

# Patterns of fluid flow in the East Coast Basin

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## Abstract

The East Coast Basin, situated on the frontal arc of the Hikurangi subduction zone, is a region of increasing petroleum exploration activity. The widespread distribution of oil and gas seeps across the region proves the existence of mature source rocks. However, Late Cretaceous to Paleocene source rocks are separated from Neogene reservoirs by a sequence of Paleogene mudstones, so an improved understanding of migration pathways is critical to assessing petroleum prospectivity. Mudstone properties prove to be an important controlling factor in the migration of hydrocarbons. The presence of high-pressure formation fluids encountered during drilling is due to rapid burial, uplift and shearing, linked to sealing by the widespread low-permeability mudstones. Smectite content of mudstones is shown to control porosity, permeability and fracturing behaviour of the seal. The maturation, expulsion and migration of hydrocarbons from a series of Late Cretaceous and Paleocene source rocks are modelled using finite element based numerical modelling tools. High resolution 2D models are developed to illustrate migration of hydrocarbons from potential kitchen areas to traps along a cross-section in the Hawke Bay area. Migration channels considered in the models include faults and fractures as well as lateral flow along more permeable clastic formations. The application of these techniques illustrate the importance of understanding the timing of denudation related to faulting, maturation and structural development in assessing the likely exploration risk of specific prospects.

## Introduction

The East Coast Basin is perhaps New Zealand's most prospective basin after Taranaki. The 1998 Kauhauroa-1 gas discovery increased exploration focus in the East Coast Basin (ECB), and demonstrated the presence of a working hydrocarbon system. The region has promising Palaeocene and Cretaceous source rocks that have generated and expelled hydrocarbons (Field et al. 1997, Rogers 1995), effective Cretaceous-Pliocene reservoirs (Francis 1998), and abundant seals and structures. However, the element of the hydrocarbon system that has received little attention to date is migration. This study aims to identify critical issues in migration in the ECB, and advance a series of generic quantitative basin models to illustrate patterns of fluid flow.

Figure 1 shows the location of the ECB, and the position of wells discussed in this paper. Field et al. (1998) reviewed fluids and migration systems in the region. The position of the ECB on the frontal arc of the convergent Hikurangi subduction zone has led to rapid sedimentation and uplift, with rates approaching  $1000 \text{ m Ma}^{-1}$  (Field et al. 1997). The basin is structurally complex, containing structures related to compressional, extensional, and strike-slip deformation. There is evidence of contemporaneous uplift and local resedimentation of eroded sediments (Field et al. 1997). High levels of fluid overpressure have been encountered in hydrocarbon exploration wells (fluid pressures of 34 MPa at 1500 m, which approaches lithostatic pressure). This requires mudweights of up to 19 ppg (SG 2.3) to control formation fluids, with kicks and mud losses commonly encountered.



Figure 1: Location map of the East Coast Basin, showing wells discussed in the text and the location of modelled line CQX-H90-07.

High overpressure suggests restricted fluid flow and low effective stress in the subsurface, which is consistent with the mud diapirism observed in the basin. Mudstones are the dominant sedimentary fill of the basin. Mudstone formations include the Late Cretaceous-Palaeocene siliceous Whangai Formation (Moore 1988), the Palaeocene organic-rich Waipawa Black Shale, the Eocene Wanstead Formation, the Eocene-Oligocene Weber Formation, and numerous mudstone formations in the Miocene and Pliocene. Of particular note are widespread, uncemented, smectite-rich, bathyal mudstones of the Wanstead Formation (see Fergusson 1985). Commonly referred to as bentonites, these formations provide significant drilling problems in wells. The mudstones appear ubiquitously fractured in outcrop and commonly sheared in the subsurface. They form landslips and mud diapirs (Mazengarb 1998), and have been identified as a critical factor in determining migration pathways (Field et al. 1998). Finally, the widespread presence of many hydrocarbon seeps suggests active, effective migration.

This study considers the distribution and origin of overpressure in the ECB, and relates this to the properties of the widespread mudstones. This forms a framework for quantitative modelling of hydrocarbon migration and a following discussion of fluid flow patterns.

## Overpressure in the East Coast Basin

The distribution of overpressure with depth derived from mudweights for selected open-file wells is shown in Figure

2. The distribution is remarkable for the high pressures encountered throughout the region, and there is no clear relationship between pressure and depth. Overpressures commonly approach lithostatic pressures within Eocene mudstones, even at relatively shallow depths (<1000 m). Overpressure requires both a generative mechanism, and a sealing mechanism to restrict fluid flow. Grauls (1999) provided a useful framework for the origin of overpressure in sedimentary basins, proposing that mechanical, chemical or thermal processes can generate overpressure. Due to the complexity of a typical sedimentary basin, overpressures are likely to have several generative mechanisms acting in unison or at different stages in basin evolution.

Thermal and chemical generative processes (such as dewatering due to smectite-illite transformation, or gas generation) become active at temperatures in excess of 100°C. The low thermal gradients (Field et al. 1997, Townend 1997) in the basin suggest that many significantly overpressured wells have remained at temperatures below this critical value, although off-structure regions will have attained these temperatures. We suggest that thermal and chemical mechanisms are unlikely to be a significant factor in the generation of the overpressures observed in wells in the ECB.

Mechanical processes of generating overpressure associated with the convergent-margin setting of the ECB include rapid sedimentation (compaction disequilibrium), rapid uplift and shearing. During rapid sedimentation, the change in porosity during mudstone compaction will cause the rapid expulsion of large volumes of water. If this expulsion is restricted by low permeability, overpressure will develop and compaction

