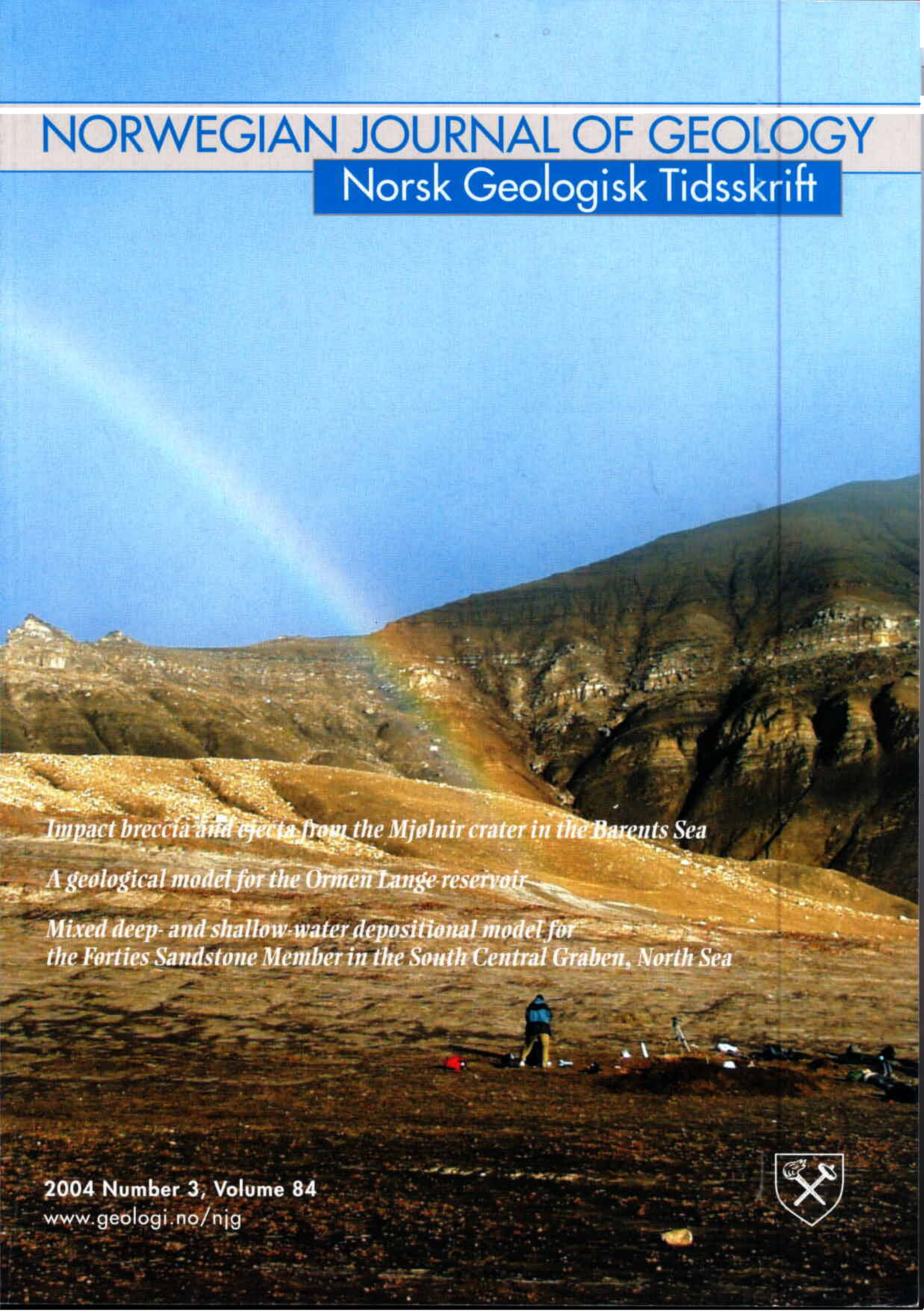
NORWEGIAN JOURNAL OF GEOLOGY
Norsk Geologisk Tidsskrift



Impact breccia and ejecta from the Mjølnir crater in the Barents Sea

A geological model for the Ormen Lange reservoir

Mixed deep- and shallow-water depositional model for the Forties Sandstone Member in the South Central Graben, North Sea

2004 Number 3, Volume 84
www.geologi.no/njg

A geological model for the Ormen Lange hydrocarbon reservoir

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Möller, N. K., Gjelberg, J.G., Martinsen, O. M., Charnock M.A, Færseth, R.B., Sperrevik, S. & Cartwright, J. A.: A geological model for the Ormen Lange hydrocarbon reservoir. Norwegian Journal of Geology, Vol. 84, pp. 169-190, Oslo 2004. ISSN 029-196X.

The Paleocene Egga Reservoir Unit of the Ormen Lange Field was deposited by high-density turbidity currents in a N-S elongated, structurally controlled sub-basin. A weak saddle area, separating two depressions, characterized the sea floor topography of this Ormen Lange Basin. The basin probably narrowed considerably towards the North, and the basin floor was tilted slightly towards the East. Deposition was confined by topography, preferentially preserving the coarsest grained deposits of the most powerful suspension currents. Basin topography was continuously or sporadically rejuvenated by differential subsidence along propagating polygonal faults due to the differential compaction of underlying Cretaceous shales. A high quality reservoir was then generated all the way up to the northern field boundary. Fault planes are frequent and are characterized by strongly varying throws. They generally juxtapose sand-rich reservoirs in the upper part and more clay-rich rocks towards the base. Combined with their early origin these fault characteristics may explain the observed static communication within the gas zone and pressure compartmentalization of the water zone. As the Egga reservoir unit is over- and underlain by sealing shales over large parts of the structure, it locally retains basal "water pockets" up to more than 100 m above the gas-water/oil-water contact.

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Introduction

The giant Ormen Lange gas field is situated in the Møre Basin below the Storegga Slide scar. Water depths are around 1000 m. A rugged topography and temperatures around –2°C at the sea floor complicate the future development.

Gas fills the southern part of a north-south elongated Eocene dome structure as indicated by direct hydrocarbon indications on the seismic (DHI). The exploration history of the field is summarized in the appendix. Reservoir sandstones were deposited by turbidity currents in the Cretaceous/Tertiary (Maastrichtian/Danian) transitional period. The geological description of the reservoir is complicated by noise in the seismic data. Furthermore a network of polygonal faults transects the reservoir, causing a complex filling situation with stepping hydrocarbon contacts, and water-filled sandstones high above free water levels.

Two seismic reflectors have been interpreted, one close to the top of the gas reservoir and one close below Top Cretaceous. The 'Egga' main reservoir unit is found between these two surfaces. It represents the progradation of a sand-rich submarine fan system into a north-south elongated depression on the palaeo-sea floor. Sediment accumulation was slow, probably due to high rates of bypass (of well locations) and re-suspension, as indicated by frequent amalgamation and erosion surfaces. Deposition is assumed to have been controlled by topography, causing flow stripping and focussing of the stream lines of the suspension currents, generating an excellent reservoir quality in this unit.

Polygonal faults propagated through the reservoir sandstones during deposition. It is not completely understood what effect these will have on gas production. Underlying units (described below) are more heterogeneous than the main Egga Reservoir Unit and have significantly lower hydrocarbon potential. Cores and logs from the five wells in the area and a high-resolution biostratigraphic well correlation have been integrated to develop a dynamic depositional model. This was used as a basis for digital 3D modelling and reservoir simulations.

Modelling and dynamic reservoir simulation work showed that estimates of in place resources to some extent are influenced by uncertainty in the sedimentological interpretation, while the recovery factor will vary depending on the extent of dynamic fault sealing. The development concept for the Ormen Lange field thus has to be flexible with respect to these unresolved geological factors.

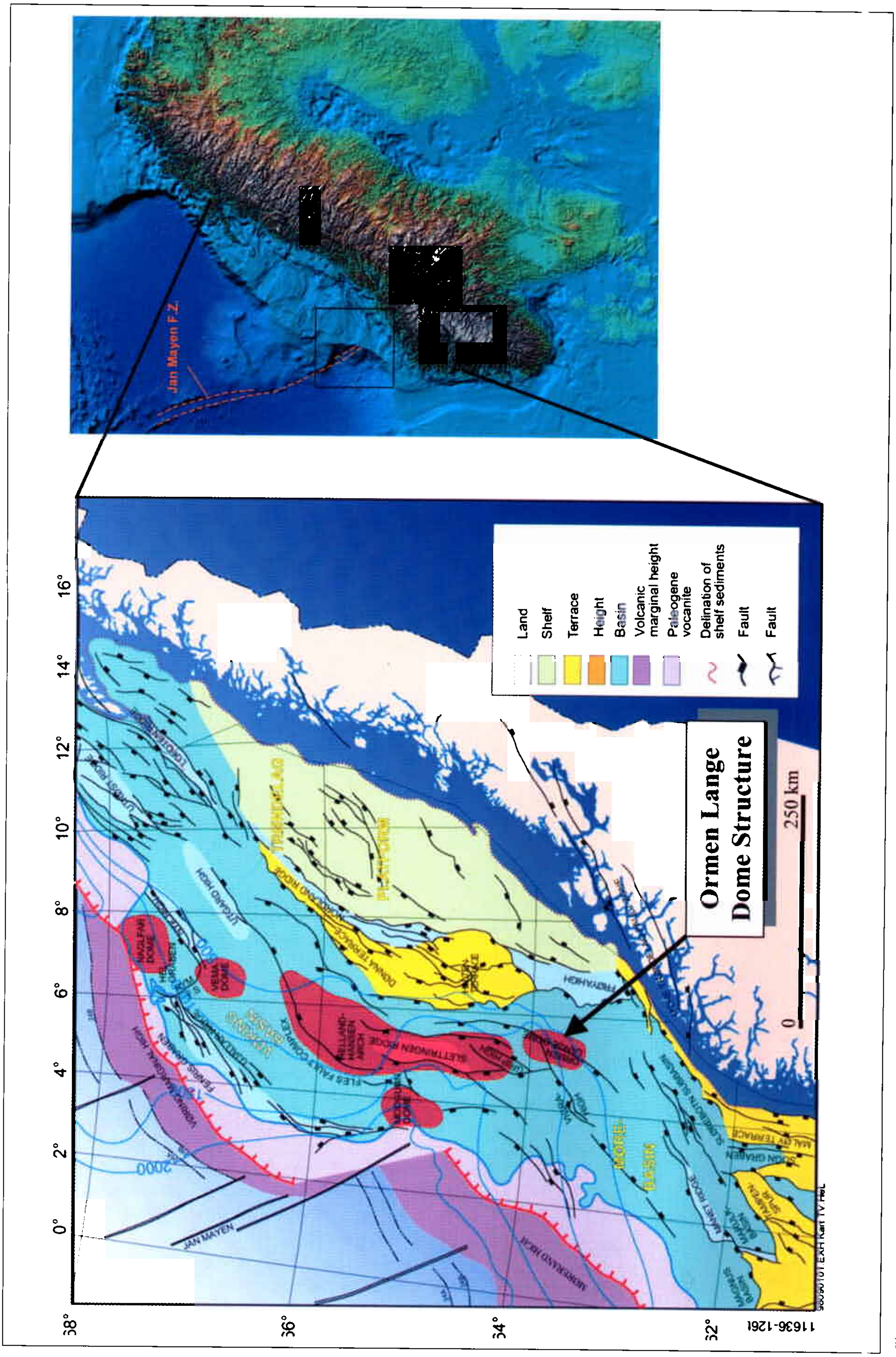

Fig. 1. Location map with the main Jurassic-Cretaceous structural elements. The Ormen Lange subbasin was situated in the position of the present day Ormen Lange Dome, the structural inversion being reflected in thickness developments as shown in Fig.2. Modified from Blystad et al. (1995).

The installations must be able to realize the potential of a high quality reservoir but at the same time have a contingency plan for possible complications resulting from faults and stratigraphical heterogeneities. The database for the geological evaluation is summarized in the appendix.

