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PVT—Modelling as a Predictive Tool in Hydrocarbon Exploration, with Examples from the Mid Norwegian Continental Shelf

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Abstract: Computerized PVT-modelling has been applied on several case examples to demonstrate how the basic PVT-properties (pressure, temperature and hydrocarbon component distribution) may be critical for the hydrocarbon phase relations in a trap (oil vs gas or condensates). The predictive force of PVT-tools in hydrocarbon exploration is tremendous. Hydrocarbon densities, phase relations, gas oil ratios, shrinkage, expansion factor etc. can be calculated with great certainty if provided with reliable input data. The multiple applications include general basin modelling, flash analysis, dew point analysis and boiling point analysis.

INTRODUCTION

The Haltenbanken hydrocarbon province is situated offshore Mid Norway (Figure 1) in water depths from approximately 200 to over 300 meters. Large quantities of oil, condensate and gas have been tested from several structures in the area. The depths of the hydrocarbon accumulations vary from approximately 1500 to more than 4000 meters. The hydrocarbons have been sourced from coals and shales of Early Jurassic age and from shales of Late Jurassic age. The main accumulations are found in sandstone reservoirs of Middle Jurassic age, but major accumulations also occur in sandstone reservoirs of Early and Late Jurassic age.

A simple subsidence history and geologic setting in general makes Haltenbanken an ideal area for advanced basin modelling studies. In addition the generation of a full range of hydrocarbon components from the different source rocks presents an excellent opportunity to study PVT-properties and PVT-modelling.

TECTONIC SETTING

The area of exploration licences at Haltenbanken is shown in Figure 1 in a pre-rift reconstruction of the Norwegian-Greenland Sea area. The main structural elements of the Norwegian continental shelf between Møre and Lofoten are outlined in Figure 2. With the exception of the large, low amplitude dome structures and escarpments in the north-western part, the structural features shown on the map were established mainly during Late Jurassic and Early Cretaceous, a time of very active rifting in the area. Gabrielsen *et al.* (1984), Bøen *et al.* (1984) and Bukovics and Ziegler (1985), have recently discussed the structural geology of the Mid Norway shelf area.

A major part of the Haltenbanken concession area is situated on the Halten Terrace between the Sklinna High (or West Haltenbanken High of Bukovics and Ziegler, 1985) and the Trøndelag Platform to the east. The Halten Terrace is highly block faulted, with its shallowest part to the north-east where the top of the Jurassic is found at depths between 2000 and 3000 m.

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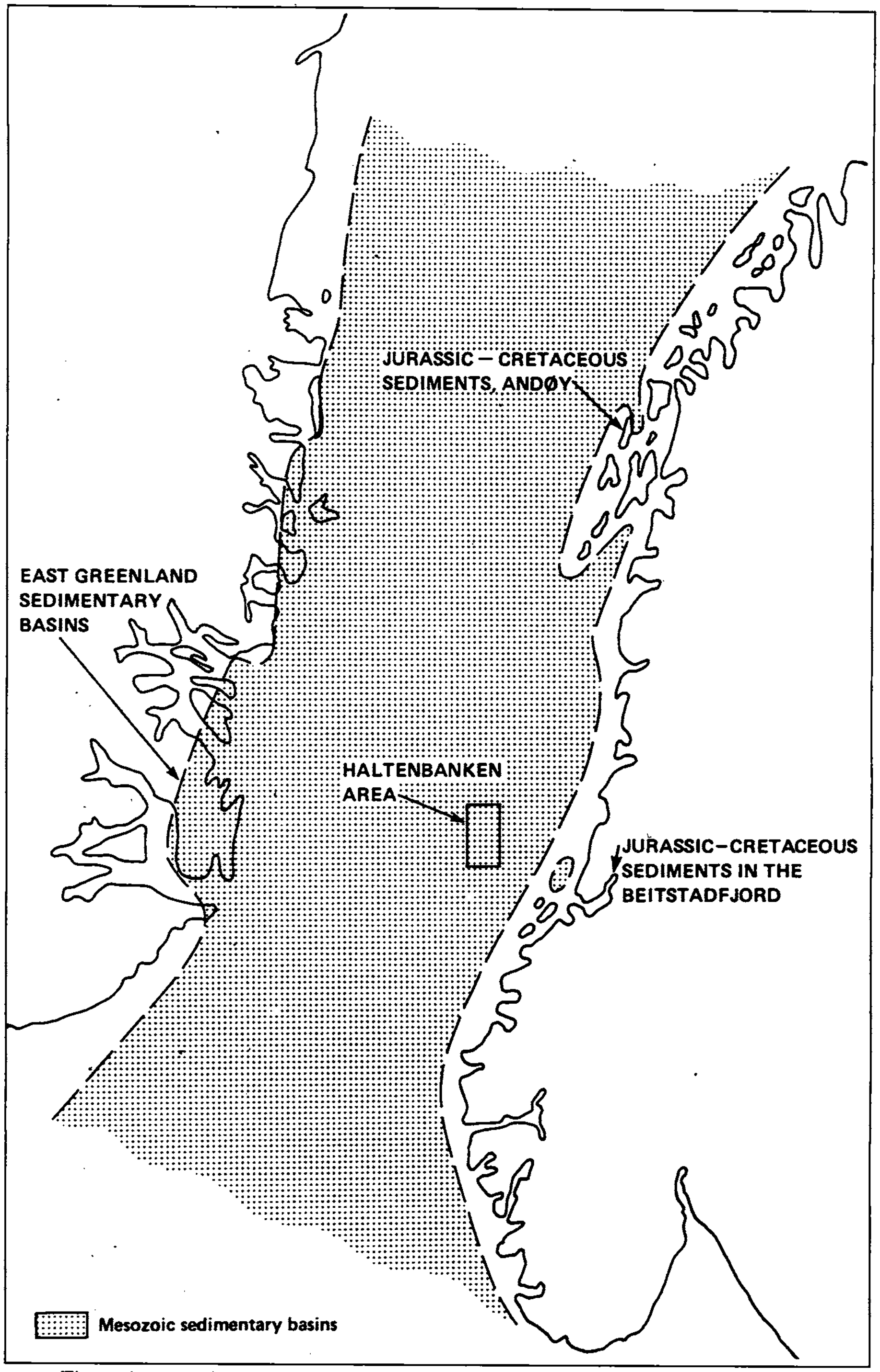

Figure 1: Location of the Haltenbanken area. Mesozoic paleogeographic reconstruction.

The northwards transition into the Nordland Ridge, although intensely faulted, is a gradual one. To the south, the depth to the Jurassic is 4000 m or more. Deep subsidence of the Sklinna High makes a more or less gradual transition from the Halten Terrace towards the very deep Møre Basin to the south-west, whereas major faults along the Kristiansund-Bodø Fault Complex form a rather abrupt termination of the terrace area against the Frøya High and the Trøndelag Platform to the south-east (Figure 3).

The marked relief shown by the cross-section did not exist before Late Jurassic time. During Early and Middle Jurassic times the Trøndelag Platform and Halten Terrace were both parts of the same deltaic to shallow marine depositional environment, with the main land area to the east and possibly more local emergent highs to the west. The subsidence of the whole Halten Terrace relative to the Trøndelag Platform continued throughout Cretaceous times. Figure 3 also shows a deep local basin that developed along a small section of the Kristiansund-Bodø Fault Complex during Late Jurassic time. This basin may be a pull-apart feature related to right-lateral movements along the Kristiansund-Bodø Fault Complex. A marked bend of the fault zone around the northern edge of the Frøya High (Figure 2) may have been critical for the basin development at this location.

Simultaneous with the Late Jurassic basin formation and continuing into the Early Cretaceous times, the western edge of the Trøndelag Platform was uplifted and eroded. The narrow ridge thus formed east of the Halten Terrace extends into the Frøya High to the south and along the Nordland ridge to the north and has been referred to as the Nidaros Arch (Bukovics and Ziegler, 1985). The paleohigh to the west, here called the Sklinna High is today buried beneath nearly 4000 m of Tertiary and Upper Cretaceous sediments, but was emergent during much of the Early Cretaceous times. The Jurassic section is not preserved over much of the Sklinna High. This may to a large degree be due to uplift and erosion during Early Cretaceous, but there are signs of uplift, at least intermittantly, already during Early Jurassic times. It is quite possible that the Sklinna High was a positive element already during Triassic times. Together with other paleohighs to the north, it may have formed a western barrier that separated the Triassic salt basin in the Haltenbanken-Trænabanken area from a more normal marine area to the west and north-west.

The high prospectivity of the Halten Terrace is clearly related to its structural setting. The abundance of fault blocks and the intermediate structural position between the deep Møre and Vøring basins and the shallower Trøndelag Platform provides a near-optimal combination of maturity and structuring at the Jurassic level where the main source and reservoir rocks are found.

STRATIGRAPHY

Palaeozoic Rocks

None of the more than 20 wells drilled to date in the Haltenbanken area have penetrated rocks older than Triassic. Some of the seismic lines, however, show indications of pre-Triassic sedimentary succession. Devonian to Permian sedimentary rocks may be present in the area. Potential Devonian to Carboniferous strata are likely to consist of very thick coarse clastic successions, restricted to local fault bounded basins, while Permian deposits are probably thinner and of mixed clastic and carbonate facies.

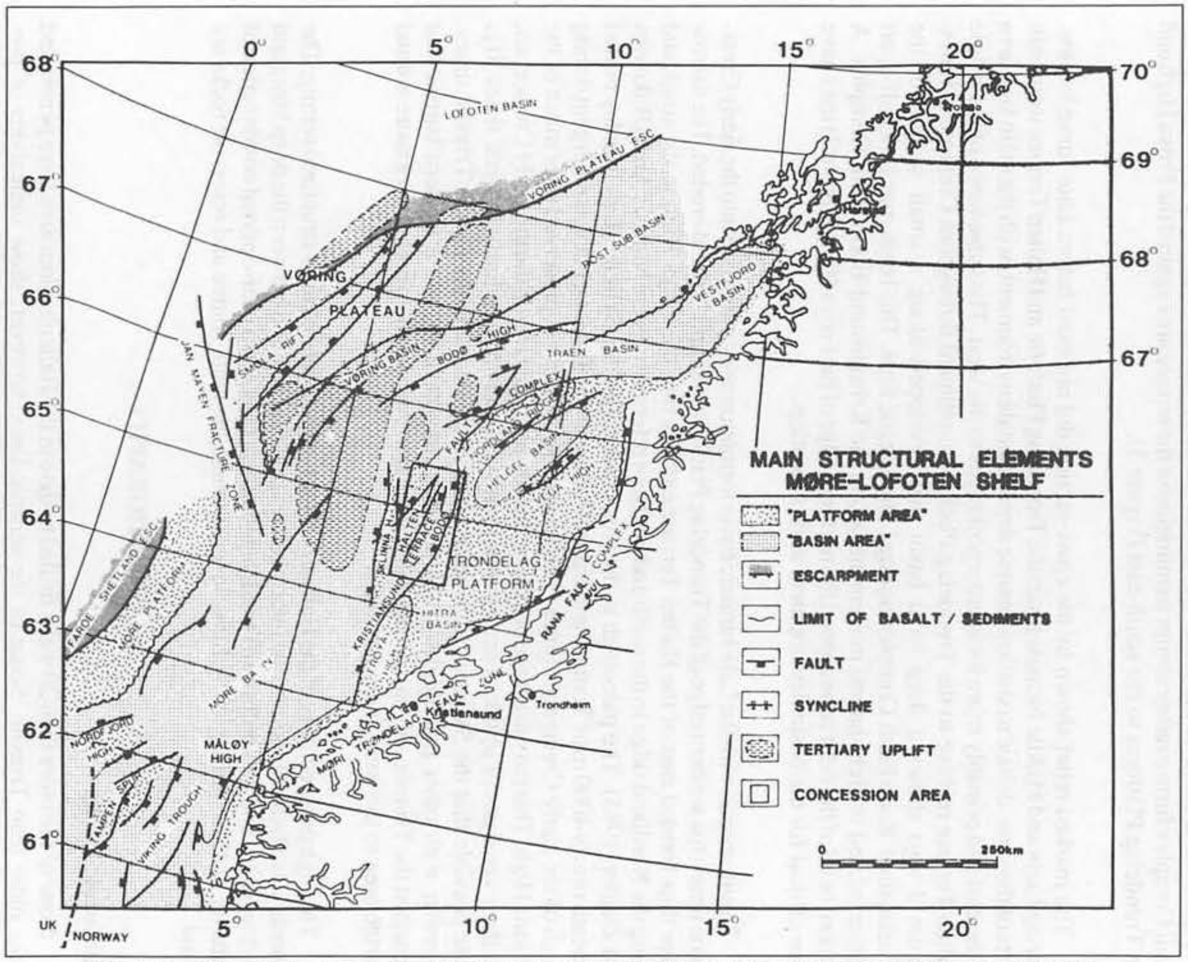

Figure 2: Main structural elements of the Mid-Norway continental shelf. Modified from Gabrielsen *et al.*, (1984)

