ture measurement for a given depth (last °C) and the time since cessation of circulation are noted. If at least two measurements have been carried out after cessation of mud circulation, the true formation temperature is estimated by the above mentioned correction formula (corr. °C). The maximum correction factor was 10°C. The mean gradient between the surface and a given depth is computed (grad. °C/km). Mean values for sea floor temperatures as a function of depth can be found in Evans & Coleman (1974). To avoid the influence of local heating of the upper 1.5 km since the last glaciation, the true formation temperature has been corrected (ice corr. °C), accepting a value of 0°C as the mean surface value during the Quaternary. The corresponding mean gradients are listed (corr. grad. °C/km).

Table on temperatures and mean gradients

Well	Feet b.KB	Metres b.GL	Time since circ. hrs.	Last °C	Corr. °C	Ice corr. °C	Grad. °C/km	Corr. grad. °C/km	Type
Adda-1	3973	1139	4	40	45	41	34	36	logs
	7042	2074	-	74	-	74	32	36	tests
	7474	2206	18	72	76	76	31	34	logs
	10000	2976	18	94	101	101	31	34	logs
E-1	3526	1000	5.5	46	47	42	40	42	logs
	6798	1997	-	66	-	66	29	33	tests
	6900	2028	-	67	-	67	30	33	tests
	8088	2391	26	80	80	80	31	34	logs
	10650	3171	5.5	94	-	94	27	30	logs
	12926	3865	-	122	-	122	30	32	tests
	13406	4012	12.5	126	-	126	30	31	logs
E-4	4038	1162	4.5	62	67	60	51	52	logs
	6599	1942	-	71	-	71	33	37	tests
	7425	2195	7	73	-	73	30	33	logs
	7520	2233	27	72	73	73	30	33	logs
G-1	6822	1993	5.5	63	-	63	28	32	tests
H-1	6789	1986	-	67	-	67	30	34	tests
I-1	9195	2708	-	107	-	107	37	40	tests
	12848	3822	10	129	139	139	35	36	logs

The corrected formation temperatures (corr. °C) listed in the table are plotted on fig. 37 as a function of depth. The temperature around the Tyra field at 1 km depth is between 40 and 55 °C. The mean gradients to this depth (33-48 °C/km) indicate a surface layer of relatively low heat conductivity which corresponds approximately to the uncompacted Quaternary and Upper Tertiary sandy/silty formations. At a depth of 2 km, the temperature ranges from 63 to 72°C. The mean gradient through the consolidated Lower Tertiary and Upper Cretaceous formations is about 20°C/km. Computation of the temperature and the gradient in the Upper Jurassic formations is of interest since these are considered to be possible source rocks. The temperature for the Upper Jurassic varies from 82 to 88°C. The E-1 well indicates a gradient of 40°C/km in Jurassic shales. A temperature estimate of the Upper Jurassic boundary at I-1 yields 123°C and a gradient for the Lower Cretaceous and Jurassic formations of 30°C/km. The relatively high temperature is caused by greater depth of burial and a high mean gradient for the I-1 well.

The few examined temperature measurements indicate that the present temperature field can be explained by a purely conductive model. During previous geological periods, the higher tectonic activities might have contributed to a higher regional heat flow as well as local heating by intrusions or convective systems.

Presently, additional wells in the Central Graben are being investigated to discover the regional trend and to determine relative heat conductivity contrasts for all lithostratigraphical units.

5.0 Source rocks

By Holger Lindgreen, Erik Thomsen & Per Wrang

Little has been published on source rocks of Paleozoic and Mesozoic ages in the North Sea. Gas in many fields of the southern North Sea is known to originate from Late Carboniferous Coal Measures, (Eames 1975). In the East Midlands area of England, the oil in Carboniferous reservoirs is believed to originate from Carboniferous rocks (Bernard & Cooper 1981). Several papers published on the oil fields in the southern and northern North Sea suggest a Late Jurassic source rock (see review by Weismann 1979 and Bernard & Cooper 1981). Also Early and Middle Jurassic shales are suggested as possible source rocks in parts of the North Sea (Fuller 1975, Oudin 1976). Published data on source rock conditions in the Danish sector is limited to Weismann (1979).

5.1 Source rock definition

The term source rock is often used in an ambiguous way.

In the present report a source rock is defined as a rock containing a sufficient amount of organic matter of a proper type, and of sufficient maturity. A potential source rock is an immature source rock. The source rock parameters applied herein are 1) amount of organic matter, 2) type of organic matter, 3) maturity of the organic matter.

Results from the source rock analyses carried out by DGU are illustrated by selected wells located in the Central Graben area.

Methods

The source rock analyses have been performed by mineralogical organo-chemical, and coal petrographical methods. The amount of organic matter was determined as a total organic carbon percentage. The type of organic matter was determined by optical and chemical methods. Optically the organic matter was rated qualitatively in reflected light supplemented with blue-light induced fluorescence. Additional information is given by organochemical parameters (extractability, alifate/hydrocarbon ratio, prostane/phytane ratio, pyrolysis). The mineralogical analysis determines sediemntation and deagenesis parameters and contributes to the determination of the organic matter and type. The maturity of the organic matter was determined by vitrinite reflectance, by organochemical parameters (extractability, pristane/n-C17 ratio, CPI values, alifate/hydrocarbon ratio and composition of alifate fraction from gas chromatography) and by inorganic parameters (degree of diagenesis of carbonates, iron compounds and clay minerals, catalytic effect of clay minerals).

Total Carbon (TC) and Total Organic Carbon (TOC) were measured on a Leco carbon analysator. TOC was measured after pretreatment with hot, concentrated HCl. Soluble Organic Matter (SOM) was determined from the extract from a Soxhlet extraction of the chrushed sample with methylenchloride in 24 hours. The separation of SOM was performed by column-chromatography with hexane, methylenchloride and methanol as eluents. GLC (Gas Liquid Chromatography) of the alifate fraction was performed on an OV 1 capillary column. Rock-Eval analyses was performed on some selected samples.

Semiquantitative mineralogy and clay mineralogy were determined by X-ray diffraction on powdered bulk samples and on pretreated oriented clay samples. Qualitative and for carbonates and sulfides quantitative mineralogy was determined by differential thermal analysis on powdered bulk samples, with detection of CO_2, H_2O, and SO_2. The oxidation state and mineralogical positions of Fe was determined by Mossbauer spectroscopy on powdered bulk samples.

Viewing and measurements were made with a refelcted-light Zeiss Photomicroscope. Measuring principles were in accordance with the outlines in Stach et al. 1975. The organic matter was rated using three broad categories: vitrinite, liptinite and inertinite (for details see Tissot & Welte 1978). Approximate threshold values for the maturity levels corresponding to the onset of oil generation, expulsion of oil and the peak zone of oil generation, were used according to the suggestions by Hood et al. 1975, Dow 1977, and Tissot & Welte 1978.

5.2 Review of possible source rocks

Only Mesozoic rocks have up til now been analysed in the laboratory at DGU. However, based on the the geology of the Danish area and published information from the surrounding areas, the following tentative source rock possibilities are suggested.

Palaeozoic source rocks

A possible source rock of Early Palaeozoic age may be excluded due to an overprint of the area by the Caledonian metamorphism.

Devonian sediments have not yet been drilled in the study area, but they are known from the British and German sectors. However, no source rock of this age has been identified in these areas.

Lower Carboniferous (coals, sandstones, siltstones, and shales) was drilled in the P-1 well. The coal bearing Upper Carboniferous is probably limited to the basins south of the Mid-North Sea High and Ringkøbing-Fyn High, but may extend into the southern part of the study area. Upper Carboniferous coal measures are the sources for gas in the southern North Sea (Eames 1975) Carboniferous oil source rocks are less frequent, but oil shales in the Lower Carboniferous are believed to be the sources for the oil discoveries in the East-Midlands area of England.

Rotliegendes and Zechstein deposits have been drilled in the study area and are expected to cover main parts of the area. No source rock of Rotliegendes age is known. The volcanic rocks drilled on a few locations may possibly cover larger parts of the area, making the presence of source rocks of Rotliegendes and Carboniferous age speculative.

