Recognition of caprock leakage in the Snorre Field, Norwegian North Sea*

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The aim of this study was the evaluation of the distribution of hydrocarbons in the Cretaceous 'caprock' succession that unconformably overlies the Triassic-Lower Jurassic reservoir of the Snorre Field. The Snorre Field is located in the Tampen Spur area of the Norwegian North Sea. Evaluation of the hydrocarbon distribution was based on data from hydrocarbon shows encountered during drilling and organic geochemical data from canned cuttings' samples, 27 DST oils and rock samples from two wells. Oil shows were recorded in the Cretaceous Shetland Group. Over the crest of the structure, oil shows were present up to 400 m above the top of the reservoir. The occurrence of these shows coincided with high (>50%) gas wetness values of $\frac{\Sigma(C_2 - C_4)}{\Sigma(C_1 - C_4)}\times 100$. The incidence of these high gas wetness values also showed evidence of a relationship with the thickness of the underlying oil column, but showed a poorer correlation with evidence of undercompaction/overpressuring in the Cretaceous-Tertiary succession. Gas chromatography and combined gas chromatography-mass spectrometry data from selected rock samples indicated that the liquid hydrocarbons in the caprock succession were similar in composition to the oil from the underlying reservoir.

Diffusion processes may play a part in the distribution of gaseous hydrocarbon compounds, bulk flow processes provide a better explanation for the distribution of liquid hydrocarbons in the caprock succession. The distribution pattern of the caprock hydrocarbons makes it unlikely that leakage along major fault planes represents the major emplacement pathway for these hydrocarbons. A combination of relatively low pore entry pressures in the undercompacted Cretaceous strata and extensive microfracturing of the caprock succession provide a more appropriate mechanism.

Published estimates of hydrocarbon migration in the vicinity of the northern Tampen Spur suggest that the reservoirs of the Snorre Field began to receive a hydrocarbon charge during deposition of the Shetland Group, or shortly afterwards. Development of undercompaction/overpressuring in the argillaceous strata of the Shetland, Rogaland and Hordaland Groups may therefore be directly related to the filling history of the underlying reservoir.

Keywords: caprocks; leakage; Snorre Field

Introduction

One of the many factors affecting the occurrence and size of a subsurface hydrocarbon accumulation is the existence of an effective permeability barrier overlying or adjoining the reservoir horizon. This permeability barrier commonly takes the form of a rock with relatively low porosity or permeability, or both, such as shale. Capillary properties, such as the size of the largest interconnected pore throat and water saturation, determine the sealing capacity of a caprock (Hubbert, 1953). If conditions exceed the capacity of the caprock, then the caprock will fail and hydrocarbons will escape from the reservoir.

Watts (1987) divided caprocks into two groups, i.e. those that fail by capillary leakage (membrane seals) and those that fail by fracturing (hydraulic seals).

Membrane seals will fail when the net buoyancy pressure of the hydrocarbon column exceeds the capillary displacement pressure of the caprock. This capillary displacement pressure may be modified if the rock is oil-wet. The thickness of a membrane seal caprock is effectively irrelevant to its sealing capacity. Hydraulic seals, in contrast, occur when rocks have such high capillary displacement pressures (e.g. shale and salt) that a hydrocarbon column’s buoyancy pressure will exceed the mechanical strength of the rock before it exceeds the capillary displacement pressure. In consequence, the rock will fail by fracturing. The effectiveness of a hydraulic seal is dependent on its thickness.

In the Gulf of Mexico, McIver (1974) and Kennicutt et al. (1988) reported the occurrence of gaseous and liquid hydrocarbons in shallow sediments that were similar in composition to reservoir hydrocarbons 2000–3000 m deeper. In Canada, Thompson (1979) reported enrichment in the C$_2$–C$_8$ cuttings’ gas fraction from
samples up to 183 m above an oil-stained horizon. In addition, Welte et al. (1984) showed that substantial gas leakage may be associated with most hydrocarbon accumulations.

