integrated into play prospect evaluations.

Supervisors: *Ken McClay & Nicola Scarselli (RHUL); Philip Cox (Ophir)*

Data provided by: *Ophir*

Arthur Keep

Seismic characterisation of mass transport complexes and their potential sealing properties, Niger Delta

The structurally complex distal outer toe thrust region of the Niger Delta, like many other deep-water stratigraphic successions, is a depositional environment for mass transport complexes (MTCs). The Fortuna complex, a 1.3 Tcf biogenic gas-filled, channel levee complex is directly below a MTC only 700 m below the sea floor. Previous work has shown mud rich MTCs acting as seals in other basins, due to shear related deformation during transport realigning clay minerals and closing pore throats to reduce permeability. This study used 2265 km^2 of 3-D seismic data to create RMS amplitude and coherency maps to interpret the extent and nature of the Fortuna capping MTC. This MTC was seen to cover the entire reservoir complex in a 4 to 150 m layer of debritic material. The MTC and hemipelagic sediments above are an effective top and lateral seal to the reservoir, with potentially only minor gas leakage through the faulted extensional blocks of the headwall domain. Sandy beds within the headwall domain were observed to be acting as reservoir intervals also. The timing of levee deposition, MTC triggering and hemipelagic deposition may be linked to a sequence stratigraphic framework and may present a new play type for hydrocarbon exploration in deep-water thrust belts throughout the Niger Delta region and beyond.

Supervisors: *Nicola Scarselli (RHUL); Philip Cox (Ophir)*

Data provided by: *Ophir*

William Cranston

Characterisation and distribution of Upper Cretaceous mass flows, deepwater Côte d'Ivoire, West Africa

The Tano Basin, offshore Côte d'Ivoire, has an established petroleum system dating back to the 1970s when the offshore Espoir field was announced. However, this activity was concentrated on the continental shelf. This caused a bias for drilling and seismic surveys to rarely venture beyond the shelf, leaving the deepwater portion of the basin high risk. The 2007 Jubilee discovery opened up a new stacked turbidite play in Turonian and de-risked the deepwaters. Subsequently, exploration has moved on to the mid-slope of the Côte d'Ivoire-Ghana margin but rarely beyond, leaving the ultra-deepwaters poorly constrained.

Periods of transgression and regression have often been difficult to identify in deepwater basins. This is due to a disconnect between the shelf and abyssal plane, hence eustatic sea level changes are often heavily based on what is observed in the shelf and not the deeper sections. This study found that by using frequency decomposition and attribute extractions to track changes in channel morphology through time the fluctuations in sea level can be constrained to a high level of precision. Additionally, facies changes were found to relate to the channel systems.

Supervisors: *Nicola Scarselli (RHUL); Gregor Duval & Javier Martin (CGG)*

Data provided by: *CGG*

Aizhan Zhakupova

Microstructural characterisation of porosity, elastic moduli and permeability of the Berea Sandstone from synchrotron microtomography

The Berea sandstone has been a major reservoir rock in Pennsylvania, West Virginia, and Kentucky for decades. This rock consists predominantly of fine-grained to medium-grained well-sorted quartz grains, held together by silica cement. It has some minor quantities of feldspar, ferric carbonate and clays. The Berea sandstone has been used as a standard material in core analysis research and core flooding experiments for many years. In this project we presented a methodology for accurate analysis of the high-resolution microscopic CT rock images. Connected and unconnected pore networks were visualized in 3-D and effective parameters (such as effective porosity, absolute permeability, pore size distribution, effective elastic moduli, shear wave velocity) were estimated. The Absolute Permeability Experiment simulation module in Pergeos was used to simulate single-phase fluid flow through the extracted pore network. All the results were compared with laboratory measurements. This comparison demonstrated similarity in the total trend of the data. In combination with laboratory study and well log analysis, proposed technique can significantly improve the effect of enhanced oil recovery technics implementation.

