Prediction of the hydrocarbon system in exhumed basins, and application to the NW European margin

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Abstract: Uplift, erosion and removal of overburden have profound effects on sedimentary basins and the hydrocarbon systems they contain. These effects are predictable from theory and from observation of explored exhumed basins. Exhumed basins are frequently evaluated in the same way as 'normal' subsiding basins, leading to errors and unrealistic expectations. In this paper we discuss the consequences of exhumation in terms of prospect risk analysis, resource estimation, and overall basin characteristics.

Exhumation should be taken into account when assigning risk factors used to estimate the probability of discovery for a prospect. In general, exhumation reduces the probability of trapping or sealing hydrocarbons, except where highly ductile seals such as evaporites are present. Exhumation modifies the probability of reservoir in extreme cases; for example, where a unit may have been buried so deeply before uplift that it is no longer an effective reservoir, or where fracturing on uplift may have created an entirely new reservoir. The probability of sourcing or charging is affected by multiple factors, but primarily by the magnitude of the post-exhumation hydrocarbon budget and the efficiency of remigration. Generally gas will predominate as a result of methane liberation from oil, formation water and coal, and because of expansion of gas trapped before uplift. These factors in combination tend to result in gas flushing of exhumed hydrocarbon basins.

Compared with a similar prospect in a non-exhumed basin, resource levels of a prospect in an exhumed basin are generally lower. Higher levels of reservoir diagenesis influence the standard parameters used to calculate prospect resources. Porosity, water saturation and net-to-gross ratio are adversely affected, and (as a consequence of all three) lower recovery factors are likely. Hydrostatic or near-hydrostatic fluid pressure gradients (as observed in exhumed NE Atlantic margin basins) will also reduce the recovery factor and, in the case of gas, will adversely affect the formation volume factor.

Hydrocarbon systems in exhumed settings show a common set of characteristics. They can include: (1) large, basin-centred gas fields; (2) smaller, peripheral, remigrated oil accumulations; (3) two-phase accumulations; (4) residual oil columns; (5) biodegraded oils; (6) underfilled traps. Many basins on the NE Atlantic seaboard underwent kilometre-scale uplift during Cenozoic time and contain hydrocarbon systems showing the effects of exhumation. This knowledge can constrain risk and resource expectation in further evaluation of these basins, and in unexplored exhumed basins.

Global oil and gas resources are finite and depleting rapidly. Estimates as to when world oil production will begin its terminal decline vary, but all authorities agree that this must take place within a few decades (e.g. Campbell 1996). Natural gas, the logical short-term replacement for oil, is more abundant and may provide global supply for about a century at projected rates of consumption (Lerche 1996). Therefore, the search for oil may be said to be entering its 'end game', characterized by increasing difficulty in locating major new reserves. In the case of gas, economic attractiveness is tied to market availability and thus to location. In both cases, the result is a drive to explore the more difficult, higher risk basins.

Although no hydrocarbon basin is without exploration problems, an 'ideal' basin is perhaps one containing abundant reservoirs and rich source rocks, which is continuously subsiding and where hydrocarbons are being generated at the present day, replenishing those that leak to the surface. Examples include the Northern North Sea, the Gulf of Mexico and the South Caspian Basin. Most such basins are now known and under production. Exhumed basins, on the

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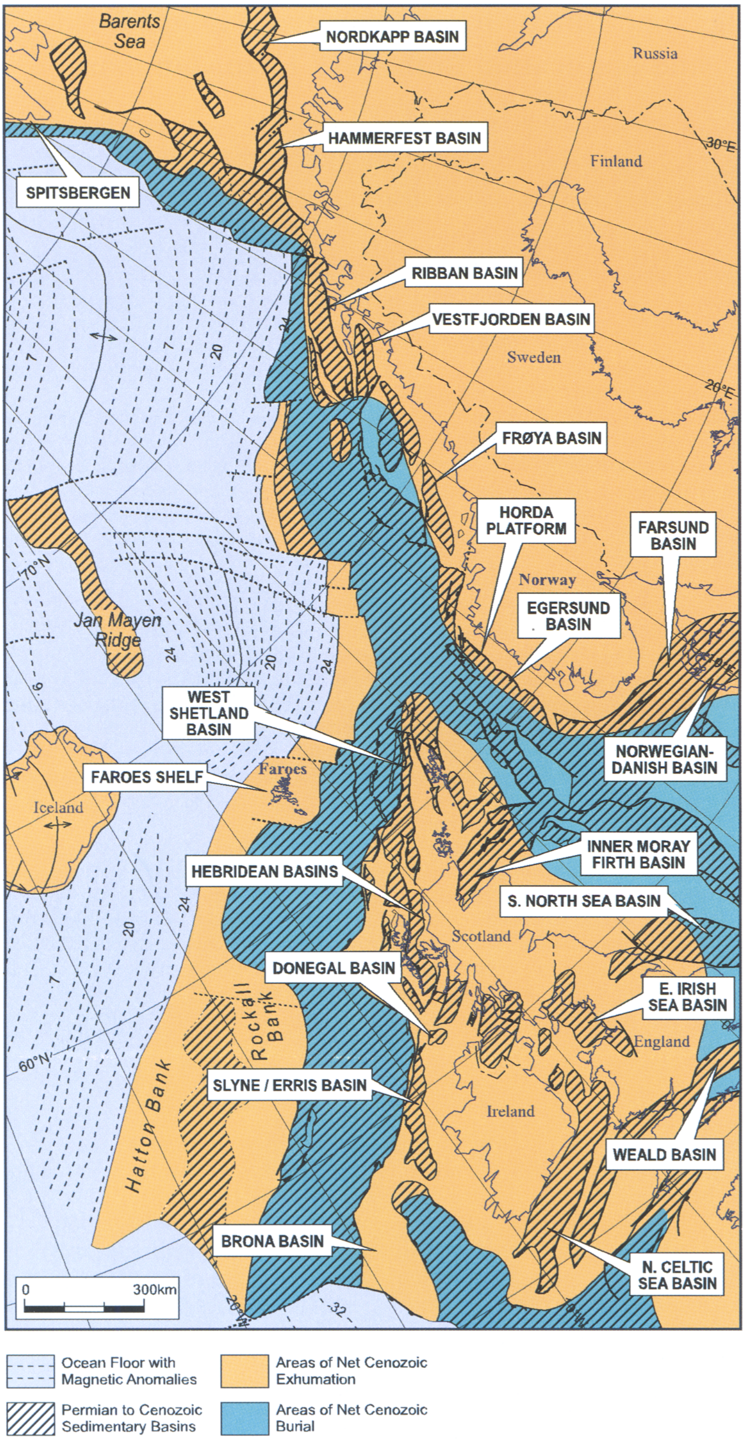


Fig. 1. Location map of the NW European Atlantic margin, showing basins affected by Cenozoic exhumation.

other hand, belong in the higher risk category, and will become increasingly important as global resources diminish.

For the purposes of this paper, an exhumed basin is loosely defined as one that has undergone uplift and erosion, such that the sedimentary rocks that constitute the petroleum system (source, reservoir and seal) are significantly shallower now than in the past (see more formal definitions given by Riis & Jensen (1992) and Doré & Jensen (1996) and Doré *et al.* (2002)). In such basins, the rock properties and hydrocarbon systems will be radically different from those at a similar depth in a continuously subsiding basin. These properties can be studied by observation of drilled exhumed basins, or predicted by modelling and experimentation (e.g. Nyland *et al.* 1992; Doré & Jensen 1996). Although most effects are individually understood, they are rarely studied systematically in the initial exploration of an exhumed basin. Together, however, they constitute a powerful predictive tool.

In the past, inappropriate comparison of the exploration potential of exhumed basins with 'classic' subsiding basins has resulted in unfulfilled expectations. Realization early in the exploration process that a basin has been exhumed gives rise to a different approach to hydrocarbon exploration, and can help to constrain resource prediction. In this paper we systematically describe the effects of exhumation with reference to two of the standard procedures of petroleum exploration: (1) estimation of the probability of finding hydrocarbons in a prospect; (2) calculation of its volumetric resource potential. Then, based on these discussions, we derive a generalized set of key characteristics for exhumed petroleum basins.

It is now generally understood that major uplift and erosion took place in the circum-North Atlantic borderlands during Cenozoic time, transforming a region dominated by low relief and shelf seas (Late Cretaceous) to one bordered by highlands such as Norway, Scotland and East Greenland (e.g. Riis & Fjeldskaar 1992; Riis 1996; Doré *et al.* 1999; Japsen & Chalmers 2000). It is also apparent that many of the offshore basins marginal to the landmasses underwent Cenozoic uplift and erosion. These include basins where hydrocarbon systems are proven (the western Barents Sea and Horda Platform (Norway), Inner Moray Firth, West Shetland Basin and East Irish Sea Basin (UK) and the North Celtic Sea and Slyne–Erris Basin (Ireland)) in addition to many unexplored basins (Fig. 1). Exhumation in these areas has been quantified using numerous methods, including seismic velocities, shale velocities, vitrinite reflectance, apatite fission track, mass balance and basin restoration (e.g. Riis & Jensen 1992). These measurements show that Cenozoic uplift around the North Atlantic was geographically variable and took place in several phases. Three of these phases have particularly widespread significance: an uplift of Paleocene age, generally thought to be associated with effects of the Iceland plume and incipient opening of the North Atlantic (e.g. White 1988; White & McKenzie 1989; Milton *et al.* 1990), an Oligo-Miocene episode usually associated with inversion (e.g. Underhill 1991; Murdoch *et al.* 1995; Parnell *et al.* 1999) and a Neogene (primarily Plio-Pleistocene) event of more enigmatic origin (e.g. Solheim *et al.* 1996; Doré *et al.* 1999; Japsen & Chalmers 2000). A discussion of alternative uplift mechanisms is not within the scope of this paper, except to note that explanations essentially fall into three groupings: (1) isostatic (response to erosional unloading); (2) thermal (associated with a mantle plume); (3) compressional (intraplate stress and inversion). Categories (1) and (2) are broad regional effects, whereas category (3) may be very local in nature.

In most cases, exploration of these basins has occurred without a full understanding of their exhumed nature. A particularly instructive example is the western Barents Sea (offshore Norway), where licencing in the early 1980s carried the hope of a major North Sea rift-type hydrocarbon province, but where expectations were radically revised as the effects of uplift became apparent during early exploration (Nyland *et al.* 1992; Doré 1995). This experience alerted researchers, particularly in Norway, to the widespread nature of the exhumation and, importantly, to its commercial consequences. We therefore believe that a template for prospect evaluation of the type presented here, although largely qualitative, can be beneficial in future exploration and resource evaluation of such provinces. Although specific reference is made to the NW European basins, this appproach is applicable to any exhumed basin.

Prospect risk analysis in exhumed basins

Introduction

Explorationists address prospect risk at two levels: (1) risk with respect to the validity of the prospect, i.e. the chance of success; (2) the range of possible reserves. In this account, we simply address the chance before drilling of discovering any hydrocarbon accumulation within a mapped prospect. Methods used to calculate this figure

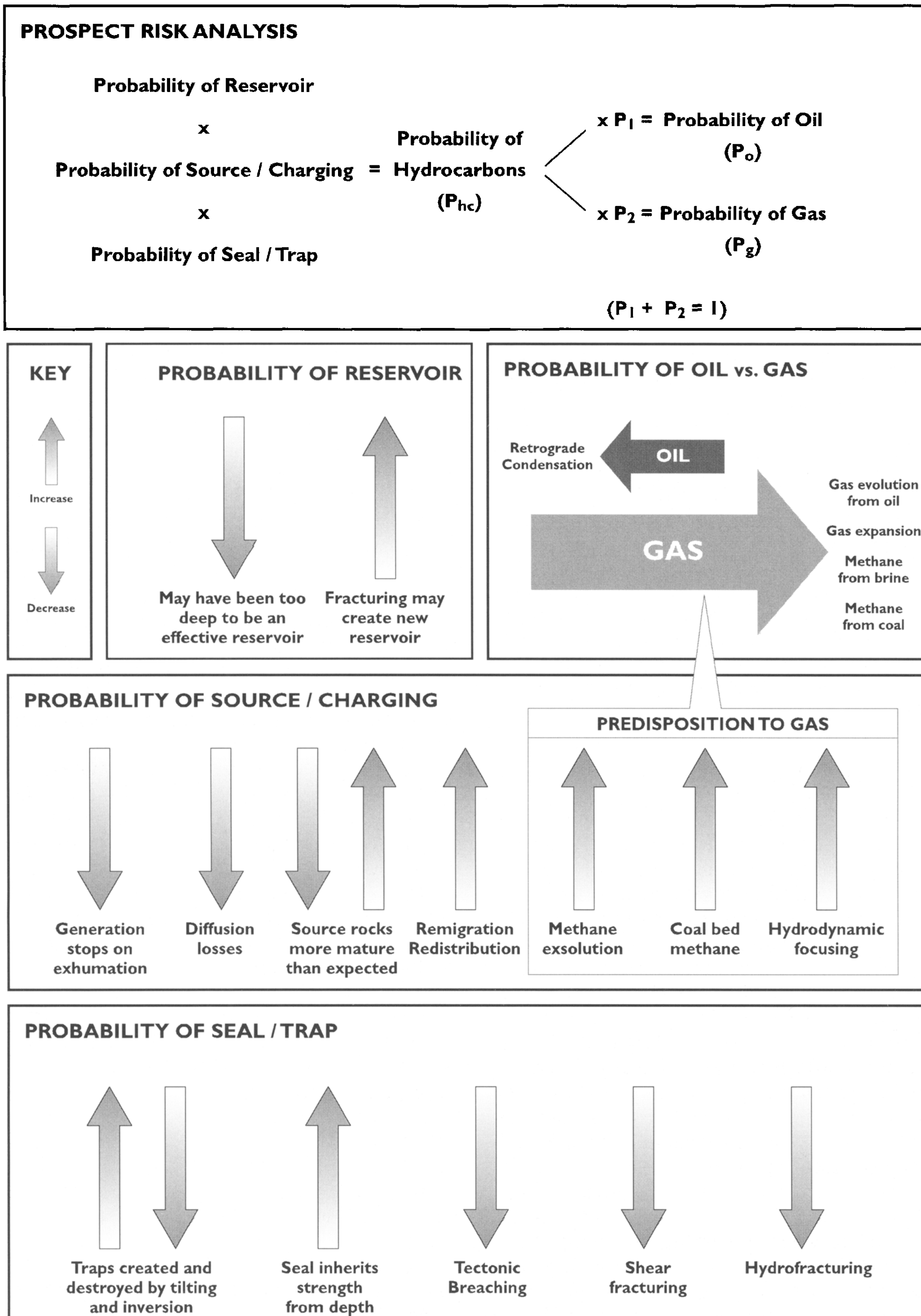


Fig. 2. Factors to be considered when carrying out risk analysis of a prospect in an exhumed basin. Arrows indicate increased or decreased probability in exhumed settings.

