INTEGRATED HYDROCARBON SEAL EVALUATION IN THE PENOLA TROUGH, OTWAY BASIN

R.M. Jones[1], P. Boult[2], R.R. Hillis[1], S.D. Mildren[1] and J. Kaldi[1]

[1]NCPGG and Australian Petroleum Cooperative Research Centre (APCRC)
Thebarton Campus
University of Adelaide
Adelaide SA 5005.
[2]Boral Energy
1 King William Road
Adelaide SA 5000
rjones@ncpgg.adelaide.edu.au
pjb@sagres.com.au
rhillis@ncpgg.adelaide.edu.au
smildren@ncpgg.adelaide.edu.au
jkaldi@ncpgg.adelaide.edu.au

ABSTRACT

Seals are one of the main components of the petroleum system, yet their evaluation has received surprisingly little attention in terms of integrated risk assessment. This paper emphasises the need for an integrated multi-disciplinary approach for robust cap and fault seal evaluation so to minimise seal risk. The region of study is the Penola Trough, Otway Basin, where recent improvements in seismic quality, stratigraphic modelling and additional well control have greatly enhanced regional prospectivity.

The Laira Formation has the lowest cap seal risk of Penola Trough strata based on empirical data. The Eumeralla Formation has a similar gamma ray log signature to the Laira Formation yet contains a higher frequency of sandy, relatively high permeability horizons. These horizons increase the likelihood of fault juxtaposition and the development of leaky windows that allow cross fault communication.

Faults in the Penola Trough display fractal characteristics from seismic to core scale. A prediction of regional fault extension and deformation intensity below seismic resolution is viable since fault systems appear to be systematic. Extrapolation of fault populations to the millimetre scale shows good agreement with fault density recorded in core from a fault damage zone. Deformation intensities close to seismically resolvable faults are indicative of inner damage zone geometry where faults form linked cluster arrays. Microstructural fault analysis indicates the dominant fault processes in the Upper Crayfish Group are grain boundary sliding and cataclasis with gouge quartz cementation. Petrophysical analysis indicates these faults are able to support gas columns of up to 102 m.

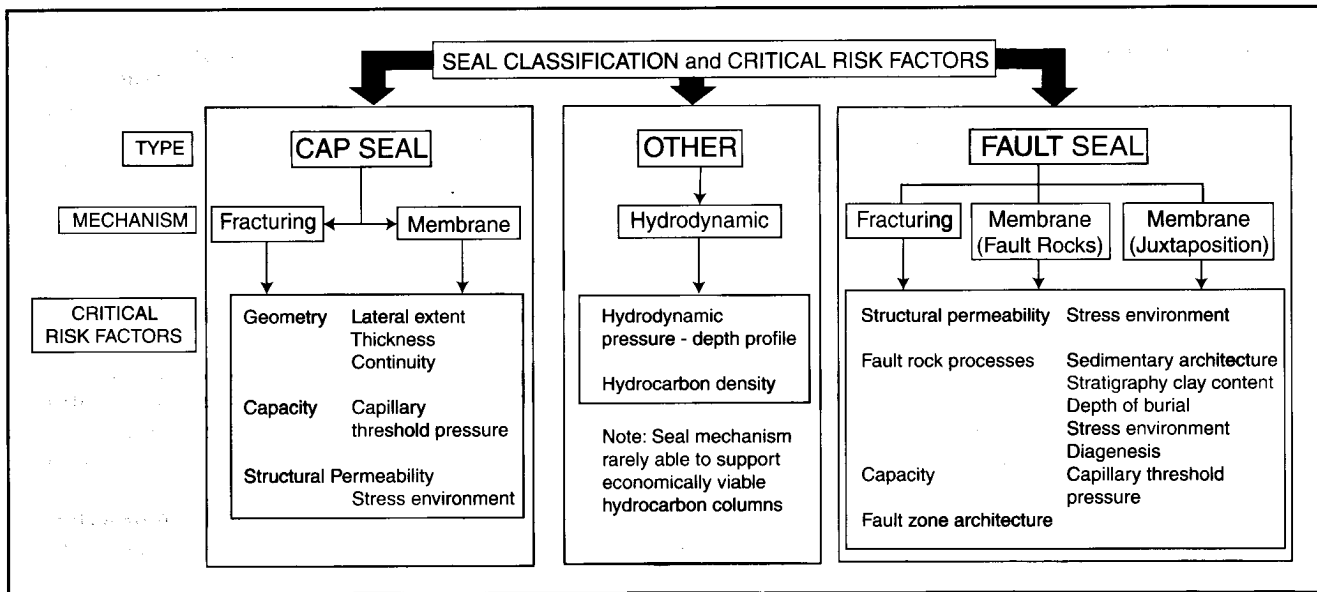The relative probability of seal failure due to the development of effective structural permeability within the in-situ stress field indicates that planes at the greatest risk of failure are steeply dipping (>60°) and strike between 110°N and 200°N. Open fractures crosscutting pre-existing faults have been identified through microstructural examination and these may provide a mechanism for trap leakage and tertiary hydrocarbon migration. An integrated technique for mapping the relative risk of seal breach due to the development of effective structural permeability at the seismic scale is also presented.

KEYWORDS

Cap rock, top seal, fault seal, fault architecture, structural permeability, multi-disciplinary seal evaluation.

INTRODUCTION

Hydrocarbon exploration and production strategies all involve an element of risk. As with any investment strategy, it is the goal of the venture capitalist to understand this risk. Geological risk assessment should begin with a focussed evaluation as to the chance of success. That is, determining the likelihood that all elements of the petroleum system required for economically viable volumes of hydrocarbons to be developed and trapped have been satisfied. One of the main components of the petroleum system that has received surprisingly little attention, with respect to risk minimisation, is the evaluation of reservoir seals. Previous evaluations of seal potential have tended to focus on single parameters such as fault plane processes (Knipe, 1992; Yielding et al, 1997), regional stress regime (Hillis et al, 1995) and seal geometry/thickness to evaluate seal potential. It is the authors' view that in order to fully understand the factor(s) responsible for hydrocarbon sealing, a more comprehensive analysis incorporating data from all scales and pertaining to all possible mechanisms of seal failure should be undertaken.

A multi-disciplinary approach that provides a methodology platform for integrated seal evaluation is presented. The approach is applied to the Penola Trough (Otway Basin, South Australia) and illustrates that without an integrated seal evaluation methodology, the mechanism for seal success/failure may have been incorrectly identified. It is also intended that this paper should act as a catalyst for further research into integrated seal analysis for Australasian provinces.

SEAL ANALYSIS: AN OVERVIEW OF SEAL TYPE, SEALING PROCESSES, FAILURE MECHANISMS AND EVALUATION STRATEGIES

A seal is a barrier to the migration of petroleum, either to shallower strata or laterally across faults. According to the mechanism of failure, seals can be considered as

Figure 1. Classification and critical risk factors of hydrocarbon seals.

membrane or hydraulic (Watts, 1987). Geometrically, two major types of seal are crucial for entrapment of hydrocarbons; cap seal and fault seal. Figure 1 illustrates the classification of seal by geometric type and process.

Cap seal

Theoretically, any lithology may form a cap seal to a static hydrocarbon column as long as the capillary forces within that sequence act to confine the buoyancy forces of accumulated hydrocarbons. The majority of cap seals operate as membrane seals, such that the dominant seal mechanism is the difference in the largest interconnected pore-throat of adjacent lithotypes. Diagenetic processes such as cementation and diffusive mass transfer can also act within facies boundaries to form effective seals by reducing pore-throat apertures. Identification of the dominant cap seal processes is important when evaluating seal capacity (the hydrocarbon column height a seal can support). This is a function of the relationship between the buoyancy pressure of the hydrocarbon column and the membrane and hydraulic properties of the seal. For a more in-depth review of factors controlling seal capacity the reader is directed towards Schowalter (1979), Downey (1984), Sneider (1987) and Vavra et al (1992).

The threshold pressure of some cap seals is so high that membrane failure is almost inconceivable. In this case, leakage due to natural fracturing presents the principal risk of seal breach. The likelihood of seal breach due to fractures providing effective structural permeability may be determined by analysing the in-situ stress field, and may thereby be incorporated into an integrated assessment of the risk of seal breach. Natural fractures may develop within intact cap rocks, or may be associated with existing faults (e.g. through reactivation).

Hence, fracturing presents a risk with respect to both cap and fault seals. Herein, because natural fracturing is likely to be focussed by existing faults and fractures, we consider it in the context of fault seal, but the same principles of classic brittle failure theory may be applied to the analysis of fracture-related breach in cap seals.

CAP SEAL EVALUATION STRATEGIES

The cap seal potential of a lithology is the combination of the seal capacity, structural position, thickness and areal extent of the lithology (seal geometry), mechanical properties such as ductility (seal integrity), and time of formation relative to hydrocarbon migration. For a cap seal to be effective it needs to be relatively thick, laterally continuous, homogeneous and fairly ductile (Downey, 1984). Recent cap seal methodologies have focussed on the relationship between seal thickness, ductility and depth of burial versus measured column height effectiveness (e.g. Sluijk and Parker, 1986). The interdependence of seal thickness, geometry and integrity is also documented by Murris (1980). Where seal area is equal to or greater than the area of the reservoir or structure, the seal is likely to be more effective (Kaldi and Atkinson, 1997). Similarly, as seal thickness increases, the potential for faults or fractures propagating through cap seal strata is reduced.

Seal geometry relates the structural position, thickness and lateral extent of the sealing lithology to that of the reservoir and/or structure. All other variables being equal, a lithology on the crest of a tightly folded structure has a higher probability of tensile fracture development than the same lithology on a broad, open structure. Seal integrity refers to rock mechanical properties such as ductility, compressibility and propensity for fracturing.

Rocks with high seal integrity, such as salts and anhydrites are generally better seals than brittle rocks such as dolomites, coals or quartzites. Seal integrity can be measured in a laboratory or evaluated qualitatively by core examination, borehole imaging and petrographic studies. For gas accumulations, an additional component to cap seal potential is the diffusion rate of gas. For a comprehensive review of gas diffusion through cap seals the reader is referred to recent publications by Krooss and Leythaeuser (1997) and Nelson and Simmons (1997). Risking of seal potential is often done empirically by comparing known accumulations with their seals, either within the same basin, or, where data is sparse, on a worldwide basis. However, if the fundamentals of seal mechanisms are not clearly understood, this methodology may lead to inaccurate risking and missed opportunities.

Fault seals

Fault sealing is now recognised as one of the key factors in controlling hydrocarbon accumulations in addition to being a significant influence on reservoir behavior during production (e.g. Bouvier et al, 1989, Berg and Avery, 1995). Fault seals can be subdivided into juxtaposition seals and fault plane seals. Most seals in clastic sequences can be classified as membrane seals. Only when threshold pressure exceeds the geomechanical strength of the gouge is the fault considered to have been breached by hydraulic forces.

JUXTAPOSITION ANALYSIS

Juxtaposition seals are generated via differences in the capillary properties of strata laterally offset across a fault plane. The differences in pore-throat size, distribution and connectivity of juxtaposed strata control the fault sealing capacity. Juxtaposition relationships can be assessed via the integration of high resolution seismic and fault throw data. This technique allows creation of strike-projection fault plane maps that illustrate the offset relationships of faulted sequences along the major dislocation plane (Allan, 1989; Freeman et al, 1990; Yielding et al, 1997).

FAULT PLANE SEALS

Fault plane processes are categorised by the primary mechanism responsible for production of the membrane seal. The term fault rock mechanism refers to the process responsible for reducing the fault rock pore-throat aperture relative to the undeformed reservoir. A detailed discussion of each process is beyond the scope of this publication, however, the fundamental processes responsible for hydrocarbon baffling are outlined below:

- Deformation-induced porosity collapse by dis-aggregation, mixing and grain-boundary sliding (Knipe, 1997). Crucially, these processes involve no/little cataclasis. Deformation processes of this nature are largely restricted to relatively unconsolidated sediments and are characteristic of deformation styles at shallow depths (<3 km burial depth).
- Cataclasis. Cataclastic deformation processes are characterised by crushing/fracturing of material to produce a gouge of fine-grained material with reduced pore-throat apertures relative to the undeformed reservoir (e.g. Aydin, 1978; Underhill and Woodcock, 1987; Antonellini and Aydin, 1994).
- Cementation/Diagenesis. Faults may act as relatively high permeability conduits for fluid migration during deformation (e.g. Burley et al, 1989; Sibson, 1994). Preferential fluid migration and solute precipitation within an originally permeable fault plane may completely occlude porosity to generate hydraulic seals. Diffusive mass transfer processes can also be included in this fault type (e.g. Ruter, 1983; Spiers et al, 1990).
- Clay Smearing. A generic term used to describe the generation of fault gouge by the entrapment and deformation-induced shearing of clays or phyllosilicates (e.g. Bouvier et al, 1989; Gibson, 1994). Three sub-categories of clay smear have been recognised: abrasion, injection and shear (Lindsay et al, 1993).

