The Scott Field, Blocks 15/21a, 15/22, UK North Sea

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Abstract: The Scott Field straddles Blocks 15/21 and 15/22 on the southern flanks of the Witch Ground Graben in the Outer Moray Firth Basin, UKCS. The oil field is developed in the highly productive Upper Jurassic Humber Group sandstones of Oxfordian to Kimmeridgian age. The field was discovered in 1983, sanctioned in 1990, and produced first oil in 1993.

The field structure, effectively a large southwards tilted fault block, is compartmentalized into a series of four main pressure isolated fault blocks by mid to late Jurassic faulting. The Kimmeridge Clay Formation provides both the top seal and the source of the trapped hydrocarbons. Fluid contact, overpressure and compositional trends suggest that the trap was filled primarily from the north. Some trap-defining faults were already active during the deposition of the reservoir intervals. Well data indicate that the development of accommodation space was tectonically controlled during this period, with subsidence occurring more rapidly in the western areas of the field.

The Scott Field reservoir consists of two major sand packages, the Scott Sandstone Member and the Piper Sandstone Member, bounded above and below by marine flooding surfaces. The late Oxfordian Scott Sandstone Member consists of a westwards prograding marine shoreface sandstone overlain by aggradational and retrogradational back-barrier deposits. Above this, the Mid Shale is a regionally extensive flooding event separating the Scott Sandstone Member from the overlying Piper Sandstone Member. The early Kimmeridgian Piper Sandstone Member consists of stacked mass flow sandstones, overlain by a shoreface/back-barrier system. Lateral facies changes and thickness variations significantly affect reservoir distribution in both Scott and Piper intervals.

The best reservoir quality occurs within the coarsest grained, highest energy facies, particularly the shoreface and proximal washover deposits. At the crest of the field, 10400 ft TVDss, multi-Darcy permeabilities and porosities of 20% are common. However, reservoir quality declines progressively downflank due to increased quartz cementation and compaction.

The Scott Field currently produces from 23 wells supported by 20 water injectors. Current modelling is aimed at targeting bypassed oil to increase ultimate recovery. The field has presently produced 300 MMSTB of oil from forecast reserves of 440 MMSTB with an estimated ultimate recovery factor of *c.* 46%.

The Scott Field is located on the southern flank of the Witch Ground Graben in the Outer Moray Firth Basin (Figs 1 and 2). The Upper Jurassic reservoir interval is developed in a series of rotated fault blocks that straddle the boundary between Blocks 15/21 and 15/22 of the UKCS. Reservoir sandstones of late Oxfordian to early Kimmeridgian age are separated by laterally extensive mudstones. These sandstones are correlated with Humber Group reservoir sandstones in the Piper, Tartan, Ivanhoe, Rob Roy and Telford Fields (Fig. 1). In the Outer Moray Firth Basin, Harker & Rieuf (1996) estimate that these sandstones contain oil reserves of almost three billion barrels.

The Scott Field was discovered by well 15/22-4 (Fig. 3) in 1983 and came on-stream in September 1993. The field has an areal extent of *c.* 35 km^2 and has been developed with a combination of sub-sea and platform drilled wells. There are currently 26 sub-sea wells tied back to five manifolds and a further 17 wells drilled directly from

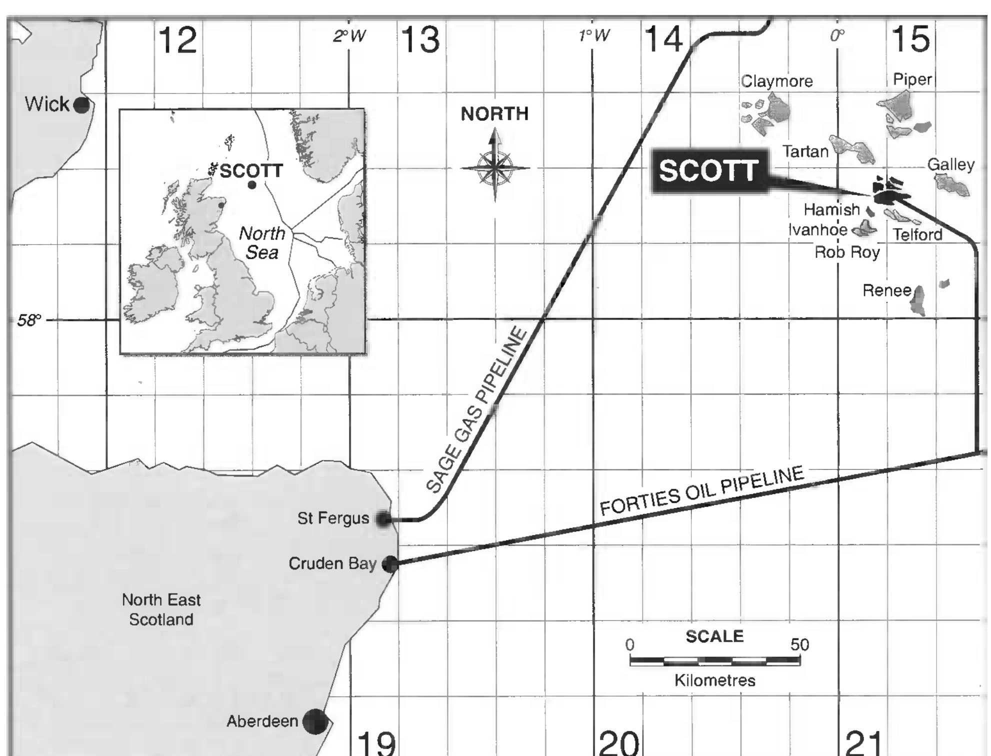

Fig. 1. Location map of the Scott Field.

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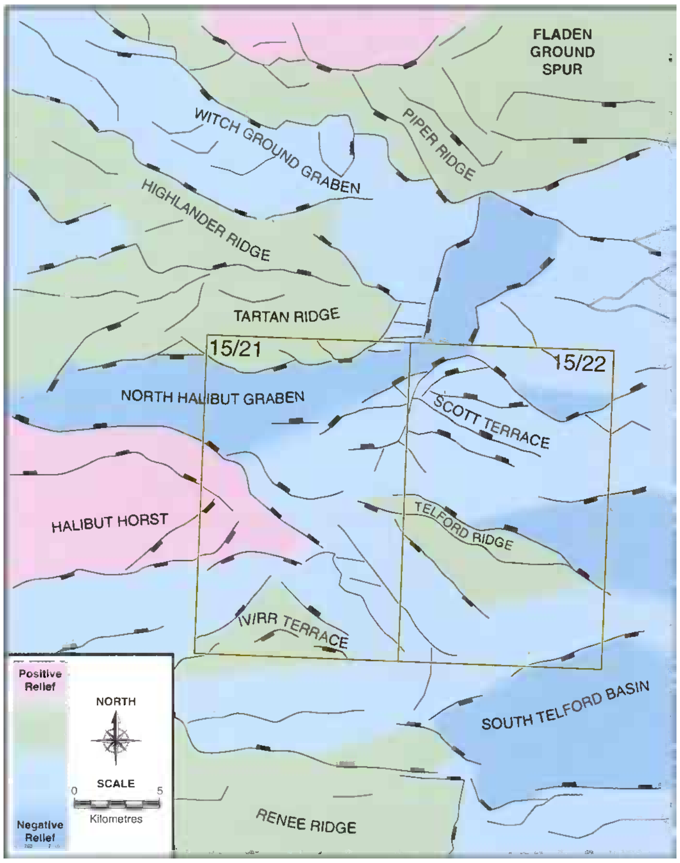

Fig. 2. The major structural elements of the Outer Moray Firth Basin in the vicinity of the Scott Field. The map is based on a composite seismic image created for the top Zechstein. Blocks 15/21 and 15/22 of the UKCS are shown in outline.

the Scott Platform. Peak production of *c.* 220 000 STB d^{-1} was achieved in 1995. Production in 1999 averaged *c.* 80 000 STB d^{-1} with a water cut of 60%. Ultimate recoverable reserves are estimated at 440 MMSTB, and as such the Scott Field was one of the largest developments to have come on stream in the UKCS during the 1990s. Current projections suggest that the field will continue producing oil into the latter part of the next decade.

History

Blocks 15/21 and 15/22 were both awarded as part of the 4th Round of UK Offshore Licensing in 1972. Initial exploration focused on relatively shallow prospects, 7000 ft to 8000 ft TVDss, and resulted in the discovery of the Ivanhoe Field by well 15/21-3 in 1975. Appraisal of the deeper Scott structure, with a crest at 10 400 ft TVDss, began in 1977 when well 15/22-3 was drilled as a joint venture between the licence groups (Fig. 3). The well was targeted downflank from the crest of the structure but failed to find reservoir in the Upper Jurassic interval. Extensive crestal erosion was interpreted at the time and further appraisal was delayed for several years.

In 1983, the 15/22 licence group returned to the Scott structure, drilling well 15/22-4 to a target location significantly further downdip than that of well 15/22-3 (Fig. 3). This well encountered *c.* 200 ft of Upper Jurassic reservoir just below 12 000 ft TVDss, comprising two main sandstones separated by a 50 ft mudstone. The upper sandstone was water-bearing, but an oil-bearing lower sandstone (Fig. 4) demonstrated the existence of a charged trap. Further down-dip appraisal by well 15/22-5 in 1985 encountered a thin water-bearing interval of poor reservoir quality at approximately 13 100 ft TVDss (Figs 3 and 4); optimism regarding the value of the field was muted.

The potential for a major oilfield associated with the Scott structure only became apparent when well 15/21a-15 was drilled in 1987 (Figs 3, 4 & 5). The well penetrated top reservoir just below 11 100 ft TVDss and encountered nearly 400 ft of net pay. Moreover, oil pressure data lay on the same oil pressure gradient as that from well 15/22-4, over 1000 ft below (Fig. 4). A rapid programme of appraisal drilling over the following two years revealed the existence of several large oil pools with different pressure regimes in separate downthrown fault blocks to the north.

The South Scott oil accumulation lies to the south of a syncline that separates it from the main Scott Field structure and was discovered by well 15/22-9 in 1990 (Fig. 3). This well penetrated top reservoir at approximately 11 840 ft TVDss and encountered 24 ft of oil-bearing Upper Jurassic sandstone. The well was side-tracked downdip and encountered 101 ft of net pay with an average oil saturation of >90% just below 12 300 ft TVDss. The economic nature of the area was finally proven by well 15/21a-43 (Fig. 3), drilled during 1991, which encountered 245 ft of net pay near the western limit of the South Scott structure.

Structural evolution

The Scott Field reservoir is highly compartmentalized by faulting and is delineated by two main structural trends (Fig. 3). The first reflects those of the Theta Graben area of Block 15/21 (Hibbert & Mackertich 1993) and consists of both N–S and NE–SW fault systems. These systems are a combination of mid Cimmerian extension in the early Jurassic (N–S trending faults), and the reactivation of Caledonide fault trends (NE–SW faulting). The second trend comprises E–W orientated faults that result from late Jurassic N–S extension in the Witch Ground Graben area to the north of the field. The E–W 'Witch Ground' trend faulting broadly post-dates the deposition of the reservoir interval.

The crest of the Scott Field occurs at *c.* 10 400 ft TVDss and the main field structure, a southwards dipping complexly faulted block, can be broadly divided into two subequal areas by a substantial NE–SW trending fault system that down throws to the northwest (Fig. 3). This faulting isolates structural Block II from the rest of the field (Fig. 6a). To the south and east of this faulting lie Scott Field structural blocks I, Ib, III and IV (Fig. 3). Late Jurassic fault influence is most apparent in these blocks where the reservoir is compartmentalized by a series of broadly E–W orientated faults that downthrow northwards, towards the Witch Ground Graben (Fig. 6b).

