

# Asphaltene-rich residues in sandstone reservoirs of Haltenbanken province, mid-Norwegian continental shelf

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Thin zones of asphaltene-rich residue are present near the crests of two adjacent oil- and gas-filled structures. In one structure, the Smørifik Sør Field, multiple thin (5–50 cm) dark coloured zones are observed within the lower 20 m of the 88 m thick Garn Formation. These dark coloured zones tend to occur immediately above stylolitized mica–clay laminations and become gradually lighter upwards, apparently reflecting gradual upward decrease in residue abundance. In the other structure, the Smørifik Field, the lowermost 1 m of the formation is dark coloured and the sandstone gradually becomes lighter in colour upwards for a distance of about 3 m. Similar, but more diffuse, residues are also present throughout the oil zone in two other fields nearby. Organic geochemical analyses show that the residue-rich (dark coloured) zones differ from the surrounding lighter coloured sandstone mainly in having a higher content of asphaltenes, whereas the total content of extractable organic matter is often similar. Thus the darker rocks might be regarded more as zones of conspicuous oil staining due to asphaltene deposition, rather than as small tar mats. The residues typically appear to have accumulated under the influence of gravity at points where the downward flow was hindered by a lithological discontinuity. Present day zonation (upward-decreasing gas to oil ratio) in the oil column of the Smørifik Sør reservoir is consistent with a model of asphaltene precipitation in the lower part of the reservoir in response to upward leakage of gas from an underlying gas condensate reservoir in the Ile Formation. This is also consistent with the available organic geochemical data. In thin section, the asphaltene-rich material is seen to preferentially coat feldspar and clay but not quartz surfaces, thus illustrating why sandstone wettability should be expected to depend on both mineralogy and the asphaltene content of the petroleum involved.

**Keywords:** organic geochemistry; sandstones; diagenesis

This paper describes some thin zones of asphaltene-rich residue in sandstone cores from the Middle Jurassic Garn Formation in several adjacent oil and gas condensate fields (*Figure 1*). Our goals are to describe the residues in terms of quantitative measurements; to compare them with other published examples of similar appearing residues; and finally to offer our interpretations of their origin and the factors controlling their spatial distribution. We believe that it is important to consider both the organic geochemistry of the residues and their mineralogical/textural relationships with the host reservoir rock. Three colour plates are therefore included to provide an adequate descriptive basis of the latter aspect.

Our basic motivation for carrying out this study and publishing the results has been to provide a description and genetic interpretation for an aspect of reservoir petrology which has previously been little studied, but which can probably yield significant new information about both organic and inorganic processes relevant to petroleum exploitation. Although asphaltene-rich resi-

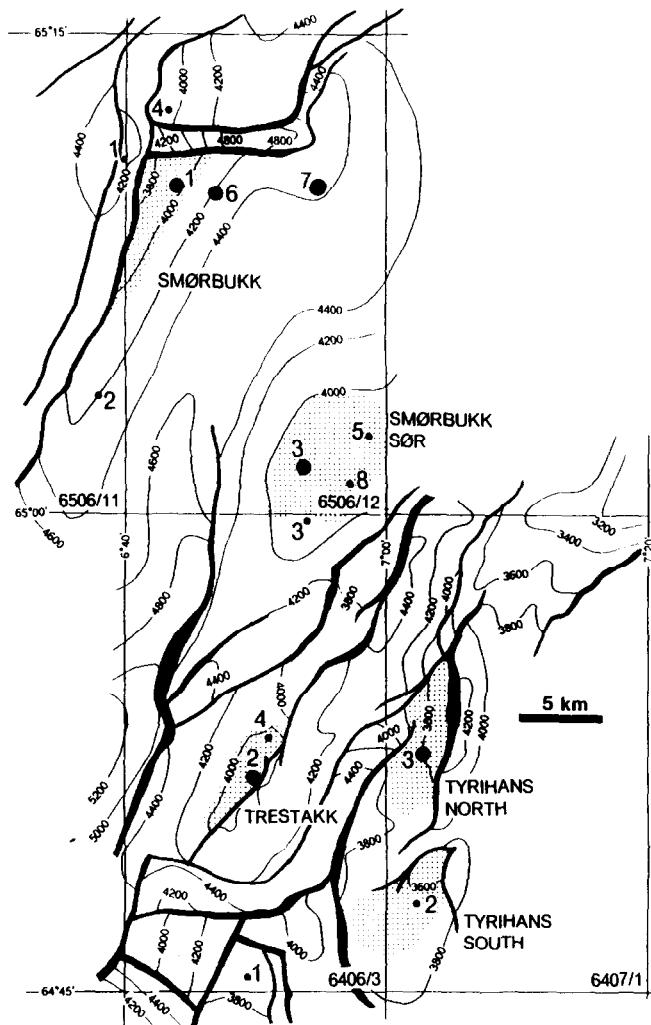
dues are becoming recognized as a common feature of hydrocarbon reservoirs, their systematic study is a relatively new field of research. The distribution and chemistry of such residues can potentially provide information about migration and filling history, the nature of petroleum interaction with mineral surfaces and the sequence of inorganic diagenetic processes. Where such residues become abundant enough to form tar mats, they can have direct economic significance by reducing the overall reservoir quality and forming laterally extensive barriers to fluid displacement.

This study is part of a long-term petrological study of diagenesis and reservoir quality in the Garn Formation, portions of which have been released in Ehrenberg and Nadeau (1989), Ehrenberg (1990; 1991), Ehrenberg and Boassen (1993) and Ehrenberg *et al.* (1993). The geology and diagenesis of one of the occurrences included here, the Smørifik Field, are specifically described in Ehrenberg *et al.* (1992).

## Previous work

Asphaltene-rich residues associated with petroleum reservoirs may be either production-induced or

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**Figure 1** Structural depth map of the top of the Garn Formation in blocks 6506/12, 6406/3 and 6407/1 showing locations of wells studied. The extent of hydrocarbon zones in the Garn Formation is shown by the stippled pattern

naturally occurring. Leontaritis and Mansoori (1988) give an overview of the former type, where production operations may result in residues being deposited both within the reservoir and in production equipment. The residues described here are of the naturally occurring type, whose range of occurrences and properties are summarized by Lomando (1992).

Natural asphaltic residues in petroleum reservoirs commonly occur concentrated in sharply bounded zones called tar mats (Wilhelms and Larter, 1994b). However, it is not clear whether the residues of this study should be referred to as tar mats because: (1) several of our examples are diffusely distributed, lacking sharp contacts; and (2) most of our examples have rather low bulk contents of residue and thus do not conform to the conventional expectation that a tar mat should have an appreciable content of pore-filling 'tar'. Most of our examples are perhaps best regarded as zones of conspicuous oil staining due to asphaltic bitumen coatings on pore surfaces; zones which might be gradational toward being tar mats with increasing residue content.

Asphaltene-rich zones analogous to those of this study have previously been reported from two other oilfields of the Norwegian continental shelf. A tar mat

at the base of the oil zone in the southern part of the Oseberg Field is approximately 13 m thick in two wells examined (Dahl and Speers, 1985; 1986) or, alternatively, can be regarded as consisting of two tar mats separated by a low permeability 'lean zone' several metres thick (Wilhelms and Larter, 1994a). Residual oil extracted from a core in the tar mat contains around 50 wt.% asphaltenes versus around 5% through the rest of the oil column. Various geochemical parameters indicate that the petroleums in the tar mat and the main oil column are closely related. Dahl and Speers concluded that the tar mat probably formed by deasphaltation of the present oil column, accompanied by gravitational settling. However, Wilhelms and Larter pointed out difficulties with this model, including the presence of permeability barriers both within and just above the tar mat and mass balance calculations showing that too much residue is present to have accumulated from the present oil column. They concluded that no simple explanation is readily apparent and suggested that much of the residue may have accumulated during secondary migration as the structure filled.

At Ula Field, Larter *et al.* (1990) and Wilhelms and Larter (1994a) analysed five tar mats, 0.4–0.9 m thick, which occur at the bases of coarsening-upward sequences. Again, compositional similarity with the main oil column indicates an origin either by deasphalting of the oil in place or, as favoured by vertical permeability and mass balance considerations, by settling of entrained heavy petroleum particles during filling of the field.

Another study which provides important background for this work was reported by Miles (1990), where asphaltene-rich residues occur within the upper several metres of the Etive Formation in numerous UK sector wells. Geochemical similarities with reservoir oil support preferential deposition of the heavier, more polar compounds in the oil during migration along the top contact of this regional conduit of maximum permeability and continuity.

### Analytical techniques

The distribution of saturated and aromatic hydrocarbons as well as polar compounds in extracts and oils was determined by Iatroscan (thin-layer chromatography with flame ionization detection; TLC-FID). The sample preparation and analytical procedures are described in Karlsen and Larter (1991). A TH-10 Iatroscan instrument was used. Because of problems encountered in determining the asphaltene fraction by Iatroscan, the asphaltene content of our samples was determined by precipitation (described later) and the Iatroscan results were then normalized to match (*Table 2*).

