Modelling Sedimentary Basins and their Petroleum Systems

3-4 June 2010

The Petroleum Group would like to thank BP, Eni and ExxonMobil for their support of this event:

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Thursday 3 June

Keynote Speaker: How to Model the Thermal Evolution of Extensional Sedimentary Basins and Passive Margins

Nicky White, *Cambridge University*

It is widely agreed that many basins and margins form by stretching of continental lithosphere. Nevertheless, there is considerable disagreement about the way in which stretching is accommodated at depth. Does lithosphere ever stretch uniformly? If depth-dependent stretching does occur, what form does it take? The answers to these general and important questions have profound implications for the structural, thermal and magmatic evolution of margins. Ten years ago, the hydrocarbon industry began to explore deep-water margins in earnest. A quantitative understanding of the way in which these highly stretched margins develop will play a central role in reducing exploration risk (White et al., 2003). Two contrasting strategies have been used to address the problem of depth-dependent stretching. One approach exploits increasingly sophisticated dynamical models, which assume that body forces act upon the rheological framework of the lithosphere to produce deformation. These forward models have two drawbacks. First, the rheological framework is based upon extrapolating the results of laboratory experiments by over ten orders of magnitude and so is poorly understood. For example, it is still unclear whether the strength of the lithosphere is controlled by crust or by lithospheric mantle. Secondly, dynamical algorithms are slow and the more useful inverse problem cannot yet be posed. An alternative approach has concentrated on developing simple kinematic algorithms which are fast enough to be used as the basis of inverse modelling. These inverse algorithms seek patterns of deformation which generate the best possible match between model and observation. We have developed a flexible inverse model which assumes that the lithosphere deforms by spatial and temporal variation of the strain rate tensor. In this kinematic model, strain rate can vary with time, with distance across the margin, and with depth. Crucially, and in contrast to other groups, we make no assumptions about the way in which strain rate varies with depth. Instead, we invert for the existence and form of depth dependency. This strategy is therefore a logical generalization of our previously published work (Bellingham & White, 2000). To ensure computational speed and conservation of mass, we employ a spectral approach. In order to invert, we must assume an initial distribution of strain rate. This starting model is calculated by setting the thermal expansion coefficient of the lithosphere to zero and by assuming that material does not move sideways. The algorithm then seeks the smoothest spatial and temporal distribution of strain rate which yields the smallest misfit between predicted and observed subsidence and crustal thinning profiles. Different search algorithms have been tested and we conclude that the conjugate gradient method is a suitably efficient and stable search engine. This general inverse model has been tested on synthetic datasets which display different patterns of depth dependency. In general, depth dependency is recoverable when its existence is manifested by changes in the pattern of subsidence. We have also modelled datasets from basins (e.g. North Sea, Gulf of Suez) and from margins (e.g. South China Sea, Black Sea, Brazil-Angola). The results from these regions suggest that depth dependency is mild and that lithosphere stretching is largely, but not completely, uniform. An important exception is the Newfoundland-Iberia conjugate margin system which exhibits marked depth dependency for reasons which are not clearly understood (Crosby et al., 2008). Our inverse algorithms are flexible and powerful tools for mitigating exploration risk at deep-water margins where stretching history is poorly known. These algorithms can also be used to calculate thermal histories at margins (Jones et al., 2004).

3D Advanced Basin Modelling Workflow

M. Thibaut, I. Faille, A. Jardin, *IFP, Rueil Malmaison, France*

Basin modelling tools aim at giving a qualitative and quantitative description of petroleum systems. To enhance oil and gas recovery, they need to improve the fault description in structurally deformed environments.

This paper presents a 3D basin modelling workflow with the ongoing research on volumetric restoration and basin scale simulation adapted to a faulted and thrusted area.

Methodology

An integrated workflow that combines a variety of expertises from geophysics to geology for petroleum system evaluation has been developed. This workflow is based on a flow chart. The first step is the building of the structural model at present day. Second step builds the history of the structural deformation of the basin. Last step is the forward simulation in pressure, maturity coupled with the structural deformation. This step implies the development of a new basin simulator taking into account folded and faulted structures.

First studied area

Our integrated approach has been tested on the Gaspé belt. The Gaspé Peninsula is located in the northern part of the Canadian Appalachians.

Field observations and timing relationships within the fault zone provide evidence of thrusting during Ordovician times, normal faulting during the Silurian and Early Devonian times and dextral strike-slip movement during the Middle Devonian Acadian Orogeny. To the south, the Causapscal fault is interpreted as a backthrust.

Results

In this area of foothills, the building of the 3D model is complicated because of the shadow zones on seismic images. The structural paleo-models are generated using Kine3D-3, a volumetric restoration. From this approach is generated a suitable evolutive mesh for the thermal history, the deformation of rock properties such as sedimentation, erosion and compaction, and fluid transfer.

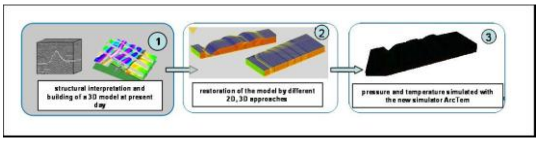
Last step of the 3D adapted basin workflow is the coupling the structural deformation with the forward simulation. Results exist at different significant time steps: a) at present day after the Quaternary erosion, b) after the deposition of the youngest rocks of the syncline, c) after the compressive phase of the Saint Leon formation, d) during the extension phase after the deposition of Doublet Val-Brillant – Sayabec, the oldest formation.

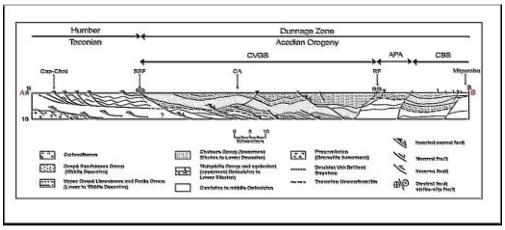
Second case study

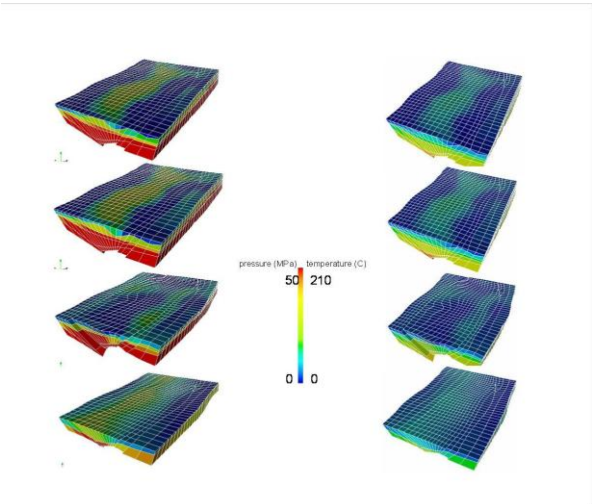
The second application is a high-resolution scaled sandbox model designed to investigate the precise kinematics during the growth of a normal fault system. We apply the same workflow as for the previous example, and results on a simplified model in temperature and overpressure are been simulated.

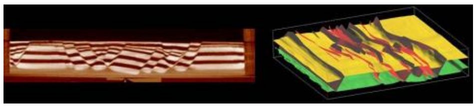
Conclusion

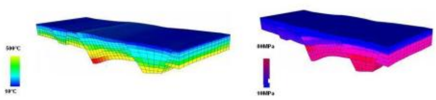
We have presented the main steps of an integrated workflow for basin modelling studies in a deformed context in 3D on two case studies. The first results with the new calculator ArcTem linking a dynamic geometry with a fluid flow simulation are very encouraging, because they demonstrate that a solution exists for 3D future petroleum system evaluation studies in complex areas.











The Role of Crust and Mantle in the Reconstruction of Heat-Flow in Sedimentary Basins, an Example from the Taranaki Basin, New Zealand

K.F. Kroeger, K.J. Bland, M. Fohrmann & R.H. Funnell, *Institute of Geological and Nuclear Sciences, PO Box 30368, Lower Hutt.*

A typical approach to modelling the influence of crustal- and lithospheric-scale processes on heat-flow in sedimentary basins is to use standardised models of heat-flow evolution through time, based on the regional tectonic setting and type of underlying crust. Our study in the Taranaki Basin on the west coast of the North Island of New Zealand provides an example where this generalised approach is inadequate to reproduce the observed present-day heat-flow pattern. Surface heat-flow calculated from numerous exploration wells varies between 46 and 83 mW/m^2 within a distance of 200 km. An explanation for this variability, apart from sedimentation and erosion effects, lies in the compositionally and structurally heterogeneous basement of the Taranaki Basin. The crust consists of a series of terranes ranging from continental, granite-dominated Gondwana crust in the west to sedimentary, continental and oceanic arc related sedimentary rocks in the east with a series of more mafic plutons inbetween. The calculated present-day heat productivity of these units varies between 3.3 $microW/m^3$ in Palaeozoic granites and 0.85 $microW/m^3$ in mafic plutons. In addition, during the Tertiary the Taranaki Basin has progressively evolved from a rift margin to a hybrid intra-arc/back-arc basin/fold-thrust belt in response to propagation of Pacific Plate subduction beneath the Australian Plate in the region. This plate boundary development has had considerable impact on Taranaki Basin subsidence and exhumation, crustal thickness, and mantle heat advection.

We have mapped basement composition and sedimentary architecture from seismic data and, using mid- and lower-crust analogues exhumed in the South Island of New Zealand, have constructed a Petromod model of the crust and the sedimentary cover of the Taranaki Basin. Model results indicate that crustal thickening in the foreland basin phase resulted in considerable crustal-scale cooling in the south-eastern part of the basin. The north-eastern part of the basin, on the other hand, has been influenced by mantle heat-advection and related magmatic and hydrothermal processes. An exhumation event in the Late Miocene resulted in a modelled transient increase in surface heat-flow in parts of the basin of up to 10 mW/m^2. The influence of the variability in crustal heat generation on surface heat-flow, however, is modelled to be as large as all other overall effects taken together, being as high as 20 mW/m^2. In basins situated on a structurally complex and heterogeneous crust such as the Taranaki Basin, it is therefore vital to consider crustal-scale processes and composition when assessing hydrocarbon generation potential.

