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A unified 3D pore pressure and lithology model for a structurally complex reservoir

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Summary

Throughout the Central North Sea Basin, pressures above normal hydrostatic values are frequently observed within all Mesozoic sequences. The distribution of pore pressure within these successions can be very complex due to the complicated structural evolution including rift and salt movement deformations, large fluctuations in the sea level, more recent glacial events, and the presence of non-siliciclastic rocks and kerogen-rich hydrocarbon source rocks.

This paper presents and discusses a modified approach for the estimation of pore pressure using Eaton's method (Eaton, 1972), in which a predictive model of pore pressure is first calculated at wells. This relationship makes use of the total vertical stress (overburden stress), the normal hydrostatic pressure, the ratio of measured velocity to the expected value from the normal compaction trend, and an empirical constant which helps to calibrate the prediction results with direct pressure measurements. The pore pressure prediction model was then applied to estimate the pore pressure distribution using results from simultaneous inversion of 3D seismic data. We integrated the pressure field with a detailed structural and lithological model to evaluate the reservoir connectivity and the complex relationship between pressures, lithology and porosity distribution, structural framework, and fault geometry and sealing properties.

Geological background

At the Volve oil field in Central North Sea, rapid sedimentation and burial during the Cenozoic has caused the accumulation of a thick sedimentary cover over the Mesozoic sequences. These sequences are structurally complicated, mainly because of the complex deformations occurring in the Viking Graben during the mid-Jurassic to early Cretaceous extension (Figure 1). Even though the field was decommissioned in 2016, an improved understanding of the three-dimensional pore pressure distribution within the field structural framework and how it relates to trap integrity and distribution of hydrocarbons could be very important in the discovery and evaluation of other fields in areas with similar tectonic evolution.

The field consists of structural traps with hydrocarbon accumulations within the Jurassic Hugin Formation (Statoil, 1993). The reservoir is complicated on two different levels: first, by the configuration of faults with complicated genetic history, affecting the Triassic and Jurassic formations, and second, by the rapid lateral variation of reservoir thickness. Because the reservoir is compartmentalized by faulting, the spatial distribution of pore fluid pressure is very important because it carries information about the interconnectivity of the pore space and fluid flow within the reservoir. If the reservoir blocks are confined, fluid pressure can be either hydrostatic or abnormally high or low. The pressure will affect the rock properties, the amount of hydrocarbons in each fault-bounded block, and the possible reactivation of existing faults. These considerations can determine how each distinct compartment is produced and can drive well designs including placement, casing, or drilling-fluid weight in order to minimize drilling and completion risks (Zoback, 2015).