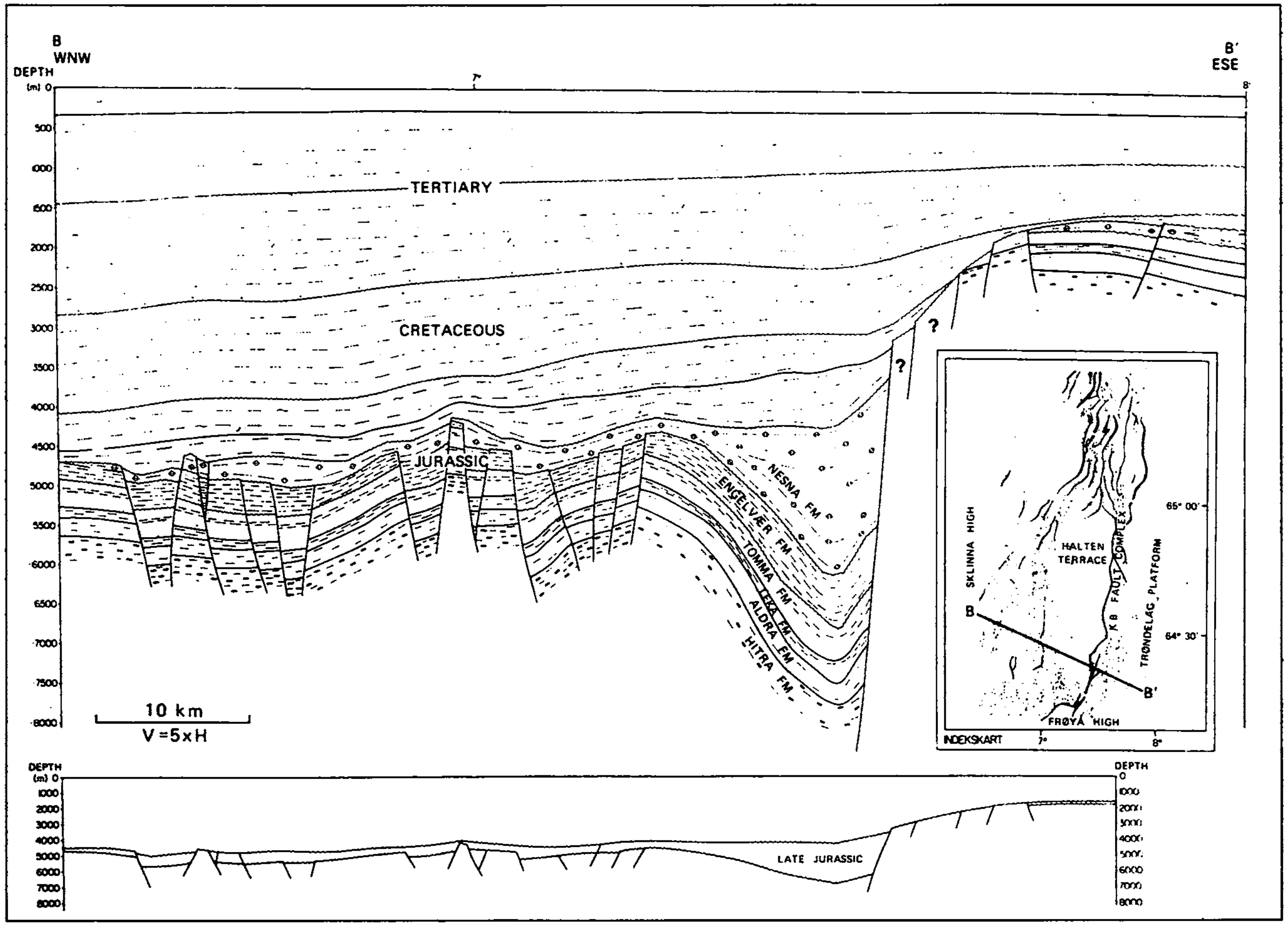

Figure 3: Structural/stratigraphic profile across Haltenbanken

In the Halten Terrace area Palaeozoic rocks are too deeply buried to be of economic interest, but future drilling on the Trøndelag Platform and possibly also on parts of the Sklinna High may prove the existence of Late Palaeozoic strata. According to Bukovics and Ziegler (1985) a very thick succession of Palaeozoic sediments is indicated at the inner part of the shelf beneath the Trøndelag Platform and Helgeland Basin.

The Drilled Stratigraphic Succession

The stratigraphic succession from the Middle Triassic and upwards is known from wells (Figure 4). It is important to note that the lithostratigraphic names used are not officially approved and that strong doubts have been expressed by some Norwegian stratigraphers about the appropriateness of employing geographical names from land areas for type sections in far offshore wells.

Parts or all of the Triassic to Recent succession have been described by Wiik-Jacobsen and van Veen (1984), Karlsson (1984), Aasheim and Larsen (1984) and Hollander (1984).

Triassic

Well 6507/12-2 penetrated more than 2500 m of Middle and Upper Triassic strata. Mudstones and finegrained sandstones of continental origin were found at the base, followed by two halite formations separated by a mudstone/anhydrite interval. The salt deposits are of marine origin (Jacobsen and van Veen 1984) and have a total thickness of about 800 m.

As mentioned earlier, the Triassic salt basins may have terminated against the Sklinna palaeohigh to the west. The configuration of the Møre Basin area during Triassic time is highly speculative, as the basin developed mainly during Cretaceous and Tertiary times and older strata lies too deep to be clearly identified by seismic lines.

The upper part of the Triassic in this well consists of a very thick mud dominated lacustrine to fluvial red bed sequence followed by a thinner more sandy "grey bed" series that are finally capped by a coal-bearing succession that continues into the Lower Jurassic. This 1000 m thick Upper Triassic succession reflects a shift from arid to humid climate towards the end of the period.

Jurassic

The coal-bearing Upper Triassic to Lower Jurassic succession, called the Hitra Formation, is found throughout the Haltenbanken area, and it is present also in the Trænabanken area. The formation is up to 500 m thick, consisting of shales, coals and sandstone beds. It is interpreted as fluvio-deltaic deposits and intercalated marine beds seem to be present only in the upper part. The Hitra Formation passes gradually upwards into the shallow marine sandstones of the Aldra Formation. This formation is also of wide lateral extent and is found both at Haltenbanken and Trænabanken.

The Hitra and Aldra formations may be regarded as a delta plain/delta front pair in a general transgressive situation. Fluvial input is indicated mainly in the lower part of the Aldra Formation, but the main part of the formation is interpreted in terms of marine nearshore to shallow offshore deposits. Tidal influence is suggested for some intervals (Karlsson 1984).

Through the whole Aldra succession there is an alternation of shale and mudstone units and sand units from less than a meter in thickness and up to a few tens of meters. The sand content generally increases towards the top of the formation. Many of the sand and shale units of this formation may be correlated laterally for several tens of kilometers, indicating a distinct sheet-like geometry of the units. The thickest development of the formation is in the western part of the Haltenbanken area, where it is up to 220 m thick.

The top of the Aldra Formation seems to be slightly truncated in many of the wells, and the upper boundary probably represents a minor hiatus in the succession.

Following a small regression that marked the end of the Lower Jurassic sand deposition of the Aldra Formation, the Leka Formation represents a major marine transgression over most of the Haltenbanken area. It is dominated by marine shales and mudstones with numerous laterally extensive coarsening upwards sand sequences, commonly containing storm-generated structures. As a whole, the Leka Formation shows an upwards coarsening trend.

The westernmost Haltenbanken wells show higher input of coarse-grained sand in the middle and lower part of the formation. Especially in the Smørbukk field, the lower part of the succession (if our correlation is correct) is dominated by coarse-grained crossbedded sand with marine trace fossils. The sand deposits had a source area to the west, which probably was formed by uplift of the Sklinna High. The local massive sandstones which are found only locally, are interpreted to be fan delta deposits. The Leka Formation is about 170 m thick in the south-western part of the Halten Terrace but decreases in thickness towards the north-east.

The overlying Tomma Formation is a sand dominated succession of late Toarcian to Bajocian or Bathonian age. The formation consists of 3 units, a lower sand unit up to 85 m thick, a silt- and mudstone unit with a maximum thickness in excess of 40 and an upper sandstone unit of up to 135 m in thickness.

All the units have their maximum thicknesses in the southwestern part of the Halten Terrace, and they all thin markedly towards the north-east. The base of the formation is defined at a laterally extensive carbonate cemented bed, interpreted as a hardground by Karlsson (1984). The upper boundary is a major unconformity and the upper sandstone unit is strongly truncated in many wells.

The lower sandstone unit was deposited in shallow marine offshore to coastal environments and consists of stacked bar sand deposits separated by thinner marine shales. In this respect it is somewhat similar to the Lower Jurassic Aldra Formation, but the sand to shale ratio of the Lower Tomma unit is generally somewhat higher, while the individual sand bodies are less easy to correlate from well to well. Signs of tidal influence are commonly observed within the unit. The unit probably prograded from east towards west or southwest.

A gradual transition to marine shales and siltstone marks the beginning of the middle siltstone "member" of the Tomma Formation. In the south-west, the lower part of the siltstone member (which is actually a pure shale) seems to be time equivalent to the last major sand lobe of the lower sandstone unit further to the north-east in the Halten Terrace area. This is the main reason for the apparent rapid eastward thinning of the siltstone member and it confirms the general southwestward direction of progradation for the lower part of the Tomma Formation. The siltstone member consists mainly of highly bioturbated siltstone and towards the top, micaceous sandstone, and has a general regressive character.

The upper unit of the Tomma Formation consists of a thick, rather uniform sandstone succession in the western part of the Halten Terrace area. Shaly interbeds are extremely rare and seldom more than a few centimeters in thickness. Parts of the sandstone unit are very coarse-grained and pebbly layers are common. Large-scale cross-bedding are commonly observed and occasional bioturbation suggest marginal marine conditions, but fluvial braided stream processes probably deposited parts of the succession. In the central to northern parts of the Halten Terrace the unit gets thinner, in part a result of more extensive truncation in this area. Low-angle crossbedding is a very common sedimentary structure and the inferred environment of deposition is foreshore to upper shoreface.

Just a few meters of cores have been studied from the eastern part of the area (the Trøndelag Platform). Here thicker shaly intervals are found between the sandstone beds and an abundance of coaly material may indicate nearby fluvial input or partly non-marine conditions. The apparent contradiction of having the most proximal deposits to the east and west and more clearly marine succession in between may be explained by a rejuvenation of the uplift along the Sklinna High to the west.

A western source for the upper Tomma sandstone was first suggested by Aasheim and Larsen (1984). They also interpreted the succession have been deposited in a fan delta environment. The upper Tomma sandstone shows a slightly more varied facies distribution than the Leka sandstone, but the facies association does not seem incompatible with a fan delta model. The eastern near-shore deposits were clearly not associated with fan deltas, and a more "normal" shoreline without nearby fault scarps is inferred for the Trøndelag Platform area.

The unconformity on top of the Tomma Formation is the result of late Middle Jurassic rifting activity in the area. Especially on the Trøndelag Platform the unconformity represents a large time gap.

The Engelvér Formation is a marine shale and siltstone unit, commonly 100 meters or less in thickness in the Haltenbanken wells, but considerably thicker locally, in areas downfaulted during the Middle Jurassic tectonic pulse. The marine transgression was much delayed in the Trøndelag Platform area compared to the Halten Terrace, indicating that the two areas now had started to behave as separate structural units. The Engelvér Formation is regarded as equivalent to the Heather Formation in North Sea and represents a transgressive phase in the area. Interbedded in the clay- and siltstones are thin fine grained sandstone layers and carbonate-cemented horizons. The succession is low in organic content and shows comparatively low gamma radiation. The environment of deposition is assumed to be open marine, mainly below wave base, but probably not very deep.

