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Modelling and evaluating petroleum migration pathways in the Paris, Williston and west of Shetlands and Wessex Basins

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ABSTRACT

Petroleum migration pathways through a basin are determined by the three-dimensional distribution of discontinuous sealing surfaces, which are usually parallel to bedding. The petroleum migrates below the sealing surface taking the structurally most advantageous route. The three-dimensional distribution of migration pathways within the petroleum system can be modelled on a personal computer using a program based on the parameters developed during the research summarised in this thesis. Application of the model to the Paris, Williston, West of Shetlands and Wessex Basins demonstrates that a good correlation can be made between predicted pathways and discovered accumulations using simple models.

Migration pathways form a dense network overlying hydrocarbon generating areas in the central parts of basins. Towards the basin margins they commonly become increasingly focused into discrete pathways by the sealing-surface morphologies. The Paris and Williston Basin research showed how relatively minor structuring of geological strata can result in a significant focusing of pathways. Eventually these pathways may reach the surface as shown by seepages. Research in the Wessex Basin revealed that reverse modelling of pathways from seeps assists in the prediction of the location of leaking accumulations.

Deflection of the pathways from the structurally most advantageous route below the sealing surface may be caused by lateral sealing barriers due to facies variation in the carrier rock below the seal, fault juxtaposition, or cross-formational seals such as salt intrusions. Deflection of pathways also occurs where there are hydrodynamic conditions in response to topography-driven groundwater flow.

Zones of vertical migration are associated with facies changes along the horizon of the sealing surface into a non-sealing facies, or juxtaposition to non-sealing strata by faults. The results of research in the West of Shetlands Basin demonstrated that vertical migration from either normally or abnormally pressured strata is most likely to occur into normally or lesser pressured strata at intrabasinal highs where hydrocarbons can be stored and transferred at times of temporary seal rupture. In such circumstances long distance and vertical petroleum migration will be episodic.

1.0 OVERVIEW OF RESEARCH PROJECT HISTORY

My research began in late 1993 with the title 'The geological controls on the surface occurrence of migrated hydrocarbons with particular reference to the Anglo - Paris Basin'. The original objective of the research was to gain an understanding of the occurrence of oil and gas seepages on the surface of the Earth at areally restricted sites. It was considered important to devise models that could track back a seep into the subsurface to the point of origin. The Anglo (Wessex/Channel/Weald) – Paris Basin of southern England/ northern France was considered a good test bed because it has seeps, impregnations and commercial reservoirs of petroleum. Field work was undertaken in 1995 and 1997 in the county of Dorset (Wessex Basin) in order to locate and study the relationship between the seep/ impregnation locations and the underlying geological structure.

Since surface seepages are outcrops of petroleum migration pathways which originate at depths normally exceeding 3000 m in the sub-surface it became necessary to fully understand the sub-surface migration of petroleum. I had been interested in petroleum migration prior to commencing the research and realised that understanding migration pathways was a three-dimensional problem. In 1993, therefore, I asked my father (retired and experienced in computer programming) to write a program to simulate petroleum migration using parameters supplied by me. An early prototype of the program was completed in 1994. Later a company was formed, Geofocus Limited, to market the software ("Pathways") commercially and copies of the software are licensed by a number of companies. The availability of the software enabled me to broaden my research from only studying the structural context of surface seepages to investigate the factors affecting oil and gas migration. The Paris Basin in France together with the

Williston Basin of North America were use to test theories developed during this phase of my work. The results of my work on the controls on petroleum migration pathways, including hydrodynamic water flow, was published in the Bulletin of the American Association of Petroleum Geologists in 1997 (Hindle, 1997). I have been chosen by the American Association of Petroleum Geologists to receive, during their 1999 convention, the J. C. "Cam" Sproule Memorial Award for the best paper published in 1997.

The early theoretical modelling was undertaken while I worked for Texaco Limited. At the same time (1994 – 1995) I undertook research into the petroleum systems of the West of Shetlands, with particular emphasis on migration modelling. The research was incorporated as an appendix to the Texaco applications in the 16th Round of offshore licensing in 1995. The results of my research, together with a sequence stratigraphic study of the basin, will be published shortly (Jowitt et al., in press).

I have undertaken research in the Wessex Basin throughout the project. Between 1994 and 1997 I focused on field work, but in 1997 I began to study seismic and well data in an attempt to understand the migration of oil from the Lias source rock prior to the late Tertiary inversion and the re-migration of oil to form the surface seepages. The Wessex Basin portion of my research is included in this thesis as a separate chapter.

I currently work for Egdon Resources, a company I co-founded in 1997, exploring for oil in the Wessex Basin in partnership with two Canadian independent oil companies. The group was successful with an application for a petroleum exploration and production licence in the 8th Landward Licensing Round during 1998. The application document included theories on oil migration in the Wessex Basin developed during the research. Following the award of the licence, and at my recommendation, the partners in

the Wessex Basin licence sponsored an MSc student to undertake a geochemical analysis of the active (inter-tidal) seep at Osmington Mills as no analyses have been previously published on this seep. Diane Watson, at Newcastle University, completed the work for her 1998 summer thesis (Watson, 1998). Diane, Paul Farrimond (her supervisor) and I plan to submit the work for publication in 1999, following incorporation of my geological research summarised in this thesis.

The title of the research was changed to 'Modelling and Evaluating Petroleum Migration Pathways in the Paris, Williston, West of Shetlands and Wessex Basins' to reflect the scope of the completed research, which became much wider than that originally conceived in 1993.

2.0 A THREE-DIMENSIONAL MODEL

2.1 Introduction

Today the petroleum exploration industry can understand and predict complicated trapping geometries in the subsurface. Sequence stratigraphy concepts and increased seismic resolution are now giving us the ability to predict more subtle traps and stratigraphic configurations. Advances in geochemistry have allowed us to understand better and predict hydrocarbon compositions. Further, in combination with theories of hydrocarbon generation and basin modelling, we can now estimate the relative timing of hydrocarbon generation. However, fewer advances have been made in predicting the actual migration routes that the petroleum takes from leaving a source rock and arriving in a trap.

The physical mechanics of oil and gas migration between a source rock and first entrapment (secondary migration) have been established for some time (Schowalter, 1979, England et al., 1987). The principals of re-migration (tertiary migration) are also well understood and applied in hydrocarbon exploration (Gussow, 1954; Silverman, 1965). The main advances in the field of migration in recent years have been in the understanding of the role of seals in migration, principally in regard to hydrocarbon entrapment (Berg, 1975; Smith, 1980; Downey M. W., 1984; Watts, 1987; Hindle, 1989; Milton and Bertram, 1992). However, the prediction of the three-dimensional migration routes of petroleum between source and ultimately to 'outcrops' (surface seeps) at the surface of the Earth, referred to in this thesis as pathways, is not routinely undertaken.

Momper (1978) commented that "primary and secondary oil migration tend to disperse oil along the flanks of basins. Dispersal is counteracted by broad regional noses and structural platforms or salients extending into a basin that focus migrating oil into traps". Such focusing of pathways away from structurally low areas will create areas that do not receive petroleum, particularly outside the area of petroleum expulsion. These are sometimes referred to as areas of bypass or shadows to migration (Meissner, 1988). It will be demonstrated that, in addition to structural morphology, the degree of bed disruption, lateral barriers, and lateral continuity of sealing horizons are the principal controls upon the migration pathways. The approach outlined here offers a method to assess quickly migration risk by matching results to all observed petroleum occurrences in a basin.

2.2 Mechanics of Secondary Migration

Once hydrocarbons have left the source rock they are driven by two forces: buoyancy and groundwater flow. The buoyancy force varies directly as the density difference between the petroleum phase and the water phase. The greater the density difference, the greater the buoyant force for a given length of petroleum column. This buoyancy force will drive the petroleum vertically upwards, with gas having a larger driving force than oil. The greater the height (measured vertically) of the petroleum column (either in a trap or as a petroleum filament during migration) the greater this force will be at the top of the column.

The second force driving secondary and tertiary migration is groundwater flow (hydrodynamic condition). The relative importance of this process is the principal point of contention in the modelling of migration. A number of authors believe water flow to

be a primary control on the distribution of petroleum in a sedimentary basin (Toth, 1980, 1987; Downing and Penn, 1992; Roberts, 1993). These models propose that the petroleum is dissolved in the water phase during transport. However, it is generally accepted that petroleum migrates in an oil or gas phase (McAuliffe, 1979; Bissada, 1982; England et al., 1987). The importance of water flow as a modifier to oil or gas phase migration can be estimated using simple mathematical modelling which is discussed in further detail below. This research predicts that water flow is of minor importance in most situations, but can be important to model during periods when a basin is sub-aerially exposed.

The restraining force upon petroleum movement is capillary pressure. This is the resistive force to movement of the petroleum through the pores of the rock. The force increases with decreasing pore throat size, increasing interfacial tension, and increasing wettability. Wettability is the work necessary to separate the wetting fluid from the rock surface. If the rocks are partially oil wet, it may significantly reduce the capillary pressure for oil migration, favouring the continued use of an established migration pathway.

The well established theory described above predicts that in hydrostatic conditions petroleum will rise through the sedimentary section due to buoyancy unless it encounters a capillary pressure sufficient to restrain it (a seal). If the petroleum becomes trapped and unable to continue upwards, the trapping envelope of sealing rock will fill up, given sufficient petroleum, or leak if the buoyancy force becomes too great enabling the capillary pressure to be overcome (i.e., any seal will have an upper limit of hydrocarbon column it can support (Watts, 1987)). An accumulation could be trapped by a single stratigraphic sequence, such as in an simple anticline, or multiple sealing

units, such as top, lateral and bottom seals in stratigraphic, or more complex structural traps (Milton and Bertram, 1992). For a commercial trap it is preferable that the reservoir interval lies immediately below the sealing horizon so as to reduce the potential waste zone of poor reservoir rock at the top of the trapped reservoir (Schowalter and Hess, 1982). In hydrostatic conditions the base of the petroleum accumulation will be horizontal, which is the case in the majority of sedimentary basins.

Once full or having reached the capacity of the seal, petroleum reaching the trap will continue on its upward journey. The situation will be more complex if the petroleum now reaching the trap is less dense than that previously entrapped. For example, gas will tend to displace oil by rising to the crest of the trap, filling the trap, and thus force the oil to remigrate updip (tertiary migration). Remigration will also occur if the trap is tilted by structural movements.

Gases containing higher hydrocarbon (C_2+) components can accumulate downdip from lighter gases if the higher molecular weight hydrocarbons, which are least saturated in compressed gas, are condensed to form liquids in traps adjacent to the generative areas (Shamsuddin and Khan, 1991).

The theory of migration under predominately hydrostatic, or hydrodynamic conditions, controlled by two opposing forces of buoyancy and capillary pressure (as briefly outlined above) can be applied in general terms to explain the majority of the observed distributions of petroleum in sedimentary basins. The accuracy of such predictions will be shown to be greater using computer based three-dimensional modelling applying these principals. The locations of the basins studied during the research project are shown on Figure 1.

Since the very early days of exploration, the concept of trapping oil in a porous reservoir rock beneath a seal could easily be envisaged, and the "anticlinal theory" evolved quickly in the last century (Howell, 1934). T. Sterry Hunt in 1865 stated that oil "naturally rises and accumulates along the crown of these anticlinals. This process is favoured by the fact that the strata on either side of the anticlinal dip in the opposite directions". This is a very early discussion of the focused migration and concentration of petroleum. In 1866, E. W. Evans discussed "the collection, from a wider area, of oil...being lighter than water, it would naturally work up between the strata of the slopes". This is perhaps one of the first statements on the concept of gathering or drainage areas of petroleum, and lateral migration.

2.3 Migration and Concentration in Three-Dimensions

2.31 Simple models

The principals of three-dimensional migration will be introduced using very simple models.

The simplest case of migration is where no sealing sequences lie above a source rock, for example, if the overlying sequence contained only porous sandstones. In this case, the petroleum would migrate vertically from its point of exit from the generating source rock, and be represented at the surface by an areally extensive impregnation (Figure 2a). If the whole stratigraphic sequence was dipping at a constant angle, and a single sealing horizon was present, the petroleum would be deflected by the horizon, perpendicular to the strike of the strata, until it reached the end of the sealing surface, then continuing vertically to produce a line of impregnation (Figure 2b).

If the sealing surface is domal or anticlinal in shape the petroleum would be gathered into the crest of the structure, filling it from the top downwards (Figure 2c). The petroleum will be focused and increasingly concentrated towards the crest. Provided the trap is large enough, petroleum will only reach the surface if the capillary pressure of the sealing horizon is overcome. If the trap is filled it will spill from the structure as a focused stream. In the case of a plunging anticline the petroleum migration will also be focused and will reach the surface as a single point seepage (Figure 2d). In a synclinal situation, the petroleum will be dispersed, reaching the surface as a curved line of impregnation above the edge of the sealing surface (Figure 2e).

The models deal solely with the effects of structural morphology. In these simple examples the sealing surfaces are bedding parallel. In some circumstances the sealing surfaces will cut across bedding, for example in areas of faults, salt intrusions and lateral facies changes (Figure 2f). These aspects will be discussed in more detail below.

These simple cases serve to introduce the important ways in which seal distribution, and particularly morphology of the sealing surfaces, affect the areal distribution of petroleum. Petroleum migration flow can therefore be visualised as routes of flow on the underside of regional sealing surfaces, effectively providing roofs (Downey M. W., 1984) to the flow.

It is important to recognise focusing and dispersion in regard to migration pathways, and the attendant phenomena of concentration and dilution of hydrocarbons generated in and expelled from the source rock. Concentration into trapping geometries is not only confined to focused migration pathways, but can occur in dispersive situations (discussed further below). In addition, a focusing geometry well away from a source

rock generative area will not necessarily result in a concentration with respect to the source rock, if the pathways have become significantly dispersed and diluted during the early stages of petroleum migration.

In this thesis the common terms 'top of the oil or gas window', 'generative area' or 'kitchen areas' are used to refer to the onset of oil expulsion from the source rock, rather than the onset of oil generation.

2.32 Petroleum Concentration

The concepts discussed above are very important when considering the degree of concentration required to produce a commercial accumulation. Concentration in a sedimentary basin is most easily illustrated by considering a model of a circular basin, with a generative source rock occupying the centre (Figure 3). Note that this is a dispersive situation. A sealing horizon overlies the reservoir unit which in turn overlies the source rock. The trap is assumed to remain the same size but located at an increasing distance from the basin centre only perturbating the circular contours at the trap location. In such a model, the concentration profile is the ratio of the area of the kitchen supplying the hydrocarbons to the trap to the area of the trap. This relationship holds provided that the volume of hydrocarbons expelled in an area equal to the area of the trap is the volume of hydrocarbons required to fill the trap. Therefore, when the trap is located in the centre of the basin the concentration factor is one. Starting from the basin centre, the concentration profile rises to a peak when the outer edge of the trap is positioned at the edge of the kitchen area but then falls with increasing distance laterally away from the kitchen (Figure 3).

The degree of concentration commonly required can be illustrated using the *SPI* (source potential index) of Demaison and Huizinga (1991). This is a measure of the ultimate generative potential for a given area of a source rock measured in metric tons per square metre. This value can range from less than 1 metric ton/m^2 to in excess of 50 metric tons/m^2, but is generally in the range 1-10 metric tons/m^2. In comparison, in a producing commercial field the corresponding concentration of oil (in metric tons per square metre of the field area) will typically be in a similar range of less than 1 metric ton/m^2 (for a low porosity field with a short oil column) to in excess of 10 metric tons/m^2 (for high porosity, long oil column fields). However, since not all the petroleum is usually expelled from the source rock prior to trap formation and a small proportion of petroleum remains along the migration pathway (Thomas and Clouse, 1995), a concentration between source rock and trap is commonly required. An exception might be a small trap formed before oil generation in close proximity to a thick rich source rock.

The models displayed in Figure 2 illustrate the effect of increased structural complexity upon this simple model of concentration. Therefore, in most situations the degree of concentration near the generative area and the decline in concentration will be more marked in sedimentary basins since there is an increasing probability that the petroleum will become trapped or focused into discrete pathways, as will be demonstrated in the Paris Basin later in this thesis.

The very simple models in Figures 2 and 3 suggest that prospectivity in a basin will increase towards the edge of the generative kitchen area, and then become less prospective away from the source area unless concentration can occur due to focusing of pathways associated with plunging anticlinal ridge features (often referred to as

structural noses) or closed anticlines. This explains the common association of oil and gas fields within or close to the generative area of a basin (Demaison, 1984).

The model in Figure 3 addresses migration in an areal sense, but does not deal with the vertical dimension. In the case of a circular depression involving sub-parallel strata the movement of petroleum in the vertical sense will be determined by the lateral extent of sealing strata. The model in Figure 3 is for a single sealing surface lying close to the top of the source rock over the entire basin area. In this case the depth of the trap is just above the depth of the source rock. Since the centre of sedimentary basins are generally more shale prone, and therefore more likely to contain laterally extensive sealing horizons, petroleum accumulations are more likely to be close to the top of the source horizon in this area.

Towards the flanks of a basin the situation becomes more complex, with generally poorer lateral continuity of sealing strata in proximal parts of depositional systems. This results in a greater chance of vertical migration, particularly associated with faults (discussed below), resulting in the tendency for entrapment above the stratigraphic level of the source horizon. Lateral migration close to the stratigraphic level of the source rock relies on the presence of regional seals such as those often resulting from transgressive units, or regional salt deposits (Murris, 1988). Migration into stratigraphically older strata can occur across fault planes.

The optimum location for a trap is close to the top of the oil or gas window for the basin at the time of entrapment (Figure 4). In some basins that have experienced uplift or burial since the time of entrapment the optimum depth would vary accordingly.

Plots of petroleum concentration within a basin with respect to the kitchen tip line at the time of entrapment (Figure 4) can be a useful technique to describe a petroleum system. Such a plot will be used below to describe the Paris Basin.

So far the discussion has addressed some of the basic concepts of migration in relation to the concentration process that is usually necessary for a commercial accumulation. The concept of predicting migration pathways will now be explored.

2.3.3 Migration Pathways

Petroleum migration pathways can be viewed as very restricted rivers or streams whose position is controlled largely by structural morphology (Gussow, 1954, 1968). Experiments to simulate migration, using columns packed with water-wet quartz, dolomite, sand or glass beads (for example, Dembicki and Anderson, 1989; Catalan et al., 1992) show that secondary oil migration occurs along very restricted pathways or conduits concentrated immediately below the sealing surface at the top of the carrier bed. Thomas and Clouse (1994) used a scaled physical model in a tank packed with water-wet sand. Scaling the model to the geological scale they concluded that most of the carrier bed above a mature source rock will be contacted by oil (saturations typically 5-10%), but during lateral migration, oil moves through only a small portion of the carrier rock, just 0.5-1 m below the sealing surface (for a 100 md rock). The observed rates of flow in the experiments suggest that the secondary migration process is instantaneous in the context of geological time.

Recent results from studies of chemical tracers in crude oil support the restricted pathway theory by suggesting that some oil fields may have been filled through carrier

systems with pathway or channel diameters of only a few tens of metres or less in width since geochemically the oils have had very little contact with formation waters (S. R. Larter, personal communication). Only 1-10 % of the cross-sectional area of a carrier bed in a pathway is probably utilised (England et al., 1987).

Alternatively, the nature of migration pathways in the subsurface has been described as a sheet-like migrating petroleum front whose progress in a given direction is controlled significantly by horizontal permeability contrasts of the rock through which the petroleum is migrating (Rhea et al., 1994). At the scale of centimetres to metres, rock permeability will determine which beds will carry the majority of the petroleum along the pathway. Therefore at this scale, the base of the sealing surface is not planar. However, at the scale of the basin, permeability contrasts will probably only determine the orientation of pathways if the lithology will not allow passage and can be considered as a lateral seal.

Above the area of petroleum generation (generative kitchen) pathways will be very numerous and form a dense network, but laterally away from these areas very restricted streams of focused pathways will be the predominant mode of movement.

The importance of structural morphology of a basin in determining petroleum migration is well accepted (Gussow, 1968; Momper, 1978; Pratsch, 1983, 1986, 1988, 1994; Meissner 1988) but not well documented. The importance of faults in petroleum migration is often greatly exaggerated (see below) since the areas of significant morphological changes and bed disruption are usually associated with deep-seated faults. Structural morphology is also important in determining the composition of the

petroleum since pathways may merge from different kitchens of different source facies (Cooper, 1990).

The distances of migration will depend on the structural style of the basin (Demaison and Huizinga, 1991; Pratsch, 1991). Given sufficient extensive sealing strata, migration distances can be in excess of 150 kms. In other basins that are extensively faulted or intruded by salt or mud diapirs, the distances of migration may be less than 50 kms from the area of generative source rock.

Oil and gas macro-seepages (defined here as occurrences detectable by the human senses) at the Earth's surface represent the outcrop of migration pathways. These are most likely re-migration pathways from a pre-concentrated source, since the rate of migration from a source rock is probably not sufficient to provide the volumes required for a visible seep (Clarke and Cleverly, 1991). These outcrops are usually displaced many kilometres from accumulations (Macgregor, 1993).

The distribution of surface macro-seepages in a sedimentary basin reflects the subsurface migration patterns. For example, in large foreland basins (such as the Western Canadian Basin) seeps are commonly located some distance from the generative areas at the end of long distance focused migration pathways (Thrasher et al., 1996). Macro-seepage occurrence should therefore be routinely integrated into migration modelling. Macro-seepages are usually very areally restricted, usually of the order of metres to tens of metres in extent or in clusters up to hundreds of metres across (Beeby-Thompson, 1925; Link, 1952; Sassen et al., 1993), suggesting that focusing of pathways is an important process even near the Earth's surface. Micro-seepages

(detectable only by chemical analysis) commonly show a similar concentration (Dickinson and Matthews, 1993).

2.4 Hydrodynamics and Petroleum Migration

2.4.1 Potentiometric Surfaces

In a number of basins, tilted petroleum-water contacts exist due to the effect of ground water flow through the reservoir interval (Hubbert, 1953; Dahlberg, 1982). The flow of water may create hydrodynamic traps which do not have structural closure (see Hubbert, 1953, and Dahlberg, 1995 for examples). Such flow may deflect migration pathways from a structurally more advantageous route and therefore must be considered when modelling.

Water flow in the subsurface can occur in response to water expelled by compacting sediments, or introduced in subaerially exposed parts of the basin and driven by gravity (topographic drive). The potential energy of the fluid per unit mass, Φ is given by:

$$\Phi = gz + P/\rho \qquad (1)$$

where z is the elevation above (or below) a datum, usually sea level, ρ is the density of the fluid, P is the fluid pressure and g is the acceleration due to gravity.

The flow of water in a basin can be detected by pressure data. The potential energy possessed by the fluid will be constant in hydrostatic conditions. The pressure of the fluid will increase with depth linearly for a given density. This is usually referred to as

the pressure gradient. For pure water the gradient is 9.8 Pa/m (0.433 psi/ft), for oil typically 6.8-9.1 Pa/m (0.3-0.4 psi/ft) and for a typical methane-rich gas 1.5 Pa/m (0.066 psi/ft). In hydrodynamic conditions the pressure gradient will be less than an equivalent hydrostatic gradient for the given salinity of the water. However, care must be taken interpreting pressure data since a different pressure could also result from no flow if a formation has an anomalous pressure regime due to isolation by seals (Bradley 1975). Also fluid density variations between positions of pressure measurement may give the impression of water flow or pressure seals if not carefully integrated in the interpretation.

A useful measure of the potential of the fluid is given by the hydraulic head, h, which is the height above (or below) a datum that the fluid would rise to in an imaginary vertical tube inserted in the aquifer at the point of measurement. The potential energy possessed by the fluid is equivalent to this height multiplied by the acceleration due to gravity, therefore;

$$hg = gz + P/\rho,$$

$$or \ h = z + P/\rho g \qquad\qquad (2)$$

A map constructed of the hydraulic head, h at the top of the reservoir unit is called the potentiometric surface when the fluid is water. The flow of water in the reservoir will be directed along the maximum gradient of this imaginary surface from areas of high to low hydraulic head.

2.4.2 Petroleum Potentiometric Surfaces

To predict accurately oil or gas migration routes below a sealing surface in hydrodynamic conditions, it is possible to construct a map of surfaces of oil or gas potential within the water phase using a modification of a method discussed by Hubbert (1953) and Dahlberg (1982). It can be shown that the petroleum head, h_p is given by;

$$h_p = \frac{z\,(\rho_p - \rho_w)}{\rho_p} + \frac{h_w \cdot \rho_w}{\rho_p} \qquad (3)$$

where z is the depth with respect to sea level in metres, ρ_p is the density of the petroleum phase in g/cc, ρ_w is the density of the water phase in g/cc, and h_w is the hydraulic head, in metres, of the water phase with respect to sea level. This equation assumes that the capillary effects are excluded (Hubbert, 1953), and is explained in more detail in Appendix A.

If maps of potentiometry, structure, petroleum density and water density are constructed, the petroleum potential surface values can be calculated by computer gridding operations using the above formula. This computer gridding method allows aerial variations in water density to be taken into account, if such detailed data are available. A map of this surface, referred to in this thesis as the petroleum potential surface (parallel to the oil or gas equipotential surfaces of Hubbert (1953) and Dahlberg (1982) for a constant water density) can be used to predict the migration and entrapment of petroleum. Migration pathways move under this surface following the same rules as those under a structure map of the sealing surface in hydrostatic conditions. Hydrodynamic traps can be located using this map by looking for features with closed

contours in the same way as a normal structure map. Note that this imaginary surface will be different for different densities of petroleum and water.

The density of water depends upon pressure, temperature and the amount and kinds of dissolved salts; it generally ranges between 1.0 and 1.15 g/cc, for oil between 0.5 and 0.95 g/cc, and for gas from less than 0.1, to approximately 0.5 g/cc at very high pressures.

The density of oil in the subsurface is dependent upon the composition of the oil and dissolved gases, temperature and pressure. It generally decreases with depth due to the tendency for large heavy molecules to undergo thermal cracking to smaller, lighter molecules. This results simultaneously in increasing the gas:oil ratio reflected by an increase in the API gravity (England et al., 1987). The oil density can be estimated if the API gravity and gas:oil ratio are known using nomographs (Schowalter, 1979). However, pressure-volume-temperature (PVT) values provide the most reliable estimates if such data are available.

The density of gas is determined by its molecular weight, pressure and temperature. Unlike oil, it generally increases with depth. Subsurface gas densities can also be estimated using nomographs (Schowalter, 1979).

Apart from direct data on the composition of petroleum and water, subsurface densities can be estimated from accurate pressure data, since as discussed above the density of the phase in the pore space determines the pressure gradient through the reservoir.

2.4.3 Hydrodynamics and Migration Pathway Deflection

It is clearly important to determine the likely effects of hydrodynamic conditions on petroleum migration pathways, so that care can be taken to model these conditions if it is felt that they would significantly effect the prediction. It is possible to show that the deflection, ψ in degrees of a migration pathway (petroleum density ρ_p in g/cc) moving through a bed dipping at an angle β in response to a water flow (water density ρ_w in g/cc) along the maximum dip of a potentiometric surface of gradient tanγ at an angle α to the bedding dip is given by;

$$\psi = \text{arcos} ((\cos\alpha\text{-FR})/(FR^2\text{-2FRcos}\alpha+1)^{0.5}) \tag{4}$$

where R is the ratio of the gradient of the bedding surface to the gradient of the potentiometric surface (tanβ/tanγ), and F is called the buoyancy factor equal to ρ_p-ρ_w / ρ_w . The derivation of this equation is given in Appendix B.

Figure 5a illustrates the effect of increasing the angle α on the deflection of an oil migration pathway for different values of R assuming a constant value of F (assuming an oil of density 0.75 g/cc, formation water 1.04 g/cc). In this case a value of R less than 10 will start to have a significant effect on oil migration pathway direction. The angle of water flow (α) which has the maximum effect upon the deflection of a migration pathway increases from 90^0 to 180^0 as the magnitude of R decreases (steeper potentiometric surface or lesser bedding dip).

As the value of R decreases, for a given petroleum and water density, there comes a critical value where the water flow is sufficient to reverse completely the direction of

the migration pathway. This critical value is reached when F multiplied by R has a value of −1 (in the example given in Figure 5a, when the value of R is equal to 3.586). When F multiplied by R is greater than -1 then the petroleum migration direction will not be reversed (i.e. ψ will not exceed 90°), however when it is less than -1 it will become reversed. In the special case of FR=-1, the petroleum migration pathway will be deflected beyond 90°, however it will not be completely reversed by 180°. When the water flow is 180° to the maximum bedding dip the flow of petroleum along the migration pathway will be completely balanced by the water flow for the special case of FR=-1, i.e. stationary.

Figure 5b illustrates the effect of increasing the angle α on the deflection of a gas migration pathway for different values of R assuming a constant value of F (assuming an gas of density 0.15 g/cc; formation water 1.04 g/cc). In this case the value of R needs to be less than 2 for it to start to have a significant effect on a gas migration pathway direction.

To appreciate when water flow in a basin needs to be considered, it is important to determine the value of R. In most cases, the value of R is greater than a value of 5. (see Appendix C for more details). The potentiometric surface is commonly similar to a smoothed form of a topographic map. Therefore the potentiometric surfaces normally have the greatest dip in onshore basins where the basin aquifers outcrop in mountainous areas. In such areas the bedding dip is usually somewhat greater which will reduce the value of R.

Actively subsiding sedimentary basins are normally covered by water. In such cases the flow of water in the basinal areas is very minor and limited to the flow of water from

compacting sediments (discussed below). In such cases the value of R is very large. This has important implications for secondary migration since petroleum generation is normally greatest when a source rock is experiencing increasing temperatures as the basin is undergoing active burial normally in sub-marine conditions. Exceptions will be during periods of eustatic sea-level drop or increasing heat-flow causing generation in a background of minimal burial or even uplift. Therefore, if petroleum generation is anticipated to have occurred during a period of sub-aerial conditions then care must be taken in migration pathway modelling.

The deflection of pathways is also very much dependent upon the density of the petroleum, which determines the value of F. Figure 6a demonstrates the case where the value of R is fixed at 10 and the formation water density is fixed at the same value (1.04 g/cc) as the examples in Figure 5, but the hydrocarbon density is varied. In this example, the water flow direction will have little effect upon the orientation of gas migration (density less than 0.5 g/cc). However, the water flow will dominate the direction of the migration of a heavy oil (when densities are above 0.9 g/cc). Therefore, when modelling seepages of petroleum, particularly oil, in onshore areas potentiometric surfaces must be generated. In the near subsurface, water flow is likely to have a large effect unless the bedding is steeply dipping. Near surface water flow will significantly influence the re-migration of heavy biodegraded oils, hence their common occurrence associated with springs. It is important to determine the most likely depth of biodegradation to model the influence of the water flow in the subsurface.

Since the density of an oil phase generally decreases with increasing depth, the effect of water flow upon the orientation of migration pathways will decrease with depth. This is compounded by that fact that the topographic drive of water through porous reservoirs

becomes less common in the deeper portions of sedimentary basins where the water is normally saline and connate. For gas the effect of water flow increases with depth but is only significant at a depth when the flow of water in the basin is negligible.

In Figure 6b the effect of water salinity variations on petroleum migration is demonstrated, by taking three different petroleum densities (0.95, 0.75 and 0.15 (gas) g/cc). It can be observed that water salinity has a greater effect the more dense the petroleum phase. It has only a very minor impact on gas migration pathways.

It is particularly important to model water flow when considering re-migration (tertiary migration) associated with basin inversion where the rocks are sub-aerially exposed and groundwater flow becomes significant. This should be done particularly if structures are filled to the spill point, even during periods when generation may not have occurred, since a minor water flow will cause the structures to spill. In such basins water flow may have had very little effect upon secondary migration but may have been a very important control on the recent redistribution of oil and gas, and may currently be tilting oil and gas contacts and providing hydrodynamic traps (Hubbert, 1953). Gussow (1968) suggested that in most cases, present hydrodynamic tilts are superimposed on former hydrostatic accumulations.

In addition to water flow from topographic drive, basins also have water flow in response to water expelled from compacting sediments. However, this is a very slow process and has a negligible impact on the orientation of migration pathways. The value of R in these circumstances is very large (see Appendix C for more details).

2.5 Predicting Migration Pathways Using a Computer

The prediction of three-dimensional aspects of migration in the subsurface using computers is a recent development that holds the promise of significantly reducing exploration risk (Sylta, 1987, 1991; Lehner et al., 1988; Hermans et al., 1992).

The computer program PATHWAYS of Geofocus Limited was used in this study to predict the migration pathways of petroleum using a personal computer. It assumes that the petroleum migrates vertically until it encounters a sealing horizon, after which it moves in the direction of the most structurally elevated position below this sealing surface, until it reaches the edge of the seal. The edge may either be a result of a change in facies of the sealing horizon or because a fault is encountered with a non-sealing facies facing it across the fault plane surface. After reaching the edge, the migration path will continue vertically again. The computer model divides the mapped surface up into 250,000 cells for each sealing surface. Hydrodynamic conditions can be modelled by using surfaces of oil or gas potential, discussed above, as the surface of migration.