Asphaltenes were prepared and analysed as follows. Crushed core samples were extracted in a Soxtech apparatus by an azeotropic mixture of dichloromethane–methanol (93.7 v/v). Asphaltenes were precipitated from oil or extracts by dissolving the oil/extract in a minimum amount of dichloromethane, followed by the addition of a 40-fold excess of *n*-pentane. The mixtures were left in the dark overnight before filtering (0.5 µm Millipore filter). This process

**Table 1** Petroleum compositions determined from drillstem test samples

Field:	Smørbukk S.	Smørbukk S.	Smørbukk S.	Smørbukk	Trestakk	Tyrihans N.
Well:	6506/12-3	6506/12-3	6506/12-3	6506/12-1	6406/3-2	6407/1-3
DST:	3	4	5	7	2	1
Depth (m RKB):	3969-3980	3880-3890	3822-3836	3993-4011	3937-3995	3698-3703
<b>Recombined reservoir fluid (mol.%)</b>						
Nitrogen	0.5	0.5	0.6	0.5	0.4	0.3
CO <sub>2</sub>	3.6	3.4	3.3	3.3	3.2	2.0
C <sub>1</sub>	70.4	62.4	53.9	73.0	43.8	57.1
C <sub>2</sub>	9.0	8.9	8.6	7.7	8.3	4.4
C <sub>3</sub>	4.7	5.3	6.1	4.1	7.3	3.1
C <sub>4</sub>	2.5	3.0	3.5	2.1	4.8	1.9
C <sub>5</sub>	1.3	1.6	2.1	1.2	3.1	1.3
C <sub>6</sub> -C <sub>9</sub>	4.5	6.1	8.2	4.3	12.1	7.1
C <sub>10</sub> -C <sub>19</sub>	3.0	6.4	9.6	3.0	11.6	12.0
C <sub>20+</sub>	0.7	2.6	4.3	0.8	5.5	10.8
GOR	1400	510	270	1460	200	150
Temperature (°C)	143	142	138	144	145	132
Reservoir pressure (bar)	412	402	397	467	415	379
Saturation pressure*	390	391	340	446	262	379
<b>Stock tank oil (wt.%)</b>						
C <sub>4</sub>	0.2	0.3	0.3	0.06	1.2	0.02
C <sub>5</sub>	8.0	5.3	5.1	2.1	2.3	0.8
C <sub>6</sub> -C <sub>9</sub>	30.2	21.5	20.7	31.0	21.5	9.0
C <sub>10</sub> -C <sub>19</sub>	41.7	38.0	36.3	42.3	35.8	29.4
C <sub>20+</sub>	19.9	34.8	37.5	24.5	39.1	60.6
Wax	3.9	5.5	7.8	2.6	6.9	8.6
Asphaltenes†	0.01	0.03 (0.8)	0.15 (1.1)	— (0.5)	0.5 (1.0)	1.51 (2.7)
Sulphur	0.05	0.19	0.26	—	0.25	—
Avg. mol. wt.	140	168	172	156	179	261
C <sub>20+</sub> mol. wt.	371	406	411	391	418	446
Viscosity (40°C)	1.2	2.0	2.3	1.7	2.6	9.2
Density (g/cm <sup>3</sup> ) (15°C)	0.783	0.816	0.826	0.798	0.828	0.875
API gravity	49	42	40	46	39	30

\*Saturation pressure at reservoir temperature

†Asphaltenes values are taken from reports of petroleum compositional analyses. Values in parentheses are subsequent analyses by the method described in the text

was repeated three times in total to remove as much of the co-precipitated material as possible. For several of the reservoir fluid samples analysed the asphaltene contents determined by this technique can be compared with previous analyses by generally similar techniques, but taken from a variety of sources where bulk fluid compositions were reported (*Table 1*).

The purified asphaltenes were analysed by temperature programmed (Rock-Eval type) pyrolysis gas chromatography utilizing a Varian gas chromatograph with a custom-made pyrolysis unit. The pyrolysis was carried out in a helium atmosphere by starting at 330°C for three minutes, followed by an increase in temperature by 25°C/minute to 550°C. The pyrolysate was split approximately 1:40 and trapped in liquid nitrogen before the gas chromatographic analysis was initiated. A Chrompack column (CP Sil-5 CB, 0.25 µm film thickness, length 25 m) was used for gas chromatographic analyses and the oven was programmed from -10 to 295°C at 6°C/minute. The temperature was kept at 295°C for three minutes before cooling. The detector was kept at 300°C. We suggest that our asphaltene pyrolysis gas chromatographic analyses are useful for providing an overall characterization of the distributions of components present, but that significance should not be attached to the relative heights of individual peaks. This is because resources were insufficient to allow the evaluation of reproducibility by running samples in duplicate, and there were apparent problems with the baseline at higher

temperatures in some of the analyses.

## Occurrence of asphaltene-rich residues

### Smørbukk Sør Field

Dark residues visible on the slabbed core surface are found in well 6506/12-3, located at the crest of this domal structure (*Figure 1*). Similar dark coloured residues have been not observed in the other three wells from this field, two of which have core coverage of nearly the entire Garn Formation. These other wells are located in flank positions, structurally lower than the crestral well 6506/12-3 by 100–120 m.

In well 6506/12-3 the Garn Formation is 87 m thick and comprises a lower 47 m of 'proximal facies' sandstone (foreshore, upper shoreface and possibly also fluvial) overlain by 40 m of 'distal facies' (lower shoreface) thinly interlayered sandstone and shale (*Figure 2*, upper panel). In this and all other cores studied, the Garn sandstones are mainly subarkosic to arkosic arenites containing 1–3% mica and very minor rock fragments and chert (Ehrenberg, 1990). Typically the Garn sandstones are medium grained and well to very well sorted, but the 'distal facies' at Smørbukk Sør Field is mostly fine grained (*Figure 2*, upper panel).

In the Smørbukk Sør Field the Garn Formation contains a near-critical light oil in its lower part (DST-4 in *Table 1*) and a slightly heavier, moderately undersaturated oil in its upper part (DST-5), whereas the

**Table 2** Analysis of drillstem test fluids (stock tank oil) and extracted organic matter (EOM)

Field and well	Depth (m RKB)	EOM* (% of rock)	Iatroscan§			Asphaltenes		Pyrolysis GC (% of asphaltenes)				$\delta^{13}\text{C}$ of asphaltenes
			SAT	ARO	RES	Percentage of EOM	ppm rock	C <sub>1</sub>	C <sub>2</sub> –C <sub>5</sub>	C <sub>6</sub> –C <sub>14</sub>	C <sub>15</sub> +	
<b>Smørifik Sør Field</b>												
6506/12-3	†DST-5 (3822–3836)		70	26	3	1.1	—	7	21	37	36	-29.3
6506/12-3	†DST-4 (3880–3890)		74	24	1	0.8	—	—	—	—	—	—
Zone 3												
6506/12-3	3886.25–3886.32	0.52	69	22	5	3.3	172	7	13	41	38	—
6506/12-3	3887.30–3887.40	0.51	68	20	6	5.4	278	6	19	32	43	-28.8
6506/12-3	‡3887.8	0.35	39	12	7	46.2	1639	7	20	37	36	-28.6
Zone 2												
6506/12-3	3894.58–3894.68	0.44	68	21	7	4.6	203	7	25	37	31	—
6506/12-3	‡3896.15–3896.20	0.34	54	15	13	17.7	599	7	16	35	42	-28.9
6506/12-3	‡3896.20–3896.30	0.82	26	16	4	54.5	4464	9	15	42	35	-29.2
6506/12-3	3896.35–3896.45	0.32	66	21	9	4.0	128	7	17	40	37	—
6506/12-3	3896.91–3896.96	0.23 (0.18)	67	19	8	6.3	148	8	11	38	43	—
6506/12-3	3898.40–3898.60	0.46	—	—	—	3.7	169	—	—	—	—	—
Zone 1												
6506/12-3	3905.00–3905.10	0.39	67	23	5	5.5	213	—	—	—	—	—
6506/12-3	‡3905.58–3905.60	0.40	42	17	6	35.2	1420	7	16	34	44	-29.5
<b>Smørifik Field</b>												
6506/12-1	†DST-7 (3993–4011)		84	14	2	0.5	—	—	—	—	—	—
6506/12-1	4003.68–4003.72	0.07	69	8	14	9.5	66	—	—	—	—	—
6506/12-1	‡4010.30	0.13 (0.13)	51	17	13	18.8	241	5	22	34	39	—
6506/12-1	‡4010.60	— (0.13)	56	11	15	19.1	181	—	—	—	—	—
6506/12-6	4254.00	0.10	69	8	15	7.5	76	3	14	35	48	—
6506/12-6	4258.00	0.07	70	9	15	6.2	42	4	10	25	61	—
6506/12-6	‡4263.00	0.07	58	10	21	11.0	76	5	13	24	58	—
6506/12-6	‡4265.00	0.11	59	12	18	11.1	124	6	14	28	52	—
6506/12-6	‡4265.75	0.06	56	8	22	14.1	89	6	16	32	46	—
6506/12-6	‡4266.25	0.15	27	29	29	15.0	226	6	16	29	49	—
6506/12-7	‡4436.00–4436.10	0.08	64	16	13	6.7	51	—	—	—	—	—
<b>Trestakk Field</b>												
6406/3-2	†DST-2 (3937–3995)		64	34	2	1.0	—	6	14	43	38	—
6406/3-2	‡3959.50	0.36 (0.25)	54	17	8	22.3	811	10	20	36	35	—
<b>Tyrihans North Field</b>												
6407/1-3	†DST-1 (3698–3703)		58	36	3	2.7	—	9	7	28	56	—
6407/1-3	3687.00	0.05 (0.03)	50	11	25	14.3	76	4	14	30	52	—
6407/1-3	‡3693.20	1.32 (1.37)	45	31	5	19.7	2594	6	13	38	42	—

\* Values in parentheses from Iatroscan

† DST perforation depths are given in parentheses

‡ Samples with dark or 'oil stained' colour on core surface

§ Iatroscan SATurates, AROmatics, and RESins are normalized to sum to (100 – %asphaltenes)

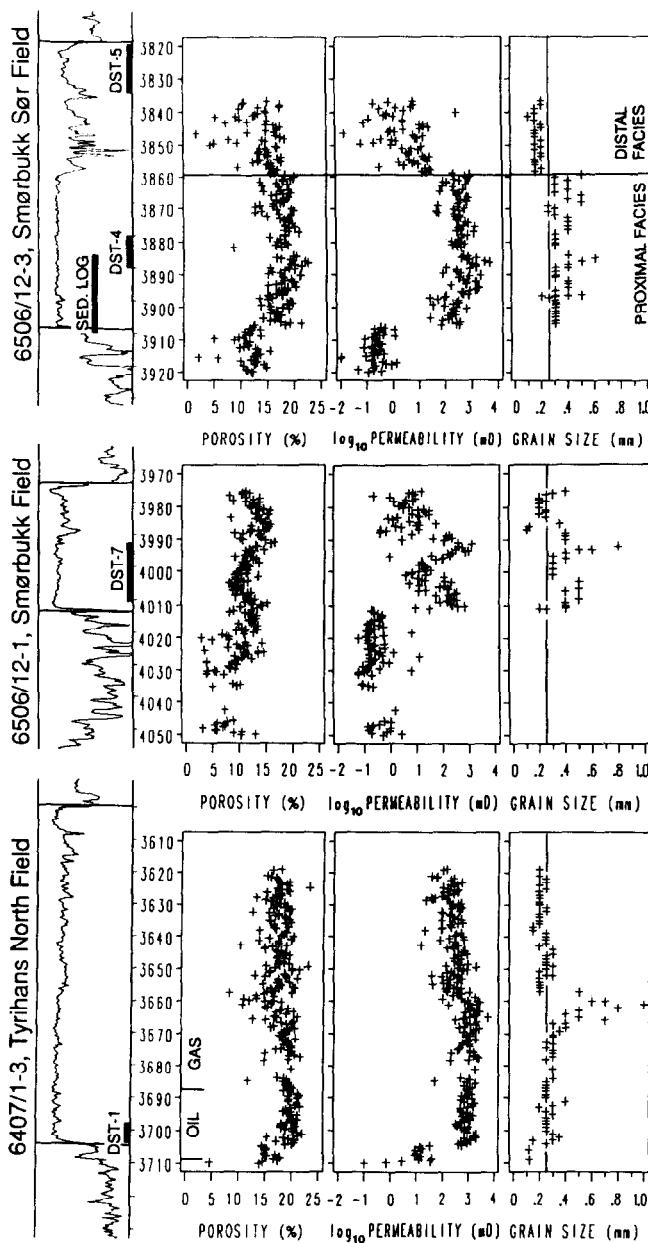
underlying Ile Formation contains gas/condensate (DST-3). The difference between the oils in the Garn Formation is interpreted to reflect leakage from the gas/condensate in the Ile reservoir upwards into the lower part of the oil column in the Garn Formation (based on unpublished Statoil work; T. Meyer, pers. comm.).

