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 of the Mesozoic Central Graben and Viking Graben in the North Sea. The composition of the investigated oils is 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 vary 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 for several Upper Jurassic North Sea organic geochemical parameters have been established by numerous authors (Northam 1985; Barwise 1990; Chung et al. 1992; Clayton & Bjoery 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; Skâlnes 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 Froy fields by Karlsen & Larter 1991; Skâlnes 1993; Bhullar 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 petroleum 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.

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 (Ronnevik 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 sapropellic 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 matter than those deposited in basinwards.
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 1 or less, and the rock facies. The nickel/vanadium (N/V) ratio is usually around indicating Type II kerogen, and a marine siliciclastic source-rock extracts. The average pristane/phytane (Pr/Ph) ratio is about 1.3, Sulphur contents are low to moderate, ranging from 0.02% to 0.93%. The 13C value varies between 27.1 to 28.6‰ and 25.6 to 28.5 1.2–5.8 Karlsen et al. (1995). 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);
- 13C 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 removed.

**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 Zechezstein 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.

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

<table>
<thead>
<tr>
<th>Property</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pr/Ph</td>
<td></td>
</tr>
<tr>
<td>Whole oil δ13C (%)</td>
<td>Sat/Aro</td>
</tr>
<tr>
<td>Oil</td>
<td>Reference</td>
</tr>
<tr>
<td>0.9–2.0 (N. North Sea)</td>
<td>– 27.4 to – 30.2</td>
</tr>
<tr>
<td>1.3 (North Sea)</td>
<td>– 28 to – 30</td>
</tr>
<tr>
<td>1.5 (Kimmeridge Fm.)</td>
<td>– 29°</td>
</tr>
<tr>
<td>2–3 (Heather Fm.)</td>
<td>– 26 to – 28°</td>
</tr>
<tr>
<td>1.3–2.9 (N. North Sea; 44 oils)</td>
<td>– 25.6 to – 30.4</td>
</tr>
<tr>
<td>0.99–1.84 (UK North Sea; 4 oils)</td>
<td>– 28.5 to – 29.8</td>
</tr>
<tr>
<td>0.6–1.9 (average 1.24) (Kimmeridge Fm.)</td>
<td>– 27.1 to – 30.4 (average – 28.9)</td>
</tr>
<tr>
<td>0.9–1.6 (Haltenbanken; 33 oils)</td>
<td>– 28.5</td>
</tr>
<tr>
<td>1.4–2.8 (Hammerfest Basin)</td>
<td>– 28.6 to – 31.0</td>
</tr>
<tr>
<td>1.3–2.5 (NOCS; 12 oils)</td>
<td>– 28.4 to – 30.1</td>
</tr>
</tbody>
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*a-source-rock extracts*
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 a 5% 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 A200 S autosampler injected the samples with a 10 µl syringe. The temperature programme was 120 min.

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. 189). 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...
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-alkane and Ph/n-alkane 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-alkane ratios 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 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. However, 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. 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.
The GC-MS m/z=191 chromatogram for sample N1 shows some unusual and interesting features, such as the occurrence of C30 gammacerane and high amounts of abnormal extended hopanes (C31–C35) (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 (C31–C35) 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 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 C27, C29, and C30 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 C27 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
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 isoprenoids 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 \( R_c = 1.1 \times \log_{10} \text{MPR} + 0.95 \), where MPR=2MP/1MP (Radke 1988) is 0.77% \( R_c \) and the methyldibenzothiophene (MDBT)-based calculated vitrinite reflectance (\( R_c = 0.073 \times \text{MDR} + 0.51 \), 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/(diaphane+normoretan) (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.

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-C34=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 discovery (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 δ13C values has been reported from the Edlisfisk Field (Block 2/7) in the Norwegian North Sea (Bailey et al. 1990; Stoddart et al. 1995) and the Bream and Brising 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 13C (–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 from 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 (C35H72). These characteristics are also found in sample N1, except for the high concentration of tricyclic terpanes. Bugge et al. (2002) found gammamacerane 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 Permain 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 Froy 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
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 Utira 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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