EUG XI

Symposium FMF3

Petroleum Geology and Fluid Flow and Property Predictions from Basin Scale Numerical Models

Sponsored by BP – Amoco

Convenors

Stuart Burley
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Wednesday AM Session

FMF3 : WEam01 : F4
Source, Maturation and Petroleum Migration: From Industry to Academia

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Petroleum geochemistry is a tool of growing importance, which allows assessment of the risk, value and volume of petroleum in a prospect ahead of drilling.

Determining the probability (risk) of petroleum being present in an identified subsurface structure thought to contain a trap involves the answering of a number of questions.
• Is there a source rock in the vicinity of the structure (that is, a rock relatively rich in kerogen)?
• During its burial has the source rock reached sufficient maturity to yield petroleum (that is, has the source rock been heated sufficiently for the reactive kerogen which it contains to break down to form oil and/or gas? ·
• Did this process of petroleum generation occur after the identified trap formed?
• Would the generated petroleum have moved from the source rock to the trap (or is it likely to have flowed - migrated - away from the trap)?

It is not enough to know that petroleum is likely to have filled a trap, for what is often critical to any evaluation of the trap ahead of drilling is the likely value of that petroleum. Geochemistry provides most of the data and reasoning for any such evaluation (although in some instances direct hydrocarbon indicator - DHIs - are relied on). At the simplest level, the question is whether the structure contains oil or gas or both. Questions about sulphur or wax contents etc. come as more information becomes available.

In theory, the volume of the petroleum charge can be estimated. In reality, all of the uncertainties involved mean that the estimate must very much be a coarse approximation exercise, which is a check of whether or not there is a charge.

Using geochemical technology to improve assessment of risk, value and volume has set, and is setting, challenges for industry-academia research collaboration, such as:
• what depositional environments give rise to effective source rocks and can these be related in seismic sequences?
• how are the generation characteristics of source rocks best described? - how is maturation best constrained?
• what controls primary migration from a source rock?
• how do we model petroleum migration in space and time?
• what do oil and gases samples obtained at the surface or in wells tell us of the subsurface?
• how can we predict 'pollutants' in petroleum reservoir such as carbon dioxide, nitrogen and hydrogen sulphide?

FMF3 : WEam02 : F4
Thermal Modelling Applied to Sedimentary Basins

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Modelling the thermicity of sedimentary basin permits the reconstruction of the thermal history of the basin. The purpose of this work is to present a kinetic model applied to organic geochemistry and organic petrology. The results expected when simulating numerically the thermal evolution of the organic matter are to: - evaluate the kinetic parameters associated to the thermal transformation. - determine the composition of hydrocarbons by considering the maceral composition of the organic matter. - reconstruct the thermal history of the sedimentary basin. In order to test the validity of the model, we have chosen to apply data coming from : - the Carboniferous basin of Asturias located in the Cantabrian Mountains in NW of Spain. - the basin of Paris (France). Data integrated in the model come from : - an experimental simulation in laboratory of the thermal decomposition of the coals sampled in the Asturias basin. This was done by the way of Rock-Eval pyrolysis. - observations in optical microscope that consist in determining the macerals composition of the coals sampled in the Asturias Basin and in measuring the vitrinite reflectance which is an indicator for palaeothermicity. - literature data on the thermal history of the basin of Paris.

As for the Asturias basin, the test of the model based on the coals sampled in this basin permitted to determine a model of distribution of the activation energies and to characterise the thermal evolution of the hydrocarbons formed according to the maceral composition of the organic matter.

As for the basin of Paris, the numerical simulation has been operated until the estimation of the heat flux according to time by considering : - the maceral composition of the organic matter. - the palaeothermal indicator that is the vitrinite reflectance. - kinetic parameters obtained in laboratory. - subsidence of the basin that includes compaction of the sedimentary units filling the basin.

FMF3 : WEam03 : F4
Subsidence, Thermal and Maturity Modelling of the Northern Foreland of the Mecsek Mountains (Oil and Gas Potential of the Mesozoic Formations)

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Introduction The Mecsek Mountains are situated in southwestern Hungary. The mountains are built up of Mesozoic formations, including a thick coal-bearing sequence. In the northern foreland of the mountains, these rocks can be found under thick Neogene sediments. Few boreholes penetrated these rocks here. My research considers the subsidence, thermal and maturity modelling of this area.

The geology of the foreland The Middle Triassic limestones are overlain by the deepening sequence of Upper Triassic sandstones, thick Liassic coal and spotted marl deposits. These are more, than 2500 m thick in the southern Mecsek, but decrease to the north. The J2 - K3 pelagic limestones and K1 basalts have been eroded north of the Mecsek. The 1000 m thick M1-2 formations and the M3 prograding delta complexes represent the last 2000 thick sedimentary units.

Oil and gas potential The possible oil and gas potential of the area is represented by the presence of a 1000 m thick T3-J1 series, containing:
1. organic-rich lagoon formations of T3 age
2. 500 - 400 m thick Liassic coal deposits
3. 500 - 1000 m thick organic-rich spotted marls
4. a thin black "toarcian shale" with 5-10% Corg (DULAI et al., 1992)

The main field of interest is the T3-J1 sequence. These rocks are rich in organic matter (0,5-5% TOC), and contain II - III type kerogen, so these can be good gas source rocks (RAUCSIK et al., 1999). The rocks are in the oil window in the closest foreland (0,8-1,2 Ro%), and more mature in the northern parts (1,5-2,2 Ro%).

Subsidence, thermal and maturity modelling The maturity modelling of the area had been carried out with PDI/1D software in selected wells, where enough maturity data were available. With the interpretation of seismic sections the tectonic features of the area could be interpreted, and the modelling was corrected.

Summary The Mesozoic formations of the Mecsek Mountains can turn out to be possible source rocks because of the presence of a relatively thick (600- -1000 m) organic rich sequence of T3 - J2 depositss, which are now in the oil window, and slightly underneath. The exact timing of eventual hydrocarbon generation needs a more detailed organic geochemical and structural research.

