The 17th HGS-PESGB Conference on African E&P

Oral Presentations – Tuesday, September 11, 2018

7:30	**Registration and Coffee**	
8:15	Welcome and Opening Remarks: **Brian W. Horn**, *General Chair*	
8:20	**Session 1 Chairs: Paul Haryott,** *Rose & Associates* and **Brian W. Horn,** *ION*	
	Theme 1 - African Exploration in the Evolving Business Environment - Above Ground Risks and Rewards	
8:25	**Opening Keynote Address**	**Tim O'Hanlon** (Tullow)
8:50	The Golden Age of Super Basins - An African Perspective	**Charles Sternbach** (AAPG Past President)
9:15	Entering the Next Phase of the Oil Price Cycle: What It Means for E&P in Sub-Saharan Africa	**Emma Woodward** (Drilling Info)
9:40	**Coffee and Posters**	
10:00	**Theme 2 - New and Emerging Exploration Trendss**	
10:05	Why is Everyone Excited About the Sao Tome and Principe EEZ; the 4 Key Reasons Why This Has Been One of the Hottest Areas for Exploration in 2017	**Matt Tyrrell (**PGS), J. May, E. Mueller, O. D'Abreu
10:30	Compelling Evidence for Oil Offshore Angoche, Mozambique	**Neil Hodgson (**Spectrum), R. MacDonald, P. Hargereaves, K. Rodriguez
10:55	Chasing the TAGI Play into Morocco: Assessing the Contribution of Local Versus Regional Drainage Systems on the Character and Provenance of Upper Triassic Fluvial Deposits	**Jonathan Redfern** (University of Manchester), J. Lovell-Kennedy, J. Argent and J. Canning
11:20	Palaeozoic to Present: Assessing the Petroleum Potential of the Offshore Sirt Basin, Libya, Using Newly Reprocessed Regional-scale 2D Seismic Data	**Lisa Fullarton** (ION), E. C. A. C. Gillbard, K. G. McDermott, N. Clarke, P. Bellingham
11:45	**Special Session: Exploration in Africa Past, Present and Future – Keys to Exploration Success and Disaster Avoidance**	*Moderator:* **Paul Haryott (**Senior Assoc., Rose & Associates)
11:50	Exploration in Africa Past, Present and Future – A Historical Perspective	Bob Fryklund (IHS)
12:05	**Lunch and Special Session: Round Table Panel Discussion**	
	Exploration in Africa Past, Present and Future – Keys to Exploration Success and Disaster Avoidance *Moderator:* **Paul Haryott** (Senior Assoc., Rose & Associates) *Panel:* **Ernie Leyendecker** (former EVP Worldwide Exploration, Anadarko), **Bob Fryklund** (Chief Upstream Strategist, IHS), **Dorie McGuiness** (VP Geology, Kosmos), **Tim O'Hanlon** (VP African Business, Tullow)	
13:30	**Session 2 Chairs: Bill Dickson**, *DIGs* and **Bryan Cronin**, *Tullow Oil Ghana Ltd.*	
	Theme 2 - New and Emerging Exploration Trends (continued)	
13:35	Break-up Processes in the Presence of Plume Magmatism: New Insights into the Tectonostratigraphic Development and Petroleum Potential of the Austral South Atlantic	**Ken G. McDermott** (ION), E. C. A. C. Gillbard, P. Bellingham, B. W. Horn
14:00	The Austral South Atlantic: Early Formation and Crustal Structure of the Orange and Cape Basins	**Dale E. Bird** (Bird Geophysical), S. A. Hall, D. J. McLean, P. J. Towle, J. V. Grant, and H. A. Danque
14:25	Post-rift Potential Source Rock Correlations and Prospectivity of the Deep Atlantic Conjugate Margins South of the Walvis Ridge	**Ian Davison** (Earthmoves), Duncan Wallace
14:50	Offshore Somalia: Source Rock Identification in a Frontier Margin	**Neil Hodgson** (Spectrum), H. Kearns, K. Rodriguez, B. Allen, D. Paton, and A. Abiikar Hussein (Spectrum)
15:15	**Coffee and Posters**	
15:45	Hunting the SNE in Guinea Bissau	**Neil Hodgson** (Spectrum), A. Intawong, and K. Rodriguez
16:10	Gabon's Wild West Frontier Promises a Golden Age of Discovery for the Deep Offshore	**Tony Younis** (Impact Oil & Gas), M. Clutterbuck, P. Birch
16:35	Gabon Deep Offshore: New Petroleum System Insights from the Full Integration of Geology and Geophysics	**Rob Crossley** (CGG) and G. Duval
17:00	**Evening Reception**	

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Oral Presentations – Wednesday, September 12, 2018

8:00	**Registration and Coffee**	
8:30	**Session 3 Chairs: Ana Krueger,** *University of Houston* and **Onochie Okonkwo,** *Anadarko*	
	Theme 3 - Developing and Integrating Geological Concepts: Impact on Exploration in Africa	
8:35	Entrenched Slope Channel Complex Systems: Reservoir Opportunities Through Understanding Architectural Element Distribution and Application to West Africa E&P	**Bryan Cronin** (Tullow)
9:00	Towards the Development of an Integrated Central Atlantic Tectono-Stratigraphic Framework	**Max Casson** (University of Manchester), J. Redfern, L. G. Bulot, J. Jeremiah
9:25	Reservoir Modeling of a Deep-Water West African Reservoir: A Fully Integrated, Multi-Scenario Approach	**Monica Miley** (Anadarko), A. Dufournet, J. Villa, M. Bentley
9:50	Sedimentological Characteristics of Deepwater Sandstones Associated with Transgressive-Regressive Cycles Offshore Ghana	**Luisa Man** (CoreLab), Tom Wilson, Simon Greenfield
10:15	**Coffee and Posters**	
10:40	Magmatic Modification of African Crust: Implications for Strain Localization and Basin Subsidence	**Cynthia Ebinger,** SarahJaye Oliva, Ryan Gallacher (Tulane University)
11:05	An Animated Model for the Mesozoic-Recent Tectonic Evolution of Sub-Saharan Africa: From Plates And Structures to Basins and Paleogeography	**Jon Teasdale**, C. Reeves, (Geognostics International Limited, Earthworks BV)
11:30	Tracing the West and Central African Rift and Shear Systems Offshore onto Oceanic Crust: a "Rolling" Triple Junction	**William Dickson** (DIGs) and J. W. Granath
11:55	Influence of Proterozoic Heritage on Development of Rift Segments in the Equatorial Atlantic	**Ana Krueger** (University of Houston), M. Murphy, I. Norton, K. Casey, R. D. de Matos
12:20	**Lunch and Posters**	
13:45	**Session 4 Chairs: Luis Baez** *Shell* and **Ian Davison**, *Earthmoves*	
	Theme 4 - What We Thought We Knew: Exploration Concepts to Production Reality	
13:50	**Keynote** - The Evolution of the Pre-Salt Play in the Kwanza Benguela Basins, Angola	**Andrew Witt** (BP), A. Bump, T. Love and F. Setzer
14:15	A New Beginning: Remaining Potential and the Case for Investment in the Niger Delta	**Paul Bellingham** (ION), J. Deckelman, B. W. Horn
14:40	Play Fairway and Petroleum Systems Analysis of Nigeria's Cretaceous Benin (Dahomey) Basin: Key to Unlocking Additional Hydrocarbon Volumes from an Emerging Exploration Trend	**Olusanmi O. Emmanuel** (Acetop Energy), K. Taiwo, O. Mojisola and E. Enu
15:05	**Coffee and Posters**	
15:30	Jubilee Field: From World Class Exploration Discovery to Producing Asset. Learnings from 7 Years of Production	**Kathryn E. Dawson** (Tullow Ghana Ltd)
15:55	**Closing Keynote/Future Perspective** – Jubilee to Liza: Lessons From a Decade of Exploration in the Central Atlantic	**Keith Myers** (Westwood Energy), E. Zanella, J. Collard, H. Doran
16:20	**Awards and Closing Remarks**	

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Poster Session Agenda

Using Generative Adversarial Networks to Improve Deep Learning Fault Prediction Networks	**Matt Morris**, Ping Lu, *Anadarko*
South Gabon's Pre-Salt Revelation	**Neil Hodgson**, Karyan Rodriguez, *Spectrum Geo Multi-Client Seismic Imaging*
Data-Driven Transformation in Geology, Geophysics and Engineering	Mik Isernia, Paul Endresen, **Ana Krueger**, *Bluewarre, University of Houston*
Is Namibia Really an Oil Province?	**W. Wornardt**, *Micro-strat*
The influence of Shale Ridges on Reservoir Development and Implications for Exploration – A Case Study from Onshore Niger Delta, Nigeria	**Syed Dabeer,** Umar Ngala, *PetroVision*
Evolution of East African Rift System (EARS)	**Sadat Sembatya,** *Makerere University – Kampala, Uganda*
The Next Phase of Exploration in Sierra Leone: A Closer Look at the Basinward Cretaceous Plays in the Search for Improved Reservoir Quality	**Magenta McDougall**, *African Petroleum*
An Atlas of Character: A Model For the Control of Passive Margin Development	**Neil Hodgson,** and K. Rodriguez, *Spectrum Geo*
Visualization of Vertical Hydrocarbon Migration Pathways in Seismic Data: Toward the Quantification of Seal and Charge Risk for African Exploration Plays	**David Connolly,** *dGB Earth Sciences USA*
JMA – The Hidden Treasure Below the Basalt	**Neil Hodgson,** K. Rodriguez, J. Watson, *Spectrum Geo*
Hidden Boundary Fault at East African Rift Basin Revealed with FALCON© Airborne Gravity Gradiometry Data	Janine Weber, Ivonne M, Araujo, **R. Yalamanchili,** S. Maduhu, *CGG Multi-Physics, TPDC*
Enhancing Gas Production in Nigeria's Marginal Field. A Case Study of Ughelli-X Field	Kemi Taiwo, O. O. Emmanuel, O. Aworanti, T. Ologun and U. Olorunmola, *ND Western Limited, Acetop Energy*
Cape Fold Belt Fractured Basement Play Fairway	Neil Hodgson, K. Rodriguez, and H. Kearns, *Spectrum Geo*
The Underexplored Shelf-Edge Plays of the West Africa Transform Margin and the Opportunity to De-Risk These on Merged 3D Seismic and Well Datasets Through Togo, Benin and Western Nigeria	Matt Tyrrell, M. Martin, A. Ashfield, A. Maioli and B. Biaou, *PGS, Société Béninoise des Hydrocarbures (Sobeh)*
Hydrocarbon Potential of the Onshore Dahomey Embayment of Benin; Exploration of Devonian, Jurassic, Cretaceous and Tertiary Plays Using Integrated Seismic and High Resolution Airborne Gravity and Magnetic Data	Emma Tyrrell, P. Elliot and M. Lofgran, *Elephant Oil Ltd*
Conjugate Margin Chronostratigraphy – Comparison of Cretaceous-Tertiary Petroleum Systems in Namibia and Uruguay	Katie-Joe McDonough, K. Reuber, B. W. Horn, K. G. McDermott, E. C. Gillbard, F. Brouwer, *KJM Consulting, Pine, ION, 3 GEO*
Regional Reservoir Quality Trands in Cretaceous Sandstone Reservoirs in the Transform Margin Basins of Ghana	**Simon Greenfield**, Dr. P. Cox, *Core Laboratories UK*
Using Broadband 3D Seismic to Validate and Upgrade Satellite Seepage Data, Gabon	**Rowan Edwards**, M. King and G. Duval, *CGG*

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Student Poster Session Agenda

3-D Crustal Model of Northwest Africa	Naila Dowla, Dale Bird, Mike Murphy, Janusz Grebowicz, *University of Houston*
Geometry and Kinematics of Seismically Active Border and Transfer Fault Systems in the Malawi Rift, Africa	Pham, T.Q., C. Ebinger, S. Oliva, K. Peterson, P. Chindandali, D. Shillington, *Tulane University*
Comparing Controls on the Formation of 27 Passive Margin Fold-belts from the Margins of the Gulf of Mexico, South Atlantic and Africa	Malik Muhammad Alam, *University of Houston*
Compilation of Widespread, Cretaceous OAE1, OAE2, and OAE3 Black Shale Horizons Documented in Wells from the Gulf of Mexico, Caribbean, and Atlantic Passive Margins	Nikola Bjelica, *University of Houston*
New Insights into the Assembly and Breakup of Pangea from a Mega-regional Compilation of 8,672 Detrital Zircon Ages from the Circum-Gulf of Mexico, Northern South America, and West Africa	Marie-Nelsy Kouassi, Paul Mann, Joel Saylor, Kurt Sundell, *University of Houston*
Constraints on Central Atlantic Rrifting Based on a Compilation of Low-temperature Thermochronology Ages from Rifted, Conjugate Margins of the East Coast of the USA and Northwestern Africa	Geraldine Tijerina, *University of Houston*
Is Africa Stationary? —A New Look at an Old Question	Daniel Woodworth, Chengzu Wang, Nuhazein Mohamed and Richard G. Gordon, *Rice University*
Rift History of the South Atlantic Ocean from Subsidence Histories of Offshore Wells and Low-temperature Thermochronology (AFT) Cooling Ages from the South American and West African Conjugate Margins	Omar Zavala, *University of Houston*
Plate Tectonic Framework for Petroleum Systems of Atlantic Conjugate Margins: Northwest Africa-Eastern USA and Northeast South America-Equatorial West Africa	Marcus P. Zinecker, Paul Mann, *University of Houston*
Application of Raman Spectroscopy for Determination of Natural Gas Composition	Johnathan Torres, Sage Muttel, Dougles Syzdek, S, Nagy, Janusz Grebowicz, *AGH University of Science and Technology; University of Houston- Downtown*

Notes

Oral Presentations
Day One

Abstracts

September 10-13, 2018
Norris Convention Centre, Houston Texas

Tuesday, September 11 | Opening Keynote Address | 8:25

Tim O'Hanlon

Tullow Oil

Tim O'Hanlon is from Ireland. As a young Reservoir Engineer fresh from Imperial College London, he joined Ireland's brand new start-up, Tullow Oil, in the mid 1980's. He has been with this very exciting and ambitious company ever since, living in Africa for many years.

More recently as Vice President African Business, or Tullow's *Mr Africa*, Tim has helped to drive Tullow's rapid expansion on the Mother Continent. Whether it is targeting new company acquisitions in Africa, chasing new ventures or mending fences in the many African countries where Tullow operates, you can be sure that Tim's fingerprints can be found on the files.

Charles A. Sternbach
President of AAPG (2017/2018)

The Golden Age of Super Basins An African Perspective

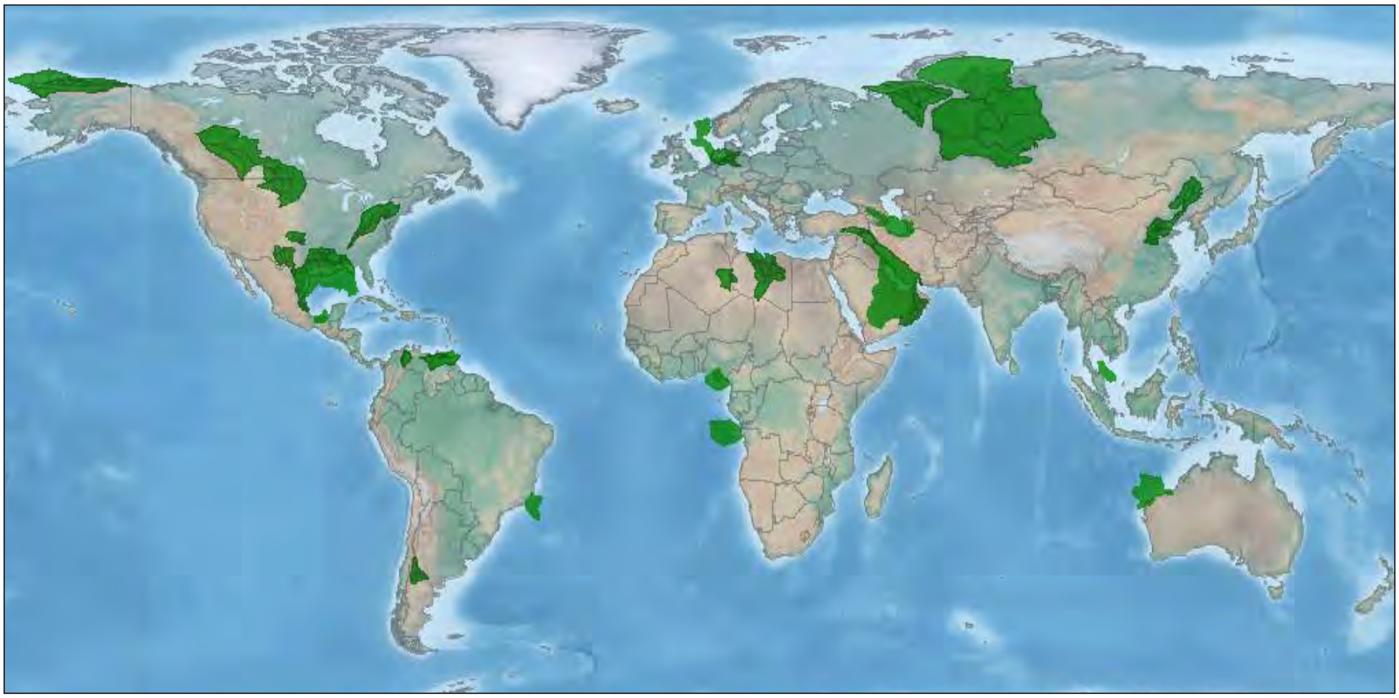


Figure 1. Map of top 25 super basins, (courtesy IHS_Markit)

Building on the success of AAPG Discovery Thinking (individual game changing discoveries) and Playmaker Forums (exploration plays), we are up-scaling our efforts to the basin scale and total petroleum system of the world's most petroliferous basins. The introduction of the Global Super Basin Leadership Conference in March in Houston provided the opportunity to share best practices among the world's greatest basins. AAPG plans to advance our mission to deliver science and professionalism through multimedia presentations, a new initiative to publish papers on super basins in the *AAPG Bulletin*, and other events.

Super Basin Anatomy

Many Super Basins were thought to be on their way out of sustainable production. Key enablers that have made possible old basins reaching new production peaks include hydraulic fracturing in horizontal wells and enhanced seismic imaging. Each basin has unique geoscience architecture. A common scheme includes multiple rich source rocks located beneath thick sedimentary packages containing many reservoirs and seals.

Onshore basins like the Permian are dominated by perfecting multi-lateral multi-directional drilling, finding the right fluid mix, varying hydraulic fracture stages, proppant materials, and well length in the realization of unconventional resources. These basins are benefiting from multi generations of engineering refinements and breakthroughs.

Other basins, many offshore, are benefiting from improved seismic imaging to unlock deeper or hidden basins, sedimentary packages previously obscured for various reasons. Many of the new resources are being found below salt or around basement highs. Examples include GOM, Brazil, and the European North Sea. Some basins benefit from both engineering and seismic. In all cases, understanding the geoscience architecture is key to success. Many super basins in Africa need further study.

The AAPG Bulletin Initiative

The *AAPG Bulletin* introduces a new initiative for its second century – the super basin series. The inaugural publication features an overview of the super basin concept by Bob Fryklund and Pete Stark (IHS_Markit). AAPG plans to roll out new super basin papers regularly in the months ahead. Together with the AAPG Editor, Barry J. Katz, our plan is to build a legacy of foundational papers of the world's top petroliferous areas that continue to produce prodigious amounts of energy (**Figure 1**). We anticipate that these papers will be revisited as a valuable resource in the years and decades ahead. The authors of these papers will be invited and acknowledged for their expertise in their particular basin or region. It is also envisioned that super basins will be an important component of AAPG conferences and technical events.

These publications will show the importance of geoscience as these basins continue to have new life breathed into them by innovative geoscientists using new technology, and how rocks tell the story. This series will frame the geoscience architecture of the world's most petroliferous basins including an understanding of their petroleum systems, richness, distribution, and position in the stratigraphic column of the source rocks and their maturity and an appreciation of the reservoirs, seals, and structural configuration. For example, the Permian Basin will be included in this series. It is endowed with multiple rich source rocks (Simpson, Woodford, Barnett, and Permian/Pennsylvanian) deep within the sedimentary section that contains many reservoir seal pairs, all within the oil and gas window, a shallow regional evaporite seal and a structural evolution that prevents leakage to the surface, abundant surface infrastructure, open access to mineral rights, and favorable regulation.

"Petroleum Provinces of the Twenty-first Century" (Marlan Downey, Jack Threet, and William Morgan 2001) AAPG Memoir 74, was a landmark publication for frontier exploration. The super basins concept is a dramatically different focus in a return to established mature basins, where resources are known to be present, and will be a key resource for tomorrow's oil and gas supplies.

Super basins, as defined by Fryklund and Stark, are established producers with at least 5 billion boe produced and 5 billion boe remaining recoverable, two or more petroleum systems or source rocks, stacked reservoirs, existing infrastructure / oil field services, and access to markets. Horizontal drilling and multi-staged horizontal fracturing and their unconventional resource potential are driving the onshore super basin renaissance. Improved seismic imaging, particularly below salt (or obscurred layers), is driving offshore super basins rejuvenation. The Permian Basin, Gulf of Mexico, and Middle East basins are prototype oil and gas prone super basins.

Energy is where you find it. In many cases, the most promising reserves for today and tomorrow are in areas that have long been productive. The total petroleum systems concept guides our approach. Much has been said and written about peak oil. Peak oil is a concept defined by a population of energy accumulations known, detectable, and producible at a particular time and place. When there are "multiple" peaks to a basin historical hydrocarbon production, each peak represents new technology and ideas that resurrect a maturing or declining petroleum province. Many of the super basins that will be featured in this series discuss basins that only recently were thought to be played out but are now experiencing production peaks and in some cases exceeding production peaks of previous decades, such as in the Permian basin. The super basin series will also discuss the new technology driving this rejuvenation and the sharing of best practices of these new technologies that can be applied in various super basins.

Topics the papers will address include:

- What makes a super basin special and unique and what can we learn from them?
- What are the critical geoscience elements that contribute to success?
- What is the exploration/ production history, and what are the major plays with remaining potential - conventional, unconventional, and field growth.
- What are key innovations in each super basin like: adoption of horizontal drilling, hydraulic stimulation, completion and drilling techniques, and seismic imaging that helped unlock the potential, and what is needed to grow it further?
- How do "above ground" issues like politics, access, mineral ownership, and geography influence realizing the full resource potential of each super basin?
- Will the basin be a regional or global disrupter?

In addition to their geologic energy endowment, super basins have large scale and infrastructure to incubate new technology. Technology nurtured and proven in super basins has great relevance and application to basins of all sizes. Thus, super basin papers will have widespread value to energy producers not just in super basins. Super basins are creating valuable contributions to our energy, economy, and environment. We will continue to enjoy abundant and affordable energy due to super basins. In addition, super basins will have a great impact on sustainability, security, and geopolitical factors.

We believe that:

1. our energy industry has made major contributions to global prosperity
2. this prosperity will grow far into the future,
3. professional societies will continue to play a key role in preparing men and women to provide this energy and prosperity long into our next century.

Thus, we begin the super basins initiative.

Biographical Sketch

Charles A. Sternbach has explored for and discovered Energy in the US and around the globe for 35 years. He was Staff Geologist for Shell Oil Company, Exploration Manager for Tom Jordan (Jordan Oil and Gas), President of First Place Energy (International frontier exploration) and is currently President of Star Creek Energy. Charles has a PhD (and MS) in Geology from Rensselaer Polytechnic Institute and a BA in geology from Columbia University. He is also proudly a member of AAPG since 1980.

Charles has focused his efforts on Exploration Creativity, studying how explorers and their teams have found giant fields. He created and leads the popular AAPG Discovery Thinking Forums which have been standing room only events at annual AAPG conventions in North America (ACE) and around the world (ICE). These impactful programs integrate geology, geophysics, and engineering into case studies of business success. There have been 19 Discovery Thinking Forums since 2008 with about 10,000 attendees. About 115 speakers have permitted their video presentations to be posted on the AAPG Search and Discovery Website with 40,000 viewings around the globe.

In addition, Charles created the AAPG Playmaker program in 2012. These immersive 1-day forums on exploration creativity have been presented 10 times in the US, Canada, and Europe. More than 1,500 professionals have attended and presentations have received 10,000 web views around the world. More of these forums are planned.

Charles believes case histories of successful explorers and their discoveries is a shortcut to wisdom. Every geologist around the globe raises the level of collective intelligence for all by sharing information and techniques. Critical insights fall into patterns that can be recognized and anticipated. The legacy of exploration literature forms a syllabus for future explorers. Technology enables preservation and communication of critical knowledge via the internet through programs like Search and Discovery, Datapages, and GIS spatial related databases. Prior to founding the Discovery Thinking forums, Charles founded the HGS Legends programs (as HGS president in 2000). He is a co-editor with Dr. Robert Merrill on the fifth installment of the AAPG memoir series Giant Fields of the Decade 2000-2010 (Memoir 113).

Charles resides in Houston, Texas. His wife Linda is also a distinguished geophysical advisor. Charles is a leader in the global geological community: president-elect AAPG, past president Gulf Coast Association of Geological Societies, past president Houston Geological Society, and past president of AAPG's Division of Professional Affairs. He is an Honorary Member of AAPG, HGS, GCAGS, and DPA.

Tuesday, September 11 | Theme 1 | 9:15

Emma Woodward
Regional Manager – East, West & South Africa, DrillingInfo

Entering the Next Phase of the Oil Price Cycle: What it means for E&P in Sub-Saharan Africa

After several years of industry downturn it appears we are finally entering into the next phase of the oil price cycle. At the time of writing (March 2018), oil prices have stabilised at US$60-70/bo and most oil companies have either managed to successfully reduce their operational costs and budgets, or have gone under. However, service costs remain low, meaning it's an ideal time for companies with a healthy balance sheet to be undertaking new exploration and development programmes. Renewed optimism in the industry has resulted in a significant uptick in the number of awards, acquisitions, and farm-ins being made. This has been predominantly driven by the majors and supermajors, but independents will follow. A corresponding increase in the amount of seismic shot and number of exploration wells drilled is now expected, particularly through 2019. Long-delayed field development plans are also finally moving forwards again. This will provide much needed relief for seismic and rig contractors.

In Sub-Saharan Africa, recent operations have generally been focussed in offshore West Africa, both in emerging basins such as the MSGBC (Mauritania-Senegal-Gambia-Bissau-Conarky), but also in more mature basins such as in Nigeria, Gabon, and Angola. East Africa has lagged behind the recovery.

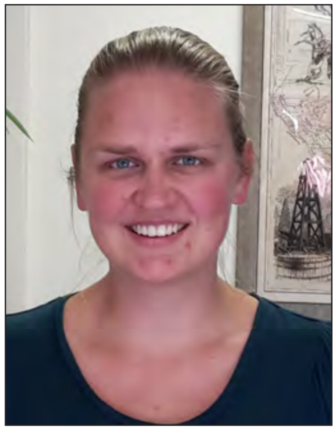
The MSGBC Basin has been one of just a handful of global exploration hotspots to have emerged since 2014, and supermajors such as ExxonMobil, BP, and Total, as well as Asian NOC's CNOOC and PETRONAS have worked hard to establish a footprint. The first mover advantage has now long gone, and for smaller independents looking for a slice of the pie the only remaining opportunities may be in Guinea-Bissau, historically seen as a riskier place to operate.

Nigeria remains the largest producer in Sub-Saharan Africa, and as a result has severely suffered economically through the downturn. It has also suffered serious security problems: offshore piracy, militant attacks in the Niger Delta, and Boko Haram activity in its northern provinces (where NNPC is trying to kickstart a frontier exploration programme). Uncertainty over the fiscal regime has also not helped the E&P outlook. However, the situation is changing, with parts of the Petroleum Industries Bill being passed in Parliament, and militant activity being curbed from its 2016 peaks. The government has signed a deal for new offshore multi-client seismic to take place, in preparation for a future offshore licensing round, for which there has been significant interest. All legislative issues will need to be resolved before this can be launched. There is also a renewed sense of optimism surrounding Angola, where there have been signs that the government is willing to incentivise investment again, with new tax deals being signed with both producers and explorers. Whilst it is unlikely companies will re-enter the deepwater Kwanza Basin in the near future, much interest has been generated in the ultra-deepwater Lower Congo Basin.

E&P activity has also been increasing in Ghana, Cote d'Ivoire, Equatorial Guinea, Sao Tome & Principe, Gabon, Namibia, and South Africa. However, operations in East Africa have so far remained depressed. This is in part due to the inability of governments to move quickly: with drawn-out decisions over infrastructure (for example the East African Crude Oil Pipeline and the onshore LNG plant in Tanzania) and the delayed ratification of new awards (most notable in Tanzania and Mozambique) leading to companies losing interest or changing operational strategy; Additionally, companies appear less keen to invest in gas-prone basins, due to the longer-lead times to production, distance to markets, and in some cases lack of clarity surrounding fiscal terms for gas. Many geologically attractive areas onshore East Africa are also far from possible markets, resulting in the need for substantial investment in infrastructure prior to first production. But plenty of opportunities remain, and with the right incentives companies will be attracted back to the region.

This presentation will look at some of the main E&P events of 2018, and will look forward to what Drillinginfo expects to take place through 2019 and beyond across key countries in Sub-Saharan Africa. There will be particular focus on major legislative changes and other above ground risks, key asset transactions, licensing rounds and awards, discoveries made, important future wells, significant upcoming field development plans, and options for gas utilisation.

Biographical Sketch



Emma Woodward graduated from the University of Cambridge in 2012 with a BA in Natural Sciences and an MSci in Geological Sciences. She has been working at DrillingInfo since June 2013 and is currently the Regional Manager for West, East & Southern Africa. Prior to working at DrillingInfo, Emma completed a petroleum geology internship at BP.

Tuesday, September 11 | Theme 2 | 10:05
Matt Tyrrell, Joshua May, Eric Mueller
PGS
Ovsvaldo D'Abreu
National Petroleum Agency of São Tomé & Príncipe (ANP-STP)

Why is Everyone Excited About the Sao Tome and Principe EEZ; the 4 Key Reasons Why This Has Been One of the Hottest Areas for Exploration in 2017

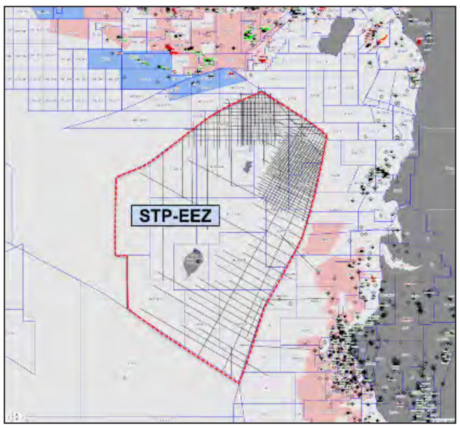


Figure 1. Basemap showing the multiclient seismic datasets that span from the Niger Delta, through STP-EEZ to North Gabon Basin.

Introduction

The São Tomé and Príncipe Exclusive Economic Zone (STP-EEZ) lies within the heart of a successful petroleum neighborhood that in recent years has been the subject of significant attention from major oil companies scrutinizing the available multiclient datasets, and applying for exploration licenses over multiple open blocks.

With a large multiclient seismic and well data library that reveals the subsurface geology of the Niger Delta (Figure 1), the distal parts of the Douala and Rio Muni Basins, and the North Gabon Basin, PGS has conducted interpretation work to unravel the prospectivity story and explain the recent excitement that the industry has experienced over the STP-EEZ.

Fitting into the regional geological picture

The STP-EEZ is bounded to the north by the Niger Delta with its prolific Tertiary deltaic petroleum systems, to the east by Equatorial Guinea and Cameroon where the Rio Muni and Douala basins have witnessed exploration success in Cretaceous plays, and to the south by Gabon, the northernmost Aptian salt basin with associated halokinetic plays and discoveries.

Exploration work conducted by PGS has sought to delineate the tectonic history and the nature of the crustal basement by calibrating both shipborne and public gravity data with multiclient 2D seismic data interpretations, and then to use these results as input and calibration for basin models to constrain source rock maturity and expulsion modelling.

The four key reasons why the Săo Tomé and Príncipe Exclusive Economic Zone (STP-EEZ) have been one of the hottest exploration areas of 2017

1. **Continental and transition crust provides source and structure:**
   Historic geological interpretations have predicted that the outboard waters of the southern Gulf of Guinea, including the Niger Delta, are underpinned by oceanic crust. Modern long-offset seismic data and its application in the calibration of gravity data, has resulted in revised crustal models that suggest these outboard areas contain a mélange of continental, transitional, and oceanic crustal types controlled by transform fracture zones. These revised crustal models have alerted oil companies to the potential for syn-kinematic sediment fills that can provide restricted marine source rock deposits and accompanying structural plays.
2. **Sub-Akata Shale plays in the distal parts of the Niger Delta:**
   In the Niger Delta, historic exploration efforts have concentrated on thick Tertiary siliciclastic reservoirs charged by the underlying Akata Shale source rock. An exciting new play concept, that has captured the recent attentions of operators and explorers alike, is within the sub-Akata sedimentary succession of the distal or outboard parts of the Niger Delta, where a thinned Tertiary succession (and thus reduced overburden to the Akata Shale) lies atop continental or transitional crusts. This play that is yet untested, models syn-kinematic sediment fills to contain source rocks that are mature for oil that has charged pre-Akata reservoirs with hydrocarbons trapping beneath the Akata Shale.
   Towards the south, this play continues into and is directly correlatable to the tectonic and sedimentary successions of STP-EEZ.

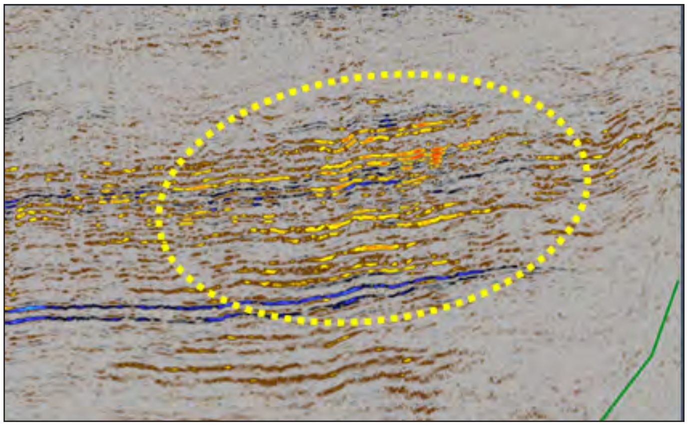


Figure 2. AVO analysis highlights anomalies in sands associated with transform fracture zone structures.

3. **Thick clastic sedimentary successions fed from long-lived fluvial systems:**
   Within the Doula Basin, the long-lived fluvial systems of Cameroon and Equatorial Guinea such as the Sanaga River and the Rio Del Rey River, which are understood to have historic roots in the Cretaceous period, have resulted in thicker Upper Cretaceous and Tertiary sediment successions. To the south, the Ogooué River of Gabon is present day the fourth largest river in Africa and again has a long-lived history, shedding large volumes of clastic sediments into the North Gabon Basin. Located within the heart of the southern Gulf of Guinea, the waters of STP-EEZ have received the distal outputs of all four of these fluvial systems resulting in a thick succession of well-sorted, distal fluvial outflow sediments with varying points of input (**Figure 2**).
4. **Basin Modelling studies suggest that Cretaceous, syn-kinematic sediment fills are mature for oil:**
   The revised crustal models and new sub-Akata play concepts of the outboard Niger Delta, together with temperature data from wells within the vicinity, have provided input for a recent basin modelling study undertaken by PGS (**Figure 2**). The study has modelled numerous pseudowell locations in STP-EEZ with the results showing that both the syn-kinematic sediments and the early post-kinematic sediments (Cenomanian-Turonian) are mature for oil, and are able to have charged the multiple sandstone reservoirs of the Tertiary succession.

Conclusions

The recent excitement that the industry has experience over STP-EEZ has its roots it recent advances in the understanding of the petroleum stories of the deepwater Niger Delta and the Northern Gabon Basin. As exploration advances and wells are planned, it may only be a matter of time before we see the fruits that these new play concepts may bear.

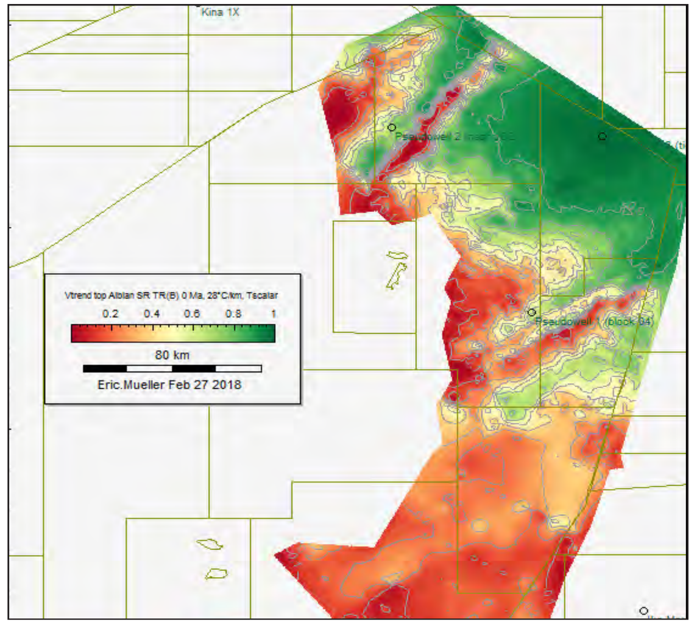


Figure 3. Results of Basin Modelling work show that maturity trends follow major fracture zones.

Biographical Sketch

Matt Tyrrell attained an MSc in Petroleum Geoscience from Oxford Brookes University before joining Fugro-Aperia as an engineer, then Aceca as a Geologist focused on North Sea stratigraphy. He joined TGS in 2006 where he was responsible for geoscience interpretation in Canada and Brazil, before joining the TGS Africa group as Lead Geologist where he worked on new ventures and interpretation projects focused on East and West Africa. Matt joined PGS in 2015 as Principal Geologist for Africa where he works on geoscience and business development tasks in West Africa, with a focus on Cote d'Ivoire, Benin, Congo, and Angola.

Matt is a principal geoscientist and project developer with over 18 years of industry experience. Responsible for delivering exploration opportunities to clients through an understanding of geoscience, project development, business development, and both client and Ministry relationships. He is responsible for developing, scoping, and delivering integrated geoscience studies that provide our clients with exploration opportunities

Tuesday, September 11 | Theme 2 | 10:30
Neil Hodgson, Robert MacDonald, Phillip Hargereaves, Karyna Rodriguez
Spectrum Geo, United Kingdom
+44 1483 730201, neil.hodgson@spectrumgeo.com

Compelling Evidence for Oil Offshore Angoche, Mozambique

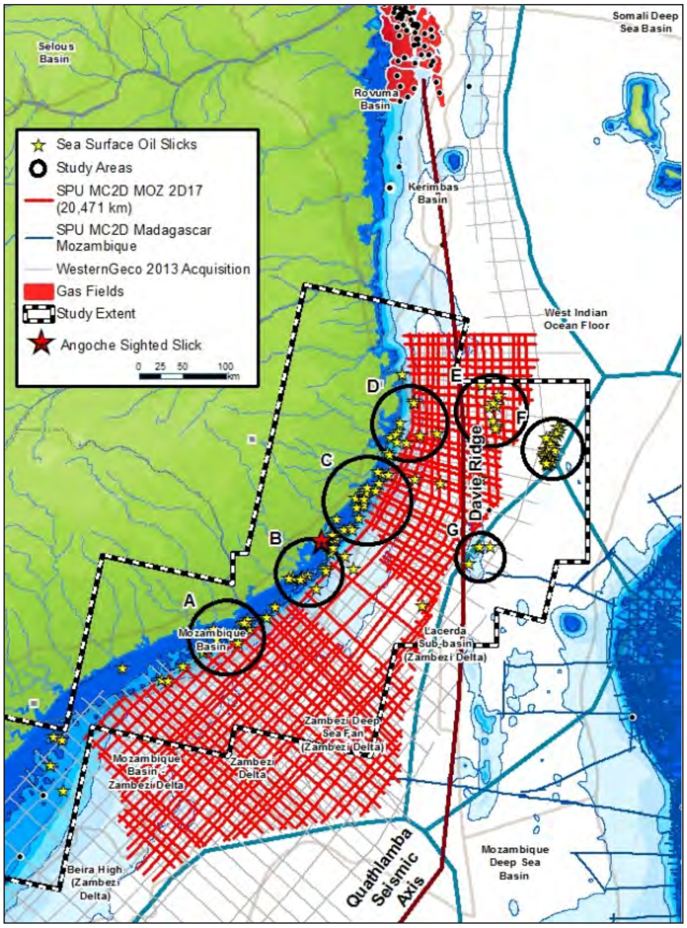


Figure 1. Regional Map showing analysis locations

Introduction

The Rovuma Basin in northern Mozambique is a a well-established world-class gas province with over 100 TCF of gas discovered so far. The rest of the Mozambique margin remains unexplored with most oil companies trying to find the big oil prize. Spectrum is acquiring a 2D regional seismic grid designed to image the subsurface potential in the southern Rovuma Basin and the NE Zambezi Delta (Angoche) region, providing a more detailed understanding of the prospectivity where no wells have been drilled to date. Potential targets along the Mozambique margin have already been identified in both structural and stratigraphic trapping geometries. Several potential source, reservoir, and seal intervals have also been identified with Cretaceous and Tertiary play types including onlaps and drapes over basement highs, stratigraphic and structural traps of deep water slope channel and basin floor fan complexes, lowstand plays (both wedge and pro-delta fan), syn-rift graben hanging wall and footwall plays, and strike slip structural plays. Enhanced clastic reservoir quality is expected from turbidite systems interacting with strong drift currents which are known to winnow turbidite channels leaving behind reservoirs of exceptional quality such as the Lower Grudja formation, a recognized significant reservoir target, with sandstones exhibiting porosities up to 34% and permeabilities up to 5,000 mD. Recent understanding of the influence of active rifting and mantle plume activity causing elevated heat flow in the northern Rovuma Basin, has explained the anomalously high geothermal gradient in that area which has resulted in significant gas generation. Spectrum's acquisition area, east of the Zambezi and south of the Rovuma, is far from rifting and mantle plume activity such that geothermal gradients are lower and so the main potential source rocks are modelled to be generating oil, as supported by onshore oil seeps.

Methodolgy

Two hundred forty two optical satellite images covering the central Mozambique offshore have been examined for evidence of oil floating on the surface of the sea. These sea surface slicks, when appearing in persistent clusters can be indicative of a working subsurface hydrocarbon system. The principle takes advantage of the difference in surface texture between a natural sea surface and an oil slick floating on top of the sea. In suitable conditions the sea surface is slightly rougher than the oil slicks; sunlight reflects off the slick in a different direction than the sea and this is captured by the satellite image [1]. Distinguishing between pollution and naturally occuring slicks is critical. By looking for locations with persistently occuring slicks (i.e. found in images of different dates) forming a cluster over time we can rule out random pollution events and be confident that the oils are indicative of a naturally occuring thermogenic oil source.

Oil Seep Observations

In total 120 sea surface slicks were identified in the interest area, some comprised of clusters re-occuring over time. The majority follow the continental shelf edge along the East coast of Mozambique. Sedimentary facies from the Mozambique channel generally dip gently upwards towards the shelf edge, so it is thought that a mature oil source in the centre of the basin is responsible, with hydrocarbons migrating upwards and Westwards towards the mozambique coast. There is a very

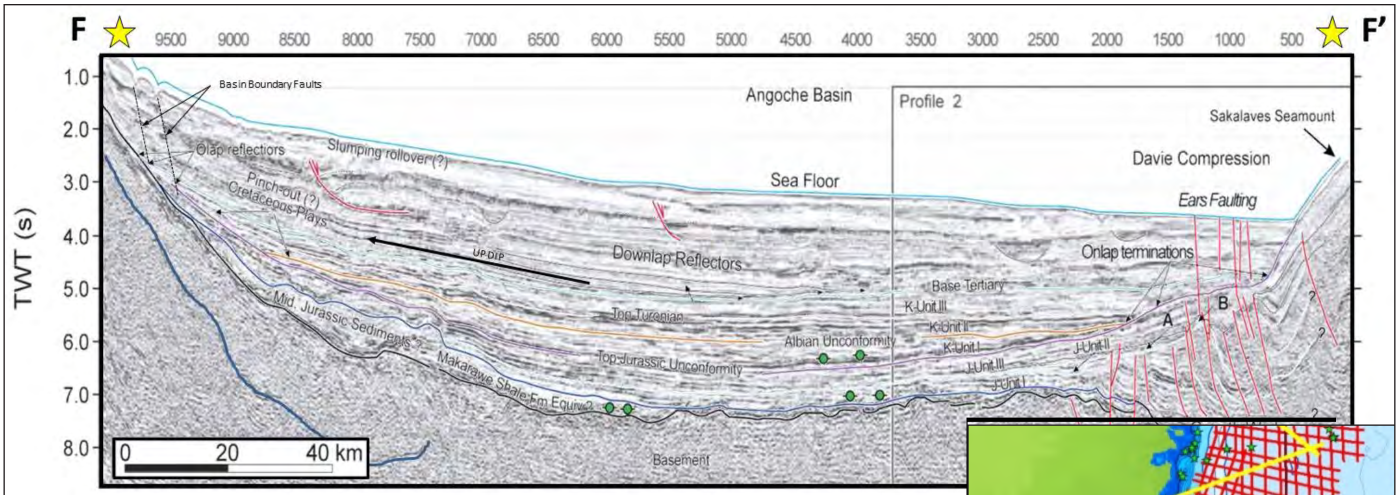


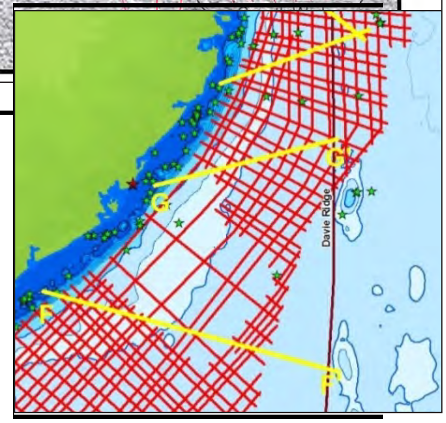
Figure 2 : Example Seismic Line F [2]

prominent cluster of slicks in the region of Angoche Island. Observed on images from several different dates, these slicks are also located away from the predominant marine routes. They are evident near the onshore location slicks also identified at Angoche. Some trends have been observed in deeper water, 185 km from the Mozambique coast. Image availability is much lower here, so identifying repeating trends is more difficult. However, a large number of high confidence oil slicks are observed from a single image, grouped together over a 10km area, away from shipping routes (**Figure 2**, location E). This unusual distribution of oil slicks appears in correlation with the Grandidier seamount. Two similar groups of slicks are observed (**Figure 1**, locations E & G)

Oil Seep Analysis

The distribution and re-occurrence of the slicks convincingly indicates that there is or has been a mature oil source in the Mozambique Channel. Persistently occuring oil slicks in correlation with the basin edge from the north to the south of the study area indicate that the source rock is present throughout the channel rather than focused in smaller sub basins.

Looking at the some of the available seismic (e.g. **Figure 2**) it is easy to see why slicks may be focused at this point. The basin geology dips upwards and westwards towards the edge of the basin. At least three source have been proposed in the basin, from Late Triassic Karoo to sources in the mid Jurassic. The Triassic and Albian strata move up dip towards the shelf edge so could well explain the assemblage of seeps found there but the Cretaceous plays pinch out further offshore. These strata pinching out could explain the sea surface slicks that were not part of the main clusters. The DFZ is up dip of the potential Triassic source rocks and between the source and the Grandidier seamount are a series of onlap terminations, fractured and faulted. These provide ideal conduits for hydrocarbons to migrate updip and escape through the above geology.



Conclusions

The distribution and re-occurrence of the slicks provides strong evidence that there is or has been a mature oil source in the Mozambique Channel. Slicks along the entire shelf edge and around several bathymetric highs in the study area suggest that the source is regionally prolific.The distribution does not allow us to isolate the age of the hydrocarbon source rock; but three possible source rock intervals have been proposed, from the Late Triassic (Karoo) and Mid Jurassic. New 2D data will play a key role in refining our understanding of the hydrocarbon potential of the area and accelerate hydrocarbon exploration activity in what is believed to be an oil-dominated region with exceptional quality reservoirs.

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Tuesday, September 11 | Theme 2 | 10:55
Jonathan Redfern, James Lovell-Kennedy
North Africa Research Group, School of Earth and Environmental Science, Manchester, UK
John Argent and Jason Canning
Sound Energy PLC, Sevenoaks, UK

Chasing the TAGI Play into Morocco: Assessing the Contribution of Local Versus Regional Drainage Systems on the Character and Provenance of Upper Triassic Fluvial Deposits

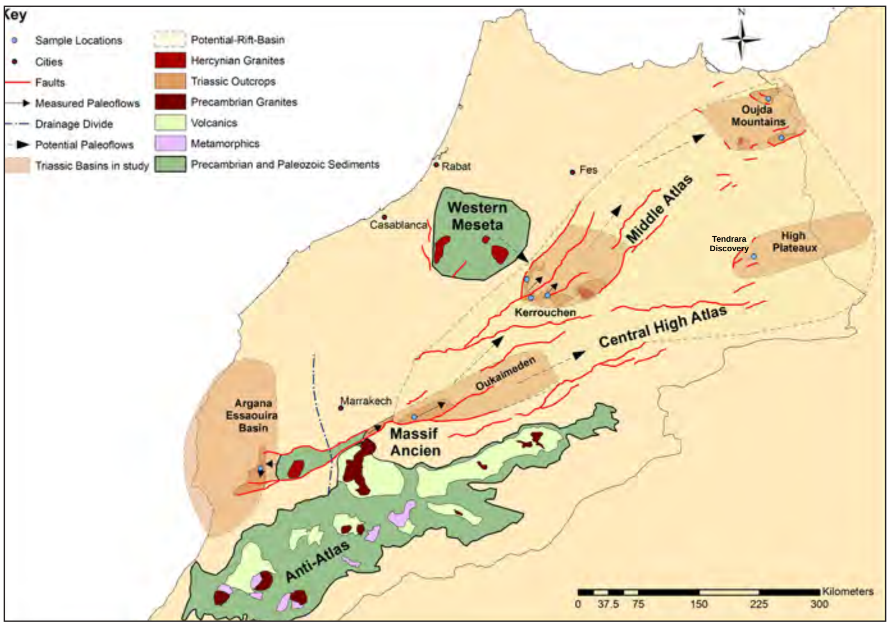

Figure 1: Late Triassic palaeogeography and potential clastic source areas in Morocco.

Results from the recent Tendrara wells drilled in Eastern Morocco prove economic flowrates from Late Triassic continental sandstones. Sourced from the Palaeozoic and trapped with post Hercynian rift structures, the play has many similarities to the prolific TAGI play in the Berkine Basin and offers potential for extension of the petroleum system further west into Morocco.

Reservoir quality and thickness is a key uncertainty and to better understand this, studies are ongoing to assess the main controls on the depositional systems and provenance. A complex suite of Triassic facies are exposed along the inverted Mesozoic sequences of the Atlas Mountain Chain, providing an excellent opportunity to study the sedimentology of syn-rift sequences that formed during the early break up of Pangea. Augmented by data from hydrocarbon exploration wells, the research is investigating how the basin fill changes both temporally and spatially. The wealth of previous work undertaken on the Triassic in Morocco provides a robust regional framework on which to build further detailed work. Our study aims to improve understanding of the local versus regional controls on facies variation and in particular the prediction of sandstone distribution and quality.

This study compares the provenance and character of the Triassic section outcropping in Oukaimeden Basin (F4, F5, and F6 sandstones) with the age equivalent units in the Kerrouchen Basin, Middle Atlas, and east to outcrops in the Oujda Mountains in the Eastern Meseta and to the subsurface, accessing data from vintage exploration wells and core data from the Tendrara gas discovery.

At Oukaimeden, in the High Atlas, the thick suite of Triassic clastics were deposited within an intra-montane basin, to the east of a well-documented drainage divide. The main coarse clastic fluvial interval, Unit F5, contains thick, stacked channel fluvial deposits that record the presence of a large perennial fluvial system flowing to the east. Later, more ephemeral conditions prevailed, with thinner fluvial packages and interbedded aeolian, floodplain, and alluvial fans facies. Toward the end of the Triassic a thin restricted marine to tidally influenced unit is recognised that is interpreted to mark the most westerly extent of the Tethyan transgression in the Triassic.

Further east, in the Kerrouchen Basin of the Middle Atlas, the fluvial packages observed at outcrop are thinner, and basin fill is dominated by alluvial fan and alluvial plain / playa deposits. Thick axial fluvial systems do not seem to be recorded, suggesting they are either absent or not exposed, possibly only located in the subsurface.

In the Eastern Meseta, outcrops are more limited, and thus understanding of facies distribution more uncertain. The few good sections in the Oujda Mountains record a distal low-energy facies, composed of basal locally derived angular conglomerates, overlain predominantly by mudrocks, with only very thin laterally restricted sandstones. The section shows an increasing marine influence, with interbedded shallow water carbonate sequences.

How this correlates south, into the subsurface, where control points are more sparse and only limited to widely spaced exploration wells of varying vintages, is still uncertain. The equivalent section in the Tendrara gas discovery displays an increasing proportion of fluvial sandstones, with stacked fluvial channels interbedded with floodplain mudstone and laterally equivalent alluvial fan deposits.

A heavy mineral study is being undertaken in order to constrain the provenance of these sediments. Paleocurrents data and published provenance studies suggest a drainage divide within the Massif Ancien, separating the Atlantic realm to the west from the eastern Tethyan domain. Key questions include whether a long distance axial system existed, running sub parallel to the main structural trend, transporting clastics from the Central High Atlas east-northeast to Tethys or if more south to northward feeder systems prevailed. The results also aim to address the role of intra-basinal topography through time: how this affected the distribution of fluvial systems and the role of local sediment source from basement blocks. Finally, the work will attempt to integrate the regional data to evaluate evolution of the basins as they mature, associated with rift linkage.

Preliminary work on the composition of samples collected during recent fieldwork in the Kerrouchen Basin has identified a distinct variation in clastic composition between the fluvial and alluvial systems. In the east, alluvial plain sediments contained granitic and carbonate clasts, likely derived from the local Hercynian basement of granites and carbonates. This suggests a large alluvial plain, with deposits derived from local basement paleohighs.

The fluvial sands found in the west contain metamorphic clasts of a schistose nature, with an absence of granitic or carbonate clasts. In this locality a contribution from an extra-basinal metamorphic source is indicated, which based on paleocurrent analysis, is most-likely located to the southwest of the basin. This supports previous work in the region, which also indicated an extra-basinal (Anti Atlas) source for the fluvial deposits.

Work is ongoing, but initial investigation suggests that the linking of the Late Triassic depositional systems across Oukaimeden, Oujda and Kerrouchen Basins may offer analogues for facies distribution in the Eastern Meseta.

Tuesday, September 11 | Theme 2| 11:20
Lisa Fullarton, Elisabeth C. A. C. Gillbard, Ken G. McDermott, Nicola Clarke, Paul Bellingham
ION, UK
+44 1932 792283, Lisa.Fullarton@iongeo.com

Palaeozoic to Present: Assessing the Petroleum Potential of the Offshore Sirt Basin, Libya, Using Newly Reprocessed Regional-Scale 2D Seismic Data

Introduction

The onshore Sirt Basin, Libya, has yielded some of the world's largest petroleum discoveries, with known reserves in excess of 40 billion barrels of oil equivalent. The offshore extent of this system, however, is poorly constrained due to of the limited amount of exploration activity. Recent wells have proven both equivalent and new petroleum systems in the offshore, but the extent, character, and full potential of these systems is currently poorly understood. Furthermore, the structural complexities of the offshore area and the relationships between the ancient crustal domains is only starting to be realized. Placing the offshore Sirt Basin and adjacent Cyrenaica Margin into a regional context, and understanding the relationship with the onshore basins will be key to future exploration of this potentially huge yet underexplored province.

Newly Integrated Mega-Regional Data

Over 45,000 km of recently acquired and depth processed deep regional seismic data and newly reimaged legacy 2D seismic data has been interpreted and integrated with offshore well data in a mega-regional basin study. These data allow a well constrained crustal-scale structural and tectonic model to be defined and placed within the regional context of the tectonically complex central Mediterranean. For the first time, deep imaging of the pre- and early rift basin is interpreted within a structural context to pull together the full tectonostratigraphic history of the offshore Sirt Basin and Cyrenaica Margin, from Hercynian Orogeny to Mesozoic extension and Cenozoic inversion.

Evaluation of Petroleum Potential

Regional stratigraphy from the Palaeozoic to present, has been interpreted in the context of assessing the petroleum potential of this structurally complex region. Basin modelling of several proven and speculative source rock units shows the significant offshore potential for both oil and gas maturation, and optimal timing of trap formation. Enhanced understanding of the regional context of proven and speculative plays is presented, extending the petroleum potential of the offshore along the Cyrenaica Margin and into the deeper water.

Conclusions

The regional stratigraphic interpretation is placed into a structural context in order to understand the deposition and development of reservoir facies, source rock maturation and migration, and trap development to fully integrate the petroleum potential of the offshore Sirt Basin and Cyrenaica Margin. ■

Paul Haryott, Rose & Associates
Bob Fryklund, IHSMarkit
Ernie Leyendecker, Anadarko
Dorrie McGuiness, Kosmos
Tim O'Hanlon, Tullow

Biographical Sketches

Paul Haryott has an extensive global background in oil and gas exploration that stretches over the 40 years since he began his career in the UK North Sea.

Formerly a senior executive and member of senior management in Chevron, with responsibility for Africa and Latin America, he is now a Senior Associate with Rose & Associates.

He has authored and co-authored numerous publications that include risk and uncertainty insights, and is a member of the AAPG and a Fellow of the Geological Society of Great Britain.

Paul holds a BSc in Geology from Liverpool University and a MSc in Petroleum Exploration Studies from Aberdeen University.

Bob Fryklund, Chief Strategist-Upstream , at IHSMarkit, has 38 years of experience. A proven oil finder and seasoned executive Bob has worked for both majors and independents. He focusses on high impact global strategic Upstream issues such as IPO's, acquisitions, portfolio's and expert witness assistance.

He is a geologist, member of the AAPG, HGS, member of Board of ARPEL, Trustee of AGI and Chair of the IPAA Supply and Demand Committee. He was awarded the AAPG Presidents Award in 2018.

Mr. Leyendecker recently retired as Executive Vice President, Exploration for Anadarko Petroleum Corporation, one of the world's largest independent oil and natural gas exploration and production companies. He took on this role in October 2016.

Mr. Leyendecker has more than 35 years of experience in the oil and natural gas industry. He began his career in Midland, Texas in 1982 with Marathon Oil Company, where he served in multiple engineering roles including drilling, completions and reservoir engineering. After various assignments, he left to pursue a leadership role in the start-up of Enterprise Oil Gulf of Mexico. In 2002, Enterprise Oil was acquired by Shell, and Mr. Leyendecker joined Kerr-McGee's Gulf of Mexico team. He served in increasing roles of responsibility as Exploration Manager before Kerr-McGee was acquired by Anadarko in 2006. Since 2006, he has held positions of increasing responsibility at Anadarko, including General Manager for Worldwide Exploration, Engineering and Planning; Vice President of Corporate Planning; Vice President of Gulf of Mexico Exploration and Senior Vice President, International Exploration where he was responsible for the company's exploration activities around the world. He most recently served as Executive Vice President, International and Deepwater Exploration until his retirement in June 2018.

Mr. Leyendecker holds a Bachelor of Science in Petroleum Engineering from Texas A&M University. He is a member of the Society of Petroleum Engineers, the Association of Petroleum Geologists and the Houston Geological Society. Mr. Leyendecker serves on the Texas A&M Engineering Experiment Station's External Advisory Board (TEES).

As an exploration geologist, **Dorie McGuinness** has contributed to exploration and appraisal of major discoveries in the Gulf of Mexico, South America, and Africa. During her early tenure at Kosmos Energy she contributed to the exploration and appraisal of the Ghanaian discoveries. After Ghana, she worked as a New Venture Senior Advisor and led Kosmos' entrance into Mauritania & Senegal, and Suriname. During the last several years she served as a functional leader as VP, Geology across Kosmos' portfolio, and has recently advanced to Senior VP of New Ventures. Prior to Kosmos, Dorie worked at Triton Energy contributing to the exploration entry into Equatorial Guinea, and exploration and appraisal in the Cupiagua Field in Colombia. She began her career at BP Exploration, where, after her tenure in exploration and development, she served as a structural geology/salt tectonics technical advisor in the Gulf of Mexico. Dorie holds a BS in Geology from Bucknell University, and an MS in Geology from Virginia Tech.

Tim O'Hanlon is from Ireland. As a young Reservoir Engineer fresh from Imperial College London, he joined Ireland's brand new start-up, Tullow Oil, in the mid 1980's. He has been with this very exciting and ambitious company ever since, living in Africa for many years.

More recently as Vice President African Business, or Tullow's *Mr Africa*, Tim has helped to drive Tullow's rapid expansion on the Mother Continent. Whether it is targeting new company acquisitions in Africa, chasing new ventures or mending fences in the many African countries where Tullow operates, you can be sure that Tim's fingerprints can be found on the files.

Tuesday, September 11 | Theme 2 | 13:35
Ken G. McDermott, Elisabeth C. A. C. Gillbard, Paul Bellingham
ION, E & P Advisors Chertsey, UK
Brian W. Horn
ION, E & P Advisors, Houston, TX , USA

Break-up Processes in the Presence of Plume Magmatism: New Insights into the Tectonostratigraphic Development and Petroleum Potential of the Austral South Atlantic

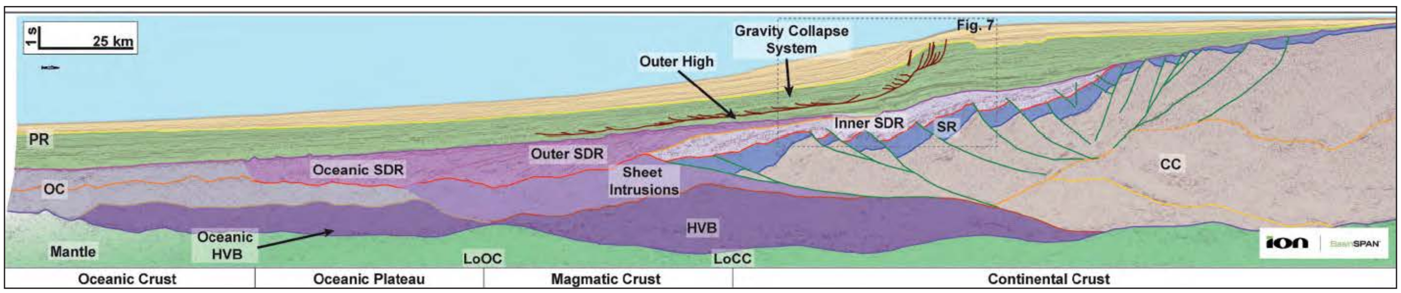

Figure 1. Geoseismic section[3] shown in TWTT details the a typical crustal configuration through the Namibian magma-rich margin. The margin has been CC – continental crust; OC – Oceanic crust; HVB – High-velocity body; SDR – seaward dipping reflectors; SR – syn-rift; PR – Post-rift sediments; LoCC – Limit of Continental Crust; LoOC – Limit of Oceanic Crust.

Introduction

The conjugate rifted margins of the austral South Atlantic are classically magma-rich and display extremely well developed examples of all the volcanostratigraphic elements commonly observed on magma-rich margins globally: stretched continental crust, inner and outer SDR (seaward dipping reflector) packages, an outer (volcanic) high, a zone of high-velocity lower crust, and relatively thick early oceanic crust[1,2].

Rifted continental margins are often considered independently due to a paucity of conjugate high-resolution reflection seismic profiles. Here, ION's South Atlantic mega-regional, conjugate seismic datasets are through paleogeographic reconstructions considered as they once were; a single basin through their shared geological history. Observations from these seismic data provide new and important insights into the principle mechanisms involved in highly magmatic continental break-up.