Supervisor: *Saswata Hier-Majumder (RHUL)*

Data provided by: *ETH Zurich (Rocketh)*

Robert Batterbury

Halokinetic characteristics, timing and hydrocarbon trapping assessment of resultant salt structures, Nordkapp Basin, SW Barents Sea

Buried evaporite units in sedimentary basins are remarkably mobile and dynamic. The Nordkapp Basin of the South-West Barents Sea hosts thick accumulations of Upper Carboniferous - Lower Permian salt that have diapirically risen through to Quaternary level in a series of complex halokinetic events. This research has primarily used 3-D seismic data that encompasses a handful of the salt structures. Seismic attributes have been applied alongside numerous visual and computational enhancements in an attempt to unravel the poorly understood tectonostratigraphic evolution of the SW sub-basin of the greater Nordkapp Basin. This research has found that halokinesis was initiated in the early Triassic during a basin-wide extensional event, in which reactive diapirism formed juvenile salt rollers. Diapirs subsequently grew passively by differential loading of the overburden, promptly depleting the salt source layer. After a period of halokinetic dormancy during the Early Cretaceous, regional compression reactivated the diapirs by actively squeezing their stems, forcing them to deform and break through their thick overlay. Three dimensional salt constructions produced sophisticated visualisations of the halokinetic morphology that is active in the Nordkapp Basin, enabling the diapirs to be compared to classical plume theories. The architecture of the salt diapirs results in ideal petroleum trapping geometries under the salt overhangs, in which several oil-producing source rock intervals are believed to be present.

Supervisors: *Saswata Hier-Majumder, Domenico Chiarella & Nicola Scarselli (RHUL); Neil Hodgson (Spectrum)*

Data provided by: *Spectrum*

Abigail Taylor

Structural and depositional development of the Loppa High, Barents Sea and implications for hydrocarbon prospectivity

The Loppa High in the south-western Barents Sea, is a structural basement high with a complex history ranging from the Carboniferous to the Quaternary. There are major uncertainties remaining as to the cause and timing of uplift of the high. Currently, the area is highly prospective with the most recent Kayak Oil discovery by Statoil on the Polhem Sub-Platform in July 2017. This study combines tectonostratigraphic analysis with detailed fault interpretation to gain an insight into the causes of uplift and formation of related trapping structures. Using Spectrum's 3-D seamless seismic dataset, stratal termination analysis is paired with surface attribute analysis to determine faulting styles and kinematic packages. Distinct phases of faulting activity are identified on the high, including: eastern flank faulting; a NE-SW trending graben; the N-S trending Jason Fault Complex; transtensional tectonic faulting; and finally reactivation and inversion of the Jason Fault Complex. Additional gravity and magnetic data have been incorporated into the study to help analyse basement architecture, prior to the separation of the Polhem Sub-Platform from the Loppa High, and to help fully understand the regional and local uplift. Stratigraphic pinch-out traps are common in the Permian carbonate reservoirs due to uplift and erosion, and fault anticlines are formed over the crest and on the flanks of the high. The highly active and reactive nature of the high during the Mesozoic is the major influence and cause of trapping structures on the high, from erosional unconformities due to tilting and uplift, to fault reactivation and inversion anticlines.

Supervisors: *Jürgen Adam & Ian M. Watkinson (RHUL); Neil Hodgson (Spectrum)*

Data provided by: *Spectrum*

Billal Nawaz

Cretaceous and Paleogene plays in the Sørvestsnaget Basin, SW Barents Sea

Deep-water depositional systems and associated sandy turbidites are classically considered as appealing exploration targets. The highest rates of exploration success in the Norwegian Barents Sea have been achieved within the southwest Barents Sea. The incorporation of an understanding of sediment provenance into petroleum geoscience workflows can deliver fundamental insights at all stages of the exploration and production life cycle. In a frontier basin, such as the Sørvestsnaget Basin (SW Barents Sea), these studies can develop the understanding of potential reservoir presence, distribution, and quality. This insight can have a discernible impact on risk reduction at both play and prospect levels. Improved quality 3-D seismic reflection data and well data have been utilised to describe new insights into the Middle Cretaceous, Upper Cretaceous, and Middle Eocene stratigraphic units in the Sørvestsnaget Basin. During the Cretaceous-Paleogene, differential subsidence, ample accommodation space, and high rates of sedimentation fashioned ideal settings for the accumulation of thick clastic sequences of sand turbidites and extensive deep-water deposits.

