The geochemistry of two unusual oils from the Norwegian North Sea: implications for new source rock and play scenario

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ABSTRACT: Two oils from the Norwegian North Sea and a source-rock extract from the Danish North Sea are seen to have chemical properties deviating from any previously known North Sea oils. An organic geochemical investigation concludes that the two oils are of low to medium maturity, and that these oils represent alternative organic facies of Upper Jurassic age. The organic facies that sourced the investigated oils are believed to be hypersaline and carbonate-type source rocks, which were most likely deposited in locally developed, secluded lagoonal settings with elevated salinity and low clastic influx. The alternative source rocks inferred by the two atypical oils may add new concepts to petroleum exploration on the margins of the Mesozoic Central Graben and Viking Graben in the North Sea.

KEYWORDS: *petroleum, source rocks, maturity, facies*

INTRODUCTION

In one of the world's most important oil and gas provinces, the North Sea of NW Europe, the dominating source rock is the Upper Jurassic marine Kimmeridge Clay Formation and its equivalents, i.e. the Mandal, Draupne and Tau formations. Further north, the equivalent Spekk and Hekkingen formations are the main oil-generative strata off Mid-Norway (Karlsen *et al.* 1995, 2004) and in the Hammerfest Basin (Stewart *et al.* 1995), respectively. Up to one kilometre of this source-rock formation was deposited in an extensive Jurassic rift system developed along almost the entire Norwegian continental shelf, from the Central Graben in the south to the Barents Sea in the north (Fjæran & Spencer 1991). The Upper Jurassic source rocks in the depocentres of the North Sea reached oil maturity in the Late Cretaceous–Early Paleocene, and the maturity today ranges from immature on basin margins to post-mature in the deepest basinal parts.

Huc *et al.* (1985), Northam (1985) and Bailey *et al.* (1990) used carbon isotopes and biomarkers to show that the organic facies of the Upper Jurassic shales varies both stratigraphically and geographically in the North Sea. The Upper Jurassic shales are not parts of a homogeneous, consistent lithology, but vary regionally in maturity and facies. These variations are, however, moderate and typical values for several Upper Jurassic North Sea organic geochemical parameters have been established by numerous authors (Northam 1985; Barwise 1990; Chung *et al.* 1992; Clayton & Bjorøy 1994; Cornford 1998; Pedersen 2002).

Studies of petroleum inclusions in authigenic mineral cements, applied together with microthermometry, may give detailed knowledge of the filling history of a reservoir (Roedder 1984; Karlsen *et al.* 1993; Nedkvitne *et al.* 1993; Skålnes 1993; Johansen 1997). Karlsen *et al.* (1993) and Bhullar *et al.* (1998,1999) found petroleum from authigenic mineral inclusions from reservoirs on the Norwegian Offshore Continental Shelf (NOCS) to be chemically different from the Upper Jurassic-derived oil now filling the reservoirs. The reservoirs studied were charged earlier by source rocks other than the Upper Jurassic shales that are responsible for the present petroleum charges. In some cases evidence suggests palaeo-sourcing from Palaeozoic source rocks (Karlsen *et al.* 1993, 1995). Petroleum migration of commercial importance occurs along the most favourable pathways, i.e. the most permeable sandstones (England 1994) or fracture systems (Aydin 2000). Once a migration pathway has been established, it may be used several times by successive source-rock systems, potentially allowing a reservoir to be filled several times during its lifetime. Traces of ancient petroleum may, however, still exist within a reservoir filled several times, in the form of fluid inclusions or as solid bitumen. This allows an unravelling of the reservoir filling history. (e.g. case histories from the Norwegian North Sea: Ula, Hild and Frøy fields by Karlsen & Larter 1991; Karlsen *et al.* 1993; Skålnes 1993; Skålnes *et al.* 1993; Bharati 1997; Ashan *et al.* 1998; Bhullar *et al.* 1998, 1999). To an oil company, proving the presence of a commercial petroleum system is the major objective. A number of petroleum samples from the Norwegian North Sea are found to have chemical and compositional properties that deviate dramatically from the vast majority of North Sea oils (Pedersen 2002). These atypical petroleums must have been derived from either a totally different source-rock system, or from a very different Jurassic source-rock facies compared with the well-known marine Upper Jurassic Kimmeridge Clay Formation. The composition and chemistry of two atypical oils from the Central Graben and the Viking Graben is investigated in order to assess their thermal maturity and the source-rock facies from which these oils might have been expelled. This may help in understanding the existence of other source rocks, and ultimately other petroleum play scenarios.

Period		Group	Formation	Source	Reservoir	Cap
Cretaceous	Upper	Shetland	Ekofisk		✓	
			Jorsalfare/Tor			
			Kyrre/Hod			
			Blodøks			
			Svarte/Hidra			
	Lower	Cromer Knoll	Rødberg			
			Sola			
			Åsgård			✓
Jurassic	Upper	Viking	Draupne/Mandal	●		✓
			Heather	○		✓
	Middle	Brent	Tarbert/Hugin		✓	
			Ness/Bryne	○		
			Etive		✓	
			Rannoch		✓	
			Broom/Oseberg		✓	
	Lower	Dunlin	Statfjord		✓	
Triassic	Upper	Hegre	Lunde/Skagerrak			
	Middle		Lomvi			
	Lower		Teist/Smiths Bank			

Fig. 1. The main elements of Mesozoic stratigraphy of the North Sea Viking Graben and Central Graben. Important source, reservoir and cap-rock intervals are indicated.

THE NORWEGIAN NORTH SEA

The Norwegian North Sea, approximately in the region 56°N to 61°N, 0°E to 10°E, is an area of great importance for petroleum exploration and production. Exploration began in the mid-1960s, and has continued to date, with over 900 wells drilled, over 200 discoveries made and 70 fields developed (see Norwegian Petroleum Directorate, www.npd.no, 15 August 2005). The water depth on the Norwegian Continental Shelf varies from 40 m to 400 m and harsh climatic conditions have made field development a challenging task, both technically and economically. Despite this, the North Sea in general and the Norwegian sector in particular has proved to be a highly profitable petroleum province. The geological history of the northern North Sea region has been extensively discussed in Evans *et al.* (2003), for example.

STRUCTURAL ELEMENTS OF THE NORWEGIAN NORTHERN NORTH SEA

The North Sea is described as an intracratonic basin with a complex geological history (Ziegler *et al.* 1986). Figure 1 shows the Mesozoic stratigraphy of the North Sea Viking Graben and Central Graben and Figure 2 shows the North Sea region, with the main structural elements indicated. The overall picture is that of a N–S-trending rift basin bordered in the east by the Fennoscandian Shield and in the south and west by the Mid-North Sea High and the East Shetland Platform. The main basins in the Norwegian North Sea, from south to east, are the Central Graben, the Norwegian–Danish Basin and the Viking Graben. The most prominent highs are the SE–NW-trending Vestland Ridge, separating the Norwegian–Danish Basin from the Central Graben, and the Ringkøbing–Fyn High, forming the southern limit of the Norwegian–Danish Basin (Rønnevik *et al.* 1975). The maximum accumulated thickness of Mesozoic and Tertiary sediments in central parts of the graben system is about 9 km (Thomas *et al.* 1985).