Seismic Stratigraphy and Integrated Reverse-Basin and Forward Stratigraphic Modelling of the Southern Brazilian Margin (Campos, Santos and Pelotas Basins)

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An integrated approach of sequence stratigraphy, two-dimensional reverse-basin and forward stratigraphic modelling have been carried out on three seismic reflection profiles (300-340 km long), located in the Campos (CB), Santos (SB) and Pelotas (PB) basins, offshore Brazil. Twenty-one calibration wells provided lithologic and bio-/chronostratigraphic correlation ties for the Barremian to Holocene basin fill. Main results for each of the studied basins include: (i) identification of twelve to fourteen seismo-stratigraphic units (3-50 m.y. of duration), containing smaller-scale stacking patterns and key stratigraphic surfaces; (ii) recognition of six major subsidence trends (ST1 to ST6) controlling the Barremian-Holocene basin development; (iii) genetic subsidence model in time (i.e., thermo-tectonic, flexural- and compaction-induced components); (iv) analysis of processes controlling accommodation space evolution and basin infill: subsidence, eustacy and sediment supply (Fig. 1); (v) impact of basin evolution stages and plate-tectonic reconfigurations on basin architecture: Barremian syn-rift, Aptian syn-rift sag in CB, SB or post-rift in PB, Early-Middle Albian postrift and Middle Albian-Holocene drift. Forward stratigraphic modelling simulates the basin development and predicts the sedimentary distribution in time (Fig. 2). It incorporates a comprehensive set of algorithms, including: lithologies, ages and geometry of seismo-stratigraphic units, flexural rigidity of the crust, eustatic sea-level and quantitative reverse modelling results of subsidence, paleobathymetry and sediment flux.

After Barremian syn-rift brittle extension had ceased (subsidence trend ST1), depth-dependent lithospheric extension in the CB and SB controlled the syn-rift sag stage (trend ST2). Fault-bounded depocenters expanded; lacustrine environments evolved to salt basins in the Late Aptian, prior to continental break up. In the PB, Barremian syn-rift volcanism (SDRs) and crustal thickening preceded post-rift Aptian clastic progradation in open marine environments. During the Late Cretaceous drift stage (ST3), decreasing subsidence characterized the thermal phase of “passive margins”. Long-term retrogradation in the CB and PB contrast with progradation in the SB led by higher sediment supply. During the Tertiary (ST4-ST6), flexural-induced subsidence controlled decreases and increases in accommodation space. Subsidence/uplift trends are highly variable between basins and along the shelf-basin transition. These variations are related to changes in sediment flux and resulting accommodation, far-field stress and thermal re-adjustments of the crust. Salt deformation in the CB and SB was also a major control on sedimentation patterns. In the PB, where the salt succession is absent, the basin development was largely controlled by differential flexural subsidence. Results of forward stratigraphic modelling can be compared with the initial seismo stratigraphic interpretation and previous quantitative analysis; it allows to control and modifies existing sedimentary genetic models.

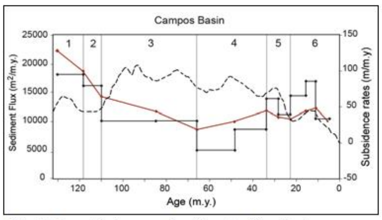

Fig. 1. Quantitative results of controlling factors on accommodation space evolution, Campos Basin.
Red line: total subsidence; black line: sed. flux; dashed line: eustatic sea-level (Hardenbol et al., 1998)

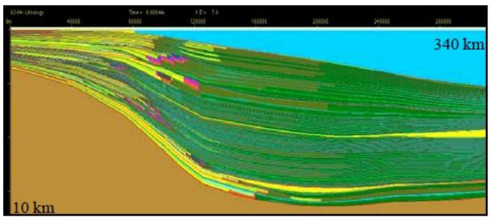

Fig. 2. Forward stratigraphic modelling, Pelotas B. (130-0 Ma)
Predicted lithofacies distribution
Lights (sandstones, siltstones, limestones); green (shales)

Petroleum Systems Dynamics of the Shah Deniz Field in the South Caspian Basin

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The South Caspian Basin represents an extremely young petroleum system in which over 8 kilometres of sediment have been deposited in the past 6-10 million years. Within the last 1-2 million years sediment deposition rates increased up to 3 kilometres. These high deposition rates have pushed the sedimentary section into significant disequilibrium with respect to the evolution of temperature and pore pressure as well as the generation and migration of hydrocarbons. The basin dynamics are expressed in:

(1) Rapid, vertical and lateral pressure changes in the sediments that limit the capacity of seals to build and preserve petroleum columns and present challenges for well planning and execution.
(2) Low temperature gradients which delay petroleum generation from the source rock intervals and slow down diagenetic processes in the reservoirs.

In the South Caspian the Miocene Maykop Source Rock series is overlain by the Pliocene ‘Productive Series’ (PS) which consist of world-class reservoir systems and lacustrine shales. This sedimentary sequence is strongly layered at the scale of meters to hundreds of meters. Structural events during the Pliocene resulted in the creation of large anticlines with significant relief and local surface exposure of reservoir/aquifer intervals on the basin margin due to uplift. Pressure observations from wells in the widespread reservoir sequences of the lower PS show that overpressure is increasing towards the basin centre.

The large Shah Deniz structure developed as a doubly plunging anticline over the last 3 Ma, with approximately 2km of vertical relief and 360km^2 of four-way dip closure. From the extensive drainage area around anticline petroleum migration was focussed for considerable time into the core of the structure. A recent, large scale pressure regression event created seal capacity, and thus the hydrocarbon trap within the reservoir units which created significant petroleum column heights for a number of reservoirs.

3D Basin Modelling studies were the key to understand the fundamental controls on pressure distribution and the capacity to build hydrocarbon columns in Shah Deniz. The complex interaction between the 3D connectivity of high permeability sediments (aquifers) and the 3D architecture of the low permeability sediments (aquitards) are best understood by fluid flow simulation techniques. Our Basin Modelling work links the observation of pressure regressed reservoirs to the phenomena of a hydrodynamic aquifer in the most recent geologic history. The complex distribution of regional aquifer pressures around the Shah Deniz Structure is felt to explain the hydrocarbon column heights as well as the fluid contact variations in the field.

Keynote Speaker: Geophysical Evidence for Highly Focused Fluid Flow in Sedimentary Basins

J. Cartwright, *3DLab, School of Earth, Ocean and Planetary Sciences, Cardiff University, Main Building, Park Place, Cardiff CF10 3YE, Wales, UK*

Modern 3D seismic has opened a high spatial resolution window into a number of subsurface processes, but perhaps none more so than into mechanisms contributing to subsurface fluid flow regimes. There is a diversity of seismic expression of fluid flow, arising either from the change in acoustic properties due to changes in the pore filling fluid (or cement), or from the damage to the acoustic layering resulting from the fluid flow (hydraulic fracture, liquefaction, fluidization). In this presentation, I show examples of both: firstly, how amplitude anomalies related to gas or cements can provide clues as to migration pathways, and secondly how vigorous fluid flow is associated with propagation of natural hydraulic fractures on a range of scales, but all under conditions of extreme fluid pressure gradient.

Seismic amplitude is sensitive to the presence of free gas, through its impact on both velocity and density of most sedimentary rocks. Free gas is thus easily detected with seismic data in the shallow sedimentary realm. Examples are presented showing how methane accumulations appear in three dimensions, and how their spatial context with respect to structure and lithofacies can be used to explore the possibility of different migration pathways.

Subsurface fluid pressures are only very rarely known to approach the present day lithostatic gradient, but evidence is presented here that supralithostatic fluid pressures have existed in many sedimentary basins in the past. The evidence comes from: (1) the widespread occurrence of development of sandstone intrusions with a sill-like geometry, and (2) fluid expulsion pipes ascending >1km from synclinal regions and homoclinally dipping slopes. The sandstone sills can be up to 2km in diameter and >100m thick, and form interconnected conical networks ascending over 1000m through ultra-fine ‘sealing’ sequences, providing pathways for subsequent highly focused vertical fluid flow. It is argued here from the classical mechanics of sheet intrusions that sandstone sills of this scale can only be sourced from a pressure compartment (with a major net sand component) that has pore fluid pressure in excess of lithostatic. The fluid expulsion pipes are typically 50-100m in diameter, with cylindrical geometry and with circular to elliptical appearance on slice imagery. They can be >2000m tall, and are associated with hydrocarbon anomalies on seismic data. They feed surface or palaeo pockmark craters, indicating a significant fluid flux was in transit along the pipes, either during their formation, or over subsequent periods.

Forward Modelling the Miocene Stratigraphy of an Unconventional Basin Centred Hydrocarbon Play, Pannonian Basin, Hungary

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The trapping mechanism of a continuous basin centred tight hydrocarbon play depends upon both the reservoir quality and the geometry of the reservoir and potential seal horizons. To aid the understanding of the depositional system and stratigraphic architecture a Dionisos forward model was built to simulate the fill of the Mako-Trough and Bekes Basins of the Pannonian Basin of Hungary with the objective of integrating observations made from wells and seismic and investigate plausible stratigraphic scenarios.

The Pannonian basin was formed in the early to middle Miocene by back-arc extension behind the Carpathian orogenic belt. The basin is surrounded by mountains on all sides which are pre-Miocene in age. The basement consists of Palaeozoic successions and Mesozoic Tethyan carbonates. The region underwent WSW-ENE extension along normal faults, forming half grabens. This study focuses on two half-grabens, the Mako Trough and Bekes Basin. The basins are filled with Miocene through Pliocene post rift sediments, with only a thin Miocene syn-rift succession, sourced from the Palaeo-Danube and Palaeo-Tisza Rivers. The fill consists of deepwater lacustrine marls and locally sourced clastics (Endrod Formation) overlain by turbidites (Szolnok Formation), slope deposits (Algyo Fm), delta front (Ujfalu Fm) and alluvial plain (Zagyva Fm).

Seal continuity and stratal connectivity are key to the potential trap risks and data from the basins and analogues suggest a distal distributive lobe dominated system dominates Szolnok deposition with extensive lateral mudstones defined as maximum flooding surfaces from the downlap surface in their correlative toe of slope settings. Pressure data from wells drilled indicated that these surfaces might be important pressure cell boundaries. Data from wells also shows two provenances for the sandstones in the Szolnok with some evidence for differential reservoir quality. The mix of these two sediment sources and their presence and or absence was also seen as a key risk.

Key observations from the stratal geometry observed from seismic include two sources for deltaic clinoforms illustrating high frequency aggradational-progradational cycles punctuated by infrequent episodes of major to the basin down step of the depositional system associated with incision Dionisos was used iteratively to alter sedimentation rates and timing, compaction, subsidence, lake level to recreate these geometries, and thereby gain insight into the process of filling the basin.

These insights were used to understand the potential trap geometry; likely reservoir and seal layer continuity and their impact on hydrocarbon migration and formation pressure. The timing of infill and mix of the two provenances from the Palaeo-Danube / Tisza systems was also examined.

Application of Stratigraphic Forward Modelling to Exploration Problems

Peter Burgess, *Shell International E&P, Rijswijk, The Netherlands*

The first numerical stratigraphic forward models (SFMs) applied to hydrocarbon exploration were developed during the 1980s. Since then models have increased in sophistication and, debatably, realism, with development of 3D process-based models of depositional systems spanning siliciclastic and carbonate deposystems and ranging from terrestrial to deep-marine environments. Three basic approaches exist for application of SFM; best-fit models, preferably generated via an inversion process, scenario modelling, and experimental modelling. However, in general SFM technology remains immature and is rarely applied compared to charge modelling methods.