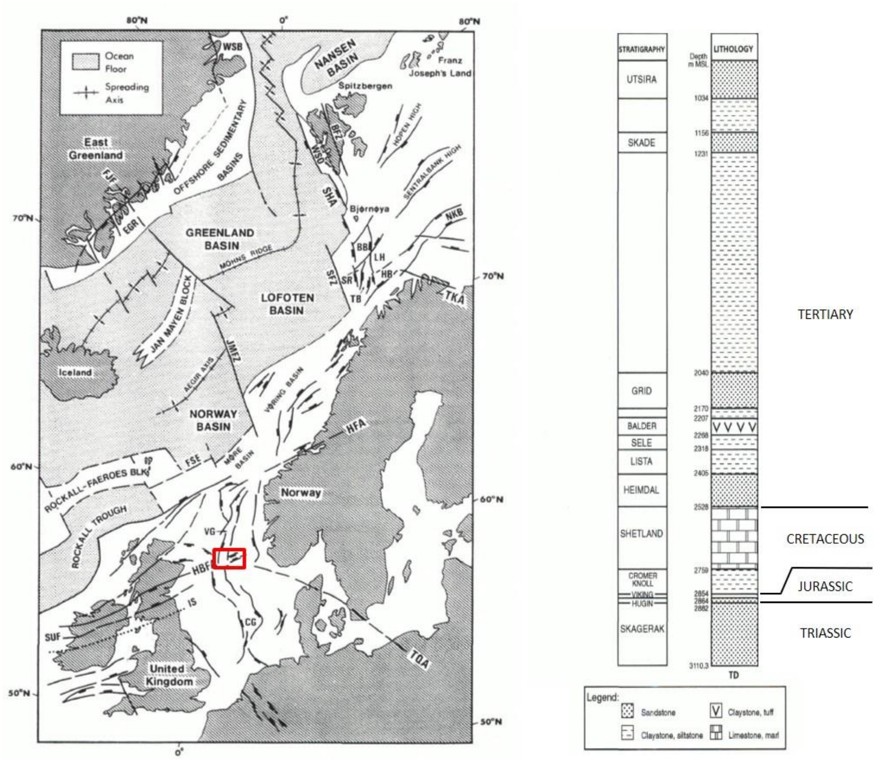

Figure 1 *North Sea regional structural map and lithostratigraphy (from Discovery evaluation Well 15/9-19 SR, Theta Vest Structure, 1993; Gage and Dore, 1987, modified). Volve field is shown in red rectangle.*

TQA – Tornquist Alignment, CG – Central Graben, HBFA – Highland Boundary Fault Alignment, VG – Viking Graben.

Analysis and modelling of pore pressure

Within the study area, the Jurassic reservoir and caprock pair is buried under a thick sequence of approximately 2500 m of Tertiary clastics and 400 m of Cretaceous carbonates. Direct downhole measurements of formation pressures were available at 14 locations throughout the field, the majority from the producing Hugin Formation, but also in the surrounding formations (Figure 2).

To model and match the measured pore pressures at wells, we used velocities from sonic data and the estimated magnitudes of the total vertical stress from density logs. The vertical stress was corrected for water depth and normal hydrostatic pressure, which was in turn adjusted for geothermal gradient and pressure. We applied a modified Eaton's method, with three separate normal compaction trends assumed for the Tertiary, Cretaceous and Jurassic sequences, and derived Eaton's exponent to fit the original pressure data. Using a non-unique compaction-induced trend permitted to account for changes in velocity with the mineralogical composition, and for potential differences in pressure mechanisms below the shallow, newer sediments.

The normal compaction trend within the shallow clastics was interpreted using the velocities measured in the predominantly shale intervals at 4 wells above the Ty sandstone. Using this trend to estimate the pore pressures in the Cretaceous carbonates below this interval would predict abnormally low values, in contradiction with the measured pressures which are generally above hydrostatic. For this subsequent zone, we used a normal velocity-depth trend introduced by Japsen (1998), who suggested that the dominant mechanism for the observed overpressure within carbonates is mechanical and consists of the preferential collapse of the larger pores. The

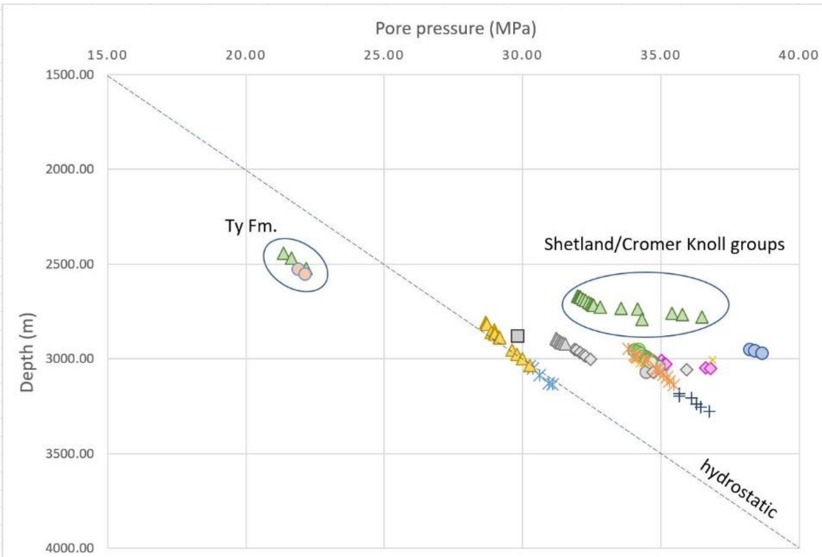

Figure 2 *Pore pressure measurements at 14 wells from Volve field, showing lower than hydrostatic values within the Ty Formation, and increased overpressure with depth within the Cretaceous limestones. Within the caprock and reservoir, two wells have hydrostatic pressures, and four wells show rapid increase of pore pressure with depth. Blue line indicates the hydrostatic pore pressure gradient.*

trend was obtained from data covering the entire lateral extent and depth range of the Chalk Group across the North Sea (the equivalent of the Shetland Group from the Norwegian sector).