The Nesna Formation consists of dark-coloured shales and mudstones with a high content of organic material and characteristic high gamma radiation. It is generally thin (0 to 60 m) in the Haltenbanken wells, but is expected to be considerably thicker in down-faulted areas as shown by Figure 3. Dating of the formation spans from Late Oxfordian to

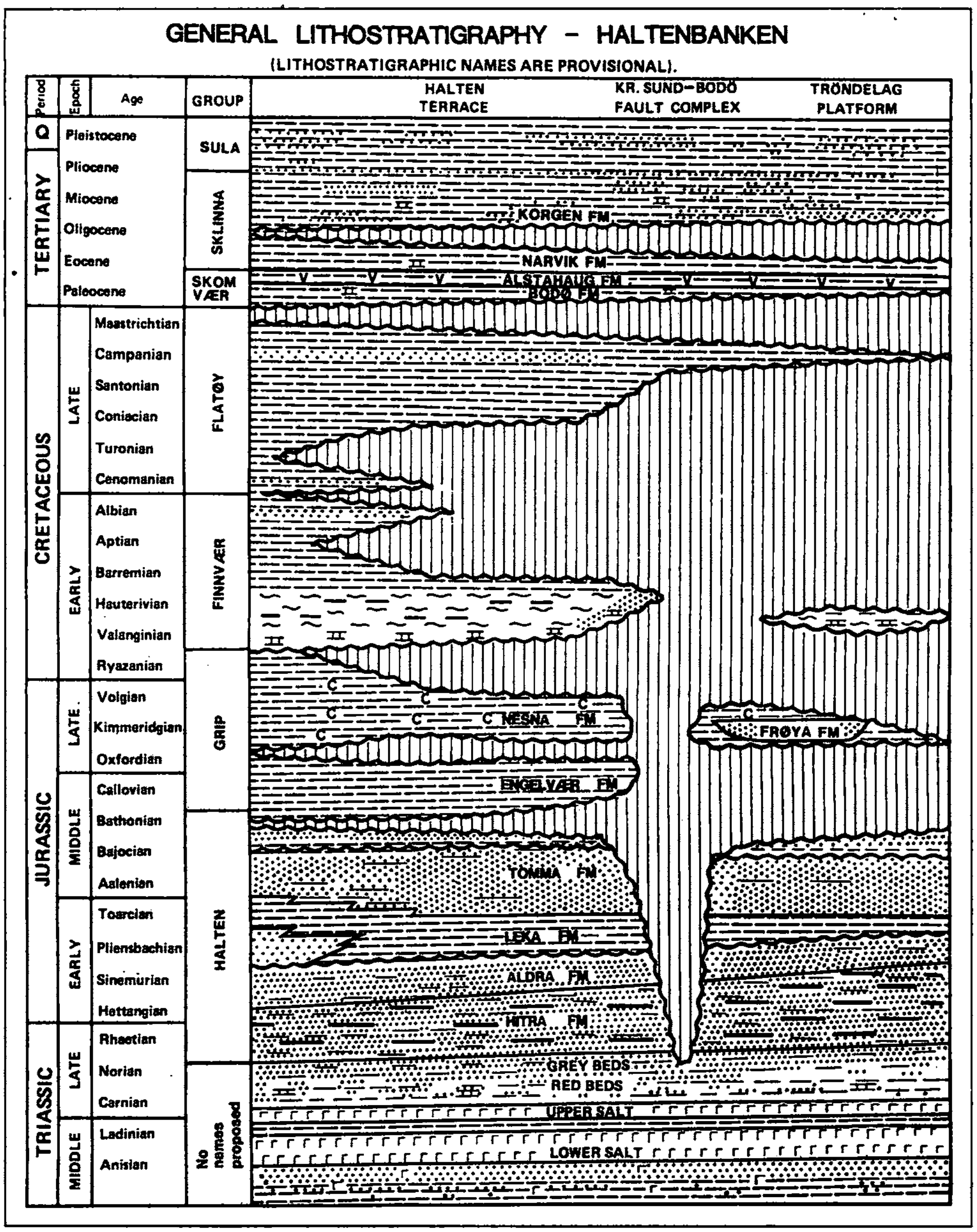

Figure 4: Lithostratigraphic units at Haltenbanken. Generalized east-west section.

Valanginian, but in most wells it has a much narrower age range. The formation is bounded by unconformities (Figure 4). The Late Kimmerian Unconformity, which defines the top of the formation is particularly pronounced in the area and is clearly seen on most seismic lines.

Cretaceous

The Cretaceous succession is dominated by marine shales and mudstones. In the lower part (Valanginian to Hauterivian) the mudstones are commonly calcareous and occasionally brick-red in colour. Sandy beds occur, but good reservoir sands have so far not been found in this part of the sequence.

Near mid-Cretaceous level, sands of turbiditic affinities are recorded in some of the wells, especially close to the Nordland Ridge area. Similar sands of Campanian age are present locally. The turbidite sands are clearly related to the relief created by the continued uplift of the Nordland Ridge and the Trøndelag Platform during much of the Cretaceous.

The Cretaceous succession is in excess of 2000 m thick in parts of the Halten Terrace area. To the east it laps into the major escarpment along the Kristiansund-Bodø Fault Complex (Figure 3). Commonly only the uppermost parts of the succession drapes over the uplifted areas. The Cretaceous shales are generally lean in organic content and no part of the succession seems to have good source rock potential.

Tertiary

The Tertiary succession is separated from the underlying Upper Cretaceous shales by a regional unconformity. The lower part of the succession is dominated by claystones of Paleocene to Early Oligocene age. A tuffaceous interval, the Alstahaug Formation (Figure 3), is supposed to be equivalent to the Balder Formation in the North Sea. An intra-Oligocene unconformity seems to be present all over the Haltenbanken area. Above this unconformity the succession is composed of thick units that on seismic lines can be seen prograding towards the west. The units are clay dominated, but contains numerous sandy intervals. The Tertiary succession is up to 2500 m thick in the western part of the Halten Terrace and gradually thins eastwards (Figure 3).

THE "SOURCEVAL" COMPUTER PROGRAMME

The "SOURCEVAL" computer programme is designed to model hydrocarbon generation, migration and accumulation. The programme, developed by Statoil, is frequently referred to throughout this paper and is hence briefly described here.

Figure 5 shows a simplified flow diagram for the programme based on mass balance. The programme can calculate:

- Generation of hydrocarbons from one or several source rocks (primary cracking of bitumens).
- Primary migration
- Secondary cracking of the hydrocarbons retained within the source rock (i.e. those that have not undergone primary migration)
- Loss during vertical secondary migration

- Loss during lateral secondary migration
- Recombination in the trap of all hydrocarbon components from all source rocks
- Phase relations in the trap including one/two phases, volumes, density, composition, shrinkage, expansion factor and GOR.
- Fill/Spill/Leak analysis
- Reservoir cracking analysis

The amount and type of input data varies according to the objective of the modelling. For a full 3D volumetric modelling the following main input data is necessary:

- Present pressure
- Present temperature
- Maturity versus depth (the programme does not calculate maturity, but can work with whatever information is available)
- Lithologies
- Rock volumes

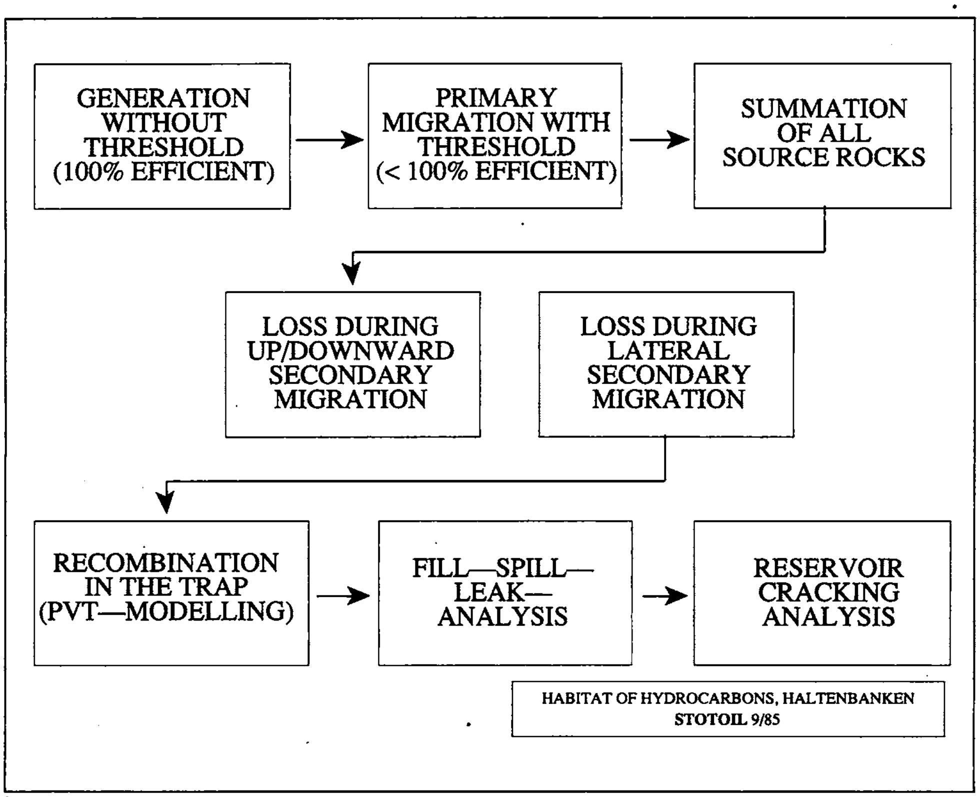

Figure 5: Generalized flow chart of the computer programme SOURCEVAL.

- Total Organic Carbon of the source rock and Generation Potential of the kerogens
- Source rock quality in terms of accumulative hydrocarbon composition at complete maturity

The four hydrocarbon components are methane (C1), wet gas (C2-C5), condensate (C6-C14) and oil (C15+). These component groups are very practical to use both in terms of data acquisition and in terms of PVT-modelling.

"SOURCEVAL" can also be applied to calculate generation and primary migration in 1D in individual source rocks as a function of depth (see examples in the next chapter).

In addition the programme can be used for separate PVT-modelling by direct input of hydrocarbon composition, nitrogen, carbon dioxide, pressure and temperature.

SOURCE ROCK PROPERTIES

Figure 6 presents an overview of some hydrocarbon related properties of the most important source rocks at Haltenbanken. Each "SOURCEVAL" diagram shows how generation, retention and primary migration (all expressed in mass) vary accumulatively with maturity. The diagrams also present data on kerogen type, total organic carbon (TOC), generation potential (GP) and the subdivision of the generation potential into the four hydrocarbon component groups. The component subdivision is based on quantitative pyrolysis gas chromatography which implies complete primary cracking (infinite maturity) and immediate expulsion. Hence no secondary cracking is included in the input data.

The "SOURCEVAL" diagrams work as follows:

The potential (TOC x GP) of each individual source rock is converted into hydrocarbon components as a function of the maturity. The internal storage capacity of the rock is related to the available pore space which decreases with increasing burial.

This volumetric storage capacity is converted into hydrocarbon mass by one of the PVT-modules at each modelling step based on the density of the present hydrocarbon composition.
When the internal storage capacity (left boundary curve in the diagram) is surmounted, primary migration occurs. The hydrocarbons left behind within the rock undergo secondary cracking to lighter hydrocarbons and heavier residues.

Figure 6 shows that the Upper Jurassic hot shale (Nesna Fm) is a fairly rich oil prone source rock comparable to the typical Kimmeridge Clay and Draupne formations of the North Sea. Primary migration starts at a maturity level of approximately 0.7% vitrinite reflectance (hereafter called VRE). Based on the most typical thicknesses at Haltenbanken the hot shale has a potential generative capacity of 7 to 20 million cubic meters of light oil per square kilometer at infinite maturity.

The Upper Jurassic cold shale (Engelvær Fm) is evidently not an important source rock at Haltenbanken. The potential is low, mainly for gas and primary migration starts very late at a maturity of approximately 1.7 VRE. The Engelvær Fm is considered representative also for the other shallow marine shales intercalated in the Aldra, Leka and Tomma formations.

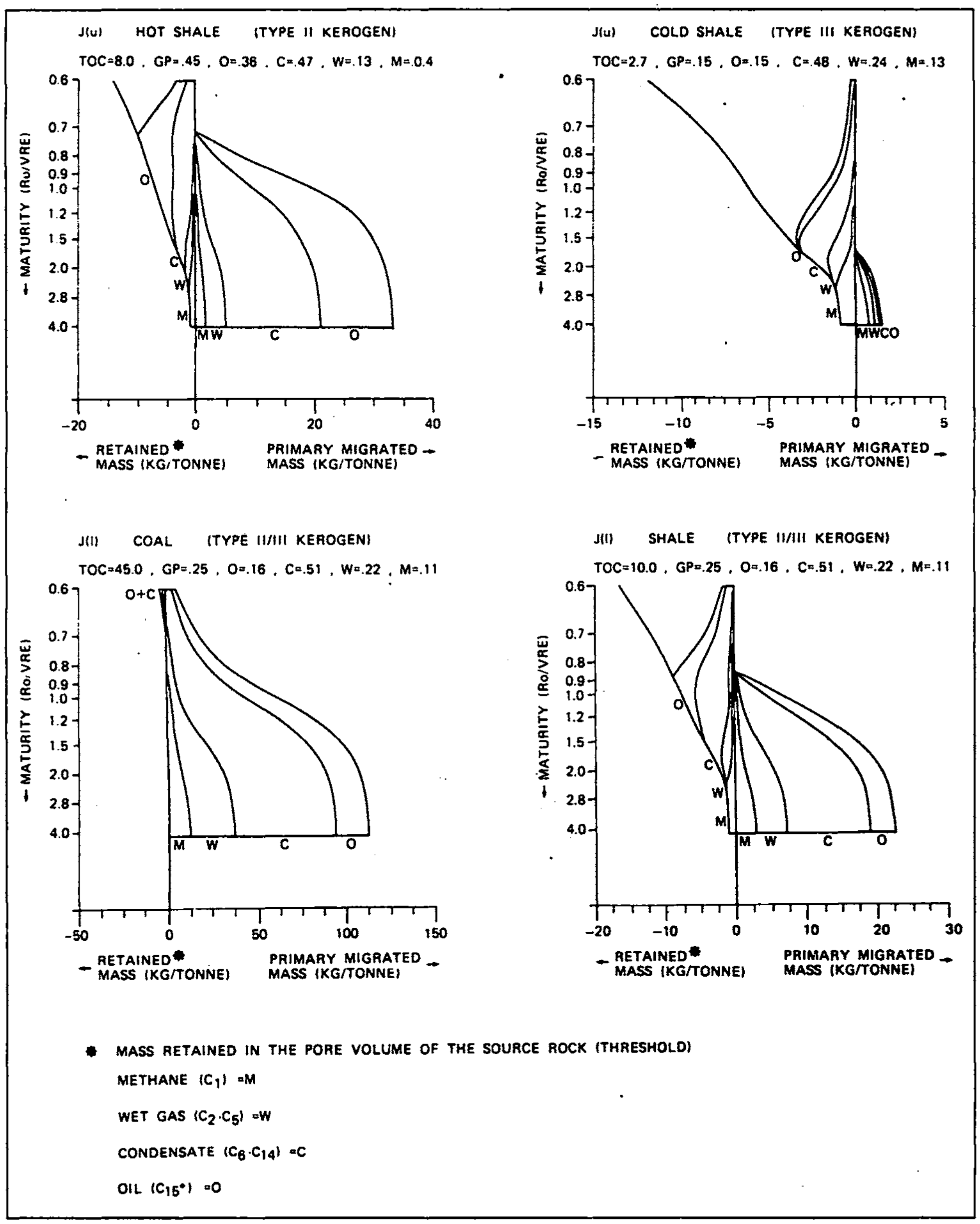

Figure 6: SOURCEVAL diagrams for representative source rocks at Haltenbanken.