In the Zechstein, the possible source rocks are the Kupferschiefer and the Stinkschiefer and Stinkkalk (Taylor 1981). As these deposits are known both north and south of the Ringkøbing-Fyn High, they are presumably present in the Danish Central Graben.

Mesozoic source rocks

Triassic sediments have mainly been drilled in the southern part of the study area. Apart from the Winterton Formation, the known Triassic deposits consist of sandstones and evaporites in red bed facies with no source rock potential. The Jurassic sequence is comparable to that of the southern North Sea (Rhys 1974), the central and northern North Sea (Deegan & Scull 1977), and the Norwegian-Danish Basin (Michelsen 1975). The Jurassic Posidonomya Shale, which is regarded as the source rock for the oil elsewhere in Northwest Europe, has not yet been recorded from the Danish Central Graben. The Middle Jurassic is mainly represented by coal-bearing fluvio-deltaic deposits. These sediments are generally regarded as poor source rocks for oil due to the dominance of vitrinite and inertinite. However, sapropelic deposits are encountered in this depositional environment and represents possible sources for oil (Bernard & Cooper 1981). The Late Jurassic 'Kimmeridge Clay' is regarded as the main source rock for oil in the North Sea (see review by Bernard & Cooper 1981).

Upper Cretaceous and Tertiary deposits have been drilled in a large number of wells in the study area. According to Weismann (1979) these deposits have not generated hydrocarbons in any significant quantities.

5.3 Results from laboratory analyses

Winterton Formation

The Danish M-8 and O-1 wells have been investigated. The Winterton Formation is present in the Danish M-8, U-1, and O-1 wells. The mineralogy has been investigated in M-8 and O-1. The presence of medium to large amounts of anhydrite, salts, and mica points to sedimentation in alkaline environments in a dry climate unfavourable for the formation of potential source rocks. Few samples from the upper part of the formation in M-8 have been analyzed organo-chemically. They are rich in organic carbon. The material is unfavourable for oil generation, but may be a potential source rock for gas.

Fjerritslev Formation

The Danish M-8, A-2, and O-1 wells have been investigated.

M-8 well: The amount of organic matter is high and it is mainly represented by alginite and liptodetrinite, associated with vitrinite and inertinite. The samples are mature, but the extractabilities are generally too low to permit oil expulsion. This is probably due to weathering effects possibly associated with the Mid Cimmerian uplift, or to neutral to fresh water solutions migrating during early diagenesis (Millot 1970). This is supported by the high content of early diagenetic kaolinite of the side wall core at 10520' in well M-8 (fig. 41), and by the absence of pyrite. From mineralogical data of the O-1 well, it is indicated that weathering of the Fjerritslev Formation has not taken place in this well, but the diagenesis is low, indicating a low maturity of the organic matter.

The limited number of samples investigated so far permit only tentative conclusions concerning the hydrocarbon potential. However, it may be concluded that the formation will represent a good oil source rock where it is mature and not weathered.

J-2 Unit

The Danish M-8 well has been investigated.

M-8 well: The amount of organic matter is rich to extremely rich. The coal seams encountered in this formation are composed of humic coal and sapropelic coal. In the sapropelic coal and in carbagillites, the organic matter is dominated by sporinite, alginite, liptodetrinite and bituminite. Micrinite is frequently associated with desmocollinite. Expulsion of oil droplets is observed. The amount of extract is rich, and it is of algal origin. The pristane/phytane ratio indicates some oxidation of the material. The extractability, however, is only fair, which shows that only little migration has taken place. According to vitrinite reflectance, the formation is just within the zone of principal oil formation, and the Rock-Eval analysis shows a great residual potential for oil generation.

J-3 Unit

Only the M-8 well has been investigated. The amount of organic matter is high. The organic matter is dominated by vitrinite and inertinite associated with a varying amount of liptinite. With depth, the pristane/phytane ratio indicates an increasing influx of more oxidized material. The vitrinite reflectance (fig. 38) shows that the formation is just within the zone of oil generation. The amount of extract and the extractability is low. The degree of diagenesis of the carbonates and clay minerals is moderate (fig. 40). The clay

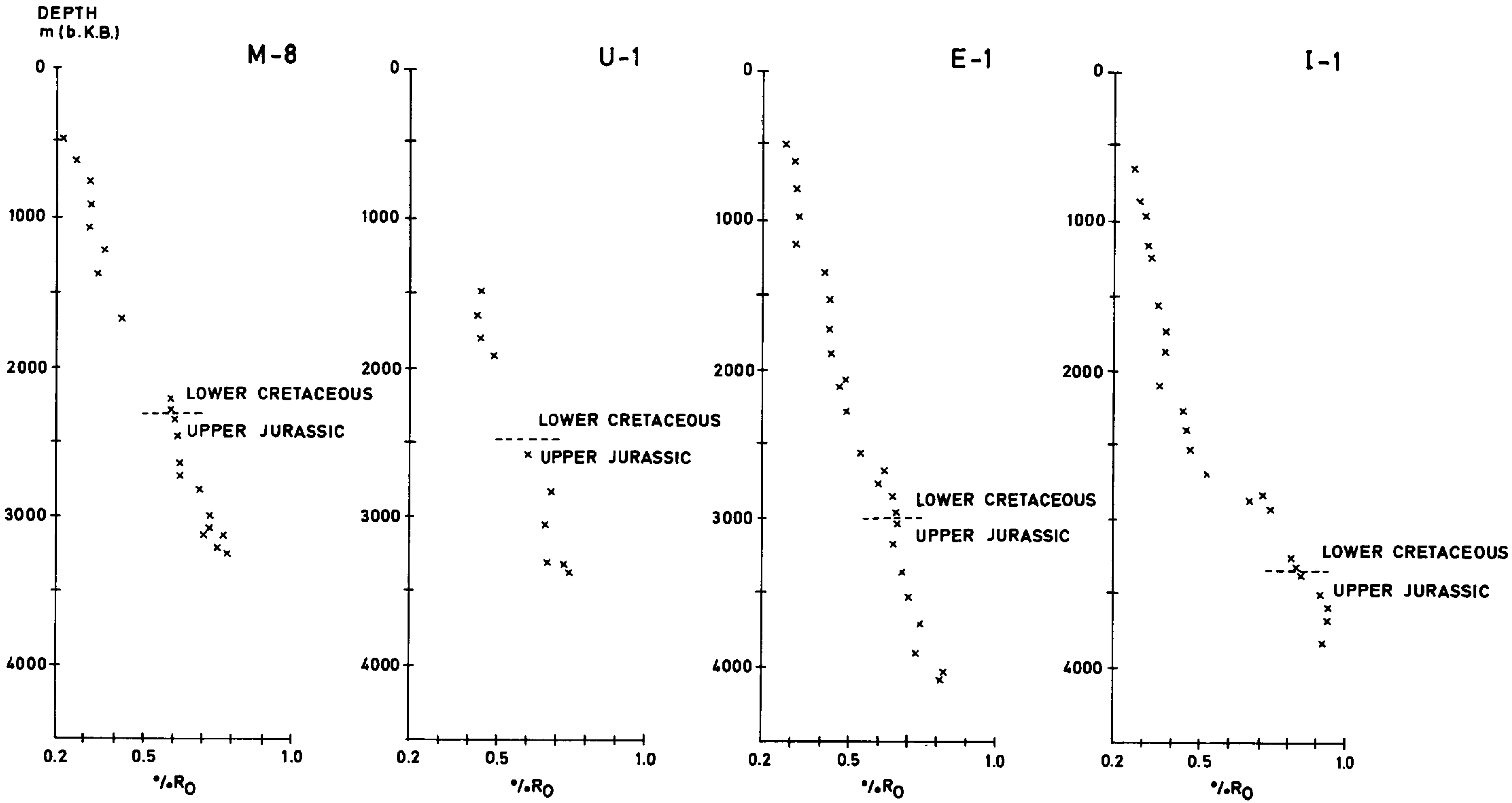


Fig. 38: Vitrinite reflection trends in the E-1, I-1, M-8, and U-1 wells. The Lower Cretaceous – Upper Jurassic boundary is marked.