Geological setting

Structural configuration

Similar to the other dome features in the Norwegian Sea (Fig.1) the Ormen Lange Dome occurs as a solitary, isolated structure and is not part of an organized fold system. The dome structures are compression features of Cenozoic age (Doré & Lundin 1996), and include simple domes or anticlines, reverse faults and broad scale inversions. The Ormen Lange Dome is a N-S oriented structure, some 50 km in length (Fig.1) with its maximum relief near top Paleocene and intra Eocene levels. At these levels the amplitude is 450 m, and the wavelength approximately 20 km, the average dip of the limbs being about 2.5°. As the eastern limb is shorter than the western limb, the structure is slightly asymmetrical in profile. Due to Cenozoic tilting and associated anticlockwise rotation, the western limb has a steeper dip. The structure represents a gentle fold and in spite of the relatively large size and amplitude, the total shortening is modest and estimated to be in the order of 0.5% (Vågnes et al. 1998).

The overall compressive stress field that gave rise to the Mid-Norway dome structures has been explained as a result of the combination of spreading in the adjacent ocean (ridge push) and the distant effects of Alpine tectonics (Doré & Lundin 1996, Vågnes et al.1998). The extensional vector at break-up time (early Eocene, 55 Ma) was directed NW-SE, i.e. more or less parallel to the trend of major transform zones such as the Jan Mayen Fracture Zone. The weakly compressive regime, which is assumed to have been established at the onset of spreading, still exists at the present day. Borehole breakouts, drilling induced tension fractures and hole ovalisation from well 6305/5-1, indicate a NW-SE to N-S maximum horizontal present day stress field. It is likely that the evolution of the Ormen Lange Dome has been controlled by both underlying and adjacent structures. Such elements are represented by Mesozoic faults striking N-S and NE-SW, as well as a NW-SE trend, which is ascribed to the Cenozoic Jan Mayen lineament.

The block and basin topography (Fig.1), which is evident beneath and above the interpreted base Cretaceous unconformity, resulted from Jurassic extension on mainly NE-SW oriented faults south of the Trøndelag Platform and the Halten Terrace (Blystad et al. 1995). Several N-S trending faults are also present in the Klakk fault complex (Fig. 2), and align with the present western margin of the Frøya High (Fig. 1). There is ample seismic evidence that several Jurassic faults were reactivated during the Cretaceous period (Brekke 2000). In addition, due to the relative lack of coarse grained, gravitation-controlled sedimentation during the Cretaceous period, the relief created was sustained for long periods of time after the Jurassic (the fine-grained sedimentation was draping, but not smoothing out topography). Major structures, such as the Slørebotn Sub basin, the Gossen, Vigra, Ona and Frøya Highs (Fig. 2), are thus likely to have acted as basinal highs and lows, trapping or controlling the distribution of even uppermost Cretaceous and Paleogene deep water sediments. The primary distribution of thick Paleocene sands within the Slørebotn Sub basin is clear evidence of Jurassic structures indirectly controlling the Paleocene deep-water sedimentation.

Pre- and syn-depositional basin physiography

The broad Trøndelag Platform and the Halten Terrace are the main structural features to the North of the southeastern Møre Basin area. The relative distance to the Cretaceous-Cenozoic deep-water areas (sustained by interpretations of sedimentary successions: Dalland et al. 1988) across these structural elements is comparatively much larger than from the Norwegian mainland across the Slørebotn Sub basin. The difference may be interpreted as a reflection of the presence of a wide Cretaceous-Cenozoic shelf area in the Trøndelag Platform/Halten Terrace area, while a much narrower shelf existed immediately southeast of the Ormen Lange area.

The concept that Jurassic structures had some influence on the distribution of sediments also in the latest Cretaceous and Early Paleocene (see above) introduces the possibility that several minor sub basins may have existed between the Norwegian mainland and the Møre Basin floor. Such a model is favored by the present authors. It can only be supported by actual data, and in particular thickness data of deep water systems with mass flow and turbidity current deposits, since their distribution is controlled by slope inclination and topography. It is generally less important what process or medium (salt, shale, faulting or hard rock) actually formed the topography in deep-water areas. To what degree the deep water slope and basin floor setting, existing basinwards of the Slørebotn Sub basin, was segmented into several minor subbasins, is uncertain.

Phases of uplift

Recent work both in the northern North Sea and in the mid-Norway area suggests that several phases of uplift

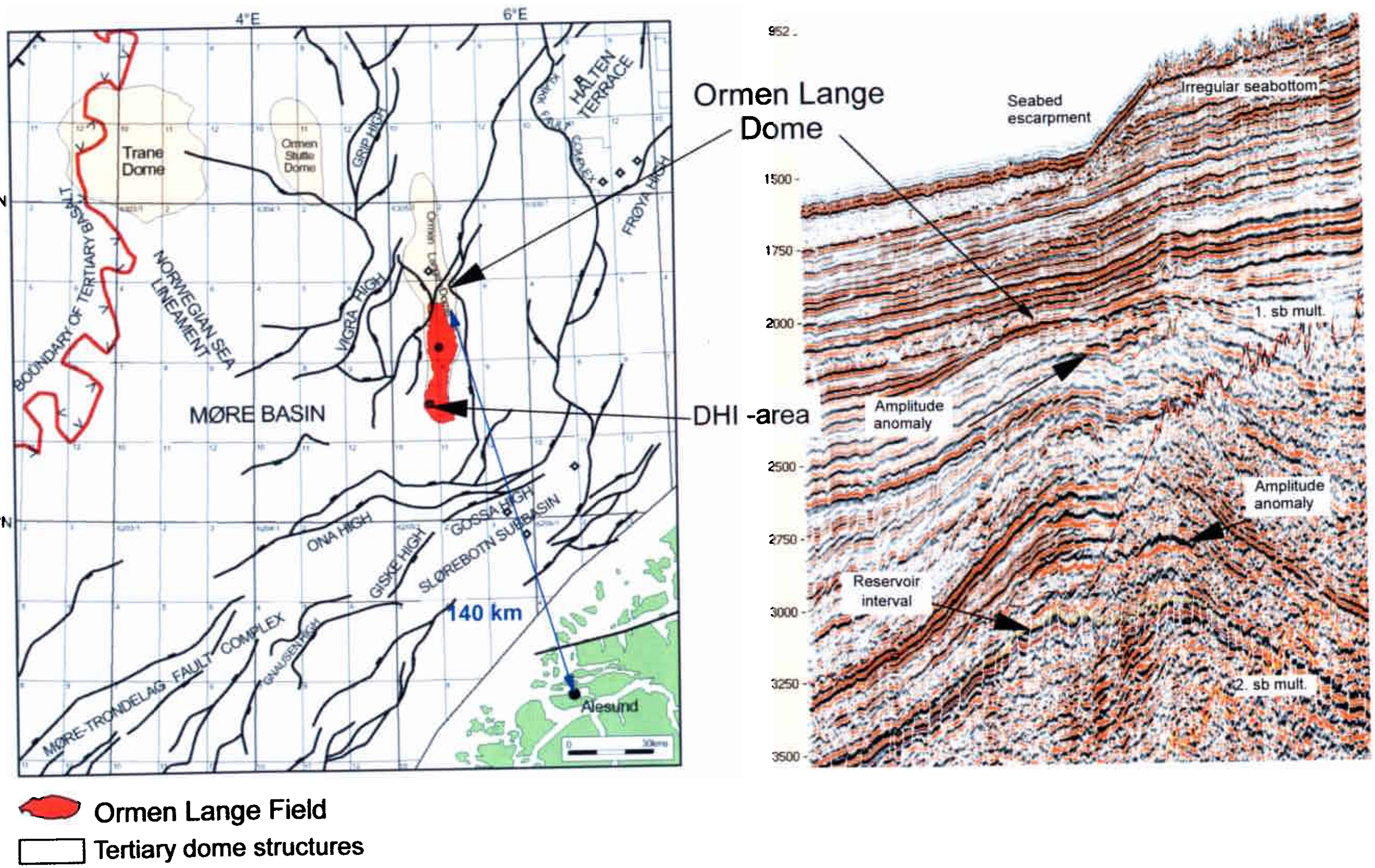

Fig. 2. Structural closure of Ormen Lange Dome indicated by light green area and gas filled area shown in red. The seismic cross-section shows some of the characteristic amplitude anomalies and multiples, which severed the seismic interpretation.

of Fennoscandia took place through the Cenozoic (Riis & Fjeldskaar 1992; Martinsen et al. 1999; Brekke et al. 2001 and references therein). Plio-Pleistocene uplift is best documented, but the presence of several unconformities of regional extent, and significantly tilted succession on seismic lines supports the view that at least five phases of uplift may have taken place (Martinsen et al. 1999):

1. Latest Maastrichtian and earliest Paleocene
2. Early Eocene
3. Late Eocene/Early Oligocene
4. Early-mid Miocene
5. Plio-Pleistocene

While the latter phase is closely linked to Plio-Pleistocene glaciation, the preceding phases are probably tied to regional tectonics. The latest Maastrichtian-Early Paleocene phase is of interest for the Ormen Lange geological interpretation because it may have been the time of generation of the N-S elongated Ormen Lange basin as well as the primary cause for the supply of clastic material from the Norwegian mainland to the deep marine areas in the Møre Basin. Sands were delivered into a basin, which throughout most of the preceding Cretaceous was dominated by deposition of fine-grained material (Dalland et al. 1988). The mechanism for this uplift phase was probably pre-Atlantic break up with shoulder uplift of the basin margin.

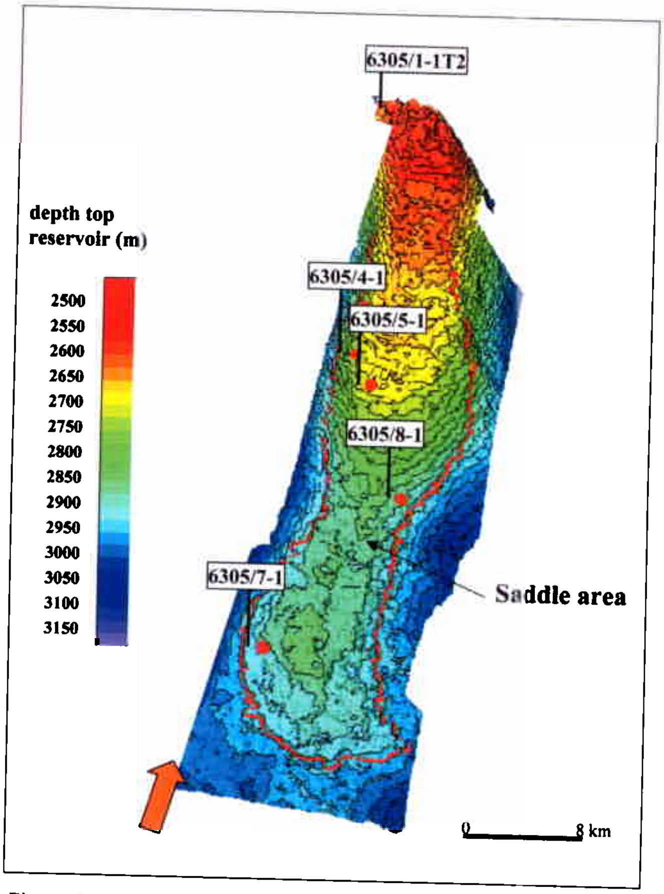

Fig. 3. Ormen Lange: top reservoir and well positions. See Fig.1 and Fig.2 for location.

Shelf and onshore extension of oceanic fracture zones

Several NW-SE oceanic fracture zones occur within the Møre and Vøring Basins (see Brekke 2001 and references therein). One of these zones, the Jan Mayen Lineament, is of importance for the Ormen Lange area (Fig.1). The postulated onshore extension of this lineament coincides with the southern extension of the Klakk fault complex, the southern end of the Frøya High and the northeastern end of the Gossen and Ona Highs. This area coincides with the postulated position of the feeder system to the greater Ormen Lange deep-water depositional system. Thus, it is assumed that the presence of the Jan Mayen Lineament had some influence on the delivery of uppermost Maastrichtian and lowermost Paleocene sands to the deeper water areas in the Møre Basin, prior to Atlantic break-up.