For the deeper clastics, including the reservoir, the normal trend was a shift of the carbonates normal trend line with the intercept chosen based on the velocity measured at the base of the carbonates, as suggested by Weakley (1991) and Bowers (1995). The exponent in the Eaton's equation that best predicted the measured pressures was determined to be one in all three cases.

The total vertical stress was estimated by integrating the rock densities over depth and corrected for water depth. The normal hydrostatic pressure was determined using the density of the saline water, corrected in depth for the local pressure and temperature conditions using the Batzle-Wang equations for fluid density (Batzle and Wang, 1992).

The formation pore pressure was estimated within the 3D volume using the prediction model obtained at the wells and the density and velocity volumes obtained from the simultaneous AVO inversion of seismic data. To evaluate the pore pressure regimes and the amount of overpressuring we estimated the total and effective vertical stresses, and the ratio of pore pressure to overburden stress (λ_P).

Results and discussion on pore pressure, lithology distribution and reservoir compartmentalization

The estimated pore pressure and overburden stress were integrated with reservoir properties obtained from simultaneous AVO inversion and log-to-core calibrations. Elastic properties, including density, Mu-Rho, VpVs Ratio, and P-impedance, were crossplotted to separate several lithologies. The most important distinctions were the two facies within the Cretaceous limestone formations, separating the limestones from the basal marl and claystone, and the two facies within the Jurassic deeper clastics, the silty claystone caprock, and the porous reservoir sandstone. The Jurassic clastics were further separated into low, medium, and high porosity ranges.

The lateral and vertical distribution of pressure regimes was delineated using the λ_P parameter. The vertical stratification of pore pressure shows that the younger Ty Formation has pressures 3-4 MPa lower than hydrostatic, while the Cretaceous limestones transition to pressures exceeding hydrostatic values by 6-9 MPa, indicating hydraulic disconnection from the overlying Ty Formation. The estimated average λ_P shows that the caprock has larger excess pressures than the reservoir, with the degree of overpressuring generally increasing from NE to SW. Within the Hugin Formation, pressures are generally at the hydrostatic/overpressure boundary (λ_P ~ 0.55), with preferential development of moderate overpressure (λ_P = 0.6) on the crest and southwestern flank of the structure (Figure 3).

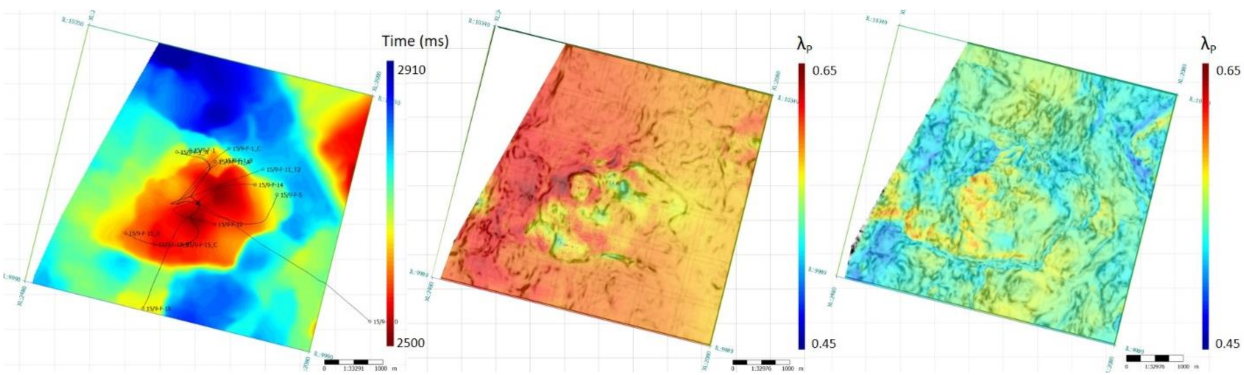

Figure 3 *Time structure map of the top of the Hugin Formation (left), and the average pore pressure to overburden stress ratio for the caprock (centre) and reservoir (right), co-rendered with the coherence attribute in grey scale. Warm colors above 0.55 on λ_P maps suggest pressures above hydrostatic values.*