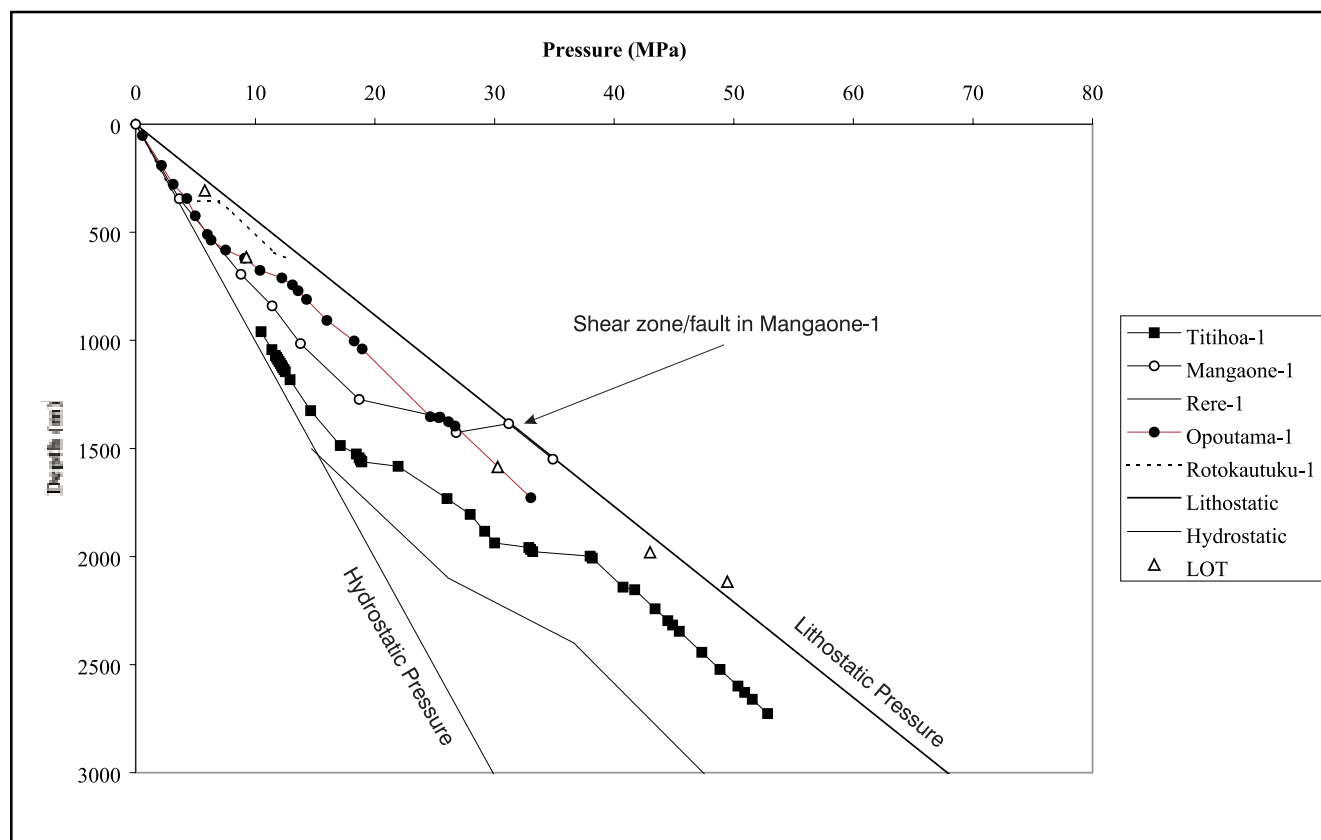


Figure 2: Pressure-depth plot for selected open-file wells in the East Coast Basin.

will be slowed or halted. The hypothesis that rapid sedimentation, coupled with restricted fluid movement, has caused overpressuring in the ECB can be tested against well data. This hypothesis makes the prediction that mudstone porosity should be higher in overpressured zones than in normally-pressured zones for a depth; this is termed undercompaction. Rere-1 (Figure 3) shows a decrease in density with depth typical of overpressured, undercompacted systems. The unambiguous presence of low-density (high porosity) sediments at depth in overpressured zones confirms that compaction disequilibrium is a significant overpressuring mechanism in the ECB. Additionally, the lithostatic-parallel nature of most fluid pressure trends in the ECB (Figure 2) suggests constant effective stress with depth within the overpressured regions, a phenomenon indicative of disequilibrium compaction in mudstones (Swarbrick & Osborne 1996).

However, it is difficult to propose compaction disequilibrium as an overpressuring mechanism for the very shallow overpressures encountered in onshore areas, where uplift and erosion dominate. It is necessary to consider generative mechanisms that could operate in shallow, cool settings. Yassir (1999) proposed a model of undrained shear of ductile muds as a mechanism for generating overpressure in compressional stress regimes. In this case, overpressure can be expected to equal the minimum stress (Figure 4). Leak-off test pressures approximate minimum stress. Figure 2 shows that pressure in some wells (e.g. the sheared section of Mangaone-1) closely matches or even exceeds the regional minimum stress gradient, supporting the role of shearing in generating overpressure. Alternatively, Gretener (1993)

proposed that uplifted rocks, sealed by ductile lithologies such as salt, can become overpressured (Figure 4). The ductility of the Wanstead Formation, discussed below, will aid preservation of overpressure during the rapid uplift experienced in the ECB. Note that weak, ductile mudstones are likely to shear during uplift due to gravitational instability, and thus both shearing and uplift mechanisms may be valid for some regions of the ECB. With both mechanisms, the minimum stress acting in a formation will form a maximum limit to overpressure (Grauls 1999).

Regardless of origin, overpressures require a pressure seal. The primary control on the distribution and magnitude of overpressure in the East Coast is the volume of low-permeability mudstones. The low permeability inferred for mudstones will retard fluid flow and act as seals to fluid movement. Thus to understand the patterns of fluid flow in the East Coast Basin it is necessary to understand the nature of porosity and permeability in fine-grained sediments.

## Characterising fine-grained sediments of the East Coast

The compaction of fine-grained sediment is a poorly understood area in geology, despite its importance in controlling fluid flow in basins. Quantitative simulation of basins (e.g. Ungerer et al. 1990) typically use a simple exponential porosity-depth relationship for mudstones. However, the field of soil mechanics provides much information on the nature of mudstone compaction at the low effective stresses and temperatures typical of the East Coast.