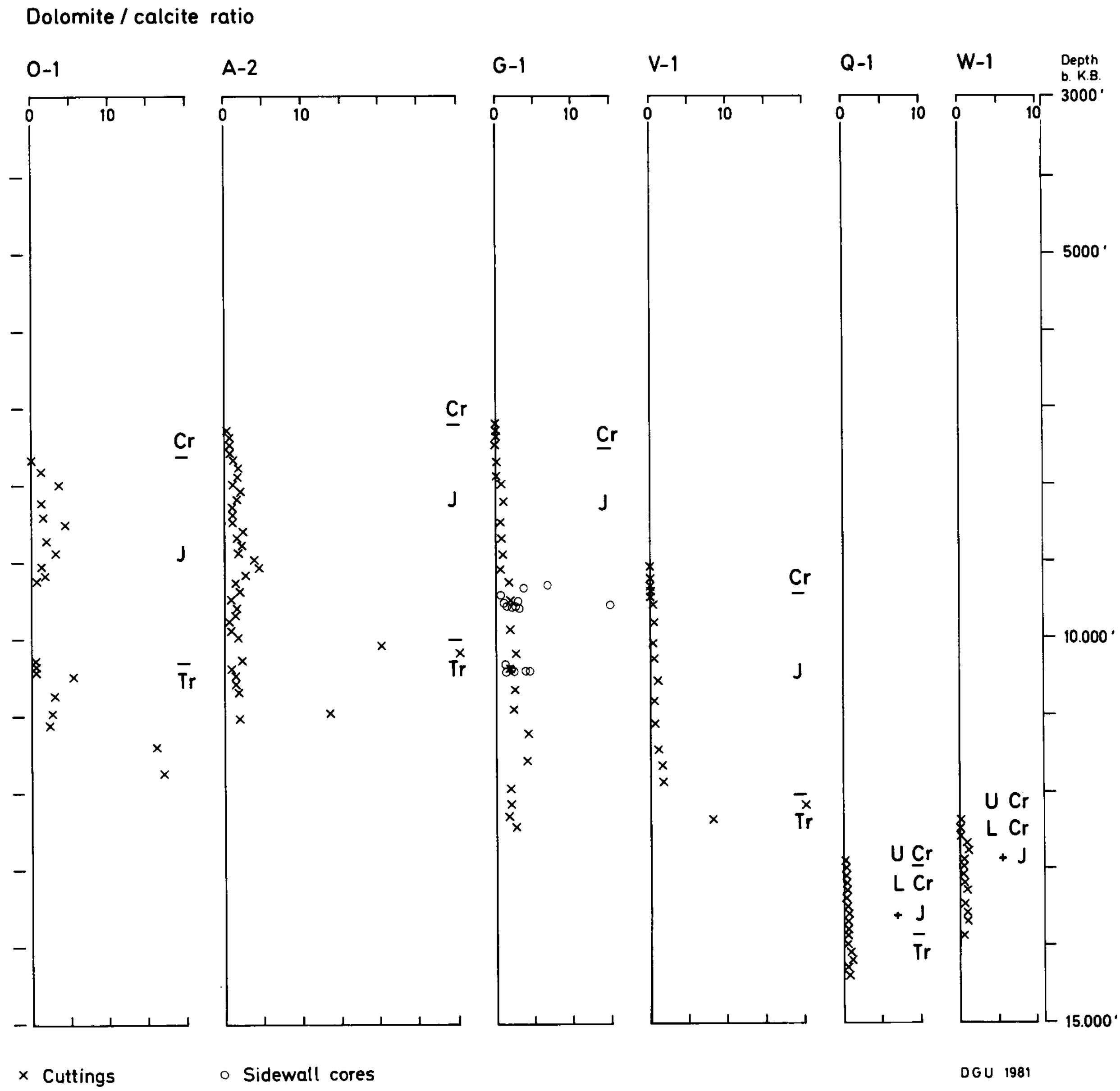


Fig. 39: Calcite/dolomite ratio in the O-1, A-2, G-1, V-1, Q-1, and W-1 wells. Cr = Createaceous, J = Jurassic, Tr = Triassic.

minerals contain a fair amount of smectite layers and provides the formation with good catalytic properties.

The Formation is not a promising source rock for oil, due to the unfavourable type of organic matter, but it might be a potential source rock for gas.

J-4 Unit

The M-8, E-1, and I-1 wells have been investigated. The amount of organic matter in the M-8 well is high. Microscopically the organic matter in the well is dominated by liptinite, mainly alginite, associated with varying contents of vitrinite and inertinite. Locally high contents of liptinite are observed. The extract is of algal origin. M-8 is just approaching the zone of oil formation as judged from vitrinite reflectance data (fig. 38). The amount of extract and the extractability shows that the formation has not yet generated sufficient amounts of oil to classify it as an actual source rock.

The amount of organic matter in the J-4 Unit of the well E-1 is good to rich. Microscopically the type of organic matter is analogous to the organic matter found in the M-8 well. However, the content of liptinite shows a significant increase upwards through the formation, and intervals very rich in liptinite, mainly alginite, also occur in the upper part of the formation. The same trend is seen in the organo-

Dolomite / calcite ratio.

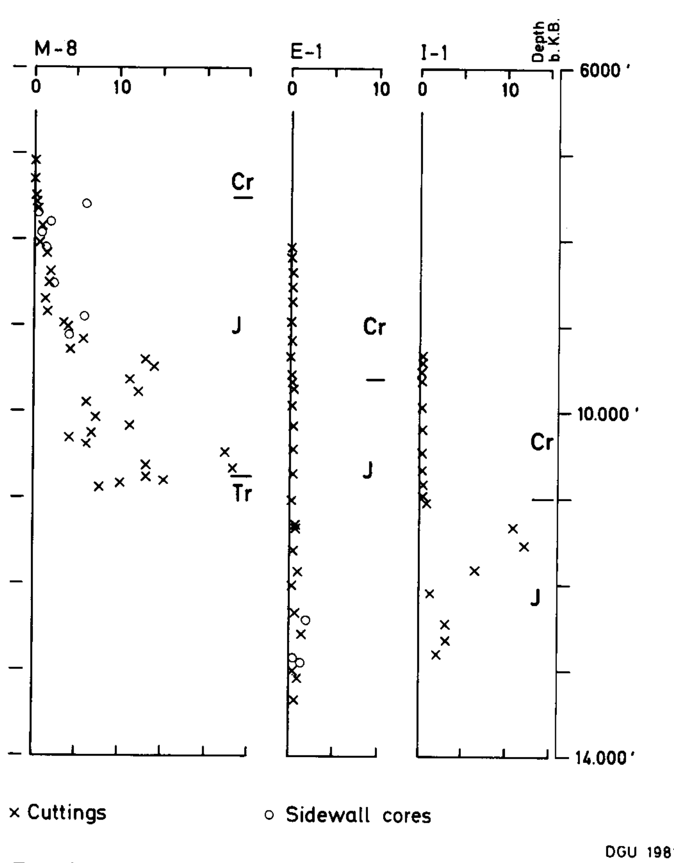


Fig. 40: Calcite/dolomite ratio in the M-8, E-1, and I-1 wells. Cr = Cretaceous, J = Jurassic, Tr = Triassic.

chemical data, but the diesel oil added to the drilling mud makes a proper evaluation difficult. Vitrinite reflectance (fig. 38) shows that the upper part of the formation is within the zone of oil generation, while the lowermost part has reached the zone of maximum oil generation (fig. 38). The extraction data indicate higher maturity than in the M-8 well. The mineralogical data show a very high amount of smectite in the interval 7530-7630' of M-8 and a high smectite content at 10400' in E-1 (fig. 41), which - indicated by a crystallographic analysis - was probably formed from volcanic ash weathered in a restricted basin with a high supply of nutrients from the ash. It has also a very high catalytic effect on the oil generation. The degree of inorganic diagenesis is the same at the maximum depth of the J-4 Unit in the E-1 and M-8 wells (fig. 40).