Migration pathways deflected from the structurally most advantageous route below the sealing surface by lateral sealing barriers due to facies variation in the rock below the seal, fault juxtaposition or cross formational seals such as salt intrusions can also be modelled. Alternatively, the petroleum will accumulate if there is a trapping geometry.

In addition, if sufficient data are available on the quantity and distribution of generated petroleum in the source rock, the quantity of migrated hydrocarbons that may have potentially used a pathway can be determined.

The migration model can be used to forward model migration from the source rock to the trap, or reverse model possible points of origin for fields or surface seepage locations (discussed further below).

The inputs into the program to determine the pathways are structure maps of the sealing surfaces, definition of lateral barriers, and the outline of the generative area as best understood from either well maturity data and/or geochemical modelling. Clearly the main benefits of using a program lies in its predictive ability, and the reduction of exploration risk. The predictive ability of the program will improve with more accurate mapping of sealing surfaces in the subsurface, and a more accurate knowledge of the generative history of a given basin. To obtain a true three-dimensional view of the distribution of petroleum in a basin, multiple horizons need to be mapped, and their structural morphology at the time of petroleum expulsion must be well understood.

2.6 Effects of Abnormal Pressures and Lateral Barriers

Differential pressures between different stratigraphic units need not imply hydrodynamic conditions. Each unit may be part of a compartment or cell with static conditions prevailing within them, but with an abnormal pressure (with respect to hydrostatic pressure) within the cell. These cases have an important effect on migration pathways, providing in some cases lateral seals to migration and stratigraphic traps. It is important to determine the geometry of these cells and their relative juxtaposition in order to model their effects on migration pathway prediction.

The top and base of the cells will normally be defined by two or more regional sealing surfaces sub-parallel to bedding, with lateral boundaries defined by facies changes into

sealing strata within the porous and permeable sequences. However, there is evidence that cell boundaries may cross stratigraphic boundaries (Hunt, 1990) and perhaps be related to diagenetic seals (Dewers and Ortoleva, 1988).

Cell boundaries should be defined using subsurface pressure data. Drilling mud data should be used with caution. Care must be taken when constructing cell boundaries when a limited number of data points are available, and if data for different wells are plotted together on the same graph. Overpressure onset in a basin commonly commences at a similar depth within a basin (approximately 3000 m (Hunt, 1990)). This may give the impression that the top of a regional cell cuts across stratigraphic boundaries. However, if sufficient data are collected below this level for individual wells, a number of cells may be identified which are bounded on the top and base by bedding parallel surfaces (Dahlberg, 1995).

It is important to model the transfer of charge into or out of cells when the source rock and the prospective trap are in different pressure cells. Transfer out of the cell is most likely to occur if it is temporarily ruptured by structural movements. In addition, the timing of cell generation with respect to hydrocarbon migration must be addressed.

In migration modelling the location of the sealing boundaries must be estimated using all the available data. The lateral boundaries are important to model since these will potentially exert a large effect on deflecting migration pathways and providing stratigraphic trapping opportunities.

However, it is important to realise that the same effects can occur in normally pressured sequences if there is not complete sealing of a volume in three-dimensions (Figure 7). In

such situations stratigraphic traps and surface seepages can be found in synclinal locations. Sealing faults (fault plane itself or by juxtaposition of a sealing lithology) can also deflect and focus migration pathways (Figure 8). The model illustrated in Figure 8 demonstrates the focusing effect of the fill and spill phenomena. Once a structure is filled and begins to spill it usually will do so at a single point. Other examples of lateral barriers are salt intrusions (Thrasher et al., 1996).

2.7 Vertical Migration

The models discussed in this thesis illustrate the importance of the lateral component to petroleum migration. However, hydrocarbons found in a stratigraphic level different to the generative source horizon require a component of vertical migration.

In the absence of perfect seals over an accumulation or a kitchen area, vertical migration will take place (Figure 2a). Techniques evaluating hydrocarbons or the effects of hydrocarbons in the soil (surface geochemistry) exploit this fact providing in some cases a useful contribution to the analysis of a basin (Jones and Drozd, 1983; Sundberg, 1994; Dickinson and Matthews, 1993; Abrams, 1996; Matthews, 1996; Potter et al., 1996).

The role of faults and fractures in vertical migration is much debated (Rich, 1931; Landes, 1951; Weeks, 1958; Price, 1980a, 1980b; Downey M. W., 1984; Chapman, 1987). The importance of fault planes as conduits for oil migration is perhaps over emphasised. However, modelling in two-dimensions by only viewing a basin in cross-section tends to lead to the conclusion that migration along faults is required (Figure 9). Such models run the risk of over-emphasising the importance of faults since migration along them may be the only way to model migration from the source rock to a

stratigraphically younger reservoir if fault juxtaposition is not present on the line of the cross-section. A pathway can result, however, from juxtaposition somewhere out of section along the structural disturbance associated with a fault (Allan, 1980; Downey M. W., 1984; Hindle, 1989).

Clearly open fracture networks do exist in certain lithologies in the subsurface, as evidenced in fractured reservoirs in many parts of the world (Stearns and Friedman, 1972) and near the surface. Good examples are found in thrust belts (Conner and Covlin, 1977). In addition, at times of fault movement trapped oil and gas associated with a fault could escape until the fault planes close again. This is supported by the fluid flows often associated with earthquake fault plane releases (Nur 1974). The role of faults is discussed in the context of near surface migration in Section 4.2.

Increases in pressures within sealed cells, for example by gas (hydrocarbon or non-hydrocarbon) or water expansion, may be sufficient to fracture the rock (Meissner, 1978; Bell, 1989; Barker, 1990) allowing vertical migration to take place if only intermittently. Further discussion is made in Section 3.4.5. Fracture of the rock occurs usually between 85 and 100% of the lithostatic pressure (Swarbrick, 1996). The lithostatic pressure is that exerted by overlying rocks, including any fluids contained within the pores. It will occur where the cell is structurally most shallow, such as at an intrabasinal high. Such a location is very favourable since the petroleum accumulates at, or will be in the process of being focused to, this position. Intrabasinal highs are also often sites of condensed sequences with reduced sealing capacity where the capillary pressure can be overcome by a short oil column. Rupture of the rock may also occur by tectonic compression (Hubbert and Rubey, 1969; Grauls and Cassignol, 1993).

Faults may be more important because they disrupt sealing strata surfaces and juxtapose permeable rocks rather than by providing the vertical means of transfer. Present day macro-seepages are generally found within areas of active disruption by earthquakes (Wilson et al., 1973, Hunt, 1979). The retention of gas phase petroleum by fault planes is more problematical, as witnessed by the gas anomalies often seen on seismic data associated with fault planes (Anderson et al., 1994; Hovland et al., 1994). There is also a close association of gas micro-seepage with faults (Dickinson and Matthews, 1993, Jones and Drozd, 1983). Similar phenomena are often associated with salt intrusions (Sassen et al., 1993). Indeed gas is often found in shallower sections overlying deep areas associated with faults and salt intrusions (Bissada et al., 1990).

Surface occurrences of hydrocarbons, in particular oil (either as macro or micro seeps) vertically above an accumulation are only likely to occur in special circumstances (Figure 10). In general they are most likely if the structural form of the trap extends to the near surface or if there is a lack of impermeable horizons above to provide the seal to the trap. In onshore areas the location of seepage will also be modified by water flow (discussed above).

Fault planes are, in most cases, unable to focus or concentrate hydrocarbons, being largely planar in shape, or even concave which would have a dispersive effect (Figure 11). The limited areal extent of seepages of oil suggests that pathways remain narrow from leaving the point of spill or leakage from a trap. Such seepages at the surface if associated with faults would also be expected to be closely associated with a focusing structural configuration in the near subsurface such as an anticline. Weeks (1958) stated that "the fault plane is only one coordinate of the seepage occurrence; the other is the bed that impinges against the fault and out of which the oil derives to feed the seepage".

Micro-seepages, only detectable by geochemical techniques, could originate from a source rock generating today in addition to a leaking trap, and could therefore be located in any structural setting including synclines, particularly where there are poor lateral seals above the generative area.

Vertical migration is most likely to occur at intrabasinal highs where hydrocarbons can be focused, particularly if there is a breach of the seal. Figure 12 illustrates the three-dimensional nature of petroleum migration prediction and the dangers of drawing conclusions about mechanisms of migration on two-dimensional cross-sections. The accumulation marked A on Figure 12b (younger horizon) could have been sourced from many locations within the two kitchen areas including A', A", A'" and A"" on Figure 12a (older horizon close to source interval). No cross-section could be drawn to illustrate all these pathways. The pathway from A"" is bi-directional, starting off towards the north-west beneath the older seal before turning to the south-west beneath the younger seal. The pathway from A" involves a complex pathway through three fill and spill geometries at the deeper sealing surface. Figure 12 also illustrates the way pathways can cross over each other at different stratigraphic horizons. The migration pathway commencing at B', close to A', migrates eastward beneath the older seal before moving southward beneath the younger seal crossing the pathway from A' which passes below it beneath the older sealing surface. The pathway from B' will ultimately reach structure B if a large anticline on the shallower horizon is filled to spill point.

The only way to model petroleum migration in two-dimensions is by drawing the cross-section along the track of a migration pathway, but this is impossible to determine without first modelling, at least approximately, in three-dimensions! Therefore two-dimensional modelling can be virtually useless.

2.8 Reverse Modelling of Migration Pathways

The biggest pitfall in migration modelling and charge estimation is recognising the difference between forward modelling and reverse modelling. So far the examples shown have illustrated the forward modelling process from source rock to trap, and from trap to the surface. In many circumstances it is necessary to determine the area of charge for a given trap. The concept of gathering or drainage area for prospects is well established (Momper, 1978; Momper and Williams, 1984; Goff, 1983; Bishop et al., 1983; Sluijk and Nederlof, 1984; Radlinski and Cadman, 1993) and the extension of this concept to define the edge of the petroleum system (Magoon and Dow, 1994).

Charge is often estimated by partitioning a basin into drainage segments by drawing lines orthogonal to contours, and determining the volume for each segment. Care must be taken when undertaking this process for an individual prospect. Migration pathways cannot be predicted by reversing the direction of movement (Figure 13). By analogy, the shortest path up a mountain side is not necessarily the same as the route taken by water flowing down the streams. A simple method of determining if a trap can receive charge is to draw orthogonal lines from the edge of the prospect on the base of the sealing surface. If these cross before the generative area is reached, then it will not receive charge (Figure 13b). Conversely, if they do reach the generative area the prospect will receive charge. The portion of the generative area within the envelope of the orthogonal lines is the drainage area for the trap.

Reverse modelling using a computer is achieved by starting at the known end point of a pathway, such as a discovery, show or seep. The grid of cells making up the sealing surface is then interrogated to determine possible origins of the pathway. The result is a

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dendritic pattern with a pathway at every cell that may have been a source, were it to be forward modelled. It is important to note that a unique solution will not be found. However, the model can identify the area within which the petroleum must have been sourced, assuming accurate maps of the sealing surfaces and knowledge of lateral barriers are known. A simple example of the evaluation of the possible source for a surface seep is shown in Figure 14 to illustrate the model. The area on the map from within which the petroleum may have been sourced is shaded. The result can be viewed as the potential drainage area of the petroleum occurrence. Four specific pathways from possible sources of the seepage are also shown.

Reverse modelling of individual pathways from fields and seepages to potential sources is a powerful exploration tool. It can also assist with the prediction of the boundaries of the areas of petroleum expulsion if the discoveries in a basin are reverse modelled and the results analysed to determine the possible outlines of the source of the occurrences.

3.0 APPLICATION OF MODEL

3.1 Introduction

The Paris Basin in northern France, and the Williston Basin in North America, are used as examples of a very simplified approach. A single stratigraphic surface is used to predict migration pathways in an areal sense for all reservoirs to illustrate the migration principals of focusing and dispersion. The study demonstrates that exploration risk can be significantly reduced using only a single mapped surface on a regional scale with no detailed mapping of individual structures, or any accurate temporal modelling of the generative area. This is valid since both basins are structurally simple with sub-parallel stratigraphic horizons. The sealing surface maps are not detailed enough to locate all the traps, which are either low relief closures below the resolution of the map, or stratigraphic. Vertical migration is not modelled since it is assumed that all horizons have a similar structural form. However, as a result of this, the vertical distribution of hydrocarbons cannot be predicted in such a simple model since fault juxtapositions and all the sealing surfaces are not modelled.

A study of the West of Shetlands Basin, U.K. demonstrates the importance of integrating sequence stratigraphic models and pressure data for accurate modelling of migration pathways through geological time.

3.2 Paris Basin, France

3.2.1 Introduction

The Paris Basin is an intracratonic basin covering approximately 50,000 km², which contains over 3000 m of Mesozoic sediments at its centre (Pages, 1987). Clastic deposition prevailed during the Triassic to early Jurassic and the Tertiary intervals. However, carbonate deposition dominated the intervening period. The principal reservoirs are Triassic sandstones and Middle Jurassic carbonates.

3.2.2 Prediction of Generative Areas and Migration Pathways

The program was used to determine the most likely generative area, by comparing the drilling results to the model predictions for differing areas of expulsion of the Lower Jurassic source rocks. The principal source intervals are of Hettangian-Sinemurian and Toarcian age (Espitalié et al., 1988). The structural surface used is the seal to the Middle Jurassic reservoir at the present day. The structure at the time of principal oil expulsion (Cretaceous-Oligocene (Espitalié et al., 1988)) was very similar except for the recent uplift that has occurred around the margins of the basin (principally since the Oligocene). The Middle Jurassic reservoir contains approximately 40% of the reserves in the basin. The remaining reserves are located in Triassic (50%) or Lower Cretaceous reservoirs (10%). Migration of oil from the Lower Jurassic source rocks into the stratigraphically older Triassic reservoirs has occurred by fault juxtaposition, principally along the Bray Fault (Figure 15), or downward directed expulsion from the basal part of the source rock.

The results of the modelling are displayed in Figure 15. The location of the discoveries, together with the wells that encountered shows are displayed on the maps. The unsuccessful wells are not shown for simplicity. Figure 15a displays a simplified form of the structural map at the top of the Middle Jurassic that was used for the model (it was contoured at a 150 m contour interval for the modelling). The migration pathways are then predicted assuming oil rises vertically to the sealing surface above the generative area (outlined) and then migrates under the sealing surface taking the most structurally advantageous route. However, since the seals to the Triassic and the Lower Cretaceous reservoirs are sub-parallel to this surface it is also assumed to apply those stratigraphic levels where vertical migration has occurred.

Kitchen outlines relating to Transformation Ratios of the Lower Jurassic (Hettangian-Sinemurian) source rock of 80%, 25%, and 0% (using data from Espitalié et al., 1988) were modelled (Figures 15b-d). The accuracy of the model prediction is assessed using a "migration predictive index (MPI)" defined as follows:

MPI = (prediction of discoveries (%) + prediction of dry holes (%))/2

The index should reach a maximum at the most accurate model for a basin. The maximum the index can reach is a value of 100. The basin area is assumed in this case to extend to the outcrop of the Middle Jurassic interval. For the three cases displayed, Figures 15b, 15c, 15d, the indexes were 53, 66 and 59 respectively. The highest index was recorded in Figure 15c where the predicted generative area covers approximately 7000 km^2 in the centre of the basin. Within this area it is assumed that migration pathways are present at all points. The outline corresponds to a source rock Transformation Ratio of 25%. This is in agreement with the conclusions of Espitalié et

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al. (1988) who determined that oil expulsion from the Lower Jurassic source rocks begins at 2350 m, at which depth the average Transformation Ratio reaches 25%. In this prediction, 81% of discoveries and wells with oil shows (85% of discoveries) fall within 2000 m of a predicted pathway, which cover only 13% of the basin area. It is thought likely that with more accurate modelling using multiple sealing surfaces that the prediction would improve but the percentage of the basin covered by pathways would remain similar. If the map in 15c had been available at the time of drilling, 85% of the discoveries could have been found at a success rate of 44%. This compares with an overall success rate of exploration in the basin of approximately 9%.

This model predicts very restricted pathways of migration to explain the distribution of oil seen in the basin. The model of migration in the basin by Rhea et al. (1994), suggested that the control on the distribution was principally that of permeability heterogeneity in the reservoir and hydrodynamics, arguing that the basin is structurally very simple compared to the areally restricted oil discoveries. The model presented here shows that even very subtle structuring exhibits a significant control over migration of oil away from a generative area. The hydraulic head variation over the area of the basin within the Middle Jurassic reservoir is less than 150 m (using data from Rhea et al., 1994), with the dominant water flow direction south-east to north-west. The variation in the depth to the top of the reservoir is over 1500 m. Therefore the ratio R, discussed above (equation 4), is generally greater than 10. Assuming that the current water flow was not exceeded at the time of migration it had only a minor effect of migration pathway orientation. It is likely that the water flow was largely initiated during the exposure of the basin since the Miocene, and was less important during the principal phase of migration which predates this exposure.

3.2.3 Effects of Basin Morphology on Migration Pathways

The Paris Basin example illustrates the importance of basin morphology on petroleum migration. In particular anticlinal features are very important for determining the pathways. This is exemplified by the location of shallow oil shows in the Pays de Bray region in the north-west part of the basin (Heritier, 1994), some 90 kms away from the area of expulsion of oil in the basin. The anticlinal feature of this area is closely related to a deep-seated fault (called the Bray fault). The association of shows in the basin with such faults has been used to support the importance of faults for vertical and lateral migration (Poulet and Espitalié, 1987). However, this modelling demonstrates that it is not so much the faults themselves but their associated structural/ morphological features which focus migrating petroleum. In this respect the maximum vertical stratigraphic component to the migration from the area of expulsion to the Pays de Bray region is less than 1 km, compared to the 90 km horizontal component. This example illustrates that although a fault can be a significant structural feature in a basin the fault plane itself may have only a minor impact on migration. The role of faults in migration is discussed further below.

This simple model illustrates the potential to reduce exploration risk in basins, where less is known about the source rock, by predicting areas of source rock expulsion through modelling different kitchen outlines and matching the output to drilling results. It also highlights the importance of regional mapping in evaluating a prospect. The study of seals just in the immediate vicinity of the prospect is too restrictive. A regional model of concentration of petroleum must be sought.

3.2.4 Charge Concentration

The model discussed above plots the position of pathways, but clearly some pathways will be more prospective than others, with a greater potential charge having passed along them. Figure 16 assumes the model of Figure 15c but assigns a quantity of petroleum expelled to each cell within the generative area. The source rock expulsion quantities were estimated using data of initial organic matter richness and Transformation Ratio from Espitalié et al (1988). No absolute units of oil expelled from the source rock in each cell is used. Instead, a relative range of between zero at the edge of the area of expulsion and a maximum of 100 in the cell where the maximum quantity of expelled oil is calculated. The oil from each cell is then migrated as before but the quantity of oil passing each cell is recorded. The resultant map provides a measure of the potential quantity of oil that may have migrated to a given location, assuming it is not trapped along the path, using a logarithmic grey scale of 16 units (darkest being the greatest quantity). Such maps can be used in charge risk assessments for prospects.

Figure 16 identifies the Villeperdue Field as very favourably located on a plunging anticline perpendicular to the basin centre (Pages, 1987). Synclinal locations, such as the south-western part of the basin are less attractive for exploration away from the generative area of the basin. This illustrates the risks in all sedimentary basins of targeting synclinal stratigraphic traps away from areas of oil and gas generation unless lateral barriers to migration are present (discussed further below). The computer model in Figure 16 supports the simple assumptions in Figure 3 of a very favourable concentration near the edge of the source area. Figure 17 shows an oil concentration plot for the Paris Basin. This illustrates that 75% of the hydrocarbons in reservoirs are located within 15 kms of the edge of the area of oil expulsion, despite the fact that

maximum migration distances have been in excess of 50 kms. The lower bar-graph in Figure 17 shows good similarities to the simple model of Figure 3. It also suggests that although lateral migration has been very efficient in the basin, vertical migration via imperfect sealing surfaces, and fault disruption has been important to enable oil to pass into the Middle Jurassic reservoirs within the area of oil expulsion. With more data the model could be refined to predict the vertical migration pathways.

The lack of oil discoveries in the north of the basin has been attributed to poor reservoir characteristics or an absence of major faulting (Poulet and Espitalié, 1987). Oil migration into Triassic reservoirs in the centre and west of the basin has been possible due to juxtaposition of the Triassic section against the Jurassic across the Bray Fault. The modelling presented here indicates that the presence of localised lateral barriers within the Jurassic reservoirs, the absence of favourable fault juxtapositions or limited recent exploratory drilling is required to explain areas where oil is predicted but has not been discovered in economic quantities.

3.3 Williston Basin, North America

3.3.1 Introduction

The Williston Basin in North America is an extensional intracratonic basin containing over 5000 m of Palaeozoic to recent sedimentary section. Carbonate deposition prevailed within the basin and surrounding area during much of the early-middle Palaeozoic, changing to primarily clastic deposition in the late Palaeozoic, Mesozoic and Tertiary (Peterson and MacCary, 1987). The basin is a large basement warp, covering approximately 300,000 km^2. The basin contains many scales of structures

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trending in numerous orientations, from smaller anticlines and synclines less than 10 kms across to regional anticlinal features over 150 kms long.

The principal source rocks in Williston Basin are the Bakken Formation of late Devonian-early Carboniferous age and the overlying Lodgepole Formation (Madison Group) of early Carboniferous age. The latter source rock has a more limited areal distribution. Additional source rocks are found in the Winnipeg Formation of Ordovician age and the Devonian Winnipegosis Formation (Burrus et al., 1996). The overlying predominantly carbonate sequence within the Carboniferous Madison Group is the principal reservoir sequence, accounting for most of the production in the basin.

The map of the base of the Bakken Formation, simplified without faults, is shown in Figure 18. This map integrates data from Cohee (1962), Meissner (1978) and Hansen (1972). The map also locates the majority of the discovery locations in the basin. Oil expulsion from the Bakken Formation probably commenced in the Cretaceous (Dow, 1974; Dembicki and Pirkle, 1985) and reached a peak in the late Cretaceous- early Tertiary over much of the areal extent of the source rock. The structural configuration of the basin during secondary oil migration was comparable to the present structure (Dow, 1974). Therefore using the Bakken Formation structure map at the present day for migration modelling is considered to be justified. Only the Bakken Formation is modelled.

3.3.2 Quantity of Petroleum along Migration Pathways

A density of expulsion map for the Bakken Formation was constructed (Figure 19a). The values of expulsion are not absolute but range from zero to 100, as discussed above

in the Paris Basin example. The data for this map is based on the work undertaken by Dembicki and Pirkle (1985), with an emphasis on expulsion rather than generation. The mapped area where oil expulsion is predicted coincides closely with the area where the Bakken Formation shales are overpressured (Meissner, 1978, 1984).

The migration model displayed in Figure 19b records the quantities of petroleum that pass along the migration pathways based upon the modelled density of generation and expulsion within the basin. The resultant map shows a good correlation to the discovered oil fields. The Bakken Formation is not the only source rock in the basin and the proportion of reservoired oils from the different source rocks cannot be modelled fully in three-dimensions without modelling many horizons including lateral barriers through time, together with the timing and quantities of expelled oil from each source rock. However, this model illustrates how using regional scale maps and limited data some useful predictions of petroleum distribution can be made.

Migration distances in the basin are highly variable, ranging from less than 10 kms in the centre of the basin within the generative area in North Dakota, to in excess of 100 kms for oils found in the Canadian province of Saskatchewan. Many of the oils discovered in the north-east of the basin are heavy due to biodegradation and water washing (Bailey et al., 1973). This has occurred by invasion of fresh meteoric water in the northern part of the basin. Such alteration is common, and is also observed to the west in the Northeastern Alberta Basin (Bachu and Underschultz, 1993).

It has been suggested that the location of oil fields in the Williston Basin is closely linked to the location of large scale faults (Price, 1980b). Indeed the main structural features in the basin such as the Nesson and Cedar Creek anticlines (Figure 18) are

associated with faults. These will assist the vertical migration of oil into stratigraphically younger sequences, or cross-fault migration into stratigraphically older or younger sequences. However, the modelling in Figure 19b shows that it is the morphology associated with the faults that is the principal factor in the regional distribution of petroleum.

3.3.3 Effects of Hydrodynamic Flow

There is currently a hydrodynamic flow through the Carboniferous Madison Group overlying the Bakken Formation. A number of authors have suggested that this has a potential effect upon the distribution of oil in the Williston Basin (Downey J. S., 1984a; Downey et al., 1987; Dahlberg, 1995; Bachu and Hitchon, 1996). Therefore, aspects of their work were investigated to see what effect water flow can have on migration pathways. The map of the potentiometric surface for the Madison Group (Figure 20a), is based upon data published by J. S. Downey (1984b) in the US portion of the basin for fresh water hydraulic head, and data in Hannon (1987). The fresh water hydraulic heads were converted to true hydraulic head using a water density map. The water density map for the sequence, constructed using data from Edie (1958), Bailey et al. (1973) and J. S. Downey (1984b), is displayed in Figure 20b. The basin contains hydrodynamic traps (Meissner, 1988; Berg et al., 1994). Figure 20a shows the oil-water-contact tilt orientation for some of the traps in the basin, taken from Meissner (1988). The tilt orientations are consistent with predicted water flow directions indicated by the potentiometric surface. The fresh water potentiometric maps, of Downey (1984b) and Hannon (1987), suggest a flow across the basin from southwest to northeast. These fail to explain the oil-water contact tilt orientations in the central and northern parts of the

basin, or the fresh water influx in the north of the basin which causes the alteration of the reservoired crudes.

A petroleum potential map has been created using computer gridding methods using equation 4 above, assuming that the oil density is 0.75 g/cc (Figure 21a).

There were at least four periods during which hydrodynamic flow could have taken place: late Cretaceous-early Eocene, Pliocene, Pleistocene, and Holocene (Berg et al., 1994). Regional uplift of the Rocky Mountains and the Great Plains to their present elevations took place during the late Pliocene allowing the Mission Canyon and other aquifers to be recharged by meteoric water at high elevations, and hydrodynamic flow across the area to be initiated (Downey J. S., 1984b).

Assuming the hydrodynamic conditions today prevailed at the time of migration, which is unlikely, the plot in Figure 21b displays the predicted migration pathways, assuming the kitchen outline from Figure 19a. A comparison of this map with the hydrostatic conditions in Figure 19b reveals that hydrodynamic conditions today may not have significantly effected the aerial distribution of oil. The hydrostatic model appears to fit the observed occurrences in the basin better than the hydrodynamic model suggesting that the oil was trapped before the onset of water flow. Nevertheless it is very important to integrate hydrodynamics since at the local scale it clearly has resulted in the modification of traps, particularly where the structural dip is gentle and sub-parallel to the potentiometric dip (Berg et al., 1994). In some places in the basin the oil potential gradients are greater than the regional structural dip suggesting that the accumulations are not in equilibrium with the present hydrodynamic regime and are moving downdip in the Mission Canyon Formation on the south flank of the basin (Berg et al., 1994).

Hydrodynamic flow has been used to explain the lack of oil discoveries on the eastern flank of the Williston Basin due to flushing of oil from the existing traps (Downey J. S., 1984a). The analysis presented in this thesis indicates that the present hydrodynamic regime would also result in migration into this area. The oil accumulations in the Williston Basin lie predominantly on a south-west to north-east trend (Figure 18). It has been suggested that water flow deduced using fresh water potentiometric maps is in the same orientation and therefore there may be a link (Downey J. S., 1984a; Downey et al., 1987; Dahlberg, 1995; Bachu and Hitchon, 1996). Even if the flow of water was simply from the southwest to the northeast, the flow would not be great enough today to confine all expelled hydrocarbons into this orientation. The flow would need to be great enough to modify the oil that would migrate to the east or west of the basin, but not be great enough to completely reverse the migration to the south of the basin. The value of FR (equation 4) would need to be just greater than a value of -1. The recharge area in the southwest of the basin would need to be at an elevation of approximately 5000-6000 m rather than the present day 1000-1500 m. The most likely explanation is that the proportion of oil migrating towards the east of the basin is minor. In addition, lateral barriers within the carrier beds, and poor trapping geometries and a hydrodynamic re-migration component have all contributed to the observed oil occurrences.

The Williston Basin example reinforces the importance of the focusing effects of structural morphology, and highlights the importance of migration modelling in identifying lower risk exploration areas even when a simple model is applied. It also shows the importance of integrating potentiometric data into the evaluation of a petroleum system.

3.4 West of Shetlands Basin, UK

3.4.1 Introduction

The Lower Tertiary petroleum system in the West of Shetland was reconstructed by integrating sequence stratigraphical interpretation, pressure data analysis and basin modelling with hydrocarbon migration pathways prediction.

The Palaeocene Play in the West of Shetlands area has been actively explored since the early 1980's. Although early results were disappointing with the discovery of gas in the northern and central parts of the basin, exploration interest was increased in the early 1990's with the discovery of BP's Foinaven and Schiehallion Fields in Quadrant 204 (Cooper et al., in press; Leach et al., in press). Within the Palaeocene section the trapping style is a combination of stratigraphical pinchout with structural dip closure. Exploration of this play within this area requires integration of the structure, sedimentology and stratigraphical architecture of the principal reservoir horizons, with an understanding of the petroleum system.

The structural history of the West of Shetland area has been complex (Duindam and Van Hoorn, 1987; Earle et al. 1989; Stoker et al., 1993; Rumph et al., 1993) with Phanerozoic reactivation of inherited structural grains. The principal structural elements that define the many Mesozoic and Cenozoic depocentres are shown in Figure 22. The area is divided at the base Cretaceous stratigraphical level into a number of sub-basins defined by four principal structural grains; NW-SE, NNE-SSW, E-W and NE-SW.

The post-Precambrian Basement stratigraphy of the area ranges from the Devonian to the Recent (Figure 23). The dominant basin axial trend switched from NNE-SSW in the Jurassic to a NE-SW direction in the Cretaceous, which has been confirmed by regional isopach maps for these intervals (Lundin and Dore, 1997).

Post-rift sedimentation commenced during the Late Cretaceous with marls, shales and thin limestones (with some sandstones at the base) onlapping the syn-rift sequence. As a result of both sea-level rise and post-rift thermal subsidence, the old basins and basement ridges were buried beneath an argillaceous Upper Cretaceous section that is now up to 3000 m thick. An unconformity near the Cretaceous/Palaeocene boundary is identified by uplift and erosion on the basin margins and some structural highs. An increase in subsidence related to thermal uplift and faulting occurred during the Palaeocene to Early Eocene. This was coincident with extensive volcanic activity; north of Quadrant 205 sills were intruded (Hitchen and Ritchie, 1993) while volcanics were extruded over a large area to the north-west of the Corona Ridge and along the north-east margin of the West Shetland Platform.

Sedimentation during the Palaeocene to Early Eocene occurred within a pronounced NE-SW trough developed between the Flett and Corona Ridges. Upper Palaeocene sediments consist of deep marine turbidites made up of interbedded reservoir quality sandstones and shales, overlain by a Lower Eocene deltaic system. This deltaic system was terminated by a major marine transgression. During the Eocene to Recent a regressive sequence of north westerly prograding shelf sands developed. Deposition was broken up by a period of uplift and erosion in the Oligocene-Miocene.

3.4.2 Lower Tertiary Sequence Stratigraphy

The Tertiary succession West of the Shetlands has been subdivided into sequence stratigraphical units by several companies (e.g. Mitchell et al., 1993, Ebdon et al, 1995) with low-stand (LST), transgressive (TST) and high-stand (HST) systems tracts all being identified. Jowitt and Jones (Jowitt et al., in press) have interpreted 12 third order sequences (sensu. Vail et al., 1977) in the Palaeocene and Lower Eocene (Figure 24). The sequences boundaries picked in this framework are seismically defined surfaces that formed in response to relative sea level fall.

This late Palaeocene sequence set is dominated volumetrically by rocks deposited within low-stand and transgressive systems tracts. Collectively, they have a thickness of up to 1750 m and are developed in the NE-SW trending Faeroe Basin located between the Flett and Corona Ridges/ Mid Faeroes Ridge (Figure 22). They tend to be thin to absent on the shelf area to the south-east and to the west over the Corona Ridge/Mid Faeroes Ridge.

Shelfal facies associated with low-stand and high-stand prograding complexes have not been definitively identified across much of the area because of subsequent erosion.

Sedimentary facies within sequence set P3 in the Faeroes Basin are composed of stacked turbidite sandstones. These are overlain by and separated laterally by siltstones and hemipelagic shales which act as effective seals. Individual turbidite fan complexes have been constrained by NNW-SSE and E-W structural lineaments, movement along these lineaments creates intra-basin ridges that break up the overall NE-SW trending trough. This has resulted in a series of vertically and laterally isolated reservoir

sandstone bodies separated by hemipelagic shales. Three major sub-troughs have been identified within the Faeroes Basin which are illustrated on Figure 25 as Lowstand fan thicks/ Lowstand fan areas.

The top of sequence set P3 is marked by a thick shale unit. Jowitt (Jowitt et al., in press) suggested that the shale was deposited within the transgressive systems tract during a change in the tectonic style from rapid localised subsidence within the Faeroes Basin to a more regional and slower phase of subsidence. The shale acts as an extensive top-seal for hydrocarbon migration. The study of the areal extent of such seals, as previously discussed, is critical to basin analysis (Downey, M. W., 1984). Beneath the transgressive mudstone, oil and gas-condensate accumulations are reservoired within the stacked turbidite fan sandstones that are sealed laterally and vertically by deep marine shales, siltstones and mudstones.