In the south of Block I a WNW–ESE orientated syncline defines the southern extent of the main Scott Field (Fig. 3). To the south of this syncline is the South Scott oil accumulation. The South Scott area is characterized by a complex E–W fault system that parallels the main bounding fault. The South Scott/Telford bounding fault downthrows approximately 1000 ft to the north and separates the South Scott reservoir from the Telford and Marmion oil accumulations developed in the footwall of the structure. The South Scott reserves accumulated in a complex series of rotated fault blocks that are interpreted to have formed as a result of footwall collapse along the main bounding fault.

Three dimensional structural restorations have identified a complex structural evolution for the field, with a number of episodes of fault movement recognized along both the main structural trends. Early post-Zechstein structural activity involved the major fault trends. The mid-Jurassic Rattray Formation volcanics are anomalous as their deposition appears to be controlled by a structural lineament trending NW–SE. This lineament also acted as a strain partition during later extension, but shows little vertical or horizontal displacement. Similar structures have been documented further east in Quad 15 where they also appear to control deposition of the Rattray Formation volcanics (Jones *et al.* 1999).

In the late Oxfordian there is evidence from isopach data for syndepositional fault movement as a result of NW–SE orientated

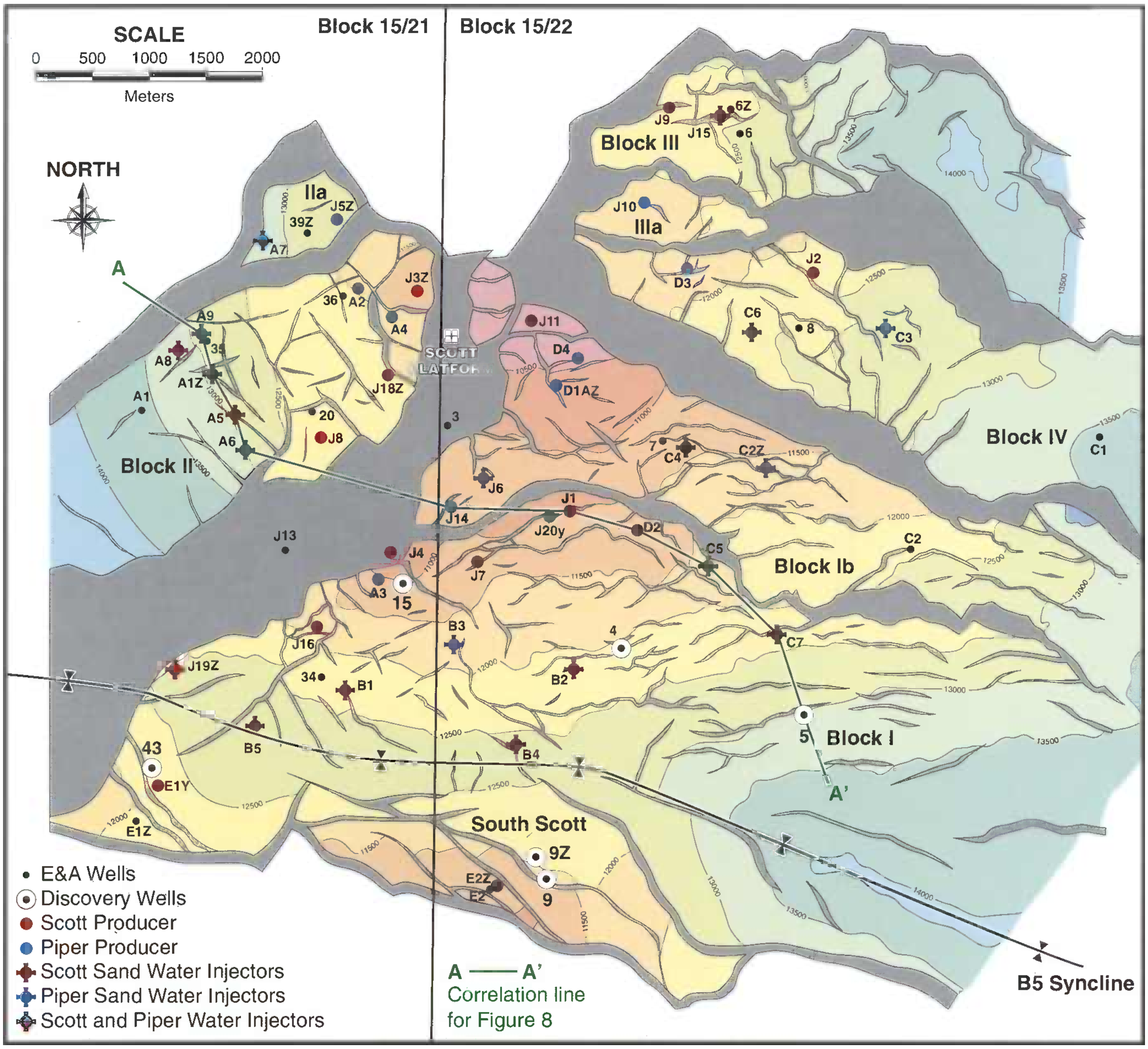

Fig. 3. Top Piper Formation structure map for the Scott Field showing the location of exploration, appraisal and development wells.

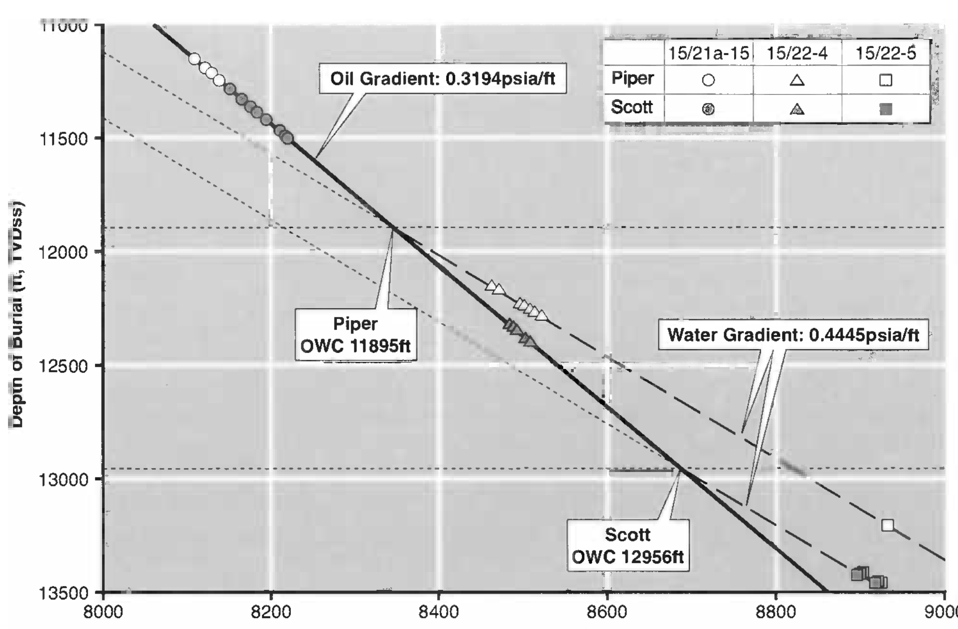

Fig. 4. Reservoir fluid pressure data for exploration wells 15/22-4, 15/22-5 and 15/21a-15. Data shows oil and water pressure gradients in the Scott Field structural Block I and the inferred oil–water contacts in the block. Note that the oil–water contact in the Piper Sandstones is significantly shallower than that in the Scott Sandstones, creating a perched contact.

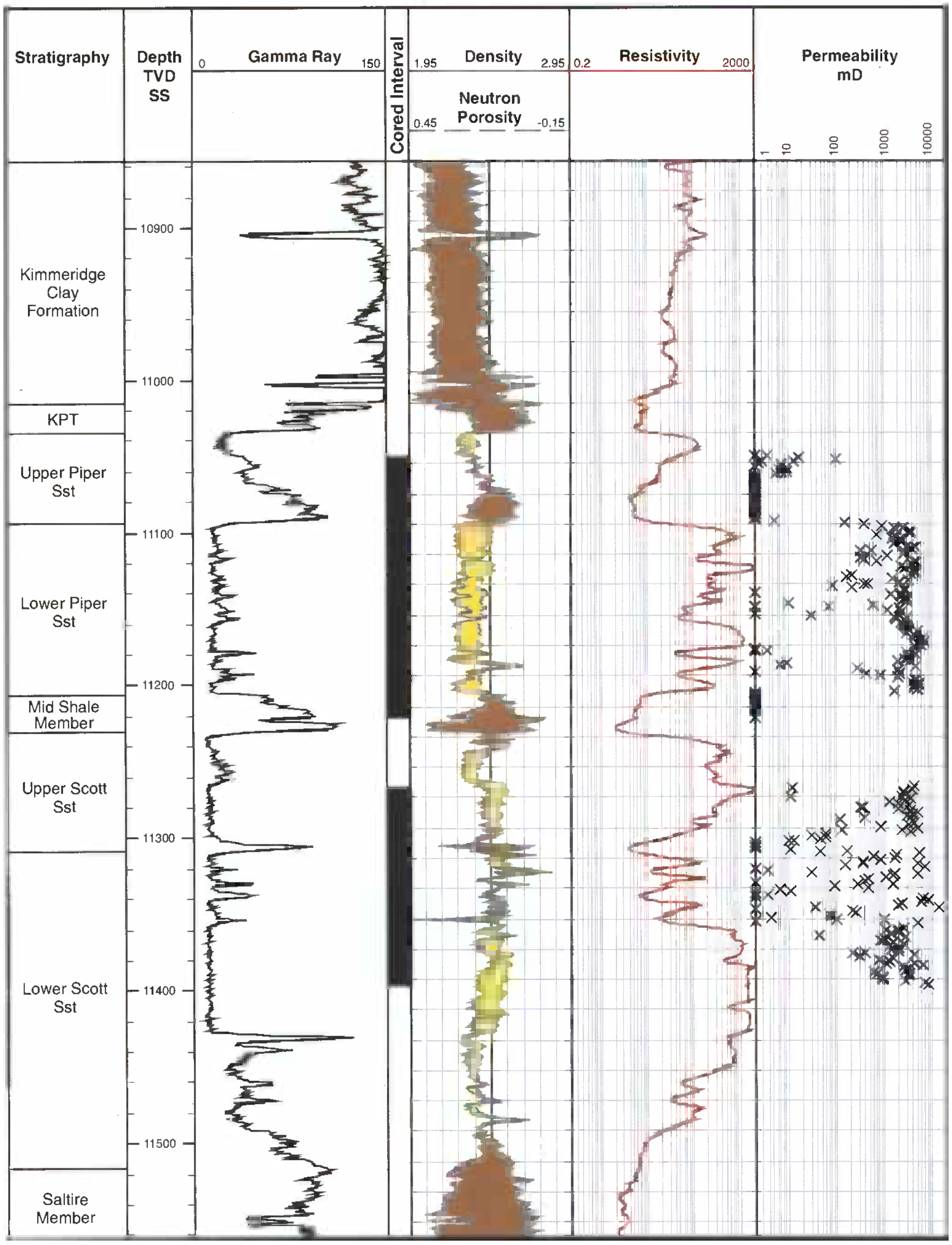

Fig 5. Scott Field type well 15/21a-15. Well 15/21a-15 is defined as the reference well for the Sgiath Formation (Humber Group) by Harker *et al.* (1993). Spudded in 1987, the well was the first to prove the economic nature of the Scott structure. All four major sand packages (Upper Piper, Lower Piper, Upper Scott, Lower Scott) were oil-bearing (see text for details).

extension. The extension created a transtensional environment in the Scott Field area and, as a consequence, the area was gently folded. During the Kimmeridgian, extension continued along the main NE–SW trending structures, and by this time there is also evidence for limited extension along the east–west structures.