THE UPPER JURASSIC SHALES

The Upper Jurassic marine organic-rich shales of the Oxfordian to Ryazanian Viking Group are widely recognized as the main source for oil and gas in the North Sea (Field 1985; Northam 1985; Chung *et al.* 1992). The late Upper Jurassic Kimmeridge Clay Formation, especially, and its equivalents – the Tau, Draupne and Mandal formations – have high total organic carbon (TOC) values in the order of 5–12 wt%, and hydrogen index (HI) values reaching 700 mgHC g^{-1}TOC when immature. This kerogen is mainly marine Type II, as defined by Tissot & Welte (1984, p. 153). In the North Sea Graben system, the Viking Group reaches a thickness exceeding 1000 m in basinal areas, whilst on the highs and graben flanks it may be thin (condensed or part eroded), not deposited or completely eroded. The amount and quality of kerogen in the source rocks of the Viking Group degrades towards the graben flanks (Cornford *et al.* 1986). The Viking Group was deposited following a marine transgression in the Viking Graben in the Bathonian. During the late Oxfordian to early Kimmeridgian the conditions in the basins varied from dysaerobic to aerobic, and less rich source rocks, such as the Heather Formation, were deposited (Huc *et al.* 1985). As the basins became deeper due to rifting activity, anaerobic conditions developed widely during the Volgian and Ryazanian. In this anoxic environment the black, partly radioactive 'hot' shale, known in the UK sector as the Kimmeridge Clay Formation, was deposited (Thomas *et al.* 1985). These clays contain partly a sappropelic bacterial- and algal-rich organic matter. There is some variation in source quality in the Upper Jurassic source rocks, reflecting variations in the depositional conditions. Distal shales deposited in deep, anoxic parts of the basin are generally richer in organic

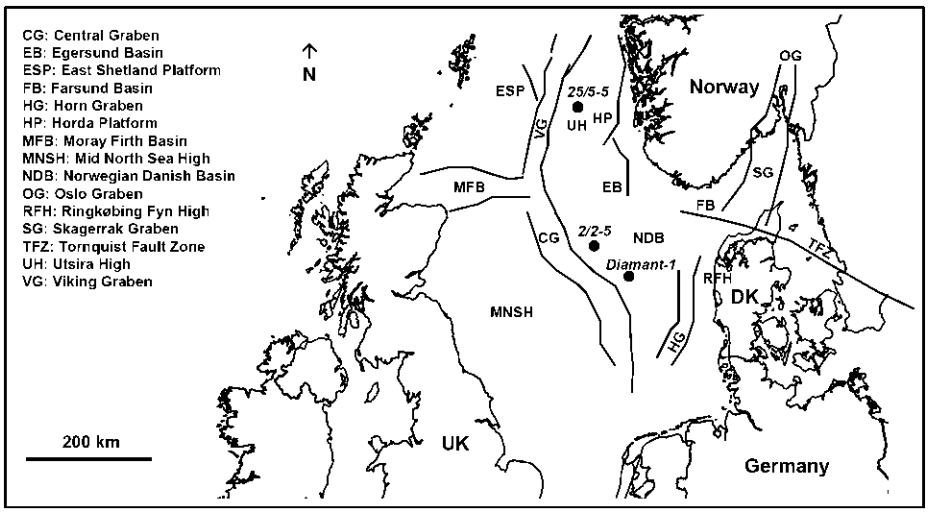

Fig. 2. Map of the North Sea and fringing land areas, showing the main structural elements and the location of wells NO 2/2-5, NO 25/5-5 and DK Diamant-1.

Table 1. *Some properties of petroleum from the North Sea and Norwegian Offshore Continental Shelf reported from earlier publications*

Pr/Ph	Whole oil $\delta^{13}C$ (‰)	Sat/Aro	Reference
0.9–2.0 (N. North Sea)	−27.4 to −30.2	—	Northam (1985)
1.3 (North Sea)	−28 to −30	—	Barwise (1990)
1.5 (Kimmeridge Fm.)[a]	−29[a]	—	Chung *et al.* (1992)
2–3 (Heather Fm.)[a]	−26 to −28[a]	—	Chung *et al.* (1992)
1.3–2.9 (N. North Sea; 44 oils)	−25.6 to −30.4	—	Chung *et al.* (1992)
0.99–1.84 (UK North Sea; 4 oils)	−28.5 to −29.8	5.6–8.3	Clayton & Bjorøy (1994
0.6–1.9 (average 1.24) (Kimmeridge Fm.)	−27.1 to −30.4 (average −28.9)	0.6–8.0 (average 2.0)	Cornford (1998)
0.9–1.6 (Haltenbanken; 33 oils)	−28.5	1.2–5.8	Karlsen *et al.* (1995)
1.4–2.8 (Hammerfest Basin)	−28.6 to −31.0	1.8–13.8	Vobes (1998)
1.3–2.5 (NOCS; 12 oils)	−28.4 to −30.1	1.7–5.3	Pedersen (2002)

[a]source-rock extracts

algal-derived matter, i.e. oil-prone Type II kerogen. More proximal shales from more oxygenated, shallower parts of the basin are of lower source-rock quality, and are more influenced by terrigenous organic matter, i.e. a mix of oil-prone Type II and gas-prone Type III kerogen, following the same pattern as the equivalent Spekk Formation off Mid-Norway (Karlsen *et al.* 1995).

PETROLEUM IN THE NORTH SEA

The petroleum found in reservoirs in the North Sea generally has API gravity values around 36–38°, which classifies the petroleum as light. Gas: oil ratio (GOR) values usually range between 20 $m^3 m^{-3}$ and 110 $m^3 m^{-3}$ (Kubala *et al.* 2003). Sulphur contents are low to moderate, ranging from 0.02% to 0.93%. The average pristane/phytane (Pr/Ph) ratio is about 1.3, indicating Type II kerogen, and a marine siliciclastic source-rock facies. The nickel/vanadium (N/V) ratio is usually around 1 or less, and the $\delta^{13}C$ value varies between −28‰ and −30‰ (Barwise 1990). Table 1 gives an overview of some key properties for petroleum from the North Sea and NOCS taken from the literature. The onset of petroleum generation from Jurassic source rocks in the major depocentres was in the late Upper Cretaceous, and generation continued into the Tertiary. Petroleum from the Norwegian North Sea varies in thermal maturity from early mature to late mature, but the majority of oils have a maturity corresponding with the middle part of the oil window (Pedersen 2002). Oils derived from the Upper Jurassic shales of the North Sea are typically rich in the compound bisnorhopane (Peters & Moldovan 1993) and are low in gammacerance and carotane (Grantham *et al.* 1980; Bailey *et al.* 1990).

THE SAMPLE SET

The two specific North Sea oil samples discussed here were selected because they are characterized by being chemically different from the typical North Sea oil. A typical North Sea oil is defined here as having originated from Upper Jurassic marine, dominantly siliciclastic source rocks, with kerogen mostly of Type II. The chemical properties of the selected samples point to an alternative origin of these samples. The locations of the wells are shown in Figure 2.

Sample N1: well 2/2-5 DST-1 (3666.2–3670.5 mRKB)

The Norwegian 2/2-5 well is located south of the Gyda Field (Block 2/1). It was drilled in 1991 by the Saga Petroleum Company to test a reservoir in the Upper Jurassic Ula Formation within a salt-induced anticline. Oil was discovered in the Ula Formation at 3671 mRKB. The well was tested, but subsequently plugged and abandoned as an oil discovery. The well terminated at 4081 mRKB (final vertical depth) in the Upper Permian Zechstein Group.

Sample N2: well 25/5-5 DST-1 (2159–2170 mRKB)

The Norwegian 25/5-5 well was drilled in 1995 by Elf Petroleum to a reservoir target of Paleocene turbiditic sands. Petroleum was found in the Paleocene Heimdal Formation, with an oil–water contact (OWC) at 2176.3 m. The well was terminated in the Paleocene Våle Formation at 2600 mRKB, and was plugged and abandoned as an oil discovery.

Also included in this paper are gas chromatography–flame ionization detection (GC-FID) parameters for a Jurassic rock extract from Danish well Diamant-1 (3733.8 m). These data are from the Ministry of the Environment, Geological Survey of Denmark (1994). For comparison, nine unidentified oils from the Norwegian North Sea and from the Haltenbanken area offshore Mid-Norway are presented to represent typical Upper Jurassic oils.

EXPERIMENTAL DETAILS

The samples underwent four separate analyses:

- thin layer chromatography combined with flame ionization detection (TLC-FID);
- gas chromatography combined with flame ionization detection (GC-FID);
- gas chromatography combined with mass spectrometry (GC-MS);
- $\delta^{13}C$ isotopic analysis of whole oils (external work).