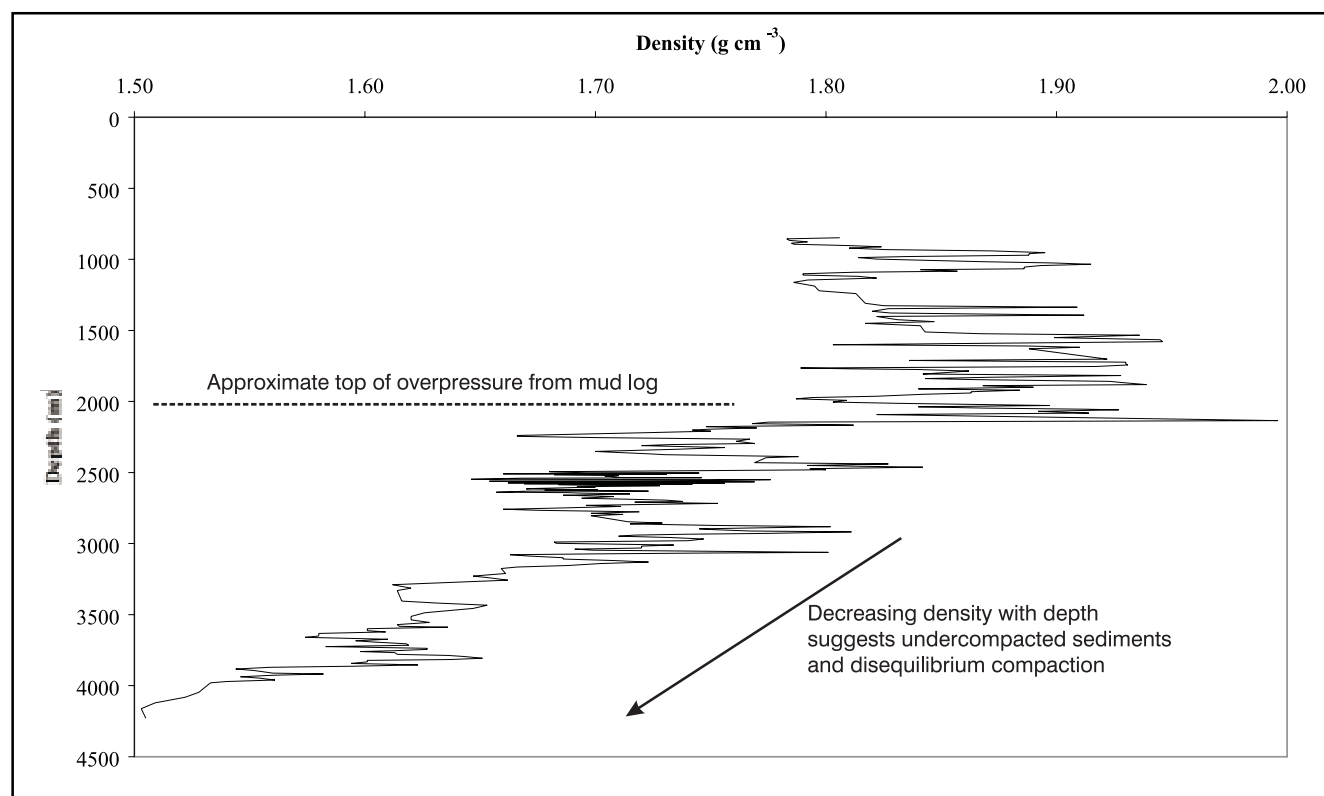


Figure 3: Density (derived from density log) against depth for Rere-1 showing low-density sediments below top overpressure.

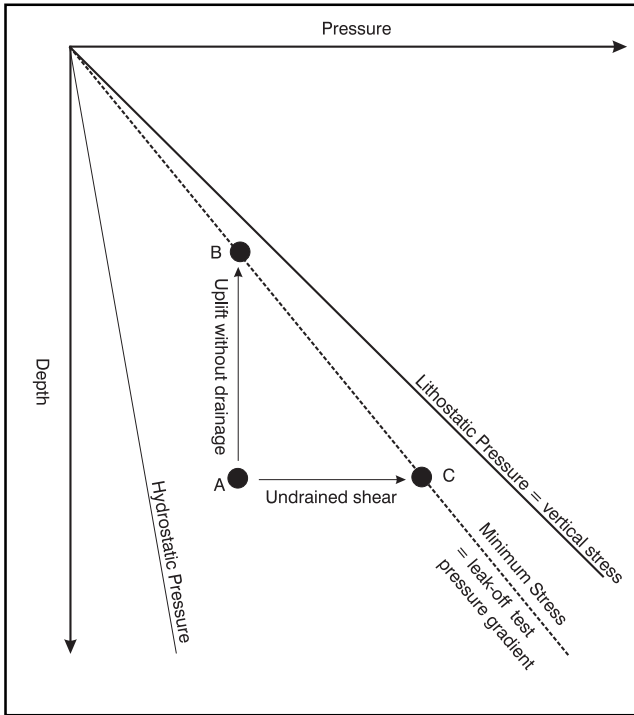


Figure 4: Schematic pressure-depth plot showing pressure changes during uplift (A-B) and shearing (A-C).

Using a soil mechanics approach allows us to take advantage of geomechanical studies of the “soft rocks” of the East Coast.

Mudstone porosity can be related to effective stress (Skempton 1970) by:

$$\sigma' = \sigma^* \exp\left(\frac{e^* - e}{\beta}\right)$$

where:

$\sigma'$  = effective stress

$e$  = void ratio

$e^*$  = void ratio at a reference effective stress  $\sigma^*$

$\beta$  = compression coefficient

This relationship has been explored by Aplin et al. (1995) for geological settings and demonstrated to be valid to burial depths of 3000 m. The compression coefficient  $\beta$  is strongly correlated to void ratio  $e$ , to grain size expressed as % clay (Aplin et al. 1995, and to the soil mechanics property liquid limit (Burland 1990; the liquid limit of a soil is the experimentally-derived water content at which the soil achieves a liquid state, and is assumed to be a measure of the surface attraction between soil particles):

$$e^* = 0.0158 (\text{Liquid limit}) + 0.1094$$

$$\beta = 0.0034 (\text{Liquid limit}) - 0.014$$

$$\beta = 0.0789 + 0.677 (\text{clay \%})$$

These relationships suggest that mudstone compaction is influenced by the surface area of the minerals in the sediment. Surface area will be overwhelmingly controlled by the clay-

sized fraction in the rock, and the composition of that fraction. Fergusson (1985) noted that the Wanstead Formation is characterised by the absence of clay-sized quartz and the high content (>60%) of smectite, suggesting that the formation has a very high surface area. Uppert (1986) presented a correlation between smectite content and liquid limit for the ECB:

$$\text{Liquid limit} = 1.6059(\text{smectite \%}) + 27.906$$

This relationship allows us to define compaction curves for a given composition for the sealing mudstone formations in the basin (Figure 5).

The relationship between mudstone compaction and clay type suggests that estimation of a “normal” porosity-depth compaction trend is difficult. Extrapolation of trends between formations with different clay contents, and thus different compaction characteristics, will be invalid. Calculations based on deviation from a “normal” trend, such as estimates of uplift and quantification of overpressure, will be inaccurate. This implies that conventional overpressure prediction from porosity-based methods (e.g. d-exponent) must be applied with caution in the ECB.

