The Kingfisher Field, Block 16/8a, UK North Sea

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Abstract: The Kingfisher Field is located in the South Viking Graben, Block 16/8a, with a minor extension into Block 16/8c. Block 16/8 was initially awarded in June 1970 to Shell and Esso, with the Kingfisher discovery well 16/8-1 spudded in 1972. The well tested high H_2S oil at marginal rates from Upper Jurassic Brae Formation sandstones. Subsequent appraisal well 16/8a-4 (1984) tested gas/condensate from better quality Brae Formation sandstone reservoirs. This well also discovered the deeper Middle Jurassic Heather Formation sandstone gas/condensate accumulation at near-HPHT conditions. The Brae and Heather Formation sandstones contain stacked hydrocarbon accumulations in separate combinations of stratigraphic and structural traps. Production by natural aquifer drive commenced from a sub-sea satellite to Marathon's Brae B platform in 1997, initially from the Brae reservoirs. To date, three production wells have been completed and a fourth well is planned to be on stream in 2000. The Brae Formation sandstones at Kingfisher are interpreted as distal deposits of the Brae/Miller fan-apron system and range in quality from excellent to very poor across the field. The Heather Formation reservoir consists of medium quality sands deposited within a submarine incised valley. The most recent volumetric estimate (1998) for the total field predicts an ultimate recovery of 41.2 MMBBL of pipeline liquids and 280 BCF of dry export gas. Regional reservoir architecture and connectivity as well as hydrocarbon composition are key to understanding the production performance of the critical gas/condensate below dewpoint. Advances in sub-sea and horizontal drilling technology have enabled field development.

The Kingfisher Field is situated 153 miles NE of Aberdeen, in a water depth of 110 m (Fig. 1). The structure at the Upper Jurassic Brae Formation sandstone level consists of a NW–SE elongated anticline which is fault-bounded to the northeast and stratigraphically closed to the east. At the Middle Jurassic Heather Formation sandstone level the structure comprises a tilted fault block with a steep southwesterly dip and stratigraphic closure to the east. The Upper Jurassic Kimmeridge Clay Formation and Middle Jurassic Heather Formation shales provide the top seals to the Brae Formation and Heather Formation reservoirs respectively. Hydrocarbons are sourced from the Kimmeridge Clay Formation in the deeper Viking Graben. The free water levels for the Brae Formation sandstone accumulations are between 13 100 and 13 220 ft TVSS. The Heather Formation sandstone free water level is at 15 700 ft TVSS. The current licence holders for the Kingfisher Unitized Area are Marathon Oil UK (operator for Block 16/8c and the Brae 'B' Platform), Shell UK Exploration and Production (operator for Block 16/8a and Kingfisher), and Esso Exploration and Production UK. This paper outlines the geology and development history of the Kingfisher Field.

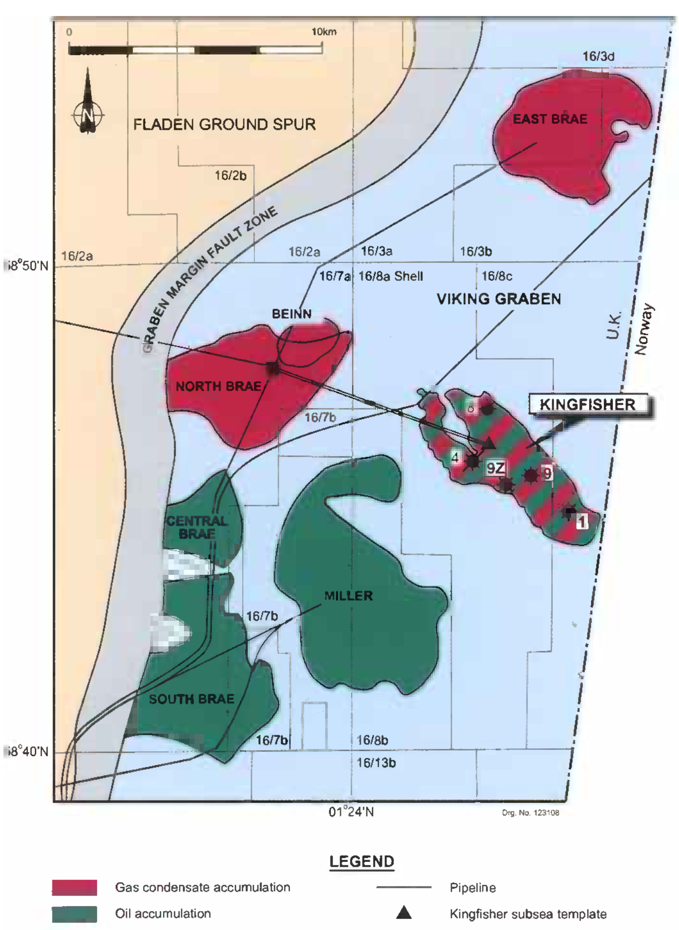

Fig. 1. Location map of the Kingfisher, Miller and Brae Fields in the South Viking Graben.

History

Pre-discovery and discovery

Licence P.116, initially comprising the Auk/Fulmar Block 30/16, the Kingfisher Block 16/8, and Block 22/2, was granted to Shell/Esso during the third Licensing Round in 1970. Block 16/8 had been applied for to test the Middle Jurassic Brent play, with the Brent Field having been discovered just a few months before the drilling of Kingfisher discovery well 16/8-1 (Fig. 1). Whilst drilling the intermediate hole section in well 16/8-1, the rig reported sand traces within the Kimmeridge Clay Formation which later became named the Brae Formation sandstone and which tested 1276 BOPD with 500 ppm H_2S. Reservoir was not encountered in the Middle Jurassic. Well 16/8-1 reached total depth after a high pressure/low volume water kick was encountered in the Pentland Formation, too high in pressure to be managed by any rig at that time. The Kingfisher discovery remained unnamed until 1995 but has been frequently referred to in the literature as 'Miller East'.