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FMF3 : WEam04 : F4
Temperature-Dependent Viscoelastic Compaction and Compartmentalization in Sedimentary Basins

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The near surface compaction regime of most sedimentary basins is characterized by hydrostatic fluid pressures and is therefore determined entirely by sediment matrix rheology. Within this regime, compaction is initially well described by a pseudoelastic rheological model. With increasing depth, precipitation-dissolution processes lead to thermally activated viscous deformation. The steady state porosity profile of the viscous regime is a function of two length scales; the viscous e-fold length, related to the compaction activation energy; and a scale determined by the remaining parameters of the sedimentary process (Connolly and Podladchikov 2000). Overpressure development is weakly dependent on the second scale for activation energies > 20 kJ/mol. Application of the steady state model to Pannonian basin shales and sandstones indicates a dominant role for viscous compaction in these lithologies at porosities below 10 and 25%, respectively. Activation energies and shear viscosities derived from the profiles are 20-40 kJ/mol and 10^{20}-10^{21} Pa-s at 3 km depth. The analytical formulation of the compaction model provides a simple method of predicting both the depth at which permeability limits compaction, resulting in top-seal formation, and the amount of fluid trapped beneath the top-seal. Fluid flow during hydraulically limited compaction is unstable such that sedimentation rate perturbations or devolatilization cause nucleation of porosity waves on the viscous e-fold length scale, ~ 0.5-1.5 km. The porosity waves are characterized by fluid overpressure with a hydrostatic fluid pressure gradient and propagate through creation of secondary porosity in response to the mean stress gradient. The waves are a mechanism of episodic fluid expulsion that can be significantly more efficient than uniform Darcyian fluid flow, but upward wave propagation is constrained by the compaction front so that the waves evolve into essentially static domains of high porosity following cessation of sedimentation. Yielding mechanisms do not appreciably alter the time and length scale of episodic fluid flow, because fluid expulsion is ultimately controlled by compaction. The flow instabilities inherent in viscous compaction are similar to, and a possible explanation for, fluid compartments.

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FMF3 : WEam05 : F4
Porosity, Permeability and Compressibility of Fine Grained Sediments: Quantitative Constraints from the ODP

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Quantifying the evolution of porosity and permeability of fine-grained sediments underpins the prediction of fluid flow, seal formation and overpressure generation in sedimentary basins. Constraints on the compressibility and poroperm characteristics of muds have been largely derived from work in soil mechanics and deep within sedimentary basins. This work suggests that the compressibility and poroperm of mudstones are both strongly influenced by clay fraction: finer-grained sediments are more compressible and have lower permeabilities at a given porosity. The limitations of these studies are that (1) the soil mechanics data are mainly derived at very low stress levels and (2) the geological data may be influenced by processes such as mineral recrystallisation and creep. We present here data from ODP samples from intermediate burial depths (100-1000 m), which provide a link between the soil mechanics and geological data sets. Eighty clay and mudstone samples from the DSDP and ODP have been analysed, focusing on the void ratio / effective stress / pore size distribution / permeability relationships. The results support the proposition that clay fraction is indeed the single most important parameter controlling the evolution of void ratio and permeability in mechanically compacted mudstones. At these depths clays and muds lose up to 50% of their initial porosities (40-85%) and calculated porosity/effective stress as well as porosity/permeability relationships agree well with models derived from more deeply buried sequences. Creep, and thus geological time, appears to be of minor importance. Samples containing higher fractions of siliceous nannofossils (e.g. diatoms) deviate from established compaction trends and need to be treated separately.

FMF3 : WEam08 : F4
The Geologist's Role in Seismic Attribute-Based Predictions of Reservoir Properties

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Geologists have important contributions to make in seismic attribute studies and should seek to participate in these projects. As defined here, a seismic attribute study is an attempt to establish then exploit emprical correlations between attributes derived from 3-D seismic data (frequency, amplitude, isochron, coherence, etc.) and wire-line log-derived rock properties (e.g., phi xh, bed thickness, water saturation) to make predictions about those properties away from existing well control (1, 2). For a variety of reasons, it can be difficult (if not impossible) to predict the relationships between attributes and rock properties from first principles. As such, interpreters seek empirical but statistically significant correlations between one or several attributes and a rock property of interest at individual well locations. If such a relationship can be established, it may then be used to predict that rock property throughout the entire 3-D seismic survey area. Multivariate regression, geostatistics and artificial intelligence (e.g., neural networks and fuzzy logic) are amongst the techniques that have been employed in this work.

Seismic attribute studies have proven their value in a variety of geologic settings and hold enormous potential for even more widespread application. There are, however, pitfalls that can befall the unwary analyst(3). Spurious correlations, statistically significant but physically meaningless relationships, are one such pitfall. A drilling program that is based on such a relationship could be disastrous. Given this possibility, the results of seismic attribute studies should be evaluated by geologists to test whether the rock properties prediction makes geologic sense. If so, then the team's confidence in the prediction is enhanced. If not, then the prediction should be rejected, no matter what the level of statistical significance might be. The geologist needs to be open to the idea that the results might make geologic sense, even if they do not conform to his/her preconceived notions. The results of these analyses can provide information that may be used by geoscientists to develop or explore for analog fields, potentially even where 3-D seismic data are unavailable (4). Other approaches, such as investigating the physical basis for the attributes used in the prediction (however qualitatively) should also be employed as risk reduction tools.

Seismic attribute studies will become more widespread as software, interpreters and managers become more sophisticated, and successful case studies are more widely documented. Geologists need to be proactive in these studies to ensure that vital geologic information is not neglected in the process.

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FMF3 : WEam09 : F4
Analogue Modelling of Tectonic Structures and Hydrocarbon Traps: A Mature Technique with Future Possibilities