In well 6506/12-3, several thin (5–50 cm) zones of dark coloured sandstone are visible on the core surface between 3886 m core depth and the base of the formation at 3906 m (*Figure 3* and *Plate 1A–1C*). The dark zones tend to occur immediately above laminations (0.5–2 mm thick) rich in clay, mica and, in some instances, also organic matter (mainly vitrinite). Styolites have developed along many of these laminations due to the effect of illitic clay and mica on promoting the pressure dissolution of quartz (Heald, 1959). The sandstone is darkest just above these barriers to vertical permeability and becomes gradually lighter for distances of 5–50 cm upward, apparently reflecting a gradual decrease in the abundance of asphaltene-rich residue. However, not all barriers in the core have dark zones above them, and zone darkness does not appear to be related to the thickness or prominence of the basal barriers.

### Smørifik Field

In this area the Garn Formation is only around 40 m thick, reflecting thinning of the entire unit relative to Smørifik Sør Field due to lesser syn-depositional subsidence. The upper 'distal facies' zone here is also less distinctive from the lower 'proximal facies' part of the formation.

Asphaltene-rich residues are present in cores from several Smørifik wells. In well 6506/12-1, near the crest of this tilted fault block (*Figure 1*), a single residue zone is present at the base of the formation (*Figure 2*, middle panel, and *Plate 2A*). Here the formation is filled with gas/condensate near its dew point (*Table 1*). In this core, the lowermost 1 m of the formation is dark coloured and the sandstone gradually becomes lighter in colour upwards over a distance of another 3–4 m. Thus, in common with the 6506/12-3 examples, the residues appear to have accumulated over a barrier to vertical permeability — the contact with the shaly siltstones of the underlying Not Formation (*Plate 2A*). Although there are a number of stylolitic clay–mica laminations within the lower several metres of the Garn Formation in the 6506/12-1 core, none of these is associated with overlying residue accumulations such as those in the 6506/12-3 core. The lowermost 40 cm of



**Figure 2** Profiles through the Garn Formation in three of the wells studied showing gamma ray log, porosity and horizontal permeability (routine core analyses), median grain size (vertical line marks division between fine and medium size; 0.25 mm) and locations of drillstem tests (compositional data given in Table 1). The position of the sedimentological log in Figure 3 is marked on the gamma ray log of well 6506/12-3. Similar profiles for the wells in Trestakk Field are presented in Ehrenberg and Boassen (1993).

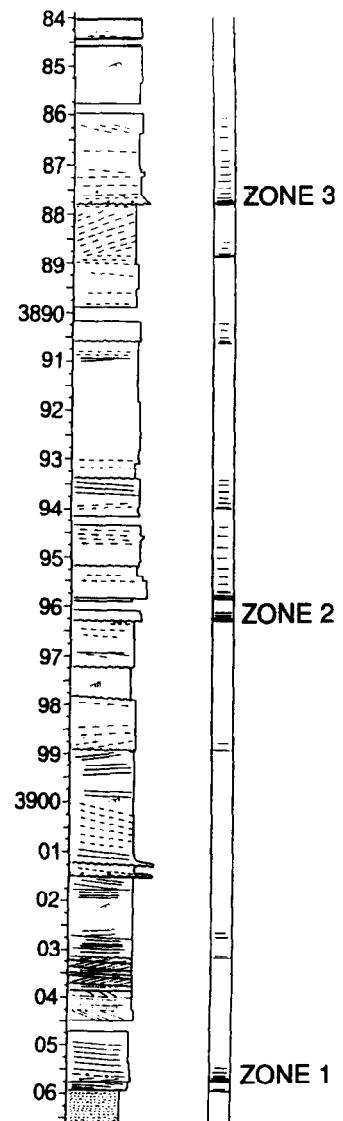
the formation in well 6506/12-1 is laminated (*Plate 2A*) due to variations in mica content and grain size. However, this textural difference is not believed to be related to the residue accumulation because the dark zone extends well above the laminated 40 cm into the overlying more massive sandstone.

Cores have also been recovered from the Garn Formation of the Smørbukk Field in three other wells, all within the water zone (*Figure 1*). The presence of the residues in these locations provides supporting evidence that the Garn reservoir was previously filled to its spillpoint, as is already suspected based on basin modelling and migration studies. In well 6506/12-6, where the upper three-quarters of the formation is

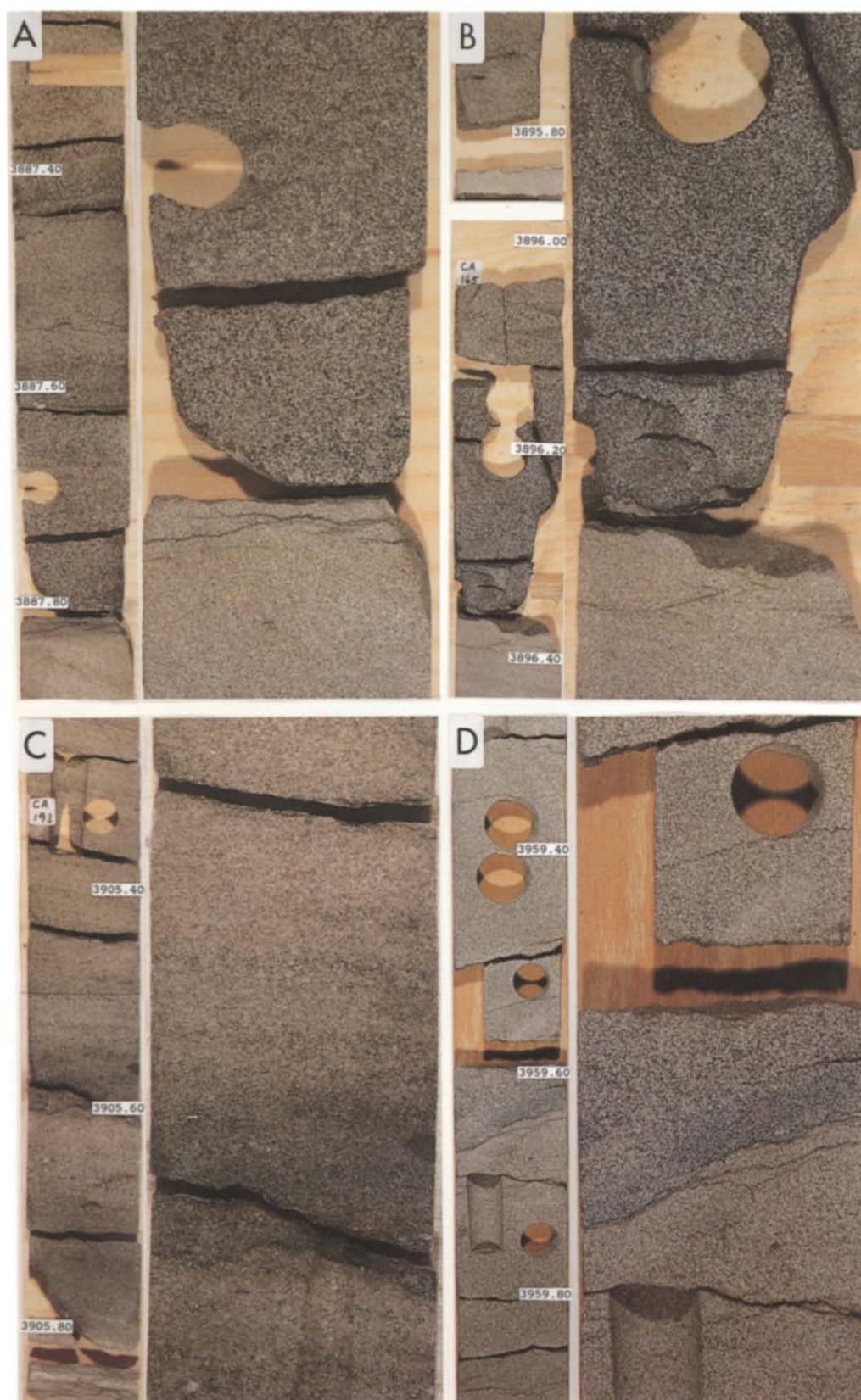
cored, dark coloured residues are present only within the lower 4 m of the cored interval (12–16 m above the base of the formation). Here there is a moderately darker overall coloration to the core surface than in the overlying rock and there are also at least four zones, 3–10 cm thick, of darker colour than the surrounding moderately dark coloured rock. As in well 6506/12-3, the bases of these darker zones tend to be marked by sharp sedimentary discontinuities, whereas the tops are more gradational.

In well 6506/12-7, where the lower approximately one-quarter of the formation is cored, the entire cored interval is moderately coloured by coatings of residue, but no zones of concentrated residue are present (*Plate 2B*).