This project sheds light on the influences of rift tectonics and halokinesis on basin architecture to understand basin fill. Moreover, the understanding of temporal and spatial variations in basin subsidence have helped recognise the development of accommodation space. These factors are principle parameters that dictate the gross-scale pattern of sedimentation. The style of sediment supply and configurations of sediment dispersal are recognised as a NE-SW delivery of possible reservoirs and seals, potentially reducing exploration risk within the Upper-Middle Cretaceous and Middle Eocene sequences.

Supervisors: *Dan Le Heron (RHUL); John Hughes; Neil Hodgson (Spectrum)*

Data provided by: *Spectrum*

William Mosdell

Reservoir Characterisation of the syn-rift Røgn Formation, Norwegian Sea

A fundamental understanding of the characterisation of hydrocarbon reservoirs is required to recognise, realise and optimise a petroleum system's full potential and lifetime performance. Utilising seismic characteristics and petrophysical responses, analysis of the Røgn Fm., a known Upper Jurassic hydrocarbon reservoir on the Frøya High (Norwegian Sea), has been undertaken to constrain its depositional controls, lateral extent and continuity. Deposition occurred in a tectonically formed, laterally constrained, shallow marine setting during Late Jurassic rifting whereby amplified tidal currents delivered sediment from the reworking of delta sets. Four Røgn Fm. deposits have been identified within the study area along a NNE-SSW lineament indicating a prominent, concentrated flow direction. Observed cross-bedding in inverse graded sequences produced by oblique 3-D dune migration, provides evidence for a sand bar facies. Porosities and permeabilities of up to 33% and 10D have been recorded within elongate Røgn Fm. palaeo-sand bars; however, a reduction in reservoir quality has been documented from well 6306/6-1 petrophysical data. Pertaining to a laterally constrained depositional setting, a reduction in reservoir quality has been interpreted as a decrease in tidal energy nearing the extents of the lateral confines. The intra-formational Røgn Fm. is enclosed in inter-bar shales, resulting in interfingering stratigraphic traps, little reservoir compartmentalisation and generally, excellent reservoir potential.

Supervisor: *Domenico Chiarella (RHUL)*

Data provided by: *Norwegian Petroleum Directorate*

Charles Ross

Sedimentological and reservoir characterization of the Cretaceous Kyrre Sandstone and Agat Member, Maloy slope, Norwegian North Sea

Reservoir characterization is an important factor in the hydrocarbon industry when evaluating a prospect. The Agat Member and Intra-Kyrre Formation sandstones provide prolific reservoirs for the recent Cara discovery and the Agat discovery. This study better defines the reservoir characteristics of the two stratigraphic intervals in the hope of rejuvenating hydrocarbon exploration on the Maløy Slope.

This study utilizes 3-D seismic data alongside well data and core data to better understand potential reservoir intervals within the Agat Member (Lower Cretaceous) and Intra-Kyrre Formation sandstone (Upper Cretaceous) on the Maløy Slope. Small sediment catchment areas from the Norwegian continent fed delta facies and shelf slope canyons through fluvial systems which are orientated similar to the present-day fjord system. Clastic material supplied to the slope by canyons allowed for the deposition of Agat and Kyrre turbidite and debris flows. The morphology of these deposits is controlled by intra-slope structural highs with the Agat Member directly responding to basement morphology and the Intra-Kyrre Formation sandstones controlled by intra-slope decompaction folding of pre-Turonian strata over the Jurassic fault complex and pre-existing canyon systems. Tectonic uplift of the continent and change in eustatic sea level provided the necessary conditions to supply and transport clastic material to the slope.

Four major reservoirs have been identified: the Agat Member, situated between basement structural highs; two channel complexes with terminal fans; a large sinuous channel complex; and a large intra-slope fan within the Kyrre Formation. Petrophysical analysis of the reservoirs show up to 35% porosity in areas with up to 1000 mD permeability. High permeability and porosity values suggest that reservoirs have been sealed quickly from fine grained sedimentation and over-pressured. Sediment storage on the slope provides sediments with high glauconite content giving sands a high gAPI reading from the gamma logs. Reservoirs show heavy compartmentalisation from the core data with large sequences of interbedded shale between high density deposits. Deposits show little lateral relationship along the slope suggesting sediment supply from the canyons were independent of each other and directly related to more localised processes on the shelf in response to continental evolution.