vary widely within the oil industry, but can be generalized in an equation of the type

$$P_{hc} = P_r \times P_s \times P_t \tag{1}$$

where P_{hc} is the probability of finding hydrocarbons, oil or gas (this value is sometimes regarded as the chance of finding any hydrocarbons at all, some specified minimum quantity, or hydrocarbons capable of flowing to the surface (see, e.g. Snow *et al.* 1996)), P_r is the probability that a reservoir rock is present, capable of holding oil or gas, P_s is the probability that there is a source rock that has charged the prospect and P_t is the probability that a sealed trap exists capable of holding oil or gas. The chance of a particular hydrocarbon phase being present (assuming a single-phase accumulation) is then given by

$$P_{hc} = P_o + P_g \tag{2}$$

where P_o and P_g are the probabilities of discovering oil and gas, respectively, as the main phase.

All of these factors are subjectively estimated by the petroleum geoscientist before drilling. Where basins are mature in terms of exploration they can be calibrated against known success rates. The influence of exhumation on these factors is summarized in Fig. 2 and discussed below.

Probability of reservoir

Reservoir rocks can be both enhanced or degraded in an exhumed terrane, depending on the type of reservoir and the nature of the process. Degradation compared with a reservoir at a similar depth in a subsiding basin can occur as a result of inheritance of a compactional and diagenetic state reflecting a previously greater burial (e.g. Walderhaug 1992). Improvement may occur because of fracture enhancement of porosity and permeability during uplift (e.g. Aguilera 1980). However, risk analysis does not take into account the quality of a reservoir, only whether a suitable reservoir exists or not. Thus, exhumation is probably neutral for the probability of reservoir except in extreme cases; for example, where a unit has been buried so deeply before uplift that it is no longer an effective reservoir, or where fracturing on extreme uplift has created an entirely new reservoir. The much more important effect on reservoir volumetric parameters (porosity, net/gross ratio and hydrocarbon saturation) and recovery factor is examined in the section on prospect resource estimation.

Probability of source and charge

The probability that a source rock is present is independent of whether or not the basin has been exhumed. However, the probability that such a source rock has been effective in charging a reservoir is strongly influenced by exhumation. A complex interplay of positive and negative factors must be considered.

In exhumed basins, any source rock will be more mature than expected for its present depth. Therefore, there will be an increased probability that source rocks now lying shallower than the oil generation window will have generated oil in the past. Whether such oil has survived uplift is a separate question. This reasoning has been applied to evaluate risk in marginal basins around Norway, where the Upper Jurassic source rock is shallow (Ghazi 1992: Jensen & Schmidt 1993). Conversely, a more deeply buried source rock may previously have been below oil window depths, increasing the chance of gas or that the source rock is 'burnt out' (postmature). This risk has been evaluated for uplifted Upper Palaeozoic source rocks in the eastern Norwegian Barents Sea (Theis *et al.* 1993). In most cases some indication of the degree of exhumation can be obtained even before drilling (e.g. from regional setting, seismic velocities and structural modelling) and can therefore be used to derive a first-order estimate of source rock maturity attained before uplift.

A critical observation is that, whatever the maturity state, generation is curtailed once uplift commences. Using the widely accepted kinetic model for generation of hydrocarbons from kerogen (Tissot & Espitalié 1975), which stresses the importance of temperature rather than time, it follows that any source rock that is significantly uplifted through a thermal frame of reference will cease hydrocarbon generation. No generation can occur until the basin subsides again and the previous maximum temperature is reached. In exhumed basins, no new hydrocarbons will be available to charge traps vacated during uplift by spillage and seal failure, or newly created traps (for example, folds formed during inversion-related uplift). Thus, any remaining original charge must have survived both the uplift and any subsequent leakage (e.g. by diffusion in the case of gas; Krooss *et al.* 1992), thereby significantly increasing risk.

An exception occurs where the uplifted basin is on the migration route for oil or gas generated in an adjacent, continuously subsiding basin. On the NW European margin such areas include parts of the Horda Platform, Inner Moray Firth Basin and West Shetland Basin. In such areas hydrocarbons lost during the uplift process can be replenished, and the probability of sourcing must therefore take into account migration timing, route and efficiency from the adjacent kitchen (e.g. Skjervøy & Sylta 1993; Goodchild *et al.* 1999; Parnell *et al.* 1999).

Hydrocarbon charging following an episode of uplift, in the absence of newly generated hydrocarbons, can take place only with hydrocarbons already present in the basin. The simplest of these processes is by remigration. In uplifted basins numerous processes can displace and redistribute hydrocarbons from pre-existing accumulations. Vertical remigration is a well-known phenomenon in subsiding basins, where reservoir overpressure builds until it exceeds the sealing capacity of the caprock, causing hydrocarbons to escape to shallower levels (e.g. in the Gulf of Mexico (Lopez 1990), in the North Sea Central Graben (Taylor *et al.* 1999) and in the Faeroe–Shetland Basin (Illiffe *et al.* 1999)). As shown later (see probability of trap and seal) and by Corcoran & Doré (2002), seal failure can also be anticipated during uplift. This means that hydrocarbons may subsequently accumulate in previously uncharged shallower levels. A notable example of such charging is in the Zagros fold belt in Iran and Iraq, where seal failure in Cretaceous reservoirs during the Late Miocene–Recent Zagros uplift expelled oil upwards into the highly prolific Oligocene–Miocene Asmari reservoir (Ala 1982; Bordenave & Burwood 1989). However, in many cases hydrocarbons must be lost to the surface during uplift. Assessment of this risk must take into account the position and geometry of the shallower reservoirs, and the amount of erosion of shallower levels that has taken place during uplift.

Assuming that uplift is not perfectly uniform, lateral remigration will occur through tilting and spilling, resulting in loss of some hydrocarbons from pre-existing traps and migration updip. Although some hydrocarbons will accumulate in updip traps, there will be a net decrease in hydrocarbon budget as a result of migration losses and escape to the surface. In pre-existing two-phase accumulations the oil leg will preferentially spill. In the Hammerfest Basin area of the Barents Sea, residual oil legs in fields such as Snøhvit and Askeladden show that significant oil spillage took place during Plio-Pleistocene uplift (Kjemperud & Fjeldskaar 1992; Nyland *et al.* 1992; Doré & Jensen 1996). It has been assumed by some workers that most of the oil from the Middle Jurassic reservoir has been lost to the surface, but recent careful modelling of the direction of remigration has led to the discovery of a new oilfield (Goliath) on the periphery of the basin (B. Wandaas, pers. comm.). All of the basins immediately adjacent to the Norwegian landmass (e.g. Horda Platform, Egersund Basin) will have been tilted westwards during the Cenozoic uplift of Scandinavia, and hydrocarbon redistribution by spillage can confidently be inferred there (Doré & Jensen 1996).

Risk associated with charging in an exhumed basin can be mitigated in the following ways: (1) by assessing the residual hydrocarbon budget after 'switching off' of source rock maturation; (2) by recognizing the hydrocarbon displacement drivers in the basin; (3) by identifying the post-exhumation regional spill direction; (4) by determining remigration pathways and bypassed areas ('shadows'). Timing of trap formation (pre-, syn- or post-uplift) is also critical with respect to charge adequacy.

Probability of oil versus gas

Perhaps the most radical effect of uplift on hydrocarbon basins is the shift towards gas-dominated systems. Several phenomena conspire to produce this effect, as follows.

(1) Gas exsolution from oil. Assuming a reservoired fluid is at or below its bubble-point pressure at maximum burial, a gaseous phase will be exsolved on uplift and consequent pressure–temperature reduction. Unless a trap is initially underfilled, oil will therefore be driven from the trap (Nyland *et al.* 1992; Doré & Jensen 1996).

(2) Gas expansion as a result of pressure–temperature reduction. This will result in net loss from gas-filled traps and, again, preferential displacement of the oil leg in two-phase accumulations. Nyland *et al.* (1992) estimated that over two billion barrels of oil were lost from the Snøhvit Field in the Barents Sea because of the combined effect of gas exsolution and expansion during regional uplift.

(3) Methane liberation from formation brine. At constant pressure, the solubility of methane in water attains a minimum between about 60 and 90 °C, then increases with temperature. At constant temperature, methane solubility increases with pressure. Therefore, in general, methane solubility in formation brines will increase with burial and, conversely, free methane will be liberated during uplift as pressure and temperature decrease (e.g. Culberson & McKetta 1951; Price 1979; Cramer *et al.* 1999; Cramer & Poelchau 2002). This mechanism is perhaps the most potent source of gas during exhumation as gas will be liberated

over the whole basin, tapping methane originally generated by dispersed organic matter as well as from rich source rocks. The potential for gas liberation is vast. All of the giant dry gas fields in the West Siberian Basin probably derive from this process (Cramer *et al.* 1999), as do the major basin-centred gas fields in uplifted basins in the western USA such as the Alberta, Denver and San Juan Basins (Doré & Jensen 1996: Price 2002). Gas fields in uplifted basins in Central Europe (Pannonian, Vienna and Po Basins) have been tied directly to a groundwater origin via noble gas markers (Ballentine *et al.* 1991). Exsolution from water probably also accounts for a significant part of the hydrocarbon budget in gas-dominated uplifted basins on the NW European margin such as the Barents Sea, East Irish Sea Basin, Slyne–Erris Basins and North Celtic Sea Basin. To date, however, the only quantitative work in such areas known to the authors is that reported for the Barents Sea by Doré & Jensen (1996).

(4) Methane expulsion from coal. Coal beds are widespread in many petroleum basins and expel gas as the coal is progressively buried through maturation thresholds. However, coal-bed methane studies show that significant quantities of gas are retained in the coal on internal surfaces (adsorption) or within the molecular framework of the organic matter (absorption). This methane will migrate out of the coal by desorption and diffusion during reduction in pressure (Littke & Leythaeuser 1993, Fig. 4; Rice 1993). Expulsion during uplift is also aided by increase of macroporosity and permeability in the coals compared with deeply buried coals of similar rank, presumably partly as a result of fracture dilation (Littke & Leythaeuser 1993, Fig. 5).

(5) Hydrodynamic flow. During subsidence, compaction-driven water flow outwards to the flanks of the basin is normal, whereas the outcrop of aquifers and development of topography during uplift and erosion may reverse this situation and create gravity-driven water flow towards the basin centre (see further discussion by Corcoran & Doré (2002)). As shown by Cramer *et al.* (1999), this flow provides a recharge mechanism whereby methane may be brought in from outside the normal drainage area of a gas field and liberated as a result of drop in reservoir pressure. Cramer *et al.* estimated that about 12% of the gas reserves of the giant Urengoy Field (Western Siberia) were emplaced in this way. Additional biogenic methane may be introduced during or after uplift by groundwater flow through coal beds, a process that can stimulate bacterial acivity and gas production from coal of any rank (Rice 1993). Finally, introduction of fresh groundwater into the system is also likely to promote bacterial biodegradation of any shallow oils within the aquifer, leading to the formation of heavy oil residues and again changing the oil–gas balance.

A changed oil–gas balance can also occur via retrograde condensation. In this case oil is favoured as a result of the dropping out of liquids from a wet gas during a reduction in pressure and temperature induced by uplift (e.g. Piggott & Lines 1991; Duncan *et al.* 1998). Otherwise the overwhelming tendency is for an increase in gas exsolution from oils, brines and coals. It may be predicted that significant exhumation of a petroliferous basin will produce a massive gas bloom in the basin centre, driving oil to peripheral locations, to more shallow depths where it will be biodegraded, or to the surface.