Tectonostratigraphic Model Overview

Through a well-correlated stratigraphic and crustal structure interpretation, a new tectonostratigraphic model for the formation of the austral South Atlantic is presented. This model describes the development of magma-rich margins influenced by plume magmatism and may have global applications to equivalent margins. The model consists of four distinct crustal domains (continental, magmatic, oceanic, and oceanic plateau), with two important crustal boundaries; the limit of continental crust (LoCC), and limit of oceanic crust (LoOC)[3] (**Figure 1**[3]). These crustal domains are delineated with respect to, and reflect the effects of, variable melt volume during continental stretching and break-up.

The tectonostratigraphic model also describes strongly diachronous post-rift and drift phase subsidence and highlights the role the Walvis Ridge – Rio Grande Rise system played in the separation of the central and austral segments of the South Atlantic Ocean.

Analysis of subsidence patterns on both conjugates, compared to the drowning of the Walvis – Rio Grande Ridge systems, reveals intriguing correlations between distribution of major source rock intervals and evaporite deposition in the Lower Cretaceous through time and space.

Conclusions

The observations and processes described here underpin the development of a regional petroleum systems model, allowing prediction of regional heatflow through time as well as the likely location of source and reservoir lithologies across the entire austral South Atlantic Basin, reducing exploration uncertainty for the discovery of commercial hydrocarbons.

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Biographical Sketches

Ken McDermott was awarded his Ph. D from the University of Birmingham in 2013 for his work on crustal hyper-extension at magma-poor rifted margins; and a B. Sc in Geology from University College Dublin in 2007. From 2012 – 2014 Ken held a postdoctoral research position at University College Dublin, working on the tectonostratigraphy of the North Atlantic. Since 2014, Ken has held the position of Structural Geologist at ION's E & P Advisor service and is to a large extent focussed on the South Atlantic.

Ken has authored and co-authored numerous papers in internationally regarded peer-reviewed journals focussed on the formation, crustal structure, and tectonostratigraphy of continental margins around the world, and often speaks at national and international industry and academic conferences. Ken is a member of the PESGB and a fellow of the Geological Society of London.

Brian W. Horn - Senior Vice President and Chief Geologist for ION E&P Advisors. Brian has worked in exploration and production for 27 years with Amoco, BP, and Maersk Oil prior to joining ION in 2010. In his current role he is responsible for the technical and commercial advisory group in support of E&P operators, NOC's and government minsitries. His experience includes integrating geological and engineering/production data for play-based exploration, and development, basin and play fairway analysis, petroleum systems, regional stratigraphic and seismic correlations, prospect development and resource potential assessments. In addition to exploration projects he has delivered exploitation/development programs generating prospects, development and reservoir characterization for (infill) drilling designed to identify and evaluate critical geologic uncertainties focused on increasing recovery efficiencies and reservoir management strategies.

Dr. Horn received his Bachelors and Master degrees in Geology from The University of Colorado, Boulder and his PhD in Geology and Geological Engineering from the Colorado School of Mines, Golden, CO.

Dale E. Bird
Department of Earth & Atmospheric Sciences, University of Houston
Bird Geophysical, dale@birdgeo.com
Stuart A. Hall
Department of Earth & Atmospheric Sciences, University of Houston
David J. McLean, Philip J. Towle, Hunter A. Danque
Anadarko Petroleum Corporation
James V. Grant
Chesapeake Energy Corporation

The Austral South Atlantic: Early Formation and Crustal Structure of the Orange and Cape Basins

New high-resolution marine magnetic anomaly data acquired over the southwestern margin of South Africa, integrated with reprocessed open-file marine magnetic anomaly data, displays a pattern of well-defined northwest-southeast striking linear anomalies that can be traced with confidence over distances greater than 150 km (**Figure 1**) (Hall et al., in press). We interpret these anomalies to be M-series seafloor spreading anomalies M9 to M11, suggesting seafloor spreading initiation at about 135 Ma (Late Valanginian / Early Hauterivian). A two-phase spreading rate, from seafloor spreading models (M11 to M0), matches the two-phase spreading rate for M-series anomalies over the conjugate South American margin, offshore Argentina. Importantly, the presence of M11 anomalies over both margins suggests an earlier opening for the austral South Atlantic than previously recognized.

We identify four breaks in the continuity of the linear magnetic anomaly pattern, oriented approximately northwest-southeast, which may be early fracture zones. One such discontinuity, which we have termed the "Cape Lineament" (CL) ("D2" in **Figure 2**), marks a significant change in crustal character and Cretaceous depositional history. Two northwest-southeast striking regional 2D modeled cross sections, integrating wells, seismic reflection, seismic refraction and gravity data, were built northwest and southeast of the CL. Northwest of the CL, the Orange Basin crust is characterized by greater thickness and the presence of seismically-imaged seaward dipping reflectors (SDRs). The modeled cross section through the Orange Basin includes a region of rifted / attenuated continental crust; a wide zone of underplated thin continental crust overlain by SDRs; and another wide zone of thick oceanic crust, associated with smoother seafloor spreading anomalies, that thins progressively to normal oceanic crustal thickness at the seaward edge of the overlying SDRs. However southeast of the CL, the crust has a more "normal" oceanic thickness and SDRs are either absent or more limited in areal extent. The modeled cross section through the Cape Basin indicates a change in crustal character from attenuated continental crust to normal thickness oceanic crust occurring over a much shorter distance, which suggests a diminished influence of magmatic material. Magnetic anomalies over the Cape Basin are better correlated with those predicted by our seafloor spreading model than the anomalies over the Orange Basin.

Our reconstructions of the African and South American margins, south of 32°S at M11 and M4 times (i.e., ~135 Ma and ~131 Ma, respectively), successfully overlay magnetochrons of the conjugate margins. In Figure 2 we compare seafloor spreading anomalies M4 and M11, as well as the inboard "G" anomalies over both transitional / continental margins. The new M11 rotation pole (38.86°N, 31.46°W) applies only to the southernmost margins of the Austral segment where the M11 anomalies are observed, because at this time the margins were undergoing non-rigid deformation farther north, including crustal extension and magmatism.

The recognition of initiation of seafloor spreading earlier than previously documented, together with the identification of differing crustal character northwest and southeast of CL, carry important implications for heat flow and the subsidence / depositional history of the margin.

Reference

Hall, S. A., Bird, D. E., McLean, D. J., Towle, P. J., Grant, J. V., and Danque, H. A., in press, New constraints on the age of the opening of the South Atlantic basin: Marine and Petroleum Geology.

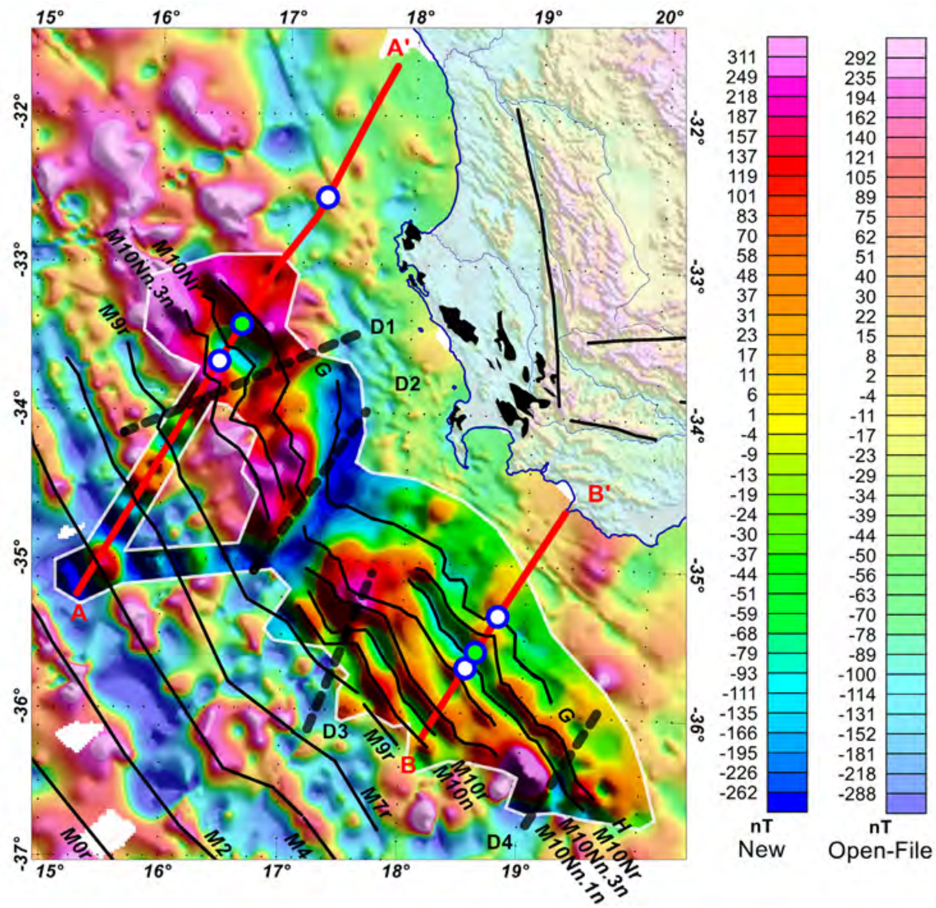

Figure 1. Total magnetic intensity anomalies and African topography (see Hall et al., in press, for additional information). Reprocessed open-file marine magnetic anomalies (Bird Geophysical) are overlain by new, high-resolution magnetic anomalies (Anadarko Petroleum Corporation); Interpreted discontinuities are heavy gray dashed lines (D1 through D4); new high-resolution marine magnetic data survey outline is white; labelled magnetic anomaly correla-tions from this study are black lines. Two-dimensional modeled cross sections are heavy red lines; blue and white circles posted on the model lines correspond to the extents of modeled magmatic underplating, blue and green circles correspond to the modeled boundary between oceanic and continental crust; onshore outcropping basement areas are colored black; the north-south and east-west oriented lines over South Africa trace the Cape Syntaxis.

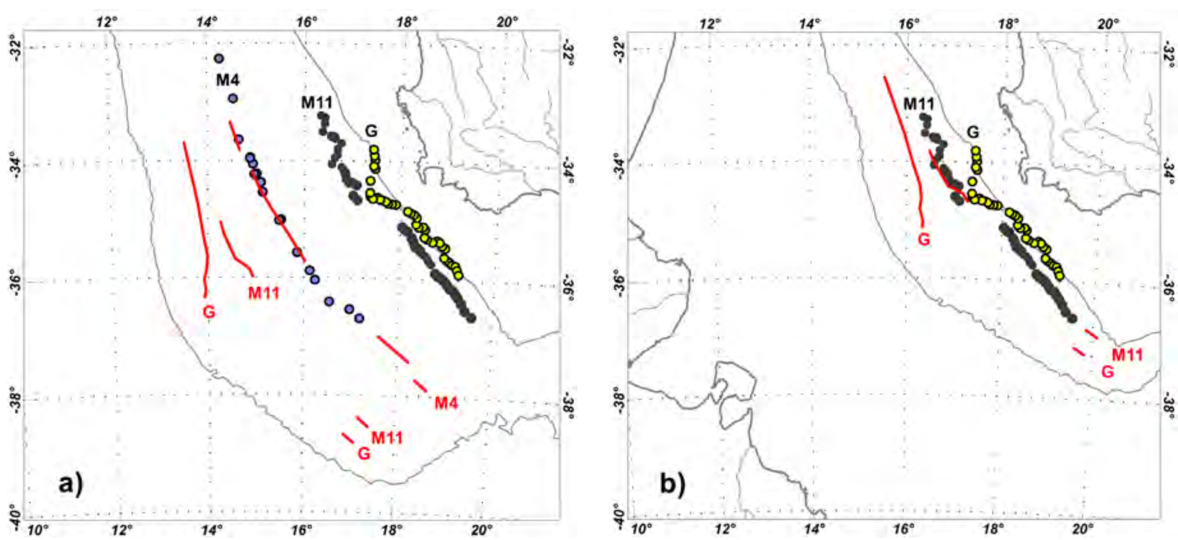

Figure 2. Africa – South America reconstructions of coast lines and 1 km isobaths (see Hall et al., in press, for additional information). a) M4 reconstruction (rotation pole = 45.5°N, 33.0°W, and angle = 54.2°), with our anomaly picks for Africa by blue (M4), black (M11), and yellow ("G") circles; and red for South American magnetochrons and "G" anomaly. B) M11 reconstruction (rotation pole = 38.86°N, 31.46°W, and angle = 56.6°).

Tuesday, September 11 | Theme 2 | 14:25
Ian Davison
Earthmoves Ltd., Camberley, Surrey, UK
Duncan Wallace
Chariot Oil and Gas Ltd., London, UK

Post-Rift Potential Source Rock Correlations and Prospectivity of the Deep Atlantic Conjugate Margins South of the Walvis Ridge

Several isolated small half grabens (5-10 km wide and 1-2 km deep) are present along the conjugate margins of the South Atlantic south of the Walvis Ridge which were produced by Early Cretaceous rifting. These can contain source rocks (e.g. AJ-1 well in South Africa). However, the areal extent of these grabens is restricted. The main accommodation space created by Early Cretaceous extension is filled by magma which has produced seaward dipping reflectors (SDRs). The upper part of the SDRs has been drilled in the Walvis and Pelotas basins and consists of sub-aerial reddened basalts. No source rock potential has been encountered, nor is any expected in such a sub-aerial sequence. Hence, the hydrocarbon prospectivity of the deepwater margins will largely rely on the presence of post-rift source rocks.

Early drift, Barremian to Aptian age, marine source rocks were identified in several wells including the recent Murombe-1, Wingat -1, and Moosehead-1 wells, where residual TOC levels up to 6% in source packages of up to 150m were measured. The deposition of this source rock is interpreted to be widespread in the deep water and modelled to be oil mature in several large kitchen areas, situated in present day water depths from <500m to over 3000m. Additionally, good quality Cenomanian to Santonian age source rocks have also been identified in several wells offshore Namibia, such as the 1911/15-1 well with TOC levels reaching up to 10 % and a gross thickness of 170m, and the Kabeljou-1 well with average TOC of 5.3% and approximately 50m thickness.

The Barremian to Aptian age source rocks on the Namibian margin are now recognised to be the principal source rock for future exploration drilling and they are characterised by parallel-bedded, low amplitude, low frequency, continuous low-impedance reflectors, which lie above the SDRs. The equivalent Barremian to Aptian section above the SDRs in the deepwater (>2 km) Pelotas-Argentine margin has never been drilled, but seismic data indicates a similar stratal package. Recent 2D/3D seismic data from Namibia will be used to characterise the source rock package, and compare with recently acquired seismic from Argentina and Uruguay.

Biographical Sketch

Since 1999 **Ian Davison** has been Managing Director of Earthmoves Ltd. a consultancy working frontier exploration areas and on salt tectonics He regularly gives industry short courses on Salt Tectonics and frontier exploration along the Atlantic margins and Mexico.. Ian is a co-director of GEO International Ltd. which specialises in African onshore rifts and East African Hydrocarbon Exploration. He is also Visiting Professor at Royal Holloway, University of London

Tuesday, September 11 | Theme 2 | 14:50
Neil Hodgson, Hannah Kearns, Karyna Rodriguez
Spectrum Geo Ltd, United Kingdom
Benjamin Allen, Douglas Paton
School of Earth & Environment, University of Leeds
Abdulkadir Abiikar Hussein
Ministry of Petroleum and Mineral Resources (MOPMR), Federal Government of Somalia
+44 1483 730201, Neil.hodgson@spectrumgeo.com

Offshore Somalia: Source Rock Identification in a Frontier Margin

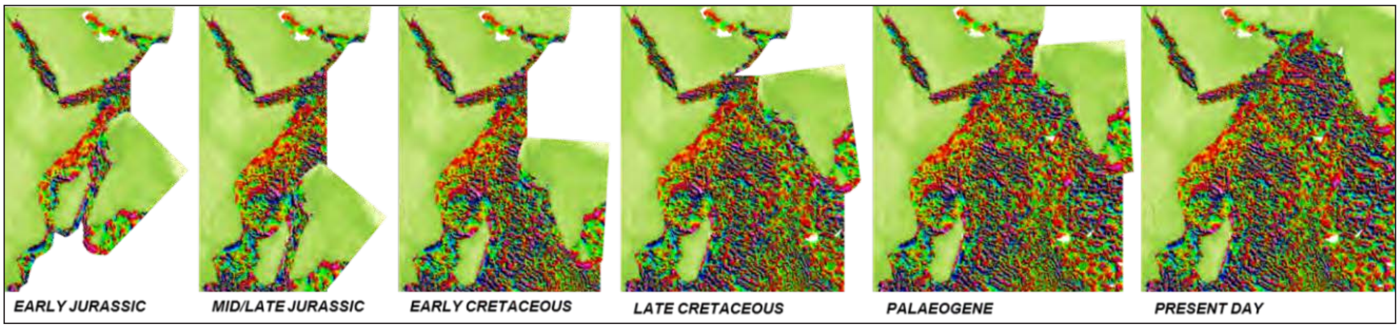

Figure 1. The EMAG2 V3 dataset was used to create a magnetic plate reconstruction from the Early Jurassic to present day

Offshore Somalia remains one of the last truly frontier passive margins in the world. Only two exploration wells have been drilled offshore along the 1000km long margin, and both are on the shelf in <100m water depth. Identifying potential source rocks on such an unexplored margin requires integration of multiple datasets to build a robust geological model that fits with our observations from seismic data. We use gravity and magnetic data to reconstruct tectonic plate positions, conjugate margin and onshore well information, regional geological understanding and records of Ocean Anoxic Events (OAEs), and we complement this with seismic observation and analysis including source rock characterisation, sequence stratigraphy models, and slick clusters on satellite imagery.

Regional Geology

The initial Karoo rifting of Gondwana began in the Late Carboniferous/Early Permian[1]. Deposition of the continentally-derived Karoo Supergroup, comprising both source and reservoir, occurred across Southern and East Africa at this time. Breakup of Somalia and the Madagascar-Seychelles-India (MSI) block occurred in the Early Jurassic[2] (**Figure 1**). This coincided with an initial marine transgression which saw lacustrine to brackish-marine restricted basin sediments deposited in rifted half grabens formed by fault block rotation. In the Middle to Late Jurassic, a restricted seaway formed between the Indian and Somali plates. Restricted marine marls were deposited in the basin at this time, and shallow water platform carbonate growth occurred on the continental shelf. From the Early Cretaceous, the northward movement of the Indian plate past the Somali plate coincided with the formation of large-scale transpressional and transtensional flower structures in the deep offshore, creating potentially very large trapping structures, as well as partial barriers to oceanic circulation which may have facilitated the deposition of an organic-rich Late Cretaceous source rock. In the Late Cretaceous and Palaeogene, slope failure events occurred in the southern offshore.

Potential Source Rocks

A lack of drilling offshore leaves the stratigraphy untested. However, observations from onshore well data, seismic characteristics, structural deformation styles, and sequence stratigraphy models are used to build a consistent framework for seismic analysis and characterization of potential source intervals. Source rocks are proposed at pre- syn- and post-rift levels. Pre-rift sources may be present in Permo-Triassic to Lower Jurassic (Karoo) coals and lacustrine shales such as the Permian Bokh Shale which is the source for the Calub gas and condensate field onshore Ethiopia. Lacustrine sources are also well developed in the Madagascan conjugate – particularly the onshore Karoo sourced oil feilds.

Syn-rift sources may comprise Lower to Mid Jurassic shallow marine shales, located on the southern extension of Tethys where a Tethyan Ocean Anoxic Event (OAE) occurred in the Toarcian promoting the development of anoxic sedimentation.

In the early post-rift, Upper Jurassic marine shales are a key source in the Ethiopian Ogaden Basin and in northern Somalia (Uarandab Formation). Organic-rich shales of similar age are present in the Rovuma Basin and have moderate TOCs in the

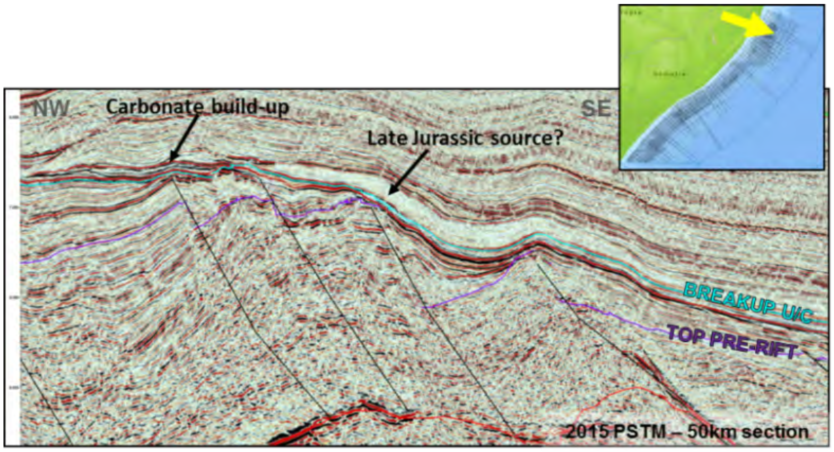

Figure 2. Possible late Jurassic source rock identified in the deep basin

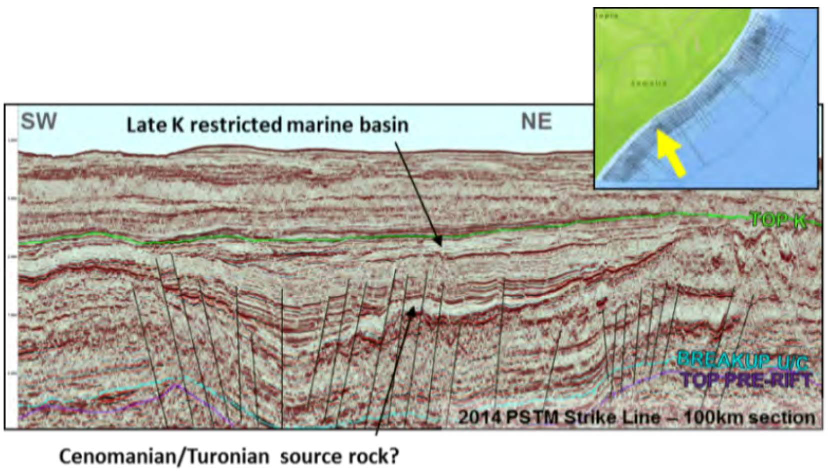

Figure 3. Late Cretaceous restricted marine basins formed by transform movement may have been ideal environments for source rock deposition

Seychelles. In the deep basin, an acoustically quiet homogeneous unit can be mapped at this level and is interpreted as a deep marine organic-rich marl source (**Figure 2**).

In the Cretaceous, global OAEs are known in the Aptian and Cenomanian-Turonian, and localised restricted marine environments were created by transform faults linked to the movement of the Indian plate past the Somali plate in the Late Cretaceous. These may have been ideal anoxic depositional environments for source rocks to develop in (**Figure 3**). Cretaceous and Tertiary shale décollement surfaces linked to slope failure events in the southern offshore may also have source rock potential. Where burial is sufficient to mature organic-rich sediments, this can reduce viscosity and increase pore pressure sufficiently to facilitate low angle displacement.

2D seismic acquired in 2015 is interpreted within a sequence stratigraphic framework to characterize these potential source source using the methods of Loseth et al[3]. These results give further support for the presence of thick sequences of effective source rocks.

Basin Modelling

Leeds University carried out basin modelling considering four potential source rock intervals identified by the seismic characterization technique. Peak maturation maps for source rocks at pre-rift (Karoo), syn-rift, Late Jurassic and Early Cretaceous levels indicate that where the sediment column is thickest in the south, shallower Early Cretaceous and Late Jurassic sources are in the oil window. Where the pre- and syn-rift is not so deeply buried in the north, these source intervals sit in the present-day oil window.

Conclusions

Defining source rocks in untested frontier margins can present a challenge, however by integrating multiple datasets and geological models developed from seismic analysis, gravity and magnetic data, offset well information, satellite slick mapping, and sequence stratigraphy models we can propose various scenarios in which organic-rich sediments may have been deposited and matured. This is both a useful tool in de-risking frontier passive margins where limited data exists, and also allows the key prize for East Africa - the oil prone hydrocarbon system to be identified.

References

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[3]Loseth, H., Wensaas, L., Gading, M. Duffaut, K., and Springer, M., 2011. Can hydrocarbon source rocks be identified on seismic data? Geology; 39 (12); 1167-1170.

Neil Hodgson, Anongporn Intawong, and Karyna Rodriguez
Spectrum Geo Ltd, Woking, United Kingdom
+44 1483 730201, Neil.hodgson@spectrumgeo.com

Hunting the SNE in Guinea Bissau

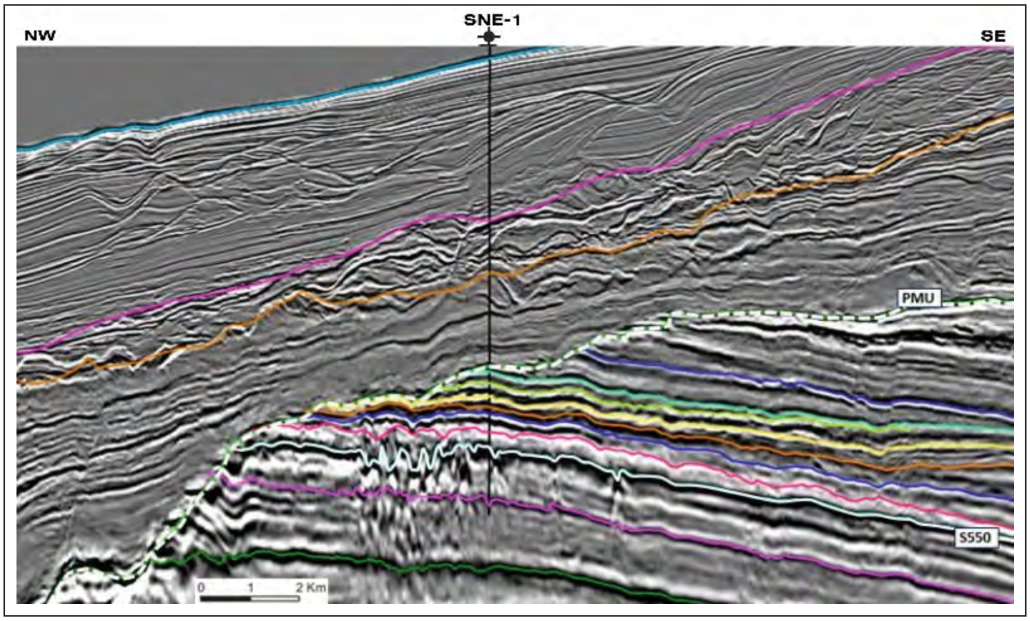

Figure 1. A west-east orientation PSDM seismic line through SNE-1 well[1].

The recent eruption of giant oil and gas hydrocarbon discoveries on the North West African coast began in 2014 with the SNE-1 discovery by Cairn in Senegal (**Figure 1**[1]). This play-making well targeted Albian sandstones and Aptian carbonates in a structural trap, at the eroded edge of the Early Cretaceous platform margin.

There are a number of interesting play elements at work in this play that suggest a play-model can be extracted and re-used elsewhere along the margin in the chase for analogue traps. At the southern end of the margin is Guinea Bissau, Senegal's southern neighbour, where the plays are as yet unexplored and appear to have an even more promising potential.

Working Petroleum System

To the south of SNE, the carbonate platform margin is seen to extend through The Gambia and the Casamanche region of Senegal into Guinea Bissau. Here, Albian sands of equivalent age to those in SNE are seen prograding towards the bounding unconformity in a similar trapping geometry to SNE.

Potential source rocks in the deep basin are likely to comprise Turonian and Aptian Ocean Anoxic Event (OAE) source rocks, and consequently will be as rich and well developed offshore Guinea Bissau as they are offshore Senegal. The thick Cretaceous section (up to 4 km thick) in the basin onlaps against the Early Cretaceous and Jurassic carbonate platform where migration

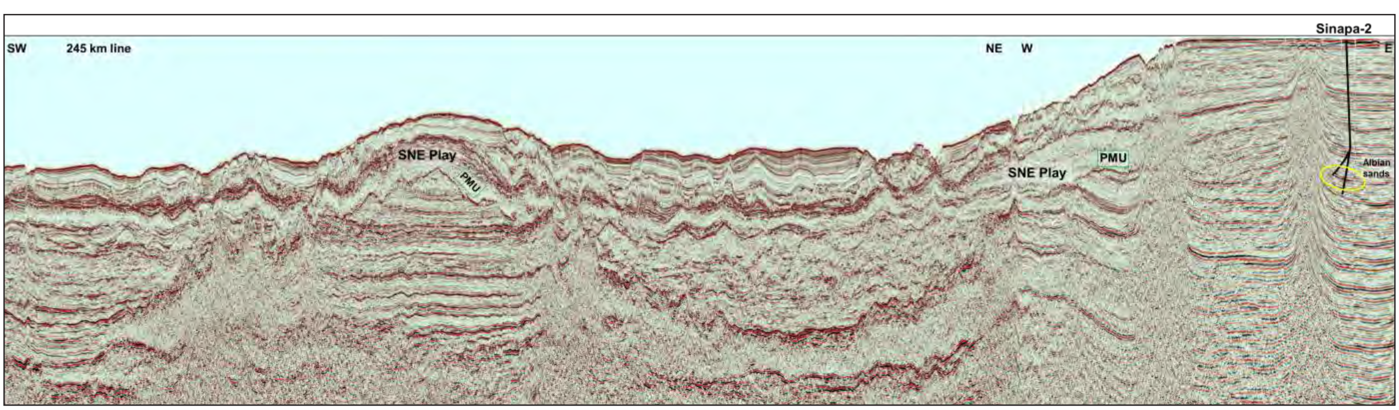

Figure 2. Sea water compensated 2D conventional PSTM composite line in second TWT ties to the Sinapa-2 oil discovery well. The line also demonstrates the presence of the Albian deltaic SNE (PMU) play along the shelf margin.

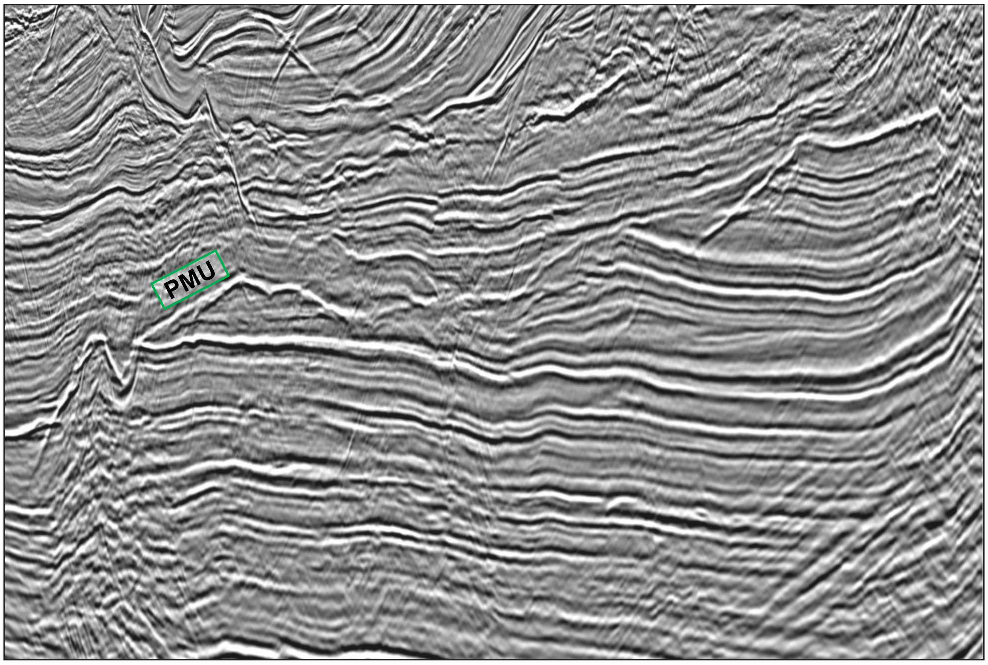

Figure 3. Detail of west - east orientation 2017 reprocessed broadband data in second TWT, seawater compensated, demonstrates the SNE play in Guinea Bissau. Line length is 30 km.

through talus porosity and/or slope fan sands is envisaged to mirror the SNE example. The migration pathways are analogous and the tectonic tilting that generates the landward dipping carbonate platform, and therefore the structural dip of the trap, is also present from Senegal to Guinea Bissau.

Indeed all the play elements that work effectively in SNE also appear to be present and effective on the Guinea Bissau margin. In addition, on the shelf west of the SNE trend in Guinea Bissau lies a partially explored salt diapir province. Sinapa-2 discovered 35° API oil in 2004 in Albian aged deltaic sands in the flanks of the Sinapa salt dome. This is one of 18 salt diapirs on the shelf that appears to have been tested in a definitive way, and it was successful. Two sand units were penetrated; an upper sand interval with 90m of locally poor quality sand above a second sand interval with 250m of excellent quality sands. The well was side-tracked up-dip and similar pair of Albian sand intervals were penetrated, defining a 500m oil column in the upper sand interval. The Sinapa oil proves a working petroleum system on the shelf offshore Guinea Bissau, and the pair of sands penetrated by Sinapa-2 can be correlated to the shelf edge where they comprise a double target in the SNE play (**Figure 2** and **3**).

The appearance at the beginning of the Albian of clastic deltas that then dominate this previously clastic starved carbonate platform margin is likewise correlated and indeed the same sequence stratigraphic processes appear to have controlled deposition from north to south along this margin. However, variation in the submarine erosion that generated the PMU would appear to dramatically change the prognosis of the facies of Albian deltaics that one might encounter in the trap.

Conclusion

An analysis of the play elements within our database that have come together in the giant SNE discovery, suggests that these elements are also present south of the SNE area through The Gambia and into Guinea Bissau. Here the detail of the trap suggests that multiple Albian sandstone targets may be present, with high quality sandstone facies comprising the majority of the trap volume.

References

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[2]Cairn Energy PLC investor announcement dated 07/10/2014.

Tuesday, September 11 | Theme 2 | 16:10
Tony Younis, Michael Clutterbuck, Phil Birch
Impact Oil & Gas Limited

Gabon's "Wild West Frontier" Promises a Golden Age of Discovery for the Deep-Offshore

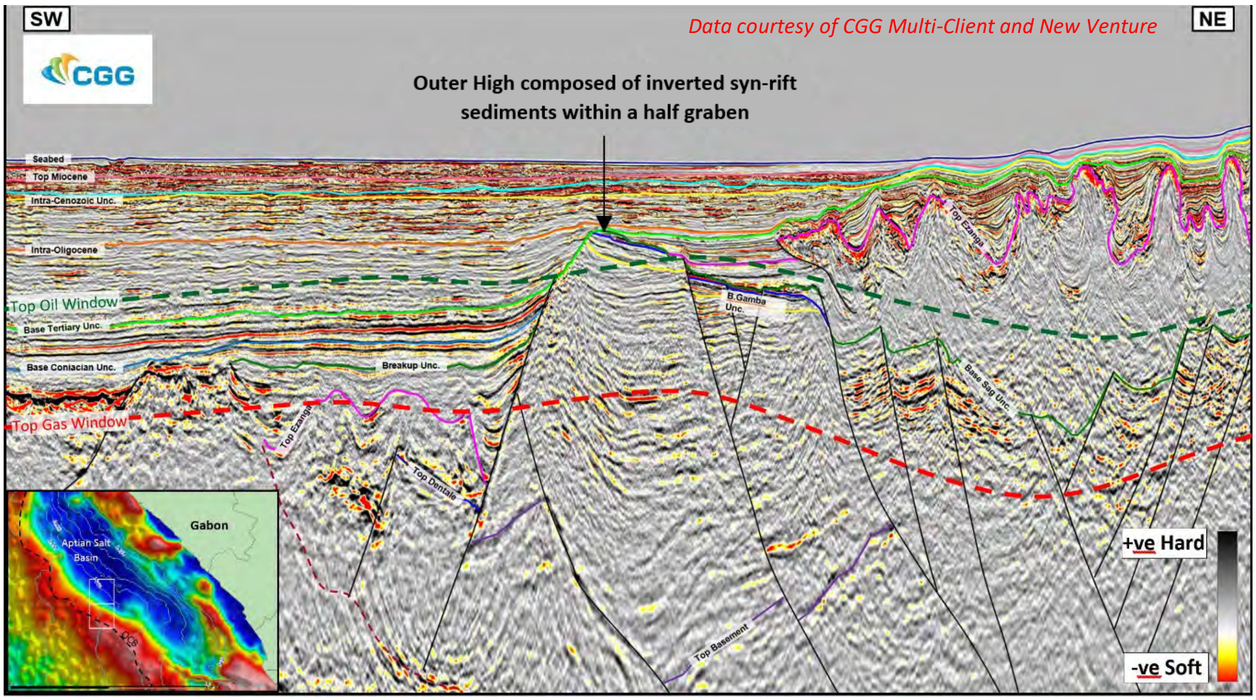

Figure 1. NE-SW dip profile offshore South Gabon showing a large inverted half graben preserved as a sediment filled outer high which divides the landward inner Aptian salt basin and the oceanward hyperextended tectonic domains (Data courtesy of CGG Multi-Client and New Ventures)

Oil has dominated Gabon's economy for decades, however, this mature province has seen its production decline from a peak of 370,000 barrels per day in 1997 to around 200,000 in 2017. The Diaman, Leopard, Boudji, and Ivela discoveries made by Total, Shell, Petronas, and Repsol respectively, have opened up the deep water pre-salt play of South Gabon, and substantially moved the known limit of the active petroleum system westward into the deep offshore. Currently other operators such as Noble and Impact are continuing to push the limits of the deep water pre-salt play distally southwards along the South Gabon Margin and still farther west to the ocean-continental boundary, aided by higher quality seismic data.

Along the western flank of the South Gabon Salt Basin, the presence of a prominent high, (**Figure 1**), has frequently been identified on various vintages of 2D seismic. The exploration community has typically considered this structure to be basement or igneous in origin at least[4], with little or no exploration significance. However, with the advent of 3D seismic and the latest in depth imaging techniques, this old assumption has now been turned on its head.

There is evidence for the Outer High to be that of a large inverted half-graben, opening up the potential for not only a series of stacked Barremian-Aptian Dentale fluviatile reservoir intervals, but also a substantial section of transgressive marine mid-Aptian Gamba reservoir sands, up to 300m in gross thickness, above the syn-rift sequence. The boundary between these two clastic reservoir units can clearly be defined through seismic stratigraphic analysis as an angular unconformity (**Figure 2**).

West of the Outer High lies an adjacent marginal trough, superimposed onto hyper-extended crust[2] formed through continued westward extension. Halokinetic activity is observed within this narrow interval of the basin, yet is found below the break-up unconformity. Assuming that the salt identified within the hyper-extended zone was deposited contemporaneously as part of the Aptian Ezanga evaporitic cycle, this finding demonstrates the transient nature of continental extension, moving westwards in the case of the West African Margin, suggesting that continental separation occurred during the Early Albian[3].

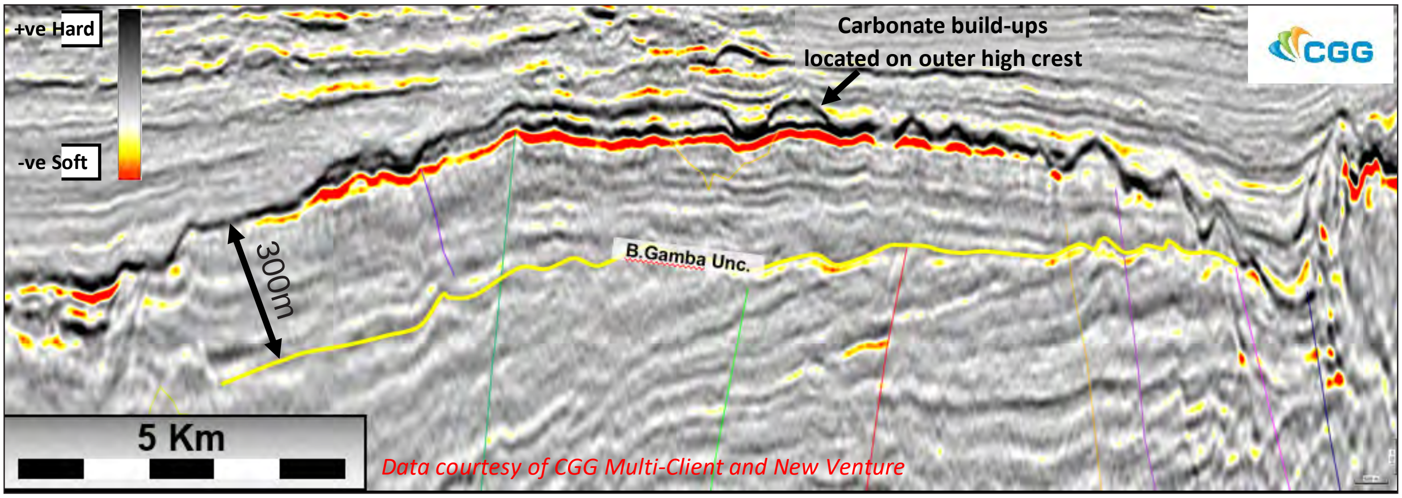

Figure 2. NW-SE section of the outer high crest, highlighting an angular unconformity between the syn-rift Dentale and sag-phase Gamba Formations. Mapping of the high quality Gamba transgressive sand shows thicknesses up to 300m (Data courtesy of CGG Multi-Client and New Ventures)

Following continental separation, the Outer Margin underwent accelerated thermal subsidence allowing for the accommodation of high quality post-rift marine source rocks of Albo-Turonian age. This interval's seismic character is recognised further south in Angola and along the Brazilian conjugate, and is considered to be the primary generative interval within these basins, but is as yet untested in S. Gabon.

Whilst the nearby discoveries demonstrate the presence of a syn-rift petroleum system, the Albo-Turonian source rocks within the Outer Margin offer a significantly higher probability of oil generation at the present day [1], migrating laterally into the pre-salt reservoir units of the Outer High. Furthermore, whilst the presence of Aptian salt within the inner South Gabon Basin is considered to be an ideal seal to any trap, its absence over this structural high is fortuitous, allowing the gas generated from Neocomian-Barremian source rocks to migrate through and out of the structure, prior to the deposition of the Tertiary shale seal. Rather, this seal timing is favourable for the capture of Albo-Turonian generated oil instead.

With dwindling reserves and an economy heavily dependent on its hydrocarbon wealth, the need to offset Gabon's oil industry decline is ever more pressing. Exploring in the deep offshore for these very large plays, will be the key to halting and reversing that decline.

References

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[3]Péron-Pinvidic G., Manatschal G., Masini E., Sutra E., Flament J. M., Haupert I., Unternehr P. (2015); Unravelling the along-strike variability of the Angola-Gabon rifted margin: a mapping approach. Geological Society London Special Publications 438

[4]Unternehr P., Péron-Pinvidic G., Manatschal G., Sutra E. (2010); Hyper-extended crust in the South Atlantic: in search of a model. Petroleum geoscience, 16, 207-215

Biographical Sketch

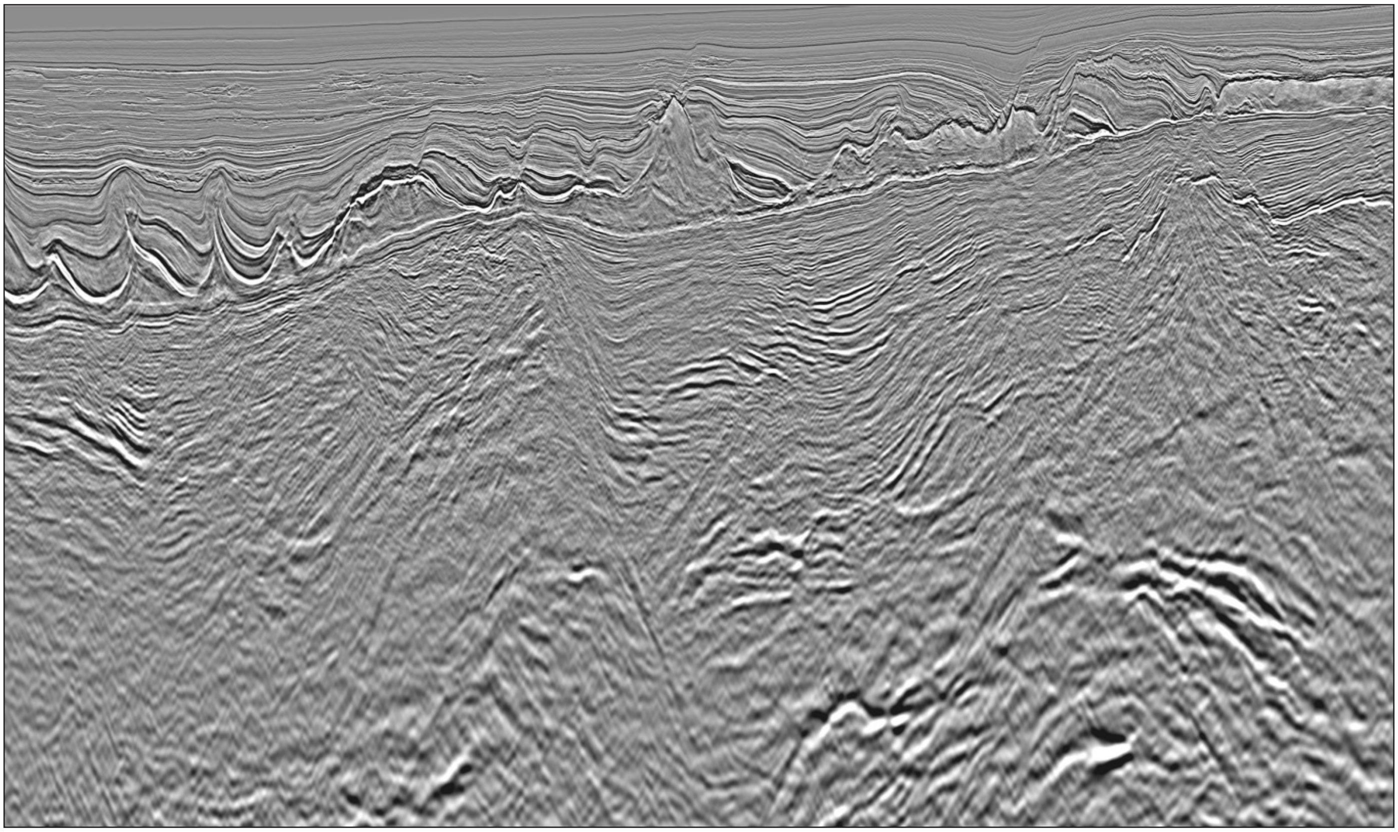
Tony Younis has a BSc in Geophysics from the University of Edinburgh and a Masters in Petroleum Geology from the University of Aberdeen.

With over 20 years industry experience, Tony began his career working in offshore seismic acquisition with Schlumberger as a Processing Geophysicist in 1997. In 2004, he opted to join Total's UK subsidiary in Aberdeen as a Seismic Interpretation Geophysicist where he played a key role in the Tormore discovery that eventually led to the Laggan-Tormore development in the West of Shetlands. From 2008, Tony took on various exploration roles within Total's New Venture department in Paris as well as an operations role in Gabon in 2010.

In 2015 and after 10 years at Total, Tony decided to join the small and dynamic West African exploration company Impact, based in Woking, England, as the company's Exploration Manager.

Tuesday, September 11 | Theme 2 | 16:35
Rob Crossley, Gregor Duval, Max Norman
CGG Services (UK) Ltd

Gabon Deep Offshore: New Petroleum System Insights from the Full Integration of Geology and Geophysics



Pre-Salt and Post-Salt section offshore South Gabon

New insights have been developed through the integration of regional geology, satellite imagery, potential fields geophysics, and the interpretation of a new basin-wide broadband 3D seismic survey offshore South Gabon.

At the regional scale, the outer limit of continental crust has been mapped using gravity and magnetic data, calibrated with 3D seismic imagery, across the continental to oceanic crust transition zone. This helps mapping the extent of Pre-Aptian sedimentary basins where much of the petroleum potential remains. Combined with this, a set of new gross depositional environment (GDE) maps, focussed on the Pre-Aptian Salt and Early Drift sedimentary units, have been compiled to help better characterise reservoir and source facies distribution. Geological data from wells and outcrops on the West African and Brazilian margins were used as control points and rotated into paleo-position using Plate Wizard for six key time slices through the warp, rift, sag, and drift phases.

GDE mapping integrated this control data with seismic interpretation in the light of analogues from Brazil and the Red Sea. This led to new concepts regarding the changing hydrology of the basin and mechanisms driving some of the diapiric salt movement. This in turn led to new ideas regarding both the distribution of oil-prone verses gas-prone source facies, and the origin of the different sand systems at Dentale, Coniquet, and Gamba Formation levels.

The seismic resolution beneath the Aptian salt has driven greatly improved understanding of the tectonostratigraphy, with clear evidence for multiple phases of rift fault block movement in the late syn-rift, and changing geometries within the sag phase. A suite of 1D basin models which tested a range of thermal scenarios shows that oil-mature sections are widely-developed in the upper part of the pre-salt sequence, whereas the deeper syn-rift section is in the gas window. These new observations, coupled with recognition of fluid escape pathways, permits the development of exploration concepts which aim to target oil-charged traps, rather than gas charged traps, in the pre-salt.

Furthermore, the NW part of the Congo fan buries the lower part of the post-salt section and contains numerous turbidite systems. The 1D basin models show that the lower part of the post-salt section is oil-mature in several areas. The new image quality gives a better basis for identifying potential charge pathways from the pre-salt and from depocentres in the post-salt, into potential traps in the turbidite sand intervals.

Biographical Sketch

Rob Crossley graduated from Reading University in 1972 and gained his PhD from the University of Lancaster on the volcanic tectonostratigraphy of the Kenya Rift in 1976. This was followed by 9 years as a lecturer in the University of Malawi, where he extended his research into rift sediment fills, basin hydrology, sedimentation by termites and archaeology. He then joined Robertson Research in North Wales as a sedimentologist, where he worked at scales ranging from pore throats, through unitisation of North Sea Fields, to global Earth Systems modelling. Today, as Chief Geologist in CGG, he still occasionally finds himself looking down a microscope and interpreting seismic, as well as being involved in asset evaluations, regional-scale exploration projects and mentoring members of our up-and-coming technical staff.

Notes

Oral Presentations
Day Two

Abstracts

September 10-13, 2018
Norris Convention Centre, Houston Texas

Wednesday, September 12 | Theme 3 | 8:35
Professor Bryan T. Cronin
Tullow Ghana Ltd, North Dworzulu, Accra, Ghana

Entrenched Slope Channel Complex Systems: Reservoir Opportunities through Understanding Architectural Element Distribution and Application to West Africa E&P

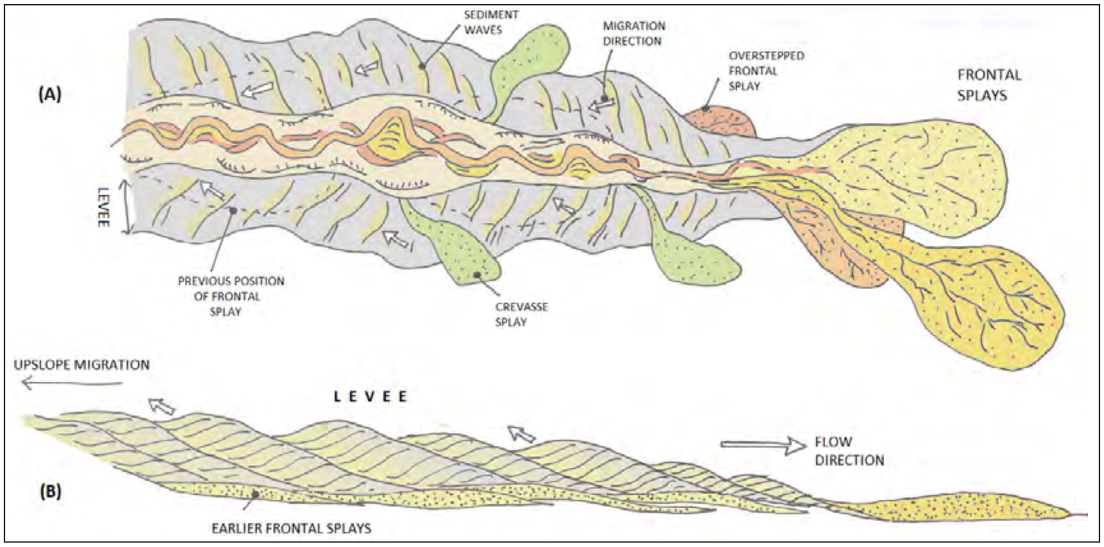


Figure 1. Planform and dip profile views of slope-basin floor showing the location of entrenched slope channel complexes, and levee growth patterns

Confined, entrenched, or simply slope channel complexes, have been described from a range of outcrop, subsurface and sea floor settings. In the West African context, they constitute a family of reservoirs that have a wide range of reservoir quality, reservoir connectivity, trapping style, and recovery factor. Geological models all focus on the architecture of the main channel belt and show that the phases of channel complex system occupancy pass from a bypass phase, through a stacked channel element phase of various character, through an aggradational phase with smaller, usually meandering channel elements, to an end phase of progressive switch off of the system. A wide range of terms are now in common use that conflict in scale and usage, reflecting perhaps experience with specific case studies, and belie the true range of slope channel complex system expression. A unified model that allows true variability to be captured is needed.

Channel complex systems range widely in net sand, net thin bed, or net mud slump or debris flow volume. The channel complex systems also vary widely in the proportion of channel element style. These styles range from (i) highly amalgamated sand bodies that extend across the channel complex system but are made entirely of individual meanderform, or braidform, channel elements, sometimes called 'confined sheets', to (ii) more clearly distinguished stacked channel elements that are underfit to the channel complex system, and have laterally equivalent inside levees and terraces, to (iii) even smaller scale skinny, later stage meanderform channel elements with higher proportions of related volumes of laterally equivalent, smaller scale internal levees, internal crevasse splays, internal frontal splays, or passive drape. The lateral channel complex system wall may have a range of morphologies that reflect the evolution of the system, from lateral rotational failure of the wall (often made of external master levee material), to erosional entrenchment and other types of terrace, to passive onlap of underfit late stage meanderform channel internal levee. Lateral rotational block failure and associated scalloped slump scar wall morphology, is often difficult to distinguish from internal levee and associated meander cut banks, though either can co-exist.

External to many of the slope channel complex systems are extensive master levee complexes, which are not always included in conventional models for slope channel complex system architecture. These external master levee complexes may themselves record multiphase occupancy of the main slope channel complex system, with each phase of levee build recording (i) a precursive phase of external crevasse splay build, followed by (ii) the principal phase of spill cap aggradation of the master levee, terminating in (iii) shutdown and hemipelagic drape of the external master levee complex. The timing of master levee build is also interpreted differently in current models, and needs further investigation here.

Beneath the slope channel complex systems, sedimentary

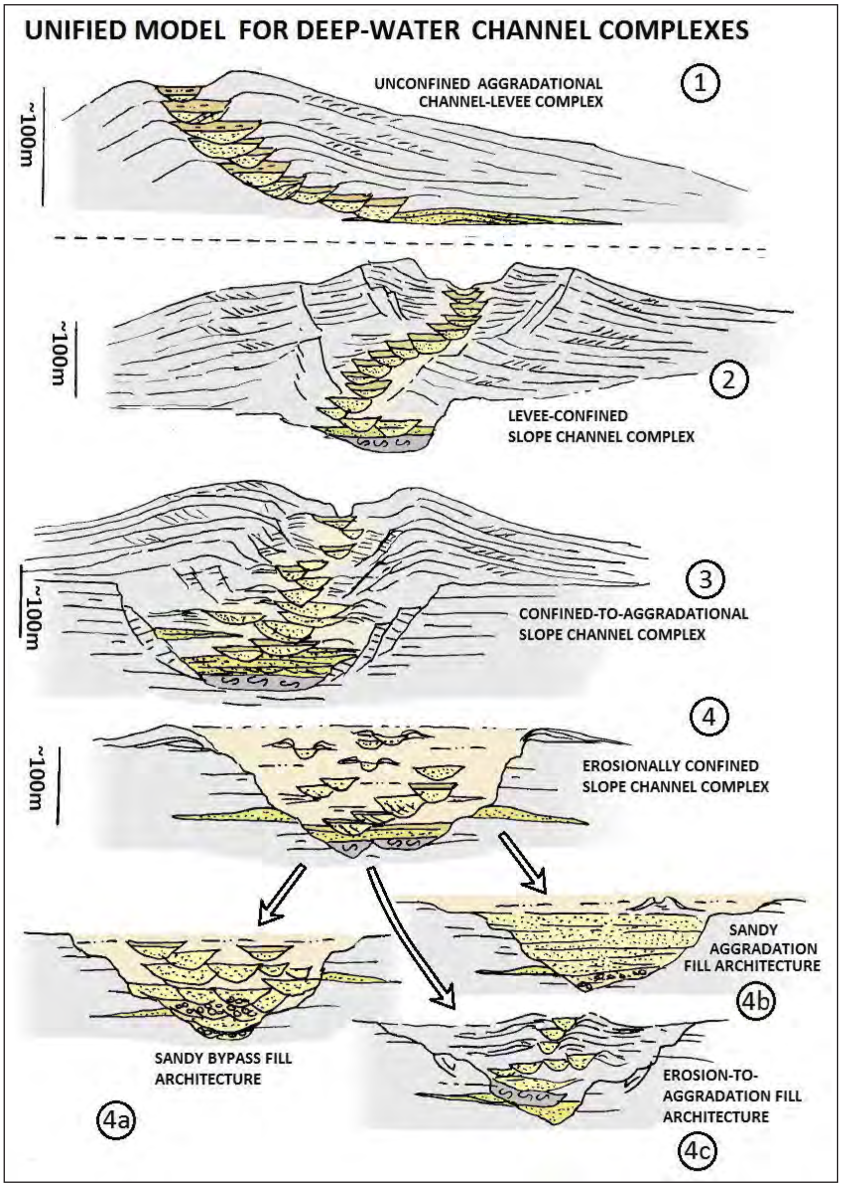


Figure 2. Unified model for deep-water channel complexes

architecture is highly variable, reflecting the position of the system on the slope or shelf. Some systems are highly entrenched and have excavated headwards on the upper slope, where they evolve to canyons, cutting into highstand shelfal systems such as deltas, beach-barrier systems or offshore bars. Further down system, in upper to mid-slope settings, slope channel complex systems are often preceded by mass-transport complexes, which may have initiated system entrenchment by providing diversion and fairway access to sand on the shelf. Channel complex systems may touch down onto, or erode through, such mass-transport complexes, leaving residual erosional remnants of the mass-transport complex lateral to the slope channel complex margin. Channel complex systems further downslope may also touch down into or erode through precursive frontal splay complexes, that were initially deposited outboard of the channel system. Distinguishing precursive frontal splays, from unrelated highstand deposits, and from crevasse splays, also requires further investigation here.

A unified model for entrenched slope channel complex systems is proposed that captures internal channel belt, external master levee complex, and precursive architectural element character, based on outcrop examples from the Cerro Torro Formation of southern Chile, various formations from southern and eastern Turkey, and the Eocene of the Spanish Pyrenees; seafloor examples from the Mediterranean and western California; and subsurface examples from offshore Myanmar, Equatorial Guinea, Angola, the North Sea, Colombia, and Ghana, to reflect commonality and contrast in slope channel complex architecture. The synthesis is long overdue. With the large amount of reservoirs of this style offshore West Africa and elsewhere have come an array of models that are mostly field specific without generic use. This paper draws on many years of work on a large number of global examples. ■

Biographical Sketch

Bryan Cronin is a geologist with 28 years of technical experience with turbidites at outcrop, on the sea floor and in the subsurface. He is currently principal geologist for Tullow Ghana Ltd, based in Accra.

He was an independent consultant (2005-2016), working on deep-water reservoirs in the North Sea, Africa, SE Asia, South America, the former Soviet Union and in other areas. He has running field courses in the Alps, Pyrenees, California, Ireland, Spain and Turkey for many years. He instructed for Petroskills and Nautilus. He is Honorary Professor at University of Aberdeen, The Robert Gordon University and Hangzhou Petrochina Institute for Petroleum Geology.

He is still involved in education and training with MSc and PhD students and oil company employees, with the PRACCS research group where he is joint principal investigator with Ben Kneller, working in southern Chile, Turkey, France, Argentina, Tibet and Mexico.

Professor Cronin was awarded the William Smith Fund by the Geological Society, London, in 2007.

His list of publications is extensive and in most mainstream peer reviewed journals.

Wednesday, September 12 | Theme 3 | 9:00

Max Casson, Jonathan Redfern
North Africa Research Group (NARG), Williamson Building, University of Manchester, UK.
Luc G. Bulot
North Africa Research Group (NARG), Williamson Building, University of Manchester, UK.
Aix-Marseille Université, CNRS, IRD, Collège de France, Cerege, Site Saint-Charles, Marseille, France.
Jason Jeremiah
Golden Spike Geosolutions Ltd, Stevenage, Hertfordshire, UK.

Towards the Development of an Integrated Central Atlantic Tectono-Stratigraphic Framework

The Central Atlantic region is an under-explored world-class hydrocarbon province. The recent oil and gas discoveries on the West African Atlantic margin and the Guyana/Suriname margin further confirm the significant resource potential of Central Atlantic basin. This paper presents results from an ongoing multi-disciplinary project that aims to define a new stratigraphic framework for the Mesozoic in the Central Atlantic by integrating a suite of geoscience data from outcrop and subsurface wells. The results are already identifying pan-Atlantic sequence stratigraphic surfaces, improving stratigraphic resolution and providing insights into the geographical extent of source rock development.

During the late Mesozoic, the Central Atlantic region was a large enclosed basin; this offers the potential to compare the conjugate margins to provide a comprehensive assessment of basin evolution. The new biostratigraphically-constrained framework employs numerous dating techniques, including: calcareous nannofossils, calpionellids, palynology, and ammonites, to build a high resolution age model. New data includes detailed logging and sampling of the exposed Mesozoic stratigraphy of Maio, Cape Verde, a re-evaluation of 7 IODP sites, integration of data from available exploration wells across the region, and logging of exposed sections of Cretaceous sediments outcropping at Cap de Naze, Senegal. This extensive dataset covers a broad geographical area along the African and conjugate margin.

Cumulatively, over 400 samples have been collected and analysed. Early results include a new interpretation from DSDP Leg 41 Site 367 that highlights a previously unreported Lower Berriasian unconformity (LBU), which removes much of the late Tithonian sediments. This scientific borehole is a key data point in the basin. Detailed logging also identifies more extensive black shale development, indicating anoxia is more widespread stratigraphically than previously recorded. In ODP 207-1258C, DSDP 41-367, and 41-368 anoxia extends beyond the known global anoxic events throughout the late Albian into the Cenomanian. Similar observations at the OAE-1A event (earliest Aptian) are recorded across the Atlantic. Multiple source rock facies are observed throughout the stratigraphy, characterised by TOC and pyrolysis analysis, which are being integrated to better understand the hydrocarbon generating potential of these rich source rock intervals.

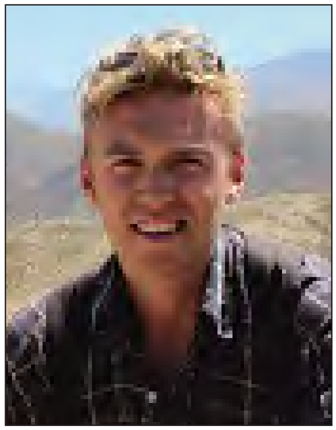
High core recovery in DSDP 76-534a has permitted a new interpretation of the Base Albian unconformity (BAU), recognised elsewhere across the Atlantic (Morocco - Luber et al. 2017), suggesting there is a significant super-regional event at this time. This is associated with a major progradational phase of deltaic systems on both sides of the conjugate margins during the Albian, delivering plant debris-rich sediment to the deep basin (Type III source rocks) and forming prolific reservoirs on the shelf (i.e. SNE field, Senegal). Further work by NARG defining exhumation rates from low-temperature thermochronology data in northwest Africa, suggests a pulse of source area uplift around 120Ma. Hence at this time, a source to sink approach is used to postulate the mechanisms for this significant unconformity.