Late Jurassic extension in the Witch Ground Graben area probably initiated in the latest Oxfordian, although the main phase of extension occurred during the Kimmeridgian and Volgian. The N–S orientated extension was accommodated by large E–W trending faults (Fig. 2) and resulted in significant thickening of the Kimmeridge Clay Formation mudstones in the hanging walls of the major faults controlling the extension. Thickened Kimmeridge Clay Formation sections are observed in the Block II area and into the main South Scott bounding fault (see Fig. 6a, b).

Seismic data indicate that during the mid-late Cretaceous the Scott Field underwent inversion that resulted from transpression along the South Scott/Telford bounding fault. The inversion is also locally evident along the main NE–SW Block I/Block II bounding fault, where the base Cretaceous reflector shows positive relief in the immediate hanging wall to the fault (Fig. 6a), and probably continued into the Tertiary.

Stratigraphy

The stratigraphy of the Upper Jurassic in the Witch Ground Graben has been addressed by a number of workers over the past ten years. A listing of the available published work is given in their introduction by Duxbury *et al.* (1999). Figure 7 shows the stratigraphic units presently recognized in the Scott Field and relates these to the regional scheme proposed by Harker *et al.* (1993). It also shows how the units compare with the UKOOA scheme for the North Sea (Richards *et al.* 1993), and to the previous published stratigraphy of the nearby Rob Roy Field (Boldy & Brealey 1990). Detailed correlation of the late Oxfordian to early Kimmeridgian interval has historically proved difficult due to poor biostratigraphic resolution, and there is still disagreement over the reliability of criteria used to define correlative marker events. On a broad scale however, there is now an emerging consensus that two major sand packages, bounded above and below by marine flooding episodes, can be widely recognized across the area. In the Scott Field, these are the Piper Sandstone Member and the Scott Sandstone Member, separated by the Mid Shale Member which can be correlated with the Mid Shale on Rob Roy Field and the I Shale on the Piper Field (Harker

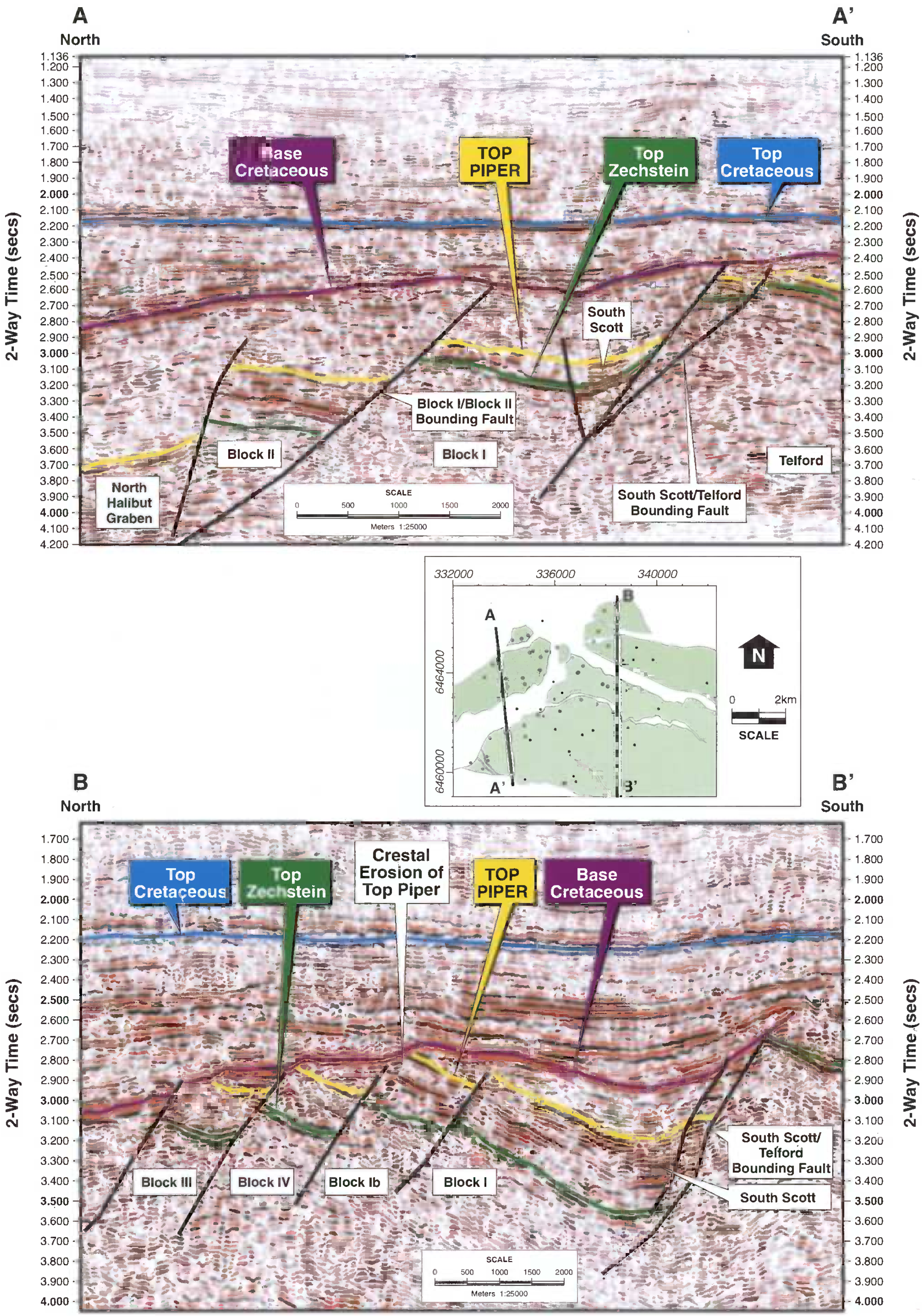

Fig. 6. (**a**) Seismic line A–A′ (see inset for location) showing the NE–SW 'Theta' trend faulting that downthrows the Block II area of the Scott Field to the NW. Note the thickened Kimmeridge Clay Formation sections in the Block I and Block II areas compared to the Telford area to the extreme south on the diagram shown. (**b**) Seismic line B–B′ (see inset for location) shows the rotated fault blocks that downthrow to the north in response to late Jurassic N–S extension in the Witch Ground Graben area. Each of the fault blocks shown has different hydrocarbon compositions and different overpressures relative to hydrostatic pressure.

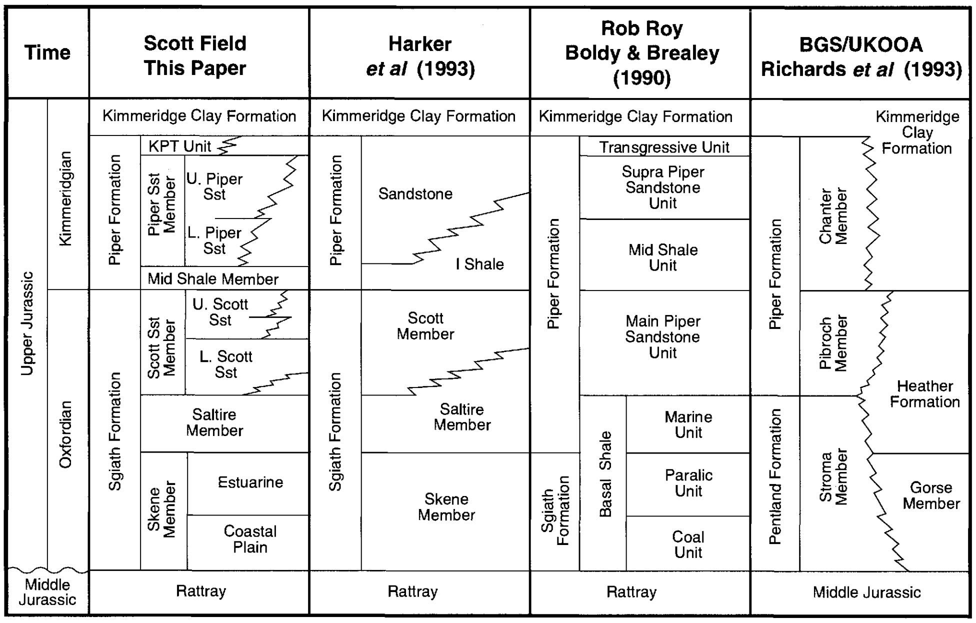

Fig. 7. Stratigraphic nomenclature utilized in the Scott Field compared to that previously published for the Witch Ground Graben area.

et al. 1993). These authors assign the Skene, Saltire and Scott Sandstone Members to the Sgiath Formation, and the Mid Shale and Piper Sandstone Members to the overlying Piper Formation (Fig. 7).

The oldest stratigraphic level penetrated by wells on the Scott Field is that of the Permian Zechstein, penetrated by well 15/22-E2 in the South Scott area. More typically, however, wells penetrate volcanic rocks of the Middle Jurassic (Fladen Group) Rattray Formation. Overlying the Rattray Formation, probably unconformably, are emergent coastal plain sediments and paralic estuarine mudstones that together comprise the Skene Member of the Sgiath Formation. Although not generally cored in the Scott Field, these are extensively cored in the Marmion and Telford areas immediately to the south, where they contain abundant reworked igneous clasts and localized rootlet traces. The Saltire Member, an open marine mudstone that represents the first widely correlatable marine flooding episode, overlies the Skene Member. Harker *et al.* (1993) equate this with the major regional flooding event that occurs within the *glosense* ammonite zone, although Kadolsky *et al.* (1999) equate it with the younger *serratum* zone (maximum flooding surface). Above the Saltire Member, the Sgiath Formation consists of a thick shallowing-upwards sandstone package, the Scott Sandstone Member, deposited by a westwards prograding shoreface and back-barrier system. The Scott Sandstone Member is divided into a thick Lower Scott Sandstone and a thinner Upper Scott Sandstone. The Lower Scott Sandstone was deposited during the main progradation and vertical aggradation phase of the system. The Upper Scott Sandstone was deposited during a later retrogradational period, during which barrier sands were reworked eastwards into the back-barrier lagoon as two stacked flood-tidal delta lobes.

The Scott depositional system was terminated by the next major regional flooding episode, represented by the Mid Shale Member, marking a return to open marine conditions at the end of the late Oxfordian. It defines the boundary between the Sgiath and Piper Formations, and Harker *et al.* (1993) equate it with the major regional flooding episode within the *rosenkrantzi* ammonite zone.

Overlying the Mid Shale Member is the second major sandstone package, the Piper Sandstone Member. This comprises two parts, a Lower Piper Sandstone and an Upper Piper Sandstone. The Lower Piper Sandstone consists of a series of stacked mass-flow sandstones that were deposited over a large area of the Scott Field. The Upper Piper Sandstone is a separate shallowing-upwards sandstone package, deposited by a westwards prograding shoreface and back-barrier system not unlike the Scott Sandstone Member, except that its progradation was more limited and it shales out progressively in the west of the field.