FAULT SEAL EVALUATION STRATEGIES

Fault seal evaluation strategies have become increasingly reliant on the development of algorithms (e.g. shale gouge ratio [SGR] and shale smear factor [SSF]) to predict the chance of sealing. Such algorithms tend to focus on the nature of fault rock processes likely to be developed during deformation (e.g. Yielding et al, 1997; Lindsay et al, 1993). These groups of methodologies suggest that the principal process responsible for fault sealing is the entrainment of clay into the fault gouge. Sealing is predicted by establishing a calibrated dataset based on calculating the proportion of clay likely to be present within the fault plane, and cross plotting this factor against parameters such as across fault pressure differences associated with trapped hydrocarbons. Whilst it is recognised that these innovative techniques have significantly reduced the uncertainty associated with fault seal prediction, there are large risks inherent in only using these predictive algorithms. A number of additional components need to be considered.

- Faults developed in clean sands (<5% clay) can and do form effective seals. Seal prediction via clay smear processes does not account for fault seal development in clean sands. Recent work by Engelder (1974), Fulljames et al (1997) and Fisher and Knipe (1998) have demonstrated cataclasis is the principal process for reducing porosity, permeability and increasing threshold pressure of porous, clay-poor sandstones during deformation. Petrophysical analysis of cataclastic fault rocks from the Southern North Sea petroleum province has revealed that cataclastic faults in clean (<5% clay) Rotliegendes reservoir sandstones can exhibit permeability reduction factors of up to
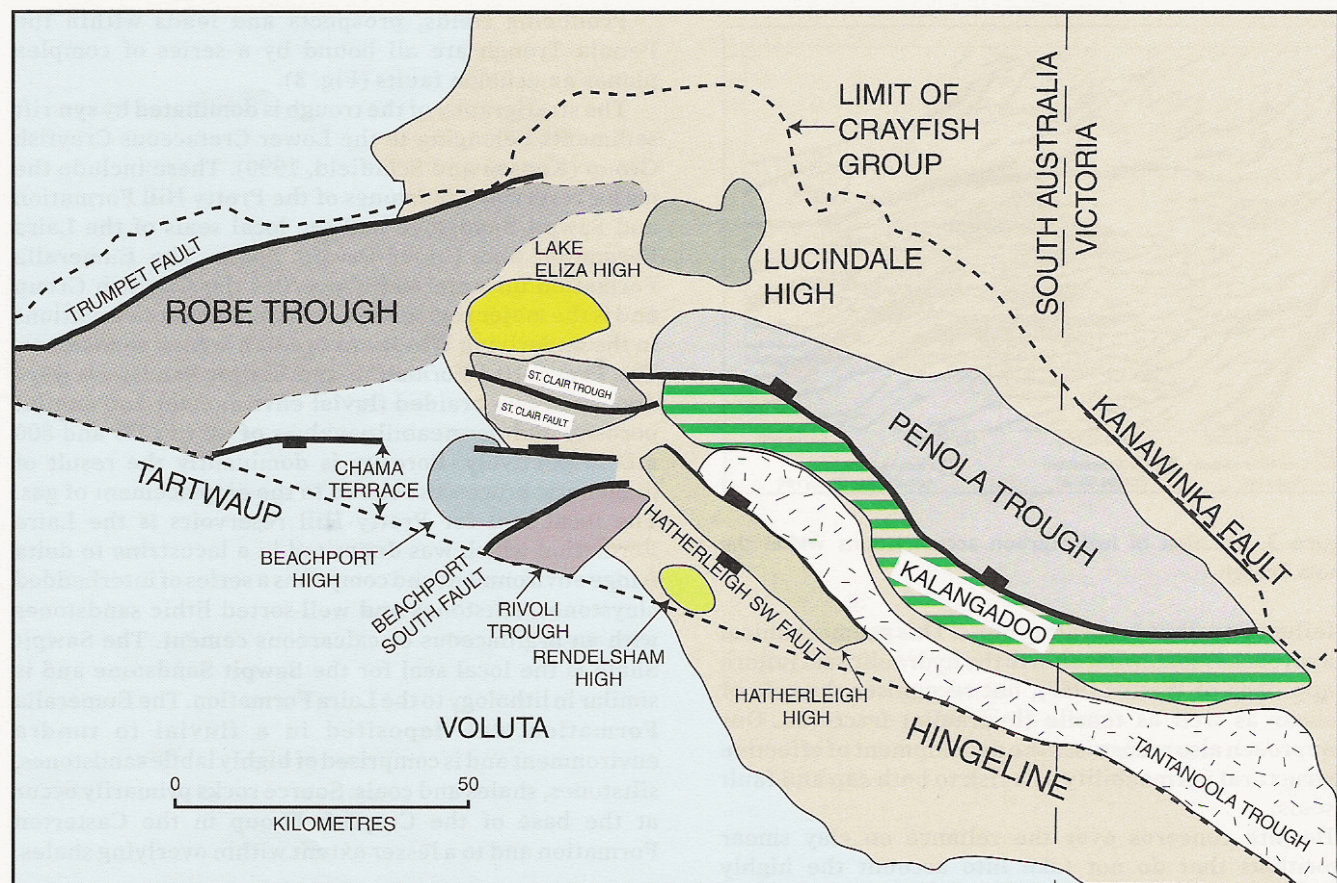
Figure 2. Structural elements of the Otway Basin (after Cockshell et al, 1995).

five orders of magnitude relative to the undeformed sandstone (Knipe et al, 1997). The principal control on the extent of cataclastic deformation appears to be the magnitude of effective stress present on the fault plane. Recognition of the existence of sand-on-sand seals is vital to ensure accurate exploration strategies as the sealing capacity of well-lithified cataclasites can be equivalent to intraformational/cap seal strata. The assumption that sand-on-sand juxtaposition will always provide a pathway for cross fault communication may lead not only to by passing pay but also to unforeseen trap compartmentalisation and reservoir management problems.

- Fault growth appears to be fractal. Recent recognition that some fault geometrical characteristics appear to be fractal (Walsh and Watterson, 1992; Yielding et al, 1996) decreases the risks in interpolating core scale fault data to the seismic scale. The truncation effects of seismic scale data are, however, a major uncertainty for fractal geometric studies, especially at fault tips where deformation is likely to be below resolution limits.

- Fault geometry is typically complex with strain accommodated in a halo of deformation (termed the damage zone) around the major slip plane. Geometrical, petrophysical and microstructural

characterisation of the damage zone is considered vital to any detailed fault seal analysis program for a number of reasons. (i) Seismically-defined offset effectively reflects the cumulative offset within the fault zone. Failure to characterise the true geometry of the fault may lead to inaccurate juxtaposition of footwall-hangingwall strata and may also impact on recoverable reserves estimation if damage zone width is ignored. (ii) Accurate characterisation of the spatial distribution of sub-seismic faults within the damage zone can provide input parameters such as transmissibility and hydraulic resistance factors for reservoir simulation studies. (iii) Microstructural, petrophysical and geomechanical investigation of faults in the cored interval can provide vital information on regional fault seal processes.

- Regional stress regime and fault reactivation considerations. Comprehensive fault seal study should include an assessment of the likelihood of breach due to natural fracturing. Shear and tensile fractures may form interlinked networks of structural permeability (Sibson, 1996). Such networks best provide effective structural permeability, when they are at, or close to failure. Hence assessment of the risk of fracture-related seal breach should involve combining information on the in-situ stress field with that on the
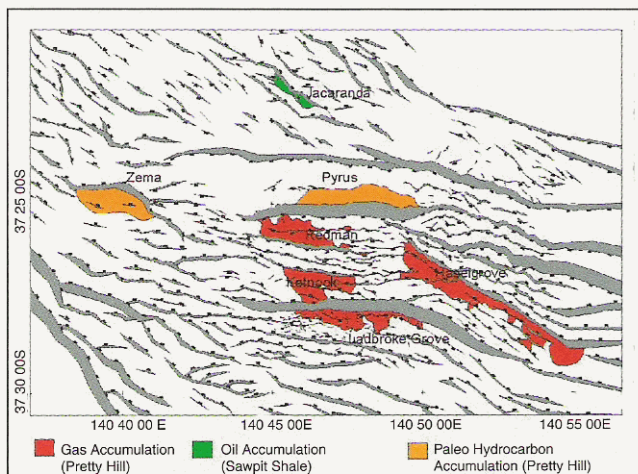
Figure 3. Location of hydrocarbon accumulations within the Penola Trough.

failure envelope for sealing units. This geomechanical approach is somewhat akin to the hydraulic seal failure approach of Watts (1987), but recognises the role of shear as well as tensile (hydraulic) fractures. Our approach also recognises the development of effective structural permeability as a risk to both cap and fault seals.

Despite concerns over the reliance on clay smear algorithms that do not take into account the highly complex geometry of fault zones, these methods have proved to have some predictive success in settings such as clay-rich clastic environments where early faulting has occurred and favourable stress regimes exist. This success may in part be related to the fact that algorithms such as SGR also include a prediction component about the tendency of the fault zone to be comprised of multiple slip planes. At low effective stress and relatively high clay contents, strain is more likely to be accommodated about a single dislocation plane. Under high stress conditions and low clay contents, the low SGR values predict low fault seal potential and reflect the increased likelihood that strain will be accommodated by multiple slip planes. The impact of complex geometry on fault seal risking is, therefore, reduced under low effective stress and at high SGR values. Any fault seal analysis study should consider all of the above components and their relative importance in risking a prospect.

AN INTEGRATED AND MULTI-DISCIPLINARY SEAL EVALUATION STUDY: THE PENOLA TROUGH

Structural setting and stratigraphy

The Penola Trough forms a prominent northwest–southeast orientated rift feature in the Mesozoic-Cenozoic Otway Basin of South Australia and is bound to the south by a major north dipping fault system (Fig. 2).

Producing fields, prospects and leads within the Penola Trough are all bound by a series of complex planar en-echelon faults (Fig. 3).

The stratigraphy of the trough is dominated by syn-rift sediments belonging to the Lower Cretaceous Crayfish Group (Kopsen and Schofield, 1990). These include the major reservoir sandstones of the Pretty Hill Formation and Sawpit Sandstone and the local seals of the Laira Formation and Upper Sawpit Shale. The Eumeralla Formation unconformably overlies the Crayfish Group and is the major regional seal to minor gas accumulations in the underlying Windermere and Katnook sandstones. The Pretty Hill Formation and Sawpit Sandstone were deposited in a braided fluvial environment and exhibit porosity and permeability values of up to 27% and 800 mD respectively. Porosity is dominantly the result of diagenetic processes related to the emplacement of gas. The local seal for Pretty Hill reservoirs is the Laira Formation which was deposited in a lacustrine to delta fringe environment and comprises a series of interbedded claystones, siltstones and well-sorted lithic sandstones with an argillaceous or calcareous cement. The Sawpit Shale is the local seal for the Sawpit Sandstone and is similar in lithology to the Laira Formation. The Eumeralla Formation was deposited in a fluvial to tundra environment and is comprised of highly labile sandstones, siltstones, shales and coals. Source rocks primarily occur at the base of the Crayfish Group in the Casterton Formation and to a lesser extent within overlying shales.