Hollander (1987) identifies claystones of the Lower Jurassic Dunlin Group and Cretaceous marls and claystones of the Shetland Group as the main seals for the Snorre Field. Karlsson (1986) indicated that a lack of competent caprocks is a limiting factor on oil accumulations in the Tampen Spur area. This is well illustrated in the Gullfaks Field in adjacent block 34/10, where Cretaceous shales were thought to seal the Jurassic reservoir (Erichsen et al., 1987). However, the occurrence of shallow gas accumulations in overlying Pliocene sands due to leakage and microbial degradation of gas from the main Jurassic reservoir unit (Irwin, 1989) tends to dispute this.

This paper will consider the distribution of both gaseous and liquid hydrocarbons in the Cretaceous–Tertiary ‘caprock’ succession that overlies the Triassic–Lower Jurassic reservoirs of the Snorre Field, and their relationship with the underlying oil accumulation and the caprock lithology. The study is based on shows or direct hydrocarbon indications (DHIs) from mud logs and completion logs, characterization of headspace and occluded gas from canned cuttings samples from six wells, and organic geochemical characterization of 27 DST oils and rock samples from two wells (Table 1).

Recognition of undercompaction and overpressuring in the caprock succession was based on sonic log characteristics and variations in mud weight. Use of mud weights as an indication of overpressuring must be tempered by the fact that mud programmes are often biased towards the lower molecular weight compounds (Irwin, 1989) tends to dispute this. Pristane:phytane ratios also show little variation, with values of between 1.3 and 1.6. Isoprenoid and sterane data (Figure 4) suggest a common source for the Snorre oils, which is likely to be the shales of the Draupne Formation, based on biomarker data.

The Snorre Field proper consists of a series of slightly inclined, rotated fault blocks bounded to the east by the scarp of a major fault known as the Inner Snorre Fault (Figure 1). A series of lesser NNE–SSW and east–west trending faults divide the field. The rotated fault blocks underwent a strong erosive event which occurred in this area in Late Jurassic to Early Cretaceous times. As a result, Cretaceous strata were deposited unconformably on Triassic or Lower Jurassic strata over much of the structure (Figure 5). A number of the faults that cut the Mesozoic strata of the Snorre Field also penetrate overlying Cretaceous–Tertiary strata, particularly in the vicinity of well 34/7-1 (Caillet, 1993). Karlsson (1986) showed an extension of the Inner Snorre Fault (Figures 1 and 5) into the upper part of the Shetland Group and the Rogaland Group.

The best reservoir quality (Figure 6) occurs in stacked fluvial channel sands of the Lower Jurassic

### Geology of the Snorre Field

The Snorre Field and its associated satellite structures are located on the Tampen Spur, lying on the western margin of the northern Viking Graben (Figure 1). The Snorre Field is elongated along a north–north-east to south–south-west axis, similar to that of the nearby Statfjord and Gullfaks Fields, and covers an area of approximately 105 km² (Hollander, 1987).

Estimates indicate that the main Snorre structure contains approximately 300 million Sm³ oil in place. There is no discrete gas-cap present in the field. The oil is undersaturated with an average API gravity of 35° and a low sulphur content of less than 0.5%. The gas:oil ratio (GOR) at the top of the reservoir varies from 70 to 80 Sm³/Sm³ along the western flank of the Snorre Field (34/7-4 and 34/7-7), to values of between 180 Sm³/Sm³ (34/4-4) and 221 Sm³/Sm³ (34/4-1) along the crest of the structure adjacent to the eastern margin of the field (Figure 2). The GOR shows a constant decrease in value with depth in any given well in the Snorre Field.