The Lower Jurassic coal sequence is extremely rich in terms of organic content. The dominant hydrocarbon component generated is condensate, but considerable amounts of oil, wet gas and methane can also be expected. The primary migration of hydrocarbons from the coal beds proper is expected to start at approximately 0.54 VRE. Hence hydrocarbon shows and minor accumulations are to be expected within the coal sequence at a very early mature stage. However, primary (grading to secondary) migration out of the coal sequence as a whole into the overlying shallow marine sandstone carrier beds of Early to Middle Jurassic age probably does not occur before the maturity exceeds 0.65 VRE (based on a composition of 20% coal, 30% coaly shales and 50% sand).

The primary migration from a typical shale in the coal sequence seems to start at approximately 0.85 VRE. Based on its most typical thicknesses at Haltenbanken the coal sequence has a potential generative capacity of between 10 and 25 million cubic meters of liquids plus at least a similar amount of gases (at reservoir conditions) per square kilometer at infinite maturity.

The properties presented in the "SOURCEVAL" diagrams are based on extensive laboratory analyses. They are considered typical averages, but it must be emphasized that large variations occur both laterally between wells and vertically within each individual well sequence. It should also be emphasized that the compositional breakdown is based on a relatively new technique, and therefore subject to considerable uncertainty.

SOURCE ROCK MATURITY

Figure 7 illustrates the most important aspects of the thermal maturity at Haltenbanken. The right hand unbroken straight line indicates how the maturity of Lower Jurassic rocks (ideally in the middle of the coal sequence) increases *regionally* as a function of depth. Similarly the left hand unbroken line presents the *regional* maturity-depth relationship of the Upper Jurassic shales (ideally in the middle of the hot shale). In contrast the dotted curve shows how the maturity increases with depth at a single locality, the Tyrihans South well 6407/1-2, starting at approximately 0.6 VRE in the Upper Jurassic sequence and ending at approximately 1.0 in the Lower Jurassic coal sequence. The right side of figure 7 indicates the most important maturity milestones at Haltenbanken based on the "SOURCEVAL" analysis discussed earlier.

Four factors should be emphasized:

- Although the maturity curves are averages only, it is clear that the lateral variations in maturity profiles are small. This is likely to be due to the rather simple and uniform subsidence history of the Haltenbanken area.

- The curves are based on a combination of direct vitrinite reflectance measurements in the wells and maturity modelling. The latter is performed based on a modified TTI-method after Waples (1980).

- The direct measurements of VRE are very uncertain in the Upper Jurassic sequence due to a restricted content of vitrinite. The main part of the calibration is therefore based on

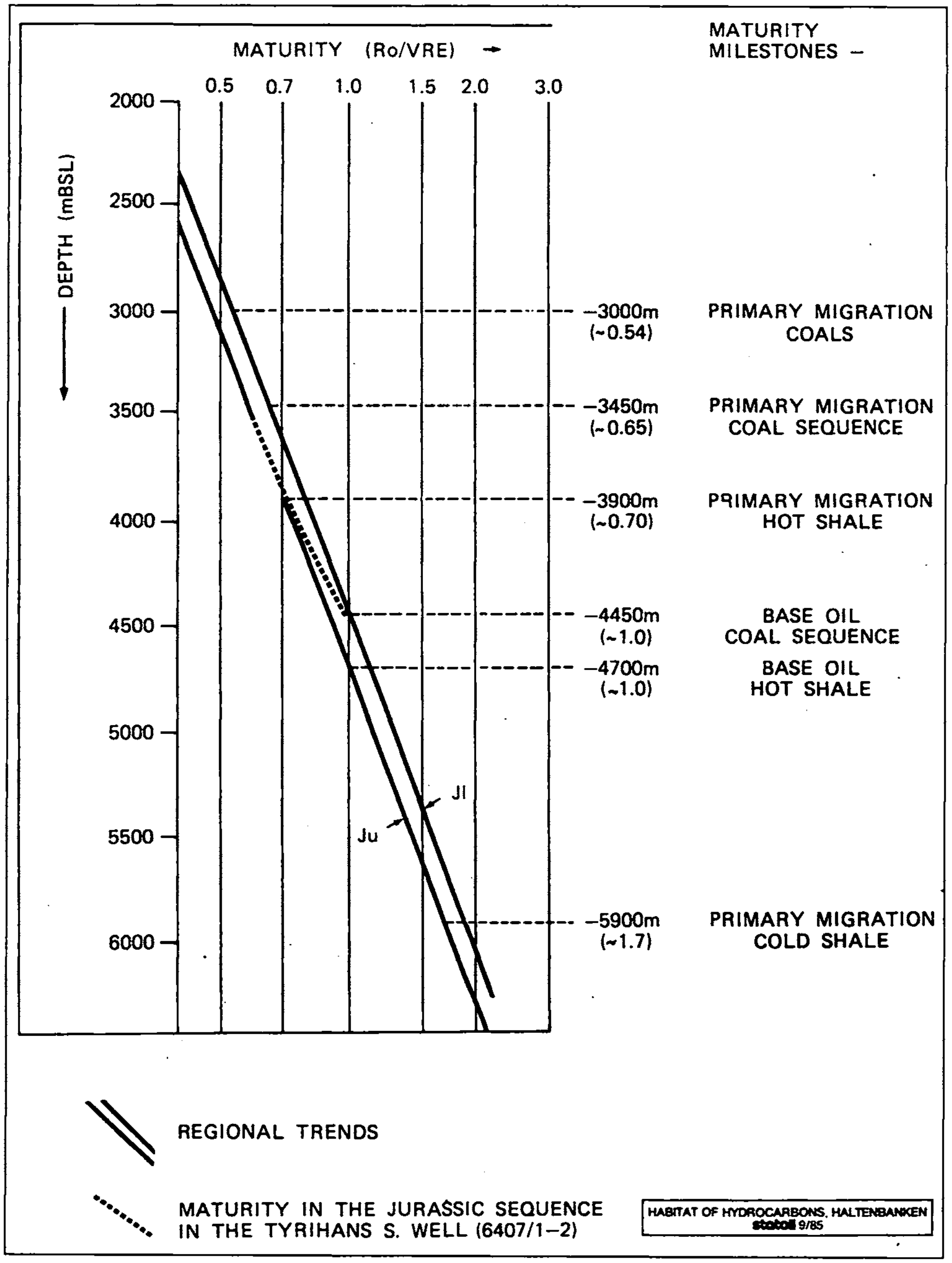

Figure 7: Maturity and depth of Haltenbanken.

measurements within the vitrinite-rich coals and coaly shales of the Lower Jurassic sequence.

- The maturity milestones, which quantify the onset of primary migration, are highly dependant on the properties of the source rock in question. Hence for instance if the coal content in the coal sequence were reduced to under 20% a higher VRE than 0.65 might be required to achieve the desired migration up into the overlying shallow marine sandstones.

HYDROCARBON TYPES

In this chapter the main aspects of the hydrocarbon habitat of Haltenbanken is discussed. Figure 8 presents the hydrocarbon types at Haltenbanken in relation to reservoir and source rock quality. Figure 9 shows the areal distribution of hydrocarbon accumulations in the Jurassic reservoirs as a function of source rock maturity, drainage conditions and structural setting.

Apart from the anomalous Draugen undersaturated oilfield, practically all the other hydrocarbon finds at Haltenbanken are saturated. All the oils are at their bubble point and all the gases at their dewpoint. Hence all oils are in a phase equilibrium with a gas phase and vice versa. This observation is very important for the understanding of the hydrocarbon habitat in the area. It implies that at present there is a relative balance between the migration of liquids and gases from the mature part of the basin. This fits well with the overall picture of the present maturity levels in the area. All these fields have drainage areas extending down into the late mature parts of the basin, i.e. where both gases, condensates and oils are being generated today.

The saturated hydrocarbon finds can be subdivided into two main classes according to structural setting. The deeper finds on the lower part of the Halten Terrace (except Tyrihans North) contain mainly very rich gas-condensate mixtures occasionally in phase equilibrium with ultra light oils. Typical Gas-Oil-Ratios (hereafter GOR) are between 500 and 1500 (volume per volume). The depths to the accumulations are typically 4000 m.

The shallower finds on the structural transition zone between the Trøndelag Platform, the Nordland Ridge and the Halten Terrace contain more polar hydrocarbons, i.e. relatively dry gases (GOR about 6000) and relatively low-gas oils (GOR about 150).

It is evident that the difference between the two main classes is directly related to the difference in physical conditions (temperature and pressure) since there is little difference in the hydrocarbon supply from the source rocks.

The individual difference between the major discoveries is discussed in more detail in the case history chapter below.

In addition to the discovery wells, ten dry wells have been drilled at Haltenbanken so far. Four of these were drilled in areas without migration routes from the mature basin. Three were drilled in positions where a closing mechanism is absent or very dubious. The last three were dry probably due to vertical leakage into permeable strata in the Cretaceous sequence. The

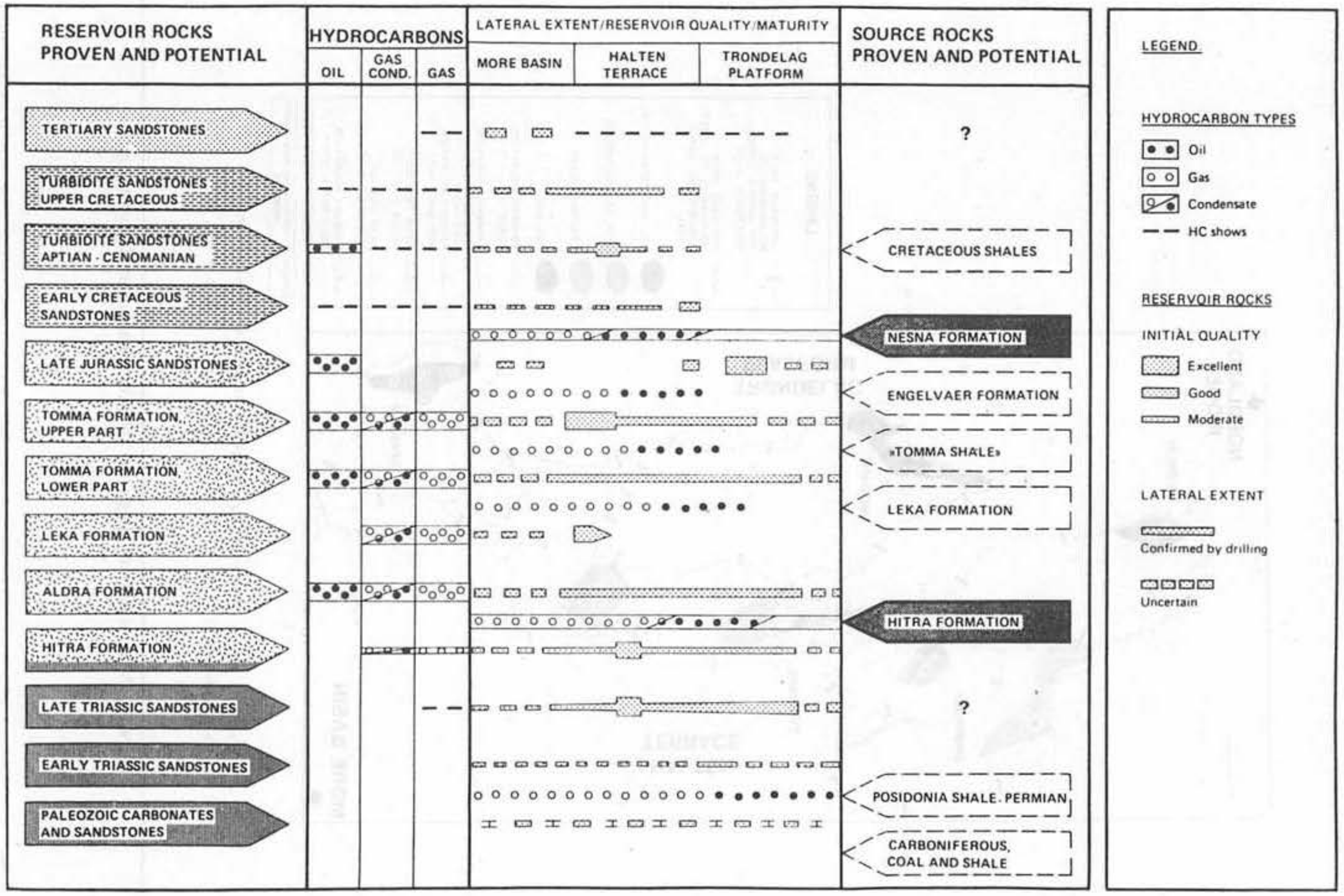

Figure 8: Stratigraphic distribution of hydrocarbon finds, reservoirs and source rocks in the Haltenbanken