Penola Trough cap seal evaluation

The Laira Formation has the lowest seal potential risk of Penola Trough strata. This assessment is based on seal capacity, thickness and geometry, and on the empirical observation that at least six hydrocarbon accumulations dependent on Laira Formation cap seals were charged full to spill. Facies geometry analyses of this formation revealed that interbedded shales within the Laira Formation have a 50% to 80% chance of being continuous across the fields (Weber, 1982). Mercury injection capillary pressure (MICP) analyses indicate that the intervening sandstones (which may be the weak link within this seal) would only be capable of supporting a maximum gas column of 30 m. As the average column height for accumulations in the Pretty Hill is greater than 70 m, it is interpreted that the shale forms the effective seal in these strata. The thickness of the Laira Formation is typically greater than 300 m (Morgan, 1993) which is greater than the average offset for the closure on all Penola Trough prospects. The risk weighting for the Laira Formation thickness is, therefore, considered minimal.

The database for empirically risking the seal potential of the upper Sawpit Shale is less robust than for the Laira Formation and it has not been cored in the Penola Trough. However, prospects where Sawpit Shale provides the cap seal have also been filled to structural spill. Gamma ray log signatures for the Sawpit Shale are also
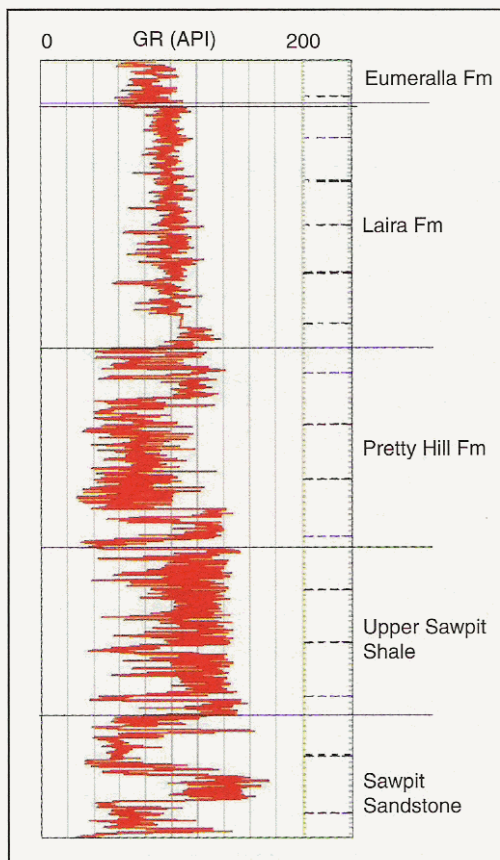
Figure 4. Gamma log signature of Early Cretaceous Penola Trough strata.

Figure 5. Gamma Ray and Spontaneous Potential (SP) log signature of Laira, Katnook, Windermere and Eumeralla Formations. Not use of SP log to locate permeable sand horizons in the Eumeral Formation. Potential 'leaky windows' in the Eumeralla seal woul not have been identified by using Gamma Ray log data.

very similar to Laira Formation, although shale interbeds have a generally higher gamma ray response suggesting a similar seal capacity may be inferred for this sequence (Fig. 4). The thickness of the upper Sawpit Shale is generally greater than 400 m and, therefore, its risk of fault breach is considered low.

The Eumeralla Formation contains a higher frequency of sandy, high permeability interbeds than the Laira Formation. However, it still has a high gamma ray signature that is largely due to its high volcanogenic grain content (Fig. 5). In the Penola Trough, despite the drilling of many prospects, only one minor gas accumulation (20 m column height) has been discovered which relies on the Eumeralla Formation as the cap seal.

The high frequency of sandstone horizons within the Eumeralla Formation suggests these units are more likely to be naturally interconnected, and have a greater chance of being fault juxtaposed, than the sand-rich horizons in the Laira Formation. These sandy strata will have significantly lower threshold pressures than Eumeralla shale-rich strata and so act as preferential hydrocarbon migration pathways. This would explain the Eumeralla Formation's poor record as a regional top seal. Alternatively, the lack of gas found trapped beneath the
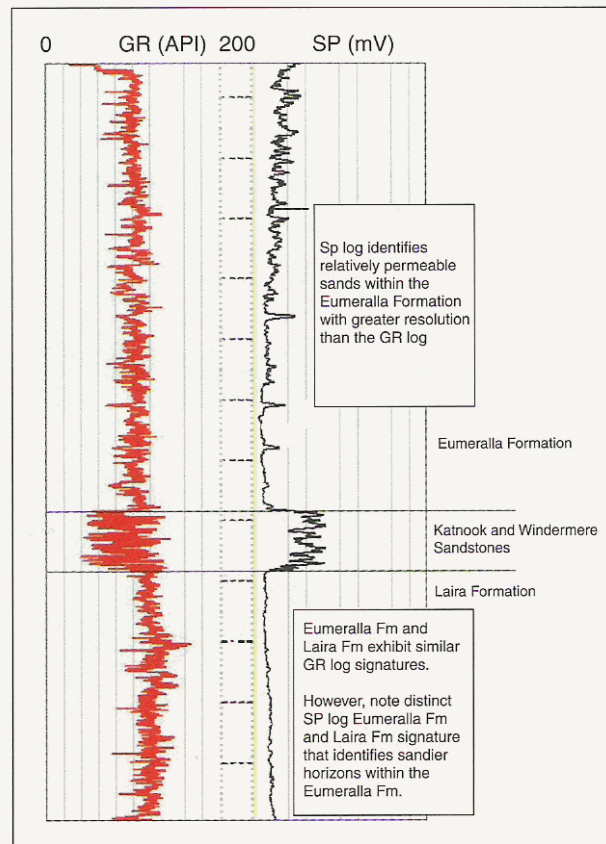
Eumeralla Formation may be related to the long migratio pathways required from the Casterton Formation an lack of charge. However, in many other parts of th Otway Basin the coals at the base of the Eumeralla Formation are sufficiently mature to expel hydrocarbon and yet an economically viable hydrocarbon column ha yet to be found either trapped by, or within, the Eumeralla Formation.

Penola Trough fault seal evaluation

Successful fault seal analysis is dependent on th integration of data from macro to micro-scale. This stud has utilised a number of predictive strategies an amalgamated data from different scales as part of a integrated multi-disciplinary fault seal study.

SEISMIC SCALE FAULT ANALYSIS

All prospects containing strata from the Crayfish Grou were generated by faulting directly related to obliqu syn-depositional rifting of the Penola Trough (Lovibon
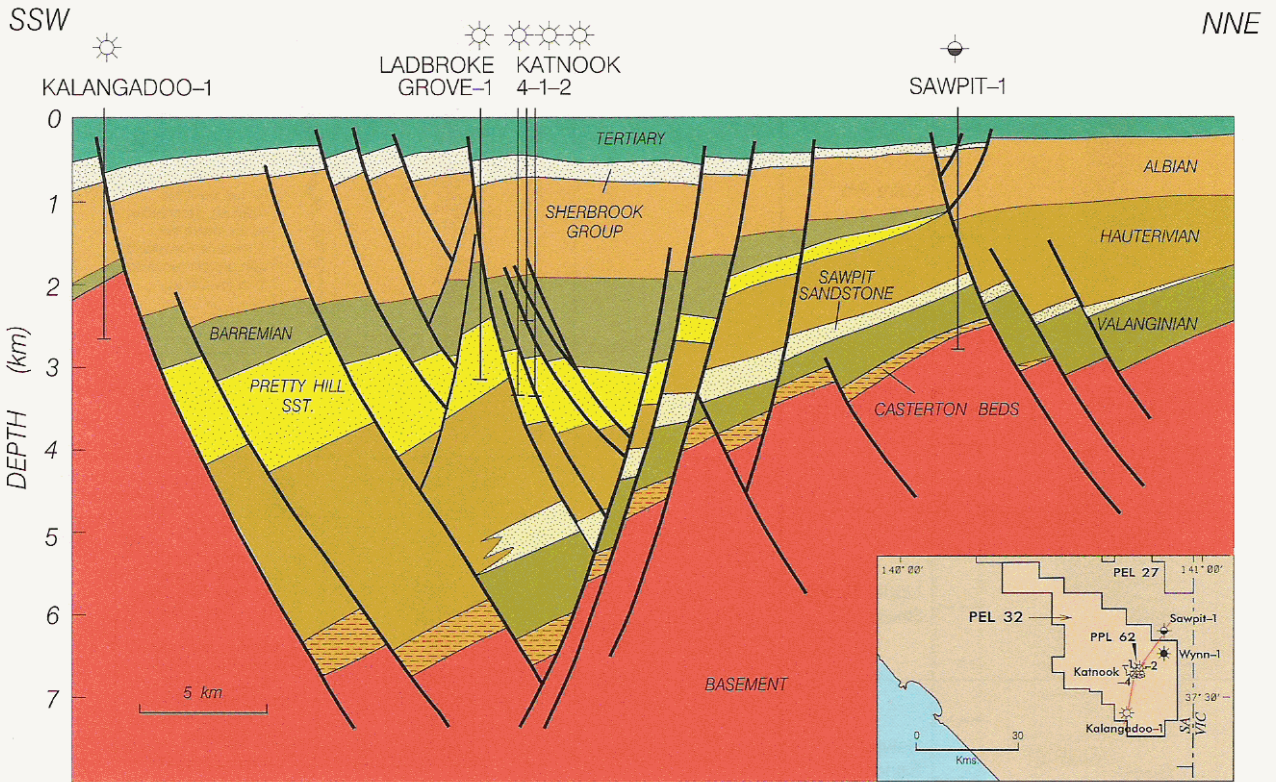
Figure 6. Otway Basin cross section (modified from Lovibond et al, 1995).

et al, 1995). Two fault orientation patterns are present, a dominant northwest-southeast preferred orientation and a less prominent east-west strike (Fig. 6). The location of fault-bound prospects in the region reveals hydrocarbon accumulations on both footwall and hangingwall sides of major dislocation planes.

Ideally, high quality seismic attribute maps would allow interpretation of complex fault zone architecture and detailed mapping of juxtaposition relationships. For this study attribute data were not available. However, the recognition of the fractal nature of fault attributes does allow regional analysis of the likely scale of deformation as it provides a methodology to overcome the limits of vertical seismic resolution. Figure 7 illustrates the length to offset ratio for Penola Trough faults imaged on seismic at the Top Crayfish horizon.

A positive length to offset ratio is apparent for fault data that can be described by a power-law relationship. Employing a linear growth relationship between fault length and throw, a mean length- offset ratio of 50:1 is defined for Penola Trough region. Due to the noise captured in geological data, considerable variation this ratio is observed. Data spread is also explained by differences in the reactivation stress (dominantly strike-slip or reverse) faults have accommodated in response to

regional Miocene-Recent compression. Faults that have undergone no/little reactivation will exhibit tighter regional length-offset correlation than faults that have experienced significant reactivation. Figure 7 presents evidence that a number of faults exhibit length-offset ratios that fall outside limits (95% confidence intervals)
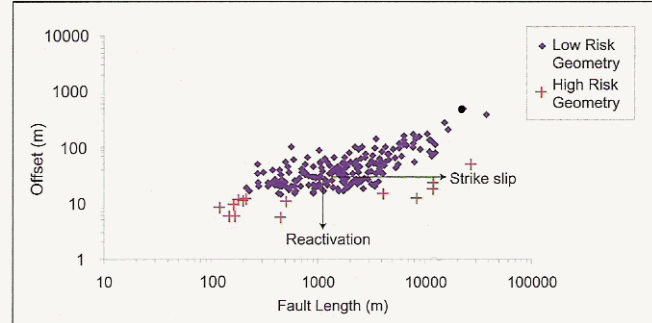

Figure 7. Length to offset relationships for all Penola Trough faults measured at Top Crayfish horizon. Throw (m) is depth converted from TWT data and length (m) is measured from fault polygon limits. Data does not account for vertical seismic resolution inaccuracy.
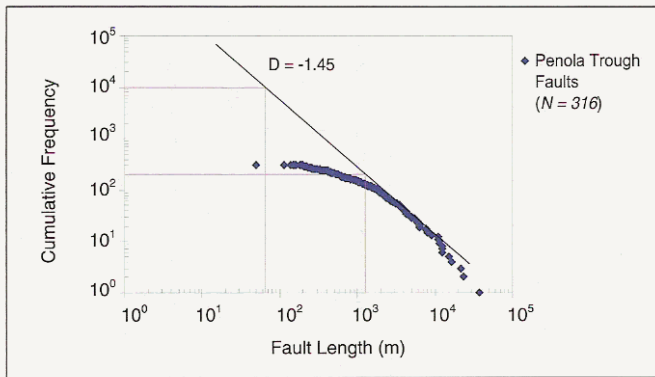
Figure 8. Extrapolation of power-law gradient for Penola Trough faults measured at Top Crayfish horizon for predicting scale of deformation below seismic resolution. Tailing of data is due to seismic resolution effects and truncation of fault lengths at regional seismic boundaries. Number of faults analysed N = 316.

statistically robust for the Penola Trough region. These faults display high-risk geometries that require further investigation if critical for exploration and production decisions. Alternatively it may reflect non-uniform Miocene inversion with reactivation focused on a sub-set fault population.