Pre-development appraisal

A large part of Block 16/8 was relinquished in 1976 but the more prospective Auk/Fulmar acreage, in Block 30/16, was retained. The western part (16/8b) together with the subsequent Miller discovery was later licensed to Conoco, whilst the eastern part (16/8c) was awarded to a joint venture led by Marathon Oil UK. Even though Shell/Esso recognized from the beginning the submarine depositional environment of the Brae Formation sandstones with a westerly provenance area, appraisal appeared uneconomic due to the distal location from the sand source until 12 years later when a further structure at Heather Formation level was identified. Well

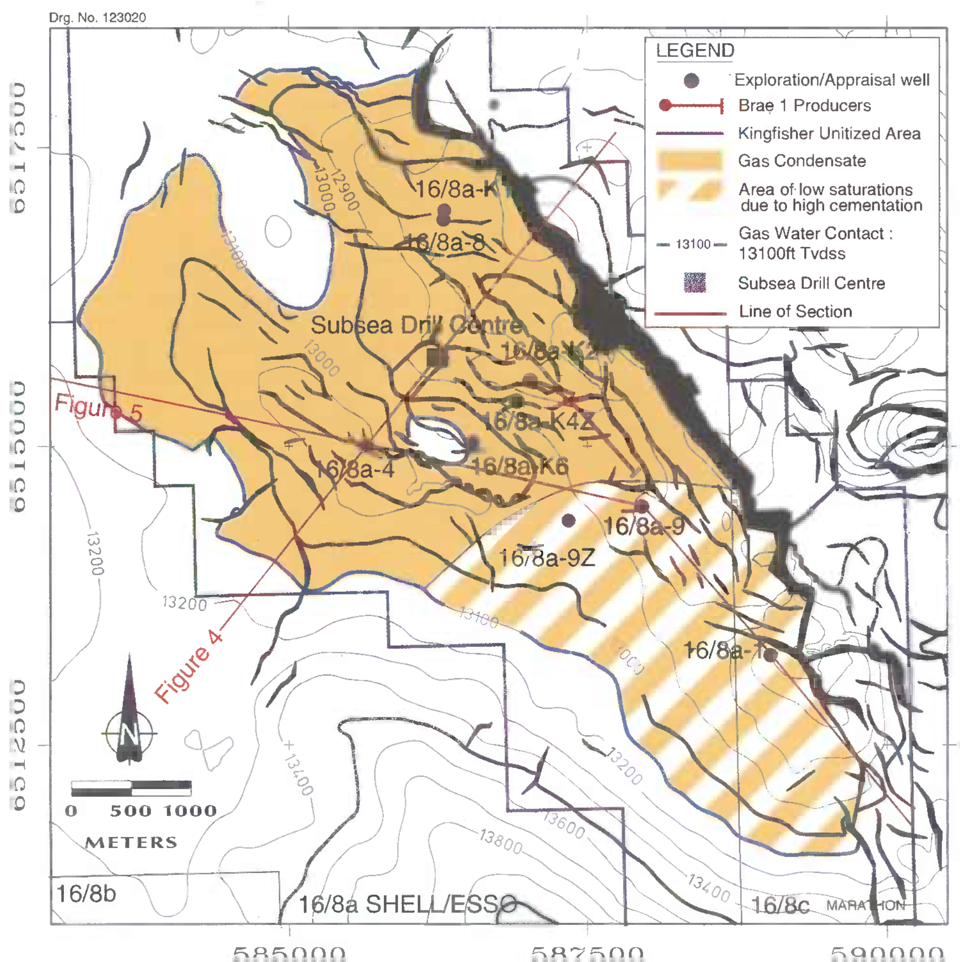

Fig. 2. Top Brae Formation Unit 1 structure map.

16/8a-4 (1984) proved this structure to be hydrocarbon bearing and also confirmed the predicted improvement in Brae Formation sandstone quality to the west (Figs 2 and 3). Two separate tests of the Brae Formation sandstones produced volatile oil in the deeper Brae interval and gas/condensate from the shallower interval. Another appraisal well (16/8a-8, 1988) was therefore drilled to obtain information about the gas/condensate accumulation at Brae Formation level and again found a better reservoir than the previous wells, testing at a rate of 4115 BPD condensate. The final appraisal well, 16/8a-9 & 9Z (1989), was drilled to appraise at Brae Formation level the transition from prolific channelized lobe sandstones in well 16/8a-8 to marginal fringe deposits in well 16/8-1, but the well found poorer sand quality than expected. Well 16/8a-9Z appraised and confirmed the Heather Formation level accumulation, discovered by well 16/8a-4. Development feasibility studies concluded that the only economic development for the field would be via sub-sea tie-back, however neither technology or infrastructure capacity were available at this time. Three-dimensional seismic data was initially acquired in 1985 but proved to be too poor in quality to resolve the deep Heather Formation accumulation. A more extensive 3D survey was acquired in 1993, coordinated by BP, which has significantly improved resolution.

Development and early production

By 1995, sub-sea technology had sufficiently progressed to consider development of the field. The main breakthrough was reached when it became possible to commingle near-high pressure/high temperature Heather Formation production with lower pressure Brae Formation production in one pipeline system, by means of the world's first sub-sea HIPPS (High Integrity Pressure Protection System) (Spence *et al.* 1999). The large pressure difference between both reservoirs also required the commissioning of Super Duplex stainless steel choke valves with a design temperature as low as −60°C. The field was brought on stream in October 1997 as a sub-sea satellite to Marathon's Brae 'B' platform (Fig. 1). One vertical gas/condensate producer for the Brae Formation reservoir was predrilled and two further horizontal producers for this reservoir were brought on stream by mid-1998. These were the first horizontal wells drilled in the South Viking Graben. The first horizontal Heather Formation producer is expected to be brought on stream later in 2000. Early production results confirm that the Brae Formation sandstone accumulations share two complex aquifers with the surrounding Miller and Brae Fields. The combined offtake of the fields from the upper aquifer, which is connected to the gas/condensate accumulations of the North and East Brae Fields, as expected had brought the pressure down to around dew point at first oil.

Structure

The Kingfisher area has undergone three major tectonic phases. Rotational block faulting during graben development took place during the Middle Jurassic and was followed by slump and slide listric faulting associated with Zechstein salt movements, starting at the end of the Jurassic and continuing into the Lower Cretaceous (Roberts 1991; Partington *et al.* 1993). In the final phase during the Tertiary only gentle salt movements and subsidence continued to form the present structure. Structure at Middle Jurassic Heather Formation and Upper Jurassic Brae Formation level are therefore distinctly different (Figs 4, 5a and b).

The Heather Formation accumulation is trapped in a NW–SE trending tilted fault block, bound to the northeast by a major normal fault (Fig. 3). Small scale faulting inside the block is dense at top sandstone level whilst the underlying top Pentland Formation