Stratigraphy

Regional Stratigraphy

According to the stratigraphic nomenclature and formal definition of the Mid Norway succession in the Halten Terrace and Trøndelag Platform area (Dalland et al. 1988), Maastrichtian rocks are named the Springar Formation and the Paleocene rocks the Tang Formation. However, neither the Springar Formation nor the Tang Formation include sandstones of significant volume, and are claystone-dominated in the type wells 6506/12-4 and 6407/6-1, respectively (Dalland et al. 1988). Thus, the Egga member was introduced as an informal name for the sandstones of Paleocene age in the wells in the Slørebotn Subbasin. In that area, there are no sandstones of Maastrichtian age, since, based on biostratigraphic evidence, there is a major stratigraphic break between the Campanian and the Paleocene. In contrast, in the Ormen Lange wells, there is a continuous sandstone bearing section from the Campanian through the Maastrichtian and into the Paleocene (Gjelberg et al. 2001), and thus the Maastrichtian sandstones there were in principle unnamed.

In the exploration phase of the Ormen Lange licenses, a Northern North Sea stratigraphic nomenclature has been used (Isaksen & Tonstad 1989), as some lithological similarity with the North Sea units was encountered and has the obvious advantage of a higher resolution, and more precise lithostratigraphical description. It could be discussed if a geological rather than a present day geographical boundary should be used between the two nomenclatures. A case could be made to apply North Sea nomenclature south of the extension of the Jan Mayen Fracture Zone (Fig. 1) and the Mid-Norway

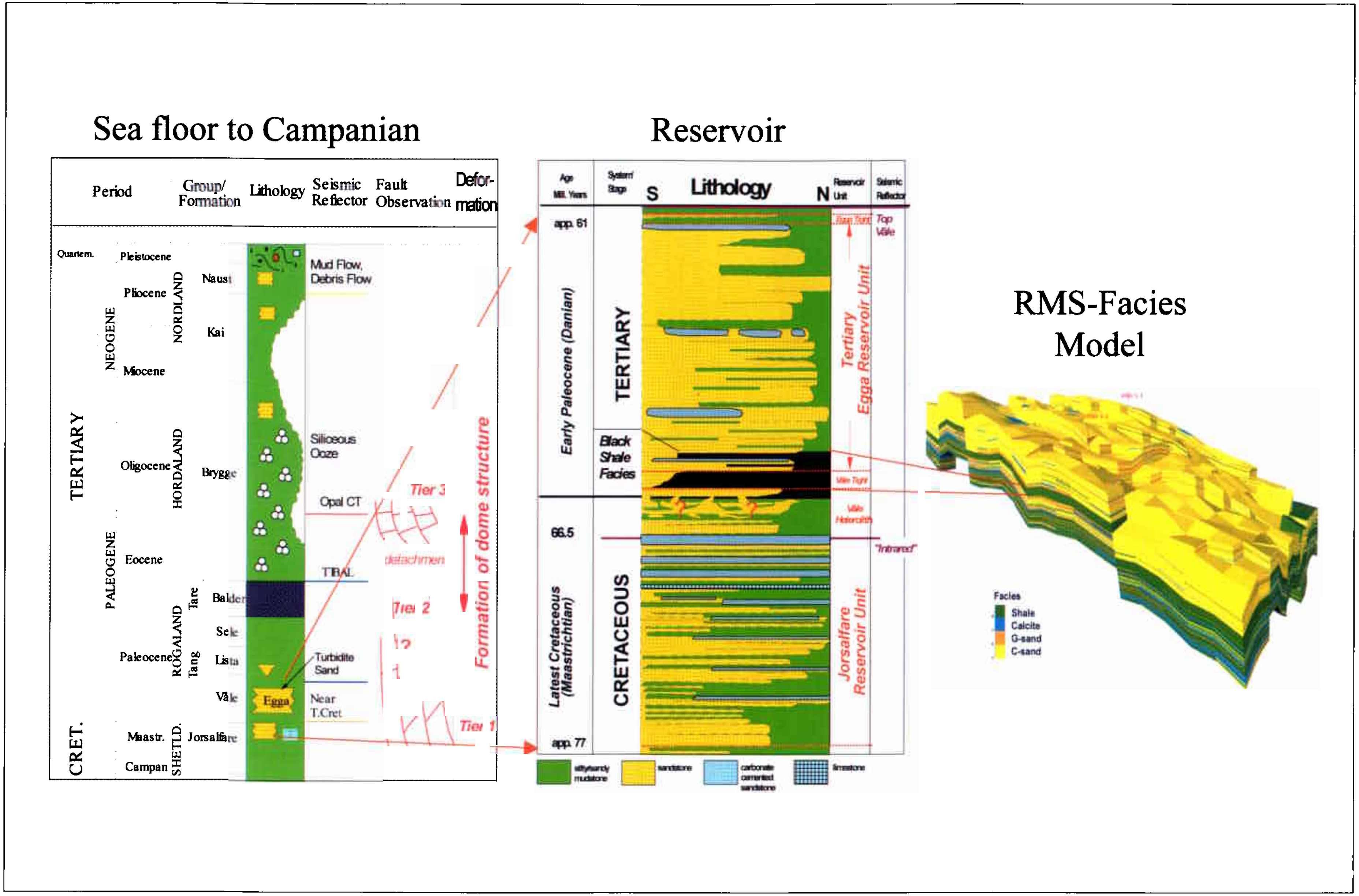

Fig. 4. Stratigraphy and 3D reservoir model of the Ormen Lange Field.

nomenclature for the area north of this important lineament. In the present paper, the North Sea nomenclature is preferred for the Ormen Lange Region, for practical purposes, and is used in a modified form for reservoir zones.

A generalized stratigraphic column is shown in Fig. 4. Below Quaternary to uppermost Tertiary mud- and debris flow deposits a thick series of silty mudstones with minor amounts of thin sand intercalations covers the Lower Paleocene reservoir sandstones. In particular the Brygge Formation, comprising rocks of Middle Miocene to Lower Eocene age, may contain a significant component of siliceous ooze, alternating cyclically with laminated claystones.

Lithostratigraphy of the reservoir interval

The Ormen Lange reservoir interval comprises deep marine turbidite deposits of Late Cretaceous (Maastrichtian) to Early Tertiary (Early Paleocene) age (Fig. 4).

Jorsalfare (Springar) Sandstones (Late Maastrichtian) in the lower part are overlain by heterolithic but upwards increasingly sand-dominated deposits of the Egga Sandstone Member (Danian), which represents the main reservoir interval and has been subdivided into three reservoir zones: the Våle Heterolithic/Våle Tight and the Egga Reservoir Units are all parts of the Våle Formation (Fig. 5). In addition, a 10-15 m thick shale and siltstone unit on top of the Egga Member is also included in the Våle Formation (Våle Shale).

Maastrichtian (Jorsalfare Formation)

The Maastrichtian interval consists of sandstone, mudstone and limestone alternations and shows an increase in sand content upwards. The trend is accompanied by a thickening upwards of individual sandstone beds. Furthermore, well 6305/7-1 to the South shows a significantly higher sand content than the wells to the North (Fig. 5).

In the lower part of the succession high-density turbidites predominate, interbedded with thick beds of green and grey, strongly bioturbated mudstones. Bioturbated chalk is present in the middle part of the interval in all wells. It is considered to indicate a period of low siliciclastic accumulation, in which climatic conditions allowed the preservation of delicate carbonate particles into the burial stage and carbonate cementation at, or close to, the sea floor. Consequently chalk layers are correlatable from well to well and represent isochrones for the lower part of the reservoir. Generally, significant amounts of carbonate cement are seen in the Maastrichtian rocks.

This is in contrast to the overlying Tertiary rocks, which only display minor carbonate cementation, and are considered to be of limited extension. The increased competence, due to early carbonate cementation, most probably rendered the Jorsalfare Formation more susceptible to brittle deformation.

The upper part of the Maastrichtian deposits shows a similar facies development to the lower part, the main difference being that individual turbidites are thicker and there are thinner mudstone intervals between each turbidite. There is also a gradual change upwards in the nature of the fine-grained sediments from greenish-grey, bioturbated mudstone to dark grey, less bioturbated mudstone.

The stratigraphic development of the Cretaceous reservoir section suggests a depositional environment dominated by slow background sedimentation from suspension fallout in a fairly well-oxygenated, open marine basin. This was interrupted by pulses of deposition from turbidity currents.

Paleocene (Våle Formation)

The Paleocene reservoir interval comprises the sand-dominated Egga Member, which displays a general trend of increasingly more massive and sand-rich developments towards the top. The Egga Member is strongly dominated by turbidite sandstones. Egga sandstones have good reservoir qualities and consist of massive amalgamated or weakly separated sand/sandstone bodies with nearly blocky log responses in the upper part. In the lower part thinner, more clearly separated layers are seen. The sandstones may be poorly lithified. Sporadic carbonate cemented intervals probably occur. Due to the vertical variation the Egga Member has been subdivided into 3 reservoir units: the Egga Reservoir Unit (Egga RU), which comprises the massive part of the Egga Member, the "Våle Tight", an extensive intra reservoir shale, and the "Våle Heterolithic Unit", which is characterized by sand/shale alternations.

A marked change in sedimentation took place across the Cretaceous-Tertiary boundary. Above this level black mudstones with a very low degree of bioturbation replace the green to grey, strongly bioturbated mudstones as the background sedimentation. High-density turbidites, however, occur with the same average thickness as below the boundary. The low degree and diversity of bioturbation in the black mudstones suggests that significant changes in external factors such as bottom circulation and climate may have taken place.

The interval of dark mudstone (Våle Tight) appears to be an obvious candidate for field wide correlation, as supported by biostratigraphy. However, a thin develop-

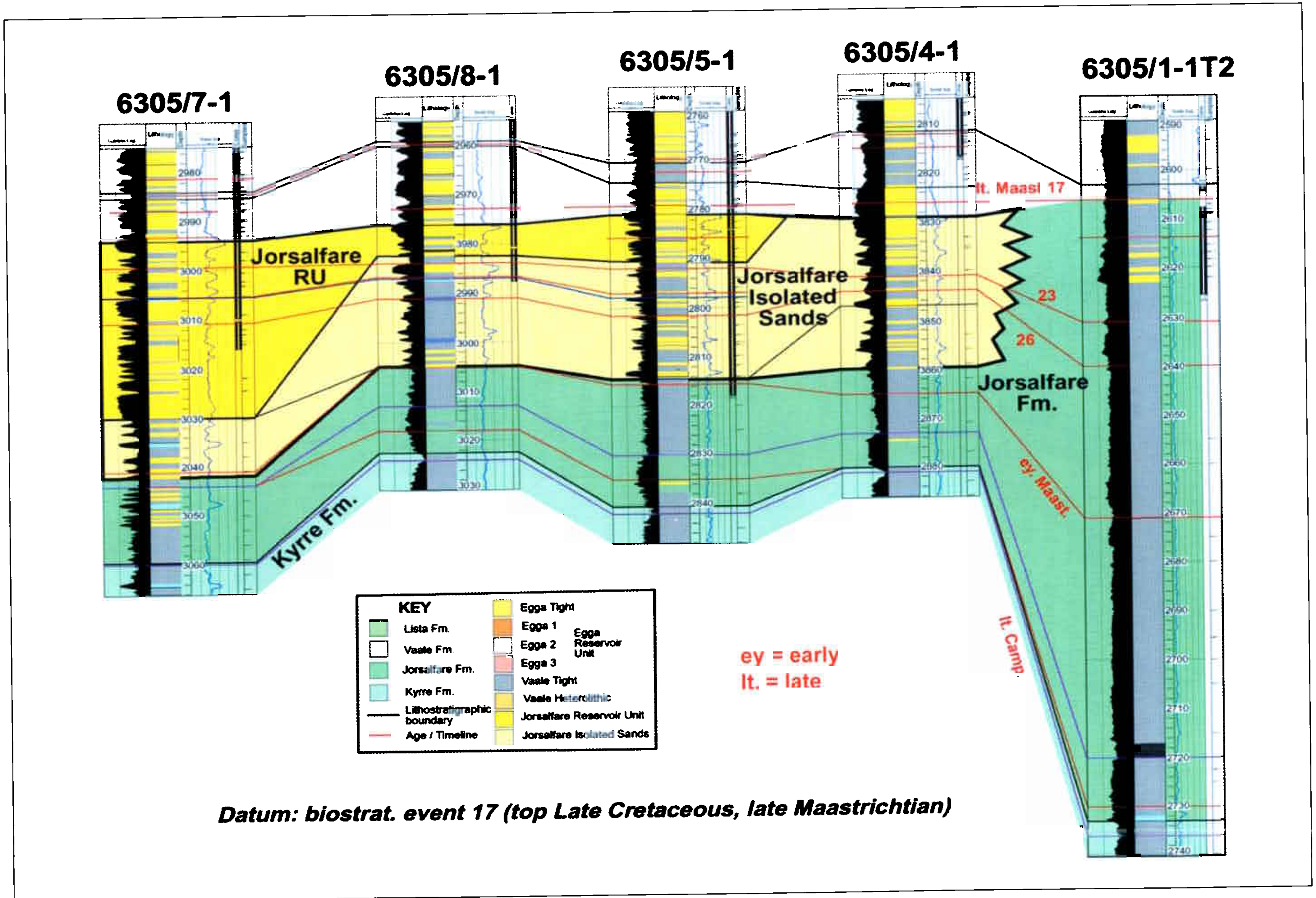

Fig. 5. Biostratigraphic correlations of Upper Cretaceous sandstones and reservoir zonation (datum: biostrat. Event 17 = top Late Cretaceous, late Maastrichtian). Two reservoir units have been identified within the Jorsalfare Formation: "Jorsalfare RU" and "Jorsalfare Isolated Sands". Hydrocarbons will probably only be recoverable from the Jorsalfare RU.