The reservoir contains a paraffinic–naphthenic oil with a typical ‘oil-like’, unimodal n-alkane profile biased towards the lower molecular weight compounds. This oil shows little significant compositional variation and has a low content of asphaltenes (1–2%) and NSO (9–10%) compounds. Isoprenoid and sterane data (Figure 4) suggest a common source for the Snorre oils, which is likely to be the shales of the Draupne Formation, based on biomarker data.

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The best reservoir quality (Figure 6) occurs in stacked fluvial channel sands of the Lower Jurassic

### Table 1 Well data for samples used in this study

<table>
<thead>
<tr>
<th>Well No.</th>
<th>Structure</th>
<th>DST samples (number of)</th>
<th>Headspace and occluded gas (interval m)</th>
<th>Total organic carbon (interval m)</th>
<th>Extraction, GC and GC–MS (interval m)</th>
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Figure 1 Map of the northern Viking Graben showing the position of the Snorre Field in relation to other major oilfields in the area. The position of the cross-sections in Figure 5 is shown by the broken lines I-I' and II-II'. Reproduced by permission of Graham & Trotman Ltd from Geology of the Norwegian Oil and Gas Fields (Campbell and Ormassen, 1987)

Middle and Upper Statfjord Formation, and units D and F of the Triassic Lunde Formation (Hollander, 1987). The shales and siltstones of unit A of the Lunde Formation represent a possible permeability barrier.

Figure 2 Map showing variation in gas:oil ratio (GOR) at the top of the reservoir interval. Values in parentheses refer to the difference in GOR between the oil-water contact and the top of the reservoir. All values are in units of Sm³/Sm³

Hollander (1987) describes the remaining units, i.e. the Lower Statfjord Formation, units B/C and E of the Upper Lunde Formation and the Lower and Middle Lunde Formation, to be of moderate reservoir quality. The Statfjord sands are the main reservoir unit in the southern part of the field, whereas the older sands of the Lunde Formation form the main reservoir in the northern part of the field.

With the exception of the south-western margin of the Snorre Field, a 5 m thick marl horizon representing the Lower Cretaceous Cromer Knoll Group directly overlies rocks of the Statfjord and Lunde Formations. In the south-western quarter of the field, rocks of the Dunlin Group occur between the top of the Statfjord Formation and the base of the Cromer Knoll Group. The Cromer Knoll marl is unconformably overlain by a predominantly argillaceous succession composed of the Upper Cretaceous Shetland Group and the Tertiary Rogaland, Hordaland and Nordland Groups.

The Shetland Group over the Snorre Field varies from 400 to 700 m in thickness, the thickest succession being developed over block 34/4. Nybakken and Bäckström (1989) subdivided the Shetland Group of the northern Viking Graben area into five formations, of which only the upper two, the Kyrre and Jorsafare Formations, appear to be present over the Snorre Field. The Kyrre Formation over the Snorre Field typically consists of a series of calcareous mudstones, with thin isolated limestone and dolomite beds.
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This lithology extends into the overlying Jorsalfare Formation, where it becomes increasingly calcareous towards the top of the formation.

Analytical procedures

The headspace and occluded gas fractions were analysed using Carlo-Erba Fractovap 2150 and 2350 gas chromatographs. Each gas chromatograph was equipped with 2 m stainless-steel columns packed with Poropack Q on Chromosorb, and used nitrogen as the carrier gas. After elution of n-butane, the column was back-flushed and Cs+ compounds were recorded as one peak.

The rock extracts were obtained from powdered rock samples extracted by the Soxhlet technique with a boiling mixture of dichloromethane and methanol (93:7). Activated copper filings were used to remove any free sulphur from the samples. After extraction, the solvent was evaporated off using a Buchi Rotavapor and the amount of extractable organic matter (EOM) was determined.

The EOM was diluted in dichloromethane and the asphaltenes were precipitated using excess n-pentane. The remaining maltene fraction was separated into its component saturate, aromatic and non-hydrocarbon fractions using a high-performance liquid chromatography system with n-hexane as eluant.