The regional seismic scale fault length-offset rati can also be used to predict the continuation of faul below seismic resolution. This allows evaluation o likely fault linkage, reservoir compartmentalisatio and cap rock breaching. Assuming a vertical seismi resolution of 10 ms (approximately 25 m), all Penol Trough faults measured at the seismic scale shoul have their total lengths increased by 1,250 m (625 r added to each end of the seismically mapped fault).

Statistical fault population data allows extrapolatio of the power-law gradient, defined at the seismic scale to the core scale in order to predict deformatio intensity below seismic resolution. This methodolog assumes scale invariant fault geometry and growth The Penola Trough seismic scale fault population i described by a power-law relationship with a gradier of -1.45 (Fig. 8). Extrapolation of the regional powe law gradient predicts the number of sub-seismic fault with 25 m offset as 160, and 10,000 with 1 m offse These fault numbers are significantly abov deformation levels interpreted from seismic. Th identification of spatial population and clusterin gradients via techniques such as structural loggin allows estimation of the damage zone dimensions. Cor data are insufficient to permit a geostatistica assessment of the size of the damage zones. Howeve
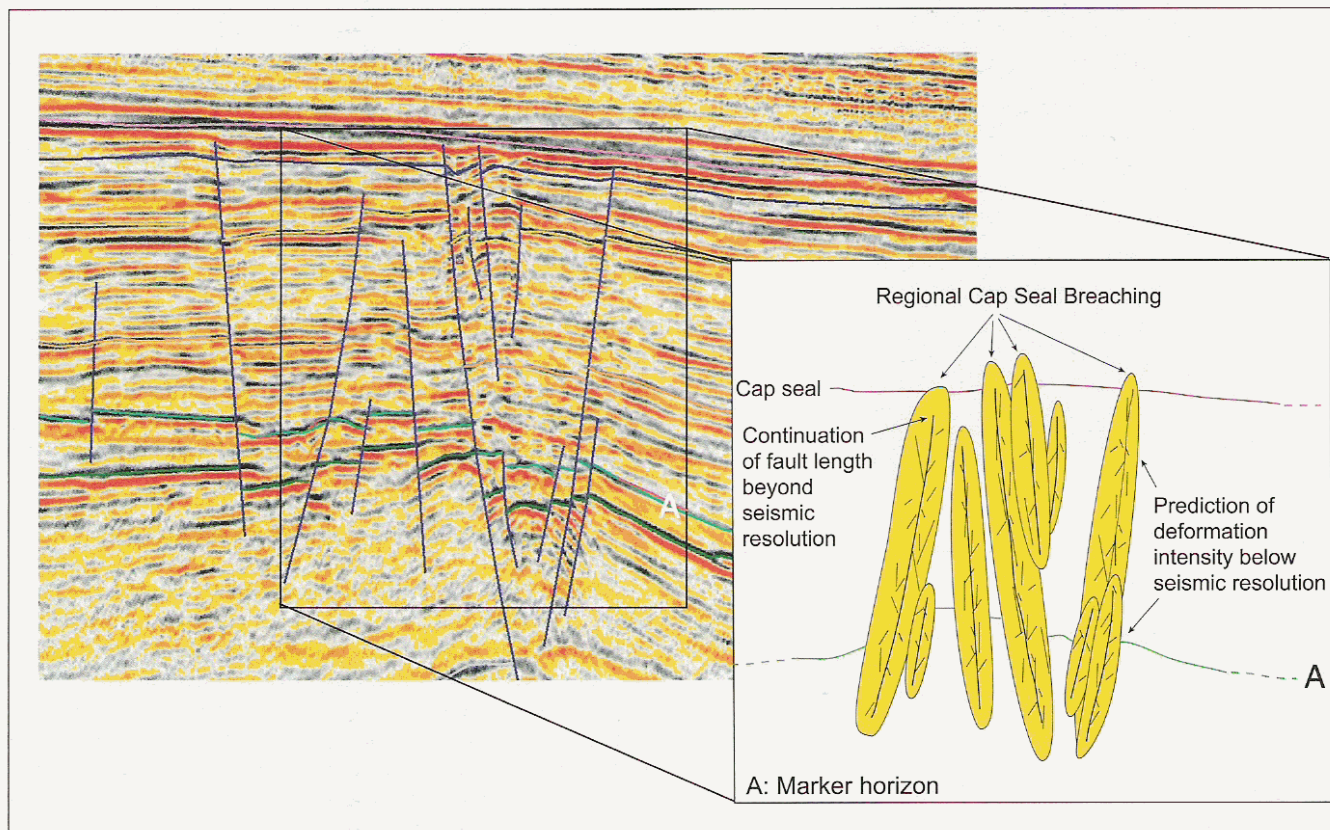

Figure 9. Cartoon illustrating the application of fault scaling relationships and fractal characterisation of the Penola Trough populatic statistics in fault seal analysis. Note the overlap of damage zones surrounding seismically defined faults, the reduction in volume undeformed reservoir and breaching of regional cap seal when fault length is extended beyond seismic tips.
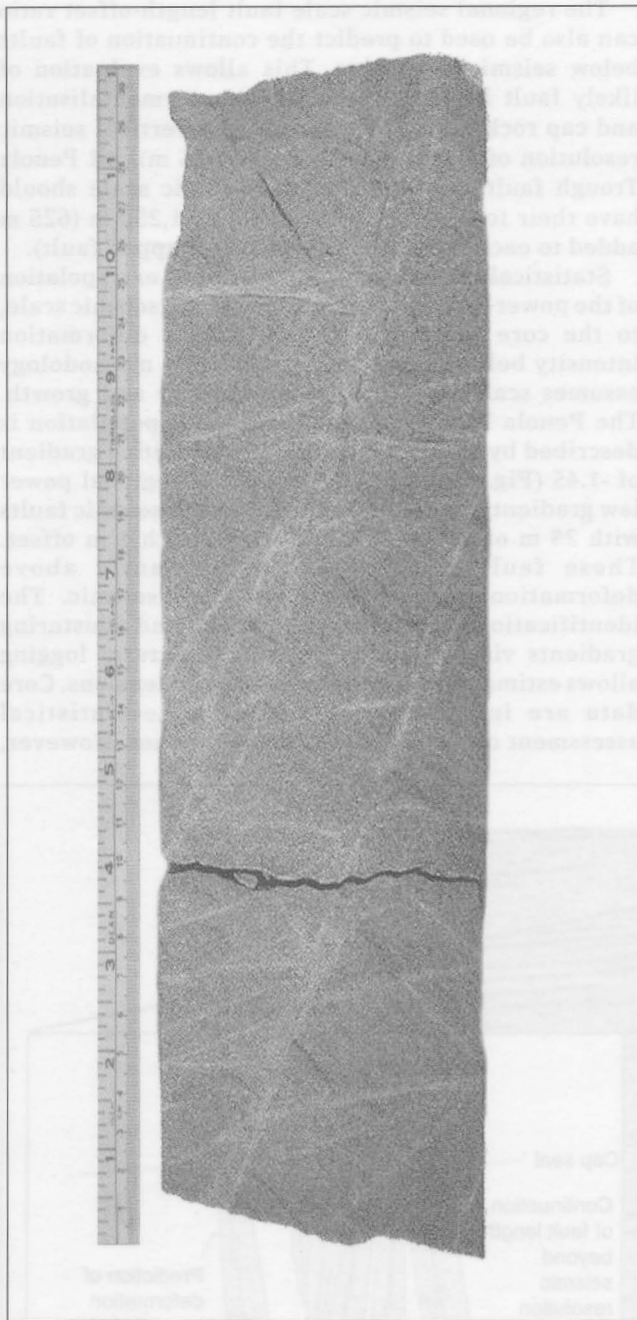
Figure 11. Structural log of half-cut core from the Penola Trough. Note development of "hourglass" structures suggestive of scale invariant fault geometry. Faults are scaled so that thicker lines reflect relatively wide dislocation planes, dashed lines reflect breaks in core, P denotes core plug sectors. Note: horizontal scale exaggeration of 33% relative to vertical axis.

MESO-SCALE FAULT SEAL ANALYSIS

Where core is available, structural, microstructural and petrophysical analysis allows detailed characterisation of fault damage zones. Structural logging of core recovered from an exploration well drilled <10 m from a seismically resolvable fault has provided opportunity to assess damage zone architecture and fault rock processes. Structural analysis of the core revealed an extensive linked fault array that continued throughout the cored interval (Fig. 10).

Many of the features identified the in core display no displacement indicators. The similarity of these features to structures that exhibit well-defined displacement markers allows the majority of features to be identified

Figure 10. Conventional half-cut core with multiple, sub-vertical and sub-horizontal deformation features comprised of well-lithified cataclasites. Extensional offsets are clearly visible throughout the cored interval.

core deformation intensities of approximately 700 features/100 m from a well drilled <10 m from a seismically resolvable fault demonstrate sub-seismic fault populations are likely to be clustered around major dislocation planes. Application of power-law data to fault seal studies is illustrated in Figure 9.
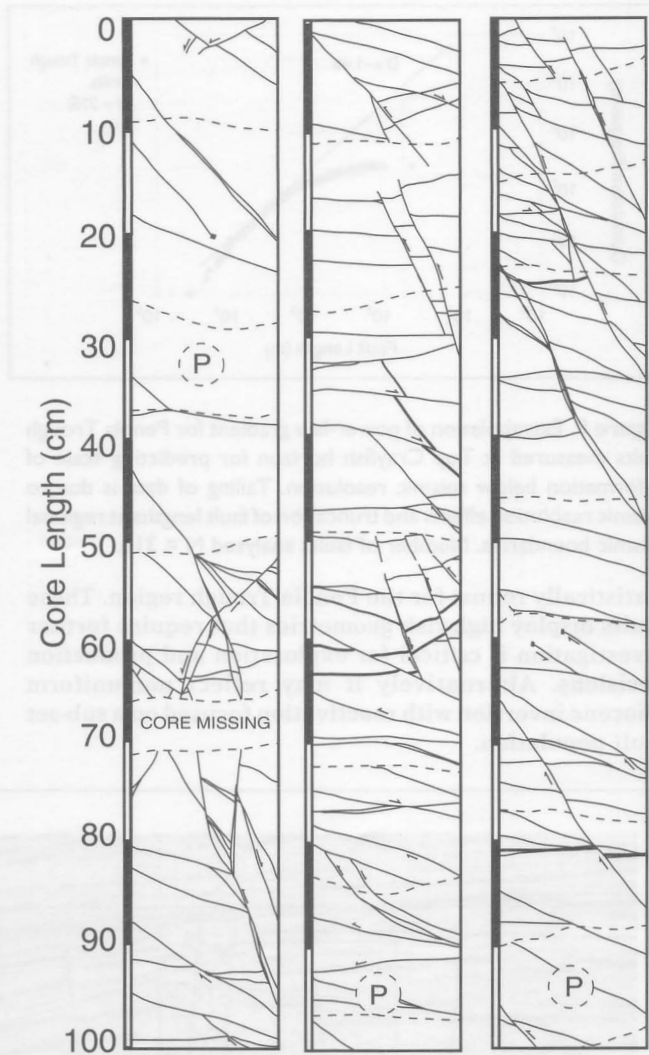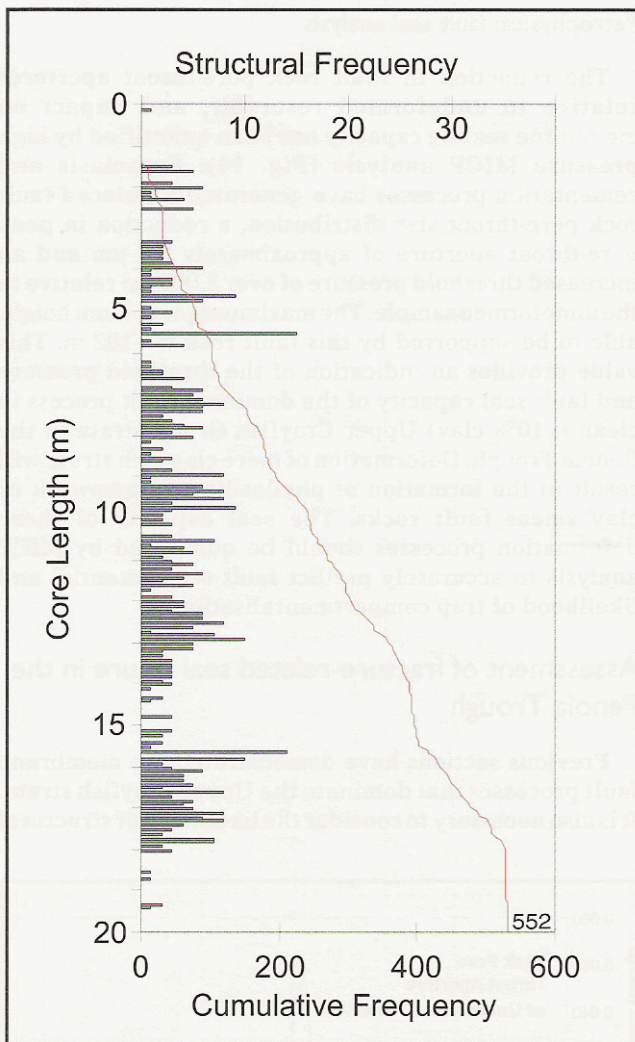
Figure 12. Structural frequency and cumulative structural frequency histogram of fault damage zone illustrated in Figs 10 and 11.