Fieldwork data from Maio strongly supports this model and a clear, refined stratigraphic correlation has been made to the DSDP-based framework. Multi-technique, biostratigraphical analysis has improved the dating of these sediments from previous work and a composite, fully integrated type-section from the island is presented. Early applications of the stratigraphic framework to seismic data in the West African Atlantic margin strengthens our interpretations to allow better prediction of reservoir and source rock development, understanding of the sequence stratigraphy, and regional knowledge of the basin evolution.

Reference

Luber, T.L., Bulot, L.G., Redfern, J., Frau, C., Arantegui, A., & Masrour, M., 2017. A revised ammonoid biostratigraphy for the Aptian of NW Africa: Essaouira-Agadir Basin, Morocco. Cretaceous Research, 79, pp.12-34.

Biographical Sketch



Max Casson is working in the North Africa Research Group at the University of Manchester on his PhD project examining the regional geology of the NW African Atlantic Margin. Max's research is sponsored by a consortium of oil companies active in NW Africa, as well as an ECORD research grant. Having spent his first year of the PhD collecting data in Senegal and Cape Verde, Max would like to share his initial thoughts towards an integrated tectono-stratigraphic framework for the Central Atlantic.

Wednesday, September 12 | Theme 3 | 9:25

Monica Miley, Amelie Dufournet, Jose Villa
Anadarko Petroleum Corporation
Mark Bentley
AGR-TRACS

Reservoir Modeling of a Deep-Water West African Reservoir: A Fully Integrated, Multi-Scenario Approach

In the early stages of field development, there is a high degree of uncertainty in reservoir description. Creating a range of reservoir models allows proper assessment of reservoir uncertainties in a more rigorous way than using a single base case model. This is crucial in fields with significant geologic and production complexities where new in-fill wells are drilled to accelerate production, increase reserves, and maximize oil recovery. This case study demonstrates the application of a decision tree-based methodology to model multiple uncertainties for an off-shore field in West Africa. The goal was to understand which uncertainties have the most significant impact on fluid flow and create several dynamically tested reservoir models to represent them. Models were created quickly over a small sector area. Initial dynamic simulations provided feedback that improved the seismic interpretation and static model construction for subsequent iterations. An integrated team composed of a geophysicist, geomodeler, and simulation engineer were able to produce a set of geologically plausible, dynamically tested full field models.

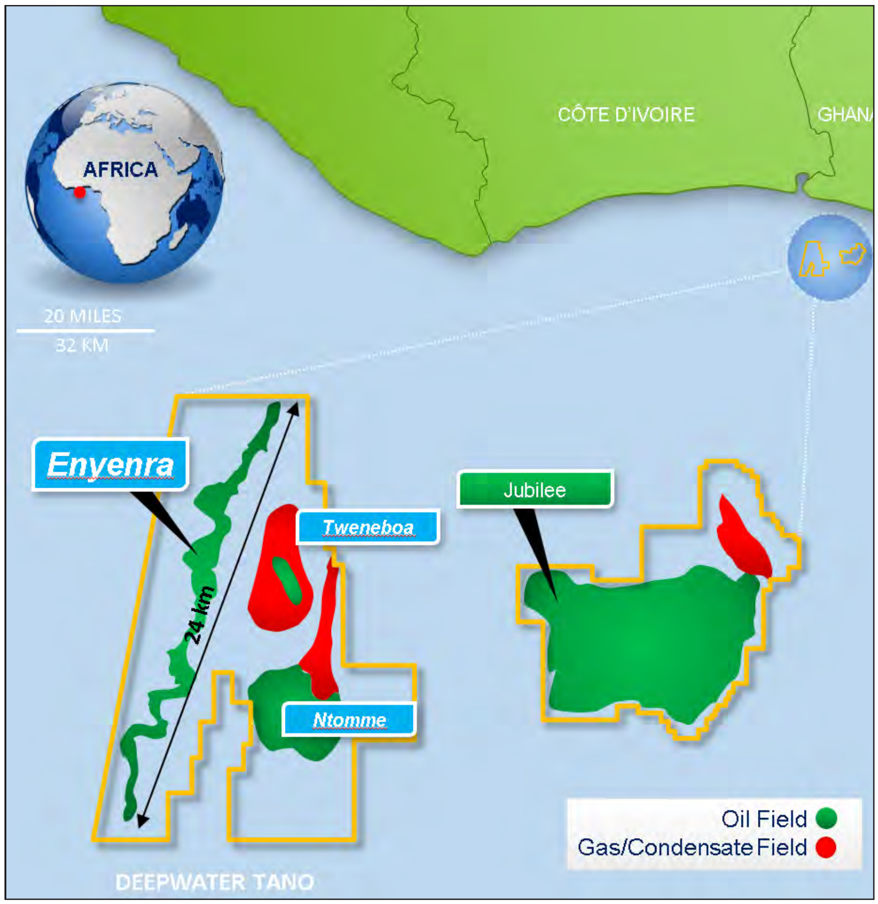


Figure 1. Location map for Enyenra field. The field is located 60 km off the coast of Ghana and 25 km west of the Jubilee field. From the northernmost to southernmost wells, the field extends 24 km and varies in width from 300-1000m.

Background

The subject of this study, the Enyenra field, is part of theTweneboa-Enyenra-Ntomme (TEN) complex of fields. It is located in the Tano sub-basin of the Deep Ivorian Basin between the Romanche and St. Paul fracture zones. Basement-rooted extensional faulting created accommodation space for deepwater deposition. During the Turonian, sediments comprising the Enyenra reservoir were shed from the Tano high and deposited in the lower to middle slope as a series of aggradational levee-confined channel complexes. The reservoir is trapped laterally by stratigraphic pinch-outs and updip by faults or pinch-outs.

Enyenra is located 60 km offshore from Ghana and 25 km west of the Jubilee field in water depths varying from 1400 to 1700 m (**Figure 1**). From the northernmost to southernmost well, the field extends 24 km and is 300 to 1000 m wide. The Owo-1 discovery well, drilled in 2010, encountered 46 m of oil pay. Eleven wells have been drilled, six of which were completed as producer-injector pairs spaced 2 km apart. Production started in August 2017 and the current production rate is 35 MSTB/day. As of May 2018, the cumulative oil produced is 18 MMSTB and 26 MMSTB of water have been injected. Current recovery factor is 4%. Data used in this study include dual azimuth seismic data from 2014, three cores, well logs, pre-production drill stem tests, interference tests, and production data.

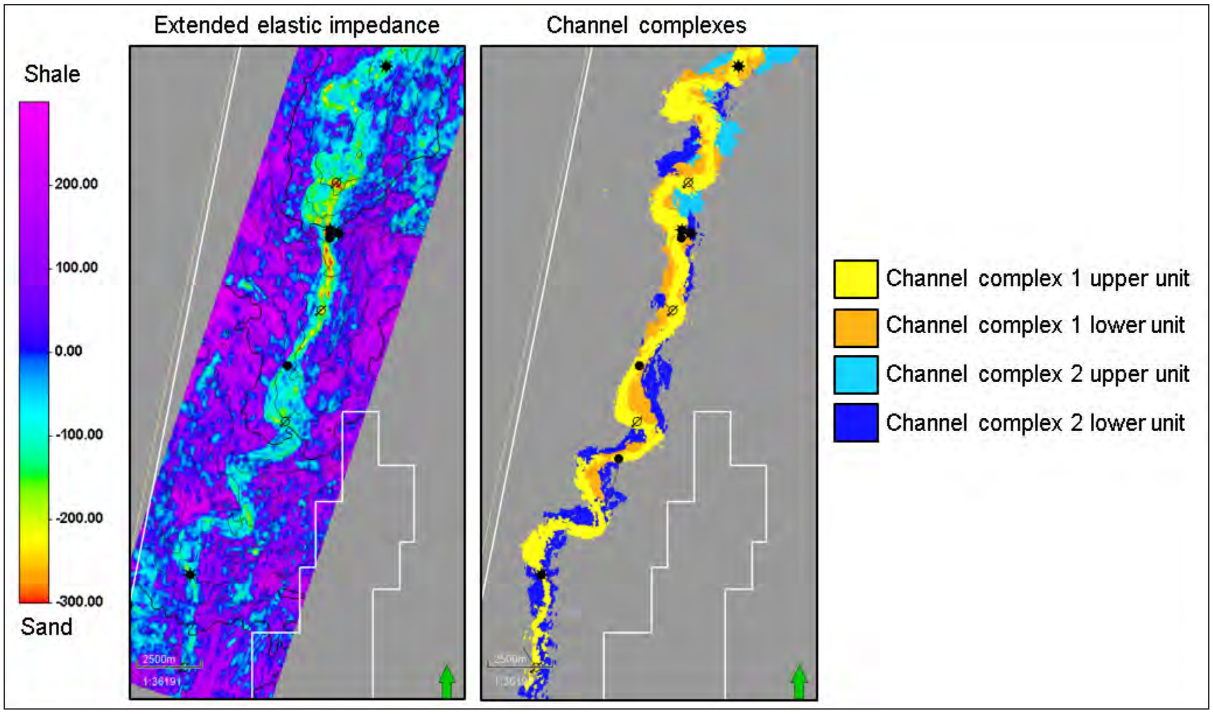


Figure 2: Sum of negative amplitudes extracted from an extended elastic impedance volume showing possible sand distribution. Four channel complexes were identified on seismic data and verified with static pressure data.

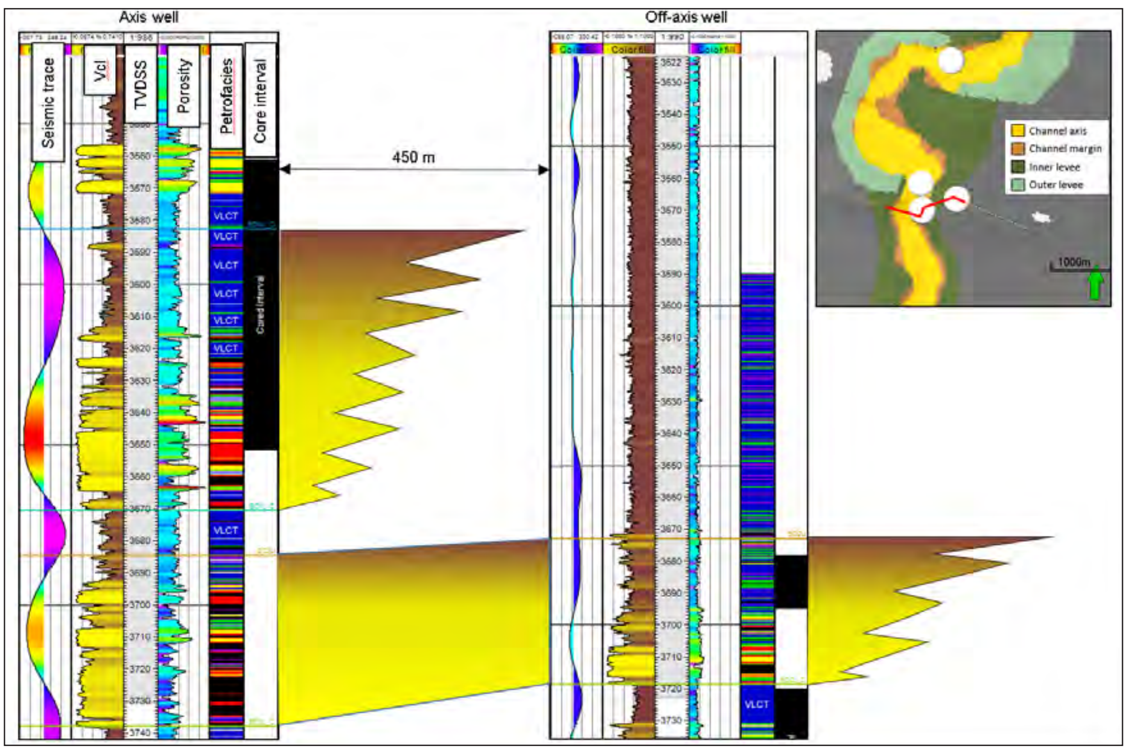


Figure 3. Wells inside and outside the channel axis show a highly variable net to gross.

Due to the channelized nature of the deposits, there is a high degree of stratigraphic complexity and potential for compartmentalization. Multiple channel complexes have been identified and interpretation of these is complicated by variation in erosion rates, stacking patterns, and sinuosity (**Figure 2**). Individual reservoir intervals are identified by upward fining successions on gamma ray logs. Reservoir extent and continuity are further validated through integration of seismic interpretations, static reservoir pressures, and interference tests. Reservoir quality is highly variable in and outside the channel axis making the location and description of this boundary critical in modeling (**Figure 3**). There are also finer-scale heterogeneities observed at the core scale: a range of facies types from traction to muddy debrites to cement with varying porosity-permeability relationships that will exhibit different flow behaviors (**Figure 4**).

Production from the Enyenra field has had a number of issues. Wells are currently equipped with inflow control devices allowing continued production/injection from different reservoir intervals, but some production allocation issues have been observed. High-pressure water injection created hydraulic fractures in some injectors. In addition, there is a short production history and no evidence of water breakthrough. All of these factors impact the dynamic response of the reservoir during the process of model calibration and history matching.

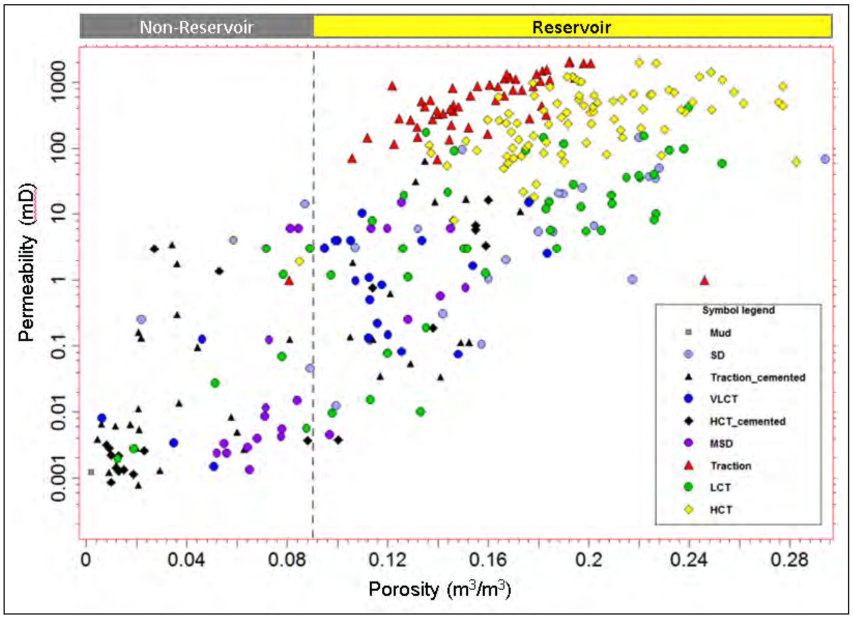


Figure 4. Facies identified from core were grouped into 8 primary petrofacies. Based on similarities in porosity-permeability trends, these were recombined into 5 groups representing different responses to fluid flow.

Methodology

Given the large number of uncertainties, it was important to evaluate them systematically and understand which have the most significant impact on fluid flow. They were divided into geologic, modeling, and dynamic uncertainties, and organized in a decision tree with a range of possible values. These possibilities were combined in multiple ways to create a suite of reservoir models (**Figure 5**).

To quickly build and simulate these models, a subset of the field (15% of the total area) was selected for a sector model study. This area showed a variety of stratigraphic and production complexities, representative of the larger field. Various styles of seismic interpretation were created and multiple models were generated from these using different combinations of geologic and modeling uncertainties. These models were dynamically tested and the simulation engineer, geomodeler, and geophysicist jointly analyzed the results in an iterative loop shown in **Figure 6**. Together, the team learned which factors were of most importance and focused on those for subsequent rounds of testing.

During this phase, only six months of production data were available. The dynamic models were constrained by daily production and injection rates. The difference between the simulated pressures and observed pressures were compared for the different scenarios from the decision tree.

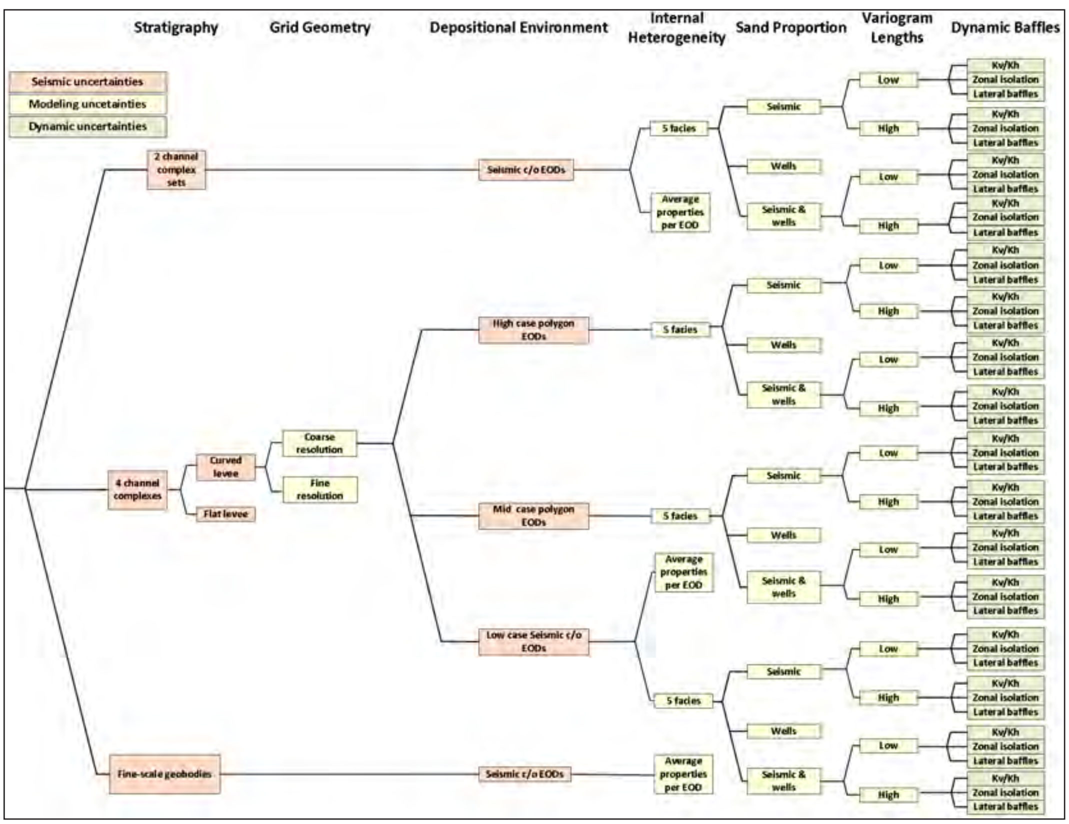


Figure 5. Decision tree illustrating the seismic, modeling, and dynamic uncertainties considered in model construction.

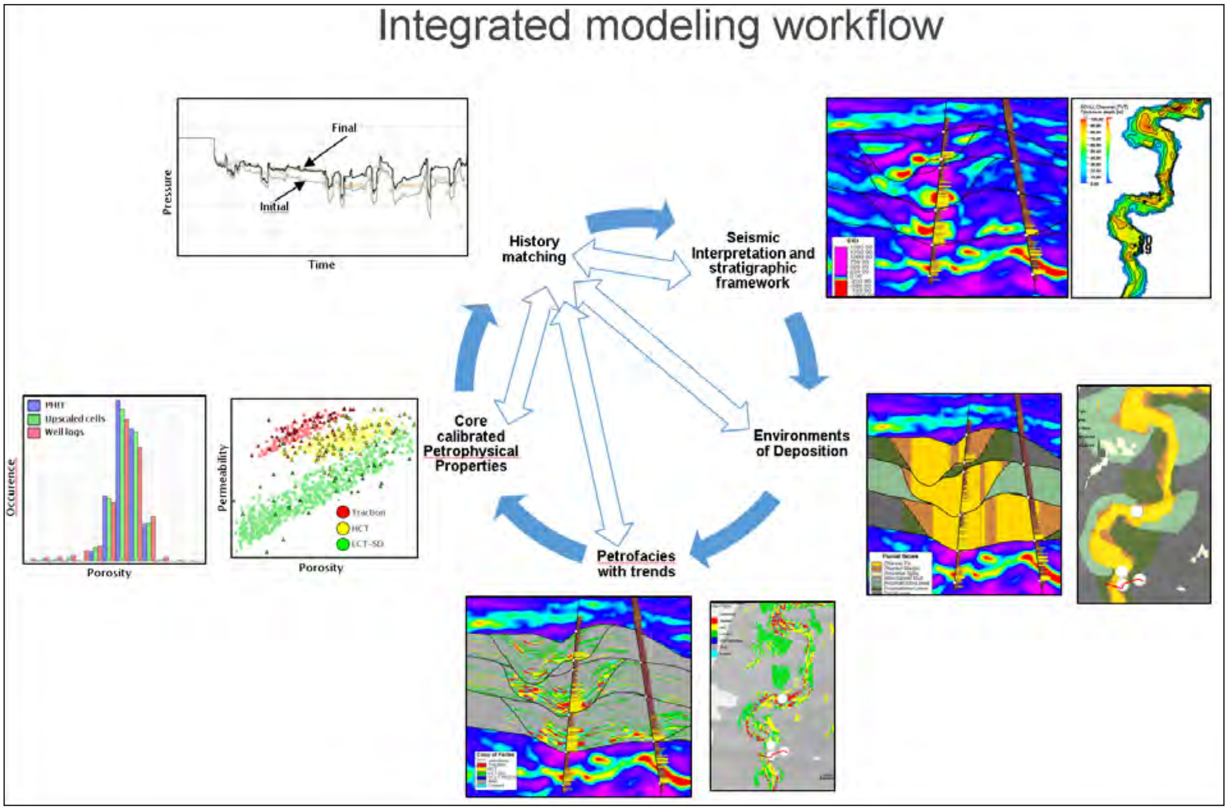


Figure 6. Integrated modeling workflow illustrating the loop from seismic interpretation to static modeling to dynamic simulation and the feedback provided by history matching to update the seismic interpretation and static model.

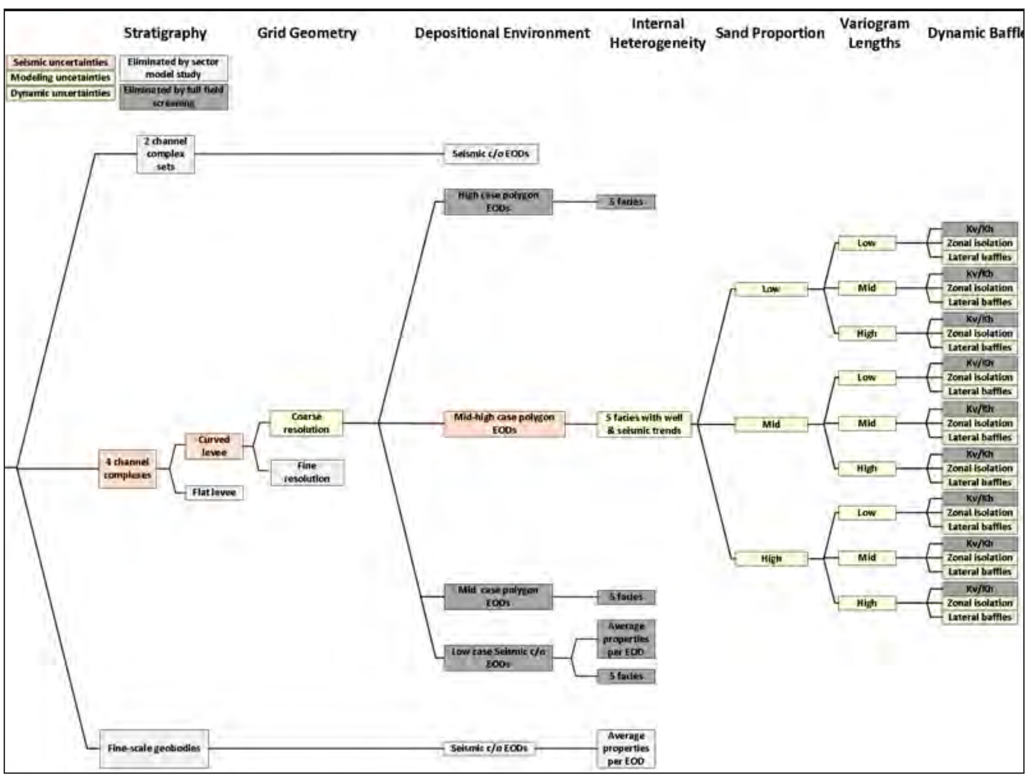


Figure 7. Simplified decision tree after testing in sector area.

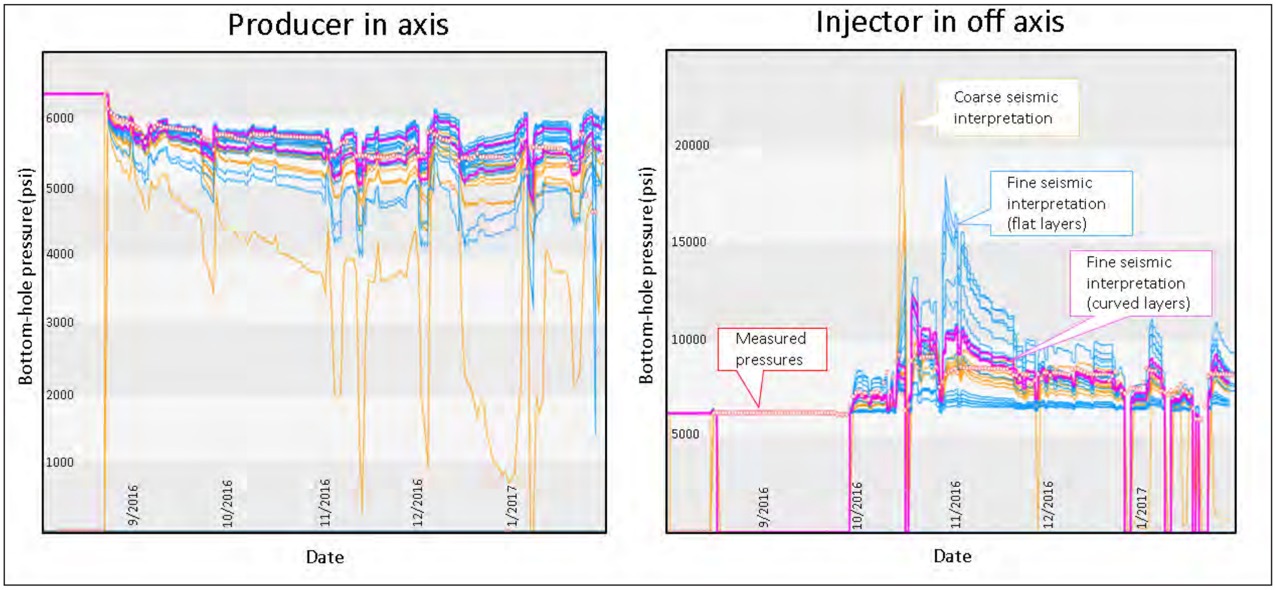


Figure 8. Comparison of actual bottom hole pressures (red circles) and simulated pressures for various scenarios (colored lines) over six months. These results indicated that the coarse-scale seismic interpretation (yellow lines) produced pressures that were too low, suggesting the models were too disconnected. Using curved layers in the fine scale seismic interpretation (pink lines) produced a better match between modeled and actual pressures.

Results

The sector model testing reduced the number of plausible models resulting in a simplified decision tree, shown in **Figure 7**. Following are some details on how various branches of the tree were retained or discarded.

Seismic interpretation styles from channel sequence (coarse) to channel scale (fine) were tested along with different variations of channel geometries. Comparisons of predicted versus actual pressures indicated that a fine-scale (channel complex scale) interpretation of four continuous complexes produced the best match (**Figure 8**).

Environments of deposition such as channel axis, margin and levee, were defined in various ways: using seismic amplitude cutoffs or polygons interpreted on amplitude and thickness maps. History matching showed that 3D amplitude-based cutoffs produced models that were too disconnected, so this branch of the decision tree was discarded from future testing.

Grid resolution was tested early so that simulations could be accelerated using a coarser grid without compromising the desired level of geological realism.

Fine-scale uncertainties were also tested. The layering style of the grid was especially critical for wells located near the channel-levee boundary. There is a large variation in net to gross in this area which impacts how these regions are connected to each other. History matching provided guidance on connecting these regions into a single zone, indicating that layers should follow the base of that zone (curved layers) rather than pinching out as flat layers (**Figure 8**).

Other fine-scale uncertainties evaluated were the vertical and lateral extents of petrofacies derived from seismic and well data. Testing showed longer correlation lengths, implying greater connectivity, led to better history matches.

The proportion of petrofacies was also a major uncertainty due to limited sampling. Petrofacies were populated using a soft trend based on seismic amplitudes. Vertical proportion curves were implemented to distribute traction facies at the base of channels and shalier facies at the top.

The location of lateral baffles were derived from seismic amplitude extractions showing potential discontinuities in the reservoir. Different global permeability adjustments were applied to the straight and sinuous portions of the channels to account for varying connectivities and predictable contrasts in effective permeability in areas of contrasting depositional architecture. The number and location of these additional baffles were verified by history matching.

In two months of testing, the range of uncertainty was narrowed as several branches of the decision tree were eliminated. Remaining uncertainties such as transmissibility multipliers, petrofacies proportions, and correlation lengths were combined to generate a range of plausible models. From this range, independently derived low, mid, and high case models were selected. This approach is more valuable in the context of uncertainty assessment than creating a single base case model or generating an ensemble of purely stochastic permutations of a single underlying concept.

Conclusion

The benefit of this workflow is to systematically create a range of reservoir models by identifying multiple complexities at different scales and testing them to understand which are the most important for fluid flow. By confining the work to a sector area, the team quickly learned which modifications needed to be made to the static model rather than applying more blunt modifications in the dynamic model. The sector model workflow was employed to make multiple full field models by extending the seismic interpretation and incorporating all wells. These models have been used to optimize locations of infill wells and assess the value of accelerating production. There is greater confidence in the predictability of these models as minimal adjustments to the dynamic model were required to achieve history matches. ■

Biographical Sketches

Monica Miley currently works for Anadarko Petroleum as a project geophysical advisor for the Ghana development team. Her experience also includes carbonates in Brazil and onshore East Texas. She was previously employed at Chevron and Houston Advanced Research Center in technology groups focusing on seismic attributes and data processing. She earned a Master's degree in Geophysics at Rice University and a Bachelor's degree in Geology at University of Rochester.

Amelie Dufournet currently works for Anadarko Petroleum as a contract geomodeler in the Ghana development team. She was formerly employed by Maersk Oil as a geomodeler on fields in West Africa, and by Schlumberger. She earned a Master's degree at Universite Pierre et Marie Curie.

Jose Villa currently works for Anadarko Petroleum as a Senior Staff Reservoir Engineer for the Ghana development team. He previously worked for Shell International E&P and PDVSA-Intevep in several teams including Integrated Reservoir Modeling (IRM), Water Flood Deployment, and Modeling and Optimization. His experience includes onshore and offshore fields in Venezuela, Norway, Brazil, Nigeria, and USA. He earned a MS degree at Stanford University and a BS degree at Central University of Venezuela, both in Petroleum Engineering.

Mark Bentley is Training Director at AGR TRACS and an Associate Professor at the Institute of Petroleum Engineering at Heriot-Watt University in Edinburgh. He has spent most of his career working in or leading integrated study teams and his specialist fields of expertise are 3D reservoir modelling and scenario-based approaches to handling subsurface uncertainty and risk. He is co-author of the textbook *Reservoir Model Design*. He is a graduate of the University of Wales with a PhD in structural geology.

Wednesday, September 12 | Theme 3 | 9:50
Luisa Man, Tom Wilson
Core Laboratories UK

Sedimentological Characteristics of Deepwater Sandstones Associated with Transgressive-Regressive Cycles Offshore Ghana

Stratigraphic and sedimentological data from over 50 wells, courtesy of the Petroleum Commission, Ghana, have been analysed to construct a stratigraphic framework and sedimentological logs, enabling a series of paleogeographic maps to be drawn. Detailed mapping of sand fairways through successive stratigraphically-defined packages provides a valuable resource for successful exploration within this complex West African petroleum province. The data shows that in the Tano Basin a series of deepwater sands were deposited during the Upper Cretaceous which are related to major sequence boundaries; these may be tectonically or eustatically driven. The maturity and grain-size of these sandstones varies up-section and is related to the tectono-stratigraphy of the Equatorial African margin.

High resolution palynological, micro- and nannopaleontological data have enabled a series of major sequence boundaries to be identified in the deep water sediments offshore Ghana; these include the Middle Cenomanian, Middle Turonian, Santonian, and top Cretaceous. The biostratigraphic data has been integrated with the logs, including INPEFA curves generated in CycloLog software, to assist with the stratigraphic interpretation. The log trends have been used to erect a series of sediment packages (StratPacs) in the Upper Cretaceous, UK1 to UK7. The rapid changes in sediment thickness and type associated with deepwater sediments of this kind hinders log correlation and make good quality biostratigraphic data crucial for well correlations.

Transgressive Middle-Lower Cenomanian limestones and shales are overlain by a unit of Upper Cenomanian silty mudstones and/or sandstones within the lower part of UK2. Deep marine mudstones and siliceous mudstones were deposited above this in the Turonian (upper UK2).

The top of the Middle Turonian is identified biostratigraphically within this transgressive section and commonly, but not always, is located at the base of a unit of gravity flow sands. Widespread erosion is not associated with this boundary and it appears to be related solely to sea level fall. Within the Mid Cenomanian-Mid Turonian succession (UK2), sedimentological analysis of logs and core material from Tano Basin syn-transform succession, reveals a range of very thick bedded fine to medium-grained stacked channel sandstones, thin conglomerates, and pebbly sandstones, deposited as a result of alternating turbidity and debris flows. Some of the conglomerates present pebble-sized sub-rounded to angular quartz particles. Conspicuous slumping, sand injection, and convolute lamination suggest unstable settings and frequent slope and channel margin collapse.

Regressive trends in the Upper Turonian-Lower Coniacian (UK3) reflect the reservoir sandstones which were first found to be oil bearing in the Tano Basin, and grade into deep marine mudstones at the top of this package. Coniacian sediments are notable for variably containing the first downhole occurrence of Late Santonian, Early Santonian, and Coniacian microfossils. This clearly indicates the presence of a break in section and in many cases the Upper Santonian is seen sitting unconformably on the Lower Coniacian. This period of non-deposition/erosion could be seen as an amalgamation of the Sa1 and Sa3 sequence boundaries (Haq and Schutter 2008 / Hardenbol et al., 1998). However, transpression is known to have occurred along the Equatorial African margin at this time and the unconformity is regarded as at least partially tectonic in nature. It is notable that despite this the lithological change at the boundary is minor and in many wells the contact occurs within marine mudstones. Within the Upper Turonian (UK3) interval, cored sections intercepted significant sand deposited in a series of channel-sheet/channel complexes composed of very fine to very coarse, locally pebbly sandstone beds, showing blocky to FU trends. The succession includes thick stacked amalgamated units deposited largely by dumping and waning of high-density turbidity currents, with some intervals of traction sedimentation developing cross-stratification and flat lamination. Conspicuous deformation, dewatering, and structureless features are interpreted as recurrence of debris flow, slump and channel margin collapse.

The Upper Santonian to Campanian (UK5-UK6) comprises a thick mud dominated interval, which can be difficult to sub-divide biostratigraphically due to more hostile surface water conditions. The broadly regressive trend reflects a reduction in subsidence and gradual filling of the basin; multiple phases of sand deposition have been identified. Observed core material in the Upper Santonian-Upper Campanian succession (UK5) penetrated deep shelf-slope proximal to distal lobe facies presenting thick to thin bedded and amalgamated channel-sheet/channel complexes encased by low gamma, organic-rich to red-stained and slumped claystones. The sandstones are mainly fine to medium-grained with common carbonaceous drapes, locally interbedded with thin pebbly sandstones beds that fine upwards to sandy claystones, indicating gradual loss of sand. Analysed logs and cuttings material from Latest Campanian (UK6) show mud-prone successions with isolated fine to medium-grained slope channel sands present at several distal locations. In some offshore wells recurrent bypass to the deeper basin might occur.

The top of the Campanian is associated with a transgressive surface overlain by distinctly higher gamma mudstones of the Maastrichtian (UK7). No sandstones are present in the Maastrichtian, and its top is marked by a significant unconformity with Upper Paleocene (LT1) sediments sitting on a probably incomplete Maastrichtian interval. The Maastrichtian lithologies reflect peneplantion of the hinterland, and the final reduction of sand supply to the basin.

The reduction in sand supply concomitant with sand maturation (texturally and compositional) is evident when comparing the Cenomanian-Turonian to the Campanian deposits. Uplift and transpression in the Santonian probably rejuvenated the hinterland and provided the coarser sediments seen in some wells, resulting in sand deposition throughout the Campanian.

Biographical Sketch

Dr. Luisa Man joined Core Laboratories in 2011 as a sedimentologist in the regional studies group (Integrated Reservoir Solutions), specializing in core description, reservoir sedimentology, and facies analysis. Since joining the group, she has been involved in recognition of depositional environments and facies analysis from core and log data in regional and proprietary studies with emphasis on the Atlantic Margin basins of West Africa and Southern America. In her current position as Staff Geologist, she specializes in the paleogeographic mapping through the integration of all sedimentological, petrographical, stratigraphic, and structural data-sets. Dr. Man did her PhD in the University of Bucharest, Romania studying sedimentary siliciclastic and mixed deposits of Upper Miocene shelfal sediments from the western flank of the Focsani Basin. She frequently attends international industry conferences, at which she has presented a number of poster and oral presentations on African Basins.

Wednesday, September 12 | Theme 3 | 10:40
Cynthia J. Ebinger, SarahJaye Oliva, Ryan Gallacher
Department of Earth and Environmental Sciences, Tulane University, New Orleans, LA, USA
cebinger@tulane.edu

Magmatic Modification of African Crust: Implications for Strain Localization and Basin Subsidence

The Cenozoic East African Rift (EAR) and Cameroon Volcanic Line (CVL) formed on the slow-moving African continent, which last experienced orogeny during the Pan-African. We synthesize primarily geophysical data to evaluate the role of magmatism in shaping Africa's crust. In young magmatic rift zones, melt and volatiles migrate from the asthenosphere to gas-rich magma reservoirs at the Moho, altering crustal composition and reducing strength. Within the southernmost Eastern rift, the crust comprises ~20% new magmatic material ponded in lower crustal sills (underplate), and as sills and dikes at shallower depths. In at least one area, the rift topography and low density intrusive bodies cause a local rotation in the regional stress field, enhancing transverse rift structures linking segments. In the Main Ethiopian rift, intrusions comprise 30% of the crust below axial zones of dike-dominated extension. In the incipient rupture zones of the Afar rift, magma intrusions fed from crustal magma chambers beneath segment centers create new columns of mafic crust, as along slow-spreading ridges. Our comparisons suggest that transitional crust, including seaward-dipping sequences, is created as progressively smaller screens of continental crust are heated and weakened by magma intrusion into 15-20 km-thick crust. In the 30 Ma-Recent CVL, which lacks a hotspot age-progression, extensional forces are small, inhibiting the creation and rise of magma into the crust. Our syntheses show that magma and volatiles are migrating from the asthenosphere through the plates, modifying rheology, changing crustal density, and enhancing strain localization to magma intrusion zones. We interpret lower crustal seismicity and seismic velocity patterns in the magma-poor Tanganyika rift as evidence for the onset of magma intrusion at the crust-mantle boundary, offering new insights into the time progression of strain localization, and geotherms. ■

Wednesday, September 12 | Theme 3 | 11:05
Jon Teasdale
Geognostics International Limited
Colin Reeves
Earthworks BV

An Animated Model for the Mesozoic-Recent Tectonic Evolution of Sub-Saharan Africa: From Plates and Structures to Basins and Paleogeography

Ever since its Paleozoic Gondwanan origin, Africa has never been entirely stable. Progressive breakup and formation of Africa per se spanned more than 200 myr from Late Triassic to Neogene, forming and then modifying basins via a complex series of tectonic events. This process has been fundamentally controlled by pre-existing basement structure and rheology; most basins have formed via reactivation of older structures under a succession of different stress regimes. Understanding these events and basin phases is key to exploring Africa effectively.

Here we present a "bottom-up" interpretation of Africa, starting with basement terranes and structural fabric. We have undertaken a rigorous interpretation of regional, Mesozoic to Recent map-view structures that explains the location and framework of basins, based on geological maps and publications, gravity, magnetics, and seismic. We have paid particular attention to interpreting the oceanic fabric surrounding Africa to constrain the kinematics, plate motions, and timing of breakup. We have then worked back in time to undo these deformation patterns and accurately reconstruct Africa to its Gondwana origins.

The resulting structurally constrained, animated plate tectonic model for the evolution of Africa explains how basins have been formed and modified. Importantly the model is globally consistent as it is part of the Geognostics Earth Model (GEM). Because of its structural constraints, GEM is by far the most accurate plate model available – it can even be used to reconstruct wells, seismic lines, and play fairways from one conjugate margin to another. It is a powerful tool for understanding basin formation and paleogeography, particularly for source rock and reservoir prediction, as well as trap timing and kinematics.

In West Africa, Late Triassic to Early Jurassic rifting and magmatism opened the early Central Atlantic, linked to the proto-Gulf of Mexico via a series of sinistral transtensional basins. This controversial new tectonic interpretation of Pangea breakup has significant implications for the kinematics, timing of basin development and segmentation of the West African margin, hence marine restriction, and source rock and salt deposition.

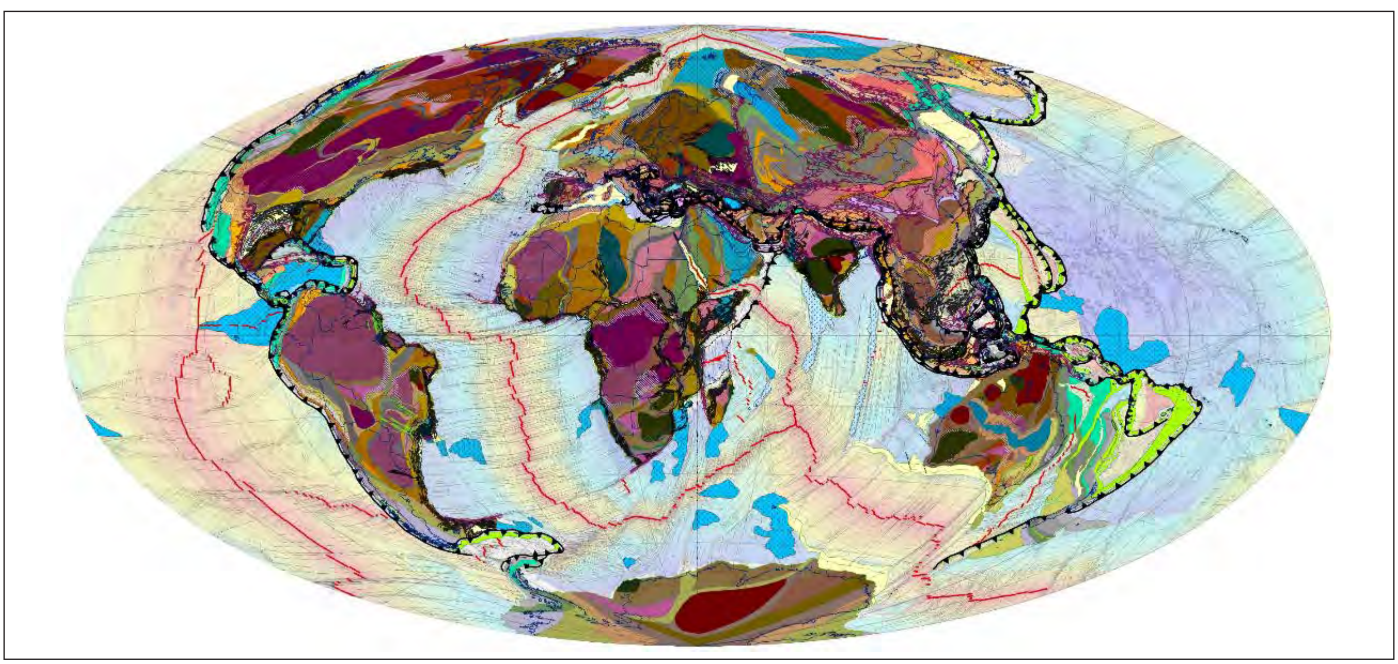


Figure 1. The present-day starting point: the Geognostics Earth Model (GEM)

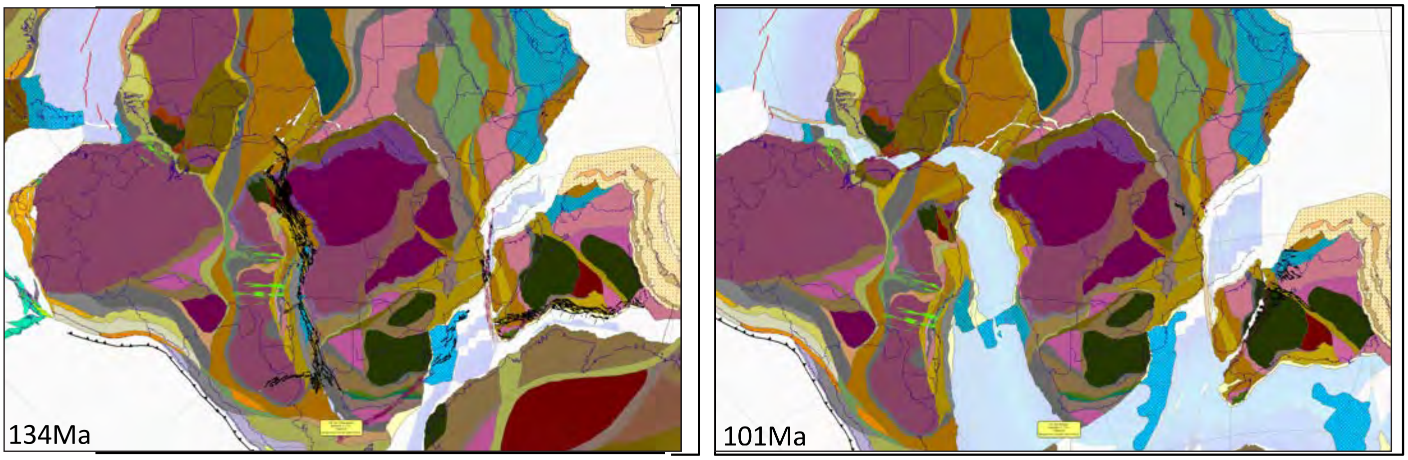


Figure 2. Screenshots from the animated model illustrating its level of detail

In East Africa we identify an Early Jurassic, NW-SE-directed rift event that opened a series of narrow, isolated, salt-prone basins along the entire margin. A major kinematic change in the Kimmeridgian (~155 Ma) initiated N-S-trending dextral transpressional shear between East and West Gondwana, including the Davie Transform. Once Antarctica cleared SE Africa thus "unlocking" the Falklands Plateau from Africa, Pacific-derived slab rollback caused progressive opening of the South Atlantic through the Early Cretaceous, "unzipping" it from south to north. Two main rift systems are interpreted, with an accommodation zone in the Santos Basin of Brazil. Significant internal deformation in Africa accompanied this phase of Gondwana breakup, via a tripartite system of transtensional rifts that extended from Nigeria to Kenya, and NW into Chad and Niger.

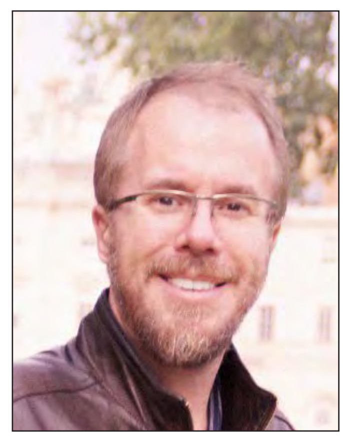
Formation of the Equatorial Atlantic occurred via a complex series of rotational extensional events in the Albian-Cenomanian. Early ~NE-SW-directed extension exploited end-Triassic dykes and basement terrane boundaries to open a series of narrow rift basins. At about 108Ma a shift in the pole of rotation between West Africa and South America initiated a significant dextral shear couple between the two continents, forming a series of deep, oceanic pull-apart basins separated by dextral transpressional fold-thrust belts, culminating in progressive continental breakup through the Cenomanian-Turonian.

Collisions of the African plate with Europe have driven complex inversion events through the Late Cretaceous to Recent. A significant dynamic change in Tethyan subduction rates in the Santonian caused ophiolite obduction along the NE Afro-Arabian margin, as well as significant plate-wide basin inversion, notably in Central Africa. Further inversion in the Maastrichtian was caused by the closure of Neotethys. The Mid Eocene onset of the Alpine collision between Africa and Europe caused widespread uplift and inversion in many Central and North African basins.

Neogene Indian Ocean opening coupled with plume-related uplift caused widespread onshore and offshore rifting in East Africa and the Red Sea, finally forming the present-day outline of the African continent in the Late Miocene.

Our model has significant implications for the paleogeographic evolution of the African margins and interior, with consequent constraints on marine restriction, source rock deposition, salt presence, reservoir distribution, and trap location and timing. We encourage companies to get involved with this work as we endeavour to improve its accuracy and applicability.

Biographical Sketch



After graduating as a geologist in 1992, **Jon Teasdale** worked as a field geologist in remote areas in Australia and Antarctica, mapping complex basement rocks and exploring for gold, uranium, and diamonds. Jon obtained his PhD in Geology from The University of Adelaide in 1997, during which he pioneered new methods for understanding poorly exposed geology. He has worked as a geological consultant for the past 20 years; initially with Etheridge Henley Williams and SRK Consulting serving the minerals industry in Australia, Africa, and PNG. In 1999 he helped form SRK's Energy Services division and co-founded Frogtech in 2004, where he consulted widely in the oil, gas, coal, and geothermal energy sectors in more than 30 countries on all continents. He joined Shell in 2007 as a Global Geological Consultant, where he advised and mentored all Shell exploration teams worldwide. Jon founded Geognostics in 2017, where he built GEM (the Geognostics Earth Model) as an innovative tool for exploring basins. Jon is an expert in non-seismic integration and interpretation, plate tectonics, structural geology, basin modeling, and exploration risk management.

Wednesday, September 12 | Theme 3 | 11:30
William Dickson
DIGs
James W. Granath, PhD
Granath & Associates

Tracing the West and Central African Rift and Shear Systems Offshore onto Oceanic Crust: a "Rolling" Triple Junction

Compared to the understood kinematics of its continental margins and adjacent ocean basins, the African continent is unevenly or even poorly known. Consequently, the connections from onshore fault systems into offshore spreading centers and ridges are inaccurately positioned and inadequately understood. This work considers a set of triple junctions and the related oceanic fracture systems within the Gulf of Guinea from Nigeria to Liberia. Our effort redefines the greater Benue Trough, onshore Nigeria, and reframes WCARS (West and Central African Rift and Shear Systems) as it traces beneath the onshore Niger Delta and across the Cameroon Volcanic Line (CVL), **Figure 1**. We thus join onshore architecture to oceanic fracture systems, forming a kinematically sound whole. This required updating basin outlines and relocating mis-positioned features, marrying illustrations from the literature to imagery suitable for basin to sub-basin mapping. The resulting application of systems structural geology explains intraplate deformation in terms of known structural styles and interplay of their elements. Across the Benue Trough and along WCARS, we infer variations in both structural setting and thermal controls that require further interpretation of their petroleum systems.

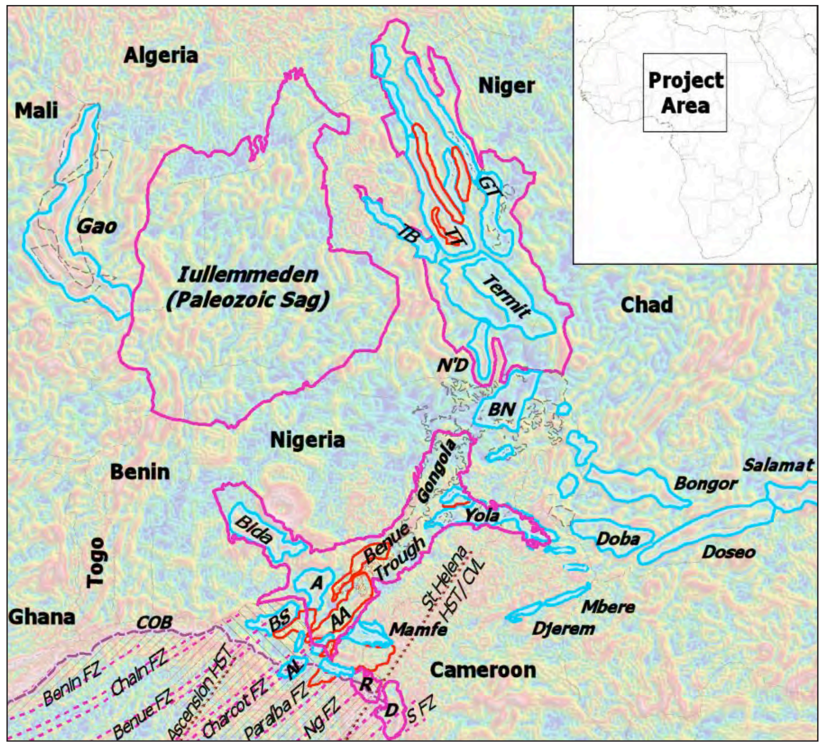


Figure 1. WCARS features. a) General location map (inset). b) Country names (bold); basins (bold italics), oceanic fracture zones (FZ, italics), hot spot tracks (HST). Main basins outlined in mauve; sub-basins in blue; intra-basin highs in red; possible sub-basins in grey dashes. COB = Continental-Oceanic Crust boundary. Basin abbreviations: A: Anambra Basin; AA: Abakaliki Anticlinorium; BN: Benue NE (sub-basin); BS: Benue SW (sub-basin); D: Douala; GT: Grein Trough (Termit Basin); N'D: N'Dgel Edgi; R: Rio del Rey; TB: Tefidet Basin (Termit Basin); TT: Tenere Trough (Termit Basin). FZ abbreviations: Ng FZ: Ngaoundere FZ; S FZ: Sanaga FZ. Backdrop is the total horizontal derivative of the gravity isostatic residual (GI-THD).

Introduction

Excellent work has defined Africa's onshore geology and the evolution and driving mechanisms of the adjacent (particularly the circum-Atlantic) ocean basins. However, understanding of the oceanic realm has outpaced that of the continent of Africa. This paper briefly reviews onshore work. We then discuss theoretical geometry of tectonic boundaries (including triple junctions) and our data (sources and compilation methods). Additional sections discuss application of theory and data to the Gulf of Guinea system; and illustrate an updated interpretation of connecting elements along WCARS via our remapped Benue Trough into the Gulf of Guinea fracture system (**Figure 1**). We conclude by summarizing our efforts and suggest avenues to reassess hydrocarbon exploration along these features.

Africa: Prior and New "Big Pictures"

Following mapping by the colonial surveys, a generation of regional geologists applied 'Big Picture' integrative thinking in Africa per the seminal work of, inter alia, Bosworth, Burke, Fairhead, Genik, Guiraud, and co-authors, establishing the basin-and-craton framework. The Ed Purdy Memorial GIS project (Exploration Fabric of Africa or EFA) then offered a continent-scale view derived from a 1:5MM scale compilation. Although EFA included key structural features such as faults and basin outlines, they were often generalized and mostly

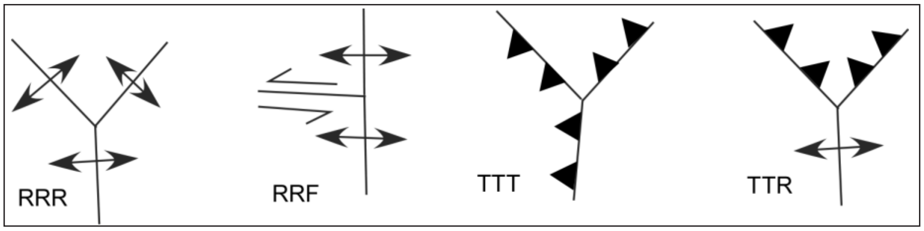


Figure 2A. Simple representation of four triple junctions with different stability relationships. Rift-Rift-Rift (RRR) is stable under all circumstances. Rift-Rift-Transform (RRF) is inherently unstable unless the boundaries are perpendicular and certain rate balances are met. Trench-Trench-Trench (TTT) is stable under certain balanced rates of plate motion. Trench-Trench-Rift (TTR) can be stable if rate balances or equal angles are met.

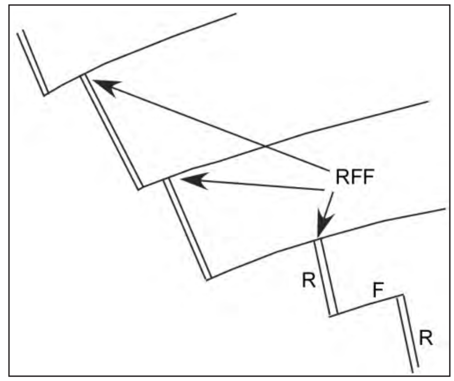


Figure 2B. Left-stepping arrangement of three RFF triple junctions along a generalized extensional plate margin. The triple junctions are formed from by three transform fault systems that penetrate into the right hand plate well beyond the tips of their respective rifts. This is a generalization of the analysis of the Gulf of Guinea triple junction region in this paper.

divorced from underlying genetic linkages. Our synthesis (Tectonic Fabric of Africa, or TFA) uses more advanced data to build upon EFA, connecting adjacent oceanic realms across the continent in a kinematically sound fashion to suggest and define missing tectonic elements. We previously discussed that work (Granath & Dickson, 2016a, b; 2017) for both WCARS and a less-recognized 'Trans-Southern Africa Rift & Shear System' (STARSS), seen in eastern Africa as the Karoo system.

Theoretical Geometries

Triple junctions, while integral to the kinematics of plate tectonics, also illustrate any geology where the relative motion of blocks is involved. Motions are described by the interaction of block boundaries with simple vectors. Boundaries may involve a) ridges, rifts, or extensional margins (R); b) transforms or strike-slip fault systems (F); and c) trenches or convergent margins (T), **Figure 2**. Only some junctions are inherently stable, capable of simultaneously accumulating significant displacements (McKenzie & Morgan, 1969) while maintaining the same vector relationship and so surviving for substantial geologic time. When survival of a triple junction is limited, it usually fragments into two separate triple junctions or one arm is essentially abandoned.

Plate divergence, as in the case of Atlantic opening, produced a series of rift segments that evolved into an ocean spreading system composed of spreading-ridge segments linked by transforms. Beyond the neighboring ridge segment limits, transforms became dormant as fracture zones (FZ). At initiation of continental breakup, transform/FZ locations often corresponded to pre-existing features within the marginal continental block, suggesting some (usually minor and rift-restricted) reactivation. Nascent spreading segments may, however, link with a transform that actively extends into the continent, thus forming a triple junction composed of a transform, the spreading ridge/rift, and an intra-continental fault system. Unless two ocean basins develop between the continental blocks, the situation decays to a transform and a rift segment with abandonment of the third element. The spreading system then drifts away from the two separated continental crustal blocks (e.g. Dewey & Burke, 1974). If the third element is a rift or a trough, at its outset this system forms an aulacogen, sensu Shatsky (1946).

The Gulf of Guinea provides a good example with the West African Transform Margin (WATM) connected to the ridge (or rift) segment running south and in which WCARS was the abandoned arm. The Benue Trough is then likened to Shatsky's aulacogen.

Development of such a system is illustrated by **Figure 3**, a stability diagram a la McKenzie & Morgan (1969), drawn for the Gulf of Guinea system. Figure 3a shows a typical map relationship between FZ precursor in blue, an onshore fault system in red, and the continental margin rift in black. A connected string of these forms a sweep from, i. e. the West African southern extensional margin to the West African Transform Margin.

Figures 3 b and **c** are in "velocity space" with arrows showing displacement vectors between blocks and dotted lines showing orientations of boundaries between blocks. Symbol AvB signifies the vector motion of block A relative to block B (shown by the arrow). For WCARS, we do not know exact angular relationships between elements during the Cretaceous nor the displacement rates on the faults involved, so these vectors are generalized to represent all the component triple "junctionettes". Viewing the triple junction region in this way offers a twofold observation:

1. For small displacements and low displacement rates (**Figure 3b**), there is great latitude in configurations that retain stability, i.e. a rift can connect to two divergent transform segments with a wide angular relationship. If deformation is concentrated at the intersection, internal accommodation can accommodate orientation mismatches, as for example, within the Benue Trough.

Figure 3. Stability relationships for the Gulf of Guinea complex triple junction. Elements of the triple junction: on the west side the fracture zones in blue, rift segments to south (or equivalently north) in black, and onshore African fault systems in red.

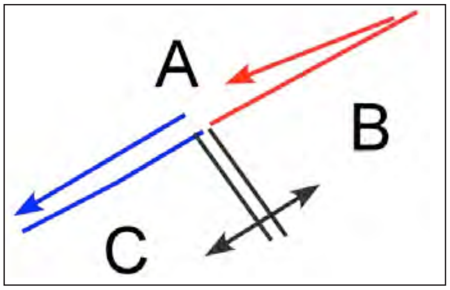


Figure 3A. Map topology as three blocks: the north side of triple junction A, and the two sides B and C of the extensional basin. C will evolve into oceanic crust. Relative displacements between blocks are shown by arrows (e.g. AvB).

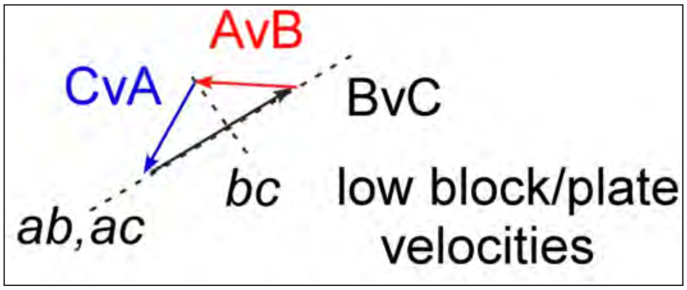


Figure 3B. While displacement rates between the three elements are relatively low and similar (upper right), the system can evolve if the rift segment is allowed to propagate, despite different relative directions of displacement.

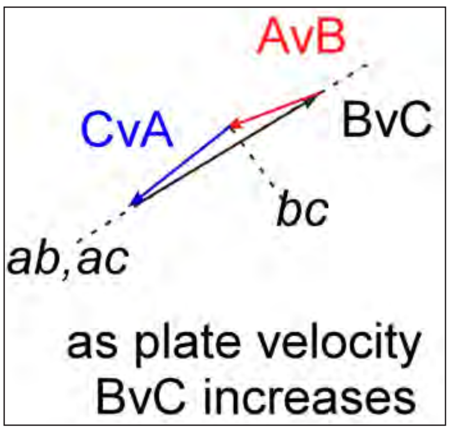


Figure 3C. As oceanic crust is born, and fast plate divergence rates (which usually exceed intraplate rates) begin to apply to the BvC relationship, the triple junction stays stable if AvB and CvB are collinear. Otherwise the triple junction becomes unstable and is abandoned or replaced with a different configuration. One replacement is the introduction of another rift segment, the mechanism by which the rift system propagates along the continental margin and negotiates the plate margin bend in the Gulf of Guinea.

2. At higher displacements or displacement velocities (**Figure 3c**), CvA and AvB become collinear. As the rift widens and oceanic spreading begins, CvA dominates and AvB becomes irrelevant. A triple junction may fit the initiation of these tectonic elements but with time it decays to a rift and a transform, with spreading carrying the relationship away to the west. Blocks A and B are left behind, as C links with its counterpart in the next (adjacent) triple junction, and ocean spreading fills the gap.