Best fit modelling is in most respects the least useful of the three methods in exploration applications because, like other non-numerical modelling methods, it suffers from issues of model uniqueness, and the tendency to over-interpret a single model result that may well be based on sparse data, and dubious implicit assumptions. Inversion methods help to address this problem by addressing issues of non-uniqueness and sensitivity, and adding important objectivity and quantitative rigour.

Scenario modelling has links to aspects of inversion methods and is particularly useful in exploration applications where data are sparse and a variety of subsurface possibilities exist. It has the advantage of being able to investigate sensitivities and the stratal consequences of various different assumptions. Multiple model runs can quickly investigate the range of possibilities and results can be combined into easily interpreted maps, for example reservoir presence maps.

Experimental modelling is rarely of direct use in exploration problems, but results from this method may be very useful in developing knowledge and understanding of how stratal systems operate. This knowledge and understanding can then be applied to subsurface prediction. Examples include investigation of carbonate ramp dynamics and shelf-edge delta formation.

Coupling 3D Structural Restoration with Stratigraphic Modelling in Rifted Margins, Suez Rift, Egypt

A. Barrois, **S. Rohais**, D. Granjeon, J-L. Rudkiewicz, M.C. Cacas, *IFP, France*

IFP is developing two innovative simulation tools applied to basin modelling. The first one is a backward volumetric restoration (Kine3D): its output is a set of 3D complex-architecture geo-models of the basin under consideration at different times through geological history. The second one is a forward stratigraphic model (Dionisos): it simulates sedimentologic processes through geological times and provides the user with a full 3D description of the stratigraphic architecture of the basin at different times.

The aim of this project is to integrate the two applications in a single workflow in order to get a better characterization of the evolution of sedimentary basins, thanks to taking interactions between tectonic and sedimentary processes into account.

The project is based on the well documented case study of the Gulf of Suez where cross-sections, maps and wells are available.

The modelling workflow was conducted as follows:

1. four stratigraphic correlation cross-sections were realised from well-logs, in order to provide a reference 3D stratigraphic model;
2. the structural 3D model was built with Gocad by integrating all the relevant data;
3. the structural geo-model at Present was restored with Kine3D-3;
4. then, subsidence maps and horizontal displacements calculated with Kine-3D at the bottom of the syn-rift sediments were exported to Dionisos in order to build a stratigraphic model constrained by these tectonic deformations. Different hypotheses on location and volume of sediment input at the basin boundaries were tested in order to fit the model with observed data.

This project illustrates a combined approach integrating structural volumetric restoration with stratigraphic modelling in order to build 3D basin models which take into account interactions between tectonic and sedimentary processes. Reservoir and seal distribution, as well as burial history are finally much better constrained, providing more consistent input for a next step of petroleum systems modelling.

3D Structural Restoration and Forward Turbidite Modelling to Predict Sand Deposition Patterns on Restored Palaeo-Bathymetric Surfaces: A Case Study in the North Sea

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Modelling ancient turbidity flow deposits on palaeosurfaces is a key method to estimate depositional patterns of sand deposits in areas where no seismic attribute or high-quality isopach maps are available. We describe here a methodology to sequentially restore the present-day horizons up to the time of turbidite deposition and predict areas of sand deposition on the obtained palaeoseafloor as well as the preferential sediment-source locations. We present an example of restoration in an extensional tectonic setting in the North Sea which integrates 2D and 3D structural restoration with forward modelling of turbidity flows.

The first part of the workflow is to establish the palaeo-geometry at the time of deposition of target sand reservoirs. Restoration of 2D seismic lines is performed by sequential backstripping and restoring up to the desired palaeosurface to determine transport direction and deformation style in the study area. Restoration and back-stripping parameters can be fine-tuned in this stage as well as the sequence of deformation events. Then the same workflow needs to be applied to 3D surfaces in order to obtain palaeo-bathymetric surfaces at the time of reservoir turbidites deposition. For this we use geometric and geomechanical algorithms available in Midland Valley's software Move to restore the 3D surfaces.

Forward modelling of turbidity flows and sediment deposition patterns is then performed on the obtained palaeobathymetry using 4DSediment software. A multiple scenarios approach allows to assess the influence of the input parameters, such as: flow dimensions, volume, direction and origin of the flow and grain properties. Additionally, a Monte Carlo approach was used to find a set of parameters that produces a flow which gives results closest to the available well data in terms of sand fraction and deposit thicknesses. The paleaoseafloor and the modelled sediment deposits can then be forward modelled to their present-day position to estimate the position of present-day sand reservoirs. The presented workflow therefore provides powerful tools to identify potential sediment source location and preferential areas for sand deposition in zones of poor seismic definition and away from existing wells.

3D Forward Modelling of Carbonate Platform Sedimentology and Diagenesis

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Forward sediment models offer considerable potential for reducing the uncertainty in prediction of reservoir quality and bridging between seismic and well-scale data to populate geologic models. CARB3D$^+$ is a 3D forward model for simulation of the sedimentary architecture of isolated carbonate platforms, and the distribution of porosity and permeability as a function of both depositional and early diagenetic processes. The model includes depth-dependent sediment production in four carbonate factories, wave-driven sediment entrainment and transport by currents and by gravity on angle of repose slopes, for user specified sea-level curves and subsidence rates. Prediction of depositional porosity is based on the proportion of coarse and fine grains, and primary permeability is derived from the porosity using facies dependent empirical relationships.

CARB3D$^+$ simulations of the Triassic Latemar platform, Northern Italy, successfully replicate the 3D distribution of depositional facies and platform top topography described by Egenhoff et al. (1999). The classic Latemar cyclic sequences are arranged in thinning upwards packages, probably providing a complete record of sedimentation, and allowing investigation of cycle bundling resulting from sea-level oscillations with a hierarchy of periodicities. However, during condensed intervals, accommodation is limiting and many cycles can be shown by modeling to be absent ("missed beats") due to lack or deposition and/or subaerial dissolution. Although stacking patterns in the Latemar and many other cyclic platform carbonate sequences have been interpreted in terms of Milankovitch-driven cyclicity in sea level, others have suggested that such patterns are illusory or related to auto-cyclicity. CARB3D$^+$ synthetic stratigraphies using both stationary Milankovitch cyclic and random sea level drivers suggest the layer thickness inventories (LTI) test devised by Bailey and Smith (2005) is a more reliable method for detected cyclicity than the exponential distribution test used by Burgess (2008).

CARB3D+ also simulates early diagenetic modification of depositional mineralogy, porosity and primary permeability by mineral stabilization, carbonate dissolution, cementation and dolomitisation within four hydrologically-defined diagenetic zones ("hydrozones"). Diagenetic rates are controlled by climate, the presence and nature of soil cover and grain size, and vary within hydrozone reflecting results from hydrochemical studies of modern platforms and reactive transport modeling. CARB3D$^+$ also includes prediction of secondary (dissolutional) porosity which provides an important feedback between the extent of meteoric hydrozones and evolving sediment properties.

CARB3D$^+$ simulations of meteoric diagenesis show a strong lateral continuity, with depth-dependent diagenesis within the vadose and meteoric phreatic zones, and systematic lateral variations from margin to interior particularly within the fresh-salt water mixing zone. These patterns reflect a high degree of temporal overprinting, particularly during periods of high amplitude (icehouse) sea-level fluctuations. CARB3D+ simulations generate diagenetic patterns which are similar to those reported in the Bahamas during the middle to late Cenozoic icehouse period (Beach 1995; Melim et al. 2001). Here low subsidence rates and protracted periods of subaerial exposure result in thinning and elimination of platform top cycles, and intense subsurface meteoric diagenetic overprinting. In contrast for the Latemar, low amplitude (greenhouse) sea-level cyclicity limits the depth of vadose meteoric diagenetic alteration, and also the lateral extent of the freshwater lens, which may be confined to platform margin highs. However, during condensed intervals the limited accommodation results in significant surface dissolution and overprinting.

Friday 4 June

Keynote Speaker: Charge and Flow Modeling: It's Not Only About Geochemistry

J. Wendebourg, **A. Bell**, *Shell International, Rijswijk, Netherlands*

Charge and flow modeling is performed routinely as part of the exploration workflow in IOCs like Shell. Its purpose is to quantify the risks associated with charge availability, volumes and hydrocarbon type for greenfield exploration, and to obtain more detailed information on composition and volumetrics in near-field exploration. Geochemistry plays a major role to link source rocks with oil and gas occurrence and to identify processes that may have altered HC fluids within the source rock, during migration or in the reservoir. Historically, basin and charge modeling has originated as a sub-discipline of organic geochemistry (e.g. Tissot and Welte 1978). Sophisticated workflows and software tools have been developed since which closely link source rock kinetics and HC migration with thermal and flow history.

Evidence of HC presence and charge is derived at the molecular level from fluid samples that are not only taken from the production stream but also in situ, sometimes under difficult subsurface conditions. Tiny samples can be obtained from fluid inclusions, even in the absence of material discoveries. However, in many exploration cases, large uncertainties remain that cannot be reduced, even if we take into account sensitivities and uncertainties in our tools and workflows. Additional evidence from other data sources is needed to effectively de-risk charge access and occurrence. This is particularly true in cases where the present day conditions do not represent maximum stress and temperature conditions. Examples of additional data sources include surface evidence of HC migration, geophysical DHIs, active hydrodynamics, fault reactivation etc.

Shell's exploration effort in the Southern Rub-al Khali basin in Saudi Arabia is shown as an example where sophisticated geochemical evidence has been used to de-risk charge in a greenfield area. Geochemical and petrophysical source rock characterization is linked with shows of oil and gas and geophysical evidence of HC presence, and the evolution of the petroleum and fluid system is explained as part of the very long and complex tectonic history of the southern Arabian Peninsula.

Reconstructing the HC-Filling History of a Haltenbanken Oil Field, Mid-Norway on Basin and Reservoir Scales

R. Ondrak[1], R. di Primio[1], T. L. Leith[2], G. Lescoffit[2], B. Horsfield[1]

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[2]*StatoilHydro ASA, Trondheim, Norway*

We present a basin modeling study for the reconstruction of the detailed hydrocarbon-filling history of a Haltenbanken oil field. The main focus of the study lays on the filling history of the field, specifically the identification of the spatial and temporal maturity evolution of different kitchen areas as well as the migration pathways into the reservoir.

We constructed a large scale regional model based on seismic horizons of the main stratigraphic units and well-tops of about 100 exploration wells. The regional model covers an area of approximately 80 by 60 km on a 500 by 500 m equidistant grid. We calibrated the temperature and pressure history of the basin model of the northern part of Haltenbanken with vitrinite reflectance, temperature and pressure data which was obtained from a public data base supplemented by confidential data. The model provided the framework to study hydrocarbon generation and migration.