The porosity-effective stress relationships for different formations defined using the approach above have been used to constrain compaction curves in quantitative basin models. This study has used the industry-standard basin modelling software, PetroMod. This is a two-dimensional, finite-element basin model, based around a fully-coupled multiphase fluid flow and compaction calculation engine (IES 1999). Permeability is assumed to be linearly related to porosity on a logarithmic scale (IES 1999):

$$\log k(\phi) = \frac{75\% - \phi}{70\%} \log k^5 + \frac{\phi - 5\%}{70\%} \log k^{75}$$

where:

$k(\phi)$  = permeability at any given porosity

$k^5$  = permeability at 5% porosity

$k^{75}$  = permeability at 75% porosity

$\phi$  = porosity

Mudstone permeabilities were determined by iterative calculations of model overpressures resulting from compaction and constrained by observed overpressures. This inverse hydrological analysis is an established practice in basin modelling (Person & Garven 1992, Audet & McConnell 1992) and assumes that if porosity, sedimentation rate and effective stress are known, permeability can be found. This technique allows estimation of the value of permeability appropriate for modelling at the basin scale, which commonly differs from the permeability value measured on small-scale (core) samples due to the geological variation that exists at the scale of a model finite-element grid block (10-100 m). For the models discussed in the following section, a preferred model permeability for Eocene mudstones of  $10^{-5}$  mD at 5% porosity can be defined. At higher model permeabilities,

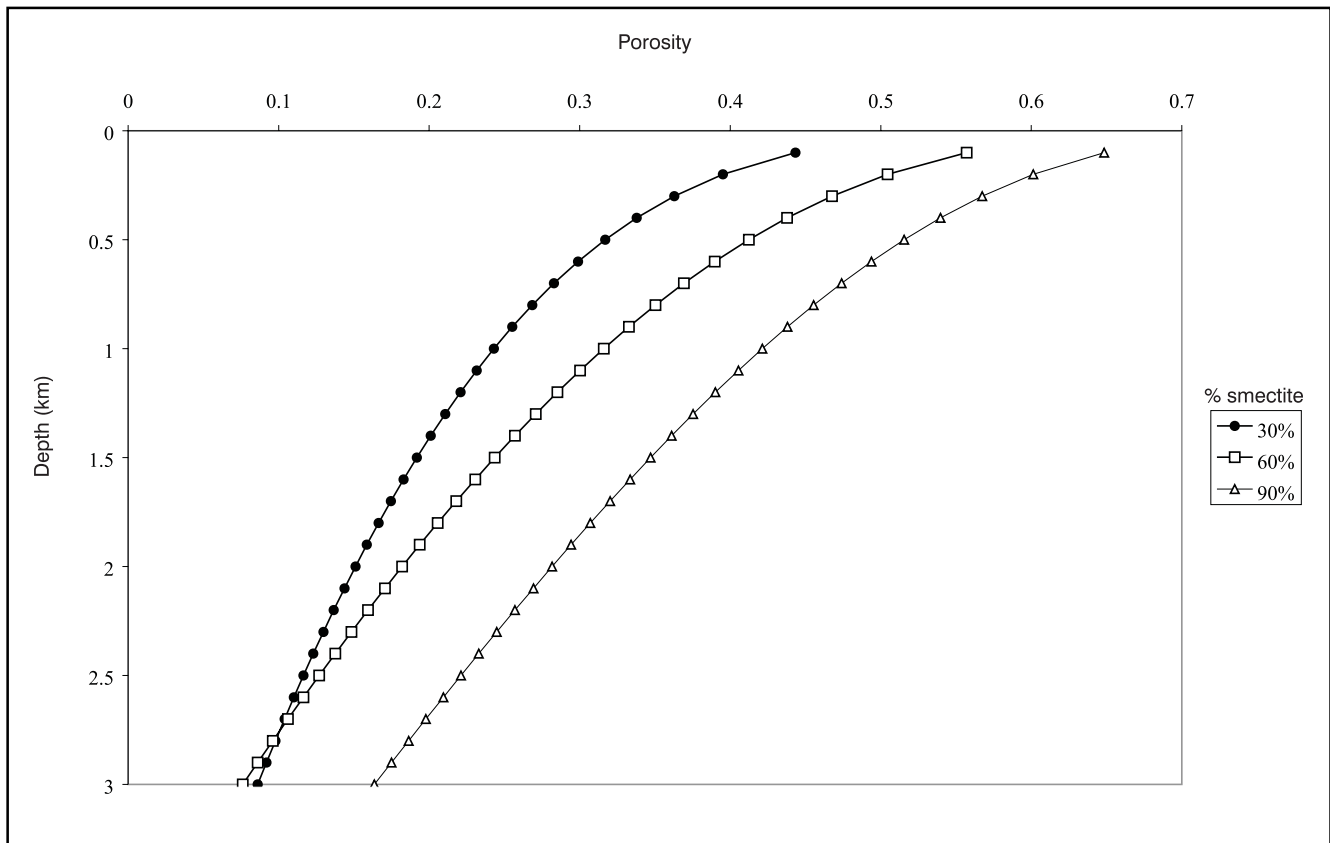


Figure 5: Compaction curves for ECB mudstones for varying smectite content.

modelled overpressures do not match regional trends in observed pressure. Note that modelled permeability is a maximum value, and actual values may be significantly lower.

Permeability is the critical factor for controlling single phase (water) flow, and thus level of overpressure. However, the critical parameter for hydrocarbon migration in a water-wet system is capillary entry pressure,  $P_{th}$  which can be correlated to permeability (Figure 6), although there is a considerable spread in the limited data available worldwide (Schowalter 1979, Pittman 1992, Schlomer & Krooss 1997). The spread of data may be in part related to difficulty in accurately measuring physical parameters on fine-grained rocks. The uncertainty in  $P_{th}$  must be accepted and lends itself to migration assessment using high, low and most-likely cases. A “high  $P_{th}$ ” case has been defined where  $P_{th}$  is equal to the highest  $P_{th}$  measured for a given permeability (Figure 6). A low  $P_{th}$  case is defined as being equal to the lowest measured value, and the most-likely  $P_{th}$  case is the median value. The results of these cases are discussed below.

## Modelling the East Coast hydrocarbon system

The discussion of ECB mudstone properties above provides a framework for quantitative basin modelling. These models are generic investigations of the patterns of fluid flow, and are not intended to predict hydrocarbon migration in specific prospects. A NW-SE trending line in offshore Hawkes Bay (Figure 1) has been modelled using the PetroMod software. The model input geometry is derived from released seismic

line CQX-H90-7 (Field et al. 1997). Depth-conversion and model properties are tied to well Hawke Bay-1.