Analytical methods

For bulk quantification of the samples, an Iatroscan TH-10 TLC-FID Analyzer from Iatron Laboratories Inc., Tokyo was used, applying the procedures described by Karlsen & Larter (1991). A Varian Capillary Gas Chromatograph Model 3500 and a Hewlett Packard Ultra 1 Crosslinked Methyl Silicone Gum column with length 25 m, inner diameter 0.2 mm and chromatographic film thickness 0.33 μm was used for characterization of whole oils. The detector temperature (FID) was 330 °C, initial column temperature 40 °C and initial hold time 2 min. The temperature gradient was 4 °C min^{-1}, with a final column temperature at 325 °C and final hold time 20 min. The total time of the temperature programme was 93.25 min.

Before GC-MS analysis, a molecular sieve was used to remove *n*-alkanes, resins and asphaltenes from the samples. About 0.2 g of molecular sieve (5 Å pore diameter) was

Table 2. *Key figures for samples N1 and N2 compared with the NSO-1 standard oil*

	2/2-5 DST-1	25/5-5 DST-1	NSO-1 (standard oil)
Whole oil $\delta^{13}C$	−21.9	−29.6	−28.8
%Saturated	54.9	37.8	49.2
%Aromatic	22.8	32.0	28.6
%Polar	22.2	30.2	22.1
Sat/Aro	2.4	1.2	1.7
Pr/Ph	0.9	0.8	1.5
Pr/*n*-C_{17}	5.32	0.69	0.55
Ph/*n*-C_{18}	8.92	0.88	0.42
Ts/(Ts+Tm)	0.40	0.45	0.54
diahopane/(diahopane+normoretane	0.5	0.54	0.60
bisnorhopane/(bisnorhopane+norhopane)	0.15	0.42	0.43
hopane/sterane	1.11	1.68	2.33
ßß(ßß+aa) of C_{29} (20R+20S) sterane isomers	0.55	0.61	0.60
diasteranes/(diasteranes+regular steranes)	0.34	0.59	0.56
%C_{27} regular steranes	37.5	44.0	35.3
%C_{28} regular steranes	30.7	30.4	31.5
%C_{29} regular steranes	31.8	25.6	33.2
Vitrinite reflection[a]	0.58	0.60	0.73

[a]$R_c = 0.073 \times MDR + 0.51$ (Radke 1988).

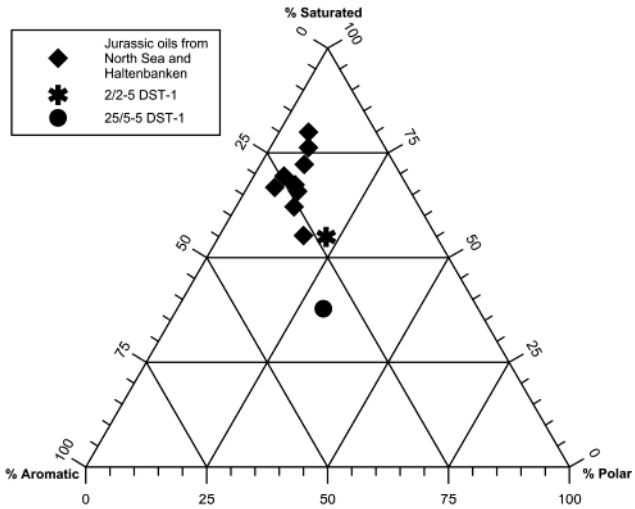

Fig. 3. A ternary-plot of the three main petroleum fractions shows that sample N1 (2/2-5 DST-1) and N2 (25/5-5 DST-1) are enriched in polar components, compared with nine Jurassic oils from the North Sea and Haltenbanken. The N2 sample is also high in aromatic components.

transferred to a 15 ml glass vial. Five drops of sample were then mixed with the powder-like sieve using a pipette. The sample mixture was diluted with 2.5 ml cyclohexane and stirred thoroughly, then centrifuged at 2000 rpm for 4 min to settle the sieve. Subsequently, the sample was decanted into a second 15 ml glass vial, and *c.* 75% of the solvent evaporated using a warming plate and a flow of nitrogen. After the sample had been concentrated in this way, the procedure was repeated once for heavy to medium oils and twice for lights oils and condensates, which have a higher content of *n*-alkanes relative to biomarkers. The GC unit, a Fisons GC800, was connected to a Fisons Instruments MD800 MS unit. A Fisons A200 S autosampler injected the samples with a 10 µl syringe. The chromatographic column was a Chromapak CP-SIL 5CB-MS FS 50X.32(.40) WCOT fused silica-type column, with a CP-SIL 5CB Low Bleed/MS stationary phase. The film thickness was 0.40 µm, column length 50 m and inner and outer diameter 0.32 mm and 0.45 mm, respectively. The initial column temperature was 80 °C, the first temperature gradient 10 °C min^{-1} for 10 min (80–180 °C) and the second temperature gradient 1.7 °C min^{-1} for 80 min (180–316 °C). The final column temperature was 316 °C and final hold time 30 min. Total time of the temperature programme was 120 min.

RESULTS AND DISCUSSION

Composition

The results from the described analysis are presented in Table 2. From bulk composition analysis of sample N1, it appears to be slightly enriched in polar compounds (55% saturated hydrocarbons, 23% aromatic hydrocarbons, 22% polar compounds plus asphaltenes) but it is similar to the majority of North Sea oils (Fig. 3). Sample N1 may be classified as a normal crude oil of moderate maturity in terms of bulk composition, according to a classification made by Tissot & Welte (1984, p. 380). Sample N2, on the other hand, is quite enriched in polars and aromatic hydrocarbons and correspondingly low in saturated components (38% saturated hydrocarbons, 32% aromatic hydrocarbons, 30% polar compounds, asphaltenes included) (Fig. 3). Sample N1 was found to be enriched in polyaromatic components (42% polyaromatic hydrocarbons, 58% monoaromatic hydrocarbons), compared with a set of seven Jurassic oils from the North Sea and Haltenbanken (average 25% polyaromatic hydrocarbons (range 20–36%) and 75% monoaromatic hydrocarbons (range 64–80%)). This unusual composition is, together with the high concentration of isoprenoids seen on the GC-FID chromatogram, a manifestation of the highly unusual organic facies of this sample. Sample N2 does not deviate in this way, with 28% polyaromatic hydrocarbons and 72% monoaromatic hydrocarbons.

The sat/aro ratio for sample N1 (2.4) does not deviate from most North Sea petroleum (see Table 1). The sat/aro ratio is relatively low for sample N2 (sat/aro=1.2), and low sat/aro ratios are one of the characteristics of a carbonate source-rock facies (Peters & Moldowan 1993, p. 209). The relative enrichment in polar compounds seen for sample N1 and N2 is believed to relate to low maturity, as source rocks expel polar and NSO- (nitrogen, sulphur and oxygen) rich products at the onset of petroleum generation (Tissot & Welte 1984, p. 189). The uncommon compositional characteristics observed, like enrichment of aromatic hydrocarbons in sample N2, and a high concentration of polyaromatic hydrocarbons in sample N1 may, most likely be characteristics inherited from the organic matter within the source rock, and could hence indicate a source facies unlike that of most North Sea oils.

One of the most striking features of sample N1 is the very heavy $\delta^{13}C$ value (−21.9‰). This has been recognized by earlier authors. Mills *et al.* (2000) stated that 'the oil was proved to be compositionally and isotopically the most unusual oil discovered offshore Norway'. Khoshbakht (2001) reported a $\delta^{13}C$ value of −21.15‰ for this oil and Pancost *et al.* (2001) found a $\delta^{13}C$ value of −21.5‰ (saturate fraction) and −22‰ (aromatic fraction) in their analysis of the 2/2-5 oil. Sample N2 has a 'normal' $\delta^{13}C$ value at −29.6‰, which does not vary much from the $\delta^{13}C$ values observed for seven Upper Jurassic oils from the North Sea and Haltenbanken (Fig. 4). Galimov (1980) concluded, based on thermodynamic principles, that isoprenoids include more ^{13}C in their structure than *n*-alkanes, and sample N1 clearly has more abundant isoprenoids, not only pristane and phytane, than is normal for a North Sea oil. Pancost *et al.* (2001) concluded that the saturated fraction of the 2/2-5 oil is dominated by ^{13}C-enriched isoprenoids, and

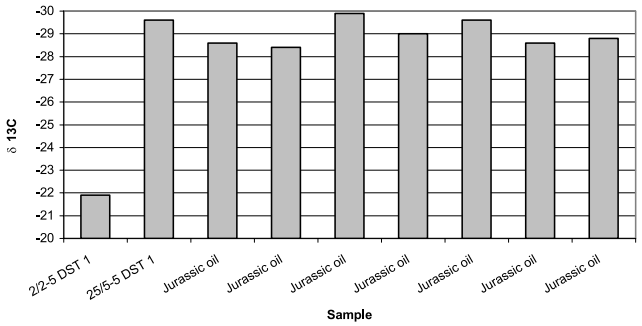

Fig. 4. A comparison of $\delta^{13}C$ values reveals the unusually low value observed for sample N1 (2/2-5 DST-1). Sample N2 (25/5-5 DST-1) is within the normal range of most North Sea oils.