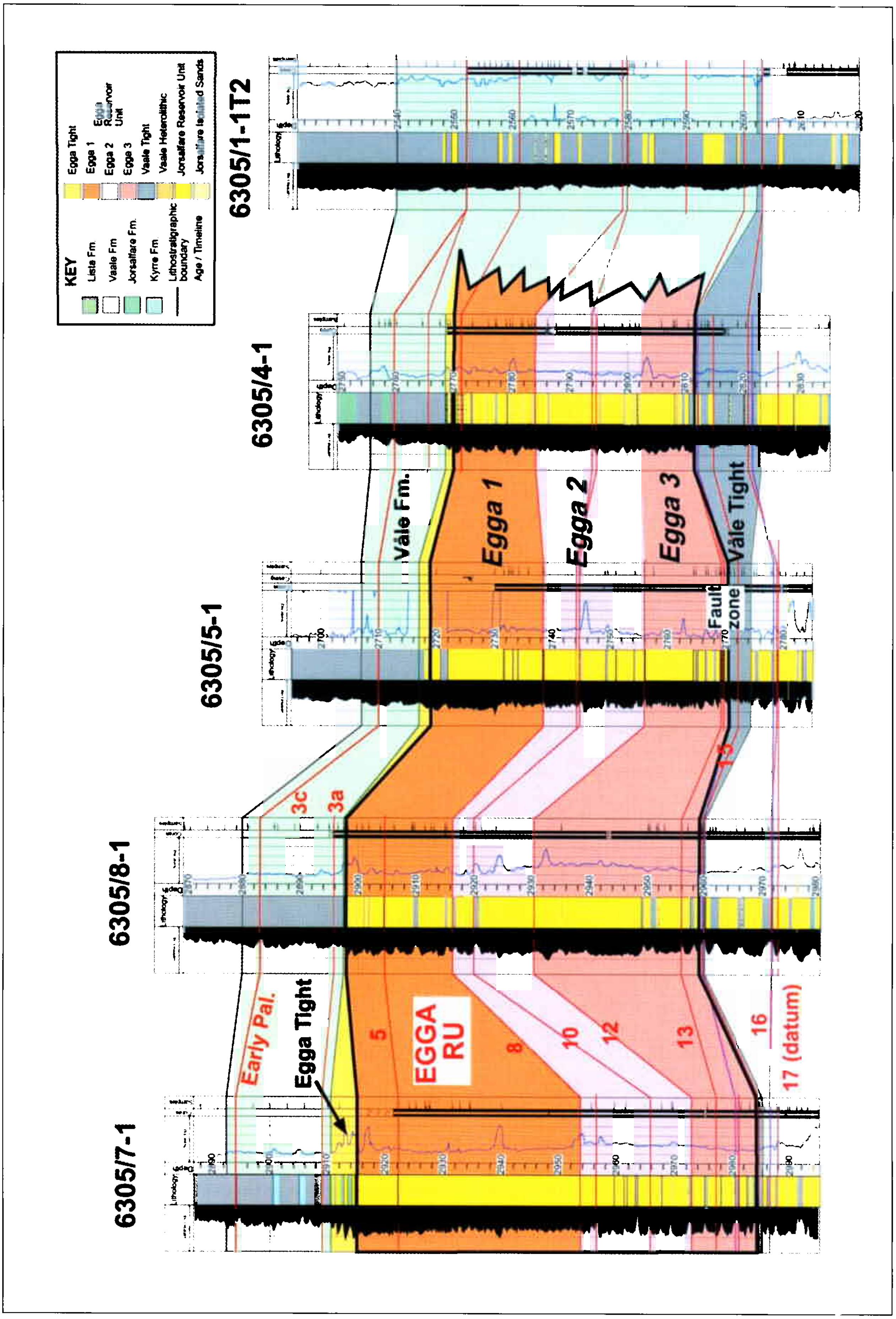

Fig. 6. Biostratigraphic correlation of the Egga Reservoir Unit and underlying Våle Tight and Våle Heterolithic Units (see Fig. 3 for well positions).

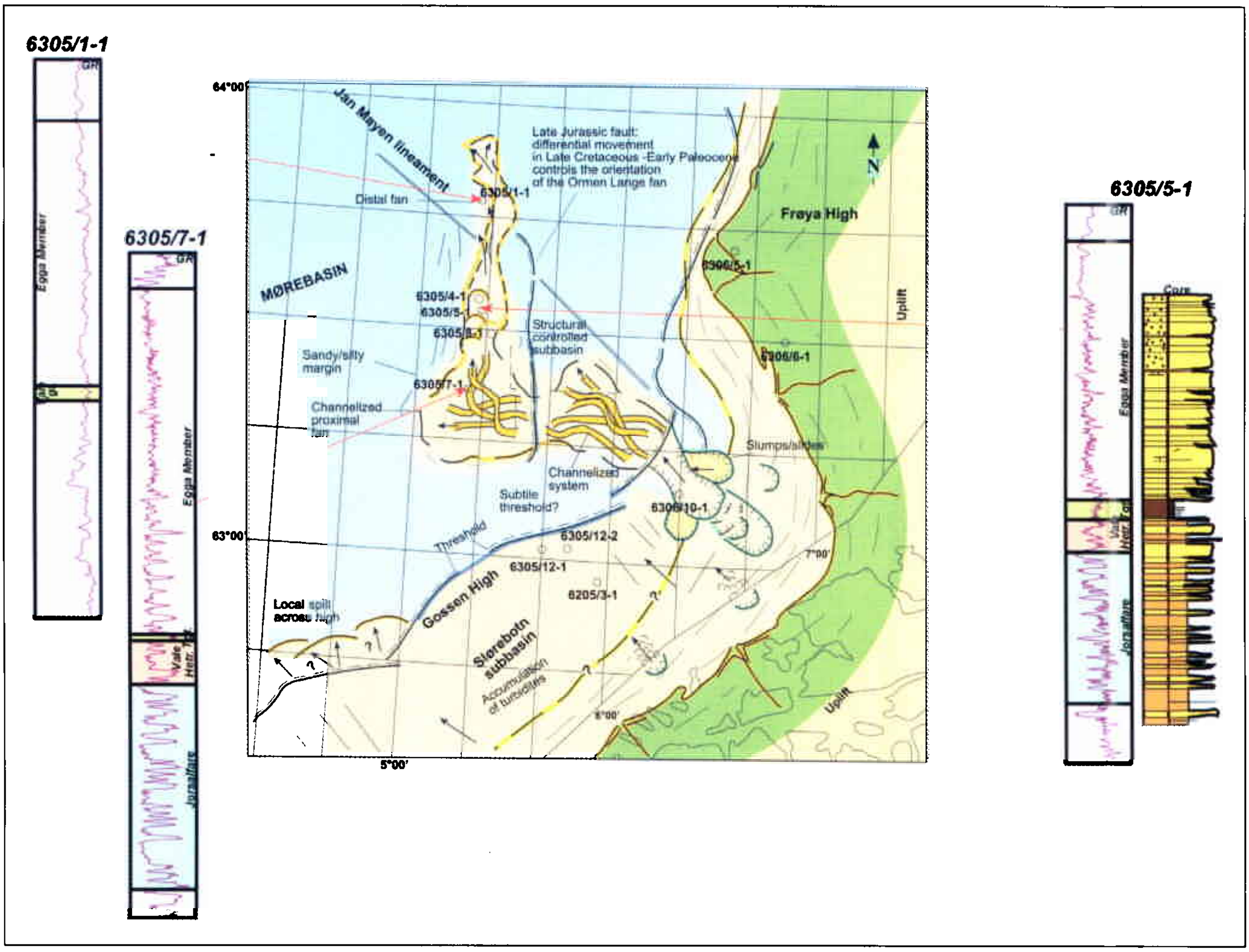

Fig. 7. Depositional model and characteristic well-observations. Gamma-ray log responses are shown for three wells together with a schematic core log for well 6305/5-1. Yellow colour represents high quality reservoir sandstones, brown low permeable siltstones. The Ormen Lange Turbidites are thought to be derived from slumping in the tectonically unstable ramp area between the Klakk and Møre-Trøndelags fault systems (cf. Fig.2).

ment in well 6305/7-1 and intercalated thick turbididte sandstones in well 6305/8-1 suggest that it may have been locally removed by erosive turbidity currents in the southern and southeastern parts of the field. For the northern part a thickness of over 10 m as observed in the well 6305/4-1 indicates much greater chances of lateral continuity. The interval seems to represent the base of those gas filled sands, which are in pressure communication with the main accumulation in these shallower parts of the field.

Biostratigraphy

Detailed quantitative biostratigraphic analyses, mainly palynology (marine microplankton), were performed on the reservoir sections of wells 6305/1-1, 6305/4-1, 6305/5-1, 6305/7-1, and 6305/8-1. The total number of correlative bio-events over the Egga to Jorsalfare reservoir units is 31 of which 16 are considered very reliable. The secondary bio-events identified can be used to constrain the main markers. The biostratigraphic work allows a high-resolution time correlation (Fig. 5 and Fig. 6). It is supported by an analysis and dating of resedimented microfossils.

Depositional model

A depositional model (Fig.7), developed prior to drilling the 6305/5-1 discovery well, is still used as a reference case, but has become elaborated and refined, particularly for the Paleocene part of the Ormen Lange reservoir (Fig. 8). It is based on a regional Upper Cretaceous to Lower Tertiary isochore (Fig. 9) as well as the Danian isochore (Fig. 10), well log and core data.

A more detailed compilation of the sedimentological evidence is provided in Smith et al. (2003) and Gjelberg et al. (in press) (Fig.8). Sands are considered to have been sourced from the southeast and deposited within a north-south elongated sub-basin, controlled by reactivated Jurassic structural elements in the field area.