Lithologies are derived from Field et al. 1997, and assume that Miocene and Cretaceous-age rocks contain permeable sandstone reservoir intervals. Mudstone properties are discussed above. We assume total organic carbon values of 4% and hydrogen indices of 300 mg g<sup>-1</sup> TOC for Palaeocene source rocks and TOC values of 1% and HI values of 150 mg g<sup>-1</sup> TOC for Cretaceous source rocks (Field et al. 1997). A standard Type II-S kinetic scheme has been used for Palaeocene and Type III kinetic scheme for Cretaceous source rocks. Heat flow is modelled as constant throughout the Tertiary at 45 mWm<sup>-2</sup>, which calibrates to measured vitrinite reflectance in Hawke Bay-1 and proves a reasonable regional average (Field et al. 1997, Townend 1997). As discussed above, fluid pressure is calibrated to measured mudweights in Hawke Bay-1 and to regional trends for deeper formations, allowing forward modelling of permeability and capillary entry pressure. Flow or sealing due to faults is not modelled in the base case model, and will be discussed later. Note that use of a 2D basin model to investigate a 3D geological system introduces errors due to out-of-plane effects, which should be considered when relating model results to geological reality.

Figure 7 shows the modelled movement of oil and gas at the present day in the base (most-likely) case. Migration across the Palaeocene-Eocene pressure seal is minimal with minor gas migration at the crests of anticlines. The pressure seal effectively decouples the Cretaceous-Palaeocene source rocks from Miocene reservoirs. Palaeocene source rocks are mature

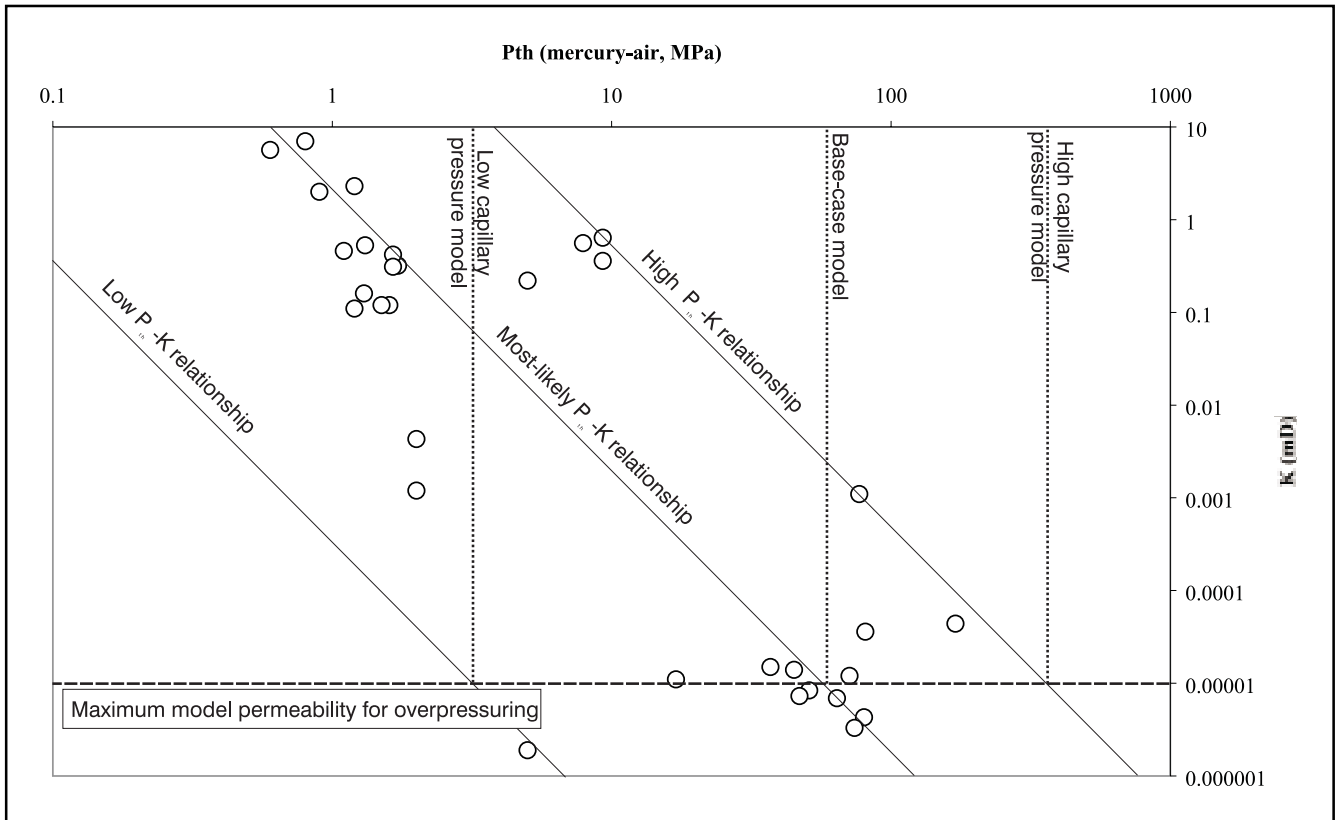


Figure 6: Capillary entry pressures ( $P_{th}$ , mercury-air) versus permeability for global database.  $10^{-5}$  mD is maximum model permeability to produce overpressuring. High, low, and most-likely (base-case) capillary entry pressure values can be derived.

but have not yet expelled hydrocarbons. No migration of oil is modelled to occur through the pressure seal. Low efficiencies are predicted for the ECB hydrocarbon system in the base-case models due to poor drainage of the source rocks.

Basin modelling allows the rapid examination of “what-if” scenarios to investigate poorly constrained parameters. One such parameter is the nature of potential Cretaceous source rocks that have not yet been penetrated by drilling but are inferred to exist due to the presence of seeps in exposed Cretaceous rocks (Field et al. 1997). Figure 8 shows the modelled movement of oil and gas in the case of a more deeply buried source rock with similar composition to the Palaeocene source rock. This case can also be considered to simulate deeper burial of Palaeocene source rocks out of the plane of section, where migration is limited by the sealing properties of the Palaeogene and not by generation/expulsion from source rocks. In this model, gas migration is more widespread, with low saturations (10-20%) of gas trapped in Miocene reservoirs. This result calibrates to gas shows in Hawke Bay-1. Significant oil volumes remain trapped below the Palaeogene seal, and only minor oil migration occurs through the seal. Note that gas migration to surface occurs over deep structural closures, suggesting that observed gas seeps are not necessarily indicative of breached traps (Lowry et al. 1998). Modelling of low capillary entry pressures produces an increase in gas saturation of 5% in Miocene reservoirs. Modelling of high capillary entry pressures effectively prevents any gas migration into the Miocene reservoirs.