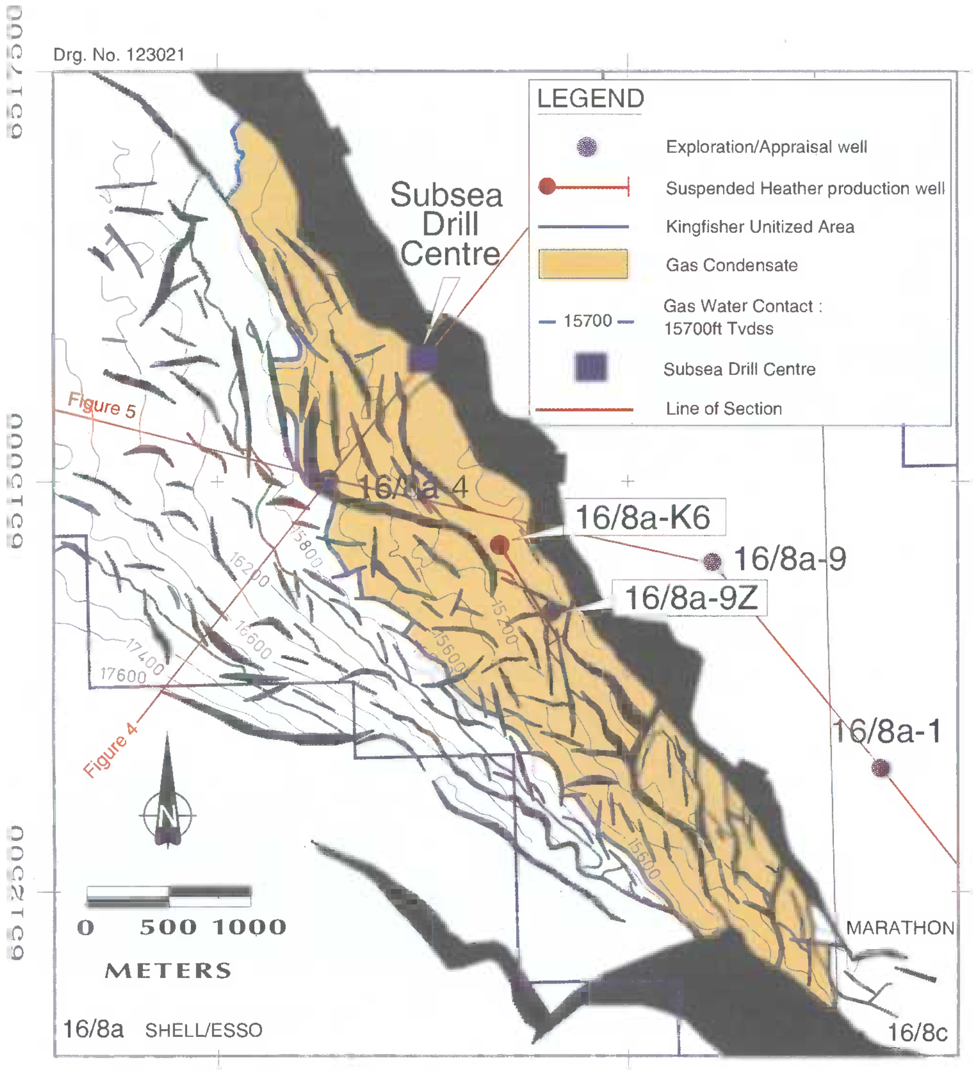

Fig. 3. Top Heather Sandstone unit structure map.

coal marker is nearly unfaulted. This has led to the interpretation of numerous short/minor listric faults soling out on Pentland Formation coals and dipping mainly southwest in the same direction as the tilted fault block. Very few of these faults have throws of more than 100 ft and are thus insufficient to fully offset the Heather Formation sandstone reservoir. To the east the Heather Formation rises above a major salt high and is increasingly broken up into smaller rotated fault blocks. The larger throw of faults in this area would be sufficient to fully offset the reservoir and seal it against Heather Formation shale, however, a stratigraphic trap in this direction is equally likely to explain the hydrocarbon distribution.

At Brae Formation sandstone level, the structure forms an elongated NW–SE trending anticline in the footwall of a major normal fault trending sub-parallel, but located further northeast than the bounding fault to the Heather accumulation (Figs 2, 4, 5a and b). Salt uplift during the late Jurassic re-activated both normal faults leading to the northeast block sliding down and rotating against the upthrown block in the southwest. The resulting fault shape within the Upper Jurassic is strongly listric. The bounding fault to the Heather accumulation shows similar rejuvenation, forming a separate but less pronounced Upper Jurassic high around well 16/8a-4 (Figs 4 and 5). Salt movements might have started during the Upper Jurassic but are completely disguised by a strong regional tilt of the graben towards the west, which created accommodation space for the Brae Formation sandstone deposition. At Lower Cretaceous level, when the extensional movements forming the Viking Graben slowed down, localized salt migration took over and controlled sediment deposition. Accumulation of Cromer Knoll marl and shale filled up the space created by the rotating blocks above the listric fault planes (Fig. 4). Minor lineations with a predominantly W–E trend fill the space between both fault planes and increase in density eastwards towards the center of the underlying salt high.

Tertiary movements had little impact on the structural configuration and consist only of a gentle rise of the salt high to the east of Kingfisher. Minor faulting of post-Lower Cretaceous levels is visible in this area.

The quality of the 1993 vintage 3D seismic at Brae Unit 1 and Brae Unit 2 level is reasonable, exhibiting some but not all of the Brae Formation sandstone architecture. Resolution at Heather/Pentland Formation level is moderate in the main Kingfisher block, where a strong Pentland coal marker is present, however elsewhere resolution is poor.

Stratigraphy

The general stratigraphic sequence of the Kingfisher Field is shown in Figure 6. Unconformities are present in the area at late Middle Jurassic, early Upper Jurassic, base Cretaceous, base Upper Cretaceous, and sub-Paleocene level.

Middle Jurassic Pentland Formation

Two wells within the Kingfisher Field penetrate the Bajocian to Bathonian Pentland Formation. This is a sequence of sandstones,