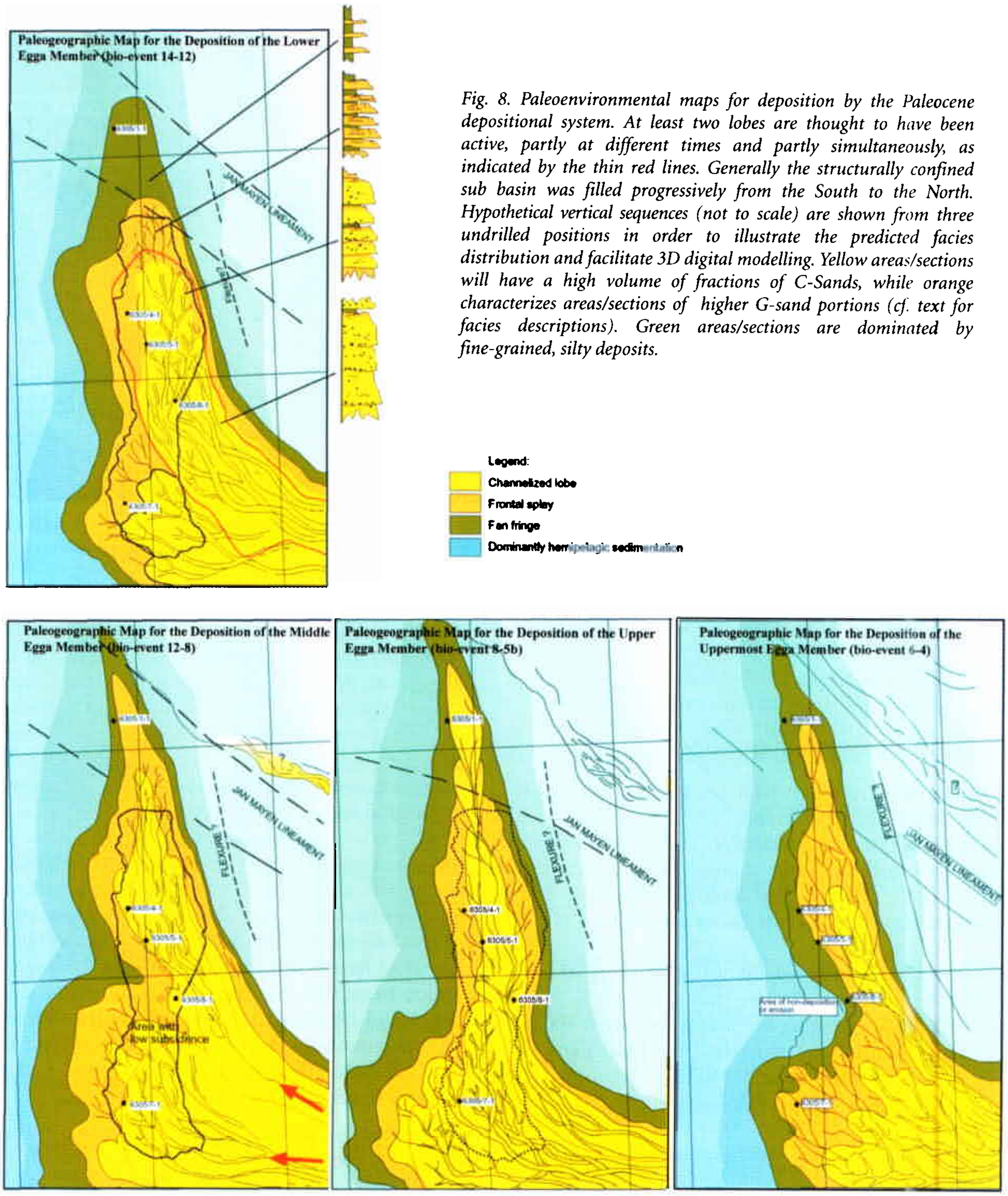

Fig. 8. Paleoenvironmental maps for deposition by the Paleocene depositional system. At least two lobes are thought to have been active, partly at different times and partly simultaneously, as indicated by the thin red lines. Generally the structurally confined sub basin was filled progressively from the South to the North. Hypothetical vertical sequences (not to scale) are shown from three undrilled positions in order to illustrate the predicted facies distribution and facilitate 3D digital modelling. Yellow areas/sections will have a high volume of fractions of C-Sands, while orange characterizes areas/sections of higher G-sand portions (cf. text for facies descriptions). Green areas/sections are dominated by fine-grained, silty deposits.

Sandstone-dominated Tertiary sequences were encountered in all four appraisal wells. The wells have a significant areal spread and therefore this observation encourages the prediction of high sand dominance in the Egga Reservoir Unit throughout the gas field. This is an important observation, as it means there is no reason for assuming any significant deterioration of reservoir quality within the gas field. Coarse sand has also been reported from the Egga unit of well 6305/4-1, which is the northernmost appraisal well in the DHI-defined gas field. This means that the turbidity currents had enough energy to travel far beyond the northern limits of the DHI area, presuming that they did not encounter any topographic feature to change their velocity (Walker pers.comm.). Topographic control and palaeo-topographic reconstruction have thus an important research interest for the sedimentological investigation of the Ormen Lange reservoir

(Heimsund et al. in prep).

The combination of the sandstone dominated successions with high amalgamation frequencies, observed in The Egga Reservoir Unit, and the N-S elongated shapes of the seismically mapped isochore (Fig. 9 and Fig. 10) indicates a sand-rich, confined depositional system, and a preferential preservation of the deposits of the most powerful, suspension currents, with the highest particle densities.

Based on high resolution biostratigraphy (Fig. 6) average accumulation rates for the Egga Reservoir Unit in the position of well 6305/7-1 can be estimated to some 28mm/1000 yrs (undecompacted) and the time intervals between preserved successive suspension currents average some 100 000 yrs. Considerably lower accumulation rates and more intermittent deposition is indicated for the Cretaceous part of the reservoir (app. 13mm/1000 yrs undecompacted) (Fig. 6).

Based on comprehensive petrographic macro and micro scale analyses sand transport and deposition are thought to have taken place in mobile and short-lived low-sinuosity channels, spillover- and frontal splay lobes (Fig. 7 and Fig. 8).

Facies and reservoir quality

Four main facies elements have been identified, based on log responses, appearance in core, lithological character and reservoir properties. These occur in two main facies associations, the channel facies association (highly mobile, shallow, low sinuosity channels) and the spillover/frontal splay lobe facies association:

- **C-Sand:** clean moderately to well sorted sub-arkosic sandstone, with porosities averaging 29% and permeabilities averaging 870 mD (range from 300 to 3000 mD). This facies represents the basal parts of high-density turbidites and probably accounts for more than 75% of the gas filled reservoir.

- **G-Sand:** greenish-grey, clay bearing sandstones with high connate water saturations, porosities averaging 26%, permeabilities averaging 277 mD (range from 1 to 3000 mD). This facies generally represents the higher part of turbidite deposits, the clay content either being due to waning flow, bioturbation or diagenesis. Due to topographic confinement and the high energy of a relatively coarse-grained turbidite deposition, the preservation potential for this facies is assumed to be low in the Egga Reservoir Unit throughout the field. Estimated volume fractions are below 15%.

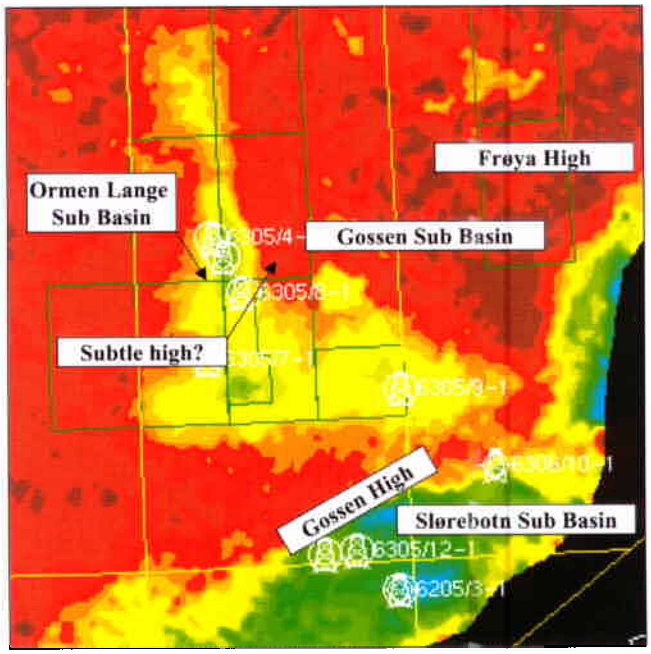

Fig. 9. Regional time isochore map for the sand-rich parts of the Upper Cretaceous and Lower Tertiary of the greater Ormen Lange area (Modified from Gjelberg et al. in press).

- **Shales:** including sandy and silty mudstones. No hydrocarbons are assumed to be recoverable from this facies, due to low permeability and high connate water saturations. Due to technical difficulties correct permeability measurements are hard to achieve and this facies has conservatively been treated as non-permeable (100% water saturated) in the digital reservoir model.

  In the Egga Reservoir Unit this facies generally represents the most fine-grained dilute late stage phases of turbidite deposition. Possible hemipelagic shales have only been found in the lowermost part of the Egga Reservoir Unit and in the underlying older units, based on the degree of bioturbation, trace fossil and benthic microfossil diversities. Preservation potentials for shales in the Egga Reservoir Unit, are still lower than for the G-sands and probably volume fractions are not higher than 5-8%.

  Based on field analogue studies lateral extensions of shales in the Egga Reservoir Unit are assumed to be in the order of up to a few hundred metres in the channel facies association and up to 2000 metres in the lobe facies association.

- **Carbonate cemented rocks:** carbonate cemented sandstones, generally less than a metre in thickness, have been observed rarely in the Egga Reservoir Unit, but more frequently in the underlying Upper Cretaceous deposits. As evidenced by comparison of shallow and deep resistivity logs and formation image data, part of them are nodules, while the rest

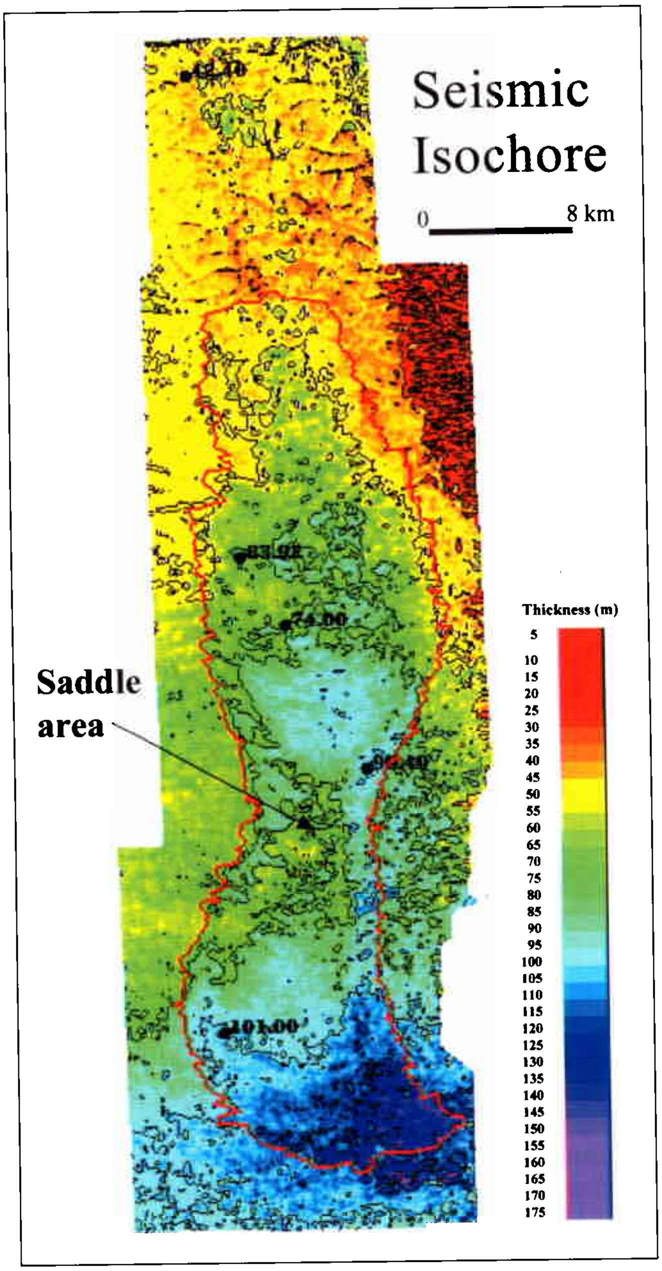

Fig. 10. Lower Paleocene isochore for the Ormen Lange sub basin.

represent more extensive features.