## Opening up the system: faulting and fracturing

The base case models suggest that only limited migration of gas can occur in the modelled section of the ECB due to the prevalence of low-permeability mudstones. This is at odds with observations of widespread seeps and discoveries which demonstrate that hydrocarbon migration from Palaeocene-Cretaceous source rocks has occurred. This divergence between the dominance of low-permeability sediments and evidence for widespread, rapid fluid flow is common to all studied accretionary margins (e.g. Barbados, Brown et al. 1994). It is probable that migration is occurring through faults and fractures rather than the matrix permeability of the sediments.

Modelling shows that if faults are considered to be permeable pathways, widespread cross-seal hydrocarbon migration occurs. It is necessary to consider under what conditions are faults likely to become dilatant and permeable. A detailed review of the role of faults in mudstones has been provided by Dewhurst et al. (1999) who concluded that faults in mudstones have intrinsically low permeability and are unlikely to significantly increase sediment permeability. However, as compaction proceeds with burial, mudstones become increasingly consolidated and increasingly brittle, which renders them more susceptible to dilation during faulting. Modes of failure for mudstones can conventionally be represented on a Mohr circle, shown in Figure 9. The Mohr circle can intersect the failure envelope either in a zone of ductile (compacting) shear, a zone of dilatant shear, or a zone

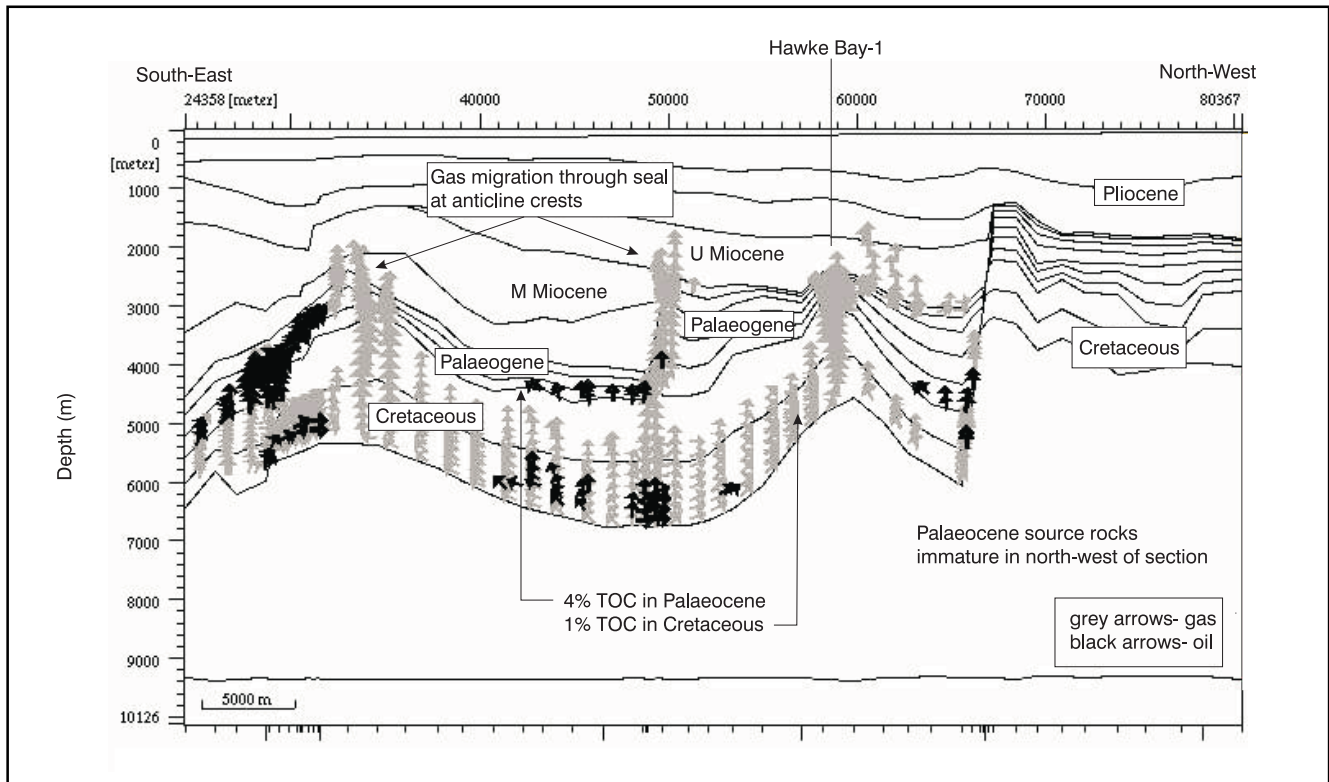


Figure 7: Modelled oil and gas migration for the present day, base-case model of line CQX-H90-07, Hawke Bay-1 region.