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Analogue modelling of tectonic structures was first put on a firm basis in 1937 by M. King Hubbert of Shell Oil Co. He described the dynamic scaling of geological models and advocated the use of dry sand as a mechanical analogue for the brittle upper crust. Sandbox modelling was used at the Shell Laboratories for many years afterward. However, it did not spread to academia until the early 1980s, when several other laboratories appeared. In a matter of years, the technique rapidly became more sophisticated, through the combined use of brittle and ductile materials, with a view to modelling structures at various scales, from that of a sedimentary basin, to that of the entire lithosphere. Motivation and funding for this expansion came mainly from the petroleum industry. A notable early success of the method was the modelling of salt tectonics. Silicone putty was the analogue for salt; dry quartz sand, for overlying sediments. Sand could be deposited at a free surface, simulating sedimentation; or vacuumed off, simulating erosion. The experiments succesfully mimicked the formation of listric extensional faults; salt rollers and walls; thrust faults with associated footwall depocentres; minibasins; and so on. The experiments bore out existing theories of gliding and they triggered new understanding, especially of the interactions between faulting and sedimentation. The resulting structures were remarkably similar to those which petroleum geologists were interpreting on seismic data from the Gulf of Mexico and the Atlantic margins. Many other successes have been registered, such as the modelling of thrust wedges, flower strucures, fault reactivation, basin inversion, continental indentation, rifting and even subduction. To this extent, the technique has come of age and many of the most obvious applications have been explored. In comparison with analogue models, numerical calculations have many advantages. Calculations can be reproduced at will, input parameters can be varied systematically, output data can be displayed easily and extra routines can be added, to take account of thermal conduction, fluid migration, transitions from brittle to ductile behaviour, and so on. The future probably lies mainly with numerical models. However, analogue models have a big head start, especially in three dimensions and where faults nucleate, propagate and interfere during ongoing sedimentation. A new and exciting application of analogue modelling is to pore fluids and their interaction with deformation. This is the realm of overpressures, primary or secondary migration, seepage forces and fluid-assisted detachments. It is possible to study how deformation influences permeability, via fault seals or pathways. Many new applications are envisaged, for example to delta tectonics, gas chimneys, pockmarks and other signs of migrating fluids. Once again, collaboration between industry and academia is likely to foster rapid advances in understanding.

FMF3 : WEam10 : F4
Lost Ancient Oil Traced using the $^{20}Ne/^{36}Ar$ Ratio: Hydrocarbon Migration, Rare Gas Distillation and Basin Dynamics

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Fractionated rare gas abundance ratios have often been reported for crustal fluids, as for example the $^{20}Ne/^{36}Ar$ ratio of either natural gas (Ballentine et al. 1991) or aquifer waters (Castro et al., 1998), which reach values of ~ 1.5, starting from 0.1 - 0.2 in either seawater of freshwater equilibrated with air.

Here, we show the results of two studies on natural gas, one in the Indus Basin, Pakistan, the other in the Macuspana Basin, Mexico (Battani et al., 1999, 2000), where gas is exploited but no oil was found. Again, fractionated $^{20}Ne/^{36}Ar$ ratios are found reaching 1.5 in Pakistan and as high as 5 in Mexico. The He-Ne-Ar systematics suggests that the elevated $^{20}Ne/^{36}Ar$ values appear together with low rare gas concentrations and, in most cases, radiogenic $^{40}Ar/^{36}Ar$ isotopic ratios.

These fractionated abundance ratios are classically interpreted by small volumes of gas equilibrated with large volumes of water, but such models cannot account for $^{20}Ne/^{36}Ar$ higher than 0.6 and certainly cannot explain a value of 5. We therefore proposed another model where the elevated $^{20}Ne/^{36}Ar$ ratios appear in water that was in contact with migrating oil in the past. Rare gases have stronger affinity for oil than for water and this behavior is enhanced for the heavier ones. Oil-water contact must thus induce rare gas depletion together with an increase of the $^{20}Ne/^{36}Ar$ in water. Natural gas should then have contact with the depleted water, thus taking the fractionated rare gas signature.

Using Henry's law constants we found that a distillation for rare gas abundance ratios provides a better fit to the data, in part because fractionation in the residue is not limited in this case. A Rayleigh law therefore can fit the very elevated $^{20}Ne/^{36}Ar$ Mexico data. Distillations for both the oil-water and the following gas-water contact is our preferred model. This double distillation model also provides temperatures, which are found to be of 100-150°C for the oil-water stage and of 15-90°C for the gas water stage. These values are reasonable and suggest an upward migration of part of the rare gas depleted water. Consideration of present reservoir depths suggests a dynamic view where a gas accumulation could be buried to greater depths after emplacement. The model further provides estimates for both distillations intensities, which can be translated into Oil/Water and Gas/Water volume ratios. Gas/Oil volume ratios obtained by simply dividing the latter ratios are of 40-150 for Pakistan, and of 5 for Macuspana. Such low values suggest a correction due to water migration which would be a measure of the fraction of water that migrated before the gas-water stage.

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FMF3 : WEam11 : F4
Overpressuring from Mineral Dehydration

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Although we normally define equilibrium to require the temperature, pressure, and chemical potential to be identical in all phases, sedimentary rocks usually have pressures on the solids greater than the fluid pressure. The simplest approach is to examine fluid-solid equilibrium, specifying that the temperature and chemical potential of water are the same in all the phases, but allow the fluid pressure to be different from the pressure on the solids. The clay minerals in mudrocks are the most abundant hydrated phases. The major conclusion of this paper is that temperature determines how clay dehydration apportions the total overburden load into a fluid pressure and a solid pressure.

Pitzer and Brewer(1961)derive a Clapeyron equation for the pressure on different phases as a function of the temperature. Translating their result into the terminology used by Hubbert and Rubey (1959) gives an expression for the effective stress σ as a function of temperature:

$$\sigma = -\Delta H/V_w \log(T/T_o)$$

In this expression, all the solid phases are presumed to be at the same pressure.

The dehydration of gypsum to anhydrite illustrates the application of this equation. If a permeable connection exists to the surface, rising temperature simply causes the gypsum to dehydrate to anhydrite. However, if a permeable path does not exist, then increasing the temperature causes the effective stress to go towards zero and causes the system to become fully overpressured.

Amongst the clay minerals, sodium-exchanged Llano vermiculite exhibits a transition from two to one water interlayers that is essentially as sharp as the dehydration of gypsum to anhydrite. However, the equivalent dehydration stage in montmorillonite is spread over a range of 20 K. The equation above is applicable to isosteric properties: to contours of equal water content. The transition from two water interlayers to one in montmorillonite is interpreted to be the dominant cause of overpressuring in the U.S. Gulf Coast.

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FMF3 : WEam12 : F4
Porosity Preservation and Creation: Sandstone Cementation in Hydrocarbon Basins

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The study of sandstone cementation often has two objectives: 1) Reconstructing the subsurface motion, or stasis, of fluids and mass-transfer; 2) Prediction of economic porosity and permeability in hydrocarbon fields (Haszeldine et al 2000).

A major cause of porosity reduction is fill by quartz cement. During normal deep burial to 4 km, quartz is supplied by local pressure-solution. The resulting porosity can be successfully simulated in deep aquifers, and cementation is sometimes considered to continue at the same rate in the oil zone. However predictions of porosity in the oil zone are sometimes much lower than observations. We consider this to be evidence that oil charge greatly slows cementation, and can preserve exceptionally high porosities >20% at 4 km (Marchand 2000). Differences of porosity preservation are due to differences of timing in oil charge. Silicon isotope ratios have been newly applied, to discriminate quartz cement originating from biogenic sources from cement derived by pressure solution. Consequently two gradients of porosity decline exist: above and below the oil-water contact, with water zone dynamic permeabilities sometimes 40x less than those of the oil zone.