There is almost no effective porosity or permeability in this facies and it has been treated as non-permeable (100% water saturated) in the digital reservoir model. Volume portions in the Egga Reservoir Unit are estimated to be of the order of 2-5%.

This facies is not generally expected to represent significant obstacles to gas flows, except for one possible occurrence in relationship with a hiatus at a subunit-boundary (Egga1/Egga2 in Fig. 6). Here a possible combination of carbonate cemented sandstones and shaly deposits could provide a more extensive barrier to vertical fluid flow.

Isotope signatures of carbonate cements generally indicate a late (high temperature) origin; however, in some cases remobilisation of an early diagenetic cementation phase is suggested. Extensions of cemented objects in the Egga Reservoir Unit are assumed to be up to some 200 m.

A more detailed sedimentological description and interpretation of lithofacies is provided by Gjelberg et al. (in press).

Faults

General characteristics

A network of polygonal faults (Dewhurst et al. 1999) intersects the Ormen Lange reservoir (Stuevold et al. 2003). These have been mapped extensively using the seismic data (Fig. 11) and the main characteristics are as follows:

- A dominant sub-set of the polygonal faults displays E-W strike and a dip towards the North (Fig. 12).
- The faults, which can be mapped in corresponding positions on dip maps of Near Top Våle and Near Top Cretaceous seismic interpretations are likely to penetrate the whole Paleocene reservoir.
- Fault throws are generally smaller than the thickness of the Egga Reservoir Unit.
- Fault throws and frequencies increase from South to North.
- All faults (which are mapped inside as well as outside the DHI area) seem to form part of polygonal patterns and display highly irregular variations of throw. An origin as polygonal faults is likely for most of them. However, inside the hydrocarbon-filled reservoir, acoustic effects of the gas obscure fault observations (Stuevold et al. 2003).
- Polygonal fault patterns observed in the central parts of the field seem to be different from those on the flanks and to the sides of the gas field, displaying both decreased throws and less random orientations. They are very clearly dominated by East-West striking components. This is most likely related to a northward dipping palaeo-topography, but may also indicate tectonic reactivation of original polygonal faults during the main phases of doming.
- Fault throws generally decrease from the Upper Cretaceous to Top Våle. However, some of the most

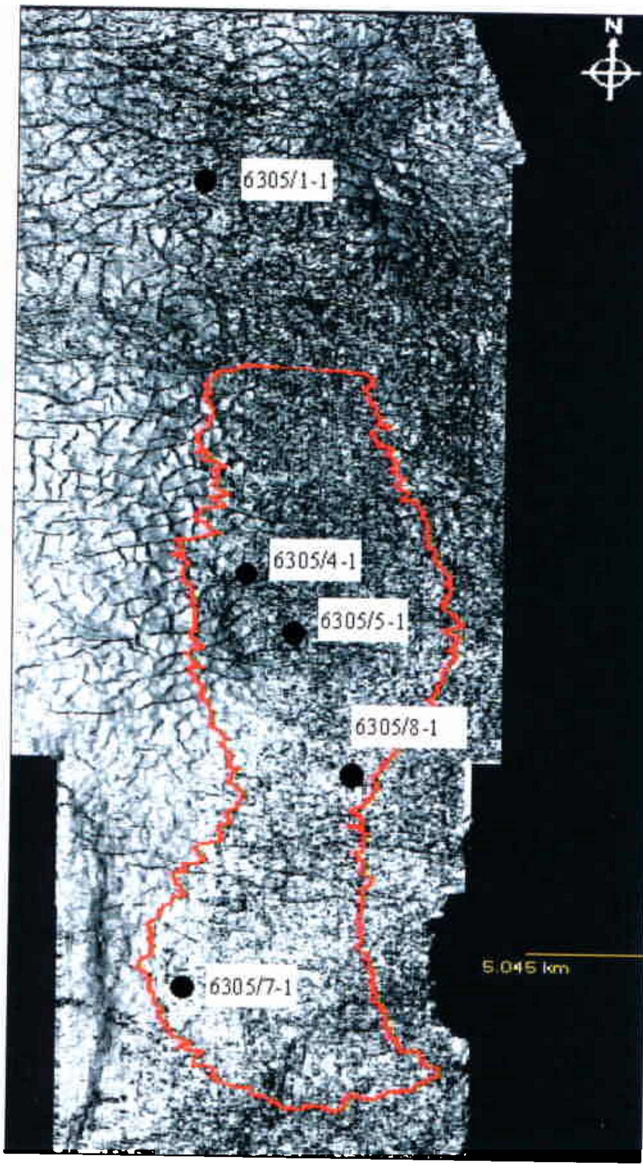

Fig. 11. Dip Map from Top Våle, showing polygonal fault patterns and their regional changes. The difference between the patterns inside and outside the DHI-area (red line) may partly be an effect of the hydrocarbon saturations.

vertically extensive faults appear to consist of two components, the upper one showing the largest throw within the Balder Formation and dying out in or above the near-Top-Balder reflector (Fig. 12 and Stuevold et al. 2003).

- Thickness changes across faults as well as reflection patterns inside the reservoir section indicate that some of the faults have been active during deposition of the reservoir sandstones. These faults show clear evidence of growth (Fig. 12), with possible thickness increases of up to one third on the Egga Member, indicating syn-sedimentary faulting.

- Fault intersection points generally represent throw minima.

- The polygonal faults, which affect the reservoir, are likely to have originated in underlying smectite-rich Cretaceous shales and to have propagated upwards during reservoir deposition.

- Not all faults have propagated through the reservoir and many die out upwards before even reaching Top Jorsalfare (Near Top Cretaceous reflector). Therefore not all faults, which are mapped at Near Top Cretaceous, will intersect the whole Egga Reservoir Unit.

Polygonal Faults occur at 3 different levels (tiers 1,2 and 3) in the Ormen Lange succession: at reservoir level, at Lista/Balder level and in the ooze below a Mid-Miocene unconformity. Faults in tier 2 (Lista/-Balder) are often linked up with faults in the reservoir. This might imply minor reactivation at reservoir level. Tier 3 is generally detached from the underlying layers, but some large faults appear to link up all 3 levels (tiers). Some of the latter are assumed to have acted as conduits for gas migration/leakage. This might imply minor reactivation at reservoir level. Some polygonal faults at reservoir level might thus have been reactivated several times after their main period of activity, up to and including the time of the sub-Recent Storegga Slide (Bryn et al. 2003).

Fault sealing potential

To complement the seismic structural evaluation, detailed studies of cores through the reservoir interval and of Formation Micro Imaging logs (FMI) were performed to provide constraints on the risk of dynamic fault sealing throughout the field. Two small normal faults intersecting cores in the reservoir interval in well 6305/5-1 were subjected to micro-structural analysis. Thin zones of clay smear were observed in both cases. Together with the absence of any signs of grain crushing this suggests that slip occurred whilst the host reservoir sediments and interbedded clays were unlithified. This interpretation of the core data thus supports the seismic observation that the polygonal faults were evident at or near the seabed during reservoir deposition, and some of them continued to be active into the Eocene, whilst the reservoir was buried to perhaps 300-500m below the sea floor.

The interpretation of an early deformational history for the polygonal faults in the Ormen Lange area suggests that membrane mechanisms such as cataclasis, cementation and micro-crystalline quartz framework development are of much less importance than juxtaposition seals, clay smear and the development of phyllosilicate framework rocks (Fig.13, cf. Sperrevik et

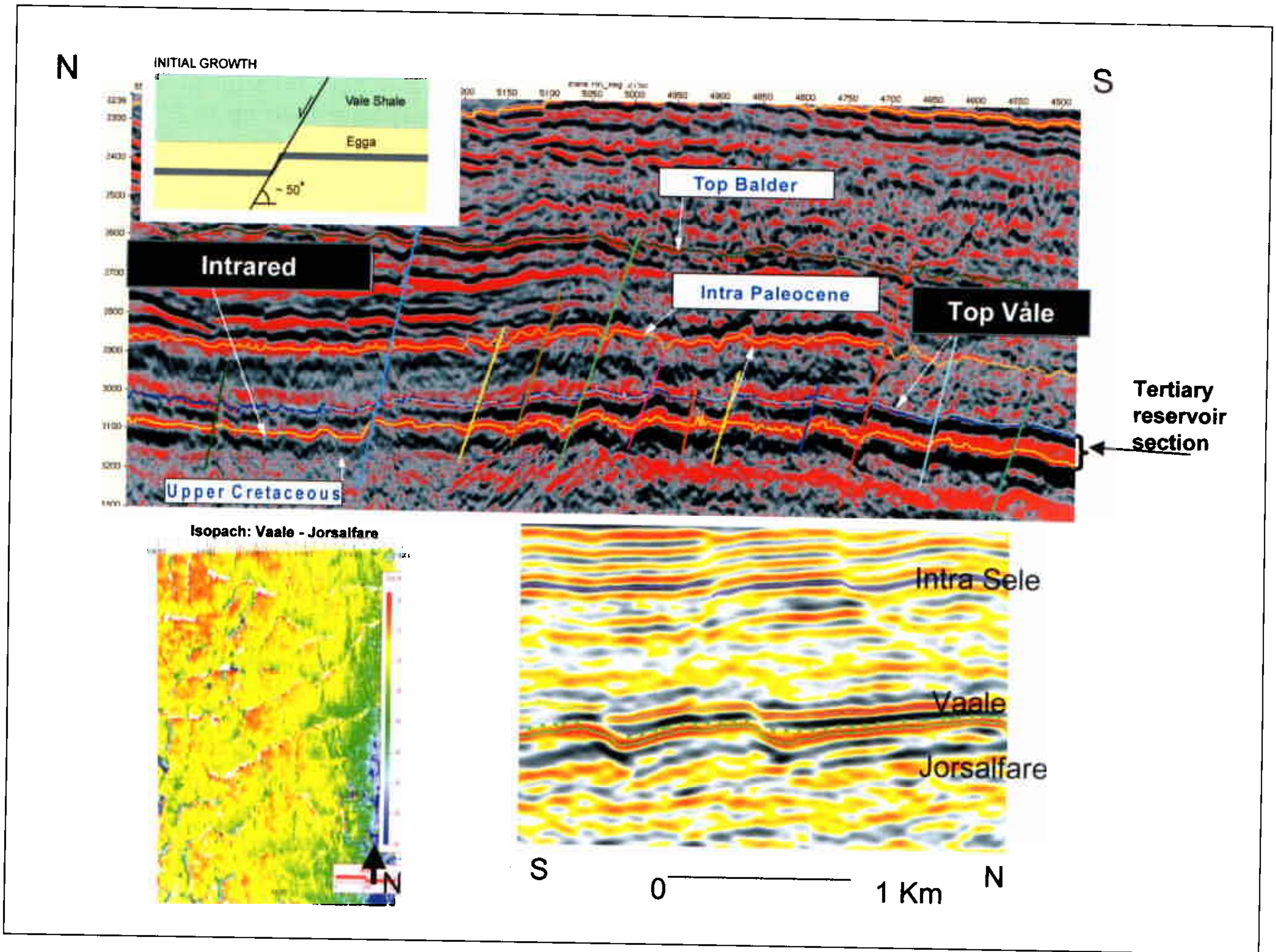

Fig. 12. Growth across Faults. The large faults, which offset Top Balder, display a throw minimum at Intra Paleocene level.

al. 2002; Yielding 2002). However, clay smears could be formed by different processes including the injection of water-bearing clays along fault planes, either from above or below the reservoir or both (Fig. 13).

Cement filled faults are reported from the FMI, from relatively shallow depths, but are difficult to predict, and would not be expected to form during the shallow deformation of unconsolidated sandstones. However, for those faults which have been reactivated at several stages during the deformation history, cementation may be more likely to occur.

When evaluating the risk of cataclastic shear bands, developing fault reactivation is also an important feature to consider. However, the vast majority of faults (>90%) do not seem to have been affected by late stage reactivation.

Generally, reactivation may counteract sealing, by disrupting continuous clay smears or breaking up cementation seals.