The amount of organic matter in the I-1 well is rich to extremely rich. The extract is of algal origin. The vitrinite reflectance (fig. 38) indicates that the J-4 Unit is well within the zone of maximum oil generation. The amount of extract is rich, and the extractability shows that the formation is releasing oil, which classifies the J-4 Unit as a rich source rock for oil in this area. The degree of inorganic diagenesis is much higher in the I-1 well than in the E-1 and M-8 wells (fig. 39).

The investigation shows that the J-4 Unit must be regarded as a much better oil source rock in the northern well I-1 than in the E-1 well in the central part of the study area or in the M-8 well in the southern part of the study area.

Valhall Formation

The E-1 and I-1 wells have been investigated. The amount of organic matter in E-1 is poor to fair. Microscopically, the organic matter is dominated by reworked vitrinite and inertinite, associated with a low content of liptinite. Vitrinite reflectance shows that the sequence is premature to mature. The degree of inorganic diagenesis is very low (fig. 39). The section in E-1 has a poor source rock potential.

The amount of organic matter in the I-1 well is poor to fair. The degree of inorganic diagenesis is very low (fig. 39). The extracts contain varying amounts of migrated oil, and this migrated oil dominates the extracts at a depth of 10630'. The vitrinite reflectance (fig. 38) shows that the formation is well within the zone of oil formation. The section is regarded as a poor to fair source rock.

Rødby Formation

The E-1 and I-1 wells have been investigated. The amount of organic matter in I-1 is fair but locally rich. The vitrinite reflectance shows that the formation is within the zone of oil formation. The extraction data show a great content of migrated oil. The degree of inorganic diagenesis is very low. The formation is generally a poor source rock, but certain horizons may act as a source rock for oil and gas.

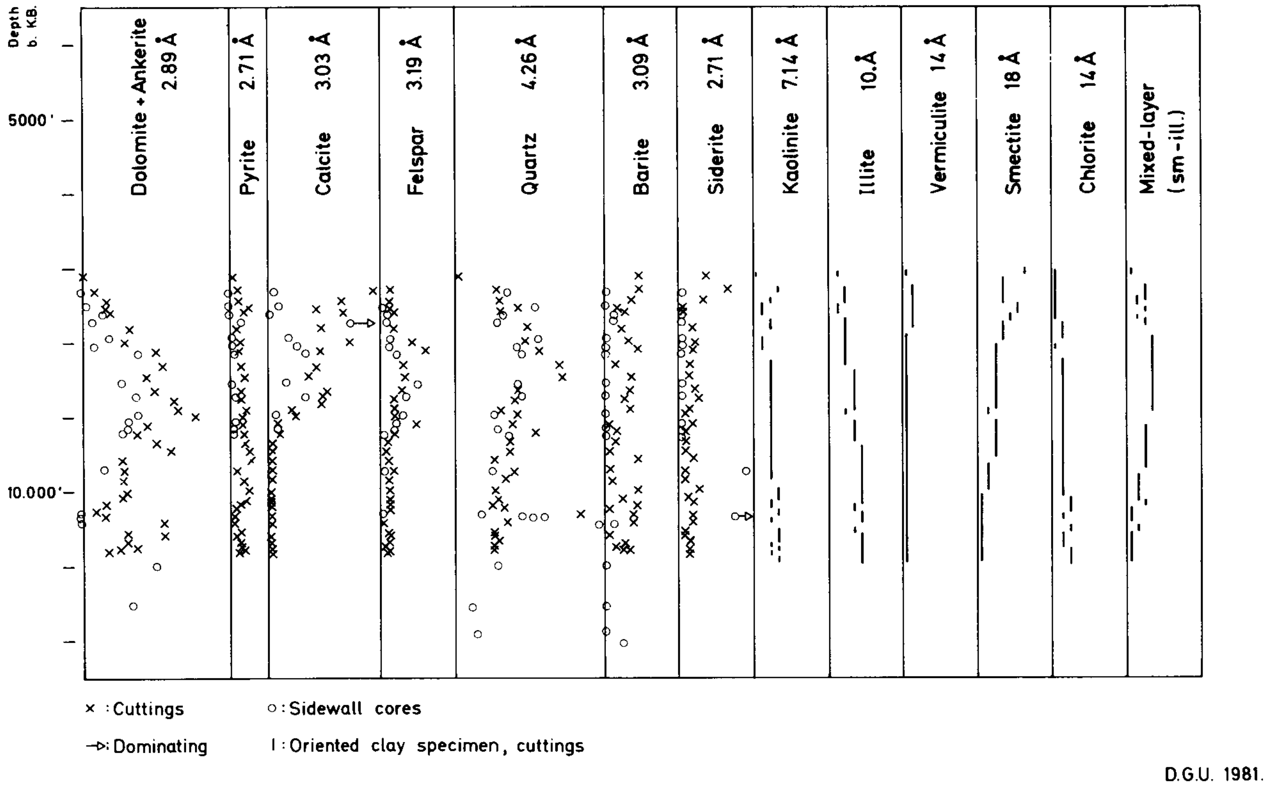
Chalk Group

The M-8, U-1, E-1, and I-1 wells have been investigated. The amount of organic matter is poor. The vitrinite reflectance shows that the formations are immature in the E-1 well (fig. 38). The Chalk Group has no potential for oil and gas generation in the examined wells due to the low content of organic matter.

Tertiary sequences

Vitrinite reflectance measurements have been carried

M-8 well x-ray reflection areas



E-1 well x-ray reflection areas

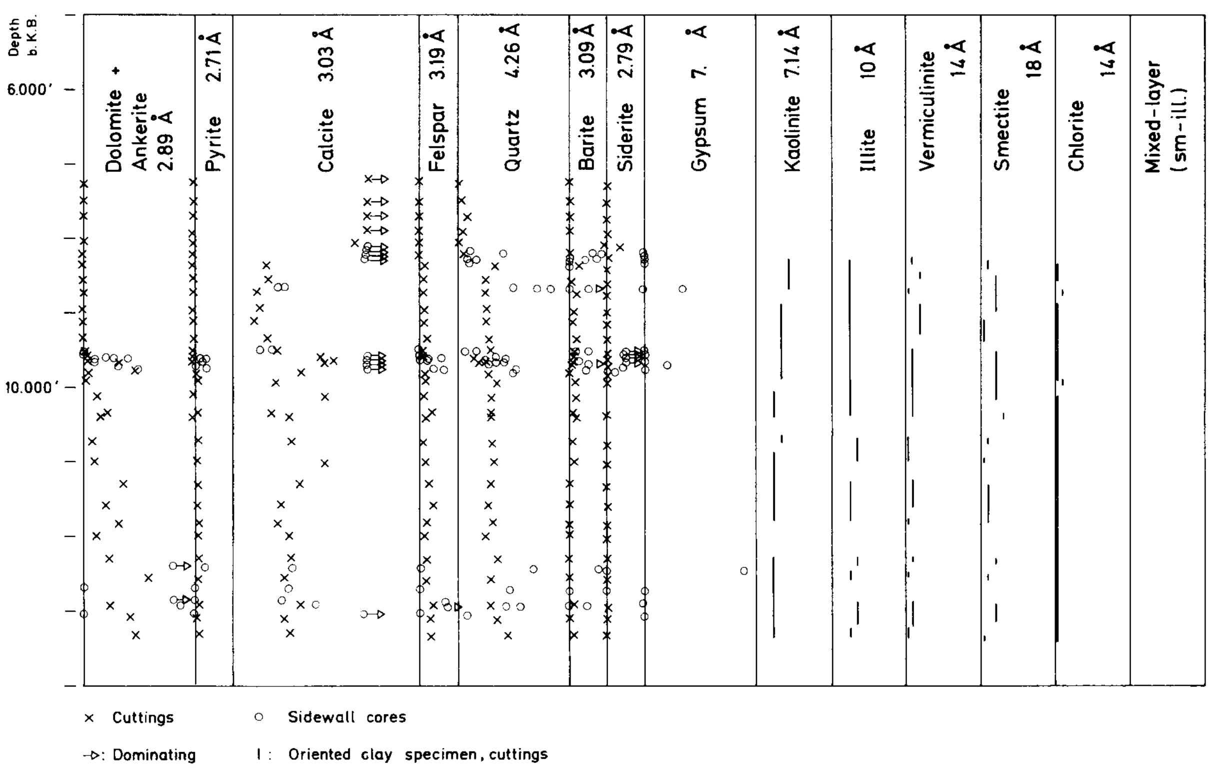


Fig. 41: X-ray reflection areas in the M-8 and E-1 wells.

out on samples from the M-8, U-1, E-1, and I-1 wells (fig. 38). The Tertiary sequences are immature in these wells.