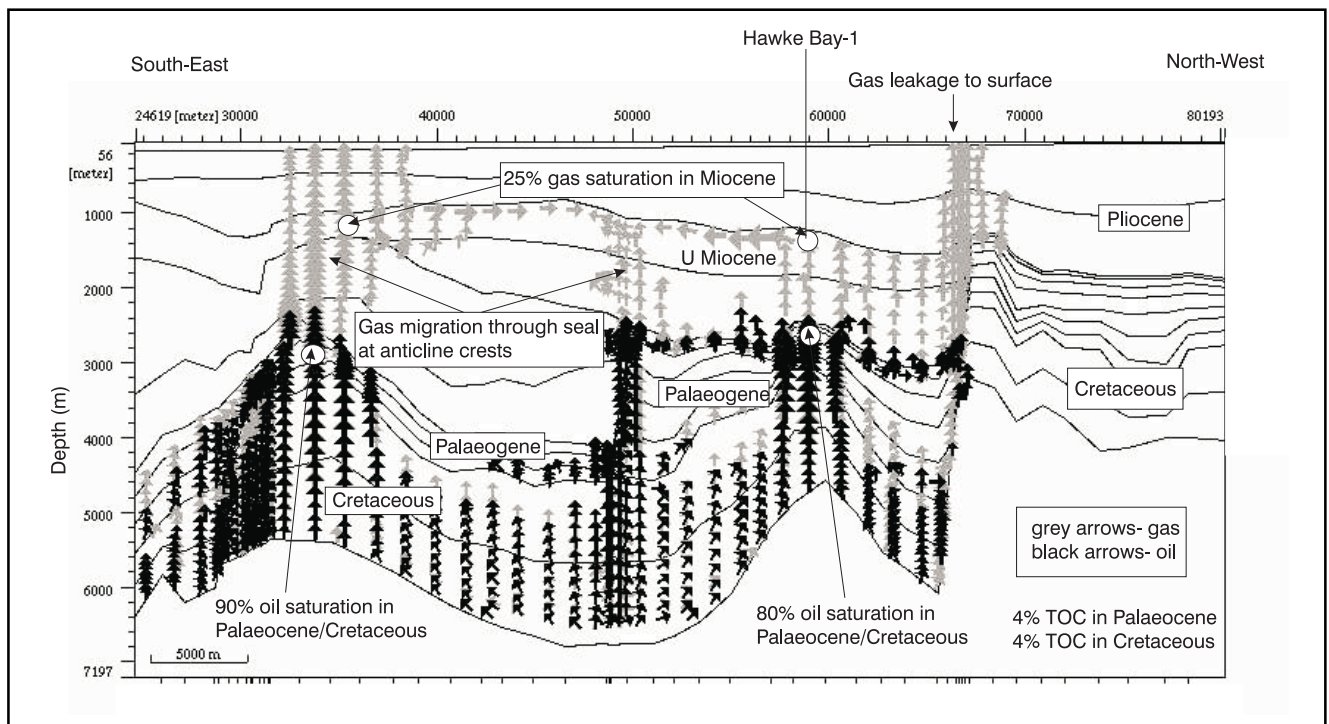


Figure 8: Modelled oil and gas migration for the present day in line CQX-H90-07, assuming richer Cretaceous source rock, Hawke Bay-1 region.

of extensional fracture. The point of intersection between the Mohr circle and the failure envelope is determined by the effective stress and the friction angle, with low friction angle favouring ductile shear. The friction angle decreases with increasing plasticity, and so can be correlated to liquid limit (Lambe & Whitman 1969) and thus smectite content.

Ingram & Urai (1999) suggest that a simple parameter for assessing shear deformation in mudstones where little other data is available is the level of overconsolidation of the sediment, expressed as overconsolidation ratio:

$$OCR = \frac{\sigma'_{max}}{\sigma'_{present}}$$

where:

$\sigma'_{max}$  = maximum effective stress experienced by the sediment

$\sigma'_{present}$  = current effective stress experienced by the sediment

Experimental studies have shown that smectite-rich, highly ductile mudstones will not fail dilatantly until very high OCRs ( $OCR > 4$ ) (Olgaard et al. 1997, Ingram & Urai 1999). More brittle material (such as carbonate-cemented muds) can fail dilatantly at  $OCR = 1$  (Ingram & Urai 1999). Accordingly mudstone composition will be critical in predicting behaviour during faulting in the ECB, and smectite content has a profound effect on the deformation behaviour of mudrocks. Faults in the siliceous Whangai Formation (Moore 1988) and in well-cemented marls in the Wanstead Formation (Fergusson 1985) can be assumed to dilate under shear when overconsolidated (uplifted). However, faults in uncemented Wanstead Formation will dilate only when highly overconsolidated and uplifted. The observation of extremely high overpressures (Figure 2) in uplifted, sheared Wanstead Formation mudstones suggests that faulting does not significantly enhance fluid flow.

OCR control on fault dilation suggests that faults in strongly uplifted regions will be most likely to dilate and allow fluid flow, although the role of fluid pressure in controlling effective stress must be assessed. Faults in normally-consolidated regions with limited uplift are unlikely to dilate and will remain as seals to hydrocarbon movement. Fault

dilation will be particularly effective around faulted crests of anticlines where trap breaching of deeper Cretaceous-reservoired oil or gas will occur. Deformation paths for ECB sediments are summarised in Figure 10.

## Conclusions

Quantitative modelling in a frontier environment such as the ECB must be applied cautiously with a full appreciation of the sensitivity of model results to unconstrained variables. However, basin modelling can define critical aspects of the system.

- Overpressure in the ECB is caused primarily by compaction disequilibrium, due to restricted fluid escape in low-permeability Eocene mudstones during rapid Miocene-Pliocene subsidence. The presence of extremely high, shallow overpressure is related to uplift and shearing, and will be controlled by the minimum stress acting in the formation.
- Mudstone compaction is controlled by smectite content, allowing prediction of porosity, permeability and capillary entry pressure for Palaeogene mudstones.
- Generic two-dimensional models of hydrocarbon migration show that limited gas migration can occur through unfaulted Palaeogene mudstones into Miocene reservoirs. Modelled saturations of gas in Miocene reservoirs are low.
- Dilatant faulting and shearing of uplifted, overconsolidated mudstones may provide permeable