This implies that motion in and around the triple junction on African crust in the A or B block evolved with time, imparting interesting structural relationships. Rotation of displacement vectors between A and B may cause inversion of early structure in the triple junction. Indeed the Abakaliki Anticlinorium onshore Niger Delta (Reijers et al., 1997) demonstrates such inversion.

The second implication is that multiple triple "junctionettes" may evolve to a simpler geometry. The Yola and Doba Basins (**Figure 1**) may effect a connection between the CARS and WARS/Benue systems, so de-emphasizing or abandoning the lower (southerly) CARS faults in western Cameroon. This reduces complexity towards the simpler triple junction idea.

Data

Modern densely sampled data from ships (2D and 3D seismic especially) and satellites have driven forward the understanding of passive margin evolution and development of ocean basins and continental margins (Dickson et al. 2016 and references therein). From want of regional tectonically-focused data and lack of incentive from big oil & gas discoveries, this progress has lagged onshore. Still, adequate spatial resolution (to sub-basin or better scales) continent-wide grids have been compiled of potential field data (Odegard et al., 2007b). These in turn constrained inversions for sediment and crustal thicknesses (i.e., MARIMBA project depths to basement, Moho and Curie surfaces). This provided scaffolding for GIS-based geo-locating and mosaicing of published material.

Along the West African margin, the edge of magnetically striped oceanic crust is defined on our magnetic imagery (TMI-THD or total horizontal derivative of total magnetic intensity; not shown), along with a narrow bordering strip of 'transitional crust', be it exposed upper mantle and/or hyperextended continental crust. However, the gravity isostatic residual anomaly (GI) and its total horizontal derivative (GI-THD) have been most-used to locate, revise, and connect known and interpreted tectono-structural features both on- and near-shore.

The tectonic connection between the Bight spreading system and WCARS has lacked clarity, being obscured by twenty-some km of Niger Delta sediments. A multi-disciplinary approach, combining geophysical and geochemical methods concluded that crustal features could be well-imaged and accurately positioned (Dickson & Schiefelbein, 2015), identifying and connecting offshore fracture zones (FZ) beneath the delta both off- and onshore. A proprietary reprocessed compilation of gravity data provided primary control for tectono-structural interpretation, augmented by similarly compiled magnetics, depth, and thickness grids to define the deep rift-phase structure (Odegard et al., 2007a & b described compilation and processing steps). Active hydrocarbon exploration meant that broad coverages of detailed 3D seismic and surface geochemical exploration (SGE) programs had been presented in cited papers. From a non-exclusive study (used by permission), characteristic oil geochemistry of the Niger Delta was matched to SGE results. Our correlations from basement features up across intra-sedimentary structuring through inferred hydrocarbon leakage pathways terminating at the surface demonstrated both precision and accuracy in defining the deeply-buried crustal architecture (**Figure 4**).

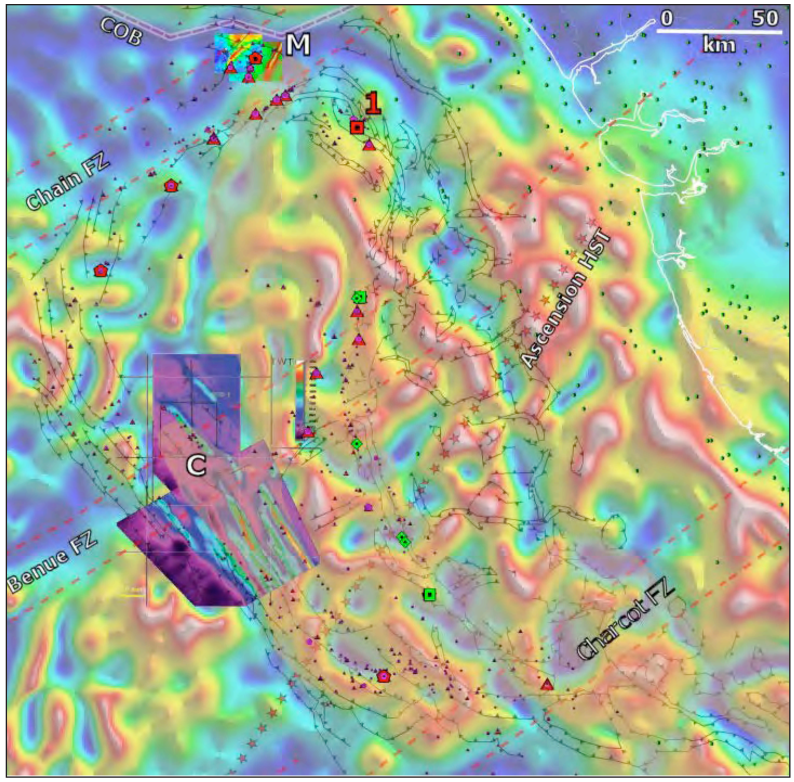


Figure 4. Offshore Niger Delta feature correlations from basement to surface (after Dickson & Schiefelbein, 2015) demonstrate reliability and precision of data employed to interpret basin floor offsets and long-lived basement control on tectono-sedimentary evolution of the on- and offshore delta. Crustal features and gravity backdrop with overlays from Cobbold et al., 2009 (C) and Matthews et al., 2010 (M) of intra-Miocene structures on 3D seismic. Piston core (PC) data (red, green & purple points), toe-thrust-belt (TTB) subcrops (black) and BSR outlines (faint orange shading) represent at/near seafloor control. Note the density of PC samples along intra-Miocene anticlines (Cobbold), demonstrating accuracy of PC targeting (PC locations normally test potential leakage paths). PC anomalies lie between the Matthews et al. 2010 (M) Miocene anticlines, suggesting a registration error in the georeferencing. However, structural trends on overlays C and M align closely with PC and TTB trends and anticline offsets of overlay C fall across the trace of the Chain FZ which is mimicked by seafloor offsets in the TTBs.

Gulf of Guinea System

A simple triple junction underlying the Niger Delta is usually pictured as having evolved into the Mid-Atlantic Ridge, receding from the divergent African margin and abandoning the Benue Trough (onshore Nigeria) in its wake. With most of the lower Benue Trough hidden beneath the Niger Delta, this evolution had largely been assumed. Our imagery indicated that the triple junction was not a simple three-armed system as theory suggested, but rather a west-stepped, progressive sweep in which a N-S trending extensional system converted to the E-W trending transform (trans-tensional) margin in discrete segments that accommodated the overall larger "triple region" (**Figure 2b**). The serrated transform margin continued westward as strike-slip segments connected extensional segment step-wise to extensional segment along the length of the coast across present-day Nigeria to Liberia. One segment ran from Benin and Cote D'Ivoire along the Romanche FZ, which keys off the Akwapim Fault system bordering Ghana's Neoproterozoic Voltaian Basin. The next step to the north connects to the St. Paul FZ, which keys off major Precambrian basement faults in Cote d'Ivoire at the southern end of the Liberia coast.

As described above, the oceanic FZs can now be traced nearly one-to-one to discrete onshore tectonic elements that were significantly active during birth of the continental margin (**Figure 1**). Some FZs connect to African tectonic elements and some to Brazilian (Krueger et al., 2018, this conference). The Charcot FZ connects beneath the Niger Delta to the southern boundary of the Anambra Basin and Benue Trough. Hence extension in the Chad-Niger Rifts is transferred to spreading between the Romanche and Charcot FZs (including the Benin, Chain, and Benue) which last is continuous with the northern bounding margin of the Benue Trough. The Ngaoundere FZ connects to the main strand of the Central African shear zone across the Cameroon Volcanic Line (CVL). The Paraíba FZ connects to South American features discussed by Krueger et al., 2018, this conference.

Southwards along the West African margin from Douala to Cape Town, fracture zones often lie opposite tectonic features in the African continental crust, but they were not reactivated within the continent itself at breakup and are not further discussed in this paper.

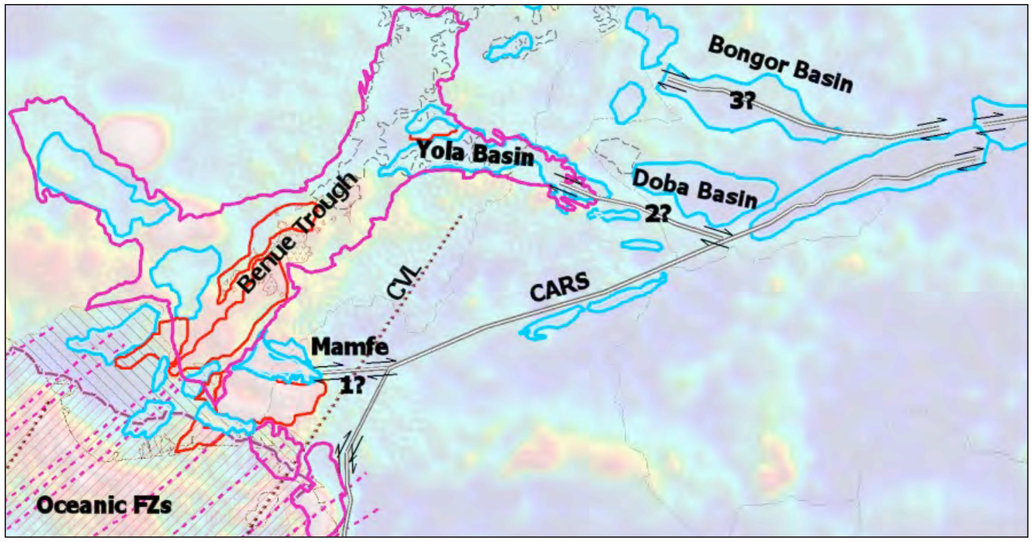


Figure 5. Gravity (GI) underlay with basin outlines. Representation of WCARS northern shears shows possible Benue Trough connections via Mamfe (1?), Yola-Doba (2?) and Bongor (3?) basins, or a combination of these paths, likely masked by younger CVL activity.

Niger Delta – CARS (Central African Rift System)

Work by Weber & Daukoru 1975 (citing Murat 1970) shows main tectonic features of the Niger Delta floor. Genik, 1993 remains the key reference defining WCARS basins and shears of Chad, Niger, and Sudan. PGW flew Nigeria-wide aero-geophysics surveys and published a depth-to-magnetic-basement initial interpretation (Reford et al., 2010) particularly illustrating the greater Benue Trough, and associated sub-basins. Dou et al., 2014 illustrated the CARS shear system using an uncited rectilinear representation of the affected basins & sub-basins to emphasize directional control via shear on the basin shapes.

Our work refines these features and provides estimates of the crustal deformation involved. We observe that crustal thinning is not a function of feature amplitude on our gravity imagery (not shown). Prominent narrow, high-amplitude GI-THD anomalies associated with north-west and south-west flanks of the Termit / Tenere Basin resulted from shallow depth to the main sediment-basement density contrast. The much deeper (c. 14 km) basin center has a subdued gravity response as sediments have compacted, reducing the density contrast at the interface whose gravity signature at depth is also strongly attenuated by the inverse square law.

Across our interpretation region, the cumulative ne-sw width of the Bida (Benue SW), Yola (Benue NE), and Termit basins is about 500 km which implies ne-sw stretch of perhaps one-third of that. Published gravity inversion models across these basins and sub-basins indicate crustal thinning of about one-third, from a normal continental 30 - 35 km thickness to about 22 - 26 km.

The ne-sw-trending Benue Trough present-day varies in width from about 140 - 260 km. It contains, as stated earlier, the inverted Abakaliki Anticlinorium, within the Anambra Basin, lower Benue Trough (Reijers et al., 1997) plus the Onitsha High and the Benue Folded Belt, implying a greater pre-inversion width. Adjacent to the southwest, the onshore Niger Delta contains three deeply-buried sub-basins, from northwest to southeast being the Benue SW; the Awaizombe Low (squeezed between the southwest ends of the Onitsha High and the Abakaliki Anticlinorium); and the two-part Afikpo Low. Roughly rhomboidal, the steep flanks of the Benue SW and Afikpo are formed by vertical offsets along the Benue and Charcot FZs. Prior to burial by the drift-age delta, they may have formed as early pull-aparts floored by highly-thinned continental crust. Because we need first to undo observed Santonian inversion and restore the effect of Apto-Albian extension, our interpretation thus far has no estimate for the amount of crustal thinning caused by Barremian nw-se extension.

To the north-east, the Yola and Doba Basins appear to have formed a connection between the Doseo pull apart Basin in CARS and the WARS/Benue system (**Figure 5**). This would transfer upper (northern) CARS motion directly into the Benue Trough, thus de-emphasizing or abandoning the lower (southern) CARS faults in western Cameroon. The timing would correspond to opening of the adjacent ocean as the "junctionettes" are de-emphasized or even abandoned in western Cameroon. The rectangular shape and substantial depths of the Benue internal sub-basins (Benue SW and Afikpo Low) are consistent with such a history.

Our interpretation confidence is lowest carrying these features across the CVL with its thermal and volcanic activity masking the density changes so easily traced both east and west of the CVL. We rely more on principles of structural geology and less on the weaker expressions in the potential field data in this area to infer that early in the evolution of the passive margin the lower CARS and perhaps also the Sanaga Fault made a connection through to the fracture zones.

We suggest that the Benue SW and Afikpo sub-basins initially filled with restricted lacustrine sediments, offering source potential that may augment the well-known terrestrial and marine sources (Haack et al., 2000; Schiefelbein et al., 2000) of the Niger Delta.

Conclusions

Triple junctions have interesting origins and histories, developing for example within oceanic crust of the Gulf of Guinea as a stepping series of "rolling triple junctions". Linked triple "junctionettes" may have evolved to a simpler geometry, reducing complexity towards the simpler, classic triple junction.

Evolving motions in and around the initial Gulf of Guinea triple junction on African crust imparted varied structural relationships. Inversion resulting from rotation of the angular relationship required by the breakdown of initial displacements would explain the Abakaliki Anticlinorium, within the Benue Trough, onshore Nigeria.

Our kinematically-constrained structural interpretation of the West and Central African Rift System (WCARS) is consistent with our current understanding of the evolution of the adjacent oceanic crust. The Yola and Doba Basins may have effected a connection between the CARS and WARS/Benue systems, and the previously obscured Benue architecture provides the key linkage between continental and oceanic systems.

Deep pull-aparts beneath the onshore Niger Delta, likely of Barremian to Albian age, would initially have been lacustrine rather than marine, with implications for source rock deposition.

Basins belonging to the WCARS system can be re-evaluated based on their revised shapes, deformation history, and relationships to sources of thermal and sedimentary inputs with an eye to their hydrocarbon potential. ■

Acknowledgements

The Purdy Project (Exploration Fabric of Africa or EFA, www.efafrica.com) is now available from AAPG's Datapages subsidiary as a non-exclusive adjunct to other DEO (Datapages Exploration Objects) material.

MARIMBA (Margins of the Atlantic Region Integrated Multidisciplinary Basin Analysis) and TFA (Tectonic Fabric of Africa) are non-exclusive studies referenced with permission; more at www.digsgeo.com

Map-based figures in this paper were generated as screen exports from ArcGIS(TM) 10 and annotated using PaintShopPro 9. Maps are in unprojected geographic coordinates (lat-longs) using the WGS84 datum.

An extended set of citations is available from the authors

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Wednesday, September 12 | Theme 3 | 11:55
Ana Krueger
University of Houston, Austin, TX, Bluware
I. Norton
University of Texas, Austin, TX
K. Casey
Actus Veritas, Houston, TX
R. D. de Matos
Nandy Oil and Gas, Rio de Janeiro, Brazil
M. Murphy
University of Houston, Austin, TX

Influence of Proterozoic Heritage on Development of Rift Segments in the Equatorial Atlantic

The last phase of Atlantic Ocean opening involved Late Albian rifting and separation of Africa and South America along the Equatorial Atlantic. Prior to the Albian, initiation and northward propagation of sea-floor spreading caused rotation of the South American plate and formation of two main rift systems in NE Brazil and West Africa: The Northeast Brazilian Rift System, consisting of the Reconcavo-Tucano-Jatoba (RTJ); Sergipe Alagoas/Gabon (SAG), and Cariri-Potiguar (CP) rifts in Brazil, and the West-Central African Rift System (WCARS) in Africa. The Brazilian basins developed inside and around the Borborema Province, a key Proterozoic structure that controlled spatial and temporal differences between these rift systems. Our analysis of a new compilation of onshore and offshore faults of the Equatorial Atlantic led us to the conclusion that the segment bound by the Kribi and Bode Verde fracture zones south of Borborema acted as a link between intracontinental rifting to the north and late rifting stages in the Central Atlantic. During the Albian, this region acted as a ¨buffer zone¨, balancing, kinematically, in time and space, dextral strike slip rifting in the Equatorial branch, with simultaneous sea floor spreading in the Central segment. In this paper we tie sequence stratigraphic rift sequences to plate kinematic changes described in our new plate model. Attempts to consider the thermal and tectonic evolution of the Central Salt Basins of the South Atlantic as an analog for the Equatorial Margin may lead to wrong predictions in hydrocarbon exploration. The differences in the development of these segments may explain the asymmetry in the distribution of oil and gas reserves along the South Atlantic Margin.

Introduction

Onshore studies of Northern Brazilian basins (Amazonas, Foz do Amazonas, Marajo, Grajau, Sao Luis, and Ilha Nova basins) by Soares Jr. et al. (2008) and (2011), dated rifting phases from Late Triassic to Albian. The structural styles of the basins were interpreted to be controlled by an interplay between inherited geology during the early rifting stage and by readjustment of the plates at the initiation of the seafloor spreading (Matos 2017; Krueger 2012; Krueger et al. (2014, 2015a, 2015b).

Offshore basins along the Brazilian Equatorial Atlantic margin were previously described as contemporary strike-slip basins, separated by the Romanche Fracture Zone and the northern and southern branches of Sao Paulo Fracture Zone (FZ). We integrated all newly published observations along the margin into a New Plate Tectonic Model, which predicts diachronous development and fits the data reducing misfit errors along the South American and African margins.

Methodology

This work consists of a compilation of multiple datasets that include: 2D seismic mapping (Krueger, 2012), digitized and edited onshore faults, new tectonic maps of South America (Cordani et al., 2016) and Africa (Meghraoui, et al., 2016), combined with offshore maps from Matos (2000) South America and Casey (2014) Africa. Using our combined seismic data interpretation (Matos, 2000, Krueger, 2012, and Casey, 2014) aided by free-air gravity interpretation (Sandwell et al., 2014) (**Figure 1**), we mapped the limit of oceanic crust on both sides of the Atlantic. Our interpretation was used in the updates for the UTIG PLATES model. We used PaleoGis software from the Rothwell Group L.P. and the UTIG PLATES Model to restore basement structures and faults from Krueger (2012) together with Matos (2004) and Casey (2014) and new structural interpretation of the faults onshore of South America to build the paleogeographic maps for the Lower to Mid-Cretaceous.

Proterozoic Heritage

West Gondwana was a collage of diversified Tonian terranes (1000 – 900 Ma) amalgamated during diachronic Brasiliano/Pan African orogenies (ca. 800 – 500 Ma, Brito Neves at al., 2014). The Trans-Brazilian terranes (TBL) is a complex net of Neoproterozoic mobile belts of Neoproterozoic age, formed as the Brazilian and African Cratons collided with the Congo craton (Brito Neves et al., 2014). This event is called Brasiliano or PanAfrican. The Brasiliano/Pan African tectonic event produced the main structures of West Gondwana; 1) the 3000 km-long Trans–Saharan (**TSL**) lineament and 2) its southward continuation: the Transbrasiliano Lineament (**TBL**, from NW

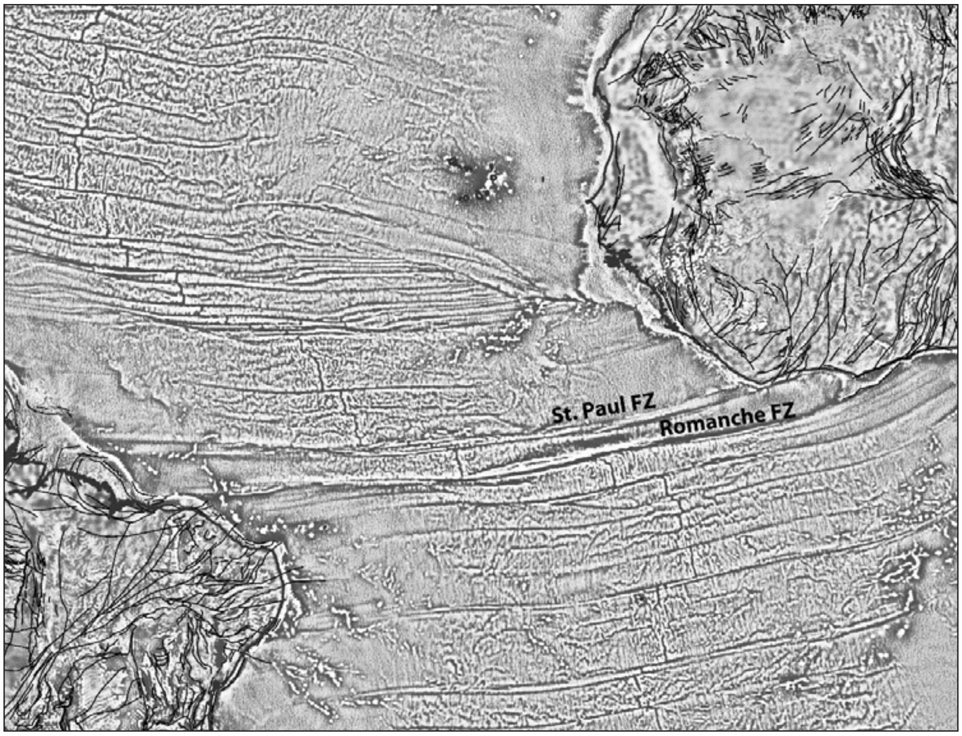

Figure 1. Equatorial Atlantic. Vertical gradient of the free-air gravity anomalies derived from satellite altimetry data (Sandwell and Smith, 2014). Onshore fault interpretation modified from the Commission for the Geological map of the World (CCGM/CGMW) maps of South America (Cordani et al., 2016) and Africa (Meghraoui, 2016).

Ceará, in Brazil, all the way to Argentina), also a 3000 km-long shear zone (**Figure 2**). The **TSL** borders the West African Craton, with associated arc-related Neoproterozoic rocks, ophiolites, and accretionary prisms. The TBL separates the Amazon Craton (Amazonian or pre-Brasiliano domain) from the Brasiliano terrains (Brito Neves at al., 2014). Linked with the **TBL**, the Borborema Province is one important Neoproterozoic cratonic nuclei, formed by a complex framework of orogenic branching system. We named this large polycyclic NNE shear belt in Brazil, and its continuity in Africa, as the Borborema Horsetail Splay (**BHS**) (**Figure 2**).

The Transversal Zone (**TZ**) is located in the central domain of the Borborema province (BHS) between Patos (**LPT**) and Pernambuco (**LPE**) lineaments; the **LPT** has been recognized as a continental transform linking a recognized magmatic arc at the northern portion of the **TZ** (ca. 635-580 Ma), products of a Meso and Neoproterozoic plate-tectonic accretionary processes (Brito Neves at. al (2016),

The eastward extension of the TZ is represented by the Central African belt or shear zone (**CASZ**), another Neoproterozoic shear zone, the product of a continental collision during which the Nigerian Shield was thrusted onto the Congo Craton.

The Orthogonal Zone (OZ) exploited Neoproterozoic zones of weakness and was active during the Early Cretaceous as initiation and northward propagation of sea-floor spreading caused rotation of the South American plate. To avoid confusion between the Proterozoic kinematic behavior of this Transversal Zone and Cretaceous here we refer to the Cretaceous kinematic segment as "*Orthogonal Zone*".

The OZ behaved as a large scale dextral transfer zone, balancing rift development between the future Equatorial and Central Atlantic branches of the South Atlantic. Two main rift systems in NE Brazil and West Africa formed exploiting these zones of weakness: 1) in Brazil; the Northeast Brazilian Rift System, consisting of the Reconcavo-Tucano-Jatoba rifts (RTJ); Sergipe Alagoas/Gabon (SAG), and Cariri-Potiguar (CP) rift valleys (Magnavita, 1992, Matos, 1999, Destro et al., 2003, and Burke et al. 2003, Brito Neves and Cordani, 1991), and the West and Central African Rift System (WCARS). 2) in Africa (Brown and Fairhead, 1983; Fairhead et al., 2012, 2013; Fairhead and Binks, 1991, Fairhead and Green, 1989, Hargue et al., 1992, Yandoka et al., 2014, Yassin et al., 2017). Both rift systems aborted, and final rifting took place along the present day continental margins. This switch was driven by the presence of lithospheric keels under the Nigerian and Borborema Shields, not allowing rifting to propagate through them. The last phase of Atlantic Ocean opening finally took place in Late Albian.

Opening of the Equatorial South Atlantic

Initiation and northward propagation of sea-floor spreading in the South Atlantic caused rotation of the South American plate in respect to Africa, and formation of the two main rift

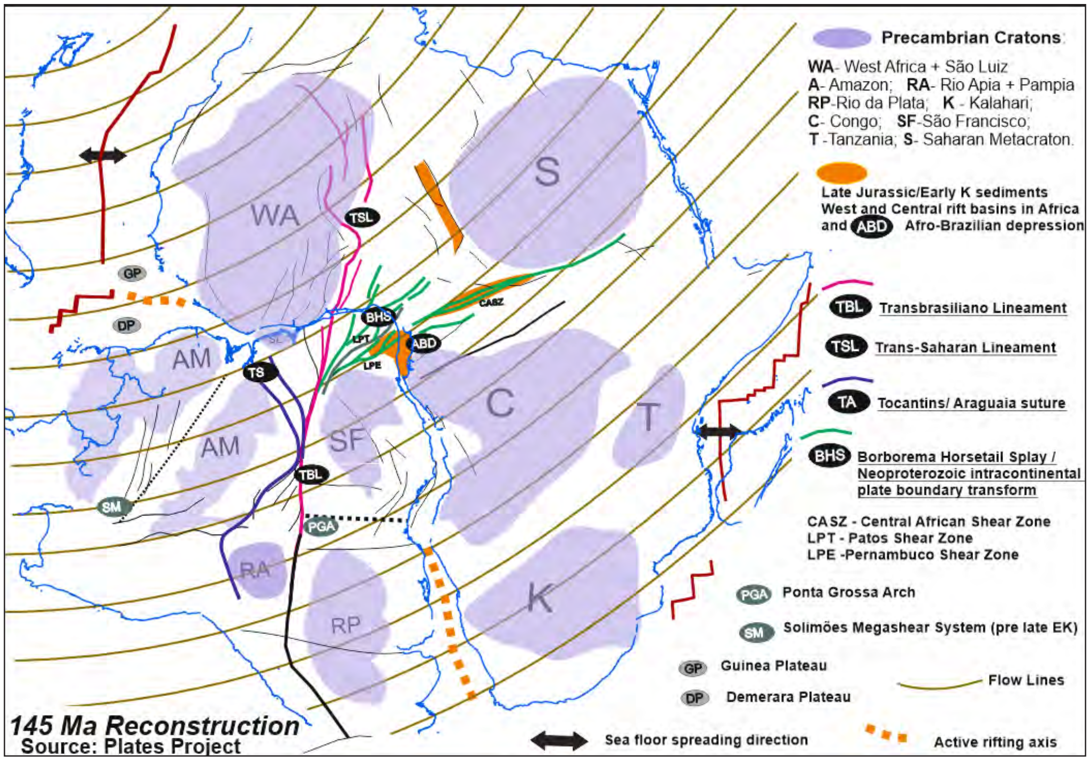

Figure 2. Tectono-structural map of the South Atlantic Ocean at 145 Ma, summarizing main geological terrains and structures that influenced the lithospheric rupture process. This figure also shows the distribution of Pre-rift sediments and active rift axes at 145 MA.

systems in NE Brazil and West Africa. Oblique deformation requires less strain and as much as two times less force in order to reach the brittle yield stress (Brune et al., 2012, Brune and Autin, 2013, and Heine and Brune, 2014). Once yield is reached, hot asthenospheric upwelling and friction softening promote extensive lithospheric weakening (Heine and Brune, 2014).

Basins in an around the Borborema Province record pre-rift and post-rift stages from 145 to 100 Ma. Strike slip movements in the Equatorial Margin, kinematically linked to the final rifting stages in the Central South Atlantic segment, began during the Aptian (Matos et al., 2017). Therefore, from Aptian to Albian time (120 Ma to 110 Ma) the South Atlantic path of continental rifting moved around the Borborema Province, and developed into a system of oblique and narrow rifted basins floored by oceanic crust. Rifts exhibit episodes of transpression and transtension during this phase of deformation, controlled primarily by the degree of obliquity of each basin to the plate motion vector (Krueger, 2012). Oceanic crust emplacement in each basin was diachronous. South of the Romanche FZ, outboard of Rio Grande do Norte and Nigeria, oceanic crust began to form around 112 Ma, while north of the Romanche continent-ocean transform fault, oceanic crust emplacement occurred around 110 Ma. Oceanic crust formed outboard of the South-East corner of the Demerara Plateau in French Guiana and Guinea at 116 Ma; at Amapa and Sierra Leone at 114 Ma; in the northern part of Para and Liberia; in Piaui, Maranhao, Ivory Coast, and Ghana at 110 Ma (**Figure 3**).

Concluding Remarks

The Borborema Province – a Proterozoic element with a cratonic core and the frame of adjacent Pan African fold belts, (**Figure 2**) acted as an obstacle to northward propagating rifting in the South Atlantic, thereby delaying rifting and forcing a South Atlantic opening to the east, following zones of weakness on the orthogonal zone. We define the term "buffer zone" as a region where rifting was delayed or slowed as rifting followed a path of thinner continental lithosphere, surrounding lithospheric keels. Once the driving forces from the divergent plate movements (from the evolving Central and South Atlantic) reached a critical point, a lithospheric cutting shear zone developed around the Borborema and Nigerian cratons, defining the silhouette of the future Equatorial Atlantic. Because of the Proterozoic heritage the South Atlantic Equatorial margins developed intricate NW-SE geometries which combined with the South American plate rotation lead to the diachronicity of the oceanic crust emplacement (**Figure 3**).

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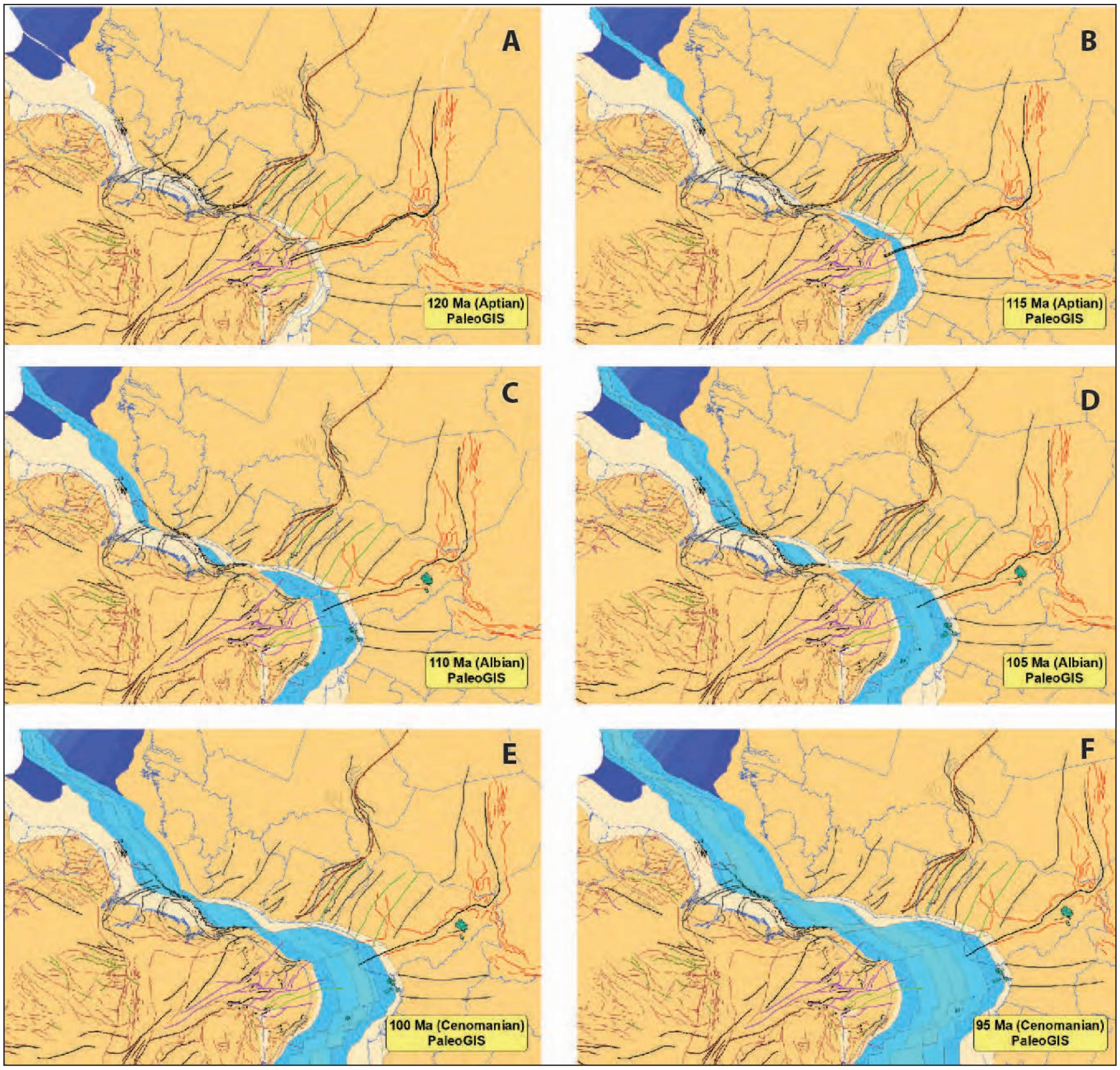

Figure 3. Composite opening of the South Atlantic, restorations for 120, 115, 110, 105, 100 and 95 Ma.

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Andrew Witt, Alex Bump, Tracy Love, Fabian Setzer

The Evolution of the Pre-salt Play in the Kwanza Benguela Basins, Angola

The original Angola pre-salt concept was an oil play targeting shallow water microbialite and coquina carbonate reservoirs accumulated over basement highs in the lacustrine rift basin, sealed by Aptian salt, and charged from Barremian source rocks.

As new seismic data were acquired, the geology began to come into focus. Crustal thickness tapers from >20km thick beneath the shelf, to <5km thick across much of the offshore basin. Tilted fault blocks were crowned with carbonate seismic facies; bright reflectors within the inner pre-salt sag basin suggested source rocks. Base-salt highs offered some large-volume traps, with robust salt seals.

Initial drilling results were promising. Maersk confirmed pre-salt oil at Azul, and Cobalt announced an oil discovery at Cameia. As the industry drilling campaign continued, results were mixed: subsequent wells found marginal volumes of oil, others found gas, several found CO_2 in reservoirs containing remnant bitumen. Many failed due to trap or reservoir. In 2015 an industry data trade programme, supported by Sonangol, enabled the industry to build a broader subsurface picture of the basin beyond their incumbent positions.

The pre-salt stratigraphic section is observed to thin towards the oceanic/continental boundary, where salt directly overlies basement and the source and reservoir sections are both absent. High temperatures caused by a post-rift heating event cracked existing oil accumulations to gas and flushed some traps with CO_2.

Thick intervals of vuggy, fractured, silicified carbonates have been encountered in several wells; this unexpected reservoir fabric directly impacts drillability and reservoir deliverability, key factors to be considered prior to development.

Structural complexities in the post-salt section have led to angular geometries above salt holes, which allow leaking and result in pre-salt hydrocarbon columns that are not filled to their mapped structural spill points.

Revisiting the original exploration model for the pre-salt play with the well data from drill-out offers points to consider in the exploration and development of other rifted margins.

Biographical Sketch

Andy Witt graduated from the Post Graduate Research Institute for Sedimentology at The University of Reading, UK in 2001. He joined BP in Aberdeen the same year working as a Petroleum Engineer in the North Sea, followed by a series of geoscientist roles in the North Sea business across exploration and development. This included working on the Clair field at the time of development start-up and many license round evaluations and exploration wells at a time of renewed interest in exploration on the UK Continental Shelf.

He moved to London in 2012 to lead BP's exploration campaign in the Great Australian Bight. In 2016 June 2016 he took the role of Exploration Manager in Angola, shaping the exploration programme in a high value area through the downturn. During his tenure he has helped to articulate the value of exploration within proven basins and contribute to the recent positive legislative changes.

In 2018 BP's exploration positions in Côte d'Ivoire and São Tomé & Príncipe were added to the portfolio, both have seismic commitments.

Wednesday, September 12 | Theme 4 | 14:15
Paul Bellingham
ION Geophysical, UK
James Deckleman, Brian W. Horn
ION Geophysical, USA
+44 (0) 1932 792 212; paul.bellingham@iongeo.com

A New Beginning: Remaining Potential and the Case for Investment in the Niger Delta

The Niger Delta is one of the most prolific petroleum provinces in the world. Since 1965, the Delta has produced over 34 billion barrels of oil and, since 1970, over 21 trillion cubic feet of gas (BP, 2017). OPEC (2017) reports that Nigeria had 37.5 billion barrels of proved oil reserves and 194 trillion cubic feet of proved natural gas reserves at year-end 2016. Nigeria currently produces ~2.0 million barrels of oil/day, implying an R:P ratio of 51.

The Delta contains many volumetrically significant petroleum accumulations. Average field size ranges from 53 mmboe onshore to 232 mmboe in the deepwater (Wood Mackenzie, 2017). Offshore, field recoverable oil and gas volumes range as high as 1.2 billion barrels (Bonga field) and 7 trillion cubic feet (Bosi field), respectively. Over 500 fields, of which more than 30% are now producing (NAPIMS, 2017), have been discovered in the Niger Delta to date. Well production rates of over 20,000 barrels of oil per day have been achieved (NAPIMS, 2017). With a mature service sector, established infrastructure, a new governance structure and the upcoming potential bid rounds for marginal fields and exploration acreage providing access to opportunity, now is the time to take another look at the Niger delta.

Niger Delta Geological Setting

The geological history of the delta has created an ideal petroleum system with the thick Akata shale oil-prone source rock (with Type II and Type III kerogens) overlain by a substantial succession of progressively shallower facies in a delta system containing many high quality reservoir sands. Seismic imaging of these sequences is excellent; calibrated seismic quantitative interpretation reliably de-risks both hydrocarbon presence and phase. These facts combine to produce a low risk exploration environment, Nigeria has experienced a >50% exploration success rate over the last 60 years. Traps are generally formed around gravitational collapse structures in both up-dip extensional and down-dip contractional systems (**Figure 1**). There is a complex relationship between the timings of source maturation, hydrocarbon expulsion and migration, and trap formation in the different structural domains which defines exploration and phase risk, highlighting the need to understand the delta system holistically. Here, we investigate long offset, deep regional 2D seismic and selected 3D data from the onshore and offshore delta to pull together an integrated story.

We show how the deep, long offset data allows for a consistent interpretation of the entire structure of the Delta with mulitple stacked thrust sheets within the Paleogene and major mappable detachment surfaces. Many of the largest fields in the Delta are reservoired in younger Neogene sediments on these uplifted, folded and faulted highs. Improved imaging of the deeper Miocene and Oligocene sediments also demonstrates the likely presence of reservoir rocks within structural closures.

Structural mapping clearly demonstrates the younger and less deformed nature of the deep water Outer fold and thrust belt compared to the Inner belt (**Figure 1**) with only the deeper

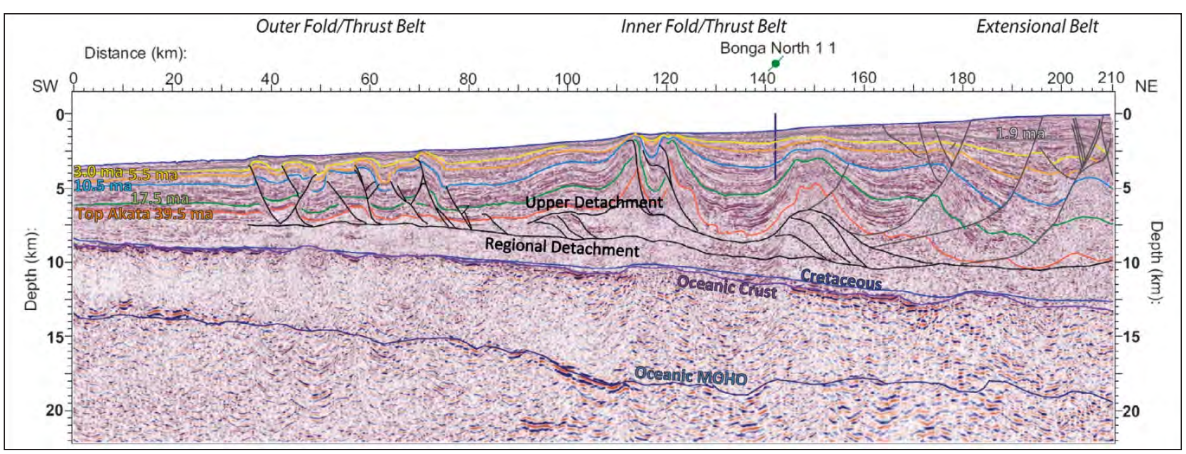

Figure 1: Regional PSDM seismic line across the main provinces of the offshore Niger Delta. The extensional domain, Inner fold and thrust belt and the Outer fold and thrust belt are all shown.

of the two main detachment zones extending out to the outer belt. Exploration results in the Outer fold and thrust belt have been largely disappointing to date with most of the discovered hydrocarbons being on the inboard side of the Outer fold and thrust belt (e.g. Etan, Zabazaba and Kuro). These results drive a need to better understand the development of the area, timing of structuration, and maturation of the major source horizons. Through integrated petroleum system modelling we discuss the potential in the area and potential risks.

Remaining Potential

By viewing the Delta as an integrated system and taking a play fairway based approach, we have assessed the future exploration potential of both deeper plays within the Inner fold and thrust belt and the likely ultimate potential of the Outer belt. We also show the remaining value in discovered, undeveloped fields. We show how once a holistic understanding of the Delta is in place it is possible to simply evaluate and rank areas and blocks with remaining potential. We demonstrate how additional detailed evaluation of high graded areas supports the overall assessment.

Conclusions

Though Nigeria historically has had agressive fiscal terms, the low sulfur, high API crude (Bonny Light) is a high value product and Nigeria has excellent access to market leading to low and robust breakeven prices. The petroleum system is prolific and has yielded some of the largest reserves on the planet but the complexity of the system has also led to many exploration surprises. We show how an integrated approach can high-grade areas and support detailed, prospect specific risking and evaluations.

Pending regulatory changes and future opening of acreage that has been inaccesible for many years means that Nigeria could once again become a highly attractive investment option. ■

Biographical Sketches

Paul Bellingham is an explorer with over 17 years of experience in the oil & gas industry as a geologist, exploration manager and director. Paul has experience with mega-regional to prospect scale projects and has worked across a wide variety of plays and provinces globally; he is currently Vice President at IONs E&P Advisors group responsible for the Eastern Hemisphere.

Paul has a PhD in Arctic tectonics from the University of Cambridge and is a fellow of the Geological Society and a member of the PESGB.

Brian W. Horn - Senior Vice President and Chief Geologist for ION E&P Advisors. Brian has worked in exploration and production for 27 years with Amoco, BP, and Maersk Oil prior to joining ION in 2010. In his current role he is responsible for the technical and commercial advisory group in support of E&P operators, NOC's and government minsitries. His experience includes integrating geological and engineering/production data for play-based exploration, and development, basin and play fairway analysis, petroleum systems, regional stratigraphic and seismic correlations, prospect development and resource potential assessments. In addition to exploration projects he has delivered exploitation/development programs generating prospects, development and reservoir characterization for (infill) drilling designed to identify and evaluate critical geologic uncertainties focused on increasing recovery efficiencies and reservoir management strategies.

Dr. Horn received his Bachelors and Master degrees in Geology from The University of Colorado, Boulder and his PhD in Geology and Geological Engineering from the Colorado School of Mines, Golden, CO.

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please check the figure rreferences in the text. Figure 5 is not referenced.

Olusanmi O. Emmanuel
Acetop Energy, Houston, Texas, United States of America
Kemi Taiwo,
ND Western Limited, Victoria Island, Lagos, Nigeria
Emmanuel Enu, Olusoji Mojisola
First Exploration and Petroleum Development Company Limited, Victoria Island, Lagos, Nigeria

Play Fairway and Petroleum Systems Analysis of Nigeria's Cretaceous Benin (Dahomey) Basin: Key to Unlocking Additional Hydrocarbon Volumes from an Emerging Exploration Trend

Nigeria is a major hydrocarbon province with known reserves exceeding 35 billion barrels of oil and 200 trillion cubic feet of gas. Much of these reserves and the already produced billions of barrels oil equivalent were discovered almost entirely within the prolific Tertiary Niger Delta (Akata-Agbada Total Petroleum System) because there has been very little exploration focus on the country's other passive margin basin - the Benin basin. The discovery of the 380 MMBOE Aje Field in OML 113 in 1996, by Yinka Folawiyo Petroleum initially sparked an interest in the Benin basin, and a decade of regional studies ensued, but no additional drilling took place in the basin until very recently when the 775 MMBOE Ogo Field in OPL 310 was discovered by Lekoil/Afren in 2013. However, integrated basin and play fairway analysis involving regional 2D/3D seismic data, gravity and magnetic data, electrical logs, core data, and geochemical data identified the existence of three working petroleum systems in the Benin basin that need to be further proven by more exploratory wells. These petroleum systems are; 1) Lower Cretaceous rift petroleum system sourced by lacustrine source rock of the Neocomian Ise Formation, 2) Upper Cretaceous transitional petroleum system sourced by Albian-Turonian marine shales of the Abeokuta Group, and 3) Late Cretaceous-Tertiary drift petroleum system sourced by deepwater marine shales of the Araromi Formation and the Tertiary Akata Formation that sourced most of the oil in the Niger Delta basin.

Reservoir facies for the Lower Cretaceous rift petroleum system include fluvio-lacustrine, fluvio-deltaic and shallow marine sandstones interbedded with carbonates as proven in the Aje 4 well in the Aje field, by YFP and by Kerr McGee in Fifa-1 and Hihon-1 wells in the Seme field. Trap styles for this petroleum system include rifted fault blocks, unconformity traps, and stratigraphic pinchouts while interbedded lacustrine shales and claystones (maximum flooding surfaces) serve as the seals. For the Upper Cretaceous transitional petroleum system, fluvio-deltaic to shallow marine sandstones, ponded turbidite sands, and tubidite fan facies proven in Aje 1, Aje 2, Aje 4, Ogo 1, and Ogo 1-ST wells are the main reservoir facies while transgressive shales and deep marine shales serve as the seals. Trap styles for this petroleum system are mostly structural, such as the four-way dip closure at Aje field, but traps can also be stratigraphic and combinational structural/stratigraphic. As proven in the Epiya 1 and Baba 1 wells, reworked marine and turbidite sands as well as confined channels and ponded turbidite sands are the main reservoir facies for the Late Cretaceous-Upper Tertiary drift petroleum system. Traps styles can include 3-way dip closures against rotated fault blocks, stratigraphic, and/or combinational stratigraphic/structural traps, while 3rd and 4th order marine shales and claystones serve as the seals.

The essential elements of a working petroleum system are well developed within the Benin basin and they have been discussed. The Cretaceous Play Fairway within Nigeria's Benin basin is an emerging exploration trend that could be of major significance in the future. The Aje field and Ogo field discoveries as well as those made in other Equatorial Atlantic margin basins with similar evolution and tectonostratigraphic history, suggest that further exploration efforts should be targeted at the Cretaceous Fairway of Nigeria's Benin basin to unlock additional hydrocarbon volumes from the basin. There are definitely several more Jubilee look-alike fields as well as numerous Aje and Ogo fields to be discovered within the Cretaceous Fairway of Nigeria's Benin basin if additional exploration wells are targeted at the play.

Introduction

The Benin (Dahomey) Basin forms one of a series of West African Atlantic Margin Coastal sedimentary basins in the Gulf of Guinea Oil Province (**Figure 1**). The basin occurs in the eastern side of the Gulf of Guinea transform margin and is bounded by Chain and Romanche Fracture Zones (Binks and Fairhead, 1992). It is one of Nigeria's two passive margin basins, the other being the prolific Niger delta, which it bounds to the west.

The basin was formed at the culmination of Late Jurassic to Early Cretaceous tectonism that was characterized by both block and

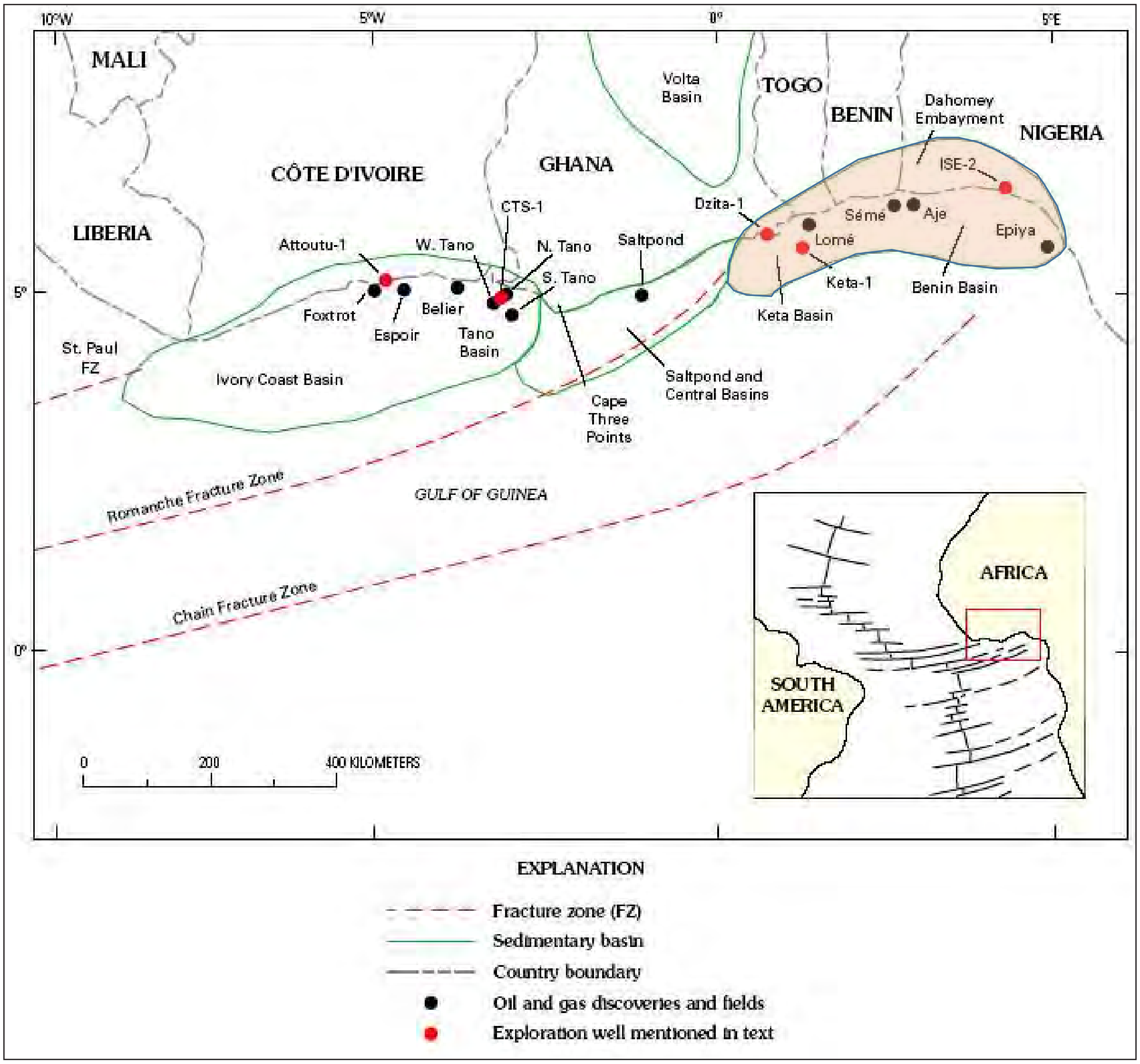

Figure 1. West African Atlantic Margin Coastal sedimentary basins in the Gulf of Guinea Oil Province. The Dahomey basin is the colored polygon that extends from offshore SW Nigeria through Offshore Benin and Togo to eastern offshore Ghana.

transform faulting during the breakup of the African and American continents (Olabode, and Adekoya, 2008). The tectonic evolution has been linked with three stages of development which also allows the stratigraphic section to be divided into three main sequences: (i) pre-transform stage (Neocomian to Barremian), (ii) syntransform stage (Aptian to latest Albian), and (iii) post-transform stage (Cenomanian to Holocene) (Omatsola and Adegoke, 1981). The formations as delineated in the Nigerian sector include Ise, Afowo, Araromi, Ewekoro, Akinbo, Ososun, Ilaro, and Benin (Coastal plain sands) Formations.

There has been very little exploration focus on the Dahomey basin. However, the discovery of the 380 MMBOE Aje Field in OML 113 in 1996, by Yinka Folawiyo Petroleum and the 775 MMBOE Ogo Field discovery in OPL 310 by Lekoil/Afren in 2013 has led to renewed interest in the basin. This paper, therefore, presents a summary of the play fairway and petroleum systems analysis carried out to better unlock the hydrocarbon potential of the basin. It is hoped that a better understanding of the elements of the petroleum system coupled with a more robust knowledge of the play types in the basin will encourage a sustained exploration interest that will help to unlock additional hydrocarbon volumes from the basin.

Data and Methods

The data used for this study includes regional 2D/3D seismic data, gravity and magnetic data, electrical logs, core data, geochemical data, and drilling results from some of the wells drilled in the basin. **Figure 2** shows the seismic data coverage for offshore Nigeria. Additional seismic data might exist.

Results and Interpretation

Three working petroleum systems were identified in the Dahomey basin. These petroleum systems are; 1) Lower Cretaceous rift petroleum system sourced by lacustrine

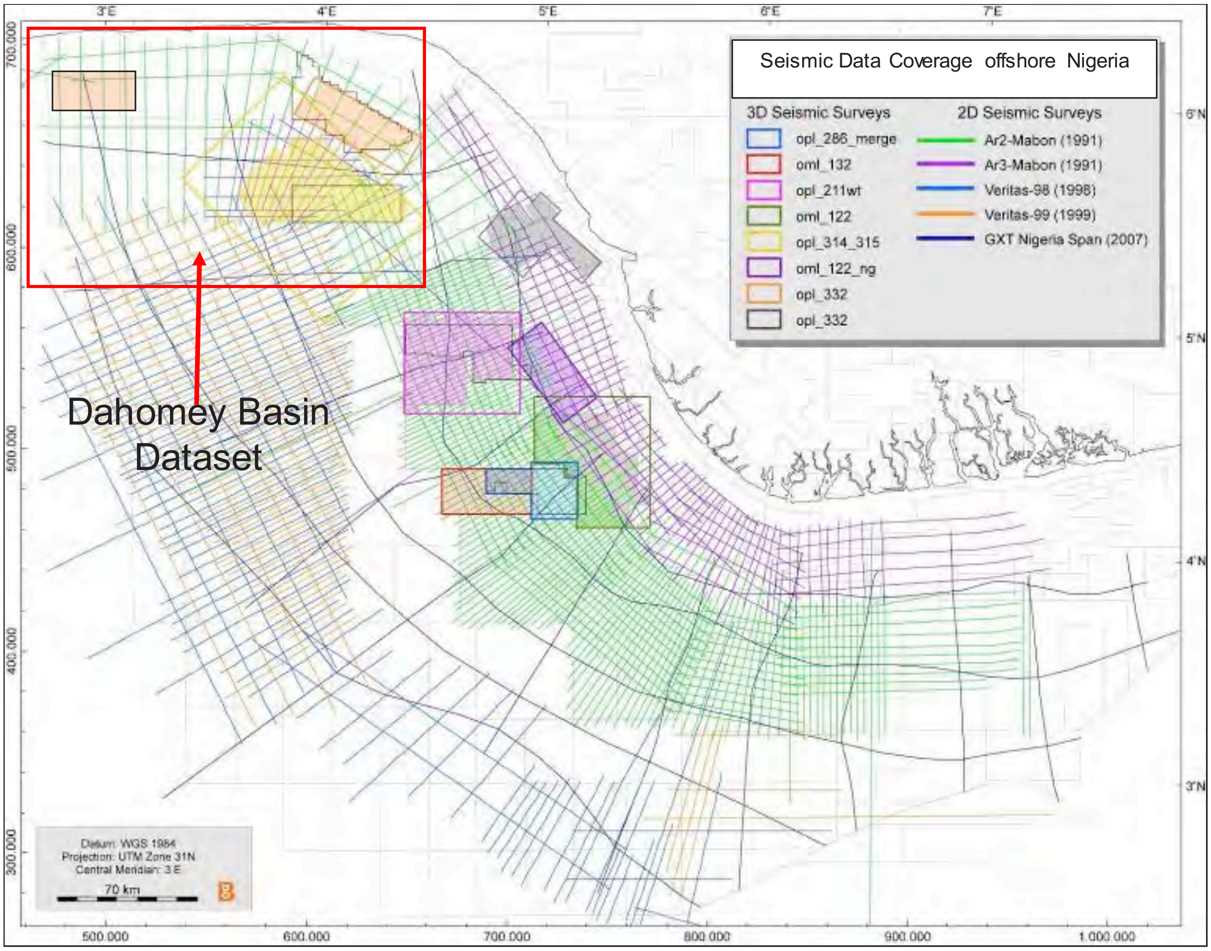

Figure 2. Seismic data coverage offshore Nigeria. Red polygon shows the seismic data coverage within the Dahomey basin.

Table 1. Dahomey basin's petroleum systems and their elements

Petroleum Systems	Source Rock	Reservoir Rock	Seal	Traps	Analogues
Drift (Maastrichtian & Tertiary)	Deepwater marine shales of Araromi Formation (Maastrichtian) & Akata Formation (Tertiary)	Shelfal (bars/channels); Slopal (mass transport deposits, debrites, turbidites) Basin floor (debrites – turbidites) **Phi=9-30%***	Marine shales/claystones (3^{rd} or 4^{th} order maximum flooding surfaces)	Structural (3-way against rotated fault) or Structural / Stratigraphic	Shelfal sands –Epiya and Baba Slopal Sands - Lazendra canyon Espiritu Basin (L.Cre., Brazil), Hackbury (Olig., Texas)
Transitional (Upper Cretaceous; Albian – Santonian)	Albian and Cenomanian/ Turonian shales (deltaic to shallow marine). Penetrated in Aje & Seme fields as well as Fifa-1 well	Fluvial/Deltaic to shelfal **(Phi= 9-25%)***, Re-worked with localized mass transport deposits **(Phi= 20-30%)***. Penetrated in Aje and Seme fields	Transgressive shales (MFS's) capping autocycles and deep marine shales above Senonian Unconformity (3^{rd} order MFS)	Structural or Structural / Stratigraphic (Aje and Seme)	Proven by Union Oil (Seme field, Benin) and YFP (Aje field, Nigeria). Also suggested by piston cores acquired east of Fifa-1 by Kerr McGee (Block 4, Benin)
Rift (Lower Cretaceous – Neocomian)	Organic rich lacustrine shales - Neocomian Ise Formation (penetrated in Seme)	Fluvio - Lacustrine sandstones - Ise Fm. Lower Cretaceous fluvio-deltaic sediments proven in Ghana, Togo and Brazil. **Phi=11-13%***. Possible carbonates as interbeds or as last phase of autocycle (Aje & Seme fields)	Lacustrine Shales (interbedded or as autocycle MFS's)	Rifted fault blocks, unconformity traps, stratigraphic pinch-outs	Proven by drilling in the Ceara - Portiguar basin, Brazil, by Union Oil (Seme Field) and Kerr McGee (Block 4), Benin

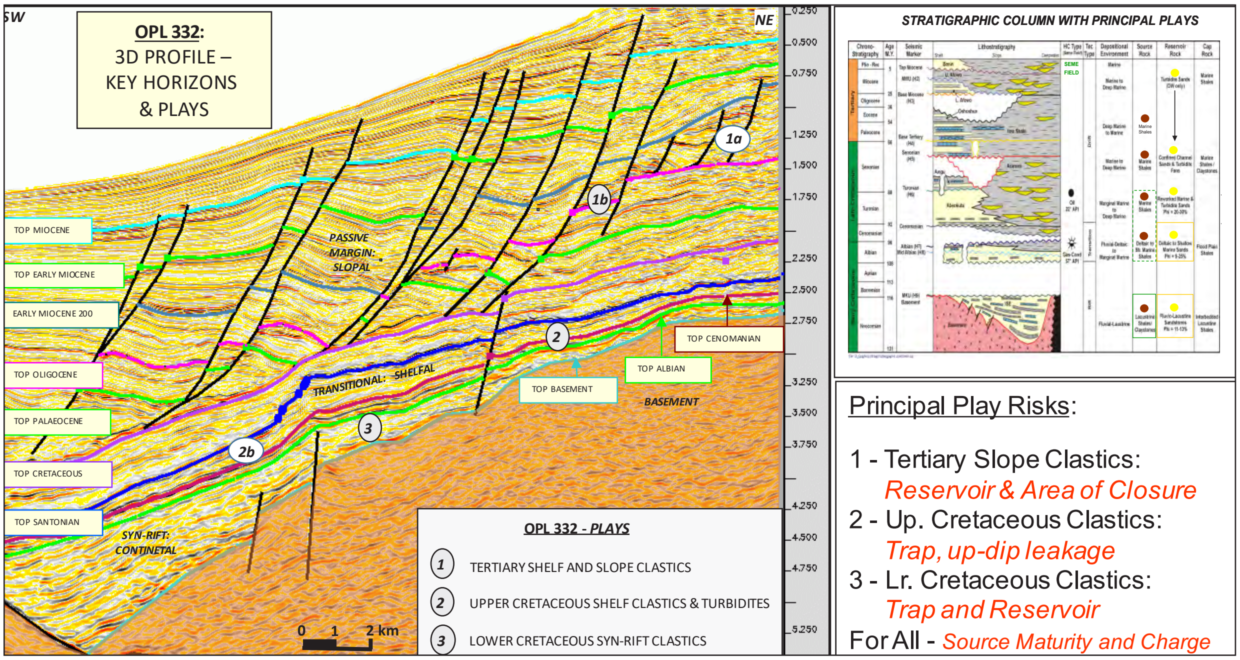

Figure 3. Play types in the Dahomey basin with their principal play risks.

source rock of the Neocomian Ise Formation, 2) Upper Cretaceous transitional petroleum system sourced by Albian-Turonian marine shales of the Abeokuta Group, and 3) Late Cretaceous-Tertiary drift petroleum system sourced by deepwater marine shales of the Araromi Formation and the Tertiary Akata Formation that sourced most of the oil in the Niger Delta basin (Brownfield and Charpentier, 2006). The elements of these petroleum systems are presented in **Table 1**.

Play fairway analysis suggests that there are three main play types present in the basin: 1) Tertiary slope clastics, 2) Upper Cretaceous shelf clastics, and 3). Lower Cretaceous syn-rift clastics (**Figure 3**).

Reservoir facies for the Lower Cretaceous rift petroleum system include fluvio-lacustrine, fluvio-deltaic and shallow marine sandstones interbedded with carbonates as proven by Kerr McGee in the Fifa-1 and Hihon-1 wells in the Seme field. Trap styles for this petroleum system include rifted fault blocks, unconformity traps and stratigraphic pinchouts while interbedded lacustrine shales and claystones (maximum flooding surfaces) serve as the seals (**Figure 4** and **Figure 5**).