The Piper depositional system was effectively terminated by a third regional marine flooding episode, although a thin, very distal, prograding unit termed the Kimmeridge Piper Transition Unit (KPT) overlies it. A similar thin 'Transgressive Unit' is recognized in the Rob Roy Field (Boldy & Brealey 1990), and may correlate with the thin 'Hot Sand Unit' in the Tartan Field (Coward *et al.* 1991). The flooding event at the base of the KPT Unit appears widespread, but there is a lack of consensus as to its age, and which biostratigraphic markers may be used to reliably identify it.

The eventual permanent drowning of the area, resulting in deposition of the Kimmeridge Clay Formation, is equated with a major regional flooding in the *eudoxus* ammonite zone (Harker *et al.* 1993). However, due to structural activity at this time, the flooding would have been controlled by local topography, and may be diachronous across different parts of the Witch Ground Graben.

Trap

The Scott Field reservoir exhibits elements of both stratigraphical and structural trapping. The Kimmeridge Clay Formation forms the top seal for the reservoir across the majority of the field structure, although the base Cretaceous in the crestal areas of structural Blocks Ib, III, and IV (Fig. 6b) truncates the reservoir. The Kimmeridge Clay Formation also provides a lateral seal to the reservoir where major faults juxtapose the reservoir sandstones against Kimmeridge Clay Formation mudstones. At the crest of Block I this mechanism supports an oil column of 2000 ft in the Scott sandstones. The presence of significant pressure differentials between adjacent fault blocks and within individual fault blocks demonstrates that fault sealing is also an important trapping mechanism within the Scott Field. In the South Scott area the top seal is provided by the Kimmeridge Clay Formation whilst the southern lateral seal is against the main South Scott/Telford bounding fault that juxtaposes the reservoir interval against the underlying Rattray Formation volcanics and older strata.

Within the reservoir interval the major mudstone intervals also act as significant barriers to vertical fluid flow. In Block I the oil–water contact in the Piper sandstones is >1000 ft shallower than in the underlying Scott sandstones, this difference is sustained across the Mid Shale Member (Fig. 8). By contrast, in the neighbouring Block Ib, the Piper and Scott sandstones share a common oil–water contact. Table 1 lists the most likely oil–water contacts for the main structural blocks within the Scott Field.

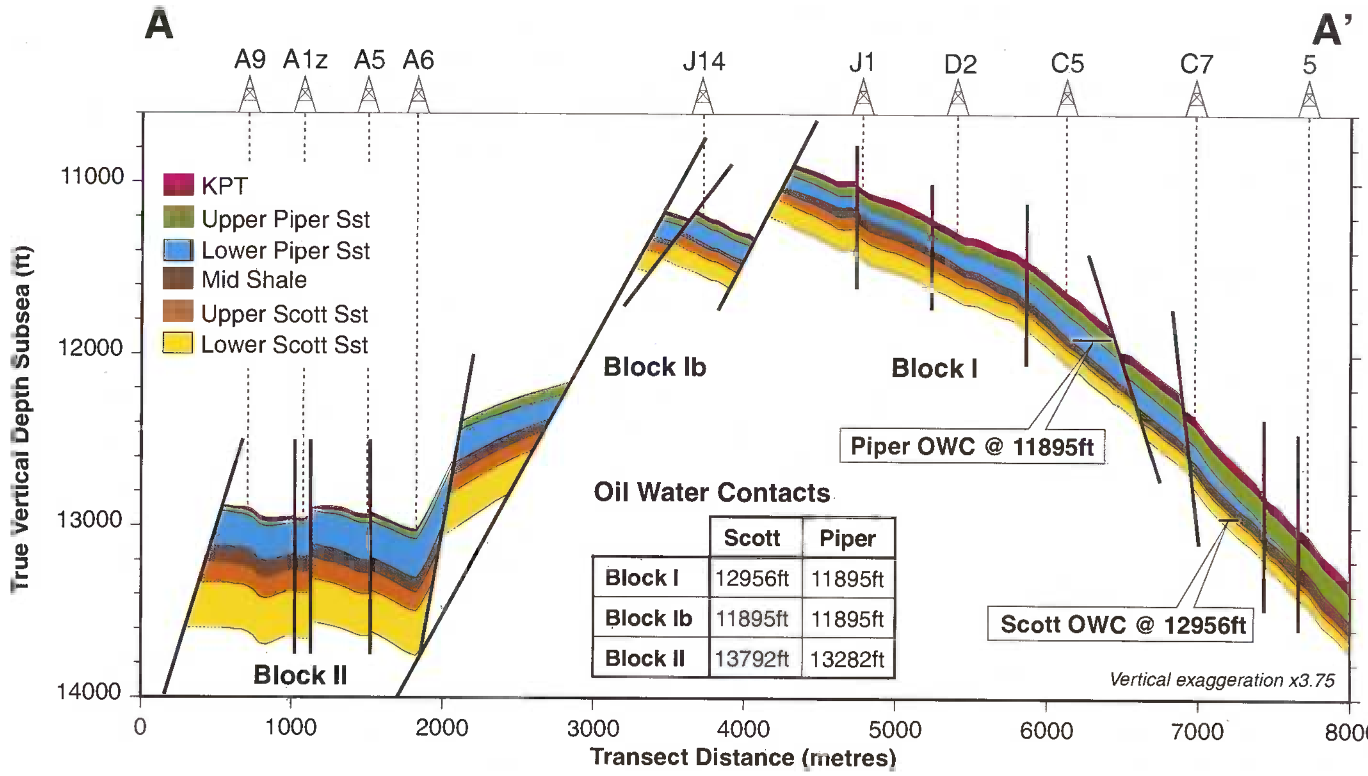

Fig. 8. Structural cross-section through structural Blocks I, Ib and II of the Scott Field (see Fig. 3 for the location of the line of section). Diagram shows main structural elements, reservoir thickness changes and location of the oil water contacts.

Table 1. *Most likely oil–water contacts for the main structural blocks within the Scott Field*

	Block I	Block Ib	Block II	Block IIa	Block III	Block IIIa	Block IV	South Scott
Piper	11 895	11 895	13 282	13 698	12 364	12 105	12 752	12 189
Scott	12 956	11 895	13 792	13 698	12 724	wet	12 752	12 956

All depths quoted in feet, TVDss

Reservoir interval

Depositional setting

The reservoir interval was deposited by two major, westwards prograding, shoreface systems (the Scott and Piper Sandstone Members), separated by a major regional marine transgressive event (the Mid Shale Member). A younger, very distal, prograding unit (the KPT Unit) overlies the Piper Sandstone, but never reached full development across the field. Figure 9 illustrates (using three typical wells) how the reservoir units and sedimentary facies vary across the field. A complete prograding package typically consists of an interval up to several hundred feet in thickness, which coarsens (shallows) upwards from offshore mudstones to medium or coarse grained shoreface and back-barrier sandstones as the system progrades outwards into the marine basin. Published regional data (Maher 1980; O'Driscoll *et al.* 1990) indicate a north-easterly sediment source. Locally, however, the presence of positive areas such as the Telford High may have affected sediment transport and deposition. Thickness and facies trends from the marine parts of both the Scott and Piper systems in Blocks 15/21 and 15/22 show a general pattern of progradation from the southeast, although the sediments may have been transported laterally by longshore currents from fluvial sources lying beyond Scott Field to the northeast. In the descriptions that follow, beach face terminology (offshore, offshore-transition, shoreface) is used in the sense of Elliott (1986).

Saltire Member. The initial major marine transgression represented by the Saltire Member blanketed the major part of this area with marine mudstones, containing scattered ammonites, belemnites and bivalve shell fragments, that typically in-fill relict pre-Upper Jurassic topography. However, in the Telford area to the south, and possibly also to the east of Scott, areas of higher relief resulted in non-deposition

Scott Sandstone Member. A major coarsening-upwards sandstone unit was deposited by a wave-dominated, barred shoreface system which prograded across the area of the Scott Field from the southeast. The contact with the underlying marine Saltire mudstones is typically gradational, and the progradational nature is shown by progressive shallowing from pervasively bioturbated, argillaceous shelf sandstones with a marine ichnofacies, to clean, bedded shoreface sandstones capped by an emergent (rootleted) coal. The barred nature of the shoreface is demonstrated by the presence of washover sandstones interfingering with back-barrier lagoonal mudstones above the coal (Fig. 10a). Although the local orientation of the facies belts (Fig. 10a and 10b) suggests land lay broadly to the southeast, with open sea to the northwest, there is no clear evidence of fluvial distributary channels feeding sediment directly into the Scott Field area. Instead, sediment transport is inferred to have been controlled by longshore currents, possibly sourcing sediment from a fluvial distributary lying along the coast further to the northeast. The Scott Sandstone Member can be separated into two units, Upper and Lower, related to changes in the style of deposition.

The Lower Scott Sandstone commences in argillaceous, pervasively bioturbated, offshore-transition zone (OTZ) sands, and coarsens upwards to clean, bedded, shoreface sands, reflecting the progradational phase. This was followed by a phase of vertical

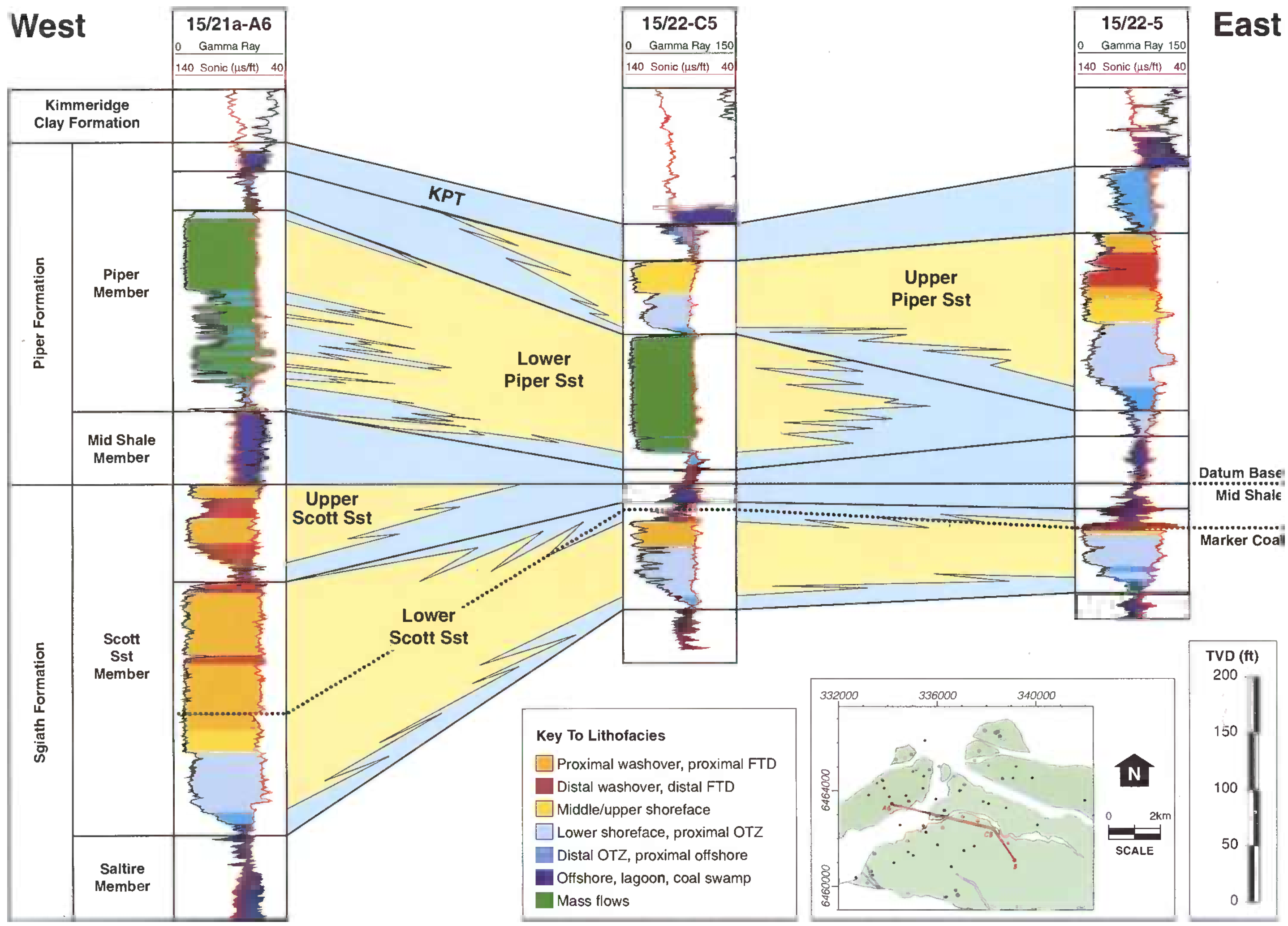

Fig. 9. Schematic correlation-section through three Scott Field wells (see inset for location) showing major reservoir intervals and facies variations across the field.