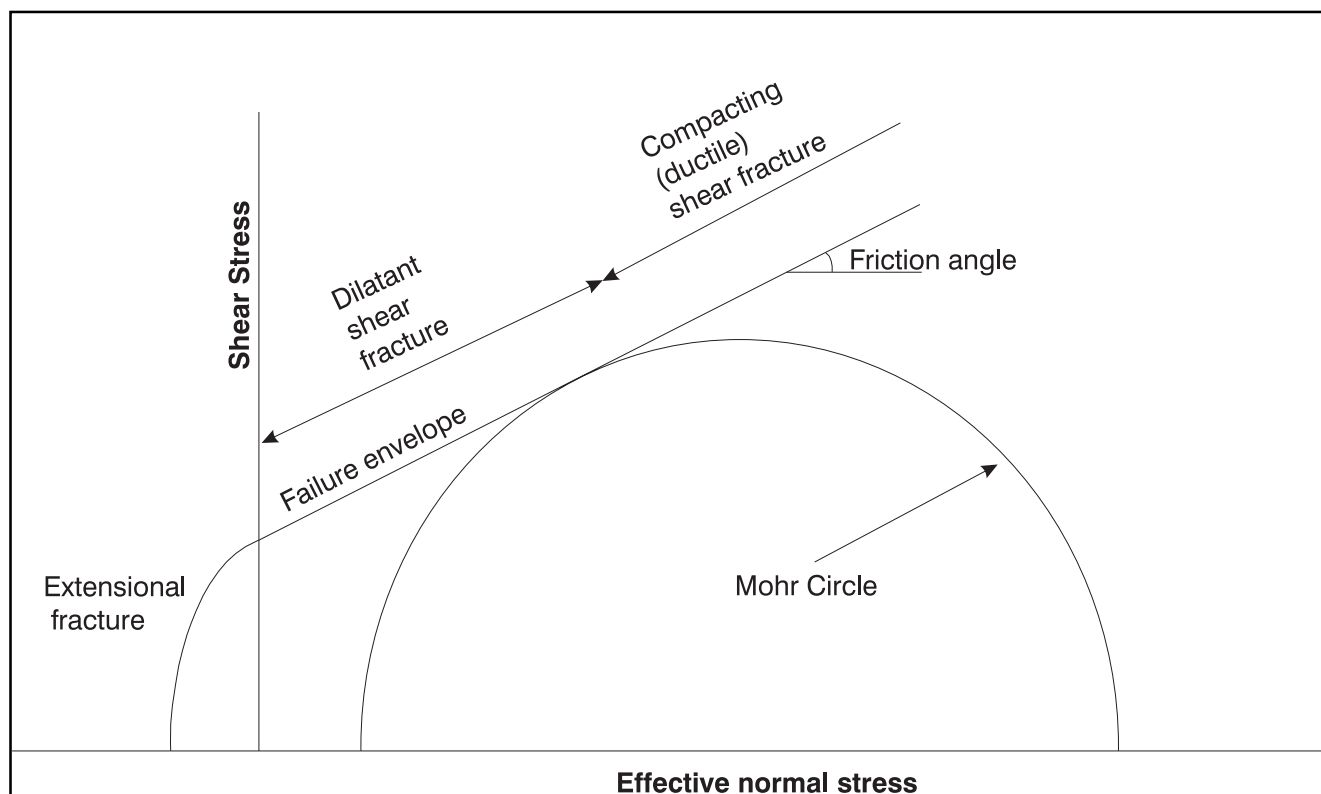


Figure 9: Schematic Mohr circle showing modes of failure for mudstones. Mudstones can fail by dilatant, extensional or compacting fractures depending on where the Mohr circle intersects the failure envelope.

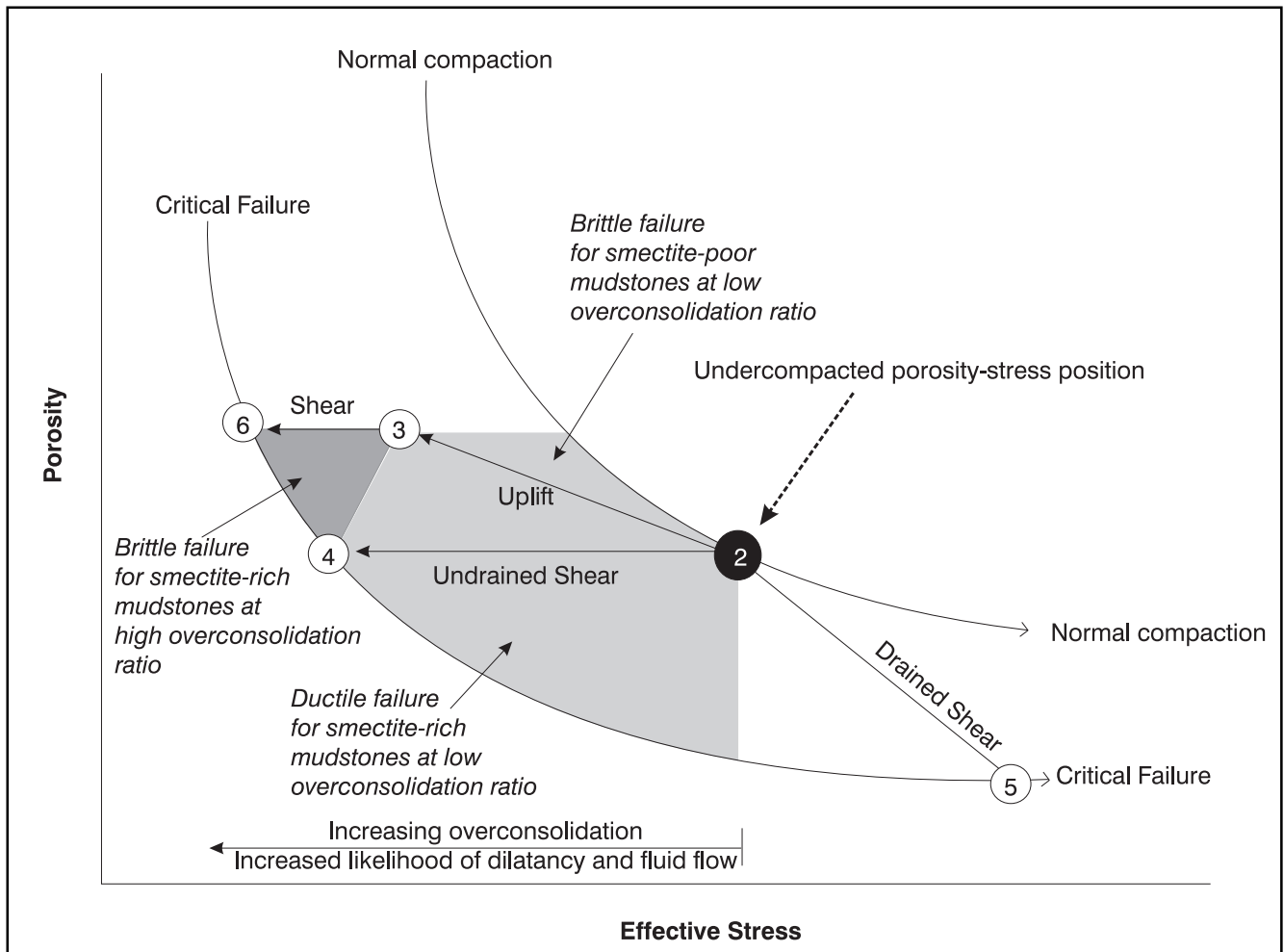


Figure 10: Deformation paths for ECB sediments. Mudstones will compact from 1 to 2, where overpressure halts compaction. Uplift will reduce effective stress and move the mudstone to position 3. Shearing will move the mudstone along path 2-4 if no fluid escape can occur, or along path 2-5 if drained. Brittle (smectite-poor) mudstones will dilate on paths 2-4 and 2-5 and allow fluid flow. However, ductile mudrocks will only dilate if sheared in an overconsolidated state (path 3-6).

pathways through the Palaeogene to link source and reservoir.

- Smectite content will have a profound effect on the deformation behaviour of mudstones.

A consideration of the structural history of a prospect is vital, in order to relate timing of faulting to timing of hydrocarbon expulsion and migration. The quantitative models presented in this study suggest that an understanding of migration route is necessary for accurately risking prospects in the ECB.

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