For the Upper Cretaceous transitional petroleum system, fluvio-deltaic to shallow marine sandstones, ponded turbidite sands and tubidite fan facies proven in Aje 1, Aje 2, Aje 4, Ogo 1, Ogo 1-ST wells as well as in Ghana's Jubilee and Ten Fields, are the main reservoir facies while transgressive shales and deep marine shales serve as the seals. Trap styles for this petroleum system can be structural, such as the four-way dip closure at Aje field (**Figure 5**), or stratigraphic and combinational structural/stratigraphic as proven in the Jubilee field. As proven in the Epiya 1 and Baba 1 wells, reworked marine and turbidite sands as well as confined channels and ponded turbidite sands are the main reservoir facies for the Late Cretaceous-Upper Tertiary drift petroleum system. Traps styles can include 3-way dip closures against rotated fault blocks, stratigraphic, and/or combinational stratigraphic/structural traps, while 3rd and 4th order marine shales and claystones serve as the seals.

Conclusion

The essential elements of a working petroleum system are well developed within the Benin basin and they have been discussed. Cretaceous Play Fairway within Nigeria's Benin basin is an emerging exploration trend that could be of major significance in the future. The Aje field and Ogo field discoveries as well as those made in other Equatorial Atlantic margin basins with similar evolution and tectonostratigraphic history, suggest that further exploration efforts should be targeted at the Cretaceous Fairway of Nigeria's Benin basin to unlock additional hydrocarbon volumes from the basin. There are definitely several more Jubilee look-alike fields as well as numerous Aje and Ogo fields to be discovered within the Cretaceous Fairway of Nigeria's Benin basin if additional exploration wells are targeted at the play.

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Brownfield M.E and Charpentier R.R, 2006. Geology and Total Petroleum Systems of the Gulf of Guinea Province of West Africa U.S. Geological Survey Bulletin 2207-C

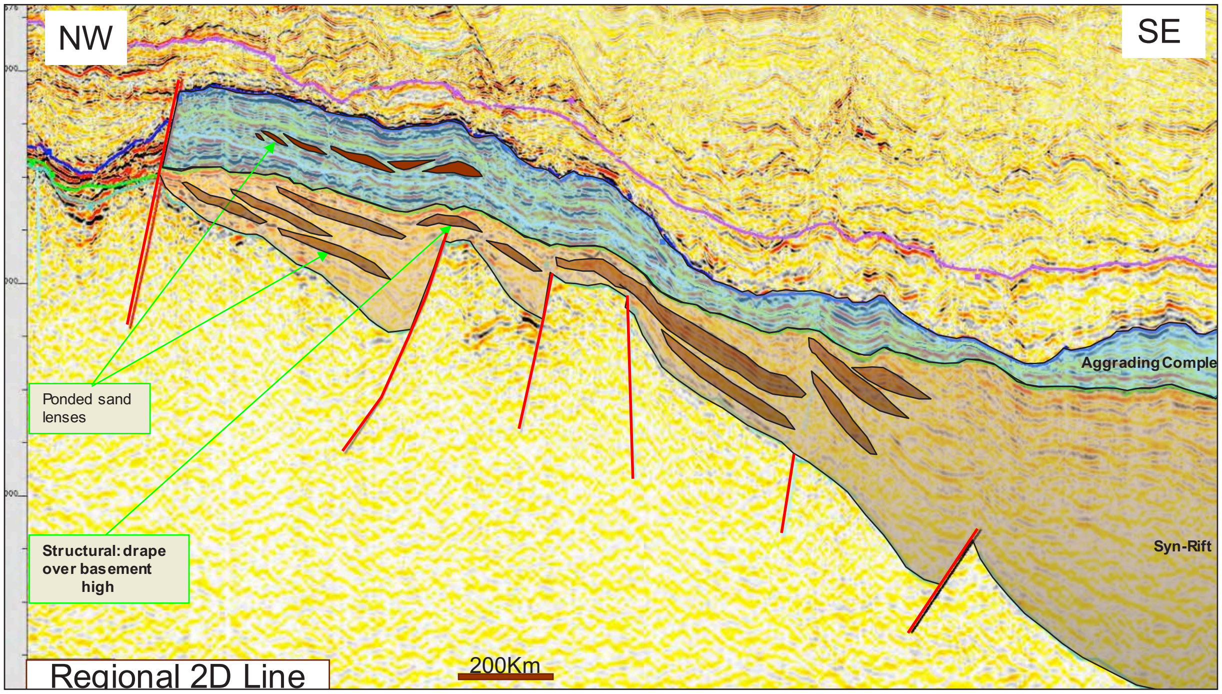

Figure 4. NW-SE regional seismic line showing trap styles in the Lower Cretaceous rift petroleum system.

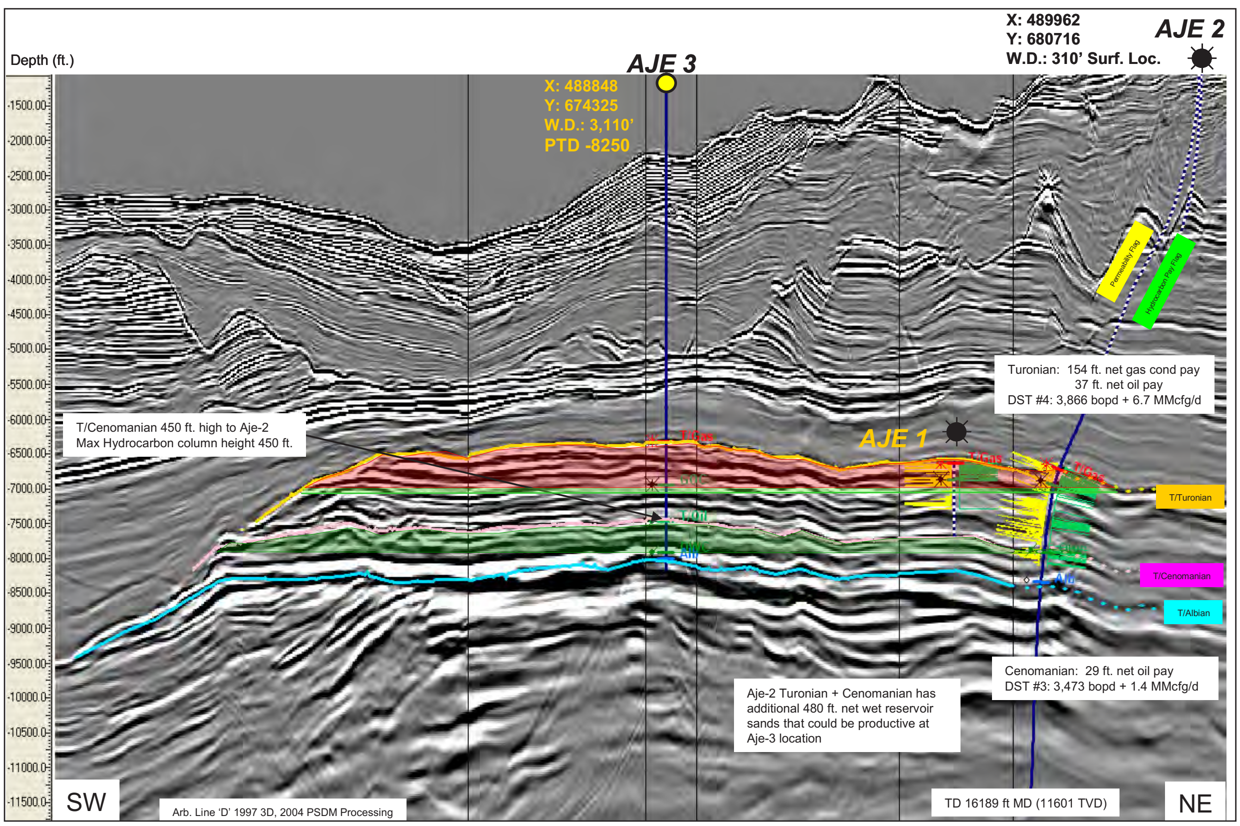

Figure 5: Aje field seismic data showing the discovery well and the appraisal wells that proved the existence of both the Lower Cretaceous Rift and Upper Cretaceous Transitional petroleum systems

Olabode, S.O. and Adekoya, J.A., 2008. Seismic stratigraphy and development of Avon canyon in Benin (Dahomey) basin, southwestern Nigeria. Journal of African Earth Sciences 50, 286–304.

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Biographical Sketch

Dr. Olusanmi 'Tunde Emmanuel is a Certified Petroleum Geologist (CPG #6301) and Certified Earth Scientist (SIPES #3501). He is a demonstrated exploration and development geoscientist with skills to integrate well control, gross-depositional environment models, reservoir models, seismic attributes, risk assessment as well as basin to play and play to prospect scale perspectives in the successful identification, drilling, and development of oil and gas prospects. He has over 14 years industry experience working for major exploration and production companies including ExxonMobil, Statoil ASA, Total, BG Group Plc., and Shell in Nigeria, Norway, United Kingdom, and the USA. He has participated in the location, planning, and drilling of several exploration and development wells on three different continents: Africa, Europe, and America. Tunde has worked on the geological and geophysical evaluation of plays and generation of prospects in the Niger Delta, the Cretaceous Dahomey/Benin, UK North Sea basin, onshore Libyan basins; the US Muddy (J) Sandstone play, the Cretaceous Olmos Sandstone, the Austin Chalk (Gulf Coast basin, Texas), as well as shale plays including the Marcellus, Haynesville, Niobrara, Eagle Ford, and Bakken Shale. Dr. Emmanuel holds a B.Tech. Applied Geology degree from the Federal University of Technology Akure, Nigeria, a Master of Science degree in Integrated Petroleum Geoscience from the University of Aberdeen, United Kingdom, and a PhD degree in Geology from the Colorado School of Mines, Golden, Colorado, USA.

Wednesday, September 12 | Theme 4 | 15:30
Kathryn E. Dawson
Principal Geoscientist
Tullow Ghana Ltd, Accra, Ghana
kathryn.dawson@tullowoil.com

Jubilee Field: From World Class Exploration Discovery to Producing Asset. Learnings from 7 Years of Production

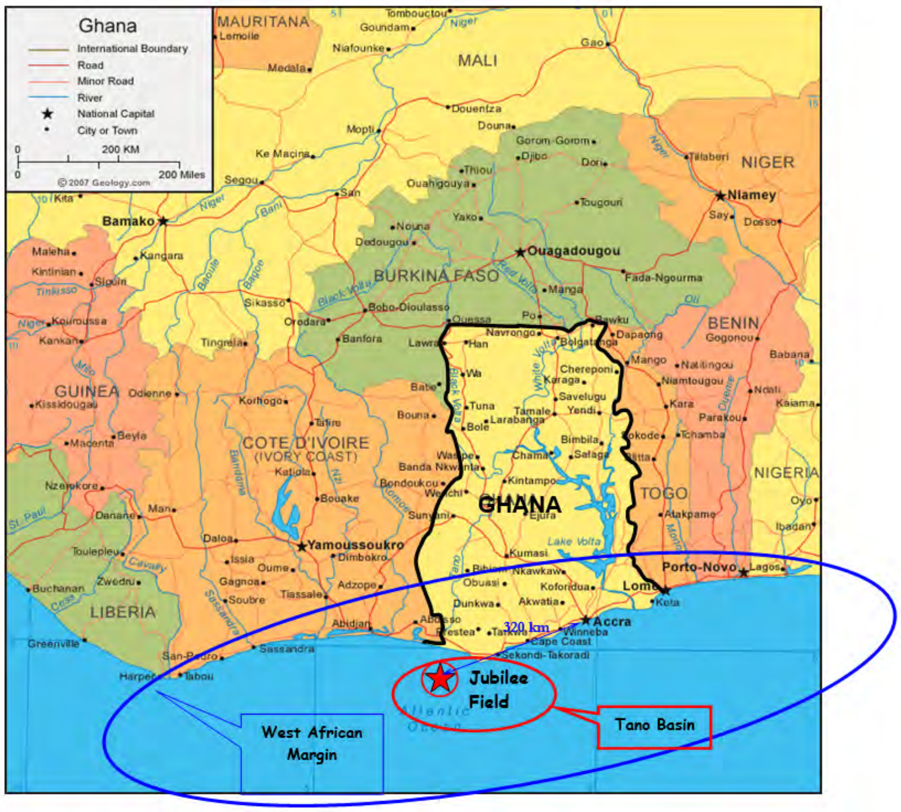


Figure 1. Field Location

Ghana's world-class Jubilee field was discovered in 2007 by the Mahogany-1 (M-1) and Hyedua-1 (H-1) exploration wells by the partnership group comprised of GNPC, Tullow Ghana Limited, Kosmos Energy Ghana HC, Anadarko WCTP Company, Sabre Oil & Gas Holdings Limited, and the EO Group Limited.

Regional studies had highlighted the strong potential within the Cretaceous play in this relatively under explored area. The locations of the wells were selected to test a Turonian turbidite fan objective, identified with early 3D seismic data and supported by seismic AVO response. Class 2 AVO suggested oil bearing sands conformant to structure in a gross sense on two separate 3D surveys over the area with a "risky" gap between.

63 km offshore in 1300m of water, the first two wells were drilled some 5 km apart and intersected large continuous accumulations of light sweet crude oil. The M-1 and H-1 wells discovered large net pays of 95m and 41m respectively in high-quality stacked reservoir sands.

The field is formed of stacked slope turbidites partially ponded within an embayment and break in slope within the Tano Basin.

In July 2009, the Minister of Energy approved the Phase 1 Plan of Development which included the use of an FPSO with a facility capacity of 120,000 bopd. In December 2010, the field came on-stream, setting an industry record for the timeline from discovery to first oil for this type development.

The guiding principles underpinned the Phase 1 Development Plan and enabled the fast track delivery were:

- Employ industry best-practices and proven technology for a deepwater FPSO scheme

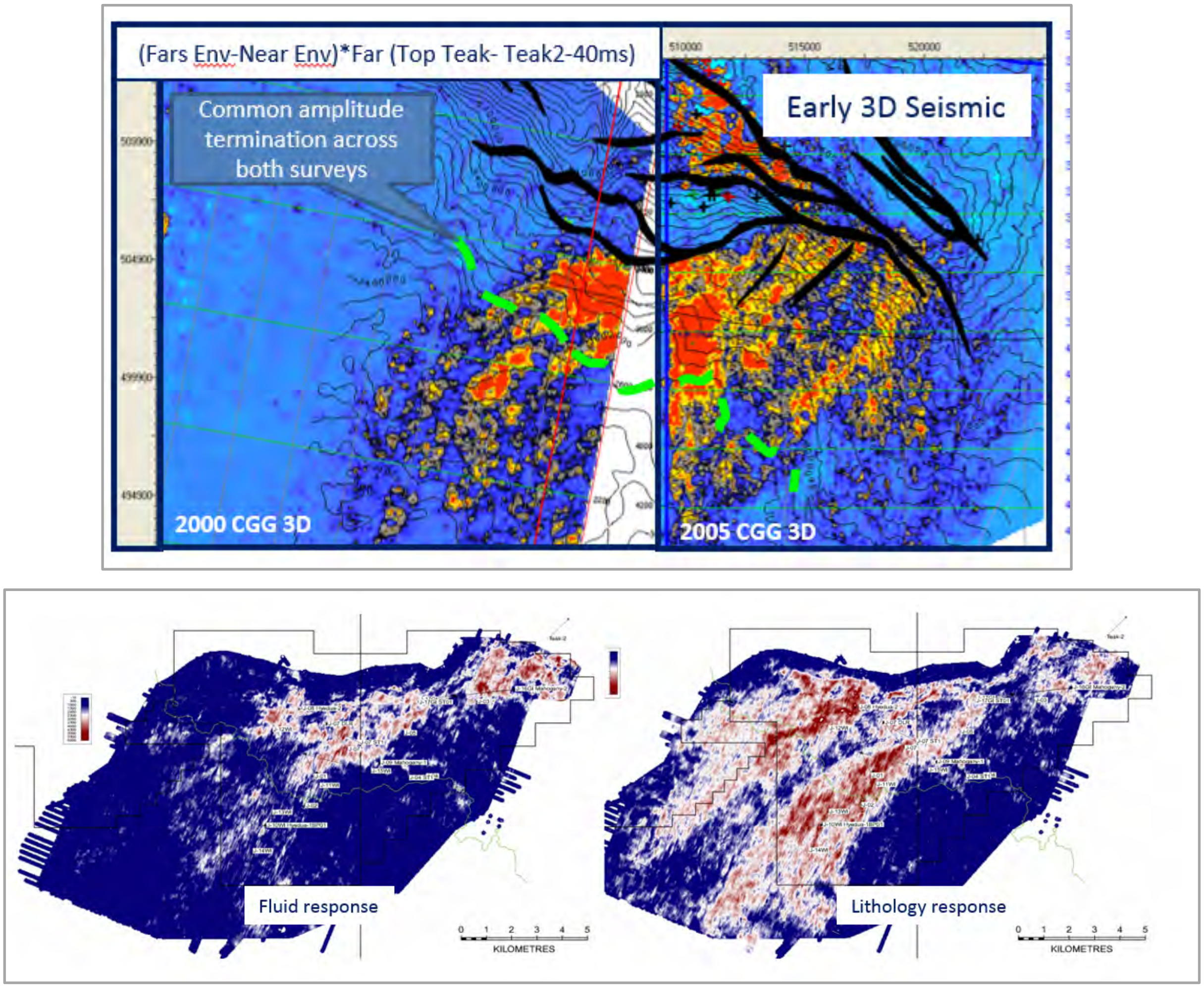
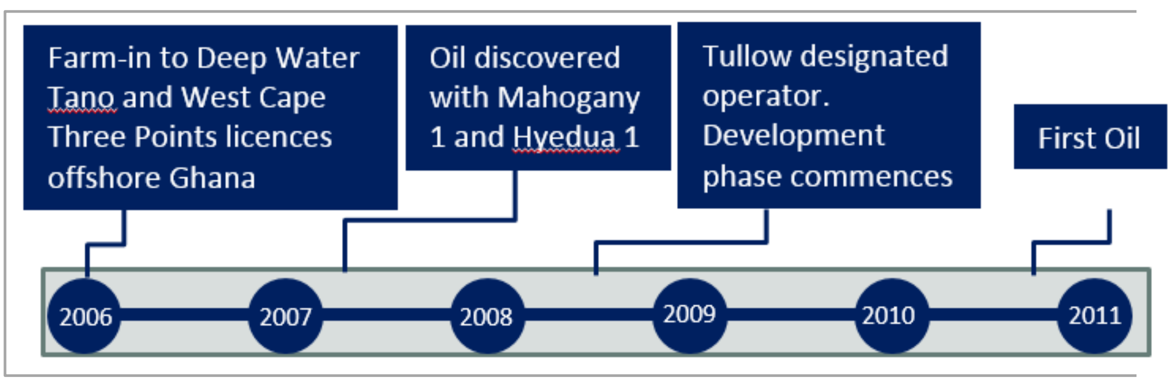


Figure 2. Early Seismic View and Later AVO View



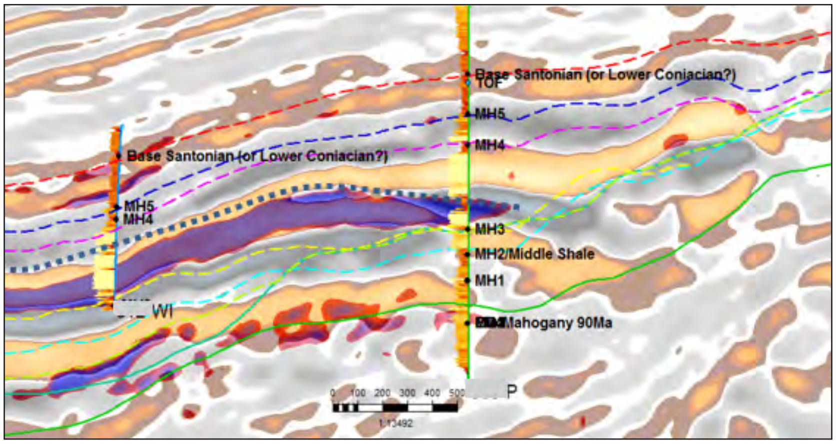


Figure 3. Lithology and 4D difference between wells

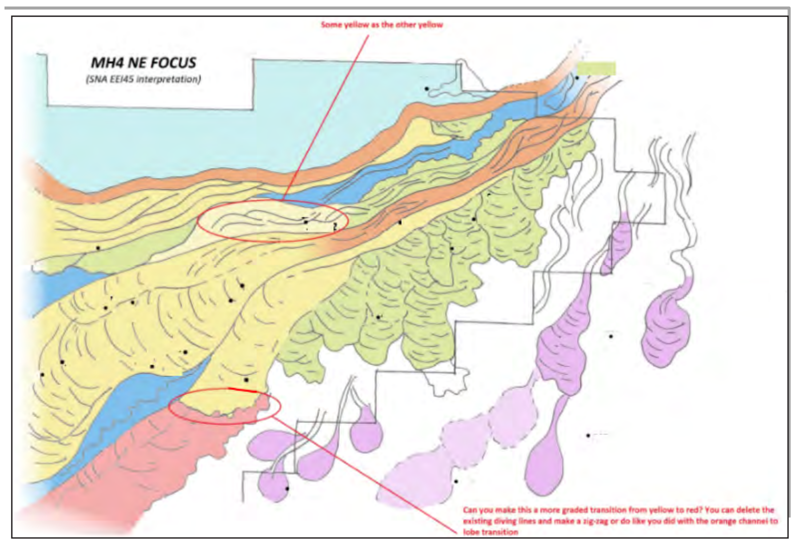


Figure 4. Detailed Conceptual Model of One part of Jubilee Reservoir

- Phased development focussing on the appraised "core" portion of the Jubilee Field
- Ongoing data acquisition during the development drilling phase to optimize the plan on a continuous basis
- Phase 1 would be used to frame future phases of development data obtained and early performance
- Focus on development of the high confidence reservoirs first.

Consistent with the phased philosophy of development, between 2014 and 2015 a further ten wells were drilled, designed to increase production and recover additional reserves, targeting the previously undeveloped areas of the field and one additional stratigraphic zone.

In the February 2016, the project encountered a major challenge: an issue with the turret bearing of the Jubilee FPSO Kwame Nkrumah was identified. This resulted in the need to implement new operating and offtake procedures. The necessary phases of operations shut down during this period however presented a unique learning opportunity for the sub-surface and enabled a series of carefully planned interference tests within the reservoir.

Learning and understanding of the dynamic behaviour and connectivity within the reservoir has been further supported by the acquisition of the first 4D survey in offshore Ghana in February 2017. With a strong lithology and weaker fluid element in the reservoir rock physics, the results of the 4D have shown a dominant pressure effect allowing pressure baffles, previously inferred through reservoir model history matching and geological understanding, to be mapped directly.

Integration of dynamic reservoir behaviour, geophysical, geological data, and with field analogues has allowed detailed insights into the evolution, architecture, and flow behaviour of this turbidite fan system.

This talk will lead the audience on a journey from the early understanding of the geology of Jubilee, sharing insights on the key learnings in the course of the development, to the latest view of the Jubilee reservoir architecture, and the impact of this understanding on the next phase of development drilling.

Keith Myers
Edwige Zanella, Jamie Collard, Helen Doran
Westwood Energy

Jubilee to Liza: Lessons from a Decade of Exploration in the Central Atlantic

The play opening the billion-barrel Jubilee oil discovery in Ghana in 2007 triggered a decade of exploration drilling chasing analogues in the deep water Central Atlantic margins, from Mauritania to Cameroon in the West Africa margin and from Guyana to NE Brazil in South America (**Figure 1**). Many were enticed into the play but the rewards have been concentrated in only a few companies. So what lessons have been learned? First and foremost, if you want to repeat a success, then you need to first understand the geological factors that are needed for the success you are trying to replicate.

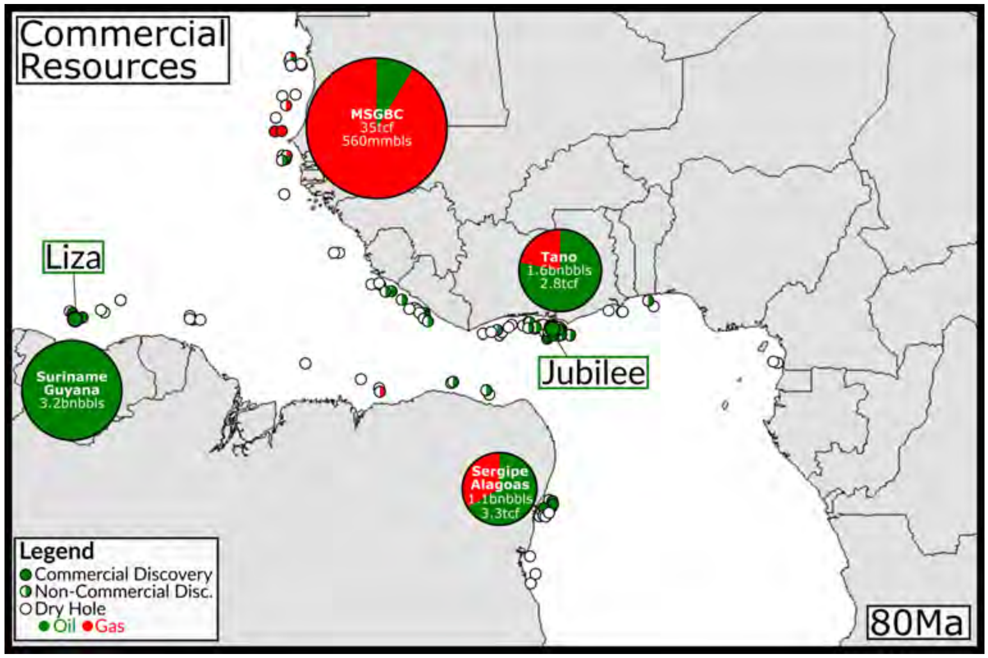


Figure 1. Late Cretaceous (80 Ma) Atlantic Margin showing the location of exploration wells and commercial resources discovered in the Cretaceous turbidite plays.

Seventy-eight companies have spent $11.4bn drilling 128 exploration wells in 13 basins along the Atlantic margins in the hunt for the next Jubilee from 2007 to early 2018.

Sixty-one wells have been drilled at the frontier stage of exploration, prior to the first commercial discovery being made in a basin. Frontier exploration delivered four commercial basin-opening discoveries at a commercial success rate (CSR) of 7% and technical success rate (TSR) of 39%. A total of 6.5 bnbbl of oil and 41 tcf of gas have been discovered in the Tano, MSGBC, Sergipe-Alagoas and Suriname-Guyana basins. Nine of the companies that participated in the frontier discoveries captured 74% of the total volume. The companies that drilled the most frontier exploration wells didn't get the most reward, however (**Figure 2**).

The keys to unlocking commercial success in the Cretaceous plays of the Central Atlantic margins lie in participating early in the opening of a new province, being selective, learning quickly the key geological elements needed for success and the integration of geological and geophysical analysis.

Lessons have been hard won for many, but there is plenty of running room for the industry. Westwood estimates that 80% of exploration wells have so far targeted the slope areas of the margins (**Figure 3**). A key lesson is that a large part of the commercial resources in the slope setting are located in areas dominated by normal faulting with gentle slopes, where higher quality deep water reservoir sands can be deposited and creating optimal conditions for hydrocarbon migration. Success rates are lower on steeper, narrow slopes where deep water sands are more confined and traps are smaller.

Significant resources remain to be discovered on the margin slopes and industry attention is also focusing on frontier plays on the ultra-deep-water basin floor settings that have a proven high potential but have been tested by only a few wells to date.

Biographical Sketch

Keith Myers is President, Research at Westwood Global Energy, responsible for research across the business. Keith joined BP in 1987, having graduated with a geology PhD at Imperial College. Following a variety of technical roles, he became Senior Commercial Advisor leading several major business negotiations for new business access. He also led strategy for BP's business in West Africa in the Strategic Alliance with Statoil. After leaving BP in 2000, Keith was an advisor to numerous energy companies on strategy and partnership issues. Keith founded Richmond Energy Partners in 2006 to provide independent advice to investors in smaller oil and gas companies. REP advised some of the largest funds and institutions investing in the sector and provided exploration strategy and benchmarking services for the global exploration industry. REP launched Wildcat, the online global exploration intelligence service in 2014 and REP became part of Westwood Global Energy Group in 2015. Keith takes a keen interest in the oil sector governance and serves as a member of the advisory group for the Natural Resource Governance Institute.

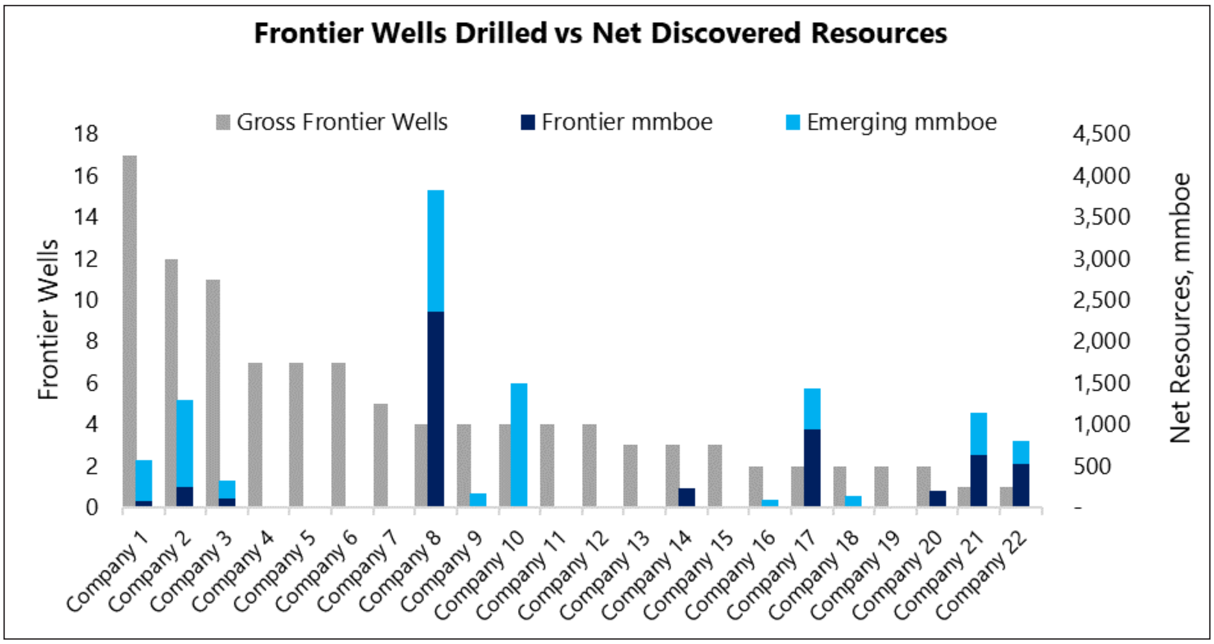


Figure 2. Gross frontier wells drilled by company in the Cretaceous turbidite plays of the Central Atlantic versus net resources discovered resources from 2007 to 1Q 2018.

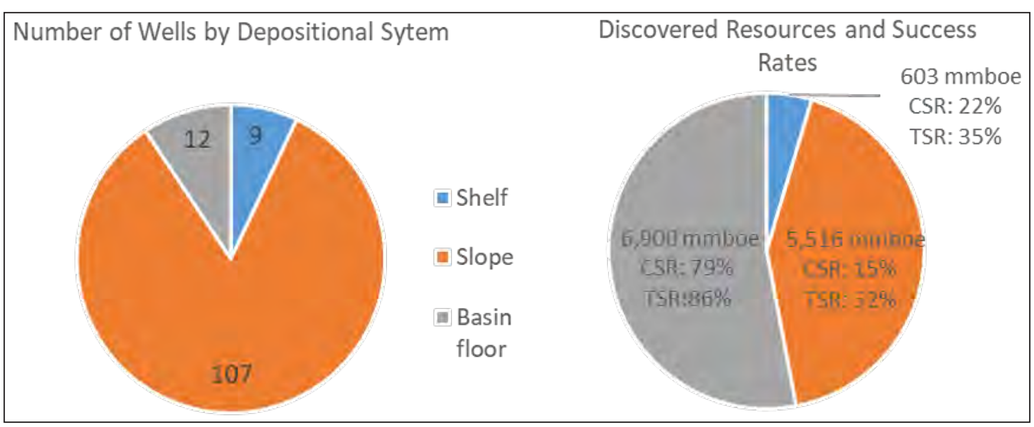


Figure 3 Wells in the study area divided into their positions on the depositional system. Only 12 penetrations to date have ventured onto the basin floor yet those wells account for >50% of the total discovered resources and have the highest success rates.

Notes

Notes

The 17th HGS-PESGB Conference on African E&P

Professional Poster Presentations

Abstracts

September 10-13, 2018

Norris Convention Centre, Houston Texas

Matt Morris, Ping Lu
Anadarko Petroleum Corporation

Using Generative Adversarial Networks to Improve Deep Learning Fault Prediction Networks

The field of Deep Learning (DL) is arguably one of the most important innovations in artificial intelligence in recent times. It allows for computational solutions to problems that aren't easily characterized by a mathematical model or deterministic algorithm. It also allows for automated solutions to problems that have inherently subjective solutions. Both of these criteria are endemic in the earth sciences, so novel solutions to these challenges should be welcomed.

Here, we demonstrate a recent refinement to Anadarko's seismic-based Deep Learning fault identification process that improves the continuity and compactness of predicted fault planes in areas where faults intersect one another. Historically, these zones of intersection were characterized by a cloud of intermediate probability values. To remediate this "blurring" problem and enhance confidence of inferences, we demonstrate a pre-processing technique in the image domain that "sharpens" the seismic image prior to training and prediction.

This sharpening solution consists of two neural networks. A feature extraction network is used for extracting both local and global features from an unrelated high-quality "donor" seismic survey. Then, the dataset of interest is sent through the donor reconstruction network where a generator architecture creates plausible-looking images at a denser-sampling rate with high perceptual quality.

In the study presented here, we create our sharpening network using a high-quality, South-American deepwater 3D survey as a donor. The resulting generator architecture is then applied to our dataset of interest—a 3D survey in the Gulf of Mexico. Similar to a 5D-interpolation, the super-sampled version of the GoM data contains three times the Inline and Crossline trace density, and the traces themselves are up-sampled by a factor of three.

The super-sampled data yields a grossly similar frequency response to its parent with two notable differences: a subtle redshift of the signal toward lower-frequencies less than 35Hz, and a significant boost in frequencies greater than 35Hz. Since this is not a spectral enhancement technique, no new thin-beds are introduced to the image.

Last, the super-sampled data is then deployed into our conventional DL training and prediction process to detect faults. By introducing a pre-processing sharpening step, the predicted faults become less blurry, more compact, and more amenable to programmatic attempts to segment them into discrete features.

Biographical Sketch

Matt Morris is a Geophysical Advisor in Anadarko's Advanced Analytics and Emerging Technologies team. He holds a Masters degree in Geophysics from The University of Texas at Austin and a B.Sc. in Geophysics from Missouri University of Science & Tech. In his 15 years with Anadarko, Matt's worked exploration and development projects across the US Lower 48, the Gulf of Mexico, and most recently in offshore Mozambique.

In recent years, Matt has served on Anadarko's risk and economic consistency teams that oversee a global portfolio of conventional and unconventional exploration prospects. In this role, Matt provided oversight for risk and uncertainty assessment, and developed a suite of Bayesian and frequentist statistical tools to aid in the assessment of exploration portfolios. Today, he's currently working alongside petrotechnical professionals and data scientists to integrate machine learning techniques into Anadarko's seismic interpretation workflows.

Neil Hodgson, Karyna Rodriguez, and David Eastwell
Spectrum Geo Ltd, Woking, United Kingdom

South Gabon's Pre-Salt Revelation

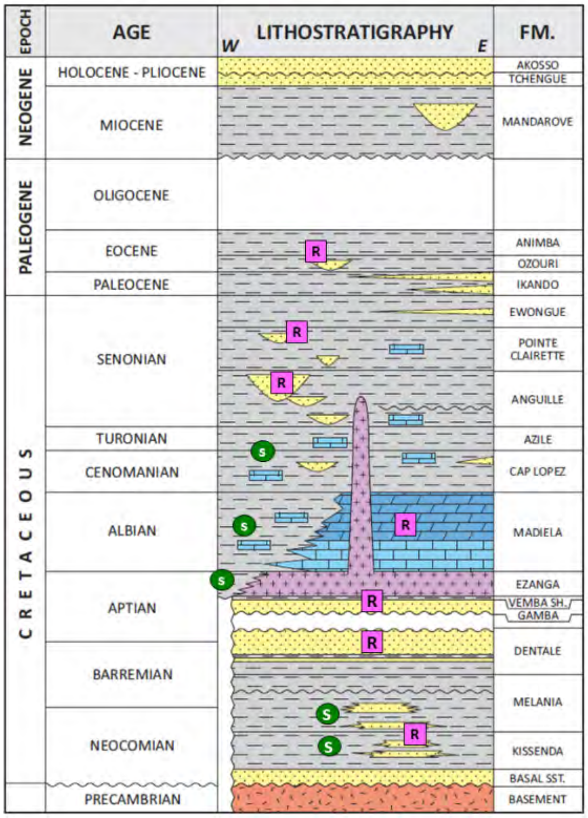


Figure 1.Simplified stratigraphic column of South Gabon's Salt Basin.

Introduction

To date, successful exploration for oil in the pre-salt play of South Gabon has primarily focussed on the Early Cretaceous Gamba sandstone play. On the shelf, the shallow water discovery creaming curve in the Gamba play had begun to plateau as explorers reached the interpretaional limitations of the inadequate imaging of available seismic resulting from complex post-salt geology. However, recent developments in 3D seismic acquisition and processing has allowed a new level of imaging to be achieved in the pre-salt, offering to unlock the remaining potential of the Gamba play and revealing a new system of traps and plays never before deliberately targetted; the intra syn-rift play.

Pre-and Post-Salt Prospectivity

A review of legacy data and historical operations records allowed understanding of the geological and geophysical complexities previously faced by operators in Gabon, specifically the challenge of resolving the pre-salt section due to velocity heterogeniity in the post-salt Albian "Madiela" carbonate. Integration of a pre-acquisition survey design study, efficient operations management [1], the use of long offset streamers and application of source and reciever de-ghosting with an interpretation-driven pre-stack depth migration, has resulted in an unprecedented image in the prospective pre- and post-salt sections [2].

During the break-up of the Gondwana, deposition of the syn-rift section comprised fluvial-lacustrine deltaic sand sequences (the Dentale and Kissenda Formations), in addition to two main anoxic lacustrine source rocks (Kissenda and Melania Formations). These sequences are characterised by listric fault extensional geometries. Upon break-up, the first marine transgression eroded the upper part of the syn-rift section creating a low relief monocline upon which the transgressive shoreface Gamba sandstone was deposited.

As the Madiela platform carbonate developed, it loaded the gently gravitationally extending Ezanga salt, quickly creating a heterogeneous pop-interpod geometry (**Figure 2**). In turn, as the carbonate platform was drowned by prograding clastic sequences from the west, these too loaded the salt, changing the geometries of the grounding pods and creating and infilling turtle back structures. Reactive fall and dissolution of salt created wide salt welds between isolated thin salt diapirs. This post-salt fabric is very heterogeneous in velocity, and this has led to the majority of seismic, both 3D and 2D, being unable to image the pre-salt syn-rift sequence.

This has now been addressed using the power of modern multiple elimination strategies and careful velicity building control on pre-stack depth migration. For the first time the syn-rift is imaged, revealing both Dentale targets and intriguingly the pre-Dentale structures with no expression at Gamba level. These are particularly exciting as the lower syn-rift play has recently been the target of very rewarding exploration offshore Congo to the south. The overlying Gamba sandstone sequence is seen to vary in thickness, creating extra volume potential in places and the potential for stratigraphic traps in others.

The shallow water Madiela carbonate platform has high porosity and reservoir potential generally at the platform margin edge. Whilst several wells in the area have hydrocarbon shows in the Madiela Fm, we are now able to identify the platform margin edge, identify karstified textures and de-risk the the petroleum system at this interval. Indeed, the fidelity of the imaging of the post-salt clastic systems (Cap Lopez Fm to Ewongue Fm) have revealed a new play system in the north of the area where pre-salt oil appears to be able to migrate into post salt. Multiple shoreface and channel sands ranging from 5-70m thick can be

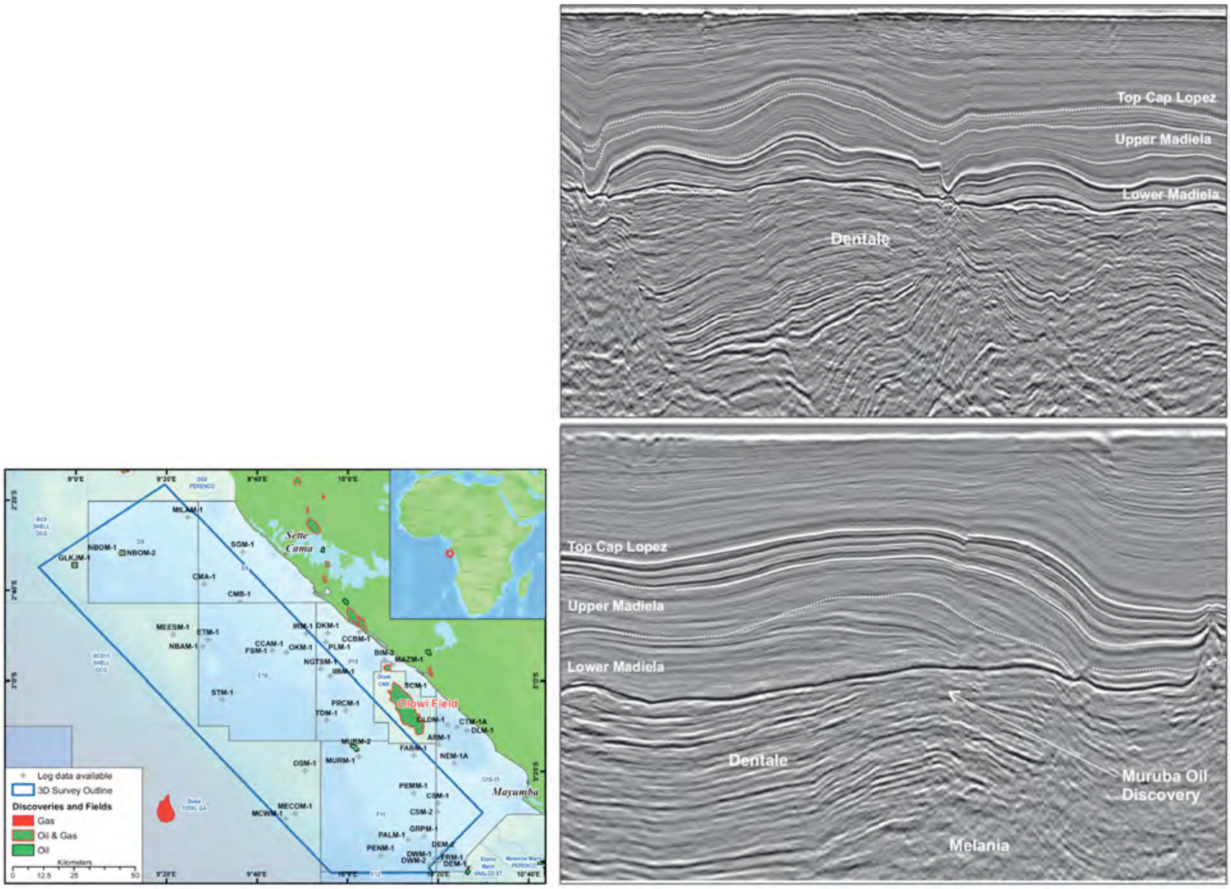


Figure 2. New 3D seismic PSTM sections demostrating pre- and post salt-targets in the shallow water South Gabon. Inset map shows 3D seismic location.

identified from both seismic and well data which can be mapped in combination structural/ stratigraphic traps.

Conclusion

To create a new creaming curve of discovery in South Gabon, requires either new technology (3D processing), new geological plays (intra syn-rift plays) or fresh access to acreage. In South Gabon in open acreage we have all three: new technology applied in processing the 3D seismic has revealed for the first time significant intra- syn-rift tilted fault block structures, heterogeneous Gamba distribution, undrilled Madiela structures with karstification textures and platform margin geometries (**Figure 2**), and detailed well correlation and reservoir mapping are revealing undrilled post-salt traps as well as an understanding of reservoir disctribution using advanced seismic attribute analysis. The new 3D in South Gabon is indeed a revelation, coincident with news of significant liquid discovery in the pre-salt adjacent to the 3D area. It's time to re-appraise this exciting oil prone basin.

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Mik Isernia, Paul Endresen
Bluware
Ana Krueger
University of Houston

Data-driven Transformation in Geology, Geophysics and Engineering

The recent industry downturn has provided an opportunity to unlock innovation to enable the industry to better compete in the future and survive future down trends or other challenges. It is all about the data, and how it transforms into information as it flows from acquisition, to imaging, to attribute generation, to reservoir modeling, dynamic simulation, and eventually to decision making.

Tangible technologies are the foundation to the success of digitalization, from seismic processing, to interpretation, new reservoir simulators, analytics, and machine learning. Removing the limitations that plague traditional software enables us to imagine workflows that were not conceivable before. One of those technologies is the modern Graphics Processing Unit (GPU). Modern GPUs have incredible potential to revolutionize the industry if they are combined with modern software architectures. Retrofitting old software with modern technology only delivers limited improvements, and this is the reason why E&P's have barely exploited the GPU potential. When we think about GPUs, the first thing that comes to mind that exemplify the best exploitation of the GPU power is the world of 3D Gaming. We will cover the reasons why 3D Games have been able to fully take advantage of GPUs, and show very tangible examples on the same approach applied to E&P, resulting, among many other things, in the ability to interactively handle seismic data at full scale.

Retaining all the data and information at every transformational step, and propagating the inherent uncertainty through the whole workflow, dramatically changes the way we work. Enabling this with a core technology optimized for random access and smart transformation of data makes new workflows that previously were regarded as impossible, possible. Connecting workflows with smart data movement through services with REST API's, HPC, and cloudification transforms the way workflows can be connected together, added to, and enhanced. Eliminating the import and export of data saves time and money. Carrying multiple realizations of models through the workflow allows a deeper exploration of solutions to the challenges being tackled. Cloud data storage opens the way for faster iteration on larger problems, problems which cannot be solved in an acceptable time scale using data stored in a traditional data management system. With the extreme amounts of data being collected, Deep Learning will have an unprecedented role to play in understanding and interpreting the data, ultimately providing better decisions faster, and at a lower cost.

Walter W. Wornardt PhD
Micro-Strat, Inc., Houston, Texas

Is Namibia Really An Oil Province?

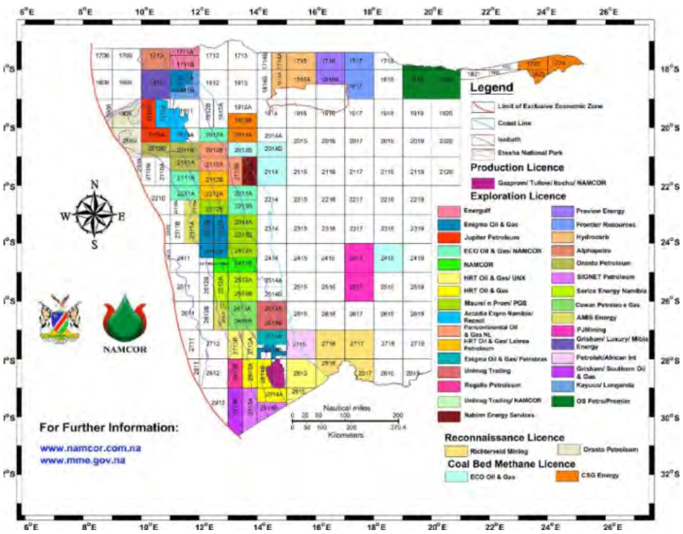

Figure 1.

Namibia, long neglected as an oil province, seems to be in the perfect place for large oil discoveries. After all Namibia is situated on the southwestern side of Africa and was originally tied to South America in the area of the oil rich country of Brazil. After drilling thirteen wells, no commercial quantities of oil have been found in Namibia. Namibia is an under explored gas and potential oil province. Only thirteen wells have been drilled along the 1200km coastline. Many of these wells have source rocks and potential reservoirs, but may not have a major seal, the key to a successful oil discovery. These wells are located in the leases in (**Figure 1**).

Dr. Marico Mello, a geochemist with HRT (a Brazilian company, South America), stated he was determined to locate and find oil in Namibia. He said that an overall understanding of the geology of Namibia was needed, especially the detailed chronostratigraphy, and identification and age of mature source rocks in many of the previous wells drilled in Namibia.

We were assigned this project using eight of the previously drilled wells in Namibia. This included wells drilled by Chevron in the Orange Basin to the South, Shell in the Central area Leuderitz Basin, Norsk Hydro, and the National Petroleum Company of Namibia (NAMCOR, private co.) in the northern Walvis Basin (**Figure 2**).

Our analysis of these eight wells included high resolution biostratigraphy using calcareous nannofossils, planktonic foraminifera, benthic foraminifera, dinoflagellates and other palynomorphs, paleobathymetry, and numerical age-dated marker species correlated to the global cycle chart of Hardenbol 1998, et al., plus available geochemical information. These detailed biostratigraphic analysis and age-datable marker species related to the global cycle chart provide a regional chronostratigraphic framework in Walvis Basin and Orange Basin. The detailed chronostratigraphy is necessary to construct accurate time structure and seismic facies map and to ensure that reservoir facies will be properly correlated regionally.

These data provided HRT with an understanding of the stratigraphic position of potential sandy reservoir facies, potential source rocks, detailed age and type of source rocks present in each well, plus the ability to correlate the same age rock and same source rocks. Unconformities with missing stratigraphic sections were identified and age-dated with the amount of time missing. Changes in age versus paleobathymetry were identified and correlated to the major maximum flooding surface condensed section on the global cycle chart, to provide further clues to find, correlate, and trace the source rocks in various basins in Namibia. These data were used by HRT in preparation for drilling the Wingat-1, Murombe-1 and Moosehead-1wells (**Figure 3** and **4**).

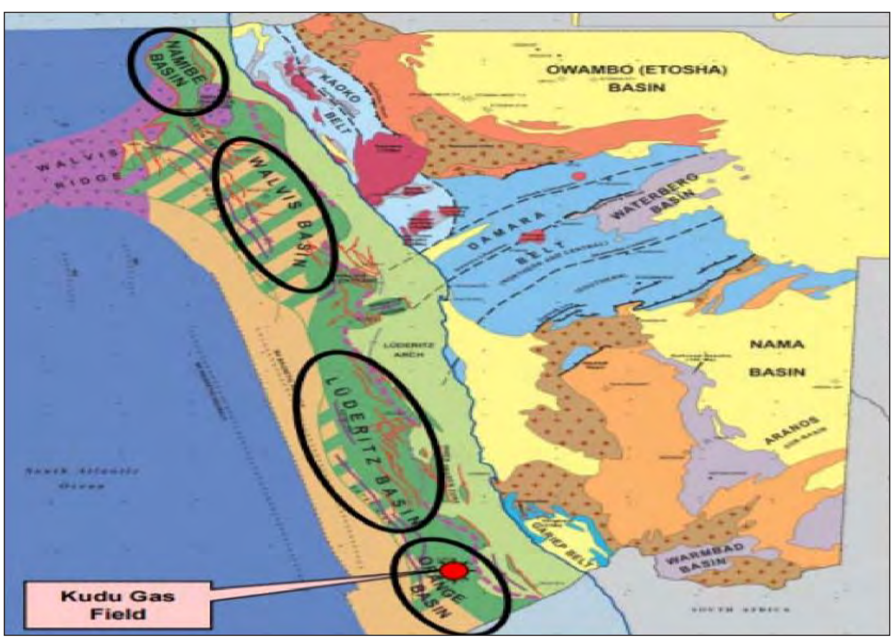

Figure 2. Nambia basins.

Wingat-1

Pre-drilled expectations for the HRT Wingat-1, (Figures 3 and 4) in the Walvis

Basin, northern Namibia were to test a seismic amplitude anomaly on 3-D seismic, a well-defined elongated combination trap with 4-way structural closure, to test the resource potential of a carbonate platform with a series of prograding carbonates of Albian age at a depth of about 4,100 meters.

The Wingat-1 spudded March 25, 2004, located in Block 2212/07-1, in 1034 meters of water in the Walvis Basin, offshore Namibia. We can confirm most of the published information about the Wingat-1. The original total depth of the well was 4127 meters. We provided detailed biostratigraphy, marker species with numerical ages, paleobathymetry interpretations on a sample by sample basis, TAI, kerogen type, maturity, and oil generation information to HRT down to their initial TD depth of 4127 meters and total depth of 5000 meters. The carbonate reservoir was encountered as predicted but with much less porosity than anticipated. With increasing concentrations of hydrocarbon shows below 1500 meters the HRT consortium and Dr. Marico Mello decided to drill ahead. Like a true wildcatter, Marcio decided to drill to 5000 meters to test the presence of turbidite reservoirs and sample the mother source rocks in the Barremian shales. We were informed that the well had reached TD and to complete our report on the well.

In May, 2004, it was announced that non-commercial amounts of high-quality oil were found in the Wingat-1 well in the Walvis Basin, Northern Namibia. Although this was the first live oil to be found in Namibia it was not found in commercial quantities. It seemed to be all there; the seal, the trap, sands, Aptian source rocks in the oil window that had generated light oil (38-42 gravity), a confirmed source potential; what was missing, the trap? In addition, there was minimum contamination and no water bearing zones identified. These results

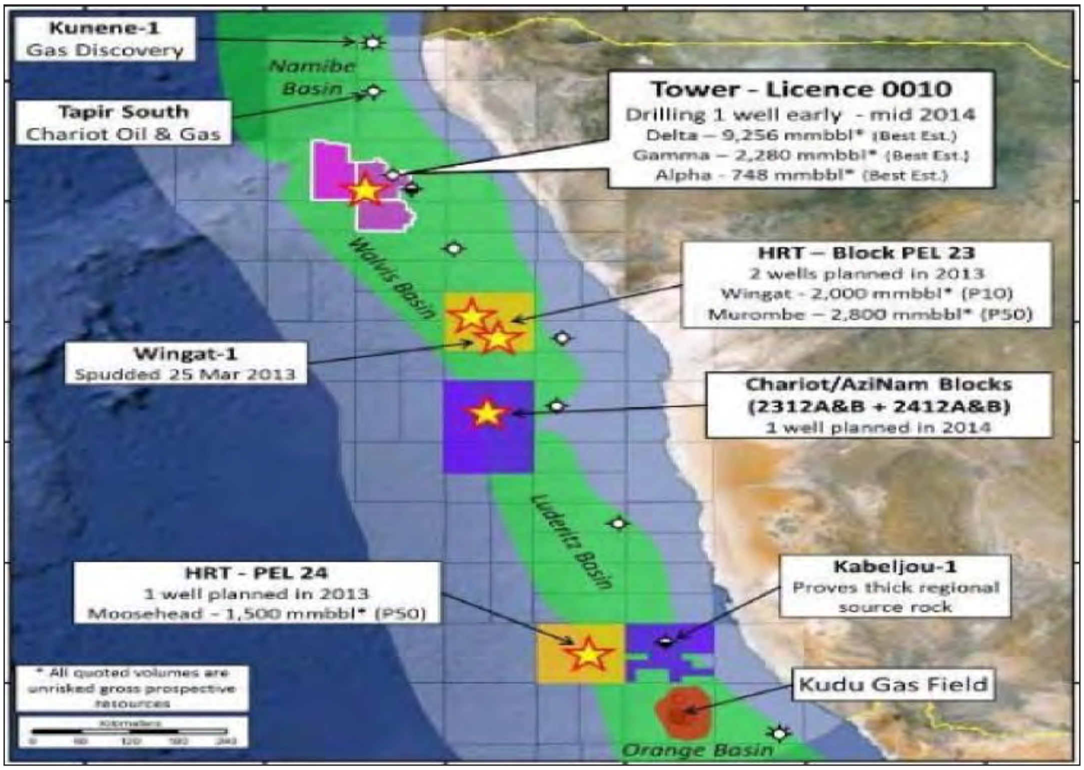

Figure 3. Location Map of HRT's Wingat-1, Murombe-1, and the Moosehead-1, Offshore Africa

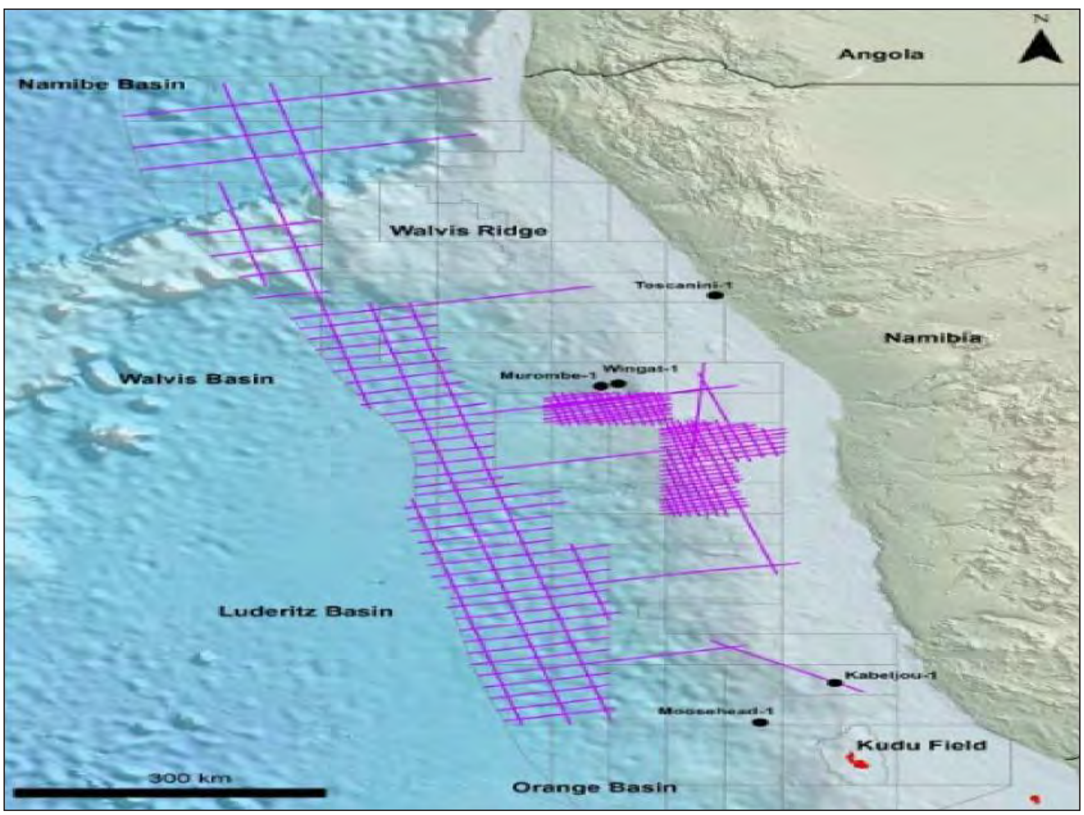

Figure 4. Location Map of Wells in Offshore Namibia (Compliments of ION basinSPAN, 2015).

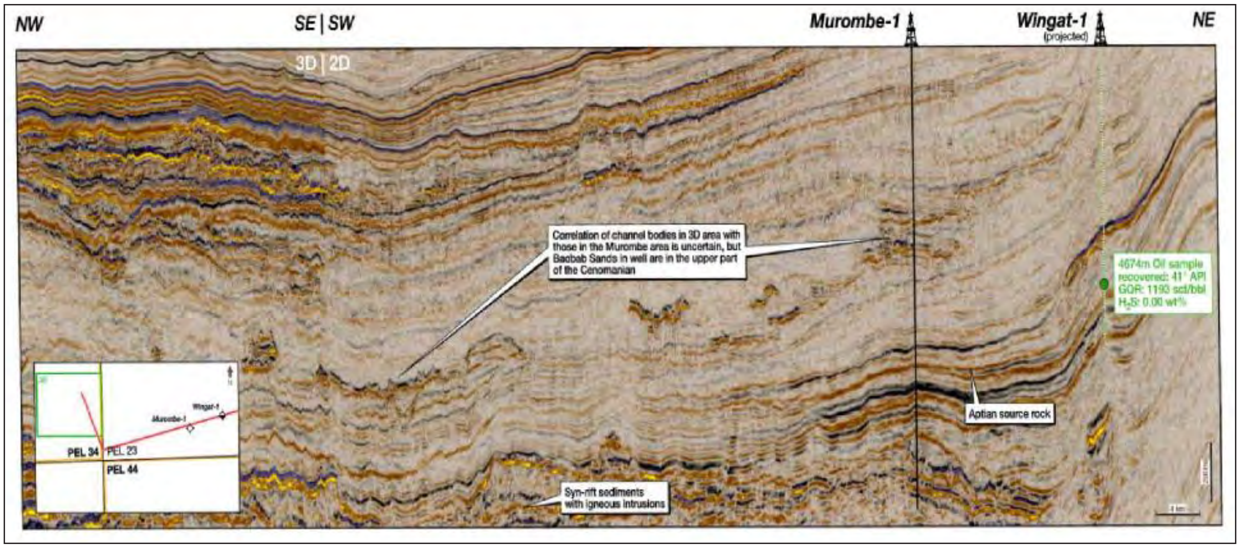

Figure 5. Regional Tie-line through Wingat-1 and Murombe-1 (Compliments of AZINAM Namibia).

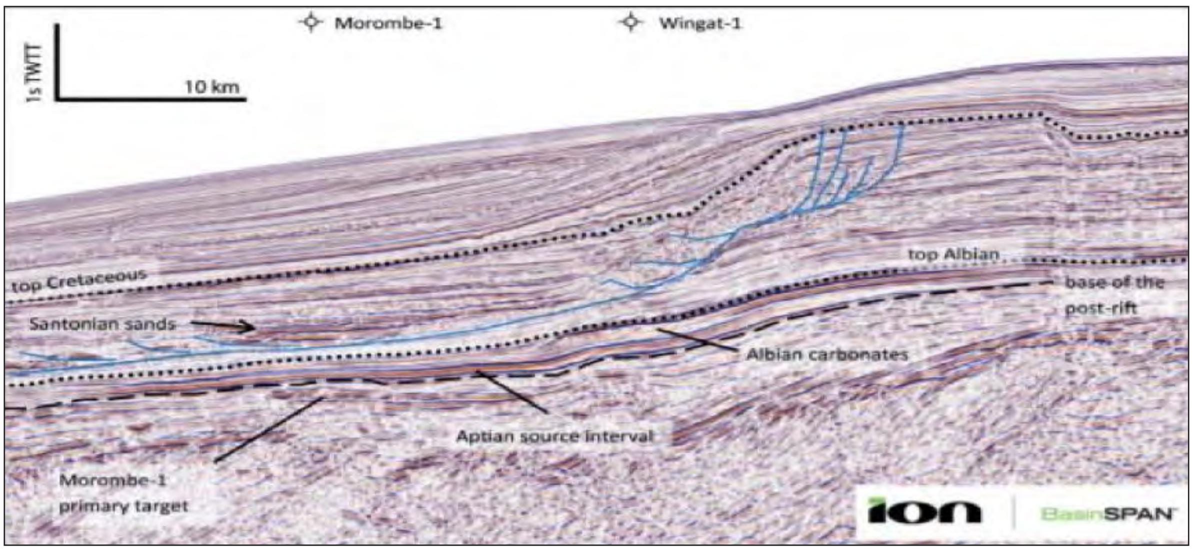

Figure 6. Enlarged seismic section showing the Wingat-1 and the Murombe-1 wells in Walvis Basin. (Compliments of ION basinSPAN, 2015)

demonstrated the occurrence of several thin-bedded sandy reservoir facies saturated with 38-42 gravity light oil associated with two Aptian mature oil generating source rocks and an active petroleum system present in the Walvis Basin.

A major contribution from the Wingate-1 is the discovery of several high quality source rocks, in the oil generation window, rich in organic carbon, coupled with the IFA formation testing, of the recovered light oil from the same shale reservoirs penetrated in the Wingat-1. These source rocks generated liquid hydrocarbons of excellent quality at several depths. This seems to confirm the source potential for the immediate area and the Walvis Basin, and a new beginning of exploration in Namibia. The Wingat-1 well was plugged and abandoned in 2004, (**Figure 5**).