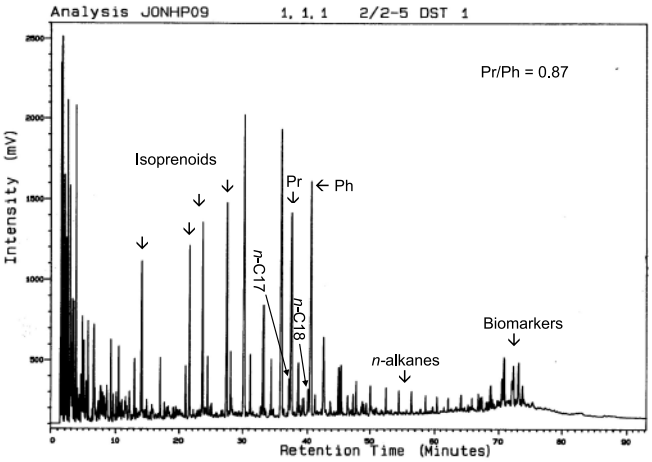

Fig. 5. GC-FID chromatogram of N1, note the high content of unidentified isoprenoids relative to *n*-alkanes, the height of pristane and phytane compared with n-C_{17} and n-C_{18} and the high concentration of biomarkers seen on the GC-FID chromatogram.

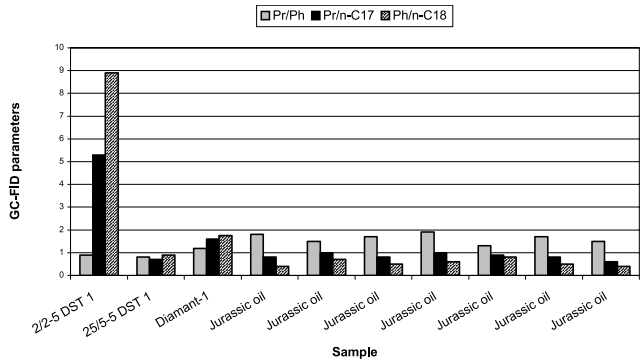

Fig. 6. The GC-FID parameters Pr/Ph, Pr/n-C_{18} and Ph/n-C_{18} for sample N1 (2/2-5 DST-1) and N2 (25/5-5 DST-1) is clearly unlike any of the other Jurassic oils in the study. Both samples have Pr/Ph<1 and are characterized by having Ph/n-C_{18}>Pr/n-C_{17}. The latter is also seen for a sample from the Danish well Diamant-1 (Ministry of the Environment, Geological Survey of Denmark 1994).

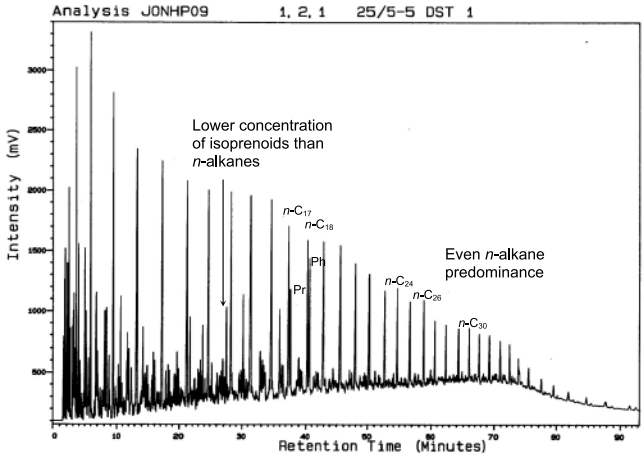

Fig. 7. GC-FID chromatogram of sample N2. The compounds, n-C_{17}, pristane, n-C_{18} and phytane are indicated. Note the higher relative amount of phytane compared with pristane, indicating an anoxic depositional environment. This sample also displays an even *n*-alkane predominance.

suggested interesting explanations for sources for isoprenoids and the ^{13}C enrichment of these isoprenoids. It is, therefore, believed that the isoprenoids account for the high amount of ^{13}C seen in sample N1.

The GC-FID chromatogram for sample N1 (Fig. 5) shows a low Pr/Ph ratio (0.87) and exceptionally high Pr/n-C_{17} and Ph/n-C_{18} ratios (5.32 and 8.92, respectively), which are unusual values compared with most non-biodegraded oils from the North Sea (Fig. 6). High isoprenoid peaks dominate the chromatogram, and the *n*-alkane pattern is unusual. The peaks seen at the end of the GC-FID trace between 65 min and 76 min are interpreted as biomarkers, and the high concentration of biomarkers and isoprenoids suggest low maturity for sample N1, if bacterial degradation is excluded (Hunt 1996, pp. 130–131). Both sample N2 (Fig. 7) and a source-rock extract from Danish well Diamant-1 (Ministry of the Environment, Geological Survey of Denmark 1994) show characteristics similar to sample N1, with low Pr/Ph ratios and Ph/n-C_{18}>Pr/n-C_{17}. A Pr/Ph ratio below 1 indicates anoxic conditions in organic-rich sediments and possibly hypersaline or carbonate facies (Peters & Moldowan 1993, p. 209; Hunt 1996, p. 82). Yet, the GC-FID chromatogram for sample N2 has a GC-FID chromatogram envelope more similar to a chromatogram for 'normal' crude oils than the N1 GC-FID chromatogram (Fig. 7), but upon closer inspection the GC-FID chromatogram for sample N2 reveals atypical properties. On the N2 GC-FID chromatogram, the *n*-alkane distribution clearly shows predominance of even-numbered *n*-alkanes, namely for C_{24}, C_{26} and C_{30} (Fig. 7), another parameter indicative for a carbonate source-rock facies (Mello *et al.* 1988). Sample N1 shows neither odd nor even *n*-alkane predominance. These unusual GC-FID traces seen for sample N1 and the Diamant-1 source-rock extract are very unlike most North Sea oils (Fig. 6), and could imply a genetic relationship between the discussed samples. In Figure 8, Pr/n-C_{17} and Ph/n-C_{18} ratios are used to indicate the source-rock facies and maturity. This figure indicates that samples N1, N2 and the Diamant-1 source-rock extract belong to a reducing, marine, algal-dominated environment, whilst eight Upper Jurassic oils from the North Sea and Haltenbanken clearly are related to another, transitional marine environment of mixed organic sources. Samples N1, N2 and the Diamant-1 rock extract also appear to be of lower maturity than the control group of Jurassic-sourced oils. The large difference in isotopic values between samples N1 and N2, and the contrasting *n*-alkane envelopes are, however, strong arguments against any relationship between samples N1 and N2. Unfortunately, the stable carbon isotopic value for the Diamant-1 sample is not known. See Table 2 for some of the key figures found for samples N1 and N2, as well as the Upper Jurassic NSO-1 oil (Norwegian Standard Oil) from the Norwegian Oseberg Field.