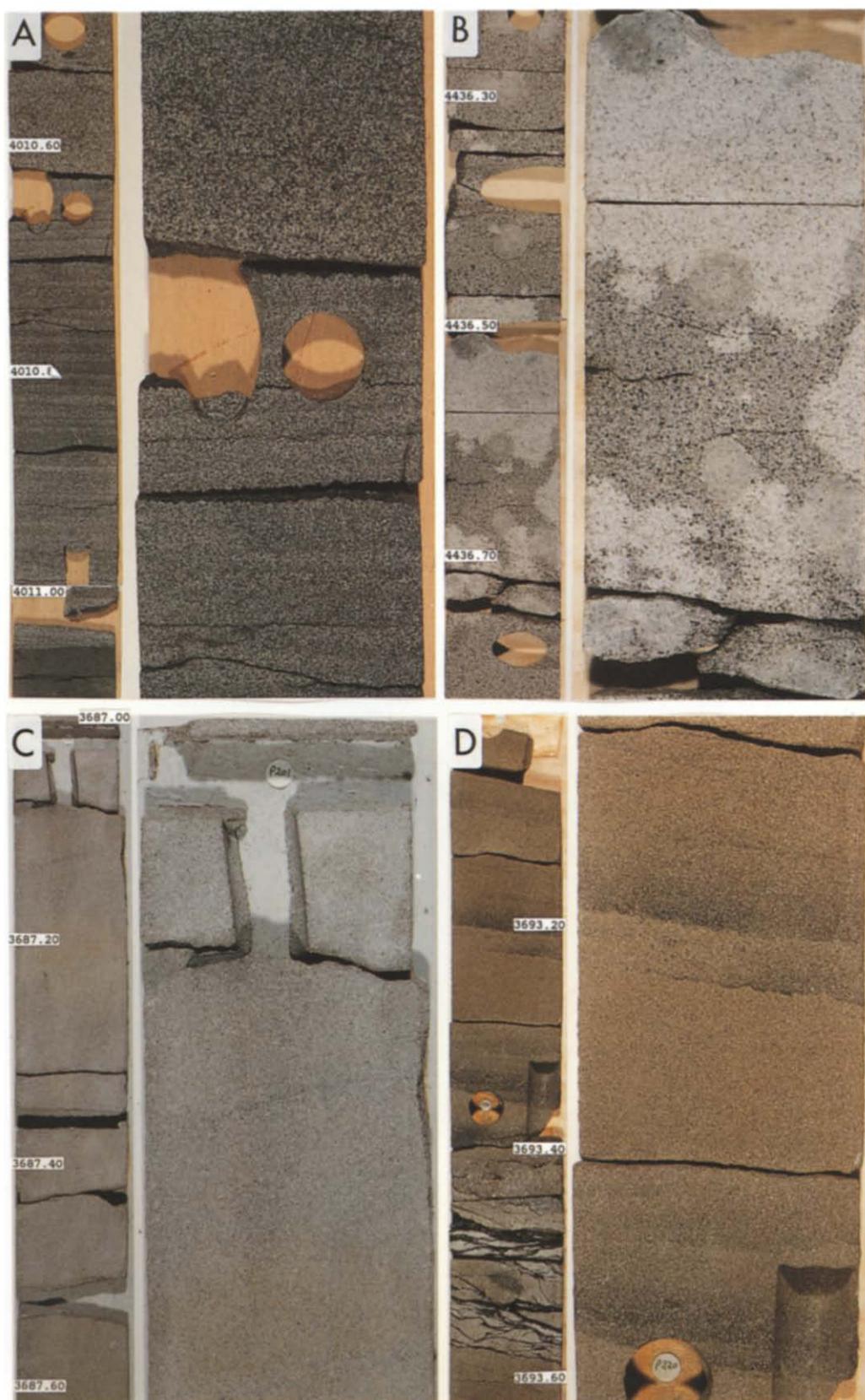
In well 6506/11-2, 30 m of core were taken through the upper central portion of the 85 m thick Garn Formation, where no dark coloured residue is observed. The following core in this well began after a gap of 40 m and recovered only the basal 0.6 m of the



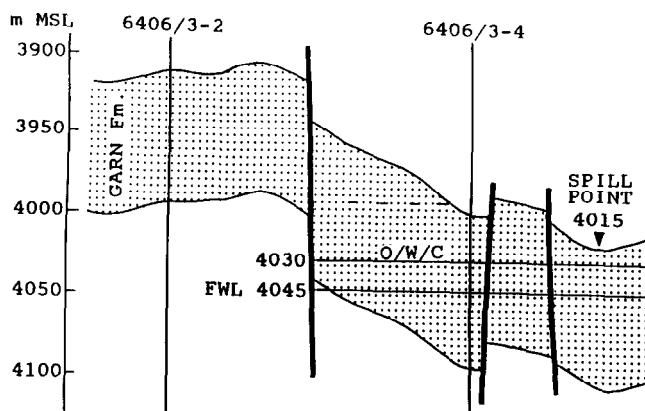
**Figure 3** Sedimentological description log of the lower half of the 'proximal facies' zone of the Garn Formation in well 6506/12-3 (from unpublished work by S. K. Strømmen, Statoil) showing locations of asphaltene-rich zones (dark shading in column at right).



**Plate 1** Core photographs showing zones of asphaltene-rich residue from Smørbukk Sør Field (A, B and C) and Trestakk Field (D). Each panel includes an overview of the core (left; with core depth labelled at 20 cm intervals) and a close-up of the zone of interest. Core width is approximately 10 cm. (A) Zone 3 in well 6506/12-3 (*Table 2*). The base of this dark coloured zone coincides with clay-rich stylolitic laminations. The core is darker just above the laminations and is relatively constant in colour for a distance of 2 m upwards. The lower part of this zone contains 0.35 wt.% total organic carbon. (B) Zone 2 in well 6506/12-3 (*Table 2*). The base of the dark zone (3896.35 m RKB) coincides with a lamination rich in vitrinite and clay. The colour of the core becomes gradually lighter upwards to 3896.05 m, where there is a 15 cm gap in the core. The lower part of this zone contains 1.35–2.75 wt.% total organic carbon. (C) Zone 1 in well 6506/12-3 (*Table 2*). This deposit is located just above the base of the Garn Formation (3905.82 m). (D) Well 6406/3-2. The entire cored interval is oil-stained, but this thin zone shows an accumulation of residue over a shaly lamination



**Plate 2** Core photographs showing variable staining by asphaltene-rich residue in Smørifik Field (A and B) and Tyrihans North Field (C and D). (A) The dark coloured zone at the base of the Garn Formation (4010.05 m) in well 6506/12-1. The lower 40 cm of the formation is laminated and fine-grained. The close-up shows the contact of the laminated zone with the overlying non-laminated, medium-grained sandstone, both stained to similar degree by the residue. (B) The core from well 6506/12-7 in the Garn Formation (water zone) is uniformly stained on clay surfaces, except within carbonate concretions, which must therefore pre-date the residue. The lighter, larger and more irregular concretions are calcite, whereas the small round grey concretions are saddle dolomite. (C) Core from the gas zone in well 6407/1-3 (just above the gas–oil contact) shows no oil staining. (D) Core from the oil zone in well 6407/1-3 is stained brown and has thin zones of residue accumulation



**Figure 4** Structural cross-section through the two wells in Trestakk Field. The free water level (FWL) determined from RFT pressure measurements (4045 m relative to mean sea level) is deeper than either the maximum depth where traces of hydrocarbons are reported from analyses of core extracts in well 4 (4030 m) or the depth of the structural spillpoint (4015 m). Reproduced with permission from Ehrenberg and Boassen (1993).

Garn Formation, where distinct residues are present coating feldspar and clay minerals.

#### Trestakk Field

Nearly 100% of the 87–96 m thick Garn Formation was cored on both the crest and flank of this domal structure (Figure 4), where the oil is strongly undersaturated and slightly heavier than in Smørifik Sør Field (Table 1). The core from the oil-filled crest (well 6406/3-2) is characterized by distinct brownish ‘oil staining’ throughout, with minor accumulations of darker colour overlying shaly laminations only within a 1 m thick interval in the upper-central part of the formation (Plate 1D). The core from the flank position (well 6406/3-4) is believed to transect the oil–water contact, based on RFT pressure data and the observation of extractable petroleum in the upper 29 m of the core (Figure 4). However, drillstem testing failed to produce oil from this upper zone, apparently due to low permeability. The core from the flank well shows no traces of visible oil staining either above or below the interpreted oil–water contact.

#### Tyrihans North Field

In the Tyrihans North Field (well 6407/1-3), the upper 87 m of the Garn Formation is filled with dry gas, which is underlain by an oil zone 22 m thick (Figure 2, lower panel). The composition of this oil (Table 1) is marked by strong depletion of the intermediate weight components (relative to the other oils shown), reflecting their dissolution into the large gas cap volume. Geological details are given in Heum *et al.* (1986) and Larsen *et al.* (1987). Brownish oil staining is pronounced in the core throughout the oil zone and terminates abruptly both upwards at the contact with the gas zone and downwards at the contact with the water zone (Plate 2C and 2D). Minor accumulations of dark residue overlying shaly laminations occur within the oil zone (Plate 2D).

#### Organic geochemistry

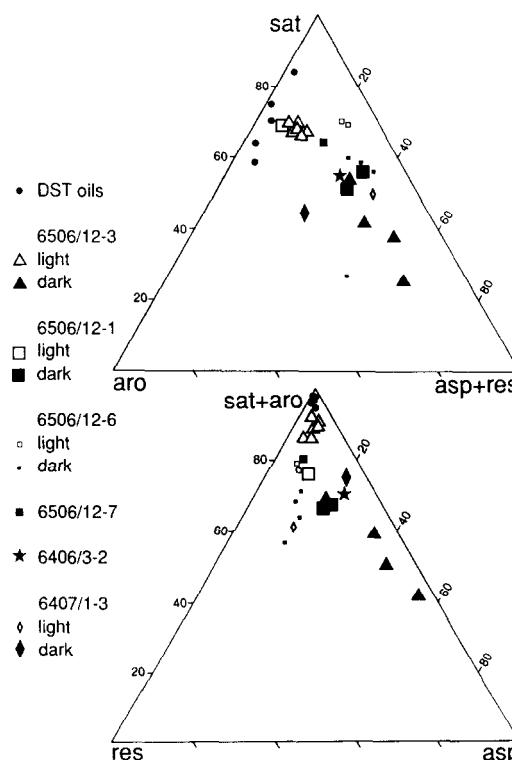
The goals of the geochemical analyses were to

characterize the organic matter present in the dark coloured or stained zones; to discover how this organic matter differs from that in nearby lighter coloured sandstone; and to compare the organic content of the dark zones with drillstem test samples of petroleum from the same reservoirs.