The following observations are considered to be critical for the assessment of the fault sealing potential on Ormen Lange:

- East–West-striking faults dip towards the North. This is opposite to the main direction of structural dip.
- The flanks of the dome structure dip towards East and West. In the same directions a slight thinning of the main reservoir and a possible decrease of the sand/shale-ratio may be expected (this may explain higher sealing potential of faults in flank positions and local occurrences of "water pockets" in the reservoir).
- A flatspot, observed along the border of the DHI area, steps across faults with moderate throws.
- The free water level (FWL) is 15 m deeper in well 6305/7-1 compared to well 6305/8-1.
- Seismic evidence of gas leakage from the Ormen Lange reservoir.
- Sandstones in well 6305/1-1T2 are highly over-pressured and contain residual gas.

- Pressure data show communication in the gas zone within the Egga Reservoir Unit.

- A fault penetrating the Lista Fm. in well 6305/7-1 is likely to offset the Egga Reservoir Unit, but did not affect the production test in this well.

- In well 6305/4-1, the lowermost part of the Egga Reservoir Unit seems to be pressure isolated. This perched water is probably a result of gas migration from above laying locally sealing shales and sealing faults.

- A test carried out in well 6305/4-1 indicates 2-3 prominent barriers to horizontal flow in the close neighbourhood of the well.

- The same test indicates that the fault polygon around the well is open, and suggests that any sub-seismic faults have no sealing effects.

- Fault throws vary between 7 m and 55 m for each of the faults surrounding well 6305/4-1.

- Log and core information from well 6305/4-1 indicate high reservoir quality for the whole Egga Reservoir Unit, with some uncertainty for the lowermost 4 m, which have an increased content of swelling clay and an unusually high content of bound water.

The main conclusions on fault sealing can be summarized as follows:

1) The faults in Ormen Lange are not likely to dynamically compartmentalize the central parts of the Ormen Lange gas reservoir.

2) Varying permeability reductions may occur across different parts of fault planes, depending on fault throws, the content of phyllosilicates, and shale inter-layers which have been displaced.

3) There is probably a close relationship between reservoir quality and fault sealing properties as well as between fault throw and fault sealing properties.

4) Polygonal faults are still not fully understood with respect to their fault sealing behaviour, and may have to be treated slightly differently compared to tectonic extensional faults. There may, for example, be an increased probability for clay injections to occur.

5) The probability and effect of clay injection along fault planes is difficult to assess and remains an important uncertainty factor. At the present stage it is not considered to represent a significant risk to field development.

6) The present reservoir depth is not the maximum burial depth, but the depth below the Pre-Storegga-Slide sea floor may have been up to 500 m larger. Temperatures may have been up to 25°C higher in the geological past than in the present reservoir, as revealed by fluid inclusion studies.

7) The last phase of carbonate cementation postdated quartz cementation and may be continuing at present day in the reservoir. It is considered unlikely that significant continuous and compartmentalizing fault seals were formed in critical parts of the reservoir during this phase.

8) Though dramatic effects are not expected, there is a possibility of increasing preservation potential for shaly turbidite tops and shaly inter-layers in the hanging wall parts of fault blocks compared to those parts closer to the footwalls, which often are preferred sites for well penetration.

Based on these relevant observations, and the additional conclusions mentioned above, a complex picture of fault sealing arises, with most of the well-known sealing mechanisms being likely to occur in certain parts of the Egga RU:

1. Disaggregation zones: early faults, which have not been reactivated, fault rock permeability not significantly reduced, compared to host rock permeability.

2. Clay smear: lower parts of fault planes, increased shale in the Egga Reservoir Unit, strong effect on permeability of fault zone, frequent occurrence.

3. Phyllosilicate framework rocks, where shale-bearing Egga sandstones (G-sands) have been offset, moderate to strong effect on permeability of fault zone, frequent occurrence.

4. Cementation: reactivated faults, moderate to strong effect on permeability of fault zone, rare occurrence.

5. Cataclasis: reactivated faults and zones of late deformation, moderate to strong effect on permeability of fault zone, rare or absent.

6. Clay injection: early faults (uncertain occurrence).

Filling observations

The basis for understanding of the reservoir fluid distribution is a combination of pressure measurements from wells, and flat spot interpretations from the seismic data:

- A common gas gradient has been observed in all

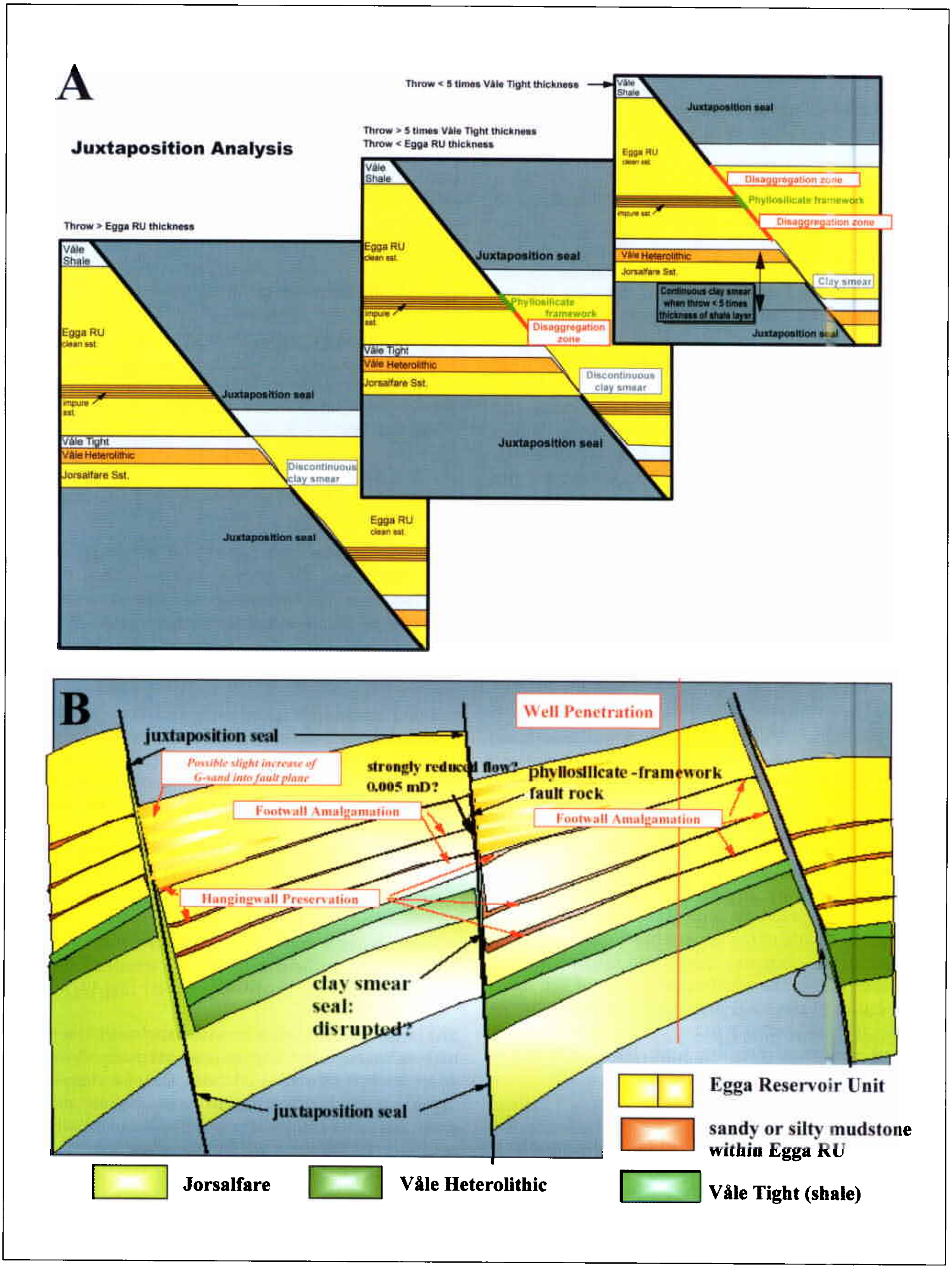

Fig. 13. A) Fault rock distribution within the Ormen Lange reservoir rocks for various throws, B) Model for the increased amalgamation frequency in the upthrown vs. downthrown parts of fault blocks, which may result in underestimation of clay smear potential, if based on well observations.

wells. Two of the wells have interpreted free water levels: Well 6305/7-1 at 2913 m MSL and well 6305/8-1 at 2898.6 m MSL.

- A thin oil leg (app. 2m) has been penetrated in well 6305/8-1. No oil has been seen in any of the other wells.
- The wells 6305/4-1 and 6305/5-1 have gas down to situations (GDT).
- Isolated water-filled and over-pressured sands are observed in the lowermost part of the Egga RU and below in 6305/4-1 and in Jorsalfare in 6305/5-1.

The well database documents a complex reservoir fluid distribution, particularly for the northern, shallower parts of the reservoir, but does not yet allow a precise prediction of the filling situation in undrilled areas. Generally the Egga RU is expected to be hydrocarbon-bearing to the depth of the flatspot, except for the possible occurrence of local isolated water-filled sandstones. Such sandstones are seen in well 6305/4-1 but are not expected to occur in more central parts of the field, corresponding to the axial parts of the turbidite receiving palaeo-basin. In flank areas they are more likely to occur, particularly close to the northwestern field boundary. Generally the occurrence of such isolated sands is expected to be limited to the lowermost parts of the Egga RU. Based on present evidence from appraisal wells the in place volume of oil is expected to be negligibly low.

High water saturations are encountered in the northern appraisal wells in the lowermost part of the Egga Reservoir Unit. In well 6305/4-1 an isolated, water-bearing sand has even been encountered in this part of the main reservoir. This is thought to be an indirect effect of basin asymmetry during the early depositional history of this reservoir unit (Fig. 8), leaving the north-western parts of the fan in a more distal position. This way higher contents of shale and interstitial mud were preserved in the northwestern part of the field. The isolation of the basal Egga Member sandstones in 6305/4-1 is most likely due to the combined effect of an extensive mudstone interlayer and clay smears in the lower parts of the adjacent fault planes.

For the reservoir units below the Våle Tight the situation is different, due to their higher shale content. Faults with 20-50 m throw are expected to compartmentalize these units due to the likely development of continuous clay smears (Fig. 13). This means that the amount of reservoir fluid in these units is impossible to predict for undrilled compartments. Generally, migration to these sections seems more difficult, at least for the shallower flank compartments.

However, due to the most likely vertical gas migration, as well as the local communication between sands in the Våle Heterolithic and Jorsalfare RU and the Egga RU, across faults with larger throws, (Fig. 13) a hydrocarbon filling of such compartments is possible.

The fact that the Våle Heterolithic (Fig. 4) Reservoir Unit is water-filled in well 6305/4-1 significantly complicates the estimation of in place resources. One, or a combination of the following, probably cause the lack of communication observed in this well:

- Statically sealing parts of fault planes
- Stratigraphically isolated sands
- Stratigraphic, fault related dips and inter-bedding of sand and shale, where gas has not been able to displace perched water.

Uncertainties

Uncertainties are associated with all steps of this evaluation from the seismic interpretation, through well-log and sedimentological interpretations to estimates of in place hydrocarbon volumes. However, for the Ormen Lange field these uncertainties are constrained by the following observations:

- Good seismic hydrocarbon indications over a large area, which have been confirmed by widely spread appraisal wells
- A thick development of the Lower Paleocene isochore
- High quality Lower Paleocene reservoir sections penetrated in all four wells in the DHI area, even in distal positions
- Pressure data and production tests indicating full static and sufficient dynamic communication in most parts of the gas-filled reservoir (Fig.14).

The largest uncertainties are associated with 1) with the rock volumes, which are situated vertically above free water levels (sensitive to uncertainties of a complicated depth conversion), particularly where these underlie steep scarps of the present sea floor, and 2) with the reservoir development in thinner, distal and marginal parts of the gas-filled turbidite fan.