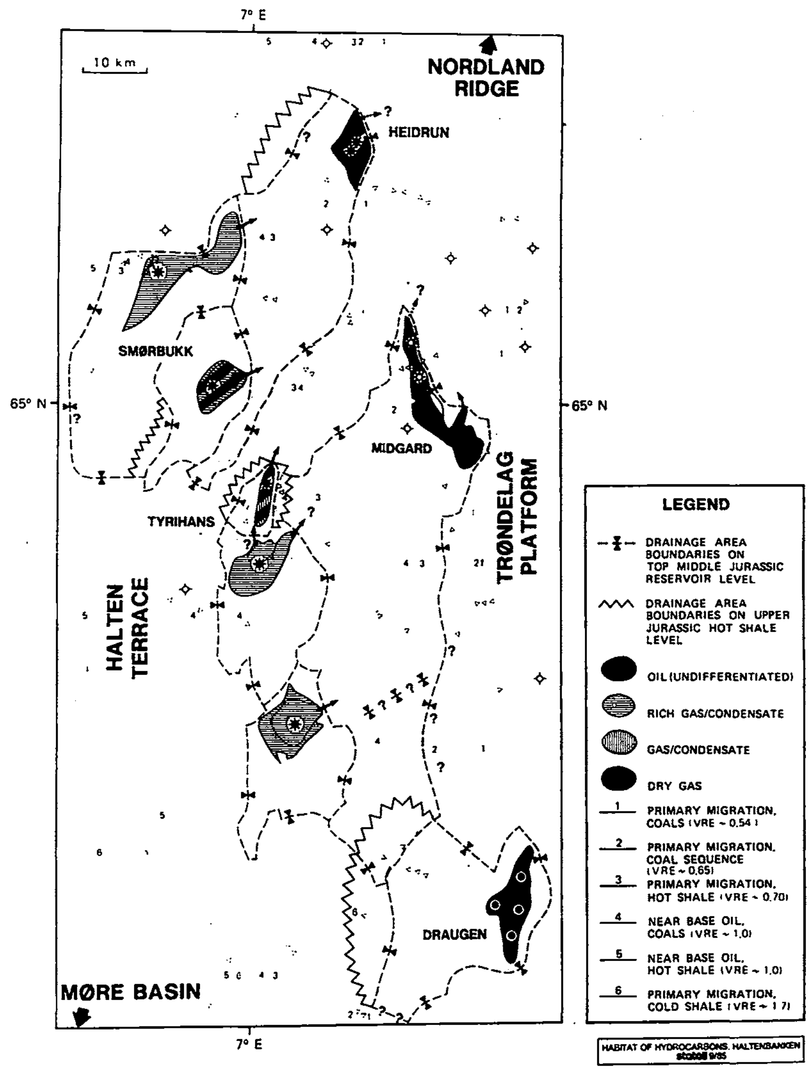

Fig. 9. Map on maturity, migration and accumulations at Haltenbanken.

Figure 9: Map on maturity, migration and accumulations at Haltenbanken.

discovery rate is approximately 50% when only the exploratory wells are considered.

MODELLING OF HYDROCARBON GENERATION AND MIGRATION AT TYRIHANS SOUTH

In order to increase the understanding of the conditions and mechanisms involved related to generation, migration and accumulation of hydrocarbons at Haltenbanken the Tyrihans South field was modelled using the "SOURCEVAL" programme. Figure 10 shows the "SOURCEVAL" BASE SCHEME FOR Tyrihans South. Drainage areas for all important stratigraphic levels in the Jurassic sequence are plotted as a function of depth. Maturity is superimposed for the Upper Jurassic shale units and for the Lower Jurassic coal sequence. Rock volumes between the maturity levels are listed in the base scheme table (assuming 30% shales and 20% coals in the coal sequence). In addition basic data on pressure, temperature and in place storage capacity are indicated. The arrows on the scheme illustrate the way migration is modelled, i.e. by following the hydrocarbons from each source rock vertically upwards (buoyancy) and downwards (hydraulic expulsion) into the top of the reservoir level, then laterally towards the trap (buoyancy). The generated and migrated masses modelled are listed for each source rock in table 1. The total amounts generated and migrated are summarized in the bar diagram of figure 11.

Most of the loss during the primary migration is modelled to be caused by the internal storage capacity of the pore volume in the shale units. This leads to variable primary

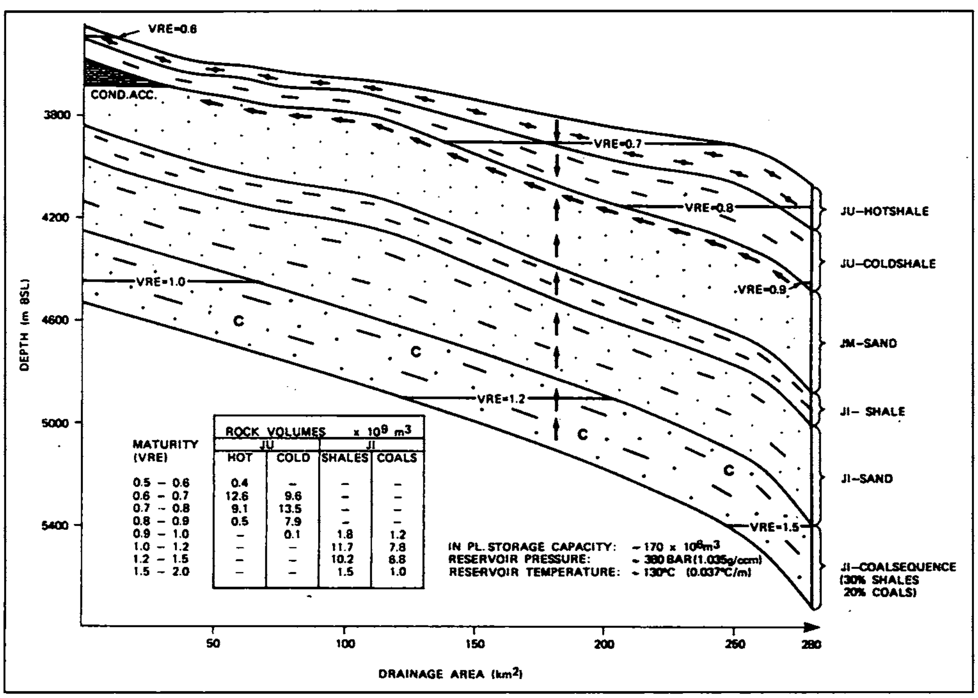

Figure 10: SOURCEVAL base scheme for Tyrihans South.

TABLE 1

DETAILED RESULTS OF GEOCHEMICAL MODELLING AT TYRIHANS SOUTH

Generated, primary migrated and secondary migrated hydrocarbons as a function of sourcerock, Tyrihans South (x 10^6 tonnes).

	Generated				Primary migrated			
	O	C	W	M	O	C	W	M
Jl-coals	630	1915	470	160	610	1860	455	155
Jl-shales	265	800	190	65	200	605	125	45
Ju-hot	360	295	20	10	100	80	6	2
Ju-cold	20	35	7	5	0	0	0	0
sum	1275	3045	687	240	910	2545	586	202
loss during secondary migration:					160	420	95	35
Approximately available to trap:					750	2125	490	165

M=C1, W=C2-C5, C=C6-C14, O=C15+

migration efficiencies dependant both on source rock richness, maturity and pore pressure. In the Tyrihans South case this efficiency is 0% for the Upper Jurassic cold shale, near 30% for the Upper Jurassic hot shale, near 75% for the Lower Jurassic shales and above 95% for the Lower Jurassic coals proper. Most of the loss during the secondary migration is modelled to be caused by the storage capacity of the sand/silt fraction of the total coal sequence (net/gross approximately 50%). The loss within the shallow marine sandstones of Early and Middle Jurassic age is modelled to be minimal. The overall migration efficiency (both primary and secondary) is modelled to be slightly below 70%.

When the total geologic history of Tyrihans South is considered, it is evident that the coal sequence must have been dominating completely over the Upper Jurassic hot shale in terms of generation and migration of hydrocarbons. It is also evident that the coal sequence has been responsible for a large portion of the heavier components, especially for condensates. However, the total volumes having passed the Tyrihans South structure are modelled to be in the order of 30 times the place storage capacity of the reservoir. Hence the hydrocarbons found today in the structure have been generated most recently in response to the subsidence of the last five million years. During this period the coal sequence passed the oil floor in most of the drainage area and began generating large amounts of gas. Therefore, when the timing effect is considered, also the hot shale has been contributing significantly to the hydrocarbons found today in Tyrihans South, especially to those in the heavy range.

Figure 12 shows two phase-envelopes from Tyrihans South. Envelope number one is based on a PVT-modelling of the measured composition in the drill stem test. It is clearly demonstrated that the hydrocarbons are in a state very close to the critical point, theoretically on the gas side. However, when taking into account the uncertainty in the composition measurements the true state could equally well be on the oil side of the critical point. Anyhow the fluid is definitely a near critical extremely rich gas/condensate mixture with a GOR of approximately 850 (volume pr. volume). Envelope two is based on the "SOURCEVAL" modelled accumulative composition. It is evident that the present inability to model the timing effect in "SOURCEVAL" leads to a too optimistic conclusion concerning the hydrocarbon type (oil) and low GOR (125).

PVT-MODELLING AS A PREDICTIVE TOOL IN EXPLORATION

PVT-modelling was introduced in the previous chapter on Tyrihans South. In this chapter other examples of the use of PVT-modelling in exploration will be discussed to illustrate the value of PVT-modelling as a predictive tool in exploration. At Tyrihans South the hydrocarbon component distribution is relatively even (Figure 13, bar diagram A). This type of distribution is typical for the majority of the hydrocarbons on the deeper part of the Halten Terrace where GOR varies from approximately 500 to approximately 1500 between and within individual fields. PVT-modelling of the hydrocarbons at Tyrihans South shows

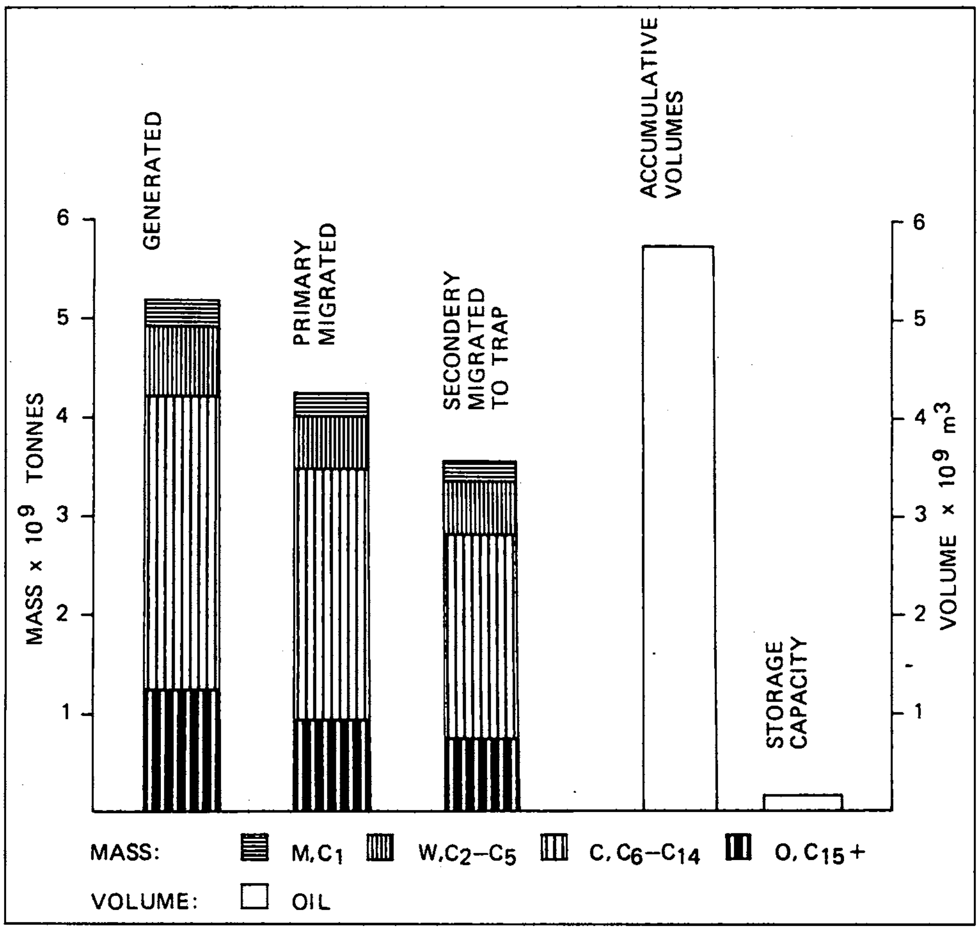

Figure 11: Summary results of geochemical modelling at Tyrihans South.

that the hydrocarbons are in a state near to the critical point. Even small changes in pressure, temperature or total composition in the model lead to a considerable change in phase conditions.