aggradation, with a thin marker coal overlain by thick back-barrier washover sands and lagoonal mudstones. Figure 10a shows facies distribution at this time, with the barrier lying just west of the field, and a well-developed washover sand apron behind it to the east, shaling out into lagoonal mudstones further to the east. The marine sands of the progradational phase are sheet-like in distribution, but the back-barrier sediments of the aggradational phase are prone to rapid lateral and vertical changes in facies. There is a clear pattern of westwards thickening in the Lower Scott Sandstone, and also in the underlying Skene and Saltire Members. The major structural control on this thickening is the NE–SW trending fault system that separates structural Block II from the rest of Scott Field (Fig. 3). In Block 15/22, the Lower Scott is typically less than 120 ft thick and thins rapidly eastwards. There is a marked thinning of the Lower Scott interval across the crest of structural Block Ib before the whole package thickens westwards into Block 15/21 where it exceeds 250 ft in the northwest of structural Block II. The observed westwards thickening trend is likely to be due to a combination of differential compaction of sand-rich and mud-rich areas of the field, and differential subsidence.

The Upper Scott Sandstone reflects a continuation of the back-barrier environment across the field, but was deposited during a retrogradational phase, prior to drowning by the Mid Shale. Eastwards reworking of barrier sands resulted in deposition of two overlapping flood-tidal delta lobes which shale out into lagoonal mudstones over the eastern part of the field (see Fig. 10b). The flood–tidal delta interpretation is consistent with a number of observed characteristics. The lobes are relatively large sand bodies within a back-barrier lagoonal environment. They show a coarsening-upwards (prograding lobe) profile with thin (?tidal) clay drapes in the lower part. They also pinch out very rapidly (from *c.* 50 ft of sandstone to lagoonal mudstone over less than 500 m lateral distance). Because the lobes formed by landward reworking of the barrier sands, they were building eastwards from the barrier, back into the lagoon. Progradation, in that sense, would have been in the opposite direction to that of the shoreface in the underlying Lower Scott Sandstone.

Mid Shale Member. Upper Scott deposition was terminated by the semi-regional marine flooding episode represented by the Mid Shale. The Mid Shale consists of predominantly laminated silty mudstones. It contains a marked glauconitic horizon near the base over the central and eastern parts of the field, representing slow condensed sedimentation on a marine shelf. The Mid Shale is relatively uniformly developed over much of Scott Field, away from the crestal area where a marked thinning occurs. However, it also appears to thin below the depositional axis of the overlying Lower Piper mass flow sandstones (see below).

Piper Sandstone Member. The Piper Sandstone Member was deposited by the second major prograding shoreface system, but did not advance as far across the field to the west as the Scott system. It consists of two units, Upper and Lower. The Lower Piper Sandstone is interpreted as stacked mass flow sands, since individual sharp-based sandstone beds can be seen interbedded with much lower energy outer shelf mudstones. The beds are typically structureless or weakly laminated, and bed tops may be slightly burrowed. Some beds contain fine rip-up mudstone intraclasts towards the bed

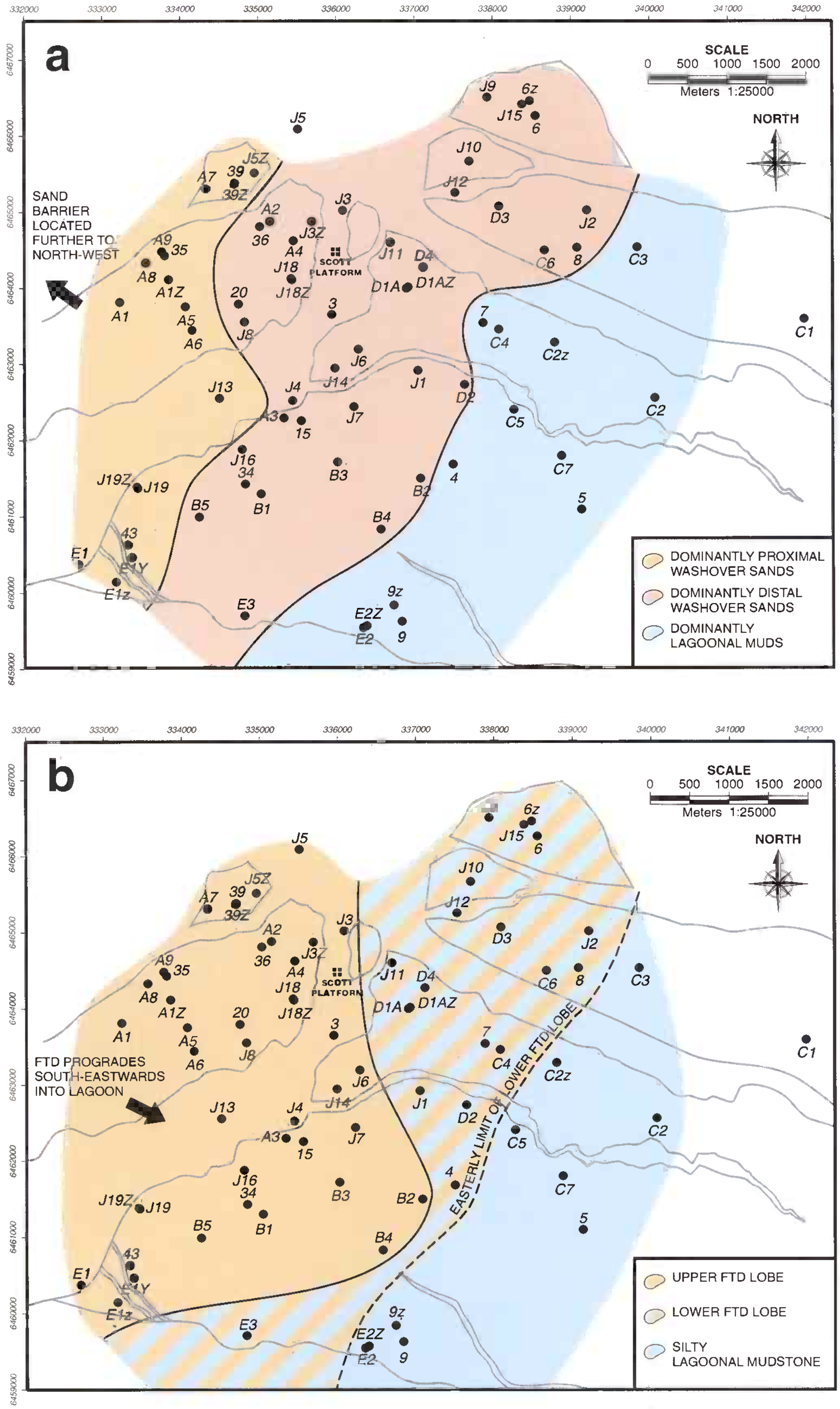

Fig. 10. (**a**) Facies map showing the dominant facies that occur between the marker coal in the Lower Scott Sand and the base of the Upper Scott Sandstone. (**b**) Facies map showing the maximum eastwards progradation of the upper and lower flood tidal deltas in the Upper Scott Sandstone. (**c**) Facies map showing the principal occurrence of mass flow sands in the Lower Piper Sandstone. (**d**) Facies map showing the limit of NW progradation at the end of Upper Piper sand deposition. Note the Upper Piper shoreface did not prograde across the entire Scott Field.

base, and examples of minor sand injection structures into adjacent mudstones have been noted. The mass flows may have originated from sediment collapse of an oversteepened basin margin (lying beyond Scott Field to the northeast), following a prolonged period when low sedimentation rates during deposition of the Mid Shale were unable to maintain pace with subsidence rates in the basin. The sands are clean and homogeneous, suggesting a winnowed shelf sand source, possibly to the northeast (Fig. 10c). As in the Lower Scott Sandstone, there is a pattern of subsidence-controlled thickening towards the west, demonstrating the increased accommodation space available in Block 15/21. Additionally, thickness considerations suggest a depositional axis (possibly a channel) running southwestwards across structural Blocks Ib and IV and then sweeping westwards into Block 15/21 (Fig. 10c). At their thickest in the west of the field, the mass flow sandstones exceed 150 ft, whilst in the east they reach 100 ft in the main channel axis but pinch out rapidly to the south and east (Fig. 9). The depositional pattern in Block 15/22 suggests that the crestal area of structural Block Ib was