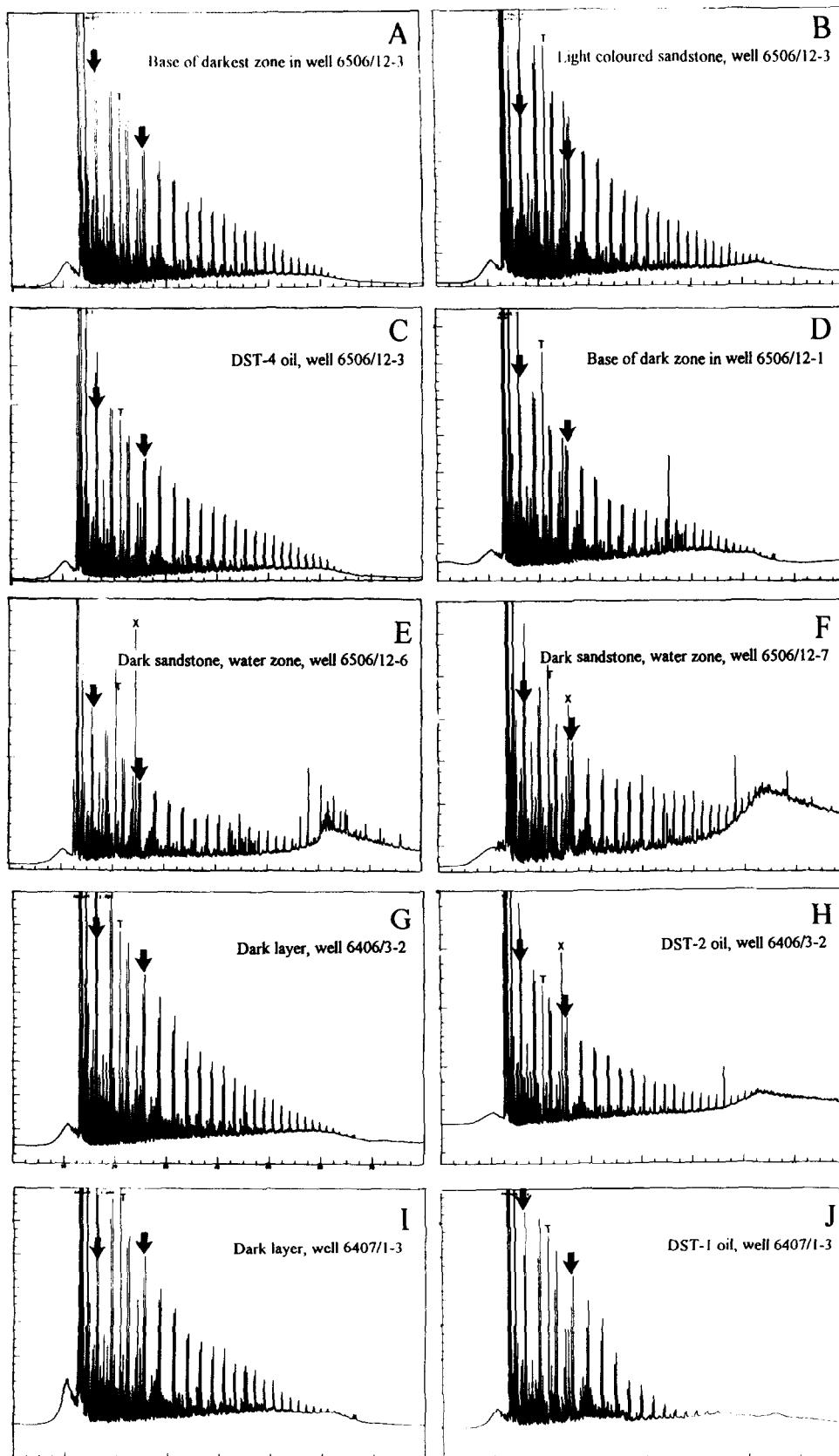
#### Smørifik Sør Field

Samples were analysed from the vicinity of three different dark zones in well 6506/12-3, designated zones 1, 2 and 3, from the bottom upwards (Figure 3; Table 2). Dark coloured samples were compared with nearby, lighter coloured ‘normal’ sandstones in terms of extractable organic matter (EOM), Iatroscan of EOM, percentage asphaltenes in the EOM and pyrolysis–gas chromatography of the asphaltene fraction.

In general, extracts from dark and light sandstones differ mainly in the higher content of asphaltenes in the former (Figure 5), the percentage EOM being either similar or only moderately higher in the darker samples. Pyrolysis–gas chromatography analyses of asphaltenes from oils and from extracts of both light and dark zones all give very similar patterns (Figure 6A–6C). It is tentatively concluded from this that the residues were deposited from the oil in place or a closely similar oil. Several published reports support this conclusion. Behar and Pelet (1985) stated that there is an overall resemblance between the saturated hydrocarbons from an oil and its asphaltene pyrolysate, in correspondence with Pelet *et al.* (1986). Jones *et al.* (1988) showed, by using hydrous pyrolysis, that the



**Figure 5** Iatroscan data plotted by well and sample type. Oils and extracts from dark coloured zones are plotted with filled symbols, whereas extracts from light coloured (not oil-stained) sandstones are plotted as open symbols. In general, there is progressive enrichment in asphaltenes from the oils to the light coloured samples to the darker samples. Different extracts show considerable variations in the ratio of resins to asphaltenes.



**Figure 6** Pyrolysis-gas chromatography plots of asphaltene fractions from oils and core extracts. Horizontal scale is time from 0 to 80 minutes on all plots. Doublets for  $C_6$  and  $C_9$  are marked by arrows. 'T' indicates toluene peak. 'X' indicates peak for *o*-xylene plus an unknown component. (A) From the base of the darkest zone in well 6506/12-3, Smørifikk Sør Field (core depth 3896.20–3896.30 m). (B) From a light coloured sandstone in well 6506/12-3, Smørifikk Sør Field (core depth 3894.58–3894.68 m). (C) From the oil sampled by DST-4 in the lower part of the Garn Formation in well 6506/12-3, Smørifikk Sør Field. (D) From the dark zone at the base of the Garn Formation in well 6506/12-1, Smørifikk Field (core depth 4010.30–4010.60 m). (E) From one of the dark zones at the base of cored interval in well 6506/12-6 in the water zone of Smørifikk Field (core depth 4265.75 m). The hump in the baseline between 60 and 70 minutes is believed to result from a gas chromatography column problem unrelated to the sample material. (F) From the dark-stained core in the Garn Formation of well 6506/12-7 in the water zone of Smørifikk Field (core depth 4436.00–4436.10 m). The hump in the baseline between 60 and 70 minutes is believed to result from a gas chromatography column problem unrelated to the sample material. (G) From a thin dark accumulation in the oil-stained core from well 6406/3-2, Trestakk Field (core depth 3959.50 m). (H) From the oil sampled by DST-2 in the Garn Formation in well 6406/3-2, Trestakk Field. The hump in the baseline between 60 and 70 minutes is believed to result from a gas chromatography column problem unrelated to the sample material. (I) From a thin, dark accumulation in the oil-stained core from well 6407/1-3, Tyrihans North Field (core depth 3693.20 m). (J) From the oil sampled by DST-1 in the Garn Formation in well 6407/1-3, Tyrihans North Field. The poor resolution above about 40 minutes is believed to reflect a temperature programming problem unrelated to the sample material

distribution of hydrocarbons in the pyrolysates of asphaltenes had many similar features to those in the free hydrocarbon fractions of oils from a variety of fields. Finally, Nali *et al.* (1993) reported that the pyrolysis products of asphaltenes qualitatively reflect structural differences shown in the original asphaltenes by non-destructive nuclear magnetic resonance

analyses. Carbon isotopic analyses of the asphaltenes from the Smørifikk Sør extracts and oil are very similar (*Table 2*), also supporting a genetic link.

#### Smørifikk Field

Two samples from the basal dark zone in well 6506/12-1 were compared with one sample extracted from a light

coloured sample located well above the dark zone (*Table 2*). Although the EOM of the dark samples is low compared with the dark samples from well 6506/12-3, the Iatroscan compositions (*Figure 5*) and pyrolysis-gas chromatography patterns (*Figure 6D*) of the 6506/12-1 extracts are very similar to those of the extracts from well 6506/12-3.

Six samples were analysed from well 6506/12-6; two from thin (6–10 cm) dark zones near the base of the cored interval (12 m above the base of the formation); two from moderately dark coloured sandstone overlying and surrounding the darker zones; and two from light coloured sandstone several metres above the moderately dark coloured rock comprising the lowest 4 m of the cored interval. The darker and lighter samples show no consistent differences in total percentage EOM. However, the degree of colouration appears to vary in proportion to the asphaltene content of the EOM: 6–8% in the light samples; 11% in the moderately dark samples; and 14–15% in the darker layers (*Table 2*). The darker samples from well 6506/12-6 differ from the other dark samples analysed in having a higher proportion of resins to asphaltenes (*Figure 5*).

The one sample analysed from well 6506/12-7 has EOM and percentage asphaltenes similar to the light coloured samples from wells 6506/12-1 and 6506/12-6. This rock is in fact rather light in colour, except for its distinct ‘salt and pepper’ appearance due to the preferential coating of clay and feldspar with residue (*Plate 2B*).

The pyrolysis-gas chromatography patterns of the asphaltenes from both 6506/12-6 and 6506/12-7 (*Figure 6E* and *6F*) appear far more depleted and irregular with respect to compounds of intermediate molecular weight than the asphaltenes from wells 6506/12-1 and 6506/12-3. Similar qualitative differences in asphaltene pyrolysis-gas chromatography patterns between oil zone and water zone extracts have been reported from Oseberg Field by both Dahl and Speers (1986) and Wilhelms and Larter (1994a).