Reservoir sands for both P2 and P1 sit stratigraphically above the regional seal interpreted in P3 and are therefore not considered highly prospective.

3.4.3 Prediction of Generative Areas

The modelling approach used in this evaluation of the West of Shetlands Basin was based on gridded map inputs. The modelling was performed using a program written by myself using ZYCOR software (Landmark Corporation). The model reconstructs the basin structure back through time by using a simple vertical decompaction model that takes into account erosion. The source rock and generation model are empirical, with generated hydrocarbon volumes derived by the combination of calibrated thermal history and source rock isopach and source rock richness maps with experimental data

on hydrocarbon transformation from similar source rocks.

Inputs consisted of present day structure maps, palaeo-erosion maps, source rock isopach and richness maps and heat flow maps over time. Five present day structure maps were derived from regional seismic mapping in the West of Shetlands area at the following stratigraphic levels: Miocene Unconformity, Top sequence set P1 (Top Balder Formation), Base Tertiary Unconformity, Top Lower Cretaceous and Base Cretaceous Unconformity. These maps were vertically decompacted to produce palaeo-structure maps which were used to constrain the time intervals modelled (Lower Cretaceous, Upper Cretaceous, Palaeocene to Lower Eocene, Lower Eocene to Oligocene and the Miocene to Recent).

Two principal erosional events were modelled at base Palaeocene and in the Oligo-Miocene; with the magnitude of these events estimated from shale velocity studies, vitrinite reflectance profiles, apatite fission track analysis and observation of truncation on structural cross sections. These were used to constrain maturation and palaeo-structural development.

In the research the only source rock modelled was the Kimmeridge Clay Formation (Bailey et al., 1987; Scotchman and Griffith, 1996). The results of partner group geochemical analysis indicate that the Kimmeridge Clay Formation contains an average TOC of 7% (maximum 15%) and pyrolysis data indicate hydrocarbon generation potential. Also a comparison of the C_{27}, C_{28} and C_{29} sterane distribution indicates a good correlation between the Kimmeridge Clay Formation source rocks and the West of Shetland oils.

Two key input maps, source rock thickness and source rock richness (genetic potential, S1 plus S2 from pyrolysis data), were generated from well control and from a geological model for the Upper Jurassic basin configuration dominated by NNE-SSW faults. Both of these parameters were assumed to increase towards the Mesozoic basin, away from the well control.

Heat flow maps were generated for each time interval to be modelled (listed above). For the Miocene to Recent time interval, the present day surface heat flow across the basin was used. Rose (Jowitt et al., in press) estimated the present day heat flow from well bottom hole temperatures using Platt River Associate's BASINMOD software. Values along the Rona Ridge trend (65 mW/m^2) are higher than those observed in the basin centre (45 mW/m^2). Heat flow maps for the older modelled time intervals were derived using heat flow ranges typical of rift basins, calibrated so that the final predicted maturity map at Base Cretaceous (Figure 26) tied extrapolated well vitrinite reflectance profiles from a dozen wells drilled on the flanks of the basin.

Outputs were maturity maps for the top and bottom of the source rock interval, generated hydrocarbons for five time intervals and palaeo-structure maps.

Results from the modelling indicate that continuous generation of hydrocarbons from the Kimmeridge Clay Formation, punctuated by periods of uplift and erosion during the Palaeocene and Miocene, has occurred in shifting generative areas since the Early Cretaceous. The majority of the hydrocarbons were generated by the end of the Cretaceous (Figure 27) with much of this charge lost through seepage from the flanks of the basin at this time or through the uplift and erosion that occurred during the early Palaeocene. The Cretaceous sequence is thin to absent on the margins of the basin

where the bulk of these early-generated hydrocarbons would have migrated. While it is likely this Cretaceous charge may account for some of the oil seen in the area (e.g. the Clair Field, Scotchman et al., 1997; Holmes et al., in press), it is thought that little or none of this charge currently remains in the basin in an un-biodegraded state.

Significant hydrocarbons continued to be generated through the Tertiary (Figure 27) and post-Palaeocene generative areas are shown on the Base Cretaceous Unconformity structure map (Figure 28). Note that the Kimmeridge Clay Formation in the deepest parts of the basin is post mature by this time and the central Flett Ridge area is dominated by gas generation. The map also indicates significant oil potential in the south of the basin, as proven by the recent discoveries in Quadrant 204, and predicts further zones of oil potential along the Corona Ridge, on the flanks of the Rona Ridge and in the northern part of the basin. Tertiary re-migration due to trap leakage or displacement of oil by a lighter charge has also been locally important.

3.4.4 Integration of Formation Pressure and Palaeocene Formation Water Salinity Data

Formation pressure formed an important component of the analysis. RFT pressure data for released wells has been plotted for the Palaeocene sandstone reservoirs (Figure 29). These data demonstrate the development of overpressure in sequence set P3, whereas the overlying sequences lie on a normal hydrostatic pressure gradient, indicating that the sequence 60 transgressive shale forms an effective regional seal in the northern and central parts of the Faeroes Basin. Indeed all the significant hydrocarbon shows have been recorded from sequence set P3 or deeper in this area.

Sequence set P3 can be divided into three principal pressure cells (Figures 29a and 30): a normally pressured cell in the south; an intermediate pressure cell centred on Quadrant 205; and an extensive pressure cell at approximately 600 psi above the normal hydrostatic gradient in the north of the basin.

Pressure data from the pre-Palaeocene sequences demonstrate that reservoirs (8000 ft (2440 m)) on the shallowly buried Rona Ridge are at hydrostatic pressure but in the centre of the basin significant overpressure can be developed. In well 204/19-1, drilled on the flanks of the Westray Ridge, the Lower Cretaceous section is 3800 psi overpressure; the overall pressure is close to the rock fracture gradient (0.8-1.0 psi/ft, Figure 29b). Such elevated pressures confirm the sealing capacity of the Upper Cretaceous Shetland Group shales. Therefore it is speculated that elevated pressure may be present in deeply buried Mesozoic reservoirs on other undrilled basement ridges for example the Flett Ridge.

Water salinity data were studied by Rose (Jowitt et al., in press). Such data are available from analysis of rare RFT samples (e.g. well 208/19-1) and has been calculated from wire line logs for key wells. These data indicate that in the deeper parts of the basin, formation water salinities are notably fresh, the freshest waters being encountered in sequence set P3 (in the Flett Ridge area averaging at 8000 ppm total dissolved solids (TDS); well 208/19-1 sample 2600 ppm TDS). More saline waters are encountered in the higher sequences. P1 reservoirs and P2 and P3 reservoirs at the margins of the basin have formation waters with normal sea water salinities (eg well 214/29-1 with 33,000 ppm TDS).

Biostratigraphicalal analysis indicates that the sequence set P3 sandstones were

deposited under normal marine conditions, therefore the fresh waters must have been introduced post deposition. The simplest way in which this could have been achieved is flushing by meteoric water. It is proposed that this would have occurred during the establishment of deltaic environments across the whole basin in P1 times, with fresh water flushing the P3 reservoirs before the development of overpressure. This implies the P3 transgressive shale did not become a regional seal until it was sufficiently compacted after the deposition of sequence P1 in the Eocene. Meteoric water influx into the basin may have been responsible for the biodegradation of an early oil charge in the Clair Field (Scotchman and Griffith, 1996; Holmes et al., in press). Subaerial exposure of parts of the basin also occurred during later periods, for example during the Oligo-Miocene inversion, which provided other opportunities for meteoric water influx.

3.4.5 Migration Pathways

To model the migration pathways, carrier beds and seal horizons were identified. The stratigraphic analysis indicates that there were extensive reservoirs at the Palaeocene level with reservoirs also occurring at Upper Jurassic e.g. Solan (Booth et al., 1993) and the Lower Cretaceous levels e.g. Victory (Goodchild et al, in press). The Upper Cretaceous provides a thick sequence of sealing shales. In the Palaeocene, as discussed, pressure data demonstrate that the transgressive shale at the top of Palaeocene sequence set P3 provides a regional seal and in the northern and central parts of the basin all significant Palaeocene hydrocarbon shows occur in the stacked basin floor fans below this horizon.

Consequently, migration in the West of Shetlands was modelled as occurring at two horizons: Base Cretaceous, to account for migration in pre Upper Cretaceous reservoirs;

and Base Tertiary, to account for migration in sequence set P3. Figure 28 outlines the post-Palaeocene generative area for the Kimmeridge Clay Formation superimposed on the Base Cretaceous structure map (i.e. the top of the Kimmeridge Clay Formation). These outlines are the starting points for oil and gas migration pathways. Migration pathways were first predicted for the Base Cretaceous level. Migration through the Upper Cretaceous into the Lower Palaeocene (P3) occurred where either the Upper Cretaceous is absent, allowing the Palaeocene to be in direct contact with Lower Cretaceous and Upper Jurassic reservoir, or by vertical migration associated with faults. The latter may occur by juxtaposition of Palaeocene reservoirs with Lower Cretaceous/ Upper Jurassic reservoirs or through fault induced fracture conduits, during periods of structural displacement, located above intrabasinal highs where the Upper Cretaceous has a reduced thickness.

Eocene to Recent charge maps are required to explain the hydrocarbon distribution in the Palaeocene play. Figure 31 shows the predicted oil and gas migration maps for pathways at the Base Tertiary structural horizon (Figure 32) during the Palaeocene to Recent time period. The migration pathways for the Base Tertiary section commence at intrabasinal highs where vertical migration from the Lower Cretaceous and Upper Jurassic was possible, as discussed above. This is illustrated on Figure 33, which is a schematic representation of the 3D model on NW-SE trending cross sections over the Flett Ridge and Westray Ridge. The reservoir sands of sequence set P3 sit stratigraphically above the Base Tertiary Unconformity and comparison of the Base Tertiary migration pathways (Figure 31) with lowstand fan sand distribution (Figure 25) predict areas of possible HC focusing.

The potential for open fracture propagation from Upper Jurassic and Lower Cretaceous

reservoirs through the Upper Cretaceous Shetland Group shales to the Lower Palaeocene is suggested by the extreme overpressure, close to the fracture gradient recorded in the Jurassic of well 204/19-1 (Figure 29b; pressure cell 4) on the Westray Ridge. The build up of formation pressure may cause the faults to dilate and expel fluids episodically (Sibson et al., 1981; Burley et al., 1989; Burley and MacQuaker, 1992; Cartwright, 1994). The zones of potential vertical migration into the Tertiary reservoirs were noted on the Base Cretaceous structure map. The locations where the migration pathways, calculated at the Base Cretaceous Unconformity, intersected these zones subsequently became the starting points for migration of oil and gas at the Base Tertiary Unconformity.

The efficiency of the vertical migration from Mesozoic reservoirs on the intrabasinal highs to the Tertiary section is probably enhanced by the storage of significant quantities of hydrocarbons. These can be released in a short time with fault movements or perhaps the buoyancy effect of the hydrocarbons induces an increase in pressure to fracture the seal. Therefore the timing of fault movement relative to trap formation is critical. However, the reservoirs in an intrabasinal high structure need not be overpressured to allow vertical release of hydrocarbons during a fault movement. An example from the west of Shetland basin may be the Victory gas field which is not filled to the spill point (Goodchild et al., in press). Evidence from oil shows indicates that an oil accumulation once existed in the structure. It is likely that the gas displaced the oil accumulation and subsequently gas was lost from the crest of the structure during later movements.

Research of active flow along faults in the Gulf of Mexico indicate that they can be identified by temperature anomalies (Anderson et al., 1994).

Pinch-out of sandstones controlled by NW-SE transfers act as lateral barriers to migration that separate the pressure compartments described above. These are largely parallel to the migration direction (c.f. Figures 25 and 31) therefore allowing hydrocarbons to migrate updip until they reach the NE-SW trending pinch-out line where the hydrocarbons are trapped. Prospectivity could theoretically occur in reservoirs above sequence set P3 if hydrocarbons could migrate through the regional seal. This is most likely in the south of the West of Shetlands where the P3 transgressive shale is poorly developed or on the faulted margins of the Corona Ridge, where sequence set P3 is thin to absent.

In summary, the development of a laterally extensive regional seal overlying reservoir sandstones which both extend over NNE-SSW and NE-SW intrabasinal highs have enabled the drainage of significant quantities of oil and gas into stratigraphical traps in the West of Shetlands area.

4.0 SURFACE SEEPS AND PETROLEUM MIGRATION IN THE WESSEX BASIN

4.1 Introduction

A better understanding of the reasons for the actual surface location of seepages of petroleum lay at the heart of my desire to undertake a research project. The research commenced with a review of world-wide seepage and previous work concerning the subject. The results of this work are summarised in the next chapter and Appendix D.

Prior to the commencement of the research, the seeps of the Wessex Basin were identified as a potential area to study the geological context of their occurrence. The study of the present day context of active seepage in the Dorset area is very important for oil exploration. It is generally accepted that generation of oil and secondary migration from the Liassic source rocks probably ceased with the inversion of the source kitchen in the late Tertiary (Stoneley and Selley, 1986). Therefore any active seepage must be the result of a leaking trap in the subsurface.

A review of previous work in the area and field studies established that the oil seep at Osmington Mills was the most likely to be currently active. My research focused on this seep in order to understand its structural setting and the potential subsurface source of the oil.

In addition to studying the seeps and impregnations of oil at the surface I attempted to understand the accumulations of oil in the basin. This work led to the identification of an area of exploration potential that ultimately led to an application to explore for oil.

4.2 A Review of the World-wide Study of Surface Seepage

Very little has been published over the years regarding oil and gas seeps, compared with other aspects of oil and gas exploration. Most of the early work, prior to the 1950's, was documented in milestone textbooks of petroleum geology. Then the emphasis was on teaching a geologist to explore for oil. In terms of the discussion of surface hydrocarbon occurrences, the texts concentrated on the occurrence of seeps, rather than trying to explain the reason for their location. Seeps were seen to be important, as an indication of oil being present in a given area, and exploration by drilling took place subsequently after the mapping of surface anticlines near to seeps. Appendix D summarises the key attempts at classifying oil and gas seeps over the years. Early pioneering texts can be found in Cunningham Craig (1912) and Beeby-Thompson (1925).

A number of works dealing with oil and gas seeps were published in the 1950's and 1960's, with Link's (1952) review still remaining one of the most important contributions on the subject. By this time the seismic method was being used more extensively in oil and gas exploration. The discussions were not significantly more advanced than the early work. The classifications are based upon the geological context of their location.

At this time, the study of micro-seepage (see Section 2.7) was beginning to be undertaken (Landes, 1951). Surface geochemical exploration, as it is usually referred to, has continued to the present day as an exploration tool, but has always been on the 'fringe' of petroleum exploration.

Clarke and Cleverly (1991) presented a classification that differs from earlier ones as it emphasizes the very near surface processes that affect the nature of the hydrocarbon at the surface. Although their research does not particularly address the geological controls on hydrocarbon seepage, it does indicate the importance of very near surface geochemical and hydrogeological processes that may control the nature and location of seepage.

The most recent classification is by Macgregor (1993). He has returned to a Link (1952) style classification, placing seeps in their geological setting. However, Macgregor (1993) did not explain why seeps are located where they are beyond saying they are associated with faults or the outcrop of dipping strata. He attempted to address the significance of seeps by studying their relative location compared with discovered fields in a mature exploration province of SE Asia, and comments upon the coincidence in various tectonic settings.

Clarke and Cleverly (1991) believe that active seeps must be derived from a breach of a subsurface accumulation, since they do not think it possible that hydrocarbons are being generated in sufficient quantities to account for rates of discharge and numbers of seepages in sedimentary basins. Macgregor (1993) concluded that if generating hydrocarbons were sufficiently focused they could account for surface seeps. This conclusion really derives from finding a poor spatial relationship between sub-surface accumulations and surface seepage in some basins. However, as quoted by Landes (1951) "If the dips are very gentle,.., the 'mother lode' may be many miles away".

Very little of the previous research has addressed the link between subsurface migration of hydrocarbons and surface seepage. As mentioned above, the location of seeps are

classified by most authors according to the context of their occurrence, essentially whether their location is associated with a certain fault type, intrusion, or, outcropping bed or unconformity. This work shows that the modes of occurrence of seeps are the same as those determining petroleum migration in the subsurface (i.e. along faults, up-dip along beds or adjacent to intrusions such as salt).

There are many that believe that petroleum does not migrate up faults (Section 2.7). Cunningham Craig (1912) stated "As channels for migration of oil to any great extent they do not act..Open fissures are..very rare in nature, and only occur in limestone formations or in hard igneous or metamorphic rocks..". This was echoed by Landes (1951) "Fault fractures play a most important role as channelways for ascending ore-depositional hydrothermal solutions, but examples of oil migration along fault planes are very scarce". In the Outer Moray Firth of the North Sea oil is trapped against faults. In this area, it is the lithology across a fault which determines whether the oil carries on its movement in the subsurface (Hindle, 1989). Downey (1984) stated that "The fault plane itself offers open passage to migrating fluids only under special conditions. The most significant of those special conditions is the circumstance of shallow faulting in an overall tensional regional stress field".

Equally, there are those who believe that faults and fractures provide the primary means of escape from the source rock and migration to the trap. Price (1980a, b) has been one of the biggest exponents of this theory. He asserted that vertical migration is the most important route taken by hydrocarbons in the subsurface. My main argument against this conclusion is that on its own it does not explain the degree of focusing needed to produce economic accumulations. Focusing on a large scale is probably only possible by collection by areally large sealing surfaces (i.e. along bedding planes).

Downey (1984) suggested that migration along faults becomes important at shallower depths. It is significant that oil and gas seepage is often noted following earthquakes (see Beeby Thompson (1925), Gold (1987) and Selley (1992) for examples). If a fault cutting an oil or gas accumulation is effected during an earthquake then flow to the surface is likely. Such seepage is probably short-lived until the fault re-seals. An example occurred in England following an earthquake in 1892 where oil entered a water borehole for a short period at Ashwick Court in Somerset (Redwood, 1922). It is therefore likely that faults play a more important role in the location of seeps than in the deep subsurface migration of petroleum.

In my research I hoped to study the relative importance of faults and the structural morphology of sealing surfaces on the surface location of seepage. I hoped to add a greater understanding to this subject by studying the seeps of the Wessex Basin

4.3 A Summary of the Petroleum Geology of the Wessex Basin

The Wessex Basin is one of a system of linked Mesozoic basins across southern England, the Channel and northern France (Underhill and Stoneley, 1998; Hawkes at al., 1998). The Wessex Basin is dominated by the WNW-ESE trending fault systems (Figure 34), however NW-SE and NNE-SSW faults have also been locally important in the development of traps and as a control on reservoir, seal and source rock thicknesses. Inversion of the basin depocentres during the late Tertiary resulted in significant uplift of the generative areas and complex structuring (Simpson et al., 1989; Chadwick, 1993; Underhill and Paterson, 1998). In Dorset the inversion structures are clearly visible along the coast. The structures and the range of the stratigraphic record exposed at the

surface have resulted in Dorest being one of the most spectacular and most studied areas of geology in the world.

Hydrocarbon exploration began in the Wessex Basin some 60 years ago due to the presence of surface anticlines and the discovery of active seeps of petroleum along the coast (Lees and Cox, 1937). Early exploration targeted the surface features. During the early 1970's improved seismic data allowed companies to explore north of the inversion anticlines and target extensional structures which pre-dated Miocene age basin inversion. The discovery of the large Wytch Farm oil field with multiple reservoirs (Figure 35) followed in 1973.

Through the centre of the onshore portion of the basin is a WNW-ESE trending structural high of extensional origin referred to here as the Central Wessex High (Figure 34). The Wytch Farm, Wareham and Stoborough oil accumulations are located within the eastern part of this structural trend.

Lying to the south is a zone that experienced considerable inversion (1500-3250 m) which culminated during the Oligocene-Miocene (Alpine tectonics). Prior to the inversion this was the area of greatest burial in the basin and the principal source kitchen area. The compression was accommodated on the former southward dipping syn-depositional extensional faults. The Kimmeridge oil field is the only discovery to date within an inversion anticline. The Central Wessex High is bounded to the north by the Winterborne Kingston Trough which also experienced moderate inversion. The large anticlines that formed in response to this inversion are evident on the 1:250,000 scale British Geological Survey geological maps of the region (Figure 36).

Lying between the two inverted sub-basins, the Central Wessex High has remained a stable zone within which there is potential to discover additional hydrocarbons that migrated towards the feature prior to the inversion.

The primary reservoir in the area is the Triassic Sherwood Sandstone (Figure 35), which consists predominantly of sandy braided stream and related deposits, ranging in thickness in the basin from 150 metres to 300 metres (Bowman et al., 1993). It forms the principal reservoir in the Wytch Farm field. The isopach of the Sherwood Sandstone (Figure 37) indicates that the WNW-ESE faults may have been active during the deposition of the sequence. The Bridport Sandstone is a secondary reservoir in the basin (Figure 35). It is composed of very fine grained shallow marine sandstones, with a thickness range of 60-130 m. This interval forms an oil reservoir in the Wytch Farm and Wareham fields. Additional reservoirs do occur locally in younger Jurassic carbonates (Figure 35).

The Mercia Mudstone Group forms an excellent regional seal to the primary Sherwood Sandstone reservoir. It comprises a succession of mudstones and evaporites of playa lake/mudflat origin. It has a thickness range of 350-1000 m in the basin. The isopach of the interval (Figure 37) suggests that faults were active during this period and that the Central Wessex High had developed at least by the late Triassic.

Overlying the Bridport Sandstone reservoir is a thick succession of shales comprising the Fullers Earth generally greater than 90 m thick.

Within the Wessex Basin there are 3 potential source rock intervals of Jurassic age; Liassic shales (Blue Lias, Shales with Beef, Black Ven Marls), Oxford Clay (Callovian-

Oxfordian) and the Kimmeridge Clay (Clayton et al., 1995) These all contain organic matter dominated by algal/bacterial input with minor amounts of woody material. The highest source potentials are developed in finely laminated shales with lower potentials in the more homogeneous, bioturbated mudstones

The Liassic is the principal source of the oil found to date in the basin. This is indicated by published oil-source rock correlation work and modelling of maximum burials of the intervals in the zone south of the Central Wessex High (Ebukanson and Kinghorn, 1986a,b; Cornford et al., 1987; Selley and Stoneley, 1984, 1987; Stoneley and Selley, 1986).

The most significant period of extensional trap formation occurred during the late Jurassic-early Cretaceous period. In the Wessex Basin these structures are truncated by an unconformity of regional significance which was previously assigned to the Aptian but the erosion, leading to the widspread truncation, is now thought to have occurred principally during the Neocomian (Ainsworth et al., 1995; McMahon and Turner, 1995). McMahon and Turner (1998) currently place the regional truncation unconformity within the lower part of the Wealden succession, based upon data from the Celtic Sea, with an Aptian Unconformity of lesser significance at the base of the Lower Greensand. The intra-Cretaceous unconformity in the Wessex Basin is seen at the top of the Wealden succession. The Wealden succession in the Chaldon area of the Wessex Basin is truncated by the unconformity (House, 1993). Arkell (1947) noted that the Wealden Formation conformably overlies the Purbeck Beds in south Dorset. The problem with the dating of the continental Wealden Formation in the Wessex Basin has made the dating of the unconformity very difficult. Arkell (1947) noted that the majority of the sequence could be Valanginian in age. It is therefore possible that the Wealden of the

Wessex Basin correlates to the Wealden sequence below the unconformity ascribed to the Berriasian in the Celtic Sea by McMahon and Underhill (1998).

The subcrop map at this unconformity was constructed (Figure 38) and reveals the principal structural trends at this time, the WNW-ESE trend being most dominant. During the early Cretaceous the western part of the Wessex Basin was uplifted to a greater extent than the eastern area. Consequently the extensional fault block structures were truncated to a deeper stratigraphic level. By the end of the period of erosion the subcrop pattern reveals that the Central Wessex High was present in a similar form as at the present including its plunge to the south-east. The interpretation of the Central Wessex High trend is consistent with maps produced by Whitaker (1987).

4.4 Regional Seismic Mapping of the Base of the Liassic Source Rock

In order to understand the structural geology of the Wessex Basin I constructed a regional two-way-time structure map at the base of the Liassic source rock sequence (Top Penarth Formation) using 440 kms of seismic data purchased from the Onshore Geophysical Library through the Open University (Figure 39).

A north-south composite seismic line (Figure 40) illustrates the structural style of the onshore portion of the Wessex Basin. The inversion of the depocentres bounding the Central Wessex High is evident. The uplift occurred on the former extensional faults bounding the high. The uplift to the south of the high is much more significant than to the north. The data quality of seismic data prior to 1975 was very poor, with a moderate improvement seen in later acquisition, particularly in the less deformed areas to the north of the coastal area of significant basin inversion. On data recorded since 1990 a

greater resolution has been achieved, with localised complex faulting within the salt of the Mercia Mudstone Group apparent (Stewart et al., 1997; Butler, 1998). However, this more recent data is not currently available through the Onshore Geophysical Library.

The regional mapping illustrates the importance of the WNW-ESE fault trend. This principal fault trend is cross cut by a N-S trend. The latter fault trend is evident on the offshore portion of the published 1:250,000 scale British Geological Survey regional geological maps (Figure 36) and at outcrop (e.g. Holworth House and in the foreshore near Kimmeridge Bay).

4.5 Petroleum Generation and Migration

Prior to undertaking research into seepages of oil in the Wessex Basin my research concentrated on the secondary migration and first entrapment of oil. I considered it important to understand the principal controls on the initial distribution of oil prior to the inversion that lead to re-migration (tertiary migration) of oil. The points of seepage at the present day surface represent outcrops of re-migration pathways.

Secondary migration occurred from the WNW-ESE depocentre located to the south of the Central Wessex High (Selley and Stoneley, 1987). Vitrinite reflectance data from the Winterborne Kingston 1 borehole, within the Winterborne Kingston Trough to the north, suggest that the Liassic section was not buried sufficiently to generate oil (Bristow et al., 1995). However, it cannot be ruled out that very localised generation and expulsion within the Trough to the north may have occurred where the Liassic interval was more deeply buried prior to the inversion.

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The main phase of oil generation and expulsion was in the south of the area during the late Cretaceous to Palaeogene. Maximum burial was reached prior to the Miocene inversion (Penn at al., 1987; Bray et al., 1998).

Petroleum migration into the Jurassic reservoirs required vertical migration, via fault juxtaposition, above the Lias source rock interval of approximately 200-300 m. Many faults in the area have throws of this magnitude and shows are commonly seen in these reservoirs.

By contrast migration into the stratigraphically older Sherwood Sandstone reservoir is more difficult to predict. The intervening Mercia Mudstone group is 350-1000 m thick (Figure 36). Prior to inversion in the Miocene, oil migrated into the Sherwood Sandstone reservoir across the large normal faults south of the Central Wessex High where fault throws were sufficient to juxtapose the Liassic source rocks against the Triassic Sherwood Sandstone (Colter and Havard, 1981). Predicting areas where such a juxtaposition of strata occurred prior to the late Tertiary inversion is very difficult to undertake due to the significant subsequent reverse movement on the fault planes. A simplified structural surface was constructed of the base of the Mercia Mudstone Group prior to the late Tertiary inversion. It was based upon the regional seismic mapping of the basin at base of the Liassic source rock (Figure 39), the isopach of the Mercia Mudstone Group (Figure 37), well tops, together with published estimates of the magnitude of the basin inversion (Bray et al., 1998; Hamblin et al., 1992; House, 1993; Law, 1998; Penn et al., 1987; Selley and Stoneley, 1987; Stoneley and Selley, 1986). The migration pathways were modelled using this simplified surface, of the base of the Mercia Mudstone Group sealing surface, with an assumption that oil could enter the

Sherwood Sandstone along the entire fault bounded edge of the main depocentre that lay to the south prior to the late Tertiary inversion (Figure 41).

The simplified model suggests that prior to inversion the Central Wessex High would have been a focus of oil migration. Within the high trend, the Wytch Farm structure formed a focus for the migration of oil from a large drainage area to the south. The Central Wessex High acted as a northern boundary to oil migration, which may account for the lack of shows encountered in wells drilled to the north of the high. Migration pathways are predicted to have been very focused away from the kitchen area. This may account for the very few oil shows have been encountered within the Sherwood Sandstone where penetrated (Figure 41). The shows in the Martinstown 1 well confirms the migration of oil across from the Jurassic section into the Triassic in the western area south of the Central Wessex High.

At the Sherwood Sandstone level the Central Wessex High feature dips to the ESE from the western end. The western end has been structurally higher since the early Cretaceous (as indicated by the subcrop map to the intra-Cretaceous unconformity (Figure 38)), prior to migration of oil through the area. This interpretation indicates that the western end of the high is prospective for oil exploration. My research led to the re-licensing of the western end of the high for petroleum exploration in 1998.

There has been re-migration of hydrocarbons since the Miocene inversion suggested by breached accumulations on some of the surface features, indicated by oil shows, and the present day seeps/impregnations along the Dorset coast. A study of these surface hydrocarbon occurrences and their significance formed an important part of the research.

In summary, the most significant accumulations found to date and the best potential for finding new oil accumulations in the Wessex Basin lie to the north of the inversion front which is north of the former generative kitchen. This is due to a favourable juxtaposition of Lias source rocks against the Triassic reservoir rock during generation and the survival of traps at all reservoir levels that were charged during the secondary migration.

4.6 Sites of Surface Seepage and Impregnations of Petroleum in Dorset

Selley (1992) noted 13 locations of petroleum seepage/ impregnation in the Wessex Basin in a review of the literature;

Upwey (Purbeck), Osmington Mills (Bencliff Grit), Holworth House (Purbeck), Chaldon (Purbeck strata), Durdle Door (Purbeck/ Wealden), Dungy Head (Wealden), Lulworth Cove (Wealden), Mupe Bay (Purbeck/ Wealden), Worbarrow Bay (Wealden), Kimmeridge Bay (Kimmeridgian), Kimmeridge (Portland), Anvil Point (gas, Purbeck) and Pevril Point (Purbeck).

The locations are plotted on Figure 42. Selley's (1992) sources were quoted as Strahan (1920), Lees and Cox (1937), Arkell (1947), Power (1978), Farrimond et al. (1984), Selley and Stoneley (1987) and Cornford et al. (1988).

In addition to the above, four other locations are known to me (Figure 42); Lulworth Banks (oil and gas from Corallian; Duckworth, personal communication), St Oswalds Bay (Wealden; Selley and Stoneley, 1984), Portland (Portlandian; Lees and Cox, 1937) and Stair Hole, Lulworth (Wealden; Bigge and Farrimond, 1998 and Purbeck; Lees and Cox, 1937).

Many of the locations have not been the subject of any research since the Arkell Memoir in 1947 and are difficult to locate. There was insufficient information about their location in the older publications to enable me to find many seeps. Many were very overgrown or covered by slumped material.

In addition to the occurrences listed above I also found an occurrence of oil in Purbeck strata at St Oswalds Bay. The oil present in the Purbeck sequence at Peveril Point is located close to the eastward plunging axis of the Purbeck anticline. At both St Oswalds Bay and Peveril Point the occurrence within the Purbeck sequence has the form of a soft tar like bitumen in fractures within the Purbeck limestones. I managed to obtain an extraction using the solvent dichloromethane. The oil is probably very biodegraded and may not represent currently active seepage. Indeed this is probably true of many of the 'seepages' in the Wessex Basin. Although I was unable to locate a seep over the Chaldon Anticline, it should be noted that oil shows were encountered in the Purbeck (48-51 ft brt) and Portland (198-200 ft brt) strata in the Chaldon Herring 1 well in 1955. No samples were collected in the well above 42 ft brt. The oil occurrence probably represents oil that re-migrated during the basin inversion and accumulated in the hangingwall anticline only to be lost when the structure was ultimately breached.

4.7 Significance of Surface Seepage of Petroleum in Dorset

The seep/ impregnation at Mupe Bay in Wealden sandstones has been cited as evidence of two phases of oil migration (Selley and Stoneley, 1987). A boulder bed contains sandstone clasts that are apparently oil-cemented set in a sandstone matrix that shows lighter oil staining. The early work (Selley and Stoneley, 1987; Cornford et al., 1988) suggested that the clasts were the result of contemporaneous seepage which cemented

poorly consolidated sand. This was supported by geochemical evidence that oil in the sandstone clasts was less mature, suggesting early generation, than the oil in the surrounding matrix (Selley and Stoneley, 1987; Cornford et al., 1988; Kinghorn et al., 1994; Wimbledon et al., 1996). This theory has been challenged by Miles et al. (1993, 1994) whose research did not support a difference in maturity of the oils, but only a difference in the level of biodegradation of the oils. They attributed differences in biodegradation to variations in permeability which would have affected the invasion of meteoric water. More detailed work by Parfitt and Farrimond (1998) confirms that there is no difference in maturity between oils extracted from the matrix and those of the clasts, but it does not preclude two phases of oil staining.

The oil impregnated Wealden sandstones at Stair Hole Lulworth have been the subject of recent research (Bigge and Farrimond, 1998). A study of biomarkers revealed significant differences to the oils found at Mupe Bay. This may represent a combination of differences in original source rock facies and biodegradation history.