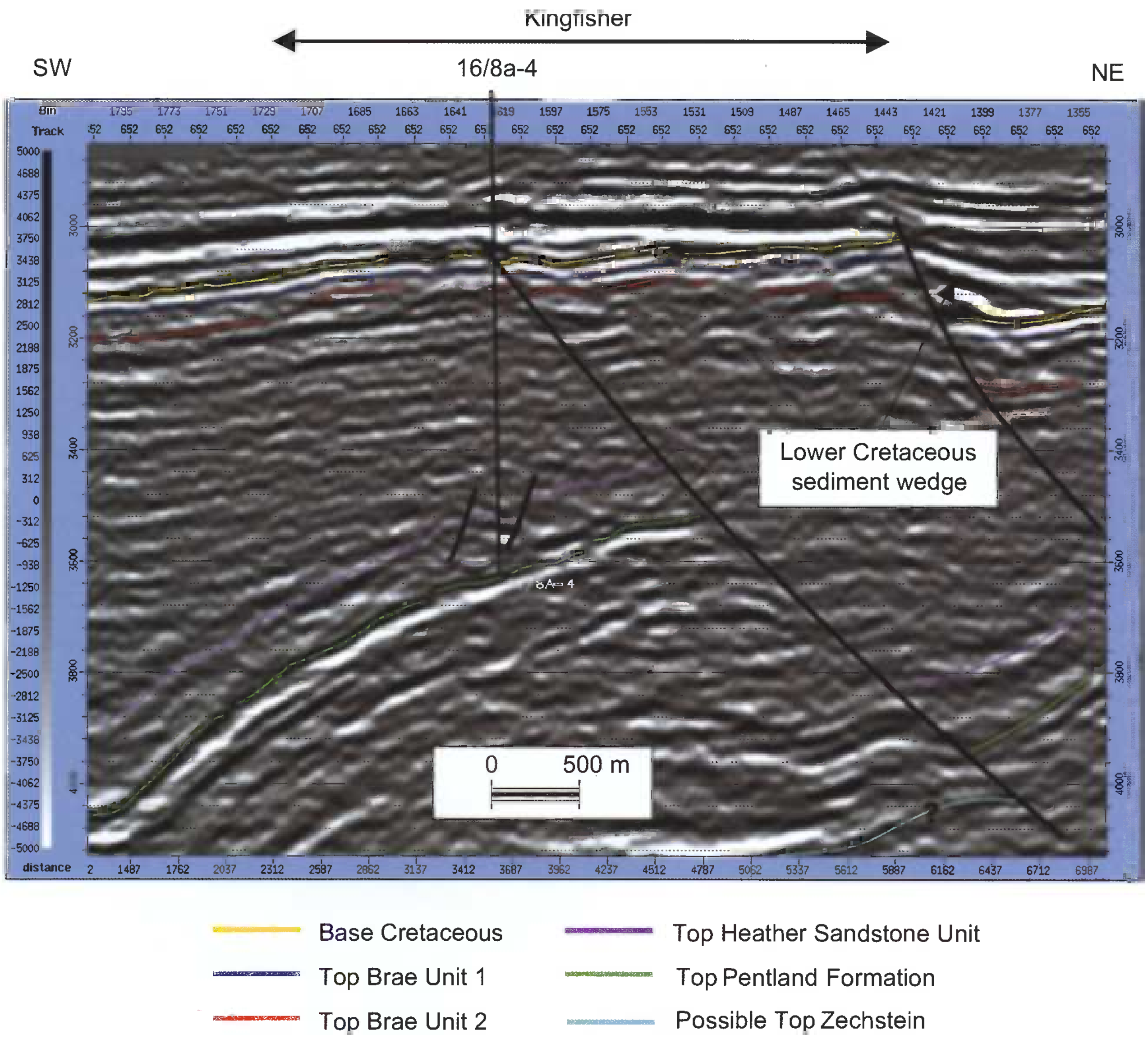

Fig. 4. SW–NE seismic section across Kingfisher (refer to Figures 2 & 3 for location).

siltstones, and mudstones and coals deposited in a lower coastal plain environment. The increasing coal content towards the top of the formation forms a prominent seismic marker in some fault blocks (Figs 4 and 5). Elsewhere the top Pentland Formation cannot be reliably identified, either due to small-scale faulting or the absence of well developed coal markers.

Middle to Upper Jurassic Heather Formation

The Heather Formation ranges from Bathonian to Oxfordian in age and predominantly consists of deep marine mudstones and siltstones. Erosively encased into these mudstones are turbidite channels trending roughly in a SE–NW direction. None of the Kingfisher wells have penetrated the stratigraphic top of this formation, due to the presence of listric low angle faulting.

Upper Jurassic Kimmeridge Clay Formation

Deep marine Kimmeridge Clay deposition prevailed throughout the Oxfordian to Ryazanian period. Dark grey, organic-rich mudstones are interbedded with turbiditic sandstones of the Brae Formation, which form the main reservoir in the Kingfisher Field. The Kimmeridge Clay Formation can be reliably subdivided into biostratigraphic zones in the east and center of Kingfisher, where mudstone deposition is dominant. Partington *et al.* (1993) describes the Late Jurassic genetic sequence stratigraphy in the South Viking Graben. The sand content increases westward and upwards from Lower Volgian times before sand deposition terminates in the Middle Volgian. The top seal for the Brae Formation reservoirs comprises Upper Volgian and Lower Ryazanian mudstones. Based on biostratigraphy and heavy mineral analysis the Brae Formation is subdivided into two reservoir units (Brae Unit 1 and Brae Unit 2) and a further non-reservoir subunit (Brae Unit 3) which can be related to different sediment point sources to the northwest, west, and southwest of the Kingfisher Field.

Cretaceous

The Cretaceous comprises a 4000 ft thick sequence of marls, limestone and claystones that accumulated within the gently subsiding South Viking Graben. No allochthonous chalk or sandstone facies are identified.

Tertiary

The Tertiary stratigraphy is dominated by an 8000 to 9000 ft thick sequence of claystone, siltstones, sandstones and marls. The complete stratigraphic subdivision of the Tertiary section is shown in Figure 6.