The saturated hydrocarbon fraction was diluted with n-hexane and analysed on an HP-5730A or 5710 gas chromatograph. Both gas chromatographs were equipped with 15 m DB-1 fused-silica columns and used hydrogen as the carrier gas. The aromatic hydrocarbon fraction was also diluted with n-hexane and analysed on an HP-5730A gas chromatograph fitted with a 15 m DB-5 fused-silica column and using hydrogen as the carrier gas. In both instances, injection was performed in the split mode with a ratio of 1:10, and a temperature program of 80°C (2 min), 4°C min⁻¹, 280°C. Data processing was carried out using a VG Multichrom laboratory data system.

A VG Micromass 70-70 gas chromatography–tandem mass spectrometry system was used for gas chromatography–mass spectrometry analysis of the EOM fractions. The Varian Series 3700 gas chromatograph was fitted with a fused-silica OV-1 capillary column. Helium was used as the carrier gas and injections were performed in the split mode using a ratio of 1:15.

Results

Evidence for hydrocarbon leakage from shows encountered during drilling

The most abundant physical evidence for the occurrence of hydrocarbons in the rock succession overlying the Snorre Field is DHI records from the mud logs and completion logs (Figure 7). In all, DHI data were evaluated from a total of 13 wells, nine of which were located on the Snorre Field itself. A major limitation in the use of such data is the criteria used in
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2 showed no evidence of DHIs, whereas yellow fluorescence and a blue–white solvent cut were recorded from the Dunlin Group in well 34/7-2. On the basis of well logs (gamma/resistivity/sonic), or descriptions of cuttings, the character of the rocks in the Shetland Group shows no variations that can be directly related to the occurrence of these oil shows.

Organic geochemical evidence for hydrocarbon leakage

Combined headspace and occluded gas data from canned cuttings' samples collected from the dry well 34/7-2 and the four oil-bearing wells, 34/7-1, 34/7-3, 34/7-4 and 34/7-6, show similar patterns in C1–C4 hydrocarbon concentration (Figure 8). In most instances, this decreases from a maximum in the strata directly overlying the reservoir sandstone to a minimum in the middle of the Tertiary Hordaland Group, before increasing to a second maximum in the upper half of the Hordaland Group (Figure 9).

The C1–C4 hydrocarbons in the combined headspace and occluded gas from samples taken below the minimum in the Hordaland Group typically show an upwardly decreasing content of C2–C4 hydrocarbons (gas wetness: Figure 9). C2–C4 hydrocarbons are almost absent from the combined headspace and occluded gas from samples above the minimum observed in the middle of the Hordaland Group. The high gaseous hydrocarbon concentrations observed in the upper half of the Hordaland Group and the overlying Nordland Group consist solely of methane. In certain wells, e.g. 34/7-1, relatively high concentrations of C1–C2 hydrocarbons with gas wetness values in excess of 40% occur below the oil–water contact.

Whereas the concentration of C1–C4 hydrocarbons reached a maximum in the strata directly overlying the reservoir interval, the concentration of C2–C4 compounds reaches a maximum in the interval containing the oil column. The gas wetness values remain relatively high (>50%) for up to 400 m above the reservoir. Above this, gas wetness values show a marked decrease from 60–70% to less than 30–40%. Values of the iC4:iC4 ratio are generally lower than 0.4 over this interval. The heights to which these relatively high gas wetness values occur above the top of the reservoir vary across the field, and are greatest in well 34/7-1 which lies close to the crest of the Snorre structure. The height of this zone above the top of the reservoir is lowest over the western flank of the field, e.g. 34/7-4.

A 10–20 m interval of decreased C1–C4 hydrocarbon concentration and gas wetness occurs at the base of the Shetland Group (Figures 8 and 9). This interval coincides with the occurrence of a marly lithology. However, the decrease in gas wetness observed higher in the Shetland Group is not accompanied by any similar change in lithology. The interval of relatively high gas wetness values that overlies the productive interval in the oil-bearing wells coincides with the interval over which oil shows are described on the well logs.