In Selley's (1992) summary of Wessex Basin seepage he comments that "Although they vary widely in geography and stratigraphy, all the Wessex basin seeps occur where northerly dipping permeable beds intersect a fault". In the context of oil migration discussed in this thesis, the observation of "dipping permeable beds" is significant. If faults alone were responsible for the surface location then the petroleum occurrences could be found at any stratigraphic horizon in fractured rock. If the oil has migrated some distance along the permeable horizons below a sealing surface then the occurrences would be expected to be close to the axis of an anticlinal feature or lateral seal and at areally focused sites. For this reason a detailed study was made of the

Osmington Mills seep to evaluate the structural geological context and discover the relative importance of faults (see Section 4.9).

From the standpoint of oil exploration in the coastal area of Dorset, the implication of the relative importance of faults and the morphology of the strata is significant since the fault planes generally dip to the south and the beds to the N – ENE. If one assumes there is potential for lateral migration then it follows that the source is likely to be located in an onshore direction. If the faults are more important then the source is more likely to be in the offshore area.

The multiple locations of impregnation in the Lulworth area might be more suggestive of multiple more local sources. They may indicate that a single trap may be breached in multiple locations, perhaps along the length of a fault. Alternatively, since the area has had a particularly complex structural history (House, 1993), the multiple sites may represent a number of phases of seepage and migration routes (from one or more accumulations) which varied through time.

4.8 Other Surface Phenomena Possibly Linked to Seepage of Petroleum

Micro-seepage of gases (Klusman and Saeed, 1996) are thought to cause a number of near surface phenomena such as alterations of soils which may lead to geobotanical anomalies (Schumacher, 1996). A review of the flora in Dorset was undertaken to establish if any species showed a distribution that did not appear to relate to the subsurface geology or have a very limited distribution. The only anomalous distribution that was found concerned the species of heath plant called *Erica ciliaris* (Rose et al., 1996). Its distribution is largely limited in Dorset to the Poole Harbour area (Good,

1948), overlying the Wytch Farm oil field (Figure 43). Good (1948) stated that "its local geographical limits follow no obviously recognizable edaphic or climatic boundary and are therefore presumably set by some unusually subtle factor or combination of factors". However, research by Haskins (1978) of sub-fossil seed remains in peat deposits suggests that *Erica ciliaris* has been slowly spreading from a source on Wytch Heath introduced between 9650-3600 years ago. Although the origin is not known, introduction by birds or from a ship seem the most likely.

While undertaking field work, I noticed areas (metres to 10's metres diameter) of burnt grass/ heath and became aware of the many fires that are located in open ground within Dorset (Figure 44). The distribution of the fires (Grassland, Heathland, Embankment, Verges) was investigated with the assistance of the Dorset Fire and Rescue Service in Dorchester to see if there were any anomalous distribution that may result from stressed vegetation relating to any subsurface micro-seepage of hydrocarbons. The data obtained and plotted were fires in the period November 1991 - May 1995 for the Isle of Purbeck area and the period September 1995 – November 1996 for the South Dorset area. The distribution showed anomalous groupings of fire occurrences, but more detailed analysis revealed them to be close to recreational areas, built up areas or agricultural land, suggesting a human origin to their source. It was felt that no benefit could be gained from further research on this topic.

4.9 Osmington Mills Oil Seep : A Breached Accumulation or an Active Seep?

4.9.1 Introduction

The first published account of the "rich impregnation" in the early Jurassic Bencliff Grit outcrop between Osmington Mills and Bran Point was given in the 1930's (Lees and Cox, 1937). Its discovery by A. H. Taitt, together with oil impregnations known elsewhere along the Dorset coast, stimulated early petroleum exploration in the Wessex Basin.

4.9.2 Stratigraphic and Structural Setting

The Bencliff Grit is a member of the Redcliff Formation (Ainsworth et al., 1998) of the Oxfordian (late Jurassic) Corallian Group (Figure 45). The Corallian consists of a variable series of clays, sands and limestones (Arkell 1933; Wilson, 1968; Talbot 1973). The Corallian Group totals approximately 60 m in thickness on the Dorset Coast. The Bencliff Grit is 5-6 m thick, sandstones comprising 80-90% of the succession. Allen and Underhill (1989) divided the Bencliff Grit into three units (Figure 46) which are separated by heterolithic and/or mudstone facies. The sandstone is fine grained with a porosity of 15-20% and permeabilities in the range 10-1000 mD (Watts et al., 1998). The presence of large scale cross-bedding, sometimes with slumps and dewatering structures indicate rapid sedimentation. Fossil burrows and the presence of plant material suggest a near-shore depositional environment. Goldring et al. (1998) favour a lagoonal or bay setting.

None of the published work to date has noted that the seepage in the Bencliff Grit is located near the crest of a plunging anticline (Figure 47). It is the western extension of the Ringstead Anticline, plunging to the ENE (Figure 48). The anticlinal trend can be viewed from the cliffs between the Smuggler's Inn and Bran Point (Figure 49).

4.9.3 Previous Work

Lees and Cox (1937) noted that "where the beds (Bencliff Grit) pass below high-tide level of Bran Point there is a small but active seepage of free oil". They determined the specific gravity of the oil from the analysis of two samples in the range 0.941-0.944 (18.4-18.9 °API), and noted a low sulphur content. Further published accounts of the geochemistry of the oil seepage did not appear until the 1980's (Selley and Stoneley, 1987, Cornford et al., 1987). The geochemical analyses of the seeps has been complicated by the effects of biodegradation, whereby bacteria have degraded certain components, modifying the composition extensively (Cornford et al, 1988; Bigge and Farrimond, 1998).

Cornford et al. (1987) analysed two samples from the cliff section and determined that the oil was derived from a mid-late mature source rock. They claimed to see "a clear oil-water contact...in the cliff section, suggesting shallowly dipping outcrop....represents a dissected reservoir". This relationship is not supported in the field, with the live seep located within what they referred to as water-wet sandstone.

However, Baylis and Clayton (1995) also concluded from geochemical analyses that the oil in the cliff (they did not analyse samples from the foreshore) represents an exhumed accumulation. They noted that there was no difference between their surface samples

and those they recovered from "some distance" into the cliff face, suggesting to them that the main phase of biodegradation occurred before exposure within a reservoir. They found the only geochemical difference between samples was a small change in the $\delta^{13}C$ of the aromatic fraction that they related to water washing. They did not consider the possibility that the biodegradation may have occurred as the oil migrates to its current location, nor the possibility that the oil in the cliff is actively washed by bacteria in the water following rainfall. The Bencliff Grit is an aquifer and forms a perched water table in the cliff at Osmington Mills-Bran Point.

4.9.4 An Active Seep

More recent and extensive geochemical analyses by Diane Watson (1998) for her MSc thesis at Newcastle University near Bran Point have revealed differences in oil samples taken from the cliff and from the foreshore. Samples of the active seep between high and low water mark on the foreshore were taken on 29th April 1998 in heavy seas and bad weather (Figure 50). Watson's analyses (1998) of over 30 samples shows evidence for two phases of migration. A study of biomarkers reveal two distinct families of oils with different degrees of biodegradation. The oil impregnation in the cliff probably represents an earlier, no longer active, phase of migration (Figure 51). The lateral extent both vertically and laterally of the oil impregnation in the cliff suggests that it may represent a breached accumulation confirming earlier research. The higher concentrations of oil are seen in the basal parts of the beds (Figure 51). There is no difference in grain size of the beds (Figure 46) and the most likely explanation is gravity settling of the oil (Farrimond, personal communication). Observations of the cliff in different weather conditions revealed that the oil is only mobile either during hot weather, particularly after prolonged rainfall. In contrast, the seepage on the foreshore is

less biodegraded, more areally confined and close to the crest of the plunging anticline. It therefore probably represents active seepage.

4.9.5 Investigating the Possible Origin of the Active Seep and the Reasons for its Surface Location

If the seep on the foreshore at Osmington Mills is active, then its source must be from a leaking trap in the subsurface as discussed in Section 4.1. The seepage is located at the crest of a surface anticline (Section 4.9.2). It is therefore likely that the crest of the anticline provides the near-surface focus for migrating oil. Subsurface mapping using the seismic data was undertaken to determine the extension in the subsurface of the anticline and the potential source of the Osmington Mills seep. The top of the Corallian is a good reliable seismic reflector that is sub-parallel to the Bencliff Grit. Mapping this horizon and the top of the Inferior Oolite shows that the structure in the area is dominated by WNW-ESE and NNE-SSW trending faults (Figure 52). The faults experienced reverse movement during the inversion that increased in amount to the west, so their eastern ends are still normal rather than reverse faults. Approximately 2250 m north of the seep location is a major E-W fault that has experienced considerable inversion (Fault A, Figure 52). Hangingwall anticlines have formed along this fault at Poxwell and Chaldon Herring (House, 1993). There was considerable throw to the south on the fault in the region of these anticlines (600-900 m) prior to the regional truncation in the early Cretaceous.

The Corallian in the hangingwall of the fault was probably juxtaposed, prior to the inversion against the Lower Lias shale sequences. There were possibly oil accumulations in the Bridport Sandstone in the footwall of the fault at that time, sealed

laterally by the Kimmeridge Clay. The late Tertiary inversion resulted in the Corallian in the hangingwall being uplifted past the Bridport Sandstone in the Poxwell area. However these two formations could be juxtaposed today in the region of Chaldon Herring (near seismic line GC86-V28; Figure 53). A north-south seismic line through the zone of inversion (Figure 53) shows the northward dip of strata from the coastline where the Osmington Mills seep is located towards fault A.

To the north of the W-E trending fault (designated Fault A) the Inferior Oolite was mapped. The Inferior Oolite/Fullers Earth boundary approximately 3 m (Coombe Keynes 1) above the Bridport Sandstone forms the reflector. The areas of possible juxtapositions of Bencliff Grit-Bencliff Grit south of Fault A, Bencliff Grit-Bridport along Fault A and Bridport-Bridport north of Fault A were determined. The fault sections marked in yellow on Figure 52 are those segments where sand-on-sand juxtaposition is predicted. Note that the Bencliff Grit and Bridport are located approximately 30 ms and 3 ms respectively below the mapped horizons.

Insufficient data was available to model lateral variations in formation velocities that might effect the morphology of the composite mapped surface. Therefore the two-way-time map was used for the migration models. South of Fault A, within the mapped area, only the Ringstead 1 and 97/14-1Z wells drilled as far as the Bencliff Grit. To the north of Fault A only Coombe Keynes 1 drilled to the Bridport Sandstone. Data was not available for the Osmington 1 and 2 wells.

A reverse model to determine the potential drainage area for the seep at Osmington Mills using the composite mapped surface is shown in Figure 54. The modelling

suggests that the source of the active seep at Osmington Mills is probably a leaking structure some distance to the north-east.

Figure 55 illustrates a model of potential long distance migration pathways from the Coombe Keynes structure (10 kms to the north-east). The Coombe Keynes 1 well, drilled in 1989, encountered a column of oil shows extending 15 m from the top of the Bridport Sandstone. The well results suggest that a structure at Bridport Sandstone level has been breached. However, there may be an accumulation remaining above the structural level of the exploration well that is still leaking today. Alternatively a leaking trap could be present to the east of the Coombe Keynes feature off the mapped area, the Coombe Keynes feature having discharged in the past. In this case the pathways would just be passing through the structure today. Another potential source of the seep is the Chaldon Herring footwall structure (Figure 55) or one of the numerous small mapped Bencliff Grit level structures.

Although the precise source of the migrating oil cannot be ascertained, the research supports a model for potential significant lateral migration along the Corallian Bencliff Grit carrier beds.

The hydrodynamic water flow through the Bencliff Grit was not modelled due to insufficient data, but it would be directed from the hills to the coast (north-south), sub-parallel to the buoyancy driven migration pathways.

The forward and reverse models both identify the Osmington Mills area as a focus of potential migration pathways from breached traps over a large area of southern Dorset. The oil is focused to the site by the structural morphology of the sealing surfaces

overlying the Bencliff Grit and Bridport sandstones together with a favourable juxtaposition of these strata across faults.

If one assumes that a gallon of oil has been seeping at Osmington Mills each month since the end of the Miocene (4 ma), the total leakage would amount to 1.1 million barrels of oil. Even if a much higher rate of seepage is assumed, considerable reserves could remain in the trap(s) from which the oil is leaking. The potential original volumes within the mapped closures (on Figure 55) are estimated to be of the order of 1 to 15 million barrels of oil.

In summary, the Osmington Mills seep on the foreshore appears to be active, located near the crest of NE plunging anticline with the Bencliff Grit carrier beds dipping in the subsurface to the N and NE. There is also evidence from the impregnations in the cliffs of a palaeo-accumulation in a breached structure. The Bencliff Grit is juxtaposed across a fault to the regionally important Bridport Sandstone reservoir and carrier bed. Faults in the vicinity of the seep are not required to transport the oil to the stratigraphic level of the late Jurassic Bencliff Grit from traps on the downthrown side of the major fault system.

5.0 CONCLUSIONS

The migration process can be thought of as movement of oil and gas on the underside of sealing surfaces. The sealing surfaces are usually bedding parallel, but locally they can be vertical or sub-vertical to bedding. They are not bedding parallel when there are lateral facies changes in the migration medium or top seal, or by juxtaposition to different sequence by faulting or salt intrusion. In cases where the migration pathway occurs in part of a stratigraphic section completely enclosed by sealing strata, there may be a pressure difference across the boundary.

In hydrodynamic conditions the effect on the orientation of migration pathways depends upon the densities of the water, and petroleum phase, and the ratio of the gradient of the sealing surface to the gradient and orientation of the potentiometric (water) surface. The flow of water from compacting sediments has an insignificant effect upon path orientation. Therefore, the accurate prediction of the quantities and movements of compaction fluids is not necessary to model hydrocarbon migration. Groundwater flow in response to topographic drive can usually be ignored when modelling gas migration, but may significantly impact oil migration in the shallower parts of the system, particularly during periods when a basin is sub-aerially exposed.

Vertical migration can occur where the capillary pressure of the overlying seal becomes insufficient to retain the migrating oil or gas. This could occur due to facies changes in the top seal or fault juxtaposition. In special circumstances, particularly for gas, this can occur along the fault plane, particularly during active movements. Vertical migration from either normally or abnormally pressured strata is most likely to occur into normally or lesser pressured strata at intrabasinal highs where hydrocarbons can be

stored and transferred at times of temporary seal rupture. In such basins a significant proportion of oil and gas migration is episodic.

Map-based computer models incorporating sealing surface geometries in combination with water potentiometric data offer a very quick appreciation of the principal controls on petroleum distribution in a basin and provide results which can be used to risk exploration prospects. Such models emphasise the importance of the regional basin analysis in evaluating prospect risks.

Migration pathways form a dense network above the generative areas of basins. However, the pattern becomes increasingly focused laterally away from the generative areas due to the effects of sealing surface morphology. By the time migrating hydrocarbons reach the surface they often form locally very discrete outcrops (surface seeps) which should be incorporated into the migration model.

The optimum location for a commercial accumulation is close to the edge of the generative area of a basin. The construction of petroleum concentration plots (depth of trapped petroleum plotted against distance from the edge of the area of expulsion) can be used as a rapid method of assessing migration styles and classifying petroleum systems.

Within a generative area it is still possible to concentrate hydrocarbons even in a generally dispersive synclinal location. However, beyond a generative area, traps in synclines of a stratigraphic or downthrown trap nature require the existence of lateral barriers to focus petroleum into these areas.

Reverse modelling of individual pathways from fields and seepages to potential sources can assist with the prediction of the boundaries of the leaking accumulations or generative areas.

Using examples and models developed from studying a variety of basins it is apparent that a thorough study of migration pathways through a sedimentary basin history requires the integration of geochemistry, structural geology, hydrogeology, sequence stratigraphy and wellsite engineering data.

Results of research on the Paris Basin showed that very subtle structural features can have a pronounced effect on the orientation of migration pathways. Research into the effects of hydrodynamic flow on migration pathways in the Williston Basin led to the development of a mathematical equation to describe the deflection that such flow can exert on pathways. The formula has applications in all sedimentary basins which have experienced hydrodynamic flow from topographic drive.

The study of the West of Shetland petroleum system particularly emphasised the importance of integrating sequence stratigraphic interpretations with traditional basin modelling to improve migration pathway prediction. The West of Shetland basin also has a complex formation pressure distribution which is important to study to model migration pathways accurately.

The research in the Wessex Basin shows the importance of integrating surface seepage data into the analysis of a petroleum system. It also demonstrated the application of the petroleum migration models in identifying new areas for exploration within a well studied petroleum province.

APPENDICES

A: Basic Equations of Hydrodynamics

Some basic equations for hydrodynamics in petroleum exploration (for more details see Hubbert (1953)):

The pressure of a fluid, P in the subsurface is given by:

$$P = -\rho gz \qquad\qquad\qquad (i)$$

where ρ is the uniform density of the fluid, g is the acceleration due to gravity, z is the depth relative to a datum, usually sea level. If z is measured in m, ρ in kg/m^3, and g in m/s^2, then ρ is in Pa.

In response to pressure P the fluid will rise in an imaginary tube inserted in the reservoir, to height h above the datum, or (h-z) above the point of measurement;

$$P = \rho g\,(h\text{-}z) \qquad\qquad\qquad (ii)$$

therefore rearranging (ii);

$$h = z + P/\rho g \qquad\qquad\qquad (iii)$$

The value h is referred to as the head, or hydraulic head when the fluid is water. A map of contours of h is called the potentiometric surface when the fluid is water. This surface

is flat if there is no water flow. Fluids are motivated by their desire to minimise their potential energy.

The potential energy per unit mass, Φ, of a fluid at a given point is given by:

$$\Phi = gz + P/\rho \qquad \text{(iv)}$$

therefore the potential energy per unit mass of water, Φ_w of density ρ_w is given by:

$$\Phi_w = gz + P/\rho_w \qquad \text{(v)}$$

Similarly the potential of the petroleum phase Φ_p of density ρ_p is:

$$\Phi_p = gz + P/\rho_p \qquad \text{(vi)}$$

This assumes that capillary effects are negligible (Hubbert, 1953).

The potential energies of petroleum and water can be expressed in terms of the head, h:

$$\Phi_w = gh_w \qquad \text{(vii)}$$

$$\Phi_p = gh_p \qquad \text{(viii)}$$

therefore using equations (v)-(viii) above the two equations below can be derived.

$$gh_w = gz + P/\rho_w \qquad \text{(ix)}$$

$$gh_p = gz + P/\rho_p \qquad \text{(x)}$$

Since the pressure, P, for each is constant these two equations can be solved simultaneously, firstly by rearranging (ix):

$$P = \rho_w(gh_w - gz) \qquad\qquad \text{(xi)}$$

substituting (xi) into (x):

$$gh_p = gz + \frac{\rho_w(gh_w - gz)}{\rho_p}$$

therefore:

$$h_p = z + \frac{\rho_w(h_w - z)}{\rho_p}$$

or

$$h_p\rho_p = \rho_p z + \rho_w h_w - z\rho_w$$

Rearranging this equation, an equation for petroleum head that can be used to construct petroleum potentiometric surfaces can be obtained:

$$h_p = \frac{z(\rho_p - \rho_w)}{\rho_p} + \frac{h_w\rho_w}{\rho_p} \qquad\qquad \text{(xii)}$$

B: Mathematical Determination of the Deflection of a Migration Pathway under Hydrodynamic Conditions

To find the angle of deflection ψ of a migration pathway in hydrodynamic conditions I used trigonometric methods. In the case of a planar dipping surface and a planar dipping potentiometric surface with an angle of α between the strike (or dip) of the surfaces, the equation (xii) above can be used to derive the angle of deflection ψ (Figure 59).

Using the cosine formula;

$$\cos\psi = \frac{w^2 + v^2 - u^2}{2wv} \qquad\qquad\text{(xiii)}$$

the terms u and w can be determined by trigonometric techniques (Figure 59):

$$u = \Delta z \, / \, \tan\beta\sin\alpha \qquad\qquad\text{(xiv)}$$

$$w = \Delta h_w \, / \, \tan\gamma\sin\alpha \qquad\qquad\text{(xv)}$$

To find Δh_w:

$$h_{p2} = h_{p1} \qquad\qquad\text{for the oil potentiometric contour}$$

therefore using (xii) above;

$$z_2(\rho_p - \rho_w) + h_{w2}(\rho_w) = z_1(\rho_p - \rho_w) + h_{w1}(\rho_w)$$

$$\rho_p \qquad\qquad \rho_p \qquad\qquad \rho_p \qquad\qquad \rho_p$$

therefore:

$$z_2 - z_1(\rho_p - \rho_w) = h_{w1} - h_{w2}(\rho_w)$$

$$\rho_p \qquad\qquad\qquad \rho_p$$

or $\quad \Delta z\, (\rho_p - \rho_w) = -\, \Delta h_w\, (\rho_w)$

$$\rho_p \qquad\qquad\quad \rho_p$$

rearranging: $\Delta h_w = -\Delta z\, (\rho_p - \rho_w)$ $\qquad\qquad\qquad\qquad$ (xvi)

$$\rho_w$$

The term $\rho_p - \rho_w\, /\rho_w$ is a measure of the buoyancy of the petroleum phase. For the purposes of this thesis it is assigned as F. Therefore (xvi) can be simplified:

so $\Delta h_w = -\Delta z F$ $\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad$ (xvii)

substituting (xvii) in (xv) above:

$w = -\Delta z F / \tan\gamma \sin\alpha$ $\qquad\qquad\qquad\qquad\qquad\qquad\qquad$ (xviii)

To determine $\cos\psi$ in equation (xiii) we need to find v. This can be achieved using the cosine formula:

$$v^2 = w^2 + u^2 - 2wu\cos(180-\alpha)$$ (xix)

substituting (xiv) and (xv) into (xix) and simplifying;

$$v^2 = \Delta z^2 \ ((F^2/\tan^2\gamma) + (1/\tan^2\beta) + (2F\cos(180-\alpha)/\tan\beta\tan\gamma))$$ (xx)
$$\sin^2\alpha$$

multiplying (xx) through by $\tan^2\beta/\tan^2\beta$ and simplifying:

$$v^2 = \Delta z^2 \ ((F^2\tan^2\beta/\tan^2\gamma)+ 1+(2F\tan\beta\cos(180-\alpha)/\tan\gamma)$$ (xxi)
$$\tan^2\beta\sin^2\alpha$$

In the above equation the term $\tan\beta/\tan\gamma$ is the ratio of the gradient of the bedding surface to the gradient of the potentiometric surface, which for the purposes of this thesis will be referred to as R, therefore:

$$v^2 = \underline{\Delta z^2} \quad (F^2R^2 + 1+ 2FR\cos(180-\alpha))$$
$$\tan^2\beta\sin^2\alpha$$ (xxii)

By substituting equations (xiv),(xviii) and (xxii) into (xiii) and simplifying, the term $\cos\psi$ can be determined:

$$\cos\psi = \frac{(F^2 / \tan^2\gamma) + ((1/\tan^2\beta)(F^2R^2 + 2FR\cos(180-\alpha)+1)) - (1/\tan^2\beta)}{(-2F/\tan\gamma\tan\beta)(F^2R^2 + 2FR\cos(180-\alpha)+1)^{0.5}} \qquad (xxiii)$$

multiplying (xxiii) through by $\tan^2\beta/\tan^2\beta$ and rearranging:

$$\cos\psi = \frac{2F^2R^2 + 2FR\cos(180-\alpha)}{-2FR(F^2R^2 + 2FR\cos(180-\alpha)+1)^{0.5}} \qquad (xxiv)$$

Simplifying and rearranging the above (xxiv):

$$\cos\psi = \frac{\cos\alpha - FR}{((FR)^2 - 2FR\cos\alpha+1)^{0.5}}$$

Therefore the angle of deflection of a migration path of a petroleum of density ρ_p passing through water of density ρ_w in a bed dipping at an angle β in response to a water flow directed down the dip of a potentiometric surface of gradient $\tan\gamma$ at an angle α (between 0-180°) to the dip of the bedding plane is given as:

$$\psi = \arccos\left((\cos\alpha - FR)/((FR)^2 - 2FR\cos\alpha+1)^{0.5}\right) \qquad (xxv)$$

where $R = \tan\beta/\tan\gamma$ and $F = \rho_p - \rho_w /\rho_w$

Note that in the limits of angle α, ψ is equal to $0°$ degrees if α is $0°$ degrees. If α is $180°$ then ψ is $180°$ if FR is less than -1 or $0°$ if FR is greater than -1. In the special case of FR=-1 when α is equal to $180°$ the flow of petroleum will be completely balanced, i.e. stationary.

C: The Magnitude of Water Flow in the Subsurface

To appreciate when water flow in a basin needs to be considered, it is important to determine the value of R, the ratio of the gradient of the bedding to the gradient of the potentiometric surface.

Magnitude of Water Flow from Topographic Drive

The dip of potentiometric surfaces for sedimentary basins generally do not exceed $1°$, even in sub-aerially exposed basins. The bedding dip usually exceeds the dip of the potentiometric surface so that R is greater than the value of 1. The typical range of gradients (tanγ) for onshore USA basins is 4×10^{-4} - 0.02 (using data from Hubbert (1953)), representing a range of dips (γ) of $0.02°$-$1°$. In shallow dipping areas where the bed dip closely parallels that of the surface topography the value of R is close to 1. However, the value of R does not usually fall below a value of 5. A notable exception is the Mesa Verde Formation of the San Juan Basin, USA, where the value of R is less than a value of 1. In this basin gas is found in a synclinal position which may be due to hydrodynamic trapping (Dahlberg, 1995). It should be noted that very locally in a basin the value of R could decrease significantly in areas of very flat bedding. In these basins of hydrodynamic flow, petroleum accumulations will have tilted contacts (Hubbert, 1953). Therefore only in special circumstances will gas be effected by water flow, but if

oil migration is being modelled then care must be taken if there is a significant dip of the potentiometric surface.

A potentiometric map must be related to a single aquifer. The aquifers in a basin may have different potentiometric surfaces that may exhibit potentiometric heads that are higher or lower than the one above it (Domenico and Schwartz, 1990).

Magnitude of Water Flow from Compacting Sediments

Darcy's law relates the volumetric flux of the groundwater movement (v) to the hydraulic conductivity (K) and to the hydraulic gradient or slope of the water table (tanγ, Figure 59):

$$v = K \tan \gamma \qquad \qquad \text{(xxvi)}$$

Expressing in terms of the volume of water Q flowing in unit time, through a cross-sectional area A:

$$Q = AK \tan \gamma \qquad \qquad \text{(xxvii)}$$

rearranging this equation;

$$\tan \gamma = Q/AK \qquad \qquad \text{(xxviii)}$$

From studying the above equation it can be seen that the hydraulic gradient will be steeper where the flow is greater, but is less where there is a higher hydraulic

conductivity. The hydraulic conductivity depends not only upon the rock property of permeability (k) but also upon the density (ρ) and viscosity (μ) of the fluid, in this case water:

$$K = k\rho/\mu \qquad \text{(xxix)}$$

The value of permeability is much more variable than the term ρ/μ. Therefore, generally when the permeability increases the value of K increases so that $\tan\gamma$ (in equation (xxviii)) decreases, and therefore the value of R increases. However, this will be compensated by the fact that the flow (Q) will increase.

Taking equation (xxviii) above and multiplying both sides by $\tan\beta$ and rearranging:

$$\tan\beta/\tan\gamma = AK\tan\beta/Q \qquad \text{(xxx)}$$

since R is defined as $\tan\beta/\tan\gamma$:

$$R = AK\tan\beta/Q \qquad \text{(xxxi)}$$

Typically for a 100mD sandstone in the subsurface, the value of the hydraulic conductivity is of the order of 10^{-6} m/s. Assuming A = 1 m^2 and angle $\beta = 2^0$, R can be estimated providing the value of Q can be estimated.

Assuming the water driven out from a 1000m (original thickness) shale sequence of initial porosity 45%, passes into a single aquifer sandstone sequence during a 10 Ma time period in which the rock volume reduces to 0.65 of its original thickness (final

porosity 15%), then the total volume of pore space lost for a 1 m^2 area above the aquifer is 353 m^3. This represents a flow rate Q of 35.3 m^3/Ma/m^2 or 1.12×10^{-12} m^3/s/m^2. This estimated flow is consistent with calculations made by Bjorlykke (1993). In this example R = 30,000, so the water flow will have no effect upon a petroleum migration pathway (Figure 4). In comparison the flow of water in response to a topographic drive can be many orders of magnitude greater.

To begin to have an important effect the value of R needs to reduce to between 20 and 2 depending upon the density of the petroleum (Figure 6a). Even if the bed dip is reduced to 0.5^0 and the water flow increased by an order of magnitude and the hydraulic conductivity increased two orders of magnitude, then R will still only reduce to the value of 100. The flow rate calculated above is higher than in most cases. Migration is also most likely to occur in the more permeable horizons, and bedding dips can be somewhat higher than 2^0. All these factors will increase the value of R. Typically the value of R will be in the range 10^4 - 10^8. At such values the maximum deflection on even a heavy oil migration pathway will be less than 0.04^0. This flow will result in a pressure difference from stationary water (hydrostatic), however at 3000m such a difference will be less than 0.007 kg/cm^2 (0.1 psi).

Therefore within the accuracy of pressure and salinity measurements, basins where compaction is the only water drive mechanism can be considered as hydrostatic for migration modelling purposes.

D: Classifications of Surface Petroleum Occurrences

Below the classifications of surface petroleum occurrences are summarised. Only the classifications of Link (1952), Clarke and Cleverly (1991), and Macgregor (1993) were actually presented as formal classifications. The remaining were text subdivisions used by the authors in their descriptions of seepage.

Cunningham Craig (1912):

- Seepages of oil

- Asphalt deposits

- Evolution of gas from gas pools, mud volcanoes or dry ground

- Outcrops of bitumen

- Veins of manjak or ozokerite

Beeby Thompson (1925):

- Seepages of oil

-Outcropping Oil Sands on eroded anticlines

-Fractured anticlinal crests

-Thrust planes

-Plunging anticlines

- Veins of Native Bitumens; in clay beds or shales overlying or flanking oil fields

- Oil or Tar Sands

-As nearly horizontal beds

-Sealed up outcropping oil sands

- Gas Exudations

    -On apices of domes

    -On crests of sharp anticlines

    -From fractured strata

- Mud Volcanoes; where water gains admission and clays overlie a fractured anticlinal arch

- Sulphurous Waters; Where waters raised by gas from petroliferous strata

Landes (1951):

- Visible seeps

    -Oil seeps

    -Gas seeps

    -Oil-impregnated rocks

    -Solid and semi-solid asphalts and waxes

- Microseeps

Tiratsoo (1951):

- Gas Shows

- Oil Shows

    -Liquid oil

    -Impregnations

- Solid Shows

    -Asphalt "Lakes"

    -Veined Bitumens or Asphaltites

-Mineral Waxes

- Oil Shales

-Oil-shales which owe their oiliness to nearby oil seepages and are purely a local

significance

-Oil-shales which consist of mechanical mixtures of pyrobitumens with mineral

matter

-Oil-shales which contain "kerogenous" material

Link (1952):

- Seeps emerging from homoclinal beds, the ends of which are exposed where these

beds reach the surface

- Seeps of oil found associated with beds and formations in which the oil was formed

- Oil and gas seeps coming from definite large oil accumulations which have been bared

by erosion or the reservoirs ruptured by faulting and folding

- Oil seeps along unconformities

- Seeps associated with intrusions, such as mud volcanoes, igneous intrusions and

pierced salt domes

Levorsen (1967):

- Seepages, springs, and bitumen exudates

-Outcrop of a pool

-Outcrop of an unconformity

-Outcrop of a normal fault

-Overlying a faulted anticline

-Outcrop of a thrust fault

-Associated with diapir folding

-Overlying a salt plug, associated with the faults that occur above the intrusion

- Mud Volanoes and Mud Flows

- Occurrences of Solid Petroleum

-Disseminated Occurances

-Bituminous Dikes

- Miscellaneous Surface Occurrences

- "Oil Shale," or Kerogen Shale

Clarke and Cleverly (1991):

- Unaltered seeps

-Flowing gas

-Flowing gas and oil (either with/without salty spring)

-Mud volcano

- Altered by surface dispersal

-Flowing gas-free oil

-Oil at water table spring

-Free soil gas above water table

-Oil impregnations in soil or rock (overlying seep, above water table)

- Altered by subsurface processes

-Sour gas seeps

-Sulphur springs

-Biogenic gas seep or seep component

-Seep pathway mineralization

-Superficial mineralization

Macgregor (1993):

-Flowing seeps

    -Diapiric association (mud or salt diapirs)

        -Mud volcanoes and associated features

        -Collapse faults over diapirs

    -Compressive association (includes transpression)

        -Reverse fault planes

        -Shattered anticlinal crests

    -Extensional association (includes transtension); normal fault planes

        -Uplifted margin association; outcropping carrier beds, especially along unconformities

-Impregnations

    -Uplift and erosion of 'fossil' petroleum systems

        -Exposed accumulations (includes many tar sands)

        -Exposed migration pathways or source rocks

    -Igneous association; igneous contacts

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23, p. 182-193.