Supervisor: *Domenico Chiarella (RHUL)*

Data provided by: *Norwegian Petroleum Directorate; Spectrum*

Cahyagempita Putri

Reservoir implication of the transition from marine to lacustrine carbonates: A seismic and field-based study, Late Jurassic, Wessex Basin, UK

The Portland – Purbeck Limestone transition of the Wessex Basin, UK, from carbonate depositited in a shallow marine environment to a non-marine lacustrine carbonate environment has been interpreted in numerous ways during the last decades. An abrupt change in sedimentology between the Portland and Purbeck has been observed by field investigation, and leads to a re-consideration of the accepted theory that this transition developed as a result of normal regression.

This project employed three different scale analyses: 2-D and 3-D seismic data interpretation; followed by a field based study involving conventional carbonate outcrop logging; and thin section analysis of collected samples. A new interpretation is proposed that the integrated results indicate the boundary between the Portland – Purbeck Limestone groups was developed due to a forced regression in respect to the relative sea level fall. This finding may also provide a new perspective to understand the potential hydrocarbon implications within these carbonate units.

Supervisors: *Dan Bosence, Arnaud Gallois & Ian M. Watkinson (RHUL)*

Data provided by: *Total; Shell; IHS*

Siyuan Wen

Faults and fractures associated with multi-phase emplacement of salt diapirs in the Broad Fourteens Dutch southern North Sea

Extensive exploration in the Southern North Sea has made the UK one of the most important nations in oil and gas production. From previous studies, the scale and distribution of salt diapirism is often considered to be related to the structural forming mechanism. Analysis of the evolution of salt diapirs and related structures enables further prediction for exploration to be made.

The Broad Fourteens Basin, Southern North Sea Dutch sector, formed around Triassic – Middle Jurassic times and has experienced phases of rifting and inversion during its evolution. Using two 3-D seismic surveys from the NE corner of the Broad Fourteens Basin, this study has divided the evolution of the basin into three phases by extensional or inversion kinematics, then divided them into several sub-phases by the timing of fault activity.

Time structure maps, thickness maps and similarity maps were generated from the seismic to distinguish the different packages, depocenters of different periods and internal or surface structures. Salt bodies are identified as passive diapirs and reactive diapirs which experienced erosion at the base Cretaceous level, together with the underlying Jurassic strata. Three different mechanisms have been applied to the salt development under the brittle overburden. Each mechanism has a different initiation on related faults and fractures which are identified as either radial or concentric around the diapirs. Similarity maps were used to understand the scale, length and orientation of structures associated with multi-phase diapirs, and were overlaid on each other, to show a clear evolution of the structures around the salt diapirs.

These outputs enable prediction of potential reservoirs and hydrocarbon leakage through fluid pipes. This study helps to improve our understanding of salt-related faults and fractures.

Supervisor: *Jürgen Adam & Nicola Scarselli (RHUL)*

Data provided by: *PGS*

Gerardo Gaitan

Structural and kinematic evolution of the Dowsing Fault Zone, Southern North Sea

The NW-SE trending Dowsing Fault Zone (DFZ) is a prominent feature within the Southern North Sea and South Permian Basin. The Southern North Sea is a basin with a complex evolution and an established Permian sub-salt basin where plenty of research has been accomplished in the last 40 years due to new methodologies and the rapid growth of 3-D seismic data, which has opened up potential for new hydrocarbon discoveries. Using 3-D PGS mega survey seismic data, well correlation analyses and state-of-the-art analytical techniques, this project addresses the relatively poorly known DFZ, for which kinematic analysis is lacking at sub-regional to local scale.