Figure 13. Scanning electron micrograph showing (a) SE image of two parallel, sub-vertical well lithified quartz-cemented cataclastic faults (b) BSE image of fault array in Figure 13a. BSE image clearly illustrates the presence of sub-vertical fault and removal of macro porosity via cataclasis and cementation processes. Undeformed reservoir has a MICP derived porosity of 12%, fault gouge porosity is <1%.

as sub-seismic faults with unknown displacements. No natural fractures with mode 1 (dilational) openings were identified at this scale.

Conjugate fault sets that produce hourglass structures in cross section were identified in core (Fig. 11). These conjugate structures exhibit symmetrical and asymmetrical partitioning of displacement between fault offsets. Recent seismic mapping of conjugate hourglass structures similar to those observed in Penola Trough core (Bretan et al, 1996) reinforces interpretation that some fault geometrical characteristics appear scale invariant. Mapping of spatial distribution patterns at the meso-scale may, therefore, aid interpretation of complex fault zone strain distribution at the seismic scale. This is particularly important for accurate juxtaposition fault seal analysis where seismic offset may be a cumulative product of linked fault arrays, many of which are below seismic resolution.

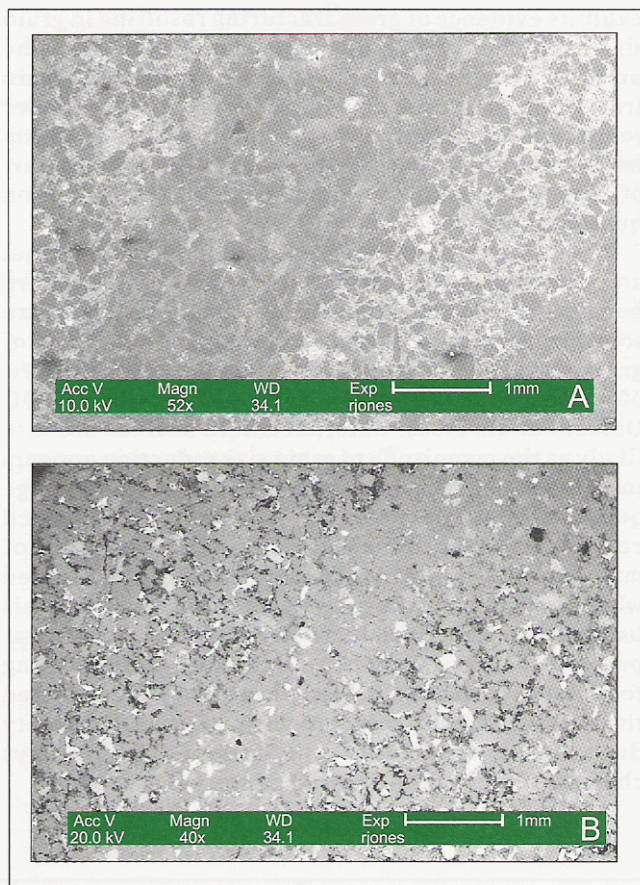Structural frequency and cumulative frequency data illustrate the spatial distribution of core scale deformation (Fig. 12). Faults in the cored interval are arranged in broad groups that define cluster steps in the cumulative frequency curve. The large step in the cumulative frequency curve towards the base of the core reflects the accommodation of strain about the large slip plane marked in core by the presence of slip breccia.

Fault zone structural density in the Crayfish Group cored interval exceeds 680 features/100 m. Deformation of this intensity is indicative of inner damage zone geometry. These data agree with structural densities recorded from inner damage zones of seismically resolvable faults in the North Sea (Knipe, 1997) and are well within the predicted frequency range extrapolated from seismic scale power law gradients for the region.

Microstructural and petrophysical fault process evaluation

Microstructural analysis of faults in the Upper Pretty Hill Sandstone reveals the dominant process of deformation to be cataclasis (Fig. 13). Fault gouge

exhibits evidence of grain fracturing resulting in grain size reduction and decreased sorting relative to the undeformed reservoir. The low intensity of grain fracturing suggests deformation took place under relatively low effective stress conditions (i.e. <4 km burial depth). All cataclastic faults examined as part of this study exhibit evidence of post-deformation quartz cementation.

The solutes for fault gouge cementation have internal and external sources. Internally sourced solutes have been generated via enhanced cementation or pressure solution processes and are related to the extent of grain-size reduction (for a more comprehensive review of these processes see Dewers and Ortoleva, 1991; Oelkers et al, 1996). External solute sources are also likely as the magnitude of grain size reduction appears insufficient to account entirely for all fault gouge quartz cement by pressure solution and enhanced cementation processes. The importance of microstructural fault process evaluation is reinforced when considering the impact of fault seal analysis using empirical algorithms that rely on clay smear processes. In this instance, fault seal analysis using techniques such as SGR would have wrongly predicted the dominant fault rock processes and seal capacity due to the relatively clay-free (<10% Vclay) characteristics of the reservoir interval.

Petrophysical fault seal analysis

The reduction in fault rock pore-throat apertures relative to undeformed reservoir, and impact on membrane sealing capacity has been quantified by high pressure MICP analysis (Fig. 14). Cataclasis and cementation processes have generated a reduced fault rock pore-throat size distribution, a reduction in peak pore-throat aperture of approximately 0.8 µm and an increased threshold pressure of over 2,000 psi relative to the undeformed sample. The maximum gas column height able to be supported by this fault rock is ~102 m. This value provides an indication of the threshold pressure and fault seal capacity of the dominant fault process in clean (<10% clay) Upper Crayfish Group strata in the Penola Trough. Deformation of more clay-rich strata will result in the formation of phyllosilicate framework or clay smear fault rocks. The seal capacity of these deformation processes should be quantified by MICP analysis to accurately predict fault seal potential and likelihood of trap compartmentalisation.

Assessment of fracture-related seal failure in the Penola Trough

Previous sections have demonstrated the membrane fault processes that dominate the Upper Crayfish strata. It is also necessary to consider the likelihood of structural
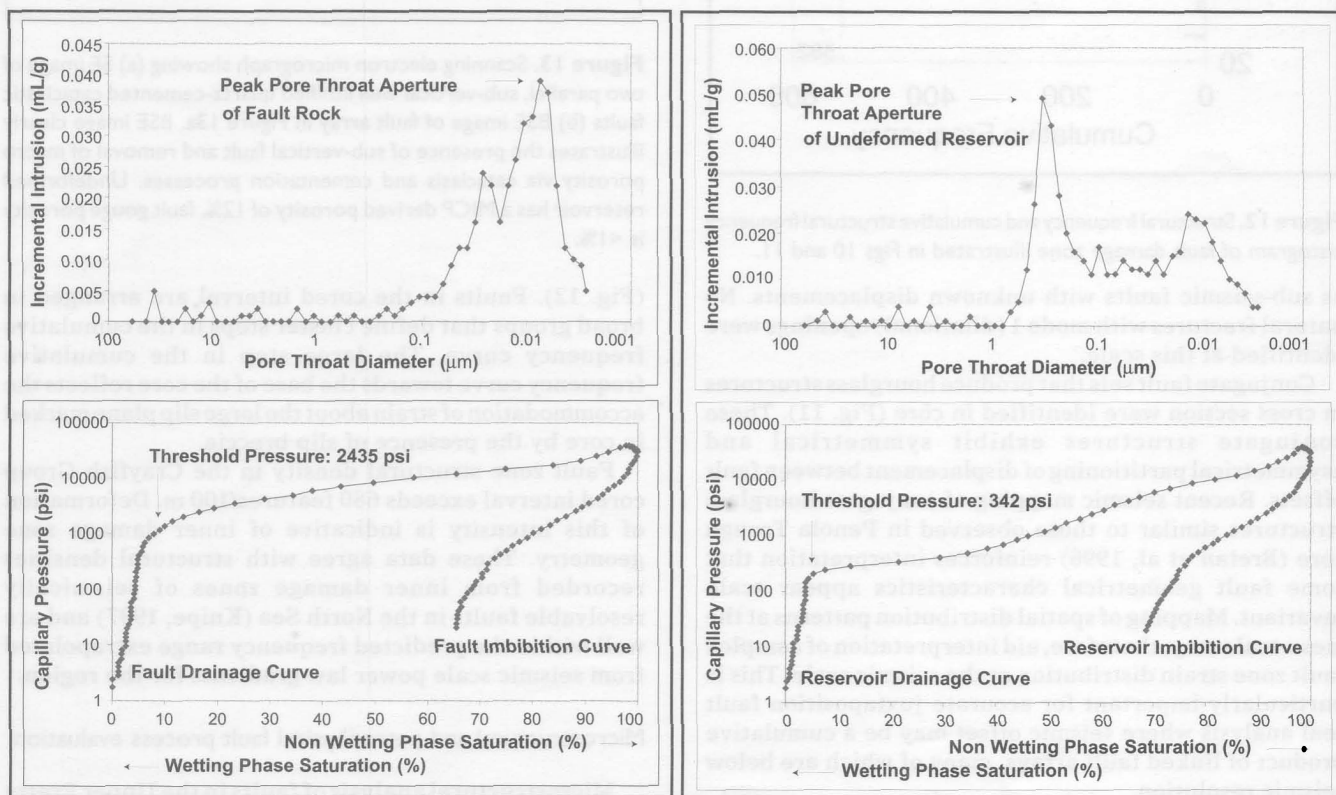

Figure 14. MICP data from Penola Trough undeformed reservoir and cataclastic fault rock.

permeability networks and the possibility of fault reactivation within the in-situ stress field. Ideally, assessing the risk of seal breach due to the development of effective structural permeability involves combining information on the in-situ stress field with that on the failure envelope for sealing units. The in-situ stress tensor for the Penola Trough can be determined. However, there is no available information on the failure envelope of sealing units in the Penola Trough. Therefore, a relative (rather than absolute) assessment of the probability of tensile or shear failure has been undertaken. The conditions for the formation and orientation of tensile and shear fractures are known from classic brittle failure theory (Sibson, 1996; Hillis, 1998).