Creation of secondary porosity during deep burial has in the past been suggested to be unimportant due to retention of clay products redistributed into microporosity. By contrast, we have discovered systematic patterns of potassium feldspar dissolution during deep and super-deep (6 km) burial (Haszeldine et al 1999), with export of clay products from the sandstone. Similar processes occur in several basins in the UK, Norwegian and USA offshore (Wilkinson et al 2000), so that bulk sandstone composition changes from arkose to quartzite, by progressive removal of albite (Na-orthoclase) with increased depth. Even though 10-20% of the rock may in total be dissolved, at any individual depth only 3% secondary porosity is visible within a sandstone; we consider this to be due to continued compaction during deep burial. However in geopressured basins, up to 10% porosity can be held open at 6 km.

When geopressured structures expel fluid by vertical migration, the hydrocarbons may contribute to authigenic clays or carbonates at shallower depth, and can be tracked by distinctive hydrogen and carbon isotope ratios (Macaulay et al 1999). This could enable detection of deep seal failure. The timing of fluid motion can be K-Ar dated in fibrous illite, which greatly reduces permeability. New theoretical insight shows that illite growth is controlled and limited by micro-crystallite size. Consequently fibrous illite can only grow during fluid flow periods, and is not controlled by equilibrium thermodynamics as previously proposed. This enables calibration of basin models back in time.

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FMF3 : WEam13 : F4
Tracing Sources of Natural Gases

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The past five years have seen dramatic changes in our understanding of natural gas origins and the development of new methods for determining their source and thermal maturity. Early understanding of the isotopic ratios of gases was academically led. The first models were purely empirical, often leading to ambiguous interpretations when applied to exploration problems. Subsequently, more scientifically rigorous models were proposed based on the temperature control of isotopic separation or calculation of isotopic equilibrium. The later recognition that carbon isotope ratio was controlled by kinetic isotope fractionation, and required inclusion of a Rayleigh distillation component for interpretation, led to predictive models which could be better adapted to specific exploration roblems. All these later developments were spearheaded by industrial laboratories and tracked the rise in the application of geochemistry in general in petroleum exploration. Most recently, industry and academia have worked more closely together and the development of new industrial interpretation methods hinges strongly on academic research into the precise chemistry and physics of oil and gas generation processes at the atomic level.

This new understanding is illustrated by a study of gases in the Malaysia-Thailand joint development area. Gas and occasional oil is generated from a thick sequence of Tertiary coals ranging from immature to highly overmature. Detailed chemical and isotopic characterisation of gas samples indicates fundamental differences in the nature of the gas charge in passing from the central inversion zone, where the gases are exceptionally homogeneous, to the basin flanks where they are more variable. The nature of the gases within the Central Inversion Zone indicates extensive mixing during migration, which here can be demonstrated to be dominantly vertical during a major expulsion phase during late Miocene inversion. In contrast, gases from wells on the basin flanks indicate derivation from mixtures of oil-associated, cracked oil and gas-prone coal sources. Using the isotopic differences between individual hydrocarbon components of these gases it is possible to derive the relative proportions of cracked oil versus pure “coal” end member gases and to rank each of these in terms of maturity. It is then possible to calibrate the local generation profiles of the source rocks in terms of temperature and timing of gas, and oil, expulsion and hence deduce migration distances and trapping efficiencies. Similar methodology has been applied to gases from the Norwegian North Sea to determine the relative contributions of gas from the oil-prone Spekk formation and the gas prone are coals.

FMF3 : WEam14 : F4
Quantitative Chemical Mapping of Adsorbed Scale Inhibitors on Representative Reservoir Mineral Surfaces

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The formation of inorganic scales (Ca, Mg carbonates and Ba, Sr, Ca sulphates) is a critical problem in oil extraction that can cause serious decline or an early halt to production. The most effective preventative measure to scaling is the application of crystal growth retarders (scale inhibitors). These are emplaced to react, either by adsorption or precipitation, at the rock surface in the near wellbore formation. Continual desorption of the scale inhibitors into the produced fluids then protects the well against scaling. Current evaluation of the effectiveness of scale inhibitors involves wet chemical or spectroscopic analysis of fluids exposed to core samples derived from coreflood experiments. Numerous analytical problems limit predictions that can be made based on current experiments.

Although it has been shown that the mineralogy of the treated rock has a significant effect on scale inhibitor adsorption/desorption (Jordan et al., 1994), only a few studies have been directed at quantifying scale inhibitor chemical loading on such substrates (Hill et al., 1997).

In this study a range of different minerals, representing detrital and authigenic components of a typical reservoir sandstone, have been treated with a number of different generic types of scale inhibitor. Evaluation of the level of scale inhibitor on each surface has been determined using a range of ultra sensitive surface analytical techniques capable of determining S, P, C, O and N.

Electron Probe Microanalysis (EMPA) has been unable to detect any scale inhibitor adsorption onto quartz, feldspar, or calcite surfaces. Precipitates of scale inhibitor have been documented, which occur as micro precipitates within fractures or at cleavage steps. In reactions with kaolinite, EMPA has been used to quantify the scale inhibitor loading between different generic types of scale inhibitors.

Particle Induced X-Ray Emission Spectroscopy (PIXE) has the capability to determine light elements at much lower detection levels in comparison to EMPA, and with much greater sensitivity and probe resolution (Grime et al., 1991). This is ideally suited for depth sensitive analysis of adsorbates, such as scale inhibitors, at ultra-low concentrations. Even with these advantages it was not possible to detect any scale inhibitor adsorbed onto quartz, feldspar or calcite in the normal operating set-up. Glancing incidence (Wogelius et al., in press) has been utilised to increase detection levels further and is now being developed to quantify scale inhibitors adsorbed at ultra-low concentrations.

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Wednesday PO Session

FMF3 : WEpo01 : PO
Simulation of Eustatic-Driven Contrasted Flow Patterns in Great Bahama Bank

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Understanding diagenesis requires the knowledge of fluid flows as they are important for the import or the export of the dissolved elements that take part in the reactions of precipitation/dissolution. Understanding flow is especially essential for dolomitization, as the local sources of magnesium are generally not sufficient for complete dolomitization, which usually necessitates an important external contribution. This is the case for the dolomite observed in the wells on the western margin of the Great Bahama Bank and most of all for the completely dolomitized reefal unit of well Unda (292-360 m; Messinian). The Kohout thermal convection is considered as one of the main mechanisms that moved the fluids through the reef. However this remain uncertain, as is the timing of dolomitization.