This project assesses the style of deformation and linkage of the DFZ with supra-salt structures, thin- and thick-skinned deformation and the different styles of Triassic deformation controlled by salt tectonics. Special attention is given to the structural and kinematic evolution of the DFZ and its hydrocarbon prospectivity. Results suggest that the DFZ has been widely affected by regional tectonism augmented by salt mobilization and withdrawal within the DFZ, that precludes any type of hydrocarbon accumulation within anticlinal-structural traps. The novel aspect of this project is that it provides evidence of the initial timing of salt tectonics, evinces the type of linkage within the DFZ, discusses the relationship within sub- and supra-salt structures, and its hydrocarbon potential. It is proposed that salt halokinesis must have been active at Early Triassic levels, controlling the style of deformation of the supra-salt DFZ during Mesozoic and Cenozoic times.

Supervisor: *Jürgen Adam (RHUL); Stephen Morse (PGS)*

Data provided by: *PGS*

Afiqah Hamir

Seismic characterisation of sand injectites in the Cenozoic section of the central North Sea (Quad 15)

Sand injectites are a field of growing importance in exploration, particularly in mature basins such as the North Sea. Since their discovery in 1984 , their mechanism of emplacement and relationship to polygonal faults remains fairly vague. Sand injectites are interpreted as post-depositional features which are formed by chaotically distributed, unconsolidated, remobilized sands which are forced upwards through overlying impermeable layers typically during shallow burial. Triggering mechanisms for the development of sand injectites include overpressure, polygonal faults and seismicity to an extent. There is apparent evidence for a causative relationship between polygonal faults and the distribution of sand injectites. Overpressure is generated through the accommodation space created by a large extensional fault, creating a basinal low. The rapid deposition of the turbidite reservoir of the Sele Formation across the study area acts as a platform for the generation of the parent unit of the sand injectites, generating enough compaction for the generation of the overpressure conditions required for the sand injectites to develop. The polygonal faults which result from the compaction and dewatering of the overburden has then allowed for the release of overpressure, forming the discordant wing-like geometries that are observed in seismic. The copious amount of fluid contained within the system has further allowed for the remobilization of sands, which are also linked to the development of polygonal faults, thus, further enhancing the connectivity of the reservoir compartments. Existing sand injectite complexes within the North Sea such as Alba (Block 16/26a) and Gryphon (9/18b) have shown their significance and capability as an alternative reservoir which has improved production. The similarity in the geometry of the sand injectite complex with the neighbouring Alba Field provides the indication of UK Quadrant 15-16 as a highly prospective license block.

Supervisors: *Dan Le Heron & Jürgen Adam (RHUL); Steve Morse (PGS)*

Data provided by: *PGS*

Grandika Septia Primadani

Tectonostratigraphy of the Asri Basin, SE Sumatera, Indonesia: Unlocking the hidden potential of Oligo-Miocene reservoirs and implications for hydrocarbon prospectivity

The offshore SE Sumatera Production Sharing Contract has been one of the prime oil producing areas in Indonesia for the past 40 years. It has produced a total of 800 MMBOE with a capacity of 90,000 BOPD. It is located in the region of the Asri Basin which is in part of a series of Cenozoic half grabens, developed on the SE Asia continental margin, occupying a retro-arc setting since early Neogene times. This paper presents the results of an integrated structural and sequence stratigraphic approach using seismic, well logs and core data to build a tectonostratigraphic framework, and discusses its implication to the Oligo-Miocene reservoirs. Hydrocarbon prospectivity of the basin is assessed using near field exploration approach. The objectives of this study are to improve present geological understanding of the Asri basin (structural development, regional tectonic setting, sequence stratigraphy, palaeo-depositional environment), and hydrocarbon prospectivity of the basin. The history of the Asri basin is a typical rift-and-sag model. A fourfold division is proposed to explain its tectonic history and stratigraphy. It comprises 4 main tectonic phases: 1, rift initiation (Eocene); 2, rift climax (Oligocene-Early Miocene); 3, immediate post rift (Middle-Late Miocene); and 4, late-post rift (Pliocene-Pleistocene). The seismic expression of these kinematic units indicates a relationship between stages of basin evolution and their respective depositional products. The stratigraphic review covered a wide range of data, from seismic (3rd order), well log (4th order), and core data (5th order). A reasonably good quality of seismic data allows interpretation of seismic sequence boundaries and maximum flooding surfaces. This was done after a detailed well log analysis incorporated with core data in the interpretation of sequences and depositional environments. At least two potential play concepts in the Oligocene-Miocene interval have been identified: an alluvial fan play of tilted horst block and the basin margin slide mass. It is expected that these plays will open-up a new exploration opportunity in the Asri Basin.