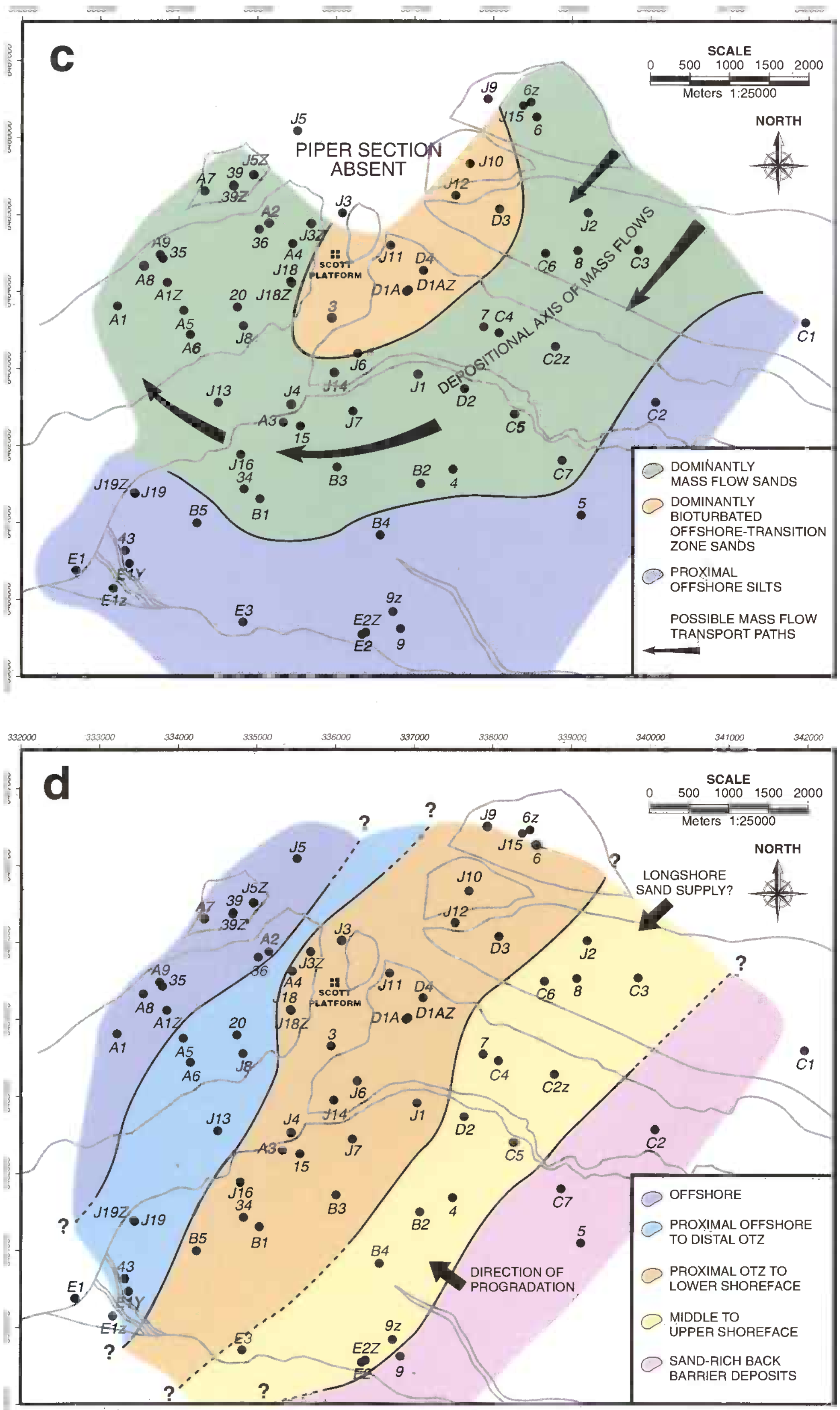

Fig. 10. (*continued*)

a positive feature in Lower Piper times, and that the E–W 'Witch Ground' trend faults were not yet active. On a local scale, lateral correlation of sand packages within the Lower Piper is problematic, since individual beds can pinch out very abruptly, and the geometry is therefore likely to consist of stacked and overlapping lobes of various dimensions.

The Upper Piper Sandstone was deposited by a westwards-prograding shoreface and back-barrier system similar to the Scott Sandstone Member, but is not as thickly developed, and as shown in the map (Fig. 10d), it did not prograde as far to the west. The trend of facies belts still clearly shows a broad NE–SW orientation. As with the Scott Sandstone Member, no direct fluvial sediment source is seen in the Scott Field area, and the sediment supply is inferred to be controlled by longshore currents (possibly from the northeast where the underlying Lower Piper mass flows also originated). The shallowing-upwards facies trends are similar to those in the Scott Sandstone, but the cleaner shoreface sands locally develop high Gamma Ray log spikes that are probably related to heavy mineral concentrations. The Upper Piper Sandstone shales out westwards, so the net reservoir is confined to the eastern and central parts of the field. Unlike the underlying units, the Upper Piper Sandstone thins towards the west, consistent with greater compaction of the shalier lithology developed in that area (Fig. 9).

The KPT Unit that overlies the Upper Piper Sandstone is a minor and very distal prograding unit of silty mudstones, glauconitic at the base. Core and log evidence show that although non-net over the Scott Field, it is thicker and shows a better coarsening-up profile towards the southeast corner of the field. Taken along with the Scott and Piper Sandstone Members, it forms the third of a series of 'prograding lobes' back-stepping towards the southeast, against a background of rising relative sea level.

Reservoir character

Sandstone composition

Analysis of the reservoir sandstones of the Scott Field indicates that the detrital assemblage becomes increasingly mineralogically mature with progressive depth of burial. Whilst the sandstones of the Piper and Scott Sandstone Members are both presently quartz arenites, reconstructions of their original detrital mineralogy indicate that the Piper sandstones were sub-arkosic to arkosic, and the Scott sandstones were quartz arenitic to subarkosic at the time of sediment deposition. The differences between the original detrital mineralogical compositions of the two main reservoir sandstones indicate that the sands were derived from different source lithologies. Data presented by Hallsworth *et al.* (1996) suggest however that the Scott and Piper sandstones were both derived from Palaeozoic rocks from the Fladen Ground Spur to the northeast (Fig. 2), although the Scott sandstones could alternatively have been derived from the East Shetland Platform to the north (Hallsworth *et al.* 1996).

The compositional evolution of the Piper sandstones from arkoses/subarkoses to quartz arenites is interpreted to be the result of the dissolution of detrital feldspar from the sandstones during early to intermediate burial. Reservoir quality is not significantly enhanced by the feldspar dissolution, since secondary pores are generally occluded by blocky kaolinite formed as a reaction product of the dissolution.

Porosity and permeability

The primary control on reservoir properties in the Scott Field is initial sediment grain size. This is illustrated by the positive correlation of reservoir permeability with depositional facies (Fig. 11). The air permeability of the Scott reservoir sandstones typically reaches several Darcies in coarser sands near the crest of the structure, declining below the 1 mD net pay cut-off in distal, silty, offshore-transition zone mudstones. Stratigraphically the most consistently high permeability sands are those of the Lower Scott upper shoreface and proximal washover deposits reflecting their reworking in the high-energy surf zone (Fig. 10a). However, the highest individual values are associated with even coarser and better sorted sands, developed within both the Upper Scott flood tidal delta

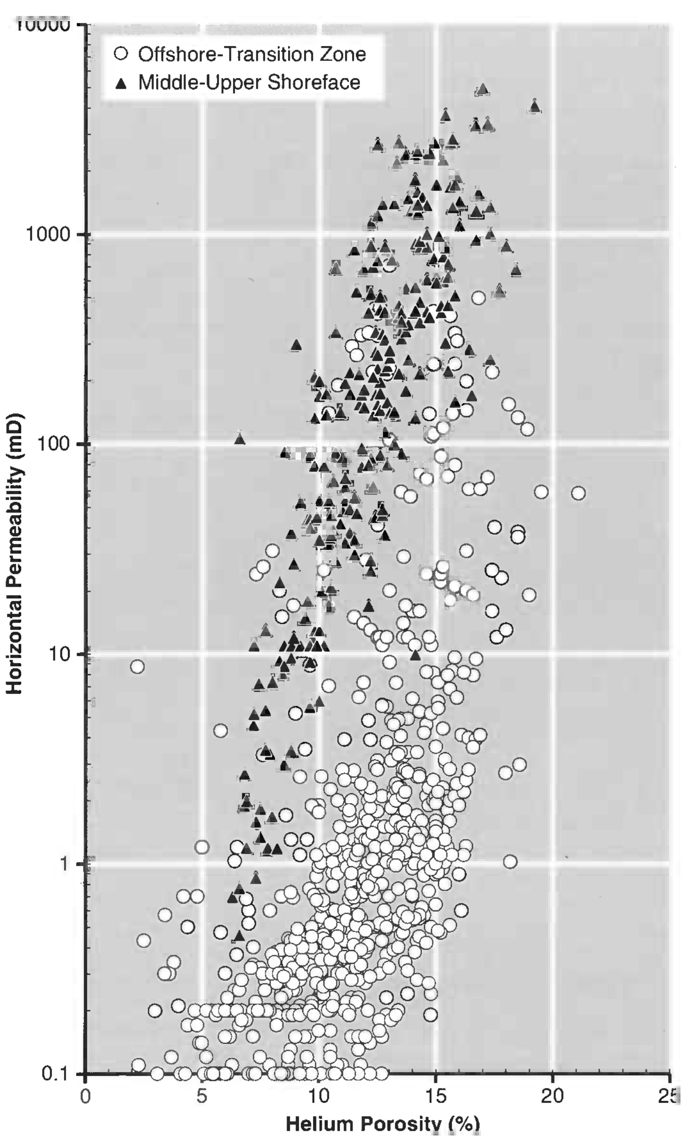

Fig. 11. Horizontal permeability plotted against helium porosity for shoreface and offshore-transition zone sandstones from Scott Field Block II. The plot shows how facies exerts a strong control on the permeability/porosity characteristics of individual sands.

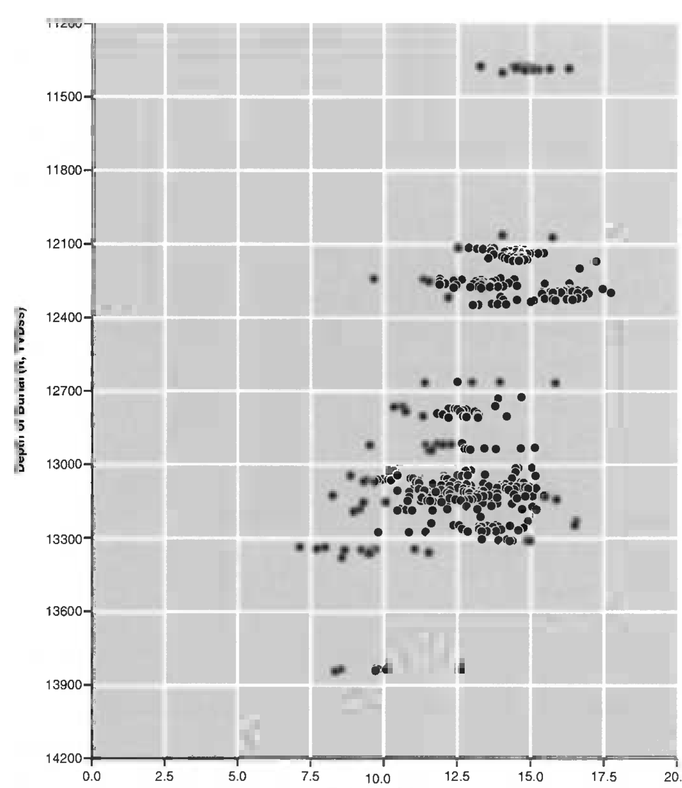

Fig. 12. Depth of burial versus helium porosity for mass flow sandstones from the Scott Field structural Block II. The plot shows that total porosity decreases with increasing depth of burial. This trend reflects both increasing quartz cementation with depth of burial and the effects of chemical compaction in downflank areas. Prior to plotting data points affected by early carbonate diagenesis were removed.

complex (Fig. 10b) and the Lower Piper mass flow sands (Fig. 10c). For example, in well 15/22-D1 at the crest of the field, air permeabilities in excess of 6500 mD are recorded in the Upper Scott, and air permeabilities in the Lower Piper regularly exceed 4000 mD.

The macropore networks of both main reservoir sandstones are dominated by primary intergranular porosity, with subordinate volumes of secondary grain dissolution porosity observed in the Piper Formation sandstones. At the crest of the field, in the cleanest shoreface facies, porosities up to 20% are commonly preserved, while in downflank areas porosities in similar sandstones decrease significantly. Figure 12 shows the porosity depth profile for the Lower Piper mass flow sands of structural Block II. These sandstones show similar grain size characteristics across the block and, as Figure 12 demonstrates, there is a clear trend of decreasing helium porosity with increasing depth of burial. The porosity decrease can be attributed to the effects of both diagenesis and increased compaction with increasing burial depth.

Although quartz cementation and compaction degrade porosity, permeabilities are more seriously affected. In general the effect of permeability degrading factors becomes more severe as grain size declines and detrital clay content increases. Decreasing grain size and increasing clay content both act to accentuate depositional differences and concentrate net reservoir in upper shoreface and proximal back-barrier deposits of the Upper and Lower Scott Sandstones, and within the mass flow deposits of the Lower Piper Sandstone. This preferential degradation of reservoir quality in fine-grained sediments appears to reflect two factors. Firstly, because these sediments tend to be richer in clay, the effects of both mechanical and chemical compaction are enhanced. Secondly, as sediment grain size and pore throat diameters decline the damaging effects of cement precipitation are accentuated. A cement layer that has little effect proportionately on a wide pore throat may completely occlude a narrow one.