Data from leak-off tests and one extended leak-off test have been compiled for the Penola Trough (Fig. 15). These data are indicative of the minimum horizontal stress magnitude in the area, with that derived from the extended leak-off test providing the most reliable indicator of minimum horizontal stress magnitude (Enever et al, 1996). Pore pressures are hydrostatic, as indicated by formation test data (Fig. 15). The vertical or overburden stress has been determined from density and sonic check shot log data as described by Hillis et al (1995). Maximum horizontal stress orientation in the area was also determined by Hillis et al. (1995) and that from the Katbook–3 well of 156°N, which is typical for the region, has been used herein. At the depth of the base of the Laira Formation regional seal in Katnook–3 (2,859 m), the minimum horizontal stress is 46 MPa, the pore pressure 28 MPa and the vertical stress 64 MPa.

Maximum horizontal stress has been constrained by the occurrence of drilling-induced tensile fractures (DITF) in vertical wells in the area. In order for DITF to form, the minimum stress concentration acting around the wellbore wall must be less than the tensile strength (taken to be negative) of the formation. The circumferential stress ($\sigma_{\theta\theta}$) acting at the wellbore wall is given by:

$$\sigma_{\theta\theta} = \sigma_H + \sigma_h - 2(\sigma_H - \sigma_h)\cos2\theta - P_w - P_0, \quad (1)$$

where σ_H and σ_h are the maximum and minimum horizontal stresses respectively, θ is the angle at the wellbore wall measured from the azimuth of σ_H, P_w is the mud pressure in the wellbore, and P_0 the pore pressure of the formation (e.g. Moos and Zoback, 1990, and references therein). All the parameters in this relation are known except the maximum horizontal stress. Since the minimum circumferential stress (which acts at the azimuth of the maximum horizontal stress) must reach 0 MPa in order for DITF to form, the maximum horizontal stress can be constrained (Fig. 16). We assume that DITF form if the minimum circumferential stress reaches 0 MPa according to the above relation, thereby ignoring cooling effects due to the drilling muds, surge pressures in drilling and any tensile strength of the formation. These factors only result in a few MPa variation in predicted stresses and, furthermore, any tensile strength will counteract cooling and surge pressure effects. Assuming that DITF form when the minimum circumferential stress reaches 0 MPa, the maximum horizontal stress must be 82 MPa (Fig. 16).
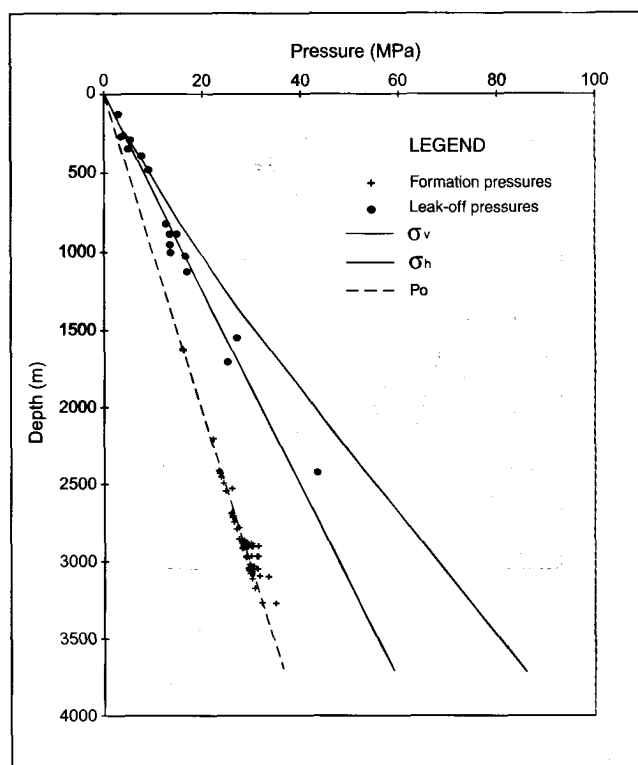

Figure 15. Formation test, leak-off test (including one extended leak-off test) pressures and vertical stress in the Penola Trough. The lines indicate the pore pressure, minimum horizontal stress and vertical stress values used herein. Extended leak-off test was given greater weighting than the standard leak-off test in determining the minimum horizontal σ relation.

The above data fully constrain the in-situ stress tensor at the base of the regional seal in the area and can be used to determine the three-dimensional Mohr's circle of stress at that depth (Fig. 17).

Planes subject to the lowest effective normal stress are the most prone to tensile failure, and those subject to the highest shear/normal stress ratio are the most prone to shear failure (Fig. 17). The most suitably oriented plane for tensile failure is that normal to σ_3 (point A in Fig. 17). The most suitably oriented plane for shear failure is that containing σ_2 and oriented approximately 30° to σ_1 (point B in Fig. 17). In the absence of a failure envelope, it is not possible to assess whether tensile or shear fracturing presents a greater risk, and indeed the precise orientation of the planes most prone to shear failure cannot be ascertained. However, the planes subject to the lowest effective normal stress (point A in Fig. 17), and that subject to the highest shear/normal stress ratio (point B in Fig. 17) can reasonably be assigned a relative probability of failure of 1. The plane with the highest value of effective normal stress (point C in Fig. 17) can be assigned a relative probability of tensile failure of 0, and those with the lowest shear/normal stress ratio (A, C and D in Fig. 17) a relative probability of shear failure of 0. Planes of all orientations lie within the
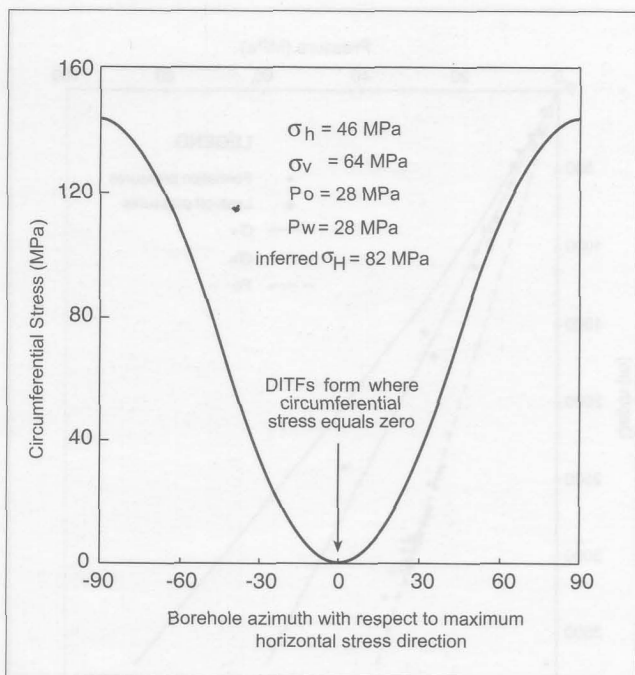
Figure 16. Circumferential stress required to produce drilling-induced tensile fractures at 2,859 m in Katnook–3 well (depth of the base of the Laira Formation regional seal). The pore pressure (P_0), minimum horizontal stress (σ_h) and vertical stress (σ_v) are known from Figure 15. Most wells are drilled approximately in balance, hence mud weight (P_w) is the same as pore pressure. Given these conditions, the maximum horizontal stress must be 82 MPa in order for drilling-induced tensile fractures to form.
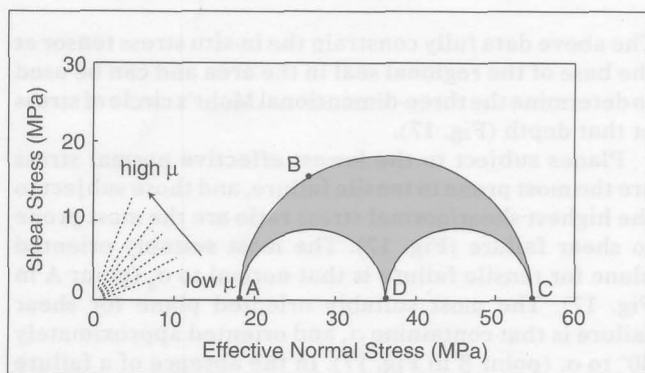

Figure 17. Three-dimensional Mohr's circle describing the state of stress at the base of the regional seal (2,859 m) in the Katnook–3 well. Planes of all orientations lie within the shaded area of Mohr's circle. The relative risk of tensile failure is given by the effective normal stress (σ_n'; lower σ_n' equating to higher risk of tensile failure). The relative risk of shear failure is given by the shear/normal stress ratio (μ; higher μ equates to higher risk of shear failure). Point A has low σ_n' (18 MPa) and low μ (0), hence is prone to tensile failure but not to shear failure. Point B has intermediate σ_n' (27 MPa) and relatively high μ (0.58), hence is moderately prone to tensile failure and relatively highly prone to shear failure. Point C has relatively high σ_n' (54 MPa) and low μ (0), hence is not prone to either tensile or shear failure.

shaded area of Mohr's circle. The relative probability of failure of planes of all orientations can therefore be determined from Figure 17 and is plotted in Figure 18.

Given the in-situ stress field, fault planes in the Penola Trough with the highest risk of failure are those steeply dipping (>60°) and striking between 110°N and 200°N. Planes with such orientations have the greatest likelihood of providing effective structural permeability, thereby breaching the seal, within the in-situ stress field. Very shallowly-dipping planes (less than approximately 30°) and those that strike in a northeast direction have a relatively low risk of failure.

This study has identified fractures that dissect pre-existing faults and are interpreted to be open under subsurface conditions (Fig. 19). Open natural fractures typically display textural and morphological characteristics similar to cemented features, the distinguishing feature of open fractures being only partial occlusion of fracture porosity by authigenic phases. The incomplete occlusion of natural dilatant fracture networks and preservation of vuggy porosity may have resulted from low solute concentrations in fluids transmitted through these relatively high permeability networks, or because hydrocarbon charge and accumulation halted diagenetic reactions. Regardless of the mechanism for porosity preservation, open fracture networks can provide pathways for migration of hydrocarbons through the seal. It is, therefore, critical to address the factors that control the spatial distribution, orientation and connectivity as part of a robust seal evaluation strategy.

The above approach assumes that the in-situ stress field, specifically the proximity to failure, controls whether fractures are likely to provide the effective structural permeability by which seals are breached. Clearly pre-existing faults may have a variety of orientations, depending on their age and the stress regime within which they formed. However, pre-existing faults that are not suitably oriented for failure within the in-situ stress field tend to be closed and do not provide pathways of effective structural permeability.

Discussion of prospectivity

Multiple siliciclastic reservoirs of Early Cretaceous age have been identified within the Penola Trough, the most important of which belong to the Upper Crayfish Group. The uppermost Pretty Hill Sandstone is the primary target for gas exploration in this region and is sealed by the Laira Formation. This study has indicated that the Laira Formation has the lowest risk for regional cap seals, however, the presence of younger intra-formational shales within this unit suggests there is significant potential for hydrocarbon trapping at deeper levels. The prospectivity potential of reservoirs below these shales carries greater risk primarily because of lateral extent and source rock maturity uncertainties.

Given the complex tectonic history of the region, and the fact that the majority of accumulations are at least partially fault-bound, the greatest risk and yet potential
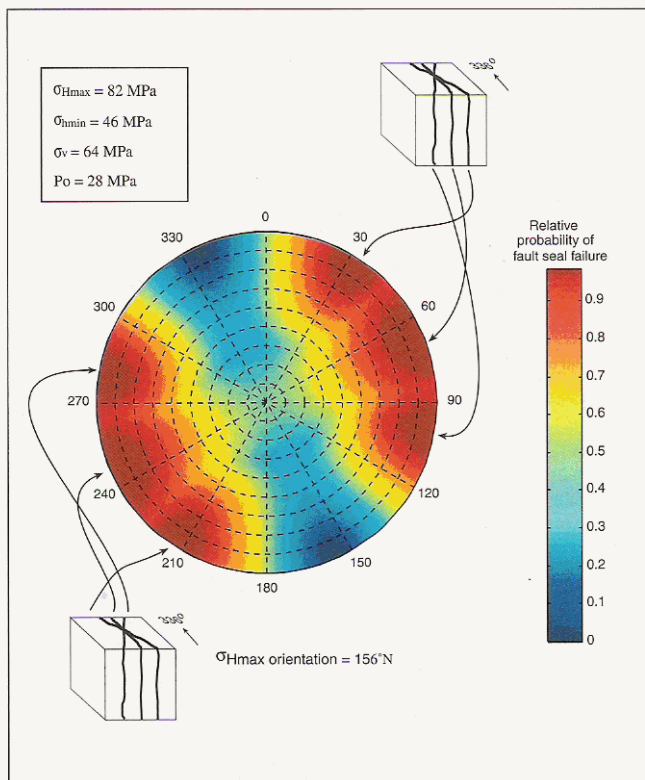
Figure 18. Likelihood of tensile or shear failure at the base of the regional seal in the Katnook–3 well based on the relative probability of failure data from Fig. 17. Equal angle, lower hemisphere, stereographic projection of poles to planes. The orientation of the tensile and shear fracture planes of highest risk is shown schematically on the block diagrams.