Further post drilling results from the Wingat-1 showed the presence of a number of systems in the Wingat-1: early Barremian Lacustrine to paralic, fluvial sediments; late Barremian to Aptian with mature shales as mature source rocks in the oil window, with the OAE1a, a major ocean anoxic event, that are associated with several thin sandy beds with light oil in the Aptian, (**Figure 4**).

HRT's second objective in the Murombe-1 well was interpreted as Santonian-age sands in a confined channel complex with high amplitude reflectors and lowstand channel like geometry. Post drilling assessment of this prospect showed that Santonian-Age sands were part of a low stand lower slope meandering channel turbidite sand channel complex in deepwater. The well penetrated a thick water wet 35 meter net sand within a thick 240 meter gross section, with average porosity of 18% in a confined channel complex. The sands were wet and considered a dry hole. The associated mature source rocks could provide oil to the lowstand sands in this channel system. This seems to show that the late Cretaceous in the Walvis Basin can also yield well developed high quality turbidite sands (**Figure 7**).

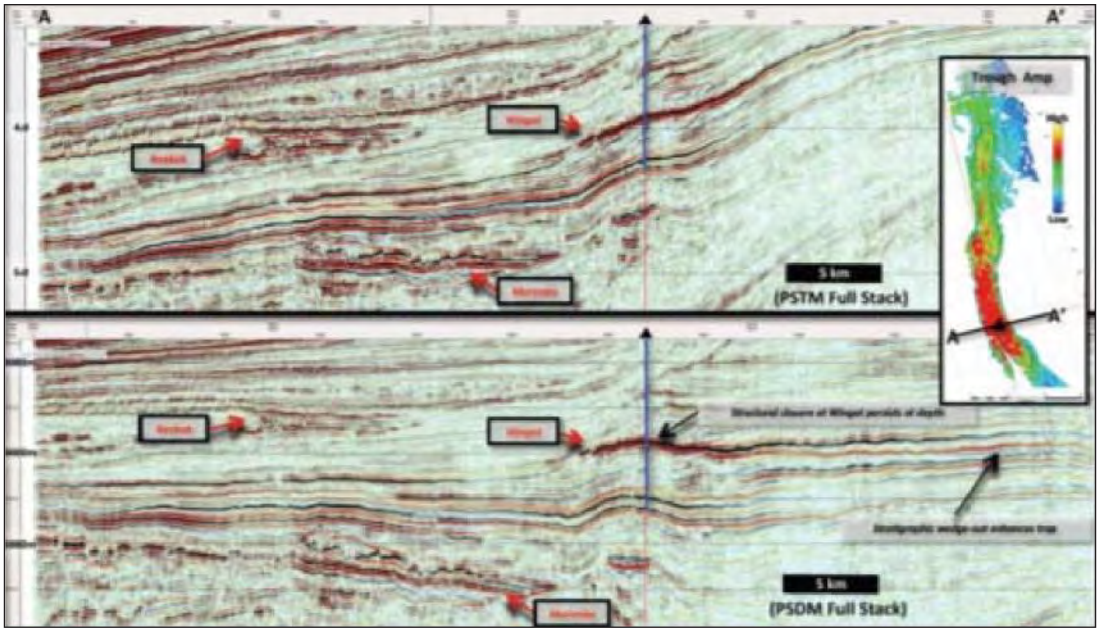

Figure 7. Prospects in the Murombe-1 well Walvis Basin, Namibia

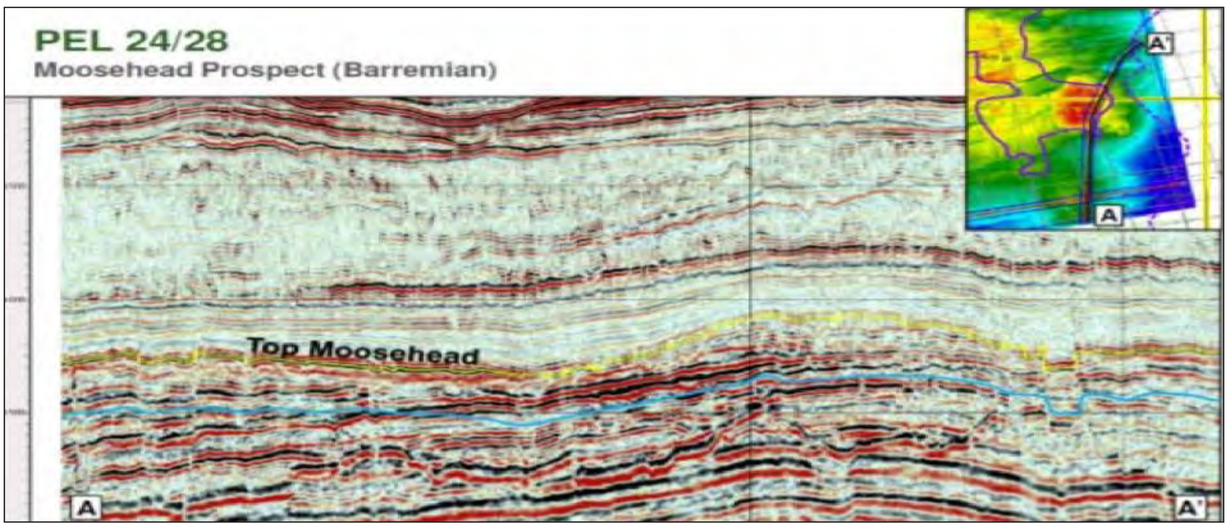

Figure 8. Pre-drill interpretation of the Moosehead-1 Prospect, Walvis Basin. (after Namcor)

Moosehead-1

After completing the Murombe-1 well, we analyzed the third and final in the HRT series of wells in Namibia, the Moosehead-1 well, drilled in the Orange Basin, (**Figures 3** and **4**) South of the Wingat-1 and Murombe-1 in the Walvis Basin. The well was drilled in 1716 meters of water in offshore Namibia, to a total depth of 4170 meters. The original objective of this well was to test the equivalent age reservoir as in Brazil, the 'pre-salt' reservoirs; Barremian age carbonate reservoirs in a large 4-way dip closure. The Moosehead-1 results were somewhat similar to the Wingat-1, without oil. The well penetrated 100 meters of carbonates, but with less porosity than was expected. Two or more potential source rocks were encountered with wet gas shows (**Figures 8** and **9**).

After completing the biostratigraphic analysis of the Moosehead-1 in the Orange Basin, 2713/16-1, we identified and recognized a similar number of the same age datable maximum flooding surfaces as recognized in the Wingat-1 and Murombe-1 well. We dated the sediments in this well to 3360 meters as Barremian to Eocene, in paleowater depth from transitional to middle bathyal (1500-3000 feet). The maximum flooding surfaces and their condensed sections are very important because they can be major seals and points of accurate correlation on logs and seismic. Figures 4 & 6 shows the location and stratigraphic position of the potential reservoirs of the Wingat-1 and Murombe-1 wells, in the Walvis Basin, offshore Namibia.

The source rock and presence of a petroleum system in the Walvis Basin is now fact. The established existence of thick restricted marine Aptian mature source rock in the oil window in the Murombe-1 and Wingat-1 and the DSDP 351 well offshore is also fact. The recovery of the light oil 38-42 gravity in thin sandstones associated with Aptian mature shales in the Wingat-1 is fact. These facts confirm an increased potential for well-developed oil reservoirs in the Walvis Basin in Namibia. When these same source rocks and sands are located in similar situations the chance of finding commercial quantities of oil is much greater than before the Wingat-1 and Murombe-1 wells were completed. It looks like a bright future for Namibia with all the potential reservoir sands, especially in the Walvis Basin (**Figure 10**).

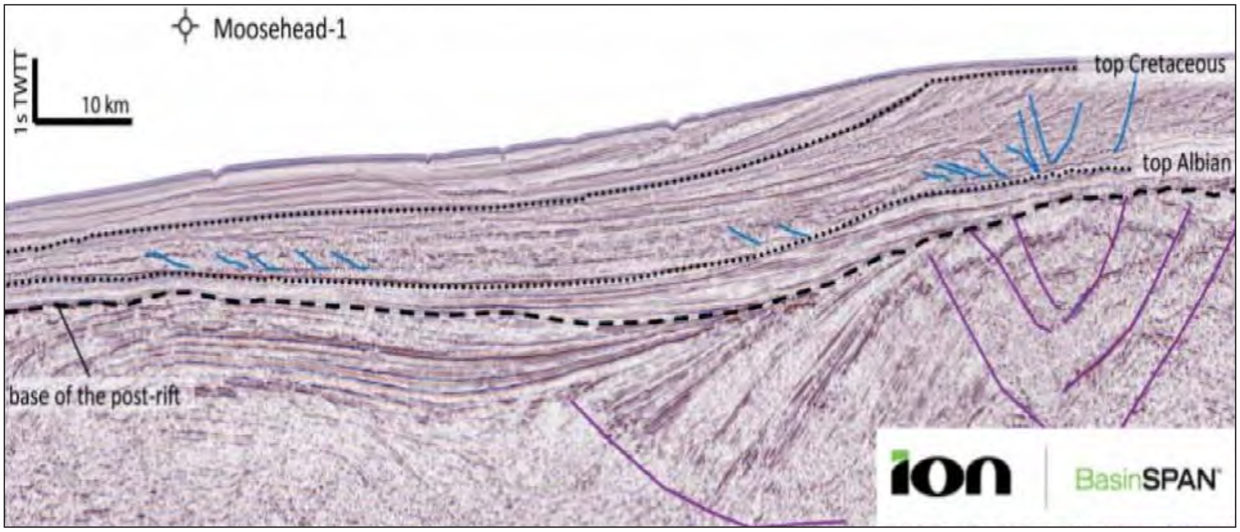

Figure 9. ION basinSPAN seismic line through Moosehead-1, Orange Basin (Compliments of ION basinSPAN)

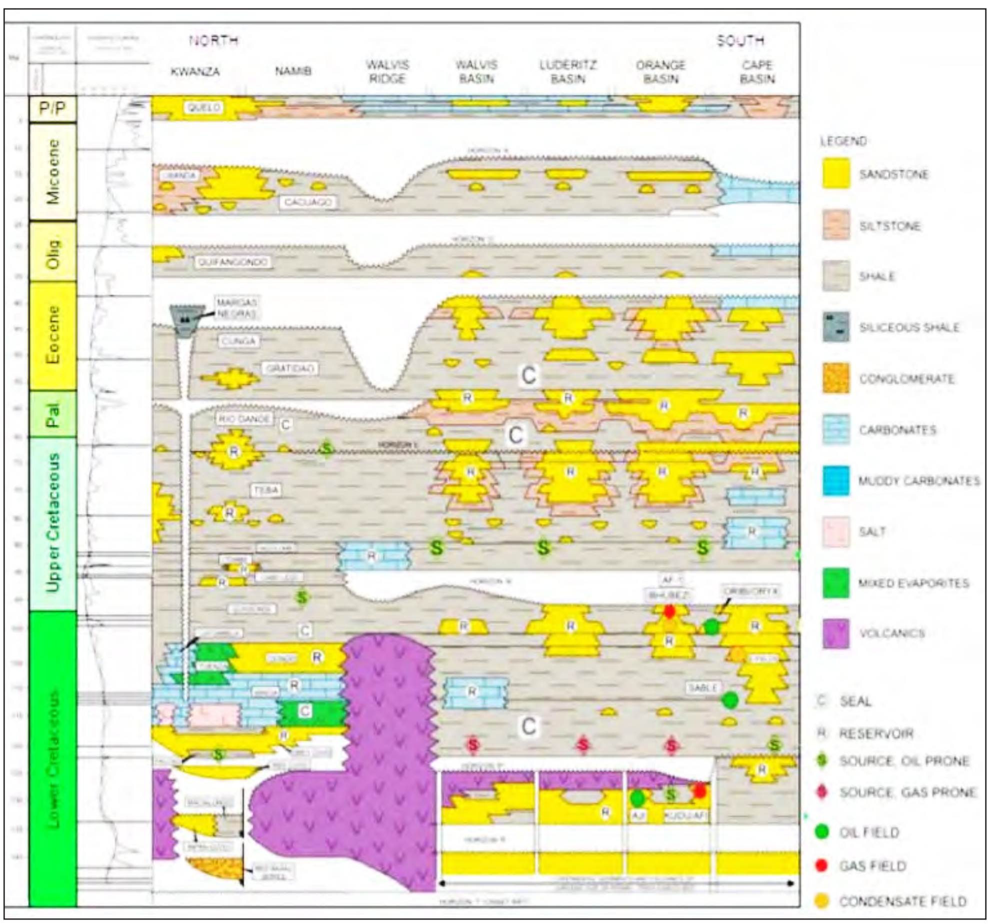

Figure 10. Summary of occurrences of reservoir sands in Namibia (after Namcor)

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Biographical Sketch

Walter W Wornardt PhD is President, MICRO-STRAT, Inc, Houston, Texas. Professional Geologist, Seismic Sequence Stratigrapher, and Micropaleontologist. Born in Milwaukee, B.S. and M.S. Geology University of Wisconsin, Madison. Ph.D. Paleontology University of California, Berkeley. Worked with Chevron; Esso Production Research, Houston, Unocal Research, California, Chairman of Geology - University Redlands, California. 1983-present, MICRO-STRAT, Inc, Houston, TX and 8+ Cairo, Egypt. With Peter R Vail, Ph.D. 1988, initiated well-log seismic sequence stratigraphic analysis, taught 41 courses worldwide; projects in Africa, South America and Far East. 2008 -present, 7 years in unconventionals: Eagle Ford, Eaglebine, Haynesville, Niobrara, Utica, West Texas, Poland, and Saudi Arabia. Registered Geologist in state(s) CA-076 and TX-5638. Member of AAPG, SEG, and HGS.

Syed Dabeer and Dr. Umar Ngala
Petro-Vision Energy Services, London, UK

The Influence of Shale Ridges on Reservoir Development and Implications for Exploration A Case Study from Onshore Niger Delta, Nigeria

Nigeria is the largest oil and gas producer in West Africa. Nearly all the country's production is coming from Agbada-Akata petroleum system of the Niger Delta (Michele et al. 1999). The source rock for this petroleum system is in the marine shales of Akata and Agbada Formations. The hydrocarbon reservoirs are within the paralic sequence of Agbada Formation (Short and Stäuble. 1967 and Evamy et al. 1978). The age of reservoirs in the zone of interest is Middle to Late Miocene. The study area is located in the Eastern Niger Delta where eight commercial fields have been discovered. All the fields were discovered using 2D seismic data, mostly in the 1960's and 1970's. Over 100 wells have been drilled in the block and most of the wells pre-date the 3D seismic data used in the current study. The "G" field is the largest and started producing in the 1970s. It has 500+ MMSTB cumulative oil and about 1Tcf cumulative gas production. The "B" field is the smallest and started producing in the 1990's. It has about 3 MMSTB cumulative oil and 3 Bscf cumulative Gas production. All fields have multiple reservoirs and still have unproduced resources.

Three unsuccessful exploration wells have also been drilled in this block. The presence and the quality of reservoir have been poor in all unsuccessful wells and considered as a major risk. This paper investigated the controls on reservoir development and hence the reasons for the inferior quality of the reservoirs in the dry wells.

A shale ridge is a depositional feature. It is formed of under-compacted sediments and located at the distal edge of a depocenter or megasequence. The shale ridges influence the tectonostratigraphic development and deposition of Agbada reservoirs in Niger Delta. Faults are initiated when high density sands of subsequent megasequences are deposited on top of a shale ridge (Evamy et al. 1978). Shale ridges mark the boundary of an individual depocenter, and considered as top of the Akata Formation. It is not possible to map the top of a shale ridge as no single event marks its top. A paralic sandy event (in Agbada Formation) changes into shaly marine sediments (of Akata Formation) on top of a shale ridge.

An excellent quality merged 3D seismic survey (around 1000 Km^2) was used to do a detailed interpretation of 39 reservoirs from 7 fields. The interpretation was extended to neighbouring fields. The well logs were correlated, where possible, with the help of seismic interpretation. The visual blending of seismic attributes was used to qualitatively interpret the top of shale ridges. The fault pattern from many interpreted horizons was overlaid on the map of shale ridges to understand the relationship between faults and shale ridges. It was observed that major structure-building faults are located on the basinward side of shale ridges. It was interpreted that the shale ridges provided the weak zones for the initiation of structure-building faults. Based on structure-building faults and shale ridges, the study area was divided into three megastructures. Each megastructure contains one megasequence. The influence of shale ridges on the tectonostratigraphic evolution of the study area is shown in **Figure 1**.

The reservoirs in the Niger Delta are generally believed to be localised in extent. It was observed that this is not always true. The reservoirs in a few fields were found to be quite extensive. Few reservoirs could be correlated across four fields or extended 40 Km across (limited by the extent of 3D seismic). The extent of an individual reservoir is controlled by the presence of shale ridges in all directions. If a shale ridge is present between two fields then it was not possible to correlate the reservoirs across those two fields. On the other hand, if there is no shale ridge present between fields then the reservoirs can be extended to larger distances. It was observed that the dry wells, Well-1 and Well-2, were located just landward of the top of shale ridge or structure-building fault (**Figure-1**). The paralic sequence of Agbada Formation was very shaly in both the wells. The Agbada Formation in well F-13 contained more sand and was located on the seaward side of a shale ridge. All successful exploration wells were drilled on the basinward side of a shale ridge and encountered good reservoirs. This was interpreted to be the result of variable subsidence. The basinward side of a shale ridge would see higher subsidence due to growth along a structure-building fault and hence coarser facies would be focussed there. On the other hand, the distal end of a megasequence experiences less subsidence and would receive finer sediments while sedimentation is ongoing in a megasequence. Based on this observation, the areas just landward of the top of shale ridges are considered to have a much higher risk of reservoir as compared to the wells located on the basinward side.

The integration of seismic interpretation, well logs, and petrophysics strongly suggest that shale ridges are one of the

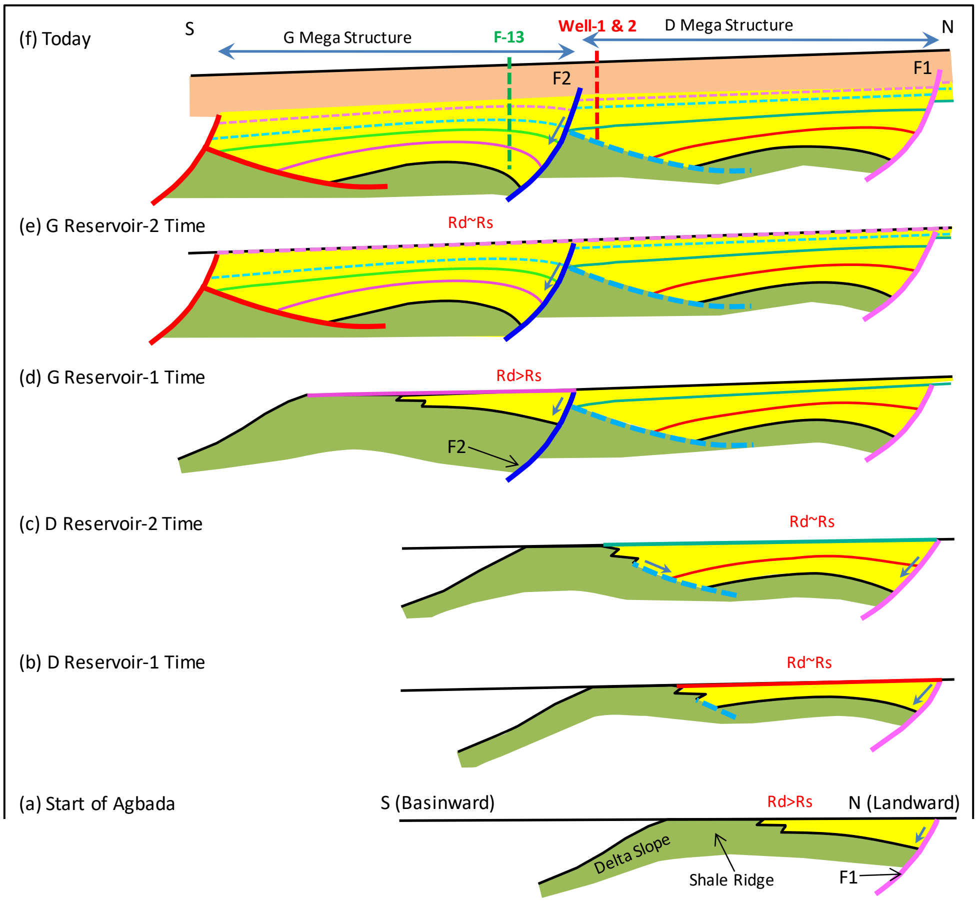

Figure 1. (a) to (f) Tectonostratigraphic development of the area of interest. The delta showed progradation when rate of deposition (Rd) surpasses rate of subsidence (Rs) and aggradation when Rate of deposition (Rd) is equal to rate of subsidence (Rs). The structure-building fault, like F2, is located toward the basinward side of a shale ridge.

strongest influences on the development of reservoirs in the study area. The top of a shale ridge may be a good structural location but it is not a favourable for encountering a good reservoir in the Niger Delta.

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Biographical Sketch

Syed Dabeer has an MSc in petroleum geoscience from Royal Holloway University and a bachelor's degree in geophysics. He worked in various exploration and reservoir geoscience roles in Eni and Schlumberger from 2001 to 2013. He is presently working in Petro-Vision and based in London, UK. He has worked in a variety of projects in West Africa, Pakistan, Northern Europe and the Gulf of Mexico. His areas of expertise are exploration geoscience, reservoir characterization and production geology. His current interests are the identification of the new plays in frontier basins and application of geoscience techniques to reduce the prospect risk.

Sadat Sembatya
Makerere University, Kampala, Uganda

Evolution of East African Rift System (EARS)

The East African Rift System (EARS) is a Tertiary intra-continental rift system which developed along the Precambrian orogenic belt of the African craton and is comprised of linked intra-continental rift basins. The ongoing extension along the rift zone reaches about 5-10mm per year (Skobelev et al 2005), 3500km long and 50-150km wide.

The system is comprised of some 30 discrete basins, mainly half-grabens, which differ substantially in their structural style, fills, and geological history. There are two dominant trends; the eastern and western branches. The Eastern branch, initiated in early Eocene/Oligocene (~30 Ma), with lakes i.e. L. Turkana, is more volcanic while the Western branch, initiated during the Late Miocene (10 Ma), contains lakes e.g. Lake Albert, Malawi, and Tanganyika, and is less volcanic.

At a large scale, the topography of the EARS is characterized by the Afar and Kenya/east African domes which are separated by the Turkana depression (~600m). The Afar dome elevation is approximately 1500m while the Kenya/East African dome is approximately 1200m. Both domes have diameters of about 1000km and are associated with negative gravity anomalies. Away from these areas, the topography ranges from 300-900m.

The EARS was formed by impingement of a thermal plume on the lithosphere, which resulted in crustal thinning and uplift. These culminated in fracturing of the brittle crust, and faulting resulted in earthquakes and volcanic activity. Consequently, there was down thrusting of the hanging wall to form graben structures.

The evolution of the Eastern Rift (Kenya Rift) directly adjoining the Afar triple junction began at 30Ma BP with initial fracturing in the Afar region and the Ethiopian plateau, which was followed by first volcanism in the Kenya Rift at 20Ma BP (Chorowicz; Ebinger 1989; Morley 2002). For the Western Rift branch, however, thermal updoming and first distributed faulting did not begin earlier than in Early Miocene time, and volcanism commenced in the middle Miocene (dated 12.6 Ma in the northern Virunga province; Bellon and Pouclet 1980; Calais et al. 2006; Chorowicz 2005; Ebinger 1989).

Evaluation of the rift basins for hydrocarbon potential shows variations in prospectivity is a result of tectonic control and sedimentation styles. Widespread lacustrine source rocks with good TOC quality have been encountered in drilled wells and surface formations, i.e. Ngorora formation in the central Kenyan rift (Amoco data). Oils from lacustrine sources are commonly waxy, have lower sulfur content, and tend to be higher quality refining oils than marine sourced oils, and similar occurrences are noted in the Lokichar basin, Albertine graben, among others. Reservoir units are sandstones and normal faults form the major structural traps.

Magenta McDougall
African Petroleum

The Next Phase of Exploration in Sierra Leone: A Closer Look at the Basinward Cretaceous Plays in the Search for Improved Reservoir Quality

The exploration pendulum has veered to the negative side after disappointing drilling results along the West African Transform Margin (WATM). Industry common belief states that reservoir quality is 'non-commercial' throughout Liberia and Sierra Leone, but thorough geological work suggests something different. Integrating key well results, reservoir provenance, and tectonostratigraphic framework provides strong evidence that there is abundant high quality reservoir in Sierra Leone in the Upper Cretaceous. As more wells are drilled along the WATM, simplistic rule of thumb methods for screening acreage do not apply. Where the younger, cleaner sands have been penetrated, charge and trap risk have been high, with shows but no commercial hydrocarbons. By looking at more distal lowstand systems, there is evidence for proximal hydrocarbon migration and apparent amplitude anomalies.

Older and deeper reservoirs should not be discounted as these are often attractive targets from a charge and trap perspective. Structural and stratigraphic trapping mechanisms set up from syn-rift faulting provide robust closures for syn-rift and younger sediments. Differing combinations of sorting, grain size, provenance, and burial diagenesis lead to different reservoir quality outcomes. Existing wells have generally been drilled in up-dip positions, located a reasonable column height down from the interpreted reservoir pinch-out. In these locations, bypass, poor sorting, and cementation have often resulted in poor reservoir quality in the up-dip areas. As exploration to date has been in shelfal/slope positions, there is little data from these basin floor reservoirs in this region. New depositional and burial diagenesis models indicate that provenance, abrasive processes during sediment transport, and reservoir temperature history are the key controls on reservoir quality. Sierra Leone straddles a transform system creating a wider shelf to the north-west of the country. Previous wells have been drilled on a narrow shelf in shallower water. By looking at channels leading from the wider shelf with longer sediment residence time, in addition to re-working of older sediments, a compelling reservoir quality story emerges which has not been explored to date.

Is the answer to target younger and shallower reservoirs or better reservoir facies downdip? How does onshore geology affect reservoir quality in the basin? How do tectonics and uplift impact sediment source areas and the resultant reservoir? How does burial diagenesis vary for different reservoir compositions? An investigation into these controls brings a more balanced perception of reservoir variability within the Cretaceous from the Albian to the Campanian. The next phase of Sierra Leone exploration will target the best quality reservoir to achieve commercial flowrates and true value creation. ■

Biographical Sketch

Magenta McDougall is a geoscientist with a keen interest in reservoir quality along the West African Transform Margin. Her work in the region began in 2014 with her MSc thesis – exploring the controls on reservoir quality in Cretaceous fan systems offshore Liberia. Since then she has worked on exploration and appraisal assets in Cote d'Ivoire, Tanzania, and Sierra Leone. Prior to working on African assets, Magenta worked on North Sea exploration. Magenta hold an MSc from Imperial College London and a BSc from Royal Holloway, University of London.

Neil Hodgson and Karyna Rodriguez
Spectrum Geo Ltd, Woking, United Kingdom

An Atlas of Character: A Model For the Control of Passive Margin Development

Introduction

As the long offset and long record length 2D seismic library acquired over the world's continental passive margins increases, so the key physical characteristics, and the variations therein, of these margins are being revealed. Three key characteristics are; 1) The nature of the continental crust to oceanic crust transition: abrupt continental margins to hyper-extended margins, and the asymmetry of the conjugates, 2) Magmatism: magma rich with Seaward Dipping Reflectors (SDRs) to magma poor margins, and 3) Stability of the passive margin fill through time. Each of these endmember series display localized variation on the basin and margin scale and indeed some are observed as part of continuums, others are binary distributions.

This presentation will take the form of a review of a number of modern 2D long offset seismic lines from Africa passive margins illustrating these characteristics and making observations about the associations of these characteristics. The number of basins illustrated comprises an atlas of African passive margins, comprising lines extending from the shelf and the continental crust, out to the oceanic crust, offering a chance to compare and contrast the influence of these key characteristics on each margin, and observe the degree of variation between them. For each of the three key characteristics a model will be presented that offers an explanation for why that characteristic endmember, and continuum set if appropriate, has developed. In conclusion we argue that one model can satisfy the observations on all the characteristics.

Nature of Continental to Oceanic Transition

Abrupt continental margins have narrow zones of transition separating oceanic crust from thick (>30km) continental crust, and are often associated with SDRs, whilst hyper-extended margins display fragments of extension and shear thinned continental crust drawn out far from the shelf and are not associated with SDRs [1]. Indeed, the latter margins often display a zone of exhumed mantle between the final continental crust fragments and oceanic crust. We propose a model where variation in abruptness of a margin along-rift relates to variation in heat from mantle during rifting. This model suggests that asymmetric conjugate margins are to be expected.

Magmatism

Magma rich margins display wide zones of SDRs comprising largely flood basalts but varying from clastic-rich (often inboard representing final syn-rift sedimentation whilst sub-areal flood basalts of pre-early drift are erupting) to clastic-poor outboard produced during drift and early oceanic crust formation. Magma poor margins apparently display no flood basalts and outboard of the final continental crust fragments either transit into oceanic crust directly or exhumed mantle then oceanic crust. The amount of subaerial and submarine magmatism is clearly a function of relative sea level; we propose a model for undulations along-rift in a syn-rift setting [1].

Stability of Clastic to Passive Margin Basins

The variation in stability of margins as expressed by gravitationally driven structures – mass transport systems, megaslides, conformable prograding clastic sequences, and lobe switching varies conspicuously between adjacent basins and through time in a given basin. This can be considered a result of local sedimentary or tectonic processes, but when taken in the whole a pattern of behavior is observed that allows such periodic and individual behavior to be seen as an expression of a global model [2]. The consequences of the global model are discussed in terms of dynamic topography, plate tectonics, and global sea level.

Conclusion

To conclude, a simple model of global dynamic topography is introduced that provides a mechanism for both the formation of, and the variation in, all of the three key characteristics on passive margins. The simple model provides a global solution to several issues in continental rifting understanding: the continental margin architecture issue (abrupt-hyperextension), the asymmetry issue, and the magmatism issue. A further consequence of this model is that firstly, the generally carried model for tectonic plate movement is compromised, and a control on coastal onlap that is specific to each basin is proposed. Consequently, Global Sea Level (GSL) curves constructed on the basis of coastal onlap may therefore represent a collation of local relative sea level observations, yet statistically the actual GSL may only be observable in a minority of basins.

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David Connolly
dGB Earth Sciences USA LLC (david.connolly@dgbes.com)

Visualization of Vertical Hydrocarbon Migration Pathways in Seismic Data: Toward the Quantification of Seal and Charge Risk for African Exploration Plays

Figure 1. Chimney Atlas for Africa. Stars are proprietary studies. Well symbols indicate entries in Atlas. Basin symbol indicates areas with published studies.

A survey of major exploration companies suggests that seal and charge provide the majority of risk in today's conventional exploration portfolio. Seal is a major cause of failure along the West Africa Transform margin, and charge is also a significant risk. Traditional tools for assessing top seal such as capillary pressure measurements of the sealing shales are often not available over the structure being drilled. Shales with excellent capillary pressures, such as we observe in offshore Nigeria, can still be very leaky. **Cross-fault leakage** can be assessed with Allen Diagrams and Smear Gouge Ratio assessment. However, the inputs (borehole breakout and pressure data) needed for the assessment of **up-fault** leakage along critically stressed faults, are not available in frontier settings. Basin models are an important tool for assessing hydrocarbon charge, but are often poorly constrained. Improving the quantification of these risks can have a significant impact on the expected value for exploration opportunities.

Most of the hydrocarbons producing basins along the African Margin are dominated by vertical hydrocarbon migration. This vertical hydrocarbon migration is often directly detected in the seismic record as zones of vertically chaotic, low energy data response called gas chimneys, blowout pipes, gas clouds, or mud volcanoes based on their morphology, rock properties, and flow mechanism. We will describe these features as "chimneys", although they can be very widespread. They are associated with both oil and gas migration. Because of their diffuse character, these "chimneys" are often difficult to visualize in three dimensions. Thus, a method has been developed to detect these features using a supervised neural network. The result is a "chimney" probability volume. However, not all chimneys detected by this method will represent true hydrocarbon migration. Therefore, the neural network results must be validated by a set of criteria. Based on these criteria, reliable chimneys can be extracted from 3D seismic data as 3D geo-bodies. These chimney geo-bodies, which represent vertical hydrocarbon migration pathways, can then be superimposed on detected reservoir geo-bodies, which indicate possible lateral migration pathways and traps. The results can be used to assess hydrocarbon charge efficiency or risk, and top seal risk for identified traps. The amount of these chimneys directly below the reservoir geo-body provide an assessment of the **charge risk**, while the morphology of the chimneys above a reservoir provide an assessment of the **top seal risk**.

How can this risk be quantified? A study of 100 traps in the Norwegian North Sea was undertaken (Heggland, 2013) to assess top seal failure, since charge was not a significant risk in the area. All traps contained effective reservoirs, and were well imaged. Thus seal was considered the major risk. Traps, associated with chimneys, were divided into three classes: Class A had a leaking fault at the crest of the trap (based on fault related chimneys over the crest) and often contained minor volumes of hydrocarbons; Class B had leakage on the flank of the structure; Class C had hydrocarbons both in the reservoir and in the cap rock (based on a diffuse gas cloud over the structure). A success rate for drilled traps with no chimneys was 46%. The success rate for traps with associated chimneys was 78%. If the trap classification was used, avoiding the Class A traps, the success rate was above 90%. We have applied this model on a worldwide basis and gotten similar results (Connolly et al, 2013). We also extended the classification to analyze charge risk, by looking at the morphology of chimneys immediately below the objective reservoir.

To improve the quantification of top seal and charge risk assessment, a Chimney Atlas (https://dgbes.com/chimney_atlas) is being compiled over known oil and gas discoveries. The Atlas also includes dry holes, which tested valid structures with effective reservoir. Thus, the well failed either from a lack of charge or seal. We will show examples from Africa, which are currently in the Atlas (**Figure 1**). One example from West Africa is a commercial gas field (**Figure 2**). A Seismic section near the crest of the drilled structural anticline showed a subtle broad diffuse gas cloud (yellow) over the main reservoir interval (Connolly et al., 2013). This trap is classified as a "Gas Cloud Trap" (Class C), indicating a high probability of effective seal underlying the gas cloud. Chimneys related to underlying thrusts may provide charge into the reservoir. These are classified as "Direct Charge Traps". Excess pressure is associated with both the overlying and underlying chimneys. While current chimney studies have focused on the offshore basins, the technology can also be applied to onshore seismic data. Studies from the Anza Graben of onshore Kenya (Baranova et al., 2012) and the Oriente Basin of Ecuador demonstrate the potential of the technology in both rift and foreland basins.

Additional case studies of drilled structures from Africa need to be included in the Chimney Atlas, to improve the quantification of charge and seal risk in this part of the world. Dry holes or disappointing wells are especially important to include in the Atlas, since the current entries in the Atlas are generally over known discoveries or undrilled prospects. **Figure 3** shows a 3D image of high probability chimneys over a drilled trap in the continental slope of offshore, Nigeria. The structure was drilled and encountered a thick permeable reservoir, which was water wet. The chimney results show fault related leakage, which shows pock marked morphology in a bathymetry map of the sea floor. We interpret this trap as a "Fault Leak Trap" (Class A). While this trap was breached, we have evaluated Fault Leak Traps which contain economic quantities of hydrocarbons (oil). Thus, additional case studies from this class of trap are especially important. The benefits of dry hole evaluations were clearly shown in the HGS "Deepwater Gulf of Mexico Dry Hole Seminar" (2000 & 2004). Similar investigations of both dry holes and discoveries should significantly improve exploration success, both in the coastal and interior basins of Africa. ■

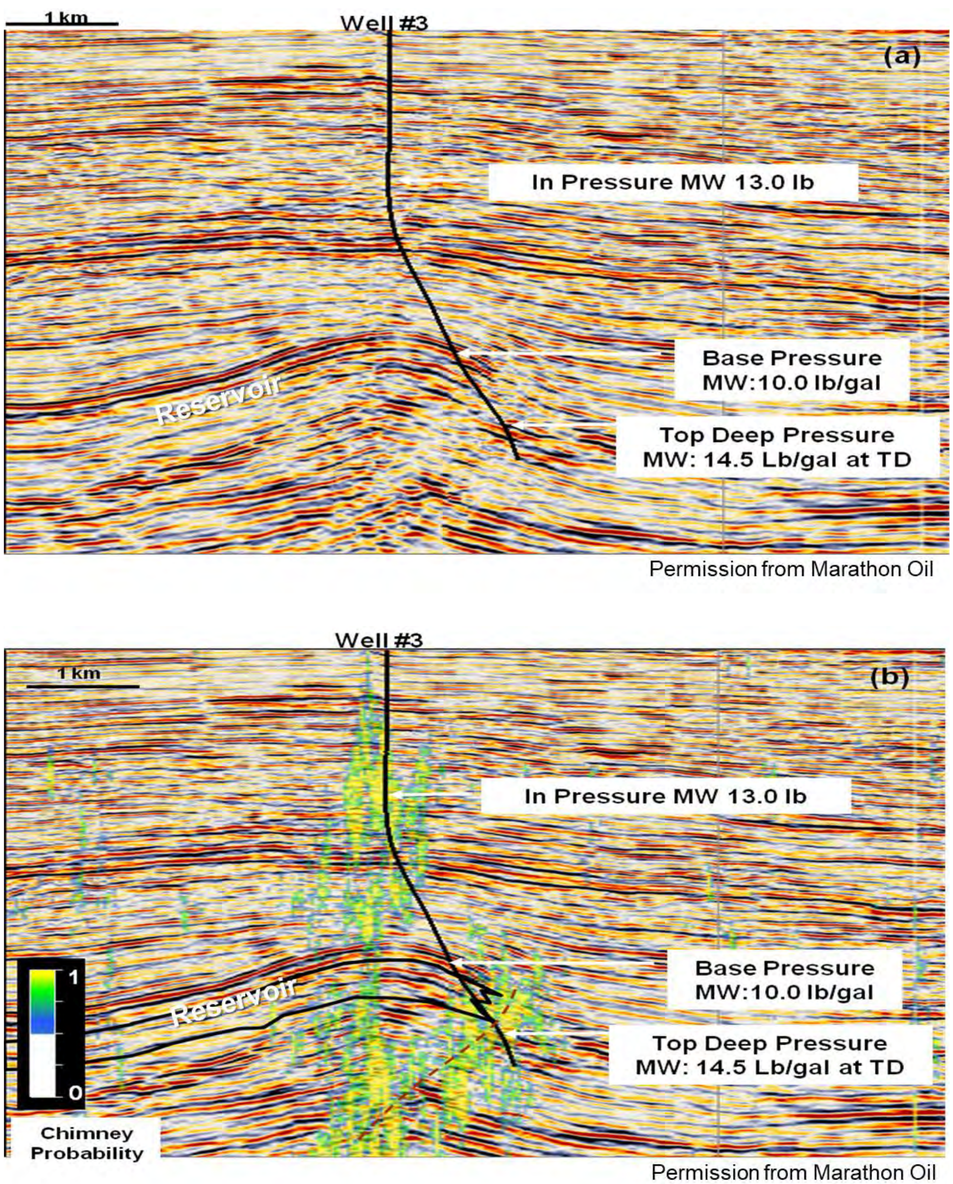

Figure 2. Seismic section through gas field uninterpreted (upper) and with chimney probability overlain (lower). Results show subtle broad diffuse gas cloud over main reservoir interval, indicating an effective seal Chimneys related to underlying thrusts, may provide charge into the reservoir. Excess pressure is associated with chimneys (from Connolly et al., 2013)

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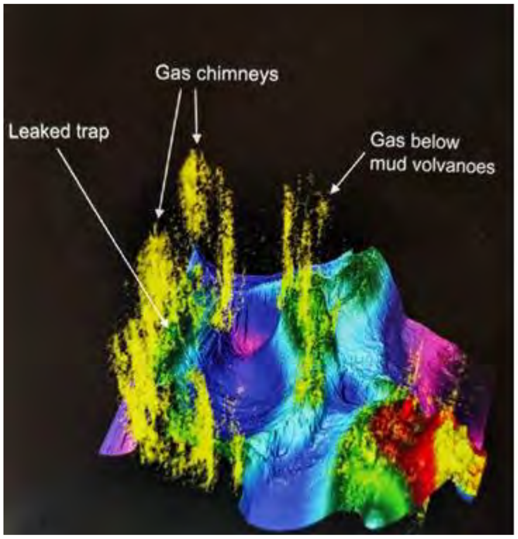

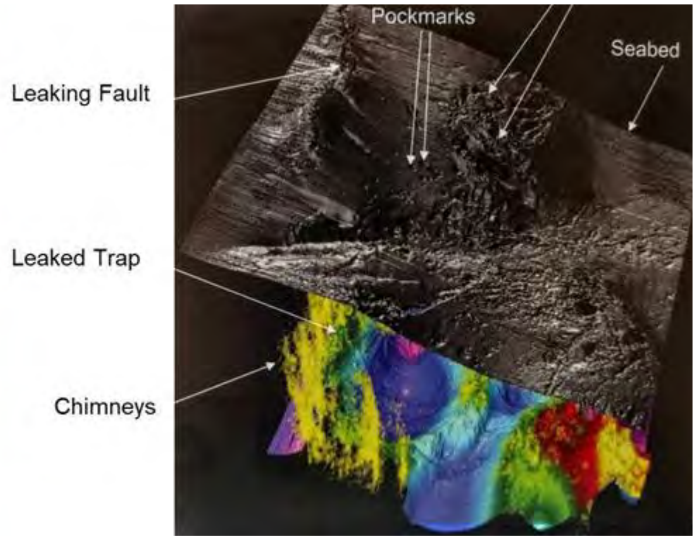

Figure 3. 3D image of drilled Fault Leak Trap Continental Slope Nigeria (left) with bathymetry map overlain (right) (Heggland, 2013).

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Acknowledgments

We would like to thank Marathon Oil for permission to publish the seismic examples from West Africa. We would also like to recognize Roar Heggland, Paul Meldahl, and others at Equinor (formerly Statoil) for the development of the Chimney detection technology.

Biographical Sketch

David Connolly is a Senior Advisor for dGB Earth Science. He has over 40 years of industry experience in various aspects of petroleum geology and geophysics. He worked for Getty / Texaco as a Petroleum Geoscientist in a variety of international and national exploration assignments.
He has been with dGB since 2001. He is co-editor for the SEG/AAPG Geophysical Developments #16, *Hydrocarbon Seepage: From Source to Surface*. His poster *Using gas chimney detection to assess hydrocarbon charge and top seal effectiveness – offshore, Namibia*, presented at the 2014 EAGE Convention, won the Cagniard Award in 2015 for the best poster. He graduated from Washington & Lee University with a BA in Geology.

Neil Hodgson, Karyna Rodriguez
Spectrum Geo Ltd, Woking, United Kingdom,
Jonathan Watson
Bridgeporth, Milton Keynes, United Kingdom

JMA – The Hidden Treasure Below the Basalt

Introduction

Despite the huge exploration successes of the last 10 years in East Africa, exploration efforts offshore Seychelles and Mauritius in the Indian Ocean have been stagnant since the last exploration over 30 years ago. This is curious as all the wells drilled in the 1980's offshore Seychelles encountered oil shows.

The Seychelles and Mauritius Governments share the administration of the Joint Management Area (JMA), located between the two island groups over the Mascarene Plateau. In this extra-ordinary setting, surrounded by oceanic crust, lies a fragment of Gondwana. An integration of remote sensing datasets, legacy 2D seismic, together with sea surface oil slick analysis, and a regional geological and conjugate margin evaluation suggest a working petroleum system ready to be revealed with modern seismic data.

Regional Geology

The Mascarene Plateau is a relatively shallow water part of the Indian Ocean, ranging in water depth from shoals to 1000m. Oceanic Crust is expected to be greater than 60 million years in age, such that thermal cooling should allow the crust to be in equilibrium in more than 4 km of water. This suggests that the crust under the plateau is less dense than oceanic crust, and indeed low gravity measurements imply that instead of oceanic crust, there is a thick buoyant continental crustal fragment below the JMA [1].

The only well drilled in the JMA, Saya De Malha-1, drilled 2424m of limestones before encountering basalt. This was a very different outcome to that prognosis, which had expected to encounter a "Seychelles" type stratigraphy, with Tertiary, Cretaceous, and Jurassic section prognosis. After 840m of basalt were drilled the well was at TD'd. However, re-interpretation of this legacy dataset suggested a thick Mesozoic section was barely half a kilometre away. This section is the prize for future exploration.

Plate reconstruction based on magnetic data suggests that the Mascarene Plateau continental crust fragment is surrounded by oceanic crust. To the south the conjugate margin is East Madagascar, and to the north the conjugate margin is the west coast of India. Oceanic crust here would have formed after Madagascar-India continental fragments rifted and during the early part of India's movement north, i.e. Late Cretaceous in age. However, the basalts encountered by the Saya De Malha well-1 were alkaine, titanium rich basalts dated ca 30 ma, i.e. plume related rather than oceanic crust.

A Frontier Hydrocarbon System Model

The model developed is that the Mascarene Plateau crust comprises the syn-rift section attached to West India at the time of separation from East Madagascar. This rift may have reactivated an older Karoo graben or fabric. As India moved north it travelled over a deep mantle plume, the hot-spot that created the Deccan Trapp volcanism of Northern India. As the west Indian margin travelled over the plume, the heat source effectively melted off the extended and thinned crust, causing a ridge jump from south of the Mascarene Plateau to north, freezing a remnant syn-rift and pre-rift block into oceanic crust. The plume volcanics continued to be erupted over the Mascarene plateau laying down a 1.5km thick unit. It is these volcanics that were intercepted by the Saya De Malha well. As both plates continued to move north over the mantle plume, the hot spot trail continues to its current location under the island of Reunion.

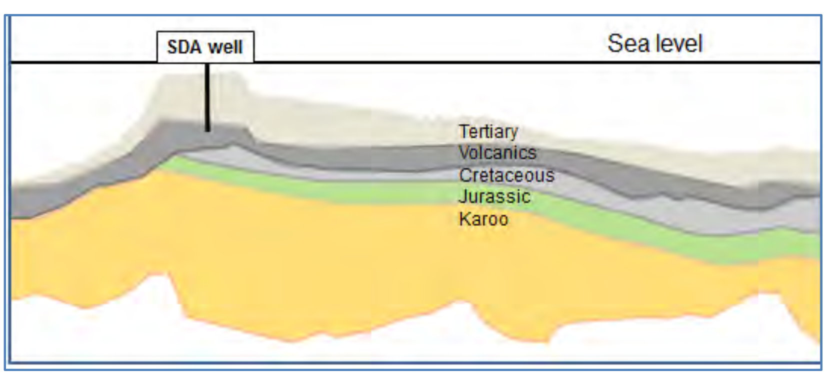

Figure 1: Geologic model for the Mascarene Plateau calibrated with gravity modelling and well data from the Seychelles

The continental crust under the Mascarene Plateau is expected to have similar geology to the Cretaceous, Jurassic, and Karoo sequence in the Seychelles. These rocks are oil prone yet suffer from shallow burial and lack of top seal. Under the Basalts and Tertiary sequence of the Mascarene Plateau it is expected that the various source rocks observed in Seychelles will currently be in the oil window. Notably a high confidence oil slick was seen on a satellite data review, interpreted as live evidence for a working oil system in the JMA.

Cretaceous and Jurassic shallow marine syn-rift sediments, as well as in the pre-rift Karoo sequence provide source rock, and reservoir potential exists in pre-rift Karoo sediments, syn-rift shallow marine coarse-grained clastics, shelf and channel sands, deepwater Cretaceous to Recent turbidites, and Cretaceous to Recent carbonate build-ups.

The key question is how thick are the basalts on the Mascarene Plateau? A study by Bridgeporth was commissioned to examine variations from a central case of a 1.5km thick basalt/volcanic unit. Base basalt topology was adjusted as was the geometry of the basement (continental upper crust) to match the observed gravity response.

The modelling of a line over the Mascarene Plateau, with well calibration from the Seychelles, involved a number of possible scenarios. The initial modelling of a line from the JMA over the Saya de Malha-1 well used the preferred scenario taken from the Seychelles line. Although alternative models were tested, a thin (1.5km) basalt layer provides the optimum modelling solution.

Conclusion

The Mascarene Plateau in the Indian Ocean offers a unique potential for an unexplored oil prone hydrocarbon system in moderate to shallow water depths, reminding us that even in perhaps the most unlikely of places, hydrocarbon systems await discovery.

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Janine Weber, Ivonne Montiel Araujo, Rao Yalamanchili
CGG Multi-Physics, Houston, Texas
Sindi Maduhu, TPDC, Dar Es Salaam, Tanzania

Hidden Boundary Fault at East African Rift Basin Revealed with FALCON© Airborne Gravity Gradiometry Data

We present the results of an integrated interpretation of high-resolution airborne gravity gradient and magnetic data survey. The potential field's data were integrated with geological data over the region of the Lake Eyasi rift valley in northern Tanzania. The Tanzania Petroleum Development Corporation (TPDC) was interested in evaluating the petroleum potential of the area where little subsurface information is available. The principal interpretation objective was an improved understanding of the subsurface geology with relevance to hydrocarbon exploration, but the region may also be of interest for helium exploration. The interpretation first focused on the structural framework of the main rift-bounding faults, intra-basinal faults, crossing structures, and locations of shallow intrusions. Estimated depth-to-basement was based on magnetic profile data analysis. Inversion of an airborne gravity gradient (AGG) data with the constraint of magnetic basement was used to model high-density basement.

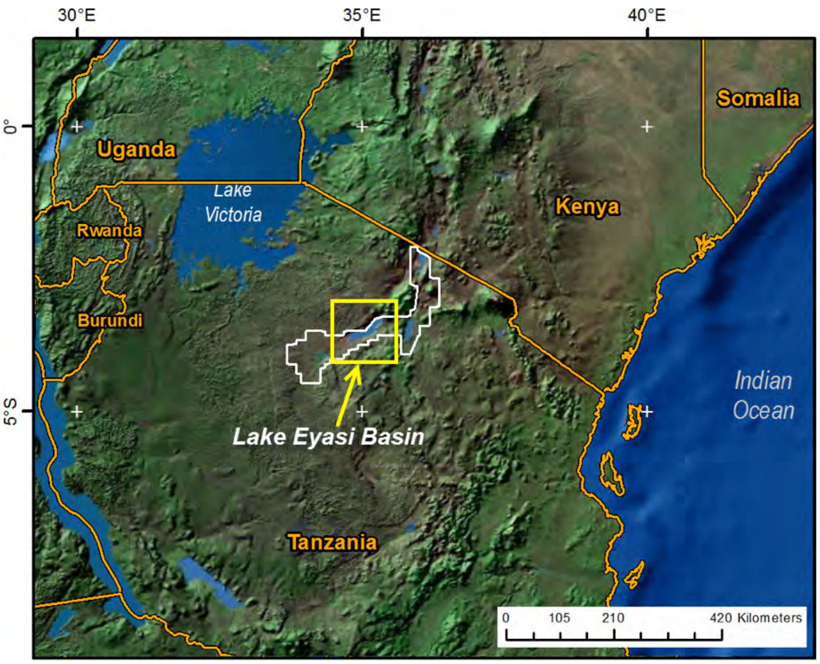

Figure 1: Survey location

CGG Multi-Physics flew an AGG and magnetic survey in December of 2015, over the Eyasi rift valley (Figure 1). The survey area straddles the portion of the East African Rift System (EARS) where the Eastern Arm of the rift diverges into several small rifts with different orientations. Accordingly, this area is referred to as the "Tanzanian Divergence Zone". Extension associated with the divergence results from tectonic plate motion, creating narrow rift valleys that occur adjacent to major faults. The rift valleys are floored by basement and are filled with a combination of sediments and volcanics both as clastics and as flows. In areas with dense volcanic activity, younger volcanic cones have intruded into and through sediment-filled basins.

Basement rocks in the western part of the survey area are of the Archaean Tanzanian craton, while basement rocks in the eastern part of the survey are of the Proterozoic Mozambique Mobile Belt. The Tanzanian craton comprises mostly gneisses, schists, and quartzites that have experienced several deformation phases.

The occurrence of Neogene volcanics to the east at Crater Highlands and of Tertiary kimberlite intrusions in the vicinity implies that the thermal history could support development of young hydrocarbons. The very same conditions that are good for hydrocarbons could also trap helium gases originating in the Archaean basement and mobilized by Tertiary volcanism and rifting. Major rift-bounding faults occur along the southeast rift margin, but are buried beneath lake deposits.

The area is defined by narrow rift grabens that have developed in the crystalline basement. The Eyasi rift structure is narrower than the surrounding rifts (the Manyara and Natron rifts) because it is primarily developed within the strong Archaean crust. The Manyara and Natron structures are half-grabens and are broader than the Eyasi rift because of the influence of the weaker basement east of Eyasi. Within the Eyasi rift, crossing structures compartmentalize the main graben. The western and central sub-basins of the Eyasi Basin have the best chances for thick sediments, extensive reservoir facies, and proximity to a hydrocarbon kitchen.

The north-western bounding fault of the Eyasi graben has topographic expression and a strong gravity signature. In contrast, the south-eastern bounding fault is completely buried

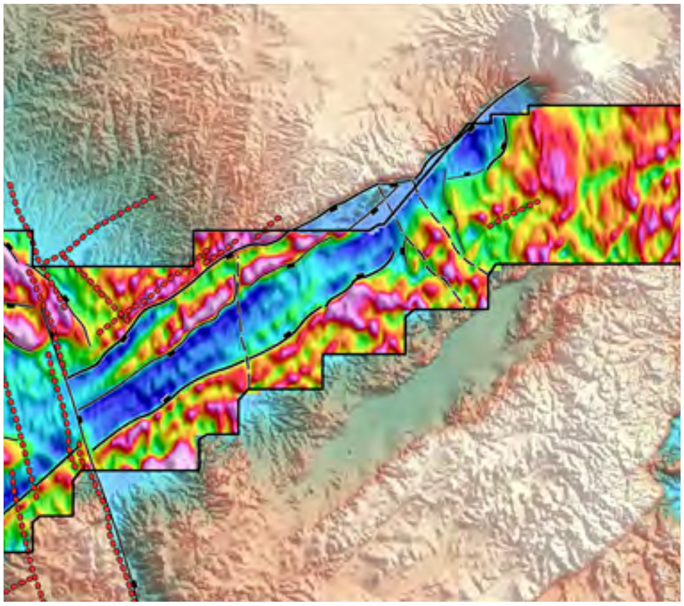

Figure 2: Central Eyasi rift valley with an overlay of the airborne gravity gradiometry data, and major interpreted structures (faults and dikes).

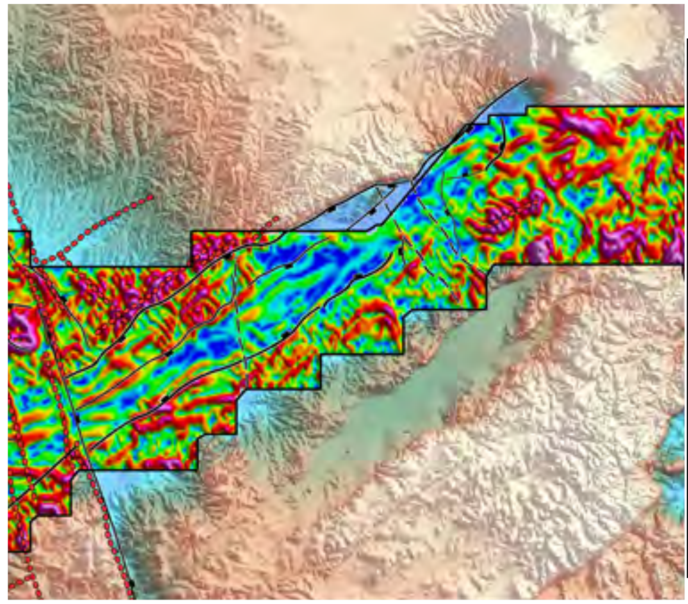

Figure 3. Central Eyasi rift valley with an overlay of the major interpreted structures (faults and dikes) on horizontal gradient of reduced-to-the-pole magnetic data

by young sediments, though it produces a strong linear anomaly in both the gravity and magnetic data (Figures 2 and 3). Because the south-eastern fault is buried, the Eyasi basin has often been described as a half-graben – consequently, basin depth has been assumed to be relatively shallow. The depth to magnetic basement was estimated to be just over 5200m in the central Eyasi sub-basin, which is sufficiently deep to contain thick sediments that could include organic-rich lake deposits. ■

Acknowledgements

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Biographical Sketch

S.V. (Rao) Yalamanchili is Vice President of interpretation in CGG Multi-Physics. He holds a MSc (Tech) and a PhD in Geophysics from Andhra University, India and a Post graduate diploma in mining exploration Geophysics from ITC, The Netherlands. He has over 40 years of teaching, research, and industry experience. He came to the USA in 1983 and worked for several geophysical companies, (Aero Service, Geonex, PGS, AOA, Fugro), at various capacities from Geophysicist to Principal Advising Geophysicist over the years. He was the recipient of a Gold medal and Young Scientist's Award for the year 1978 by the Association of Exploration Geophysicists, India. He has broad geographic experience in hydrocarbon exploration with an integrated interpretation of Gravity, Magnetic, and Seismic data. His professional memberships include SEG, AAPG, GSH, and HGS.

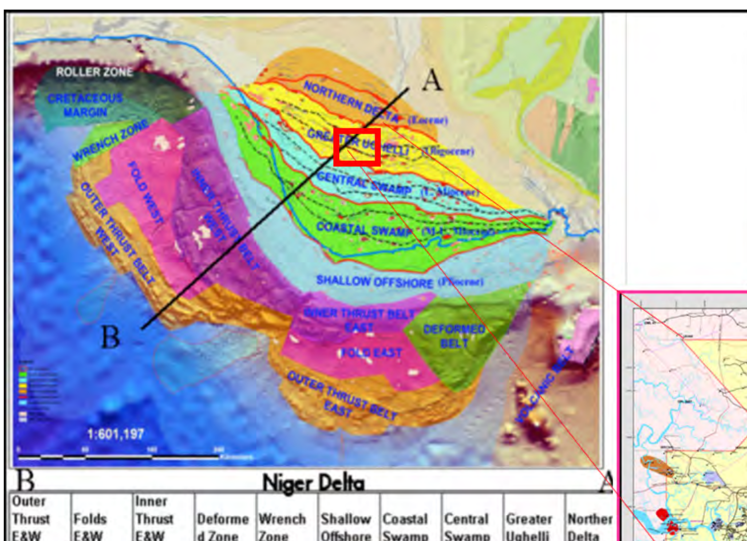
Kemi Taiwo
ND Western Limited, Victoria Island, Lagos, Nigeria
Olusanmi O. Emmanuel
Acetop Energy, Houston, Texas, USA
Olajide Aworanti, Temitayo Ologun, and Uzezi Olorunmola
ND Western Limited, Victoria Island, Lagos, Nigeria

Enhancing Gas Production in Nigeria's Marginal Fields: A Case Study of Ughelli-X Field

The X-East field is located in the Greater Ughelli Depobelt, onshore Niger Delta Basin. The field contains an estimated reserve of 1.2 Tcf of gas and has been delivering non-associated gas through its Non–Associated Gas (NAG I) plant to the Ughelli Power station since gas production started in the field in 1966. A total of eighteen wells have been drilled in the X-East field comprising nine oil wells, five gas wells, and four abandoned wells. Out of the five gas wells, only three are active producers while the rest have been shut in due to problems ranging from crude fouling to water production. To ensure and maintain the supply of gas to the NAG I plant and to satisfy the gas design capacity of 150MMscf/d for NAG II, it was imperative that gas production optimization efforts be carried out in the field while additional gas wells are drilled to assess new gas reservoirs to feed the NAG II plant. Therefore, a dual-headed workflow involving geoscience data reprocessing and reinterpretation to identify new gas accumulations on the one side, and recompletion and workover operations to optimize gas production on the other, was adopted by the team to meet both the short-term objective of increasing gas supply to NAG I, and the long-term objective of finding new gas to supply both the NAG I and NAGII plants.

The 1997 and 1999 vintage 3D seismic data over the X-East field were merged, reinterpreted, reprocessed, and then re-interpreted again to resolve the limitations around poor resolution of faults and amplitude events, and to map new horizons and new gas-bearing sand bodies identified from gamma ray (GR) logs. By integrating the improved seismic interpretation products with updated fieldwide electrical log correlations, two additional gas reservoirs: Q3000X sand and Q53000X sand, with total gross rock volume of about 70000ac-ft and 96000ac-ft respectively, were mapped across the field. The application of improved formation evaluation workflows that accounted for the presence of shaly sands and clay laminations within the target zones and reservoirs also resulted in proper delineation of the individual flow units across the field. The field development plan was thus updated to optimally guide the recompletion efforts in the existing wells and to locate additional gas development wells.

Based on the updated field development plan, successful workover operations were carried out for the shut-in wells in the field. Essentially, the approach involved pulling out the existing tubing and fishing out the packer before running and interpreting Reservoir Saturation Test (RST) logs. The RST logs helped to determine the present fluid contacts and fluid types while also identifying new gas producing reservoir zones and bypassed pay zones within the wells. Based on the results of the RST logs, newly identified reservoir zones, and bypassed pay zones such as the Q7000, were then perforated and the wells were recompleted as new gas producers. Production results from recently



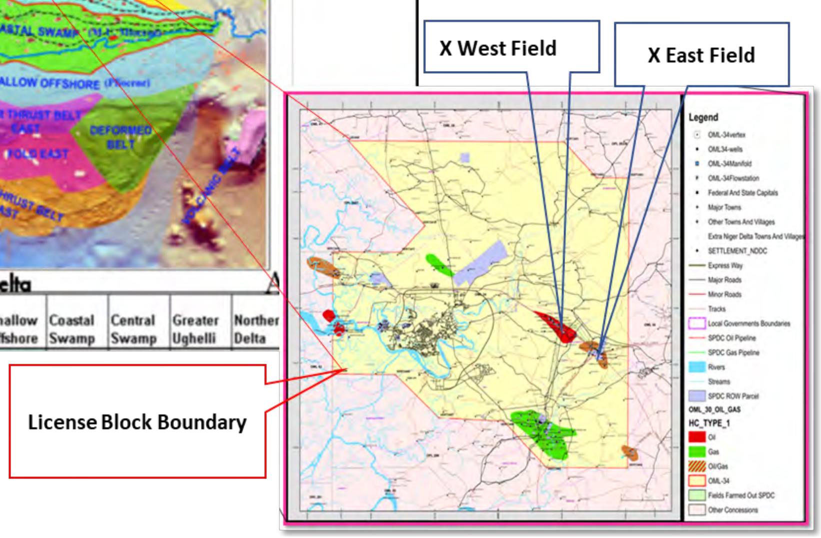


Figure 1: Location of the X-East Field (Ejadewe, 2012)

completed wells suggests that the Q3000X sand and Q53000X sand are important gas producers, and future wells have been planned to target both reservoirs in a structurally optimal position. This is to ensure a sustained sweep of gas reserves while leaving as little as possible as attic reserves.

Since the adoption of the discussed workflow, gas supply to the NAG I plant has been ensured and maintained. Once the workover operations and the proposed infill gas wells have been completed, gas production in the field is predicted to increase to about 202MMscf/d, up from around 78MMscf/d before the adoption of the current workflow. The results suggest that these workflows can be applied to other marginal fields in the Niger Delta.