In order to test this hypothesis, the numerical modelling is used in the context of the Great Bahama Bank to specify the directions of flow and to quantify the fluid flow velocities, while taking in account the morphology of the layers, the structure of the margin, the sea-level fluctuations and the petrophysical properties of sediments.

TEMISPACK developed in the Institut Français du Pétrole is a basin modelling software that is used to reconstruct the geological history of a section in a sedimentary basin. Using physical laws for flowing, packing, conduction and convection, this numerical code describes the compaction of the sediments, the temperature, the pressure, the fluid flows and the variations of permeability with porosity through the geological times with regards to the evolution of the basin geometry, but it does not simulate diagenetic processes.

TEMISPACK was used to reconstruct the history of the northwestern margin of the Great Bahama Bank, along the section constructed from the seismic profile *Western Geophysical Line*. The simulations showed that : 1) during periods of high sea-level, some important incoming fluid flows can take place from the open ocean to the interior of the platform, in the more permeable facies. These flows are in good agreement with the Kohout-type thermal convection ; 2) the Kohout convection is actually controlled by the variations of the fluid density. This type of convection induces fluid flow velocities much higher (up to 1,3 m/y in the reef) than those due to compaction alone ; 3) this hydrodynamism reverses during periods of low sea-level if the meteoric recharge is sufficient. In that case, a reflux-type mechanism of the pore fluids from the top of the platform takes place, with fluid flow velocities higher (of the order of 10 m/y) than in the case of the Kohout convection cell as long as the hydraulic head is maintained.The variations of temperature and permeability anisotropy are here less crucial parameters than for the Kohout convection.

FMF3 : WEpo02 : PO
Intermittent Basin-Wide Fluid Reorganisation Triggered by Pressure Drop of Cap-Rock: North Sea Central Graben

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The formation of rift basins can roughly be subdivided in two phases. In a first phase, subsidence mainly due to tectonic faulting causes a compartmentalisation of the rift structure into several grabens. The sedimentary fill of these individual grabens can be highly variable. In a second phase, on top of the faulted structure thermal subsidence develops, which leads to the formation of a continuous basin, filled homogeneously with fine-grained sediments.

The two rift phases create superimposed basins of different tectonic styles and with distinct pore pressure regimes. The later rift-fill forms a sediment-cap over the early high-pressured graben system. In many rifts, the pore pressure of the sediment-cap is overpressured, which frequently is explained as a consequence of under-compaction. Hydrofractures, caused by pore-pressures exceeding rock-fracture pressure, often deform the basin cap-rock.

A new method to reconstruct pore pressure history for basin cap-rock is proposed. This method, based on observed hydrofracture geometry, and on measured minimal rock strength, models the influence of cap-rock pressure on pressure and fluid behaviour in the deep graben compartments. It is assumed that with proceeding subsidence, pore pressure of the cap-rock increases due to under-compaction. As soon as pore pressure reaches the minimal fracture pressure, the cap breaks and pressure depletes to hydrostatic. With further subsidence overpressure builds up again until minimal fracture pressure is reached and a new hydrofracture layer is generated.

As an example, the model is applied to the North Sea Central Graben, where five layers of hydrofractures of regional importance can be mapped from seismic data of the cap-rock. Intermittent ruptures, consequent pressure drops and fluid expulsions of the Central Graben cap-rock occurred from late Oligocene to Pliocene, with a major event taking place at the end of the Miocene. The model shows that pulses of cap-rock pore pressure influence significantly pore pressure and fluid migration in the deep basin. With the reorganisation of pressure and fluid regimes thermal gradients will change as well. This finding is of importance to the oil prospection in rifts as the North Sea, where hydrofracture activity and hydrocarbon maturity/migration happened simultaneously.

FMF3 : WEpo03 : PO
Ultrasonic Velocity Measurements: A Useful Tool Combined with Petrophysical Investigations to Characterize Porous Solids

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In a reservoir rock, acoustic velocities are strongly linked to petrographical and petrophysical properties. The interaction between mechanical waves and the porous medium shows large-to-local scale effects like reflection, refraction, diffraction and attenuation. Reservoir engineers know these difficulties in data logging and well to seimic data interpretation. We have already developed a method to describe the pore space using the dynamics of mercury injection (Hg-porosimetry). In addition to porosity, pore throat size and distribution, the pore space can be splited in subspaces of increasing complexity. Contribution of each subspace to the total porosity and permeability of the sample can be evaluated. One objective of this work is to relate petrophysical properties to velocity variations. We measure acoustic velocities by propagating ultrasonic waves in samples of variable and well known petrographical and petrophysical properties. The experimental assembly consists in a transducer generating a 54 KHz ultrasonic signal. The propagating wave is detected by a receiver located on the opposite face of the sample. The propagation time is known with 0.1µs accuracy, allowing the detection of small velocity variations. Sample sizes were choosen to be greater than the wavelength of pulse vibrations to obtain coherent results and minimize diffraction. These samples show large variation of porosity, permeability, specific surface and distribution of pore throat size. We quantify the relations between acoustic velocities and petrographical properties, particularly texture, alteration, fracturation and sedimentary anisotropy. Variations with water saturation are carefully checked. Velocities are also related to petrophysical parameters which give us informations about the pore space and its complexity as defined by penetration thresholds numbers and the time of core saturation. We also use image analysis data which give a 2D description of the porosity and a morphological description of the pores. In conclusion, the use of acoustic velocity measurements gives complementary information to describe and characterize porous media.