Assessment of the risk of gas flushing during uplift and pressure–temperature decrease can be carried out by geochemical modelling of the original oil–gas balance in a prospect. Input of gas by exsolution from formation brine can be assessed from volumetric calculations on the aquifer draining into the prospect (Doré & Jensen 1996; Cramer *et al.* 1999). Knowledge of formation water salinity will improve such calculations, because more saline brines can dissolve less methane (Maximov *et al.* 1984). Contribution of exsolution gas from hydrodynamic flow can be estimated by mapping hydraulic gradients, as shown by Cramer *et al.* (1999). In all cases control points such as nearby wells will, of course, increase the accuracy of such estimates.

Probability of trap and seal

Traps can be eliminated, or their volume decreased, by the effects of regional tilting during exhumation. Similarly, new traps can be created by tilting of three-way dip closures ('noses'). Extreme exhumation may, of course, breach pre-existing accumulations at the surface. In areas where uplift is associated with faulting, tectonic breaching of traps can occur through fault displacement of the seal (caprock), fault juxtaposition of hydrocarbon reservoirs against aquifers or thief zones, or the formation of crestal extension fractures over domes and anticlines. Where inversion (i.e. compressive reactivation of an extensional basin) is involved, traps such as horsts or tilted fault blocks may be destroyed, whereas new traps can be created by (for example) reverse rejuvenation of half-graben or bulge of the basin centre. MacGregor (1995) has shown from a global database that exploration success rates in strongly inverted rifts are lower than those in locally inverted rifts and much lower than those in uninverted rifts. In all cases, a key consideration is the timing of generation compared with the timing of uplift and restructuring. As already demonstrated, during uplift no new hydrocarbons can be generated from source rocks to compensate for redistribution losses. Newly created structures must therefore be filled by remigration or by hydrocarbons (principally gas) from exsolution.

A second and equally important consideration is the performance of sealing lithologies during uplift. In general, as a claystone seal is buried it becomes more compacted and stronger. When exhumed it should retain the tensile strength of its maximum burial depth, and thus will be stronger than a claystone at the same depth in a continuously subsiding basin. This observation is supported by LOTs (leak-off tests) and FITs (formation integrity tests) on seals in uplifted Atlantic margin basins (Corcoran & Doré 2002). Additionally, greater compaction than 'normal' (and corresponding decrease in pore throat size) should increase the capillary retention capacity of an exhumed claystone. Therefore, under certain conditions, the seal capacity of a prospect in an exhumed basin may be superior to that in a subsiding basin, at the equivalent depth. However, several important factors combine to diminish this capacity, as follows.

(1) Brittleness of the seal. A ductile rock can accommodate more strain (up to 10%) before fracturing than a brittle rock (<3%). Changes in ductility with increasing burial depth are complex and depend on composition, temperature, confining pressure and fluid pressure (Davis & Reynolds 1996). In general, however, brittleness in claystones can be said to increase with density, with the transition from ductile to brittle behaviour taking place over the range 2.2–2.5 $g\,cm^{-3}$ (Hoshino *et al.* 1972). Consequently, exhumed claystone seals may be more brittle than normal seals at the same depth. Brittle seals will be more likely to rupture and leak in response to stress (e.g. from tectonic bending or hydrofracturing) than ductile ones, which will deform elastically and plastically before fracturing. A crucial question, therefore, is whether embrittlement of a potential claystone seal has taken place before uplift. Evaporites or mudstones containing evaporitic minerals, which deform plastically under a very wide range of pressure–temperature conditions, form the most efficient seals in uplifted basins (see, for example, work on the East Irish Sea Basin by Seedhouse & Racey (1997) and Cowan *et al.* (1999)).

(2) Hydraulic fracturing. Hydraulic leakage may occur when rapid exhumation, under conditions of low differential stress and disequilibrium fluid pressures, results in failure of brittle seals. This failure may be manifested as extensional shear fractures, dilation of fault planes, or hydrofracturing. Shear fractures will be formed in conditions of high differential stress in the caprock and will be promoted by disequilibrium pore pressures during rapid uplift. Pre-existing fractures and faults may also be induced to fail in these circumstances. The orientation of the new fractures that form, and of the pre-existing fractures that reactivate, will depend on the direction of the principal compressive stress (σ_1). Under conditions of low differential stress and similarly high retained disequilibrium fluid pressures, hydrofractures are likely to form by tensile failure of the caprock (Corcoran & Doré 2002; see also Sibson 1995).

(3) Diffusion. Leakage of hydrocarbons by means of molecular transport through caprocks is thought to be usual in petroleum basins (e.g. Krooss *et al.* 1992). Whereas diffusion rates for oil are probably negligible because of the large size of the oil molecules, gas will diffuse more readily through water-saturated claystone caprocks. There is considerable debate in the literature on diffusion rates, but there seems little doubt that over a moderate geological time scale (say, the length of the Cenozoic period, 65 Ma) diffusion losses from a shale-sealed gas field can be considerable (e.g. Leythaeuser *et al.* 1982; Krooss *et al.* 1992). In a subsiding basin the fill of a gas field will be determined by the ratio of diffusion losses through the seal to newly generated gas entering the trap. After exhumation, however, the supply of new hydrocarbons will be arrested, allowing the trap to be gradually depleted via diffusion. The diffusion rate of methane through evaporites is so low as to be negligible, again showing that evaporites are highly efficient seals that can preserve hydrocarbons over significant geological time in exhumed basin settings (see, for example, Kontorovitch *et al.* (1990), on Proterozoic gas reservoirs in the Lena–Tunguska Basin, Russia).

In summary, in exhumed basins the risk associated with trap and seal is significantly increased. Underfilled traps and near-hydrostatic reservoir pressures are commonly encountered in uplifted Atlantic margin basins (Corcoran & Doré 2002), presumably reflecting pressure depletion through the seal during exhumation, lack of new hydrocarbons from source rocks once uplift commenced, lack of new exsolution products once uplift stopped, subsequent escape of gas by diffusion and contraction of gas during post-exhumation reburial. Uplift-related depressuring in low-permeability rocks can also result in transient underpressuring, i.e. pressure gradients below hydrostatic (Luo & Vasseur 1995). Underpressuring is also a characteristic of the basin-centred gas fields in uplifted basins in the western USA. Some of these fields, such as Elmworth in the Alberta Basin, are actually synclines (Masters 1984) in which the gas accumulation probably represents a disequilibrium condition and where the underpressuring may be attributable to thermal contraction of formation fluids (Price 2002). Apart from a single well in the Barents Sea (Doré & Jensen 1996) underpressuring has not yet been reported in the Atlantic margin basins.

The probability of trapping in an exhumed basin setting is best assessed by structural modelling, whereby the timing of trap formation and modification is compared with the timing of charging. Knowledge of maximum burial depths (and hence maximum pressures and temperatures) can indicate whether a shale seal is likely to have become embrittled before exhumation. Evidence of fracture trends and present-day stress systems, combined with modelling of pressure evolution, can help in assessing whether hydraulic failure of seals is likely to have occurred. Published data on methane diffusion rates, in combination with estimation of the time elapsed since uplift of a trap, can quantify likely diffusion losses through a seal. Evidence of evaporites in an uplifted basin, even at a very preliminary stage of evaluation, significantly enhances the probability that some trapping capability will have been retained during exhumation.

Prospect resource estimation in exhumed basins

Introduction

Potential hydrocarbon reserves in a prospect are estimated from an equation of the type

$$\mathrm{RR} = \mathrm{GRV} \times \mathrm{N/G} \times \phi \times S_{\mathrm{hc}} \times \mathrm{FVF} \times \mathrm{RF} \quad (3)$$

where RR are the recoverable hydrocarbon reserves, expressed as a volume; GRV is the gross rock volume, i.e. the volume of the reservoir within the potential trap; N/G is the net-to-gross ratio, i.e. the fraction of the reservoir that is capable of containing movable hydrocarbons; ϕ is the interconnected porosity in the reservoir, expressed as a fraction; S_{hc} is the hydrocarbon saturation, i.e. the fraction of pore space taken up by hydrocarbons; FVF is the formation volume factor, a multiplier taking into account the expansion of gas or the contraction of oil (owing to liberation of dissolved gas) as the hydrocarbons are brought to surface pressure and temperature conditions during production; RF is the recovery factor, i.e. the proportion of the hydrocarbons in the prospect that can be recovered to surface given an assumed production method. These factors are estimated based on the predicted depth of the prospect, local and regional data, and experience.

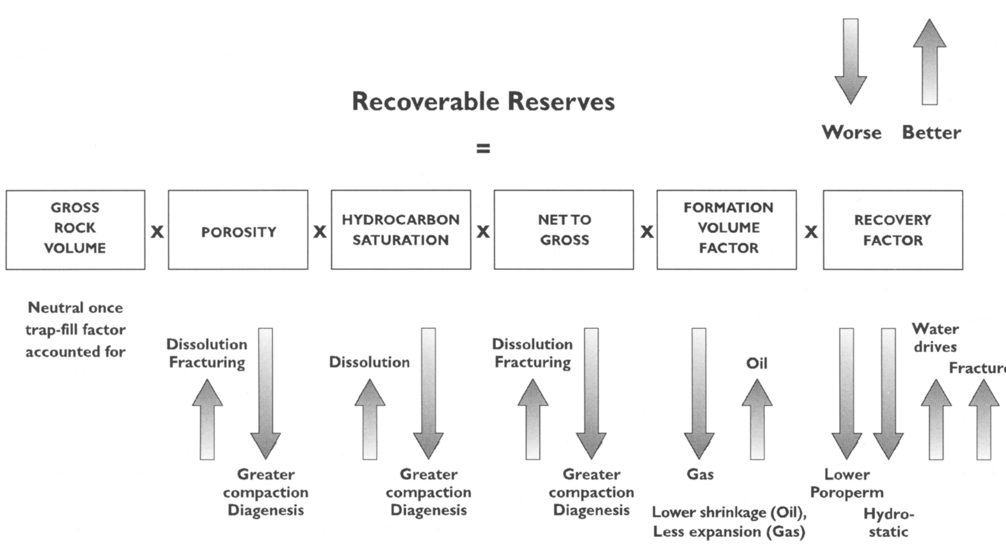


Fig. 3. Factors to be considered when carrying out recoverable reserves calculation for a prospect in an exhumed basin. Arrows indicate improvement or deterioration in reservoir parameters.

Uncertainty in reserves estimation is traditionally addressed by assuming a range of values for each prospect parameter (GRV, N/G, porosity, S_{hc}, FVF, RF) and by applying stochastic simulation procedures to generate a range of reserves. Predictive capability is, of course, mainly a function of local data density and quality. Where evaluation is mainly dependent on regional data, it is especially critical to know whether a basin has been exhumed. The effects of exhumation on the volumetric parameters are shown in Fig. 3 and discussed below.

Gross rock volume

Because the measurement of the total potential volume within a trap is made on a prospect-specific basis, this value is independent of whether the trap has been exhumed. However, the actual volume also depends on the degree-of-fill factor, i.e. the proportion of the available vertical closure taken up by the hydrocarbon column. For continuously subsiding basins, Sales (1993) and others have shown that a range of trap-fill values is possible, based on the relationship between the vertical closure (and hence the potential upward buoyancy pressure of any hydrocarbon fill) and the sealing capacity of the caprock. Because there is often a continuous supply of newly generated hydrocarbons in such basins, the sealing capacity becomes the main limiting factor. If the seal is efficient, the structure has a good chance of being completely hydrocarbon-filled: for example, Sales (1993) asserted that most gas fields in the Norwegian North Sea are full to spill. In contrast, in an exhumed basin, trap-fill is limited not only by sealing capacity (which, as shown in the section on trap and seal, can be catastrophically reduced during exhumation) but also by the hydrocarbon budget generated or liberated at the time of the last exhumation. Processes subsequent to exhumation (e.g. diffusion and reburial contraction of gas) will serve to diminish the trap-fill. This observation is strongly supported by observation of underfilled gas fields in NW European uplifted basins such as the Barents Sea (Spencer *et al.* 1987), West Shetland Basin (e.g. Goodchild *et al.* 1999), East Irish Sea (e.g. Stuart & Cowan 1991), Southern Gas Basin (e.g. Hillier & Williams 1991) and Slyne–Erris Basin (in-house data on the Corrib Field).

Net-to-gross ratio, porosity and hydrocarbon saturation

A sedimentary rock that has been uplifted with resulting removal of overburden will preserve the compactional and diagenetic state associated with its maximum burial depth. In most cases these higher levels of compaction and diagenesis (stylolitization, quartz precipitation and authigenic clay mineral formation) will involve porosity loss. Consequently, there will be a decrease in hydrocarbon saturation as a result of the increased proportion of a given pore occupied by the wetting water phase. Net-to-gross ratio will also be impaired as a result decrease in porosity or permeability of some rock below the threshold considered to define an effective reservoir. Thus, overall reservoir quality will usually be impaired compared with that at a similar depth in a subsiding basin. This general principle is illustrated in the Barents Sea, where Middle Jurassic sandstones in the Hammerfest Basin are petrographically similar to those that form major reservoirs off Mid-Norway and in the North Sea. The Barents Sea reservoirs, however, consistently show higher levels of stylolitization (Walderhaug 1992) and quartz precipitation (Berglund *et al.* 1986), with consequently lower porosities (Olaussen *et al.* 1984), because of a maximum burial depth some 1500 m greater than at present.