Some uncertainty is related to the reservoir quality in the present saddle area (Fig. 3 and Fig. 10), which is characterized by a thinner development of the Paleocene isochore and a slightly shallower flatspot indication. There is a chance that this area formed a

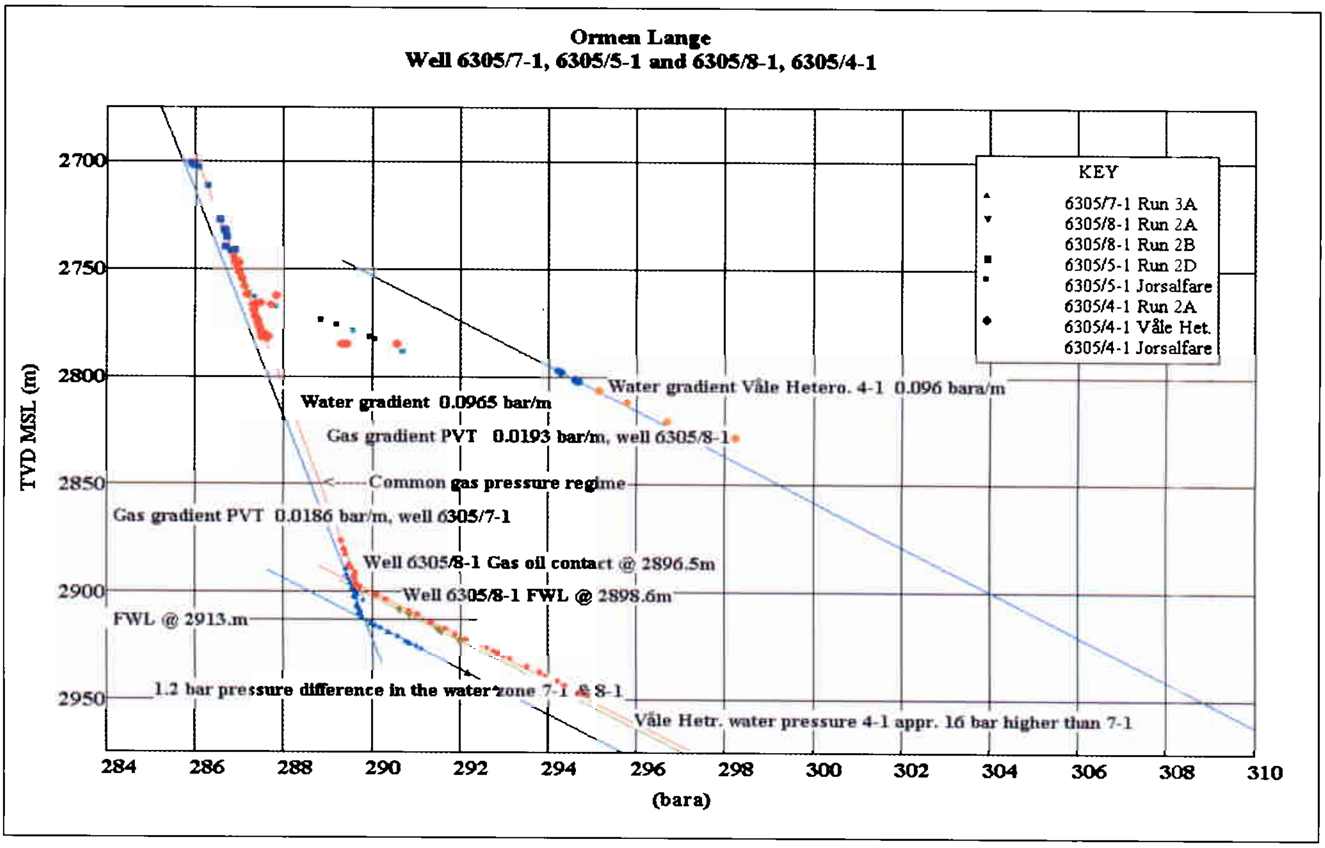

Fig. 14. Pressure information from all reservoir units. The data show that static communication most probably exists in the gas zone through major parts of the Egga Reservoir Unit.

palaeo-topographic high during deposition of the reservoir turbidites. In this case the thinner development could either indicate a late stage, sand-dominated deposition or accumulation of more clay-rich bioturbated facies, similar to the sequence seen in well 6305/1-1T2. The latter scenario would have negative consequences for the fault seal potential in this area. Similar reasoning applies to the northernmost, narrower part of the DHI area (Fig. 3 and Fig. 10).

Discussion

The strongly sandstone-dominated developments of the Lower Paleocene sections, penetrated by four widely spread appraisal wells, containing gas columns of up to 50 m, inspire confidence regarding the presence of large gas volumes. Further support comes from the clear hydrocarbon indications on the seismic data.

However, the commerciality of a complicated deep-sea development critically demands large parts of in place hydrocarbons to be recoverable over comparatively short time periods.

A good description of the reservoir architecture, representing the closest possible approximation to real conditions, is therefore imperative for a successful field development. The presence of numerous faults at all scales, in combination with the heterolithic developments seen in lower parts of the penetrated reservoir sections, therefore, represents risk elements, potentially causing future complications.

The same applies to the presence of water-filled sandstones occurring more than 100 m above penetrated free water levels. These have been observed in shallow and more marginal parts of the field.

Based on the presently available data exact predictions of local dynamic fault behaviour and/or local scale reservoir fluid distributions are not yet possible. Work on improvements of data quality as well as improvements of analysis and prediction methodology should therefore be continued, in order to optimally use the time before production start. But even exploiting the whole potential of such work, considerable geological uncertainties are expected to remain, even after gas production from the Ormen Lange Field is finished.

The main present challenge of reservoir geology in the Ormen Lange project is thus to ensure that the geological uncertainties are optimally accounted for in the further development, including the planning of production wells, production monitoring, contingency planning and a carefully controlled, stepwise and flexible hydrocarbon recovery.

Conclusions

The high reservoir quality and large volumes of gas for major parts of the Lower Paleocene Egga Reservoir Unit of the Ormen Lange structure are confirmed by all geological evaluations carried out at this stage. The latest update of the uncertainty analysis, based on new and improved seismic data and quantifications done by advanced digital 3D reservoir modelling, supports the robustness of the volume estimates of gas in place for the Egga RU. The other reservoir units are more heterogeneous and therefore subject to static compartmentalization and regular, patchy hydrocarbon distributions, which have defied all attempts so far of accurate quantification.

Dynamic fault sealing is considered to be the most critical geological factor for field development, although it is not expected to represent a serious problem in the central area and in upper parts of the main gas reservoir. A production test in well 6305/4-1 indicated dynamic baffling at certain fault segments and a number of observations indicate that static fault sealing occurs in lower zones and marginal parts of the Ormen Lange reservoir. This means that the development scenario for the Ormen Lange field has to include contingency for the risk of sealing faults and compartmentalization.

The estimation of fault sealing potential is complicated by the enormous size and complexity of the database and by the fact that scientific knowledge about polygonal fault systems is still poor. However, the strong degree of lateral segmentation and throw variation along each individual fault, as well as the early and shallow activity of this type of deformation, are all considered positive factors, reducing the overall uncertainty of fault transmissibility. Still an improved understanding of the dynamic effects of reservoir faults is critical for optimising the field development strategy and can only be achieved by careful acquisition and evaluation of future well and production data.

A strong relationship is expected to exist between fault sealing potentials and reservoir quality. The uncertainty of reservoir quality thus may not be critical for volume estimates, but critically influences the prediction of gas recovery. A core through a fault, which juxtaposes high quality reservoir rocks on both sides, would help to calibrate the cross-fault flow properties assumed in the reservoir simulation model.

The Ormen Lange reservoir sandstones were deposited by a sand-rich turbidite fan system, which was confined within in a narrow N-S elongated, structurally controlled sub-basin. Due to the preferential preservation of the coarsest grained deposits of the most powerful suspension currents, the reservoir quality of the main Egga Reservoir Unit is likely to be good to excellent all through the present DHI area.

Acknowledgements: We are grateful to Per Kjærnes and Eirik Berg who encouraged and supported us through all phases of this evaluation. We also would like to acknowledge the support of the partnership on the Ormen Lange licences and their permission to publish this work. In particular we would like to thank J. Bang, L. Stuevold, R. den Oden,. C. Holter, J. Aune Tyssekvam, L. Arnesen, J. Rykkje, R.E. Midtbø, I. Bakken, M. Rider, R.G. Walker, C. Guargena, R. Smith, and M. Schneider for interesting discussions and contributions. J.P.G. Fenton, R.J. Davey and M. Weldon of Robertson Research International are acknowledged for the original biostratigraphic analyses. We also thank R. Ravnås, Ø. Birkjeland and S. D. Johnson for critical and constructive comments to the first draft.

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Appendix
Exploration history and database

The abbreviation NH is used for "Norsk Hydro" in the text below.

Exploration history

The Ormen Lange was initially assessed as an interesting gas prospect based on DHI indications such as flatspot, low frequency anomaly, AVO-effects along top reservoir and amplitude changes at the Top Vaale reflector, on 2D data in 1989. Since then five wells have been drilled on the Ormen Lange dome (Fig. 3).

Well 6305/5-1, was drilled by Norsk Hydro in 1997. This was the Ormen Lange gas discovery well with approximately 50 m high quality, gas-filled Egga sandstone. The well is located high on the structure and does not penetrate a Free Water Level (FWL), but has Gas Down To (GDT) situation with a gas-filled high quality Paleocene ("Egga") Reservoir Unit, a gas filled heterolithic Paleocene/Cretaceous Reservoir Unit and a gas filled heterolithic and partly cemented Late Maastrichtian ("Jorsalfare") Reservoir Unit. However, isolated water-filled sands with high reservoir quality were encountered within an over-pressured interval in the Jorsalfare Reservoir Unit.

Well 6305/7-1 (BP, 1998) penetrated a FWL at 2913 m MSL in the southern field area. A gas test proved good reservoir quality and no barriers to horizontal gas flow. A residual gas zone of 14.5 m was observed below the Free Water Level (FWL) as defined by pressure data.

Well 6305/1-1 (NH, 1998) was drilled north of the DHI outline close to the crest of the Ormen Lange dome. Only gas shows were observed in the Paleocene and the Cretaceous. The well penetrated bioturbated, muddy fine-grained sandstones with a few thin (< 0.5 m) coarser sand beds in the lower Paleocene (time equivalent to the Egga Reservoir Unit).

Well 6305/8-1 (NH 2000) is located immediately to the north of the structurally low 'Saddle Area'. It penetrated a Gas-Oil Contact at 2896.5 m MSL (FWL at 2898.5 m MSL) with a thin oil zone (approx. 2.0 m) and a 8.5 m zone of residual hydrocarbons below. The well proved gas and good reservoir quality in the Egga Reservoir Unit. The shallower gas water contact compared to 6305/7-1, indicates possible structural and stratigraphic base trapping of water along the flanks of the Ormen Lange structure. A successful MDT test sampled fresh formation water.

Well 6305/4-1 (NH 2002) is located approximately 4 km northwest of 5-1. The well penetrated the top of the Egga Reservoir Unit at 2744 m MSL with a GDT situation within the lowermost part of the Egga RU. A production test proved good reservoir quality and two or three barriers or baffles to horizontal gas flow. The test result showed faults to be more sealing than previously anticipated and had a direct influence on the well layout in the development concepts. The well succeeded in disproving a possible shallow dynamic aquifer, and supported the use of a seismic flat spot for mapping the gas water contact.

Database

An overview of the database for the Ormen Lange field is as follows:

- 4 wells (6305/4-1, 5-1, 7-1 and 8-1)
- Drill stem gas production tests in 7-1 and 4-1
- One additional well, 6305/1-1, drilled north of the gas field
- One merged seismic survey OL00M1 (Merged from NH9602R99 & BPH9602R98)
- PSDM reprocessed data based on the seismic survey NH9602 and OL02M01 including all derived data

The well data include:

- An almost complete suite of cores
- Full sets of log data
- SCAL experiments (rel. perm, pc and rock mechanics) in wells 7-1, 5-1 and 8-1
- DST fluid samples were taken in 7-1 and 4-1.
- MDT samples of the gas were taken in all wells.
- One successful water sample was taken in well 6305/8-1.