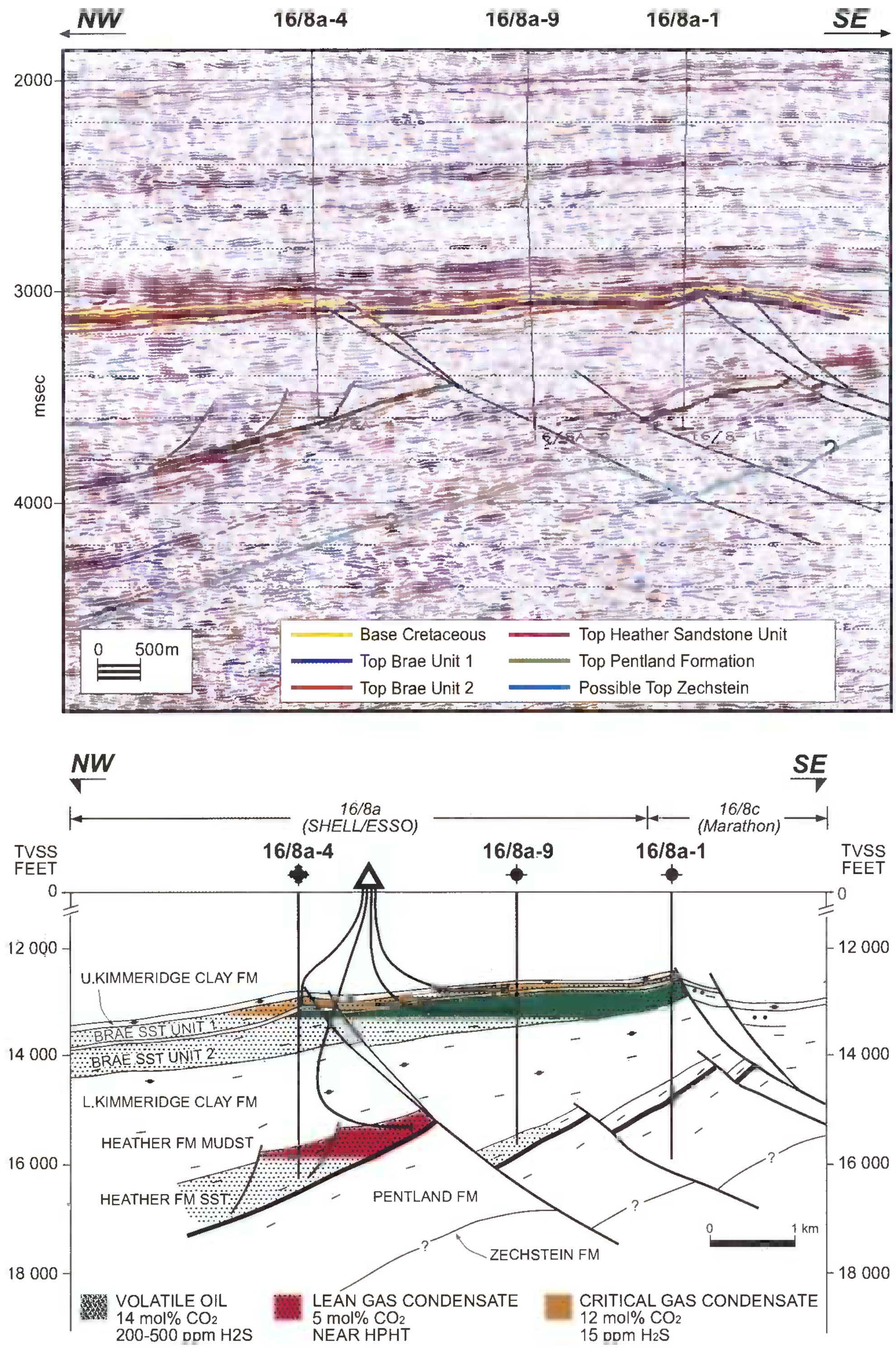

Fig. 5. (**a**) NW–SE seismic section across Kingfisher. (**b**) NW–SE schematic cross-section across Kingfisher.

Trap

The tilted fault block containing the Heather Formation sandstone accumulation provides dip closure to the west and southwest and fault closure to the northeast (Fig. 3). Towards the east, where the reservoir is thinner, there is either stratigraphic or fault closure. Heather Formation shale and Lower Kimmeridge Clay form the top seal for the highly overpressured reservoir (4800 PSI above hydrostatic) against less overpressured Brae Formation sandstones (1200 PSI over hydrostatic). The gas–water contact (GWC) at 15 700 ft TVDSS coincides with the structural spillpoint to the west.

The Brae Formation accumulations are dip closed to the west and southwest, dip/fault closed to the northeast, and stratigraphically closed to the east (Fig. 2). A field-wide correlatable intra-reservoir shale within the Brae Unit 2 reservoir and the Upper Kimmeridge Clay provide the top seals for the two Brae Formation accumulations (Figs 5b and 7). The GWC in Brae Unit 1 almost coincides with the structural spillpoint to the west, towards the North Brae Field, whilst the oil–water contact (OWC) in the Brae Unit 2 is some 100 ft above the structural spillpoint.

Reservoirs

Heather Formation

The Heather Formation sandstones comprise medium quality, very fine to coarse-grained sandstones (quartz arenites) interbedded with

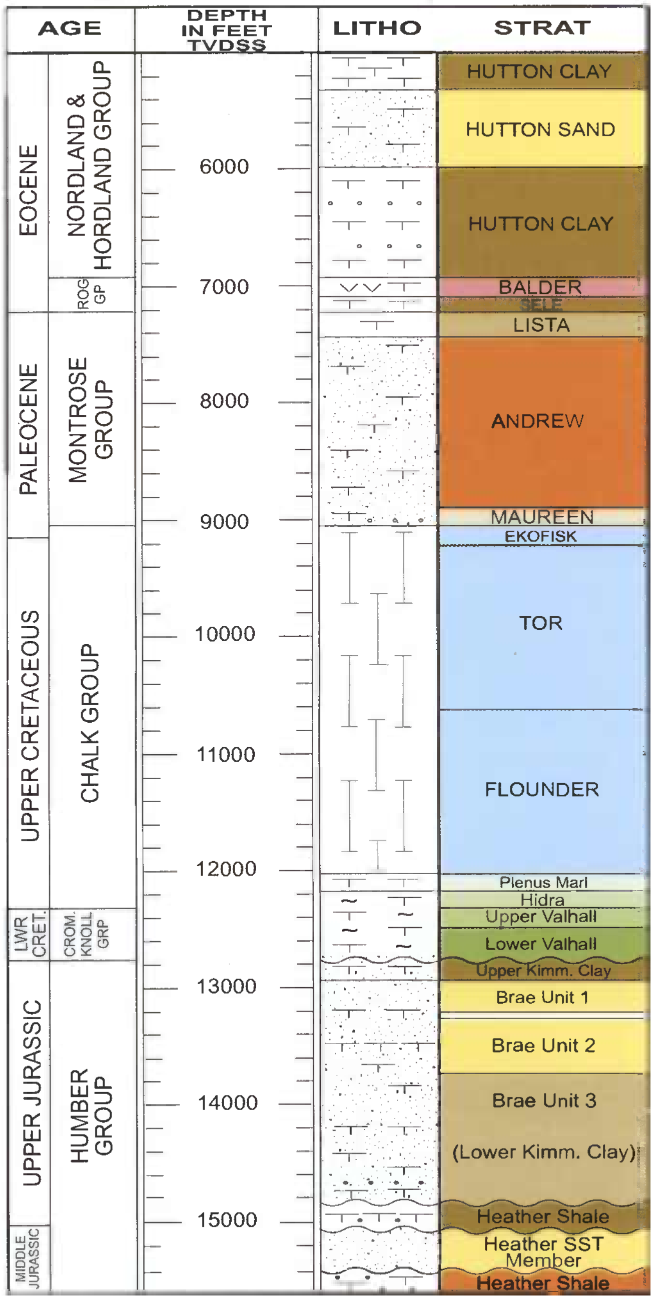

Fig. 6. Kingfisher area generalized stratigraphy.

dark grey, fissile hemipelagic marine shales. The sandstones frequently form massive amalgamated sequences (up to 40 ft thick) with a variety of internal structural fabrics. Individual sand units are predominantly well sorted, clean and structureless, whilst other units exhibit low angle/horizontal laminations or disorganised internal fabrics, indicating de-watering and slumping. Some sand units contain rare deformed mudclasts. The sandstones have sharp basal and upper contacts resulting in a blocky gamma ray profile (Fig. 7). Grain size trends are not always evident although indications of fining upward trends are observed from core. Heather Formation sandstones are thought to be deposited from channelized, variable high and low density turbidite flow regimes in a proximal slope setting. The channels are believed to be sourced from the southeast and trend in a N–NW direction across the field. Sand body geometries are uncertain due to poor seismic resolution and a limited number of well penetrations. Channel widths are estimated to be between 250 and 400 ft. The Heather Sandstone Member in well 16/8a-4 has a gross thickness of approximately 400 ft.

The main control on reservoir quality is the extensive development of quartz overgrowths which locally occlude primary porosity. Late stage dissolution of feldspars and unstable lithic grains generated a secondary pore network, which has been partially occluded by ferroan dolomite cement. Heather Formation reservoir sandstones are characterized by low core porosities (12 to 15%), and horizontal permeabilities (5 to 20 mD). The Heather Formation reservoir is gas condensate-bearing with a GWC at 15 700 ft TVDSS. The PVT condensate/gas ratio ranges from 85 to 175 BBL/MMSCF with indications of gravity segregation and fluids contain 5% CO_2 and no H_2S. The Heather Formation reservoir falls in the near HPHT category, with initial reservoir pressures of 11745 psig, overpressure of approximately 4800 psi and high temperature of 290°F. Well 16/8a-9Z, located near the crest of the structure tested 34 MMSCF/d and 4000 STB/d condensate.