PVT-modelling also shows that the Tyrihans South gas/condensate accumulation (GOR 850) is in phase equilibrium with an almost identical ultra light oil (GOR 750). Similarly, slightly lighter gas/condensate systems (GOR 1000 to 1500 are generally in phase equilib-

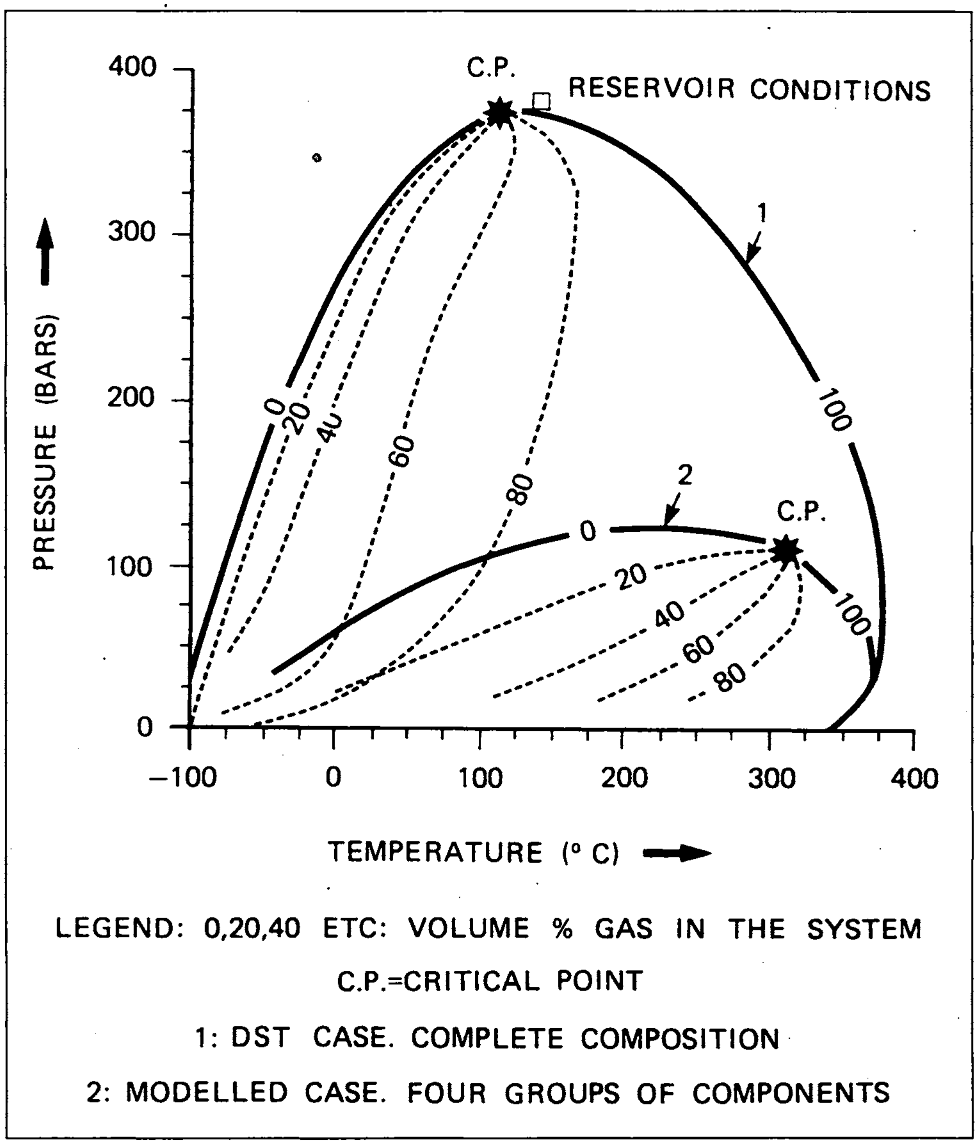

Figure 12: Comparison between measured and modelled phase envelopes at Tyrihans South.

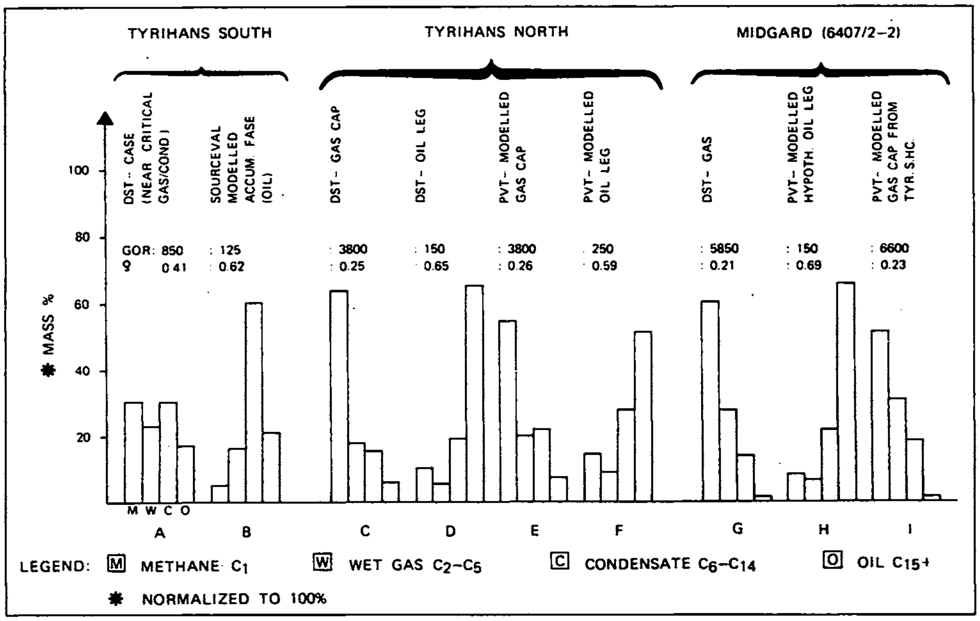

Figure 13: Comparison between measured and modelled hydrocarbon compositions at Tyrihans and Midgard fields.

rium with slightly heavier oil systems (GOR 650 to 500). For comparison, bar diagram B of fig. 13 represents the modelled hydrocarbon composition at Tyrihans South discussed in the chapter above.

Bar diagrams C and D of fig. 13 represent the measured composition in the gas cap and oil leg (in equilibrium) at Tyrihans North. The anomalously dry nature of the gas and the low GOR in the oil compared to the more typical Tyrihans South hydrocarbons is clearly demonstrated. This difference is difficult to explain based on geologic information alone, considering the identical pressure and temperature regimes and that the Tyrihans South accumulation probably spills directly into its northern neighbour. But in view of the fact that relatively small changes in composition can seriously alter the phase conditions under such near critical conditions as encountered on the lower part of the Halten Terrace, the difference becomes more easy to understand.

It is likely that the reason for the difference in hydrocarbon types between the two fields is related to the difference in the nature of the drainage area. Tyrihans South has a drainage area which covers all levels of maturity and hence all components in a gradational/continous way. Tyrihans North on the other hand has a drainage area with rather discontinuous maturity levels leading to a slight preference of the end components and consequently to a slight relative lack of the intermediate components. These differences are demonstrated both on the field overview map (Figure 9) and on the sketch illustrations of the Tyrihans fields (Figure 15 and 16). The hypothesis was tested by PVT-modelling. 70% of the Tyrihans South composition (Figure 13, bar diagram A) was added to 20% of methane and 10% of the stock tank oil from the drill stem test of the oil leg of Tyrihans North. Bar diagrams E and F of fig. 13 show the results, clearly demonstrating that the hypothesis discussed above is reasonable.

Bar diagram G of figure 13 indicates the measured composition in the Midgard well 6407/2-2. This well has been chosen as the most representative of the Midgard wells both in terms of vicinity to the mature basin and in terms of vicinity to the most likely spillpoint (Figure 9). In spite of the relative dry character of the gas, both laboratory analyses and PVT modelling show that the gas is at dew point, i.e. saturated with liquid and hence in equilibrium with a liquid phase. This liquid phase is present as an oil leg in at least one of the northern segments of Midgard, but has not been demonstrated in the southern segment. (This is probably related to the geometry and geologic history of the field and is discussed in more detail in the case history chapter). Nevertheless it is interesting that by reducing the pressure in the reservoir in the PVT-model one or two bars (dew point analysis), an oil phase comes out of solution with properties as indicated in bar diagram H of fig. 13. This modelled oil leg corresponds well with the proven oil leg found in the northern segment and is also probably representative of the oil presently spilling northeastwards to possible traps in that direction.

A similar boiling point analysis can be performed by investigating the likelihood and probable properties of a hypothetical gas cap if an oil zone is encountered in a downflank position in a well.

The difference between the dry gas at Midgard and the extremely rich gas/condensate mixture at Tyrihans South is at first glance enormous, and one would expect a totally different origin, that is from different source rocks or from different maturity levels. However, from a PVT point of view, the hydrocarbons differ only in terms of physical conditions, i.e. the pressure and temperature regimes. Bar diagram I of fig. 13 shows the results with a simple flash modelling taking the composition at Tyrihans South and reducing the pressure and temperature to the conditions at Midgard which is situated more than 1000 meters shallower. The majority of the liquid components drop out of solution and will spill away updip. The remaining gas modelled is quite comparable to the measured gas at Midgard as demonstrated in detail in fig. 14. (Note the relative difference between the carbon dioxide and the nitrogen demonstrating the difference in molecule size and hence difference in migration efficiency). Such an upflank flash analysis is relatively easy to perform because the composition can be applied independent of absolute amounts.

HYDROCARBON DISCOVERIES

In this chapter the most important case examples of discoveries at Haltenbanken are discussed to illustrate both the many similarities proving the common genetic origin of the hydrocarbons and the large differences due to structural setting, timing and PVT-conditions. The figure key to the hydrocarbon types of the figures 15 to 21 is identical to the figure key used in figure 9.

Case 1: Tyrihans South

The Tyrihans South field represents a base case for the near critical hydrocarbon systems on the lower part of the Halten Terrace. Figure 15 summarizes the migration and trapping

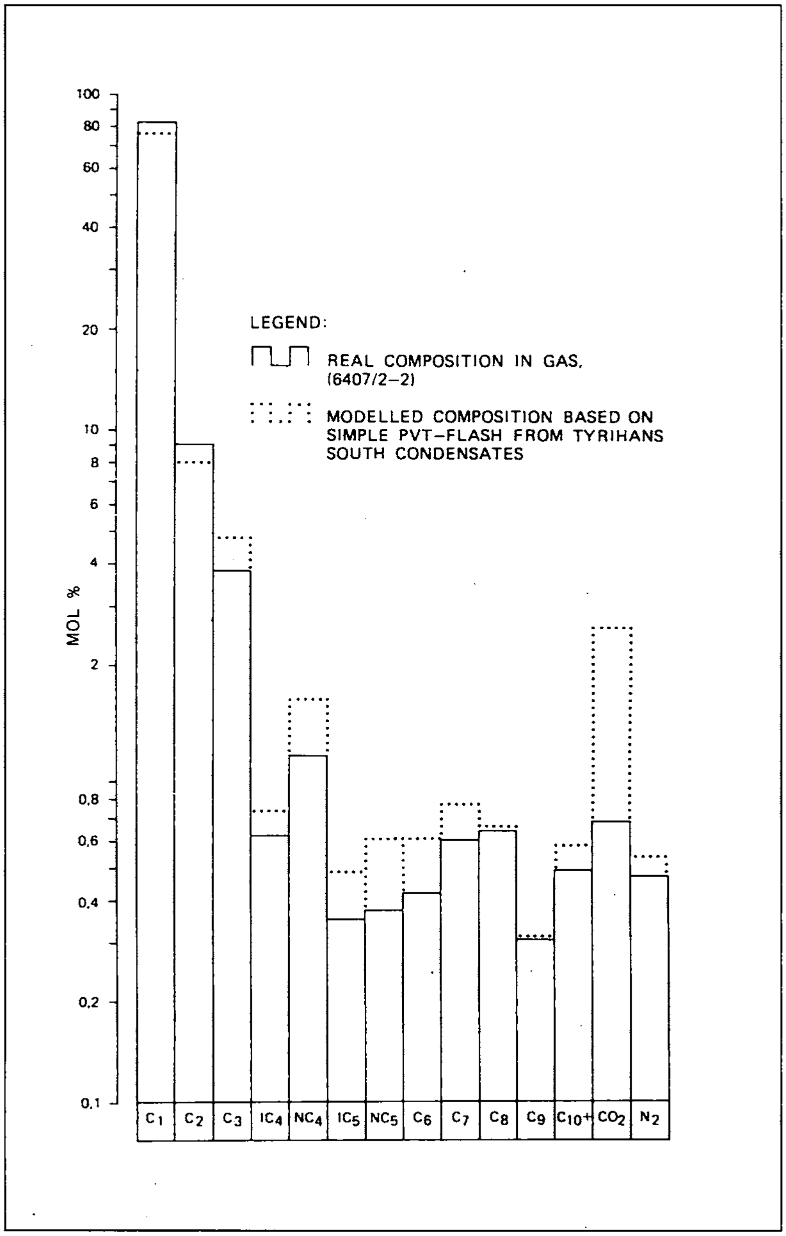

Figure 14: Detailed comparison between measured and modelled hydrocarbon composition at Midgard.