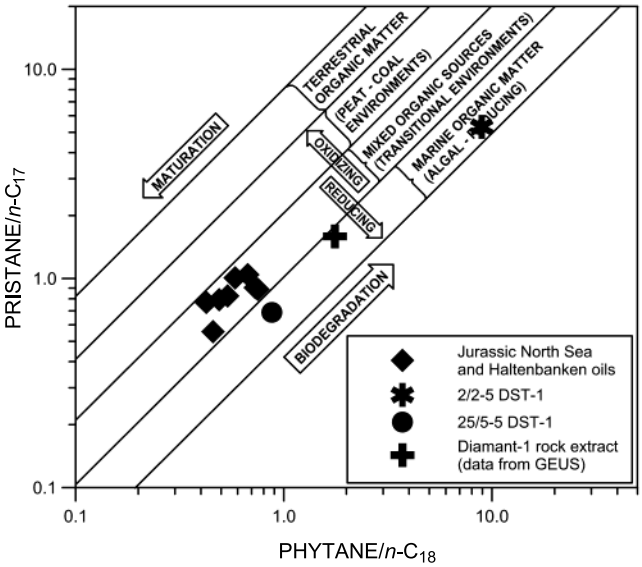

Fig. 8. A cross-plot of Ph/*n*-C_{18} versus Pr/*n*-C_{17} indicates a difference in facies and maturity between the selected samples and a suite of Jurassic oils from the North Sea and Haltenbanken. None of the samples are believed to be biodegraded. Note that the samples from 2/2-5, 25/5-5 and DK Diamant-1 all fall within a different facies definition to the Jurassic oils. Modified from Shanmugam (1985).

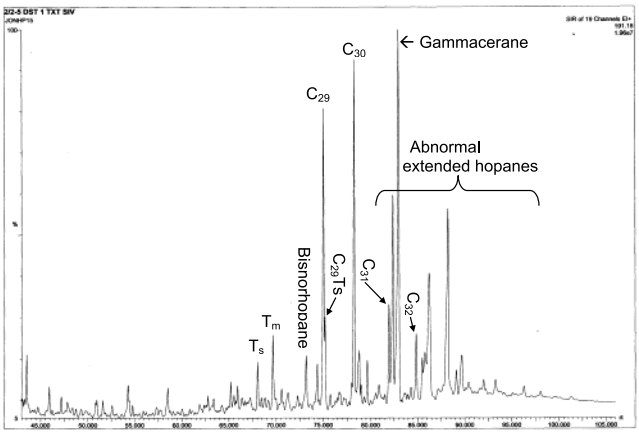

Fig. 9. GC-MS m/z=191 chromatogram of sample N1, note the high concentration of gammacerane and the abnormal extended hopanes.

The GC-MS m/z=191 chromatogram for sample N1 shows some unusual and interesting features, such as the occurrence of C_{30} gammacerane and high amounts of abnormal extended hopanes (C_{31}–C_{35}) (Fig. 9). Mills *et al.* (2000) and Khoshbakht (2001) also recognized the occurrence of gammacerane in the 2/2-5 DST-1 oil. Gammacerane is a known indicator of abnormal salinity (Peters & Moldowan 1993), and not something one would expect to find in such abundances in a North Sea oil (Bailey *et al.* 1990). Gammacerane is not present in sample N2, but this sample has a high concentration of extended hopanes (Fig. 10). High amounts of extended hopanes (C_{31}–C_{35}) are often indicative of carbonate or evaporite source rocks (Waples & Machihara 1991). This is interpreted here as yet another indication of an atypical source facies for samples N1 and N2. The abnormal and high concentrations of extended hopanes in samples N1 and N2 are not recognized in the nine North Sea and Haltenbanken oils used for comparison. Bisnorhopane, common in Upper Jurassic oils from the North

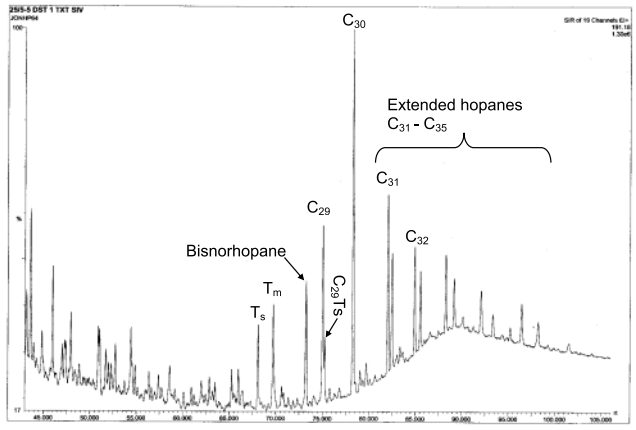

Fig. 10. GC-MS m/z=191 chromatogram of sample N2. Note the high abundance of bisnorhopane and extended hopanes.

Sea (Grantham *et al.* 1980), is also found in sample N1, and in high concentrations in sample N2 (see Figs 9, 10), suggesting a Jurassic age for these North Sea oils. Note, however, that bisnorhopane has been found in Miocene and Cretaceous oils from California and West Africa, respectively (Schoell *et al.* 1992).

The distribution of C_{27}, C_{28} and C_{29} regular steranes may be used as a facies parameter, as the regular sterane content is shown to be affected by the source-rock facies (Moldowan *et al.* 1985; Shanmugam 1985). In a ternary plot these steranes indicate that samples N1 and N2 are of marine origin, and that samples N1 and N2 fall within the same facies description as most North Sea Oils, although samples N1 and N2 are slightly enriched in C_{27} regular steranes (Fig. 11). Another facies parameter is the hopane/sterane ratio, where a high ratio indicates a lacustrine or a special, bacteria-influenced facies, and a low ratio is indicative of a marine, algal-dominated organic facies (Mackenzie 1984). The hopane/sterane ratios for samples N1 and N2 fall within the range of the oils in the control group (Fig. 12), supporting the facies type outlined by the regular

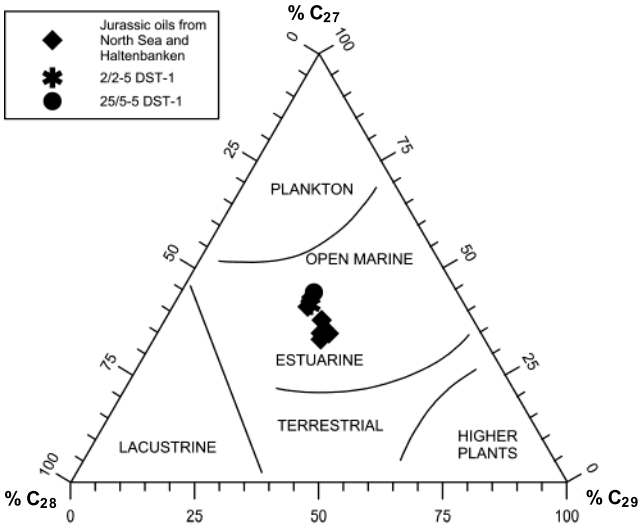

Fig. 11. A ternary plot of C_{27}, C_{28} and C_{29} from the GC-MS m/z 218 chromatogram, used to determine the organic facies of oils. The regular steranes reveal limited variation between sample N1 (2/2-5 DST-1) and N2 (25/5-5 DST-1) and nine oils representing typical North Sea Upper Jurassic-sourced oils. Samples N1 and N2 are, however, slightly enriched in C_{27} sterane. Modified from Shanmugam (1985).

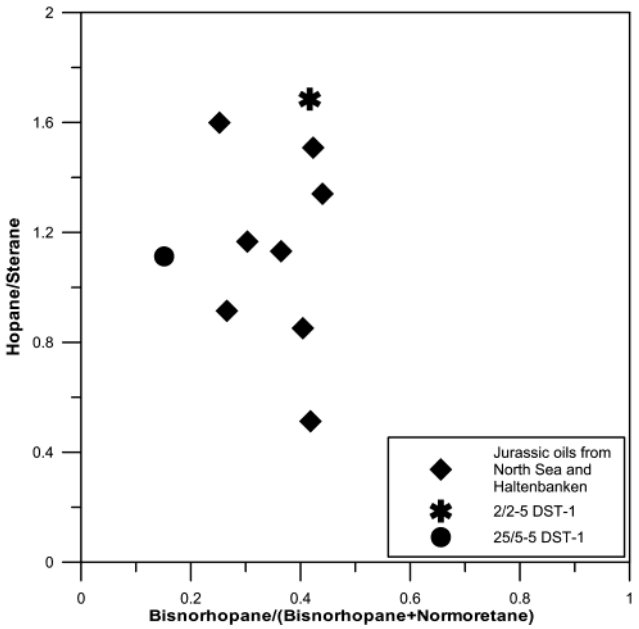

Fig. 12. In a cross-plot of facies parameters, samples N1 (2/2-5 DST-1) and N2 (25/5-5 DST-1) do not vary much from eight Upper Jurassic oils from the North Sea and the Haltenbanken area. Sample N1 is, however, relatively low in bisnorhopane.