Brae Formation

The Upper Jurassic Brae Formation comprises a thick sequence of interbedded conglomerates, sandstones and mudstones that form an eastwards thinning wedge juxtaposed against the faulted western margin of the graben. These sediments were deposited as a complex series of partially coalesced submarine fan systems, sourced from the Fladen Ground Spur to the west via entry points along the evolving basin margin. Brae Unit 2 sandstones were predominantly sourced via the South Brae/Miller and Central Brae fan systems and range from Early Volgian to earliest Middle Volgian in age (Fig. 8). The Kingfisher Field is located at the frontal channelized lobe to distal margin setting of this complex fan system. Brae Unit 2 oil-bearing reservoir sandstones are separated from the overlying gas condensate-bearing sandstones of Brae Unit 1 by a field-wide transgressive shale. Brae Unit 1 submarine fan sandstones are early to mid Middle Volgian in age and are interpreted to have been sourced from the North and East Brae fan systems (Fig. 8). Brae Unit 1 and Brae Unit 2 reservoir sandstones in the Kingfisher Field represent the most distal part of the Brae submarine fan systems to be developed in the Brae/Miller/Kingfisher area, being located approximately 15–20 km east of the graben-bounding fault.

Brae Formation lithologies in the Kingfisher Field are dominated by very fine to coarse grained sandstones interbedded with siltstones and mudstones. Unlike the South Brae and North Brae Fields (Roberts 1991; Stephenson 1991), conglomerates have not been seen in the extensively cored intervals in the Kingfisher wells.

The frequency and distribution of lithofacies observed in core varies both vertically and laterally across the Kingfisher structure. Sandstones vary in thickness and show varied degrees of internal organization with the most common fabrics characterized by low angle laminations, de-watering escape structures, dominated by mud clasts or often a complete absence of any internal structure. These units were probably deposited by variably high to low density turbidity currents. Mud dominated, poorly sorted units also occur, probably deposited from debris flows, slumps or low density turbidites. These lithofacies types were deposited in varied submarine fan settings ranging from high energy channels to channelized lobe and to lobe fringe environments (Figs 7 and 8).

Brae Unit 2 Reservoir

The Kingfisher Field is located on the distal margins of the main Miller basin-floor fan system which was predominantly sourced via the South and Central Brae fan systems (Turner & Connell 1991; Garland 1993). Brae Unit 2 reservoir quality is highly variable due to the distal submarine fan setting. Correlation between seismic amplitude anomalies and reservoir quality in the Brae Unit 2 is poor although seismic facies analysis suggest that the main channelized lobe is restricted to the down-dip western area of the field (around well 16/8a-8). In well 16/8-1, thin sands and very low net/gross ratios indicate the northern margin of the submarine channel and sand deposition in a distal lobe fringe setting. Brae Unit 2 has a maximum gross thickness of 800 ft in the Kingfisher Field and is subdivided

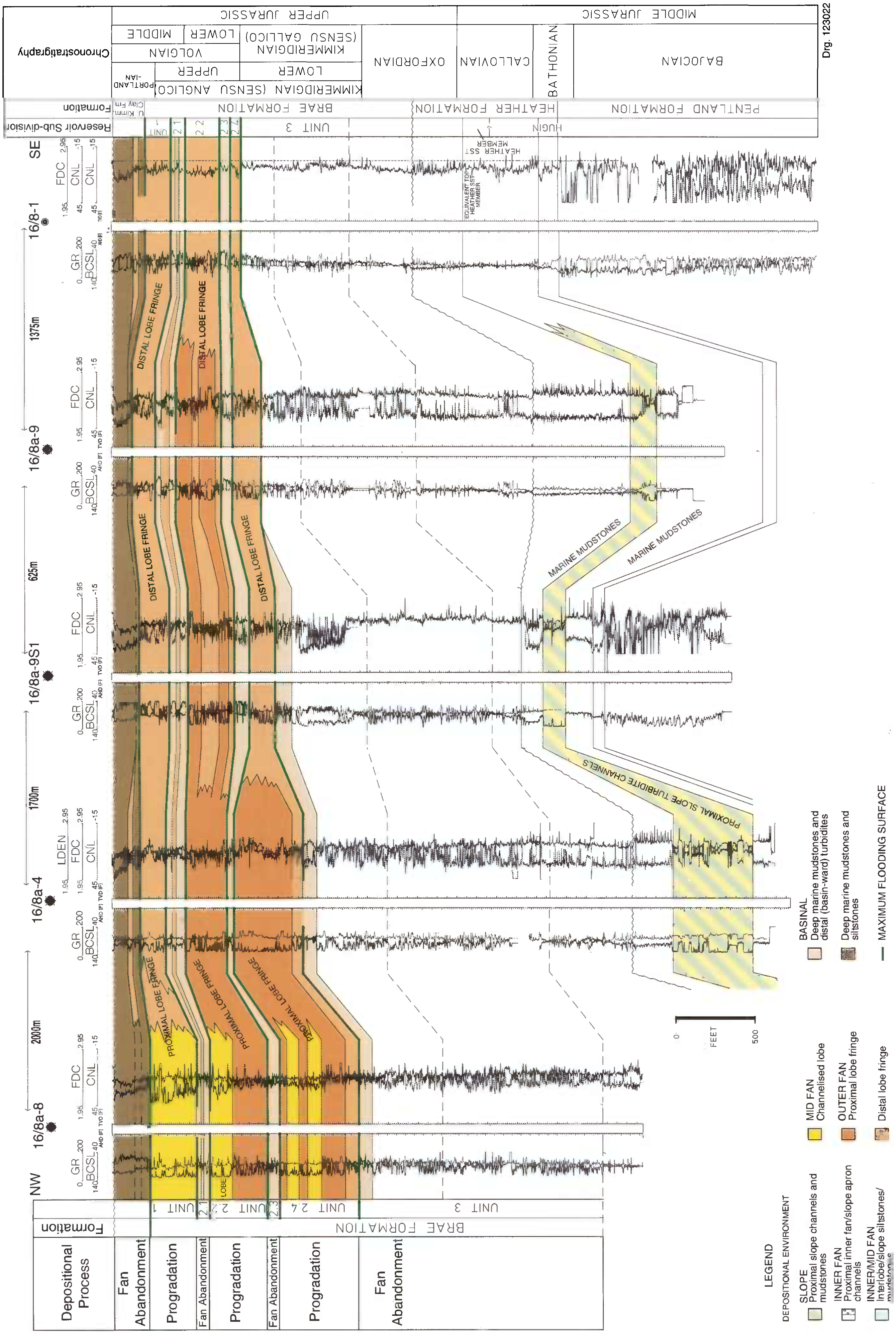

Fig. 7. Reservoir sub-division and correlation.