As indicated by Price (2002), cooling of formation waters during uplift will also result in the precipitation of solutes (e.g. silica) and hence the occluding of porosity. However, as Parnell (2002) points out, this effect may be minor and is not widely observed; furthermore, some mineral species (notably carbonates) become increasingly soluble at lower temperatures, thereby introducing the possibility of secondary porosity development.

As discussed in the section on prospect risk analysis, exhumation creates an increased probability of hydrodynamic flow and the introduction of meteoric water into the basin aquifers. Such groundwater will usually contain dissolved oxygen and will be acidic (principally as a result of dissolved carbon dioxide), leading to the possibility of oxidation and acid dissolution in reservoirs. The effect on reservoir quality will be complex and depend on the chemistry of the reservoir, the formation water and the introduced water. Oxidation of ferromagnesian minerals may form pore-clogging iron oxides, whereas acid dissolution of feldspars and carbonates can create substantial secondary porosity (see the much fuller discussion by Parnell (2002)). These effects are likely to be most prevalent close to the surface where meteoric water flow is strongest. Nevertheless, they can form an important modifier to the overall negative implications of exhumation on reservoir quality; in basins that have undergone repeated exhumation and reburial episodes, improved reservoir quality as a result of dissolution may be forecast below unconformity surfaces (e.g. Shanmugam 1988).

Knowledge that a basin has been exhumed allows the interpreter to place constraints on predicted reservoir quality. The most useful data for this process are, of course, local well descriptions, which will give direct evidence as to the detrital and authigenic mineralogy of the reservoir. However, even without such data, reconstruction of the maximum burial depth (maximum temperature exposure) of the reservoir is important. It allows a first-pass prediction as to whether the reservoir has exceeded temperature thresholds for kinetically controlled poroperm-reducing mineral transformations; for example, quartz cementation and the development of authigenic illite (e.g. Nadeau *et al.* 1985; Bjørkum *et al.* 1993).

Formation volume factor

Uplift of a hydrocarbon accumulation will result in lower temperatures and pressures, with exsolution of dissolved gas from oil and expansion of reservoired gas. Therefore, for a given hydrocarbon pore volume the expectation will be for more oil (because of lower shrinkage on production) and less gas (because of less expansion on production). It can be argued that these factors are independent of whether the reservoir has been uplifted, and are simply a function of pressure–temperature–volume relationships at a given depth. Although this is undoubtedly true, the occurrence of near-hydrostatic pressure gradients resulting from pressure dissipation on uplift (as observed on the NE Atlantic margin) will create a tendency towards lower shrinkage oils and lower expansion gases compared with a continuously subsiding basin.

Recovery factor

Recovery factor can be influenced positively and negatively by uplift and exhumation. Generally, the lower porosity and permeability of an uplifted reservoir for a given depth should impair recovery factor for both oil and gas. Additionally, the dissipation of overpressure during uplift will limit the amount of hydrocarbon that can be produced by simple pressure depletion, whereas a reservoir in a subsiding basin at the same depth may retain overpressure and hence have a higher initial reservoir pressure. Running counter to this argument, the development of open pressure systems and hydrodynamic flow as a result of exhumation may provide pressure maintenance (water drives) during commercial depletion of a field.

Fractures are an extremely important component of productive reservoirs worldwide, and can be attributed to diastrophism (for example, over fold axes, e.g. Aguilera 1980) or to removal of overburden stress by exhumation (e.g. Aguilera 1980: Sibson 1995: Corcoran & Doré 2002). As shown in the section on probability of trap and seal, shales that have been embrittled during burial may fracture during uplift. Reservoir lithologies are generally more brittle than sealing lithologies such as shales and evaporites. Tight sandstones, quartzites and dolomites are the most fracture-prone and limestones are the most ductile of the potential reservoir rocks (Handin *et al.* 1963: Stearns & Freidman 1972: Doré & Jensen 1996). Therefore, reservoirs may fracture without corresponding rupture of the caprock, a situation that creates the basis for globally important hydrocarbon resources such as the Asmari fractured carbonate fields of the Zagros fold belt (e.g. Daniel 1954).

Fracturing during uplift can create reservoirs from non-reservoir lithologies (e.g. basement or siliceous shales), contribute to both porosity and permeability in low-poroperm reservoirs, and enhance pore connectivity (and hence permeability) in higher poroperm reservoirs. Fractures therefore have the potential to significantly boost recovery in uplifted terranes where poroperms would otherwise be unacceptably low. A critical issue to well location, well completion and recovery in fractured reservoirs is identification of the fracture sets that are dilatational (and hence contribute the most to fluid flow). Dilation will occur most readily in fractures orthogonal to the least compressive stress direction (σ_3), which will be approximately horizontal in an extensional regime and approximately vertical in a compressional regime. For a simplified case of subvertical fractures, natural fractures are more likely to be open and support fluid flow if they strike close to the maximum horizontal stress (S_{hmax}) direction, an observation supported by global waterflood studies on producing fields (Heffer & Dowokpor 1990). The NE Atlantic margin at present is under a mild NW–SE compressive regime, probably attributable to ridge-push from the Atlantic spreading centre (Doré & Lundin 1996). Where evidence exists, it appears that open fractures have a strike close to the NW–SE S_{hmax} direction. The Clair Field in the uplifted West Shetland Basin has a reservoir consisting of fractured Upper Palaeozoic sandstone. Detailed studies show that specific fracture sets aligned close to S_{hmax} are dilatational, allowing a recovery program to be devised based on exploiting these fractures with directional wells (Coney *et al.* 1993).

Borehole data, regional geology, seismic reconstruction and basin modelling can help to assess whether fracture enhancement of an uplifted reservoir is likely to have occurred. Key criteria are: (1) prognosed reservoir lithology; (2) maximum burial depth and degree of uplift of the reservoir; (3) probability of overpressure development and dissipation; (4) direction of seismically mappable faults; (5) direction of fractures from boreholes or regional outcrop data; (6) present-day stress-field orientation.

Synopsis: key characteristics of hydrocarbon systems in exhumed basins

On the basis of the foregoing discussions, it is possible to describe a suite of phenomena prevalent in exhumed hydrocarbon systems (Fig. 4). Although these characteristics can also occur in subsiding basins, the occurrence of many or all factors together will be a strong signature of exhumation. Conversely, prior knowledge that a basin has been exhumed (from, for example, its truncated stratigraphic record or characteristic structural style) allows such factors to be anticipated. They are as follows:

(1) near-hydrostatically pressured or underpressured reservoirs as a result of catastrophic pressure release during exhumation. Underpressure may derive from depressuring and/or thermal contraction in low-permeability aquifers.

(2) Underfilled traps resulting from reduction in sealing capacity, spillage losses, and remigration inefficiency during exhumation, followed by cessation of the hydrocarbon supply, diffusion of gas and reburial shrinkage of gas after exhumation.

(3) Large, basin-centred gas deposits liberated during uplift from oils, formation brines and coals, and further displacing pre-existing oil by gas expansion. These accumulations often overlie the deepest part of the basin because of the thicker sedimentary succession available to generate exsolved gas, inversion of the basin centre to create new structural traps, slow dissipation of the gas bloom in low-permeability lithologies, and hydrodynamic focusing.

(4) Two-phase accumulations as a result of gas exsolution from oil and retrograde condensation of liquids from wet gas during uplift.

(5) Residual oil columns left behind by seal failure or in tectonically breached traps, by spillage, and by rising of the gas–oil and oil–water contacts during post-exhumation diffusion of the gas cap.

(6) Small, remigrated peripheral oil deposits: oil that is not driven completely from the system by seal failure, tilting and gas flooding is likely to accumulate in traps on the basin margin, for example, hanging-wall traps.

(7) Heavy oil deposits formed by the remigration of oils to shallow levels of the basin, where washing by meteoric water inflow and bacterial biodegradation can occur.

The occurrence of these characteristics on the NW European margin is discussed below with reference to selected basins (Figs 5–10) and summarized in Fig. 11.

Examples: exhumed provinces on the NW European margin

In the case histories and in Figs 5–10 the following terms of reference are used: (1) exhumation is uplift of key reference horizons above maximum burial depth; (2) two-phase accumulations are counted as both oil and gas; (3) success rate indicates the number of discovered pools of testable hydrocarbons divided by the number of exploration wells; it does not represent the rate of commercial success.

Western Barents Sea (Fig. 5)

The Barents Sea consists of a complex mosaic of basins and platforms, which in the western (Norwegian) sector become younger towards the North Atlantic Ocean. In the east, the Nordkapp Basin is a NE–SW-trending graben, initiated in Late Palaeozoic time and dominated today by near-surface salt domes and walls formed from Upper Carboniferous–Lower Permian halite. Farther west, the Hammerfest Basin, is an en echelon continuation of this trend, but in contrast the last significant rift episode was later (in Late Jurassic–Early Cretaceous time). The Hammerfest Basin is cross-cut to the west by a north–south line of deep Cretaceous depocentres (Bjørnoya and Tromsø Basins), which are in turn superceded to the west by Tertiary depocentres (e.g. Sørvestnaget Basin) close to the continent–ocean boundary (Gabrielsen *et al.* 1990).

Major exhumations took place during Cenozoic time, roughly synchronous with uplift of the Fennoscandian mainland. These included an episode of Paleogene uplift probably associated with incipient opening of the NE Atlantic, and a particularly severe Plio-Pleistocene episode emphasized by repeated glacial erosion and isostatic re-equilibration. The Nordkapp Basin is deeply exhumed, with a thin layer of Quaternary sediments overlying truncated Cretaceous rocks. Some Tertiary sediments are preserved in the Hammerfest Basin, but there is a major unconformity between the Paleocene and the Pliocene sequences (e.g. Westre 1983), and well data indicate removal of about 1500 m of overburden (e.g. Nyland *et al.* 1992; Walderhaug 1992).

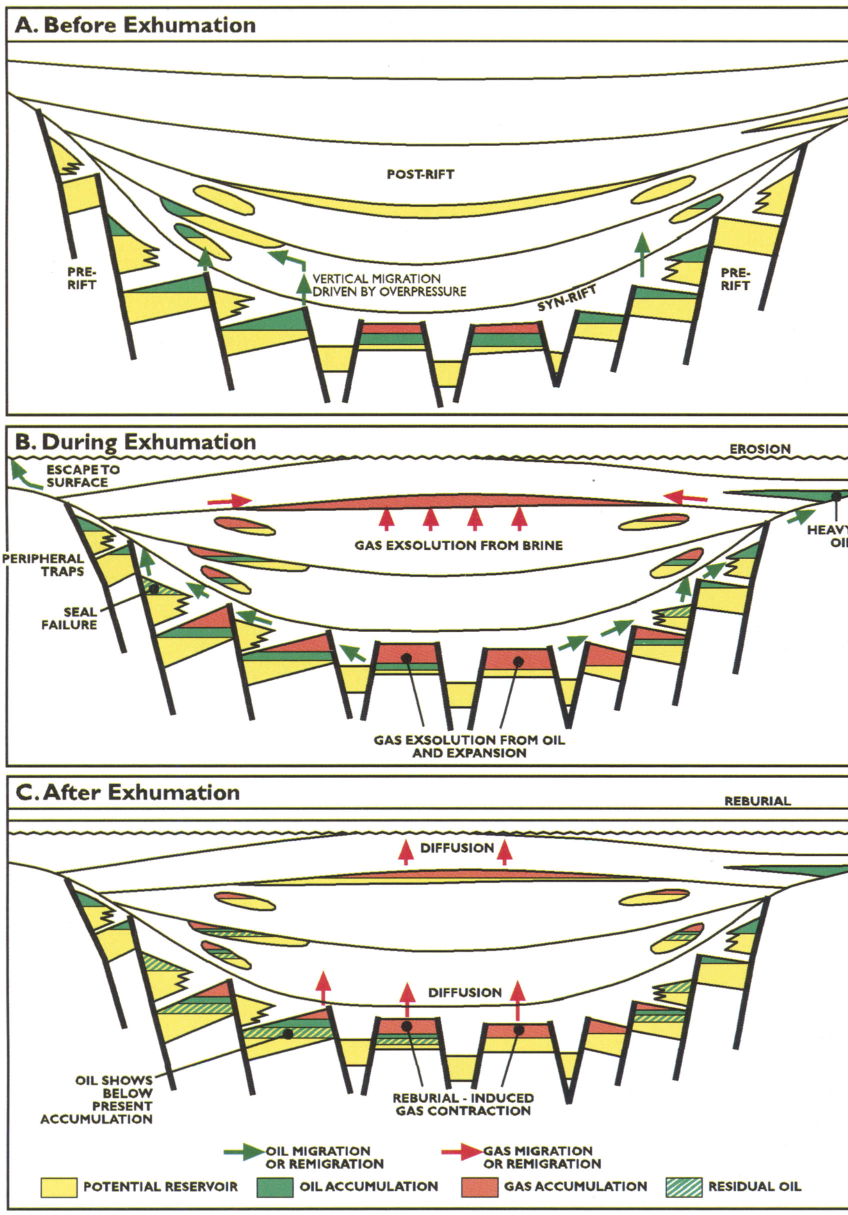


Fig. 4. Highly schematic and vertically exaggerated basin cross-section illustrating some effects of exhumation on the hydrocarbon system. (**a**) A simple rift geometry containing an oil-dominated hydrocarbon system, used as the starting point. (**b**) Effects taking place during exhumation. Regional exhumation, in this example, is accompanied by inversion of the basin centre. (**c**) Processes after exhumation has ceased and minor reburial has taken place.