Comparison of the combined headspace and occluded gas C1–C4 hydrocarbon concentration and wetness profiles from wells over the Snorre Field with data from well 34/7-2 shows a very similar profile (Figure 10). This feature was not observed in the other

selecting lithologies for evaluation and the diligence with which the logger recorded the DHIs. In most of the wells considered in this study, most DHI records in the caprock succession were obtained from minor sandstone and carbonate lithologies. Later extraction of picked samples from the intervening claystones indicated that these may also contain appreciable concentrations of hydrocarbons. Observations from DHI records must therefore only be used in a qualitative manner and probably underestimate the distribution of hydrocarbons in caprock successions.

In general, a visible oil-staining was only reported from reservoir intervals in the Triassic Lunde Formation and Lower Jurassic Statfjord Formation. Otherwise, DHIs were reported as solvent cuts and fluorescence. In the Shetland Group, DHI fluorescence colours were dull gold (e.g. 34/7-1) to bright yellow (34/7-3), whereas solvent cuts were generally either absent or slow with a milky fluorescence. The DHIs were strongest from minor sandstone lithologies. No DHIs were reported from Tertiary strata over the Snorre Field itself, although DHIs were recorded from rocks of the Rogaland Group in satellite structures, i.e. 34/7-5 and 34/7-8. In well 34/7-4, unspecified DHIs extended approximately 100 m below the oil–water contact in the Lunde Formation. This is the only instance where this feature was reported.

Of the two dry wells examined during the study, 34/4-
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The highest EOM concentrations in well 34/7-2 occur in a narrow interval at the top of the Statfjord Formation (Figure 11). Hydrocarbon compounds account for approximately 50% of the EOM from the Statfjord Formation. A marked decrease in the EOM concentrations has been noted previously. Gas chromatography and gas chromatography–mass spectrometry data (Figure 4) indicate that oils from the Snorre Field, EOM from the oil-bearing wells and EOM from 34/7-2 share a common source.

The only well in which extractable organic matter (EOM) data were available from the Shetland Group was 34/7-2, which is located on a structure to the south of the Snorre Field. Samples covered the interval from the top of the Shetland Group to the upper part of the Statfjord Formation. The similarity in the gas profiles of cuttings from the ‘dry’ 34/7-2 well and the oil-bearing dry well examined in this study, i.e. 34/4-2, which showed uniformly low headspace and occluded gas concentrations.

The location of the cross-sections is shown in Figure 1. CK = Cromer Knoll Group; D = Dunlin Group; S = Statfjord Formation.
EOM concentration above this interval coincides with an impermeable calcareous sandstone horizon (2150–2160 m) at the base of the Dunlin Group (Amundsen Formation). The sandstone interval above this horizon contains a high EOM concentration of a similar magnitude to those observed in the underlying sandstones of the Statfjord Formation. The EOM in this interval has a much higher content of non-hydrocarbon compounds, i.e. approximately 80%, than that in the Statfjord Formation. Two samples from an upper argillaceous interval of the Amundsen Formation in this well are characterized by moderate concentrations of EOM, in which hydrocarbon compounds account for 70–80% of the EOM (Figure 11).

Extractable organic matter concentrations in the mudstones of the Shetland Group show a consistent upwards decrease from approximately 2000 ppm at the base of the unit to about 800 ppm at the top of the analysed interval, i.e. 100 m from the top of the Shetland Group. Non-hydrocarbons account for 40–60% of the EOM from this interval. The succession represented in well 34/7-2 differs from those examined from the Snorre Field in that it lacks the decrease observed in the C1–C4 hydrocarbon concentrations and wetness at the base of the Shetland Group. In contrast, gas wetness values show a local peak at the base of the Shetland Group in well 34/7-2.