### Trestakk Field

Only one sample was analysed from the 6406/3-2 core, a dark coloured layer from the central part of the formation (*Plate 1D*). This sample may be compared with two samples from near the base of the formation which had been analysed in a previous study (core depths 4010.0 and 4012.2 m). These two samples have the same moderate oil-stained colour of the sandstones throughout the 6406/3-2 core, but do not contain concentrated dark layers like the sample from 3959.50 m. All three samples have similar percentage EOM, but the darker sample 3959.50 has a higher content of asphaltenes in its EOM (*Table 3*). These samples may be further compared with a set of previous analyses from the upper 30 m of the Garn Formation in well 6406/3-4, located on the flank of the field (*Figure 4*), where the upper part of the formation is within the oil zone, but is relatively impermeable and is not visibly oil stained. Here the sandstones have EOM values not greatly different from the oil-stained 6406/3-2 core, but their content of asphaltenes is much lower (*Table 3*). Thus in the Trestakk samples the

**Table 3** Analyses of extractable organic matter (EOM) from Trestakk Field cores

Well	Depth (m RKB)	EOM (% of rock)	Asphaltenes	
			% of EOM	ppm of rock
6406/3-2	3959.50	0.36	22.3	811
6406/3-2	4010.00	0.31	10.6	324
6404/3-2	4012.20	0.35	10.3	359
6406/3-4	4021.18	0.40	1.5	61
6406/3-4	4023.18	0.29	1.9	53
6406/3-4	4026.07	0.42	2.0	84
6406/3-4	4029.08	0.32	5.3	166
6406/3-4	4032.19	0.31	2.4	73
6406/3-4	4038.20	0.26	2.1	55
6406/3-4	4040.94	0.25	2.6	65
6406/3-4	4044.05	0.27	3.8	104
6406/3-4	4047.06	0.23	2.7	63
6406/3-4	4048.31	0.21	2.6	54
6406/3-4	4051.94	0.20	2.4	49

degree of visible oil staining appears to vary with the asphaltene content, but not the total EOM.

The one Trestakk extract analysed by Iatroscan has compositional proportions similar to the 6506/12-3 and 6506/12-1 extracts. Pyrolysis-gas chromatography patterns of the asphaltenes from this extract and from the DST oil are similar (*Figure 6G* and *6H*).

### Tyrihans North Field

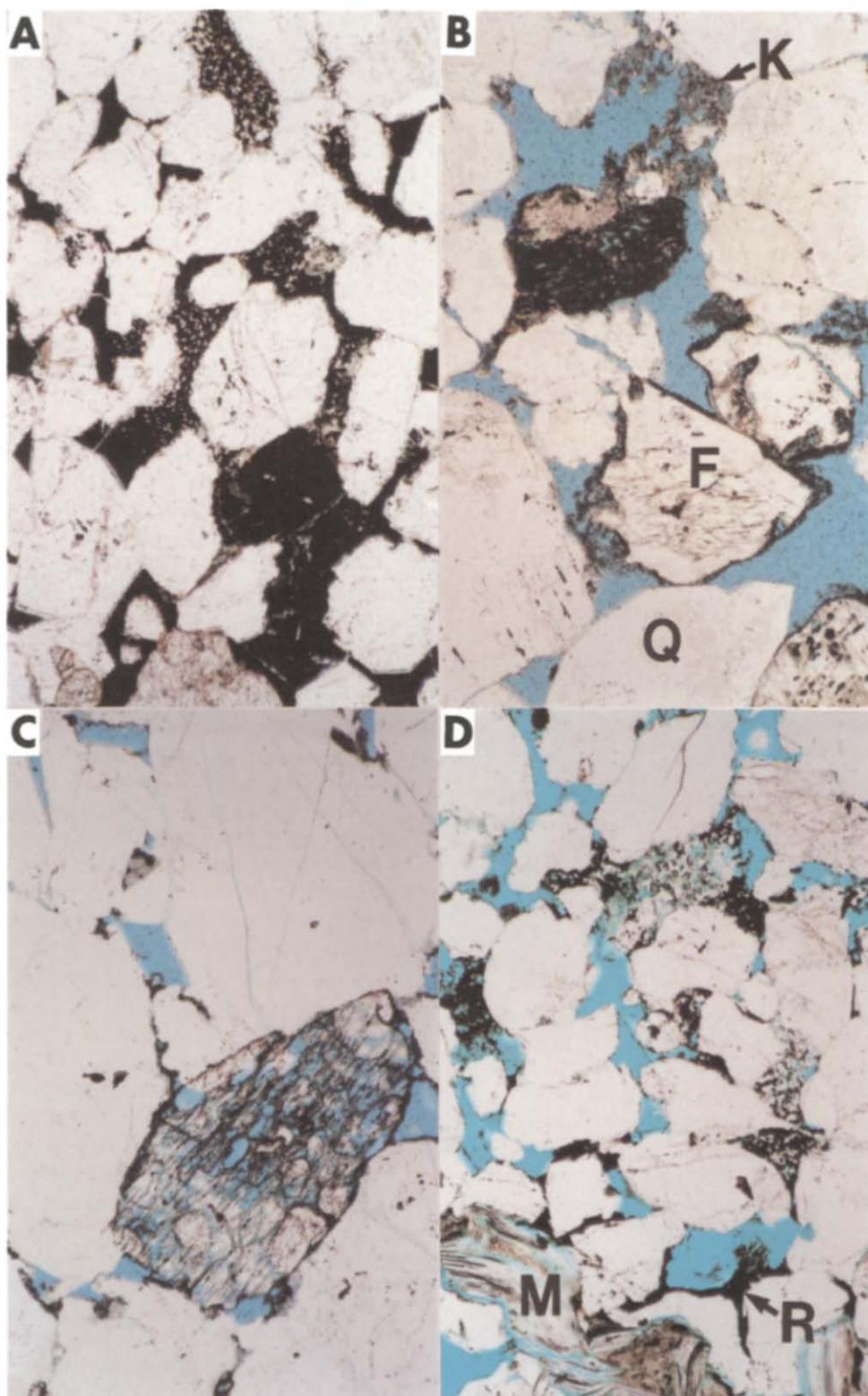
Two samples were analysed. The strongly oil-stained sample from the oil zone has much higher EOM than the light coloured sample from the gas zone (*Table 2*). Both samples have a similar content of asphaltenes in their EOM, but the light coloured sample has a higher proportion of resins to asphaltenes (*Figure 5*). Pyrolysis-gas chromatography patterns of the asphaltenes from both light and dark samples and from the DST oil are similar (*Figure 6I* and *6J*).

### Petrographic observations

#### Distribution of visible residues

There is often considerable uncertainty about the degree to which the distribution and surficial interaction of oily residues in reservoir samples has been influenced by recovery and subsequent drying effects. In several of the present examples, however, petrographic evidence (described in the following) for inorganic diagenetic effects post-dating residue deposition seems to largely rule out this uncertainty.

Under the hand lens the dark colour of the asphaltene-coated zones in well 6506/12-3 is seen to result from the presence of numerous black grains (*Plate 1A–1C*), so that the dark zones superficially resemble placer-like concentrations of opaque heavy mineral grains, such as ilmenite or magnetite. In thin section the black ‘grains’ are seen to consist of both feldspar grains and clusters of authigenic kaolin crystals that are coated with opaque black material. In some samples the adjacent quartz grains are not coated at all. In the darkest coloured samples the residue either fills all pore spaces or coats quartz grains in addition to feldspars and clays. Kaolinite group clay is referred to in this paper by the general term ‘kaolin’, but analytical



**Plate 3** Photomicrographs of thin sections from asphaltene-rich samples. Scale bar in (C) is 0.1 mm. All views are the same magnification. Porosity is impregnated with blue-dyed epoxy. (A) From the base of the darkest zone in well 6506/12-3, Smørifik Sør Field (core depth 3896.35 m). All intergranular porosity is filled by solid organic residue. This appears to be brittle and has cracked in places during thin section preparation. Granular patterns are kaolin clusters. (B) 25 cm above the base of the darkest zone in well 6506/12-3, Smørifik Sør Field (core depth 3896.10 m). Asphaltene-rich residue coats surfaces of feldspar (F) and kaolin clusters (K), but not quartz grains (Q). (C) From the dark-stained core in well 6506/12-7, in the water zone of Smørifik Field (core depth 4436.10 m). Residue coats surfaces of a partly dissolved feldspar and clusters of illite, but not quartz surfaces. (D) From a thin dark accumulation in the oil-stained core from well 6407/1-3, Tyrihans North Field (core depth 3693.20 m). As illustrated in the core photographs in *Plate 2D*, the core is darkest immediately above a stylolitized micaceous lamination (M). In the thin section, no residue is seen below this lamination, but above there is abundant opaque residue (residual oil) trapped in kaolin clusters (K) and various corners and irregularities of the pore system. Immediately above the lamination there is a thin zone (one grain diameter) where residue appears to have pooled, filling the corners and sides of pores (R).

results described in Ehrenberg *et al.* (1993) indicate that the polytype present in all of the cores examined is dominantly dickite.

A sequence of samples was examined upwards through the most strongly developed of the dark horizons (zone 2 in *Table 2*; *Plate 1B*). It should be noted that thin section samples may not correspond exactly with the depths of geochemical analyses in *Table 2* because the former are point locations, whereas the latter include all material over a range of depth. The base of this dark zone is defined by a lamination of organic matter 2 mm thick (consisting of a complex assemblage of algae and plant material). Pore spaces in the sandstone immediately above the organic lamination are entirely filled with black residue (*Plate 3A*). Measurements of the percentage reflection in oil of the pore-filling residue give a tight cluster around 0.61%  $R_o$  (standard deviation 0.11 for 14 measurements), which is similar to the value of 0.54%  $R_o$  for the overall vitrinite reflectance trend at this depth in well 6506/12-3 (Table 1 in Ehrenberg, 1990). Ten centimetres higher in the dark coloured zone the pores are only partly filled with residue, which coats the surfaces of quartz grains as well as feldspar and kaolin. Another 15 cm higher in zone 2, the dark residue occurs only as coatings on feldspar and kaolin surfaces, and is entirely absent from quartz surfaces (*Plate 3B*). Bulk chemical analyses of the sandstones from this zone show a decrease in total organic carbon (TOC) from 2.75 wt.% at the very base of the zone (*Plate 3A*) to 1.35% 12 cm higher.

A series of samples was also examined through the dark coloured zone at the base of the Garn Formation in well 6506/12-1 (*Plate 2A*). In the lowermost samples (4011.00, 4010.75 and 4010.60), the dark residue occurs only as coatings on feldspar and kaolin surfaces and is absent from quartz surfaces (texture very like *Plate 3B*). The darkness and continuity of the coatings decrease progressively upwards through the next 3 m (samples 4010.00, 4009.00 and 4008.00). Two metres higher in the core (sample 4006.00 and all overlying samples), no traces of dark residue are visible in thin section. Here also bulk chemical analyses show a trend of upward-decreasing TOC paralleling the colour change (from 0.30–0.46 wt.% TOC in the lower 0.5 m to 0.10% at 4009.00 m). Thin sections from the asphaltene-coated samples in wells 6506/12-6 and 6506/12-7 show textures similar to the lowermost samples in well 6506/12-1 (*Plate 3C*).