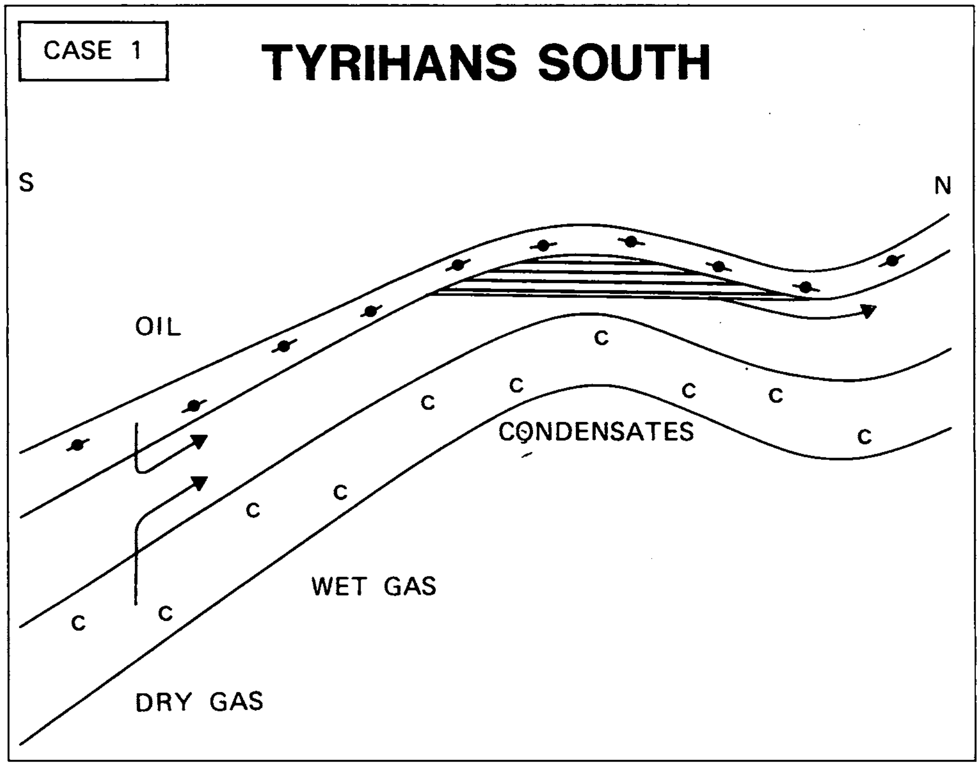

Figure 15: Case 1. Sketch of hydrocarbon migration and trapping conditions at Tyrihans South.

conditions for the field. The sketch indicates a simple fill-spill trapping mechanism and an anticlinal shape. The anticlinal shape is, however, modified locally by faults which although minor, provide a direct communication between the different stratigraphic sandstone levels in the structure and hence hinder a stacking of reservoirs. Other details of the field were discussed in earlier chapters. Case 1 is also fairly representative for the 6507/4-1 discovery just south of Tyrihans, although the hydrocarbons found there are slightly lighter due to a slightly higher degree of maturity in the drainage area.

Case 2: Tyrihans North

This is anomalous compositionally as discussed in detail in earlier chapters. Figure 16 summarizes the setting of the field, indicating a fault dependant fill-spill trapping mechanism. The thin oil leg (approximately 20 m) is typical for many dewpoint gas fields worldwide whenever the spillpoint is defined by a moderately small fault, and the reservoir sand is in direct contact with itself across the fault. Under such conditions oil and gas can spill simultaneously, the oil at the gas-oil contact and the gas at the proper structural spillpoint. This is related to the interaction between the buoyancy and surface tension properties of the oil and the gas and the pore/fracture geometry of the fault plane (capillary pressure).

Case 3: Smørbukk

Figure 17 illustrates the simple rotated fault block constituting the main trap at the Smø]rbukk field. The discovery well 6506/12-1 revealed multiple pay zones and an anomalously large hydrocarbon column. Based on pressure analyses, at least the upper reservoir zone of the field is most likely filled to spillpoint. The hydrocarbon composition varies slightly from zone to zone being moderately lighter than the hydrocarbons at Tyrihans South. Four factors are particularly important in creating the large columns and multiple pay zones at Smørbukk:

- The high pore pressure shales of the Lower Cretaceous and Upper Jurassic provide an ideal vertical seal.
- The dramatic pressure increase across the main fault (inferred from nearby drilling) probably inhibits any fluid leakage along or across the fault plane.
- The rotated fault block is completely devoid of internal relief faults restricting inter reservoir communication.
- The U-tube effect between the different reservoir zones at the crest of the structure reduces the relative pressure difference due to buoyancy, hence restricting the inter reservoir communication even further.

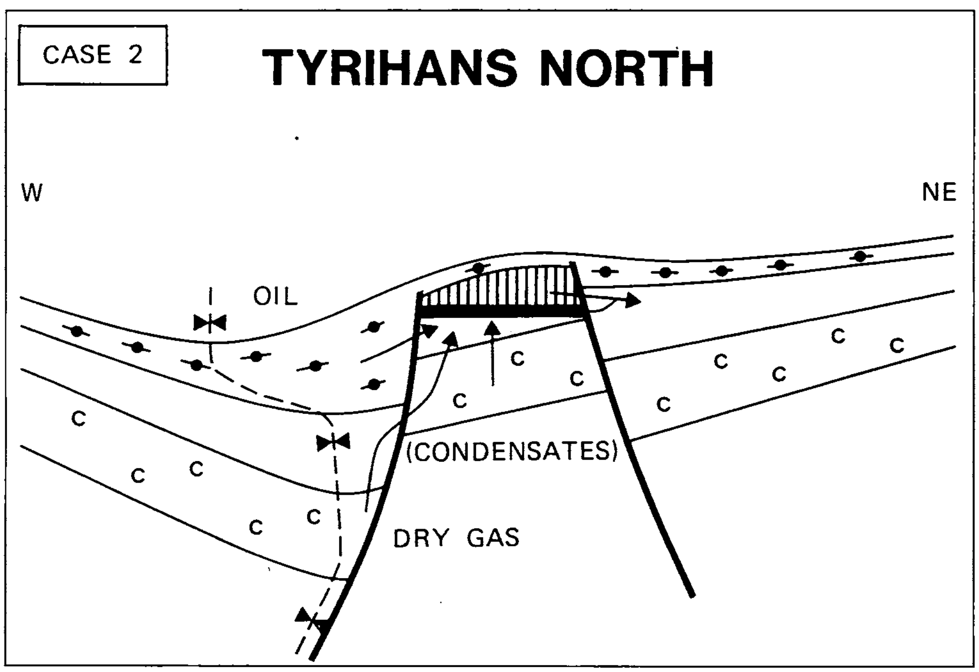

Figure 16: Case 2. Sketch of hydrocarbon migration and trapping conditions at Tyrihans North.

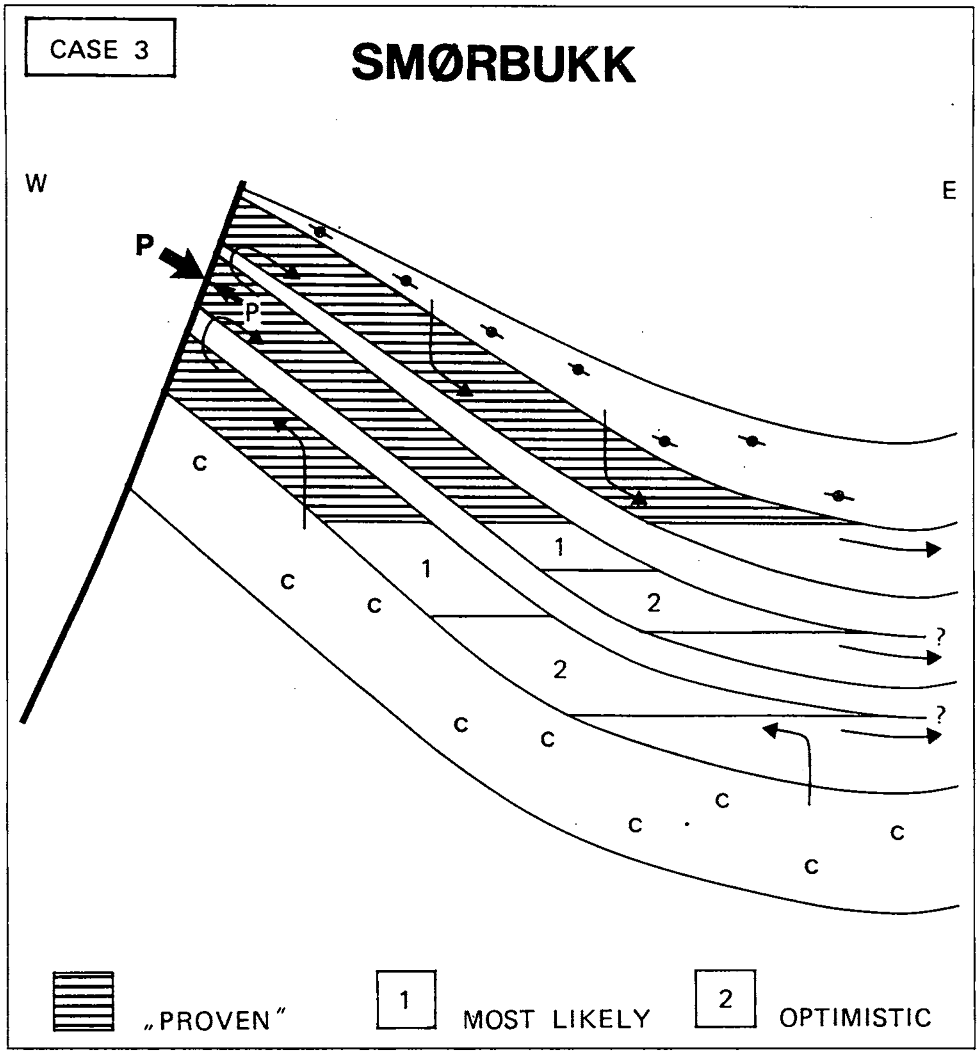

Figure 17: Case 3. Sketch of hydrocarbon migration trapping conditions at Smørbukk

The Smørbukk hydrocarbons are interpreted to be closely related to the Tyrihans South hydrocarbons. The slightly lighter nature at Smørbukk is related to the higher degree of maturity of the source rocks in the drainage area (Figure 9).

In spite of the large size of the Smørbukk structure, the modelling at Tyrihans South clearly demonstrates that the hydrocarbon supply in the area is large enough to fill the Smørbukk structure up several times.

Case 4: 6506/12-3 (Smørbukk satellite)

Figure 18 illustrates the setting of the southeastern Smørbukk satellite. The field is located in a similar setting to Tyrihans South, but the trap is perfectly anticlinal and hence ideal for multiple accumulations. Apparently there are three separate reservoirs all containing near critical two-phase equilibrium hydrocarbon systems as discussed in the PVT chapter.

From a migration point of view, the upper zone should be the most severely affected by oil migration from the Upper Jurassic hot shales of the Nesna Fm. Similarly, the lower zone should be the most affected by gas and condensate migration from the Lower Jurassic coal sequence (Hitra Fm). All three hydrocarbon systems seem however almost identical. This indicates that oil from the hot shale is at present migrating into all three zones. This probably occurs in an area south west of the field, where a relatively thick Upper Jurassic sequence is downfaulted and juxtaposed against all the reservoir zones (Figure 9). The identical nature of the three hydrocarbon systems probably also indicates that the intra reservoir shales form rather imperfect seals, letting the relatively lighter hydrocarbons from the coal sequence migrate upwards through the reservoir zones.

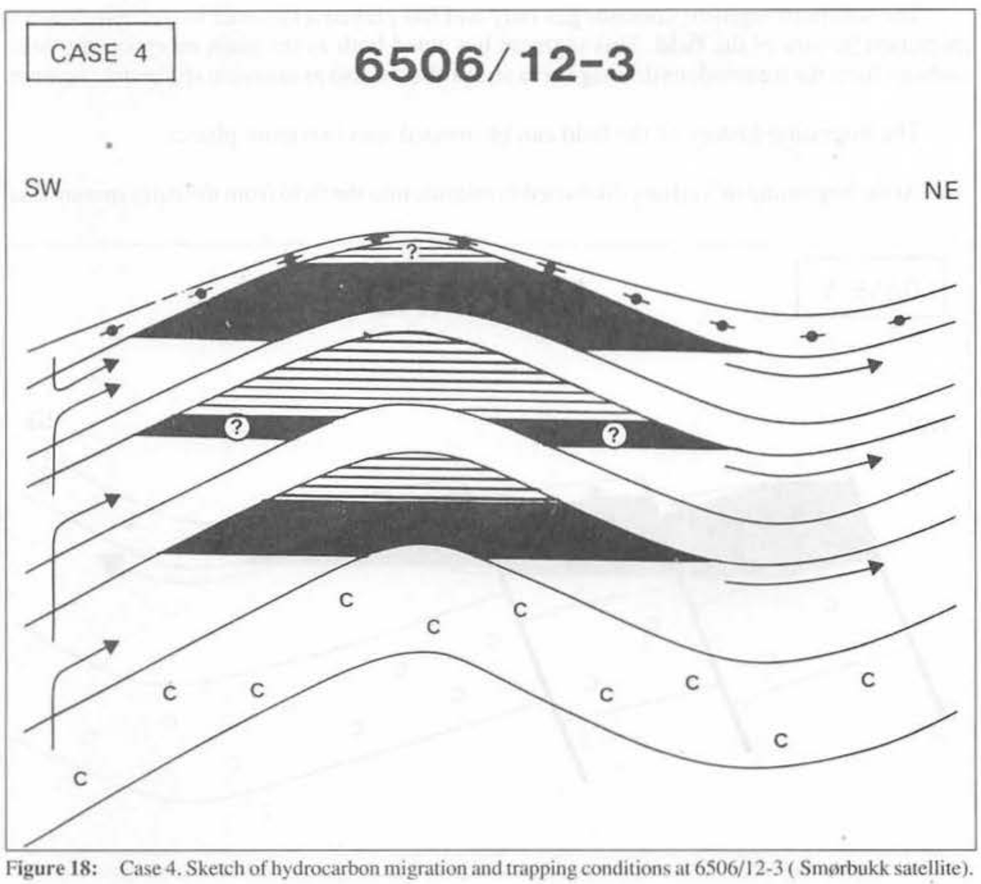

Figure 18: Case 4. Sketch of hydrocarbon migration and trapping conditions at 6506/12-3 (Smørbukk satellite).