Saturate gas chromatography data from samples from the Shetland Group show n-alkane distributions that are similar to those from the Statfjord Formation in this well and oil samples from the Snorre Field. Mean total organic carbon (TOC) values of approximately 0.5% and low pyrolysate yields indicate that the rocks of the Shetland Group have insufficient potential to account for the amount and character of the EOM observed. The n-alkane composition of the samples from the Shetland Group typically has a unimodal distribution with a maximum around nC15–nC16. This maximum becomes more pronounced towards the top of the analysed interval (Figure 12).

The n-alkane profiles observed from samples from the Dunlin Group (Amundsen Formation) show much more variation than is observed in samples from either the Statfjord Formation or Shetland Group. Extractable organic matter from sandstone at the base of the Amundsen Formation has an n-alkane distribution that is very similar to that observed in the Shetland Group. Moving up through the interval representing the Amundsen Formation, the n-alkane distribution becomes slightly bimodal with a second maximum around nC23–nC26. The most conspicuously bimodal n-alkane distribution is observed from a mixed mudstone–sandstone–marl succession in the more arenaceous lower interval of the Amundsen Formation. This n-alkane distribution is characterized by a strongly skewed bimodal distribution where the dominant maximum occurs around nC27–nC28. Although TOC contents are higher in the mudstones of the Amundsen Formation than in the Shetland Group (approximately 1%), pyrolysis yields indicate that these rocks have no hydrocarbon source potential.

The upper sample from the Statfjord Formation and the lowest sample from the Amundsen Formation have similar saturated terpane and sterane compositions that are almost identical to those of oils from the Snorre Field. However, the terpane composition of the remaining four samples from the Amundsen Formation are characterized by an increase in the prominence of the tricyclic diterpane peaks and a reversal of the 22S:22R ratio which is restricted to the C31 extended hopane (Figure 13). The C27–C30 sterane composition of the saturated hydrocarbon fraction shows only minor variations in the relative prominence of regular and rearranged species. This is reflected by the similarity in the relative composition of the C27, C28, C29 alkanes.
Figure 7 Summary of oil show occurrence compiled from well log data for selected Snorre wells. In the diagram key, 1 = oil column; 2 = undefined DHIs; 3 = strong DHIs; 4 = moderate DHIs; 5 = weak DHIs. Well locations in Figure 1. DHI = direct hydrocarbon indication.

Figure 8 Variation in concentration of headspace and occluded cuttings gas in selected well sections from the Snorre Field. Well locations in Figure 1. The position of the oil column is indicated by the shaded box.

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347/4 347/6 347/3 347/1 347/2

500 m

1000--

1500--

2000--

2500--

3000--

Nordland Gp.

Hordaland Gp.

Rogaland Gp.

Sheetrland Gp.

Cromer Knoll Gp.

Dunlin Gp.

Stafford Fms.

Hegre Gp.

Well locations in Figure 1.
Figure 9 Variation in the relative C₂–C₄ hydrocarbon content of headspace and occluded cuttings gas in selected well sections from the Snorre Field. Well locations in Figure 1. The position of the oil column is indicated by the shaded box.

Figure 10 Variation in the concentration and wetness [Σ(C₂ – C₄)/Σ(C₁ – C₄)]100 in well 34/7-2. Well location in Figure 1.
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Concentration (ppm)

0 1000 2000 3000 4000 5000 6000

1886.0
1922.0
1958.0
1994.0
2030.0
2066.0
2102.0
2120.0
2138.0
2151.8
2157.9
2172.8
2183.0

A

Evi~

Figure 11 Variation in concentration and composition of extractable organic matter (EOM) in well 34/7-2. Well location in Figure 1

steranes (Figure 4). The main variation in the saturated sterane composition of the six samples is a strong increase in the prominence of the C_{21}-C_{22} steranes from the lower two samples from the uppermost

Figure 13 Variation in the composition of C_{31}+ extended hopanes and tricyclic diterpanes in well 34/7-2. Well location in Figure 1

Statfjord/lowermost Amundsen Formation, to the remaining four samples from the Amundsen Formation. This variation is not related to changes in the lithology of the samples.