The reservoir sands with a λ_P between 0.45 and below 0.55 were classified as hydrostatic. Figure 4 shows a cross-section through the lithology volume and a map view of the pressure regime distribution within the high porosity sands. The reservoir compartmentalization is suggested by the lateral extent of high-pressure anomalies which seems controlled primarily by faults. Small or no contrast between adjacent reservoir compartments indicates possible fluid flow between compartments, while higher pressure difference suggests sealing faults. There is no apparent preferential orientation of the sealing faults, although there are some overpressure/hydrostatic contacts with N-S orientation. Understanding the sealing conditions of each compartment is very important, as we see that hydrostatic pressures and high pressures can coexist at the same depth. Sands in the north and northeast areas seem to be in a hydrostatic regime (Figure 4, right), in agreement with the pore pressure measurements in Figure 2.

We propose a prediction model based on the combination of three compaction trends derived from several techniques: a normal velocity-depth trend for the shallow clastics sediments, determined from this field well data, a basin-wide trend for the carbonates incorporating all data from North Sea proposed by Japsen (1998), and a trend for the deeper clastics, which is a shift of the shallow clastics trend. Direct pressure measurements were then used to predict the pore pressure by varying the Eaton's exponent until the predicted results approximated the well pressure data.

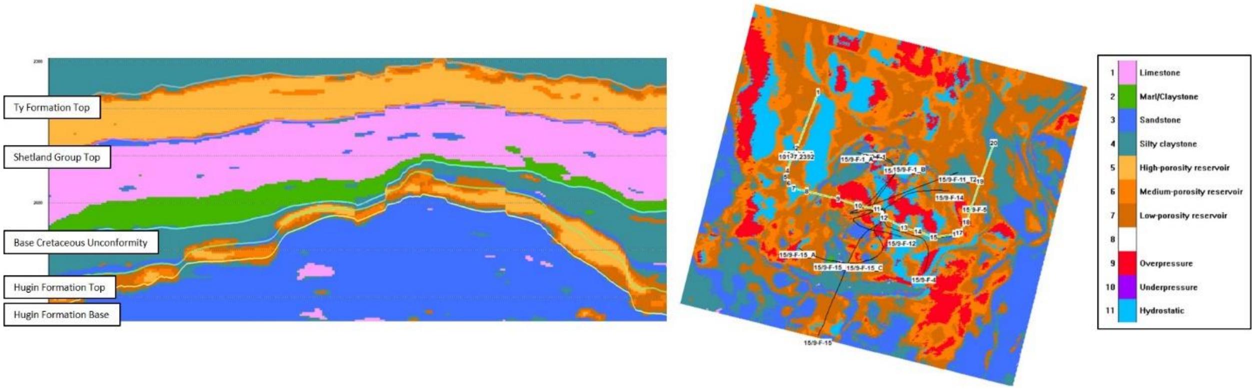

Figure 4 *Vertical section through lithology volume (left), and pore pressure compartmentalization within the Hugin high-porosity sands(right), showing the complex relationship between pore pressure, porosity and continuity of the sand body, and fault sealing properties. Green line indicated the cross-section trajectory.*

We feel that the obtained 3D pore pressure model is a good approximation of the complicated real pressure field of the area. Its integration with reservoir characterization, facies distribution, and the structural configuration provides a more unified view to better understand the pressure distribution and why the pressure is confined or transferred across faults or lithological boundaries. Understanding more about this interconnection between the pressure field and geological framework could offer a foundation for pressure prediction in other hydrocarbon fields in basins with similar evolution.

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