Data Type	Number	Coverage	Data Format
3D Seismic	5	X-East Field	SEG-Y (PSTM 15.30DEG, 25.40DEG, 35.50DEG, 45.60DEG and FULL)
2D Lines	5	Part of X-East Field	SEGY (0034-69-02-0009, 0034-75-02-0059, 0034-81-04-0170, 0034-86-04-0122 and 0034-87-02-0214)
Well Header	17	X-East field	ASCII
Well Logs	17	X-East field	LAS
Well Deviation	17	X-East field	ASCII
Checkshot	1	X-East, X-W-002	ASCII

Table 1. Database

Introduction

The tertiary Niger Delta is one of the part of the prolific Gulf of Guinea province of West Africa. It has only one identified petroleum system (Kulke, 1995) with multiple depobelts. Our study area, X-East field is within the Ughelli depobelt which is some 25km Southeast of Warri, Delta State, Nigeria (**Figure 1**). The field was discovered in 1959. X-East structure is generally a 4-way dip closed anticline with minor fault dependence. The field contains an estimated reserve of 1.4 Tcf of gas and has been delivering non-associated gas through her Non–Associated Gas (NAG I) plant to the Ughelli Power station since gas production started in the field in 1966. A total of eighteen wells have been drilled in the X–East field comprising nine oil wells, five gas wells and four abandoned wells. Out of the five gas wells, only three are active producers while the rest have been shut in due to problems ranging from crude fouling to water production. To ensure and maintain the supply of gas to the NAG I plant and to satisfy the gas design capacity of 150MMscf/d for NAG II, it was imperative that gas production optimization efforts be carried out in the field while additional gas wells are drilled to assess new gas reservoirs to feed the NAG II plant.

In order to optimize and enhance production from matured "locked-in" reserves and to also identify further development opportunities within the X-East field, a dual-headed workflow involving geoscience data reprocessing and reinterpretation to identify new gas accumulations on the one side and recompletion and workover operations to optimize gas production on the other, was adopted by our team to meet both the short-term objective of increasing gas supply to NAG I and the long-term objective of finding new gas to supply both the NAG I and NAGII plants.

Data and Methods

Essentially, the dataset comprised 1997 and 1999 vintage 3D seismic data covering about 24Km2, 2D seismic lines, electrical wireline logs including Gamma Ray, Resistivity, Neutron, and Density logs, and well deviation data from eighteen wells as well as checkshot data from one well. **Table 1** shows a summary of the data available for this work.

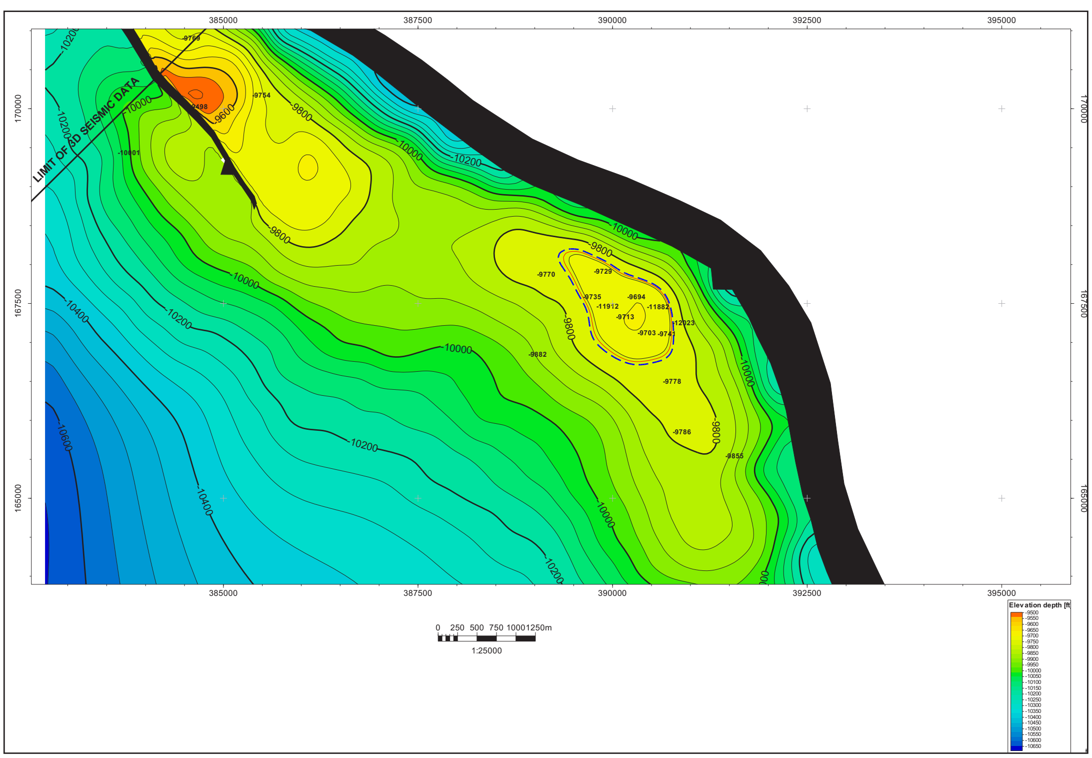


Figure 2: Top Structure Map of the X-East field.

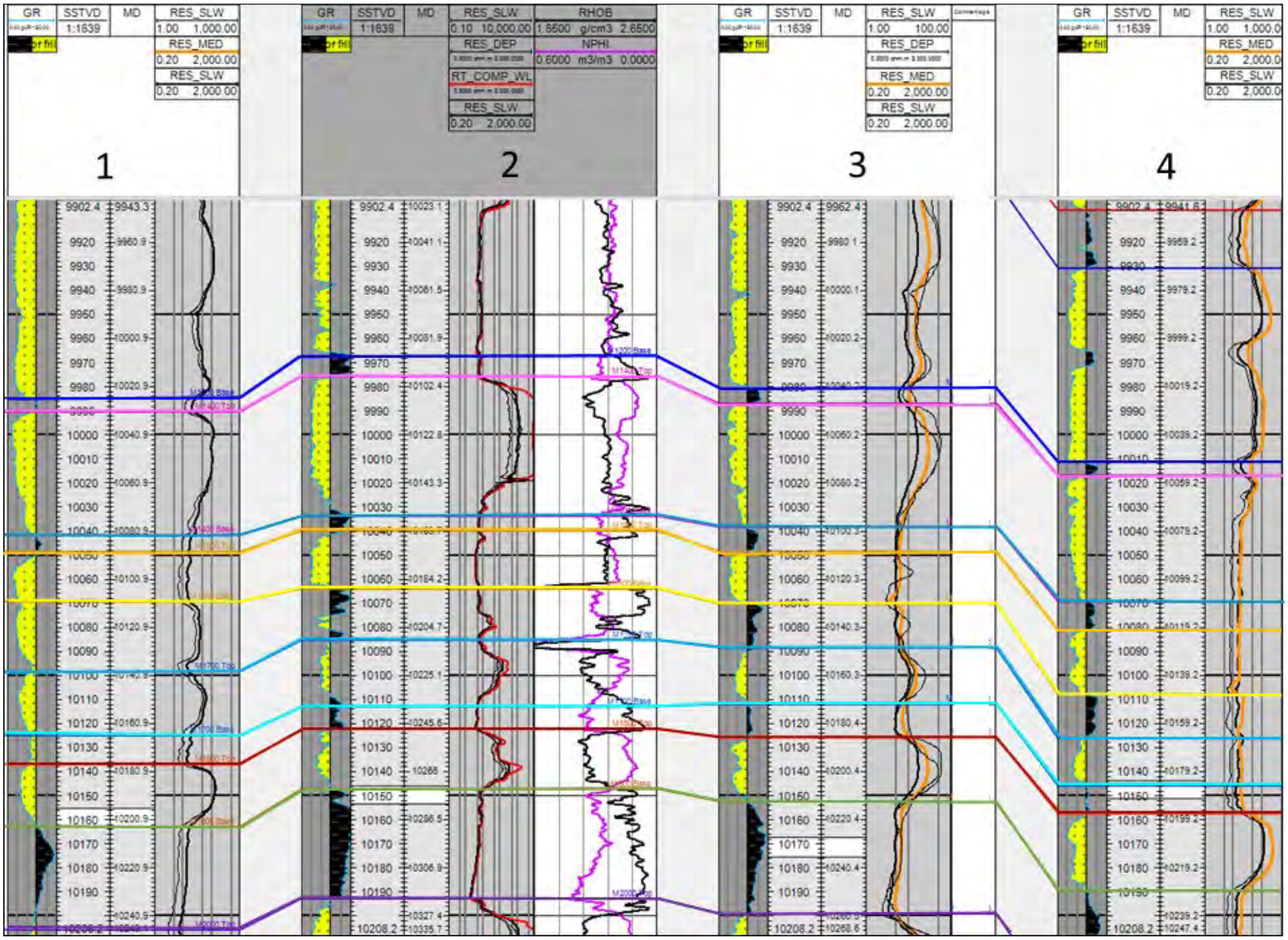


Figure 3: NE-SW Correlation of sand bodies across the X-East field showing several reservoirs with different fluid contacts.

The available electrical wireline logs were interpreted and correlated across the field to properly map existing gas-bearing reservoirs and identify new ones (**Figure 2**). Improved formation evaluation workflows that accounted for the presence of shaly sands and clay laminations within the target zones and reservoirs was also used to help delineate the individual flow units across the field. The 1997 and 1999 vintage 3D seismic data over the X-East field were merged, reinterpreted, reprocessed, and then re-interpreted again to resolve the limitations around poor resolution of faults and amplitude events, and to map new horizons and new gas-bearing sand bodies identified from GR logs and Neutron-Density cross-plots.

Results and Discussion

The reprocessed seismic data quality is good and seismic interpretation over the field revealed the X- East field as a simple rollover anticlinal structure separated from the X-West field by a saddle (**Figure 2**). It is bounded to the North by a major synthetic boundary fault trending NW-SE, and the field is situated at the maximum curvature of this fault. Most of the reservoirs of the X-East field are correlatable to those in the X-West field. Seismic interpretation and well logs analysis indicate that these reservoirs are not always in communication and often have different fluid contacts (**Figure 3**).

The integration of the improved 3D seismic interpretation with updated fieldwide electrical log correlations led to the mapping of two additional gas reservoirs: Q3000X sand and Q53000X sand, with total gross rock volume of about 70000ac-ft and 96000ac-ft respectively. The areal extent of a previously identified reservoir was equally better delineated based on the reprocessed seismic data. This is rather important as they became key inputs for a more robust field development plan with proper identification of infill well locations that enhanced the production optimization effort of the team.

The application of improved formation evaluation workflows that accounted for the presence of shaly sands and clay laminations within the target zones and reservoirs also resulted in proper delineation of the individual flow units across the field. The field development plan was thus updated to optimally guide the recompletion efforts in the existing wells, and to locate additional gas development wells.

Conclusion

Following the application of the discussed workflow, gas supply to the NAG I plant has been ensured and maintained. Once the workover operations and the proposed infill gas wells have been completed, gas production in the field is projected to increase by an additional 120MMscf/d, bringing total production to an estimated volume of 202MMscf/d post workflow optimization. These impressive results/outlook suggest that reprocessing and reinterpreting vintage seismic data is of immense benefit to production optimization in mature fields in the Niger Delta basin, Nigeria. We recommend that the discussed workflow should be applied to other marginal fields in the Niger Delta to arrest production decline and enhance gas recovery. ■

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Neil Hodgson, Karyna Rodriguez, and Hannah Kearns
Spectrum Geo Ltd, Woking, United Kingdom

Cape Fold Belt Fractured Basement Play Fairway

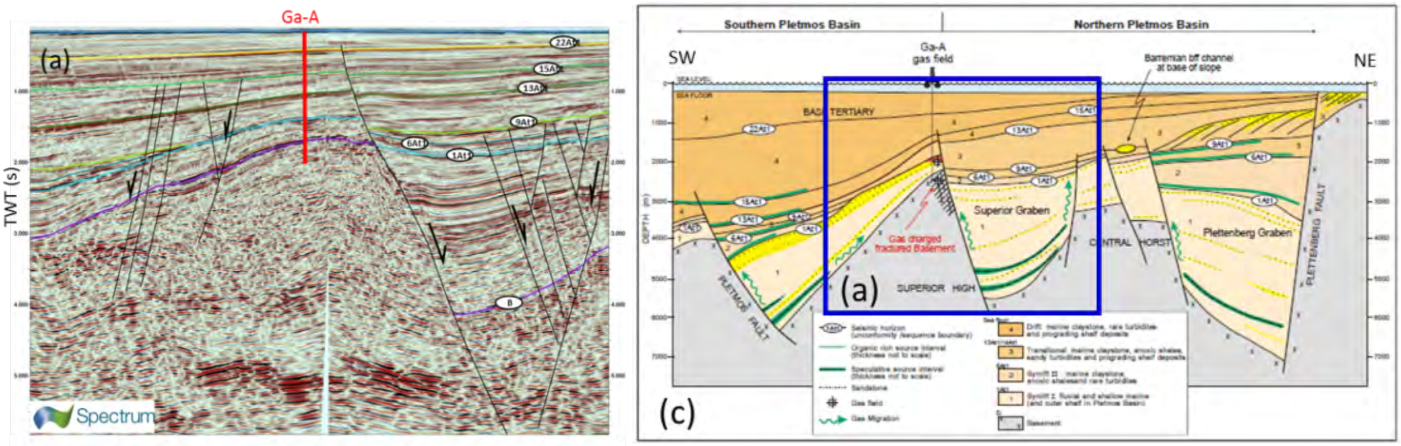

Figure 1. 2D seismic section over the Ga-A gas field in the Pletmos sub-basin, offshore South Africa and schematic geological cross section across the Pletmos sub-basin illustrating structural style and source kitchens charging the fractured quartzitic basement of the Table Mountain Group.

Introduction

In the lexicon of hydrocarbon exploration, "basement" is a pejorative term for the deepest stratigraphy that is considered unprospective. This can comprise tight sediments, metamorphic rocks, or igneous bodies, but it is usually, by definition, the last place we go looking for Oil and Gas. Yet the South African Ga-A-1 well was the first well drilled offshore in the Pletmos sub-basin in 1968 and discovered gas in fractured basement – a quartzite – of the Table Mountain Group (TMG) Formation. New understanding provided by modern and reprocessed seismic data, complemented by outcrop studies and potential field data analysis, has enabled the identification of this play fairway along the regional Cape Fold Belt (CFB) trend, onto the West African margin and across to its conjugate in Argentina.

Prolific fractured basement reservoirs have been recognized globally for decades from Vietnam's Southern Margin (Bach Ho Field, discovered in 1975) to the recent Atlantic Margin discovery of the Lancaster field [2], yet the complexity of understanding and de-risking the potential resource ahead of the drill bit have provided obstacles to chasing this play. Recently the application of modern seismic technology apears to be able to resolve some of these issues, and when combined with the re-appraisal of legacy "basement" drilling, suggests that significant volumes of undiscovered hydrocarbons hidden by a failure to identify and intersect an active fracture system can now be hunted down.

Cape Fold Belt Fractured Basement Play Fairway

The fractured quartzites comprising the Ga-A discovery reservoir are charged from an adjacent Jurassic lacustrine source from the Southern Pletmos sub-basin and Superior Graben (**Figure 1**). A structural closure at basement level can have upside from back-fill of the fracture system following Hurricane Energy's Lancaster model, in addition to a down-dip oil leg to a gas cap.

2D seismic data reprocessed in 2016 were analysed and integrated with satellite-derived gravity anomaly data, to identify similar basement highs and map the fractured quartzite basement play fairway in the Pletmos and other remaining sub-basins (Bredasdorp, Gamtoo, Algoa, and Southern Outeniqua) within the Outeniqua Basin. Regional seismic data is an essential tool for initial identification of this highly attractive play, together with a good regional geological understanding, which can be gained by integrating all available data from onshore geology, wells, and potential field data.

The occurrence of fractured basement potential within the Cape Fold Belt leads to the intriguing question of whether both plays continue along the entirety of the fold belt. Using recently reprocessed seismic reflection data, a revised plate reconstruction for the region has been proposed [1] which identifies a direct continuation of the Cape Fold Belt offshore into the southern portion of the Orange Basin. The restoration also suggests the continuation of the Cape Fold Belt westwards into the conjugate Argentinian Colorado Basin (**Figure 2**), suggesting the development of a fractured basement play along the northern Argentinian margin.

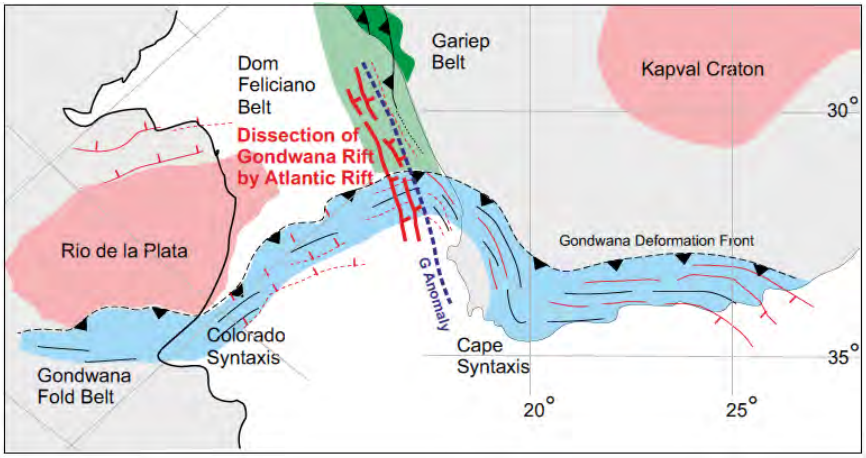

Figure 2. Reconstruction of the southern South Atlantic at 140 Ma. This reveals the continuity of the South African Cape Fold Belt (blue) into the Argentinian Colorado Basin and predicts the potential for fractured basement plays in both the Orange and Colorado Basins [1].

Conclusion

The fractured basement play is an overlooked play which has been proven on a global arena, where it is associated with large resources and significant upside potential. The re-discovery of this play offshore South Africa in both its southern and western margins is possible from a platform that integrates all available data from onshore geology, wells, seismic, and potential field data. Such work has resulted in the identification of the continuation of the pre-Atlantic opening Cape Fold Belt and potential fractured basement play fairway in the Outeniqua and Orange Basins of South Africa, and the conjugate Colorado Basin of Argentina.

References

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[2] Hurricane Energy presentation, 2017.

Matt Tyrrell, Mark Martin, Avril Ashfield, Andrea Maioli
PGS
Blandine Biaou
Société Béninoise des Hydrocarbures (Sobeh)

The Underexplored Shelf-edge Plays of the West Africa Transform Margin and the Opportunity to De-risk these on Merged 3D Seismic and Well Datasets through Togo, Benin, and Western Nigeria

Introduction

For more than 40 years, Mesozoic and Tertiary paleo-shelf edges have been identified by Africa oil explorers as offering the opportunity for high-energy, shallow water reservoir facies, combined with structural trapping styles and sealing transgressive muds, providing plays in shallow water parallel to the present-day coast. In addition to this shelf-edge play, pro-platform talus slope and mass-flow fan deposits, shed off the platform top or front and deposited to onlap the shelf edge, provide a secondary exploration target, typically within the same license area.

In the North West Africa Atlantic Margin (NWAAM), shelf-edge and pro-platform fan plays are to be found extensively, running from Morocco in the north to Guinea Conakry in the south and spanning six countries. Exploratory drilling of these plays was mostly conducted prior to the 2000's and success has been limited to the Cap Juby field, discovered by Esso in 1971, the Pelican and Fregate pro-platform fields discovered in 2003 by Total, and the SNE (shelf edge) and FAN (pro-platform fan) fields discovered by Cairn Energy in 2014. It is noticeable that these discoveries are some 30 years apart and it is believed that despite excellent 2D seismic data coverage, exploration of this play has been limited by the prevalence of block-specific, rather than play-oriented, 3D seismic datasets.

Shelf-edge and pro-platform plays are shown to continue through the Transform Margin of West Africa and in Togo, Benin, and NW Nigeria these plays are equally under-explored. In Nigeria, Mesozoic age clastic shelf-edge plays host the Aje and Ogo Fields, the former also exhibiting an Upper Albian shallow marine mixed carbonate and clastic shelf edge. In eastern Benin, the shelfal wells drilled at the Seme North and Seme South fields encountered clastic, mixed clastic, and carbonate shallow marine facies of Cretaceous age whilst the shelf edge play that lies distally to these was the target for the Gbenonkpo-1 exploration well drilled by Hunt Oil in 2014. In the waters of western Benin and Togo, multiple leads in stacked Mesozoic and Tertiary shelf-edge plays are imaged but to date are untested by drilling.

Underexplored Shelf-edge and Pro-platform Prospectivity in the West Africa Transform Margin

Recently collated and merged 2D and 3D PSTM seismic datasets over Togo, Benin, and Nigeria now provide a single multiclient seismic footprint from the western border of Togo to the Niger Delta. This merged dataset, together with multiclient well data, provides for the first time a continuous image of the shelf-edge

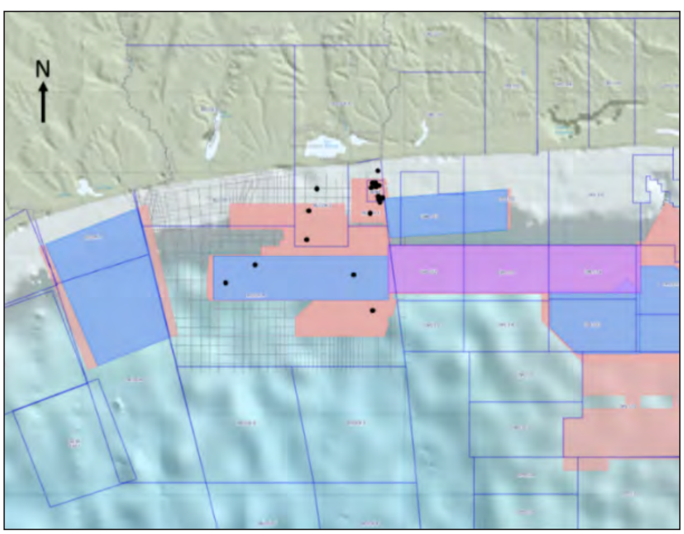


Figure 1. Basemap showing the integrated multiclient well log, 2D and 3D seismic datasets used within the study.

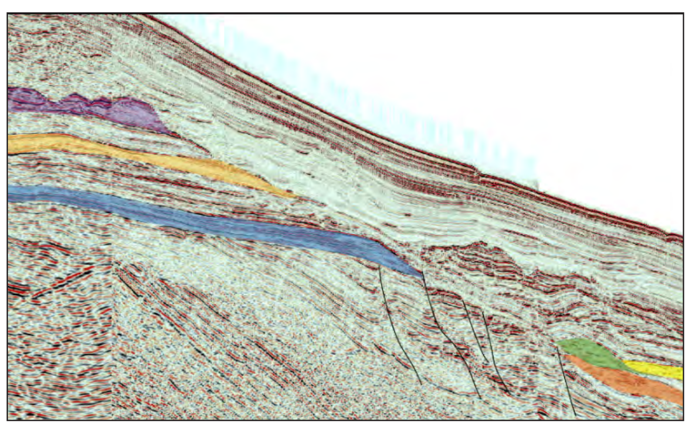


Figure 2. Seismic dip section showing the stacked shelf-edge and pro-platform fan plays. Note that this data is in two way time.

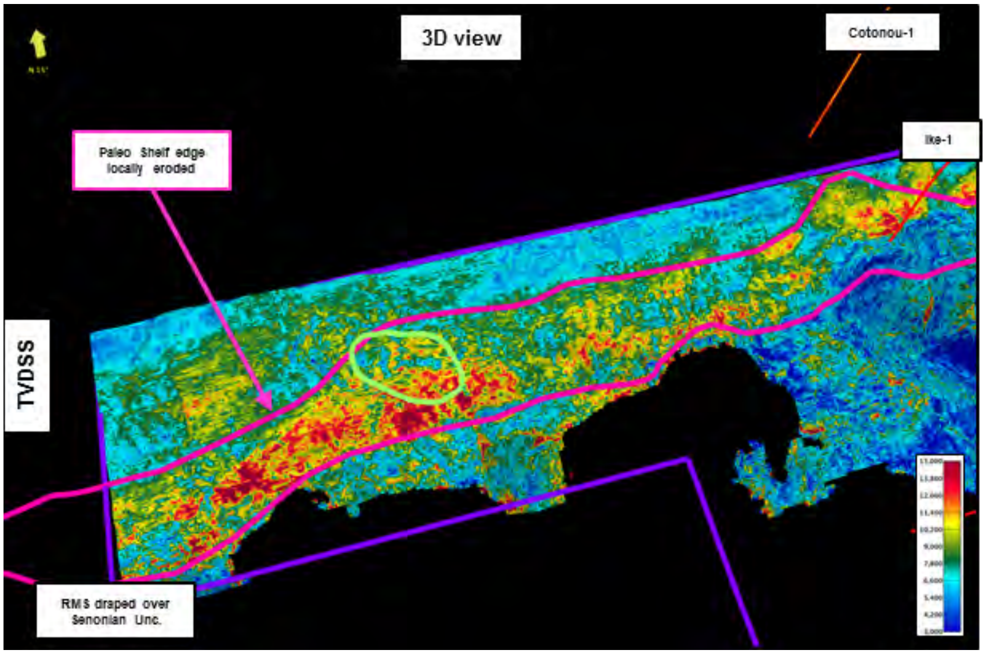


Figure 3. RMS amplitude display from MC3D data showing the paleo-shelf edge (purple outline) together with a lead location (green outline).

and pro-platform plays across three countries and some ten blocks of which six are open acreage (**Figure 1**). The opportunity thus presents itself for oil companies to interpret, explore, and de-risk this multi-country play and high-grade available acreage and farm-in opportunities. Furthermore, the availability of field tapes or raw data for many individual surveys provides the opportunity for the data footprint over the shelf-edge to be depth migrated or depth converted, adding confidence to closures and volumes.

Interpretation work conducted by PGS across these three countries has identified considerable shelf-edge and pro-platform play prospectivity within four shelfal sequences; Albian-Cenomanian, Turonian, Santonian-Campanian, and Maastrichtian (**Figure 2**). A number of leads have been identified, mapped, and risked (**Figure 3**). The application of a sequence stratigraphic framework has helped to predict facies distribution at the paleo-shelf and sequence constrained facies maps show where the best shelf-edge reservoir qualities and pro-platform fan deposits may be. Basin modelling work indicates that charge is low risk whilst rock physics work based upon multiclient well data has been used to constrain litho-fluid facies and to model the elastic properties' behaviour to further de-risk the identified leads.

Conclusions

There is significant overlooked shelf-edge and pro-platform prospectivity through Togo, Benin, and Nigeria, and de-risking of identified leads is now possible through integrated seismic and well datasets. The presentation will show examples of the shelf edge and pro-platform play concept and will show the results of the interpretation work conducted. A number of leads and prospects associated with these plays, located in both open acreage and farm-in opportunities, will be presented and explained.

Biographical Sketch

Matt Tyrrell attained an MSc in Petroleum Geoscience from Oxford Brookes University before joining Fugro-Aperia as an engineer, then Aceca as a Geologist focused on North Sea stratigraphy. He joined TGS in 2006 where he was responsible for geoscience interpretation in Canada and Brazil, before joining the TGS Africa group as Lead Geologist where he worked on new ventures and interpretation projects focused on East and West Africa. Matt joined PGS in 2015 as Principal Geologist for Africa where he works on geoscience and business development tasks in West Africa, with a focus on Cote d'Ivoire, Benin, Congo, and Angola.

Matt is a principal geoscientist and project developer with over 18 years of industry experience. Responsible for delivering exploration opportunities to clients through an understanding of geoscience, project development, business development, and both client and Ministry relationships. He is responsible for developing, scoping, and delivering integrated geoscience studies that provide our clients with exploration opportunities

Emma Tyrrell
Peter Elliot, and Matt Lofgran
Elephant Oil Ltd, Tonbridge, Kent, UK

Hydrocarbon Potential of the Onshore Dahomey Embayment of Benin; Exploration of Devonian, Jurassic, Cretaceous, and Tertiary Plays Using Integrated Seismic and High Resolution Airborne Gravity and Magnetic Data

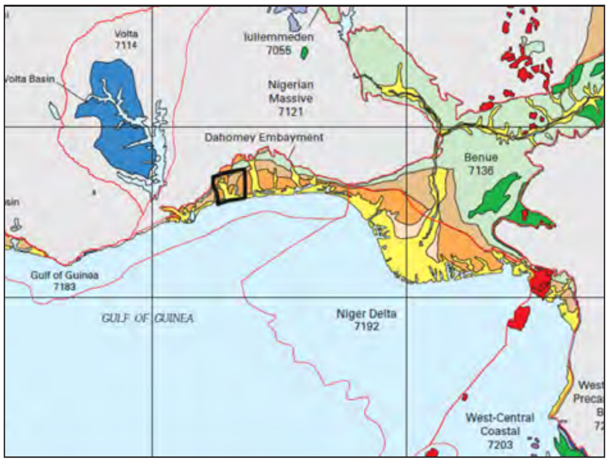


Figure 1. A map of the West Africa Transform Margin, showing the onshore extension of Cretaceous and Tertiary sedimentary basins present-day. Block B in Benin is outlined in black, at the centre of the Dahomey Embayment. (Brownfield & Charpentier, 2006).

The West African Transform Margin is characterised by a number of Mesozoic sedimentary wedges, where Cretaceous to Tertiary sequences are present onshore; the Niger Delta, the Dahomey Embayment (Benin, Togo and Ghana), and the Ivory Coast & Tano Basins. In many locations, these Mesozoic sedimentary wedges are additionally underpinned by Paleozoic failed rift basins associated with earlier intracontinental extensional phases.

The Dahomey Embayment is the least explored of the West Africa Transform margin onshore sedimentary wedges. Just eleven onshore exploration wells have been drilled to date; three in Ghana and eight in Nigeria of which five encountered hydrocarbons. A water well drilled onshore Benin in 1932 at Sazue reported gas, analysed as C1, C2 and C3, strongly indicating the presence of thermogenic gas.

The offshore section of the Dahomey Embayment however has witnessed considerable exploration success within a number of stratigraphic intervals. The Lomé field has some 80 million barrels in place within Lower Cretaceous and Devonian clastics, sourced from Devonian source rocks, whilst the nearby Sèmè Field in Benin contains ultimate recoverable reserves of c.80 million barrels within Turonian and Albian clastics. Immediately across the maritime frontier in Nigerian waters lies the Aje Field, reportedly with 200 million barrels of oil and multi-TCF gas reserves recoverable from the Turonian sandstones, whilst the nearby Ogo Field contains oil within an Albian clastic reservoir.

Within the conjugate margin; the onshore Potiguar Basin of Brazil, exploration success has been prolific with approximately 1200 wells drilled and over 100 oil fields discovered. This success suggests that the remaining potential within the Dahomey Embayment may be considerable.

Recent studies by Elephant Oil over Block B, Onshore Benin, have focused on an integration of a sparse onshore and offshore 2D seismic dataset with a high resolution airborne gravity gradiometer and magnetic survey flown in 2013.

Stratigraphic Interpretation:

Extrapolation of the known geological stratigraphy from the shallow offshore waters suggests that in the onshore, Jurassic, Albian, mid-Cretaceous, and Tertiary sediments overstep Devonian failed rift basins with clastic fills. These Devonian basins are then onlapped by Cretaceous to Tertiary fluvial deltaic sediments of the Agbada and Benin Formations. Interpretation of the seismic facies, supported by evidence from their outcrop further north, have allowed facies mapping and hint at interbedded sandstones and mudstones, deposited during transgressive phases, with intra-formational seals for hydrocarbons migrating onshore and up-dip.

Structural Interpretation:

Interpretation of airborne gravity data together with 2D seismic data enables formation thickness and depth-to-basement to be modelled to permit an extrapolation of the Devonian, Jurassic, and Cretaceous structures, basins, and sediment thicknesses across the block. Several large horst structures are mapped, providing targets for additional seismic and subsequent exploration drilling. To the west of the block, the data reveals a large transform basin of likely Albian age that at present day accommodates Lake Ahémé. At its widest part this transform basin measures 12 kilometres and extends 50 kilometres along its axis, whilst modelling of the gravity gradiometer data suggests that the basin is up to 2.7 kilometres deep.

Onshore Dahomey Petroleum Systems:

All the elements for a fully-functioning petroleum system are shown to be present in the Onshore Dahomey Embayment. The earliest rift structures are believed to be Devonian, with a high likelihood of the working petroleum system encountered offshore Togo extending into the onshore.

In the overlying Cretaceous to Tertiary sedimentary wedge, hydrocarbons from the Akata Shale can be demonstrated to have migrated up-dip and onshore, within both Cretaceous and Tertiary clastics. Traps are formed where Albian clastics drape over Devonian rift structures or where they are onlapped by Turonian sandstones. Additionally, intraformational permeability barriers likely trap hydrocarbons during their up-dip migration.

The next phase of interpretation and exploration of this prospective onshore region of the West Africa Transform margin will require the acquisition of additional 2D seismic data covering the main rift structures and basins identified by gravity and magnetic data. Once acquired, the integration of the new seismic with the gravity and magnetic data, will greatly enhance the understanding of the petroleum systems and allow the planning of the first exploration wells due in 2020.

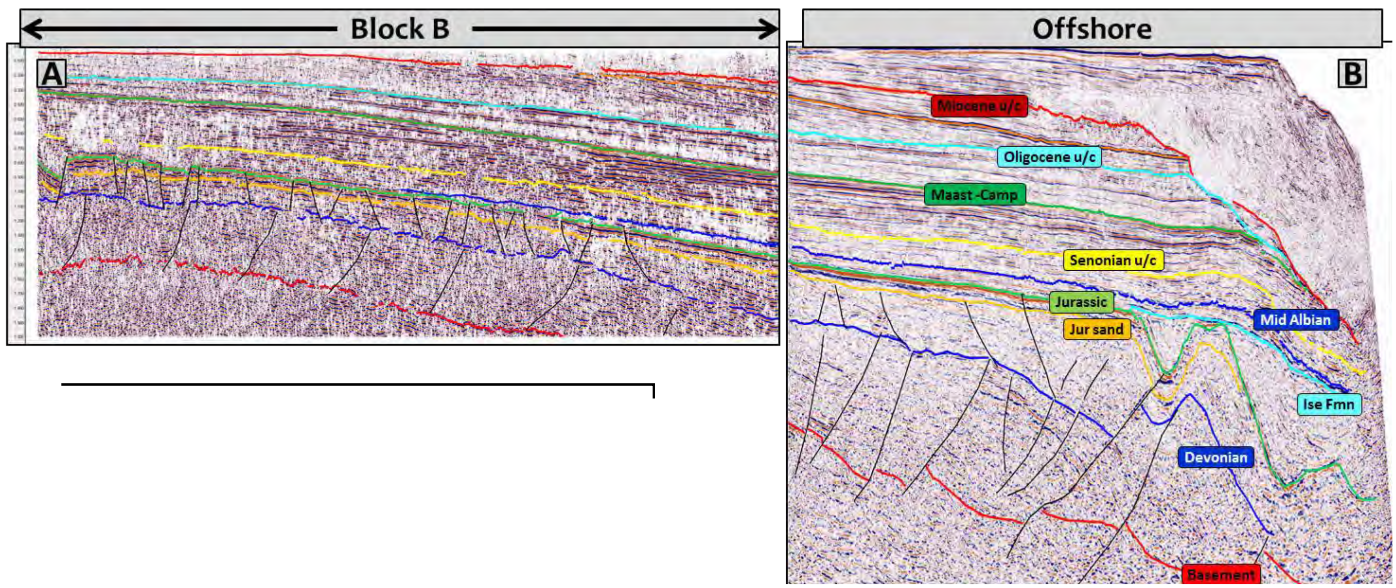


Figure 2. Onshore to offshore seismic profiles showing the structural and stratigraphic interpretation.

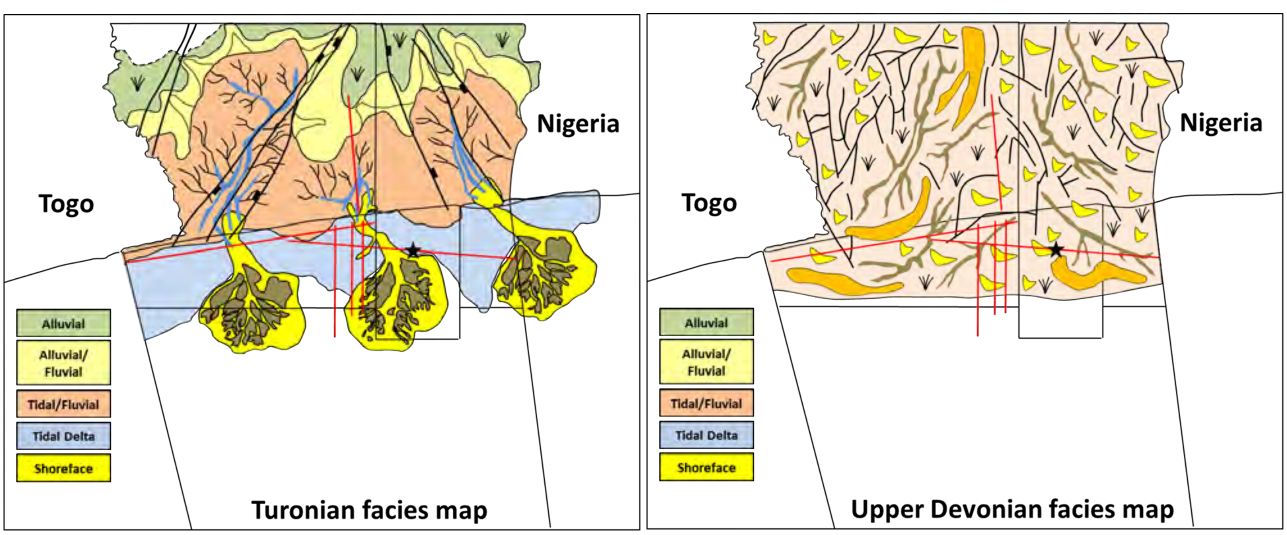


Figure 3. Examples of paleo-facies maps for the Devonian rift and Turonian post-rift reservoir intervals.

Katie-Joe McDonough
KJM Consulting, Pine, CO, USA and ION E&P Advisors, Houston, TX, USA
Kyle Reuber, Brian W. Horn, Kenneth G. McDermott, Elisabeth C. Gillbard
ION E&P Advisors, Houston, TX, USA
Friso Brouwer
I^3 GEO, Denver, CO, USA

Conjugate Margin Chronostratigraphy – Comparison of Cretaceous-Tertiary Petroleum Systems in Namibia and Uruguay

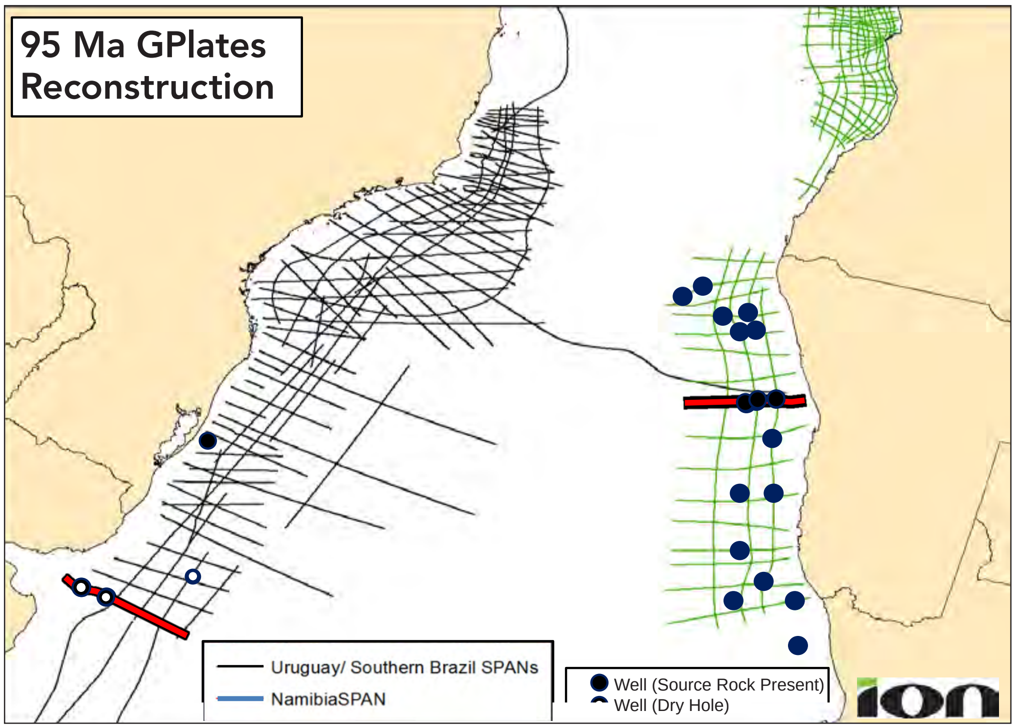


Figure 1. Early Cretaceous (95 Ma) plate reconstruction showing locations of ION seismic profiles along the offshore margins of South Atlantic and West Africa. Seismic profiles in red were used in this study, and straddled the Atlantic conjugate margin during Cretaceous time.

Significant offshore areas along the eastern and western margins of the southern South Atlantic remain underexplored. Offshore Brazil, Uruguay, and Argentina host multiple underexplored basins south of the salt provinces, and the conjugate Namibian margin has indications of a potential hydrocarbon exploration province. Offshore basins containing Early Cretaceous through Tertiary sediment fill along the South Atlantic margins contain several significant discoveries in recent years in near-shore shelf carbonates to deep-water siliciclastic reservoirs. The Kudu gas field in offshore Namibia contains an estimated 1.3 TCF shallow marine reservoirs charged by an Aptian marine source. Similarly the 2010 Sea Lion discovery on the Falkland Plateau targeted fans charged by thick, high TOC Early Cretaceous lacustrine shale. These recent discoveries reveal functioning petroleum systems on both (volcanic) margins and suggest a potential for future discoveries (**Figure 1**). These conjugate margins shared similar geological histories until Early Cretaceous rifting initiated their separation. Post-rifting, the margins show synchronous, symmetrical evolution and development of the sedimentary section suggesting tectonic controls on variable sedimentation episodes between the margins.

We develop a detailed chronostratigraphic correlation of the sedimentary section on the conjugate margins of Uruguay and Namibia through the geo-chronologic timing of syn- and post-rift fill sequences including the enigmatic seaward-dipping reflector (SDR) series. Long-offset 2D seismic profiles from both margins of the South Atlantic enable comparison of basin-fill chronostratigraphy on each margin (**Figure 2**), by establishing geochronology in the basins which form above the juncture of continental and oceanic crust. The zone composed of SDR packages links the crustal processes driving magmatic rifting/stretching of the continental crust which lead to the formation of oceanic crust, to sedimentation (including extrusive volcanic) patterns observed along the rifted margins. Therefore the SDR packages are included at the end of the syn-rift fill sediments which fill early mini-grabens overlying continental crust.

Initially we generate HorizonCubes on 2D seismic profiles from each margin. A HorizonCube comprises a set of high-resolution tracked horizons which includes virtually all stratal surfaces present in the seismic data. We previously generated HorizonCubes in the sedimentary section which excluded SDRs

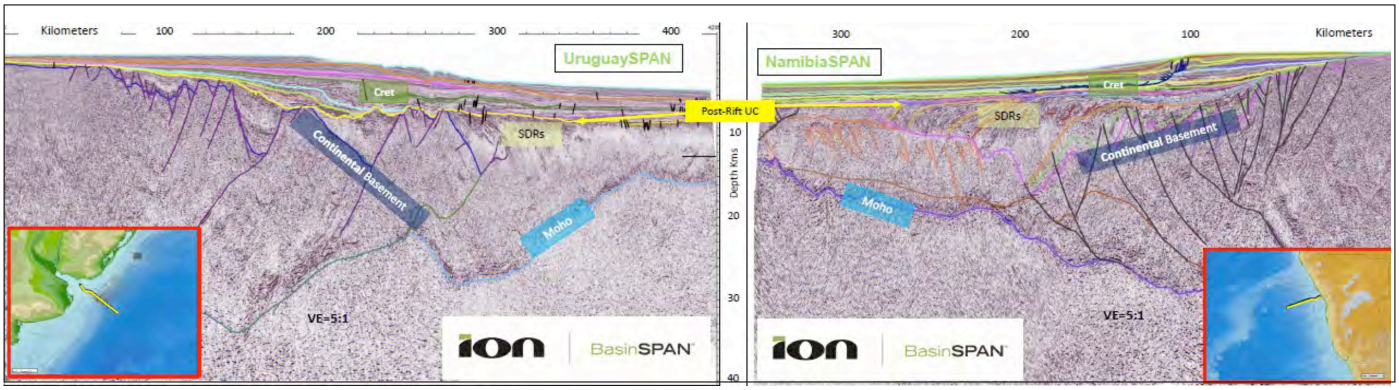


Figure 2. Seismic profiles depicting offshore margins of Uruguay and Namibia.

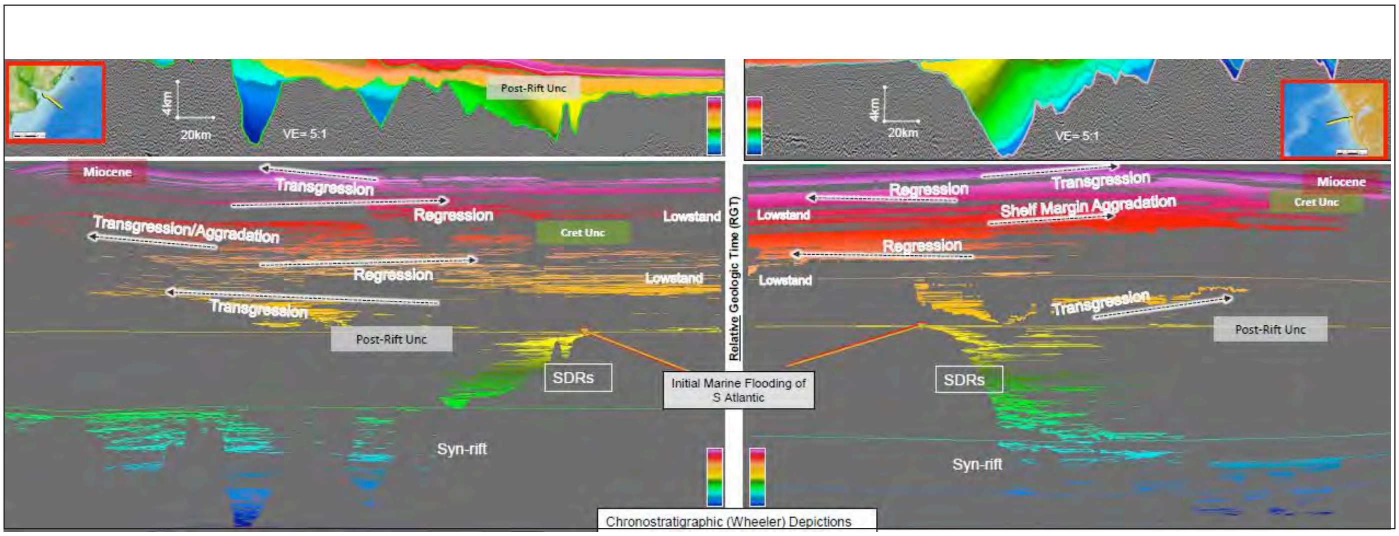


Figure 3. HorizonCube and accompanying Wheeler (chronostratigraphic) diagram from Uruguayan and Namibian margins. Note synchroneity of major transgressive/regressive cycles across the conjugate margin.

as synchronous with late syn-rift fill. However, in our model the emplacement of the non-extrusive magmatic material that underlies the SDRs is typically thought to be coevally formed at the paleo-volcanic spreading center. As this lower zone is typically void of layered material, a lower bounding limit of SDRs is currently included in generation of the HorizonCube (**Figure 3**).

The horizons generated within the HorizonCube are then flattened to create a chronostratigraphic "Wheeler"-style representation of sedimentation, including syn-rift volcaniclastic SDRs along each profile. This flattening was done for HorizonCubes generated on each seismic line. The flattened representation shows spatial variation in deposition through time. Thus, we were able to compare evolution of both sedimentary basins from the conjugate margins across the south Atlantic (Figure 3). This type of geochronological representation of the seismic data permits comparative analysis of evolution of stratigraphy in relation to the SDR series and magmatic crust.

Wheeler diagram scrutiny also permits predicting the formation and timing of key petroleum system elements across the southern South Atlantic. One difference between the margins was the lateral extent of the coeval SDR packages. The Namibian margin covers roughly twice the lateral extent as on the Uruguayan side suggesting a potentially shallower gradient on the Namibian volcanic margin during rifting. This is interpreted to be the result of basement gradient changes that persisted into the sediment section and drove subsidence variations through time.

We found that stratigraphic evolution on the conjugate margins was synchronous and geometries mirror each other for the Cretaceous as well as the Tertiary section (**Figure 3**). Key regional transgressive-regressive packages are similarly timed on both sides of the mid-Atlantic. For example, the Albian transgressive package produces coeval source rocks on both sides. Late Cretaceous fill on the Uruguayan side may be limited to slope base and lowstand fan reservoirs, whereas the Namibian side appears to contain significant aggradational deepwater deposition. Lateral extents and inferred volumes of the stratigraphic systems vary between the margins, with greater depositional dip extent existing on the Namibian margin. Stratigraphic evolution identified from the chronostratigraphic diagrams also records margin-specific events that appear to be related to local tectonic events, sediment budget, and margin architecture. These variables strongly influenced the depositional settings and facies over time.

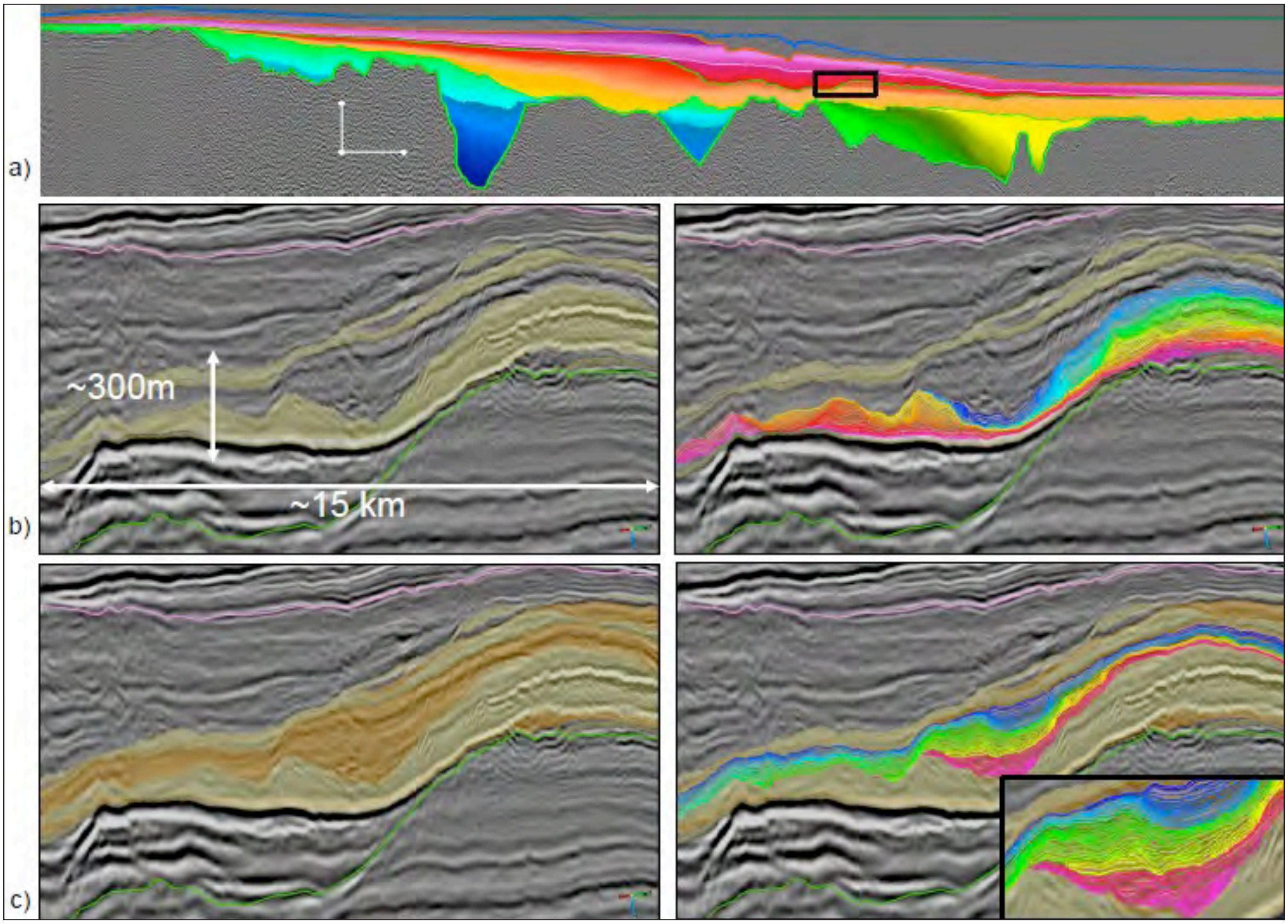


Figure 4. Example from Uruguay showing HorizonCube revealing high-resolution stratal geometries and seismic facies. a) Detailed analysis located in the black square on the upper image. Mounded geometries alternate with subparallel, infill stratal geometries which stack compensatorily. These suggest alternating incision and construction systems, possibly channel-fan reservoirs. The upper set of images b) show the mounded facies, light yellow in the left images, with the partial HorizonCube overlay showing the internal geometries and outline of the geobody on the right image. The lower set of images c) show the infill facies, shown in brown in left image. The right image shows subparallel nature and laterally-building geometries, enlarged in inset.

These observations have important ramifications for understanding petroleum systems on both margins. Our comparison predicts that Uruguay has a potential post-Cretaceous play which may also exist in Namibia, and the Cenomanian-Turonian may be a viable source interval on both margins. Further interrogation of the details of HorizonCubes permits seismic facies analysis of stratal and geobody architecture. This further supports the prediction that viable petroleum system components of reservoir (**Figure 4**) and source exist on both margins. Thus a detailed interrogation of conjugate margin chronostratigraphy permits more accurate discernment of depositional history and development of accurate play identification models within a regional framework.

Biographical Sketch

Katie-Joe McDonough, PhD is a geolophysicist specializing in multi-dataset, integrated sequence stratigraphic and seismic interpretation. Katie-Joe's areas of focus include multi-scale applications of stratigraphy to basin analysis, exploration play assessment, and reservoir-scale development. She works worldwide continental to deep marine strata in conventional and unconventional plays. Katie-Joe collaborated with colleagues at ION E&P Advisors to generate and publish the initial version of this work, which garnered the 2017 Jules Braunstein award for best presentation as poster at ACE 2017. Katie-Joe currently also serves as an industry mentor to YPs and graduate students.

Kyle Reuber, PhD is a geologist for ION's E & P Advisors Team based in Houston. His primary area of focus is Latin America and the Caribbean. His current role is multi-faceted and broad in scope. Kyle has designed SPAN programs in locations such as Panama, Argentina, and West Africa. His interpretation projects integrate the regional 2D -SPAN and available reprocessed vintage datasets. Kyle's project management background also assists in his roles as the lead interpreter for multiple basin modeling studies along the Atlantic margins using the ION data.

Friso Brouwer is geophysical consultant and owner of I^3 GEO in Denver. Friso has 15 years industry experience, involving both technical and managerial roles. His expertise covers both regular seismic interpretation and application of specialized geophysical techniques. Friso has worked offshore, onshore and unconventional areas, both in the US and internationally. His collaboration with ION Geophysical E & P Advisors is focused on enhancing the interpretation of the ION's SPAN lines using the specialized sequence stratigraphic interpretation tools for seismic data.

Simon Greenfield, Dr. Peter Cox
Core Laboratories UK

Regional Reservoir Quality Trends in Cretaceous Sandstone Reservoirs in the Transform Margin Basins of Ghana

Cretaceous sandstones form major exploration targets across the Tano, Saltpond, and Accra-Keta basins in the transform margin of Ghana. Although there have been world class discoveries in the Upper Cretaceous succession of the Tano Basin, large tracts of the margin remain relatively under explored. There is an industry imperative to increase our understanding of the factors controlling reservoir quality in these basins.

Our approach to this regional reservoir evaluation was to extract maximum geological value from a large archive of legacy rock samples (core, sidewall core (SWC), and cuttings) that has been created by multiple exploration and appraisal drilling campaigns. Detailed petrographic descriptions have been performed on over 700 thin sections describing detrital and authigenic mineralogy, the degree of compaction, and characterisation of pore systems. Reservoir quality has been assessed by combining this observational data with an extensive legacy database of core analysis data, geothermal gradient data, and density porosity analysis. The objective of the study was to compare and contrast the regional distribution of reservoir quality taking into consideration sedimentary facies, sediment provenance, burial depth, and temperatures.

Lower Cretaceous (Berriasian - Albian) sandstones represent the main rift sequence across the three studied basins. Reservoir quality is strongly impacted by provenance. The principle depositional environments at this time comprise basin margin alluvial fans, braid delta fronts, and delta front slope fan lobes in deeper water sections of the basin. Reservoir quality is generally poor in the Tano and Saltpond basins except on structural highs and in some areas close to the present day shoreline and onshore. Here, sandstone compositions are generally both compositionally and texturally immature with sediment composition strongly influenced by the immediate hinterland geology. Sandstones are rich in feldspar; ductile mica-rich foliated metamorphics and coarsely crystalline plutonic rock fragments. The sediment load has been sourced from Paleoproterozoic terranes dominated by metamorphic and plutonic lithologies, indicating that provenance is key to predicting reservoir quality at this time. Due to the high content of brittle and ductile grains, the sandstones are prone to strong mechanical compaction.

Shelf edge locations in close proximity to the Romanche fracture zone in the Saltpond Basin, and to a much lesser degree in the Tano basin, were affected by the circulation of hot fluids that were related to periods of high heat flow (Nemčok et al. 2015) that occurred following cessation of rifting and appear to have resulted in the precipitation of late carbonates and in some cases, quartz overgrowths that occlude high volumes of the remnant post compactional porosity. Lower Cretaceous sandstones from the Accra-Keta basin have much better reservoir quality. They are interpreted to have been sourced from the Neoproterozoic Voltaian Basin and are far more compositionally mature, containing far higher proportions of mechanically and chemically stable quartz, and are thus more resistive to both compaction and diagenetic alteration. Furthermore, these sediments do not appear to have been significantly impacted by hydrothermal fluids.

A major shift in sandstone composition is recorded in the Upper Cretaceous succession of the Tano Basin, and it reflects the transition to Syn-Transform and later (Uppermost Santonian – Maastrichtian) passive margin tectonic settings. Feldspar and rock fragment abundances show a marked decrease in abundance when compared with the underlying Lower Cretaceous sediments, and show a progressive maturation through the Upper Cretaceous. Compositions are generally subarkosic to sublithic during the Mid Cenomanian – Mid Turonian, subarkosic to quartz arenites during the Late Turonian – Earliest Santonian, and are predominantly super-mature quartz arenites from the Late Santonian onwards. High geothermal gradients result in the early onset of quartz overgrowth cementation at relatively shallow depths, around 1.5km burial. In some cases this had the positive effect of early shut-down of mechanical compaction. Super mature quartz arenites are generally more prone to strong quartz cementation due to the higher surface areas available for precipitation compared with coarse grained/poorly sorted quartz arenites and subarkoses. Good to excellent reservoir quality is hosted by moderately buried Mid Turonian to Earliest Santonian, coarse grained sandstones predominantly deposited in slope channel/stacked channel sequences. Microquartz is an important factor that precludes quartz cementation in sandstone deposited in Cenomanian – Late Turonian times. Its distribution may be stratigraphically controlled.

Rowan Edwards, Michael King and Gregor Duval
CGG

Using Broadband 3D Seismic to Validate and Upgrade Satellite Seepage Data, Gabon

CGG have recently combined their latest 3D Broadband Seismic survey from their MCNV (Multi Client new Ventures) group with satellite seepage data from their NPA Satellite Mapping Group. By combining NPA's sea surface oil slick data derived from SAR (synthetic-aperture radar) imagery and 3D broadband seismic data acquired off the SW coast of Gabon, and using a previously developed oil slicks to seismic workflow, links can be made between sea surface slicks with features on the seabed and within the subsurface which are potentially related to seepage.

The project aim was to both high grade and validate the seepage data, as well as create hotspot maps which describe the quality and frequency of these seepage related features, for example DHI's, possible migration pathways, fluid escape features, or seabed features. By combining these maps with the sea-surface slicks, areas of potential hydrocarbon generation, migration, and escape are able to be identified.

Additionally, by integrating the results of the seep to seismic workflow with bathymetry and interpreted channels, a model can be built up of both active and inactive hydrocarbon seepage, as well as the potential migration pathways of these hydrocarbons through a combination of channels and shallow faults. Inferences can also be made about the role of salt tectonics in hydrocarbon migration within the basin, both as a source of large structures connecting reservoirs to the shallow subsurface, and as a method of forming small scale seabed faults related to localised doming.

Biographical Sktech

I obtained my BSc in geology before taking a role as a mudlogger with Geoservcies. After working on a variety of projects from deep water west of the Shetlands to onshore North Africa I returned to university to undertake an MSc in petroleum geoscience at Royal Holloway. My thesis was on 2D analogue modelling of rift systems, this led on to my current role with NPA Satellite Mapping where I have been for 5 years. My role involves onshore mapping projects, primarily in SE Asia and Africa, as well as seismic interpretation, and working closely with offshore interpreters on our Seep to Seismic projects.

Notes

The 17th HGS-PESGB Conference on African E&P

Student Poster Presentations

Abstracts

September 10-13, 2018

Norris Convention Centre, Houston Texas

Malik Muhammad Alam
CBTH Project and Department of Earth and Atmospheric Sciences,
University of Houston, Houston, Texas

Comparing Controls on the Formation of 27 Passive Margin Fold-Belts from the Margins of the Gulf of Mexico, South Atlantic and Africa

I have compiled map information on 27 passive margin fold belts (PMFB) in the Gulf of Mexico, African, and Atlantic margins, and have grouped them according to whether their basal detachment is composed of salt or shale (**Figure 1**). 46% of the 27, PMFB are controlled by salt detachments, 16% by shale detachments, and 38% by other lithologies. In the Gulf of Mexico, salt-detached PMFB's include the following seven examples: Atwater, Keathley-Walker, Timbalier, Perdido, Campeche, Marbella, and Catemaco. Along the South Atlantic margin of South America, salt-detached PMFB's include Jequitinhonha, Campos, and Santos. Most of the African PMFB's are mostly controlled by salt detachments (Aaiun, MSGBC, Lower Congo, Kwanza, Benguela, and Majunga); only the Niger delta is controlled by shale detachments. The dip of both salt and shale detachments varies from 2° to 20° and the width of the up-dip, normal fault, breakaway zone ranges from 3 to 7 km. Tectonic-related over-steepening occurs in the Mexican Ridges in the western Gulf of Mexico. Deltaic-related progradation and over-steepening occurs in the Niger delta. Productive petroleum systems are found in 100% of the twenty-seven-passive margin fold-belts with about ¾ of past production in the shallower-water, normal fault breakaway zone and ¼ of past production in the deeper-water, fold and thrust belt.

Biographical Sketch

Malik Muhammad Alam is a second year Geology MS student at the University of Houston, working with Dr. Paul Mann as part of the Conjugate Basin, Tectonics, and Hydrocarbons (CBTH) Consortium. His research includes analyzing the CHIRP data from Houston Ship-channel area, as well as the Passive Margin Fold Belts in the Gulf of Mexico, South America, and the African Margins. He expects to graduate in May 2019.