Discussion of results

Headspace/occluded gas and overpressuring

The generally consistent decrease in both the concentration and wetness of C_{1}-C_{4} hydrocarbons from the top of the reservoir interval suggests that the faults which dissect the Snorre Field do not represent a major leakage route. If this was so, a more erratic distribution pattern might be expected in the C_{1}-C_{4} hydrocarbons. The distribution pattern observed is, however, similar to those described by Leythaeuser et al. (1982) and Krooss (1989) using diffusion models (e.g. 34/7-1; Figures 8 and 9). Nevertheless, a number of features in the distribution of the C_{1}-C_{4} and C_{5+} hydrocarbons over the Snorre Field are inconsistent with a purely diffusive movement of the gaseous hydrocarbons. These include the relatively flat gas wetness profile, e.g. 34/7-1, observed in the lower half of the Shetland Group, and the apparent relationship between oil column thickness and leakage as measured by gas wetness or iC_{4}/nC_{4} ratio (Figure 14).

Figure 12 Variation in the composition of the saturated hydrocarbon extractable organic matter (EOM) fraction in well 34/7-2. Well location in Figure 1

Figure 14 Relationship between cuttings gas composition and the vertical extent of the oil column in the Snorre Field, independent of the reservoir horizon sampled
The relationship between C1–C4 hydrocarbon distribution and oil column height suggests that relative buoyancy and bulk flow processes may represent important processes in this context. This impression is reinforced by the fact that the degree to which C2–C4 hydrocarbons penetrate the caprock is greatest where the GOR at the top of the reservoir is greatest. Thus a pure diffusion model is difficult to support for the GOR at the top of the reservoir and the base of the Cromer Knoll Group appears to have no significance for the distribution of the C1–C4 hydrocarbons.

Sonic log and mud weight data from the Snorre wells suggest that the mudstones of the Hordaland, Rogaland and Shetland Groups are undercompacted and possibly overpressured (Table 2). This is particularly true of the Shetland Group, where variations in mud weight show a similarity with the variations in headspace and occluded gas wetness (Figure 15). This suggests that a relationship exists between the development of overpressuring in the Shetland Group and the movement of gaseous hydrocarbons from the underlying reservoir. This relationship is strengthened by the greater deviation of the interval transit times from the normal compaction trend in those wells where the oil column is thickest, the GOR is highest, and where the lower half of the Shetland Group shows the highest gas wetness values.

Hydrocarbons may have started charging the Lunde and Statfjord Formations either during, or shortly after, deposition of the Shetland Group (Figure 16). Deposition of the overlying Rogaland Group started during the Danian (60–65 Ma). Jourdan et al. (1987) postulate an early hydrocarbon entrapment phase in the East Shetland Basin around this time, whereas Dahl et al. (1987) suggest that hydrocarbon generation in the Viking Graben may have started at around 75 Ma. In this event, early emplacement of hydrocarbons in the Lunde and Statfjord Formations would have occurred while the reservoir was at depths of 400–700 m, i.e. while the argillaceous sediments of the Dunlin and Shetland Groups were only partially compacted. Movement of hydrocarbons, especially gaseous hydrocarbons, into the Shetland Group would have been much easier than is now the case, and could therefore have contributed to the preservation of high porosities in the Cretaceous–Tertiary succession.

**Occurrence of extractable organic matter in the caprock succession**

The similarities in the distribution of the headspace and occluded gas hydrocarbons in the caprock succession over the Snorre Field and over the structure penetrated by the 34/7-2 well suggest that the latter well represents a valid analogue for examining the distribution of C12+ hydrocarbons over the same interval. Comparison of the EOM concentration profile and combined headspace/occluded gas wetness profile through the Shetland Group shows a strong degree of similarity between the two, although the sharp decrease in gas wetness at about 1990 m is not as strongly developed in the EOM concentration profile.