Figure 19. BSE image of (a) natural open fracture crosscutting fault gouge. The margins of micrograph B are illustrated within the image. (b) detailed BSE image of natural open fracture partially occluded by spary siderite precipitated from Fe_{2+} rich fluids late in the diagenetic history of the reservoir.

for Penola Trough exploration is structural. Numerous fault-bound leads have been identified yet most have a maximum trap capacity of less than 100 BCF (Lovibond et al, 1995). One of the major factors controlling trap capacity and recoverable reserves is the volume of undeformed reservoir. Extrapolation of regional power-law gradients to predict damage zone widths and intensity of faulting below seismic resolution, especially when the trap is structurally dependent, will aid exploration decisions. The dataset generated as part of this study has shown that faults with offsets greater than 100 m have inner damage zones widths in excess of 10 m, with structural frequencies close to 700 features/100 m. With this degree of deformation, trap capacity and recoverable reserves will be significantly lower than in reservoir rock beyond the damage zone.

Hydrocarbon leakage, due to reactivation, is perhaps the major risk for fault bound traps in the Penola Trough. This study has demonstrated that faults and fractures with the highest risk of failure are steeply dipping (>60°) and striking between 110°N and 200°N, and that reactivation of faults is a genuine risk for the region. Our multi-disciplinary approach to seal analysis has allowed integration of in-situ stress data with seismic to provide
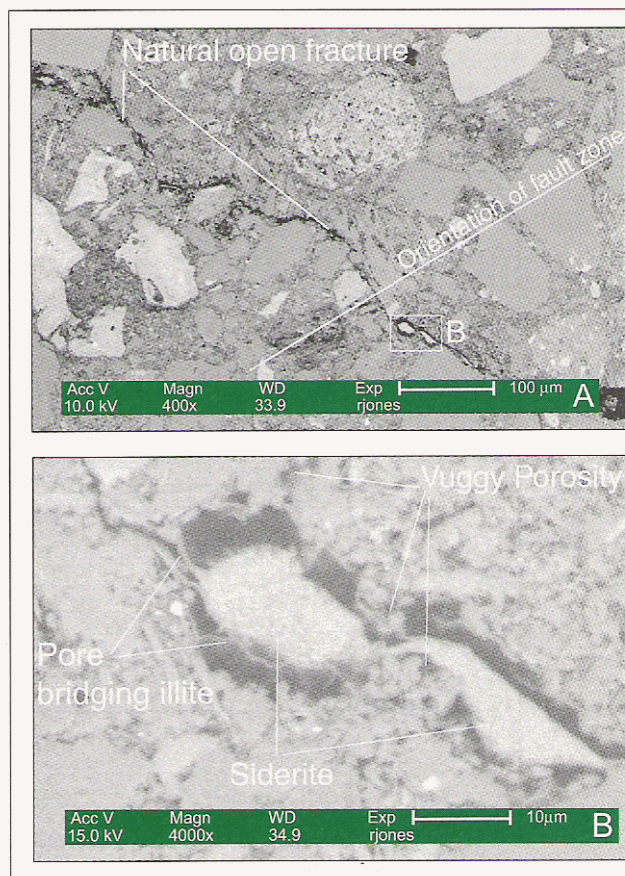
a mechanism for mapping the relative potential for seal failure along individual fault lengths (Fig. 20). The advantage of this integrated technique over stand-alone fault seal analysis tools is that it allows sections of fault-bound prospects that may be more susceptible to breaching to be rapidly identified and risked. Due to proprietary issues the Top Pretty Hill horizon is unable to be presented. However, analysis of the Top Crayfish horizon indicates the seismic scale fault population provides good correlation with the older reservoir interval.

Figure 20 illustrates that the majority of faults exhibit a suite of relative probability failure ratios along strike reflecting a complex strain distribution. The application of this technique (F.A.S.T.™) for exploration is demonstrated with respect to Zema–1 (Fig. 20). Zema–1 was plugged and abandoned with an 86 m palaeo-gas leg and a 15 m palaeo-oil leg. The trap was interpreted to have had fault dependent closure in the footwall with the main palaeo-sealing fault trending approximately eastwest with a change in strike to northwest-southeast towards the east. Seal failure by structural permeability/reactivation is the most likely reason for trap leakage in
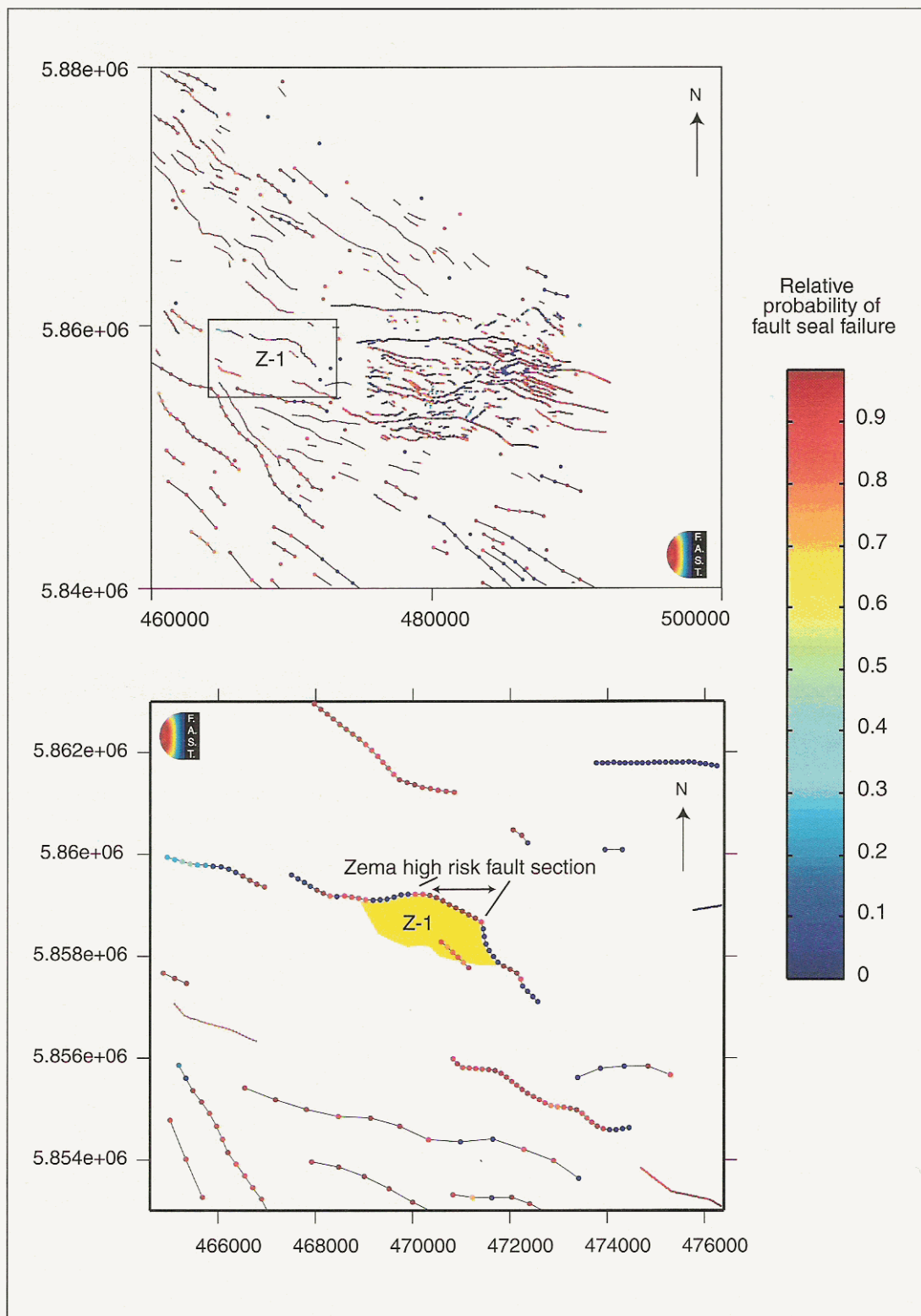
Figure 20. Fault Analysis Seal Technology (F.A.S.T.™) mapping of seal failure through structural permeability at the seismic s
incorporates stress and fault geometry data along the fault plane to predict relative probability of breaching (see text for d

this instance (as palaeo-hydrocarbon columns are less than heights able to be supported by predicted fault plane gouge). Figure 20 clearly identifies a number of sections along strike of the main Zema–1 bounding fault that have a high relatively probability of shear or tensile failure. This integrated technique has identified the most likely reason for Zema–1 leakage and also identified the locations and relative risk of seal breach along the fault length. Application of this technique in conjunction with other fault seal evaluation tools should be encouraged as part of a more robust and integrated first-phase fault seal evaluation or reservoir development strategy.

CONCLUSIONS

1. The Laira Formation has the lowest seal potential risk of Penola Trough cap seal strata. Commonly occurring sandy horizons within the Eumeralla Formation increase the potential for sand-on-sand fault juxtaposition and the development of 'leaky windows' that may allow cross fault communication.

2. Displacement and length populations for Penola Trough faults are characterised by power-law distributions. A 50:1 seismic scale mean length-offset ratio is identified. A significant proportion of faults identified at seismic scale fall outside statistical limits considered robust for the region. These faults have high-risk geometries that may suggest incorrect seismic mapping of complex fault zones.

3. Prediction of the sub-seismic fault population is viable by extrapolation of regional power-law gradient to the core scale. Assuming fractal fault growth, the number of faults at seismic vertical resolution limits in the Penola Trough is predicted to be 160. Most sub-seismic faults will be clustered around seismically resolvable dislocation planes.

4. The principal deformation process in clean (<10% clay) Crayfish Group strata is cataclasis with post-deformation quartz cementation. Maximum gas column heights able to be supported by such faults in this study are approximately 102 m.

5. Fault seal analysis using techniques based on clay smear processes will incorrectly predict the seal capacity of fault bounded traps in clean (<10% Vclay) reservoirs.

6. Analysis of the risk of regional seal breach due to the development of structural permeability indicates that faults and fractures at the greatest of reactivation are steeply dipping (>60°) and strike between 110°N and 200°N. Fractures interpreted to be open under reservoir conditions have been identified in the Crayfish Group interval. Such features can provide a pathway for secondary hydrocarbon migration and may explain the occurrence of palaeo-hydrocarbon shows within structures bounded by steeply dipping faults striking between 110°N and 200°N.

7. Multi-disciplinary fault seal analysis has allowed the development of an integrated exploration tool (F.A.S.T.™) that allows the risk of seal breaching due to shear or tensile failure to be mapped at the seismic scale. This technique is particularly useful in petroleum provinces where reactivation is of major concern and also provides a link to other rapid fault seal assessment tools such as SGR and strike projection diagrams.

ACKNOWLEDGEMENTS

REFERENCES

ALLAN, U. S., 1989—Model for hydrocarbon migration and entrapment within faulted structures. American Association of Petroleum Geologists Bulletin, 73, 803–11.

ANTONELLI, M. AND AYDIN, A., 1994—Effect of faulting on fluid flow in porous sandstones: petrophysical properties. American Association of Petroleum Geologists Bulletin, 78, 335–77.

AYDIN, A., 1978—Small faults formed as deformation bands in sandstone. Pure Applied Geophysics, 116, 913–42.

BERG, R. B. AND AVERY, A. H., 1995—Sealing properties of Tertiary growth faults, Texas Gulf Coast. American Association of Petroleum Geologists Bulletin, 79, 375–93.

BOUVIER, J.D., SIJPESTEIJN, K., KLEUSNER, D.F., ONYEJEKWE, C.C. AND VAN DER PAL, R.C., 1989—Three-dimensional seismic interpretation and fault sealing investigations, Nun River, Nigeria. American Association of Petroleum Geologists Bulletin, 73, 1397–414.