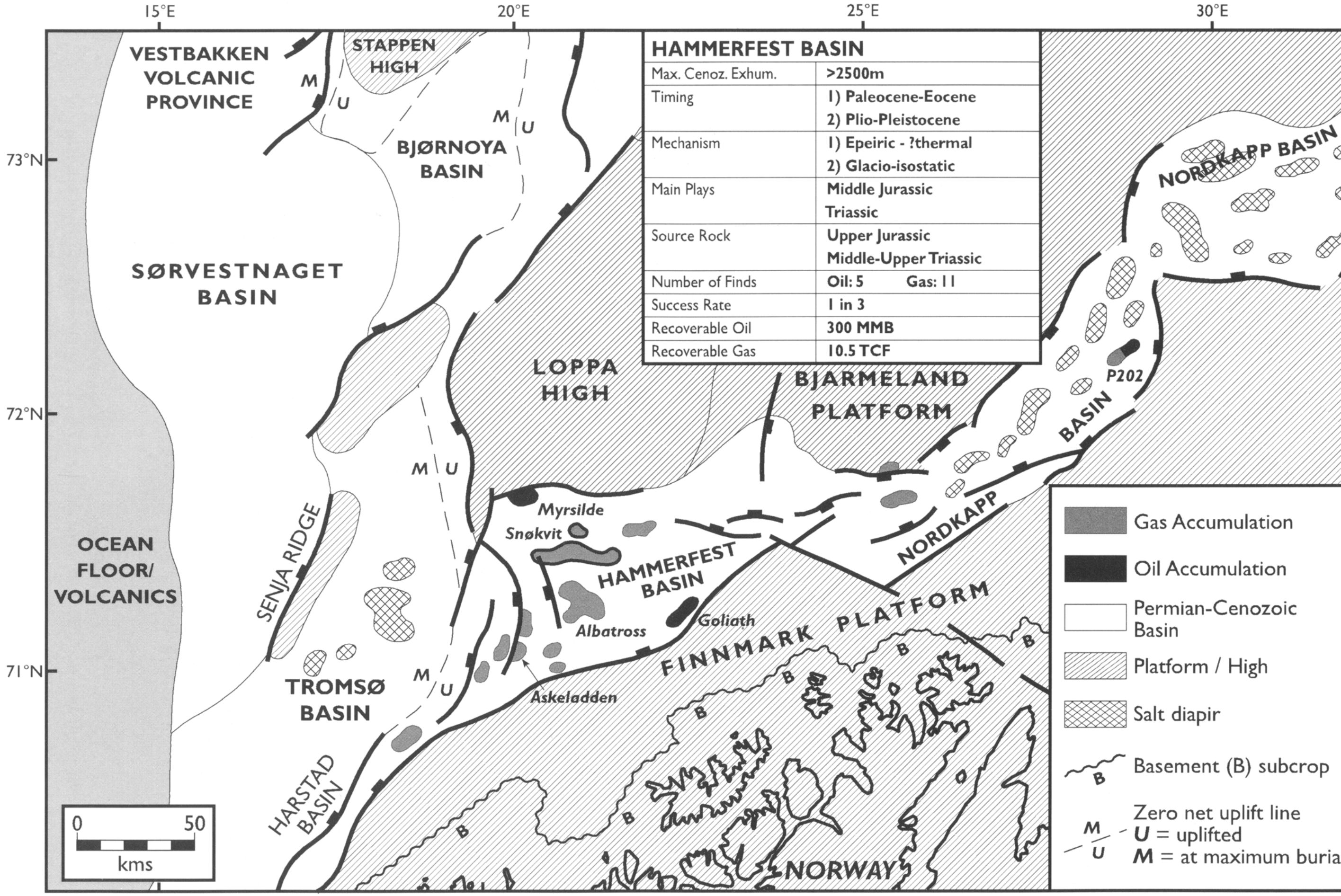
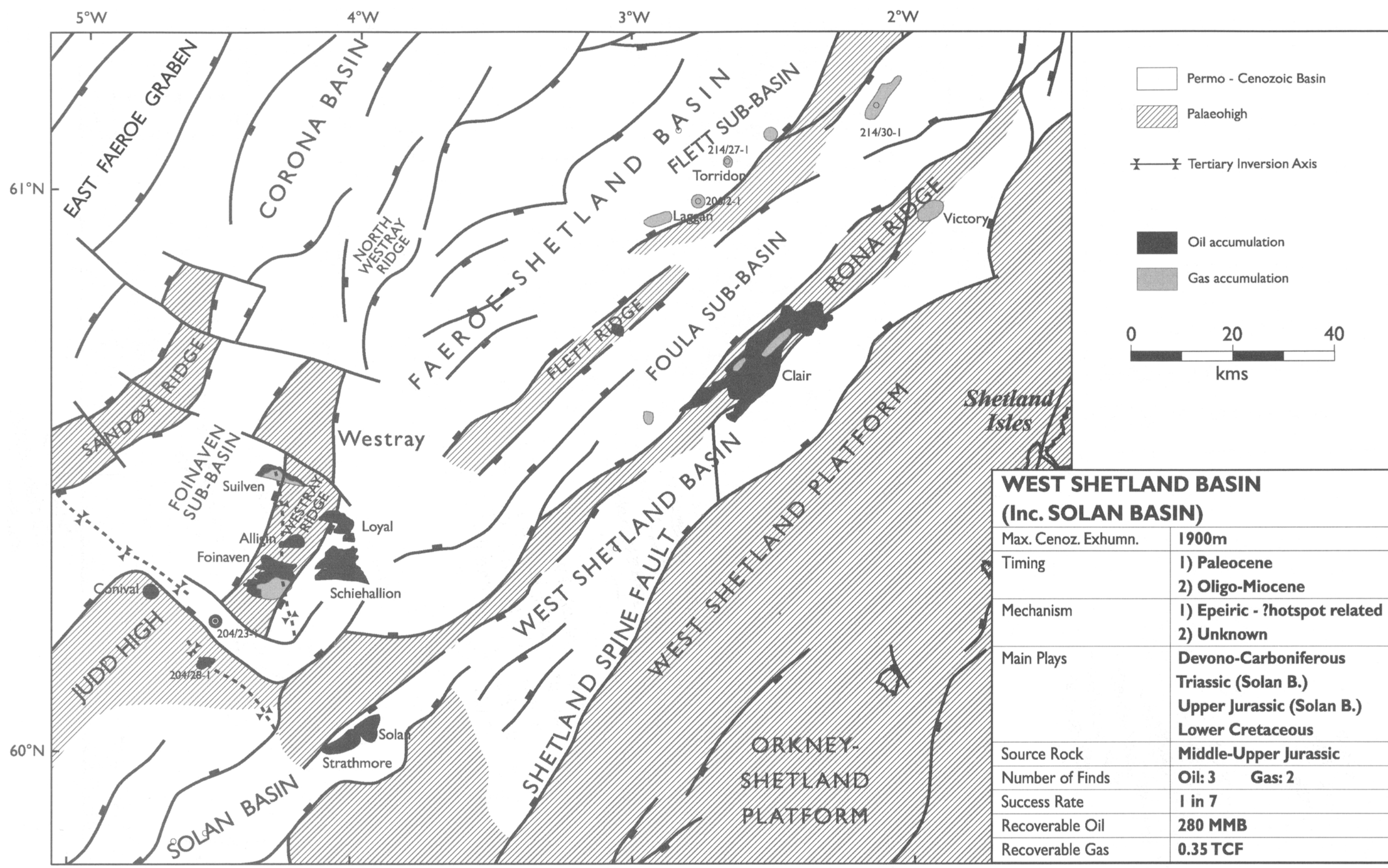


Fig. 5. Structural features, hydrocarbon discoveries and data template for the western Barents Sea. In the inset table: (1) exhumation is uplift of key reservoir horizons above maximum burial depth; (2) two-phase accumulations are counted as both oil and gas finds; (3) success rate does not represent commercial success, it indicates the number of discovered pools of testable hydrocarbons divided by the number of exploration wells.



WEST SHETLAND BASIN (Inc. SOLAN BASIN)	
Max. Cenoz. Exhumn.	1900m
Timing	1) Paleocene 2) Oligo-Miocene
Mechanism	1) Epeiric - ?hotspot related 2) Unknown
Main Plays	Devono-Carboniferous Triassic (Solan B.) Upper Jurassic (Solan B.) Lower Cretaceous
Source Rock	Middle-Upper Jurassic
Number of Finds	Oil: 3 Gas: 2
Success Rate	1 in 7
Recoverable Oil	280 MMB
Recoverable Gas	0.35 TCF

Fig. 6. Structural features, hydrocarbon discoveries and data template for the West Shetland Basin. (For qualifiers to inset table, see Fig. 3.)

Exploration drilling of the Norwegian Barents Sea commenced in 1980 and at time of writing about 60 wells have been drilled. Although success rates have been fairly high (about one in three) the results have been commercially disappointing, largely because of the dominance of gas and the remoteness of the area from potential gas markets. Discovered resources are currently about 10.5 TCF (trillion cubic feet) gas with about 300 MMB (million barrels) oil. Most of the gas discovered to date is concentrated in three fields (Snøhvit, Askeladden and Albatross) in the axial part of the Hammerfest Basin, comprising fault blocks and horsts with a Middle Jurassic reservoir (Stø Formation) sealed by Upper Jurassic shales. Sourcing is from the Upper Jurassic Hekkingen Formation, which attained maturity before uplift in northern and western parts of the Hammerfest Basin.

The hydrocarbon system shows many classic attributes of exhumation. The Middle Jurassic reservoirs have anomalously high levels of diagenesis (e.g. Walderhaug 1992). The central gas accumulations are underlain by thin oil discs or residual oil legs, a result of spilling of pre-existing oil deposits. Modelling of the largest field, Snøhvit, suggests that the oil was evacuated by gas expansion and that current underfilling of the trap is consistent with diffusion losses and gas contraction during reburial (Nyland *et al.* 1992). Methane exsolution from oil and brine has probably also contributed to the dominance of gas (Doré & Jensen 1996). Discrete oil accumulations are small, and include the Myrsilde discovery, in Lower Cretaceous sands in a hanging-wall trap against the northern margin of the Hammerfest Basin, and the recent Goliath discovery of 70–100 MMB remigrated oil in a Middle Jurassic reservoir. Current exploration efforts focus on: (1) areas that have not been recently exhumed (e.g. the western margin of the Barents Sea, which received erosion products from the Cenozoic denudations); (2) areas with potential evaporite seals such as the Nordkapp Basin (where well 7228/7-1 in Licence P202 recently found oil and gas in Triassic rocks, partly sealed by a salt overhang); (3) prospects favourably located to receive oil spilled from the main Hammerfest Basin traps.

West Shetland Basin (Fig. 6)

The West Shetland Basin (WSB) and adjacent Faeroe–Shetland Basin (FSB) have a NE–SW grain, cross-cut by NW-trending transfer zones (e.g. Dean *et al.* 1999). The structural history of the area is complex, with multiple rifting events in Permo-Triassic, late Jurassic–early Cretaceous, mid–late Cretaceous and Paleocene times (Doré *et al.* 1999). In the WSB the dominant rifting event was in Permo-Triassic time, after which the basin underwent repeated exhumations while the FSB continued to subside. Major Cretaceous unconformities and/or non-sequences in the WSB presumably represent basin-flank uplift associated with rifting in the FSB. At the end of Cretaceous time the WSB and its southern continuation, the Solan Basin, were uplifted as part of a major emergence of the Scottish massif. Further uplift of the WSB in Oligo-Miocene time was probably connected to an episode of inversion that caused broad domal structuring in the FSB (e.g. Turner & Scrutton 1993: Herries *et al.* 1999; Parnell *et al.* 1999). As a result of repeated uplift and erosion, Cenozoic deposits are thin or absent over the WSB and Solan Basin.

About 60 wells have been drilled in the WSB and Solan Basin with a success rate of one in seven. Proven recoverable resources are in the order of 280 MMB oil and 0.35 TCF gas. Only one accumulation, the Clair oilfield, is currently considered commercial (Coney *et al.* 1993). Hydrocarbons in the WSB were sourced by Upper Jurassic marine shales with a probable Middle Jurassic lacustrine component (Bailey *et al.* 1987; Scotchman *et al.* 1998). Reservoirs range in age from Lewisian basement to Early Cretaceous. Charging occurred during latest Cretaceous and Cenozoic time as pulsed episodes of migration from the adjacent FSB (Parnell *et al.* 1999). Early oil charges have frequently been lost as a result of biodegradation or breaching of traps during uplift, as shown by fluid inclusions and residual shows (e.g. Goodchild *et al.* 1999). Replenishment from a continuously subsiding kitchen in the oil window probably explains the dominance of oil over gas in the basin, despite its exhumed nature.