The lack of hydrocarbon source potential in the mudstones of the Dunlin and Shetland Groups, combined with the biomarker composition of the extracts, indicates that the caprock EOM has probably been introduced into the caprock succession from the reservoir interval in the Statfjord Formation. The biomodality observed in the saturated hydrocarbon gas chromatograms from mudstones in the Dunlin Group may reflect the influence of traces of indigenous material.

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The tendency for EOM concentrations to show a uniform decrease with distance from the top of the Statfjord Formation suggests that major faulting has not played a significant part in transporting higher molecular weight hydrocarbons into the caprock succession. Rather, it is suggested that bulk flow through an undercompacted argillaceous lithology, possibly coupled with microfracturing, has been the main mechanism for EOM emplacement. The high diffusion coefficients associated with C10+ hydrocarbons excludes diffusion as a viable mechanism to account for the distribution of EOM in the caprocks. The marked increase in the proportion of non-hydrocarbons in the EOM from mudstones of the Shetland Group may reflect preferential retention of...
the higher molecular weight species by the less porous rocks of the Shetland Group. This observation is supported by the increasing prominence of lower molecular weight hydrocarbons in the saturated hydrocarbon gas chromatograms with increasing distance from the top of the reservoir (Statfjord Formation). This pattern in variation again supports the contention that major faults have had little influence on the distribution of hydrocarbons in the caprock succession.

The movement of hydrocarbons into the Shetland Group would be aided if an early pulse of migrating hydrocarbons entered the structure shortly after the mudstones of the Shetland Group had been deposited. In this situation, these rocks would still be undergoing compaction and would still retain significant porosity and permeability. Injection of hydrocarbons into the Shetland Group at this time would tend to inhibit compaction by preserving fluid pressures and could aid the later movement of hydrocarbons through these rocks by changing the wettability. Countering this is the tendency for the proportion of polar and asphaltene compounds to increase, especially towards the base of the Shetland Group. Increased concentrations of these large, high molecular weight compounds may physically block pores and pore throats.

Conclusions

The results presented in this paper show that both gaseous and liquid hydrocarbons are present in the Cretaceous–Tertiary succession that forms the caprock for the Snorre Field. These hydrocarbons have been derived from a similar source horizon to that which generated the oil in the Snorre Field. It is therefore probable that the hydrocarbons in the caprock succession have been introduced from the underlying reservoir.

The distribution of hydrocarbons in the caprock succession suggests that they were largely emplaced through a bulk flow mechanism, which may be buoyancy-driven. Major fault systems have probably not played a significant part in introducing the hydrocarbons into the caprock. Relationships between the distribution of gaseous hydrocarbons in the caprock succession and the thickness and gas content of the underlying oil column suggest a relatively dynamic system. This relationship is not evident for the liquid hydrocarbons.

The distribution and concentration of hydrocarbons in the caprock succession suggest a relationship with the occurrence of undercompaction or overpressuring, or both. Early emplacement of oil and gas shortly after
the Shetland Group, and possibly also the Rogaland Group, was deposited may have directly contributed to the preservation of porosity and the development of overpressuring in the caprock succession. This was greatest along the present crest of the structure, where currently high GORs may be aiding or enhancing the preservation of this undercompaction/overpressuring.

The presence of liquid hydrocarbons with increased contents of polar and asphaltene compounds may also have resulted in the development of a partially oil-wet caprock succession. The reduced sealing capacity resulting from this may be countered by a reduction in effective porosity/permeability due to the high contents of polar and asphaltene compounds. This study shows that hydrocarbon accumulation may occur in structures with imperfect seals and suggests that reservoir systems in the North Sea may be more dynamic than previously thought.

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References


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