Large variations of burial depth of the upper Jurassic Spekk formation which is considered to be the main source rock but also other potential source rocks in the Haltenbanken area result in the maturation of different kitchen areas (Fig. 1) throughout basin evolution. Onset of hydrocarbon generation in different kitchen areas with progressive burial resulted in changing drainage areas and migration pathways contributing to the filling of the reservoir structure through time. The use of source rock tracers assigned to the various kitchen areas allows unraveling the timing of hydrocarbon generation and migration pathways in the study area.

The filling of the reservoir started in late Paleocene times. During subsequent burial from the Cenozoic onward until today the source rock enters the oil window progressively from North-West to South-West. Hydrocarbon migration into the reservoir occurs most likely along faults in Paleocene times. During the Eocene and Miocene long-range migration along structural highs becomes the dominant migration pathway. In Miocene times fill-spill from a deeper lying reservoir adds to reservoir filling. For the last 3-4 Ma hydrocarbon supply from the deep kitchens has been cut off by diagenetic sealing of the main fault controlling also the occurrence of overpressure in the system.

This basin modeling study provides important understanding for the filling history of this Haltenbanken oil field. Subdividing the source rock into different kitchen areas based on structural elements and burial history helps to elucidate the filling history of the reservoir. We can quantify the amounts to which the different kitchen areas contribute to the charge of the reservoir as well as the dominant migration pathways into the reservoir structure.

Different HC-migrations modeling approaches are used to model migration pathways and the filling history of the area and the comparison of the modeling approaches with respect to accuracy and efficiency of the methods is an important aspect of the project. Presently, we use either a combination of Darcy flow and ray tracing to simulate hydrocarbon migration on a regional scale and invasion percolation migration for the simulation of HC-migration on a reservoir scale.

For a detailed reconstruction of the filling history of the field a reservoir scale model was constructed based on a very detailed reservoir production model. The approach used here is thus as that of a “model in model”, and not actually a local grid refinement. The reservoir model was simplified by significantly reducing the number of units within the reservoir focusing on the main reservoir horizons and intercalated seals. The Quaternary to Cretaceous overburden units were added to the reservoir model to obtain a model which can be combined with the regional basin model. The small-scale reservoir will obtain the HC-fluid volumes which migrate into the reservoir from the large scale regional model. The detail filling history of the reservoir compartments is then calculated within the reservoir model. This approach allows a detailed study of the reservoir filling history.

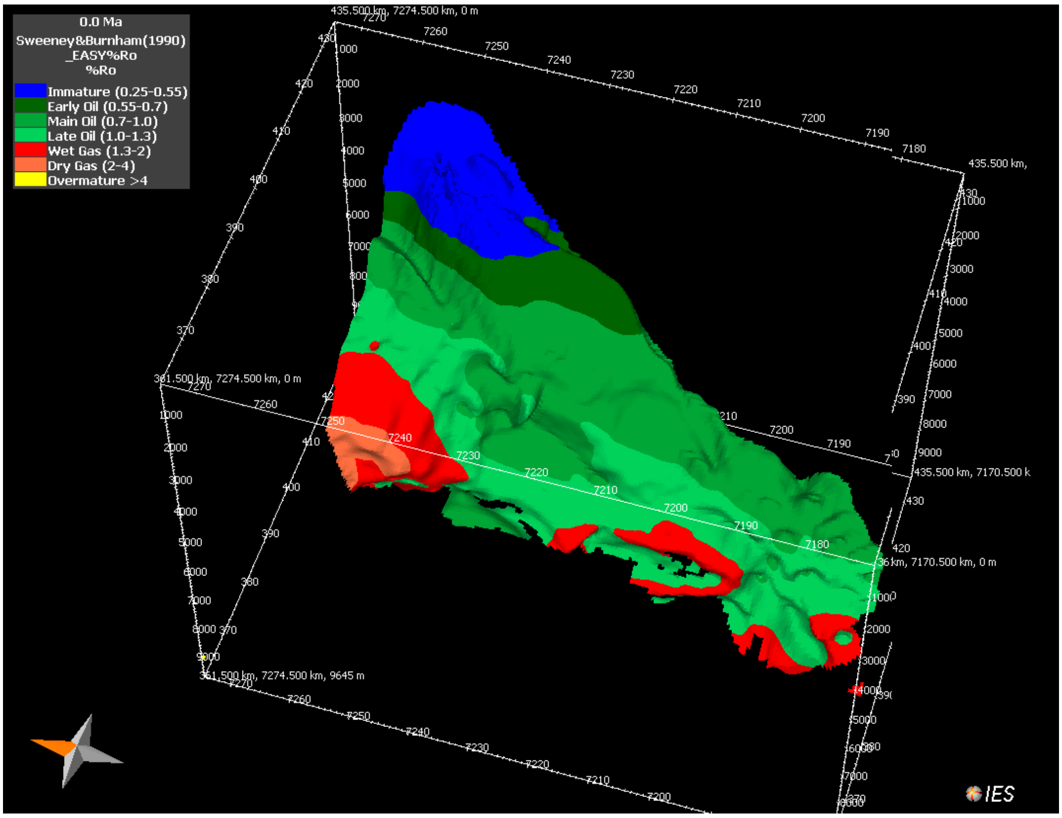

Fig. 1: Present day maturity of the main source rock in the study area.

Experimental Validation of Multicomponent Hydrocarbon Differential Expulsion From Source Rock

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To simulate generation, cracking and expulsion of hydrocarbons in source rock a multicomponent model, which considers differential retention effects (1) on organic and inorganic matrix, was attempted. Compositional kinetic schemes for seven pseudo-components (C1, C2-C5, C6-C14 Sat, C6-C14 Aro, C14+ sat, C14+ aro and NSO) were used for thermal modelling and the results compared with the more conventional four components approach.

Model validation was performed through artificial source rock maturation tests carried out in laboratory using micro scale reactors (Micro Scaled Sealed Vessels) coupled with a mass spectrometer. Each pseudo- component set was reconstructed using singles compounds representatives of the molecular classes (2,3,4). Model was validated on a type II-III kerogen and further experiments on different organic matter types are still in progress.

A simulation algorithm was developed (5), to integrate the differential retention of different components with the cracking and expulsion processes in a generation/expulsion module. This has been used to evaluate hydrocarbon expelled from source rock.

The forecast composition of expelled products is in agreement with typical well data: a higher amount of gas is produced in respect to the primary generation, as expected due to introduction of retention effects.

Evaluation of Gas Migration History through Integration of Multidisciplinary Laboratory and Field Based Measurements

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[1]*Newcastle University,*
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[3]*University College Dublin,*
[4]*BP Egypt*

The aim of this study is to combine petrophysical and geochemical data in order to reconstruct the migration history and pathways of mixed microbial-thermogenic gases drilled in part of a major North African Tertiary delta. Special attention is dedicated to understanding (a) the origin of gas in both reservoir and non-reservoir units using chemical and isotopic fingerprints and (b) whether or not a free gas phase occurs in non-reservoir units both above and below commercial accumulations. The latter is of central importance since only the presence of a free gas phase can result in relatively rapid leakage, via bulk flow, as a function of relative permeability; if gas is dissolved in water, then transport is by diffusion or by water flow, with very different consequences for rates and volumetrics.

The Pliocene section in this study is a classic slope environment comprising channels, mud-rich turbidites, mass transport complexes and hemipelagites. Data from seismic and drilled wells suggest that the channel and levee reservoirs are rarely full to spill, implying either a lack of charge and/or a balance between charge and leakage rates which precludes complete filling of the structures. Here, we are interested in understanding migration routes, rates and mechanisms.

In principle, gas migration may take place along one or both of two general routes: (a) high permeability, seismic-scale bypass systems including injected sands and sands juxtaposed at e.g. levee-levee connections ("multi-storey migration"), and/or (b) predominantly vertical flow through mud-rich sediment sequences. In this relatively shallow region, potential large-scale conduits are readily identified on seismic as gas-bearing anomalies. However, their role as migration pathways for thermogenic gas is always uncertain due to the ubiquitous generation of microbial gas in this area.

Our comprehensive dataset enables a quantitative assessment of gas distribution and its genetic fingerprint in the context of both stratigraphic position and lithology. We have a seismic cube penetrated by 28 boreholes, each provided with a conventional wireline log suite and some with borehole images and high-quality core images. For calibration of these petrophysical signals we use a mudrock database containing various measurements of more than 300 samples from the study area. Gas concentration data, plus compositional and isotope data are available from isotubes and headspace gas for both reservoir and non-reservoir units. Great care was taken to depth-match core, log and gas data.

In general, the gases comprise a variable mixture of microbial gas (~99.7% methane) and thermogenic gas containing <10% wet gas and condensate components. Mixing of these two gas types results in gases which generally contain >98% methane. In addition, there is evidence for microbially generated ethane and also for combined methanogenesis (light $\delta^{13}C_{C1}$, heavy $\delta^{13}C_{CO2}$) and wet gas biodegradation (abnormally heavy $\delta^{13}C_{C2+}$) at temperatures below 70°C. In many structures, thermogenic gas occurs not only inside the reservoirs but also in both the underseals and top seals, indicating vertical migration through mud-rich units. Generally, reservoired gas comprises a greater proportion of thermogenic gas, with a greater biogenic signature in the non-reservoir units. On a pore scale, we suggest that this implies migration through focused pathways within the non-reservoir, allowing the retention of pre-existing biogenic gas sorbed to organic matter. Mixing and flushing is prevalent in the reservoir units.

Careful assessment of the maturity of the thermogenic gas charge suggests that in a given structure, maturities are similar throughout the sampled section of underseal, reservoir and top seal. We see no evidence for compositional stratification as a result, for example, of gases of differing maturity arriving in reservoirs and non–reservoirs at different times and along different flowpaths. Furthermore, we see no evidence of biodegraded gas above ~65°C, suggesting that palaeo-degraded gas has been flushed out of the system in the last ~1my by fresh gas. Overall, the data support the idea of focused, sub-vertical, geologically rapid gas migration through an overall mud-rich stratigraphic section.

Combining the gas concentration data with wireline log data and a simplified system of a porous medium filled with methane, water and salt, we attempted to estimate the gas saturation in non-reservoir units. Initial results, which need to be tested further, suggest saturations of up to 20%, supporting the idea of bulk flow, rather than diffusion or the flow of gas-bearing water as a result of compaction.

In summary, we believe that the study shows that a combination of geochemical data with lithological and petrophysical data generates very useful insights into both rates and mechanisms of two phase flow within gas-charged basins.