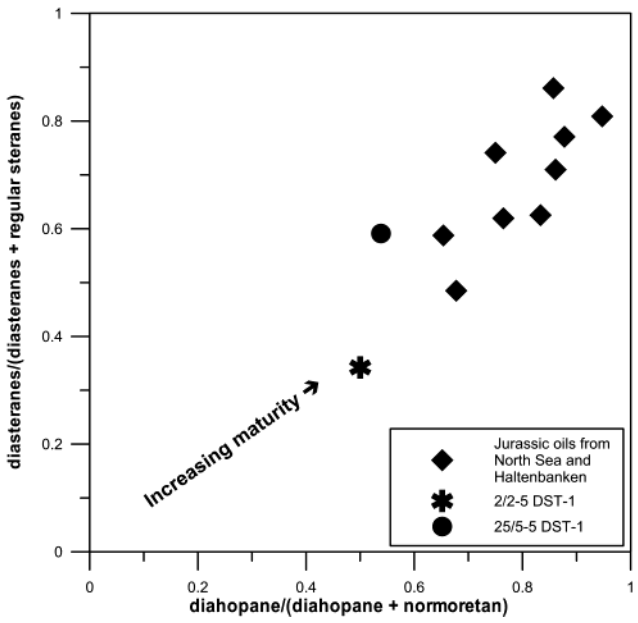

Fig. 13. Cross-plot of a hopane maturity parameter (Cornford *et al.* 1986) and a sterane maturity parameter, indicating less maturity for samples N1 (2/2-5 DST-1) and N2 (25/5-5 DST-1) than is seen for nine Jurassic oils from the North Sea and Haltenbanken.

steranes, i.e. a marine, algal-dominated source rock. It seems that the regular steranes and hopane/sterane ratios do not reflect the hypersaline and carbonate facies suspected for samples N1 and N2, respectively. This may be due to an organic input into the source rocks for the N1 and N2 samples involving solely marine algae.

Thermal maturity

The GC-FID chromatogram of sample N1 (2/2-5 DST-1) shows very high concentrations of isoprenoides relative to *n*-alkanes (see Figs 5 and 6), which is indicative of low maturity (Peters & Moldowan 1993, p. 218; Hunt 1996, pp. 130–131). Several maturity parameters based on the thermally controlled degradation and isomerization processes of biomarkers are useful in estimating source-rock maturity (Seifert & Moldowan 1978; Mackenzie *et al.* 1980; Cornford *et al.* 1986; Radke 1988). The low diasteranes/(diasteranes+regular steranes) ratio (0.34), Ts/(Ts+Tm) ratio (0.40) together with the 'vitrinite reflectance' values estimated from aromatic compounds, respectively, all point to a low-mature source for the N1 sample. The methylphenanthrene (MP)-based calculated vitrinite reflectance value (R_c=1.1 × log10MPR+0.95, where MPR=2MP/1MP (Radke 1988)) is 0.77% R_c and the methyldibenzothiophene (MDBT)-based calculated vitrinite reflection (R_c is 0.073 × MDR+0.51, where MDR=4MDBT/1MDBT (Radke 1988)) is 0.58% R_c, placing the source rock for sample N1 in the shallower part of the oil window. The corresponding values for sample N2 (25/5-5 DST-1) are 0.92% R_c and 0.60% R_c, respectively. The GC-FID parameters for sample N2 indicate it to be of medium maturity.

The diasteranes/(diasteranes+regular steranes) ratio (0.59), diahopane/(diahopane+normoretane (0.54) and the Ts/(Ts+Tm) ratio (0.45) suggest low to medium maturity for sample N2, which is more mature than sample N1, but still slightly less mature than most North Sea oils (see Figs 8, 13 and 14). From the analysis of GC-FID and GC-MS parameters, it is concluded that both samples N1 and N2 are of low to medium maturity, and that sample N1 is less mature than sample N2.

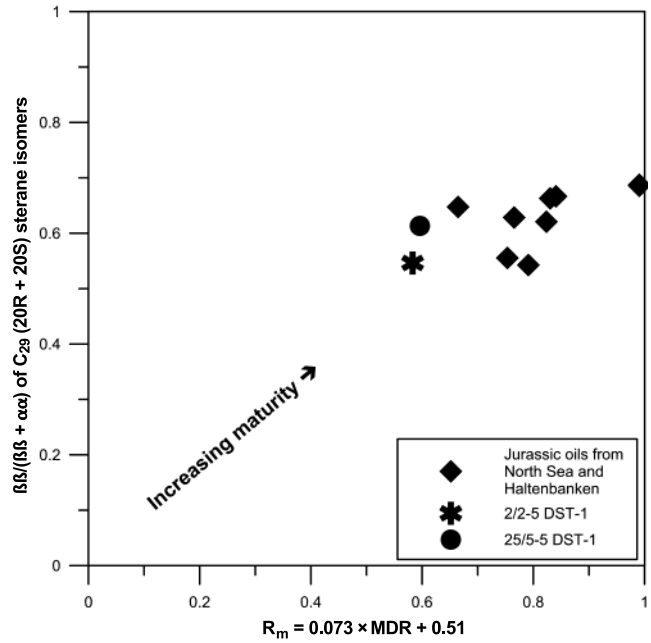

Fig. 14. Cross-plot of vitrinite reflection (R_m) calculated from methyldibenzothiophene (Radke 1988) and a sterane maturity parameter (Mackenzie *et al.* 1980), indicating that samples N1 (2/2-5 DST-1) and N2 (25/5-5 DST-1) are of lower maturity than eight typical North Sea and Haltenbanken oils. The calculated vitrinite reflection for samples N1 and N2 is around 0.6.

The low maturity observed for samples N1 and N2 and, hence, the limited burial of the source rocks for these samples, implies the source rocks to be located on the eastern margins of the Viking and Central Graben, and that secondary migration probably was of limited lateral and vertical distance.

Organic facies of the source rocks

Hunt (1996) defined organic facies as 'mappable subdivisions of stratigraphic units distinguished from the adjacent sub-

divisions by the character of their organic matter'. Besides the type of organic input that enters an early diagenetic environment, the level of the redox-potential (Eh) as well as pH, mineralogy (some clay minerals are catalytic) and the geometric micro-scale organization of the kerogen in the rock (i.e. lamina vs. 3D organo-networks) are important parameters which can influence the chemical makeup of the later formed kerogen. These also influence the relationship between maturation and actual expulsion in a temperature context. Based on the data discussed above, samples N1 and N2 represent two Jurassic sedimentary facies uncommon in the North Sea. The tectonic history of the 2/2 area in the Norwegian North Sea is complicated and influenced by halokinesis, resulting in considerable facies variation within the Jurassic sediments, both in reservoir sands and source rocks (Gabrielsen *et al.* 1985). Gabrielsen *et al.* (1985) found oil from well 2/2-1 to be of low to moderate maturity, and to originate from a source rock with significant terrestrial input (Pr/Ph=2.2, Pr/n-C_{17}=0.4). They proposed the Upper Jurassic Farsund Formation as the best source-rock candidate, based on GC-FID and GC-MS analysis of the 2/2-1 oil, and pyrolysis analysis of samples from the Farsund Formation. The Middle Jurassic Bryne Formation is, in general, gas prone, although Petersen & Brekke (2001) have correlated oil from the Trym discovey (well 3/7-4) to Middle Jurassic coals. The Trym oil does not, however, resemble samples N1 and N2 (Petersen & Brekke 2001; Pedersen 2002). The organic-rich Upper Jurassic Mandal Formation is poorly developed in Block 2/2 (Gabrielsen *et al.* 1986) and petroleum from well 2/2-5 (sample N1) is clearly different from the oil analysed by Gabrielsen *et al.* (1985). The 2/2-5 source rock could therefore be from a different organic facies than the 2/2-1 oil source rock.