Supervisors: *Ian M. Watkinson (RHUL); Heri Gunawan & Dwandari Ralanarkno (CNOOC SES, Ltd)*

Data provided by: *CNOOC SES, Ltd*

Richard Shelton

The prospectivity of the Gippsland Basin, offshore eastern Australia

The Latrobe Group clastics host all known hydrocarbon accumulations within the Gippsland Basin, offshore eastern Australia. Exploration efforts have traditionally been directed towards the Latrobe Group, however it is believed that the bulk of the commercial structural traps have now been drilled. Remaining reserves are now believed to reside in subtle traps and plays at the basin margins where deeper stratigraphy has been uplifted, and also within the deep to ultradeep-water reaches of the basin.

Both 3-D and 2-D data plus well data, covering the majority of the Gippsland Basin, is used to understand the distribution of Golden Beach and Earliest Latrobe reservoir facies within the deep-water, Eastern Graben area of the Gippsland Basin.

Sedimentation during the Late Cretaceous, a direct result of tectonic activity and marine incursion, had a profound effect on the margin physiography. The subsequent loading of the shelf edge is proposed to have initiated canyon formation and thus the development of sedimentary input points, feeding deep-water areas.

The distribution of potential reservoir facies within the Eastern Graben is determined through the completion of deep-water lithology prediction and a seismic facies analysis. Structural modelling constrained fault activity and demonstrated the effect of tectonism on sedimentation. Three depositional models were developed from these initial analyses, producing a detailed interpretation of the spatial and temporal evolution of deep-water deposition during the Late Cretaceous. The three play type models developed are:

- Mass floor fan systems
- Progradational slumping
- Sand-prone channel systems

This study aims to provide an understanding of the processes that affect the redistribution of sediments into deep water areas, specifically through the evolution of canyon systems.

Supervisors: *Ken McClay & Nicola Scarselli (RHUL); Mike Cottam (BP)*

Data provided by: *Geoscience Australia*

Adept Titu Eki

Neogene evolution of offshore eastern Sulawesi, Indonesia

Eastern Sulawesi is noted for its geologic complexity. Many hypotheses have been proposed to explain its deformation history and regional tectonic development, but it still remains a subject of controversy. Previous studies mostly focused on the geology on land, with little consideration of the geology offshore. Newly acquired 2-D seismic data and high quality multibeam bathymetry from offshore eastern Sulawesi provide an enhanced understanding of the area, and are used to present a summary of the deformation history and its implications for hydrocarbon exploration.

This study discovered very little evidence of thrusting and folding at the supposed collision zone between the Sula Spur promontory and the SE Asia margin. Significant evidence for collision is present on land in the East Arm only in the area of the Batui Thrust. Thrust faults offshore near the southern East Arm are localized deformation, and linked to the formation of the Banggai Basin. There is a good indication of linkage of the Tolo Thrust with the left-lateral Matano and Lawanopo strike-slip faults. Much of offshore eastern Sulawesi is dominated by extensional faults. These include the South-Sula Fault which is interpreted to have formed during rollback of subduction leading to the opening of the North Banda Sea. The ridges in the North Banda Sea show various orientation trends that may reflect deformation after the opening had ceased.

The Tomori Basin is a frontier basin in Eastern Indonesia, containing prolific hydrocarbon potential with some established oil and gas fields in the area. However, most of the exploration is limited to the shelf areas, whereas little attention has been made to the deeper parts of the basin. With the new understanding on the origin of the basin, this study introduces new petroleum play concepts including inversion faults associated with growth strata and carbonate platform reservoirs deeper in the offshore Tomori area. Hydrocarbon maturation is an issue.