5.4 Regional rank conditions

Fig. 38 shows vitrinite reflectance trends for a series of wells located on a north-south line through the Danish Central Graben with the I-1 well representing the northernmost location.

In the wells E-1, M-8, and I-1, the Cenozoic-Mesozoic sequence has been studied in detail. In the U-1 well only a preliminary study of this interval has been carried out.

The results show significant differences in the rank conditions. The highest rank is attained in Upper Jurassic sediments in the I-1 well. Compared with the southern wells M-8 and U-1, this could be interpreted as a result of greater depth of burial of the Jurassic in the I-1 well. The reflectance trend of the I-1 well shows a major coalification break at a depth of about 2850 m, which suggests an originally greater depth of burial of the Mesozoic deposits. However, the Mesozoic rank gradients, i.e. the rank increase with depth, are lower in the E-1 and U-1 wells as compared to the I-1 well, whereas the M-8 well has an intermediate rank gradient. This is illustrated by a comparison between the E-1 and I-1 wells at comparable stratigraphic depths, i.e. Upper Jurassic sediments at a depth of approximately 3500 m (11500'). The E-1 well is just approaching the zone of actual oil expulsion (about 0.70 %RO), while the I-1 well is within the zone of maximum oil generation (0.80-0.90 %RO).

For sediments of approximately similar age and rank ranges, different rank gradients will reflect variations of the geothermal gradients, which could indicate major regional differences of the rank conditions in the study area. However, a regional comparison can only be made with due respect to the abnormal heat flow conditions at or near salt structures or faults.

The M-8 well is drilled on a salt structure whereas the I-1 well is drilled on a structure of unknown character, the influence of which is reflected in the reflectance trend of this well. The E-1 and U-1 wells are located in areas unaffected by major structures, hence abnormal heat flow conditions are not to be expected. Thus the high and intermediate rank gradients observed in the I-1 and M-8 wells are tentatively attributed to local heat flow anomalies.

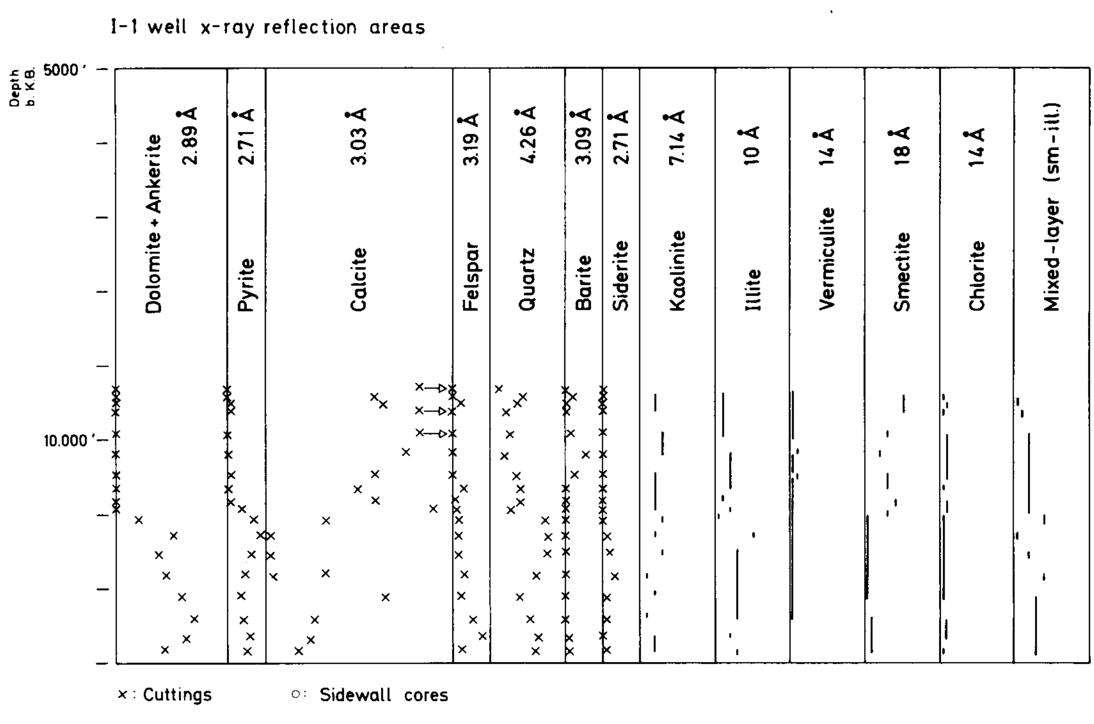


Fig. 42: X-ray reflection areas in the I-1 well.

It can be concluded that the northernmost well I-1 is the most promising in terms of maturity conditions, because favourable Upper Jurassic sediments attain higher maturity levels than sediments of similar age in the wells investigated in the central (well E-1) and southern (wells M-8, U-1) part of the study area.

5.5 Regional diagenesis

The mineralogy of the E-1, I-1, and M-8 wells is shown in figs. 41 and 42. Some minerals are detrital (quartz, some of the felspars, some clay minerals), some formed during sedimentation and early diagenesis (microcrystalline pyrite, some smectites, most of the calcite, and siderite), some are detrital minerals altered during diagenesis (mixed-layer clay minerals), and some were formed during late diagenesis (kaolinite, mica, well-crystalline pyrite, ankerite, dolomite, some of the felspars). Judging from the mineralogical investigations - by scanning electron microscopy, X-ray diffraction, Moessbauer spectroscopy, X-ray fluorescence, and differential thermal analysis (with gas detection and quantitative determination of evolved CO_2, H_2O, and SO_2) - kaolinite was probably formed during an early fresh water diagenesis, and mica (or at least a potassium fixation by expandable clays) was formed during a late brine diagenesis, in agreement with Millot (1970) and Hancock & Taylor (1978). In the investigated well sections, the formation of a well-crystalline pyrite, dolomite, ankerite, and of Na-feldspars, seems to have taken place during the same stage of diagenesis as the formation of mica or of potassium three layer clay minerals, i.e. during a late brine diagenesis.

The correlation between the rank of the vitrinite and the degree of late diagenesis (as measured from the dolomite+ankerite/calcite ratio) is fairly good for sediments older than the Cretaceous, whereas it is low for younger sediments (figs. 38, 39, 40). The late diagenesis is strongly influenced by the heat flow as well as by the brine chemistry, which partly explains the positive correlation. However, a certain heat threshold is presumably necessary for the late diagenesis to take place, whereas the rank of the vitrinite does not have such a precise threshold. This might explain the low correlation above the Jurassic-Cretaceous boundary.

As seen from the correlation between the rank data and the degree of late diagenesis, the Jurassic of the O-1 and A-2 wells are at the same level of maturity as that of M-8 (figs. 38, 39, 40). The well sections, G-1 and V-1, are furthermore at the same maturity level as E-1, although G-1 has undergone a little stronger diagenesis than E-1. On the contrary, the Jurassic deposits in the northerly located wells Q-1 and W-1 have undergone only weak diagenesis and seem to be only slightly mature despite the greater depth.