In thin sections of the oil-stained samples from well 6406/3-2, uniform light brown coloration is present on all feldspar and clay surfaces, but not on quartz surfaces. Colour photomicrographs comparing typical thin sections from wells 6406/3-2 and 6406/3-4 have been published by Ehrenberg and Boassen (1993) and are therefore not reproduced here.

In well 6407/1-3, thin sections from the oil zone display a slight brownish coloration of feldspar and clay surfaces (similar to the texture in well 6406/3-2). However, in the dark layer at 3693.20 m (*Plate 2D*), opaque material (apparently residual oil) is preferentially trapped in kaolin clusters and other micropores and has accumulated as a discontinuous layer overlying the micaceous lamination that forms the lower boundary of the dark layer (*Plate 3D*).

#### *Mineralogy and texture of dark versus light zones*

In well 6506/12-3, observations of thin sections reveal no consistent differences in texture (*Figure 2*, upper panel) or primary mineral composition between the samples from the dark coloured zones and the surrounding light coloured sandstones. To investigate this question more quantitatively, samples of dark and light coloured sandstone were analysed petrologically from within and immediately below each of the two most strongly developed dark zones in the 6506/12-3 core (zones 2 and 3; *Plate 1A* and *1B*; *Table 2*). The light samples were chosen below rather than above the dark zones to give sample pairs with close proximity, but contrasting coloration. The results are given in *Table 4*. In both of the two sample pairs, the samples representing the dark zones have somewhat coarser grain size than the underlying light coloured sandstones. The modal analyses of thin sections show moderately lower amounts of quartz cement and dissolved grain moulds (partly dissolved feldspar) and higher kaolin clay in the dark sandstones than the light sandstones.

The X-ray diffraction (XRD) data show that the dark sandstones in both instances have lower ratios of illite/(illite + kaolin). Because it was suspected that the organic residue in the dark samples might affect the clay separation by trapping the finest clay fraction, the XRD analyses were performed on duplicate splits of each sample. One split was washed with dichloromethane to extract organic residue, and the other split was analysed with the organic residue intact. The comparison in *Table 4* shows that the residue had in fact no significant effect on the analyses, although the yield of total clay from all samples was modestly improved by extraction, as indicated by the higher values of 'total intensity' (sum of areas under selected clay peaks) for the extracted splits.

Analyses of TOC confirm the higher organic content of the dark samples. In the light sandstones, a little over half the organic content is removed by extraction. For the dark sandstones, extraction brings the organic content down to the same low level as in the light samples, showing that the dark residue is entirely soluble in dichloromethane and that almost all of the residue is accessible to the pore system.

The mineralogical and textural differences noted above between the dark and light samples are regarded as being small enough to be of questionable significance. Previous analyses of light coloured sandstones in the lower part of the Garn Formation in well 6506/12-3 (Ehrenberg, 1990) show variations of similar or greater magnitude from metre to metre along the core (7–19% quartz cement; 1–6% dissolved grains; 2–8% kaolin; 100×illite/(illite+kaolin) = 0–59). Therefore it is concluded that the dark zones in well 6506/12-3 are no different in mineralogy and texture from the surrounding lighter coloured sandstones.

In well 6506/12-1, the lower 40 cm of the Garn Formation (corresponding to the base of the asphaltene-rich zone) is laminated and is generally fine grained and more mica-rich than the overlying sandstone. The lower several metres of the formation are also less illitized and therefore richer in kaolin than the rest of the formation, as described in Ehrenberg (1991).

**Table 4** Petrological analyses of two sets of adjacent dark and light coloured sandstones from well 6506/12-3

Core depth (m):	3887.80 Dark	3887.90 Light	3896.25 Dark	3896.65 Light
<b>Modal analyses of thin sections (vol. % based on 300 counts)</b>				
Quartz grains	59.0	57.7	63.0	54.0
K-feldspar	6.0	5.3	5.0	5.3
Plagioclase	0.3	1.0	0.3	0.3
Grain moulds	2.3	3.3	1.7	5.0
Mica	0.0	0.7	1.0	0.7
Rock fragments	0.0	0.3	0.3	0.0
Kaolin	7.7	3.3	5.7	4.0
Other clay	2.0	2.0	2.3	3.0
Quartz cement	12.7	17.7	13.3	19.3
Pyrite cement	0.7	0.0	0.3	0.0
Macroporosity	9.3	8.7	5.3	8.0
Grain size (mm)	0.4	0.3	0.4	0.3
Trask sorting coefficient	1.3	1.3	1.5	1.3
<b>XRD analyses of &lt;2 µm fraction (values in parentheses are for splits with petroleum residue not extracted)</b>				
Kaolin	43 (40)	47 (46)	42 (36)	32 (44)
Illite	20 (20)	41 (37)	26 (31)	37 (35)
Chlorite	0 (0)	0 (0)	0 (0)	0 (0)
Smectite	37 (40)	12 (17)	32 (33)	31 (21)
100 x illite/(illite+kaolinite)	32 (33)	47 (45)	38 (46)	54 (44)
Total intensity	696 (560)	1088 (608)	1296 (560)	1400 (1272)
<b>Total organic carbon (wt. %) by LECO method</b>				
Not extracted	0.36	0.19	1.25	0.21
Extracted	0.11	0.09	0.08	0.08

However, these differences do not appear to be related to or to have significantly influenced accumulation of asphaltenes at the base of the formation.

#### Timing of residue deposition with respect to inorganic diagenesis

In the wells from Smørbukk Sør, Trestakk and Tyrihans North Fields, textural evidence in thin sections suggests that asphaltene deposition post-dates quartz cement growth and all clay authigenesis. A subordinate amount of feldspar dissolution in well 6506/12-3 appears to have taken place after asphaltene deposition, but no obvious evidence was found for the products of this dissolution being deposited as post-asphaltene clays. In contrast with the above fields, the thin sections from Smørbukk Field display conclusive textural evidence (described in the following) for quartz cementation, grain dissolution and clay authigenesis after asphaltene deposition. This is not surprising for wells 6506/12-6 and 6506/12-7, where the samples are from the water zone. However, in well 6506/12-1, within the gas condensate zone, the textural evidence may indicate that diagenesis took place within the residual water saturation by short-range diffusive transport, as has been suggested by Bjørlykke *et al.* (1992), Ehrenberg (1990) and Ehrenberg and Boassen (1993). Alternatively, it is conceivable that the 6506/12-1 section was first filled with hydrocarbons (depositing the observed residue), then leaked and underwent diagenesis and then re-filled with its present gas condensate column.

The textural evidence for asphaltene timing is particularly striking with regard to the dissolution of feldspar grains. Many grain moulds have coatings of dark residue around their outer boundaries, but contain no residue within their partially dissolved interiors, indicating that dissolution post-dates asphaltene depo-

sition. Other dissolved feldspars nearby are coated throughout by dark residue, indicating an earlier time of dissolution (Plate 3C). The reader is also referred to Ehrenberg (1991) for a series of colour photomicrographs illustrating the timing of asphaltene deposition with respect to both grain dissolution and kaolin precipitation at the base of the Garn Formation in well 6506/12-1. An alternative interpretation of these textural relationships is that the entry of residue was locally restricted by smaller pore throats. However, this does not seem consistent with the observation that many uncoated dissolved grain interiors have open, porous textures in thin section, whereas at least some of the thoroughly coated interiors appear relatively tight. In general, the residues seem to have experienced no difficulties in impregnating even the smallest corners of microporosity present at the time of asphaltene precipitation.

The authigenic clays showing a timing relationship to the residue are mainly kaolin (dickite) in well 6506/12-1 and illite in well 6506/12-7. In well 6506/12-1, some kaolin clusters are free of dark coatings, whereas adjacent kaolin clusters are coated throughout (Plate 1 in Ehrenberg, 1991). As discussed in Ehrenberg (1991), some of the kaolin near the lower contact of the Garn Formation in well 6506/12-1 is believed to have formed late in the burial history, which is consistent with the interpretation that the uncoated kaolin clusters formed after asphaltene deposition. In the 6506/12-7 samples, little kaolin is present, but both illite growth and feldspar dissolution appear to have occurred partly before and partly after asphaltene deposition. In well 6506/12-6, however, all illite and grain dissolution appear to post-date the residue.

In all three Smørbukk wells, considerable quartz cement growth appears to post-date asphaltene deposition because many quartz overgrowths either have

**Table 5** Stable isotopic and chemical analyses of carbonate cements in well 6506/12-7

Core depth (m):	4436.43	4434.42	4436.50	4434.38
Mineral:	Dolomite	Dolomite	Calcite	Calcite
$\delta^{13}\text{C}$ (‰ PDB)	-10.3	-11.9	-5.6	-6.5
$\delta^{18}\text{O}$ (‰ PDB)	-12.9	-9.7	-14.7	-11.9
CaO (wt. %)	33.0	32.3	53.0	50.2
MgO (wt. %)	16.7	16.7	0.5	0.7
FeO (wt. %)	1.2	1.8	0.4	0.1
Mn (ppm)	2100	2900	2027	2967
Sr (ppm)	280	300	526	687
Na (ppm)	350	270	401	435
K (ppm)	900	1000	—	—

Analyses performed by Harald Johansen, Institutt for energiteknikk, Kjeller, Norway

inclusions of residue or have engulfed residue-coated clays or moulds of dissolved grains. It should also be noted that the quartz cement in well 6506/12-1 also contains abundant fluorescent (hydrocarbon-bearing) fluid inclusions with homogenization temperatures 10–35°C below the present reservoir temperature (Figure 21 in Ehrenberg, 1990).

In well 6506/12-7 of the Smørbukk Field, the timing of residue deposition can also be constrained as after the growth of both calcite and dolomite concretions (based on the presence of the residue surrounding, but not within, the concretions; *Plate 1B*). Stable isotopic analyses of the carbonate cements (*Table 5*) indicate crystallization at high temperatures (late in the burial history; 100–140°C, assuming water with  $\delta^{18}\text{O}$  of -4 to 0‰ SMOW, respectively) and with substantial involvement of carbon from organic matter.