FMF3 : WEpo04 : PO
Tectonic Burial and Exhumation in the External Areas of Southern Apennines Thrust Belt (Italy): The Alpi Mt. Case History, Implications for Petroleum Exploration

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Amounts and rates of shortening and erosion in thrust belts are key data to define the thermal history of source and reservoir rocks in petroleum plays. Nevertheless their estimations are generally affected by huge errors in complex areas of collisional belts. Thus, organic and inorganic parameters of the thermal evolution of sedimentary rocks are widely used to calibrate the structural modelling of orogens' evolution. The Southern Apennines, a prolific hybrocarbon province of Italy, is an example of such a complexity. It includes tectonic units derived from the Neogene deformation of the Meso-Cenozoic passive margin, and ovelying Mio-Pliocene foredeep and thrust-top basin deposits. The upper part of the belt consists of allochthonous units derived from the deformation of peritidal carbonate platform and pelagic basin successions of Triassic to Paleogene age, and of the overlying foredeep deposits. These are detached from their original substratum and transported onto the buried thrust belt and the foreland carbonates of the Apulia platform. Among these units, it is the Apulian foreland and associated structures on the margin of the belt that have received most attention for oil and gas exploration. They consist of Mesozoic-Tertiary, 6-7 km thick shallow-water carbonates stratigraphically overlain by upper Messinian and/or Pliocene terrigenous deposits. These units are always buried in the chain, apart from the small structure of Alpi Mt. outcropping in tectonic window and surrounded by allochthonous thrusts as a result of tectonic uplift and erosion. Aim of this poster is to quantify the amount of load exherted by thrust sheets in Neogene times on this structure, to identify the tectonic mechanism of uplift and to estimate the rates of erosion in Plio-Quaternary. Burial and thermal histories were reconstructed using the software BMod1D and calibrated with new vitrinite reflectance, fluid inclusions and clay minaralogy data. Modelling shows that after a progressive burial due to the carbonate platform evolution during Jurassic, a hiatus in sedimentation occurred between the carbonates deposition and the Miocene sedimentation. In Lower Pliocene thrusting of the allochthonous cover brought to the burial of the structure and a subsequent permanence in the footwall of the regional thrust at depths greater than 3750 m for about 2 my. Since Upper Pliocene the tectonic overburden started being eroded at a constant rate of about 1 mm/y up to a complete erosion. The calculated curve of maturity is in good agreement with measured thermal indicators (e.g., Ro% data ranging between 2.6 and 1.5% respectively at the bottom and the top of the succession, I/S mixed layers with a 70-80 percentage of illite at the top). Fluid inclusions show lower thermalities (homogenisation temperatures ranging between 100° and 120°C) as they were trapped after the emplacement of the allochthonous thrusts as deduced from structural analysis.

FMF3 : WEpo05 : PO
Chlorine Isotopes in Residual Salts from the Elgin and Elgin-West Oil Fields (North Sea)

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The Elgin and Elgin-West Oil Fields are deep seated (burial> 5 kms), HTHP (190°C, 1100 bars) gas condensate fields in the Central Graben of the North Sea (U.K.). The hydrocarbons are trapped in the Callovo-Oxfordian Fulmar sandstones (155 Ma). The two fields are separated by a sealed fault. The salts precipitated in pores by the evaporation of formation water as cores dry out, are known as residual salts. They allow a record of the variation of the chemical and isotopic compositions of formation waters during the filling of reservoirs by hydrocarbons. The pattern of $^{87}Sr/^{86}Sr$ ratio with depth throughout core sections of reservoirs depends on the hydrocarbon filling history: presence or absence of sealed faults and of horizontal sedimentary barriers (Mearns et McBride, 1999). The two stable isotopes of chlorine, ^{35}Cl and ^{37}Cl are present in nature in the respective abundances of 75.8% and 24.2%. The $\delta^{37}Cl$ values are measured by gas spectrometric techniques and are expressed relative to the SMOC (standard mean ocean chloride). The mean precision on these measurements is ±0.05‰. Chlorine isotopic measurements of residual salts are an additional tool to estimate the hydrocarbons'origin, to understand and model their movements and to characterise the different fluids present in the reservoir (e.g. formation waters, fluids associated with oils). Seven of the twenty-four samples analysed for chlorine isotopes come from a well in the main Elgin field, at depths ranging from 5278 to 5365 metres (below sea level). The seventeen others come from a well in the Elgin-West field, at depths ranging from 5572 to 5763 metres. In this second field the hydrocarbon-water contact is located near 5702 metres. The $\delta^{37}Cl$ measured on the Elgin samples range from -0.80‰ ±0.02 at the top of the reservoir to -0.65‰ ±0.06 at its bottom. For the Elgin-West field, the $\delta^{37}Cl$ range from -1.02‰ ±0.06 at the top to -0.57‰ ±0.05 at the bottom of the profile. The $\delta^{37}Cl$ values thus increase with depth for both wells. Moreover, the $\delta^{37}Cl$ variations follow the strontium isotopic profile versus the depth. A rough relation between the $\delta^{37}Cl$ values and the rock porosity and permeability characteristics is also to evidenced. These results can be interpreted in terms of the filling history of the reservoir and the change of $\delta^{37}Cl$ of the fluids migrating with the hydrocarbons. The evolution of the formation water $\delta^{37}Cl$ signature could also result from physical processes such as diffusion (Eggenkamp and al., 1997), or ion filtration (Phillips and Bentley, 1986).

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FMF3 : WEpo06 : PO
Petrological and Geochemical Organic Characteristics of Coal Samples from the Asturias Basin, NW Spain

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The Asturias Basin in the Cantabrian Zone (NW Spain) is divided, for geological features, into five regions: 1) Fold and Mantles, 2) Carboniferous Central Basin, 3) Mantles (Ponga's Mantle), 4) Europe's Peaks, and 5) Pisuerga-Carri-n.

From a stratigraphic point of view, Asturias Basin shows a quasi complete paleozoic succession, with some local hiatus. This succession is characterized by the carbonate sediments alternating with siliclastic rocks. The oldest rocks, principally siliclastics, show a Precambrian to Carboniferous age. The sequence is affected by the Hercynian Orogeny during the Late Carboniferous. The area structure is generally controlled by fault-related folds.

The Asturias Basin contains the most important Carboniferous coal deposits in Spain. At present, these coals are used in a conventional power plant and in the largest integrated plant of gasification combined cycle in the world. In fact, detailed petrological and geochemical coal characterization is vital for industrial purposes.

In this study, coal samples of the Asturias Basin were collected from the Carboniferous Central Basin region. All the samples were picked up on Maria Luisa Unit's coal layer of the Sama Group (Valdeteja Formation - Westfalian). The maceral characterization of these coals in association with the bitumen geochemical analysis allows their maturation rank to be determined. The maceral petrographic identification was carried out by reflection and fluorescence microscopy, whereas the molecular analysis was carried out by gas chromatography - mass spectrometry (GC-MS) allows us to characterize the coal bitumen fraction.