5.6 Source rock catalysis

Several publications refer to the importance of the presence of clay minerals for the catalytic processes during oil formation (Andeev et al. (1968), Sarkusyan (1970), Weaver (1960), and Hatch & Matar (1977)). In all studied wells, the Jurassic clays and Lower Cretaceous clays contain a fair to large amount of expandible, large-surface area clays, giving the rock fair to good catalytic properties.

5.7 Organo-chemical investigations

Figs. 43 to 46 show some selected results from the chemical investigation of the M-8, and I-1 wells.

M-8 well: Apart from 2 samples, the organic carbon content is below 2% to a depth of approximately 10100', where an irregular increase takes place (fig. 43).

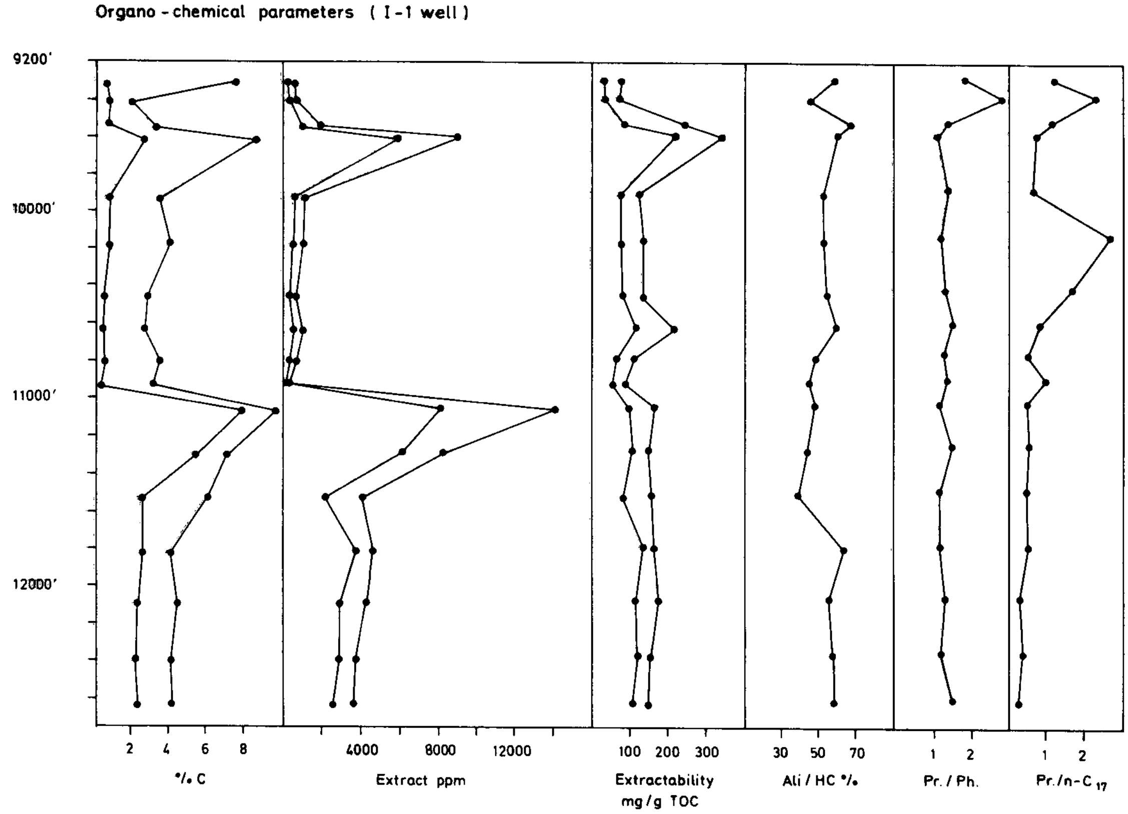
This is reflected in an increase in the amount of extract from the samples, but not in a significant increase in extractability. This means that although some levels (e.g. 10230') have produced large amounts of oil, significant migration will probably not take place.

The alifate/hydrocarbon ratio reflects increasing maturity and increasing influx from terrestrial material with depth.

The pristane/phytane ratio indicates increasing input of oxidized material (e.g. higher land plants) from 9000' to 10400'. Apart from a few levels with biodegradation, the pristane/n-C17 ratio reflects increasing maturity with depth. The value is rather high, indicating low maturity.

Fig. 44 shows the composition of the extract from M-8. The positions of the samples below 9930' are typical for marginally mature to mature extracts containing terrestrial material. Notice the position of the Dan field oil, which is typical for a migrated oil.

Fig. 45 shows the gas-chromatograms from the alifate fraction. The Dan Field oil shows the characteristic pattern for a partly bio-degraded oil. The horizons 7140', 7440', and 7530' show immature ex-



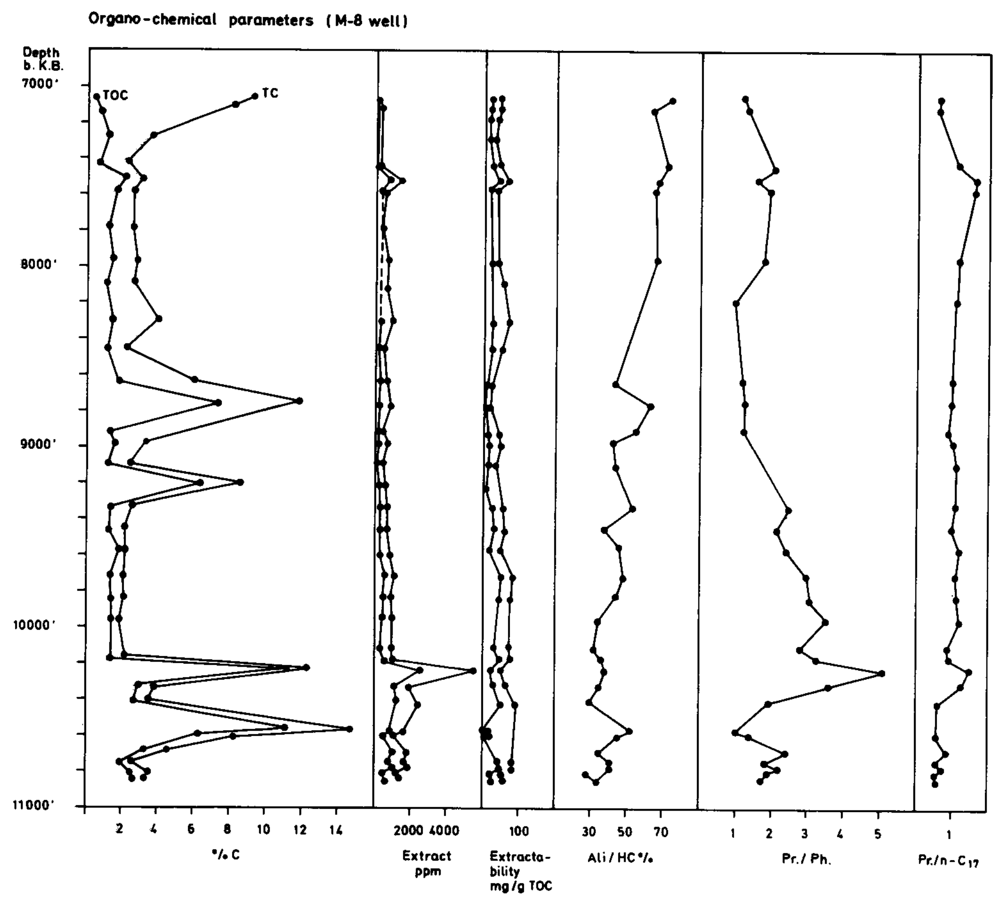


Fig. 43: Orogano-chemical parameters for the I-1 and M-8 wells. TC = total carbon, TOC = total organic carbon, SOM = soluble organic matter, HC = hydrocarbons, Ali = slifate fraction, Pr = pristane, Ph = phytane.

tracts from algal material. Rock-Eval analyses indicate the horizon at 7530' as a potential source rock.