Diagenesis

Authigenic quartz cements constitute the most important diagenetic alteration observed in the Scott Field, and are recognized in almost all the reservoir sandstones. The authigenic quartz occludes both primary and secondary intergranular pore space and reduces pore throat diameters. The quartz overgrowths post-date both mechanical compaction and feldspar dissolution. Authigenic quartz increases with increasing depth of burial over the depth range 11 000 ft–13 500 ft TVDss in the Scott Field, commonly reaching abundances of 15% bulk rock volume, and results in significant porosity degradation (Fig. 12). Evidence from similar reservoir sandstones in the Ivanhoe, Rob Roy and Telford Fields indicates that quartz cementation initiates at around 8000 ft TVDss when reservoir temperatures exceed approximately 176°F (80°C).

Other subordinate diagenetic minerals recognized in the Scott Field core include calcite, dolomite, barite, pyrite, kaolinite and illite. Of these, the carbonates can be locally important. Early calcite nodules that formed close to the sediment–water interface during early burial, locally occlude all porosity and permeability but are volumetrically insignificant. A late calcite cement is commonly observed close to faults and can locally have a serious detrimental effect on local porosity and permeability.

Hydrocarbon composition and source

The oils of the Scott Field are undersaturated low sulphur crudes with bubble points in the range 1930–3890 psia and stabilized atmospheric flash gravities in the range 34–39 API units. All four major compartments comprising the Scott Field (Fig. 3) are overpressured relative to hydrostatic, and are pressure isolated from each other (Fig. 13). Each compartment contains hydrocarbons of slightly different character. Overpressures of 3000 psi relative to a hydrostatic pressure of *c.* 5000 psia are observed in structural Block I of the field. In the adjacent downthrown structural Blocks II and IV, oil leg pressures are respectively 150 and 200 psi higher, depth for depth, than found in structural Block I. Structural Block III, northernmost and closest to the axis of the Witch Ground Graben, is the most overpressured of all, by *c.* 3500 psi relative to a hydrostatic pressure of 6000 psia (Fig. 13).

Oil densities show more or less the reverse pattern, being highest in Block I and progressively lower in structural Blocks IV, II and III respectively. These patterns suggest that the most active and mature sourcing of the Scott Field has been from the north where mature Kimmeridge Clay Formation source rocks are present in the Witch Ground Graben. Filling of the structure from this direction is also consistent with the development of a major perched oil–water contact in the southern part of the field (Figs 4 & 8). The

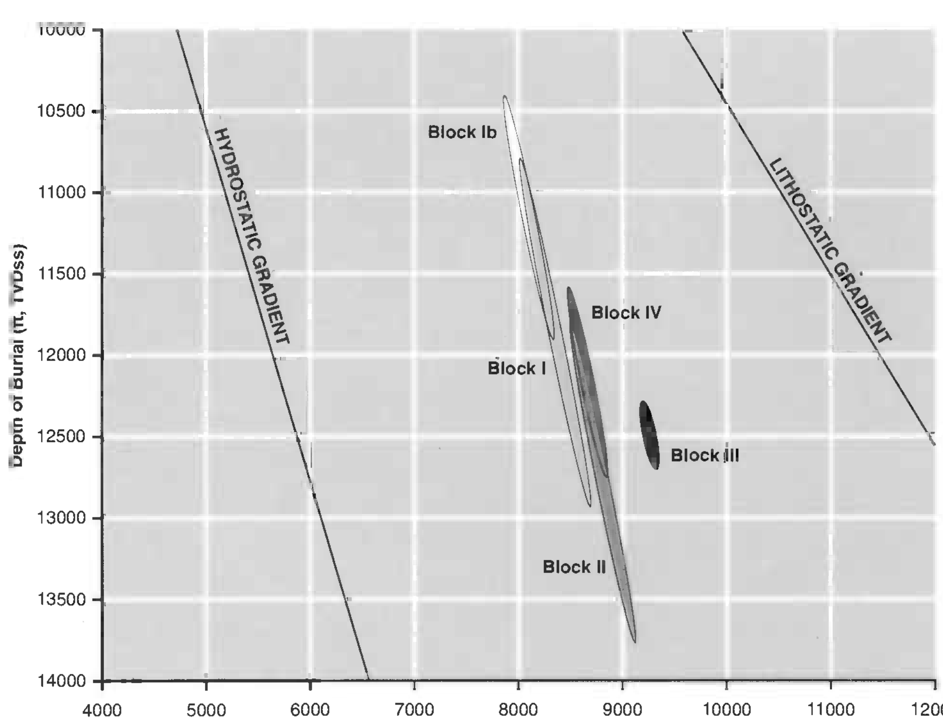

Fig. 13. Virgin pressures encountered in each of the main Scott Field pressure compartments plotted against depth of burial. These data demonstrate that structural Block III, the closest fault block to the inferred Witch Ground Graben source area, is the most overpressured relative to hydrostatic pressure. Fault blocks further from the Witch Ground Graben show relatively decreasing degrees of overpressuring.

highest gas/oil ratios observed in the Scott Field are observed in structural Blocks II and IIa which are downthrown relative to the crest of the field structure (Figs 5, 6a & 8). This pattern along with differences in the hydrocarbon composition suggest that the Block II area of the field may have been charged separately to the Block I, Ib, III, IV area with hydrocarbons sourced from the North Halibut Graben to the west of the Scott Field (Fig. 2).

Reserves and production history

Field development

Annex B approval for the development of the Scott Field was given in 1990, six years after field discovery. The field was developed from two platforms, linked by bridges, with a production capacity of 225 000 BOPD. Subsea wells are tied back to the platform via five sub-sea manifolds. The Scott platform has an additional 28 drilling slots, 20 of which have been used to date. Oil is exported via the Forties pipeline to Cruden Bay, whilst gas export is via the SAGE pipeline to St Fergus. To accelerate early production, seven sub-sea producer–injector well pairs were drilled and completed prior to the installation of the platform. As a result, first oil was exported on 2 September 1993, several months ahead of schedule. Gas export commenced six weeks later as did water injection. The delayed water injection start-up was possible due to the overpressured nature of the reservoir and the low bubble points of the crude oils in place. In early 1994, development approval for the South Scott area was granted as an addendum to the main Scott Field development plan.

Pressure maintenance is achieved using water injection wells in downflank areas, with producer wells situated up-dip. The crestal areas of the field were initially avoided as drilling targets because the seismic imaging quality in crestal areas was particularly poor. Water is injected into the oil leg since reservoir quality in the water leg is highly degraded and there is negligible aquifer support. Wells are commonly dedicated as either Piper or Scott producers and typically have monobore completions for improved access by wireline-based interventions. The perforating strategy for the start-up wells involved the perforating of all net sand in the target interval, either Piper or Scott, with gaps in the perforations left to facilitate future well control.

Currently, the Scott Field produces from 23 wells (ten on the Piper Sandstone Member, 13 on the Scott Sandstone Member), with support from 18 injector wells (seven injecting into the Piper Sandstone Member and 11 into the Scott Sandstone Member). Two wells inject water into both main reservoir sandstones. Including exploration and appraisal wells, the Scott structure has been penetrated in excess of 60 times, and approximately 17 000 ft of core has been cut and recovered from the reservoir interval.

Production history

Figure 14 shows the production profile for the Scott Field in stock tank barrels since first oil in 1993 until year-end 1999. Within three months of start-up the field was operating near capacity at *c.* 150 000 STB d^{-1} and between August 1994 and August 1995 the Scott Field production averaged 185 000 STB d^{-1}. These high production rates were, however, accompanied by early and unexpected water breakthrough in several wells. The produced water was typically >80% injection water, with only subordinate volumes of formation water. Production was also adversely affected by two key factors. Firstly, the early platform wells sited towards the crest of the field were disappointing, several wells failed to find significant reservoir intervals, and resulted in the commissioning of a new 3D seismic survey. Secondly, a continued lack of voidage replacement coupled with poor injector performance in some areas of the field, meant that reservoir pressures continued to fall, thereby limiting the potential off-take. Initial oil rates from producing wells were however excellent, with typical rates of 30 000 STB d^{-1} and production indices typically in excess of 30 BOPD/psi. Indeed, Scott Field production for October 1995 averaged 200 000 STB d^{-1} with peaks in excess of 210 000 STB d^{-1} being obtained.

Oil production in 1996 averaged only *c.* 150 000 STB d^{-1} at 26% water-cut, some 25 000–30 000 STB d^{-1} short of expectation. These figures at least partially reflected on-going problems with the water injection system, which was subsequently upgraded to a capacity of 440 000 BWPD at 4500 psi. By end August 1997 Scott Field had produced *c.* 220 MMSTB of oil and *c.* 55 MMBBL of water, and injected 318.5 MMBBL of water. Daily rates by end 1997 approached 100 000 STB d^{-1} (Fig. 14). Significantly, all but one producer had cut water. As a result, an extensive well intervention campaign to isolate high water cut reservoir zones was undertaken. High water cuts were proving problematic for several reasons. Firstly, water cycling in some areas was proving inefficient and affecting rates for adjacent wells. Secondly, reservoir layers with high water cuts were shown to be inhibiting production from dry oil zones. Thirdly, water breakthrough in the Scott Field often has a severe effect on production rate. For example, well 15/22-J2 (Fig. 3) was producing 9600 STB d^{-1} in July 1997 but slumped to 960 STB d^{-1} after water breakthrough in January 1998 as a result of scale build up. Early water breakthrough at the crest of the field was also causing

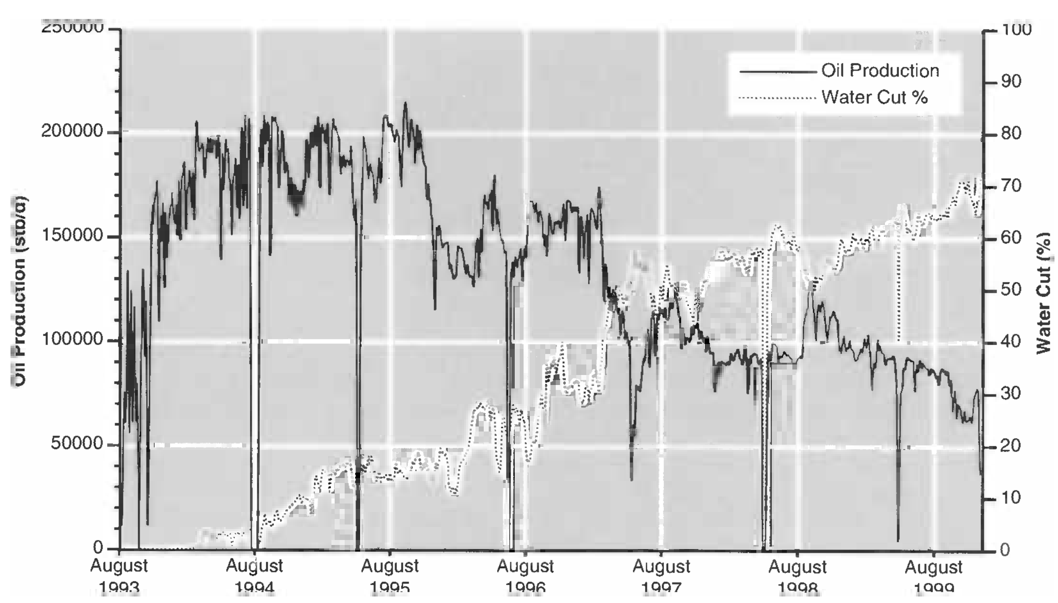

Fig. 14. Oil production plotted against time since first oil. Also shown is the percentage water cut since water breakthrough. Major decreases in oil production correspond to the watering out of key reservoir intervals during field life. Typically oil production from wells declines rapidly once they have cut water.