BRETAN, P.G., NICOL, A., WALSH, J.J. AND WATTERSON, J., 1996—Origin of some conjugate or 'X' fault structures. The Leading Edge, July, 812–16.

BURLEY, S.D., MULLIS, J. AND MATTER, A., 1989—Timing diagenesis in the Tartan Reservoir (UK North Sea): constraints from combined cathodoluminescence microscopy and fluid inclusion studies. Marine Petroleum Geology, 6, 98–120.

COCKSHELL, C.D., O'BRIEN, G.W., MCGEE, A., LOVIBOND, R., PERINCEK, D. AND HIGGINS, R.1995—Western Otway Crayfish Group Troughs, APEA Journal, 35 (1), 385–401.

DEWERS, T. AND ORTOLEVA, P. J., 1991—Influences of clay minerals on sandstone cementation and pressure Solution. Geology, 19, 1045–8.

DOWNEY, M. W., 1984—Evaluating seals for hydrocarbon accumulation. American Association of Petroleum Geologists Bulletin, 68, 1752–63.

ENEVER, J. R., YASSIR, N., WILLOUGHBY, D. R. AND ADDIS, M. A., 1996—Recent experience with extended leak-off tests for in-situ stress measurements in Australia. APPEA Journal, 36, 528–35.

ENGELDER, J. T., 1974—Cataclasis and the generation of fault gouge. Bulletin of the Geological Society of America, 85, 1515–22.

FISHER, Q.J. AND KNIPE, R.J., 1998—Fault sealing in siliciclastic sediments. In: Jones, G., Fisher, Q. J. and Knipe, R. J. (eds) Faulting, fault sealing and fluid flow in hydrocarbon reservoirs. Geological Society, London, Special Publication, 147, 117–34.

FREEMAN, B., YIELDING, G. AND BADLEY, M., 1990—Fault correlation during seismic interpretation. First Break, 8 (3).

FULLJAMES, J. R., ZIJERVELD, L. J. J., FRANSSEN, R. C. M. W., INGRAM, G. M. AND RICHARD, P. D., 1997—Fault seal processes. In: Miller-Pedersen, P. and Koeslter, A.G., (eds) Hydrocarbon seals: importance for exploration and production, NPF Special Publication, 7, 51–9.

GIBSON, R. G., 1994—Fault zone seals in siliciclastic strata of the Columbus Basin, Offshore Trinidad. American Association of Petroleum Geologists Bulletin, 78, 1372–85.

HILLIS, R. R., 1998—Mechanisms of dynamic seal failure in the Timor Sea and Central North Sea. In: Purcell, P. G. and Purcell, R.R. (eds.) The sedimentary basins of Western Australia 2. Proceedings of Petroleum Exploration Society of Australia Symposium, Perth, Western Australia, 313–24.

HILLIS, R. R., MONTE, S. A., TAN, C. P. AND WILLOUGHBY, D. R., 1995—The contemporary stress field of the Otway Basin, South Australia: Implications for Exploration and Production, APEA Journal 35 (1), 494–506.

KALDI, J. G. AND ATKINSON, C. D., 1997—Evaluating seal potential: example from the Talang Akar Formation, offshore northwest Java, Indonesia, In: Surdam, R. C. (ed). Seals, traps, and the petroleum system: American Association of Petroleum Geologists Memoir 67, 85–101.

KNIPE, R. J., 1992—Faulting process and fault seal. In: Larsen, R.M., Breke, H., Larsen, B. T., and Talleraas, E. (eds) Structural and tectonic modelling and its application to petroleum geology. NPF Special Publication 1, Stavanger, 325–42.

KNIPE, R. J., 1997—Juxtaposition and seal diagrams to help analyse fault seals in hydrocarbon reservoirs. American Association of Petroleum Geologists Bulletin, 81, 187–95.

KNIPE, R. J., JONES, G., FISHER, Q. J.F., McALLISTER, E., FARMER, A., PORTER, N., JONES, R., ALLIN, N., WIBBERLEY, C., JOLLY, S., CONDCLIFFE, D., LEAHY, K., EARNSHAW, J. AND WHITE, E., 1997—Structure and prospectivity of Rotliegendes gas reservoirs in the central southern North Sea, UK. Rock Deformation Research Ltd. Proprietary report for multi-sponsor consortium.

KOPSEN, E. AND SCHOFIELD, T., 1990—Prospectivity of the Otway Supergroup in the Central and Western Otway Basin. APEA Journal, 30, 263–79.

KROOSS, B. M. AND LEYTHAEUSER, D., 1997—Diffusion of methane and ethane through the reservoir cap rock; implications for the timing and duration of catagenesis: Discussion, American Association of Petroleum Geologists Bulletin 81, 155–61.

LINDSAY, N. G., MURPHY, F. C., WALSH, J. J. AND WATTERSON, J., 1993—Outcrop studies of shale smears on fault surfaces. In: Flint, S. and Bryant, I. D (eds) The geological modelling of hydrocarbon reservoirs and outcrop analogues. Special Publication of the International Association of Sedimentologists, 15, 113–23.

LOVIBOND, R., SUTILL, R. J., SKINNER, J. E. AND ABURAS, A.N., 1995—The hydrocarbon potential of the Penola Tough, Otway Basin. APPEA Journal, 35 (1), 358–71.

MOOS, D. AND ZOBACK, M. D., 1990—Utilisation of observations of well bore failure to constrain the orientation and magnitude of crustal stresses: application to continental, deep sea drilling project, and ocean drilling program boreholes. Journal of Geophysical Research, 95, 9305–25.

MORGAN, R., 1993—New palynology of the Laira Shale in Katnook –1, –2 and –3, Banyula–1, Laira–1, Ladbroke Grove–1 and Kalangadoo–1, Otway Basin, South Australia, unpublished.

MURRIS, R. J., 1980—Middle east: stratigraphic evolution and oil habitat. American Association of Petroleum Geologists Bulletin, 64, 597–618.

NELSON, J. S. AND SIMMONS, E. S., 1997—Diffusion of methane and ethane through the reservoir Cap Rock; implications for the timing and duration of catagenesis; Reply. American Association of Petroleum Geologists Bulletin, 81, 162–7.

OELKERS, E. H., BJORKUM, P. A. AND MURPHY, W. M., 1996—A petrographic and computational investigation of quartz cementation and porosity reduction in North Sea Sandstones. American Journal of Science, 296, 420–52.

RUTER, E. H., 1983—Pressure solution in nature, theory and experiment. Journal of the Geological Society of London, 140, 725–40.

SCHOWALTER, T.T., 1979—Mechanics of secondary hydrocarbon migration and entrapment. American Association of Petroleum Geologists Bulletin, 63, 723–60.

SIBSON, R. H., 1994—Crustal stress, faulting and fluid flow. In: Parnell, J. (ed) Geofluids: origin, migration and evolution of fluids in sedimentary basins. American Association of Petroleum Geologists Special Publication, 78, 69–84.

SIBSON, R. H., 1996—Structural permeability of fluid-driven fault-fracture meshes. Journal of Structural Geology, 18, 1031–42.

SLUIJK, D. AND PARKER, J. R., 1986—Comparisons of predrilling predictions with postdrilling outcomes, using Shell's Prospect Appraisal System. In: Rice, D. D. and James, W. R. (Eds) Oil and gas assessment—methods and applications: American Association of Petroleum Geologists Bulletin, 21, 55–8.

SNEIDER, R. M., 1987—Practical petrophysics for exploration and development. American Association of Petroleum Geologists Bulletin Education Department Short Course Notes.

SPIERS, C. J., SCHUTJENS, P. M. T. M., BRZESOWSKY, R H., PEACH, C. J., LIEZENBERG, J. L., AND ZWART, H. J., 1990—Experimental determination of constitutive parameters governing creep of rocksalt by pressure solution. In Knipe, R. J. and Ruter, E. H. (Eds) Deformation Mechanisms, Rheology and Tectonics. Geological Society Special Publication, 54, 215–28.

UNDERHILL, J.R. AND WOODCOCK, N.H., 1987—Faulting mechanisms in high porosity sandstones; New Red Sandstone, Arran, Scotland. In: Jones, M. E. and Preston, R. M. F. (Eds) Deformation of sediments and sedimentary rocks. Geological Society Special Publication 29, 91–105.

VAVRA, C. L., KALDI, J. G. AND SNEIDER, R.M., 1992—Geological applications of capillary pressure: a review. American Association of Petroleum Geologists Bulletin, 76, 840–50.

WALSH, J. J. AND WATTERSON, J., 1992—Populations of faults and fault displacements and their effects on estimates of fault-related regional extension. Journal of Structural Geology, 14, 701–12.

WATTS, N. L., 1987—Theoretical aspects of cap-rock and fault seals for two-phase hydrocarbon columns. Marine and Petroleum Geology, 4, 274–307.

WEBER, K. J., 1982—Influence of common sedimentary structures on fluid flow in reservoir models. Journal of Petroleum Technology, March, 665–72.

YIELDING, G., NEEDHAM, T., AND JONES, H., 1996—Sampling of fault populations using sub-surface data: A Review. Journal of Structural Geology 18, 135–46.

YIELDING, G., FREEMAN, B. AND NEEDHAM, D. T., 1997—Quantitative fault seal prediction. American Association of Petroleum Geologists Bulletin, 81, 897–917.

Authors' biographies over page.

APPEA

THE AUTHORS

Richard Jones obtained a BSc (Hons) in Geology in 1991 and a PhD in 1995 from Keele University, England. He joined Geochem Group Ltd in 1996 working in the Reservoir Geology Division before joining Rock Deformation Research, England in 1997. He has worked extensively in the area of fault seal analysis and been involved with fault seal research programmes in Europe, USA and Australia. His current position is at the NCPGG as fault seal project leader for the APCRC and industry sponsored 'Hydrocarbon Sealing Potential of Faults and Cap Rocks'. Member: PESGB and AAPG.
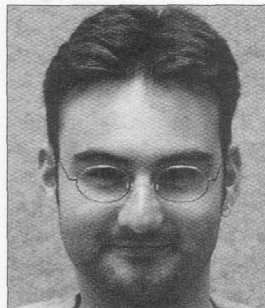
Peter Boult is a staff geoscientist with Boral Energy Resources Ltd. He graduated with a BSc (Hons) from Leeds University UK in 1976 and a PhD (Applied Geology) from the NCPGG in 1997. He worked as a lecturer at the University of South Australia from 1987–1997, but has been associated with the petroleum industry since 1980 having worked in Europe, the Middle East, Australia and Papua New Guinea. His current interests are reservoir / seal evaluation and fault seal analysis.

Scott Mildren completed his PhD at the University of Adelaide in 1997 and took up a position as structural geologist with Z&S (Asia) Ltd (now Baker Atlas Geoscience). At Z&S he interpreted resistivity and acoustic image data with application to in-situ stresses, fracture characterisation and sedimentology. He is currently a research associate at the NCPGG addressing various geomechanical issues in Australia and Brunei. Member: AAPG, ASEG, PESA and SPE.

John Kaldi studied for Bachelor and Masters degrees in Geology at Queens College, City University, New York. He received a PhD from Cambridge University in 1980. He has worked for the Saskatchewan Geological Survey, Shell Canada in Calgary and ARCO in Plano and Jakarta. Prior to accepting the directorship of NCPGG he worked for VICO Indonesia in Jakarta. His specialities include carbonate sedimentology and diagenesis, seal evaluation and reservoir evaluation. He has published more than 30 papers on these topics. He is a recipient of AAPG Special Commendation Award for Significant Contributions to Petroleum Geology.

Richard Hillis holds the State of South Australia Chair in petroleum reservoir properties/petrophysics at the NCPGG, University of Adelaide. He graduated with BSc (Hons) from Imperial College (London, 1985), and PhD from the University of Edinburgh (1989). After positions at Flinders University, Adelaide, the British Geological Survey, Edinburgh, and the Department of Geology and Geophysics, University of Adelaide, Richard joined the NCPGG in 1999. He has published approximately 50 papers and has consulted to 12 Australian and international oil companies. Member: AAPG, AGU, ASEG, EAGE, GSA, GSL, PESA and EG.