In the Clair Field 3–5 billion barrels of heavy oil are held in fractured basement and Devono-Carboniferous red beds, although only about 200 MMB are thought to be recoverable because of the low porosity and permeability of the reservoir. Open fractures are important for optimizing deliverability in the reservoir (Coney *et al.* 1993: see also section on recovery factor). The oil is a mixture of biodegraded and fresh oil, a function of the multiple charging. Two small non-associated gas caps on Clair represent a late gas charge, or possibly exsolution gas. In the nearby Victory gas field the early oil charge to the Lower Cretaceous reservoir has been lost as a result of breaching of the trap during early to mid-Cenozoic uplift. This has left residual biodegraded oil within and below the current gas column, which occupies less than half the vertical closure of the structure (e.g. Goodchild *et al.* 1999). Farther south in the Solan Basin, small oil accumulations (Solan and Strathmore) totalling 60 MMB occur in Upper Jurassic and Triassic truncation traps. The non-biodegraded oil was sourced from a limited kichen area, the East Solan Basin, where the Upper Jurassic source rocks are at early oil maturity (Herries *et al.* 1999). Herries *et al.* considered that the fields were charged in two Cenozoic pulses, separated by the Oligo-Miocene inversion episode. We note, however, that because of the current very thin post-Paleocene cover, such generation must imply episodes of reburial and re-exhumation during Cenozoic time.

Inner Moray Firth Basin (Fig. 7)

The Inner Moray Firth Basin (IMFB) lies off the NE coast of Scotland, between the Grampian and Northern Highlands. The basin forms a westerly extension of the trilete Mesozoic graben system and is separated from the eastern part, the Outer Moray Firth Basin, by the Halibut Horst. The structural history of the IMFB is dominated by the effects of Permo-Triassic and Jurassic rifting, subsidence in Late Jurassic to Late Cretaceous–earliest Tertiary time (Andrews *et al.* 1990) and subsequent uplift.

Exhumation of the IMFB has been assigned to Paleocene time by Hillis *et al.* (1994), based on the assumption of synchronicity with the onset of denudation of the Scottish Highlands. Younger uplift episodes are not, however, precluded by the data. For example, Underhill (1991) identified an Oligo-Miocene inversion phase of possible far-field 'Alpine' origin, which reactivated Mesozoic faults and gave rise to differential relief within the basin. Uplift followed by subsidence towards the North Sea graben system has imparted an eastwards tilt to the IMFB, such that Jurassic and Lower Cretaceous rocks subcrop at the sea bed in the westernmost part of the basin and are succeeded eastward by Upper Cretaceous and Tertiary subcrops (Fig. 7). Hillis *et al.* (1994) used sonic velocity data to suggest that about 1 km of erosion took place over most of the basin during early Cenozoic time. However, because of later Cenozoic sedimentation the apparent erosion (net uplift *sensu* Riis & Jensen 1992) decreases eastwards to zero at about 1°W.

Approximately 80 exploration wells have been drilled in the IMFB with a success rate of one in eight, much lower than in the adjacent North Sea. Underhill (1991) attributed poor success rates in this area to breaching of traps by reactivated faults, some of which extend to the surface. Total proven resources are of the order of 680 MMB oil and 0.51 TCF gas. In the western, most uplifted part of the basin a single commercial oil discovery has been made, the Beatrice Field (155 MMB recoverable) along with some much smaller uncommercial oil and gas pools. The Beatrice hydrocarbon system consists of a Middle Jurassic reservoir in a tilted fault-block trap sealed by Oxfordian–Kimmeridgian shales. The oil was co-sourced by Devonian and Middle Jurassic mudrocks (Peters *et al.* 1989). Charging occurred during Late Cretaceous time, after which generation must have ceased as a result of uplift. Remarkably, the oil accumulation appears to have remained intact for the duration of Cenozoic time, preserving a 335 m oil column that fills the structure to spill (Stevens 1991). Retention may be partly due to the efficiency of the shale seal (which may have retained ductility before uplift: see Corcoran & Doré 2002), and partly due to the waxy, viscous nature of the crude. The very low energy of the oil (gas–oil ratio of 126 SCF per barrel, bubble point pressure 635 psig) may testify to gas depletion by diffusion or lack of an original gas charge.

A cluster of fields of mixed phase in the east of the IMF (Captain, Blake, Ross, Cromarty, Phoenix) lie within the uplifted area, although some of these fields may be receiving charge from currently generating kitchens. In the Captain Field, overlying the western end of the Halibut Horst, shallowly buried Lower Cretaceous sandstones contain recoverable oil reserves of 350 MMB sourced from Upper Jurassic rocks. Most of the Cenozoic succession is missing above the field, and the hydrocarbon accumulation carries a strong signature of exhumation. The oil is heavily biodegraded and includes a residual oil column in the east of the field attributed by Pinnock & Clitheroe (1997) to easterly tilting during Cenozoic time. The field has a small cap of thermogenic gas introduced as a late charge (Pinnock & Clitheroe 1997) and probably representing exsolution gas. Notably, however, the field is full to its spill point.

East Irish Sea Basin (Fig. 8)

The East Irish Sea Basin (EISB) is a preserved remnant of a late Palaeozoic to early Mesozoic extensional basin system (Knipe *et al.* 1993). Subsequent uplift and denudation has removed most of the post-Triassic cover from the basin. Post-Triassic burial–uplift history is therefore difficult to reconstruct, and relies on techniques

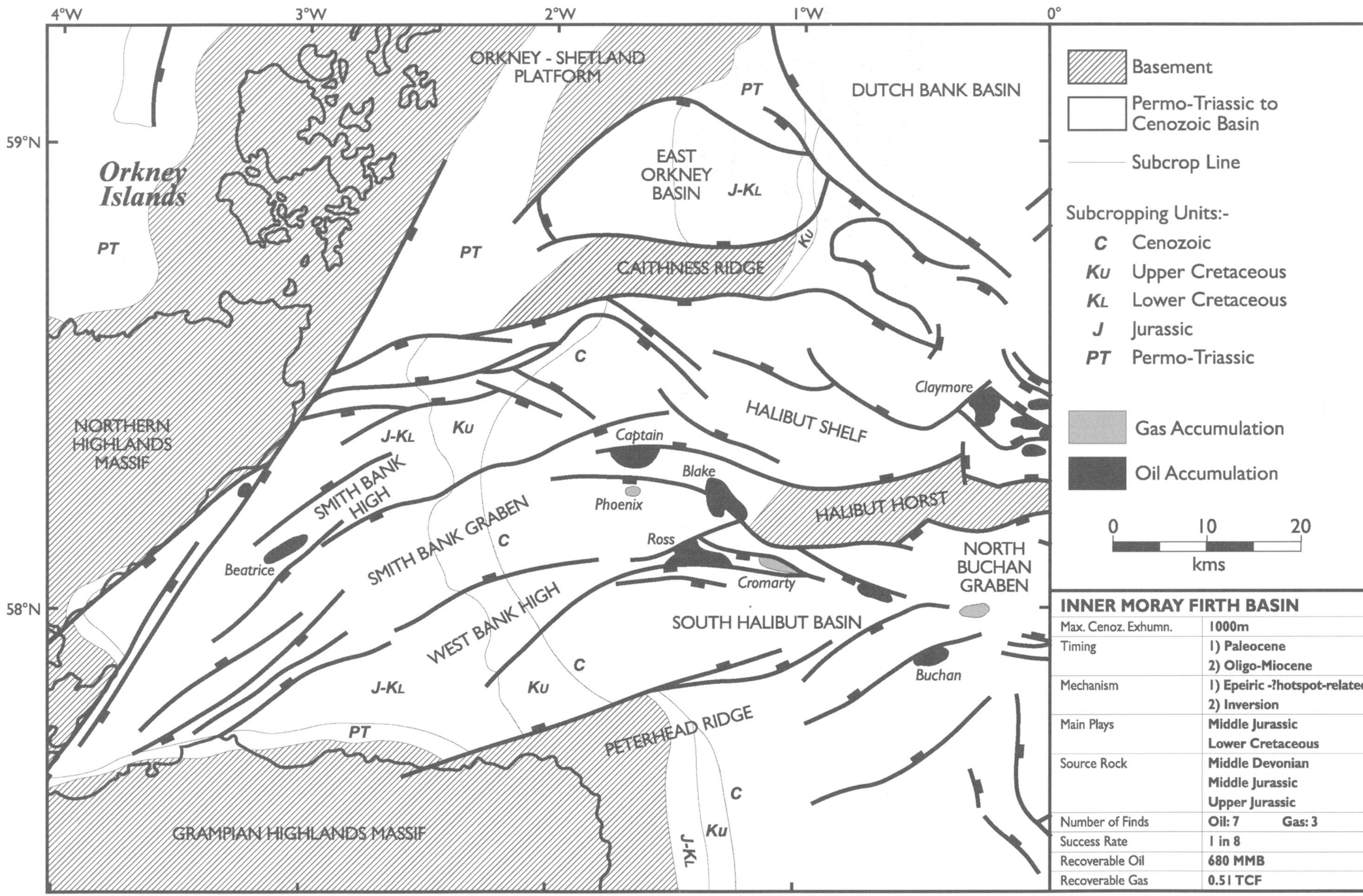
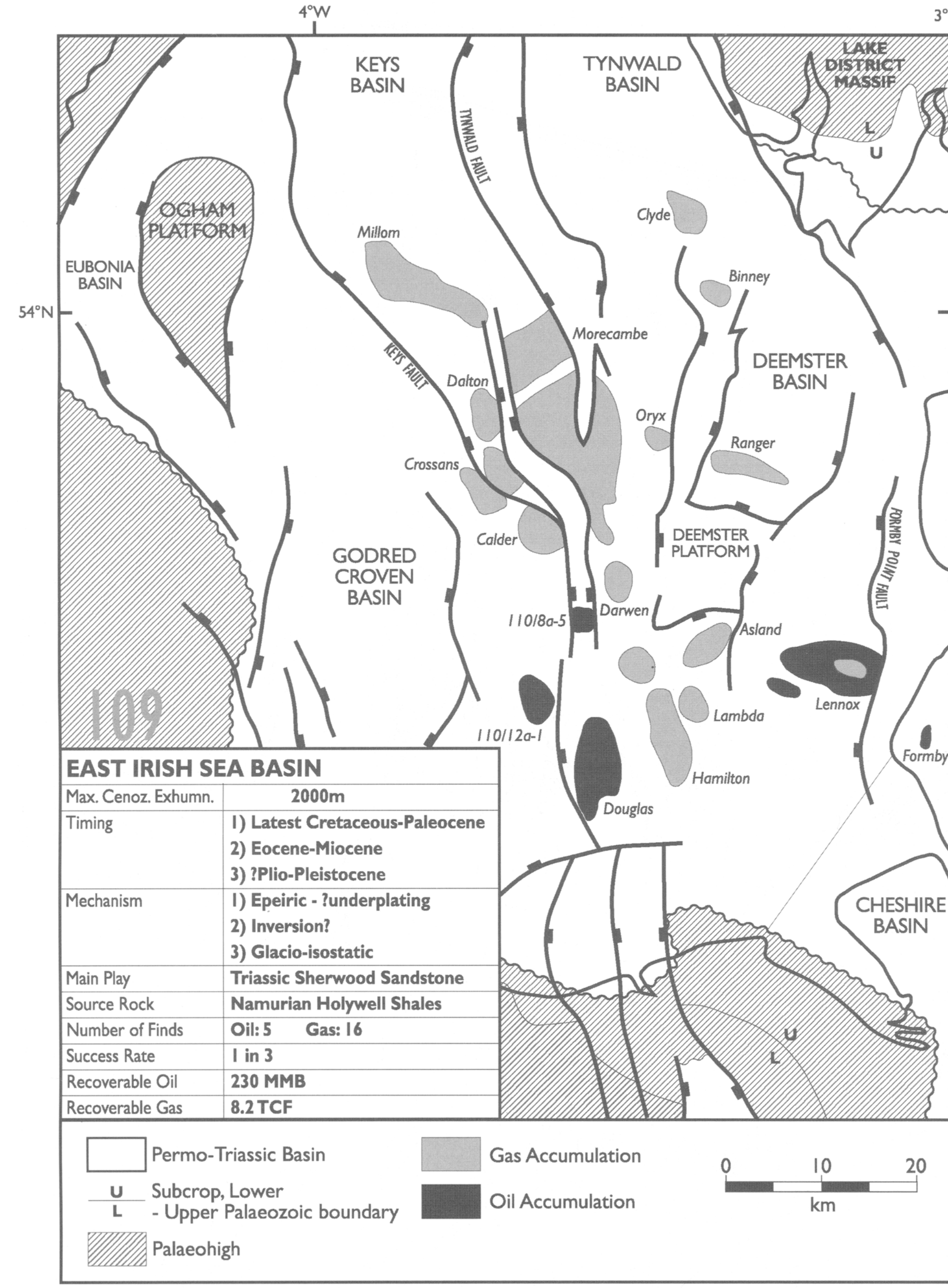