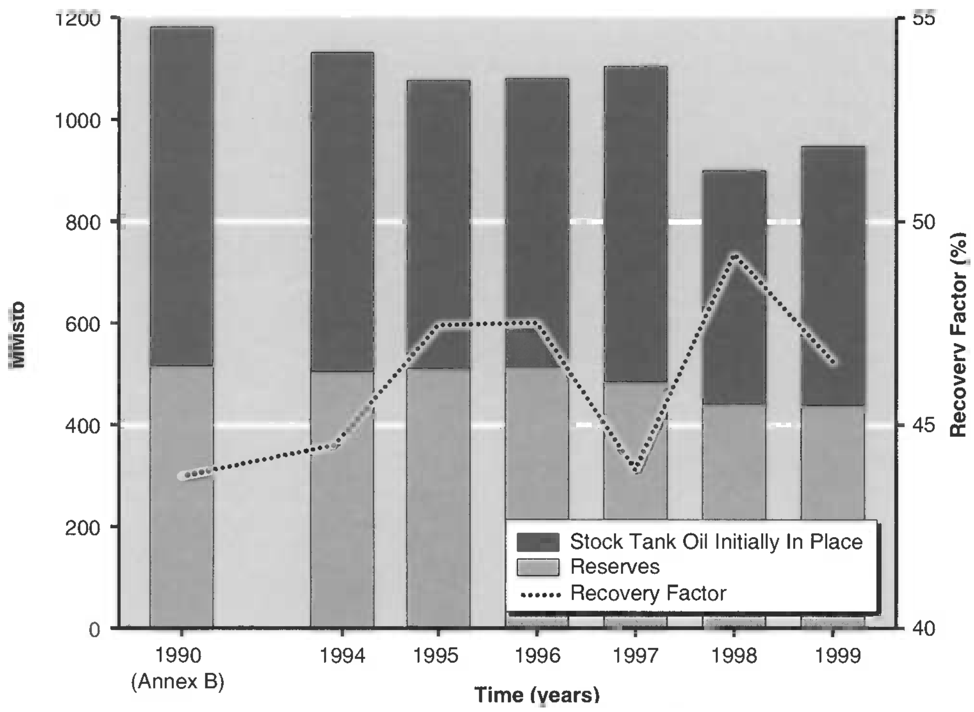

Fig. 15. Scott Field STOIIP, reserves, and recovery factor plotted against time. The first column shows data from the Scott Field Annex B in 1990. Subsequent columns show data from annual field reports since first oil in September 1993. Since the Annex B there has been a 20% decrease in field STOIIP, and a commensurate 14.5% decrease in field reserves. Over the same period, the projected recovery factor from the field has increased.

concern as it was becoming increasingly apparent that water overrun in some high permeability reservoir zones was bypassing significant volumes of down-dip oil in less permeable zones.

During 1998 production dropped below 100 000 STB d^{-1} as productive zones in key producing wells finally cut water (Fig. 14). More positively, development drilling, which had been suspended in early 1997, was resumed in mid-1998 as results of the 1996 3D seismic survey became available. The new data were a significant improvement over the 1993 dataset, although parts of the field crest were still poorly imaged. The imaging problem results from a weak acoustic impedance contrast between the oil-bearing sandstones and the overlying Kimmeridge Clay Formation mudstones at the crest, coupled with the presence of strong seabed and interbed seismic multiples. One notable success of the new drilling campaign was well 15/22-J16 (Fig. 3). Drilled on the western flank of structural Block I the well encountered a full reservoir section, with the Scott Sandstone at near virgin pressures. When well 15/22-J16 came onstream initial production rates were close to 25 000 STB d^{-1} of dry oil. These rates ultimately declined due to lack of pressure support, although the well produced *c.* 3 MMSTB solely under depletion drive. In 1999, well 15/22-J19Z (Fig. 3) was drilled down flank of well 15/22-J16 to provide pressure support to the Scott Sandstone Member. The well is currently injecting *c.* 35 000 BWPD and is in pressure communication with well 15/22-J16.

During 1999 the daily production averaged just over 83 000 STB d^{-1} at a water cut of *c.* 60%. Oil production also passed a benchmark of 300 MMSTB in late November 1999. Development drilling, which was suspended in mid-1999, will now be focused on economically locating and exploiting bypassed oil. Recent pre-stack depth migration of the 1996 3D seismic data is also providing grounds for

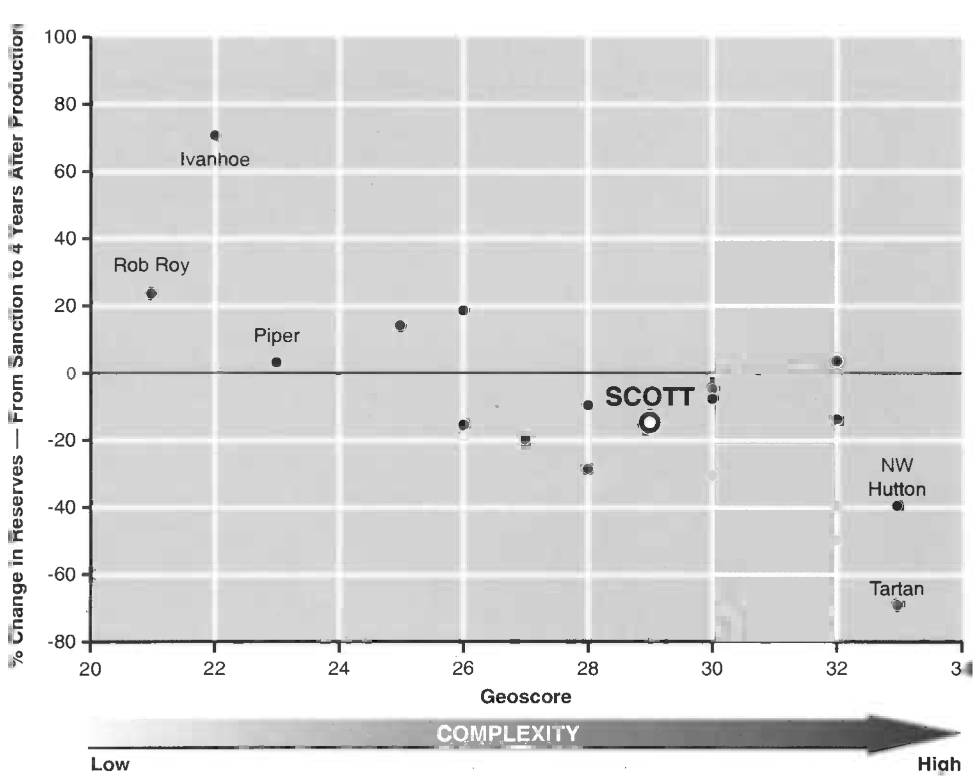

Fig. 16. Percentage change to field reserve versus the Geoscore complexity index for compartmentalized shallow marine and deltaic reservoirs in the North Sea. Data are taken from Dromgoole & Speers (1997). Geoscore is an estimate of field complexity. The plot shows that there is an inverse correlation between percentage change in reserves versus Geoscore, since as fields get more complex, there tends to be an associated decrease in reserve estimates during early field life. Data from the Scott Field are also shown and fit this trend.

optimism. Early results indicate that it has significantly improved imaging over much of the field. Consequently, drilling is expected to resume in late 2000 as a new generation of detailed 3D reservoir models become available and allow more precise targeting of bypassed reservoir zones.

Reserves

In 1990 Annex B reserves (including the South Scott area) stood at 515 MMSTB with a mapped STOIIP (Stock-Tank Oil Initially In Place) calculated as 1129.2 MMSTB (Fig. 15). These figures were carried through to 1997 when reserves were downgraded to reflect the disappointing drilling results since first oil. Of the 19 platform wells drilled since 1993, four failed to encounter reservoir and a further five wells encountered partial sections as a result of crestal erosion (Fig. 6b) and/or faulting. As a result, in August 1997, the Scott Field reserves were written down to *c.* 480 MMSTB. STOIIP was also revised downwards to 1058.6 MMSTB (Fig.15).

The 1999 reserve estimates were *c.* 440 MMSTB from a mapped STOIIP of just over 946 MMSTB. These figures represent a decrease of 20% from the Annex B STOIIP and a reserves shortfall of 14.5% compared with the Annex B prognosis. However, the anticipated recovery factor has risen from an initial 44% to *c.* 46%. The decrease in reserves, although disappointing, is consistent with data from other compartmentalized shallow marine and deltaic reservoirs in the North Sea (Dromgoole & Speers 1997; Fig. 16). These authors published data for a variety of North Sea fields that demonstrate an inverse correlation between estimated reservoir complexity or 'Geoscore' and the percentage change to field reserves between field sanction and four years into field production life. When plotted with the data of Dromgoole & Speers (1997) the Scott Field appears to be fairly typical of moderately to highly complex shoreface reservoirs in the North Sea (Fig. 16). Furthermore, in late field life, reserve estimates often increase once more as performance exceeds expectation (Dromgoole & Speers 1997).

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Scott Field data summary

Trap		
Type	Structural	–
Depth to crest	10 400	ft
Lowest closing contour	n/a	ft
GOC or GWC	–	ft
OWC	11 895–13 792	ft
Gas column	n/a	ft
Oil column	500–2000	ft
Pay zone		
Formation	Sgiath & Piper Formations	–
Age	Upper Jurassic (Latest Oxfordian to Kimmeridgian)	–
Gross thickness	*c.* 360	ft
Net/gross	0.8	ft
Porosity average (range)	10–22	%
Permeability average (range)	<0.1–*c.* 6500	mD
Petroleum saturation average (range)	85–97	%
Productivity index	1–50	BOPD/psi
Petroleum		
Oil density	36	° API
Oil type	Low Sulphur Crude	–
Gas gravity	n/a	–
Viscosity	0.297–0.578 @ 8500 psi	cp
Bubble point	1930–3890	psig
Dew point	n/a	psig
Gas/oil ratio	578–1398	SCF/BBL
Condensate yield	n/a	BBL/MMSCF
Formation volume factor	1.328–1.761 @ 8500 psi	–
Gas expansion factor	n/a	SCF/RCF
Formation water		
Salinity	110 000	NaCl eq ppm
Resistivity	0.027 @ 200°F	ohm m
Field characteristics		
Area	8650	acres
Gross rock volume	3 114 000	acre ft
Initial pressure	7879–9320	psi
Pressure gradient	0.2884–0.3167	psi/ft
Temperature	190–248	°F
Oil initially in place	946 MMSTB	MMBBL
Gas initially in place	Associated gas only	BCF
Recovery factor	46.5	%
Drive mechanism	Water flood	
Recoverable oil	441 MMSTB	MMBBL
Recoverable gas	Associated gas only	BCF
Recoverable NGL/condensate	n/a	MMBBL
Production		
Strat-up date	September 1993	
Production rate plateau oil	>200 000	BOPD
Production rate plateau gas	n/a	MCF/D
Number/type of well	13 Scott oil producers 10 Piper oil producers 11 Scott water injectors 7 Piper water injectors 2 Scott/Piper water injectors	

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