Petroleum with heavy $\delta^{13}C$ values has been reported from the Eldfisk Field (Block 2/7) in the Norwegian North Sea (Bailey *et al.* 1990; Stoddardt *et al.* 1995) and the Bream and Brisling fields (Khoshbakht 2001). Bailey *et al.* (1990) reported a thin, rich source-rock interval of Middle Volgian age in the Feyda Graben to be enriched in ^{13}C (−25‰), and a rock extract from an Upper Jurassic sample from the Danish well Diamant-1 has an isoprenoid to n-alkane relationship similar to that seen in the 2/2-5 oil (Fig. 8). These observations suggest that a special facies, inferred by the 2/2-5 oil, may have developed in the Norwegian–Danish border zone in Jurassic times.

In the Upper Permian, extensive evaporites, the salts of the Zechstein Group, were deposited in two basins – the Northern and Southern Permian basins covering the North Sea (Glennie 1998). In these basins, hypersaline source rocks could have formed in connection with periods of marine conditions followed by evaporation. Christiansen *et al.* (1993) presented GC-FID and GC-MS chromatograms from an Upper Permian source rock from Greenland, showing high amounts of isoprenoids, low waxiness, high concentrations of tricyclic terpanes and abnormal extended hopanes (C_{31+}). These characteristics are also found in sample N1, except for the high concentration of tricyclic terpanes. Bugge *et al.* (2002) found gammacerane in oil stains from Upper Permian/Lower Triassic sandstones in wells on Norwegian Block 6611/9, and related them to marine Permian source rocks after comparing them with Palaeozoic source rocks on East Greenland. As sample N1 shares several characteristics with the Permian source rocks described by Christiansen *et al.* (1993) and Bugge *et al.* (2002), it is relevant to consider a Permian source for sample N1. No Permian source rocks from the North Sea matching sample N1 are known to the authors, and Mills *et al.* (2000) concluded the source rock of the 2/2-5 oil to be of Jurassic age. Nevertheless, runoff from

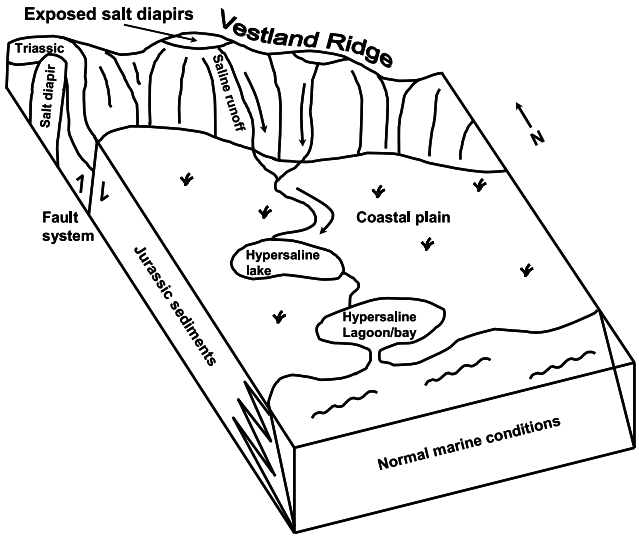

Fig. 15. A paleogeographical reconstruction of the Upper Jurassic in the 2/2-5 area south of the Vestland Ridge. Saline runoff from exposed salt diapirs may have accumulated on the coastal plain, or in bays or lagoons along the Upper Jurassic coastline. In these hypersaline sub-basins the 2/2-5 source rock may have been deposited.

Permian salt diapirs is proposed as a model for the formation of hypersaline facies in local basins of Upper Jurassic age (Degens & Paluska 1979; R. di Primio pers. comm. 2002). Within the Vestland Ridge, salt diapirs are covered by thin Triassic layers or the Triassic layers are completely absent (Goldsmith *et al.* 2003). The Vestland Ridge was affected by non-deposition or erosion in early to middle Volgian times (Gabrielsen *et al.* 1986) and the sediment transport was from north to south in the 2/2 area (Fraser *et al.* 2003). Erosion through thin covers of Triassic sediments, leading to exposure and dissolution of Permian salt in the Upper Jurassic, may have provided saline runoffs to depressions on the coastal plains south of the Vestland Ridge in Volgian Times, or into bays or lagoons along the coastline (Fig. 15). Only a very few species of algae and other specialized organisms may have survived in this low diversity, saline and hostile environment. The biomass produced by the few algal species may, however, have been very high, as there were few competitors for nutrients. If so, rich, homogeneous source rocks could develop in these assumed hypersaline, anoxic conditions. Such hypersaline conditions could also occur in lagoons along hot, arid coastlines with excess evaporation (Fig. 16).

Miller (1990) argued for hypersaline seafloor conditions caused by heavy, saline water blanketing the seafloor, overlain by normal marine water. In this model, the organic input would be normal marine algae, but the depositional environment would be hypersaline (Fig. 17). This may explain why the regular steranes and hopane/sterane ratios do not indicate any disagreements between samples N1 and N2, and the Upper Jurassic control oils.

As discussed above, several indices point to a carbonate source rock for sample N2. A study by Bhullar *et al.* (1998) of oils from Norwegian Block 25/2 and 25/5 concluded that the source rocks generating petroleum for the Rind and Frøy fields were Upper Jurassic shales of the Heather and Draupne formations, except for the A2 segment in the Frøy Field, which was filled with petroleum generated from the marine Lower Jurassic Dunlin shales. None of the samples investigated by Bhullar *et al.* (1998) had properties resembling sample N2. It may be significant that petroleum from the Frøy Field and Rind

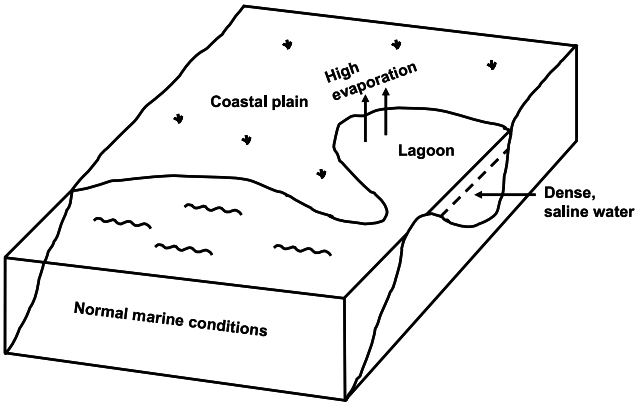

Fig. 16. Hypersaline conditions may be established in lagoons with high evaporation and a narrow outlet to the open sea. Such a setting could explain the deposition of the hypersaline 2/2-5 source rock.

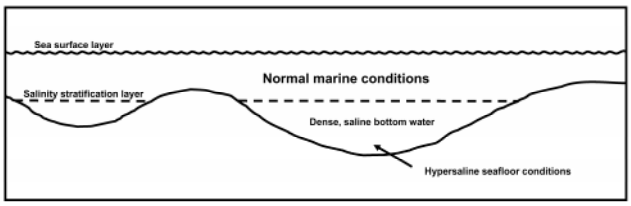

Fig. 17. Salinity stratification of the Kimmeridge Sea, based on a model by Miller (1990). Solar heating of normal sea water causes increased salinity, with the accumulation of dense, saline bottom water in seafloor basins as a consequence. Source rocks forming in these hypersaline sub-basins may have received organic input from the normal marine layer above, resulting in a kerogen derived from typical open-marine algae, which was modified by the hypersaline conditions on the seafloor after deposition. Modified from Miller (1990).