A narrow relation between the sedimentary diagenetic factors and the organic matter evolution for the coal-bearing region is pointed out. The Vitrinite reflectance, between 0.5 and 1.5 in the different samples, underline an oil-gas window evolution of the organic matter. The data have been compared with a numerical simulation called METAGAZ. This kinetic model determines principally the thermal evolution of the chemical and maceral composition in relation to the production of gas from coal.

FMF3 : WEpo07 : PO
Geodynamic Types of Global Belts of Petroleum Occurrence and their Peculiarities

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The main belts of petroleum occurrence are confined to the passive margins of the continents - recent and ancient. Recent margins form three global belts which can be confined as subtypes different in time and stages of rifting-spreading: Indooceanic-Atlantic, Circum-Arctic and Mediterranean-Persian. Sedimentary basins of all three sybtypes are characterized by high rate of sedimentation of up to 5-10 cm/10^3 but differ by recent thermal regime. The first subtype has increased thermal regime with depth of isotherm 1000ºC of 2-2.5 km in different basins. The second two subtypes are characterized by other thermal regime where the temperature of 1000ºC is established at depths of 5-7.5 km. In the case of ancient passive margins, large fields are connected with reef massifs. The post-rifting stage of this belts can be finished by thrusting emerged near orogen and accompanied by formation of fore deeps and multilayer nappe stuctures. The second type of petroleum belts is confined to active margins of these are Circum-Pacific Rim and Western Mediterranean. As a peculiar subtype by their association with different-age zones of subduction, the basins of the Caspian - Black Sea region can be distinguished. Subsidence on the last stage are accompanied by avalanche rate of sedimentation up to 30 cm/103 years. The increased thermal regime (except for the basins of the Caspian - Black Sea region) with isotherms 1000ºC from 1.5 to 2.5 km contributed to quick generation of organic matter and most total realization of petroleum potential. The third is intraplatformal type of oil-gas bearing belts associated with continental platforms. It is subdivided into subtypes - rifting proper and epirifting. In the first case, thermal regime is low with a depth of isotherm 1000ºC of about 5 km, in the second case, it is rather high with a same depth ranging between 1.5-0.5 km. The forth type includes the basins of intermontane troughs of orogens. The basins of this type are rather small but deep with great thickness of sediments and high sedimentation rate of 3-6 cm/103 years at the Late Cenozoic stage. The thermal regime with a depth of isotherm 1000ºC range from 5 km in intermontane basins of young orogens to 1.5-2.5 km in renascenced orogens. For estimate of petroleum potential in each basin, it is necessary to take into account a number of endogenic factors: thermal regime, deep fluids, lateral stress, rate of sedimentation etc.

FMF3 : WEpo08 : PO
Comparison between Outcrop-Spectral Gamma Ray (SGR) Logging and Whole Rock Geochemistry: Implications for Quantitative Reservoir Characterisation in Continental Red-Bed Sediments

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A high-resolution SGR log, whole rock geochemical study and detailed facies analysis have been produced for a reservoir scale outcrop analogue; the Otter Sandstone Formation, east Devon, UK. The character of the SGR log is consistent with observed sedimentological observations. The relationship between the measured radio-elements K, U and Th in the SGR log show statistical similarity, however, do suggest partially separate sources for the natural radioactivity. SGR data compare closely to that generated for point samples by inductively coupled plasma (ICP) techniques for the three radio-elements. Differences between the two datasets are attributable to the different sample nature i.e. that SGR data is an average of a large rock volume, whereas geochemical samples report the geochemical nature at specific points.

Geochemical point samples highlight specific conditions e.g. heavy mineral bands, thin clays and carbonate cemented horizons on which the relationship between radio-elements and mineralogy is rigorously tested. Potassium resides predominantly in K-feldspar and illite, U concentrates in clay prone samples and carbonate minerals and Th is linked primarily, though not exclusively to the heavy minerals monazite and zircon.

The differences in radio-element origin established by whole rock geochemical data enable lithotypes in the Otter Sandstone Formation to be discriminated effectively using element ratios, which have then been applied to the SGR data. A Th/U ratio of 4 separates good reservoir quality lithotypes e.g. uncemented sand from poorer reservoir quality horizons e.g. mudstones and carbonate cemented sandstones. Application of a K-log cut-off to the Th/U log separates low quality reservoir horizons into those comprising clay prone sediments and those comprising carbonate cemented horizons. The identification of these two distinct types of horizon has significant implications for reservoir quality prediction when compared to overall sedimentary architecture.

This study suggests that SGR logging in both the subsurface and outcrop is an excellent geochemical tool with significant implications for real-time reservoir quality prediction. Reciprocally, it is appropriate for geochemical point samples from cores or outcrops to be compared to downwell petrophysical data. This study highlights that interdisciplinary work between separate techniques enhances the characterisation of continental red bed reservoirs.

FMF3 : WEpo09 : PO
Oil and Gas of the Russian Arctic Shelf

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The sedimentary basins of the Russian Arctic shelf with respect to their hydrocarbon potential are comparable to the major oil and gas bearing provinces of the world. Russian shelf as a whole contains about 1/3 potential gas resources of Russia and a large portion of oil and condensate. Arctic Seas of Russia contain more than 85% of total shelf resources. The most important areas are Barents and Kara Seas with about 4/5 of total Arctic shelf hydrocarbon resources.

The quantitative estimates of the oil and gas potential show that the age of established or inferred productive units varies from Paleozoic dominating in the west to mostly Mesozoic and Cenozoic in the east.

Sedimentary basins of Russian Arctic shelf are different in oil / gas ratio. Higher gas content is characteristic of the Barents Sea sedimentary basins (excluding the offshore projection of the Timan-Pechora oil and gas province), south Kara Sea, and south East Siberian and Chukchi Seas. The reason of it is predominance of humic OM or / and subsidence of the sediments deeper than 4 km where they enter the gas window.

It was concluded from the analysis of the hydrocarbon systems of major sedimentary basins on the Russian Arctic shelf that giant hydrocarbon fields can exist within those basins. This forecast was confirmed by the discovery of four gigantic condensate fields in the Barents and south Kara Seas despite low amount of drilling.