ACKNOWLEDGEMENTS

FIGURES

Figure 1: Location of the sedimentary basins studied during research project.
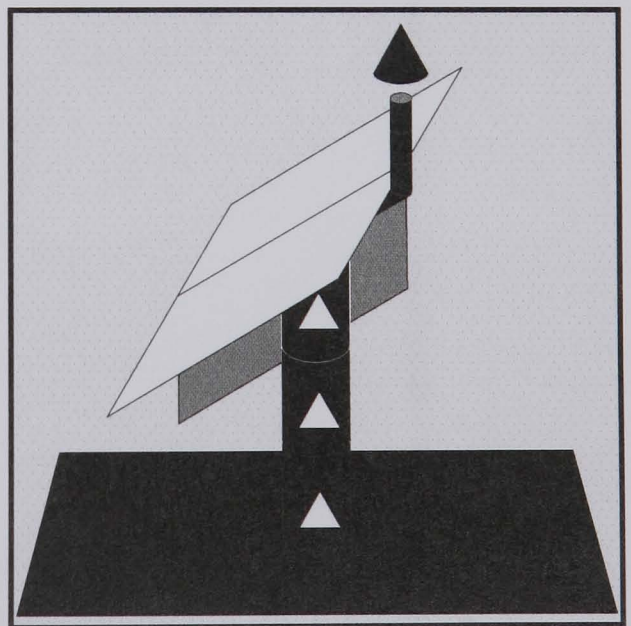
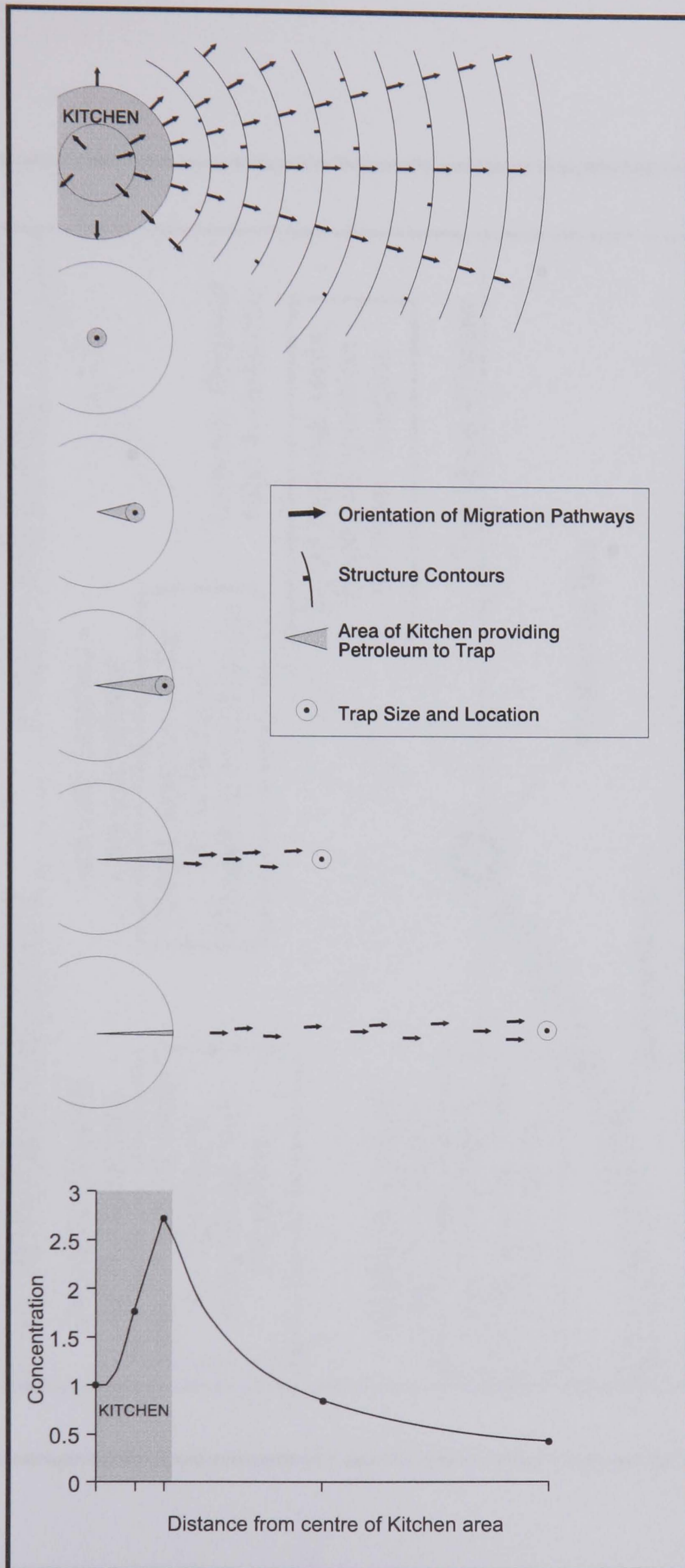Figure 2: The effect of sealing surface morphology on petroleum migration.

Figure 3: A concentration profile for a circular basin assuming a single sealing surface. For an explanation see text on p.15.
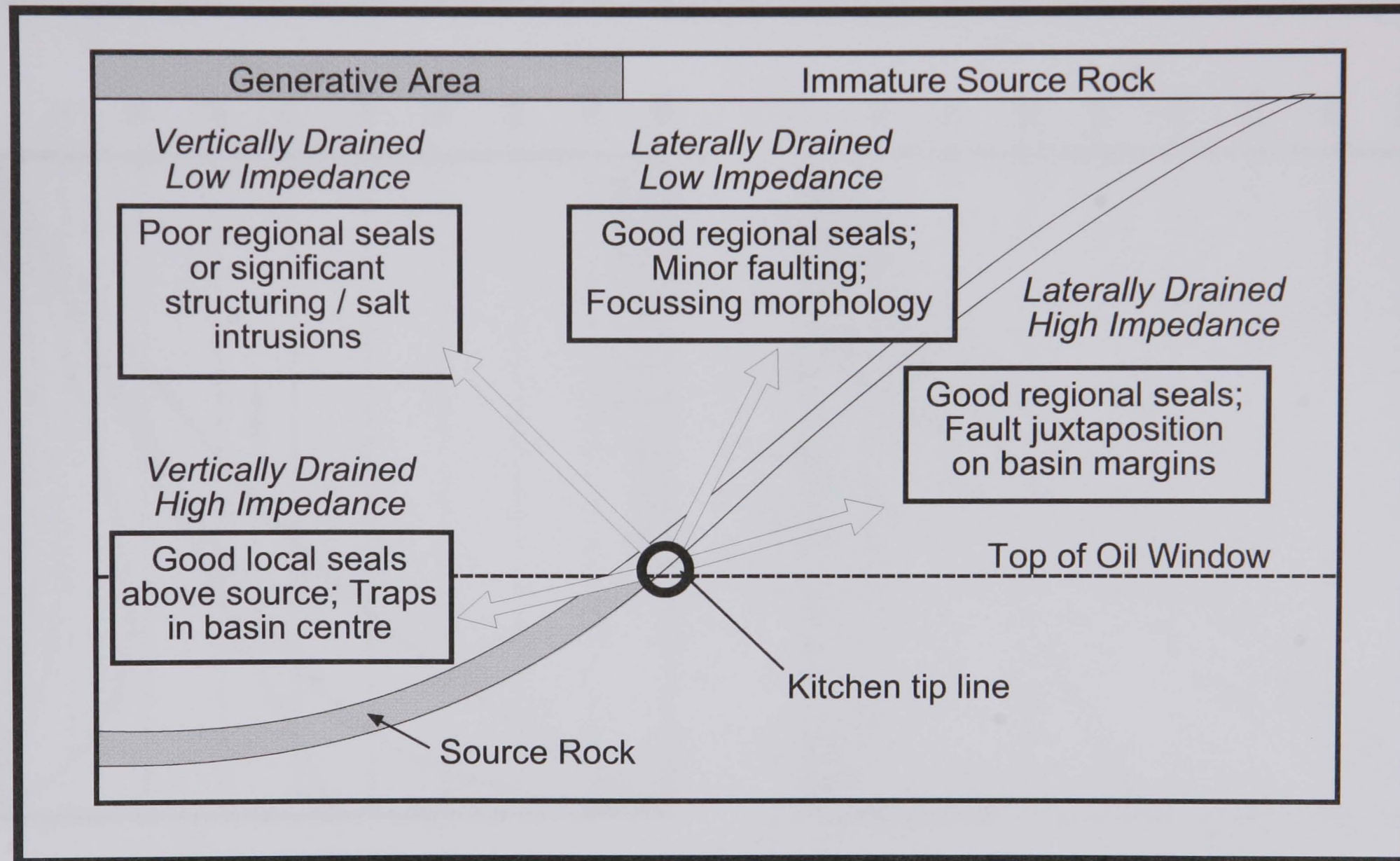
Figure 4: The optimum petroleum concentration point in a basin. Terms in italics relate to the migration styles of Demaison and Huizinga (1991).
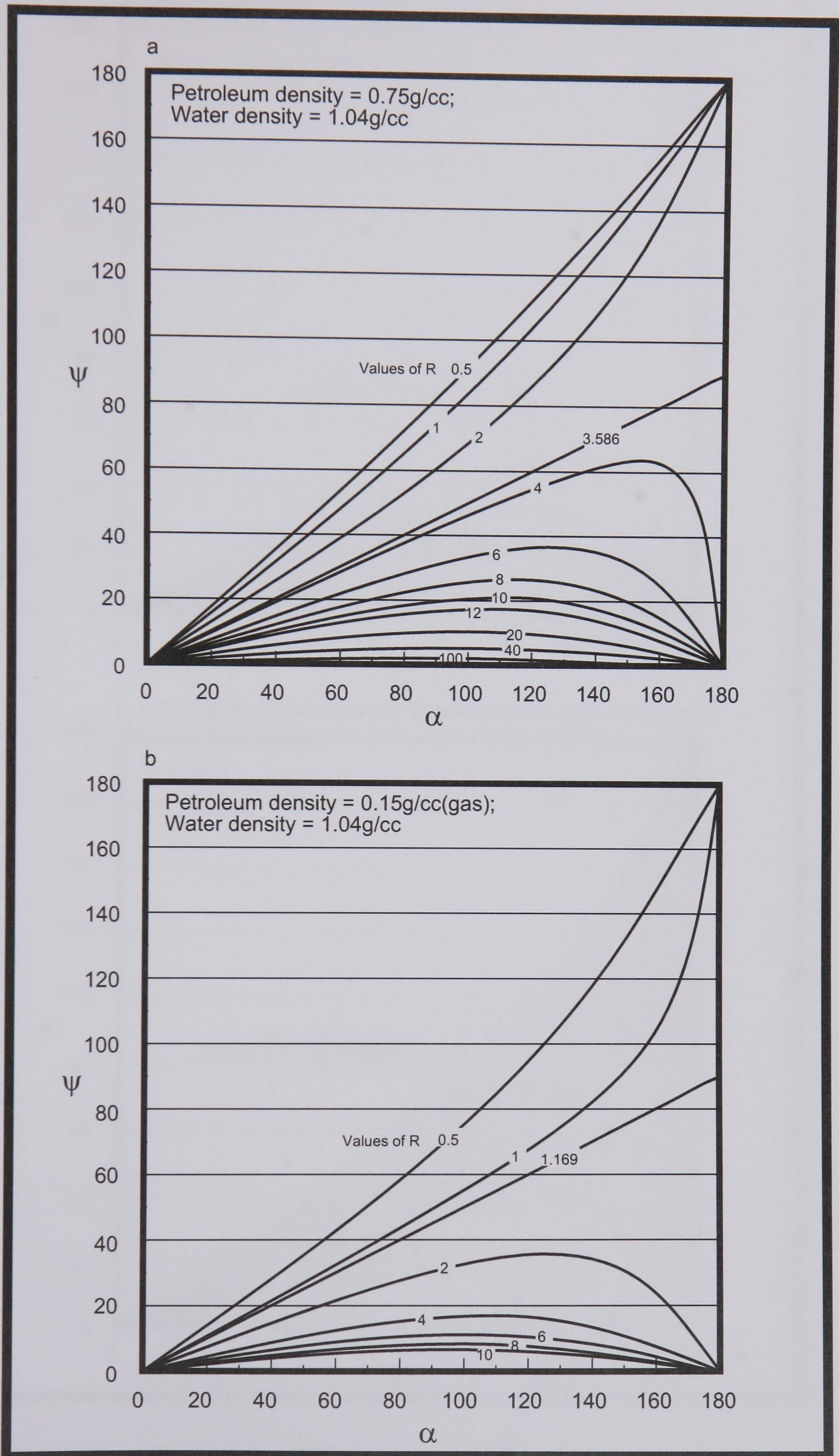
Figure 5: Deflection of migration pathways (angle ψ) versus orientation of the water flow (angle α) for various values of R (gradient of bedding/gradient of potentiometric surface).
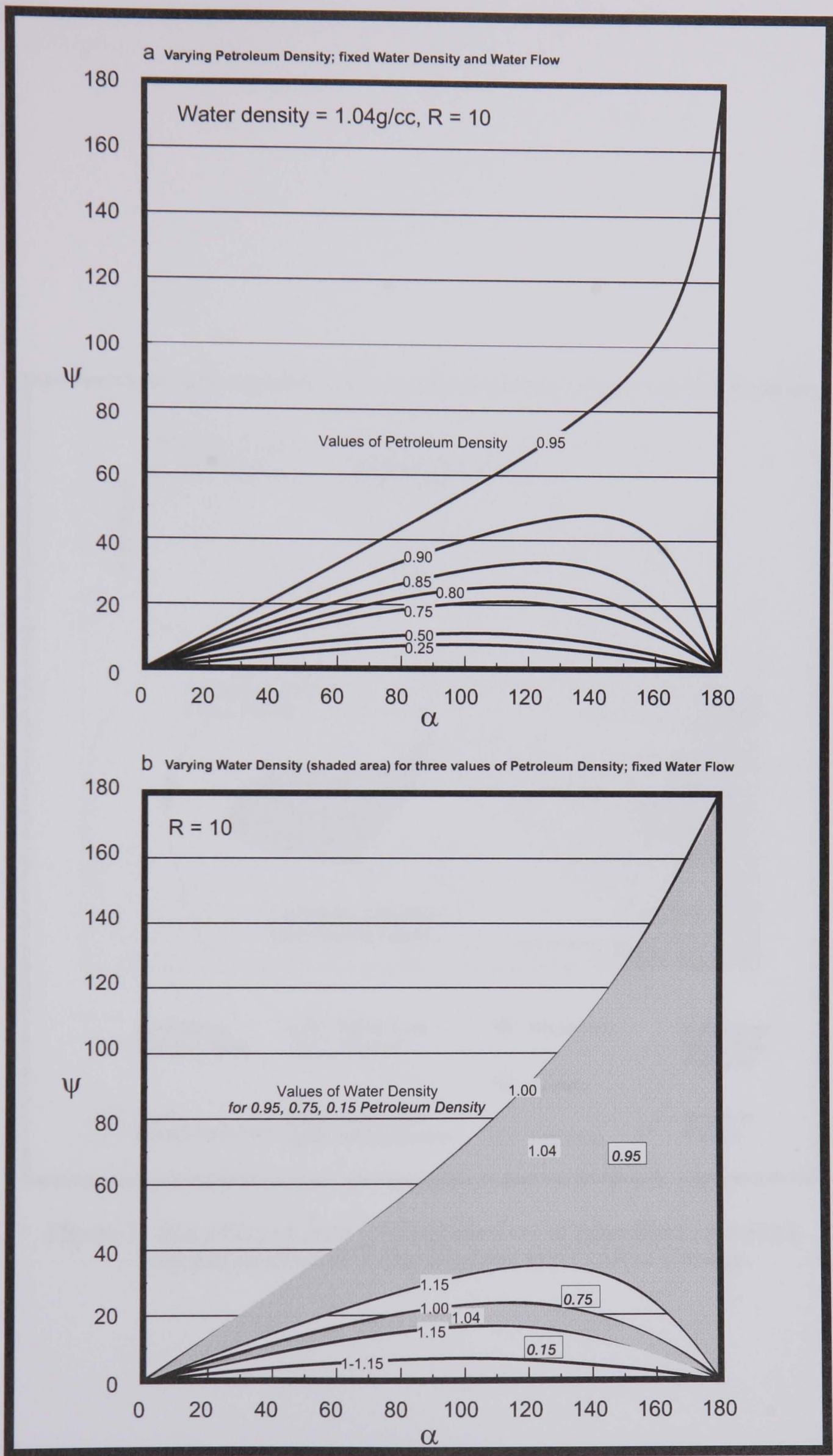
Figure 6: Deflection of migration pathways (angle ψ) versus orientation of the water flow (angle α) for varying petroleum density and water density, assuming R (gradient of bedding/gradient of potentiometric surface) has a constant value of 10.
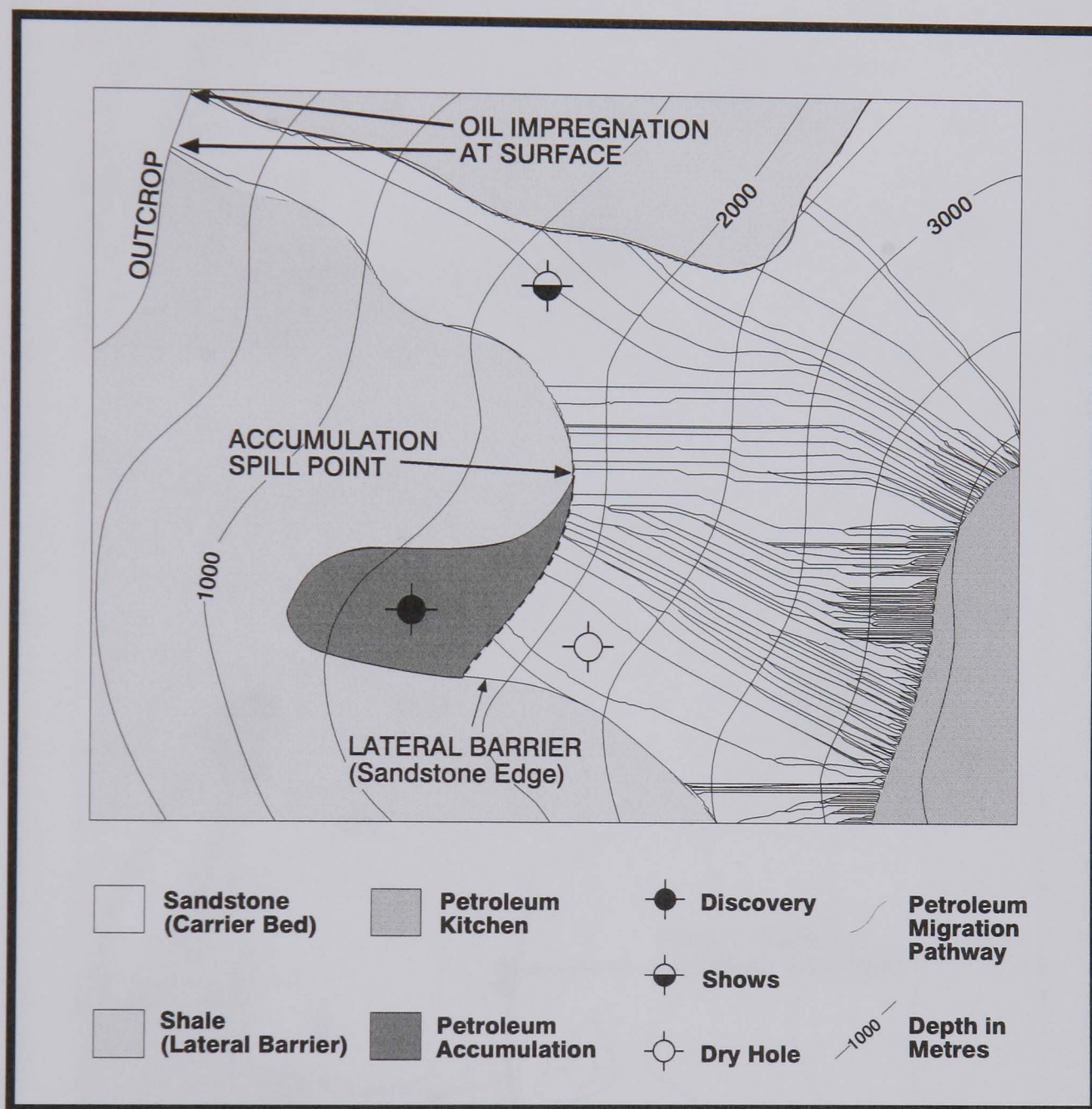
Figure 7: The effect of lateral facies barriers to migration pathways on the location of accumulations and surface seepage.

Figure 8: The effect of sealing faults on the deflection of migration pathways and the risk assessment of prospects. a: Fault is non-sealing; no effect on migration, b: Fault is sealing; pathways are deflected to a different structure.

Figure 9: The role of faults in vertical migration illustrating the dangers of making two-dimensional interpretations.

Figure 10: Schematic examples of some of the special circumstances where macro seepage or impregnations of oil lie vertically above an accumulation.

Figure 11: The effect of fault plane shape upon the distribution of migration pathways assuming the migration takes place along the fault plane.

Figure 12: Modelling migration pathways at two stratigraphic levels; illustrating the importance of intrabasinal highs on the focusing of petroleum migration pathways. Petroleum migrating from A', A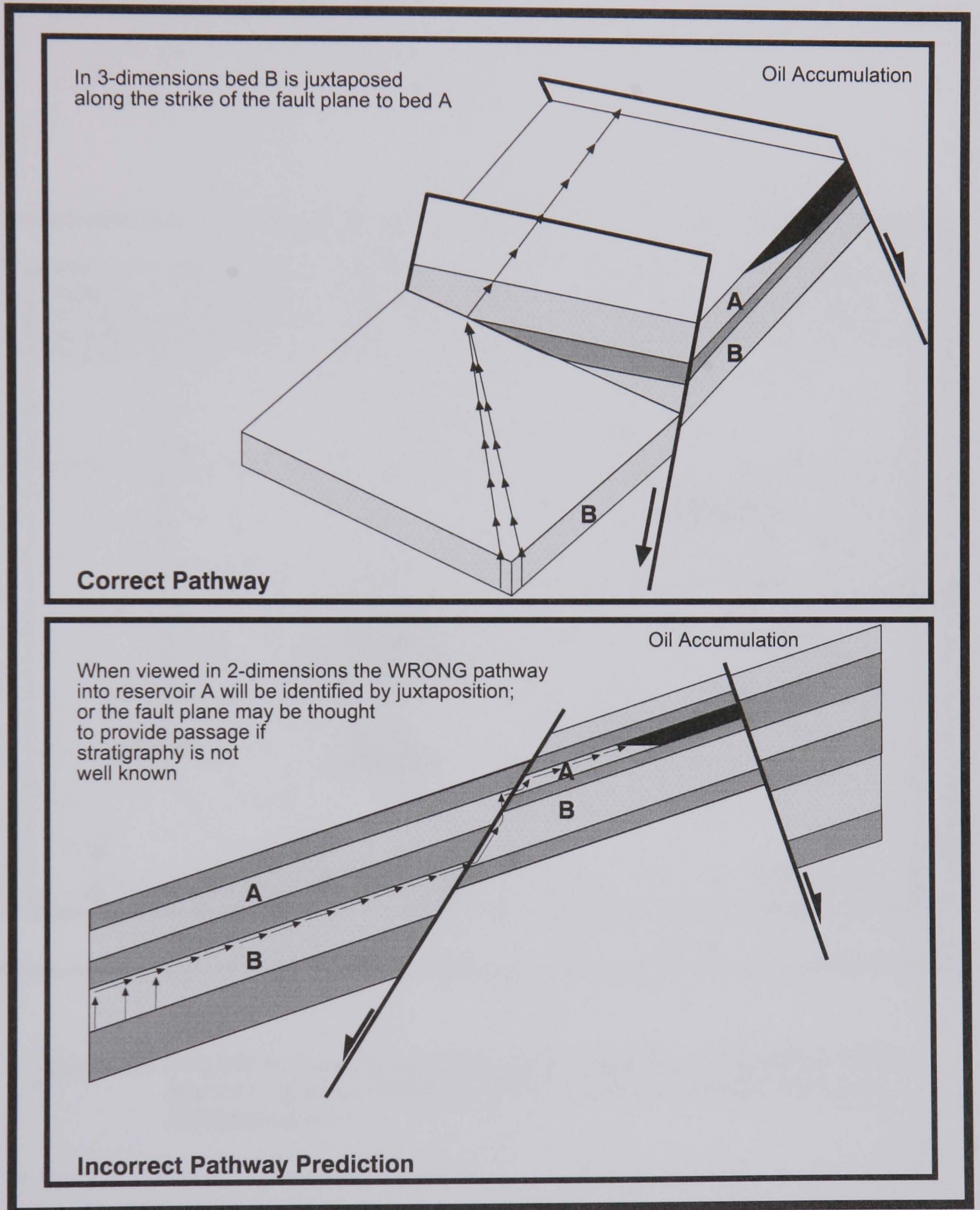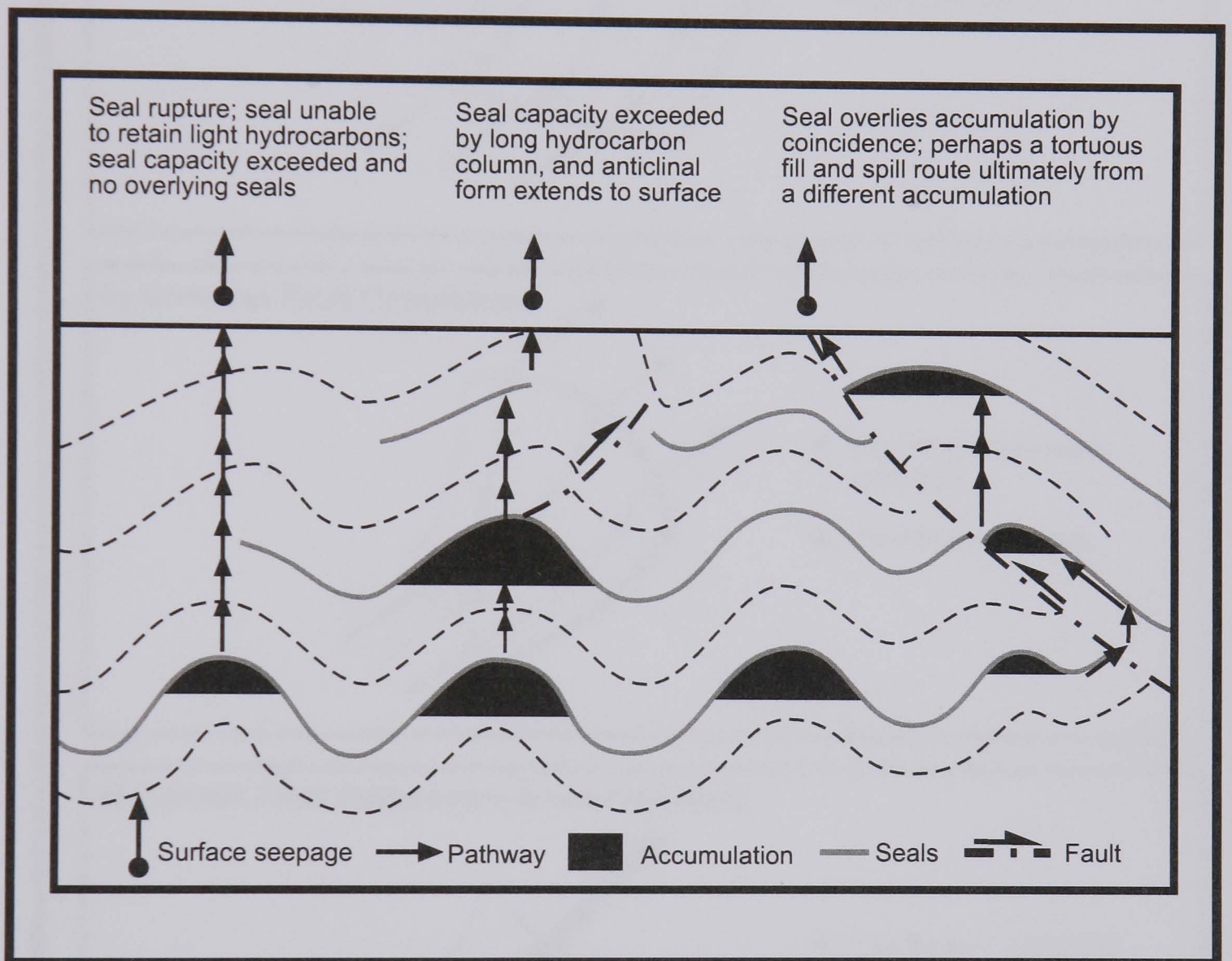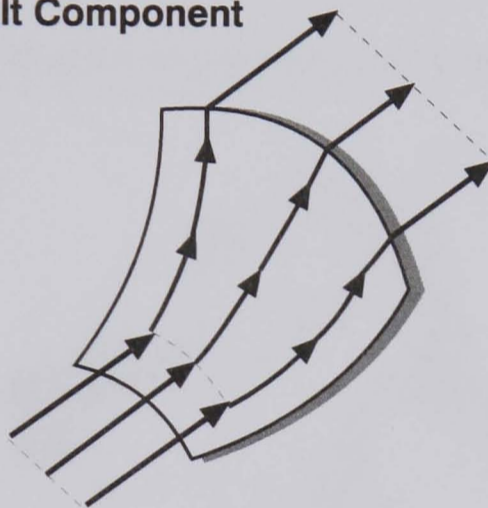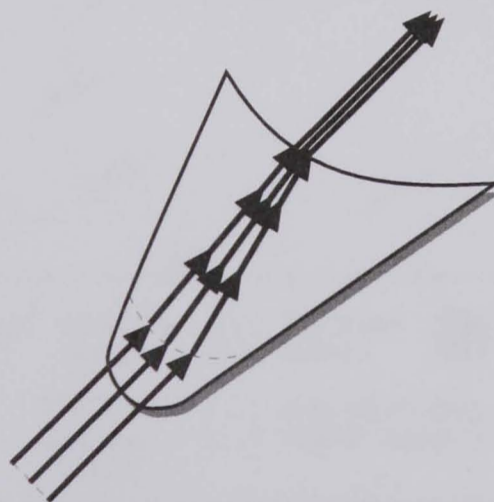'', A''' or A'''' below the older sealing surface reach accumulation A below the younger sealing surface via the breached area on the older sealing surface; The pathway originating at B' will reach B.

Figure 13: The use of backtracking to determine if a prospect can receive charge.

Figure 14: Using reverse modelling to determine the possible sources of seeping petroleum.

Figure 15: Migration pathway prediction in the Paris Basin for varying kitchen size; matching model results to discovered fields. a: Structure map at top of Middle Jurassic; b: Kitchen outline equal to Transformation Ratio (TR) of base source rock of 80%, c: Kitchen outline at TR of 25%, d: Kitchen outline at TR of 0%. Structure map contoured from well data.

Figure 16: Petroleum migration pathways in the Paris Basin. a: Expelled oil density map for Lower Jurassic source rock, b: Quantity of petroleum predicted to have moved along migration pathways.

Figure 17: Petroleum system oil concentration plot for the Paris Basin.

Figure 18: Structure map of the base of the Bakken Formation, Williston Basin. The map integrates data from Cohee (1962), Meissner (1978) and Hansen (1972).

Figure 19: Petroleum migration pathways in the Williston Basin. a: Expelled oil density map for the Bakken Formation source rock, b: Quantity of petroleum predicted to have moved along migration pathways.

Figure 20: Madison Formation aquifer, Williston Basin. a: Potentiometric surface for Madison Formation aquifer, b: Water density within the Madison Formation. See text for source of data.

Figure 21: Migration of petroleum in the Williston Basin assuming present day

hydrodynamic conditions. a: Oil potentiometric map, b: Quantity of petroleum

predicted to have moved along migration pathways (hydrodynamic case).

Figure 22: Location map of the West of Shetland area showing the main basement

structural elements and the location of cross sections; B-B' – Figure 33a and C-

C' – Figure 33b.

Figure 23: Stratigraphy of the Faeroes Basin area, West of Shetland.

Figure 24: Palaeocene to Lower Eocene stratigraphy based on biostratigraphy and well

log interpretation combined with seismic interpretation, West of Shetland;

Lithostratigraphy based on Knox et al., 1997; BP scheme extrapolated from the

Westray Ridge area taken from Ebdon et al., 1995.

Figure 25: Sequence set P3 sequence stratigraphical palaeogeography, West of

Shetlands Basin.

Figure 26: Present day predicted vitrinite reflectance at Top Kimmeridge Clay

Formation; Map ties extrapolated from actual well data.

Figure 27: Graph of hydrocarbon generation from the Lower Cretaceous to the present

day, assuming a Kimmeridge Clay Formation source rock. Hydrocarbon

volumes are derived by the combination of calibrated thermal history, source

rock isopachs and source rock richness maps with experimental data on

hydrocarbon transformation from similar source rocks.

Figure 28: Base Cretaceous Unconformity, structure map in feet, contour interval equals

2,000 ft. Map compiled by author from numerous Texaco maps. The post

Palaeocene generative areas derived by author of the underlying Kimmeridge

Clay Formation are outlined. Note that depth of oil generation areas vary

significantly across the area due to a number of factors including variations in

the heat flow and burial histories.