Incorporation of Biogenic Gas Generation into Petroleum System Models

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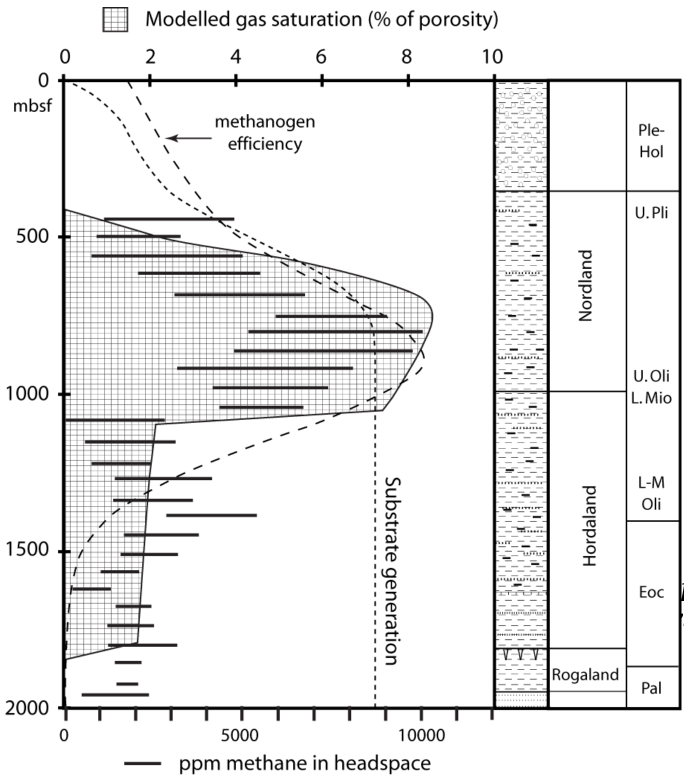
All potential petroleum source rocks will have passed through a phase of biogenic gas generation before thermogenic petroleum generation processes become active and this has important implications for modelling the behaviour of the petroleum system. Firstly, biogenic methane is becoming increasingly important as an exploration target in its own right, yet we have limited capability in predicting its presence. Secondly, most source rocks would already be saturated with biogenic methane ahead of any thermogenic gas generation, which will influence the timing of gas expulsion, expelled gas volumes, and the isotopic ratio of methane expelled at low maturity. Despite this importance, the prediction of biogenic generation rates over geological timescales has proved elusive.

Recent advances in understanding the microbiology of methane formation during diagenesis provide a basis for incorporation of biogenic methane generation processes into computational basin models. Methanogenic activity is now known to be rate-limited by the availability of substrate supplied by parallel microbial reactions. These parallel reactions are, in turn, temperature controlled and so are amenable to modelling using an Arrhenius-type kinetic approach. It is then necessary to introduce a temperature-dependant substrate conversion rate which reflects the temperature-limited efficiency of the methanogenic organisms themselves.

Modelled methane generation rates using this dual substrate generation-conversion approach closely match measured methane generation rates during early diagenesis determined for sediments recovered by ODP drilling and reproduce headspace gas profiles measured in mud-dominated sediments such as the Tertiary of the North Sea (right) and PLio-Pleistocene of the Gulf of Mexico over time scales of millions of years.



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Keynote Speaker: Hydrocarbon Mass Balance at Basin Scale with Integrated Generation and Migration Modelling

M. C. Cacas, J.L. Rudkiewicz[1], B. Carpentier[1], LF. Carvalho-Coutinho[2], J-F Lecomte[1]

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Hydrocarbon migration modelling reconstructs the generation of hydrocarbons, then their movement in the sediments of a basin through geological times and eventually itheir trapping. Therefore, when applied to a complete geological basin, HC modelling can be used for original oil or gas in place estimation. This presentation will focus on this topic and will present the principles of the application, as well as its related uncertainties, based on several real examples, among which the Reconcavo basin in Brazil.

To estimate hydrocarbon in place, the workflow goes through the following steps :

1. definition and estimation of the porosity of the main reservoir units;
2. computation of the surface and pore volume of closed structures;
3. estimation of the mass of generated hydrocarbons in the various source rocks;
4. estimation of the nature of the expelled hydrocarbons, either oil, condensate or gas;
5. calibration of migration parameters based on observations;
6. computation of accumulated HC volumes in the previously defined closures;
7. computation of lost hydrocarbons through capillary leakage;
8. estimation of volumes of hydrocarbons in surface conditions.

The structural closures are defined for each potential reservoir, with the computation of the local structural tops, the closure heights and the maximum trapped volumes. Faults can be taken into account as being laterally permeable or impermeable. Moreover, lateral fault transmissivity may vary with geological time or with azimuth, depending on the tectonic regime of the basin. Lateral facies changes from reservoir facies to non reservoir facies may result in stratigraphic traps. The size and the spill points of structural or stratigraphic traps may change through geological times with basin subsidence and tilting.

Simultaneously, the quantity of generated and expelled hydrocarbons from the source rocks of the basin can be computed, based upon compositional kinetics and volume and mass balances within the pore space of the source rock. Source rock related parameters need to be calibrated to observations, so that in situ retention is accounted for.

Then, the hydrocarbon charge of accumulations is computed along the source rock layers, the faults and the reservoir layers. Later, when the basin history goes on with increasing subsidence or tilting of the basin horizons, hydrocarbon secondary migration can occur through fill and spill along leakage points. Due to decreasing pressure and temperature with decreasing burial depth, the hydrocarbons expelled from the underlying source rock can undergo a phase split. This phase split is computed with thermodynamically based equation of states. The phase split depends thus upon composition, pressure and lastly temperature. In case of a regional uplift, phase separation can occur and the global volume of trapped hydrocarbons increases.

Once completed, the migration modelling can be used to compute the total available volume of hydrocarbons in a given sedimentay basin. Because the modelling procedure takes into consideration compositional primary and secondary cracking, both in source rock and reservoirs, as well as liquid/vapour phase separation in subsurface and in surface, the total volumes of trapped oil and gas components can be computed, which is a way to access to original oil in place.

A Workflow Solving Migration Problems with Combined Structural and Petroleum Systems Modelling: Case Studies from Offshore Brazil and Onshore Trinidad.

J. McQuilken, *BG Group plc, Thames Valley Park Drive, Reading, Berkshire, RG6 1PT*

The IES 2D PetroMod software utilizes the present day structural configuration of a depth section and back-strips it through time to give a series of time steps which are then used for petroleum systems modelling. As such, these time steps are not structurally restored and can have an impact on the modelling outcome, particularly, where structuration and migration are contemporaneous. In addition, complex geometries such as salt or thrust tectonics cannot be modelled. To overcome this inadequacy, BG Group jointly sponsored a Joint Industry Project (JIP) to develop the IES 2D PetroMod TecLink Module which enables a workflow whereby structurally restored depth sections can be directly imported into 2D PetroMod for use as a series of time steps for modelling. This workflow has now been successfully used on a number of structurally restored sections within BG Group: these include a salt tectonics section from the Santos Basin, offshore Brazil and a complex thrust tectonics section from the Central Block area, onshore Trinidad.

For the Santos Basin, BG Brazil were concerned with the role of salt on hydrocarbon migration and supplied ten structurally restored time steps directly exported from the Midland Valley 2DMove software ranging in age from the Top Albian to the present day. Simulation showed that salt windows were not developed through time and that the salt acts as a migration barrier and top seal to all the oil and gas generated from the pre-salt Barremian and Aptian source rocks allowing the generated hydrocarbons to be trapped in the pre-rift succession. Furthermore, the absence of salt windows precludes any further vertical migration through the petroleum system. It is also evident that the traps within the pre-rift succession begin to fill with gas as early as the mid Albian; in addition, there is evidence of oil being displaced by gas. Insignificant gas pools exist in the Albian fractured carbonates and are sourced from the mid Albian post-salt source and have filled by vertical migration through fractures.

BG Trinidad & Tobago were primarily concerned with being able to explain the mix of liquids and dry gases seen in the petroleum system as accumulations in the onshore Central Block area and supplied eight structurally restored time steps from the Midland Valley 2DMove software ranging in age from the Oligocene to the present day. Simulation showed that the working petroleum system in the Central Block area is a combined biogenic and thermogenic system which explains the presence of dry gas in the down-dip extension of the Corosan discovery, the mix of biogenic and thermogenic gas seen in the down-dip extension of the Carapal Field and the liquids and associated thermogenic gas in the Penal-Barrackpore structure.

Overall this workflow is now utilised within the routine workflows at BG Group and highlights how JIPs can be used to overcome problems and significantly improve workflows.

Calibration & Prediction of Petroleum Charge Scenarios – An Example from the Norwegian Barents Sea

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Petroleum systems analysis is now routinely applied in many oil and gas companies for regional and prospect scale geological evaluations for exploration. Analysis of charge adequacy and scenarios - integral to petroleum systems analysis - often carries uncertainties due to either poor characterization of source rock variability and/or inaccurate mapping of thermal stress (e.g. related to uplifting and erosion). In this paper we present a case study of regional-scale charge scenario analysis designed to constrain uncertainties for an area in the Norwegian Barents Sea.

The Norwegian Barents Sea is a prolific petroleum province with multiple proven source rocks and reservoirs. Within this province significant volume of gas and condensate have been discovered while large volume of oil was discovered only in the Snohvit field. However, the recent oil discoveries at Goliat (2000) and Nucula (2007) present a different aspect of the petroleum systems complexity in the Norwegian Barents Sea.

To help us understand such complexity and investigate for viable petroleum charge scenarios for Goliat & Nucula as well as regional evaluation of prospect charge adequacy, we conducted an integrated petroleum systems analysis. Our analysis has two important components: 1) we characterized source rocks for ultimate expellable potential (UEPs) using data from a large number of wells and built a 3D thermal history model (via ZetaWare Trinity) using regional seismic maps of key horizons; and 2) we integrated results of a regional geochemistry analysis of reservoir fluids and fluid inclusion stratigraphy analysis for multiple wells.

We applied the regional-scale 3D Trinity model, which incorporates regional estimates of erosion and is constrained by observed bottom-hole temperatures, for charge scenario and fetch history analysis. Using known pressure and temperature, fluid and reservoir properties at the Snohvit and other discoveries (oil and gas API gravities, column heights, net-to-gross, and HC in-place volume), we then applied prospect-scale Trinity model for multi-stage (pre and post- uplift) PVT considerations and understanding post-filling reservoir dynamics. Such PVT considerations provided us a unique calibration to our charge scenario/fetch history analysis. This integrated regional analysis shed important insights for us to the likely charge scenarios for Goliat and Nucula and it provided us a confident risking for prospect charge scenarios.

Petroleum System Calibration under Uncertainty Constraints

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The Petroleum System Modelling (PSM) is a complex activity as it synthesises many different expertises and it is aimed to model different geological, physical and geochemical processes, interconnected by non linear interactions.