FMF3 : WEpo10 : PO
Geochemical Characteristics of Coals in the Eskihisar (Yatagan) Area, Western Turkey

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Study area lies to SE of the town of Yatagan, Mugla province. The area is underlain by Paleozoic age schists and Mesozoic age marbles. Neogene age sediments that include coal horizons overlie the basement rocks. In this study geochemical characteristics of Eskihisar coals were investigated by proximate, elemental and trace element analyses. Coal analyses (moisture, ash, volatile matter, fixed carbon, total sulphur and net calorific value) were carried out on air dry coal samples. The moisture, ash, volatile matter, fixed carbon, total sulphur and net calorific values are respectively 8.20 - 12.32%, 23.18 -48.25%, 32.84 -41.44%, 23.56 -25.84%, 2.02 -2.65% and 3800 - 4316 Kcal /kg. On dry ash-free basis values suggest the samples are sub-bituminous A and Lignite according to ASTM (Stach et al.,1982). On dry ash-free basis, carbon, hydrogene, oxygene and nitrogene contents of the coals are respectively 64.25 -71.37%, 6.04 -6.17%, 18.53 -28.46% and 0.88 -1.24%. on the basis of these values; according to elementel composition diagram (Tassot and Welte, 1984) coalification degree falls between lignite and brawn coal and this result is also consistent with the ASTM classification of proximated analysis values.

Eskihisar coal ashes have the following trace element contents in ppm; average (min-max), Co:12(9-36), Ni:88(61-131), V:55(10-229), Rb:43(23-108), Zn:45(13-167), Pb:135(53-256), Cr:113(24-481), Cu:67(22-216), Sr:190(104-477), Zr:155(64-764 , U:30(10-109).

As a result it can be said that ash content of Eskihisar coals that are between lignite and brown coal class is high, total sulphur amount is not so high, but because the amount of volatile matter is very high, Eskihisar coals give low calrific values. According to analysis results, trace elements are found in coal ashes as a rising amounts, but they show low concentrations.

FMF3 : WEpo11 : PO
Timing of Illite Formation in the Cooper Basin, South Australia

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Petrographic and K-Ar isotopic investigations were carried out on Late Carboniferous and Early Permian sandstones of the onshore Cooper Basin in South Australia. Illite and kaolinite are the most abundant clays in these tight gas sandstones and cause significant reduction in permeability and producible reservoir porosity. Illite is characterized by a range of morphologies, has crystallinity values consistent with high grade diagenesis and has no expandable mixed layer smectite component.

Petrographic investigation reveal that illite is present in three different forms (1) as platey detrital grains, (2) as pore bridging authigenic filamentous grains and (3) as tightly packed arrangements of platy morphology comprising the main alteration product in volcanic clasts. Separation of these three different illite phases constitutes a major challenge for K-Ar age dating.

K-Ar ages of illite separates from different stratigraphic units, depths and grain sizes (from <0.5 to 2-6 micron) yield values ranging from 390 ±5 to 92±1 Ma. The wide age spread reflects the different timing of formation of the different the different illite modes of occurrence. The age range can be interpreted using the detailed mineral characterizations obtained from XRD and TEM analyses and burial history modelling across the basin. The dates obtained provide a record of the age of the detrital illitic material, the timing of alteration of the volcanic clasts and timing of illite neoformation. In one well the date obtained is tentatively interpreted the timing of illite polytypic in a well that had experienced a high maximum burial temperature (>250ºC).

FMF3 : WEpo12 : PO
The Catagenetic Zones and Modeling of the Sediment Heating in Timan-Pechora Basin

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The sedimentary cover of the Timan-Pechora basin, which thickness varies 0.5-0.7 km within the platform and 3-12 km in the Pre-Ural foredeep, is subdivided into 10-12 source horizons. They differ in their lithological-facial structure, quantity and type of organic substance, hydrocarbon generation potential, position of catagenetic zones and hydrocarbon generation. Thus, Silurian, Late Devonian and domanic deposits are mainly oil source, with oil generation in 2-3 times exceeding gas generation; to oil-and-gas source rocks are terrigenous Devonian, Upper Frasnian - Famenian sediments, in which the scales of oil and gas generation of oil and gas are close, with gas generation prevailing in the upper part of the sedimentary cover. Modeling of the sediment heating, based on vitrinite reflectance, bitumen and organic substance data, have allowed us to establish a ‘reduced’, practically oil series of catagenesis within stable blocks of the platform and complete catagenic series in separate zones of the aulacogen and in the Pre-Upal foredeep.

FMF3 : WEpo13 : PO
Basin Settings and Depositional Environment of the Napo Group (Subandean Zone and Oriente Basin, Ecuador)

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The late Albian to Campanian Napo Group of the present day Amazon Foreland Basin sequence of Ecuador has previously been divided into the Napo Basal (basal), Napo Inferior (lower), Napo Medio (middle) and Napo Superior (upper) and has a maximum thickness of 500 m. Strata consists of marine shales, marls and sandstones, and the lithological variations and hiata, correlate with relative sea level changes (eustatic and tectonic activity). The sandy units are oil bearing in many of the most productive oilfields in the flat lying region of the Foreland Basin (locally referred to as the Oriente Basin). The shale and marl strata are commonly considered to be a hydrocarbon source, due to their high organic content. Present day exposure of the Napo Formation is restricted to the Napo and Cutucu antiforms in the Subandean Zone, which form topographic highs proximal to the Andean Sierra. The sediments were deposited in a shallow (~ 20 - 40 m deep) marginal basin that was subsiding slowly within a mixed carbonate - siliciclastic system. The basin was bordered by the Guyana Shield to the east and an incipient Andean chain to the west. A possible connection with the early Atlantic Ocean existed via Colombian and Venezuelan Cretaceous basins. Preliminary results of the analyses of organic material suggests a strong variation of the origin of organic matter. Black shales of source rock quality show very high contents of marine organic matter. Other pelites contain abundant terrestrial derived phytoclasts. Deposition of the Napo Group post-dates the accretion of terranes that comprise the present day Cordillera Real (eastern Andean Sierra in Ecuador) against the Guyana Shield during the Peltetec Event (140 - 120 Ma). A strike-slip system may have prevailed during the deposition of the Napo Group.

Regional tectonic and radiometric data suggest that an important transpressive tectonic event occurred during the Santonian - Campanian period, driven by the accretion of the oceanic Pallatanga Terrane against the north western South American margin. In the Oriente Basin this event resulted in the erosion or non-deposition of rocks of the Napo Superior (upper Napo Group) in the Subandean Zone and the subsequent deposition of continental Red beds of the Tena Formation (Maastrichtian - Paleocene), which marks the transition to a Foreland basin system with terrigenous input from the uplifting Andes to the west.