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Figure 1: Location of sedimentary basins studied during research project.

a) No overlying seal

b) Planar dipping sealing surface

c) Anticlinal sealing surface

d) Plunging anticlinal sealing surface

e) Synclinal sealing surface

f) Lateral barrier to planar surface

Figure 2: The effect of sealing surface morphology on petroleum migration.

Figure 3: A concentration profile for a circular basin assuming a single sealing surface. For an explanation see text on p. 15.

Figure 4: The optimum petroleum concentration point in a basin. Terms in italics relate to the migration styles of Demaison and Huizinga (1991).

Figure 5: Deflection of migration pathways (angle ψ) versus orientation of the water flow (angle α) for various values of R (gradient of bedding/ gradient of potentiometric surface).

a Varying Petroleum Density; fixed Water Density and Water Flow

Water density = 1.04g/cc, R = 10

Values of Petroleum Density   0.95

0.90
0.85
0.80
0.75
0.50
0.25

b Varying Water Density (shaded area) for three values of Petroleum Density; fixed Water Flow

R = 10

Values of Water Density   1.00
for 0.95, 0.75, 0.15 Petroleum Density

1.04   0.95

1.15
1.00
1.04
1.15   0.75
0.15
1-1.15

Figure 6: Deflection of migration pathways (angle ψ) versus orientation of the water flow (angle α) for varying petroleum density and water density, assuming R (gradient of bedding/ gradient of potentiometric surface) has a constant value of 10.

Figure 7: The effect of lateral facies barriers to migration pathways on the location of accumulations and surface seepage.

Figure 8: The effect of sealing faults on the deflection of migration pathways and the risk assessment of prospects. a: Fault is non-sealing; no effect on migration, b: Fault is sealing; pathways are deflected to a different structure.

In 3-dimensions bed B is juxtaposed
along the strike of the fault plane to bed A

Oil Accumulation

A

B

B

Correct Pathway

When viewed in 2-dimensions the WRONG pathway
into reservoir A will be identified by juxtaposition;
or the fault plane may be thought
to provide passage if
stratigraphy is not
well known

Oil Accumulation

A

B

A

B

Incorrect Pathway Prediction

Figure 9: The role of faults in vertical migration illustrating the dangers of making two-dimensional interpretations.

Figure 10: Schematic examples of some of the special circumstances where macro seepage or impregnations of oil lie vertically above an accumulation.

a) Planar Fault Component
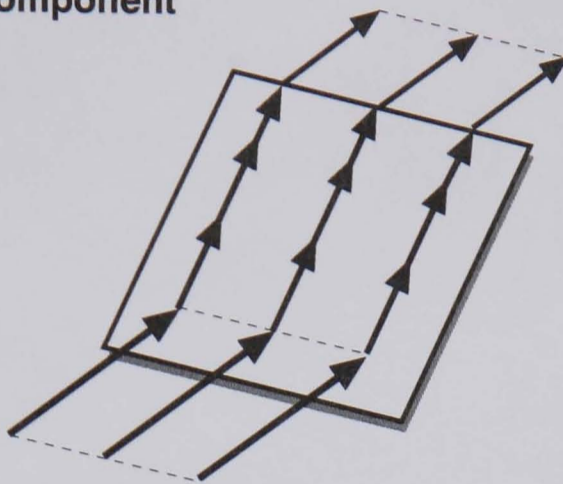
● Concentration and pathways maintained from point of entry

b) Concave Fault Component

● Dispersal of petroleum pathways

● Tendency for dilution

c) Convex Fault Component (Less Common)

● Focussing of petroleum pathways

● Tendency for concentration

Figure 11: The effect of fault plane shape upon the distribution of migration pathways, assuming the migration takes place along the fault plane.

a Structure Map of Older Sealing Surface
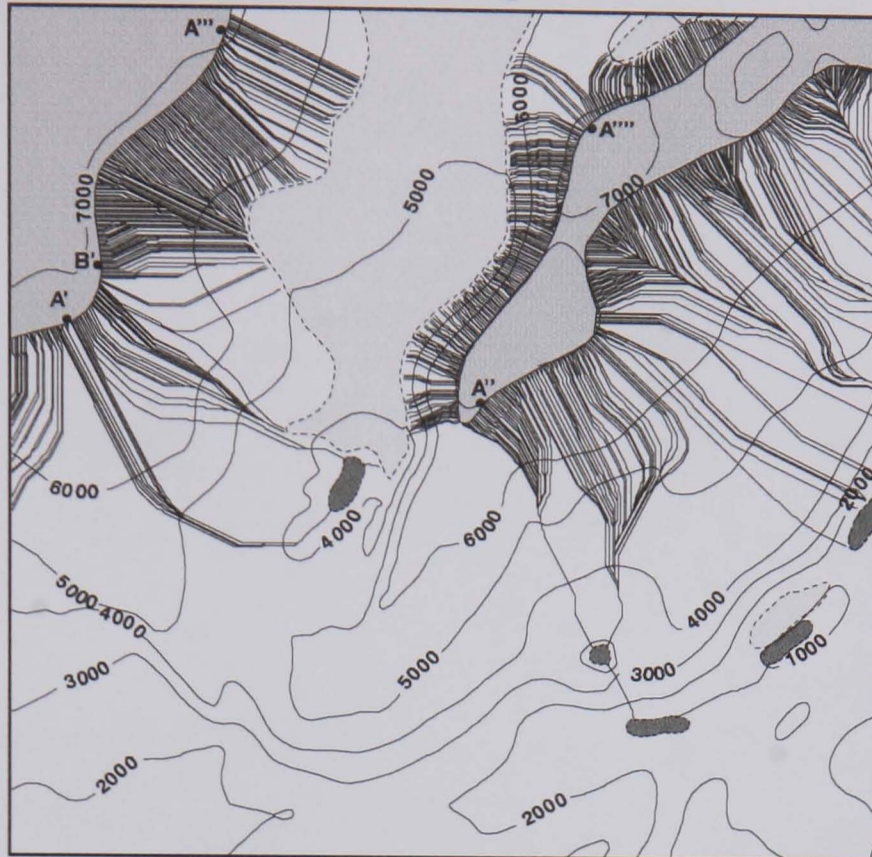
b Structure Map of Younger Sealing Surface

Figure 12: Modelling migration pathways at two stratigraphic levels, illustrating the importance of intrabasinal highs on the focusing of petroleum migration pathways. Petroleum migrating from A', A'', A''' or A'''' below the older sealing surface reach accumulation A below the younger sealing surface via the breached area on the older sealing surface; the pathway originating at B' will reach B.

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a Quantity of Oil Expelled on a Scale of 0 - 100

b Quantity of Migrated Oil on a Logarithmic Grey Scale of 0 - 15

Oil Field   Oil Show   0   50km

Figure 16: Petroleum migration pathways in the Paris Basin.
a: Expelled oil density map for Lower Jurassic
source rock, b: Quantity of petroleum predicted
to have moved along migration pathways.

Figure 17: Petroleum system oil concentration plot for the Paris Basin.

Figure 18: Structure map of the base of the Bakken Formation, Williston Basin. The map integrates data from Cohee (1962), Meissner (1978) and Hansen (1972).

a Quantity of Oil Expelled on a Scale of 0 - 100

b Quantity of Migrated Oil on a Logarithmic Grey Scale of 0 - 15

Oil Discovery   0   100km

Figure 19: Petroleum migration pathways in the Williston Basin. a: Expelled oil density map for the Bakken Formation source rock, b: Water density within the Madison Formation.

Figure 20: Madison Formation aquifer, Williston Basin. a: Potentiometric surface for Madison Formation aquifer, b: Water density within the Madison Formation. See text for source of data.

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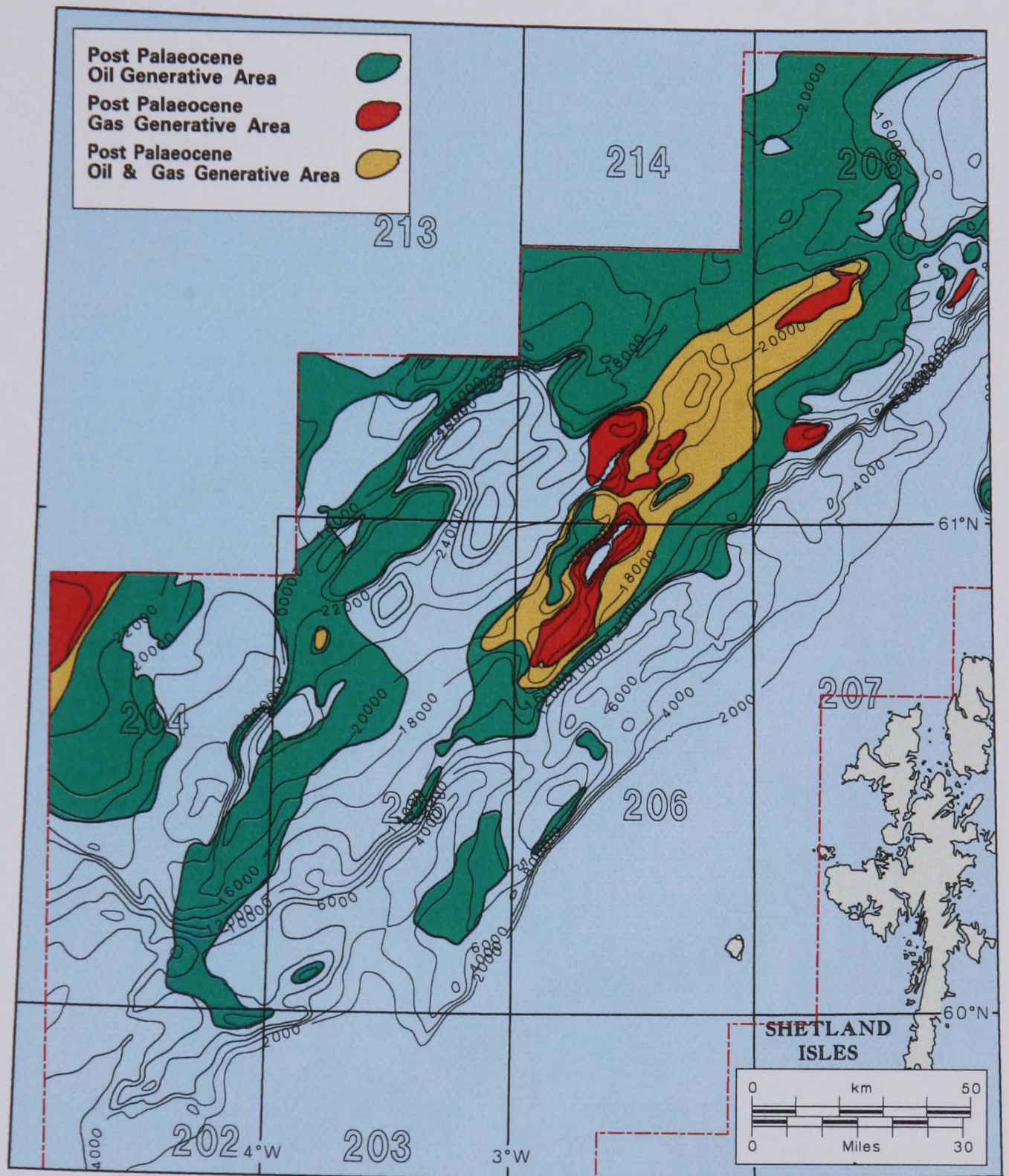
Figure 28: Base Cretaceous Unconformity, structure map in feet, contour interval equals 2,000ft. Map compiled by author from numerous Texaco maps. The post Palaeocene generative areas derived by author of the underlying Kimmeridge Clay Formation are outlined. Note that depth of oil generative areas vary significantly across the area due to a number of factors including variations in the heat flow and burial histories.
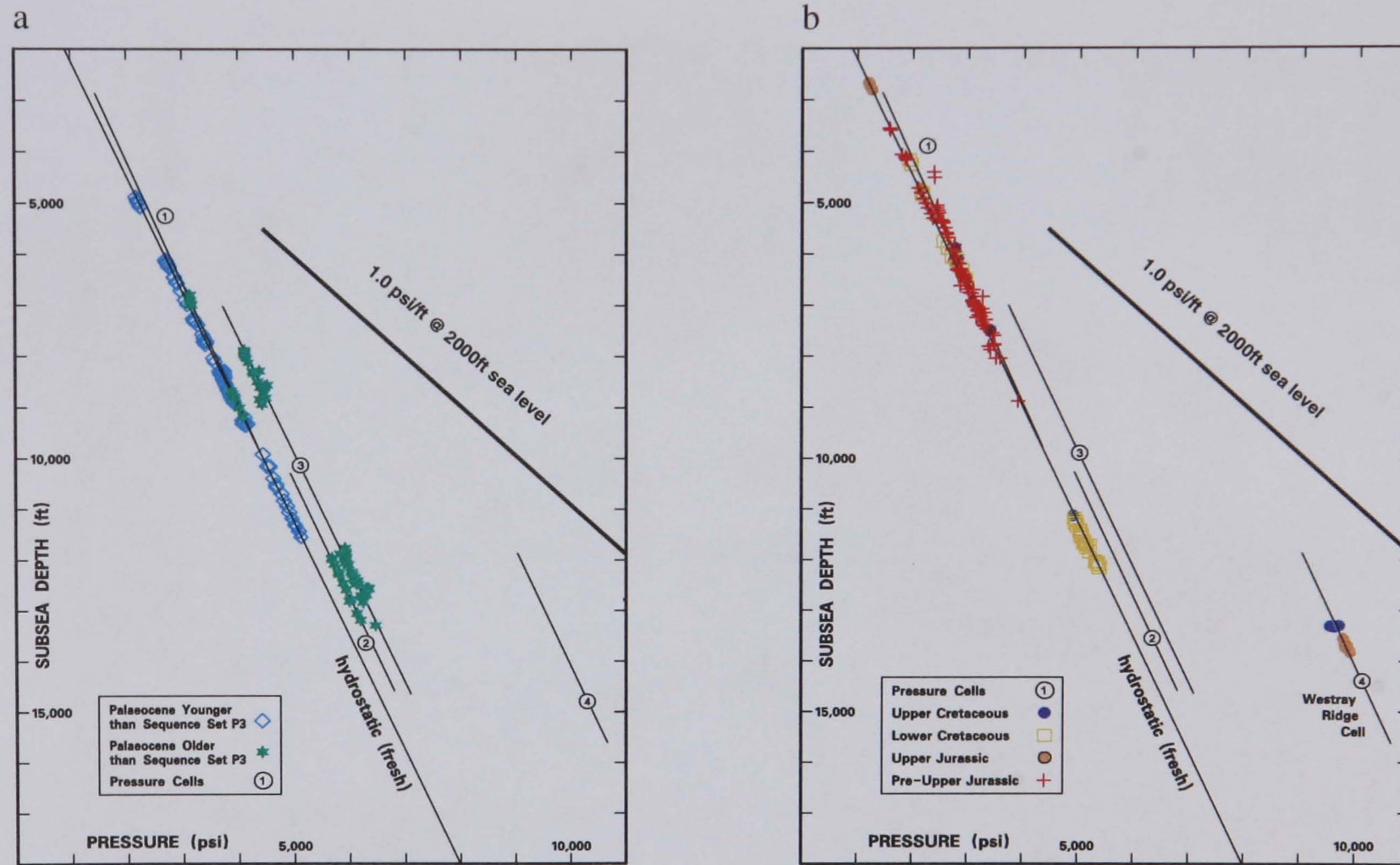
Figure 29: RFT pressure versus depth graphs, West of Shetlands Basin.
a: Palaeocene to Lower Eocene section, b: Mesozoic section.
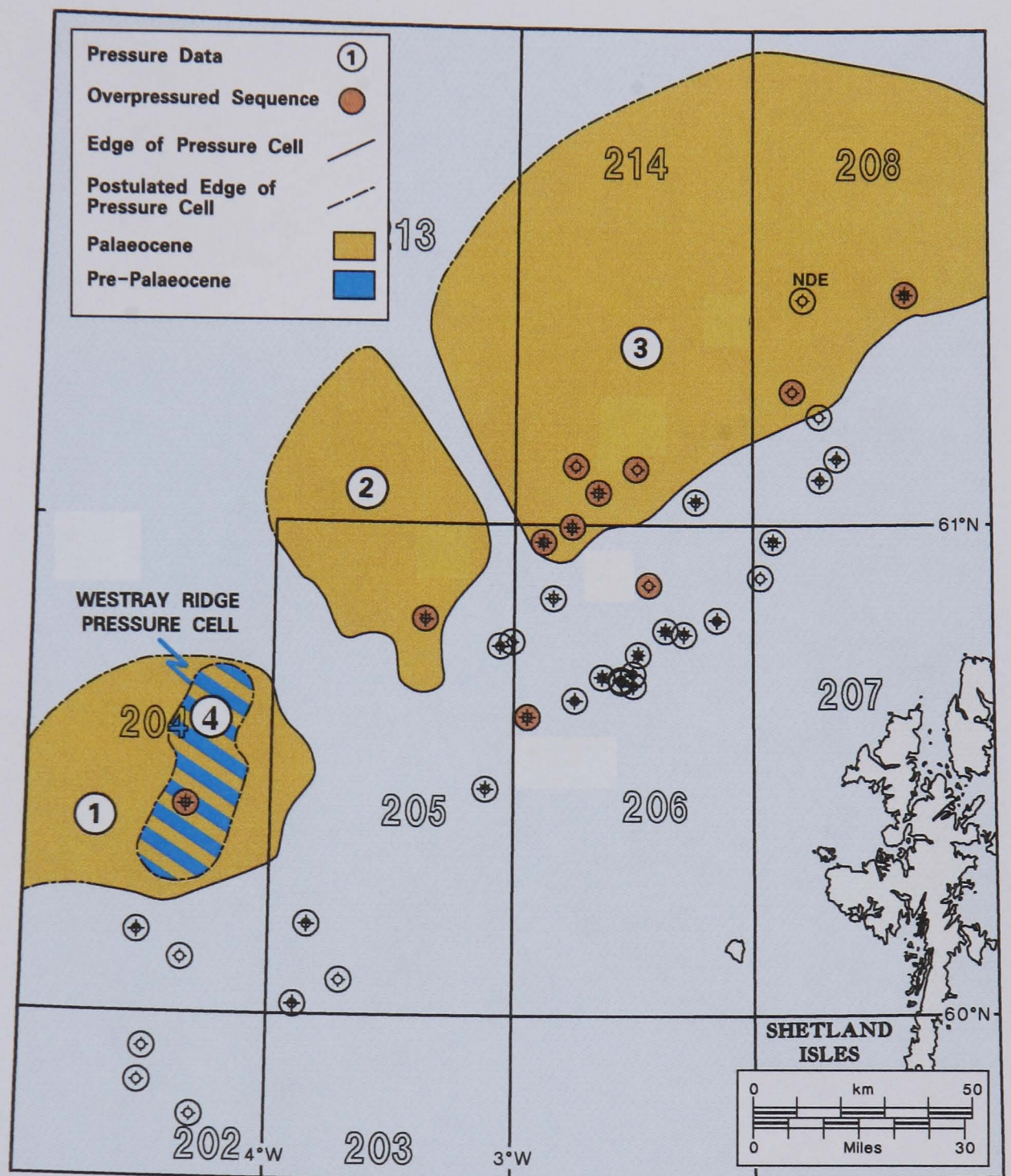
Figure 30: Areal distribution of abnormal pressure cells highlighted in Figure 29, West of Shetlands Basin. Overpressured sequences outside cell boundaries are in pre-Tertiary formations.
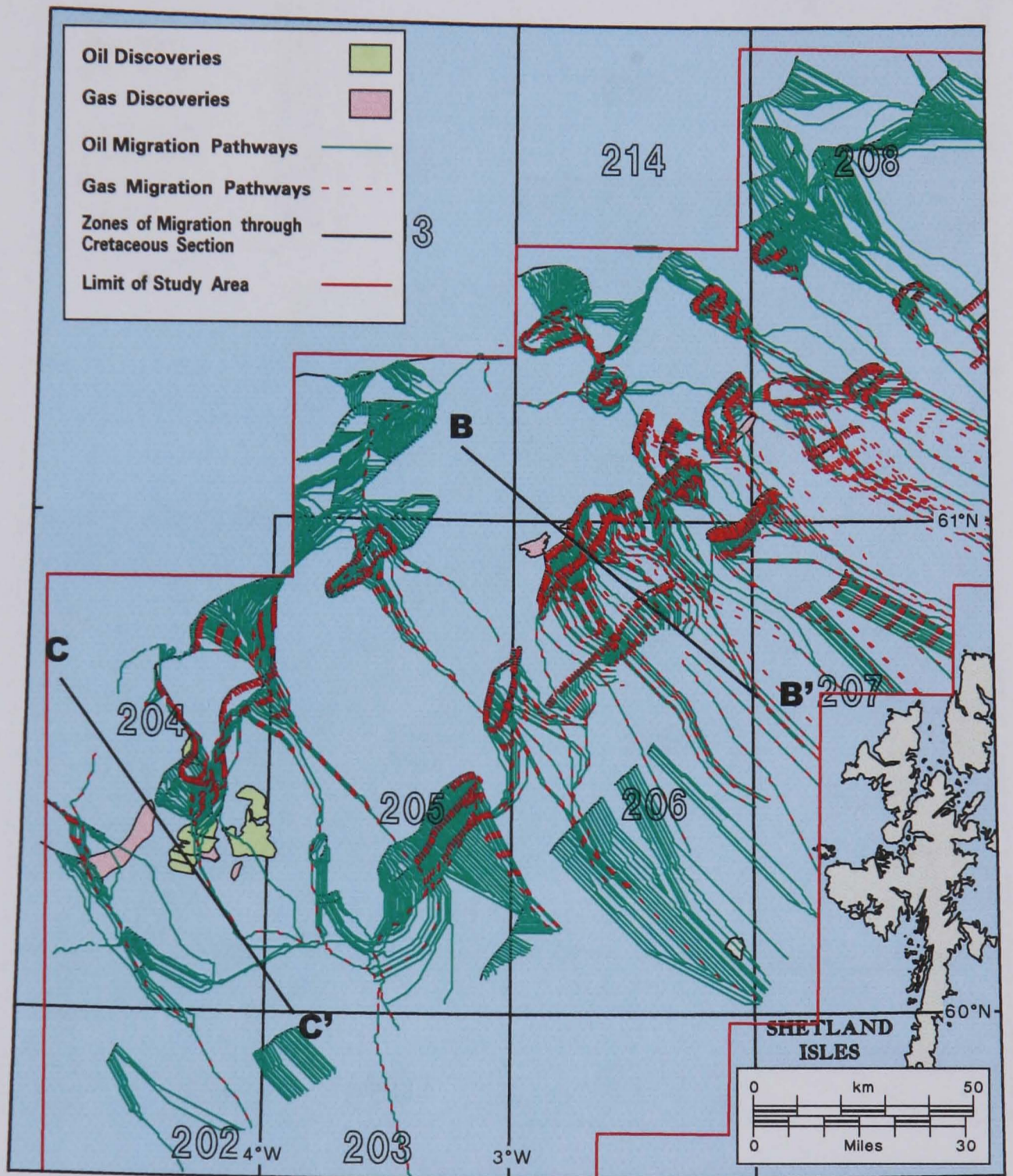
Figure 31: Post Palaeocene oil and gas migration pathways at the
Base Tertiary and the location of cross sections;
B-B' - Figure 33a and C-C' - Figure 33b.
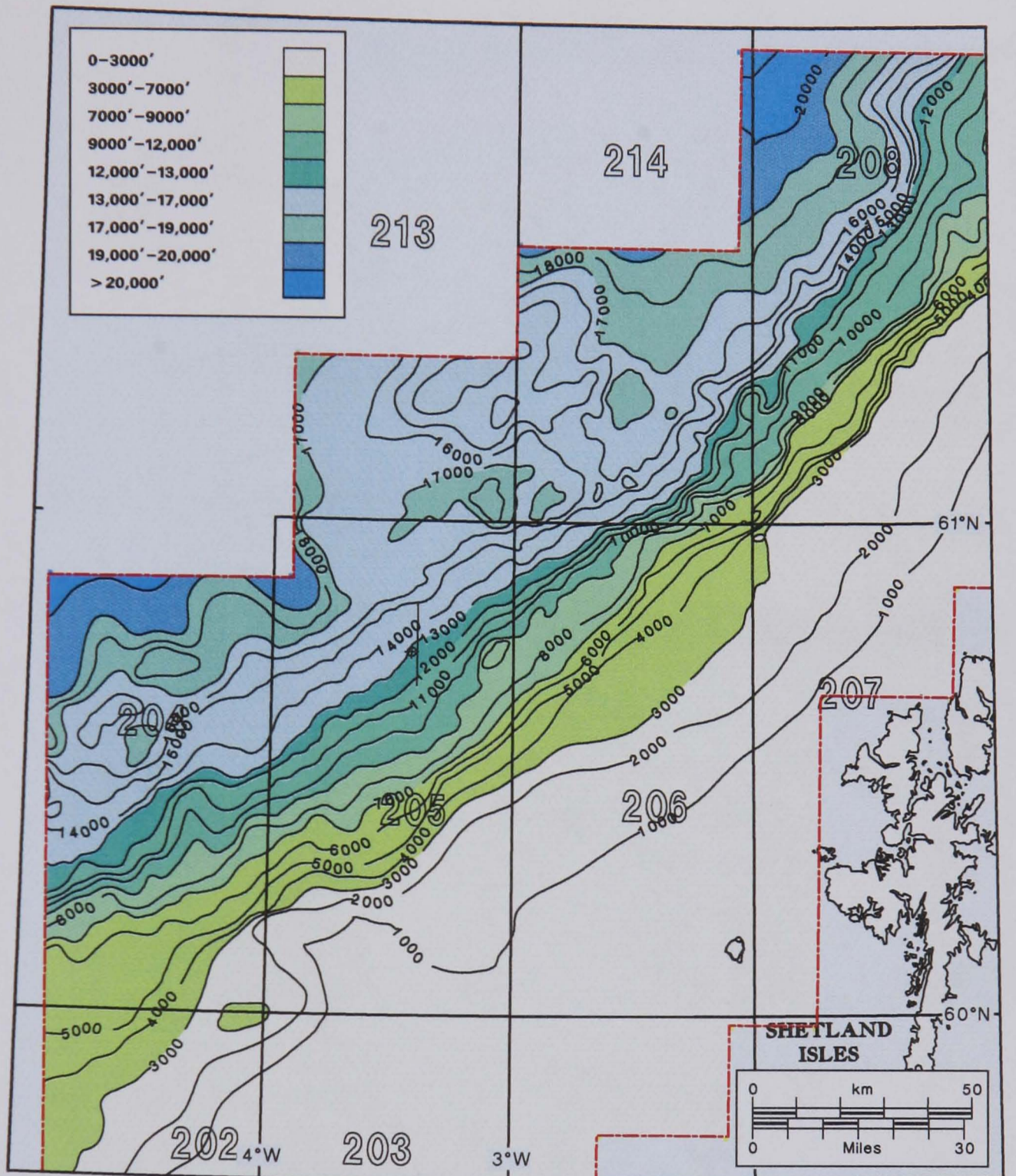
Figure 32: Base Tertiary Unconformity structure map. Compiled by author from numerous Texaco maps.
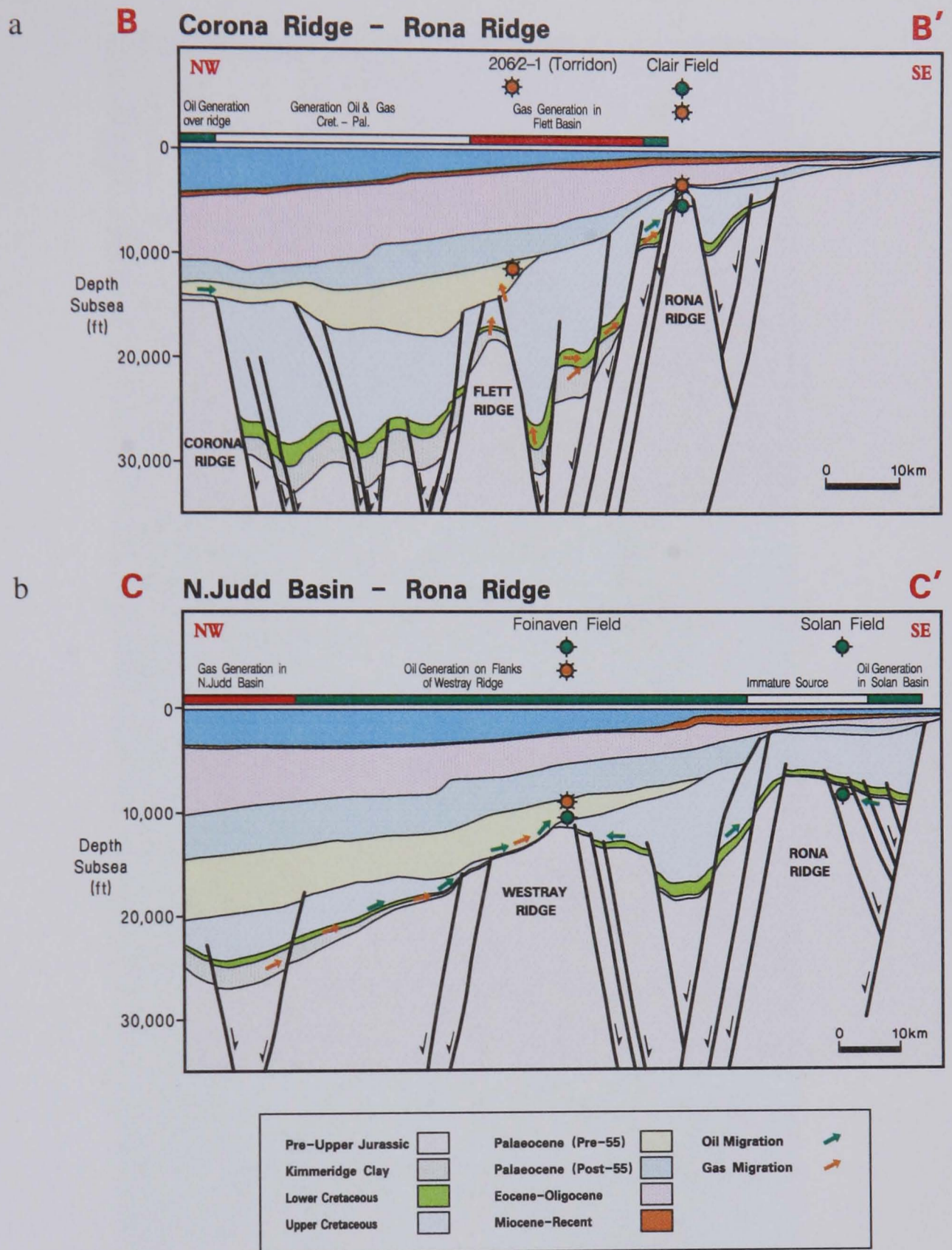
Figure 33: a: NW to SE line in the Corona Ridge to Rona Ridge area showing the migration model schematically in 2D for the post-Palaeocene, located on Figure 22; b: NW to SE line in the North Judd Basin to Rona Ridge area showing migration model schematically in 2D for the post-Palaeocene, located on Figure 22. Note the hydrocarbons migrate vertically into sequence set P3 where the Cretaceous section is thinner/ absent.
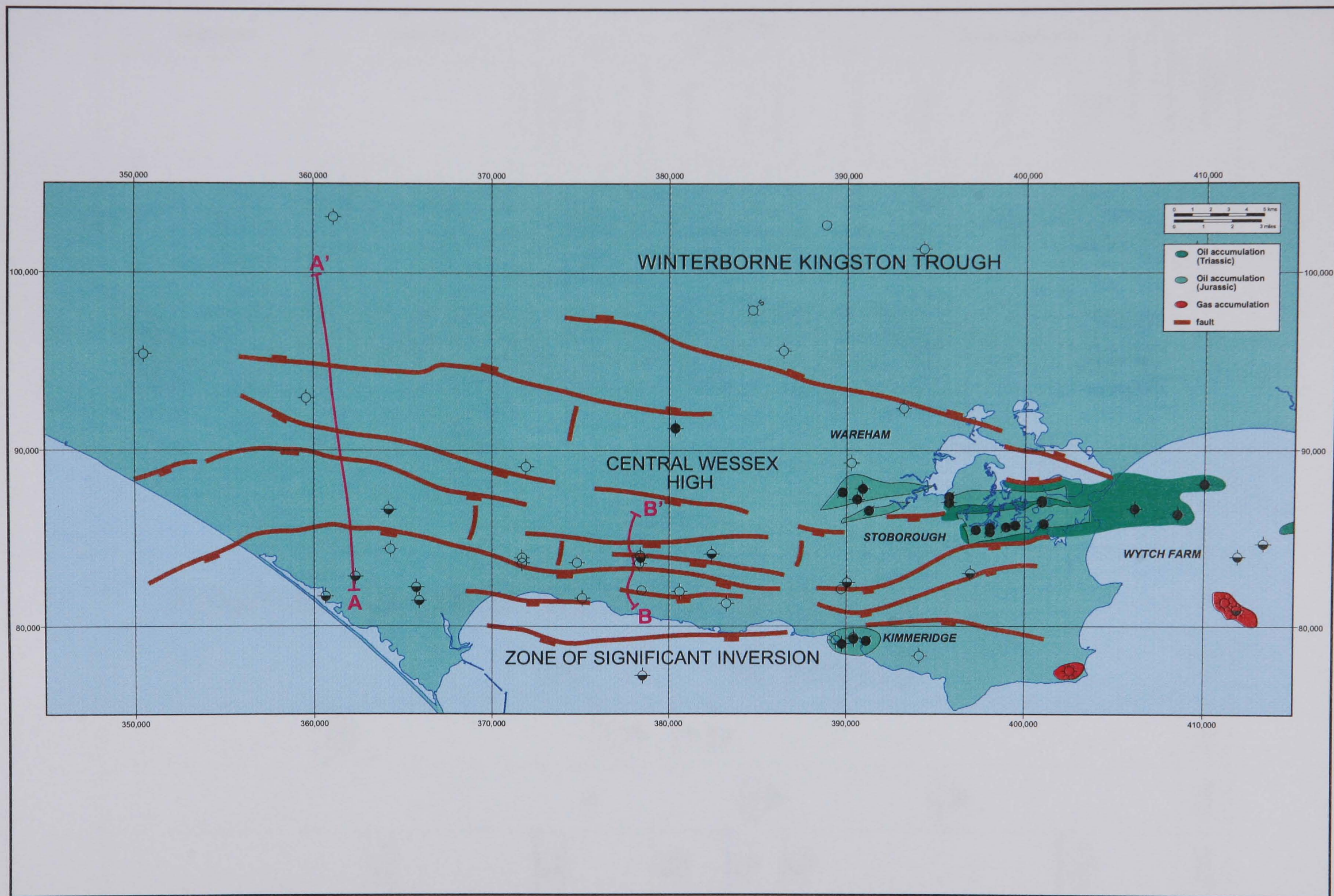
Figure 34: Location map of the Wessex Basin showing principal structural elements. Faults taken from Figure 39.
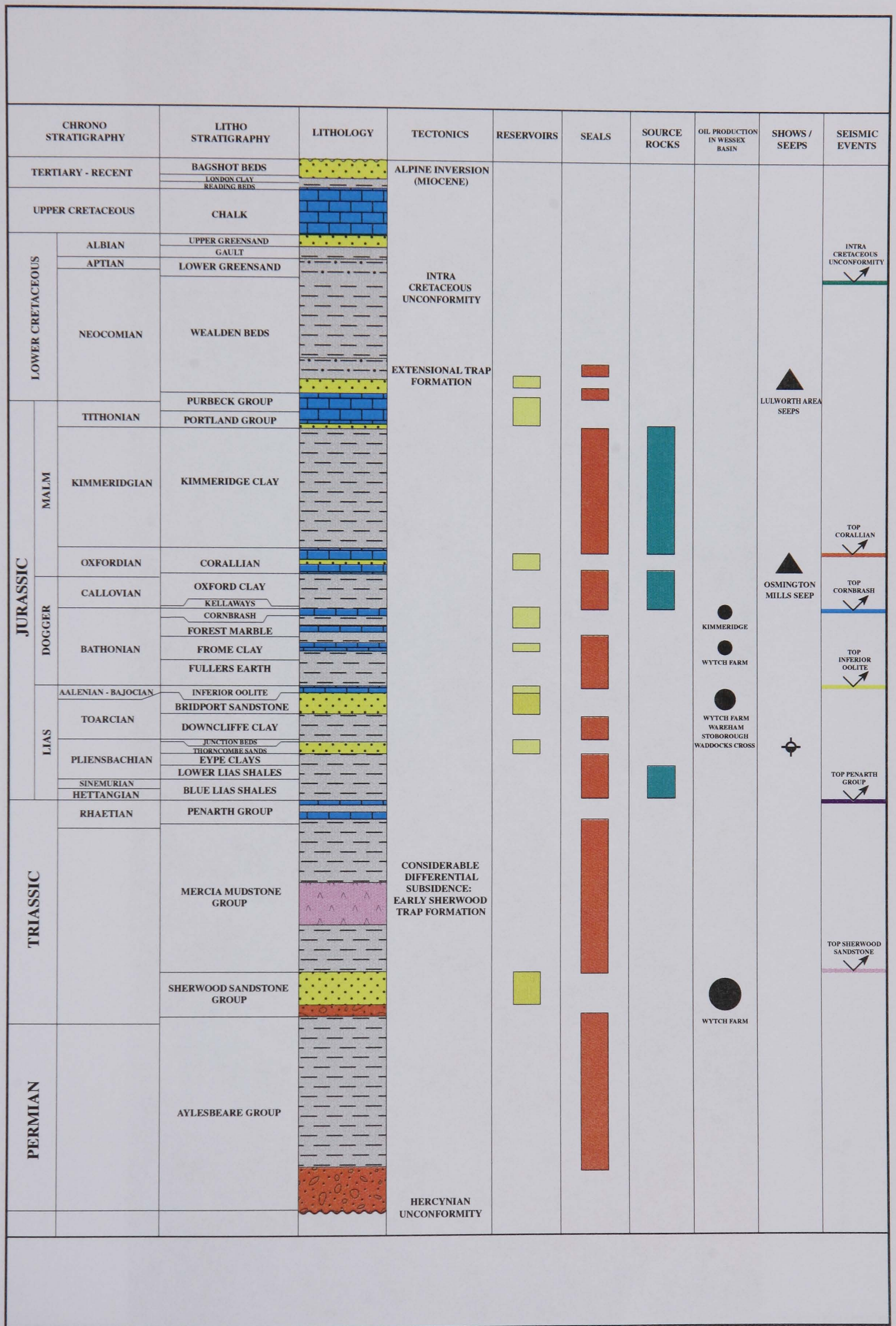
Figure 35: Wessex Basin stratigraphy.