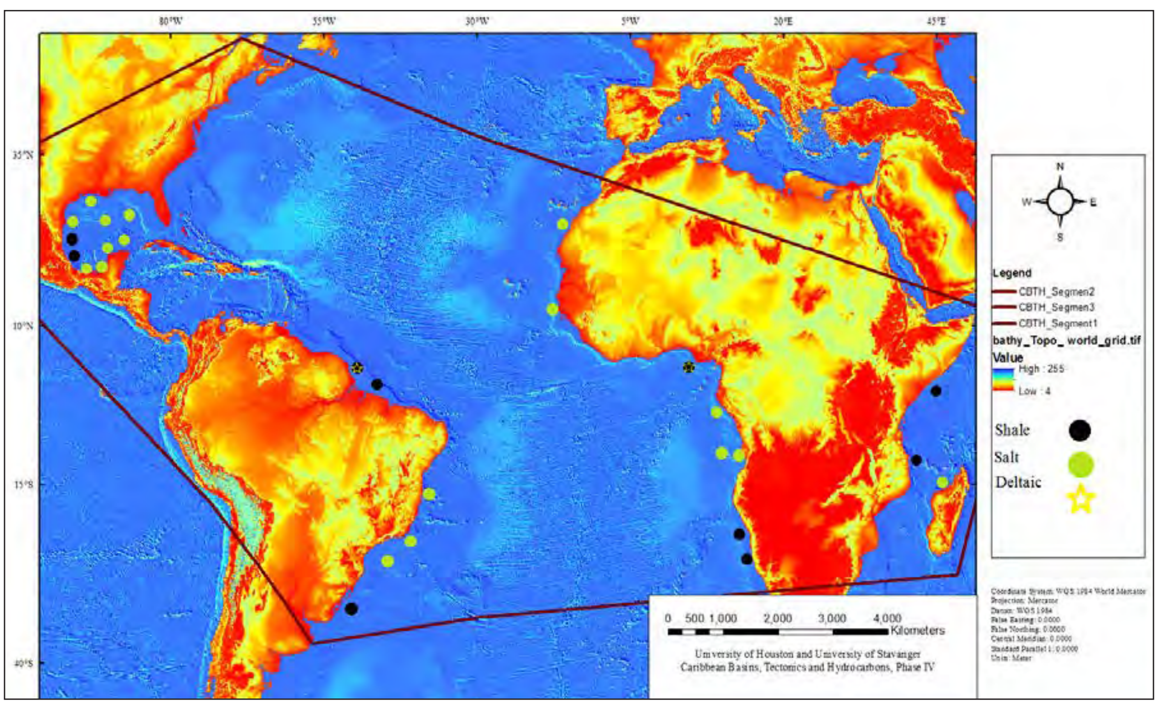


Figure 1: Locations of the Passive Margin Deepwater Fold-thrust Belts on the Gulf of Mexico, Atlantic Margin of South America and African Margin. Yellow dots signifies the Salt Detachment Fold-thrust belts and Maroon dots signifies the Shale Detachment Fold-thrust Belts.

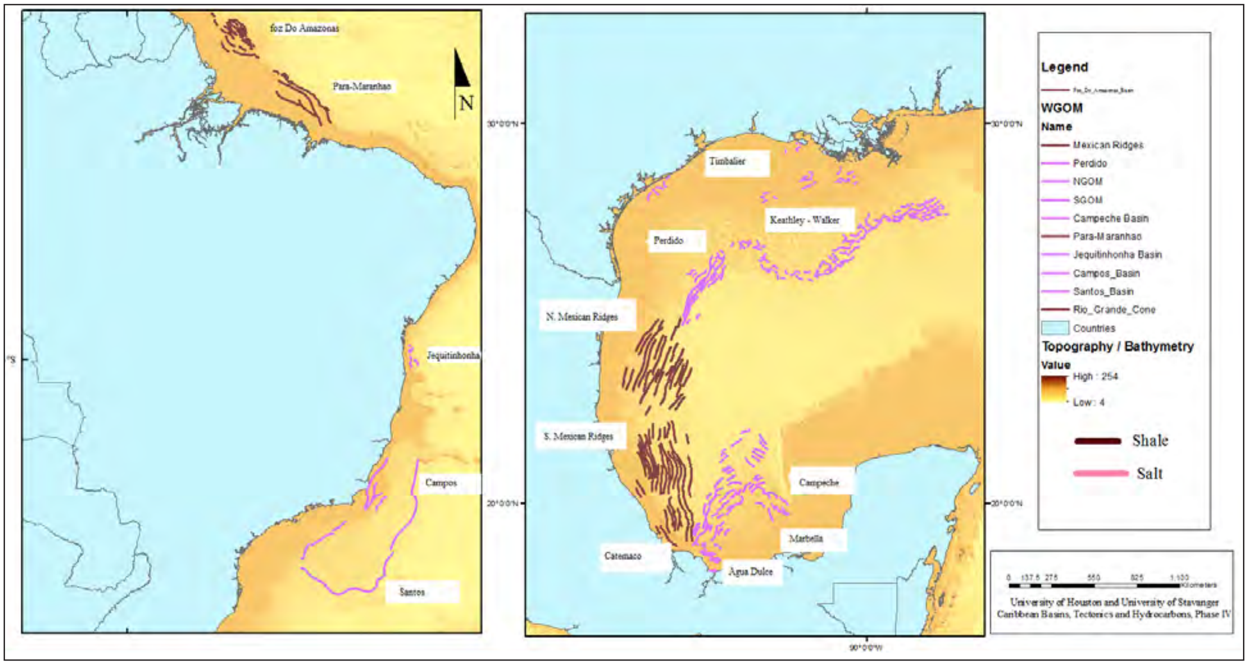


Figure 2: Marked Fold-Belts of Gulf of Mexico and South-American Margins

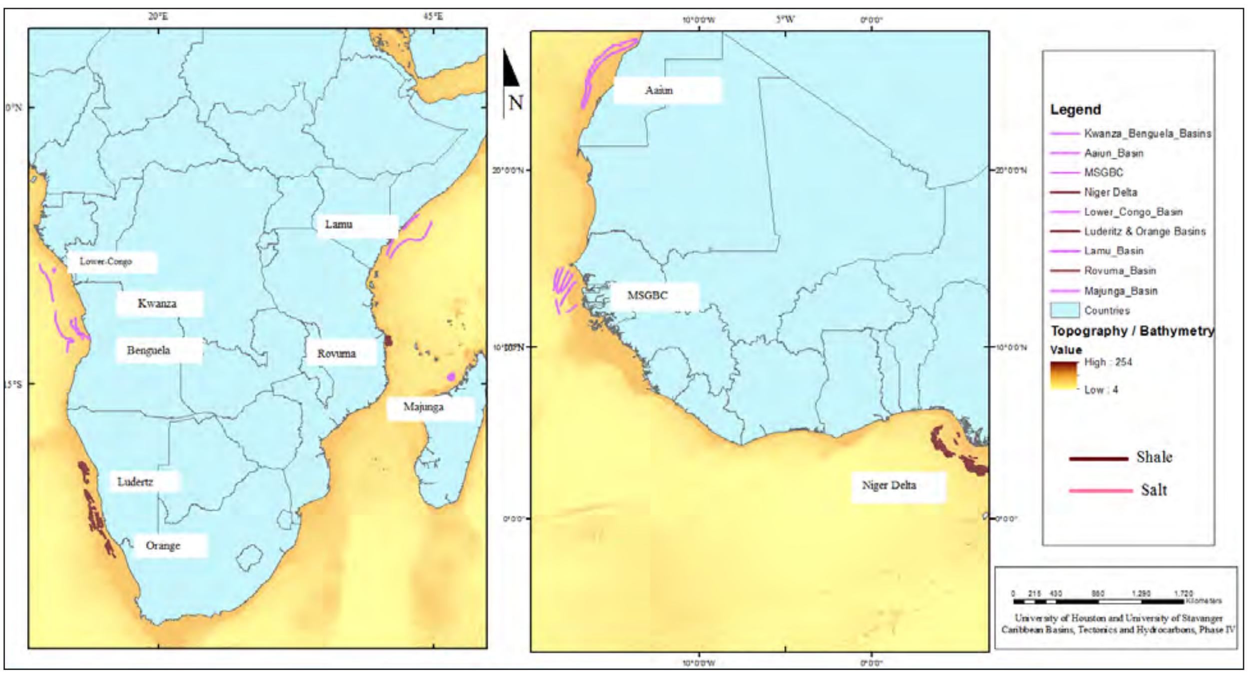


Figure 3: Marked Fold-Belts of African Margins

Nikola Bjelica
University of Houston, Houston, Texas

Compilation of Widespread, Cretaceous OAE1, OAE2, and OAE3 Black Shale Horizons Documented in Wells from the Gulf of Mexico, Caribbean, and Atlantic Passive Margins

Oceanic anoxic events (OAEs) represent intervals in the Earth's past where portions of oceans were depleted of oxygen at water depths ranging from 300-5500 meters. OAE events are caused by increased tectonic activity that led to massive volcanic eruptions and deposition of carbon-rich, black shale in marine environments. There are eight documented Cretaceous anoxic events that include:

1. OAE1a Selli event of 124.2-123.4 Ma age related to Aptian volcanic activity of the Ontong Java oceanic plateau in the western Pacific Ocean.
2. OAE1b consists of the Jacob sub-event of Aptian age (113.6-113.2 Ma), Paquier event of Albian age (112-111.6 Ma) and Urbino event of Albian age (110.9-110.6 Ma); all three of these sub-events are related to volcanic eruptions of the Albian Kerguelen Plateau eruptions in the Indian Ocean.
3. OAE1c Tollebuc event of Albian age (103.7-103.4 Ma) was related to volcanism during Albian South America-Africa breakup.
4. OAE1d Breistroffer event of (100.6-100.2 Ma) related to volcanism related to Albian rifting of South America and Africa.
5. OAE2 Bonarelli event of Cenomanian age (93.8-93.5 Ma) produced by Turonian Caribbean Plateau eruptions in the Caribbean Sea.
6. OAE3 event of Coniacian age (87.3-84.6 Ma) produced by Coniacian-Santonian volcanic eruptions related to the Caribbean oceanic plateau.

I have compiled the extent and thickness of OAE's on Gulf of Mexico, Caribbean, and Atlantic margins using published well data. This data shows that OAE1 can vary in thickness up to 200m with a TOC value up to 5% in the Gulf of Mexico whereas in the Atlantic is in range of 50-1700m with TOC values ranging from 1-20%. OAE2 thickness in the Gulf of Mexico is up to 50m with TOC values in the range of 2-3% and in Atlantic margins of South America and Africa thicknesses range from 50-500m with TOC values 2-10%. OAE3 thicknesses are up to 100m with TOC values in the range of 4-5%.

Biographical Sketch

I am an undergraduate Geology major at the University of Houston. I joined the CBTH research group in May 2018 and since then I have assisted in managing the GIS database for stratigraphy and wells, and analyzing compilation of widespread Oceanic Anoxic Events (OAEs) black shale horizons documented in wells from the Gulf of Mexico, Caribbean and Atlantic passive margins.

Naila Dowla, Dale Bird, Michael Murphy
University of Houston, Houston, Texas

3-D Crustal Model of Northwest Africa

Our understanding of the Central Atlantic conjugate continental margins is skewed; the North American side has been heavily studied, but the northwest African side has not. In particular, most studies reject or minimize the extensional deformation of continental crust along the African margin. To examine possible African deformation, we constructed a six-layer 3-D crustal model of northwest Africa and performed a gravity structural inversion to estimate its crustal structure. The African margin crustal thickness beneath the Mauritanides mountain belt varies little along strike, ranging from 35 to 40 km. East of the Mauritanides, its thickness varies little between 33 and 36 km, similar to previously published West African Craton studies. Westward, the thickness is variable, inconsistently thinning to 15 km over 500 km. This shifts the limit of extension 400 km eastward of previously interpreted crustal extension limits. We observe crustal thickness fluctuating between 25 to 15 km. The largest region of thinned crust follows the western Mauritanides foothills, trending NNW and possibly represents a foreland basin associated with Paleozoic compressional events culminating in the collision of Gondwana with Laurentia and the closing of the Rheic ocean. The NNW-SSE trends diminish southward at the expense of smaller NE-SW trending highs and lows. These features are parallel to eastern North America normal-fault bounded Triassic rift basins when the Central Atlantic is reconstructed to 185 Ma, the estimated time of oceanic crust formation. Because the orientation is comparable to those rifts east of central portion of the Appalachians, we interpret these crustal thickness highs and lows to be Triassic rift basins bounded by high to moderately dipping reactivated normal faults. The thinning of the crust, in conjunction with interpreted Triassic rift basins, suggests that the African margin did indeed undergo crustal extension and deformation during rifting. ■

Biographical Sketch

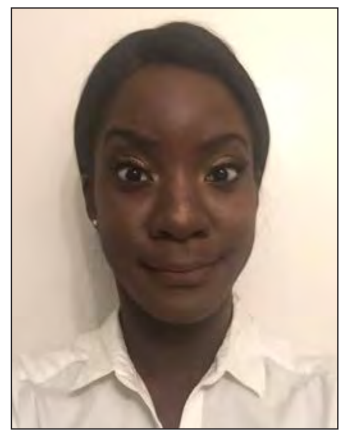
Naila Dowla is a 5th year Geology PhD candidate and teaching assistant at the University of Houston, with an expected graduation date of spring 2019. Her dissertation research focuses on extensional tectonics and the effects of rifting on crustal geometries, as well as the possible influences of pre-existing structures, using potential fields, specifically for the conjugate margins of the Central Atlantic. Naila's undergraduate studies include a BS in Physics from the University of Texas at Austin in 2011, and a post-baccalaureate BS in Geophysics from the University of Houston in 2014. She has held numerous officer positions for the AAPG student chapter at the University of Houston, such as treasurer, vice president, and president, and is an organizer for the Houston AAPG Student Expo.

Marie-Nelsy Kouassi, Paul Mann, Joel Saylor, Kurt Sundell
University of Houston, Houston, Texas

New Insights into the Assembly and Breakup of Pangea from a Mega-Regional Compilation of 8,672 Detrital Zircon Ages from the Circum-Gulf of Mexico, Northern South America, and West Africa

We present a regional compilation of 8,672, published detrital zircon ages to better constrain the linkages between the Suwannee and the Maya terranes on the West African side of Gondwana, and the linkage between the Oaxaquia and the Mixteca terranes on the South American side of Gondwana. Previous work has shown a variety of options on the spatial and temporal positioning of these terranes from the early Paleozoic to early Mesozoic. The compiled, detrital zircons ages consist of grains from Paleozoic and Mesozoic clastic rocks that blanketed the area of pre-Iapetus rifting between the early Paleozoic peri-Gondwana terranes and Gondwana and subsequently during the early Mesozoic along the Gulf of Mexico and Atlantic rifted margins of Pangea supercontinent. The age distributions of the detrital zircons for each terrane and cratonic area were compared using stacked probability density plots. Zircon populations of all terranes were compared using the K-S test D value displayed on multi-dimensional scaling plots. Abundant, Grenville age populations from Paleozoic strata from the Maya, Mixteca and Oaxaquia terranes show strong linkages and common clastic source areas with coeval Colombian Eastern Cordillera (Colombia) terranes and the Sunsas province of the Amazonian craton. In contrast, detrital zircon of the Suwannee terrane of Florida closely matches West African terranes as both regions shared Pan-African and TransAmazonian-Eburnean source areas during the early Paleozoic. Similarities of these closely-linked, Paleozoic terranes decline by post-orogenic, introduction of zircons related to reactivation of North American cratonic basement and orogenic-related magmatic activity. This shift in provenance from a dominantly Gondwanan provenance to a mixed Laurentian and Gondwanan provenance records the collision of Laurentia and Gondwana to form Pangea. The early Mesozoic breakup of Pangea left the Suwannee, Maya, Mixteca, and Oaxaquia terranes attached to the southern margin of Laurentia and enabled new and more complex, clastic sediment pathways.

Biographical Sketch



Marie-Nelsy Kouassi is a first year Geophysics PhD student at the University of Houston, working with Dr. Paul Mann as part of the Conjugate Basins, Tectonics and Hydrocarbons (CBTH) Consortium. She received her BSc degree in Geophysics in May 2017 from the University of Houston. As a senior, she completed a thesis involving the use of a large detrital zircons age compilation to correlate terranes in eastern and southern Mexico and eastern U.S. to their potential sources in West Africa and South America. Her PhD research focuses on the 3D velocity model building and depth migration of 2D seismic data in subsalt environment in the central U.S. deepwater Gulf of Mexico in order to improve the resolution for seismic attributes extraction and structural interpretation. She expects to graduate in 2021.

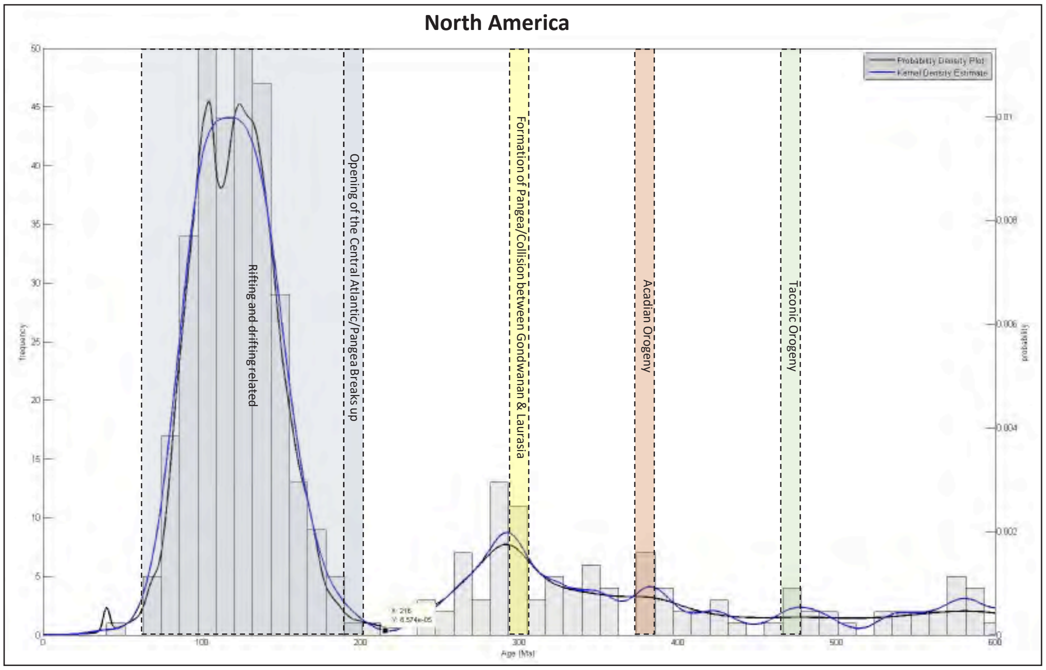
T.Q. Pham, C. Ebinger, S. Oliva
Earth & Environmental Science, Tulane University, New Orleans, LA
K. Peterson
Earth & Environmental Science, University of Rochester, Rochester, NY
P. Chindandali
Malawi Geological Survey, Zomba, Malawi
D. Shillington
LDEO, New York

Geometry and Kinematics of Seismically Active Border and Transfer Fault Systems in the Malawi Rift, Africa

Although the deep, wide basins of the Western Rift, Africa have served as models for the formation and evolution of half-graben basins, little is known of the geometry and kinematics of the border fault systems, nor of their depth extent. Using a new local earthquake database from the 8/2013 through 10/2015 SEGMeNT (Study of Extension and maGmatism in Malawi aNd Tanzania) seismic array, which comprised 57 onshore and 32 lake-bottom seismometers, we examine the kinematics and extension direction of the northern two basins of the Malawi rift, including the Rungwe volcanic province. We also evaluate the geometry and kinematics of the intra-basin and border faults using nodal planes of 62 well-determined first motion focal mechanisms, along-axis variations in seismogenic layer thickness, and existing constraints on crustal thickness. We located earthquakes using a new regional 1D velocity model, and we use double-difference methods to relocate several clusters of earthquakes. The spatial distribution of earthquakes shows that the regions with the highest levels of seismicity are intrabasinal faults in the North basin, including the Karonga region that experienced damaging earthquakes in 2009. Some earthquakes occurred at depths of 25-35 km along projections of the North basin border fault, indicating that the border fault is still active. In the Central basin, the border fault is largely inactive, as well as the zone underlain by a Permo-Triassic rift basin. Except for a few swarms of earthquakes beneath Rungwe volcano, the volcanic province is largely inactive. After developing a new local magnitude scaling, we determined magnitudes of 1160 earthquakes that are well located within the SEGMeNT array: $0.7 < ML < 5.1$. The b-value is 0.88 ± 0.04, and magnitude of completeness is M_L 1.9. The focal mechanism solutions are primarily dip-slip normal faults with steeply dipping (> 45º dips) nodal planes, with some strike-slip and oblique reverse faults. Extension direction from stress inversion and Kostrov summation of declustered local focal mechanisms and Global CMTs indicates a N56 ± 28/15ºE and N70ºE opening direction, respectively. Representative cross-sections illustrate the distribution of active strain across these archetypal half-graben basins, and enable comparisons with time-averaged deformation. ■

Geraldine Tijerina
University of Houston – Department of Earth and Atmospheric Sciences

Constraints on Central Atlantic Rifting Based on a Compilation of Low-Temperature Thermochronology Ages from Rifted, Conjugate Margins of the East Coast of the USA and Northwestern Africa



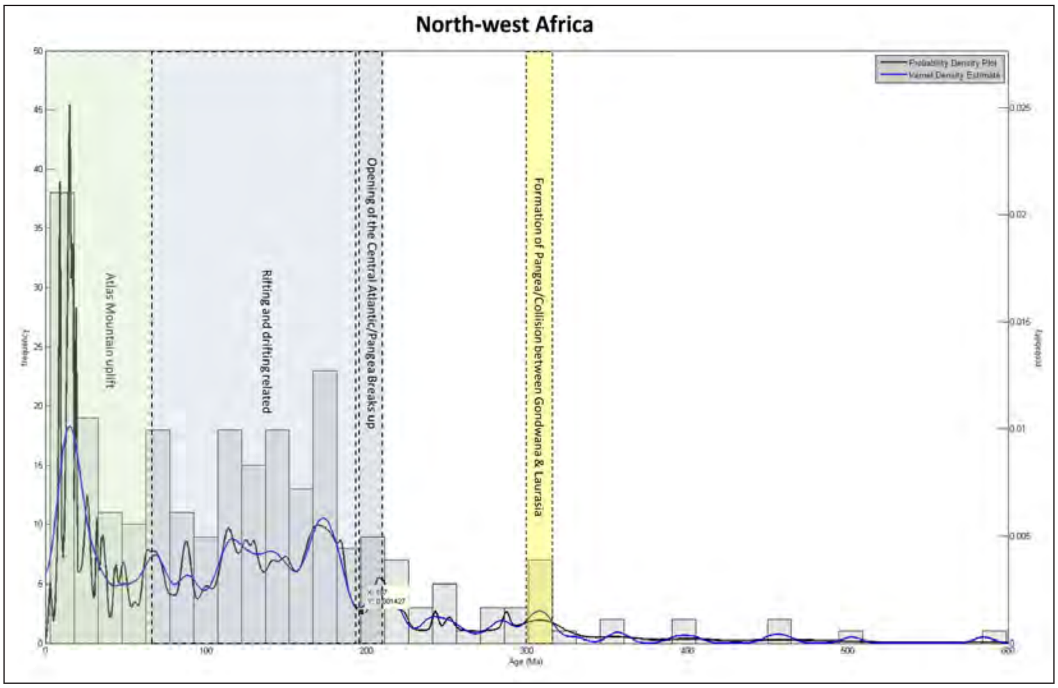
The Appalachian orogeny was the result of progressive, northeast-to-southwest closure of Gondwana (Africa and South America) and Laurasia (North America), and assembly of the Pangean supercontinent from the Ordovician through Permian time: 1) the Taconic orogeny of the northern Appalachian orogeny involved volcanic arc-continent convergence from Middle Ordovician into Early Silurian time (470-443 Ma); 2) the Acadian orogeny represented terminal collision of the North American and African plates during the late Devonian and Early Mississippian (375-359 Ma) and also had a more profound effect on the northern Appalachians; 3) progressive southwestward and terminal suturing of the two continents during Late Pennsylvanian to Permian time (299-252 Ma) led to widespread compression in the southern Appalachians during the Alleghany orogeny. During the Triassic and Jurassic, rifting extending the Appalachian-Atlas Mountains with the eventual formation of the modern Atlantic Ocean. The Anti-Atlas Mountains formed during the Alleghenian orogeny and were later rifted during the Triassic-Jurassic, Atlantic rift phase. The High Atlas Mountains formed by inversion of these rifts from the early Cretaceous to the present as the result of the collision between northern Africa and Spain. The major phase of uplift in the High Atlas Mountains occurred during the Alpine phase of deformation in the Oligocene-Miocene (30-20 Ma).

I used previous literature to compile Low-Temperature thermochronology (LTT) data from both the eastern US and northwest African margins which include apatite fission track (AFT), zircon fission track (ZFT), and helium methods (U-Th/He). A total of 440 samples were compiled on the North American margin and a total of 227 data samples from northwestern Africa. The DZ Stats software developed by Saylor and Sundell (2016) was used to generate time-density plots shown as histograms, and the natural neighbor interpolation tool in ArcMap was used to generate interpolated age surfaces. Analysis of the resulting age-histograms from the North American margin reveals, with large LLT age populations for the Taconic orogeny in the northeastern USA during the Ordovician (480-440 Ma), the Acadian Orogeny during the Devonian (398-359 Ma), and the terminal Alleghenian orogeny during the

Pennsylvania (325-260 Ma). A major exhumation phase of the Appalachians occurred in post-orogenic times from 200 to 150 Ma, and is believed to represent isostatic uplift and removal of thick, syn-collisional basins. Sample populations in northwest Africa show exhumation related to deformation of the Anti-Atlas Mountains and Cenozoic collision during the Alleghany orogeny (325-260 Ma), and early Cretaceous rift inversion (145-100 Ma). Samples from both margins show the shared Alleghany orogeny formed during terminal, continent-continent collision between Gondwana and Laurasia around 335 Ma and the late Triassic – Early Jurassic rifting between the two margins in the period of 236-199 Ma.

Biographical Sketch

Geraldine Tijerina is an undergraduate senior at the University of Houston-Downtown where she is studying Geology with a concentration in Petroleum. She is working with Dr. Paul Mann as part of the Conjugate Basins, Tectonics, and Hydrocarbons (CBTH) Consortium where she is managing the GIS database for thermochronology. Geraldine is the Treasurer for the AAPG-UHD student chapter and expects to graduate December of 2019.



JohnathanTorres
University of Houston-Downtown, Natural Sciences Department, Houston TX, USA
Stanislaw Nagy
AGH University of Science and Technology, Department of Gas Engineering, Krakow, Poland
SageMuttel, Dougles Syzdek, Janusz Grębowicz
University of Houston-Downtown, Natural Sciences Department, Houston TX, USA

Application of Raman Spectroscopy for Determination of Natural Gas Composition

Reservoir analysis plays a crucial role in both the characterization and operations of hydrocarbon exploration. Raman spectroscopy (RS) uses scattering light to measure low frequency vibrational and rotational values and can hypothetically be used to determine in situ natural gas composition.

RS displays specific gas intensity as a function of Raman shift or wavelength. Laser lights come into contact with variable concentrations of natural gas components and produces a specific amount of scattering light. The scattered light being produced is ultimately being compared to the original beam, which allows for the spectrum to be created. Upon analysis, each sample's individual spectrum at a given temperature is compared to one another and each peak is characterized by known natural gas values.

Upon concluding the analysis, it was found that temperature had little effect on the Raman shift value a given natural gas exhibited. It became clear the frequency or Raman shift remained steady and the real effect was seen in the intensity of the spectrum. This change ranges anywhere from a couple hundred to a very slight change in intensity. As well as a decrease in intensity a thinning in the peak also seems to occur in every sample. Overall the concentration of a certain gas does have an impact on the shape of the curve. It seems to depend mostly on the molecular structure of each gas. This simplistic spectroscopy technique can easily be used in individual determination of natural gas composition within gaseous mixtures.

Peak characterization and the description of the relationship of pressure and temperature on Raman shift is the core importance objective when considering identifying both in situ and predetermined gaseous mixtures. This serves to remind us in the exploration industry the simplicity of hydrocarbon determination. ■

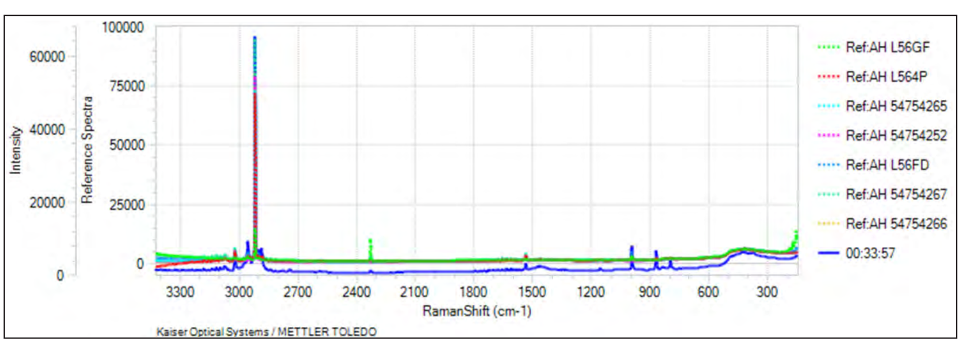


Figure 1. Full Spectrum of 8 natural gas composites

Biographical Sketch

Johnathan Torres graduated from University of Houston-Downtown where he received a bachelor's of science in Geoscience with a concentration in Petroleum Geotechnology and a minor in Applied Physics. Early in his undergraduate career, he embarked on his first research endeavor that analyzed core sediment from a local mitigation bank to determine anomalies present since urban development and natural disasters. Passionate about research he took on a field based study that focused on the lithostratigraphy and biostratigraphy of the Chinle Formation in central Utah. The study confirmed his interest in soft rock geology and encouraged Johnathan to take on a laboratory setting study that focused on the thermal analysis of hydrocarbon bearing shale for retorting purposes. Johnathan's involvement with UHD's geological faculty landed him a study abroad research opportunity in central Poland. While abroad Johnathan spent his time in the geophysical lab studying paleomagnetism on organic rich shale and in the gas engineering lab working with Raman spectroscopy on the determination of natural gas composition. Upon completion of his undergraduate degree, Johnathan landed a job in a geological service company, where he works in both the XRD and XRF lab to determine mineralogy of various exploration wells across the country. Mr. Torres has since then enrolled in Rice University's Subsurface Geoscience graduate program, where he continues his interest in research and learning industry applicable skills. Johnathan's goal is to one day intergrade both geochemistry and geomechanical data to aid 3D geological modeling for exploration and recovery processes.

Daniel Woodworth, Chengzu Wang
Department of Earth, Environmental, and Planetary Science, Rice University, Houston, TX
Nuhazein Mohamed
Department of Earth, Environmental, and Planetary Science, Rice University, Houston, TX
Geophysics Department, Al Neelain University, Khartoum, Sudan
Richard G. Gordon
Department of Earth, Environmental, and Planetary Science, Rice University, Houston, TX

Is Africa Stationary? – A New Look at an Old Question

Introduction

In a pioneering paper, Burke and Wilson (1972) proposed that the Africa plate came to rest relative to the mantle and began to rise in association with widespread intraplate volcanism at ~30 Ma. Burke (1996) further developed this hypothesis, attributing its above-average elevation to this cessation of motion, and raising several intriguing questions: Why did the African Plate come to rest over the mantle circulation? How are rifting episodes linked? Are these erupted rift volcanisms comparable over the past 30 Myr? How is the development of the East African Rift System (EARS) related to the reconstruction of the Indian Plate and to the formation of the Central Indian and Carlsberg Ridges? Do the Red Sea and the Gulf of Aden constitute part of the EARS? Understanding the evolution of the African Plate over the past 30 Myr, integrated with different kinds of relevant data, will enable a comprehensive approach in solving these queries.

Review of Africa from 65 Ma to Present

Africa from 65 Ma to 30 Ma: This interval was marked by a relatively quiet tectonic state of Africa, with high global sea level leaving Africa submerged since Late Cretaceous time (Sahagian, 1988), following Jurassic to Cretaceous rifting episodes.
From ~65 Ma to ~30 Ma, igneous activities, apart from those generated in Tristan and the Deccan Traps, were continuous only in northern Carmeroon. A potential hotspot track can be found in southern Ethiopia between 45 and 35 Ma (Ebinger et al., 1993), possibly linked to activity at Lokitipi (Morley et al. 1992). Its azimuth is roughly concentric with the Walvis Ridge trend, which might be considered a later manifestation of the same plume (Burke, 1996). The collision with Eurasia along the northern African Plate slowed at 65 Ma and accelerated at 35 Ma (Dewey et al., 1989).

Africa from ~30 Ma to ~15 Ma: Initial eruption in the main Ethiopian Rift was at ~30 Ma (Wolde Gabril et al., 1990), followed by rift-faulting episodes. Between 30 and 22 Ma, half-grabens developed south in Lokitipi and extended east in Turkana (Morley et al., 1992). A change in the eruptive composition in Kenya at ~16 Ma, from basalt to phonolite, is within the influential resolution of the Bitlis-Zagros collisional event. The initial rift development in the main Ethiopian Rift area has been assigned ages of 18 to 11 Ma (Mohr, 1983; Wolde Gabriel et al., 1990; Ebinger et al., 1993).

Africa from ~15 Ma to Present: At 15 Ma, rifting propagated southward from Afar into the main Ethiopian Rift, and the western rift initiated. It is possible that the development of these rifts and the new harrats of Arabia might have been related to the Bitlis collision. Formation of ocean floor in parts of the Red Sea, transform offset on the Dead Sea system, propagation of new ocean floor formation into the Afar region from the Gulf of Aden, and southward propagation of rifting from Turkana to form the Gregory (Kenyan) Rift, constitute the most radical changes in the EARS over the past 5 Ma.

Methods

Our analysis focuses primarily on refining the absolute motion history of the African plates over the last 48 Myr using new global plate motion models. Koivisto et al. (2014) used a global plate circuit to relate rotations between the Pacific Plate and its underlying hotspots, which rely on the clear hotspot tracks on the Pacific Plate, to a global hotspot frame. For ages older than 48 Ma, this global frame fails, likely due to flaws in the plate motion circuit, but since that age motion between hotspots has been only 2-6 mm/yr—slow enough that the hotspots can be considered to represent a global frame.

However, these Pacific-based rotations suffer from the uncertainty accumulated by rotating through the global plate motion circuit. Although they do provide useful constraints on the motion of the African plates, it would also be desirable to have a set of more specifically targeted rotations. Wang et al. (in prep.) calculate a new set of current absolute plate motions, HS4-SKS-MORVEL, combining data from both hotspot trends (e.g. Wang et al., 2017) and seismic anisotropy (e.g. Zheng et al., 2014). In combination with additional improvements in plate motion circuits, such as DeMets et al. (2016) and DeMets and Merkouriev (2016), which provide highly detailed relative rotations between Nubia, North America, and the Pacific over the last 20 Myr, we can attempt a detailed history of the absolute motion of the African plates (**Figure 1**).

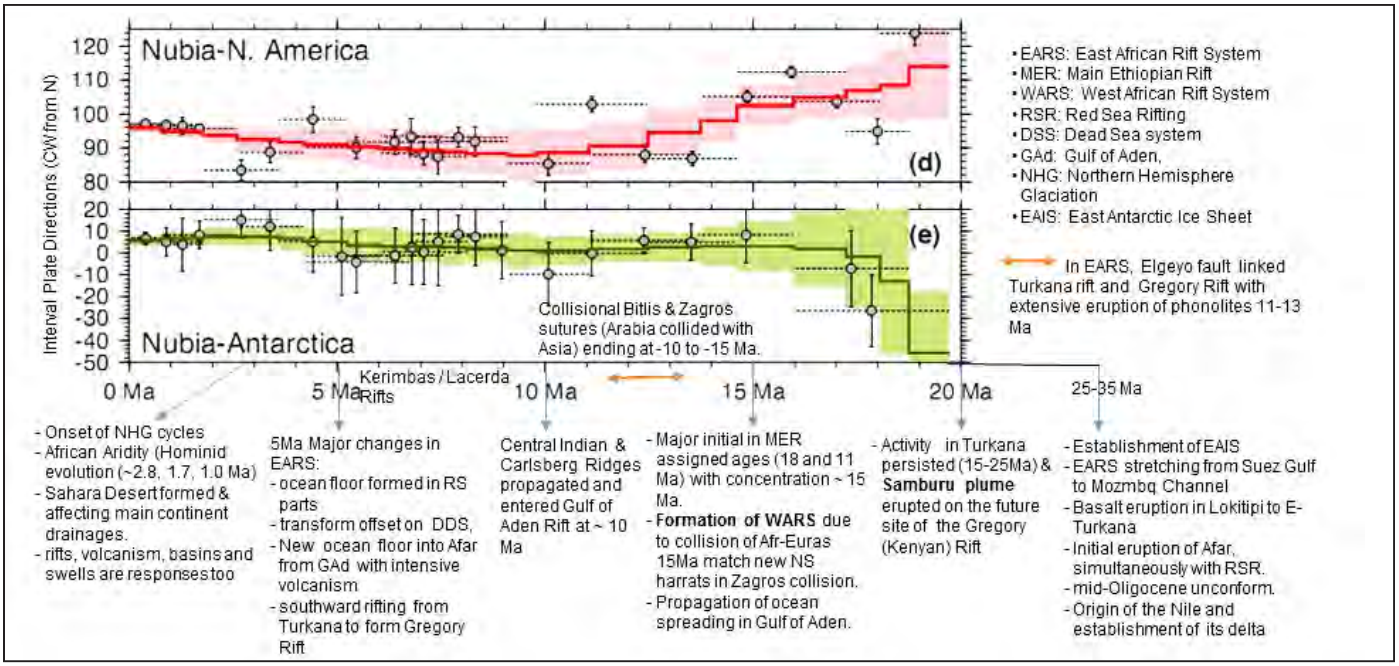


Figure 1. Major dated events that affect the African plate motion during the past 35 Ma [from Figure 7d & 7e DeMets et al. (2016)], where the interval plate directions (CW from N) gradually increase and abruptly decrease for both pairs respectively between ~17 and 20 Ma.

Initial Findings and Discussion

The rotations relative to the hotspots from Koivisto et al. (2014) agree well with the hypothesis proposed by Burke (1996). From 48-34 Ma, these predict steady motion of the African plates relative to the hotspots, with a notable slowdown between 34 and 20 Ma. For the past 20 Ma, the predicted motion between the African plates and the hotspots is insignificant.

HS4-SKS-MORVEL provides an even more precise insight into current absolute motions. This model predicts slow but still significant motion between Nubia and Somalia and the hotspots, with an RMS velocity of 11 mm/yr for the former and 15 mm/yr for the latter. Thus, both move slowly, but are not truly stationary—in contrast to the Antarctic and Eurasian plates, which both have motion so slow that it cannot be statistically distinguished from no motion at all. Figure 2 suggests an even more nuanced approach to answering the question of the stationarity of Africa. The pole of rotation of the Nubia plate relative to the hotspots actually lies on the Nubia plate near 14°N on the seafloor west of the continent. Thus at least one point on the Nubia plate is indeed stationary and nearby points move very slowly. As one moves away from this point, in particular to the southeast, the speed of the Nubia plate lithosphere increases monotonically such that the Somalia plate and the eastern edge of the Nubia plate are clearly not stationary relative to the hotspots and the deep mantle.

These combined models provide insights into the past and present motion of the African plates, and an opportunity to reexamine the Burke's seminal hypothesis—and its implications for the history of Africa over the last 48.

Biographical Sketch

Daniel Woodworth is a fifth-year PhD student in the Department of Earth, Environmental, and Planetary Sciences at Rice University in Houston, Texas. His current research focuses primarily on reconstructing plate motion and true polar wander through analysis of the shape of marine magnetic anomaly profiles, equatorial sedimentation rates and sediment facies, and secondarily on modelling strain rates distant from plate boundaries and implementing improved methods of estimating spreading rates at mid-ocean ridges.

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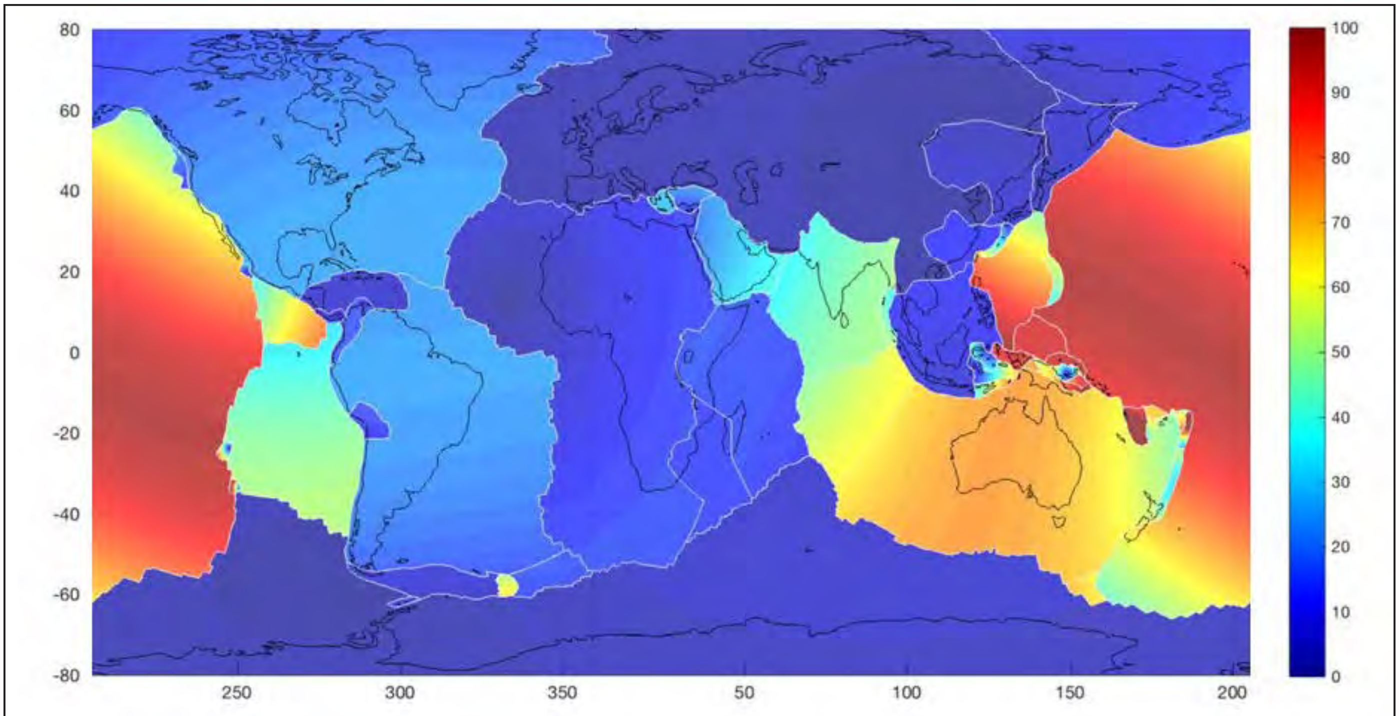

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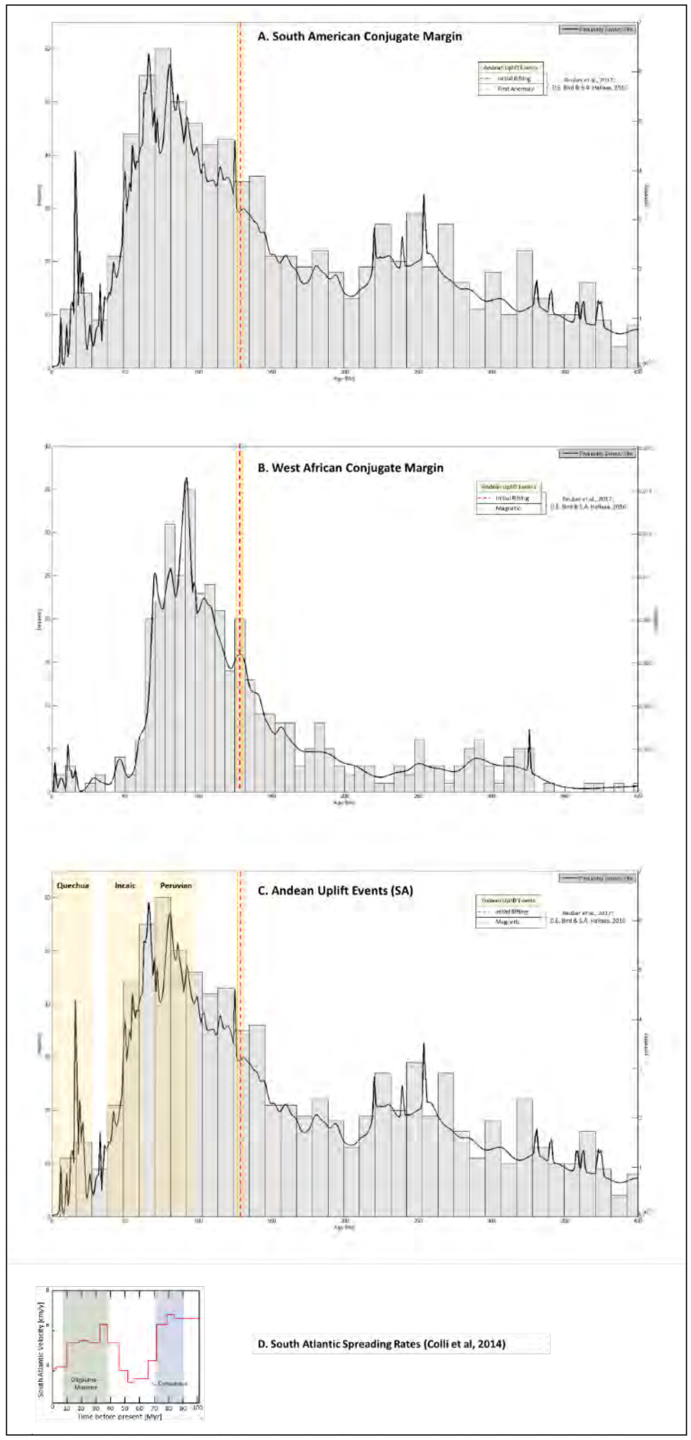
Omar Zavala
University of Houston – Department of Earth and Atmospheric Sciences

Rift History of the South Atlantic Ocean from Subsidence Histories of Offshore Wells and Low-Temperature Thermochronology (AFT) Cooling Ages from the South American and West African Conjugate Margins

Previous studies have determined the variation in South Atlantic spreading rates from the time of its initial opening in the latest Jurassic (144 Ma) to the present. All previous plate models agree on the timing for abrupt variations in spreading rate:

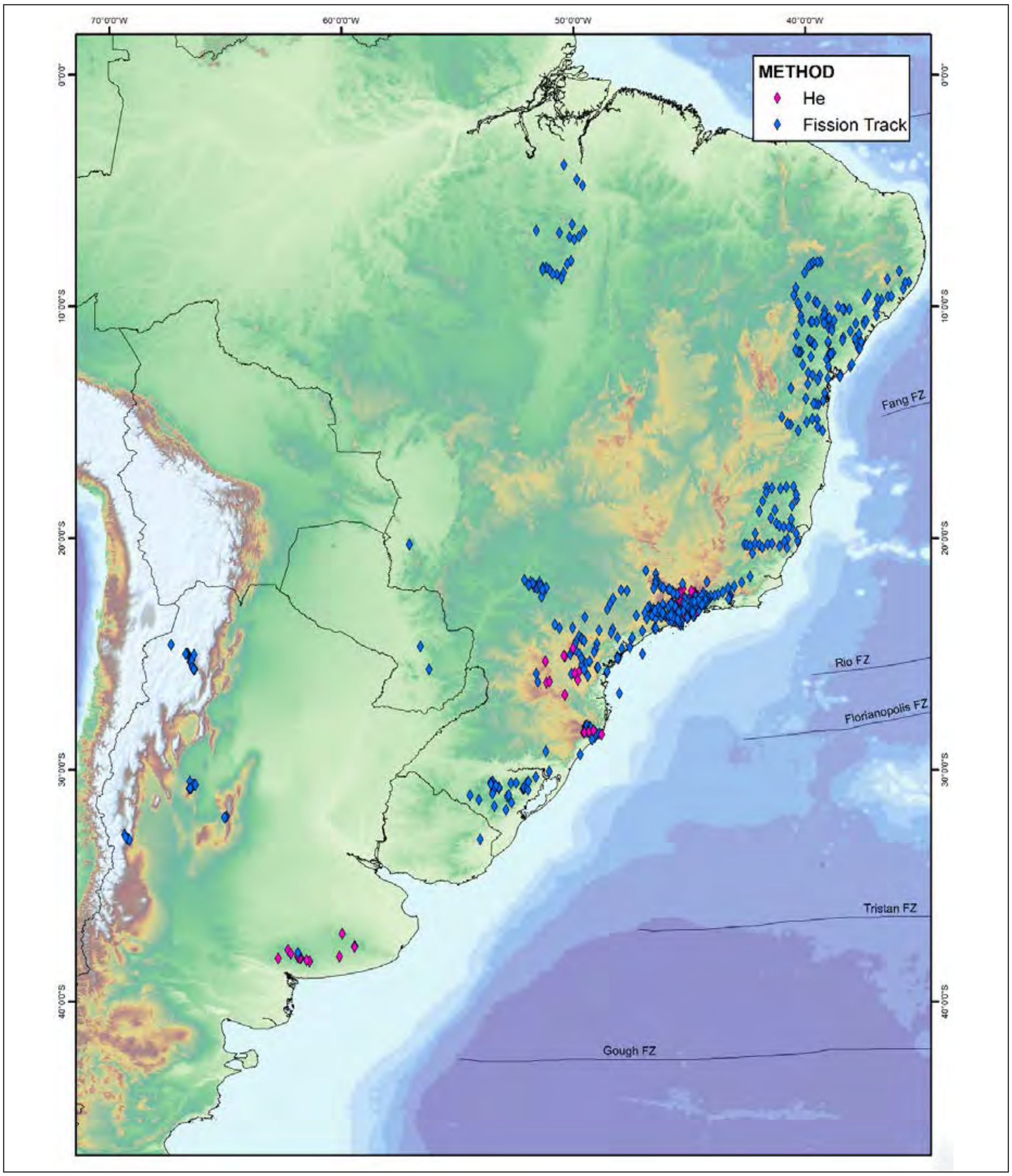
1. maximum spreading rates up to 7 cm/yr occur from the time of initial continental rifting from 150-120 Ma
2. to about 3 cm/yr. from 80-70 Ma;
3. rates remain constant before rising again to 6 mm/yr. in the Middle Eocene
4. then rates slow to a modern rate of 3.5 cm/yr (Colli et al., 2014).

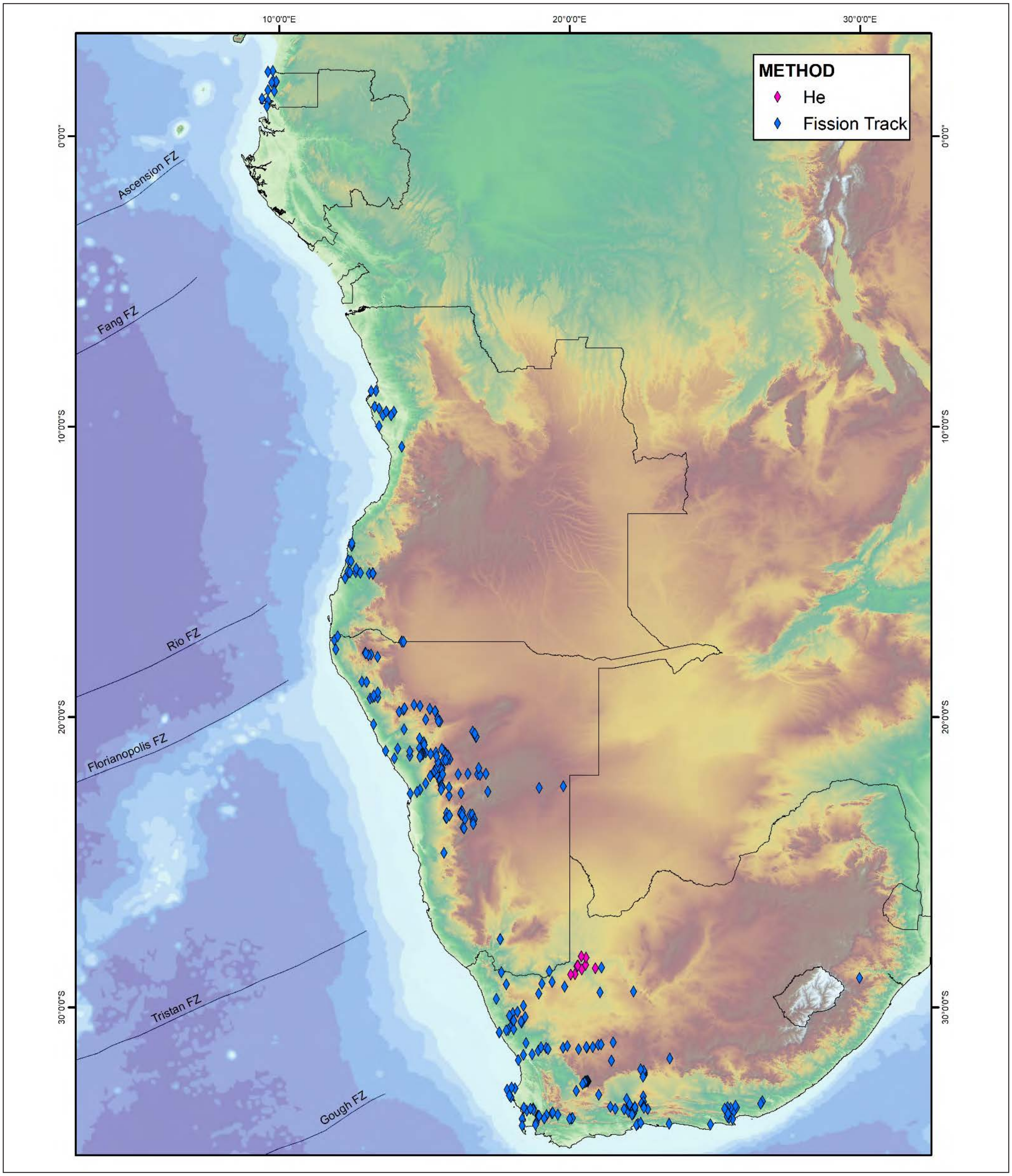


A simple, tectonic hypothesis is that periods of rapid spreading are expressed as widespread uplift of the passive margin and coastal areas that should be recorded both by the subsidence history of passive margin wells and the apatite fission track (AFT) cooling ages of near coastal rocks. To test this idea, I compiled burial-history plots of 26 passive margin wells on the two conjugate margins along with 1001 AFT ages from the South American coastal zone and 403 AFT ages from the West African coastal zone. Subsidence histories of the wells reveal the main rifting periods for the two conjugate margins and significant age differences for some conjugate, rift pairs (especially for the South Africa and southern South America conjugate margins). AFT ages for both conjugates were plotted as histograms using DZ Stats software developed by Saylor and Sundell (2016) and show a strong correlation with secular variations in spreading rates with denser clusters of cooling ages during periods of faster spreading (130-70 Ma). Andean orogenic events coincide with the high-density peaks of AFT ages in the late Cretaceous and in the Oligo-Miocene along the South American margin. The late Cretaceous peak of AFT ages on both margins may be a composite effect of continental rifting, the initial formation of oceanic crust, and the late Cretaceous, Peruvian, and Incaic orogenic events that affected the Andes. The lack of the younger age frequencies on the West African margin is consistent with the improbable transmission of compressive stress across the Mid-Atlantic spreading ridge. To add, the lack of Oligo-Miocene low-temperature ages on the West African margin and the lack of uplift in offshore wells is also not supportive of the hypothesis that faster spreading uplifted both conjugate margins by equal amounts.

Biographical Sktech

Omar Zavala worked as an undergraduate research assistant and GIS specialist for the Conjugate Basins, Tectonics, and Hydrocarbons (CBTH) project beginning in the spring semester of 2017. Omar graduated from the University of Houston with his Bachelor of Science degree in geophysics alongside a minor in mathematics. He completed his undergraduate senior research project on using subsidence histories of offshore wells and low-temperature thermochronology ages from the South American and west African conjugate margins to study the rift history of the South Atlantic Ocean. He currently works as a Field Geologist for RRC Companies in Austin, Texas.

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Marcus P. Zinecker, Paul Mann
Department of Earth and Atmospheric Sciences, University of Houston

Plate Tectonic Framework for Petroleum Systems of Atlantic Conjugate Margins: Northwest Africa-Eastern USA and Northeast South America-Equatorial West Africa

The continental Guinea Plateau and nearby Guinea fracture zone of offshore Guinea and Guinea-Bissau is a 100,000 km2 submarine plateau which lies astride the boundary separating the older, (Triassic-Jurassic to recent Central Atlantic Ocean to the north), from the younger, (Aptian-recent), Equatorial Atlantic Ocean to the south. As a result of this location between the two oceans, the Mesozoic tectonostratigraphy records west-northwest rifting of the Central Atlantic during the Triassic and early Jurassic and east-west rifting of the Equatorial Atlantic in the Cretaceous. The Guinea Plateau can be reunited with its conjugate, the 130,000 km2 submarine Blake Plateau along the southeastern margin of the USA by following the Guinea Fracture Zone and the Cape Verde/Jacksonville Fracture Zone across the Central Atlantic. Early rifting of this part of the Central Atlantic was accompanied by formation of Rhaetian-Hettangian (~204 MA to ~195 MA) salt basins along the Scotian/Moroccan and Carolina/Mauritania conjugate margins along with emplacement of thick, magmatic, seaward-dipping reflectors (SDR's) along both sides of the opening central Atlantic. Thinner SDR's and volcanic rocks of similar age were erupted during the rift phase of the northwestern African margin. For most areas of both conjugate margins, salt deposition ceased with the onset of seafloor spreading during the Sinemurian (193-190 Ma). Previous work has shown that Central Atlantic Magmatic Province (CAMP) volcanism took place over a 15 million year period, with two pulses of magmatism at 203 MA and 193 Ma. CAMP magmatic activity and lithospheric weakening likely played a major role in eventual continental breakup and the onset of seafloor spreading in the Central Atlantic. Rifting along the North American and African margins was overall symmetrical, but early accretion rates of mid-ocean ridges were much higher to the west than to the east, resulting in significantly more oceanic crust on the North American Plate (56%) compared to its African counterpart (44%).

South of the Guinea Fracture Zone, the Doldrums Fracture Zone connects the Guinea Plateau with its Equatorial Atlantic conjugate in northeastern South America, the Demerara Rise. This 60,000 km2 bathymetric high and area of continental and oceanic plateau crust is located offshore Suriname and French Guiana in northeast South America. The Demerara Rise and Guinea Plateau represent the final connection between the South America and Africa plates before Equatorial Atlantic rifting commenced in the Late Aptian. Following Jurassic rifting of North America from Gondwana, the Guinea Plateau and Demerara Rise formed a 15 to 30-km-thick passive margin. A period of thermal subsidence created accommodation space for the deposition of a 2 to 7-km-thick carbonate sequence of Late Jurassic-Early Cretaceous age, which thickens to the northwest. Rifting of Gondwana and the opening of the South and Equatorial Atlantic began in the Early Cretaceous, starting with the South Atlantic and progressing northwards. Seafloor spreading finally initiated between the Demerara Rise and Guinea Plateau by the Early Albian. The depositional histories of the Demerara Rise and Guinea Plateau diverged following their Early Albian separation. The Demerara Rise subsided quickly, accommodating deposition of thick marine shales, including black shales from the OAE 1 and 2 events. Throughout the Late Cretaceous and Cenozoic, deltas and shorelines prograded and retrograded onto the Demerara, creating interbedded, reservoir quality sands as well as shales. On the Guinea Plateau, a thin layer of volcanic rocks was covered by predominately marine shale deposition (including black shales from the Cenomanian-Turonian OAE 2 event, followed by deltaic progradation in the Late Cretaceous, and finally carbonate deposition in the Cenozoic. ■

Biographical Sketch

Marcus Zinecker is a first year Geology PhD candidate at the University of Houston, working with Dr. Paul Mann as part of the Conjugate Basins, Tectonics, and Hydrocarbons (CBTH) Consortium. He graduated Cum Laude with BS degrees in Geology and Geophysics in 2014 from the University of Houston. His PhD research includes the tectonostratigraphy and hydrocarbon potential of offshore West Africa and its conjugate margins, as well as the effect of two-phase rifting on the subsidence history and hydrocarbon generation potential of the southeast Gulf of Mexico. He expects to graduate in May of 2020.

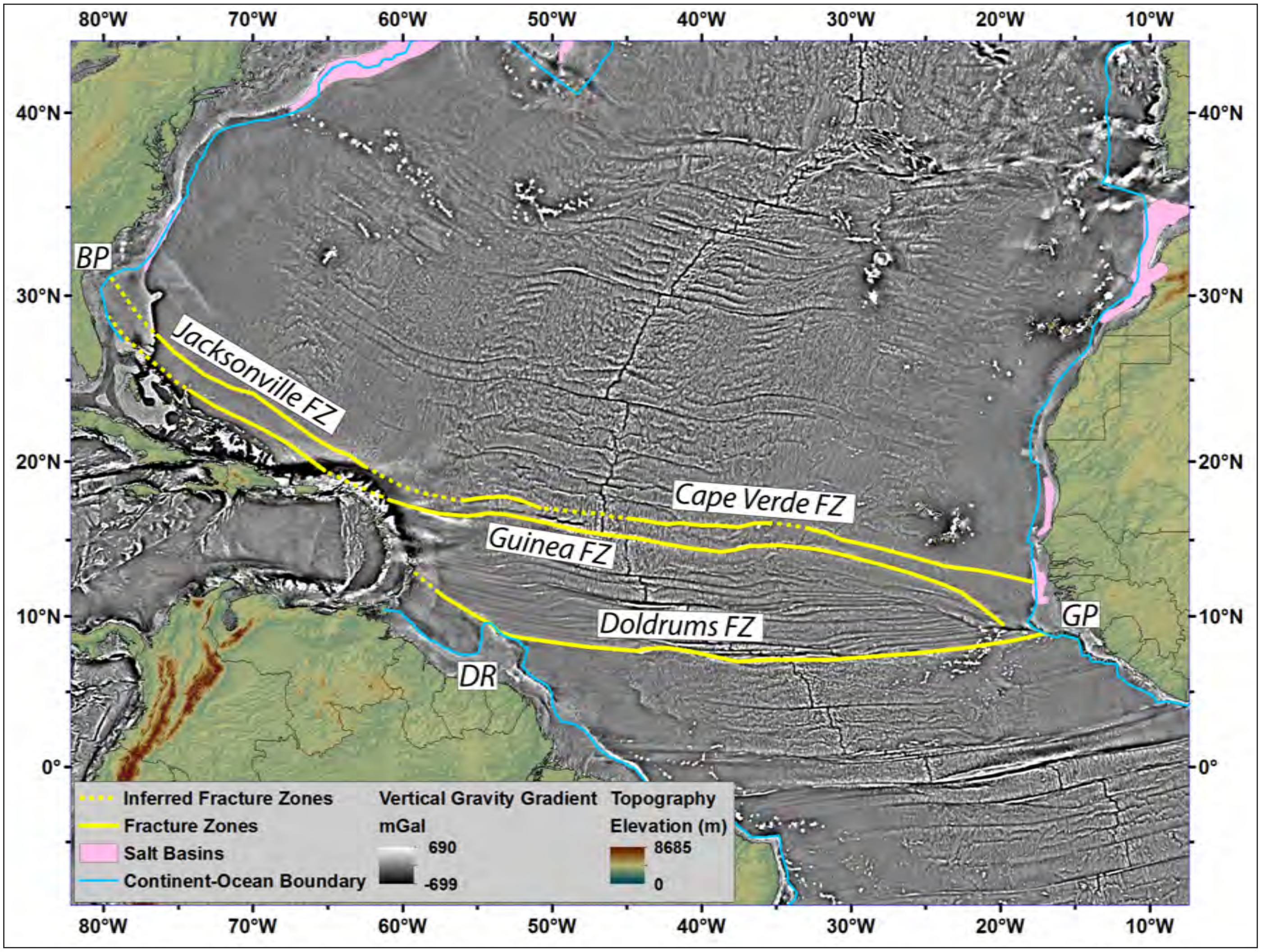

Figure 1. Overview of the Central and Equatorial Atlantic ocean and fracture zones that serve as piercing points for the cojugate margins of the Guinea Plateau (GP), Blake Plateau (BP), and Demerara Rise (DR). Continent-ocean boundaries from [Brune et al., 2016], salt basin locations from [Biari et al., 2017], vertical gravity gradient from [Sandwell et al., 2014]. Land topograpahy is in meters.

Notes

Notes

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