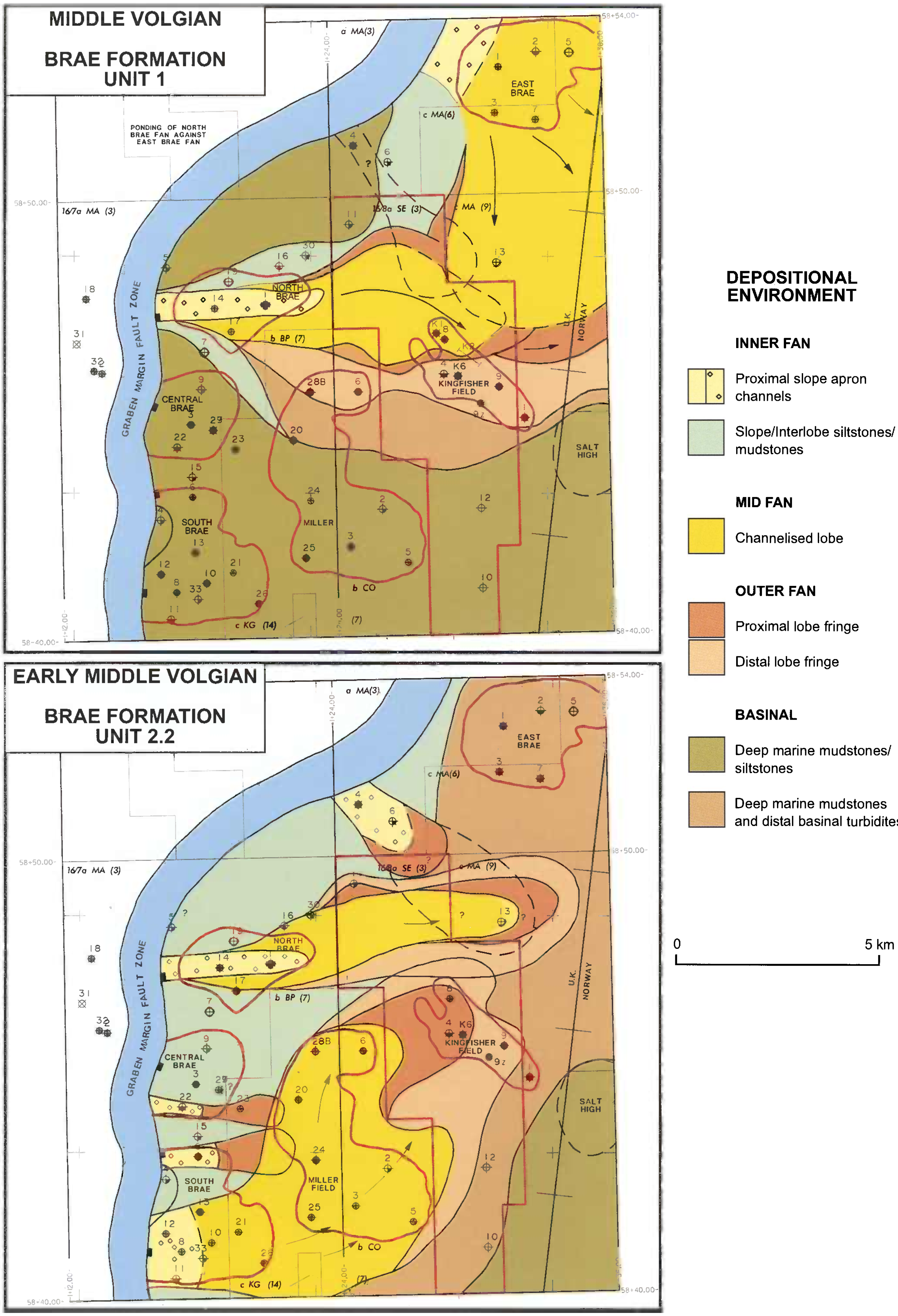

Fig. 8. Regional depositional settings of Brae Formation reservoir units (After Turner & Connell 1991; Garland 1993).

into Units 2.1–2.4, based on biostratigraphic zonation and log correlation (see fig 7). Brae Unit 2.2 sandstones provide the reservoir for the Brae Unit 2 oil accumulation in the Kingfisher Field. The overlying Brae Unit 2.1 is a shale-dominated sequence, which can be correlated in wells across the Kingfisher Field and provides the seal to the Brae Unit 2.2 oil accumulation. Brae Unit 2.1 is thought to represent the abandonment of the South Brae/Miller Field fan systems. Both the shale-dominated Brae Unit 2.3 and Brae Unit 2.4 sandstones are waterbearing.

The Brae Unit 2.2 reservoir sandstones (286 ft gross thickness) are characterized by moderate porosity (11 to 15%, average 14%) and horizontal permeability (10 to 250 mD). Volatile oils in this interval have a gravity of 35 to 40° API and a gas/oil ratio of 2000 to 2900 SCF/BBL. Brae Unit 2 has currently been developed by a single southeast orientated horizontal producer towards appraisal well 16/8a-9. Structural configuration precludes a target in the main channelized lobe as this would be too near the OWC, at approximately 13 220 ft TVDSS. Appraisal wells 16/8a-4, 16/8a-8 and 16/8a-9 tested respectively, at 4474 STB/d with 10 MMSCF/d, 3795 STB/d with 8 MMSCF/d and 3934 STB/d with 11 MMSCF/d.

From the base to the top there are three major hydraulic units which prior to intial production were all on the same pressure regime. The Brae Unit 2.4 and Brae Unit 3 Sandstones (Late Kimmeridgian–Lower Volgian) are waterbearing and do not contribute to the aquifer support. Sealed by the Brae Unit 2.3 shale against the Middle Volgian Brae Unit 2.2 oil accumulation, they are still at original pressure. Volatile oil in the Brae Unit 2.2 accumulation is sealed by a thin Brae Unit 2.1 shale against the gas/condensate accumulation of the Brae Unit 1 (Middle Volgian). Brae Unit 2.2 and Brae Unit 1 reservoirs have different hydrocarbon contacts (13 220 and 13 100 ft TVDSS respectively) and show a different pressure decline on a regional level. The Brae Unit 2.2 reservoir is in communication with the Miller and South Brae Fields as demonstrated by the 350 psi pressure depletion seen in appraisal wells 16/8a-9 and 16/8a-9Z in 1987/88 and the further 1200 psi pressure depletion seen in horizontal development well 16/8a-K4Z (1998). The initial reservoir pressure was 7250 psi at 13 000 ft TVDSS and the bubble point pressure is 5385 psia. The South Brae Field was brought on stream in 1983 and reservoir pressure has been maintained via water injection at about 5800 psi, above the bubble point pressure. The Miller Field commenced production in 1992 with reservoir pressures found to be depleted by South Brae production (Garland 1993).