Basically, PSM is equivalent to an inversion, from the available data and geological knowledge to the spatio-temporal evolution of the geological model. However such inversion is an ill-posed problem due to the irreversibility of the physical processes involved and to the scarcity and the poor quality of the data. A currently viable solution consists in generating several admissible models, running the PSM simulators on these models and then selecting the models which are calibrating with available data and information. The calibration phases, repeated several times for each step of the PSM approach, are therefore the critical ones in finding the optimal solution in a PSM study.

The proposed methodology describes how calibration is affected by the input uncertainty, not restricted as usual to some parameters (porosity, permeability, etc.) but extended to the uncertainty of the geological model itself. In fact the combination of the uncertainty of seismic interpretation and of the seismic velocities leads (through geostatistical simulations) to a number of admissible depth basin models, with different layers geometries. As such a great number of admissible basin models would be quite time consuming to manage, a selection criterion has been introduced in order to reduce the uncertainty to a narrower set of representative basin model scenarios.

For each basin model scenario a semi-automatic calibration of temperature and pressure can be performed, allowing the modeller to keep control of the data fitting as well as of a priori geological information. Using the results of this step and with the help of a geostatistical approach, a number of calibrated heat flow maps can be produced and used as input to temperature modelling. Afterwards the resulting calibrated temperature scenarios are then used in the modelling of the generation and expulsion processes and the results may be compared to available data, in order to filter out unrealistic solutions.

The effect of the geometric uncertainty on hydrocarbon migration is quite strong, affecting not only migration directions but also drainage area definition and spill directions out of a fully filled reservoir. The calibration of this step against known reserves and/or dry wells enables to keep control on hydrocarbon migration modelling results.

A final sensitivity analysis of the “calibration under uncertainty” has been performed evaluating the effects, on the final PSM results, of the uncertainty of the different parameters including that of the geological model. In conclusion the management of different sources of uncertainty in the calibration phase results in a better understanding of the petroleum system behaviour and a more robust forecast of undrilled traps.

Moreover we can discard all the simulated basin models providing unrealistic results from the viewpoint of the PSM (inconsistency with available data and information), thus improving at the same time the evaluation of the basin “deterministic” geometry (equal to the average of all the valid simulated ones).

The described methodology has been applied on an area of the North Sea where the maximum temperatures have been experienced at present day, so that for the purposes of this study the thermal calibration and the uncertainty/sensitivity analyses have been focused only on the last time-step.

In fact, in the North Sea, the lithological succession is experiencing the maximum temperatures at Present-Day consequently to the fast deposition rate that interests the Late Miocene to Present-Day interval. This is apparently in contrast with the heat flow development through time that shows a peak during the Middle to Late Cretaceous, related to a rifting phase, and a decrease in magnitude from the Paleocene to Present-Day. Despite of this, due to the contemporaneous deepening of source layers, the maximum temperatures are reached only recently.

Exploration-phase 2D Basin Modelling to Highlight Key Risks, Focus Technical Tasks and Potentially Reduce Time to Drilling: Devil's Hole Basin, UK North Sea

D. S. Moore[1], M. Camm[1], J. R. Allwardt[2]

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[2]ConocoPhillips Company, Houston

The Pre-Zechstein play, an extension of the Paleozoic Southern North Sea play north of the Mid North Sea High, will test the potential of the Early Carboniferous Scremerston Coal in an area traditionally reliant on the Upper Jurassic for source. To maximize prospect value, the play work program aims to minimize the time to mature from prospect to drill ready status.

Exploration-phase 2D basin modeling was carried out for UK Licence P.1432 both to test the potential of the Scremerston Coal for hydrocarbon generation and expulsion, and to highlight key risks, thus focusing technical evaluation. To build the model, a recent long offset 2D seismic line was selected that: 1.) goes over the license and a deeper part of the source kitchen, 2.) is near well control and 3.) crosses a mapped lead. Key horizons were depth converted, serving as the framework for entering geologic elements into a 2D basin modeling package.

Review of offset wells and publications indicated three key episodes of uplift/erosion: End-Variscan, Mid-Late Jurassic and Tertiary. Published data, however, disagreed as to the magnitude of each episode. Scenario modeling tested the impact of varying degrees of uplift/erosion per episode, indicating that End-Variscan most significantly impacts timing of source rock maturity. This not only reduced uncertainty, but also provided focus for future work plans. Similarly, the impact of Paleo heat flow was unconstrained pre-modeling. Scenarios were run limiting initial heat flow, providing for syn-rift heat flow and testing a high-end maxima syn-rift heat flow. As with uplift and erosion, heat flow scenario testing quickly demonstrated the sensitivity of generating hydrocarbons to differing conditions; in this case, proving that while high initial heat flow has little impact, interpretation of modern heat flow assumptions from well data dramatically impacts modeled hydrocarbon generation and expulsion.

Scenario modeling magnified the importance of characterizing Scremerston Coal Formation kinetics, a critical factor not identified prior to initial basin modeling. Accordingly, well cuttings (UK well 39/7-1) and core samples (UK well 26/8-1) were submitted for kinetics analysis. Resulting data, integrated with palynology/chemostrat-refined Pre-Zechstein stratigraphy, significantly improved model accuracy and clarified controls on hydrocarbon phase and timing of generation/migration/expulsion.

Hydrocarbon Leakage Indicators on the Angola Oceanic Basin, Deep-Offshore West African Margin: Seismic Interpretation and Numerical Modelling

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We analysed several of hundreds of km of 2D seismic-reflection profiles on the deep-offshore of the Angola basin. A variety of features, identified southwards of the Congo submarine canyon, such as: bright and flat spots, gas chimneys, buried and seafloor pockmarks, seabed mounds, are evidences of either past or active hydrocarbon accumulations or leakage. We have mapped and classified these seepage indicators based on whether they are associated to stratigraphic (i.e. paleo-channels, downlapping clastic wedges, onlaps and unconformities) or structural (i.e. growth faults, salt diapirs, crestal faulting) elements. Their dimensions may vary from some hundreds of meters up to few kms (fig 1). Most of the currently active chimneys, both stratigraphically and structurally-controlled, are identified on the eastern flank of a graben, while the non-active are located basinwards and buried by the post-Miocene fine-grained sedimentary cover. No evidence of gas sequestration or gas hydrates deposits as BSR was identified.

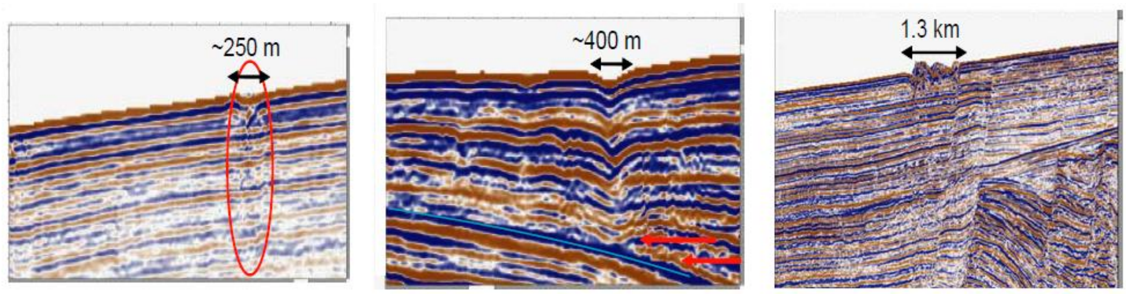

Figure 1. Stratigraphically and structurally-controlled seafloor seepage indicators identified on the slope of the Angola basin

Based on two 70 km-long NE-SW trending profiles across the slope, we developed a conceptual model of the basin that was used to build a 2D basin model We simulated the thermal evolution and hydrocarbon generation history and modelled possible hydrocarbon-migration pathways observed as leakage features on the seismic data (fig. 1). Salt diapirs present in the basin were treated in a schematic approach to consider the thermal effect of these structures.

Two main post-rift source rocks (SR) were considered: (1) Late Cretaceous oil-prone from Iabe Fm.: Type II kerogen, 5% TOC, HI 300 mgHC/gTOC; (2) Early Miocene mixed gas-oil prone from Lower Malembo Fm.: Type III kerogen, 4% TOC, HI: 200-300 mgHC/gTOC. Different paleo-heat flow scenarios were tested and an average heat flow of 55 mW/m² allowed a good calibration with the regional trend of temperature and vitrinite reflectance (Ro) borehole data (fig 2).

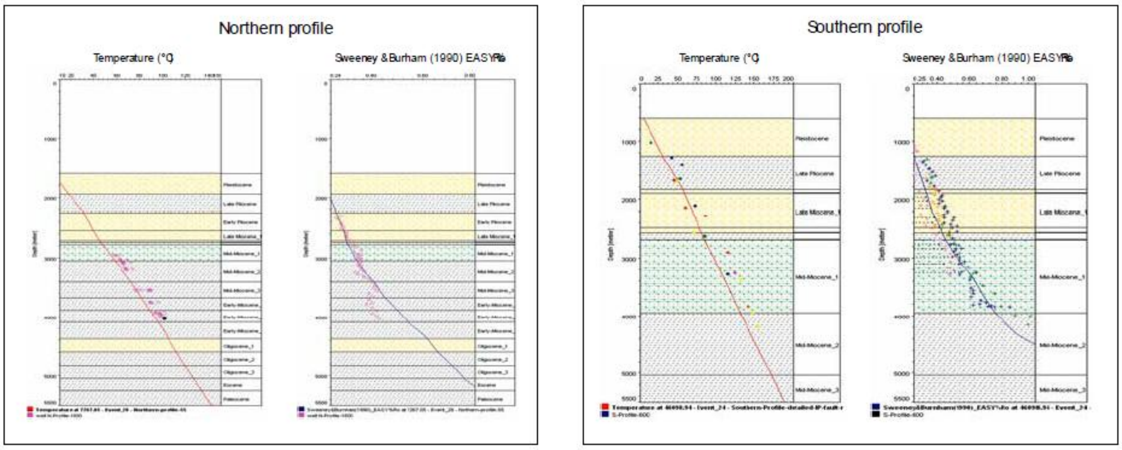

Figure 2. Calibration of the thermal model with borehole temperature and vitrinite reflectance (Ro) data.

Our results predict hydrocarbon generation from the Late Cretaceous Iabe SR starting during the lower Miocene. This was probably driven by rapid burial resulting from the abrupt increase of sediment input due to the onset of the Congo deep-sea fan. The early Miocene Malembo SR is predominantly immature, except for the deepest part of a growth fault's hanging wall on the southern profile. Although the more gas-prone Miocene source rock is currently immature, the upper Cretaceous oil-prone sorce rock can explain the observed gas chimneys.

The hydrocarbon migration was modelled using the invasion-percolation method (Petromod® software) and reproduced several of the observed gas chimneys, seafloor pockmarks, and a conspicuous mounded structure located along the hanging wall of a growth fault. As this seafloor mound lies on top of a modelled gas migration pathway, it could represent a carbonate mound resulting from anaerobic oxidation of leaked thermogenic methane.