The J-3 Unit represented at 9720' shows a shift to a clearly different type of material (oxidized terrestrial). The horizon at 10230' indicates highly oxidized oil-prone material. The Rock-Eval analysis shows a great residual potential for oil. The horizons at 10410' and 10800' indicate more reduced material. The horizon at 10800' contains significant amounts of more waxy components from higher land plants.

I-1 well: Apart from the horizon at 9610', the organic carbon content is below 1% down to 11000' (fig. 43). Below 11000' the carbon content is very high. The amount of extract reflects organic carbon content and is much higher than in M-8. Below 11000' the extractability is nearly constant with values near the maximum value for a well-mature source rock for oil.

The two high levels in extractability at 9610' and 10630' indicate migration. This is confirmed by the high alifate/hydrocarbon ratio. More than 2/3 of the extract at 9610' is presumably migrated oil. A corrected value for the organic carbon indicates a source rock potential of the level.

The alifate/hydrocarbon ratio is rather constant around 50%, and the pristane/phytane ratio below 9500' is likewise constant with values around 1.3 indicating non-oxidized mature material of algal origin.

The high value of pristane/n-C 17 ratio at the levels 9410' and 10170' reflects bio-degradation presumably due to meteoric water. The low value below 11000' shows much higher maturity than in the M-8 well.

Fig. 44 shows the composition of the extracts. The positions for all extracts from levels below 11000' are within the limits for well mature oil source rocks.

Fig. 46 shows the gas-chromatograms from the I-1 well. Apart from the horizon at 9610', which contains more heavy paraffins, the extract is dominated by light components. At 9410' and 10170' bio-degradation has taken place. At 11050' and 12640' mature material from algal origin dominates the extract.

The formations below 11000' are regarded as the best source rocks in the examined wells. The deepest level still has the characteristics of a rich source rock.

5.8 Regional variations

The limited number of wells investigated makes a general source rock evaluation for the entire Central Graben area impossible. There are, however, indications for some trends which should be noticed.

The low content of organic matter found in most Cretaceous samples indicates poor source rock potential.

The J-4 Unit contains generally high amounts of oil prone material and it is probably the most important source rock in the area. The amount of material in this formation tends to be more than twice as high in the northern I-1 well as compared to the southern wells. Similarily the amount of generated oil is much higher in the I-1 well than in the M-8 well, but due to the possibility of heatflow anomalies this interpretation should be taken with reservations.

The results from the M-8 well indicate the same variation in the J-3 Unit as in the J-4 Unit, but the type

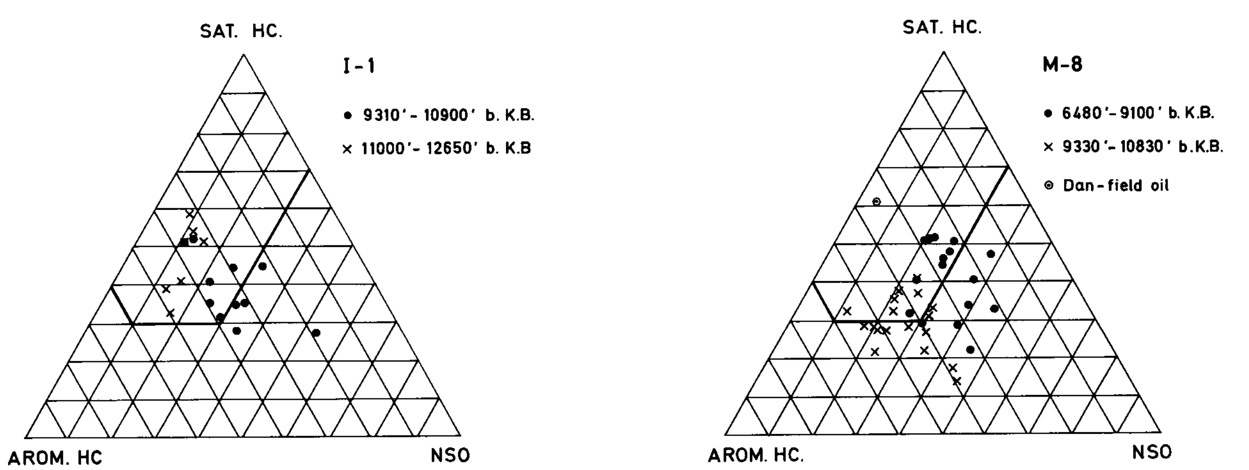


Fig. 44: Composition of extracts of the I-1 and M-8 wells. – SAT. HC. = saturated hydrocarbons, AROM. HC. = aromatic hydrocarbons, NSO = hetero-compounds.

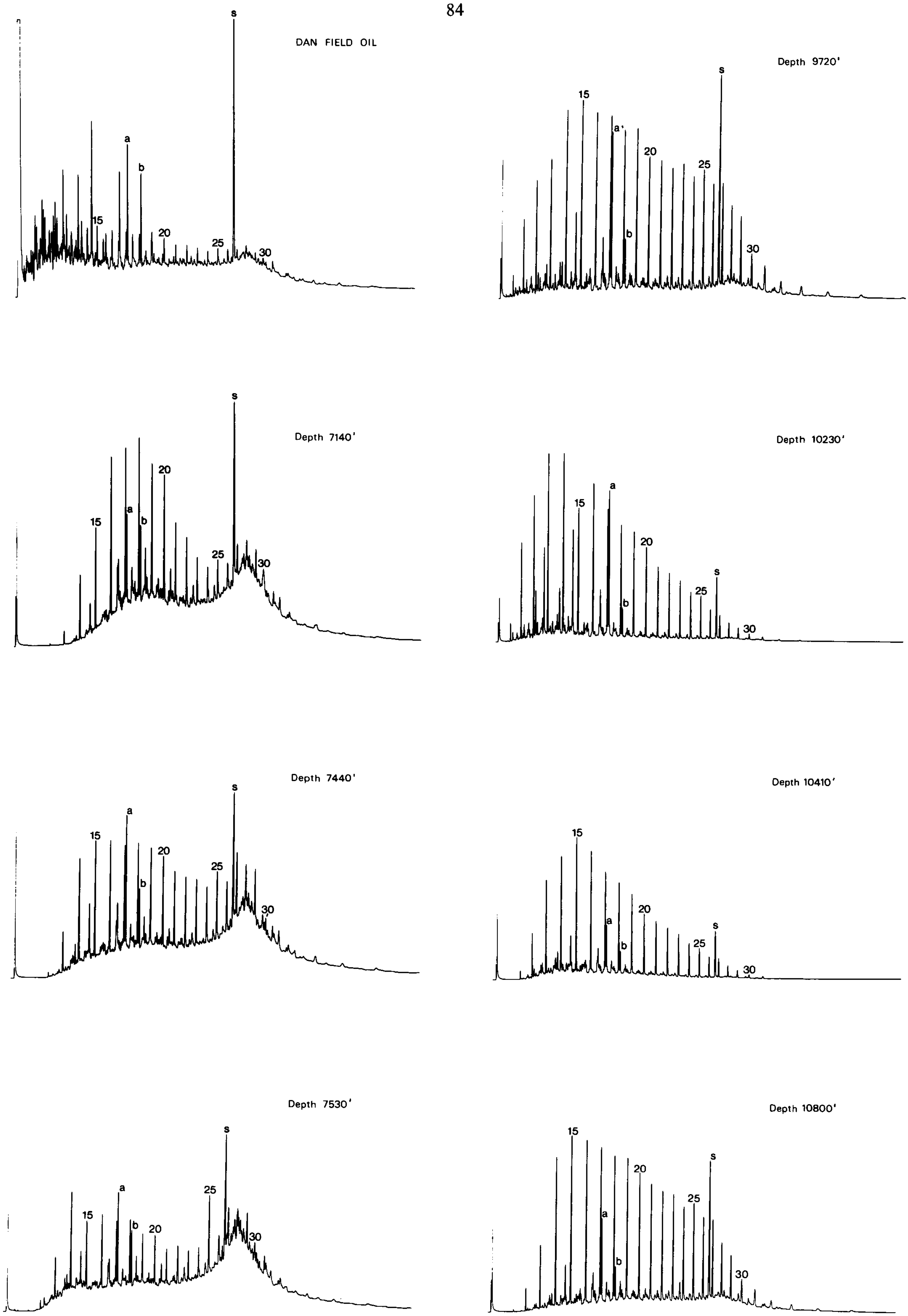


Fig. 45: Gas-chromatograms for the M-8 well. a = pristane, b = phytane, s = squalane (internal standard).