Brae Unit 1 Reservoir

Brae Unit 1 comprises a stacked sequence of interbedded sandstones and shales and is the main reservoir in terms of reserves in the Kingfisher Field. Regional correlation suggests that the Brae Unit 1 sands were mainly deposited via the North Brae turbidite fan system, following the abandonment of the South Brae/Miller fan system. Brae Unit 1 has a gross thickness of 246 ft. Across Kingfisher there is a lateral transition from massive, amalgamated fine to medium grained sandstones with occasional granule grade clasts in the northwest (well 16/8a-8 area), to thin bedded finer grained sandstones in the southeast (well 16/8-1 area). This trend of decreasing sand thickness and net/gross values towards the southeast of the field reflects the transition from proximal channelized lobe (N/G 85%) to a distal lobe fringe (N/G $<$ 10%) depositional setting (Figs 7 and 8). The highly variable reservoir quality ranges from excellent in well 16/8a-8 to marginal in well 16/8a-9. Porosity values range from 10 to 22% (average 21%) with horizontal permeabilities ranging from 10 to 800 mD. The deterioration of reservoir quality in the southeastern part of the field is also associated with an increase in calcite cementation. Cores from well 16/8-1, taken from Brae Unit 1 are both highly fractured and cemented by calcite. It is thought that the cements may be associated with the high density of faulting in this area.

The GWC is estimated to be at 13 100 ft TVDSS. Brae Unit 1 contains gas condensate with an above dew point condensate/gas ratio of some 260 wellstream BBL/MMSCF. The Brae Unit 1 reservoir has been developed by a near vertical producer (16/8a-K1) adjacent to the appraisal well 16/8a-8 and a southeasterly directed horizontal producer (16/8a-K2) which has connected both proximal and distal lobe sandstone bodies (Fig. 2). RFT pressure data, acquired in 1997 from producer 16/8a-K1, has shown a significant pressure drop (1000 psi) in the Brae Unit 1 reservoir since the Kingfisher appraisal wells were drilled. This confirms that the Brae Unit 1 reservoir is in pressure communication with the aquifer supporting the producing North and East Brae Fields.

Hydrocarbons

The Upper Jurassic Kimmeridge Clay Formation in the deeper parts of the South Viking Graben is the main source rock for the Kingfisher Field. Maturation took place from late Tertiary times. The migration path for the Heather Sandstone gas/condensate is not fully resolved. The Brae Unit 1 gas/condensate migrated into Kingfisher from a source area to the northeast and spilled westwards into the North Brae Field. The Brae Unit 2 volatile oil originated from a southerly source area, migrating via the Miller Field, spilling from the southwest into Kingfisher.

The composition of all three hydrocarbon types is significantly different. The Heather Formation gas/condensate (43–46°API) is relatively lean, has no H_2S, and only 5% CO_2. The Brae Unit 2 volatile oil with an API gravity of 35 to 40° contains 200–500 ppm H_2S and 14% CO_2. The Brae Unit 1 heavy gas/condensate (39–44°API) contains 15 ppm H_2S and 12% CO_2.

Reserves

The latest estimate (1998) of ultimate recovery for the Kingfisher Field is 41.2 MMBBL of pipeline liquids and 280 BCF of dry export gas. About 50% of these reserves, on a BOE basis, are contained within the Brae Unit 1 accumulation.

Reserves estimates increased with the appraisal of the Heather Formation and the delineation of the Brae Formation reservoirs to the west. However, prior to field development, reserves estimates decreased when it was realized that pressure maintenance in the Brae Unit 1 was not feasible due to the combined offtake of all fields in the area sharing the aquifer.

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Kingfisher Field data summary

Reservoir		**Brae Unit 1**	**Brae Unit 2**	**Heather**
Trap				
Type		structural/strat.	structural/strat.	structural/strat
Depth to crest	(ft TVDSS)	12 600	12 800	14 800
Lowest closing contour	(ft TVDSS)	13 125	13 320	15 700
GWC	(ft TVDSS)	13 100	n/a	15 700
OWC	(ft TVDSS)	n/a	13 220	n/a
Gas column	(ft)	500	n/a	900
Oil column	(ft)	n/a	420	n/a
Pay zone				
Formation		Brae Unit 1	Brae Unit 2.2	Heather
Age		U Jurassic	U Jurassic	M Jurassic
Gross thickness	(ft)	246	286	404
Net/gross ratio		0.06–0.86	0.15–0.67	0.14–0.46
Porosity average (range)	(%)	21 (10–22)	14 (11–15)	13.5 (12–15)
Permeability range	(mD)	10–800	10–250	5–20
Hc saturation range	(%)	70–85	70–85	70–80
Current productivity index	(BOPD/psi)	20	1	20
Hydrocarbons				
Oil density	(°API)	39–44	35–40	43–46
Oil type		Gas Cond.	volatile oil	Gas Cond.
H_2S	(ppm)	15	200–500	0
CO_2	(mol%)	11.6	14.1	5.2
Gas gravity		0.804		
Viscosity	(cP)	0.03	0.27	0.02
Bubble point	(psia)	n/a	5385	n/a
Dew point	(psia)	5781	n/a	6325
Gas/oil ratio	(scf/bbl)	3000–4000	2000–2900	6000–9000
Initial Condensate yield	(bbl/MMscf)	250–310	n/a	85–175
Formation volume factor	(rb/stb)	n/a	2.46	n/a
Gas expansion factor	[scf/rcf]	240	n/a	351
Formation water				
Salinity		70 000 ppm NaCl equivalent		70 000 ppm
Resistivity		0.034 ohm m at 250°F		0.034 ohm m
Field Characteristics				
Area	(km^2)	21 (5190 acres)	21 (5190 acres)	12 (2970 acres)
Gross rock volume	(acre ft)	532 012	313 445	504 986
Datum depth	(ft TVDSS)	13 000	13 000	15 000
Initial pressure	(psi)	7160	7250	11 800
Pressure gradient in reservoir	(psi/ft)	0.22	0.28	0.20
Temperature	(°F)	250	250	290
Oil initially in place	(MMstb)	total field: 104		
Gas initially in place	(Bcf export)	total field: 610		
Recovery factor (oil)	(%)	total field: 32%		
Drive mechanism		natural depletion		
Recoverable oil	(MMstb)	total field: 30		
Recoverable gas	(Bcf)	total field: 280		
Recoverable NGL/condensate	(MMstb)	total field: 11.2		
Production				
Start-up date		Oct 1997	Jul 1998	Aug 2000 (expected)
Development scheme	Sub-sea drill centre and two multiphase pipelines to Brae 'B' Platform			
Production rate plateau oil/NGL's	19600/8400 BOPD			
Production rate plateau gas	130 MMscf/d dry export gas			
Number/type of well	5 exploration/appraisal			
	3 development wells completed			