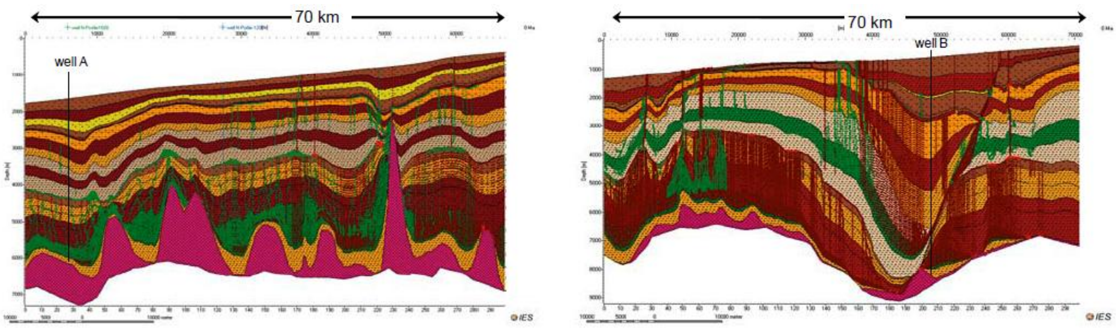

Figure 3. Hydrocarbon migration model for two 70 km-long NE-SW trending across the margin (northern and southern profile)

We are currently extending our study to a 3D basin model of the entire area. The 3D-model was constructed from the depth-convertion of several stratigraphic horizons previously interpreted on the seismic data. Results from this phase should provide more details of the genetic mechanism of the seamound structure, as well as quantification of the volumes of thermogenic leaked gas into the ocean through geologic time.

Poster Abstracts
(In alphabetical order by presenter surname)

Session One

Enhancing Seal Quality Prediction by Modelling Spatial Permeability Distributions of Meter-Scale Fine-Grained Sediments

M. Drews[1], K. D. Kurtev[1], U.Boeker[1], J. Ma[2], A. C. Aplin[1]

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Current best practice for predicting seal quality and flow in fine-grained sediments includes conventional log measurements for lithological interpretation (e.g. Yang et al., 2004) in combination with regional compaction curves and porosity-permeability models. However, conventional log measurements miss important small-scale heterogeneities and the spatial component of rock property distributions. For example, the spatial component or texture has a major impact on permeability contrast and anisotropy (Kh/Kv) (e.g. Weber, 1982).
Permeability controls migration and leakage rates, and thus seal capacity and quality, once the critical capillary entry pressure of the caprock is exceeded. Permeability estimates of fine-grained sediments should thus be as accurate as possible.

The aim of this study is to improve present seal quality prediction workflows by implementing cm-scale sedimentological textures into a new approach to model spatial permeability distributions (SPDs) of fine-grained sediments (Fig. 1). We will present results from our database, which represents an integration of sample measurements, high resolution measurements (core and microresistivity images), log measurements, geometrical attributes, and fluid flow simulation results for different sedimentological textures common in fine-grained sediments.

As a starting point, we define several typical textures present in fine-grained sediments via interpretation of high quality core and microresistivity (FMI) images. These textures may be the result of different sedimentological processes. An abstraction to purely geometric features allows for mathematical description of the different textures using geostatistical methods (variography). In parallel, log signals, sample measurements, and core and FMI images are related using a combined multivariate and probabilistic approach. Each step feeds into a database, which is later used as an input for geostatistical simulation of each texture type and finally for populating these texture models with realistic SPDs to perform fluid flow simulation. The whole workflow is an iterative process so that the initial classification model of textures might be updated according to the results of each cycle through the workflow. Current results show a strong dependence of permeability results on sedimentological textures and lithology of fine-grained sediments, such that predictions based only on homogeneous mudstones may be in error by up to 4 orders of magnitude.

Successfully modelled SPDs of different textures of fine-grained sediments can serve as building blocks for larger scale models and as a direct permeability estimate for wireline facies. Hence, our new approach closes the gap between sample and log scale in current practice upscaling workflows.

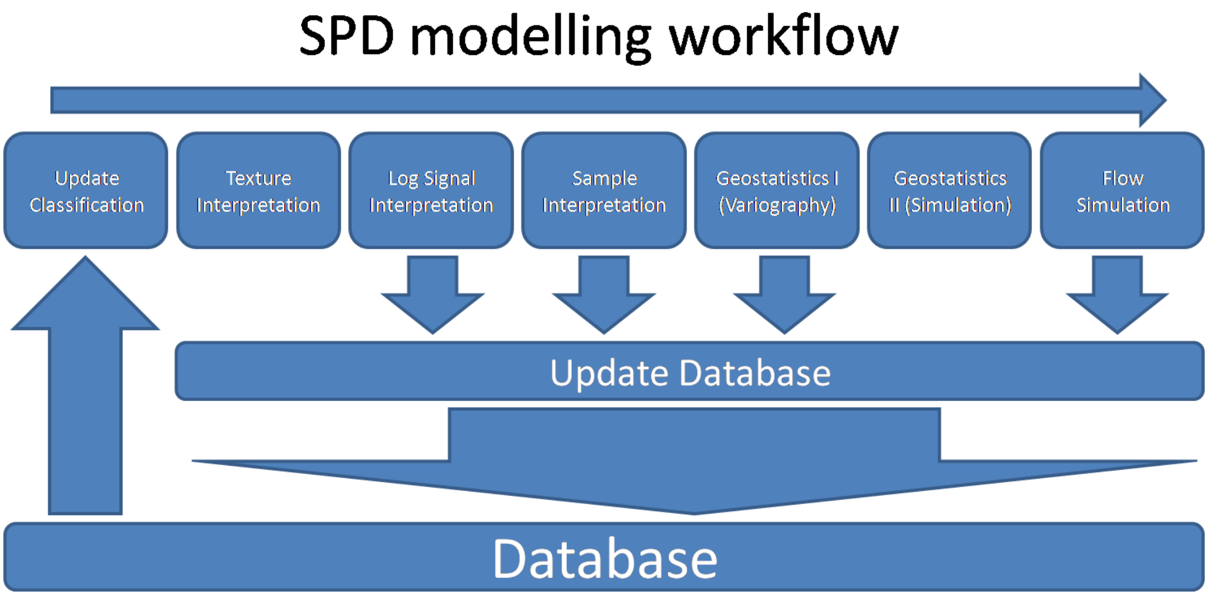

Fig. 1: Workflow implementing cm-scale textures into spatial permeability distribution (SPD) models of fine-grained sediments.

Upscaling Compaction Relationships for Basin Modelling

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Modelling the evolution of compaction is a key element of basin modelling, which aims to provide insights into the processes that occurred in a basin. In typical basin modelling, we are concerned with mechanical compaction of the sediments, i.e. the loss of porosity during burial, caused by the more recently deposited sediments, and its interaction with fluid flow. Compaction is of particular importance in predicting, among others, the pressure distributions in a basin, typically up to a burial depth of 5000 meters.

A basin-scale numerical modelling study requires a basin to be discretised into blocks whose sizes may be kilometres laterally and hundreds of meters vertically. Each block is then assumed to contain homogenous sediments described by the same mechanical and fluid properties, although the sediments are typically heterogonous to variable degrees. As a result of such simplification, the effects of intra-block heterogeneity of the sediments, such as metre-scale layers of alternating muddy and sandy/silty sediments, are not taken into account.

We report a numerical upscaling technique, which enables us to derive the effective compaction relationships for modelled heterogeneous sediments in 1-3 dimensions. Our approach is to discretise the heterogeneous medium into small cells that we can consider to be homogeneous. Each sediment of cell in the fine model is assumed to follow a mechanical compaction relationship in the following form: $e = e_{ref} - \beta ln\left(\sigma'/\sigma'_{ref}\right)$, where e and σ' are void-solid ratio and effective stress, respectively. e_{ref}, the void-solid ratio at reference effective stress σ'_{ref}, and β are two coefficients known to vary from one sediment type to another depending on the lithologies.

The calculated effective compaction relationship takes the same form, but the two upscaled coefficients become the weighted average of the respective pure-material coefficients. We prove that this effective compaction relationship ensures the same amount of compaction to the overall sediments as would occur when individual compaction relationships are applied over individual cells, respectively.

Numerical analysis shows that the effective stress at fine cells can be replaced by the mean effective stresses over a larger region, even for cases with abnormal pressures, as long as the local variation is small. This approach can, therefore, be applied to determine effective compaction relationships for the cases, e.g. well logs, where effective stresses can be estimated at discrete locations, and for cases where effective stresses are not available and have to be determined as part of basin modelling. We explore how this approach might be incorporated into existing basin modelling software, and how it might fit into future software which can capture the effects of multi-scale heterogeneity in compaction relationships more effectively and accurately.

Full High Resolution Basin Model and Local Grid Refinement – Pros and Cons.

M. Thibaut. B. Carpentier, S. Pegaze-Fiornet, S Wolf, *IFP 2-4 av. De Bois Préau Rueil-Malmaison*

Local grid refinement is a new available algorithm developed by IFP for its basin model (TemisSuite). It enables us to build a mesh which combines several grid dimensions (or sub-models) into a single, fully coupled, basin model. The mesh is made of large cells in areas where there is a lack of information and small cells (in X, Y and Z) where more precise information is available and where fine results are needed. This approach, which optimises the total number of cells, allows detailed simulations on potential target areas without any compromise on their coupling with the behaviour of the whole basin

The approach allows the fitting of the cell sizes to the heterogeneous distribution of the available data. Very fine cells are defined where detailed information with numerous wells and/or 3D seismic cubes is available whereas, in other areas of the basin, coarse cells are present where only scarce information is available. In classical basin model, constructing a numerical basin model which captures the fine information implies the use of a high resolution grid on the whole basin. This, in turn, leads to very large basin models which cannot be run with a compositional description of the fluid, especially when wanting to use a thorough migration approach like the Darcy laws.

To overcome these numerical problems, basin modellers use drastic simplifications of the expulsion and migration schemes by using percolation or ray tracing approaches. When necessary, they use “tartan” grids which can be, in some cases, a satisfying alternative. However, when several high resolution zones are present in the same basin, the “tartan” grid does not reduce significantly memory and CPU time.

The work presented in this paper aims to compare the results between full high resolution models (considered as references) and their equivalent LGR models. Based on synthetic and field case data, the comparison will show the differences found on the main results of basin modelling. Special care will be devoted to the comparison of the temperature, pressure and hydrocarbon saturation. Comparison on CPU time will also be investigated. The conclusions will highlight the pros and cons of both approaches and the interests and drawbacks of the fully coupled Local Grid Refinement algorithm developed at IFP.