a) Mercia Mudstone isopach
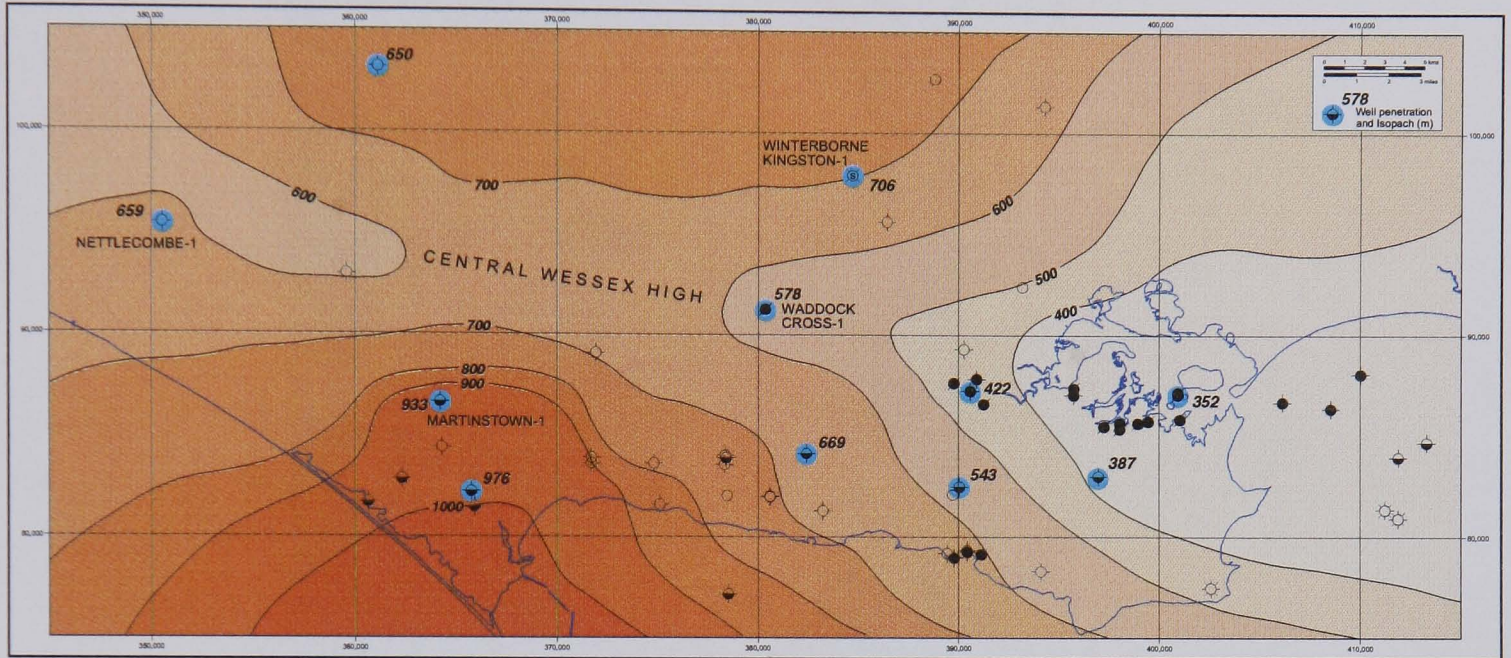
b) Sherwood Sandstone isopach
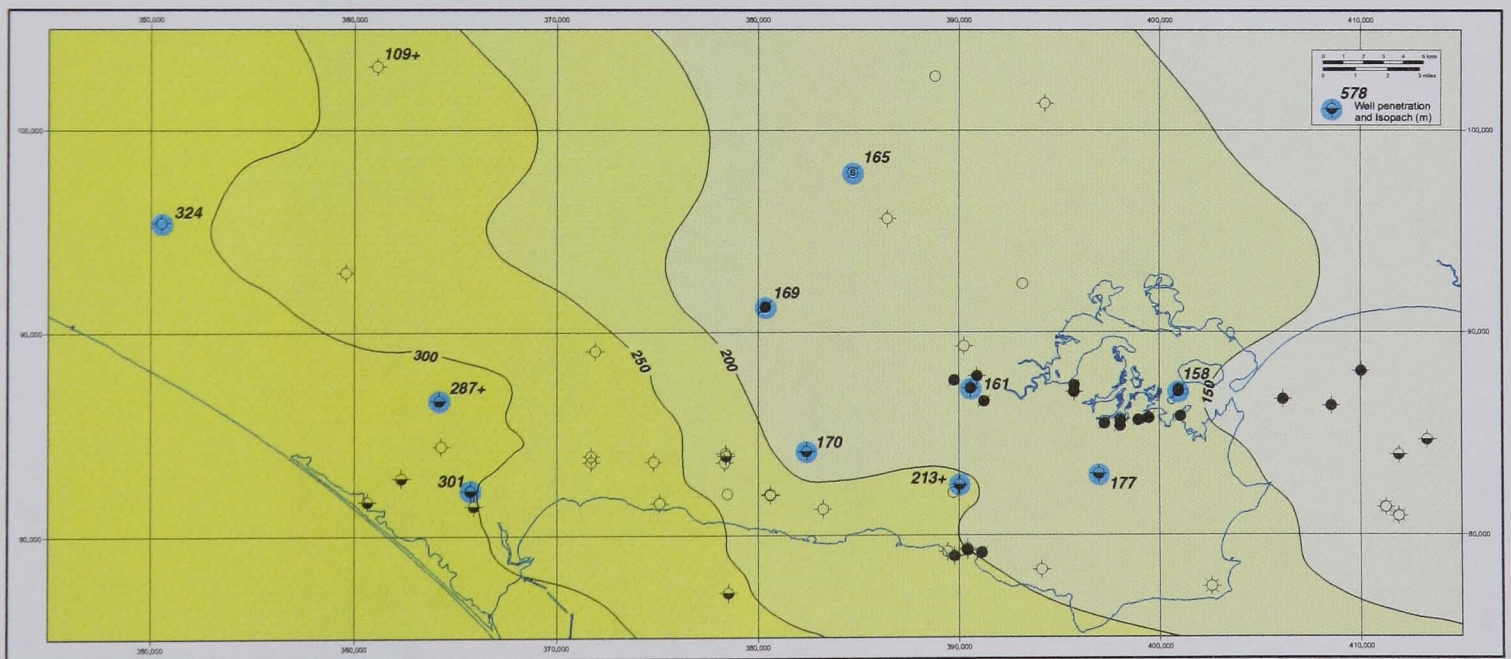
Figure 37: Isopachs of Triassic sequences.
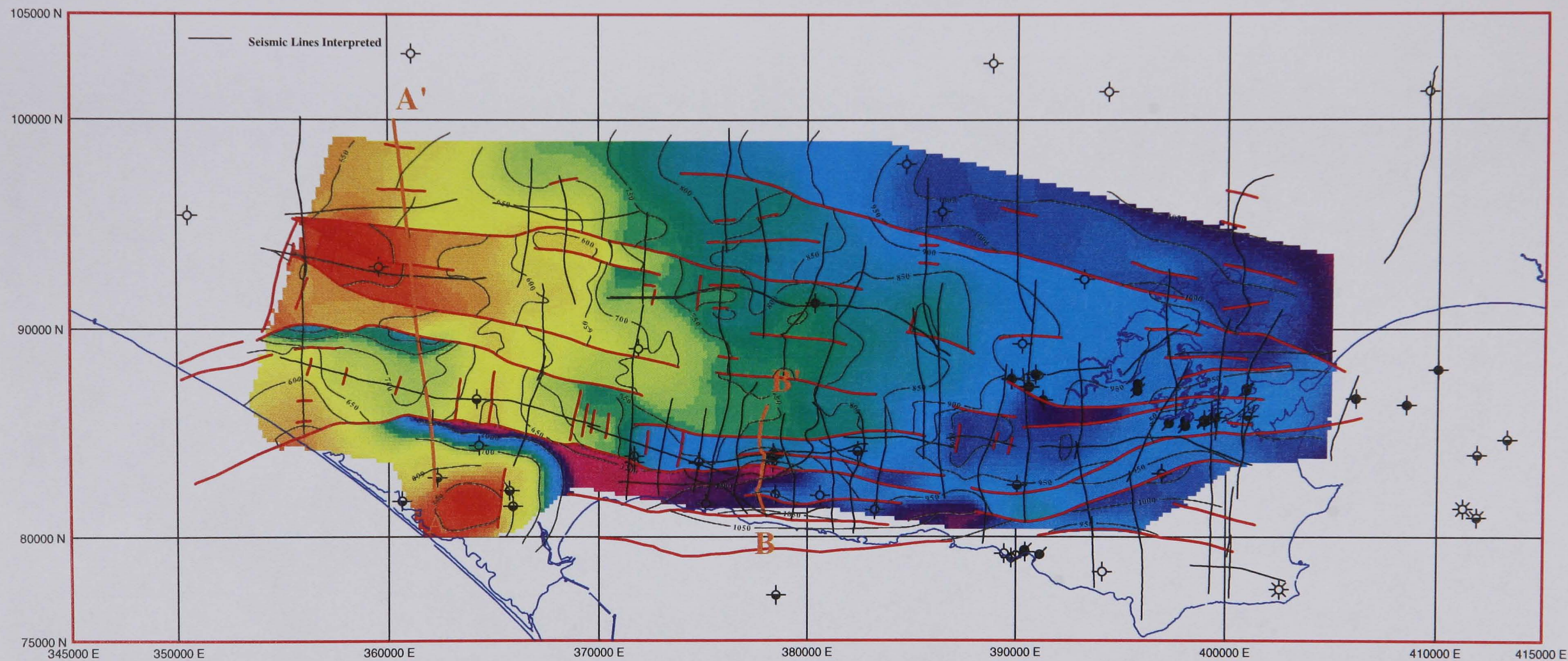a: Mercia Mudstone Group.
b: Sherwood Sandstone Group.
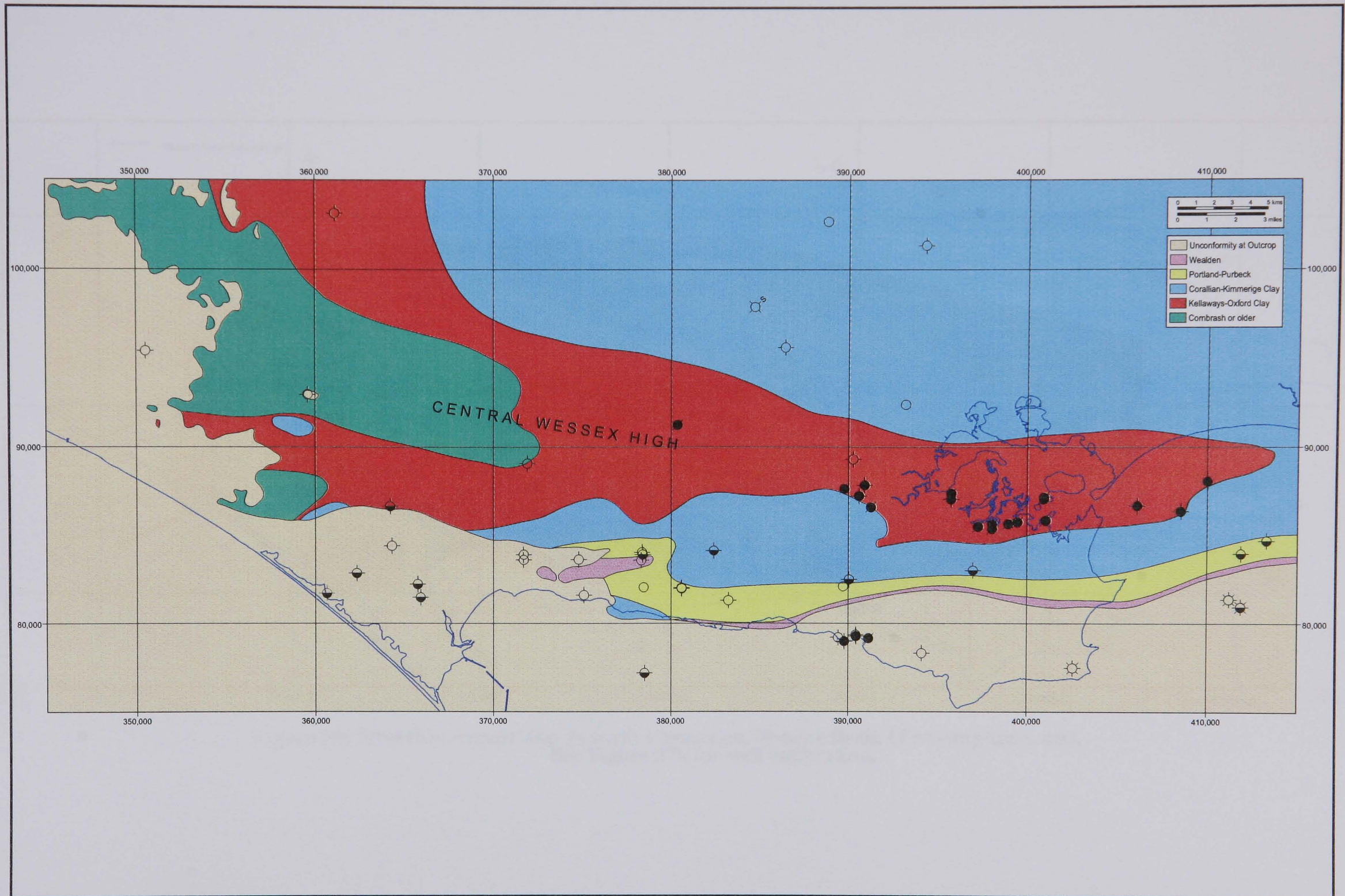
Figure 38: Simplified subcrop map of the Intra-Cretaceous Unconformity using well and outcrop data.

**Figure 39: Structure map at Top Penarth Formation, Wessex Basin (Two-way-time, ms).
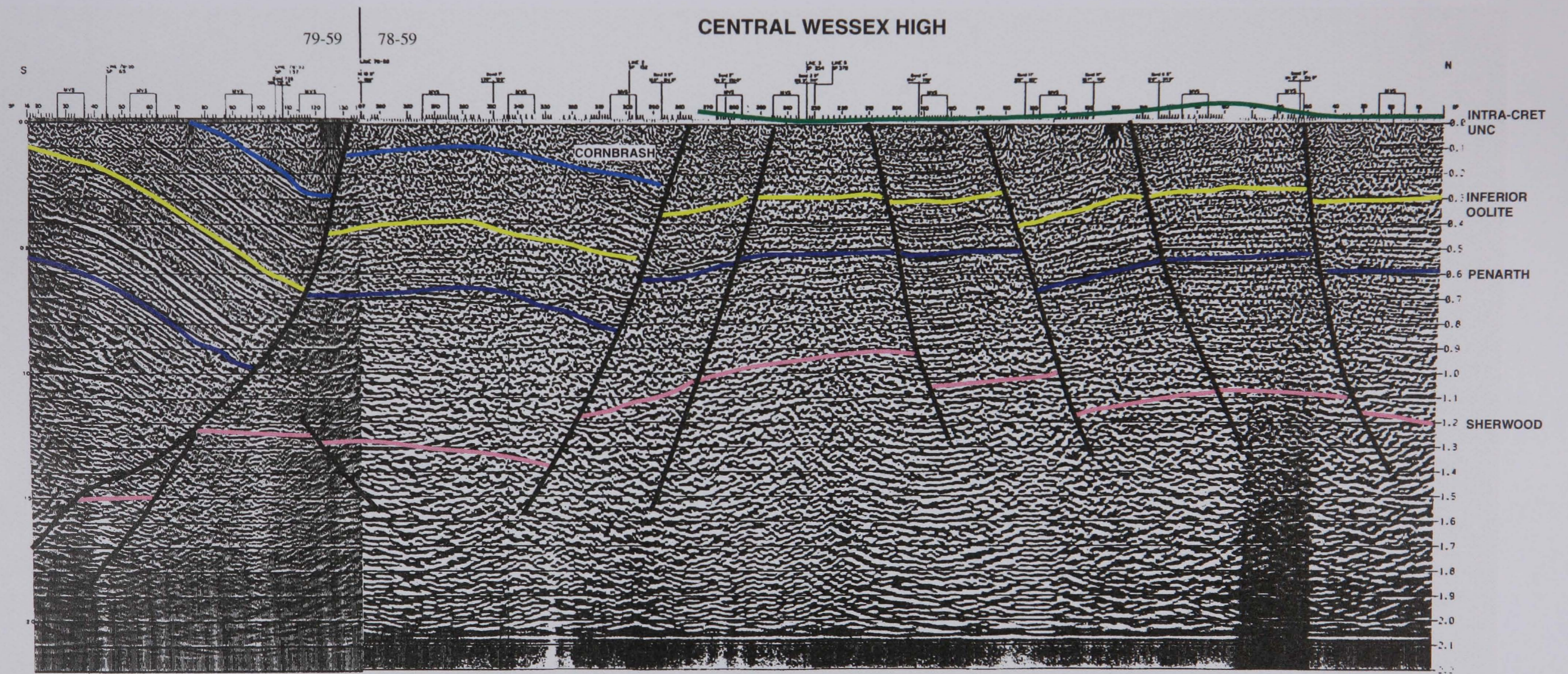See Figure 37a for well calibration.**

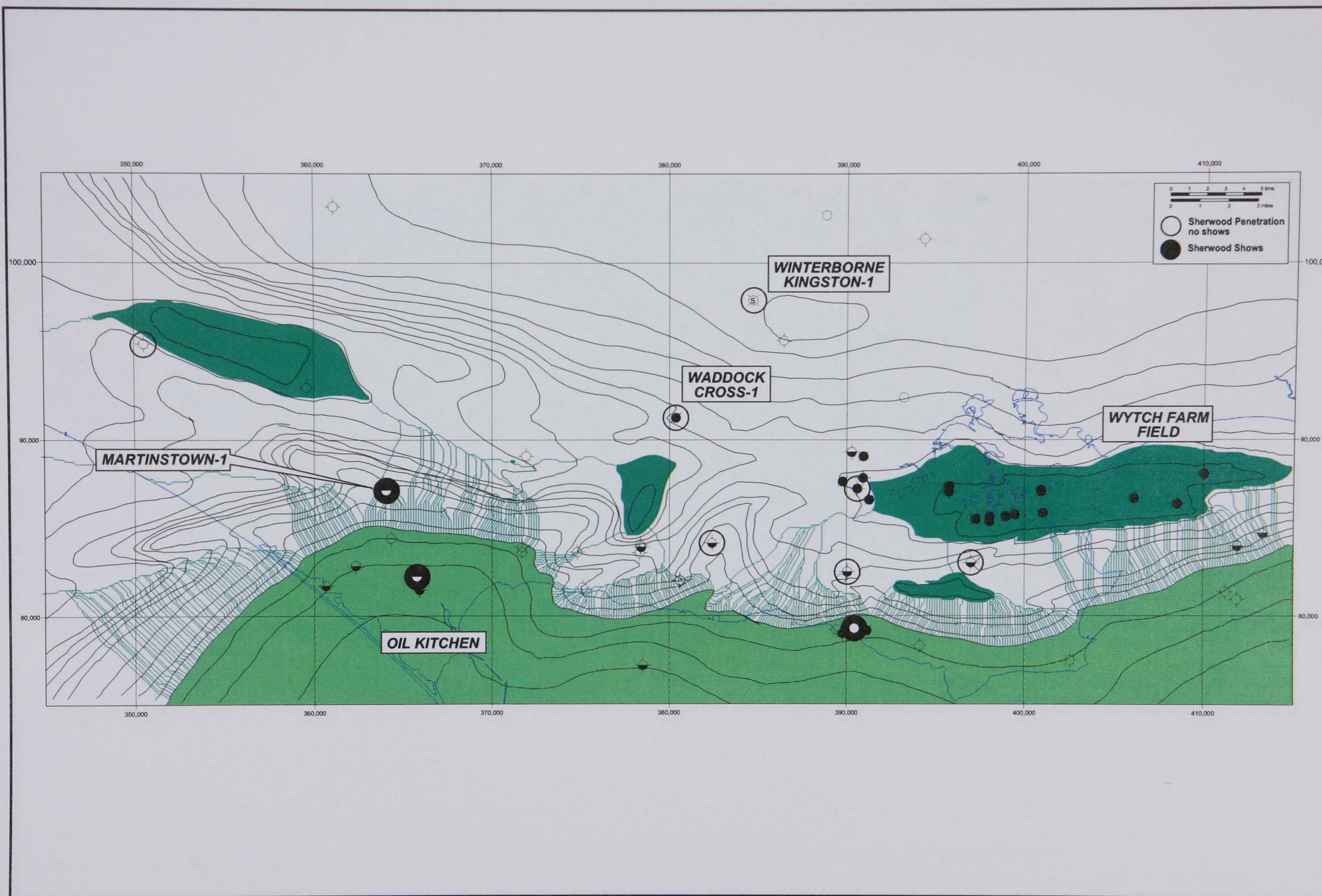**Figure 40: Composite seismic line (79-59 & 78-59); A-A' on Figures 34 and 39.**

Figure 41: Predicted migration pathways, Sherwood Sandstone reservoir prior to late Tertiary inversion.
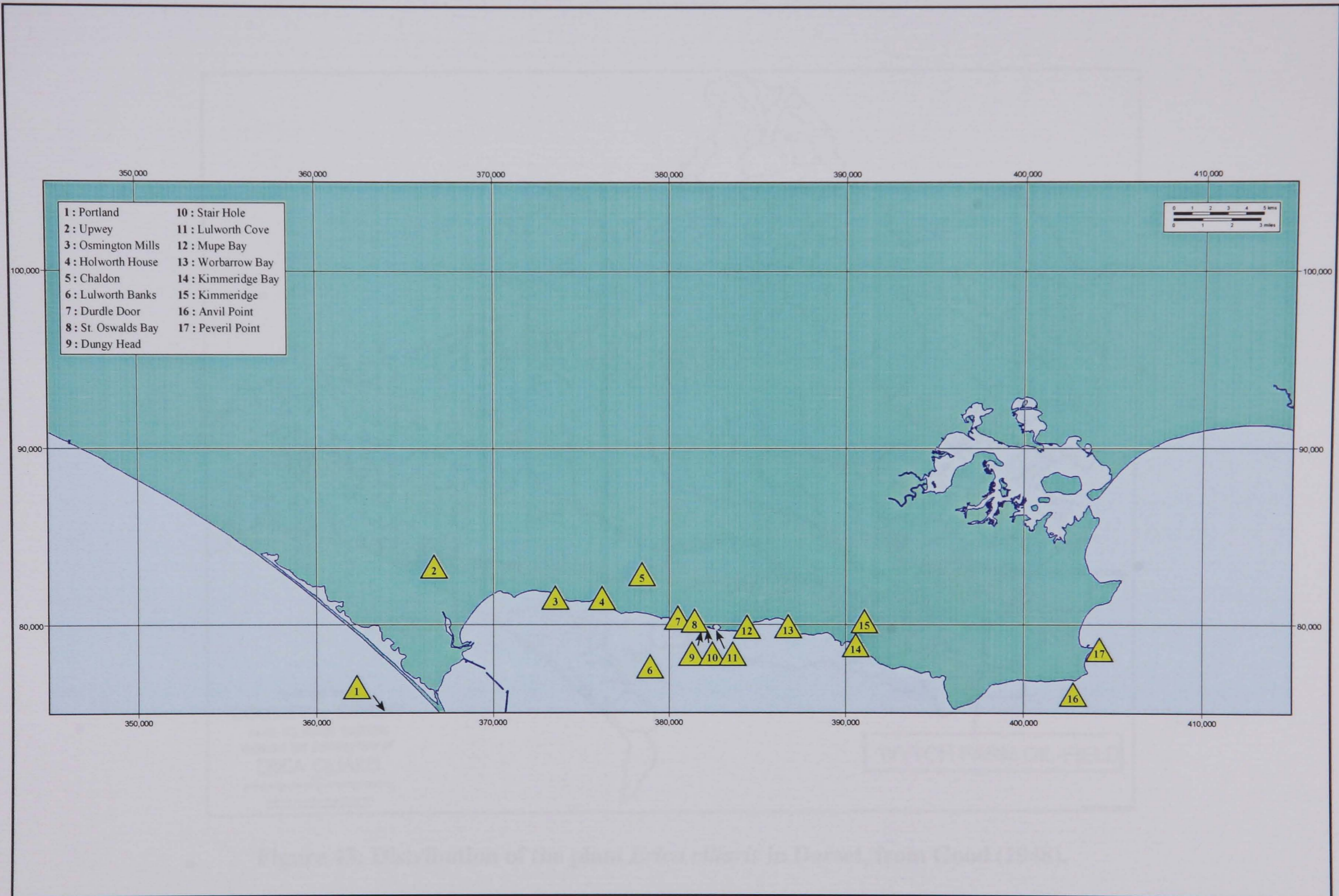
Figure 42: Petroleum seeps/impregnations, Wessex Basin.