Supervisor: *Robert Hall (RHUL)*

Data provided by: *PGS, TGS & GeoData Ventures Pte Ltd.*

Herwin Tiranda

Tectonostratigraphic evolution of offshore NW Sulawesi with implications for hydrocarbon prospectivity

The area of offshore NW Sulawesi lies between eastern Sundaland (Borneo) and the North Arm of Sulawesi. The origin and development of the basins in this area are still disputed. Possible influences on the basins include Paleogene rifting in the Celebes Sea and Makassar Strait, Neogene subsidence and uplift in Borneo, late Neogene subduction at the present day North Sulawesi Trench, and displacements related to the Palu-Koro strike-slip fault. Understanding the tectonostratigraphic evolution of offshore NW Sulawesi is critical to assessment of hydrocarbon prospects within the basins. This study presents the results of a structural and stratigraphic study offshore NW Sulawesi based on recently acquired 2-D seismic surveys and multibeam bathymetry. In this study the offshore NW Sulawesi region is divided into three parts: the Tarakan Deep Basin in the NW, the Muara Basin in the west, and separated from these by the Palu-Koro Fault, the NW Sulawesi Fold-Thrust belt in the east. There is no continuation of the left-lateral strike-slip Palu-Koro Fault to the adjacent area of Borneo via the Muara Basin and Tarakan Deep Basin. Both basins developed after extension began in the Middle Eocene associated with oceanic spreading in the Celebes Sea. Since then, sediment was fed to the basins from the east and south, with several episodes of subsidence, particularly during Early Miocene in the Muara Basin. Rapid prograding shelves from eastern Borneo are linked to regional inversion and uplift on land since the Middle Miocene and led to gravity-driven movement in the Tarakan Deep Basin which formed deep marine toe-thrust faults in the Late Miocene. Deformation in the NW Sulawesi Fold-Thrust belt is interpreted to have occurred in the Pliocene to present day with subduction at the North Sulawesi Trench and movement on the Palu-Koro Fault. Hydrocarbon indicators seen in seismic profiles suggest potential sources, reservoir, and traps in the Muara Basin and Tarakan Deep Basin. Potential plays includes Oligocene carbonates and Oligo-Miocene deep marine sandstones. Sealing capacity and timing of hydrocarbon generation due to complex deformation are the main risks.

Supervisor: *Robert Hall (RHUL)*

Data provided by: *PGS & GeoData Ventures Pte Ltd.*

Sophie Evans

Exploration potential of the southern Adriatic Sea Basin

The south-eastern Adriatic Sea is a largely unexplored area in terms of petroleum. 2-D seismic and well data from the Adriatic provides insights into the hydrocarbon systems and fault deformation mechanisms. The area is characterised by late orogenic NW-SE strike slip faults, which caused counter-clockwise rotation of earlier structures. Evidence of transpressional strike-slip fault activity includes positive flower structures, uplift of the hangingwall and disparities in anticline strike direction. Analysis of the regional structures using the 2-D seismic dataset revealed large-scale faulted structures with conflicting vertical offsets. Three causative mechanisms have been proposed with inversion of rift faults preferred. The other two mechanisms involve early normal faults which have been reactivated as reverse faults due to contraction, and older deeper thrusts linking to younger normal faults at shallower depths. By understanding the kinematic evolution of the faults of the offshore area, the structural relationship with sediment deposition was analysed from the Triassic to Recent. Present day tectonics show compressionally reactivated inverted Permian-Triassic faults, with active structures deforming late Quaternary deposits and generating areas of uplift, as seen from topographic relief of Islands. It is concluded that the evaluation of the dataset has enhanced the understanding of sedimentation and kinematic evolution of the offshore extent. 1-D basin modelling combined with geochemistry data has established a potential Triassic source rock, with plays focusing upon Jurassic and Cretaceous carbonate reservoirs.