Session Two

Basin Modeling in Foothills: A Coupled Thrustpack-Ceres Study of the Kanau-Kutubu-Mubi-Wage Cross Section (Papua New Guinea Fold And-Thrust Belt)

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Introduction

Unlike in passive margins where most deformation relates to vertical subsidence and only limited erosion occurred, petroleum modelling in fold-and-thrust belts requires a good understanding of past geometries, and to get accurate estimates of erosion. Another critical issue is the evolution through time of the free water level to define the pressure boundary condition. The Papua New Guinea fold and thrust belt offers a promising target to test the basin modelling tools (Hill et al., 2008; Hill and Hall, 2002; figure 1).

Kinematic scenario and calibration

A regional balanced and restored cross-section over the fold belt was validated kinematically using Thrustpack, (Sassi and Rudkiewicz, 1999) and a basin model was built using Ceres2D (Schneider et al., 2001). It integrates Lower Jurassic rifting, passive margin subsidence, Upper Cretaceous uplift related to the Coral Sea rifting and shortening during the Plio-Pleistocene. The scenario is based on an early growth of the frontal anticline which cuts off lateral migration of oil, and prevents charge of the Darai plateau. Calibration of the section boundary conditions and properties was done by comparison with data from 7 wells. Apart from the high pressure trend in the Kutubu-Moran structures, all data are accounted for with a good to very good fit, and most of the model appears quantitatively predictive.

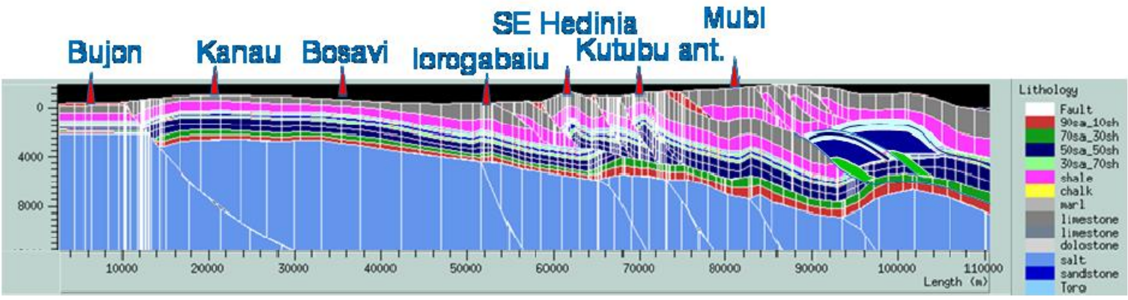

Figure 1: Present day section with the lithologies and localisation of the wells.

Pressure modelling

The pressure modelling indicates a strong under pressurization of the reservoirs below the topographic highs, with pressure values lower than the hydrostatic trend. This reproduces the data if one takes into account the correction for the burial depth of the reservoirs and the shift in the water table depth. This effect can be explained by strong water flow away from the topographic highs in the pervious Darai carbonates at surface. The underlying Ieru Shale decouples this flow from the low fluid velocity below the Ieru, creating a delay in the pressure equilibrium between the deep escape of the fluids from the highs and the slow recharge from above. The modelling demonstrates three major pathways for water: (1) topographically driven flow, active from the onset of mountain building until present day, (2) deep updip basinal flux, flowing along the flexed reservoirs and starting at the onset of thrusting, and (3) across fault escape from connected reservoir bodies during late stage of basement fault inversion.

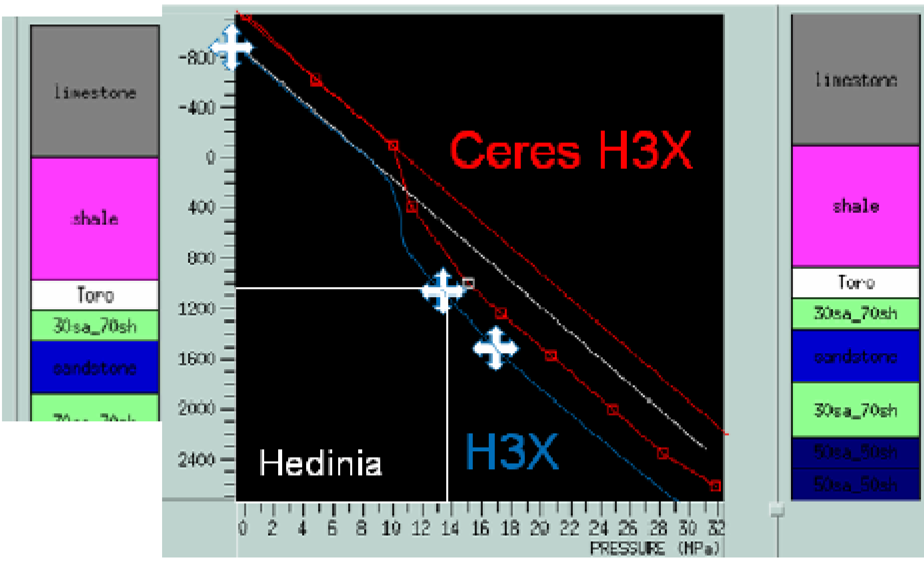

Figure 2: Example of a pressure calibration for the Hedinia 3X well. The red line and square are the predicted pressure value and trends, the white star the observed data (RFT). The blue line is he predicted pressure trend corrected for water table depth which fits the data (depth in m, pressure in MPa).

Petroleum system evolution

The petroleum system evolution shows that a type III deep source rock explains the small extent of maturation of the deep foreland. Type II or mixed type II/III can be used to model the Cretaceous source rocks. Maturation starts in the mid Cretaceous and increases regularly during burial. Maturation strongly increased during the tectonic burial (increase of 50% during the last 7 Ma). The saturation shows three main accumulations: (1) the deep part of the Mubi zone, with a vertical migration along faults; (2 the SE Hedinia and Kutubu anticlines; and (3) less important, the Darai plateau, excluded from lateral charge by the early growth of the SE Hedinia anticline.

Acknowledgements: The authors thank Oil Search Ltd for access to the data, funding and for the authorization to publish the results.

Seismic Stratigraphy and Numerical Basin Modelling of the Southern Brazilian Margin (Campos, Santos and Pelotas basins)

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This study provides an integrated approach of sequence stratigraphy, numerical reverse and forward stratigraphic basin modelling. The database includes three regional seismic reflection profiles, 300-340 km long, located in the Campos (CB), Santos (SB) and Pelotas (PB) basins. In addition, 21 calibration wells provided lithologic and bio-/chronostratigraphic information for the studied Barremian to Holocene basin fill. Main results of sequence stratigraphic and reverse modelling include: (i) identification of 12-14 seismic units (3-50 m.y.) in each basin, including smaller-scale stacking patterns and seismic geometries; (ii) recognition of six major subsidence trends (ST1 to ST6) from Barremian to recent times; (iii) genetic subsidence model in time (i.e., thermo-tectonic, flexural and compaction induced components); (iii) integrated basin modelling including accommodation space and basin infill, showing subsidence/uplift trends as primary and eustatic sea-level changes as secondary controls; (iv) four tectonic basin stages controlling the evolution of the southern Brazilian margin: Barremian syn-rift, Aptian syn-rift sag in CB, SB or post-rift in PB, Early-Middle Albian post-rift and Middle Albian-Holocene drift. Lithologies, paleobathymetry, ages and geometry of the seismic units, flexural rigidity of the crust, eustatic sea-level changes (Hardenbol et al., 1998) and subsidence trends represented the input data for statigraphic forward modelling.

After Barremian syn-rift extensional faulting had ceased, depth-dependent lithospheric extension in the CB and SB triggered thermally driven basin sagging (ST1 to ST2). Fault-bounded subsiding depocenters evolved to wide lakes and subsequently to salt basins during the Late Aptian. In the PB, widespread Barremian syn-rift volcanism was directly followed by post-rift Aptian clastic progradation in open marine environments. During the Late Cretaceous drift stage (ST3), longterm retrogradation in the CB and PB contrast with progradation in the SB. During the Tertiary (ST4-ST6), individual subsidence/uplift trends are highly variable along the shelf-basin transition. Variations are closely related to changes in sediment flux and resulting accommodation. Salt deposition and deformation in the CB and SB controlled their great hydrocarbon potential. It affected the distribution of source rocks, seals and reservoirs intervals as well as the development of potential stratigraphic-structural traps and facilitated thermal maturation of syn-rift source rocks. In the PB, where the salt succession is absent, the basin development was largely controlled by differential flexural subsidence. Potential hydrocarbon traps are mainly stratigraphic and the quality of syn-rift source intervals is uncertain to date.

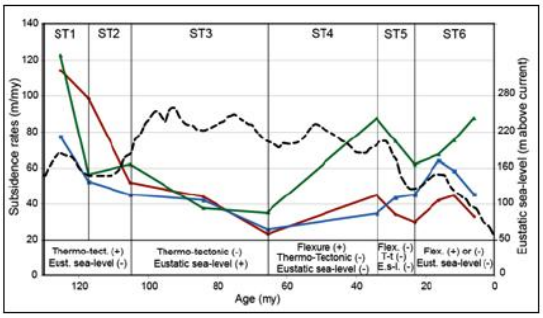

Fig. 1. Numerical accommodation space modelling red: Campos; blue: Santos; green: Pelotas dashed line: eustatic sea-level (Hardenbol et al., 1998)

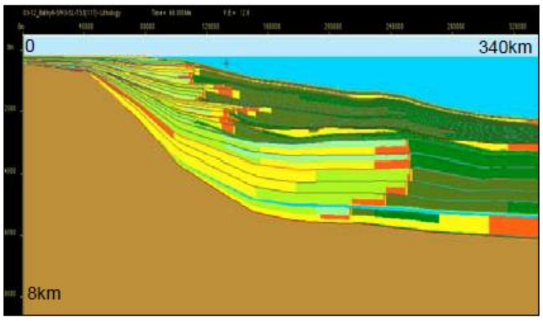

Fig. 2. Forward stratigraphic modelling (PB). Facies distribution (65.5 Ma). Lights (sand, silt, limestones); darks (shales)

Plate-Scale 3D Mapping in Exploration Workflows

W. Prendergast, C. Holley, J. Etienne, R. Martin, D. Macgregor, *Neftex*

Here we present examples that utilise a combination of 3D modelling and gross depositional environment mapping in plate scale and basin scale petroleum systems analysis.

A 3-dimensional geological model has been constructed for the entire North Africa to Middle East region using Roxar IRAP RMS. Input data for this 'CUBE' model include 1300 wells, regional depth maps, >300 structural cross sections and ~300 field structure maps sourced from the public domain. The CUBE has a grid cell resolution of 1 km x 1 km and covers an area of 7000 km (E-W) x 2500 km (N-S). The CUBE is divided into 354 regional depth surface grids which correspond to regionally significant Neftex sequence stratigraphic surfaces.

In this 3D environment, we incorporate geothermal gradient, surface temperature, heatflow and a palaeotemperature correction which takes account of burial histories to evaluate regional maturity trends.

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