### Origin of the residues

The close similarities between the pyrolysis-gas chromatography patterns of asphaltenes from oils and residue extracts from individual fields (*Figure 6*) provide possible evidence that the residues were precipitated either from the present petroleum in these structures or from closely related fluids. This is further supported by the similarity in carbon isotope compositions for the oil and residues from well 6506/12-3 (*Table 2*).

Similar interpretations about cored residues being genetically related to reservoir oil have also been reached in two previous studies based mainly on biomarker analyses. Wilhelms and Larter (1994a) report that biomarker parameters from tar mat extracts correspond to the same parameters in reservoir oil/oil leg extracts. However, their conclusion may be misleading because the biomarkers were measured on the saturated hydrocarbon fraction of the core extracts, which is not necessarily 100% related to the associated asphaltene fraction. Thus it could be argued that core extracts from oilfield tar mats in general will consist of two component fractions: (1) a heavy fraction responsible for the dark colour of the tar mat zone; and (2) a lighter fraction of residual oil analogous to the residual oil present throughout cores from the oil zone. Fraction (1) may have precipitated from the standing oil column; from similar oil during filling of the present column; or from an earlier unrelated oil that previously

filled or migrated through the cored reservoir. Whatever the origin of fraction (1), it seems reasonable to expect that the saturated hydrocarbons in a tar mat extract will be strongly influenced by fraction (2), thus calling into question the practice of using biomarker analysis to test the relationship of a tar mat to the standing oil column. Nevertheless, both Wilhelms and Larter (1994a) and Dahl and Speers (1986) also present pyrolysis-gas chromatography patterns showing close similarity between asphaltenes from the tar mat extracts and the reservoir oil.

The second study involving biomarkers is that by Miles (1990), who reports analyses of a regionally extensive residue zone present along the top of the Etive Formation. Biological marker distributions of the saturate fraction of asphaltenes precipitated from oil samples and from core extracts (apparently mainly taken from the water zone to avoid live oil contamination) are said to have 'compared closely', although no data on the oils or examples of these comparisons are shown.

### Smørbukk Sør Field

Two alternative models may be considered to explain the occurrence of the asphaltene-rich residues in well 6506/12-3: (1) segregation of entrained particles (tar globules) during filling of the structure (Wilhelms and Larter, 1994b); and (2) segregation from the standing petroleum column, possibly due to upward percolation of gaseous components from a deeper source (Dahl and Speers, 1985). The difference between these alternatives is perhaps subtle, but the choice has implications for understanding the timing of residue formation, its causes and the factors controlling residue distribution. Unfortunately, we are unlikely to be able to prove one or the other with our available data or understanding. Several other models previously proposed for tar mat formation seem inapplicable to the present examples, including pressure release during uplift (present depth = maximum depth in all instances) and biodegradation (no geochemical evidence in these examples).

According to model (1), the residue content of each individual mini-zone within the lower part of the Garn Formation in well 6506/12-3 would reflect the varying volumes and velocities of oil which migrated through it as the reservoir filled, depending on its permeability and its connectivity with respect to the distribution path of the oil. Because well 6506/12-3 is located approximately at the crest of the structure, however, it is not feasible to envisage the migrating oil as having used any part of the cored section as a conduit to anywhere except the overlying portion of the Garn Formation. This is not a serious constraint, however, because the amounts of residue involved appear to be relatively minor.

Model (2) is consistent with the difference in oil composition between DST-4 in the lower part of the Garn Formation and DST-5 in the upper part (*Figure 2*, upper panel; *Table 1*). The petroleums from both tests have similar source and maturity characteristics, but DST-4 has higher contents of gaseous components. This difference is consistent with the leakage of gaseous components upwards from the Ile Formation, where DST-3 in the same well found an appropriately gas-rich reservoir fluid (*Table 1*). Model (2) is also supported by

the presence of asphaltene-rich precipitates in well 6506/12-3, but not in 6506/12-5, because the upward leakage of gas favourable for asphaltene precipitation would be concentrated near the structural crest and not along the flanks. Finally, model (2) explains the localization of the residues near the base of the formation because this is where the upward percolating gas would first contact the petroleum column. It should be noted that none of the above points is necessarily inconsistent with model (1), although it is not immediately clear how model (1) would explain the observed localization of residues only within the lower part of the formation and on the structural crest.

A possible problem with model (2) is that precipitation from the standing oil column can be regarded as requiring the deposition of asphaltene-rich zones above all permeability barriers in the lower part of the cored interval in well 6506/12-3, which is clearly not so. This objection is not necessarily serious, however, because it can be postulated that the residue distribution reflects the complexities of baffling, lateral transport and temporary ponding of the gaseous components as they moved upwards into the standing oil column. Some mini-compartments of the reservoir would have precipitated more of their asphaltene content along their basal permeability barriers than others. This view would therefore imply that the oil within the lower part of the formation near the structural crest is today highly heterogeneous with respect to asphaltene content. However, such heterogeneity could only be detected by performing a series of closely spaced drillstem tests with narrow perforation zones.

Both models (1) and (2) are consistent with the distinctive morphology of the asphaltene-rich zones, where the residue abundance is greatest immediately above a barrier to vertical permeability and decreases gradually upward. This pattern implies that the asphaltenes settled under the influence of gravity to accumulate over barriers to downward flow. Precipitated asphaltenes possibly exist in a colloidal state (Leontaritis and Mansoori, 1988) and would therefore be susceptible to gravitational segregation. However, as noted by Wilhelms and Larter (1994b), such particles would probably be unable to move distances of several metres downward through a tortuous sandstone pore network, especially where multiple barriers are present, such as the stylolitic laminations within the dark zone in well 6506/12-1 (*Plate 2A*). Alternatively, gravity can also cause the downward concentration of asphaltenes in solution within a petroleum column (Hirschberg, 1988; Wilhelms and Larter, 1994b). The observation that the upper boundary of each accumulation is diffuse implies a balance between gravitational force and the attraction between the asphaltene-rich phase and the mineral surfaces.

#### *Smørifik Field*

An interesting question is why the asphaltenes should have accumulated as several thin zones through the lower 20 m of the formation in well 6506/12-3 versus one thick zone at the base of the formation in well 6506/12-1. This difference is probably not related to sedimentological differences because clay-rich stylolites forming apparent horizontal barriers are similarly

abundant in both cores. A possible explanation is that the much lower viscosity of the fluid (gas condensate) filling the 6506/12-1 reservoir facilitated more efficient downward transport of the asphaltene-rich phase around or through thin barriers. In such a case, additional information is needed to explain why the residue accumulated as a thick, diffuse zone, rather than as a thin layer of solid, pore-filling tar at the basal contact. Equally intriguing is the difference in residue distribution between well 6506/12-1 and the other three wells in Smørifik Field.

#### *Trestakk and Tyrihans North Fields*

In the Trestakk example, the presence of oil staining in well 6406/3-2 (at the structural crest) but not in the upper part of the Garn Formation in well 6406/3-4 (on the flank) is reminiscent of the situation at the Smørifik Sør Field, where very differently distributed residues are visible near the structural crest, but absent on the flanks. Obviously we need to study additional pairs of crest and flank position wells from other structures to determine whether structural crests are indeed especially favourable locations for the deposition of asphaltene residues.

In the Tyrihans North example, the coincidence of the oil staining with the present oil zone (*Figure 2*, lower panel and *Plate 2C* and *2D*) indicates that precipitation of the residue occurred after filling of the structure and in the latest stage of its burial history. This is because the gas–oil contact is likely to have been shifted during the additional burial of the Halten Terrace by 1 km of sediments in the last 3 Ma, whereas modelling studies suggest that the structure would have been filled before this time.

#### **Role of mineral surfaces**

The preference of the asphaltene-rich residue for feldspar and kaolin surfaces (*Plate 3*) may result from chemical bonding between the asphaltene molecules and the partially co-ordinated aluminium ions along surfaces of the aluminosilicate minerals. Various aluminium–organic complexes are known to form from reactions involving complex polar organic compounds and some of these have been used in well treatment (Walsh *et al.*, 1983). Another possibility is that the polar molecules composing the asphaltene-rich residues are electrostatically attracted to the negatively charged clay surfaces. In such a case, the preferential coating of feldspar as opposed to quartz surfaces could reflect the presence of a thin layer of clay alteration at the feldspar surfaces.

The asphaltene–aluminosilicate preference graphically illustrates how the degree of oil- or water-wettability of a sandstone is related to both the mineralogical composition of the rock and the chemical composition of the petroleum. Obviously, higher contents of clay and possibly also feldspar may be expected to increase the oil-wettability in the Garn Formation reservoirs. Studies of wettability as a function of mineralogy have documented the tendency for asphaltenes to be strongly attracted to clay mineral surfaces in particular (Clementz, 1976; Collins and Melrose, 1983; Trabelsi, 1987; Dubey and Waxman, 1989). In addition, a

number of previous studies have shown that the oil wettability increases strongly with higher asphaltene or polar compound content in the oil (Cuiec, 1984; Anderson, 1986; Trabelsi, 1987; Crocker and Marchin, 1988).

## Conclusions

1. Zones of asphaltene-coated sandstone 5–200 cm thick occur in the lower part of the Garn Formation in well 6506/12-3 and at the base of the formation in well 6506/12-1. The sandstone in these zones is darkest just above barriers to vertical permeability and becomes gradually lighter upwards, apparently reflecting a balance between gravitational accumulation and attraction to mineral surfaces.
2. Overall, the dark and light samples have similar amounts of EOM, but the dark samples have higher contents of asphaltenes in their EOM. Pyrolysis–gas chromatography analysis suggests that the compositions of the asphaltenes are similar in dark and light samples and in reservoir oil.
3. Preferential attachment of the coatings to feldspar and clay rather than quartz may result from chemical bonding between the asphaltene molecules and the partially co-ordinated aluminium ions along surfaces of the aluminosilicate minerals.
4. In Smørifik Field, textural relations in thin section show that asphaltene deposition pre-dates much quartz cementation, feldspar dissolution and kaolin formation. In the other fields, asphaltene deposition post-dates most, if not all, diagenesis.
5. The observations from Trestakk and Tyrihans fields suggest that adsorption of asphaltenes onto feldspar and clay surfaces is a principal cause for the commonly observed oil staining of sandstone cores, and that accumulation of asphaltene-enriched zones over minor barriers to vertical flow may be a common phenomenon in sandstone reservoirs.

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