Supervisors: *Ian M. Watkinson (RHUL); Raffaele Di Cuia , Angelo Ricciato, Stefano Borello (G.E.Plan Consulting)*

Data provided by: *G.E.Plan*

Zhi Lin Ng

Contourites in the Agios Konstantinos and Petra Tou Romiou sections, Lefkara and Pakhna Formations, Cyprus: Conceptual and economic considerations

Coeval units of the Tamar Sands gas reservoir (Oligo-Miocene) in the Levantine basin are found onshore Cyprus in Lefkara and Pakhna formations as one of the best examples described in literature on ancient bottom current deposits. This project focuses on the Late Oligocene to Early Miocene contourite deposits, where its distribution in the Eastern Mediterranean and implications to hydrocarbon exploration are not well understood. Following the three-stage approach for contourite identification, the sedimentary facies of the Late Oligocene to Early Miocene units for Agios Konstantinos and Petra Tou Romiou sections were observed and interpreted using macrofacies (outcrop) and microfacies (thin section) analyses. Outcrop correlation and onshore-to-offshore comparison were carried out to understand the depositional settings, palaeogeographic evolution, and the significance of bottom current in the region. The facies analysis shows coexistence of the three main deep-marine depositional processes, with contourite units distinguishable through its homogeneous texture with cyclical deposition, traction structures, and intense bioturbation. The fluctuation of bottom current intensity determine the facies-type deposits with a constant background pelagic settling, whereas influx of turbidity current from slope failure supplies sediment into the depocenter and further reworked by bottom current action. Offshore Cyprus, seismic analyses on the West Eratosthenes sub-basin show contourite drifts and their inferred bottom current action during the Late Oligocene and Early Miocene, identified from observed erosional and depositional features. Acting as an analogue for the onshore Cyprus sections, the influence of active margin tectonics in the region deformed and uplifted the sediments northward of the Cyprus Arc to its present location. The tectonism also increased diagenetic alteration which obliterated primary porosities in the sandy contourite deposits onshore Cyprus. However, the reservoir potential for contourite units could be prospective at localities with better porosity retained, complemented with excellent geometrical characteristic such as high net thickness and net-to-gross values.

Supervisors: *F. Javier Hernández-Molina (RHUL); Heiko Hüneke (Universität Greifswald, Germany)*

Data provided by: *Spectrum Geo Ltd. and Total S.A.*

George Peters

Evolution of extensional fault related structures in the Southern Lokichar Basin, Kenya

The South Lokichar Basin is an east facing half graben that is 60 km long, 30 km wide and has an area of 1200 km^2. It is located in the Northern Kenyan Rift, which is situated broadly in the middle of the 2200 km long eastern limb of the East African Rift System. The hangingwall is floored with crystalline Precambrian basement and has a 6-7 km Paleogene to Quaternary syn-rift fill of interbedded fluvio-deltaic to fluvio-lacustrine sediments, capped by basaltic flows. The basin is bounded by the N-S striking extensional Lokichar Fault. The fault and basin originally formed in the Oligo-Miocene by regional rifting events which allowed pre-existing basement weaknesses to reactivate and form several en-echelon configured half grabens. The segmented paleo-Lokichar Fault grew through periods of lower strain rates to form structures in its transfer zones known as relay ramps. These acted as conduits for E-W rivers to supply sediment into the basin. With increased strain, these relay ramps hard linked to form breached relay structures, while potentially affect drainage into the basin. Thus, the dominant drainage pathway switched from W-E to S-N in the mid-Miocene, allowing for mature and well sorted sediment to be transported into the basin by axial rivers. These linkage events correspond directly to periods of regional tectonic rifting across East Africa, which were in the mid-Miocene (σ3 = E-W) and the Plio-Pleistocene (σ3= NW-SE). A footwall entirely composed of basement and fault propagation folding of the hangingwall has created the perfect scenario for a hangingwall vs. basement trap to form. Coupled with good quality fluvio-deltaic reservoir and basin-wide lacustrine shales, formed by large paleo-lakes, a world class on-shore petroleum system has developed. Interpretation of 2-D seismic, semblance data, depth-structure-maps and isopach mapping was used to reconstruct the tectonostratigraphic evolution of the South Lokichar Basin and analyse fault geometries. Gravity & magnetics data and fault displacement models were utilised to pinpoint the location of the Lokichar Fault linkage zones. Hangingwall, footwall and dual breached relay ramps were characterised with 2-D seismic and their relative time of formation was assigned using onlapping syn-kinematic growth strata.

Supervisors: *Ken McClay & Nicola Scarselli (RHUL); Alex Orbell & Martin Insley (Tullow Oil)*

Data provided by: *Tullow Oil*