MAP OF THE
COUNTY of DORSET
AND ITS RIVER SYSTEMS
SHOWING THE DISTRIBUTION OF
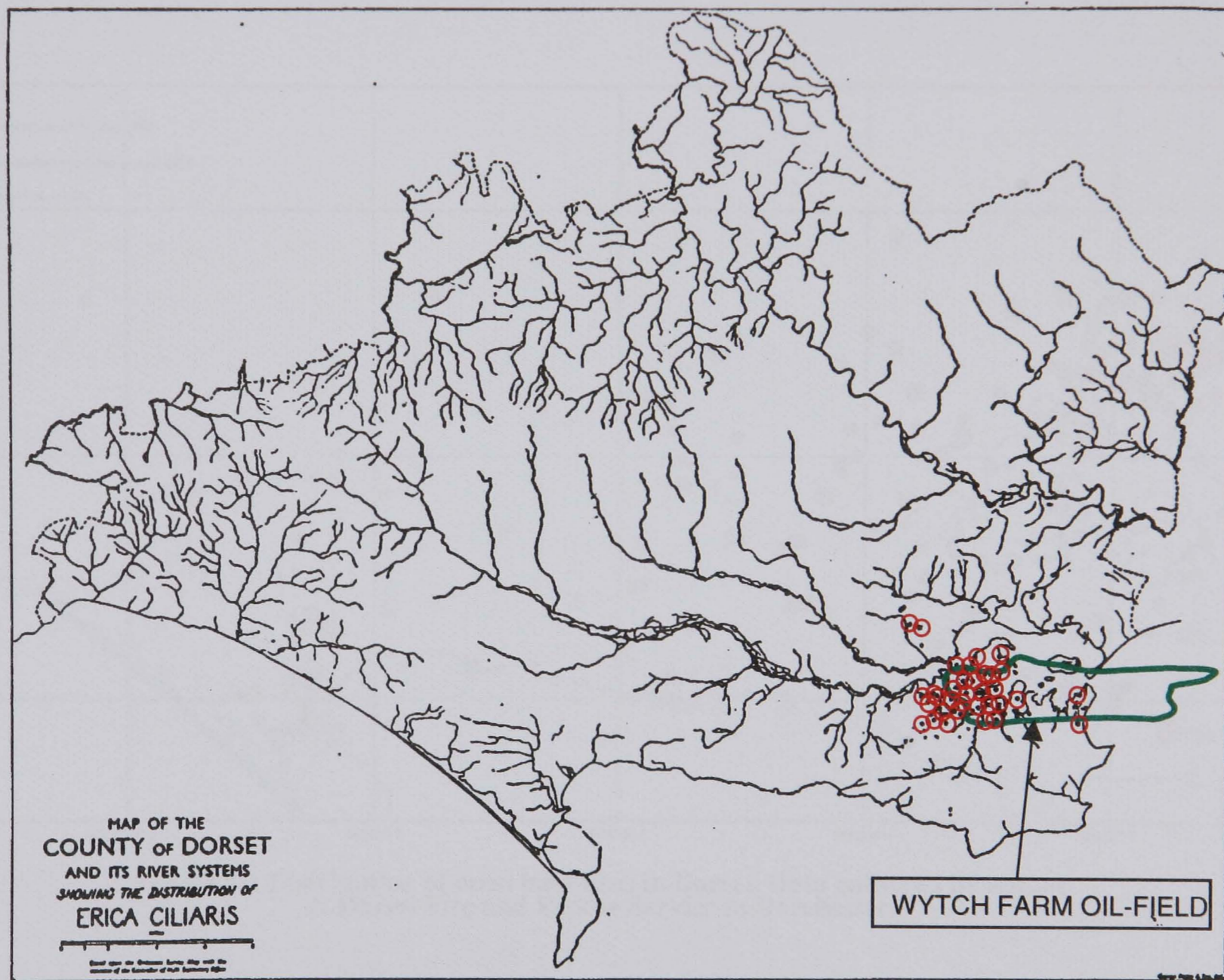ERICA CILIARIS

WYTCH FARM OIL-FIELD

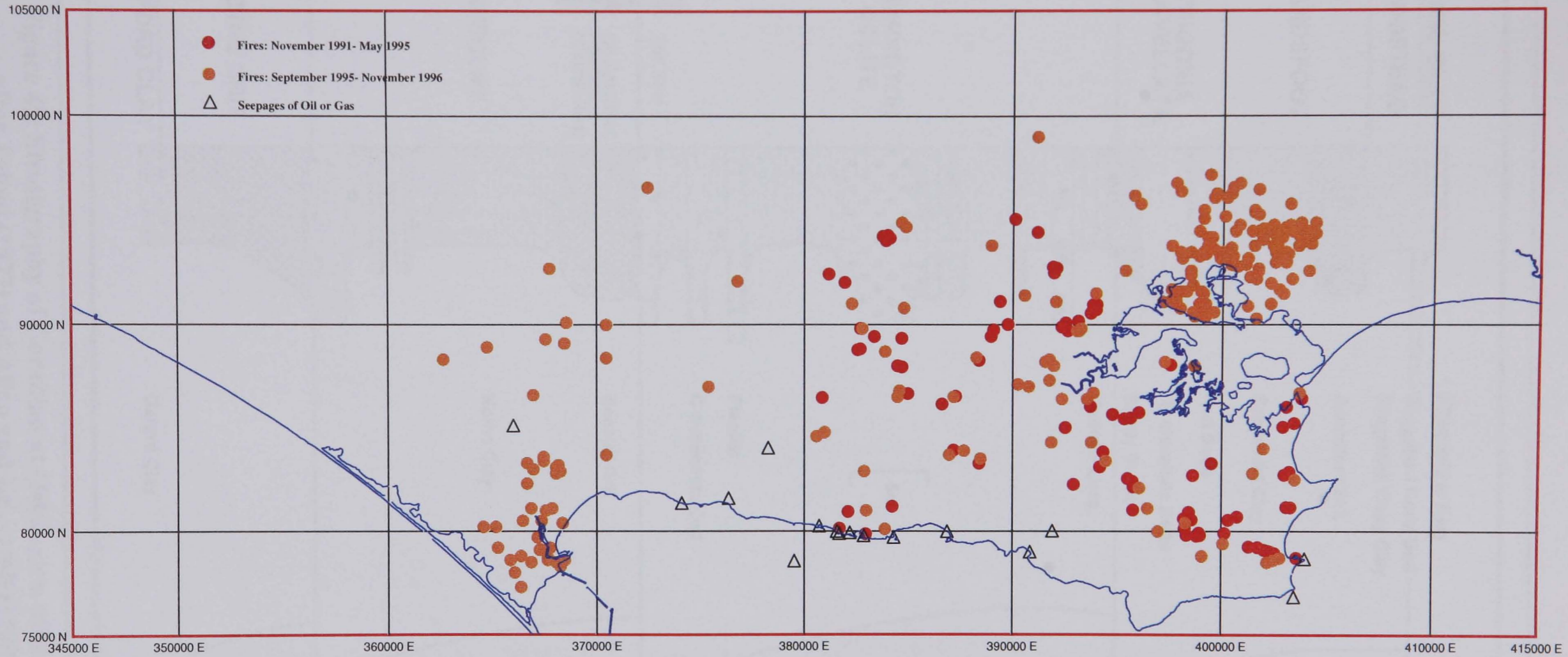**Figure 43: Distribution of the plant *Erica ciliaris* in Dorset, from Good (1948).**

Figure 44: Distribution of open land fires in Dorset. Data gathered by author at Dorset Fire and Rescue Service in Dorchester.

KEY

	OSMINGTON OOLITE
	BENCLIFF GRIT
	NOTHE CLAY
⚓	STRUCTURAL DIP

KEY

🔴	FORESHORE
🔵	CLIFF
🟢	HEAVILY BIODEGRADED SAMPLE

The Glen

Icehouse (disused)

20m

FB 15m

5m

Path

FB

Path

BRAN POINT FAULT

Perry Ledge

SITE OF ACTIVE OIL SEEP

Bran Point

Bran Ledge

BENCLIFF GRIT OBSCURED BY SLUMPING

Upton Fort

5m

Frenchman Ledge

Pool Ledge

ANTICLINE PLUNGING TO WSW

SMUGGLER'S INN PUBLIC HOUSE

Inn

15m Waterfall

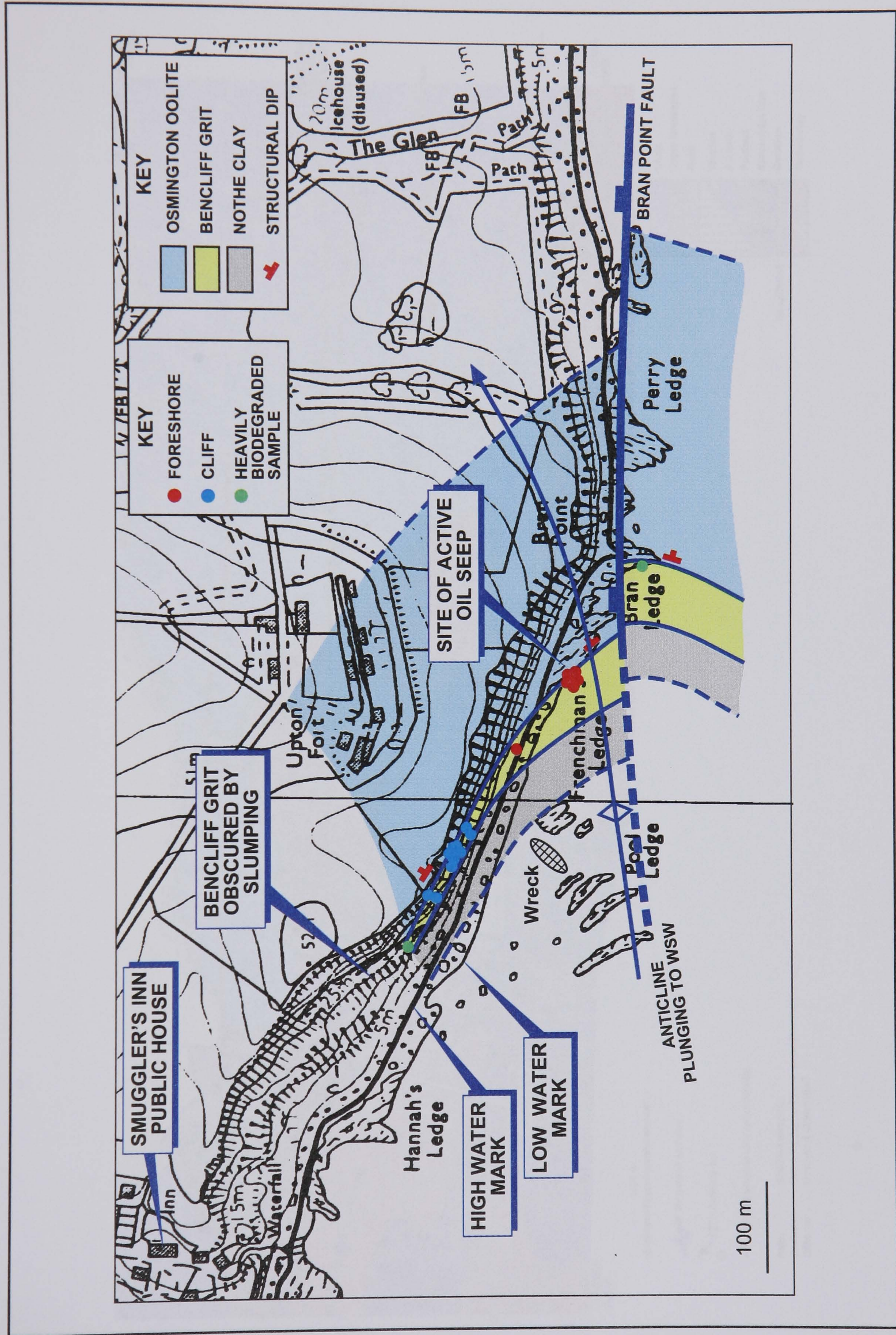Hannah's Ledge

Wreck

HIGH WATER MARK

LOW WATER MARK

100 m

Figure 47: Bencliff Grit outcrop at Osmington Mills. Modified by author from Arkell (1947).
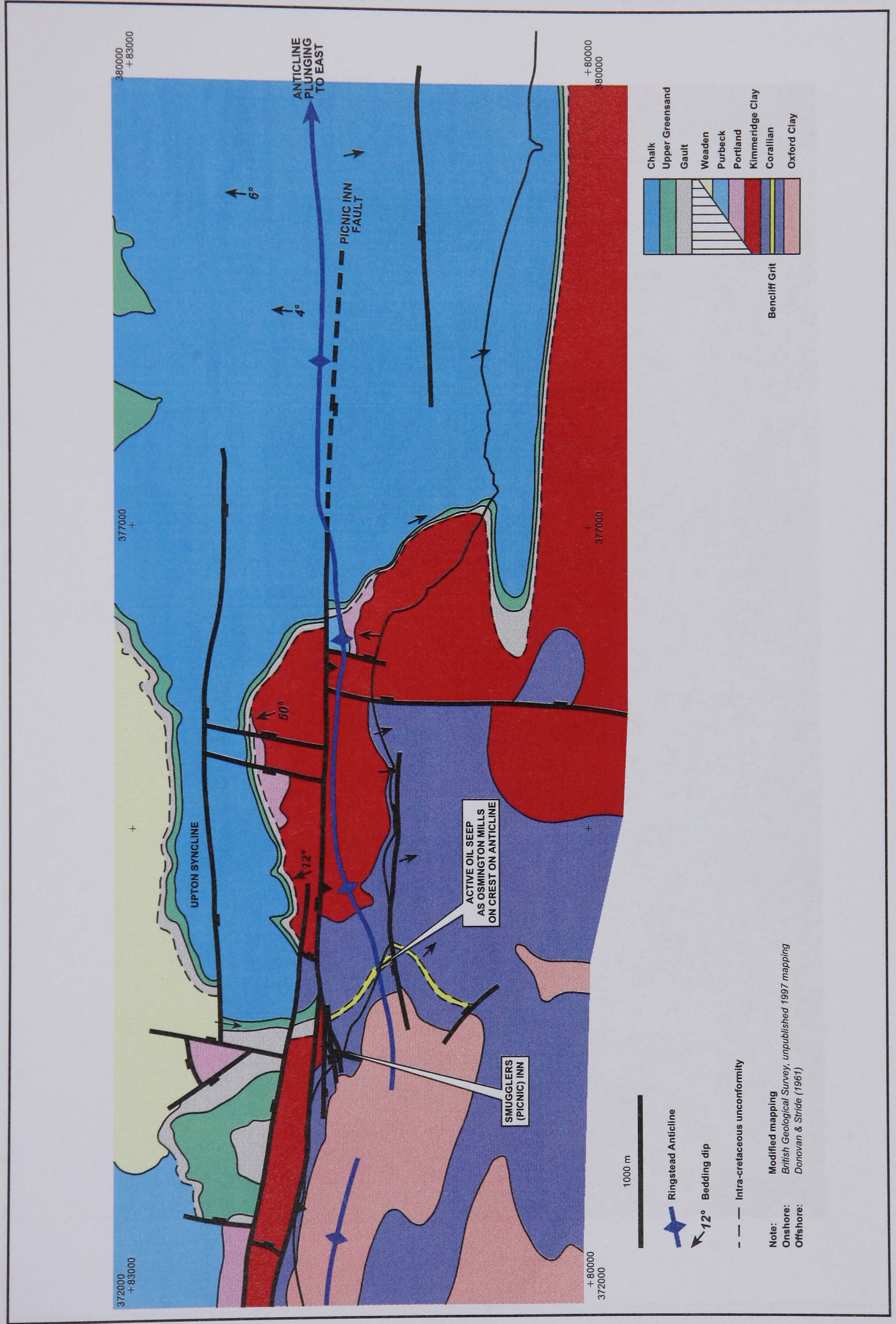
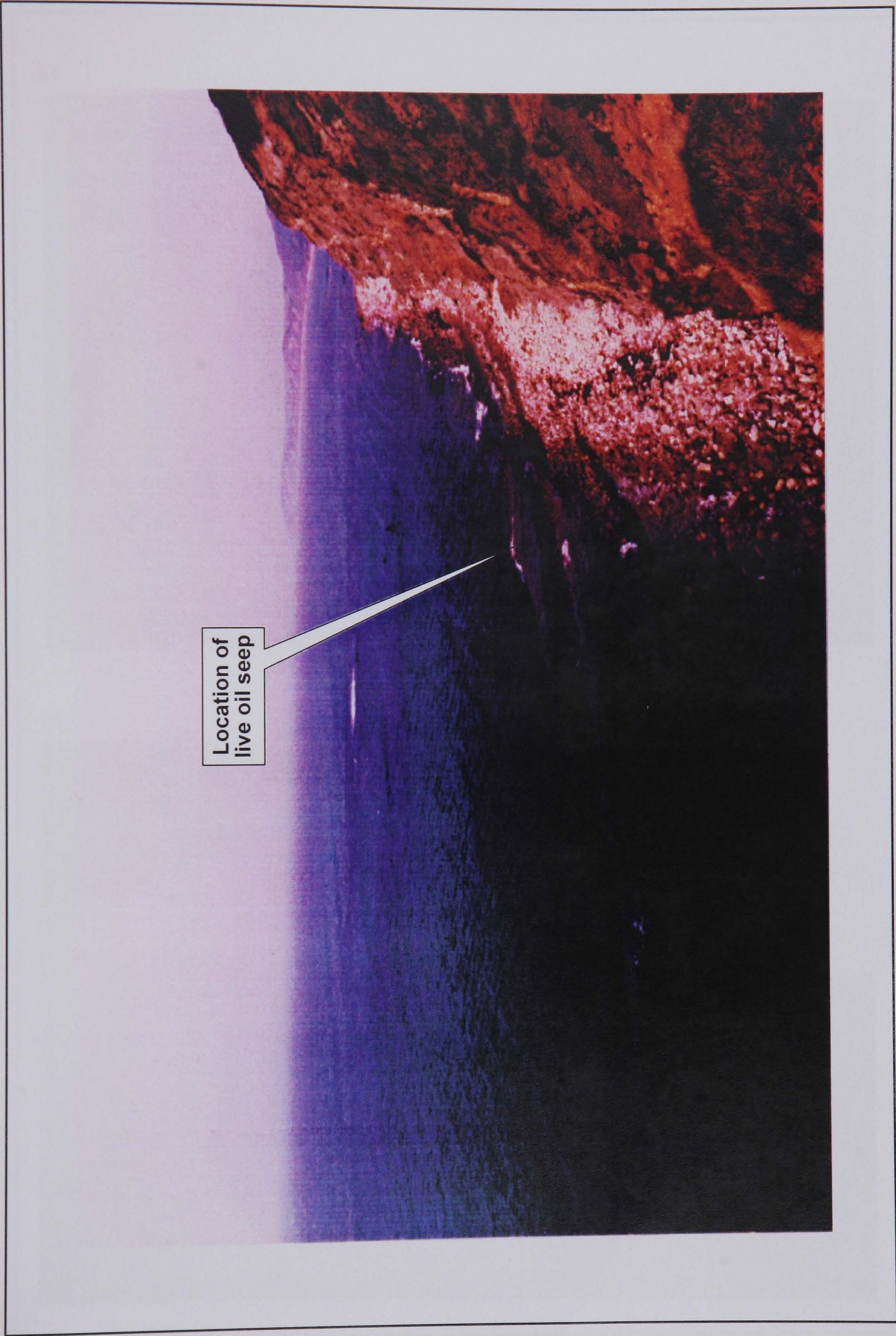**Figure 48: Geological map of the Ringstead Anticline.**

ANTICLINE
PLUNGING
TO EAST

PICNIC INN
FAULT

6°

4°

UPTON SYNCLINE

50°

12°

ACTIVE OIL SEEP
AS OSMINGTON MILLS
ON CREST ON ANTICLINE

SMUGGLERS
(PICNIC) INN

380000
+ 83000

380000
+ 80000

377000

377000

372000
+ 83000

372000
+ 80000

1000 m

Chalk
Upper Greensand
Gault
Weaden
Purbeck
Portland
Kimmeridge Clay
Corallian
Oxford Clay

Bencliff Grit

Ringstead Anticline

12°   Bedding dip

Intra-cretaceous unconformity

Note: Modified mapping
Onshore: British Geological Survey, unpublished 1997 mapping
Offshore: Donovan & Stride (1961)

Figure 49: Western extension of Ringstead Anticline.

From top of **Bran point to west**; plunging Ringstead Anticline marked by hard Osmington Oolite beds in shallow water.

Figure 51: Oil saturated Bencliff Grit sandstones in cliff.
a: Oil mobile on outcrop face.
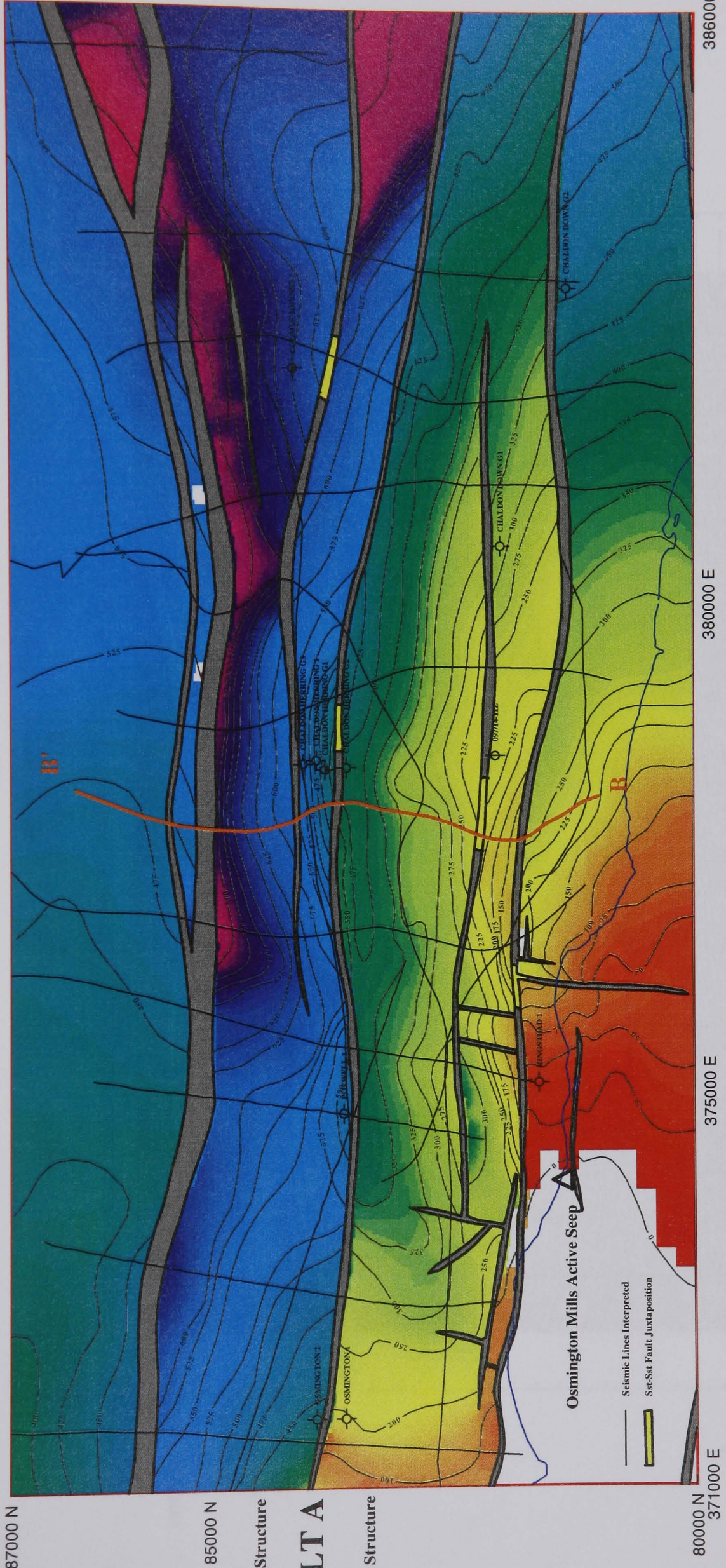b: Oil saturated Bencliff Grit.

Figure 52: Structure map of Corallian/ Inferior Oolite, Osmington Mills area (Two-way-time, ms). The map to the south of Fault A is Top Corallian and to the north is Top Inferior Oolite. The yellow portion of the faults mark where there is juxtaposition of mapped surfaces.
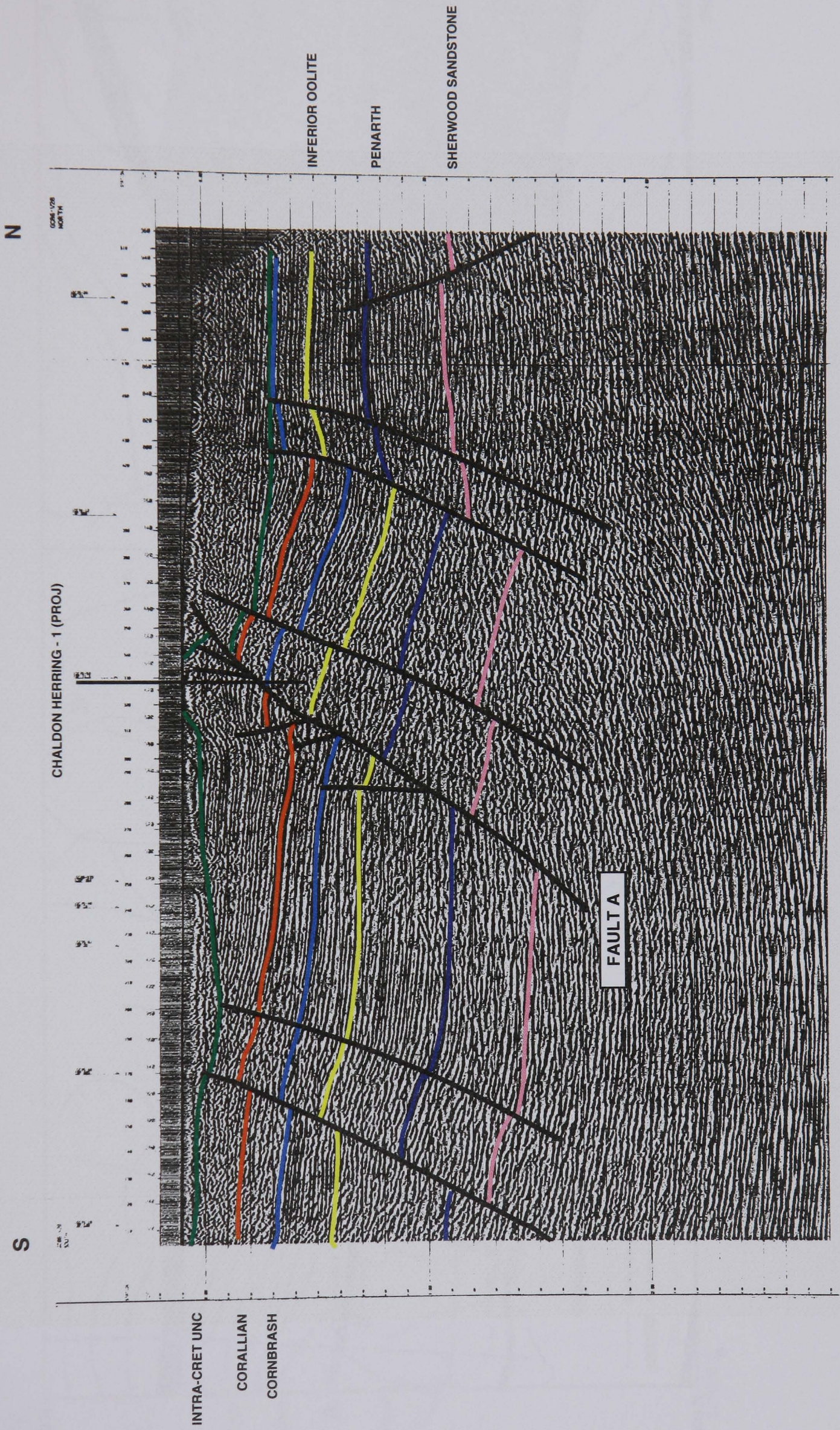
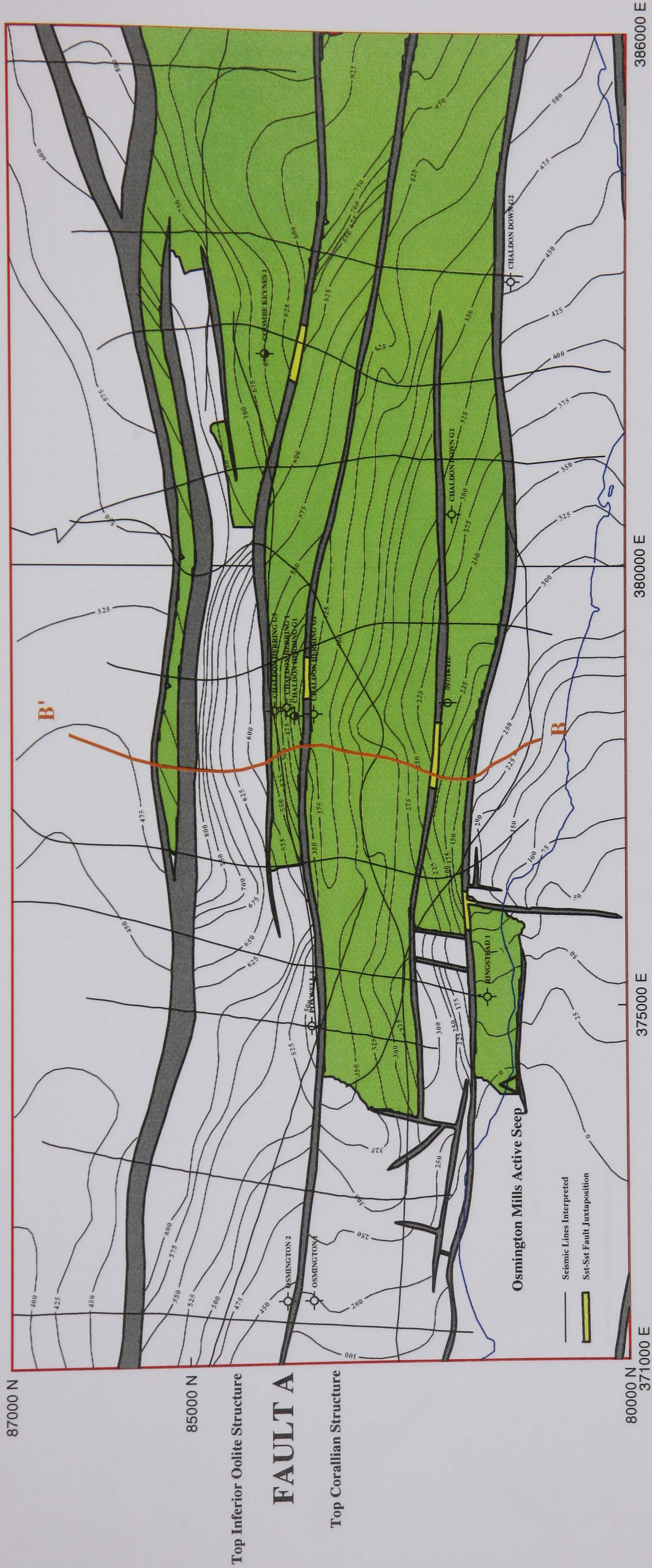**Figure 53: Seismic line GC86-V28; B-B' on Figures 34 and 52.**

Figure 54: Reverse migration model from the location of the Osmington seep; predicted fault breaches marked in yellow.

Figure 55: Forward migration model from Chaldon Herring and Coombe Keynes structures assuming breach in fault.

Map View:

α = angle between strike of dipping surface and strike of potentiometric surface; angle between water flow direction and normal migration direction

ψ = angle between strike of dipping surface and strike of hydrocarbon potentiometric surface; angle of deflection of a migration pathway
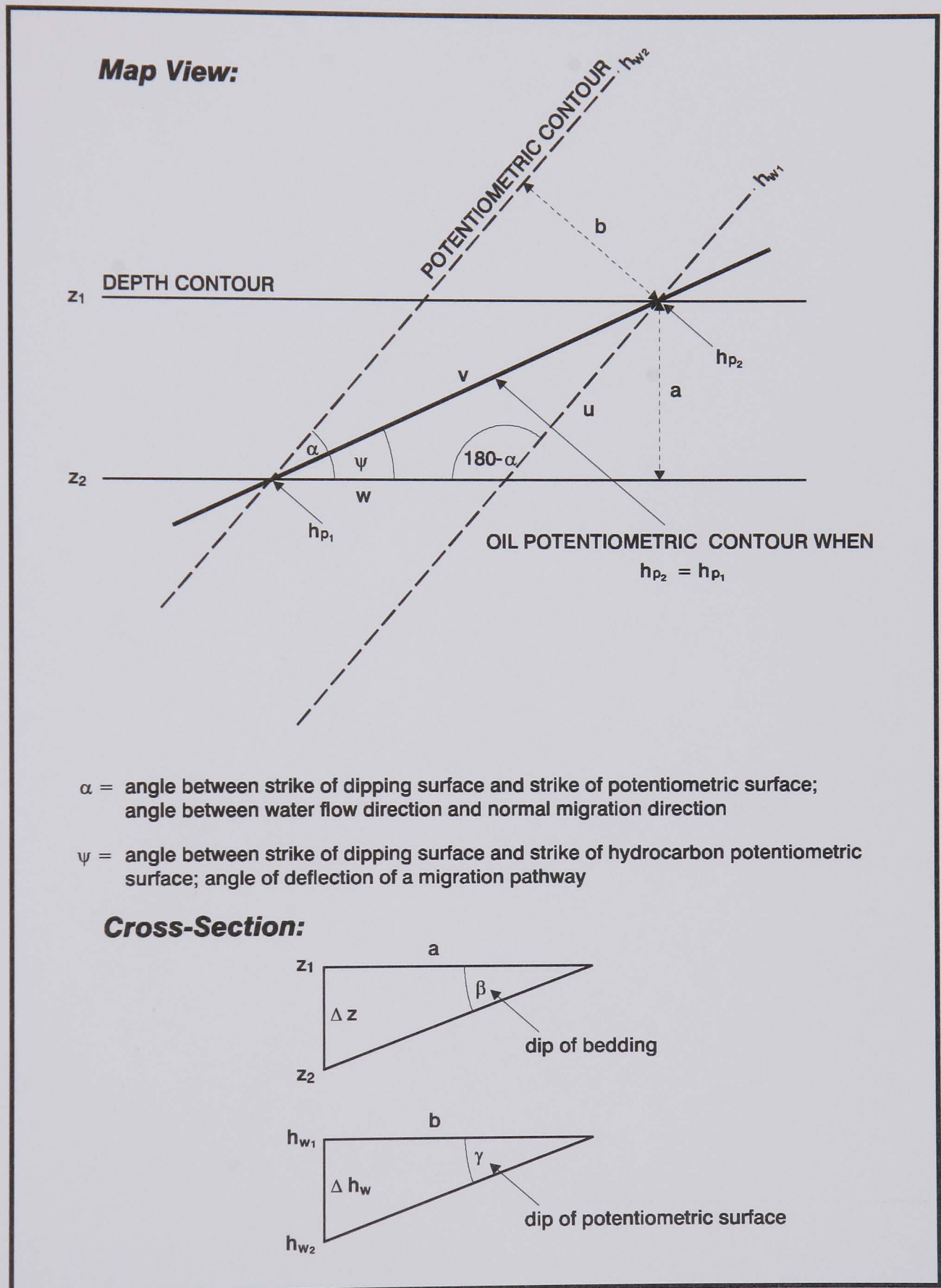
Cross-Section:

Figure 56: Trigonometric determination of the effect of hydrodynamic conditions upon the migration pathways of petroleum.