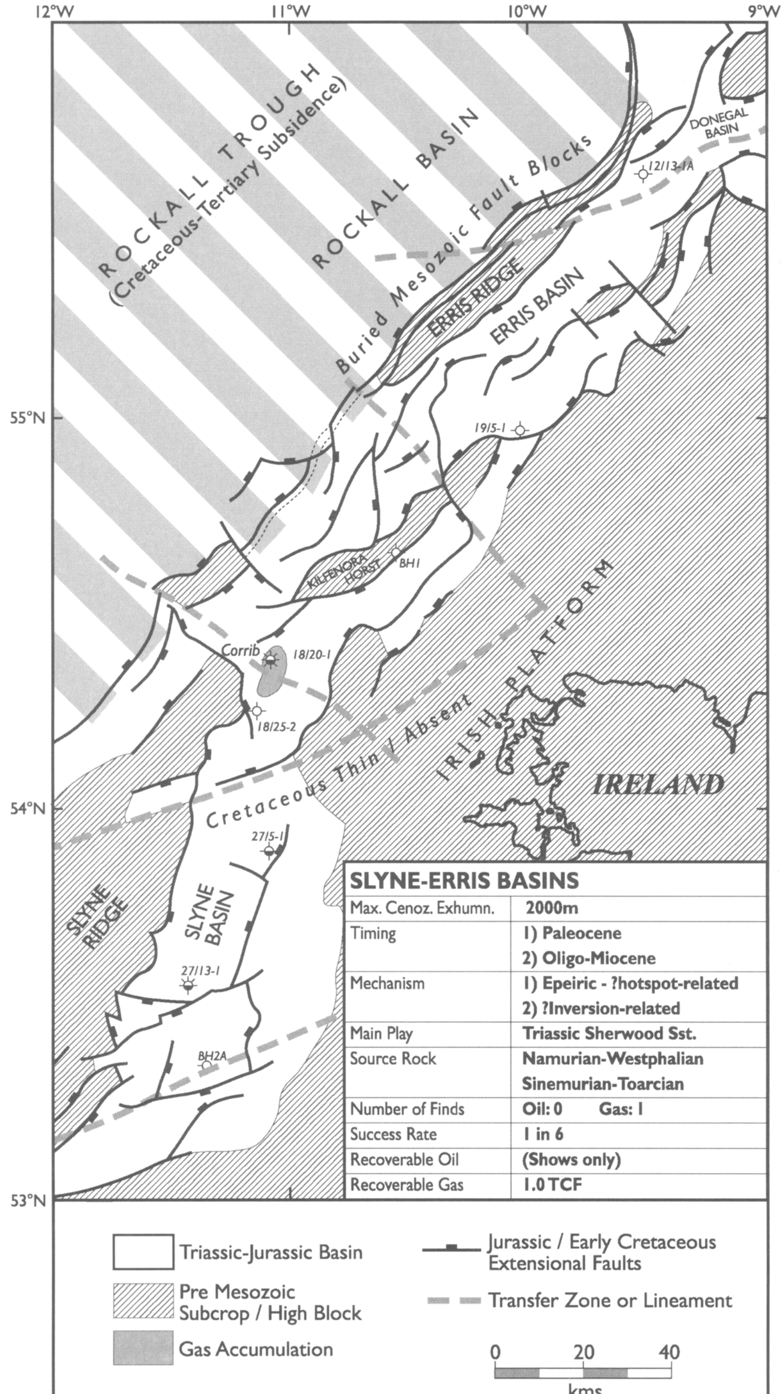
Fig. 7. Structural features, hydrocarbon discoveries and data template for the Inner Moray Firth Basin. (For qualifiers to inset table, see Fig. 5.)



EAST IRISH SEA BASIN	
Max. Cenoz. Exhumn.	2000m
Timing	1) Latest Cretaceous-Paleocene 2) Eocene-Miocene 3) ?Plio-Pleistocene
Mechanism	1) Epeiric - ?underplating 2) Inversion? 3) Glacio-isostatic
Main Play	Triassic Sherwood Sandstone
Source Rock	Namurian Holywell Shales
Number of Finds	Oil: 5 Gas: 16
Success Rate	1 in 3
Recoverable Oil	230 MMB
Recoverable Gas	8.2 TCF

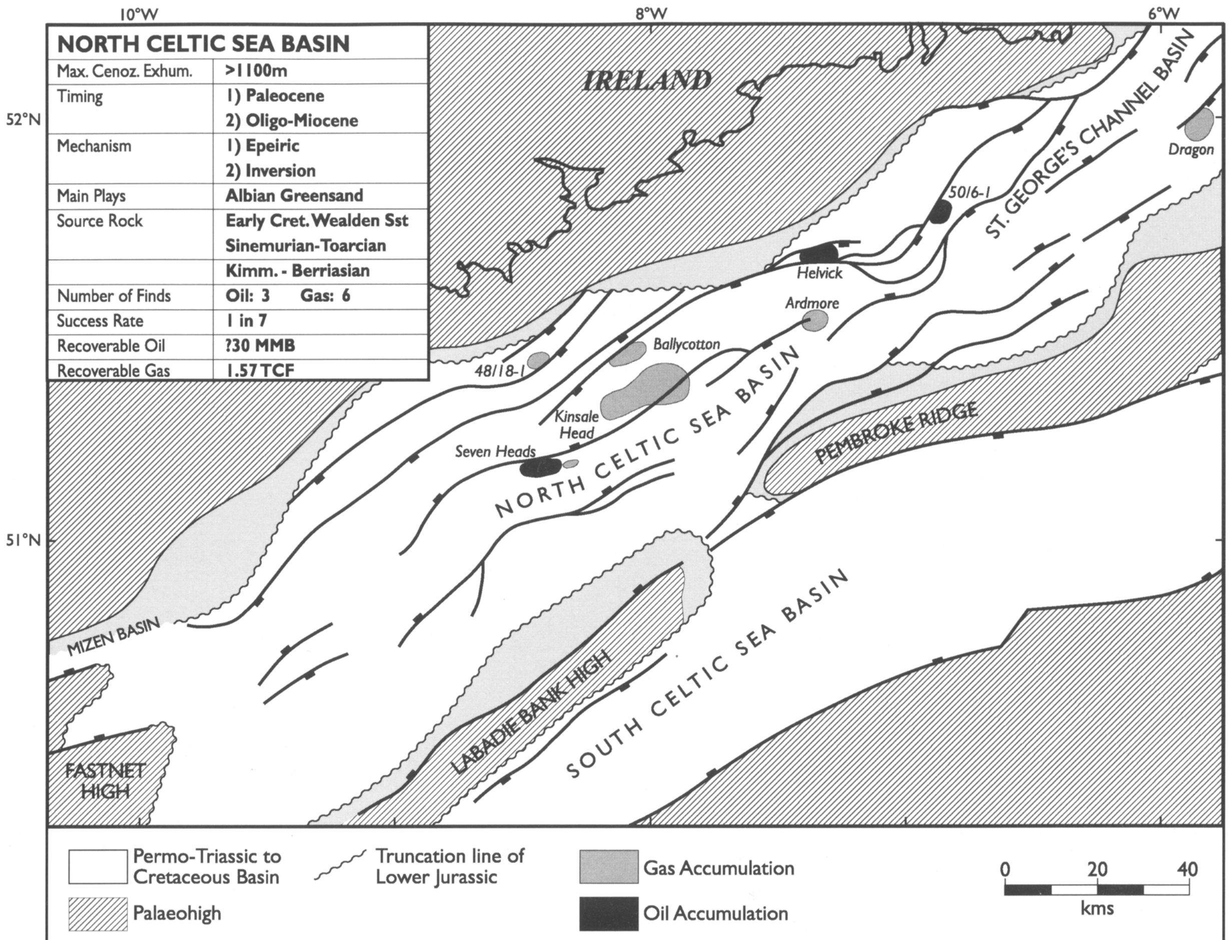
Fig. 8. Structural features, hydrocarbon discoveries and data template for the East Irish Sea Basin. (For qualifiers to inset table, see Fig. 5.)

such as apatite fission track, shale velocity and vitrinite reflectance. Some workers have modelled a major uplift phase in Early Cretaceous time (e.g. Duncan *et al.* 1998), whereas others have assigned earliest uplift to latest Cretaceous–Paleocene time, concident with North Atlantic opening and facilitated by thermal uplift or underplating (Cope 1994: Cowan *et al.*



SLYNE-ERRIS BASINS	
Max. Cenoz. Exhumn.	2000m
Timing	1) Paleocene 2) Oligo-Miocene
Mechanism	1) Epeiric - ?hotspot-related 2) ?Inversion-related
Main Play	Triassic Sherwood Sst.
Source Rock	Namurian-Westphalian Sinemurian-Toarcian
Number of Finds	Oil: 0 Gas: 1
Success Rate	1 in 6
Recoverable Oil	(Shows only)
Recoverable Gas	1.0 TCF

Fig. 9. Structural features, hydrocarbon discoveries and data template for the Slyne and Erris Basins. (For qualifiers to inset table, see Fig. 5.)



NORTH CELTIC SEA BASIN	
Max. Cenoz. Exhum.	>1100m
Timing	1) Paleocene 2) Oligo-Miocene
Mechanism	1) Epeiric 2) Inversion
Main Plays	Albian Greensand
Source Rock	Early Cret. Wealden Sst Sinemurian-Toarcian Kimm. - Berriasian
Number of Finds	Oil: 3 Gas: 6
Success Rate	1 in 7
Recoverable Oil	?30 MMB
Recoverable Gas	1.57 TCF

Fig. 10. Structural features, hydrocarbon discoveries and data template for the North Celtic Sea Basin. (For qualifiers to inset table, see Fig. 5.)

1999: Ware & Turner 2002). Later exhumation is even more difficult to constrain, but Ware & Turner (2002) have proposed a short-wavelength contribution from Eocene–Miocene inversion. The EISB was ice-covered during Pleistocene time, and a glacio-isostatic component cannot therefore be ruled out. Estimates of maximum exhumation vary between 1 and 3 km, with recent work suggesting 2 km as an upper limit (Cowan *et al.* 1999; Ware & Turner 2002).

The EISB is a prolific hydrocarbon province containing 10 gas fields, two oilfields and nine undeveloped hydrocarbon discoveries. About 60 wells have been drilled, with a one in three success record. Gas reserves of 8.2 TCF and oil reserves of about 230 MMBO have been identified in an area of 3500 km^2 (Quirk *et al.* 1999). The hydrocarbon system in the EISB consists of a Triassic aeolian–fluvial reservoir in structural traps, charged from a Namurian source rock and sealed by Upper Triassic evaporites and shales.

The hydrocarbon accumulations have a complex evolution intimately related to the exhumation history. The basin is characterized by a distinct northern gas province and a southern oil and gas province, with approximately 70% of proven reserves reservoired in the two Morecambe gas fields. Earliest gas and oil emplacement is believed to have occurred during Early Jurassic time. Breaching of seals during exhumation, for example in South Morecambe, resulted in loss of the initial oil-rich charge followed by later stage (?Early Tertiary) recharging with thermogenic gas and present-day underfilling (Stuart & Cowan 1991; Stuart 1993). Breaching or spillage of traps left behind palaeo-oil–water contacts, indicated on seismic data (Francis *et al.* 1997) and by illite cementation in Morecambe South. Residual columns of biodegraded oil also testify to the original charge (Bushell 1986; Woodward & Curtis 1987). Similarly, the Douglas and Lennox oilfields show evidence of multiple charging, with the earliest oil charge being totally degraded to bitumen, a subsequent higher maturity charge being partially biodegraded, followed by a final condensate charge (Haig *et al.* 1997; Yaliz 1997). The Formby oilfield, a pool of biodegraded oil trapped in the Sherwood Sandstone by Pleistocene till, is evidence of very recent remigration across the Formby Point Fault (Fig. 8) from a breached trap (Francis *et al.* 1997).

Recent modelling of the EISB has stressed the importance of remigration, driven by gas exsolution from oil and gas expansion during Cenozoic uplift (Cowan *et al.* 1999). Gas exsolution from formation water has not been incorporated into these models, but we suggest that it provides a powerful additional mechanism for the late gas charge. Oil was driven updip to the periphery of the basin by the late gas flux (Duncan *et al.* 1998). The complexity of the remigration process is, however, indicated by the juxtaposition of undersaturated oils (e.g. Douglas) with dry gas accumulations (e.g. Hamilton). Seedhouse & Racey (1997) and Cowan *et al.* (1999) have shown that the presence of halite beds in the basal part of the seal is a critical success factor for hydrocarbon entrapment and oil–gas balance. Gas will escape through the seal in shallow structures except where the basal evaporite is present. Conversely, this discharge of the gas leg allows oil to be preferentially trapped in the southern part of the basin where the basal evaporite is absent (Quirk *et al.* 1999).