discovery are produced from reservoir sands of Middle Jurassic age (Brent Group), whilst sample N2 was encountered in Paleocene sands. Carbonate sedimentation was abundant in the North Sea during the Cretaceous – could the 'carbonate nature' of sample N2 connect to Cretaceous organic-rich carbonate facies? Oils from the Upper Cretaceous and younger strata may contain the compound oleanane, thought to originate from flowering plants, which evolved in the Cretaceous (Moldowan *et al.* 1991; Nytoft *et al.* 2002). No trace of this compound was found in sample N2. It is also questionable if potential Cretaceous source rocks have matured sufficiently to generate petroleum, as Cretaceous sediments are buried to only 2–2.5 km in the 25/5 area. Another possible source are Palaeozoic sediments, where Permian marine carbonates are the most likely candidate. Thin oil-prone Zechstein shales and carbonates are described from the onshore Netherlands (van den Bosch 1983) and from the Thuringian Basin in Germany (Karnin *et al.* 1996), but the existence of corresponding shales in the northern North Sea is unknown. Furthermore, sample N2 does not resemble the aforementioned Permian source rocks from East Greenland described by Christiansen *et al.* (1993) and Bugge *et al.* (2002). The oil-prone Zechstein Kupferschiefer is known from most of the North Sea (Glennie *et al.* 2003), but the thickness of this source rock is usually limited to 1–2 m and the Kupferschiefer is generally a siliciclastic source rock, although it may be calcareous locally (Glennie *et al.* 2003). However local, thicker developments of the Kupferschiefer might be considered, as well as drainage of a large area of thin, oil-prone Kupferschiefer into a single trap. A third possibility, which is believed to be the most relevant, is the development of

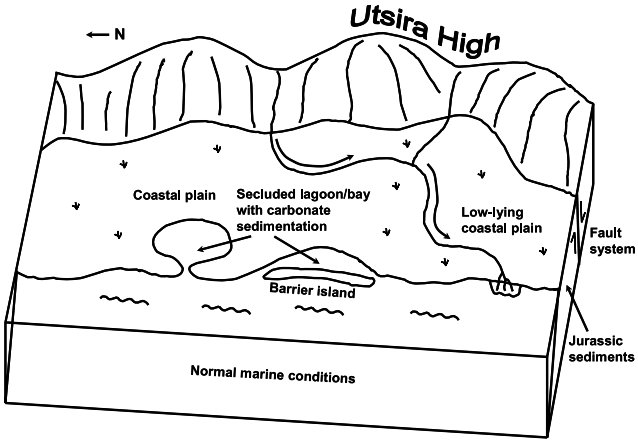

Fig. 18. A paleogeographical reconstruction of the Upper Jurassic in the 25/5-5 area. Lagoons or bays along the Upper Jurassic coastline along the western coastline of Utsira High.

a limited anoxic carbonate facies in the Upper Jurassic, somehow isolated from clastic input. A stagnant lagoon or bay with high organic productivity along an arid coastline, or an open marine environment dominated by carbonate sedimentation could be such a setting. In Upper Jurassic times, the Utsira High and other parts of the Vestland Ridge were dry land (Fraser *et al.* 2003), and secluded lagoons or bays along the shorelines of the Utsira High could have facilitated organic-rich environments with anoxic seafloor conditions (Fig. 18).

In summary, the N1 oil from Norwegian well 2/2-5 (DST-1, 3666.2-3670.5 mRKB) is most likely to have been expelled from a particular, anoxic, hypersaline sedimentary environment, dominated by siliciclastic shales with an algal-derived organic input. It is unlike any typical North Sea petroleum. The source rock may have been deposited in a small, shallow basin with no, or only restricted, access to the open ocean, maybe in a lagoonal setting, or a small, isolated hypersaline basin on an Upper Jurassic coastal plain collecting saline runoff from exposed salt diapirs (R. di Primio pers. comm. 2002). Sample N2 is believed to originate from a marine, carbonate-dominated source rock deposited under anoxic conditions. It does not resemble any of the petroleum of Quadrant 25 known to the authors. Its source may be limited to a local pod of Upper Jurassic carbonate source rocks, or less likely, it could be related to a Cretaceous or Palaeozoic source rock. See Figures 15 and 18 for reconstructed depositional environments for samples N1 and N2.

IMPLICATIONS FOR PETROLEUM EXPLORATION IN THE NORTH SEA

The existence of a number of different Jurassic source facies in the North Sea would open up new play models in the North Sea area. This is because the different source rocks may have chemical properties which react differently when subjected to thermal stress. This means that one type of source rock may become mature at a lower temperature than another type, leading to variations in timing of petroleum generation and expulsion, and where these processes take place geographically.

Mills *et al.* (2000) used kinetic analyses to show that the source for the 2/2-5 oil probably realized its full oil-generating potential in a narrow depth interval, because of the limited distribution of activation energies. The 2/2-5 source began generating petroleum slightly later than a typical Type II Upper Jurassic source rock, but reached peak generation much quicker (Mills *et al.* 2000). The maturation and petroleum expulsion of

the homogeneous 2/2-5 source may be described as 'explosive' compared with heterogeneous kerogens with more complex chemistry and a wider range of activation energies. The low thermal maturity observed for sample N1 points to a limited burial of the source when the petroleum was expelled, potentially around 2.5 km. This may have significance for exploration in the Norwegian Danish Basin area, where Upper Jurassic source rocks are buried to only 1.5–2.5 km outside the Egersund and Farsund Graben.

Carbonate-dominated source rocks, which may have sourced the 25/5-5 oil discovery, would be of interest in low-mature areas, i.e. on basin margins and graben flanks. This is because kerogen in carbonate source rocks may be high in sulphur, and a sulphur-rich source rock is known to break down and generate petroleum at a lower temperature than a siliciclastic-dominated low-sulphur source rock, due to weak C–S bonds (Orr 1986; Baskin & Peters 1992). Locally developed pods of Jurassic carbonate-dominated source rocks may have become oil mature in areas where siliciclastic source rocks are still immature, such as in areas outside the Mesozoic rifts of the North Sea. Such areas of interest would be the Stord Basin, the Egersund Basin, the Farsund Basin and maybe areas further east in the Norwegian–Danish Basin.

CONCLUSIONS

1. An oil sample from well 2/2-5 (sample N1) has unique chemical properties, making it significantly different from any typical North Sea oil. This low-mature, black oil has a Pr/Ph ratio below 1, a distinct composition dominated by isoprenoids over *n*-alkanes; it contains abundant gammacerane and is isotopically very heavy. The 2/2-5 oil is enriched in polyaromatic components, compared with other Upper Jurassic oils from the North Sea and Haltenbanken. The 2/2-5 oil is believed to be sourced from a local, highly anoxic hypersaline shale facies of Upper Jurassic age, with organic matter constituted by algal input. Hypersaline conditions may have resulted from high evaporation from protected lagoons along the Upper Jurassic shoreline of the southern margin of the Vestland Ridge, or in small basins on a coastal plain collecting brines from exposed Permian evaporites. Another model is heavy, saline water covering the seafloor in an otherwise normal marine environment, giving hypersaline bottom conditions (Miller 1990). An Upper Jurassic sample from Danish well Diamant-1 is shown to have the same isoprenoid over *n*-alkane pattern as seen for the 2/2-5 oil, suggesting that the hypersaline facies implied by the 2/2-5 oil may have had some extension in the border zone between the Norwegian and Danish sectors.
2. A black oil from well 25/5-5 (sample N2) is shown to be of low to medium maturity. Sample N2 is seen to have high concentrations of extended hopanes on the GC-MS m/z=191 fragmentogram and this, together with the enrichment in polar and aromatic compounds, low sat/aro and Pr/Ph ratios and an even *n*-alkane distribution, indicates that the source rock of sample N2 is carbonate dominated. This oil may have been generated from a local carbonate-dominated variety of the marine Upper Jurassic Draupne source rock, located along the Utsira High. It may represent a local, protected facies isolated from siliciclastic input, such as a restricted marine lagoon or bay environment. A development of Jurassic carbonate source rocks may have implications for petroleum exploration in areas of limited subsidence, such as in the Stord, Egersund and Farsund basins.
3. Contrasting isotopic values, petroleum composition and absence of gammacerane in the 25/5-5 oil indicates that there is no correlation between the 2/2-5 oil and 25/5-5 oil. These two oils are therefore seen to represent different source-rock facies.

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