The 6506/12-3 hydrocarbons are also interpreted to be closely related to the Tyrihans South hydrocarbons. The small differences are related to trapping mechanism, timing and difference in drainage conditions.

Case 5: Midgard

Figure 19 illustrates the Midgard field indicating a mixed fault dependent and fault independent fill-spill trapping mechanism. The field is a typical example of the two-phase accumulations with large phase separation to be expected along the structurally shallow transition zone between the Halten Terrace and the Trøndelag Platform.

The Midgard reservoir is divided into three main segments separated by moderate faults. All three segments contain mainly gas of approximately the same composition as indicated under the PVT-chapter above. The middle segment contains a thin oil leg proving the saturated nature of the gas. In the northern segment the nature of the hydrocarbons near the water contact was not clearly defined in the well due to a shaly lithology at the critical level, but there is probably a similar oil leg there too.

The southern segment contains gas only and has played a key role in the hydrocarbon migration history of the field. This segment has acted both as the main receptor of hydrocarbons from the tremendous drainage area and probably also as the main spillpoint segment.

The migration history of the field can be divided into two main phases.

- At the beginning of Tertiary oil started to migrate into the field from the early mature coal

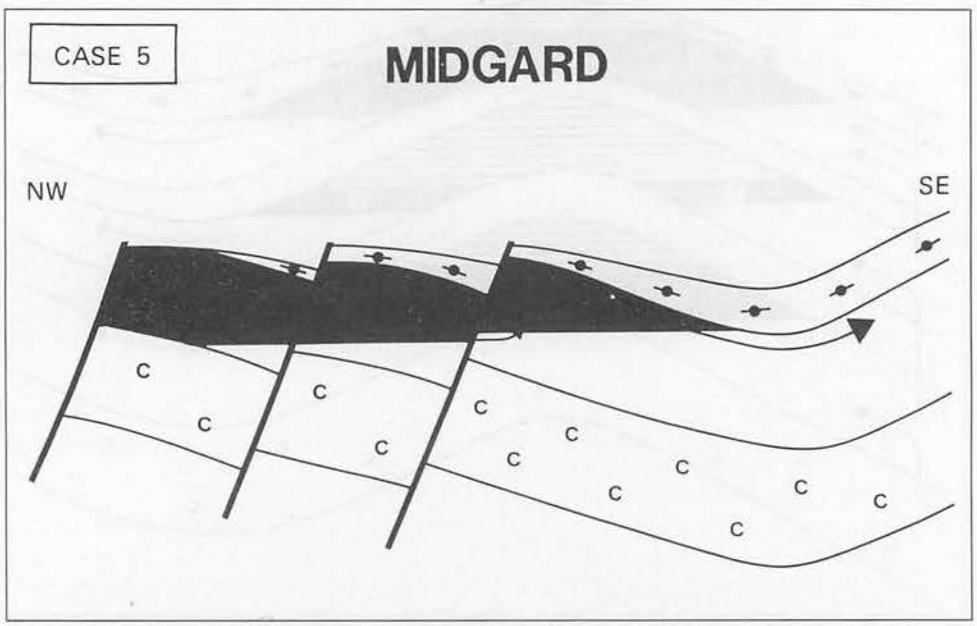

Figure 19: Case 5. Sketch of hydrocarbon migration and trapping conditions at Midgard.

sequence in the deepest parts of the drainage area. Oil migration dominated until late Tertiary as successively shallower parts of the drainage area became mature. The field was filled up with oil, probably several times.

- In late Tertiary oil also began to migrate from the hot shale, but at this stage gas was generated in such amounts from the late mature coal sequence in the basin that the hydrocarbons at Midgard changed phase from oil to gas. After this phase change most of the liquid hydrocarbons migrating to the trap have spilled along the overall gas/water contact towards the north.

The oil of the northern segments at Midgard is interpreted to be related to the presence of the fault bounding those segments towards the south, i.e. related to the buoyancy and capillary pressure characteristics across that fault (see also the discussion under case 2, Tyrihans North).

In contrast, the apparent lack of an oil leg in the southern segment seems to be related to the lack of a prominent spillpoint fault. Analyses of buoyancy vs. capillary pressure for the reservoir characteristics of the Midgard field (given no fault) indicates an oil leg thickness in the order of a foot or less. Hence the oil leg may exist, but will of course be exceedingly difficult to detect in a well.

Case 6: Heidrun

Figure 20 illustrates the trapping conditions of the Heidrun field. The migration history of the field is similar to that of the Midgard field. A relatively thick upper Jurassic sedimentary package in the oil window west of the field (Figure 9) probably contains rather large amounts of hot shale, but this has most likely only a moderate effect on the end result. The dominating hydrocarbon supply has come from the mature source rocks of the very large drainage area towards the south west. The field has also received major quantities of spill from the Smørbukk fields.

In contrast to the simple setting at Midgard, the structural and stratigraphic conditions at the structural spillpoint at Heidrun are so complicated that normal fill-spill cannot occur. Instead seat leakage towards the northeast or down flank spill seem to be important mechanisms. This is evidenced by the thick oil leg which would be impossible under normal fill-spill conditions.

Case 7: Draugen

Figure 21 illustrates the structural setting and trapping conditions at Draugen. As discussed in the hydrocarbon habitat chapter, the oil in the Draugen field represents the only significantly undersaturated liquid encountered so far offshore northern Norway. This anomaly correlates, however with an equally anomalous basinal setting. Large volumes of fully mature hot shale in the drainage area have generated oils migrating eastwards. The coal sequence, however is largely overmature. The remaining hydrocarbons generated from the coal sequence consist of dry gas which to a large extent has migrated westwards. The Draugen oil field is therefore mainly a consequence of differential migration from the two main source rocks in the area.

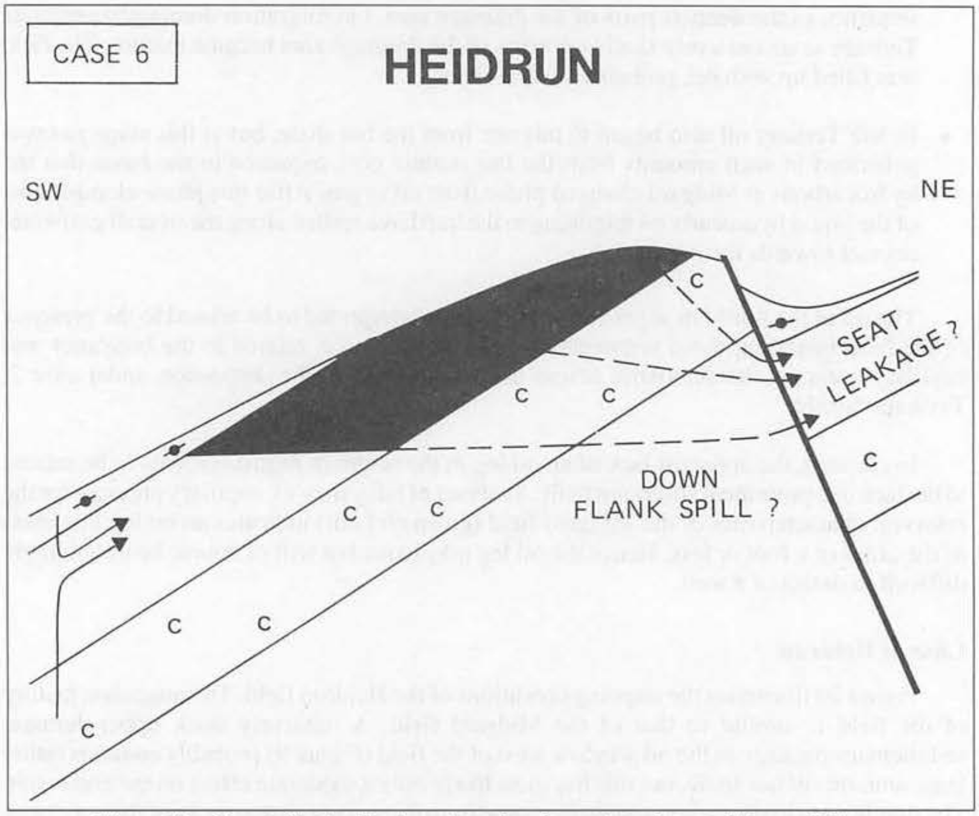

Figure 20: Case 6. Sketch of hydrocarbon migration and trapping conditions at Heidrun.

CONCLUSIONS

Haltenbanken is one of the most prolific hydrocarbon provinces in the world. Numerous large and giant oil and gas fields have been discovered so far, and still the exploration potential is large. The generative potential of the source rocks at Haltenbanken is enormous and vastly exceeds the storage capacity of the traps in the area.

The Lower Jurassic coal sequence (Hitra Fm) is by far the most important source rock for both liquids and gases, especially when the total amounts generated over the geologic history are considered. However, when the timing is considered, the Upper Jurassic hot shale (Nesna Fm) is also important, especially for oil.

At present oil is being generated from the Upper Jurassic hot shale in the lower part of the Halten Terrace. Simultaneously, from the Lower Jurassic coal sequence, gas and condensates are being generated on the Halten Terrace and oil in the structurally shallower transition zone up towards the Trøndelag Platform. Consequently most of the fields at

Haltenbanken contain saturated mixtures of oil and gas comprising both two phase systems and mono phase gas/condensates. The most important exception is the Draugen oil field with only minor amounts of gas.

The discovery rate is approximately 50 percent. There are large differences in hydrocarbon content and structural setting between individual fields, but there are also many similarities, proving the common genetic origin of the hydrocarbons.

The basic PVT properties (pressure, temperature and hydrocarbon component distribution) have a critical influence on the hydrocarbon phase relations found in the discoveries.

The predictive force and multiple applications of PVT modelling have been demonstrated through a number of examples. These include both general basin modelling applications (density, phase relations, gas oil ratios etc.) and special exploration applications (flash analysis, dew point analysis, boiling point analysis etc.).

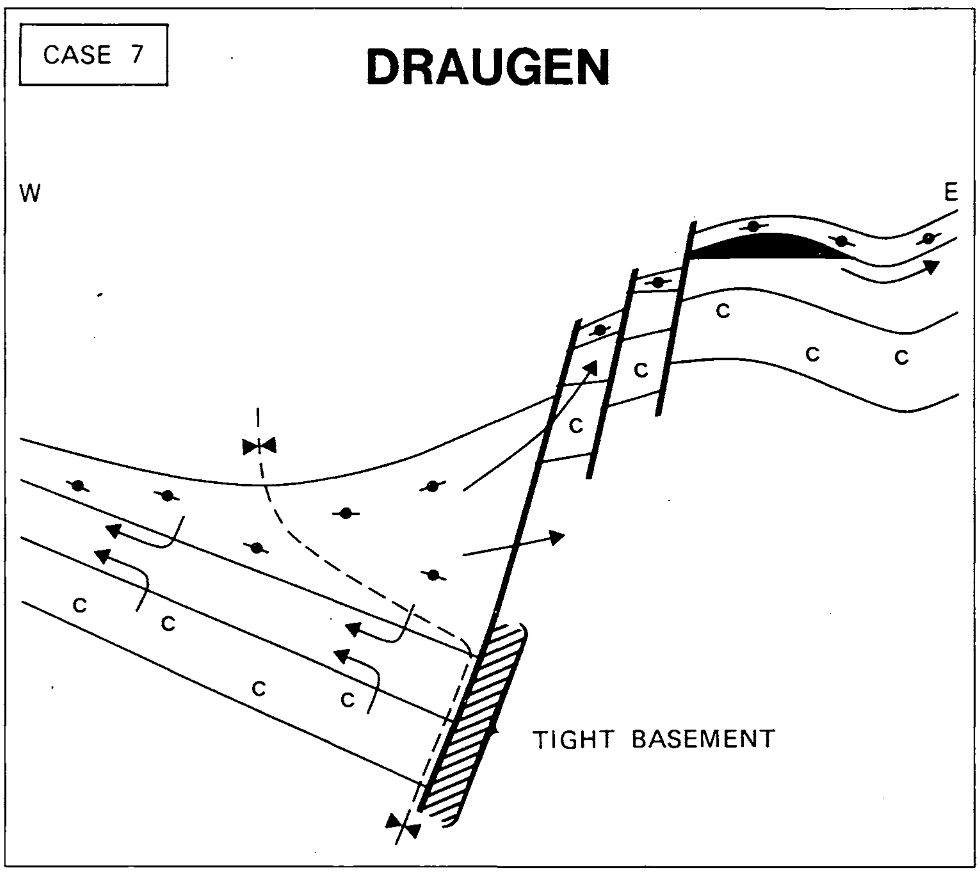

Figure 21: Case 7. Sketch of hydrocarbon migration and trapping conditions at Draugen.

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