Slyne–Erris Basin (Fig. 9)

The Slyne–Erris Basin (SEB) is a narrow, elongate, NE–SW-trending basin system 60 km off northwestern Ireland. It consists of a series of asymmetric half-grabens separated by cross-cutting transfer zones. It experienced a multiphase rifting and inversion history, although the preserved basin morphology is primarily the result of Mid–Late Jurassic rifting (Chapman *et al.* 1999; Dancer *et al.* 1999). A striking characteristic of the southerly Slyne Trough is the truncated stratigraphic record with an almost complete absence of post-rift sediments. A thin cover of Miocene sediments rests unconformably on synrift sediments of Late Bajocian to Bathonian age. However, in the northerly Erris Trough, more than 1 km of Cretaceous strata are locally preserved. Multiple phases of regional exhumation and local inversion affected the area. These included rift-related footwall uplift events in Late Jurassic–Early Cretaceous and Aptian time, regional uplift in Paleocene time probably associated with Atlantic opening, and inversion-related uplift in Oligo-Miocene time. Maximum exhumation is of the order of 2000 m, although it is difficult to establish what proportion took

Fig. 11. Summary map showing oil–gas balance and exhumation-related phenomena in exhumed basins with proven hydrocarbon systems on the NW European margin. Examples of fields or wells are given for exhumation-related characteristics in each area. Oil and gas quantities are related using oil industry standards, which are based on calorific value: 1 barrel of oil approximately equals 6000 standard cubic feet of gas.

place in Cenozoic time (Scotchman & Thomas 1995).

Sporadic exploration in this area over the past 25 years has resulted in the drilling of six exploration wells, which have yielded a single gas discovery (the Corrib Field) in the Slyne Trough. Total discovered resources to date are approximately 1 TCF gas, all in the Corrib Field, an underfilled faulted anticlinal structure (Corcoran & Doré 2002). The main gas exploration play consists of a Lower Triassic sandstone reservoir in structural traps, charged from the underlying Namurian–Westphalian claystones and coals and sealed by Upper Triassic evaporites and shales (Scotchman & Thomas 1995; Dancer *et al.* 1999). A Jurassic petroleum system is considered proven in the Slyne Trough by Spencer *et al.* (1999), based on the presence of palaeo-oil accumulations. Biodegraded, residual oil shows from a Lower Jurassic source have been encountered in Middle Jurassic reservoirs in wells 27/13-1, 27/5-1 and 18/20-1. These residual columns are consistent with breaching of traps and/or freshwater flushing during uplift to shallow levels. It has yet to be demonstrated that any producible accumulations from the Jurassic hydrocarbon system have survived the Cenozoic exhumation of the basin.

North Celtic Sea Basin (Fig. 10)

The North Celtic Sea Basin (NCSB) is a NE–SW trending Mesozoic extensional basin located to the south of Ireland. It is bounded by a series of Palaeozoic ridges and platforms and contains a thick Triassic to Cretaceous sedimentary fill. Major rifting episodes occurred during Late Jurassic and Early Cretaceous time (Rowell 1995), but post-rift subsidence was terminated by regional uplift and inversion during Cenozoic time. The exhumation resulted in subcrop of Cretaceous Chalk at the sea floor in the centre of the basin, and the complete removal of Cretaceous sediments in the NE of the basin. Two Cenozoic erosional events have been documented: regional uplift during Paleocene time and inversion characterized by basin doming and fault reversal during Oligo-Miocene time. Net exhumation in excess of 1100 m is interpreted in the NE of the basin (Murdoch *et al.* 1995).

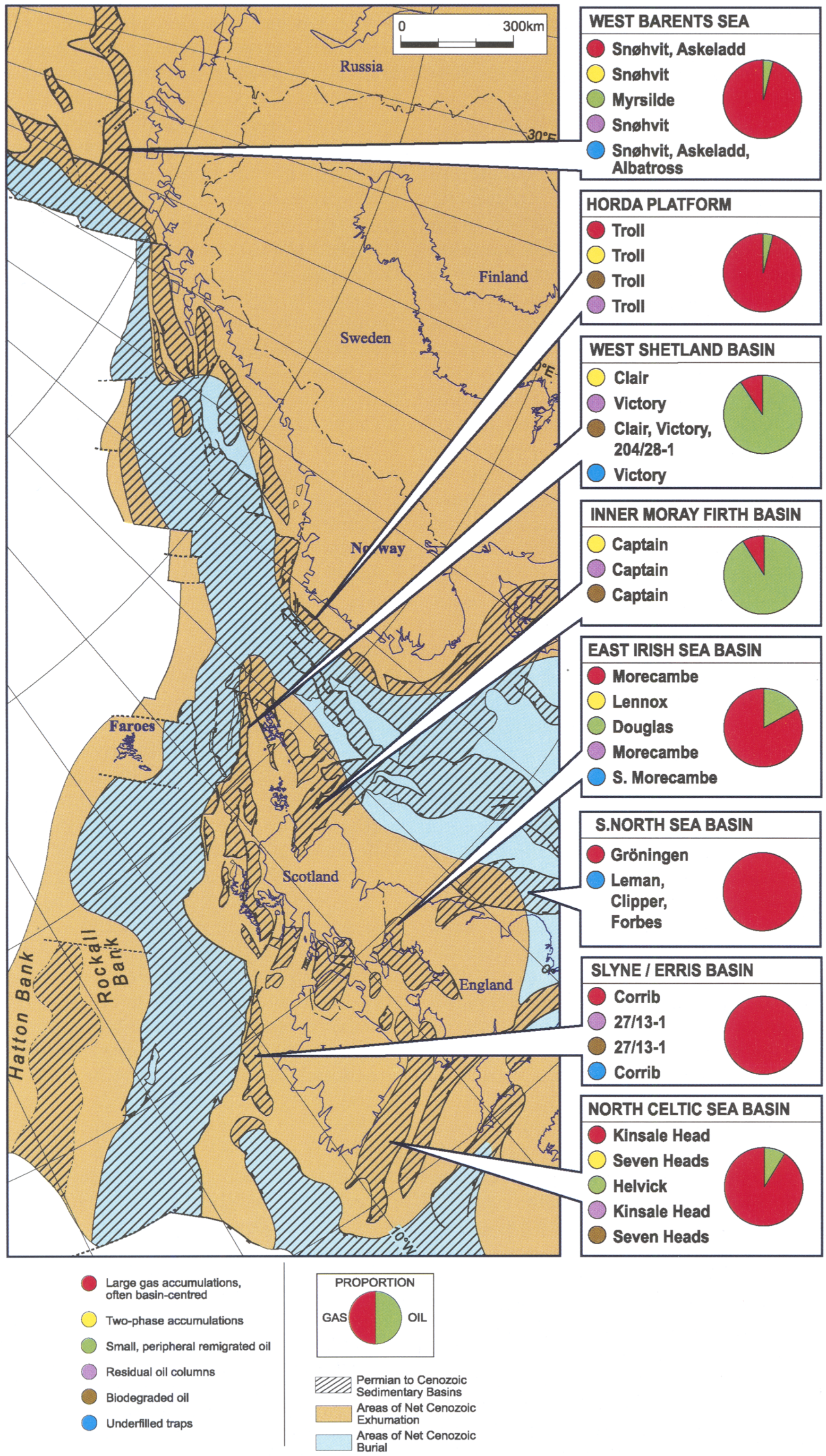
The NCSB has proved to be a somewhat enigmatic petroleum province. About 70 exploration and appraisal wells have been drilled to date, with a success rate of one in six. Only two accumulations are producing, Kinsale Head and Ballycotton, containing proven reserves of 1.6 TCF (Taber *et al.* 1995). A further seven sub-commercial oil and gas discoveries (e.g. Seven Heads, Helvick, Ardmore) have been identified. The main reservoir in the producing gas fields is the shallow marine Albian Greensand. Secondary production occurs from the fluvial Wealden reservoirs. Elsewhere in the basin oil has been tested from these stratigraphic levels and from Oxfordian fluvial sandstones and Middle Jurassic shelf limestones (Caston 1995). Seals are provided by the Albian–Cenomanian Gault Clay and intraformational claystones within the Bathonian to Aptian succession.

Typically for an exhumed basin, the NCSB is dominated by central gas deposits and in this case by a single accumulation, Kinsale Head. This structure, a basin-centre anticline, may have had some pre-Cenozoic expression but was greatly emphasized during Tertiary inversion (Taber *et al.* 1995). Atypically for fields in NE Atlantic exhumed basins, the trap is full to spill (Taber *et al.* 1995). This suggests that the maximum depth of burial of the Gault Clay caprock (1700–1800 m) may not have been enough for the claystone to achieve embrittlement, allowing it to deform plastically during exhumation and compressive overprint (Corcoran & Doré 2002). Published models for maturation and expulsion from the Lower Jurassic source rocks indicate that peak gas generation would have occurred towards the end of Cretaceous time (Murphy *et al.* 1995). Because the structure probably developed during Tertiary time, after generation from the source rocks would have been curtailed because of exhumation, it seems unlikely that the present gas represents the original thermogenic charge. Even given a ductile claystone caprock, gas losses as a result of diffusion and underfilling of the trap would be expected. Therefore, active charging of the Kinsale Head Field may have continued until recent geological time. A possible mechanism for additional gas charging is exsolution of methane from groundwater in the Greensand, Wealden and older aquifers, possibly focused by groundwater flow during uplift.

Other signatures of an exhumed hydrocarbon system in the NCSB include a residual oil column in Kinsale Head, probably indicative of an earlier oil charge later displaced by gas (Taber *et al.* 1995), minor peripheral hanging-wall oil accumulations such as Helvick (Caston 1995) and two-phase accumulations with biodegraded oil (Seven Heads).

Discussion

As summarized in Fig.11, many of the North Atlantic basins contain hydrocarbon systems



0 300km
Russia
Finland
Sweden
Norway
Faroes
Scotland
England
Hatton Bank
Rockall Bank
30°E
10°W
WEST BARENTS SEA
Snøhvit, Askeladd
Snøhvit
Myrsilde
Snøhvit
Snøhvit, Askeladd, Albatross
HORDA PLATFORM
Troll
Troll
Troll
Troll
WEST SHETLAND BASIN
Clair
Victory
Clair, Victory, 204/28-1
Victory
INNER MORAY FIRTH BASIN
Captain
Captain
Captain
EAST IRISH SEA BASIN
Morecambe
Lennox
Douglas
Morecambe
S. Morecambe
S.NORTH SEA BASIN
Gröningen
Leman, Clipper, Forbes
SLYNE / ERRIS BASIN
Corrib
27/13-1
27/13-1
Corrib
NORTH CELTIC SEA BASIN
Kinsale Head
Seven Heads
Helvick
Kinsale Head
Seven Heads
Large gas accumulations, often basin-centred
Two-phase accumulations
Small, peripheral remigrated oil
Residual oil columns
Biodegraded oil
Underfilled traps
PROPORTION
GAS
OIL
Permian to Cenozoic Sedimentary Basins
Areas of Net Cenozoic Exhumation
Areas of Net Cenozoic Burial

showing indicators of exhumation. Acknowledgement of the importance of exhumation can constrain future exploration strategy in these basins, and a similar approach can be applied to any exhumed basin.

Exploration risk analysis in exhumed terranes should take into account a decreased probability for seal or trap, and should address a complex interplay of positive and negative factors when assessing probability of source or charge. There is an increased chance that the dominant hydrocarbon phase will be gas, but oil can still be predicted by taking into account factors such as seal integrity, displacement from traps and remigration pathways. Although we have given a qualitative guide to such a risk analysis, it is not possible to provide numerical values. These will vary according to the unique geological characteristics of an area; for example, the quality of regional seals within the basin. It is frequently said that exploration risk analysis is a subjective procedure, of use as a comparative rather than an absolute measure. However, a more objective view of risk (in any basin, exhumed or otherwise) can be gained by carrying out an audit after a period of drilling, whereby the actual discovery rates are compared with the predicted ones. Thus, a risk analysis constrained by knowledge of exhumation can be checked and modified based on exploration history.

The strategy for targeting resources should also be contrained by knowledge of exhumation levels; for example, in the identification of areas of porosity preservation and potential fracture-prone lithologies. The recovery strategy for oil and gas in uplifted fields should be influenced by knowledge of present-day stress and fracture directions. As in the case of risk analysis, we provide no numerical values for resource assessment in this paper, but again point out that an audit of drilling results can provide an objective comparison of predicted and actual volumes at an intermediate stage of exploration of a basin.

Timing of exhumation is a key element in prediction of the hydrocarbon system. As shown in the case studies on the North Atlantic margin, most such areas have undergone multiple exhumations during Cenozoic time and in some cases exhumation began even earlier. It is difficult, and requires patient analysis, to disentangle the effects of the various events and to assign relative importance to them. In general, however, it may be predicted that the more extreme effects on the hydrocarbon system (for example, the flushing effect of a central gas bloom) are more likely to be observed where exhumation has been very recent; as is seen, for example, in the Barents Sea, where the Plio-Pleistocene regional uplift episode was particularly important (Nyland *et al.* 1992). The effects of older exhumations may be muted by the slow dissipation of gas by diffusion, and overprinted by reburial and the introduction of new hydrocarbons. The variability in degree of exhumation within a particular province is also important, and relates to the uplift mechanism. In an area of broad regional ('epeirogenic') uplift the effects on the hydrocarbon system should be similar over a wide area, whereas in basins inverted by compression these effects may be more local in nature as a result of selective uplift of intrabasinal structures. The fact that both forms of exhumation are superimposed in several of the North Atlantic basins (e.g. Inner Moray Firth, Eastern Irish Sea) provides an additional challenge.

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