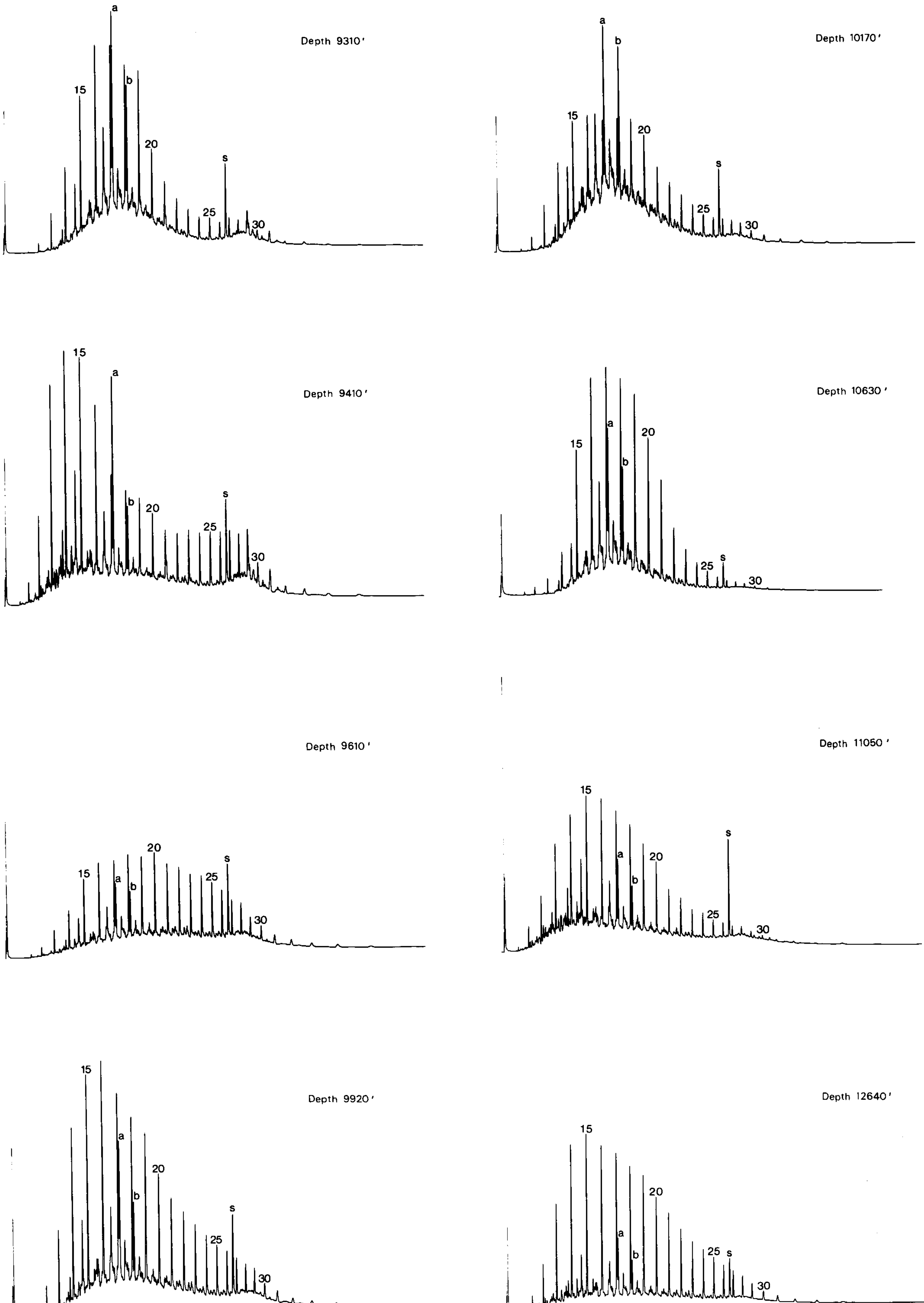


Fig. 46: Gas-chromatograms for the I-1 well. a = pristane, b = phytane, s = squalane (internal standard).

of material in the J-3 Unit is not as favourable as in the J-4 Unit.

The maturity parameters correlate to the rank gradients, with the same limitations.

5.9 Conclusions

The J-4 Unit is regarded as the principal source rock for oil in the study area. It is of a considerable thickness and the amount and type of organic matter is favourable. Data from the northern well (I-1), the central well (E-1) and the southern well (M-8) show that: 1) The organic matter is mainly of algal origin. 2) The amount of organic matter is rich to extremely rich in the northern well, and good to rich in the central and southern wells. 3) In the northern well the entire J-4 Unit is within the zone of maximum oil generation. In the central well the upper part of the unit is just within the zone of oil generation, whereas the lower part of the unit is within the zone of maximum oil generation. In the southern well the unit is just approaching this zone. The formation therefore must be regarded as a better oil source rock in the northern well. However, assuming sufficient burial, as seen in the M-8 well, the formation is still a good source rock in the southern area.

The conclusions are severely hampered by the limited number of wells drilled, especially in the northern area. The investigations show that the study area is very complex with respect to the amount of organic matter as well as the maturity conditions. Therefore, a detailed mapping of the source rock potential of the study area is strongly needed.

6.0 Potential hydrocarbon traps

By Jens Ole Koch

The formation of hydrocarbon traps is the result of local depositional and deformational history. The trap formation is governed by three main parameters: the geometry of the reservoir body, the sedimentary sealing history and the tectonic history. In the present chapter is discussed the distribution of potential hydrocarbon traps in different areas, each characterized by a structural style (figs. 47, 48). After a short definition of basic trap types, various areas of the Danish Central Graben, each of which is characterized by a certain structural style, are listed and described with emphasis on the distribution of potential hydrocarbon traps.

6.1 Definition of basic trap types

A hydrocarbon trap is a closed structure with a reservoir rock overlain by impermeable strata. The seal/reservoir interface may conform with the boundary of the two formations, but it is often a complex of unconformities and fault contacts between the reservoir body and various seals. Two basic types of potential traps exist, namely stratigraphic traps and structural traps (fig. 48).

Stratigraphic traps

A stratigraphic trap is a laterally limited reservoir body, sealed by impermeable strata. Inter alia, the reservoir may be alluvial or submarine fans fringing a sub-aerially exposed 'high' area, carbonate reefs, fluvial channel sands, and diagenetic formed high porosity zones. The seal may either be comformably deposited upon the reservoir body, or the reservoir body can be truncated and unconformably overlain by the seal. Consequently, there are two sub-types: Primary and secondary stratigraphic traps (fig. 48).

In primary stratigraphic traps, the reservoir is conformably overlain by the seal. The geometry and size of the trap is delineated by the original upper depositional surface of the reservoir body and possibly also by syn-sedimentary faults.

In secondary stratigraphic traps, the reservoir body is truncated and unconformably overlain by the seal. The geometry and size of the trap is defined by the topography of the erosional surface of the reservoir body.

Stratigraphic traps may retain hydrocarbons in completely undeformed areas, but they may also be deformed, which either improves or reduces their hydrocarbon trapping capability.

Structural traps

A structural trap is a laterally limited or unlimited reservoir body, which is overlain by an impermeable seal. It has been deformed into an upwhelming closed structure capable of trapping hydrocarbons.

Among a number of factors the deformation can be caused by extension, compression, density contrasts, differential loading, wrenching, or uplift. Two basic sub-types of structural traps can be distinguished:

Fault traps are situated in tilted fault blocks. The